2023-27 POWERLINK QUEENSLAND REVENUE PROPOSAL

Project Pack – PUBLIC

CP.02369 Blackwater Transformers 1 and 2 Replacement

CP.02369 –Blackwater Transformers 1 and 2 Replacement

Project Status: Approved

1. Network Need

Blackwater Substation, approx. 68km east of Emerald, is a significant 132/66/11kV transmission substation in the central Queensland network with 132kV circuits to Lilyvale and Baralaba as well as connections to Aurizon and Ergon Energy. The substation contains two aged 132/66/11kV 80MVA transformers (T1 and T2), and a third 132/66/11kV 160MVA transformer which was installed in 2006. An outage on one of these transformers would leave up to 10MW and up to 175MWh of customer load per day at risk[6].

A Condition Assessment (CA) conducted in October 2018 identified that T1 and T2, which are both over 40 years old (commissioned in 1979), are approaching the end of their technical service life[1]. T1 and T2 are exhibiting the following end of life attributes: degraded oil and paper insulation, deteriorated cooling fans and radiators, significant oil leaks, reduced clamping pressure due to clamp design, loss of insulating paper strength, and limited availability of spares. The CA found that the condition of these assets should be addressed prior to 2022 to enable T1 and T2 to remain in service.

Network studies confirm there is an enduring need to maintain electricity supply from the Blackwater Substation. The removal or failure of T1 or T2 at Blackwater Substation would violate Powerlink's Transmission Authority reliability obligations (N-1-50MW/maximum 600MWh unserved energy)[2].

Further decline in T1 and T2 asset condition increases the risk of failure that may cause network outages, safety incidents and additional network costs to replace assets under emergency conditions. Failure to address the existing condition of this asset is likely to result in non-compliance with Powerlink's reliability and safety obligations[7].

2. Recommended Option

As this project is 'Approved', the project need and options have been assessed via a public Regulatory Investment Test for Transmission (RIT-T) consultation process[6].

The preferred option is to replace T1 and T2 132/66/11kV 80MVA transformers at Blackwater Substation with one new 160MVA transformer by 2022[4]. This option is preferred as it had the highest net economic benefit, minimises the number of outages and mobilisation costs, and reduces the overall future operational maintenance costs.

The following options were identified but not preferred:

- Do Nothing – rejected due to non-compliance with reliability standards and safety obligations.
- Life extension of the two at-risk 80MVA transformers by June 2022, followed by the replacement of both at-risk transformers with a single 160MVA transformer by June 2027.
- Replacement of both at-risk 80MVA transformers with two 100MVA transformers by June 2022.
- Non Network Option – No viable options were identified, and no public submissions were received through the RIT-T process.

Figure 2 1 below shows the preferred option reduces the forecast risk monetisation profile of Blackwater Substation T1 & T2 transformers by up to $200k per annum in 2022. 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 $400k per annum in 2028. This is predominantly network risks (unserved energy) and financial risk costs associated mostly with the replacement of failed assets in an emergency situation[6].

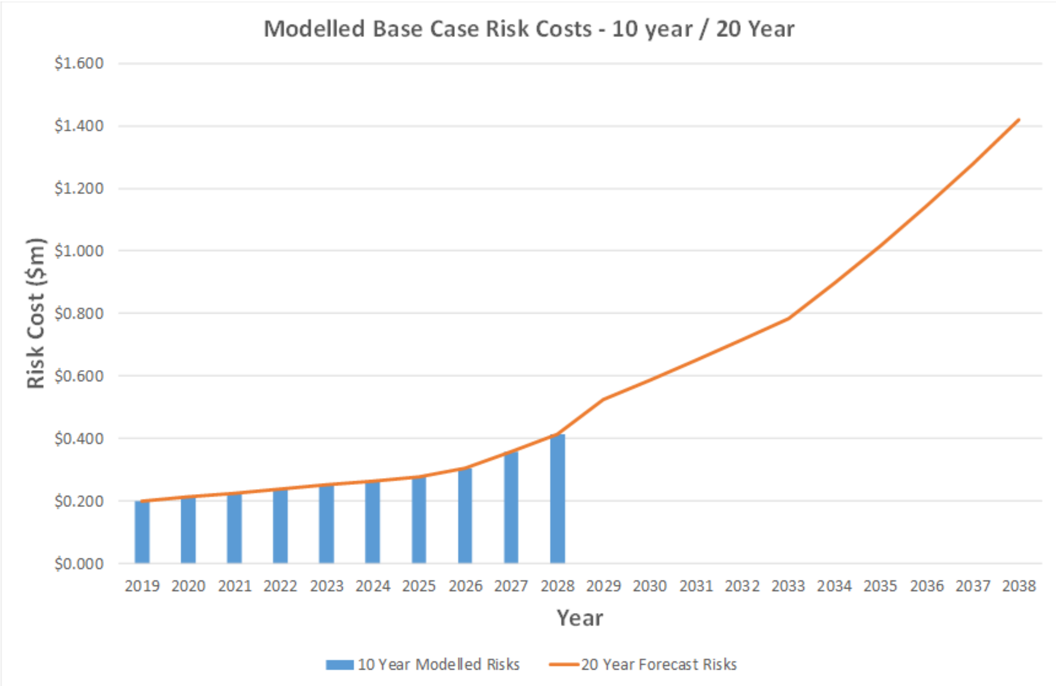

Figure 2-1 Annual Risk Monetisation Profile (Nominal)

3. Cost and Timing

The estimated cost to replace T1 and T2 with a single 160MVA transformer is $6.2m ($2018/19 Base)[5].

Target Commissioning Date: June 2022

4. Documents in CP.02369 Project Pack

Public Documents

1. Transformer T1 & T2 Condition Assessment T032 Blackwater Substation
2. Lilyvale 132/66kV Transformer and 132kV Bay Reinvestment, Blackwater 132/66kV Transformer Reinvestment – Planning Report
3. Base Case Risk and Maintenance Costs Summary Report T032 Blackwater No.1 & 2 Transformer Replacement
4. Project Scope Report CP.02369 T032 Blackwater No.1 & 2 Transformer Replacement
5. CP.02369 Blackwater Transformer 1T and 2T Replacement Project Management Plan
6. Project Assessment Conclusions Report: Maintaining reliability of supply in the Blackwater area

Supporting Documents

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

Transformer T1 & T2 Condition Assessment

T032 Blackwater Substation

Report requested by	[redacted]	**Requested Completion Date**	19/10/2018
Report Prepared by	[redacted]	**Date of site visit**	04/10/2018
AUTHOR/S	[redacted]		
Report Approved by	[redacted]	**Report Approval Date**	
Report Reviewed by	[redacted]	**Review Date**	
Issue Approved by	[redacted]	**Issue Date**	

Date	Version	Objective ID	Nature of Change	Author	Authorisation
29/07/2015	1.0	A2289888	Original		
08/01/2015	2.0	A2371191	Review	[redacted]	
30/11/2018	3.0	A3035481	Update	[redacted]	[redacted]

IMPORTANT - This condition assessment report provides an overview of the condition of power transformer/s (excluding internal transformer inspections) and high level indications of their residual reliable service life. As it is a snapshot in time and subject to the accuracy of the assessment methodology and ongoing in-service operating environment, the comments in this

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1. SUMMARY

Transformer T1 and T2 are a 40 year old General Electric design and in line with the requirements of AM-POL-0056, a condition assessment has been performed towards “end of life” including an on-site visual assessment combined with a desktop analysis of historical oil and insulation test data, maintenance history and through fault data history where available.

Although power transformer condition is monitored closely, the exact point of power transformer failure cannot be accurately predicted. As the consequences associated with catastrophic power transformer failure in electricity transmission are very high in terms of the financial costs, and potential loss of supply, impact on safety of personnel and public and on the environment (fire, gasses, oil disposal, etc.), the asset management strategy employed is to plan and execute replacement before the actual failure occurs.

This is done by assessing the condition of the major transformer components and estimating their end of life as well as that of the overall transformer. As the transformer systems and components deteriorate their probabilities of failure increase leading to an increased risk cost and decreased transformer availability. While component repair or replacement may be possible, in many cases they would provide very little or no benefit with regards to the transformer probability of failure. Typically repairs would have to be performed on a number of power transformer components, whilst the major internal components (insulation, core and mechanical enforcement of internal components) cannot be economically repaired.

No attempt has been made in this report to cover any detailed economic analysis of the viability of rectifying any highlighted issues associated with this transformer but it provides a condition assessment of the “key” parameters for the transformer and what may need to be actioned by Powerlink if in-service operation is to continue for a further 5 years and beyond.

A summary of the findings is shown in Table 1. This suggests that both transformers have an estimated reliable “as is” residual service life of about five (5) to eight (8) years even though the cellulose insulation in T1 appears to be marginally less aged by a couple of years. This is because of other expensive corrective actions that would be necessary on T1, no different to T2. To keep the transformers much beyond this would likely require significant expenditure on repairs which may not be economic due to the poor reliability of the internal active parts (the heart) of the transformers.

As a minimum and recommended approach, some routine maintenance would be required over the next few years to try and slow down existing oil leaks and fix localised corrosion in order to keep the transformers operational. This may include addressing additional radiator panel oil leaks which may develop where the oval radiator panel tubes enter the bottom radiator header and through the oval oil tube walls and header welds.

These transformers should be classified as having a low level of in-service reliability due to a range of factors, especially due to the condition of the winding insulation and the on-going mechanical stability of the active part.

Table 1 Summary of Estimated Residual Life of T1 and T2 "Key" Transformer Components

Parameter	Estimated Residual Life		Further Comments
	T1	T2	
Anti-corrosion system	10 years	10 years	Existing paint system for both T1 & T2 is in good condition. It is hiding corrosion problems in some locations.
Winding paper life	5 to 8 years	5 to 8 years	T1 calc average DP_V =319. Lowest DP_V = 260. T2 calc average DP_V =289. Lowest DP_V = 230.
Winding mechanical stability	Cannot be assessed accurately, but is questionable due to design and exposure.	Cannot be assessed accurately, but is questionable due to design and exposure.	Clamping structure considered to be weak. Old clamping structure design, lowering of DPv & repeated moisture exchange
External HV RBP bushings	3 to 5 years with increased risk	3 to 5 years with increased risk	All bushings are 40 years old in porcelain casings and have exceeded their expected service life
Insulating Oil	5 years	5 years	Oil processed when transformers were refurbished.
Radiators	3 to 5 years	3 to 5 years	Oval tubes / bottom header joints failing. Pin-hole oil leaks in shoulder welds of bottom header.
Repairs to leaking gaskets.	3 to 5 years	3 to 5 years	Significant oil leaks visible now.
OVERALL RESIDUAL LIFE	**5 years**	**5 years**	

2. INVESTIGATION

A comprehensive on-site inspection of T1 and T2 was performed on the 10th June 2015 and only the major findings which may impact the serviceability of these transformers and future cost of ownership are discussed in this report. For clarity, the Blackwater substation Operating Diagram is shown in figure 1.

[redacted]

Figure 1 T032 Blackwater Substation Operating Diagram with T1 and T2 identified.

Figure 2 T032 transformer T2 from the LV side.

2.1 Transformer T1 Identification Details

The general descriptive details for transformer T1 are shown below. A review of the system notifications for this transformer indicates that it was refurbished in April 2012 under OR.01131, which included a full repaint.

- General Electric Co. Rocklea, Brisbane manufacturer.
- Capricornia Regional Electricity Board Specification 1092 / 77
- YOM = January 1979 (36 years)
- Commissioned in 1979
- HV / LV = 40 / 50 / 80MVA ONAN / ODAN / ODAFF
- TV = 10 / 20MVA ONAN / ODAF
- 132 / 69 / 11 kV
- Serial No. A31J9385/2
- SAP No. 20006870
- Reinhausen Tap Changer Model 3Xm1501 110/B1019 3W Reversing.
- Tap Changer operations reading = 239,307

2.2 Transformer T1 On-site Inspection

2.2.1 Anti-corrosion System

More photographs of this transformer are shown in k/ Substation Photos / Blackwater / Site Visits / Transformer T1 & T2 & T7 Inspection on 11 June 2015.

This transformer has been repainted in 2012 under an OR.01131 project and the anti-corrosion coating still appears to be in a very good condition. As such, there is virtually no visible corrosion on the tank, cooler bank or fittings to report.
What is worth mentioning is the repainting tends to hide the "real" condition in some areas. The pre-paint preparation can in fact remove rust from certain areas which had been providing an oil seal up to that point. This was visible on some of the radiator panels and will be discussed further in clause 2.2.3, Oil Leaks.

2.2.2 Structural

There were no obvious signs of pending structural issues on the main tank or cooler bank due to corrosion. The cooler bank 'A'-frame support structure steel feet appeared externally to be in good condition but no assessment was performed on the hold-down bolts.

Figure 3 No visible corrosion evident around the cooler bank 'A'-frame support structure feet.

No evidence indicating any structural issues related to the condition of foundations or oil containment system was noted.

2.2.3 Oil Leaks

This transformer does have a welded steel strap bridging and sealing between lid and main tank flanges. Specially machined dome nuts and bolt heads which were designed with grooves to suit 'O'-rings replaced the original conventional clamping bolts to prevent oil from bypassing the outer steel welded strap oil seal. At the present time, there appears to be no oil leaks coming from this welded strap or dome nut seals.

Figure 4 Welded steel strap between main tank and lid, complete with 'O'-ring sealed dome nuts

Maintenance records for this transformer indicate that frequent attention has already been given to fixing oil leaks over the years and especially prior to repainting the transformer. A number of oil leaks have reappeared since the refurbishment / repainting and are coming from the following areas.

- Main Buchholz Relay.
- TV turret box gasket.
- Bottom main butterfly valve (not gate valve) adjacent to main tank.
- Neutral bushing mounting gasket.
- LV 'B' & 'C' phase bushing turret gaskets.
- HV 'B' phase bushing top cap.
- Radiator panel top mounting flanges.
- Radiator panel cooling tube / header interface.
- Radiator panel drain valves.
- Oil leaks in sealed secondary system junction boxes allowing oil to migrate downwards within the multicore cables to the Main Control Cubicle. The oil leaks within the junction boxes are not visible externally during the visual inspection from ground level.

The presence of oil was also noticed inside the Main Control Cubicle on the gland plate. The oil appears to be flowing through the sheath of at least one of the multicore cables which are connected to a junction box mounted higher up on the transformer.

Figure 5 (LHS) Oil leaks from TV turret box gasket. (RHS) Oil leak at top cap of HV 'B' phase bushing

Figure 6 (LHS) Oil leak from neutral bushing mounting gasket. (RHS) Free oil pooling on concrete due to neutral bushing mounting gasket oil leak.

Figure 7 (LHS) HV 'B'-Phase top cap oil leak. (RHS) Oil dropping on bottom header from top radiator panel mounting gaskets.

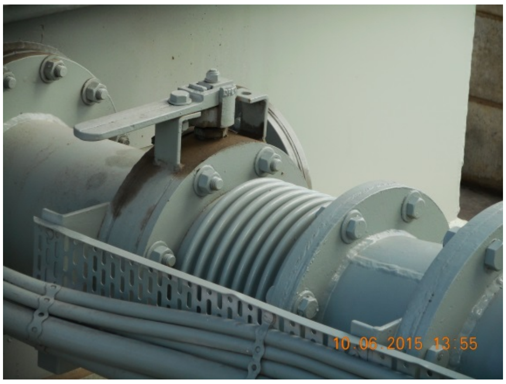


Figure 8 (LHS) Oil leak from bottom main butterfly valve (not gate valve) adjacent to main tank

Figure 9 (LHS) Oil leak from radiator panel cooling tube to bottom header joint. (RHS) Another similar oil leak between cooling tube to bottom header.

Figure 10 Oil leak from radiator panel drain valves fitted to the underside of the bottom header.

The transformer repaint covered up other potential oil leak sites but these will progressively become more visible with time. The cooler bank radiators are close to end of serviceable life so oil leaks will become more frequent. The pre-painting surface preparation process does not appear to have neutralised all of the pre-existing corrosion and this has still been active behind the new paint coating in some locations.

2.2.4 Secondary Systems

Any significant cable flexing (e.g. removal & reconnection) would likely create some insulation damage but if left physically alone, all of the multicore cables should not fail over the next several years.

Figure 11 Painted multicore cables entering the main control cubicle.

There were no obvious problems noticed in the Main Control Cubicle other than the “Pump Running” light does not illuminate when it should and the same for some of the “fans running” indication lights. These are considered to be minor faults since it is audiably obvious when either the oil pump or cooling fans are operating.

There have been issues with either the control or operation of the Reinhausen tap changer in the past, either stopping or falling out of step. With a total number of operations of 239,307, the tap changer is reaching the end of its reliable / economic life (life expectancy of approximately 300,000 operations). The high number of operations is attributed to the fact that there was interaction between Ergon SVC (controlling tap changer) and Powerlink owned SVC.

Figure 12 Reinhausen OLTC with a counter reading of 94,330 operations.

The top oil and winding hot spot temperature monitoring instruments were all readable and the indicated temperatures across all instruments appeared reasonable for the load at the time.

Figure 13 The three winding hot spot and one top oil temperature indicators are still readable through the viewing window.

Figure 14 The original Drycol refrigerant breather (now removed) control cubicle still mounted on the cooler bank support frame.

2.2.5 General Comments

A summary of the general items associated with this transformer are shown below.

When the original Drycol refrigerant breather was removed from the main conservator around the year 2000, a small diameter air pipe was installed between the main conservator and the replacement conventional desiccant breather. Refer to figure 15 for a visual arrangement.

GEC, the transformer manufacturer, designed the diameter of the main conservator air inlet / outlet pipe to the breather unit to handle a particular air mass flow rate considering reasonable rapid load changes which result in corresponding oil volume changes.

The relatively small diameter breather pipe installed when the Drycol unit was removed could result in either a negative or positive pressure build up within the transformer under significant and rapid changes in transformer loading.

The conservator breather pipe diameter should be equal to that of the original diameter used by GEC. The small pipe stubs still mounted on the end of the conservator where the Drycol use to be installed indicate the pipe size required.

The other aspect worth noting is that the home-made desiccant breather design which is installed on a number of Powerlink transformers in the Central / Northern regions while appearing very robust, does not allow a check of the desiccant at the top of the breather to confirm if there are any air leaks between the conservator and the breather. Also, it is also impossible to confirm the state of the oil bath at the bottom of the breather to ensure particles are being filtered out of the air during inhalation by the transformer.

Figure 15 The original Drycol refrigerant breather removed from the conservator and a new, small breather pipe installed to connect to the home-made desiccant breather.

The 20MVA tertiary of this transformer is being used for supplying the T10, 11kV / 400V station services transformer as well as Ergon external load. The connection to the transformer TV bushings and adjacent metering VT is aerial but with HV cables from that point. There are electrical clearance issues in this arrangement which are mitigated by the use of insulated tapes and shrouds as shown in figure 16.

Figure 16 The TV connections for supplying the station services transformer (not in this picture) and Ergon 11kV load. The metering VT is visible on the steel post structure.

The oil in this transformer has 0.45ppm PCB and is therefore classified as "non-Contaminated" (contaminated = 2mg/kg – 50mg/kg).

2.2.6 Oil and Insulation Assessment

A desktop assessment was performed using the full history of Oil & Insulation Testing Laboratory test data for this transformer.

Figure 17 The "home made" main conservator desiccant breather and oil bath.

As with many transformers inspected in the field, the condition of the oil bath on the bottom of the main conservator desiccant breather makes it very difficult to determine if the oil bath needs maintaining or is able to function correctly. This problem is made worse due to the design of the home-made breather. Figure 17 above shows what was observed on this transformer.

2.2.6.1 Oil Quality

From a review of the oil test data, its quality was fairly poor in terms of resistivity and after 40 years of service, its dielectric dissipation factor had also deteriorated making the oil more conductive.

The oil acidity appears to have remained fairly stable over its life and is still in relatively good condition.

The last measurement of dissolved PCB in oil for this transformer was in 2018 and showed a level of only 0.43ppm, well below the 2.0ppm level above which the oil has to be classified as “PCB contaminated”.

The moisture in oil / cellulose insulation will be discussed separately in clause 2.2.6.4.
Oil laboratory test data and SAP notifications do not show if this transformer oil has been passivated to inhibit the copper sulphide problem developing due to corrosive oil.

2.2.6.2 Winding Paper Quality

As expected, the dissolved furan level in oil will fluctuate depending on the transformer insulation operating environment and if the transformer internals and the oil have been subjected to vacuum treatment(s). As stated earlier, some allowances have been made in the calculations for the “real” dissolved furan level and the result is shown in figure 18. The average trend in the bulk cellulose insulation aging is shown by the red dotted line in this figure. Because of the more localised nature of the winding hot spots, when the dissolved furan generation from these higher temperature locations is averaged out in the total transformer oil volume, the hot spot contribution of furans is not easily distinguishable from that generated by the bulk insulation mass.

The dip in measured dissolved furan level in oil around the year 2012 was due to the transformer being refurbished and off line for a period of time.

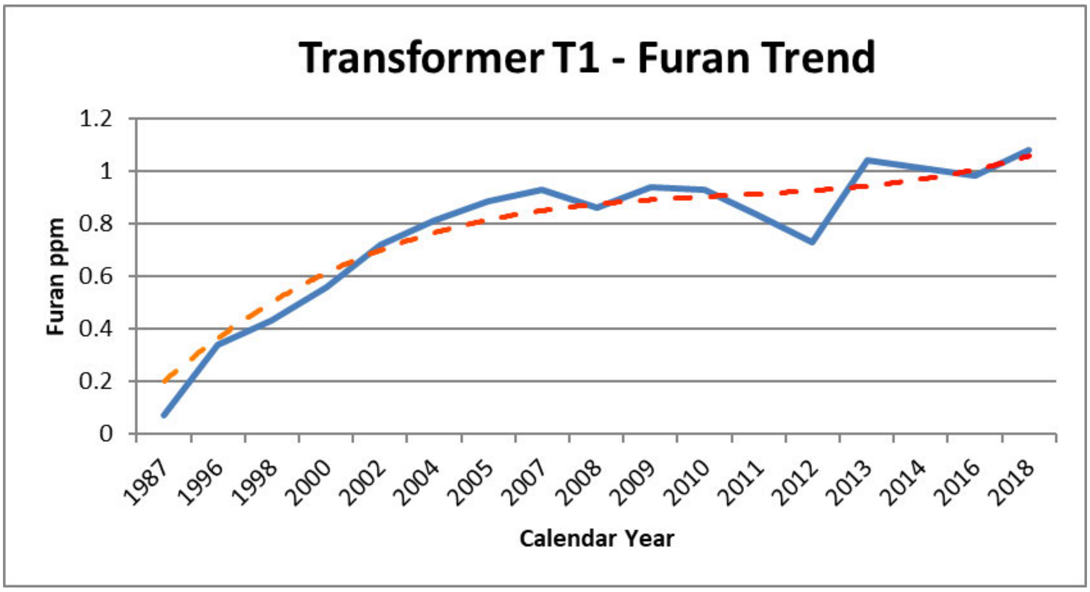


Figure 18 The dissolved furan in oil (ppm) has been plotted against sample date for T1.

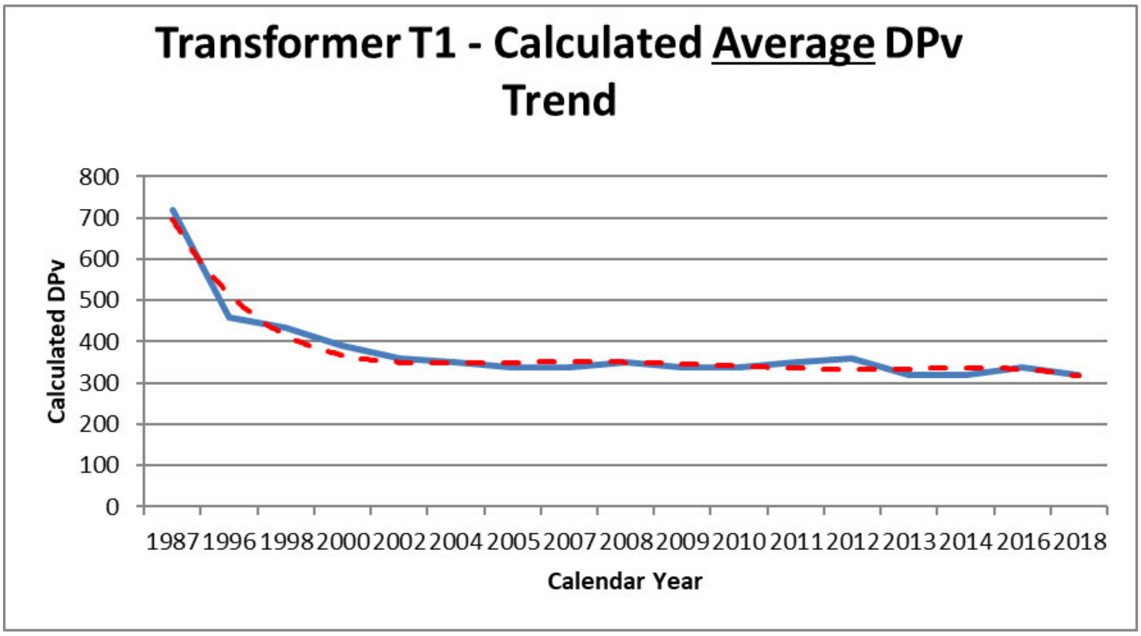


Figure 19 The bulk insulation average DP_v has been plotted against transformer age.

Now using the dissolved furan in oil data, the age of the bulk cellulose insulation can be calculated and is shown in figure 20. It is interesting because the correlation between dissolved furan in oil and insulation aging becomes more obvious when the graphs in figures 18, 19 & 20 are compared. Also, the shape of the insulation aging graph reflects how the transformer has been loaded over the years so where there is a noticeable change in aging rate, it is due to some change in loading event. For example,

- In 2006, the additional 160MVA transformer was commissioned at Blackwater substation which would have taken some of the load off the existing two GEC 80 MVA transformers.
- In 2012, the transformer appears to have been repainted so it would have been off line for a period of time. Then when T2 was repainted, T1 would have been operating at higher insulation temperatures.

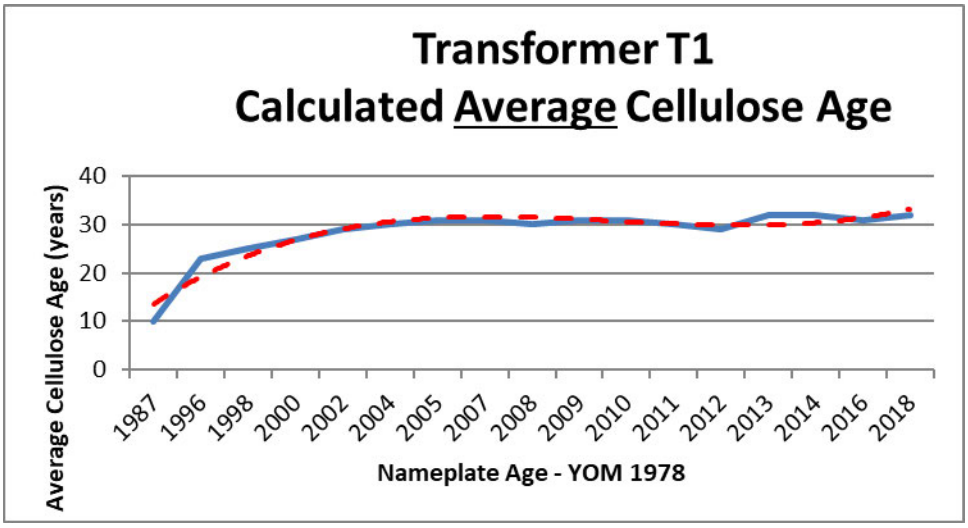


Figure 20 The calculated bulk insulation aging over the life of the transformer.

The <u>average</u> age of the bulk cellulose insulation system within the transformer is calculated to be approximately 32 years (DPv = 319) but with a more localised age of approximately

37 years (DPv = approx. 260). This suggests that the cellulose insulation in critical areas of the windings is reasonably close to end of reliable life for a transformer built in 1979 (40 years of age).

FOR CALCULATING INSULATION CHEMICAL AGE

Nameplate Age	40	Years	Expected Tx Life	40 Years
Furan in Oil	1.08	ppm		
Carbon Monoxide	727	ppm		
Carbon Dioxide	2430	ppm		
Degree of Polymerisation	260	DPv Aged Sample		
Degree of Polymerisation	1200	DPv Newly Commissioned		
	319	DPv Corrected for Oil Sample Temp		

CALCULATED INSULATION CHEMICAL AGE

FURAN	DPv	CO	CO2	
32	32	36	20	Years

Figure 21 Calculation of <u>AVERAGE</u> cellulose insulation age.

2.2.6.3 Dissolved Gas Analysis

As mentioned earlier in clause 2.2.6, this transformer is free breathing to atmosphere via a desiccant breather (previously a Drycol breather) and this is obvious when looking at the dissolved gas analysis (DGA) test data.

Apart from signs of the bulk insulation operating at elevated temperatures around 2005, the DGA up to the last oil sample dated March 2015 shows no emerging electrical or thermal issues. Loading and maintenance outages will directly impact the transformer dissolved gas generation and rate.

The only other point worth noting from the DGA is the apparent migration of dissolved gases from the OLTC diverter switches into the main tank oil. This is likely to be via two paths, one being through the diverter switch cylinder walls around contacts and the other via the common head space (only a partial oil partition) shared by the main tank conservator and the OLTC conservator. This is not a serious problem in itself however what it does do is mask emerging thermal issues / hot spots until the severity of the problem increases sufficiently to generate greater amounts of dissolved thermal fault gases which eventually will become visible above the background stray gases.

It is interesting to also note that when GEC designed this transformer for the Capricornia Regional Electricity Board (CREB), the transformer cooling modes were specified by CREB to be ONAN (40MVA), ONAF (52MVA) and ODAF (80MVA) for increasing winding / top oil temperatures. This means that fans were used to provide an additional 12 MVA prior to the oil pump being switched into service but as far as the windings are concerned, they are still operating in an ONAN mode but with a slightly lower average oil temperature. When cooling fans start on the cooler bank, they only lower the average oil temperature by a few degrees but the windings can still have up to about 20C temperature difference from the top to the bottom of the windings.

In comparison, when an oil pump starts, the forced and directed oil provides much greater winding cooling and reduces the temperature difference to about 2C from the top to the bottom of the windings. If the transformer load never increased above 65% nameplate rating, the pumps would probably not be used and the transformer internal cellulose insulation would age at a greater rate.

Figure 19 does show a greater insulation aging rate early in the transformer's life which tends to support this concept. This is also evidenced in the levels of dissolved carbon-oxide gases in the DGA test data and probably accounts for the rapid generation in dissolved furan levels early in the transformer's life. This was not as per QEGB policy (or Powerlink's policy at present) but in those days, CREB was responsible for specifying, purchasing, maintaining and operating this transformer as well as applying the temperature set points for fan and oil pump start.

2.2.6.4 Moisture in Insulation

When this transformer was designed and built, the insulation dryout methods were somewhat poor compared to the standards set by the vapour phase dryout systems used over the last 15 years or more and it was not uncommon to have relatively wet insulation (by today's standards) from new.

From the date of the first oil sample in 1981, the measured dissolved moisture in oil level appeared to progressively drop, perhaps due to the presence of the Drycol breather system fitted to this transformer up until the year 2000. The Drycol system continuously dried the air in the main conservator in direct contact with the oil, regardless of any conservator air exchange with the outside environment due to transformer load changes.

After this point in time, the moisture in oil measured level appeared to stabilise, apart from what appears like some erroneous data. This is reflected in figure 22 which shows a plot of the calculated percent by dry weight moisture in insulation over most of the transformer's life. The red dotted line in figure 22 is an attempt to compensate for any erroneous data errors.

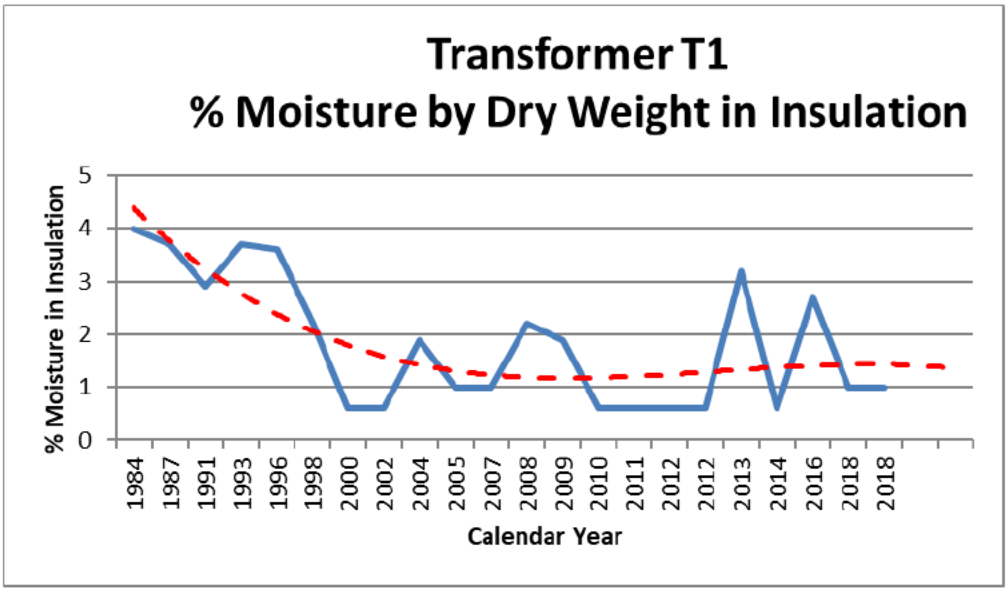


Figure 22 Calculated average of % moisture in insulation by dry weight.

So overall, the insulation system by today's standards is considered relatively dry. It is well below the 4% level beyond which can introduce risks of insulation failure under the right combination of specific operating / environmental conditions.

2.2.7 Estimated Residual Life of Transformer

Table 2 provides a quick summary of the estimated residual life of the "key" transformer components but there is further discussion on these aspects in clause 2.2.7.

Table 2 Summary of Estimated Residual Life of T1
"Key" Transformer Components

Parameter	Estimated Residual Life	Further Comments
Anti-corrosion system	10 years	Existing paint system is in good condition. It is hiding corrosion problems in some locations.
Winding paper life	5 to 8 years	Calculated average DP_V =319 Lowest DP_V = 260.
Winding mechanical stability	Cannot be assessed accurately, but is questionable due to design and exposure.	Old clamping structures design, lowering of DPv & moisture exchange.
External Micafil HV & LV bushings	Estimated 3 years with increased risk	Orginal SRBP bushings are included in a family which have exceeded the predicted design service life.
Insulating Oil	5 years	Oil processed when transformer was refurbished.
Radiators	1 to 3 years	Oval tubes / headers is the big problem area.
Repairs to leaking gaskets.	Required now	Cooler bank, main tank & HV 'B' phase top cap oil leaks.
Overall residual life	**5 years**	For as is condition.

2.2.7.1 Anti-corrosion System Life

It is obvious that due to the recent repainting of the transformer, the anti-corrosion coating is still in very good condition and should be capable of lasting a further 10 years.

It is worth noting that even though the cooler bank anti-corrosion coating is in very good condition, there is the underlying issue of oil leaks occurring on the radiator panels due to imbedded corrosion under the paint where the cooler tubes are welded to the top and bottom headers. This is a common weakness of this type of radiator panel design and no amount of painting will stop the inevitable. As such, the radiator panels have virtually reached end of life but may last a few more years provided oil leaks are addressed when they occur.

This may require replacement of panels with suitable recovered panels from other scrapped transformers (if available) or the removal of failed panels and blanking off the attachment flanges on the top and bottom cooler bank headers. However, considering the condition of other parts of this transformer, large dollar expenditure on extending the life of the cooler bank is not considered economic.

2.2.7.2 Insulation Life

<u>Winding Paper</u>
The calculated age/ mechanical condition of the winding paper suggest that it still has the potential to achieve another <u>conditional</u> 5 to 7 years of life.

<u>Insulating Oil</u>
The quality of the insulating oil is poor. There was a recommendation for an oil change in 2013 but the on-going oil test data does not suggest that the oil change occurred. It should be possible to achieve a further 5 years of service life from the insulating oil.

2.2.7.3 Mechanical Life

Even though the moisture in cellulose insulation appears to have remained relatively stable in its later life, it is very likely that it started at a higher level due to the less efficient insulation dry-out processes used when this transformer was manufacturer in 1979. This lowering of moisture in insulation level would cause some amount of insulation shrinkage.

Compounding this is the effect of moisture migration in and out of the cellulose insulation in the winding clamping structure due to changing loads over the years. This would have also caused some accumulative relaxation in the winding clamping pressure and make it less tolerant to through faults.

A third factor to consider is the continual loss of cellulose mass as evidenced by the decrease in average DP_V over the years, which also causes a relaxation in winding clamping pressure. A final concern is the clamping assembly design used on this transformer in the 1970's may not be considered appropriate by today's design standards.

In summary, due to these four factors, the residual life expectancy of the core and coils (active part) is considered to be 5 years.

2.2.7.4 Transformer Bushings

All bushings are original and Micafil SRBP design and the last test results are satisfactory. All bushings (high voltage, low voltage and neutral) have porcelain casings and can fail catastrophically resulting in significant safety consequence if personnel are present on site during failure. As they passed their service life with very limited data available re failures of bushings of this type and age, it is recommended to reduce safety risk exposure by replacing HV and LV bushings with dry type in polymer casing. Based on manufacturer data (Refer Figure 45) the service life of these type of bushings is 25 years.

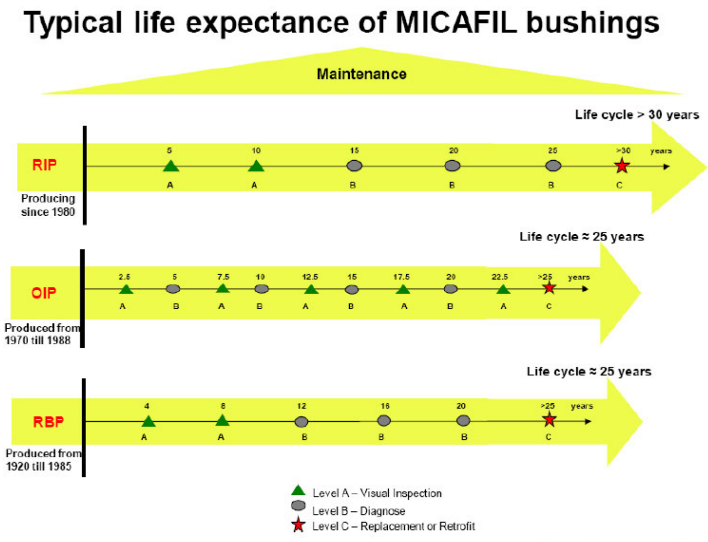


Figure 23 Bushing life expectancy provided by the bushing manufacturer.

3. CONCLUSIONS FOR TRANSFORMER T1

3.1 Condition Assessment

The following conclusions can be drawn from the condition assessment of the Blackwater T1 transformer.

3.1.1 Oil Leaks

Most of the oil leaks identified on site were of a minor nature following the transformer's refurbishment and do not require urgent attention except for what appeared to be the neutral bushing mounting gasket leak which is considered to be significant. Having said that, even though this significant neutral bushing oil leak should be fixed, there is the bigger issue associated with the existing and potential oil leaks from the cooler bank radiator panels. A broader economic view of the leak situation needs to be taken before deciding if the neutral bushing leak should be repaired because if Powerlink only wishes to have this transformer in service for another 3 to 5 years, it is not worth fixing the neutral bushing leak unless it worsens. This approach would be validated by the fact that the bulk cellulose insulation moisture content is still well down from the 4% region of concern and should not reach this level over 5 years with the existing oil leak rate from the neutral bushing gasket.

3.1.2 External Physical Condition

Due to having been repainted recently, the transformer's external condition is still very good in a general context but the repaint has hidden some potential issues which are now starting to reappear on the cooler bank. The cooler bank is going to become an on-going corrosion issue and is probably close to end of reliable life because it is virtually impossible to "fix" the corrosion which has been active for many years where the cooler bank radiator panel cooling tubes enter the top and bottom headers.

If the transformer is to be kept in service for only the next 3 to 5 years, there is no need for any major refurbishment / radiator replacement work. Performing a minor "band-aid" treatment of oil leaks when they appear, as part of routine maintenance, in order to keep the transformer / cooler bank serviceable over this period is recommended.

3.1.3 Insulation Residual Life

The winding paper insulation residual life is only considered to be a conditional 5 to 7 years.

3.1.4 Winding Mechanical Stability

The mechanical stability of the windings is unknown and based on the available data and knowledge it has a remaining life of 5 years.

3.1.5 Transformer Bushings

Considering the age of all HV and LV bushings combined with some oil leaks from the top caps, they should be receiving more frequent monitoring to avoid unscheduled outages or loss of transformer over the next 5 years.

3.2 Maintenance Going Forwards

The transformer has an assessed residual life expectancy of 5 years. To keep the transformers much beyond this would require a significant financial expenditure in the form of cooler bank replacement, likely replacement of HV and LV terminal bushings and perhaps some secondary system ancillary item replacement **BUT** this would do nothing to improve the low reliability of the internal active part (the heart) of the transformer.

Immediate action is to fix the neutral bushing gasket oil leak and address radiator panel oil leaks as they occur in order to assist in maintaining the transformer in a serviceable condition for the next 5 years.

4. Transformer T2 Identification Details

The general descriptive details for transformer T2 are shown below. A review of the system notifications for this transformer indicate that it was also refurbished in April 2012 under OR.01131, which included a full repaint.

- General Electric Co. Rocklea, Brisbane manufacturer.
- Capricornia Regional Electricity Board Specification 1092 / 77
- YOM = January 1979 (36 years)
- Commissioned in 1979
- HV / LV = 40 / 50 / 80MVA ONAN / ODAN / ODAFF
- TV = 10 / 20MVA ONAN / ODAF
- 132 / 69 / 11 kV
- Serial No. A31J9385/1
- SAP No. 20006871
- Reinhausen Tap Changer Model 3Xm1501 110/B1019 3W Reversing, Serial No. 84680.
- Tap Changer operations reading = 237,655

4.1 Transformer T2 On-site Inspection

4.1.1 Anti-corrosion System

More photographs of this transformer are shown in k/ Substation Photos / Blackwater / Site Visits / Transformer T1 & T2 & T7 Inspection on 11 June 2015.

This transformer has been recently repainted in 2012 and the anti-corrosion coating still appears to be in a very good condition. As such, there is virtually no visible corrosion on the tank and fittings but the cooler bank is showing localised corrosion (pin holes) on radiator panel bottom headers which has resulted in oil leaks.

Figure 24 Localised corrosion on the shoulder weld of radiator panel bottom headers now showing a pin hole oil leak.

Figure 25 Residual localised corrosion where the radiator panel oval cooling tubes penetrate the bottom headers is re-emerging through the new paint.

What is worth mentioning is the repainting tends to hide the “real” condition in some areas, as evidenced by figures 24 & 25. It takes time for residual corrosion to show itself through the new paint system if it is not fully removed by the pre-painting surface preparation process.

Also, the pre-painting surface preparation can in fact remove rust from certain areas which had been providing an oil seal up to that point. This was visible on some of the radiator panels and will be discussed further in clause 4.1.3, Oil Leaks.

4.1.2 Structural

There were no obvious signs of pending structural issues on the main tank or cooler bank due to corrosion. The main oil conservator support and cooler bank ‘A’-frame support structure steel feet appeared externally to be in good condition but no assessment was performed on the hold-down bolts.

Figure 26 No visible corrosion evident around the cooler bank ‘A’-frame support structure feet.

No evidence indicating any structural issues related to the condition of foundations or oil containment system was noted.

4.1.3 Oil Leaks

This transformer does have a welded steel strap bridging and sealing between lid and main tank flanges. Specially machined dome nuts and bolt heads which were designed with groves to suit 'O'-rings replaced the original conventional clamping bolts to prevent oil from bypassing the outer steel welded strap oil seal. At the present time, there appears to be no oil leaks coming from this welded strap or dome nut seals. The oil visible in figure 26 is from other sources.

Figure 27 Welded steel strap between main tank and lid, complete with 'O'-ring sealed dome nuts.

Maintenance records for this transformer indicate that frequent attention has already been given to fixing oil leaks over the years and especially prior to repainting the transformer. A number of oil leaks have reappeared since the refurbishment / repainting and are coming from the following areas.

- Main Buchholz Relay.
- TV turret box gasket.
- Bottom main butterfly valve (not gate valve) adjacent to main tank.
- Neutral bushing mounting gasket.
- LV 'A' & 'B' phase bushing turret gaskets.
- HV 'A' & 'B' phase bushing top cap.
- TV 'C' phase bushing mounting gasket.
- Radiator panel top mounting flanges.
- Radiator panel cooling tube / header interface.
- Radiator panel drain valves.
- Oil leaks in sealed secondary system junction boxes allowing oil to migrate downwards within the multicore cables to the Main Control Cubicle. The oil leaks within the junction boxes are not visible externally during the visual inspection from ground level.

The presence of oil was also noticed inside the Main Control Cubicle on the gland plate. The oil appears to be flowing through the sheath of at least one of the multicore cables which are connected to a junction box mounted higher up on the transformer.

Figure 28 (LHS) Oil leaks from TV turret box gasket. (RHS) Example of an oil leak at the bushing top cap observed on 4 bushings.

Figure 29 (LHS) Oil leak from neutral bushing mounting gasket. (RHS) Free oil pooling on concrete due to neutral bushing mounting gasket oil leak.

Figure 30 (LHS) HV side free oil on concrete. Appears to be coming from 'A' & 'B' phase HV bushing top cap oil leaks combined with oil from the multicore cables. (RHS) Oil dropping from top header radiator panel mounting gasket.

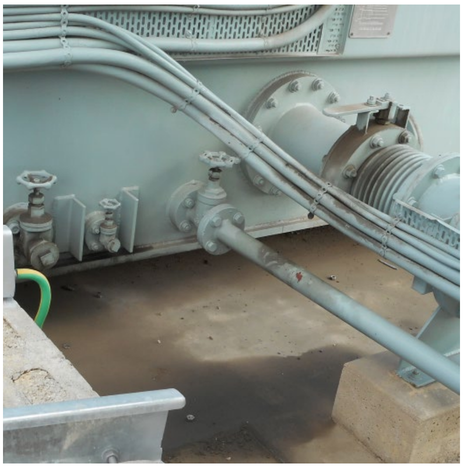


Figure 31 Oil leak from bottom main butterfly valve (not gate valve) adjacent to main tank

Figure 32 (LHS) Oil leak from radiator panel cooling tube to bottom header joint. (RHS) Another radiator panel oil leak on the lower shoulder weld seam of the bottom header. Note also the delaminating paint.

Figure 33 Oil leak from radiator panel drain valves fitted to the underside of the bottom header.

The transformer repaint covered up other potential oil leak sites but these will progressively become more visible with time. The cooler bank radiators are close to end of serviceable life so oil leaks will become more frequent. The pre-painting surface preparation process does not appear to have neutralised all of the pre-existing corrosion and this has still been active behind the new paint coating in some locations.

4.1.4 Secondary Systems

Control cables are sure to have taken a set and any significant cable flexing (e.g. removal & reconnection) would likely create some insulation damage but if left physically alone, all of the multicore cables should not fail over the next several years.

Figure 34 Painted multicore cables entering the main control cubicle.

There were no obvious problems noticed in the Main Control Cubicle other than oil ingress via multicore cable sheaths noticed on the cable gland plate. The remote end of these cables collect oil from leaking terminals within sealed junction boxes where there is oil ingress from within the transformer.

The notifications associated with this transformer show a number of issues with either the control or operation of the Reinhausen tap changer in 2001/2 and again in 2006-2009. With a total number of operations of 237,655, the tap changer is reaching the end of its reliable / economic life (life expectancy of approximately 300,000 operations).

Figure 35 Reinhausen OLTC with a counter reading of 94,330 operations.

The top oil and winding hot spot temperature monitoring instruments were all readable and the indicated temperatures across all instruments appeared reasonable for the load at the time.

Figure 36 The three winding hot spot and one top oil temperature indicators are still readable through the viewing window.

Figure 37 The original Drycol refrigerant breather (now removed) control cubicle still mounted on the cooler bank support frame.

4.1.5 General Comments

A summary of the general items associated with this transformer are shown below.

Similar to Transformer T1 When the original Drycol refrigerant breather was removed from the main conservator around the year 2000, a small diameter air pipe was installed between the main conservator and the replacement conventional desiccant breather. Refer to figure 37 for a visual arrangement.

Figure 38 The original Drycol refrigerant breather removed from the conservator and a new, small breather pipe installed to connect to the home-made desiccant breather.

4.1.6 Oil and Insulation Assessment

A desktop assessment was performed using the full history of Oil & Insulation Testing Laboratory test data for this transformer.

As with many transformers inspected in the field, the condition of the oil bath on the bottom of the main conservator desiccant breather makes it very difficult to determine if the oil bath needs maintaining or is able to function correctly. This problem is made worse due to the design of the home-made breather. Figure 39 shows what was observed on this transformer.

Figure 39 The “home made” main conservator desiccant breather and oil bath.

4.1.6.1 Oil Quality

From a review of the oil test data, by the time the transformer oil had been in service for about 20 years, its quality was slightly better than the oil quality in its sister transformer T1 in terms of “key” indicators but still not good. As time went by, the oil quality deterioration continued at a marginally faster rate than for its sister transformer T1.

The oil acidity is reasonable for a free breathing transformer of this age and has increased at a moderate rate over its life. The last measurement of dissolved PCB in oil for this transformer was in 2015 and showed a level of only 0.85 ppm, well below the 2.0ppm level above which the oil has to be classified as “PCB contaminated”.

The moisture in oil / cellulose insulation will be discussed separately in clause 4.2.6.4.
Oil laboratory test data and SAP notifications do not show if this transformer oil has been passivated to inhibit the copper sulphide problem developing due to corrosive oil.

4.1.6.2 Winding Paper Quality

As expected, the dissolved furan level in oil will fluctuate depending on the transformer insulation operating environment and if the transformer internals and the oil have been subjected to vacuum treatment(s). As stated earlier, some allowances have been made in the calculations for the “real” dissolved furan level (figure 40).

The average trend in the bulk cellulose insulation aging is shown by the red dotted line in this figure. Because of the more localised nature of the winding hot spots, when the dissolved furan generation from these higher temperature locations is averaged out in the total transformer oil volume, the hot spot contribution of furans is not easily distinguishable from that generated by the bulk insulation mass.

The dip in measured dissolved furan level in oil around the year 2012 was due to the transformer being refurbished and off line for a period of time.

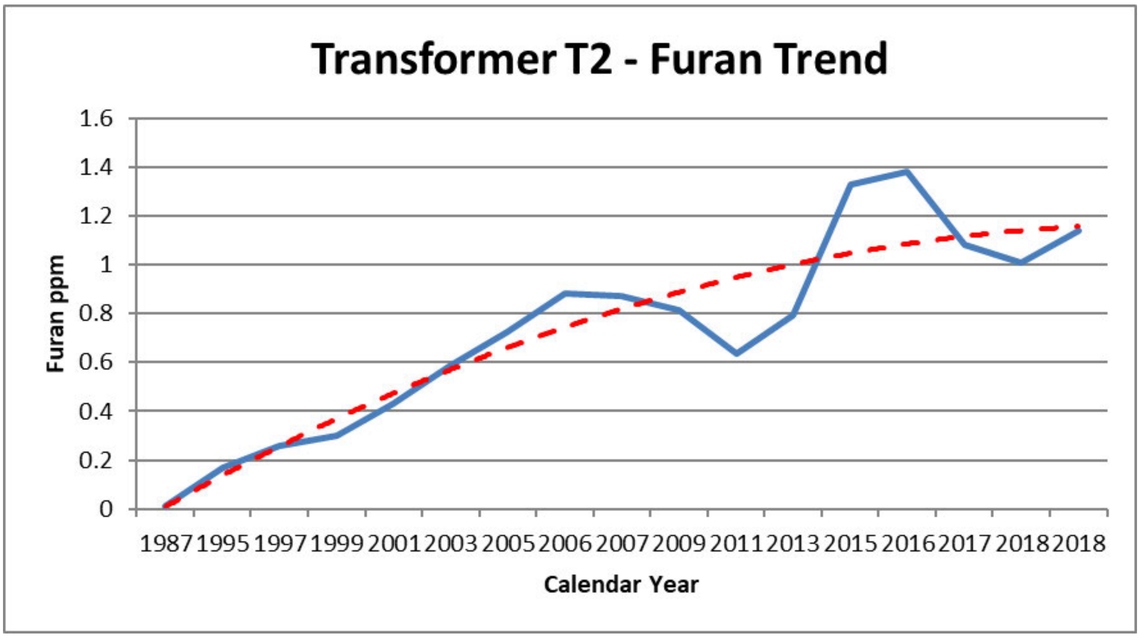


Figure 40 The dissolved furan in oil (ppm) has been plotted against sample date.

Now using the dissolved furan in oil data, the age of the bulk cellulose insulation can be calculated and is shown in figure 41. Also, the shape of the insulation aging graph reflects how the transformer has been loaded over the years so where there is a noticeable change in aging rate, it is due to some change in loading event. For example,

- In 2006/7, the additional 160MVA transformer was commissioned at Blackwater substation which would have taken some of the load off the existing two GEC 80 MVA transformers.

- In 2012, the transformer appears to have been repainted so it would have been off line for a period of time but when T1 was repainted, T2 would have been operating at higher insulation temperatures.

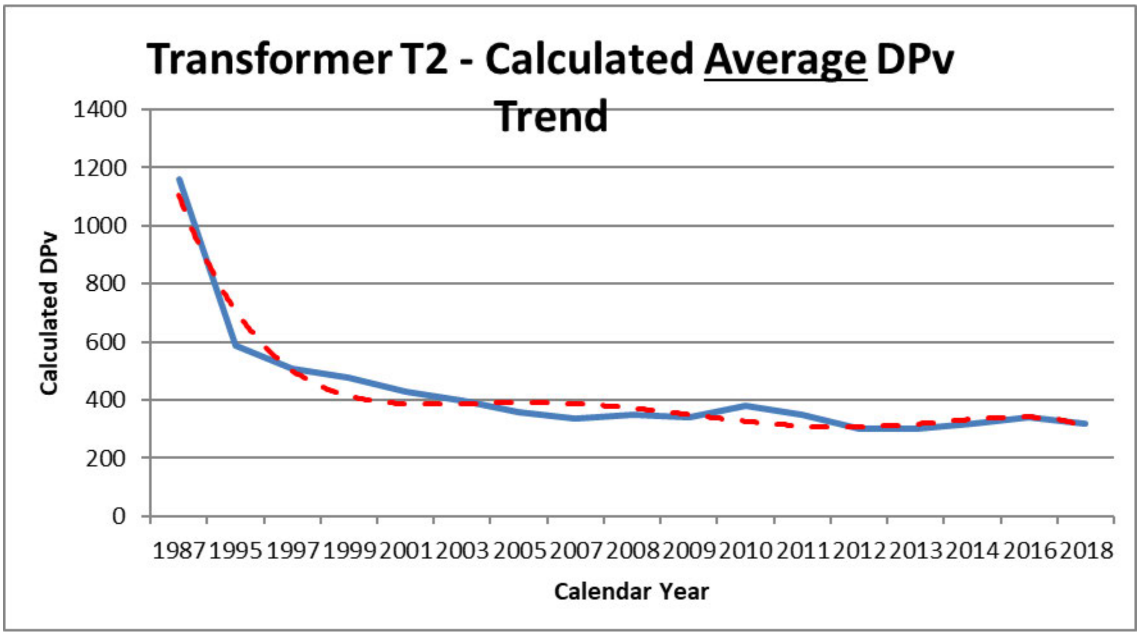


Figure 41 The bulk insulation average DP_v has been plotted against transformer age.

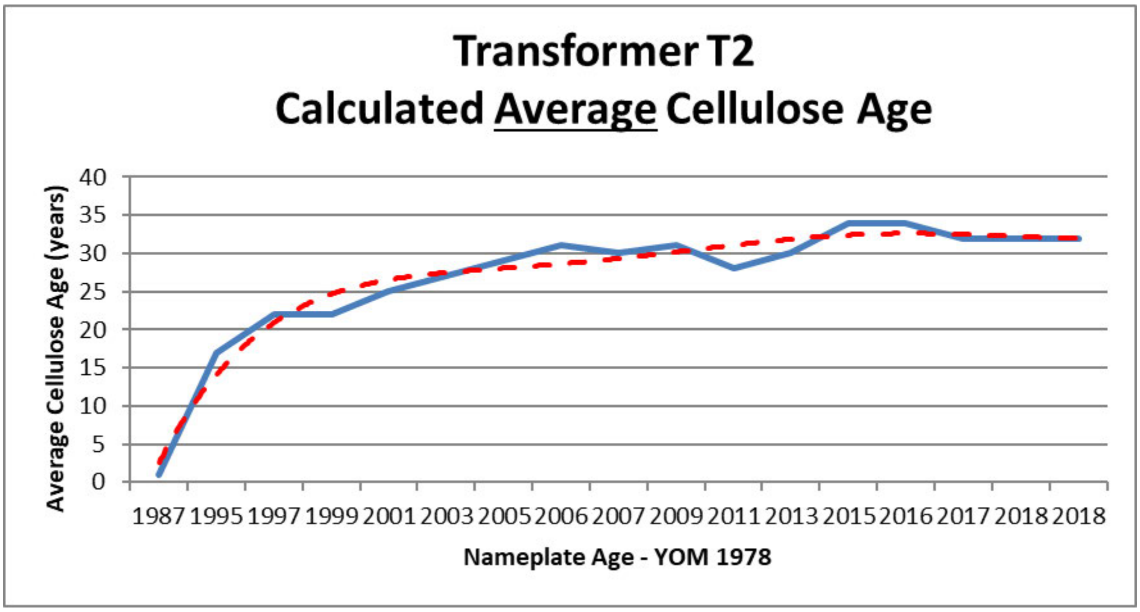


Figure 42 The calculated bulk insulation aging over the life of both transformer T1 and T2 at Blackwater.

The average age of the bulk cellulose insulation system within the transformer is calculated to be approximately 34 years (DPv = 290) but with a more localised age of approximately 40 years (DPv = approx. 230). This suggests that the cellulose insulation in critical areas of the windings has probably reached end of reliable life for a transformer built in 1979 (36 years of age). The insulation in this transformer appears to be more aged than for its sister unit, Blackwater T1, by only a couple of years.

FOR CALCULATING INSULATION CHEMICAL AGE

Nameplate Age	40	Years	Expected Tx Life	40	Years
Furan in Oil	1.38	ppm			
Carbon Monoxide	727	ppm			
Carbon Dioxide	2430	ppm			

Degree of Polymerisation	230	DPv Aged Sample
Degree of Polymerisation	1200	DPv Newly Commissioned
	289	DPv Corrected for Oil Sample Temp

CALCULATED INSULATION CHEMICAL AGE

FURAN	DPv	CO	CO2	
34	34	36	20	Years

Figure 43 Calculation of AVERAGE cellulose insulation age.

4.1.6.3 Dissolved Gas Analysis

As mentioned earlier in clause 2.2.6, this transformer is free breathing to atmosphere via a desiccant breather (previously a Drycol breather) and this is obvious when looking at the dissolved gas analysis (DGA) test data.

Apart from signs that the bulk insulation was operating at higher temperatures around 2005/2006, the DGA up to the last oil sample dated October 2018 shows no emerging electrical or thermal issues. Loading and maintenance outages will directly impact the transformer dissolved gas generation and rate.

The only other point worth noting from the DGA is the apparent migration of dissolved gases from the OLTC diverter switches into the main tank oil. This is likely to be via two paths, one being through the diverter switch cylinder walls around contacts and the other via the common head space (only a partial oil partition) shared by the main tank conservator and the OLTC conservator.

It is interesting to also note that when GEC designed this transformer for the Capricornia Regional Electricity Board (CREB), the transformer cooling modes were specified by CREB to be ONAN (40MVA), ONAF (52MVA) and OFDAF (80MVA) for increasing winding / top oil temperatures. This means that fans were used to provide an additional 12 MVA prior to the oil pump being switched into service but as far as the windings are concerned, they are still operating in an ONAN mode but with a slightly lower average oil temperature. When cooling fans start on the cooler bank, they only lower the average oil temperature by a few degrees but the windings can still have up to about 20C temperature difference from the top to the bottom of the windings.

In comparison, when an oil pump starts, the forced and directed oil provides much greater winding cooling and reduces the temperature difference to about 2C from the top to the bottom of the windings. If the transformer load never increased above 65% nameplate rating, the pumps would probably not be used and the transformer internal cellulose insulation would age at a greater rate.

Figure 42 does show a greater insulation aging rate early in the transformer's life which tends to support this concept. This is also evidenced in the levels of dissolved carbon-oxide gases in the DGA test data and probably accounts for the rapid generation in dissolved furan levels early in the transformer's life.

4.1.6.4 Moisture in Insulation

When this transformer was designed and built, the insulation dry-out methods were somewhat poor compared to the standards set by the vapour phase dryout systems used over the last 15 years or more and it was not uncommon to have relatively wet insulation (by today's standards) from new.

From the date of the first oil sample in 1981, the measured dissolved moisture in oil level appeared to progressively drop, perhaps due to the presence of the Drycol breather system fitted to this transformer up until the year 2000. This is reflected in figure 44 which shows a plot of the calculated percent by dry weight moisture in insulation over most of the transformer's life. The red dotted line in figure 44 is an attempt to compensate for any erroneous data errors.

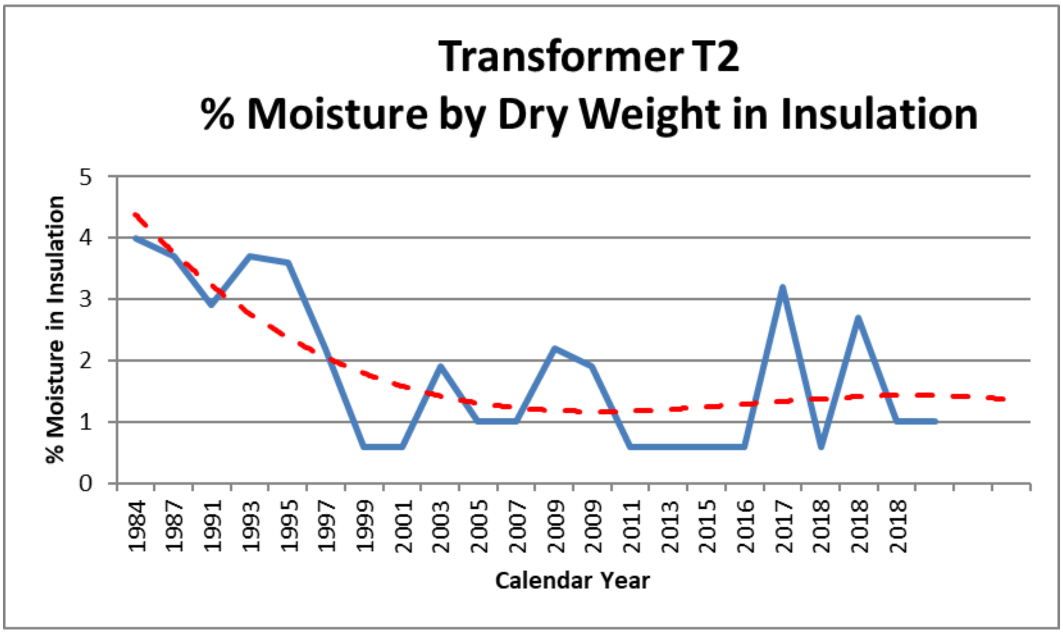


Figure 44 Calculated average of 1.5% moisture in insulation by dry weight.

So overall, the insulation system by today's standards is considered relatively dry. It is well below the 4% level beyond which can introduce risks of insulation failure under the right combination of specific operating / environmental conditions.

4.1.7 Estimated Residual Life of Transformer

Table 3 provides a quick summary of the estimated residual life of the "key" transformer components but there is further discussion on these aspects in clause 2.2.7.

Table 3 Summary of Estimated Residual Life of T2 "Key" Transformer Components

Parameter	Estimated Residual Life	Further Comments
Anti-corrosion system	10 years	Existing paint system is in good condition. It is hiding corrosion problems in some locations.
Winding paper life	5 years	Calculated average DP_V =290 Lowest DP_V = 230.
Winding mechanical stability	Cannot be assessed accurately, but is questionable due to design and exposure	Old clamping structures design, lowering of DPv & moisture exchange.
External Micafil HV & LV bushings	Estimated 3 years with increased risk	The SRBP bushings are included in a family which have exceeded the OEM age limit for reliability.
Insulating Oil	5 years	Oil processed when transformer was refurbished.
Radiators	3 to 5 years	Oval tubes / headers are the big problem area.
Repairs to leaking gaskets.	3 to 5 years	Cooler bank, main tank & HV 'B' phase top cap oil leaks.
Overall residual life	**3 to 5 years**	For as is condition.

4.1.7.1 Anti-corrosion System Life

It is obvious that due to the recent repainting of the transformer, the anti-corrosion coating is still in very good condition and should be capable of lasting a further 10 years.

It is worth noting that even though the cooler bank anti-corrosion coating is in very good condition, there is the underlying issue of oil leaks occurring on the radiator panels due to imbedded corrosion under the paint where the cooler tubes are welded to the top and bottom headers as well as along weld seams where pre-existing corrosion was not neutralised prior to repainting. This is a common weakness of this type of radiator panel design and no amount of painting will stop the inevitable. As such, the radiator panels have virtually reached end of life but may last a few more years provided oil leaks are addressed in some way when they occur.

This may require replacement of panels with suitable recovered panels from other scrapped transformers (if available) or the removal of failed panels and blanking off the attachment flanges on the top and bottom cooler bank headers. However, considering the condition of other parts of this transformer, large dollar expenditure on extending the life of the cooler bank is not considered economic.

4.1.7.2 Insulation Life

<u>Winding Paper</u>
The calculated age / mechanical condition of the winding paper suggests that it still has the potential to achieve another <u>conditional</u> 3 to 5 years of life.

<u>Insulating Oil</u>
The quality of the insulating oil is poor but it should be possible to achieve a further 10 years of service life from the insulating oil.

4.1.7.3 Mechanical Life

Even though the moisture in cellulose insulation appears to have remained relatively stable in its later life, it is very likely that it started at a higher level due to the less efficient insulation dry-out processes used when this transformer was manufactured in 1979. This lowering of moisture in insulation level would cause some amount of insulation shrinkage.

Compounding this is the effect of moisture migration in and out of the cellulose insulation in the winding clamping structure due to changing loads over the years. This would have also caused some accumulative relaxation in the winding clamping pressure and make it less tolerant to through faults.

A third factor to consider is the continual loss of cellulose mass as evidenced by the decrease in average DP_V over the years, which also causes a relaxation in winding clamping pressure. A final concern is the clamping assembly design used on this transformer in the 1970's may not be considered appropriate by today's design standards.

In summary, due to these four factors, the residual life expectancy of the core and coils (active part) is considered to be 3 to 5 years

4.1.7.4 Transformer Bushings

The reliability of the HV and LV bushings has to be considered low since they have exceeded the predicted design life and there is no established end of life criteria to date based on Utility operational experience.

All bushings are original and Micafil SRBP design and the last test results are satisfactory. All bushings (high voltage, low voltage and neutral) have porcelain casings and can fail catastrophically resulting in significant safety consequence if personnel are present on site during failure. As they passed their service life with very limited data available re failures of bushings of this type and age, it is recommended to reduce safety risk exposure by replacing HV and LV bushings with dry type in polymer casing. Based on manufacturer data (Refer Figure 45) the service life of these type of bushings is 25 years.

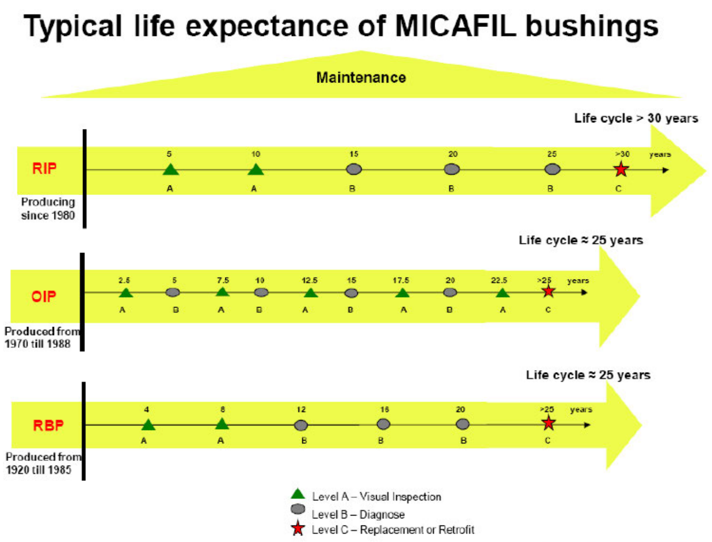


Figure 45 Bushing life expectancy provided by the bushing manufacturer.

5. CONCLUSIONS FOR TRANSFORMER T2

5.1 Condition Assessment

The following conclusions can be drawn from the condition assessment of the Blackwater T2 transformer.

5.1.1 Oil Leaks

Most of the oil leaks were of a minor nature following the transformer's refurbishment and do not require urgent attention except for what appeared to be the neutral bushing mounting gasket leak, which is considered to be significant. Even though this significant neutral bushing oil leak should be fixed, there is the issue associated with the existing and potential oil leaks from the cooler bank radiator panels. A broader economic view of the leak situation needs to be taken before deciding if the neutral bushing leak should be repaired. If Powerlink only wishes to have this transformer in service for another 3 to 5 years, it is not worth fixing the neutral bushing leak unless it worsens. This approach would be validated by the fact that the bulk cellulose insulation moisture content is still well down from the 4% region of concern and should not reach this level over 5 years with the existing oil leak rate from the neutral bushing gasket.

5.1.2 External Physical Condition

Due to having been repainted recently, the transformer's external condition is still very good in a general context but the repaint has hidden some potential issues which are now starting to reappear on the cooler bank. The cooler bank is going to become an on-going corrosion issue and is probably close to end of reliable life because it is virtually impossible to "fix" the corrosion which has been active for many years where the cooler bank radiator panel cooling tubes enter the top and bottom headers. If the transformer is to be kept in service for only the next 3 to 5 years, there is no need for any major refurbishment/ radiator replacement work. Performing a minor "band-aid" treatment of oil leaks when they appear, as part of routine maintenance, in order to keep the transformer / cooler bank serviceable over this period is recommended.

5.1.3 Insulation Residual Life

The winding paper insulation residual life is considered to be a conditional 3 to 5 years.

5.1.4 Winding Mechanical Stability

The mechanical stability of the windings is unknown and based on the available data and knowledge it has a remaining life of 3 to 5 years.

5.1.5 Transformer Bushings

Considering the age of the HV and LV bushings combined with some oil leaks from the top caps, they should be receiving more frequent monitoring to avoid unscheduled outages or loss of transformer over the next 5 years.

5.2 Maintenance Going Forward

The transformer has an assessed residual life expectancy of 3 to 5 years. To keep the transformers much beyond this would require a significant financial expenditure in the form of cooler bank replacement, replacement of HV and LV terminal bushings and some secondary system ancillary items replacement **BUT** this would do nothing to improve the low reliability of the internal active part (the heart) of the transformer.

Technology and Planning – Network Planning

November 2018

Lilyvale 132/66kV Transformer and 132kV Bay Reinvestment

Blackwater 132/66kV Transformer Reinvestment

Planning Report

Prepared by: Grid Planning

Table of Contents

1 Executive summary

Powerlink has reviewed the condition of assets located at Lilyvale and Blackwater substations. 132/66kV transformers at Blackwater and Lilyvale substations and 132kV primary plant at Lilyvale substation have been identified as approaching end of technical life and reinvestment will be required by 2022 to maintain supply reliability to the Central West Queensland zone.

This planning report assesses the enduring need for the functionality provided by the assets under consideration and, where enduring need is established, provides options which will meet the network need. Each option has been evaluated based on their impact on system strength, contributions to maximum fault levels, headroom to accommodate load growth and the level of non-network support which would be required to enable them. Where non-network support would be required to enable a particular option, high level analysis has been carried out to guide potential providers. Operating envelopes of non-network solutions will be confirmed as part of the RIT-T process.

Summary of planning report findings

- There is an enduring need for 132/66kV transformation at Lilyvale and Blackwater substations.
- There is potential to convert each substation from a three to a two transformer site.
- To avoid the need for non-network support across all modelled load growth scenarios, both substations would require two 160MVA transformers or three transformers (maintaining the current configuration at each substation).
- There is an enduring need for the three 132kV feeders between Lilyvale and Blackwater substations.
- If economic, reconfiguration of Lilyvale substation would to the meet the following criteria:
  - If the existing bypass bus is abandoned and the functionality is not replaced, Feeder 7150 and Feeder 7153 are to be located on different buses to ensure that a bus outage does not interrupt supply to Clermont
  - At least once source of 132/66kV transformation is connected to a different bus than the other source(s).
  - At least one of the 132kV feeders to Blackwater is connected to a different bus than the other feeder(s).
  - The existing 275/132kV transformers are connected to different buses to ensure 275kV injection during a 132kV bus outage/contingency.

2 Background

Lilyvale Substation:

Lilyvale Substation is a major transmission connection point in the Central West zone, supplying residential, mining and Aurizon loads via the 132kV and 66kV network. The substation consists of 275kV, 132kV and 66kV (Energy Queensland) switchyards. The substation hosts two 275/132kV transformers and three 132/66kV transformers, and facilitates the connection of two 275kV feeders and six 132kV feeders (refer to Appendix A).

A 132kV transfer bus is connected between Feeder 7150 (Lilyvale to Dysart tee Norwich Park and Bundoora) and Feeder 7153 (Lilyvale to Clermont). The bus is utilised under outages of the Feeder 7153 circuit breaker (CB71532) to ensure supply to the Clermont and Longreach areas, and for outages of the feeder 7150 circuit breaker (CB71502) to maintain system security in the Northern Bowen Basin.

A condition assessment of the substation assets has identified that the three 132/66kV transformers and items of 132kV primary plant are approaching end of technical life and will require reinvestment by 2022. Failure to address these condition issues will result in reduced reliability and increased unsupplied energy in the central west zone. Table 1 shows the affected assets and reinvestment need dates.

Table 1 - Lilyvale substation reinvestment need timings

Lilyvale	
Transformers	Need date
3T	2022
4T	2022
7T	2022
Primary plant	Need date
1T	2021
2T	2021
3T	2021
Feeder 7310	2021
Feeder 789	2021
Feeder 7150	2021
Feeder 7153	2021

Blackwater Substation:

Blackwater Substation provides supply to residential, mining and Aurizon rail traction sites via the Powerlink 132kV and Energy Queensland 66kV networks. The substation consists of 132kV and 66kV (Energy Queensland) switchyards. The substation hosts three 132/66kV transformers and facilitates the connection of seven 132kV feeders (refer to Appendix A).

A condition assessment of the substation assets has identified that two of the 132/66kV transformers are approaching end of technical life and will require reinvestment by 2022. Failure to address these condition issues will result in reduced reliability and increased unsupplied energy in the central west zone. Table 2 shows the affected assets and reinvestment need dates.

Table 2 - Blackwater substation reinvestment need timings

Blackwater	
Transformers	Need date
1T	2022
2T	2022

One line diagrams and aerial views of Lilyvale substation and Blackwater substation can be found in Appendix A.

Supply between substations

132kV feeders 789, 7310 and 7311 facilitate power flow between Lilyvale and Blackwater substations. Flow is predominantly in the direction from Lilyvale to Blackwater. The primary plant at Lilyvale which relates to Feeder 789 and Feeder 7310 has condition issues which need to be addressed by 2021. Table 3 shows the thermal ratings of the three transmission lines.

Table 3 - F789, F7310 and F7311 thermal ratings

Feeder	Normal Rating (MVA)	Emergency Rating (MVA)
789	130.94	156.88
7310	140.15	164.32
7311	136.85	162.85

Geographical Overview

Figure 1 shows the Central West transmission system. The main 275kV transmission backbone (Nebo, Broadsound and Stanwell) facilitates power flow from central to southern Queensland. The 132kV inland network runs in parallel. Lilyvale Substation facilitates 275kV injection into the Powerlink 132kV and Energy Queensland 132kV and 66kV networks. This region of the network hosts a large quantity of generation including increasing levels of renewable and embedded generation. Powerlink's new Bundoora Substation, located on Feeder 7150 between Lilyvale and Dysart substations will be energised in 2018 to facilitate the connection of Lilyvale Solar Farm. Omitted from this diagram is the parallel 66kV network from Lilyvale to Blackwater, supplying Emerald and Comet substations. The Lilyvale 66kV bus is the connection point for German Creek and Oaky Creek non-scheduled generators (waste coal mine gas).

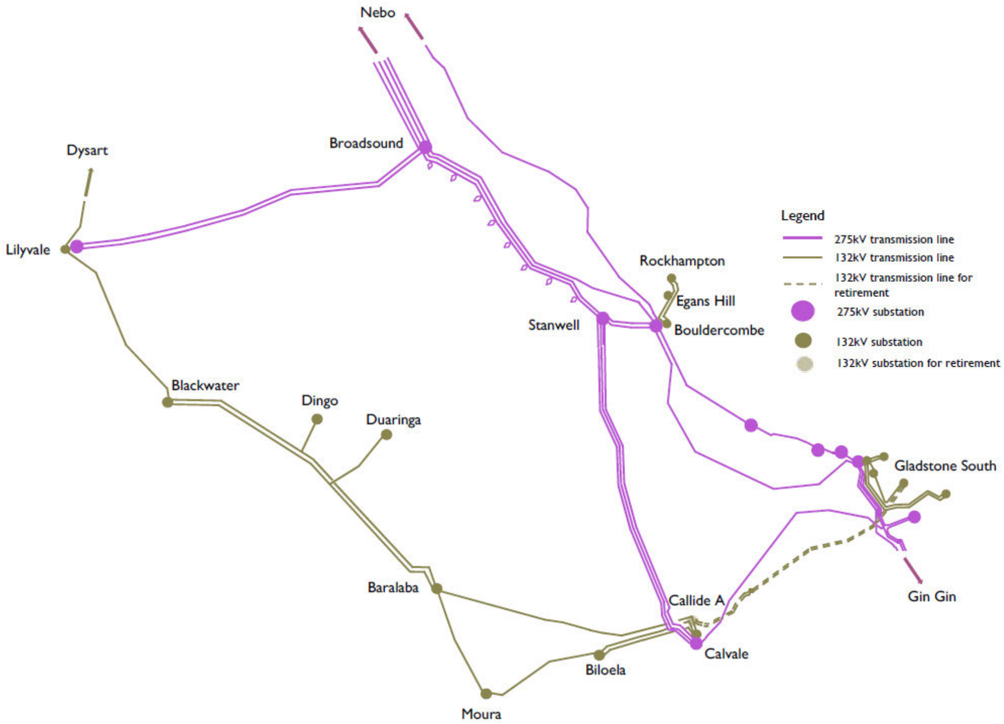


Figure 1 - Central west transmission network

3 Load Forecast and Future Supply Requirements

3.1 Lilyvale and Blackwater 66kV

As shown in Figure 2, the native 66kV load at Blackwater and Lilyvale substations is expected to increase to 113MW and 129MW respectively during the outlook period (to 2027/28).

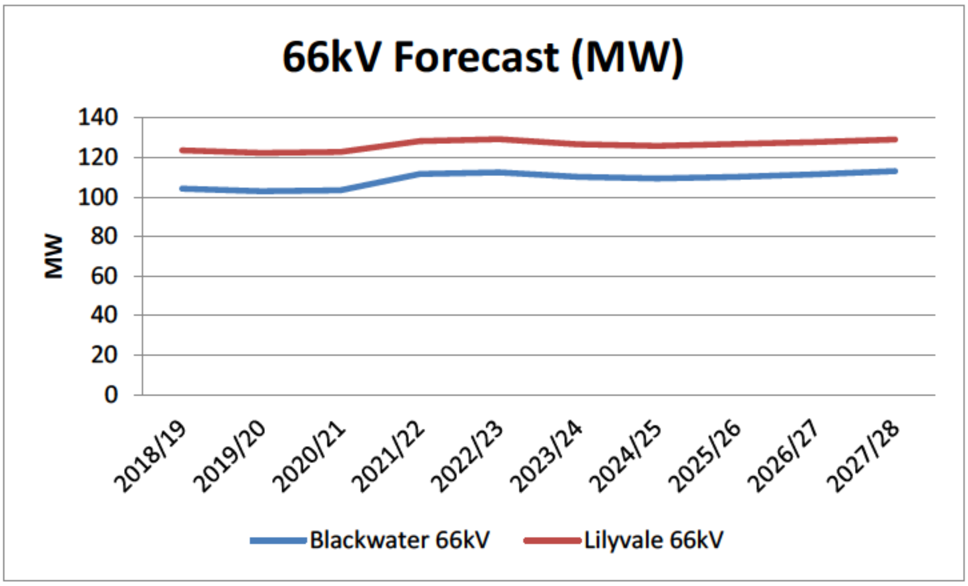


Figure 2 - Blackwater and Lilyvale 66kV forecast to 2027/28

3.2 Embedded generation and renewable energy connections

Non-scheduled embedded generation affects the peak demand and delivered energy at Lilyvale and Blackwater substations. Table 4 shows the existing embedded generation in the 66kV network and metered outputs in 2016/17 (the most recent financial year for which complete data is available).

Table 4 - Embedded generation

Generator	Peak Output 2016/17 (MW)	Delivered Energy 2016/17 (MWh)
German Creek	41.86	300071.48
Oakey Creek	19.47	120284.78

Emerald Solar Farm is committed and is scheduled to be operational in 2018. The solar farm will be connected to Ergon's 66kV network between Lilyvale and Blackwater. It is likely that further renewable generation will commit in the central west zone within the outlook period. The effect of renewable generation on peak demand at Lilyvale and Blackwater substations will need to be monitored however delivered energy at each substation is likely to decrease.

Figure 3 and Figure 4 show the 66kV load duration curves at Lilyvale and Blackwater substations for the financial years 2014/15 to 2016/17. Peak demand and delivered energy at both substations have decreased over this period.

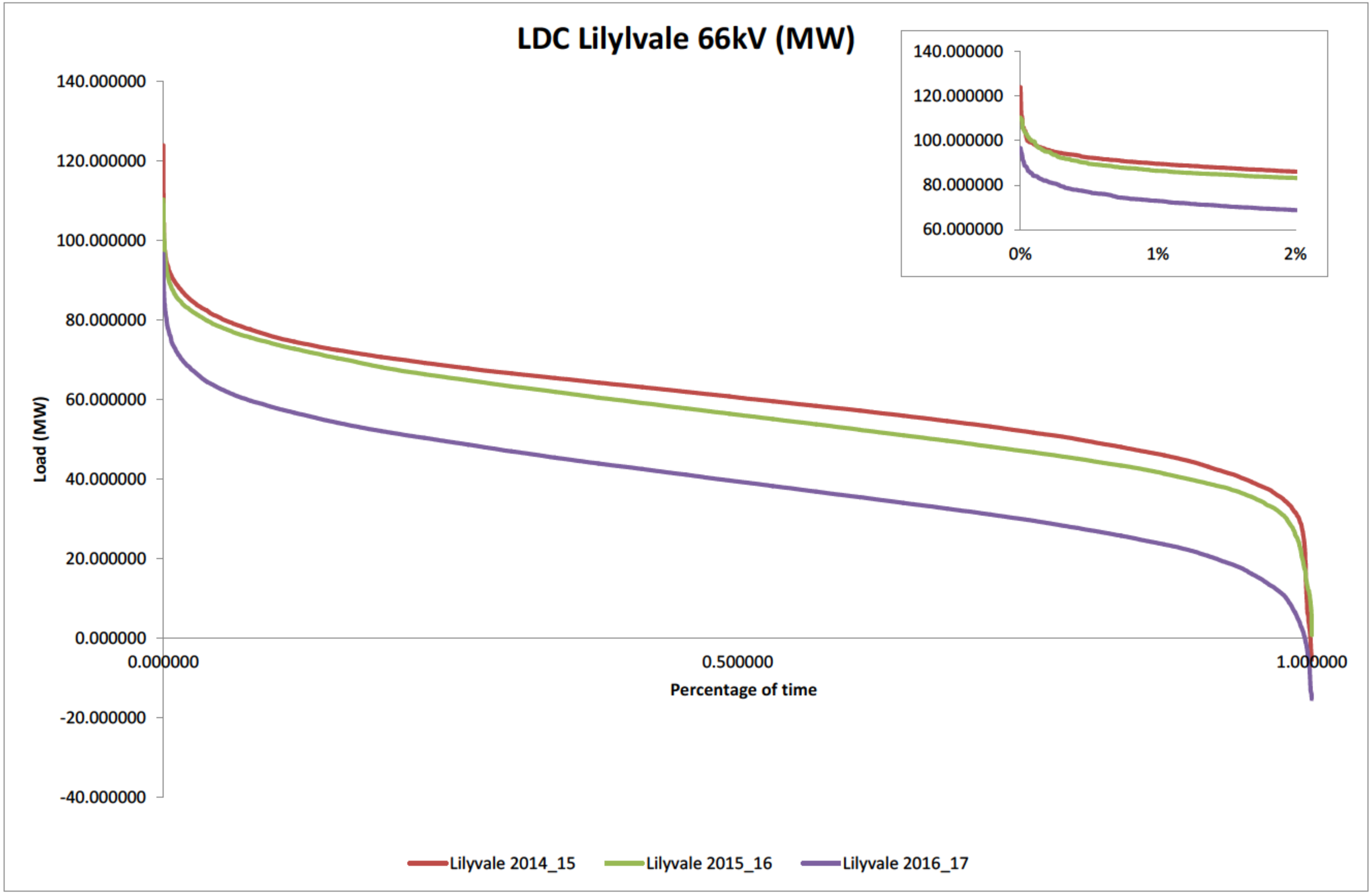


Figure 3 - Load Duration Curve (LDC), Lilyvale 66kV

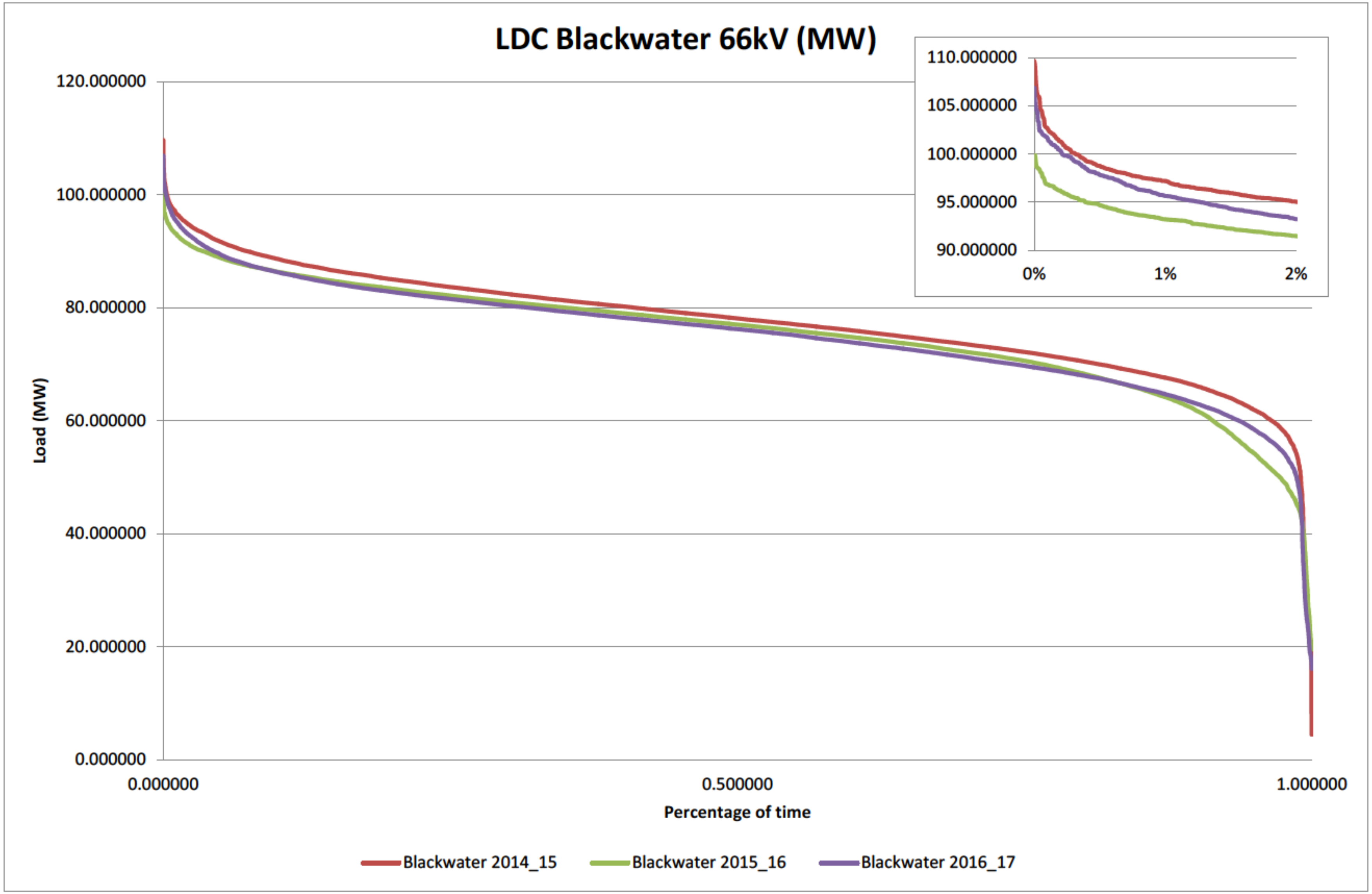


Figure 4 - Load Duration Curve (LDC), Blackwater 66kV

3.3 132kV flow between Lilyvale and Blackwater

Lilyvale and Blackwater substations are connected via three 132kV feeders and a parallel 66kV Ergon network which supplies Emerald and Comet substations. Figure 5 shows the total load (66kV and 132kV) forecast at each substation in the outlook period (to 2027/28). The total load at Lilyvale and Blackwater substations is expected to increase by 3% and 7% respectively.

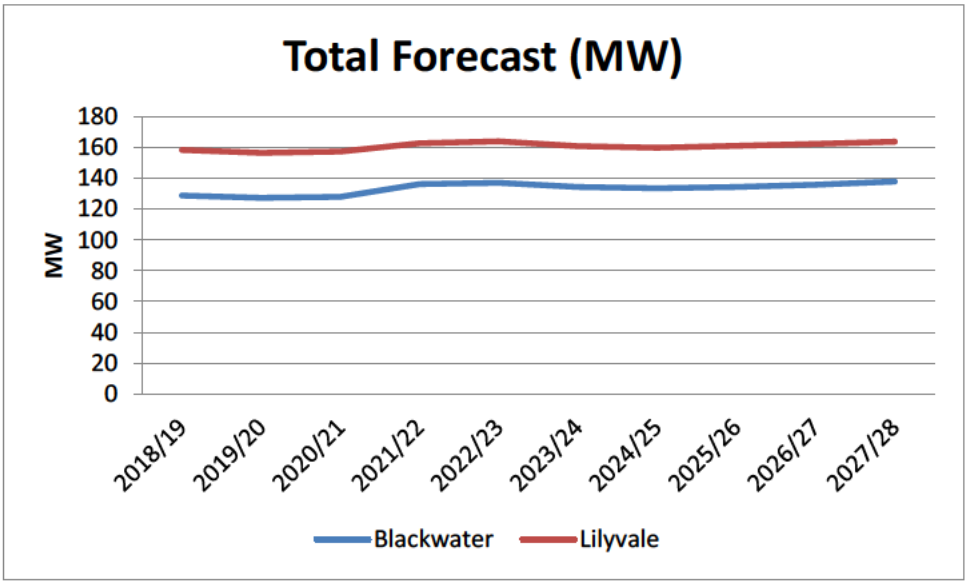


Figure 5 - Blackwater and Lilyvale 132kV and 66kV forecast to 2027/28

There are three 132kV feeders between Lilyvale and Blackwater substations. Figure 6 shows that flow between Lilyvale and Blackwater substations peaked at 216MVA in the 2017/18 financial year. If one of the 132kV feeders (Feeder 789 or Feeder 7310) is retired, this level of flow could not be supported on one feeder if a contingency occurs. There would be periods during which load would need to be shed system intact to reduce flows to an acceptable level which would violate Powerlink's Transmission Authority.

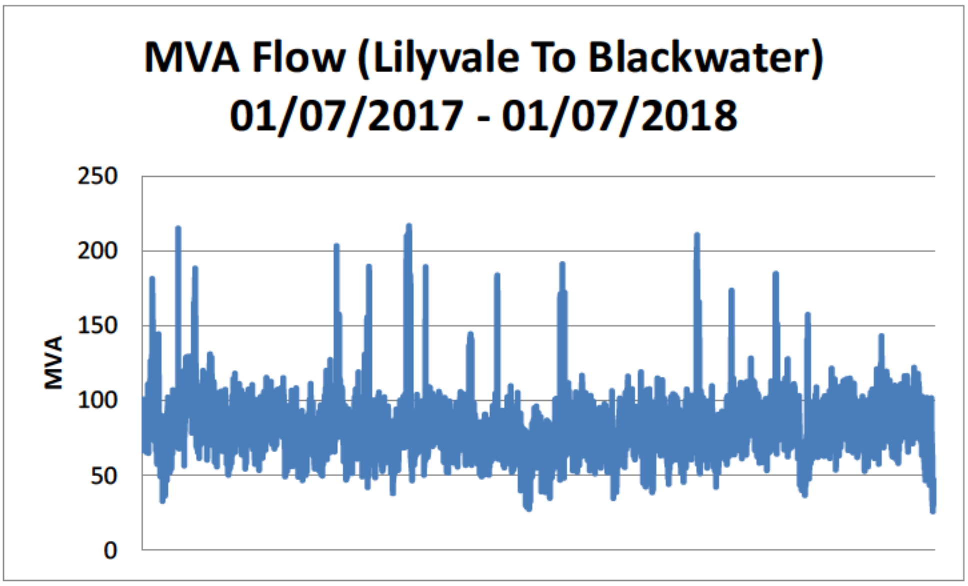


Figure 6 - MVA flow between Lilyvale and Blackwater

F7113 from Baralaba to Blackwater is scheduled to be decommissioned in 2018/19 at which time power flow from Lilyvale towards Blackwater is expected to increase, and support from Baralaba will decrease.

There is an enduring need for Feeder 789 and Feeder 7310 and reinvestment in the related primary plant at Lilyvale is required.

4 Proposed Options to Address the Identified Need

4.1 132/66kV Lilyvale Transformers

Condition assessments undertaken by Powerlink Asset Strategies have identified that all three 132/66kV 80MVA transformers at Lilyvale Substation will reach end of life by 2022.

Planning studies have shown that there is an enduring need for the functionality provided by these transformers; i.e. the need to provide reliable 66kV supply to the Lilyvale and Blackwater region.

Identified options that meet the network need include:

- **Option 1 – three 132/66kV transformers**
  1a) 3 x 80MVA
  1b) 3 x 100MVA
- **Option 2 – two 132/66kV transformers**
  2a) 2 x 80MVA
  2b) 2 x 100MVA
  2c) 2 x 160MVA
- **Option 3 – one 132/66kV transformer**
  3a) 1 x 160MVA

These options have been assessed based on their impact on system strength, contributions to maximum fault levels, headroom to accommodate load growth and the level of non-network support which would be required to enable them under different load growth scenarios.

4.1.1 System Strength - Minimum and Available Fault Levels

Under AEMO's System Strength Impact Assessment Guidelines, system strength is measured by the available synchronous fault level at a connection point. This measure is referred to as Available Fault Level (AFL). In general, a reduction in AFL at Lilyvale 66kV (and/or Blackwater 66kV) will reduce the amount of non-synchronous (renewable) generation that can be hosted in the 66kV network between Lilyvale and Blackwater without project specific system strength remediation.

Emerald Solar Farm is committed and will connect to the 66kV network between Blackwater and Lilyvale in 2018/19. Changes in AFL at the Lilyvale and Blackwater 66kV buses will be reflected at Emerald Solar Farm. The selection of a transformer option at Lilyvale that results in a negative AFL at Emerald Solar Farm would impact the operation and compliance of the solar farm. A positive AFL would need to be reinstated by a network or non-network solution.

The existing AFL at Emerald Solar Farm is ~70 MVA (system intact) and ~55MVA (during a single contingency). Table 5 shows the modelled AFL on the Lilyvale 66kV bus and the Emerald Solar Farm 66kV connection point for the different Lilyvale transformer options.

Table 5 – AFL, Lilyvale 66kV

Lilyvale 66kV Transformers	Lilyvale 66kV AFL		Mt Emerald 66kV AFL	
	System Intact	Single Contingency	System Intact	Single Contingency
Existing	473.43	378.17	68.08	55.84
3x100MVA	495.25	388.96	69.84	57.46
2x80MVA	411.22	281.41	62.99	49.32
2x100MVA	441.09	316.71	65.48	53.43
2x160MVA	513.16	396.16	71.36	58.87
1x160MVA	424.63	-17.38	64.11	-74.40

Installation of a single 160MVA transformer at Lilyvale substation would require a network or non-network solution to raise the AFL at Lilyvale 66kV and Emerald Solar Farm to above 0MVA.

Changes to generation and network configuration will affect system strength calculations. The process used to assess AFL is relatively new and is still evolving. Consequently, exact requirements will be confirmed with non-network proponents during the RIT-T process and these figures should only be used as a guide.

4.1.2 Maximum Fault Levels

Lilyvale 66kV bus is rated for a maximum fault current of 13.1kA. When reinvesting in primary plant at Lilyvale 132kV, Powerlink must consider the Energy Queensland primary plant fault current limits. Table 6 shows the modelled maximum fault levels for the different Lilyvale transformer options.

Table 6 - Maximum fault levels, Lilyvale 66kV

Option	Transformer Arrangement	Maximum fault levels	
		3 phase	L-G
1a	3 x 80MVA	9155.74	11420.97
1b	3 x 100MVA	10813.33	13939.53
2a	2 x 80MVA	7453.16	9062.35
2b	2 x 100MVA	9083.8	11451.66
2c	2 x 160MVA	10722.25	13665.3
3	1 x 160MVA	7776.23	9522.04

Option 1b and Option 2c will likely increase the fault level above the maximum fault level rating. Should either of these options be selected, there will likely be a need for a current limiting device such as a Neutral Earthing Resistor (NER) or Neutral Earthing Reactor (NEX) to be installed with the transformers to restrict the line to ground fault current.

The need to do work on Energy Queensland's network due to increased 66kV fault levels, and costed options to perform this work, will be confirmed through joint planning.

4.1.3 Headroom

Table 7 shows the headroom each of the Lilyvale transformer options would yield, using the peak 2016/17 66kV load at Lilyvale (96.65MW) and the load growth scenarios which were developed using Powerlink's 2018 TAPR connection point forecasts.

Table 7 - Headroom, Lilyvale 66kV

				Capacity - Forecast		
Option	Transformer Arrangement	N-1 Capacity (MW)	N-1 Headroom to 2016/17 Peak	Headroom (Low Forecast - 95MW)	Headroom (Medium Forecast - 105MW)	Headroom (High Forecast - 145MW)
1a	3 x 80MVA	152	57%	60%	45%	5%
1b	3 x 100MVA	190	97%	100%	81%	31%
2a	2 x 80MVA	76	-21%	-20%	-28%	-48%
2b	2 x 100MVA	95	-2%	0%	-10%	-34%
2c	2 x 160MVA	152	57%	60%	45%	5%
3	1 x 160MVA	0	N/A	N/A	N/A	N/A

4.1.4 Non network support

Table 8 indicates the amount of non-network support that would be required at Lilyvale substation to enable each of the Lilyvale transformer options, for each of the three load growth scenarios which were developed using Powerlink's 2018 TAPR connection point forecasts.

Table 8 - Non-network support requirements, Lilyvale 66kV

		Non-network (Low forecast)		Non-network (Medium forecast)		Non-network (High forecast)	
Option	Transformer Arrangement	MW	MWh	MW	MWh	MW	MWh
1a	3 x 80MVA						
1b	3 x 100MVA						
2a	2 x 80MVA					35	725
2b	2 x 100MVA					15	250
2c	2 x 160MVA						
3	1 x 160MVA	70	1675	80	1850	110	2575

These levels of non-network support would restrict load at risk for a single contingency to a maximum of 50MW and energy at risk for a single contingency to a maximum of 600MWh, therefore satisfying Powerlink N-1-50MW/600MWh reliability standard. The exact operating envelope for a non-network solution will be confirmed with non-network proponents during the RIT-T process and these figures should only be used as a guide. Non-network solutions may include, but are not limited to local generation or demand side management initiatives in the area, and would be required to be available on a firm basis.

4.2 132kV Lilyvale Substation Arrangement

4.2.1 Clermont bypass bus

A bypass arrangement exists between 132kV feeders 7150 (Lilyvale to Dysart Tee Norwich Park and Bundoora) and 7153 (Lilyvale to Clermont). This is used predominantly by Energy Queensland to maintain supply to Clermont during outages of the feeder 7153 circuit breaker. Energy Queensland (Ergon) has confirmed that there is an enduring need for the functionality provided by this bypass bus. The existing configuration of the bypass bus is shown in Figure 7.

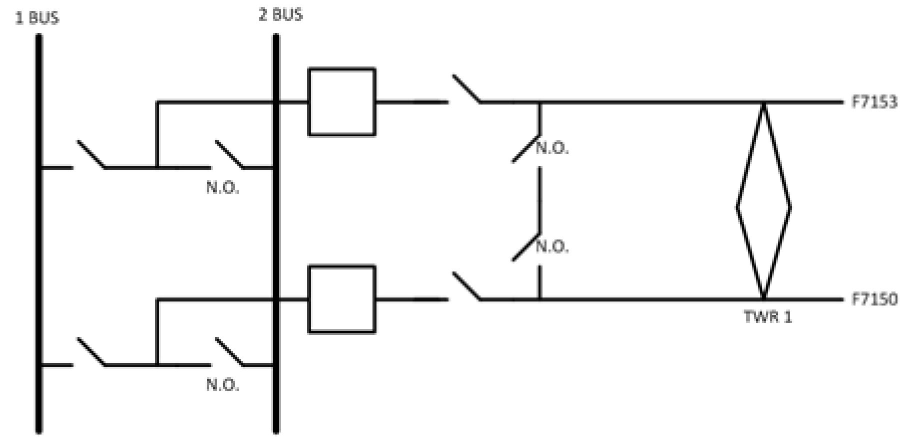


Figure 7 - Clermont bypass, Lilyvale substation

The Connection of Lilyvale Solar Farm to F7150 at Bundoora Substation will result in a system normal four ended configuration which will result in increased operational and protection complexities. The situation will be further complicated when the bypass bus is in operation because this will result in a five ended feeder. The five ended feeder connects three separate customers: Aurizon at Norwich Park, Lilyvale Solar Farm and Energy Queensland at Clermont.

To maintain the functionality of the bypass arrangement, the following options have been identified:

- Maintaining the current configuration
- Double breaker Bay for Feeder 7153
- Bypass bus using a Blackwater feeder.

Maintaining the current configuration, allows for reliable supply and flexibility for the Clermont and Dysart feeder. However to utilise the bypass bus, a short outage is required to transfer the load. Additionally a complex control and protection system is required to ensure the five ended configuration is adequately protected.

A double breaker arrangement similar to Feeder 7188 Gin Gin to Korenan tee would provide online load transfer and reduce operational complexity. This comes at the additional cost of a 132kV bay and circuit breaker. These costs would have to be agreed to by Energy Queensland.

Alternatively, the 132kV yard could be reconfigured to facilitate the bypass using one of the feeders from Lilyvale to Blackwater. This would reduce the operational complexity and maintain current supply arrangements and ongoing costs. To realise this option, extensive reconfiguration of the incoming feeders, including re-arrangement of the towers/poles, may be required.

4.2.2 Lilyvale 132kV bus arrangement

The Lilyvale 132kV bus is configured in a disconnector selectable arrangement. Whilst the disconnector selectable arrangement provides greater operational flexibility and increased reliability to radial loads at Clermont and Gregory, it comes at the cost of additional isolators and greater complexity with secondary system design and maintenance.

In addition to being economic, a reconfiguration of Lilyvale Substation would need to ensure that:

- If the existing bypass bus is abandoned and the functionality is not replaced, Feeder 7150 and Feeder 7153 are located on different buses to ensure that a bus outage does not interrupt supply to Clermont.
- At least one source of 132/66kV transformation is connected to a different bus than the other source(s).
- At least one of the 132kV feeders to Blackwater is connected to a different bus than the other feeder(s).
- The existing 275/132kV transformers are connected to different buses to ensure 275kV injection during a 132kV bus outage/contingency.

4.3 132/66kV Blackwater Transformers

Condition assessments undertaken by Powerlink Asset Strategies have identified that both 132/66kV 80MVA transformers at Blackwater substation, and associated station supply transformers, will reach end of technical life by 2022. 132/66kV 160MVA transformer 7T at Blackwater Substation has no condition issues and will be retained.

Operationally only two of the three transformers on site are loaded at any time. Due to instability of the 66kV Energy Queensland Bus Zone Relay, 2T is normally not energised in order to reduce the 66kV fault level and stabilise protection. Following a contingency of either 1T or 7T, 2T is energised which guarantees that a minimum of 160MVA of 132/66kV transformation is in service.

Planning studies have shown that there is an enduring need for the functionality provided by these transformers; i.e. the need to provide reliable 66kV supply to the Lilyvale and Blackwater region.

Identified (including the existing 160MVA transformer) options to meet the need are:

- **Option 1 – three 132/66kV transformers**
  1a) 2 x 80MVA, 1 x 160MVA
  1b) 2 x 100MVA, 1 x 160MVA
- **Option 2 – two 132/66kV transformers**
  2a) 1 x 80MVA, 1 x 160MVA
  2b) 1 x 100MVA, 1 x 160MVA
  2c) 2 x 160MVA
- **Option 3 – one 132/66kV transformer**
  3a) 1 x 160MVA

These options have been assessed based on their impact on system strength, contributions to maximum fault levels, headroom to accommodate load growth and the level of non-network support which would be required to enable them.

4.3.1 System Strength – Minimum and Available Fault Levels:

Under AEMO's System Strength Impact Assessment Guidelines, system strength is measured by the available synchronous fault level at a connection point. This measure is referred to as Available Fault Level (AFL). In general, a reduction in AFL at Lilyvale (and/or Blackwater) will reduce the amount of non-synchronous (renewable) generation that can be accommodated in the 66kV network between Lilyvale and Blackwater without project specific system strength remediation.

Emerald Solar Farm is connected to the 66kV network between Blackwater and Lilyvale. Changes in AFL at the Lilyvale and Blackwater 66kV buses will be reflected at Emerald Solar Farm. The selection of a transformer option for Blackwater substation that results in a negative AFL would impact the operation and compliance of the solar farm. A positive AFL would need to be reinstated by a network or non-network solution.

The existing AFL at Blackwater 66kV is ~430 MVA. Table 9 shows the modelled AFL on the Blackwater 66kV bus for each Blackwater transformer reinvestment option:

Table 9 – AFL, Blackwater 66kV

Blackwater 66kV Transformers	Blackwater 66kV AFL		Mt Emerald 66kV AFL	
	System Intact	Single Contingency	System Intact	Single Contingency
Existing	431.28	295.30	68.08	55.84
2x100MVA, 1x160MVA	433.90	293.88	68.31	56.04
1x80MVA, 1x160MVA	418.55	297.63	67.14	55.04
1x100MVA, 1x160MVA	421.66	297.52	67.36	55.22
2x160MVA	432.35	294.86	68.17	55.91
1x160MVA	390.20	44.54	65.41	-7.62

Installation of a single 160MVA transformer at Blackwater substation would require a network or non-network solution to raise the AFL at Lilyvale 66kV and Emerald Solar Farm to 0MVA.

Changes to generation and network configuration will affect system strength calculations. The process used to assess AFL is relatively new and is still evolving. Consequently, exact requirements will be confirmed with non-network proponents during the RIT-T process and these figures should only be used as a guide.

4.3.2 Maximum Fault Levels:

Blackwater 66kV bus is rated for a maximum fault current of 10kA. When reinvesting in primary plant at Blackwater 132kV, Powerlink must consider the Energy Queensland primary plant fault current limits. Table 10 shows the modelled maximum fault levels for the different transformer reinvestment options.

Table 10 - Maximum fault levels, Blackwater 66kV

Option	Transformer Arrangement	Maximum fault levels	
		3 phase	L-G
1a	2 x 80MVA, 1 x 160MVA	7134.05	9371.01
1b	2 x 100MVA, 1 x 160MVA	7561.51	10088.87
2a	1 x 80MVA, 1 x 160MVA	6473.83	8370.12
2b	1 x 100MVA, 1 x 160MVA	6801.41	8894.16
2c	2 x 160MVA	7201.92	9474.85
3	1 x 160MVA	5493.62	6965.86

Option 1b will likely increase the fault level above the maximum fault level rating. Should this option be selected, there will likely be a need for a current limiting device such as a Neutral Earthing Resistor (NER) or Neutral Earthing Reactor (NEX) to be installed with the transformers to restrict the line to ground fault current.

It is possible that Energy Queensland will have to upgrade the 66kV Bus Zone protection due to the increased fault levels associated with larger capacity transformers (Option 1b).

The need to do work on Energy Queensland's network due to increased 66kV fault levels, and costed solutions, will be confirmed through joint planning.

4.3.3 Headroom

Table 11 shows the headroom each Blackwater transformer option would provide, using the peak 2016/17 66kV load at Blackwater (107MW) and the load growth scenarios which were developed using Powerlink's 2018 TAPR connection point forecasts.

Table 11 - Headroom, Blackwater 66kV

				N-1 Headroom to forecast		
Option	Transformer Arrangement	N-1 Capacity (MW)	N-1 Headroom to 2016/17 Peak	Headroom (Low Forecast - 105MW)	Headroom (Medium Forecast - 120MW)	Headroom (High Forecast - 160MW)
1a	2 x 80MVA, 1 x 160MVA	152	42%	45%	27%	-5%
1b	2 x 100MVA, 1 x 160MVA	190	78%	81%	58%	19%
2a	1 x 80MVA, 1 x 160MVA	76	-29%	-28%	-37%	-53%
2b	1 x 100MVA, 1 x 160MVA	95	-11%	-10%	-21%	-41%
2c	2 x 160MVA	152	42%	45%	27%	-5%
3	1 x 160MVA	0	N/A	N/A	N/A	N/A

4.3.4 Non-network support

Table 12 indicates the amount of non-network support that would be required at Blackwater Substation to enable each of the Blackwater transformer options, for each of the three load growth scenarios which were developed using Powerlink's 2018 TAPR connection point forecasts.

Table 12 - Non-network support, Blackwater 66kV

		Non-network (Low forecast)		Non-network (Medium forecast)		Non-network (High forecast)	
Option	Transformer Arrangement	MW	MWh	MW	MWh	MW	MWh
1a	2 x 80MVA, 1 x 160MVA						
1b	2 x 100MVA, 1 x 160MVA						
2a	1 x 80MVA, 1 x 160MVA	20	350	30	650	65	1500
2b	1 x 100MVA, 1 x 160MVA			10	175	50	1025
2c	2 x 160MVA						
3	1 x 160MVA	95	2200	105	2500	145	3350

These levels of non-network support would restrict load at risk for a single contingency to a maximum of 50MW and energy at risk for a single contingency to a maximum of 600MWh, therefore satisfying Powerlink N-1-50MW/600MWh reliability standard. The exact operating envelope for a non-network solution will be confirmed with non-network proponents during the RIT-T process and these figures should only be used as a guide. Non-network solutions may include, but are not limited to local generation or demand side management initiatives in the area, and would be required to be available on a firm basis.

5 Summary of Options

The matrices below show how well each option meets against the assessed criteria. Also included is an assessment of whether operational flexibility (the ability to schedule outages for maintenance) is affected.

The traffic light assessment was carried out using the following criteria:

	Increase / maintain	Reduce by up to 20%	Reduce by >20%
Future renewable generation			
	>0MVA	<0MVA	
AFL for committed renewables			
	< Bay Rating	> Bay Rating	
Maximum Fault Level			
	>40%	20%-40%	<20%
N-1 Headroom (Medium Forecast)			
	No	Yes	
NNS Required (Medium Forecast)			
	Maintained	Reduced	
Operational Flexibility			

5.1.1 Lilyvale substation

	Lilyvale 132/66kV transformer arrangement					
	3x80MVA	3x100MVA	2x80MVA	2x100MVA	2x160MVA	1x160MVA
Future renewable generation						
AFL for committed renewables						
Maximum Fault Level						
Headroom / N-1						
NNS Required						
Operational Flexibility						

5.1.2 Blackwater substation

	Blackwater 132/66kV transformer arrangement					
	2x80MVA 1x160MVA	2x100MVA 1x160MVA	1x80MVA 1x160MVA	1x100MVA 1x160MVA	2x160MVA	1x160MVA
Future renewable generation						
AFL for committed renewables						
Maximum Fault Level						
Headroom / N-1						
NNS Required						
Operational Flexibility						

6 Conclusion

Powerlink has reviewed the condition of assets located at Lilyvale and Blackwater substations. 132/66kV transformers at Blackwater and Lilyvale substations and 132kV primary plant at Lilyvale Substation have been identified as approaching end of technical life and reinvestment will be required by 2022 to maintain reliability and supply to the Central West Queensland zone.

The key findings of this report are:

- There is potential to convert each substation from a three to a two transformer site.
- To avoid the need for non-network support across all modelled load growth scenarios, both substations would require two 160MVA transformers or three transformers (maintaining the current configuration at each substation).
- There is an enduring need for the three 132kV feeders between Lilyvale and Blackwater.
- If economic, reconfiguration of Lilyvale substation would need to the meet the following criteria:
  - If the existing bypass bus is abandoned and the functionality is not replaced, Feeder 7150 and Feeder 7153 are located on different buses to ensure that a bus outage does not interrupt supply to Clermont
  - At least once source of 132/66kV transformation is connected to a different bus than the other source(s).
  - At least one of the 132kV feeders to Blackwater is connected to a different bus than the other feeder(s).
  - The existing 275/132kV transformers are connected to different buses to ensure 275kV injection during a 132kV bus outage/contingency.

All of the options presented (some of which require non-network support) will meet the network need; i.e. maintaining reliable supply to the Lilyvale and Blackwater area. Economic analysis will determine Powerlink's proposed option.

Levels of non-network support and AFL remediation will be confirmed with non-network proponents as the RIT-T progresses.

7 References

1. A3359638 – *" Transformer Condition Assessment H015 Lilyvale Substation"*
2. A2371191 – *"Transformer T1 & T2 Condition Assessment T032 Blackwater Substation"*
3. A2837427 – *"Condition Assessment Report Lilyvale – H015"*
4. 2017 – *Powerlink Transmission Annual Planning Report*
5. *AEMO – System Strength Impact Assessment Guidelines – V0.1, 5 March 2018 "For Consultation"*

8 Appendix A

[redacted]

[redacted]

PSS®E System Diagram:

[redacted]

Base Case Risk and Maintenance Costs Summary Report

T032 Blackwater No.1 & 2 Transformer Replacement

Version Number	Date	Description
1.0	July 2019	Original document.

1 Purpose

The purpose of this model is to quantify the base case risk cost profiles and maintenance costs for 132/66kV transformers T1 and T2 at Blackwater substation which are candidates for reinvestment under CP.02369. Base case risk costs and maintenance costs have been analysed over a ten year study horizon.

2 Base Case Risk Analysis

2.1 Risk Categories

Four main categories of risk are assessed within Powerlink's risk approach; safety, network, financial, and environmental. Network, safety and financial risks were considered material for this project and modelled in this assessment.

2.2 Transformer Analysis

This section analyses the risks presented by the relevant transformers at Blackwater substation. The risk costs for T1 and T2 are the same, since both of these transformers are similar types and have the same health index.

Table 1 - Risks associated with at risk transformers

	Mode of failure	
Equipment	**Peaceful**	**Explosive**
Current Transformer (CT)	Network risks (unserved energy). Financial risks to replace the 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, clean-up and community engagement and media liaison costs.

2.2.1 Risk Cost by Year

The modelled and extrapolated total base case risk costs are shown in the following four figures.

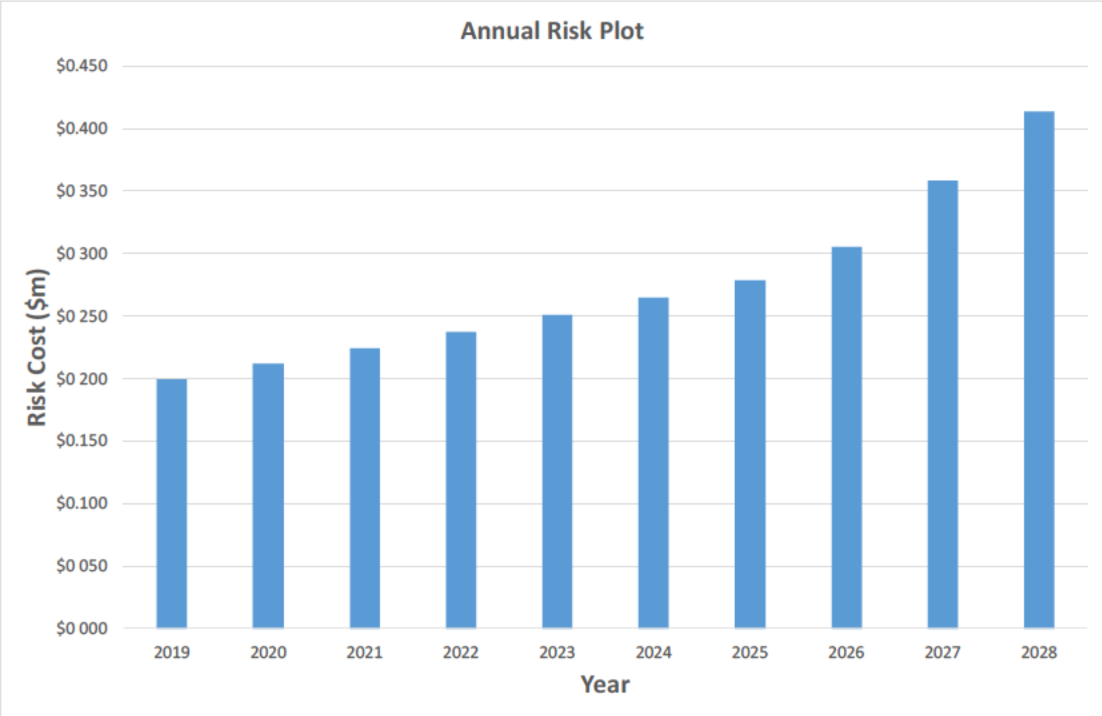


Figure 1 – Blackwater T1 and T2 total risk

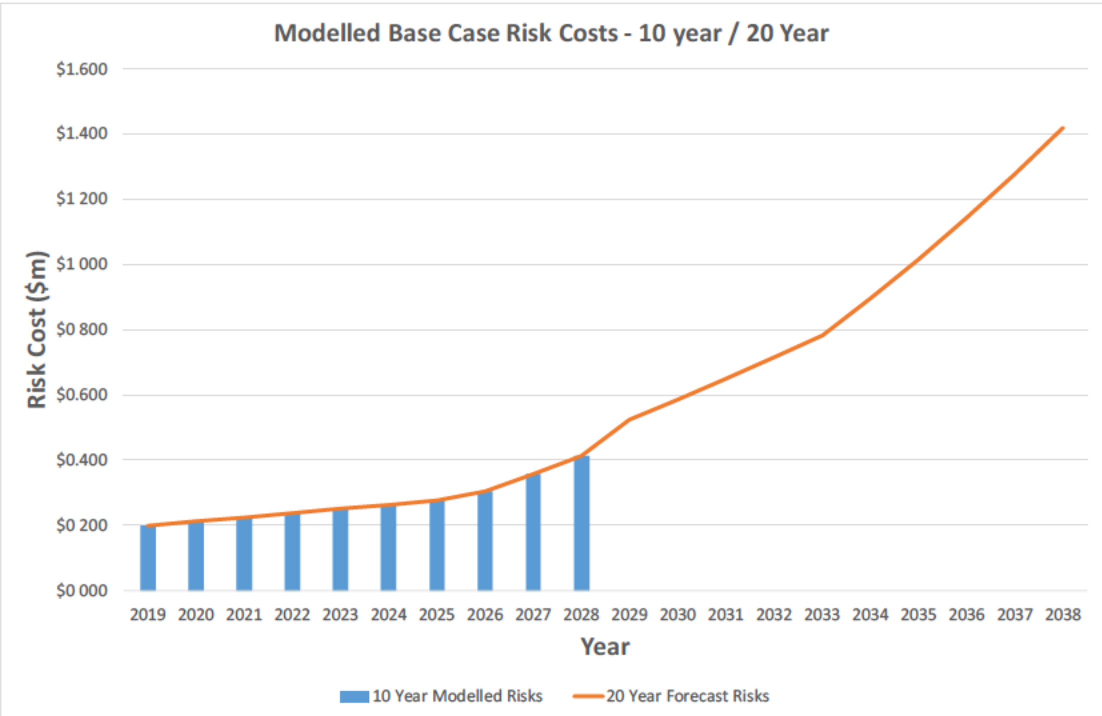


Figure 2 – Blackwater T1 & T2 risk (10 and 20 years)

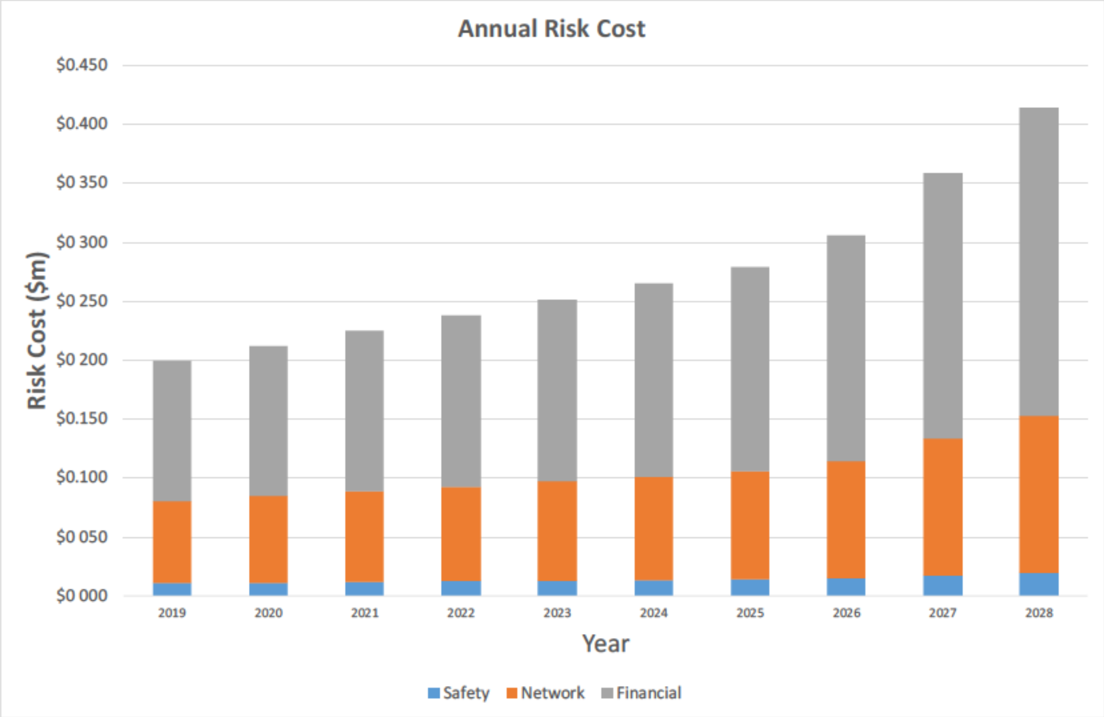


Figure 3 – Blackwater T1 & T2 risk by risk category

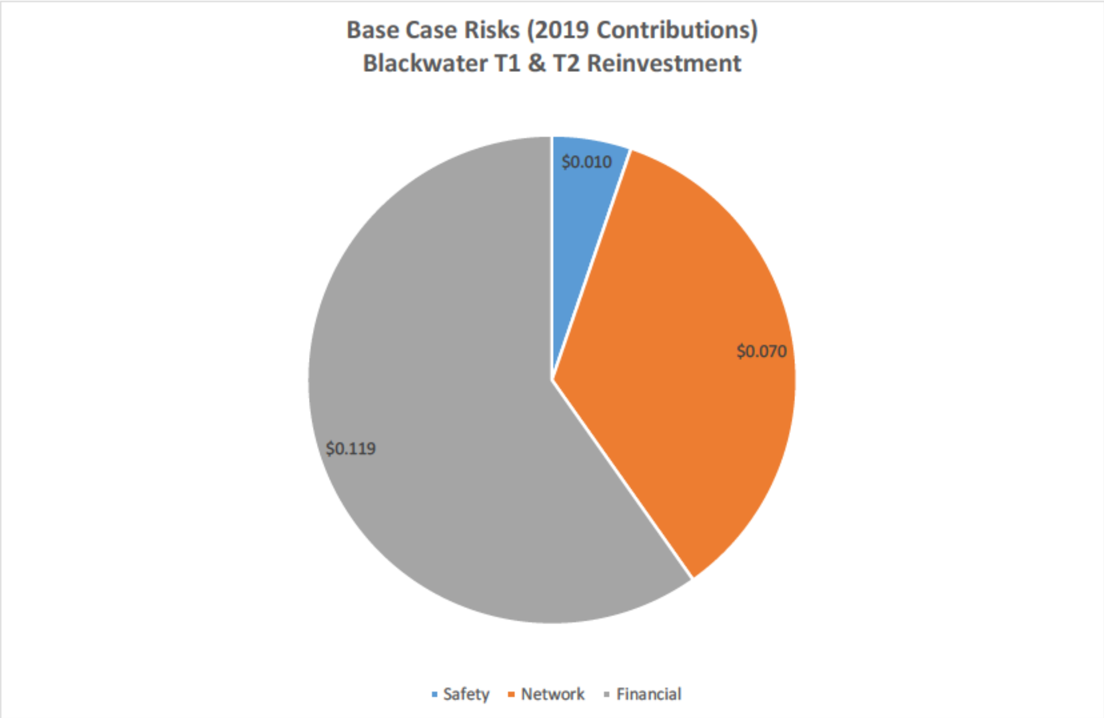


Figure 4 - Blackwater 2019 risk by risk category

2.3 Base case risk statement

The main base case risks for 132/66kV transformers T1 and T2 at Blackwater substation are network risk (unserved energy) due to concurrent outages of the transformers, and financial risks to replace the failed transformers in an unplanned (emergency) manner.

3 Maintenance costs

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

Bushing replacement is modelled to occur at the proposed time of investment to address safety risks associated with the porcelain bushings, in keeping with Powerlink's equipment replacement policy.

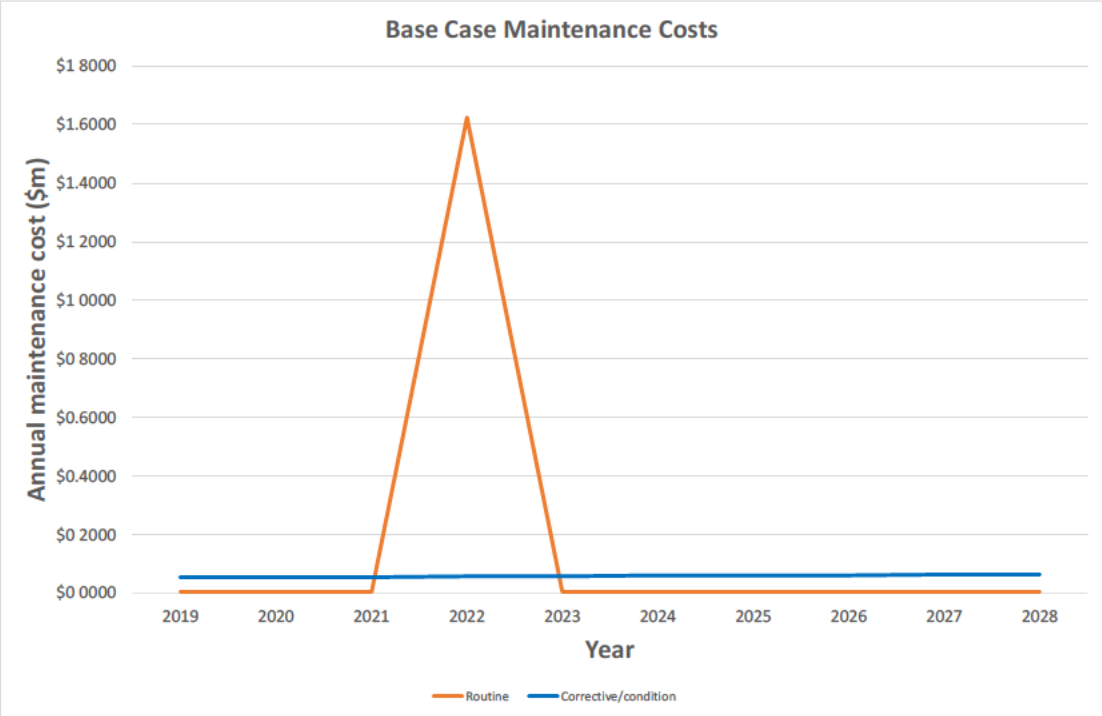


Figure 5 - Base Case maintenance Costs 2019 - 2028

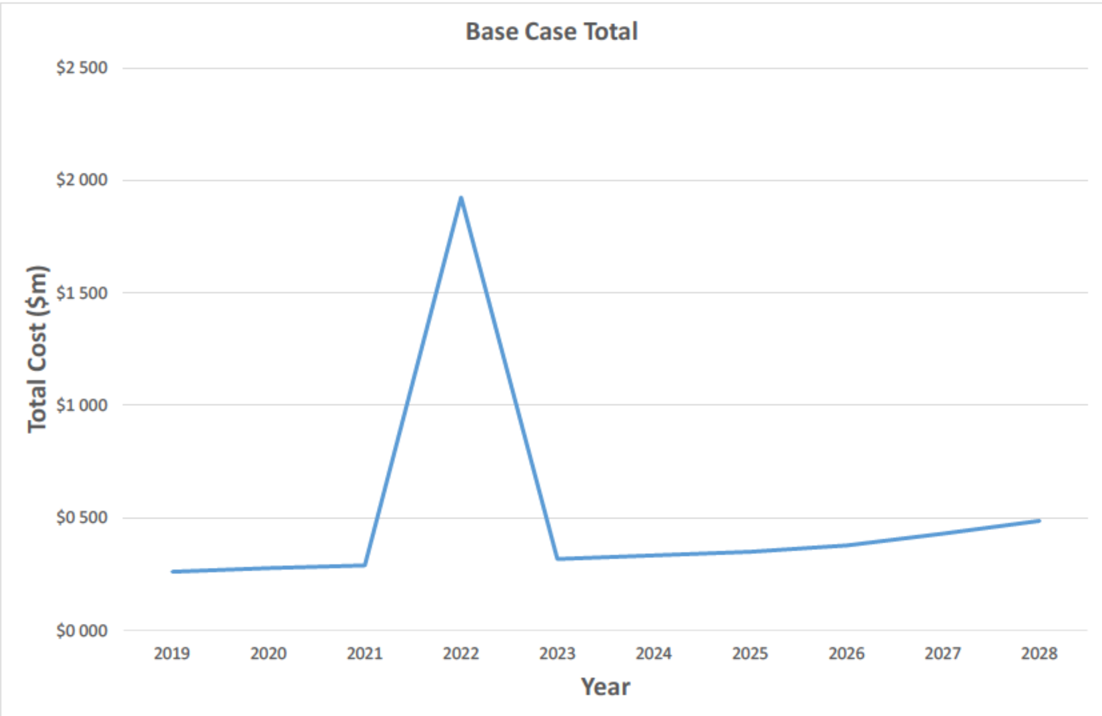


Figure 6 - Base Case Total (Risk Cost + Maintenance) 2019 to 2028

4 Participation factors

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 calculations the most).

The figures below show the input values and the percentage change of the total modelled risk for a change in an individual input (for example if VCR in the transformer model is doubled the calculated risk will increase by ~35%)

The VCR used for the network risk cost model was based on the Queensland regional value consistent with that published within the 2014 AEMO VCR report (i.e. $39,710/MWh). The Queensland regional value has been used since the Blackwater load comprises of a mix of load types, including mining, industrial and domestic loads.

Safety	Probability of personnel within substation	0.4	Ratio
	Probability of personnel adjacent to transformer	0.9	Ratio
	Equivalent cost of serious injury	1	$M
	ALARP disproportionality factor	3	Ratio
Network	VCR	39710	$/MWh
	Emergency transformer replacement time with spare (T3, T4)	4	Weeks
	Spurious trip / planned outage duration	1	Hours
	Likelihood of major fire given transformer explosion	0.8	Ratio
	Time required to de-energisation site during major fire	72	Hours
Financial	Emergency transformer/bushing replacement cost	2	$M
	Media and communication costs	0.3	$M
	Replacement transformer cost	6	$M
	Recoverable load (%, e.g. through gen. sets)	0.20	Ratio
	Cost to meet load (alternative to VCR)	1500	$/MWh
	Time until alternate supply can be arranged	1	Weeks
	Overall cost (VCR/alternative supply)	11053	$/MWh

Figure 7 - Input values, transformer model

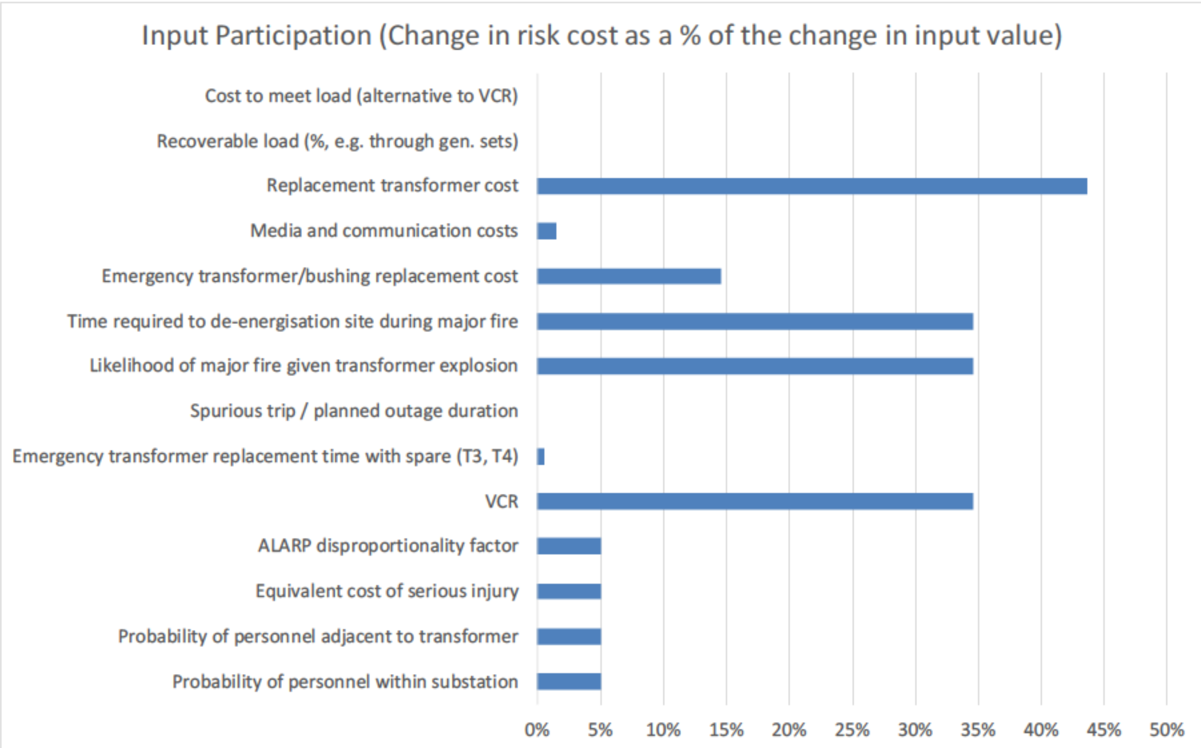


Figure 8 - Participation factors, transformer model

5 Option Risk and Maintenance Costs

5.1 Option summary

Three reinvestment options are being considered to deal with the condition issues of T1 and T2; a refurbishment of T1 and T2 (essentially reducing the modelled age of the transformers by five years), replacement of T1 and T2 with 1 x 160MVA transformer, or replacement of T1 and T2 with 2 x 100MVA transformers.

Note: option maintenance costs do not include an amount for bushing replacement since these are not included within the option scope.

5.2 Option analysis

The total risk and maintenance costs for each option are shown in Table 2 to Table 4 below. The full set of figures are available within the base case spreadsheet (Objective ID A3112801). Due to the fact that the options costs are relatively close to each other, tables have been used to present the data.

Table 2 - Annual costs for Option 1 (ultimate arrangement 2 x 80MVA, 1 x 160MVA transformers)

	2019	2020	...	2022	2023	...	2028	...	2038
Annual Risk ($m)	0.199	0.212		0.238	0.158		0.234		0.586
Annual maintenance ($m)	0.062	0.064		0.066	0.066		0.072		0.077
Total ($m)	0.262	0.275		0.304	0.224		0.306		0.662

Table 3 - Annual costs for Option 2 (ultimate arrangement 2 x 160MVA transformers)

	2019	2020	...	2022	2023	...	2028	...	2038
Annual Risk ($m)	0.199	0.212		0.238	0.019		0.039		0.089
Annual maintenance ($m)	0.062	0.064		0.066	0.008		0.011		0.017
Total ($m)	0.262	0.275		0.304	0.028		0.050		0.106

Table 4 - Annual costs for Option 3 (ultimate arrangement 2 x 100MVA, 1 x 160MVA transformers)

	2019	2020	...	2022	2023	...	2028	...	2038
Annual Risk ($m)	0.199	0.212		0.238	0.026		0.056		0.107
Annual maintenance ($m)	0.062	0.064		0.066	0.025		0.031		0.043
Total ($m)	0.262	0.275		0.304	0.052		0.087		0.151

5.3 Option comparison statement

Option 2 results in the greatest reduction of annual risks and maintenance costs due to reduced maintenance, and reduced financial and safety risks, as a result of having two transformers as opposed to three transformers under Option 1 and Option 3.

It should be noted that there is an increased network risk under Option 2 because for the loss of the two 160MVA transformers, Blackwater is left without a source of 66kV supply.

Project Scope Report

CP.02369

T032 Blackwater No.1 & 2

Transformer Replacement

Concept Estimate – Version 3

Document Control

Change Record

Issue Date	Responsible Person	Objective Document Name	Background
27 Dec 2018	[redacted]	Project Scope Report - CP.02369 Blackwater Transformer 1 & 2 Replacement [A2237386]	Ver. 1 - Concept initial issue
3 Feb 2019	[redacted]	Project Scope Report - CP.02369 Blackwater Transformer 1 & 2 Replacement [A2237386]	Ver. 2 - Include 1T tertiary protection upgrade
20 Nov 2019	[redacted]	Project Scope Report - CP.02369 Blackwater Transformer 1 & 2 Replacement [A2237386]	Ver. 3 - Remove obsolete options post completion RIT-T

Related Documents

Issue Date	Responsible Person	Objective Document Name
15 Jan 2016	[redacted]	T032 Blackwater Transformer T1 & T2 Condition Assessment Report [A2371232]
11 Sep 2018	[redacted]	H015 Lilyvale & T032 Blackwater Reinvestments – Planning Report [A2981042]

1. PROJECT DETAILS

1.1. Project Need

T032 Blackwater substation was established in 1969 in conjunction with the establishment of the coal mines in the area. It is a significant 132/66/11kV transmission substation in the central Queensland network with 132kV circuits to Lilyvale and Baralaba as well as connections to Aurizon and Ergon Energy at 132kV, 66kV and 11kV.

The 132kV switchyard includes three 132/66kV transformers, 2x 80MVA and 1x 160MVA, which provide connections to Ergon servicing coal mines and communities in the surrounding region.

The 2x 80MVA transformers (1T & 2T) were installed in January 1979 and at over 39 years of age are displaying significant condition issues typical of transformers of that age.

A condition assessment has identified that the overall residual life for both transformers is 3 to 5 years due to significant oil leaks on the main tank and around the bushings, and corrosion issues on the cooler banks. The tap changers are trending towards the end of their economic life and have issues with either the control or operation of the tap changer which either stop or fall out of step. Network studies confirm an ongoing need for transformation at Blackwater substation and therefore there is a need for corrective action.

The objective of this project is to carry out replacement of the transformers 1T & 2T by 30 June 2022.

1.2. Project Contacts

Project Sponsor	[redacted]	[redacted]
Manager Connections Contracts (Ergon)	[redacted]	[redacted]
Manager Connections Contracts (Aurizon)	[redacted]	[redacted]
Project Portfolio Optimisation Team	[redacted]	[redacted]
Strategist – HV Asset Strategies	[redacted]	[redacted]
Planner – Main/Regional Grid	[redacted]	[redacted]
Project Manager	[redacted]	[redacted]

1.3. Project Scope

1.3.1. 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 1.7 Matters to Consider*.

Briefly, the project involves replacing the existing 2x 80MVA 132/66/11kV transformers at T032 Blackwater, decommissioning, removal and disposal of the recovered transformers.

1.3.2. Options - T032 Blackwater Substation Works

Three credible scenarios were identified as potential future 132/66/11kV transformer configurations for Blackwater substation based on an ultimate substation arrangement that could include from one to three transformers.

The outcome of the associated Regulatory Investment Test for Transmission (RIT-T) and external consultation identified Option 2 (a) to be the least cost alternative and therefore the preferred option. Table 1 summarises the options considered for Blackwater transformer replacement.

Table 1 - Options summary

Option	Scope Requirements	Comm. Date
1	Life extension of both transformers (1T & 2T)	Jun 2022
2(a)	**Replace both transformers with one 160MVA transformer**	**Jun 2022**
2(b)	Replace both transformers with one 100MVA transformer & engage non-network support	Jun 2022
3	Replace both transformers with 100MVA transformers	Jun 2022
4	Decommission both transformers (1T & 2T) & engage non-network support	Jun 2022

1.3.3. Substation Works - T032 Blackwater Substation

Option 2 - Replace both transformers with one 160MVA transformer

Design, procure, construct and commission the in situ replacement of:

- 2T transformer with a 1x new 132/66/11kV transformer, with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels;
- establish new transformer foundation for 2T;
- upgrade oil containment system to current Powerlink standard allowing as needed for increased transformer oil quantity;
- integrate existing drainage systems to new oil containment system;
- review, and upgrade as required, associated bay infrastructure to achieve load rating compatible with new transformer capacity; and
- establish HV and LV connections to transformer bay infrastructure.

Auxiliary supply and 11kV Ergon interface works:

- establish a new 11kV cable route and install new 11kV cables from 2T transformer tertiary winding to the existing:-
    - 10T station services pad mount transformer; and
    - Ergon 11kV circuit breaker (BW-S101).
- upgrade 2T transformer tertiary protection scheme to satisfy NER requirements including establishment of duplicate systems and installation of earthing transformer if required.

Other works:

- decommission, remove and recover (as required) redundant 1T 66kV & 11kV bay infrastructure (E01 & F01), including cancellation of metering points;
- retain 1T 132kV bay D08 infrastructure and commission as energised stub;
- decommission the redundant 1T & 2T transformers, recover and dispose of decommissioned units;
- retain the existing 1T transformer foundation and connection with oil containment system;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly;
- modify secondary systems as required;
- upgrade metering to current Powerlink standard; and
- update drawing records, SAP, configuration files, etc. accordingly.

1.3.4. Variations to Scope (post project approval)

Not applicable

1.4. Project Timing

1.4.1. Site Access Date

T032 Blackwater is an existing Powerlink owned substation, and access is available immediately.

1.4.2. Commissioning Date

The latest date for the commissioning of the new assets included in this scope and the decommissioning and removal of redundant assets, is 30th June 2022.

1.5. (Proposed) High Level Line Requirements

Not Applicable

1.6. (Proposed) High Level Substation Requirements

Item	Requirement
Project Management	Meet all relevant Powerlink Standards.
Civil Design	
Electrical Design	
Protection Design	
Automation Design	
Telecommunications Design	
Construction	
Commissioning	

1.7. Matters to Consider

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

- the estimate should consider the implications of relevant workplace health & safety legislation in delivering the proposed solution, and identify any alternative solutions that meet the functional requirements included in the scope whilst having the potential to facilitate improvements in safety during construction, or as built, and:
  - include an assessment of the risks associated with each option identified, after all available and applicable mitigating actions have been implemented; and
  - include an allowance for any specific safety related activities required in the delivery phase of the 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 (as per Section 1.10) should be considered as part of the estimate; and
- Ergon Energy also operates 66kV, 22kV & 11kV plant located on the site, with shared access arrangements.

1.8. 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 Strategy and Business Development.

The Connection Managers will provide the primary customer interface with Ergon Energy and Aurizon. The Project Sponsor should be kept informed of any discussions with the customer.

1.9. Asset Ownership

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

Blackwater includes 66kV and 11kV connection interfaces between the Powerlink and Ergon networks. Ownership and interface boundaries that apply are described in the relevant C&AA, and in summary are:

- T032 Blackwater 66kV - The Ergon connection point is the transformer 66kV bushing. Due to legacy metering arrangements, Powerlink owns associated 66kV assets including, surge arrestors and instrument transformers; and

- T032 Blackwater 11kV - The Ergon connection point is the 11kV circuit breaker terminals. Due to legacy metering arrangements, Powerlink owns related 11kV assets, including underground HV cables, surge arrestors and instrument transformers.

1.10. 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.

1.11. Options

Not applicable

1.12. Asset Depreciation

As a result of this project, accelerated depreciation will be applied to the assets to be replaced or decommissioned. The estimate is to include a summary table of the affected assets and associated current book value.

1.13. Division of Responsibilities

A division of responsibilities document will be required to cover the changes to the interface boundaries with Energy Queensland.

The Project Manager will be required to draft the document after project approval and consult with the Project Sponsor to arrange sign-off between Powerlink and Ergon Energy.

1.14. Related Projects

Project No.	Project Description	Planned Comm Date	Comment
Pre-requisite Projects			
Co-requisite Projects			
Other Related Projects			
CP.02703	T032 Blackwater 66kV CT & VT Replacement	30 Sept 2019	

1.15. Project Drawing

[redacted]

2. PROPERTY & EASEMENT INFORMATION

2.1. Established Site - T032 Blackwater Substation

2.1.1. Site Accessibility

T032 Blackwater is an existing substation site and site access is availability immediately.

2.1.2. Issues Regarding Site Location

No Issues regarding the site location identified at this stage.

CP.02369 Blackwater Transformer 1T and 2T Replacement
Project Management Plan

Record ID	A3093755	
Authored by	Snr Project Manager	[redacted]
Reviewed by	Project Manager	[redacted]
Approved by	Team Leader Projects	[redacted]

Version History

Version	Date	Section(s)	Summary of amendment
1	2/04/2019	1-6	Development for Concept Estimate

Table of Contents

1. Executive Summary

Project background:

T032 Blackwater substation was established in 1969 in conjunction with the establishment of the coal mines in the area. It is a significant 132/66/11kV transmission substation in the central Queensland network with 132kV circuits to Lilyvale and Baralaba as well as connections to Aurizon and Ergon Energy at 132kV, 66kV and 11kV.

The 132kV switchyard includes three 132/66kV transformers, 2x 80MVA and 1x 160MVA, which provide connections to Ergon servicing coal mines and communities in the surrounding region.

The 2x 80MVA transformers (1T & 2T) were installed in January 1979 and at over 39 years of age are displaying significant condition issues typical of transformers of that age.

A condition assessment has identified that the overall residual life for both transformers is 3 to 5 years due to significant oil leaks on the main tank and around the bushings and corrosion issues on the cooler banks. The tap changers are trending towards the end of their economic life and issues with either the control or operation of the tap changer which are either stop or fall out of step.

Project objective:

The objective of this project is to carry out replacement of the transformers 1T & 2T by 30 June 2022.

Project delivery strategy is based as follows:

- Design by Powerlink using internal resources,
- Construction by SPA
- Transformer and HV Plant (period order items) procured from preferred suppliers by Powerlink.
- FAT and SAT and Commissioning by MSP

A high level project staging plan and project schedule has been developed based for Option 2 where transformers 1T and 2T are replaced with either one 100MVA or one 160MVA transformer.

The expected project commissioning date for this project is 24 June 2022.

[redacted]

2. Project Definition

2.1 Project Scope

Four options were scoped and estimated.

Option	Scope Requirements	Required Commissioning Date
1	Life extension of both transformers (1T & 2T)	June 2022
2(a)	Replace both transformers with one 160MVA transformer	June 2022
2(b)	Replace both transformers with one 100MVA transformer & engage non-network support	June 2022
3	Replace both transformers with 100MVA transformers	June 2022
4	Decommission both transformers (1T & 2T) & engage non-network support	June 2022

2.1.1 Substations: Option 1 - Life extension of both transformers (1T & 2T)

The option 1 strategy involves targeted refurbishment actions and component replacements to address oil leaks, corrosion issues and emerging reliability issues.

1T Transformer refurbishment works:

- replace cooler bank including fans;
- replace gaskets and valve seals for oil pumps and associated pipework;
- repair all oil leaks including main tank and main cover flange;
- drain and replace oil, or as a minimum filter and process oil including degas and dehumidify;
- replace HV, LV and tertiary winding bushings;
- refurbish/replace the tap changer; and
- fix clearance issues of the tertiary bushing connections.

2T Transformer refurbishment works:

- replace cooler bank including fans;
- replace gaskets and valve seals for oil pumps and associated pipework;
- repair all oil leaks including main tank, bushing cable box and main cover flange;
- drain and replace oil, or as a minimum filter and process oil including degas and dehumidify;
- replace HV, LV and tertiary winding bushings;
- refurbish/replace the tap changer; and
- fix clearance issues of the tertiary bushing connections.

Other works:

- upgrade 1T transformer tertiary protection scheme to satisfy NER requirements including establishment of duplicate systems and installation of earthing transformer if required;
- upgrade oil containment system to current Powerlink standard; and
- update drawing records, SAP, configuration files, etc. accordingly.

2.1.2 Option 2 - Replace both transformers with one transformer

The option 2 strategy involves replacement of both transformers with a single 132/66/11kV transformer. Two alternative transformer capacities are to be considered and a separate estimate provided for each, including -

(2a) 1x 160MVA 132/66/11kV transformer to Powerlink standard specifications;

(2b) 1x 100MVA 132/66/11kV transformer to Powerlink standard specifications;

Engagement of non-network support would be required in the case of option 2(b).

Design, procure, construct and commission the in situ replacement of:

- 1T transformer with a 1x new 132/66/11kV transformer, with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels;
- establish new transformer foundation 1T;
- upgrade oil containment system to current Powerlink standard allowing as needed for increased transformer oil quantity;
- integrate existing drainage systems to new oil containment system;
- review, and upgrade as required, associated bay infrastructure to achieve load rating compatible with new transformer capacity; and
- establish HV and LV connections to transformer bay infrastructure.

Auxiliary supply works:

- establish a new 11kV cable route and replace the existing 11kV cable between the 1T transformer tertiary winding and the 10T station services pad mount transformer; and
- upgrade 1T transformer tertiary protection scheme to satisfy NER requirements including establishment of duplicate systems and installation of earthing transformer if required.

  Note: in the event it is chosen to replace 2T transformer there will be a requirement to establish a new 11kV cable route to provide supply to the 10T station services transformer from 2T.

Other works:

- decommission the old 1T & 2T transformers, recover and dispose of decommissioned units;
- demolish and remove the existing 1T & 2T transformer foundations and oil containment system;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly;
- modify secondary systems as required;
- upgrade metering to current Powerlink standard; and
- update drawing records, SAP, configuration files, etc. accordingly.

2.1.3 Option 3 - Replace both transformers (1T & 2T) with 100MVA transformers

The option 3 strategy involves like for like replacement of both transformers with 2x 100MVA 132/66/11kV transformers.

Design, procure, construct and commission the in situ replacement of:

- 1T & 2T transformers with 2x 100MVA 132/66/11kV transformers, with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels;
- install a neutral earthing resistors/reactors to limit ground fault current;
- establish new transformer foundations for 1T & 2T;

- upgrade oil containment system to current Powerlink standard allowing as needed for increased transformer oil quantity;
- integrate existing drainage systems to new oil containment system;
- review, and upgrade as required, associated bay infrastructure to achieve load rating compatible with new transformer capacity; and
- establish HV and LV connections to the transformer bay infrastructure.

Auxiliary supply works:

- establish a new 11kV cable route and replace the existing 11kV cable between the 1T transformer tertiary winding and the 10T station services pad mount transformer; and
- upgrade 1T transformer tertiary protection scheme to satisfy NER requirements including establishment of duplicate systems and installation of earthing transformer if required.

Other works:

- decommission the old 1T & 2T transformers, recover and dispose of decommissioned units;
- demolish and remove the existing 1T & 2T transformer foundations and oil containment system;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly;
- modify secondary systems as required;
- upgrade metering to current Powerlink standard; and
- update drawing records, SAP, configuration files, etc. accordingly.

2.1.4 Option 4 - Decommission both transformers (1T & 2T) and engage non-network support

The option 4 strategy involves the decommissioning of both transformers, associated HV and LV switching bays, and the engagement of non-network support.

1T & 2T decommissioning works:

- decommission 1T & 2T transformers, recover and dispose of decommissioned units;
- demolish and remove the existing transformer foundations and oil containment systems;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly; and
- decommission and remove associated HV and LV bay infrastructure including structures and foundations for bays D06, D08, E01, E02, F01 & F02.

Auxiliary supply works:

- establish a new station services supply (e.g. high burden VT arrangement) to replace 10T station services transformer which is to be decommissioned with the decommissioning of 1T transformer.

Other works:

- decommission and modify affected secondary systems as required;
- decommission and modify revenue metering installations as required; and
- update drawing records, SAP, configuration files, etc. accordingly.

2.1.5 Transmission Lines / Transmission Lines Refit

Not applicable

2.1.6 Telecommunications

Not applicable

2.1.7 Revenue Metering

The project includes the modification of existing 11kV and 66kV revenue metering.

2.1.8 Other Project Works

Ergon will need to raise and approve a project to deliver the associated 66kV, 22kV and 11kV works and to align with Powerlink's requirements.

2.2 Exclusions

Exclusions as follow:

- Resolution and removal of current Restricted Access Zone (RAZ) on the 66kV CTs and VTs at Blackwater.
- Ergon's transformer stung bus 66kV connection works from Powerlink's yard to Ergon's yard.
- Upgrade or uprating of Ergon's assets due to implementation of this project.
- Termination of 11kV cable on Ergon's plant.
- No allowance to repair or upgrade existing access tracks to substation and existing roads within substation.
- No allowance for management of unsuitable ground conditions during foundation works. This would be regarded as a latent condition.
- No Allowance for Non Regulated Work Impacts, namely scope, cost and time.
- No offsetting of costs has been included for value of scrapped or recovered plant items

2.3 Assumptions

Assumptions as follow:

- Existing transformer foundations/bunds are not compatible with replacement transformers and therefore replacement foundations assumed as necessary.
- Existing oil containment system is of sufficient capacity however is to be augmented with secondary treatment SPEL tank to satisfy current environmental compliance requirements; inclusion has been included in the estimate for installation of a new SPEL tank.
- For Option 2 - transformer 2T is to be replaced in situ and 1T transformer decommissioned and removed.
- For Option 2 - no blast wall is required between 1T and the replacement 2T transformer during construction.
- For Option 2 - 132kV 1T circuit breaker bay is retained and stub energised, 66kV & 11kV 1T bay infrastructure is to be decommissioned and either demolished or recovered as appropriate.
- Restricted Access Zone (RAZ) resolved and removed on 66kV CTs on 7T Transformer prior to site establishment to deliver this project. Project does not include allowance either to resolve or work around the current and future RAZ.
- Implementation strategy and staging based on Option 2 with the removal of existing infrastructure and new construction for the new transformer and associated plant and thereafter cutover of existing connection to the new bay.
- 2T shall be taken out of service permanently with no return to service option. This will allow the rebuild of the new infrastructure. Network Operations have endorsed this approach.
- Re-use existing secondary system infrastructure (e.g. marshalling kiosks, protection and control panels, and cables from marshalling kiosk to building).
- No offsetting of costs has been included for value of scrapped or recovered plant items

- Modifications to Ergon assets will be performed within the required timeframes to avoid delaying Powerlink works.
- Parallel works are not anticipated.

2.4 Project Interaction

Interactions with other projects and Engineering Task Request (ETRs) as follows:

Project Number and Description	Interaction (Pre-requisite/Co-requisite/dependent /Related)	Expected Commissioning Date	Comment
CP.02703 Blackwater CT & VT replacement at	Dependent	30 September 2019	Project currently in Execution phase with an Agreed Commissioning date of 30 September 2019. Assumption is that this project will be completed prior to approval of CP.02369
CP.02340 H015 Lilyvale Selected Primary Plant Replacement	Concurrent	October 2022	Impacted feeders F7310 and F789 will need to be coordinated and managed to maintain security of the network.
CP.02356 H015 Lilyvale Transformer 3T and 4T Replacement	Concurrent	June 2021	

2.5 Project Risk

Project risks identified during Project Concept phase are as follows:

Risks (based on Option 2a)	Impact	Likelihood	Mitigation Strategy / Amount	Risk Amount

Availability of Resources:
- Contractor (SPA and subcontractor)
- MSP
  o 2T isolation by Ergon: March 2021
  o Testing and Commissioning: September 21 to October 2021
  o 1T isolation and disconnection by Ergon: March 2022
	Medium	Possible	Engage resources as soon as practically possible.
			Ongoing discussion and management with MSP.
				[redacted]

Change in project delivery strategy due to: - Network outage change - Staging change - MSP availability - Change of design by PQ to design by SPA	Medium	Possible	Review strategy, staging, outage and design on an ongoing basis.	[redacted]
Additional design due to complexity, temporary works and additional staging	Medium	Possible	Review strategy, staging, outage and design on an ongoing basis.	[redacted]
Project delayed due to late delivery of Ergon works (66kV, 22kV and 11kV) to align with Powerlink works.	Medium	Possible	Engage with Ergon as early as possible. Provide scope of Powerlink's work. Monitor progress of Ergon's works.	[redacted]
Potential network risk due to failure of 7T (160MVA) while there is an extended outage of 2T with no return to service. The existing substation cannot operate on just 1t (80MVA)	Low	Unlikely	Engage Ergon about extended outage of 2T and potential mitigation strategies to move load on the distribution system. This has commenced by NetOps with Ergon.	[redacted]
Late Delivery of transformer and HV plant as required	Medium	Possible		[redacted]

Risks (based on Option 2a)	Impact	Likelihood	Mitigation Strategy / Amount	Risk Amount
Latent Site Conditions - PCBs, asbestos, heavy metals, reactive soils (excludes soft spots which requires updated of the platform)	Medium	Possible	Test oil and soil samples as soon as possible. Perform geotechnical investigate to determine soil condition	[redacted]
Financial and Economic (Foreign Exchange and Commodities)	Medium	Possible		[redacted]
Project delays due to adverse weather conditions	Medium	Possible		[redacted]
Delivery issues: • Remote Location of Project - additional cost for accommodation and travel • Height clearance to QR lines to Site access • Auxiliary transformer 11kV cable connection - Sufficient area/space for new 11kV cable. • Modify existing strain tower structure (gantry) is suitable rated for the requirements of this project • Delivery strategy change – Outage staging and MSP changes. • Additional soil test – Deal with reactive soil • Extend blast wall	Medium	Possible	• Investigate accommodation options. • Engage with QR early for opportunities of outages. Inform Transformer Vendor of clearance issue • Allowance made for use of non-destructive methods to excavate trench for new cable and identify existing cable • Check ratings when project is approved.	[redacted]
			Total [redacted]	[redacted]

During Project Execution, project risks are recorded managed in PWA Server.

3. Project Estimate

3.1.1 Estimate Summary

Estimate Components	Option 1 Life Extension of both transformers				Option 2 (a) Replace both transformers with one 160MVA transformer		Option 2 (b) Replace both transformers with one 100MVA transformer		Option 3 Replace both transformers with 100MVA transformers		Option 4: Decommission both transformers (1T & 2T) & engage non-network support			
	1T		2T								1T		2T	
	Un-Escalated	Escalated	Un-Escalated	Escalated	Un-Escalated	Escalated	Un-Escalated	Escalated	Un-Escalated	Escalated	Un-Escalated	Escalated	Un-Escalated	Escalated
Base Estimate	1,792,292	2,049,170	1,704,872	1,949,220	6,158,801	7,041,501	5,659,051	6,470,125	9,091,634	10,394,678	1,449,805	1,657,596	1,160,593	1,326,933
Contingency (Unknown Risk) [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Risk Contingency (Unknown Risk) [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Proposed Contingency [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Proposed Approval	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4. Project Financials

4.1.1 Asset Write-Off Tables

CP.02369 Asset Write-off Table. Values current at 30th June 2019 – Options 2(a); 2(b) and 3

Functional Loc.	Description	Asset	Subnumber	Book val.	% Write-off	Write-off Value
T032-D06-442-	132kV 2 TRANSF BAY	129232	0	1,388,844.64	0%	0.00
T032-D08-441-	132kV 1 TRANSF BAY	129191	0	1,236,507.94	0%	0.00
T032-E01-341-	66KV 1 TRANSF BAY(Deco CP.02703)	105783	0	885.74	0%	0.00
T032-E02-342-	66KV 2 TRANSF BAY(Deco CP.02703)	105784	0	885.74	0%	0.00
T032-F01-141-	11kV 1 TRANSF BAY	105785	0	2,021.69	0%	0.00
T032-F02-142-	11kV 2 TRANSF BAY	105786	0	2,021.69	0%	0.00
T032-T01-1TRF	1 TRANSFORMER	105798	0	125,339.95	100%	125,339.95
T032-T02-2TRF	2 TRANSFORMER	105799	0	125,339.95	100%	125,339.95
Total	**250,679.90**					

CP.02369 Asset Write-off Table. Values current at 30th June 2019 – Option 4

Functional Loc.	Description	Asset	Subnumber	Book val.	% Write-off	Write-off Value
T032-D06-442-	132kV 2 TRANSF BAY	129232	0	1,388,844.64	100%	1,388,844.64
T032-D08-441-	132kV 1 TRANSF BAY	129191	0	1,236,507.94	100%	1,236,507.94
T032-E01-341-	66KV 1 TRANSF BAY(Deco CP.02703)	105783	0	885.74	100%	885.74
T032-E02-342-	66KV 2 TRANSF BAY(Deco CP.02703)	105784	0	885.74	100%	885.74
T032-F01-141-	11kV 1 TRANSF BAY	105785	0	2,021.69	100%	2,021.69
T032-F02-142-	11kV 2 TRANSF BAY	105786	0	2,021.69	100%	2,021.69
T032-SIN	SUBSTATION INFRASTRUCTURE	129192	0	1,462,692.36	10%	146,269.24
T032-SSS-441-	132 kV 1 TRANSF BAY	119016	0	529,696.44	100%	529,696.44
T032-SSS-442-	132 kV 2 TRANSF BAY	119017	0	529,696.44	100%	529,696.44
T032-T01-1TRF	1 TRANSFORMER	105798	0	125,339.95	100%	125,339.95
T032-T02-2TRF	2 TRANSFORMER	105799	0	125,339.95	100%	125,339.95
					Total	**3,307,133.12**

4.2 Approved Released Budget

To be advised

4.3 Planned Costs (Forecasted Cash Flow)

Escalated costs excluding risk

	Option 2a FY Cashflow				Option 2a - Totals
OH	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Primary Design	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Secondary Design	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Procurement		[redacted]			[redacted]
Construction & Commissioning		[redacted]	[redacted]		[redacted]
Option 2a - Total	161,880	3,748,779	2,888,024	242,819	**7,041,503**
	to June 2020	**to June 2021**	**to June 2022**	**to June 2023**	

During Project Execution, project planned cost are managed in SAP.

5. Project Planning Strategy

5.1 Milestones

The following milestones are required by the project team to deliver the project:

Milestones	Planned Dates
Project Approval (issue of PAN) – Full Approval	03/2/2020
Site Access - to carry out investigations, inspections, etc	As required as this is an existing substation site
Site Possession - to carry out construction works	
Expected Project Commissioning Date – CP.02369	24/06/2022 (Friday)

Other project delivery milestones for combined CP.02340 and CP.02356 (based on Option 1 - replacement of both 3T and 4T transformers with 2x new 132/66/11kV transformers) are as follows:

- Issue Transformer Tender: March 2020
- Design complete by Powerlink: May 2020
- SPA ITT:
  - Issue ITT: June 2020
  - Accept Tender: October 2020
- Site Works:
  - 2T isolation by Ergon: March 2021
  - Removal of 2T, construction works by SPA and installation of new transformer by vendor: April 2021 to September 2021
  - Testing and Commissioning: October 2021
  - 1T isolation and disconnection by Ergon: March 2022
  - Removal of 1T and final clean-up by SPA: April 2022 to May 2022
  - Project As built documentation and handover to MSP: May 2022 to June 2022.

5.2 Project Staging

A high level Project Staging has been developed for CP.02369 at Blackwater Substation.

For detail staging, refer to the Project Staging Plan (refer to section 13).

5.3 Project Schedule

A high level Project Staging has been developed for CP.02369 at Blackwater Substation.

Refer to the Project Schedule (refer to section 13).

5.4 Project Delivery Strategy

Strategy to deliver the project as follows:

- Design by Powerlink using internal resources and not resources from the Design Services Panel,
- Construction by SPA,
- Transformer and HV Plant (period order items) procured from preferred suppliers by Powerlink, and
- FAT, SAT and Commissioning by MSP.

Description	*Responsibility*			
	Main Site			
	Powerlink	*Contractor*	*MSP – O&SD*	*MSP - Ergon*
Primary Design Systems (PSD):				
Earthworks (Not applicable)	☐	☐	☐	☐
Civil and Structural	☒	☐	☐	☐
Electrical	☒	☐	☐	☐
Secondary Systems Design (SSD):				
Protection	☒	☐	☐	☐
Automation (Circuitry and Systems Configurations)	☒	☐	☐	☐
Telecommunication System Design (TSD):				
Data Networks	☒	☐	☐	☐
Bearer Networks	☒	☐	☐	☐
Construction:				
Earthworks (Not applicable)	☐	☐	☐	☐
Civil	☐	☒	☐	☐
Construction (support structures, plant and equipment installation and demolition Works)	☐	☒	☐	☐
Secondary Systems Installation (loose panels installation, panel modification, IED replacement, etc)	☐	☒	☐	☒

Description	*Responsibility*			
	Main Site			
	Powerlink	*Contractor*	*MSP – O&SD*	*MSP - Ergon*
Telecommunication Construction (including fibres) (Not applicable)	☐	☐	☐	☐
Testing and Commissioning:				
Factory Acceptance Test	☐	☐	☐	☒
Site Acceptance Test (partial)	☐	☐	☐	☒
System Cut Over and Commissioning	☐	☐	☐	☒
Other:				
Revenue Metering site works	☐	☐	☐	☒
Transformer Install (Transformer Vendor)	☐	☐	☐	☒

5.5 Procurement Strategy

The procurement strategy for services and selected items are listed below. All other services and items shall be procured in accordance with Powerlink's Procurement Standard.

Description	Procurement Method
Services:	
SPA – DC	ITT - Substation Panel Arrangement (SPA)
MSP	RFQ – Service Level Agreement
Primary Plant and Equipment:	
HV Plant and Equipment	Period Contractors (CBs, ISOL, CTs, PIs, SA)
Structures	Supplied by SPA Contractor
Hardware and fittings	Supplied by SPA Contractor
Transformer	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Secondary Systems Equipment - As identified during detail design:	
IEDs	Period Contract
Panels, Kiosks, Boards	Supplied by SPA Contractor
Secondary Cables	Supplied by SPA Contractor

6. References

The following documents are applicable to this Project Management Plan.

Document name and hyperlink	Version	Date
Project Definition		
Project Scope Report	2	03/02/2019
Project Schedule	N/A	13/03/2019
Asset Write off	N/A	N/A
Design:		
Electrical Design Advice (EDA CP.02369/2)	2369/1	05/032019
Civil Design Advice (CDA CP.02369 / 1.0)	1.0	15/03/2019
Protection Design Advice	CP.02369	01/03/2019
Automation Design Advice	CP.02369	01/03/2019
Testing and Commissioning:		
Commissioning Advice (CA No. CP.02369 / 1)	CP.02369/1	08/03/2019
Equipment to be Tested	N/A	N/A

Powerlink Queensland

Project Assessment Conclusions Report

10 October 2019

Maintaining reliability of supply in the Blackwater area

Document Purpose

For the benefit of those not familiar with the National Electricity Rules (the Rules) and the National Electricity Market (NEM), Powerlink offers the following clarifications on the purpose and intent of this document:

1. The Rules require Powerlink to carry out forward planning to identify future reliability of supply requirements and consult with interested parties on the proposed solution as part of the Regulatory Investment Test for Transmission (RIT-T). This includes replacement of network assets in addition to augmentations of the transmission network.
2. Powerlink must identify, evaluate and compare network and non-network options (including, but not limited to, generation and demand side management) to identify the '*preferred option*' which can address future network requirements at the lowest net cost to electricity consumers. This assessment compares the net present value (NPV) of all credible options to identify the option that provides the greatest economic benefits to the market.
3. This document contains the results of this evaluation, and a final recommended solution to address the condition risks associated with the 132/66/11kV 80MVA transformers at Blackwater Substation by June 2022.

Contents

Executive Summary

Blackwater Substation, established in 1969 and located approximately 68km east of Emerald, plays a critical role in the provision of electricity to customers in Queensland's Central West area, providing supply to residential, mining and rail traction loads. Planning studies have confirmed there is a long-term requirement to continue to supply the existing electricity services provided by Blackwater Substation supporting the diverse range of customer needs in the area.

The substation's 132kV switchyard includes three 132/66/11kV transformers (2 x 80MVA and 1 x 160MVA) which provide connections to the Ergon Energy (part of the Energy Queensland Group) distribution network. The two 80MVA transformers were installed in 1978, and at over 40 years of age have significant condition and performance issues indicating that they are reaching the end of their technical service lives. The third transformer, rated at 160MVA, was installed in 2006 and is in good working condition.

The increasing likelihood of faults arising from the condition of the ageing 80MVA transformers at Blackwater remaining in service beyond June 2022, exposes customers to the risks and consequences of an increasingly unreliable electricity supply. There is a need for Powerlink to address these emerging risks. As the identified need for the proposed investment is to meet reliability and service standards specified within Powerlink's Transmission Authority and to ensure Powerlink's ongoing compliance with Schedule 5.1 of the National Electricity Rules (the Rules) and relevant jurisdictional obligations[1], it is classified as a 'reliability corrective action'[2].

This Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process prescribed under the Rules undertaken by Powerlink to address the condition risks arising from the two 80MVA transformers at Blackwater Substation. It contains the results of the planning investigation and the cost-benefit analysis of credible options compared to a non-credible Base Case where the emerging risks are left to increase over time. In accordance with the RIT-T, the credible option that maximises the net present value (NPV) of economic benefit, or minimises the costs, is recommended as the preferred option.

Credible options considered

Powerlink published a Project Specification Consultation Report (PSCR) to Registered Participants, the Australian Energy Market Operator (AEMO) and interested parties in May 2019 to address the risks arising from the condition of the ageing 80MVA transformers at Blackwater.

No submissions were received in response to the PSCR that closed on 27 August 2019. As a result, no additional credible options have been identified as a part of this RIT-T consultation.

Powerlink has developed three credible network options to maintain the existing electricity services, ensuring an ongoing reliable, safe and cost effective supply to customers in the area. Option 1 and 2 result in a changed substation configuration, with the final configuration consisting of two 132/66/11kV transformers (i.e. 2 x 160MVA transformers; one new and one existing transformer). Option 3 maintains the existing configuration consisting of three 132/66/11kV transformers (i.e. 2 x 100MVA new transformers and 1 x 160MVA existing transformer).

By addressing the condition risks, all options presented allow Powerlink to meet the identified need and continue to meet the reliability and service standards specified within Powerlink's Transmission Authority, Schedule 5.1 of the Rules and applicable regulatory instruments.

The Base Case is a non-credible option that reflects a state of the world in which the condition of the ageing asset is only addressed through standard operational maintenance activities, with escalating safety, financial, environmental and network risks.

The three credible network options, along with their net present values (NPVs) relative to the Base Case are summarised in Table 1. Option 2 is ranked first of the three credible options, with the highest NPV relative to the Base Case.

[1] Electricity Act 1994, Electrical Safety Act 2002 and Electricity Safety Regulation 2013
[2] The Rules clause 5.10.2, Definitions, reliability corrective action.

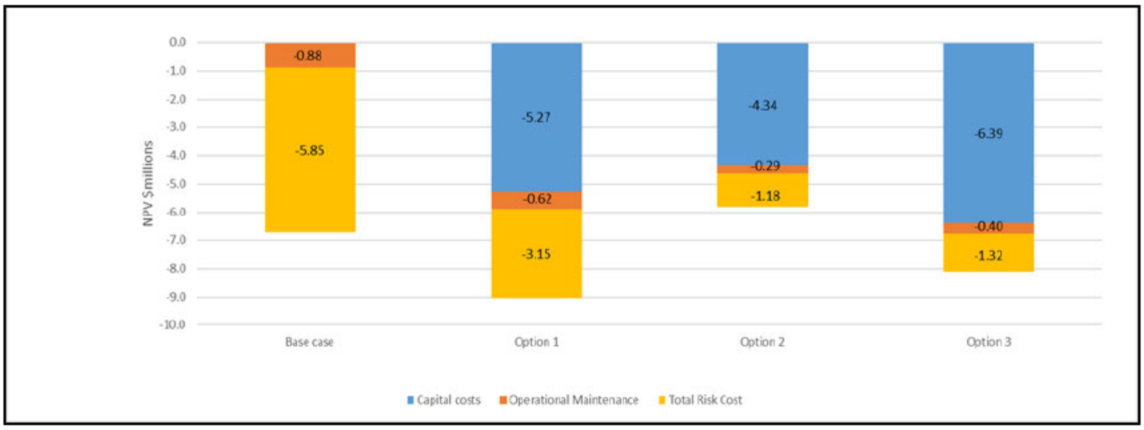
Table 1: Summary of credible network options

Option	Description	Total Cost ($m) 2018/19	NPV relative to Base Case ($m) 2018/19	Ranking
1	Repair oil leaks and replace selected components on the two at-risk 80MVA transformers to address corrosion and emerging reliability issues by June 2022 Replace both at-risk 80MVA 132/66/11kV transformers with a single 160MVA 132/66/11kV transformer by June 2027	3.50* 6.16†	-2.31	3
2	Replace both at-risk 80MVA 132/66/11kV transformers with a single 160MVA 132/66/11kV transformer by June 2022	6.16*	+0.91	1
3	Replace both at-risk 80MVA 132/66/11kV transformers with two 100MVA 132/66/11kV transformers by June 2022	9.09*	-1.39	2

*RIT-T Project
†Future modelled project

The absolute NPVs of the Base Case and the credible options are negative, shown graphically in Figure 1. All options reduce the total risk and maintenance costs arising from the ageing and obsolete assets at Blackwater remaining in service, with Option 2 having the largest reduction and reflecting a net economic benefit of $0.91 million compared to the Base Case.

Figure 1: NPV of the Base Case and Options ($m, 2018/19)



Evaluation and Conclusion

The RIT-T requires that the proposed preferred option maximises the present value of net economic benefit, or minimises the net cost, to all those who produce, consume and transport electricity in the market.

In accordance with the expedited process for this RIT-T, the PSCR made a draft recommendation to implement Option 2. The RIT-T project for Option 2 involves replacing the two 132/66/11kV 80MVA transformers with one 132/66/11 kV 160MVA transformer by June 2022, at an estimated capital cost of $6.16 million in 2018/2019 prices. Under Option 2, design work will commence in late 2019, with installation of the new transformer completed by June 2022. Powerlink is the proponent of this network solution.

As the outcomes of the economic analysis contained in this PACR remain unchanged from those published in the PSCR, the draft recommendation has been adopted without change as the final recommendation, and will now be implemented.

1. Introduction

This Project Assessment Conclusions Report (PACR) represents the final step of the RIT-T process[3] prescribed under the National Electricity Rules (the Rules) undertaken by Powerlink to address the condition risks arising from the two ageing 80MVA 132/66/11kV transformers at Blackwater Substation. It follows the publication of the Project Specification Consultation Report (PSCR) in May 2019.

The Project Specification Consultation Report (PSCR):

- described the identified need that Powerlink is seeking to address, together with the assumptions used in identifying this need
- set out the technical characteristics that a non-network option would be required to deliver in order to address the identified need
- described the credible options that Powerlink considered may address the identified need
- discussed specific categories of market benefit that in the case of this RIT-T assessment are unlikely to be material
- presented the Net Present Value (NPV) economic assessment of each of the credible options (as well as the methodologies and assumptions underlying these results) and identified the preferred option and that Powerlink was claiming an exemption from producing a Project Assessment Draft Report (PADR)
- invited submissions and comments, in response to the PSCR and the credible options presented, from Registered Participants, the Australian Energy Market Operator (AEMO), potential non-network providers and any other interested parties.

Powerlink identified Option 2, involving the replacement of the two 132/66/11kV 80MVA transformers with one 132/66/11 kV 160MVA transformer by June 2022, as the preferred option to address the identified need. The indicative capital cost of this option is $6.16 million in 2018/19 prices.

The Rules clause 5.16.4(z1) provides for a Transmission Network Service Provider to claim exemption from producing a PADR for a particular RIT-T application if all of the following conditions are met:

- the estimated capital cost of the preferred option is less than $43 million
- the preferred option is identified in the PSCR noting exemption from publishing a PADR
- the preferred option, or other credible options, do not have a material market benefit, other than benefits associated with changes in involuntary load shedding[4]
- submissions to the PSCR did not identify additional credible options that could deliver a material market benefit.

There were no submissions received in response to the PSCR that closed for consultation on 27 August 2019. As a result, no additional credible options that could deliver a material market benefit have been identified as part of this RIT-T consultation. As the conditions are now satisfied, Powerlink has not issued a PADR for this RIT-T and is now publishing this PACR, which:

- describes the identified need and the credible options that Powerlink considers address the identified need
- discusses the consultation process followed for this RIT-T together with the reasons why Powerlink is exempt from producing a PADR

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[3] This RIT-T consultation was commenced in May 2019 and has been prepared based on the following documents: National Electricity Rules, Version 121, 2 May 2019 and AER, Application guidelines, Regulatory investment test for transmission, December 2018.
[4] Section 4.3 Project assessment draft report, Exemption from preparing a draft report, AER, Application guidelines, Regulatory investment test for transmission, December 2018

- provides a quantification of costs and reasons why specific classes of market benefit are not material for the purposes of this RIT-T assessment
- provides the results of the net present value (NPV) analysis for each credible option assessed, together with accompanying explanatory statements
- identifies the preferred option for investment by Powerlink and details the technical characteristics and proposed commissioning date of the preferred option.

2. Customer and non-network engagement

Delivering electricity to almost four million Queenslanders, Powerlink recognises the importance of engaging with a diverse range of customers and stakeholders who have the potential to affect, or be affected by, Powerlink's activities and/or investments.

2.1 Powerlink takes a proactive approach to engagement

Powerlink regularly hosts a range of engagement forums and webinars, sharing information with customers and stakeholders in the broader community. These engagement activities help inform the future development of the transmission network and assist Powerlink in providing services that align with the long term interests of customers. Feedback from these activities is also incorporated into a number of publicly available reports.

2.2 Working collaboratively with Powerlink's Customer Panel

Powerlink's Customer Panel provides a face-to-face opportunity for customers and consumer representative bodies to give their input and feedback about Powerlink's decision making, processes and methodologies. It also provides Powerlink with a valuable avenue to keep customers better informed, and to receive feedback about topics of relevance, including RIT-Ts.

The Customer Panel is regularly advised on the publication of Powerlink's RIT-T documents and briefed quarterly on the status of current RIT-T consultations, as well as upcoming RIT-Ts, providing an ongoing opportunity for:

- the Customer Panel to ask questions and provide feedback to further inform RIT-Ts
- Powerlink to better understand the views of customers when undertaking the RIT-T consultation process.

2.3 Transmission Annual Planning Report (TAPR) – the initial stage of public consultation

Powerlink utilises the TAPR as a primary vehicle to engage and understand broader consumer, customer and industry views on key topics as part of the annual Transmission Network Forum (TNF) and to inform its business network and non-network planning objectives. TNF participants encompass a diverse range of stakeholders including customers, landholders, environmental groups, Traditional Owners, government agencies, and industry bodies.

2.3.1 Maintaining transfer capabilities and reliability of supply at Blackwater

- Powerlink identified in its TAPR from 2016, an expectation that action would be required at Blackwater Substation to maintain transfer capabilities and reliability of supply in the Central West transmission zone[5].
- The 2018 and 2019 TAPRs also discussed and provided technical information in relation to the identified need of this RIT-T.
- Members of Powerlink's Non-network Engagement Stakeholder Register (NNESR) were directly advised of the publication of the TAPR each year[6], including the accompanying compendium of potential non-network solution opportunities (Appendix F), which sets out

[5] This relates to the standard geographic definitions (zones) identified within the TAPR.
[6] More recently this also included the publication of a TAPR template containing detailed technical data for the connection point at Blackwater Substation.

the indicative non-network requirements to meet the identified need at Blackwater Substation. The NNESR were also advised of the publication of the PSCR for this RIT-T.

- The Customer Panel was advised of the upcoming RIT-T consultation for Blackwater Substation in December 2018.
- No submissions proposing credible and genuine non-network options have been received from prospective non-network solution providers in the normal course of business, in response to the publication of TAPRs or as a result of stakeholder engagement activities.

2.4 Powerlink applies a consistent approach to the RIT-T stakeholder engagement process

Powerlink undertakes a considered and consistent approach to ensure an appropriate level of stakeholder engagement is undertaken for each individual RIT-T. Please visit Powerlink's website for detailed information on the types of engagement activities, which may be undertaken during the consultation process. These activities focus on enhancing the value and outcomes of the RIT-T engagement process for customers and non-network providers. Powerlink welcomes feedback from all stakeholders to improve the RIT-T stakeholder engagement process.

3. Identified need

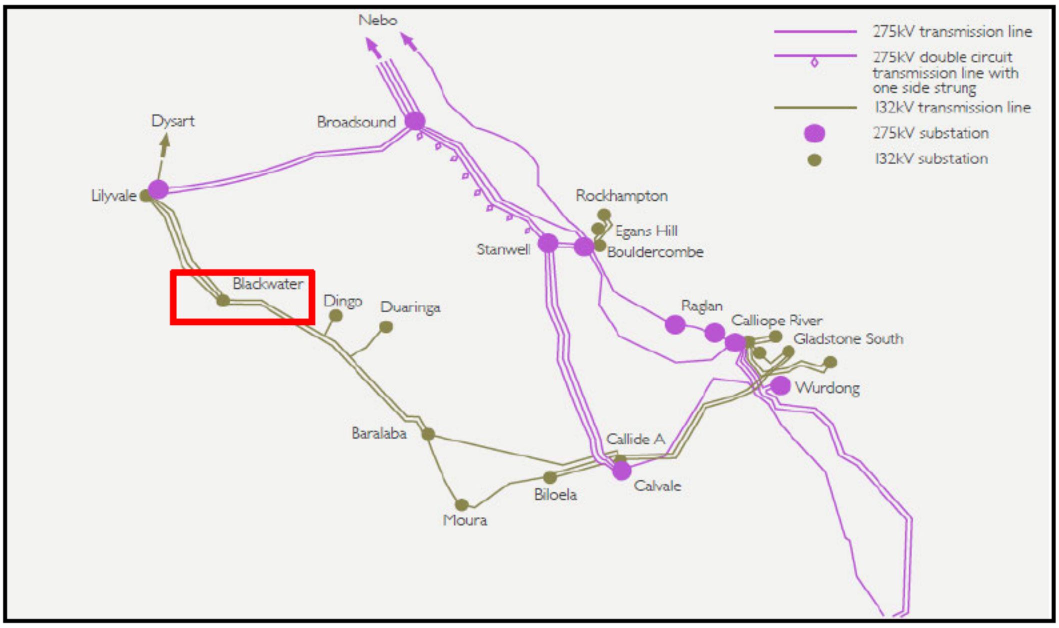
This section provides an overview of the existing arrangements at Blackwater Substation and describes the increasing risk to reliability of supply in the Central West area due to the assessed deteriorated condition of the ageing 80MVA transformers at the substation.

3.1 Geographical and network need

Blackwater Substation was established in 1969 to service the growing residential, mining and rail needs of Central West Queensland. The substation consists of 132kV (Powerlink) and 66kV (Ergon Energy) switchyards and hosts three 132/66/11kV transformers (2 x 80MVA and 1 x 160MVA) supplying the Ergon Energy load. It also facilitates the connection of seven 132kV feeders.

The Central West and Gladstone transmission zones are shown in Figure 3.1.

Figure 3.1: Central West and Gladstone transmission zones



3.2 Description of asset condition and risks

Powerlink has undertaken a comprehensive condition assessment of the transformers at Blackwater Substation.

Commissioned over 40 years ago, the two original 132/66/11kV transformers are exhibiting signs of age-related deterioration, particularly in the performance of their oil impregnated insulating paper and main tank bushing seals, as well as the corrosion of external fittings. Protective galvanised coatings have begun to break down on several components including radiators, connecting pipework, control system cabinets, bushing mountings and flanges.

The sealing integrity of numerous joints and valves has been compromised, resulting in an increased observation of oil leaks at radiators, bushings and conservator tanks. Analysis has also shown the transformers' winding paper insulation has deteriorated and is nearing the end of its technical service life, with approximately 3 to 5 years of reliable operation remaining.

The design of the winding clamping mechanism used in these older transformers also results in a loss of residual clamping pressure over time as the paper deteriorates, reducing the overall resilience of the transformers to future through faults. A failure of transformer insulation during a through fault can have major consequences to reliability of supply, safety and the environment because of the potential for oil loss and fire.

The transformers' porcelain bushings have also reached their manufacturers predicted design service life, increasing their likelihood of failure and presenting Powerlink with an unacceptable level of safety and network risks.

The age and design of the transformers means that replacements for key components are no longer available; hence, obsolescence has also become an issue with ongoing maintenance of the transformers.

The main condition-based risks of the transformers are summarised in Table 3.1.

Table 3.1: Blackwater transformer risks and consequences

Equipment	Condition/Issue	Consequence of failure
Power Transformers	• Degraded oil and paper insulation • Deteriorated cooling fans and radiators • Significant oil leaks. • Reduced clamping pressure due to clamp design • Loss of insulating paper strength • Limited availability of spares	• Increased susceptibility to power transformer failure during through faults leading to loss of supply with long return to service time. • Increased risk of fire and environmental damage.

As the consequences of a major failure of a power transformer are high, the asset management strategy employed is to plan and execute reinvestment before an actual failure occurs, given an ongoing future need to supply electricity in the area.

Notwithstanding the assessed condition of the asset, Powerlink's ongoing operational maintenance practices are designed to monitor plant condition and ensure emerging safety and environmental risks are proactively managed.

3.3 Description of identified need

With peak demand forecast to remain steady in the area for the next ten years[7], it is vital that Powerlink maintains supply to satisfy this demand and meet its reliability obligations under its Transmission Authority, the Electricity Act 1994 and the Rules[8]

It follows that the increasing likelihood of faults arising from the deteriorated condition of the 80MVA transformers remaining in service at Blackwater Substation compels Powerlink to take

[7] Powerlink Transmission Annual Planning Report 2019
[8] Transmission Authority Number T01/98, as amended 30 June 2014; Electricity Act 1994; The Rules, Schedule 5.1a System Standards and Schedule 5.1.2 Network Reliability

action if it is to continue to meet its regulatory obligations and the standards for reliability of supply set out in the Rules.

Powerlink's Transmission Authority requires it to plan and develop the transmission network "in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services". It allows load to be interrupted during a critical single network contingency, provided the maximum load and energy:

- will not exceed 50MW at any one time; or
- will not be more than 600MWh in aggregate[9].

In order to continue to meet the reliability standard within Powerlink's Transmission Authority, the services currently provided by the transformers at the Blackwater Substation are required for the foreseeable future to meet ongoing customer requirements.

Under the Electricity Act 1994, Powerlink is required to "operate, maintain (including repair and replace if necessary) and protect its transmission grid to ensure the adequate, economic reliable and safe transmission of electricity"[10]. The condition of the ageing 80MVA transformers at Blackwater requires Powerlink to take action to either repair, replace or remove them, while taking into consideration the enduring need for the services they provide, to ensure compliance with the Electricity Act 1994.

The Electrical Safety Act 2002 also requires Powerlink to operate its network in a manner that ensures electrical risk to a person or property has been eliminated, so far as is reasonably practicable; or if it is not reasonably practicable to eliminate electrical risk to the person or property, the risk has been minimised so far as is reasonably practicable[11].

As the proposed investment is to meet reliability and service standards specified within applicable regulatory instruments, and to ensure Powerlink's ongoing compliance with Schedule 5.1 of the Rules, it is classified as a "reliability corrective action", under the RIT-T[12].

A reliability corrective action differs from that of an increase in producer and consumer surplus (market-benefit) driven need in that the preferred option may have a negative net economic outcome because it is required to meet an externally imposed obligation on the network business.

3.4 Rules, Jurisdictional and Legislative Compliance

The consequences of Blackwater's at-risk transformers remaining in service beyond 2022, without corrective action, would result in Powerlink being exposed to an unacceptable risk of breaching a number of its jurisdictional network, safety, environmental and Rules' obligations - resulting in poor customer, safety and environmental outcomes.

Safety and environmental obligations could theoretically be met by removing the 80MVA transformers from service, however to ensure Powerlink remains compliant with its Transmission Authority given the enduring electricity supply needs in the area, action must be taken to ensure the services provided by the 80MVA transformers are replicated either by credible network or non-network solutions.

By addressing the risks arising from the condition of the ageing 80MVA transformers at Blackwater, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to its customers in the Blackwater area into the future.

[9] Transmission Authority No. T01/98, section 6.2(c)
[10] Electricity Act 1994, Chapter 2, Part 4, S34(1)(a)
[11] Electrical Safety Act 2002 sections 10 and 29
[12] The Rules clause 5.10.2, Definitions, reliability corrective action.

4. Submissions received

There were no submissions received in response to the PSCR that was open for consultation until the 27 August 2019[13]. As a result, no additional credible options that could deliver a material market benefit have been identified as part of this RIT-T consultation.

5. Credible options assessed in this RIT-T

Powerlink has developed three credible network options to address the identified need for maintaining reliability of supply in the Blackwater area. All three options are designed to mitigate the risks to supply before the 80MVA transformers reach the end of their technical service lives and to ensure Powerlink maintains compliance with reliability and service standards specified in its Transmission Authority, Schedule 5.1 of the Rules and relevant jurisdictional instruments.

- Option 1: Life extension of the two at-risk 80MVA transformers by June 2022, followed by the replacement of both at-risk transformers with a single 160MVA transformer by June 2027. The RIT-T portion of this option would be completed by June 2022 at a cost of $3.5 million in 2018/19 prices.
- Option 2: Replacement of both at-risk 80MVA transformers with a single 160MVA transformer by June 2022, at a cost of $6.16 million in 2018/19 prices.
- Option 3: Replacement of both at-risk 80MVA transformers with two 100MVA transformers by June 2022, at a cost of $9.09 million in 2018/19 prices.

Table 4.1: Summary of credible options

Option	Description	Indicative project costs ($million, 2018/19)	Indicative annual average O&M costs ($million, 2018/19)
1	Repair oil leaks and replace selected components on the two at-risk 80MVA 132/66/11kV transformers to address corrosion and emerging reliability issues by June 2022	3.50*	0.04
	Replace both at-risk 80MVA 132/66/11kV transformers with a single 160MVA 132/66/11kV transformer by June 2027	6.16†	
2	Replace both at-risk 80MVA 132/66/11kV transformers with a single 160MVA 132/66/11kV transformer by June 2022	6.16*	0.02
3	Replace both at-risk 80MVA 132/66/11kV transformers with two 100MVA 132/66/11kV transformers by June 2022	9.09*	0.03

*RIT-T Project
†Future modelled project

All credible network options address the major risks resulting from the deteriorated condition of ageing transformers at Blackwater Substation. None of these options has been discussed by

[13] Members of Powerlink's Non-network Engagement Stakeholder Register were also advised of the PSCR publication.

the Australian Energy Market Operator (AEMO) in its most recent National Transmission Network Development Plan (NTNDP)[14].

5.1 Material inter-network impact

Powerlink does not consider that any of the credible options being considered will have a material inter-network impact, based on AEMO's screening criteria[15].

6. Materiality of Market Benefits

The Rules require that all categories of market benefits identified in relation to a RIT-T be quantified, unless the Transmission Network Service Provider (TNSP) can demonstrate that a specific category (or categories) is unlikely to be material.

6.1 Market benefits that are material for this RIT-T assessment

Powerlink considers that changes in involuntary load shedding (i.e. the reduction in expected unserved energy) between the options set out in this PACR, may impact the ranking of the credible options under consideration, or the relativity of the credible options to the Base Case, and that this class of market benefit could be material. These benefits have been quantified and included within the cost benefit and risk cost analysis as network risk.

6.2 Market benefits that are not material for this RIT-T assessment

The AER has recognised a number of classes of market benefits may not be material in the RIT-T assessment and so do not need to be estimated[16]. Other than market benefits associated with involuntary load shedding, Powerlink does not consider any other category of market benefits to be material, and had not estimated them as part of this RIT-T.

More information on consideration of individual classes of market benefits can be found in the PSCR.

7. Base Case

7.1 Modelling a Base Case under the RIT-T

Consistent with the RIT-T Application Guidelines, the assessment undertaken in this PACR[17] compares the costs and benefits of credible options constructed to address the risks arising from an identified need, with a Base Case[18].

As characterised in the RIT-T Application Guidelines, the Base Case itself is not a credible option to meet the identified need. Specifically, the Base Case reflects a state of the world in which the condition of the ageing asset is only addressed through standard operational activities, with escalating safety, financial, environmental and network risks.

To develop the Base Case, the existing condition issues associated with an asset are managed by undertaking operational maintenance only, which results in an increase in risk levels as the condition of the asset deteriorates over time. These increasing risk levels are assigned a monetary value that is used to evaluate the credible options designed to offset or mitigate these risk costs.

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[14] Clause 5.16.4(b) (4) of the Rules requires Powerlink to advise whether the identified need and or solutions are included in the most recent NTNDP. The 2018 NTNDP is currently the most recent NTNDP.
[15] In accordance with Rules clause 5.16.4(b)(6)(ii). AEMO has published guidelines for assessing whether a credible option is expected to have a material inter-network impact.
[16] AER, Application guidelines, Regulatory investment test for transmission, December 2018.
[17] The economic assessment was also presented in the PSCR.
[18] AER, Final Regulatory investment test for transmission application guidelines, December 2018.

The Base Case therefore includes the costs of work associated with operational maintenance (i.e. routine, condition-based and corrective maintenance) and the risk costs associated with the irreparable failure of the asset. The costs associated with irreparable failures are modelled in the risk cost analysis and are not included in the corrective maintenance costs.

The Base Case acts as a benchmark and provides a clear reference point in the cost benefit analysis to compare and rank the credible options against, over the same timeframe.

7.2 Blackwater 80MVA transformer Base Case risk costs

Powerlink has developed a risk modelling framework consistent with the RIT-T Application Guidelines. An overview of the framework is available on Powerlink's website[19] and has been used to calculate the risk costs of the Base Case for the two 80MVA Blackwater transformers. The framework includes the modelling methodology and general assumptions underpinning the analysis.

7.2.1 Base Case assumptions

In calculating the potential unserved energy (USE) arising from a failure of the two ageing 132/66/11kV 80MVA transformers at Blackwater, the following modelling assumptions specific to the Blackwater network configuration have been made:

- A suitable spare transformer is available as an emergency replacement in the event of non-repairable failure of one of the aged transformers.
- The downstream Ergon Energy 66kV distribution network supplying the greater Lilyvale and Blackwater area is available to provide a level of backup supply in the event of equipment failure.
- Embedded generation within the area operates while Blackwater substation remains energised to reduce the impacts of unserved energy in the event of equipment failures.
- Historical load profiles and embedded generation patterns have been used when assessing the likelihood of unserved energy under concurrent failure events.
- Peak demand for the greater Blackwater load area consistent with medium demand forecasts published within Powerlink's 2018 Transmission Annual Planning Report have been used[20].
- Unserved energy generally accrues under concurrent failure events, and consideration has been given to potential feeder trip events within the wider Blackwater area.
- The Blackwater Substation load comprises of a mix of load types, including open cut mining, underground mining, traction loads, and residential township. The network risk cost models have used the Queensland regional Value of Customer Reliability (VCR) published within AEMO 2014 Value of Customer Reliability Review Final Report ($39,710/MWh).
- Powerlink's business response to mitigating unserved energy under prolonged supply outage events has been incorporated within the risk cost modelling.

7.2.2 Base Case risk costs

The main areas of risk cost are associated with network risks that involve reliability of supply through failure of the aged transformers modelled as probability weighted unserved energy and financial risk costs associated mostly with the replacement of failed assets in an emergency situation. Both of these risks increase over time as the condition of plant further deteriorates and the likelihood of failure rises.

Based upon the assessed condition of the ageing 80MVA transformers at Blackwater, total risk costs are projected to increase from $0.2 million in 2019 to $1.4 million in 2038.

The 20-year forecast of risk costs for the Base Case is shown in Figure 7.1.

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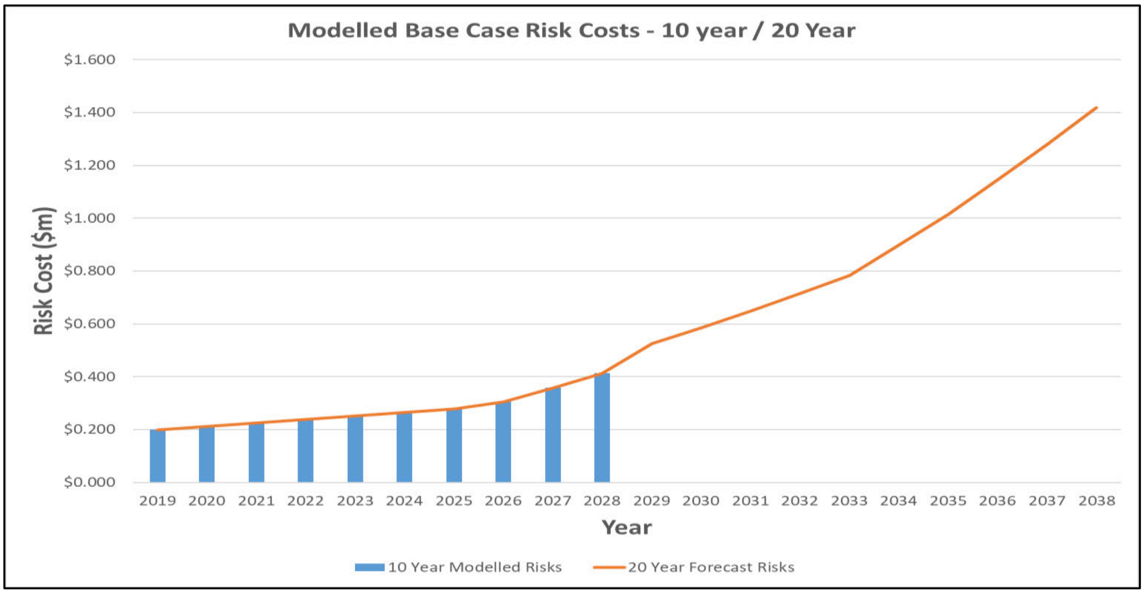
[19] The risk costs are calculated using the principles set out in the Powerlink document, [Overview of Asset Risk Cost Methodology,]() May 2019.
[20] The forecast remains unchanged in the 2019 TAPR.

Figure 7.1: Modelled Base Case risk costs



7.3 Modelling of Risk in Options

Each option is specifically scoped to mitigate the major risks arising in the Base Case and to maintain compliance with all statutory requirements. The residual risk is calculated for each option based upon the individual implementation strategy of the option. This is included with the capital and operational maintenance cost of each option to develop the NPV inputs.

8. General modelling approach adopted for net benefit analysis

8.1 Analysis period

The RIT-T analysis has been undertaken over a 20 year period, from 2019 to 2038. A 20-year period takes into account the size and complexity of the proposed primary plant investments.

For all options, there will be remaining asset life by 2038, at which point a terminal value is calculated to correctly account for capital costs under each credible option.

8.2 Discount rate

Under the RIT-T, a commercial discount rate is applied to calculate the NPV of costs and benefits of the credible options. Powerlink has adopted a real, pre-tax commercial discount rate of 5.90%[21] as the central assumption for the NPV analysis presented in this report.

Powerlink has tested the sensitivity of the results to changes in this discount rate assumption, and specifically to the adoption of a lower bound discount rate of 3.47%[22] and an upper bound discount rate of 8.33% (i.e. a symmetrical upwards adjustment).

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[21] This indicative commercial discount rate has been calculated on the assumptions that a private investment in the electricity sector would hold an investment grade credit rating and have a return on equity equal to an average firm on the Australian stock exchange, as well as a debt gearing ratio equal to an average firm on the Australian stock exchange.

[22] A discount rate of 3.47 per cent is based on the AER's Final Decision for Powerlink's 2017-2022 transmission determination, which allowed a nominal vanilla WACC of 6.0 per cent and forecast inflation of 2.45 per cent that implies a real discount rate of 3.47 per cent. See AER, Final Decision: Powerlink transmission determination 2017-2022 | Attachment 3 – Rate of return, April 2017, p 9.

8.3 Description of reasonable scenarios

The RIT-T analysis is required to incorporate a number of different reasonable scenarios, which are used to estimate market benefits. The number and choice of reasonable scenarios must be appropriate to the credible options under consideration.

The choice of reasonable scenarios must reflect any variables or parameters that are likely to affect the ranking of the credible options, where the identified need is reliability corrective action[23].

Powerlink has considered capital costs and discount rate sensitivities individually and in combination and found that these variables do not affect the relative rankings of credible options or identification of the preferred option. As sensitivities (both individually and in combination) do not affect the ranking of the preferred option, Powerlink has elected to present one central scenario in Table 8.1.

Table 8.1: Reasonable scenario assumed

Key variable/parameter	Central scenario
Capital costs	100% of central capital cost estimate
Discount rate	5.90%

9. Cost benefit analysis and identification of the preferred option

9.1 NPV Analysis

Table 9.1 outlines the NPV and the corresponding ranking of each credible option relative to the Base Case.

Table 9.1: NPV for each credible option ($m, 2018/19)

Option	Description	Central Scenario NPV relative to Base Case ($m)	Ranking
1	Repair oil leaks and replace selected components on the two at-risk 80MVA 132/66/11kV transformers to address corrosion and emerging reliability issues by June 2022 Replace both at-risk 80MVA 132/66/11kV transformers with a single 160MVA 132/66/11kV transformer by June 2027	-2.31	3
2	Replace both at-risk 80MVA 132/66/11kV transformers with a single 160MVA 132/66/11kV transformer by June 2022	+0.91	1
3	Replace both at-risk 80MVA 132/66/11kV transformers with two 100MVA 132/66/11kV transformers by June 2022	-1.39	2

All three credible options will address the identified need on an enduring basis. Option 2 is ranked first of the three credible options, with the highest NPV relative to the Base Case.

[23] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 16, p. 7

When compared to other credible options, Option 3 is $2.30 million and Option 1 is $3.22 million more expensive than Option 2 in NPV terms.

Figure 9.1 sets out the breakdown of capital cost, operational maintenance cost and total risk cost for each option in NPV terms under the central scenario. Note that the Base Case consists of operational maintenance and total risk costs and does not include any capital expenditure.

Figure 9.1: Central Scenario NPV component for each credible option (NPV $m, 2018/19)

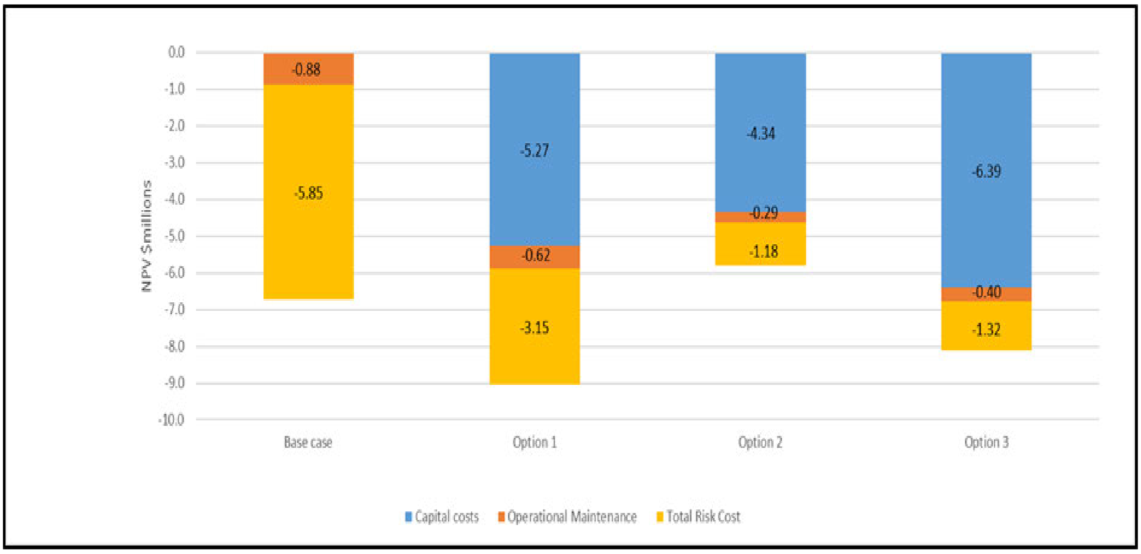


Figure 9.1 illustrates that all credible options will reduce the total risk cost and operational maintenance cost compared to the Base Case. Option 2 has the highest cost reduction benefit of the three credible options when compared with the Base Case.

Option 2 has the largest reduction in operational maintenance costs as the ultimate configuration consists of two 132/66/11kV transformers (1 new and 1 existing 160MVA transformer) at Blackwater from 2022.

Option 2 also has the largest reduction in total risk costs. This is due to the lower financial, network and safety risks associated with the ultimate two 132/66/11 kV transformer configuration to be commissioned from June 2022. Option 1 reaches the two transformer configuration at a later date in June 2027, while Option 3 retains the current three transformer configuration and has the highest residual total risk cost.

9.2 Sensitivity analysis

Powerlink has investigated the following sensitivities on key assumptions:

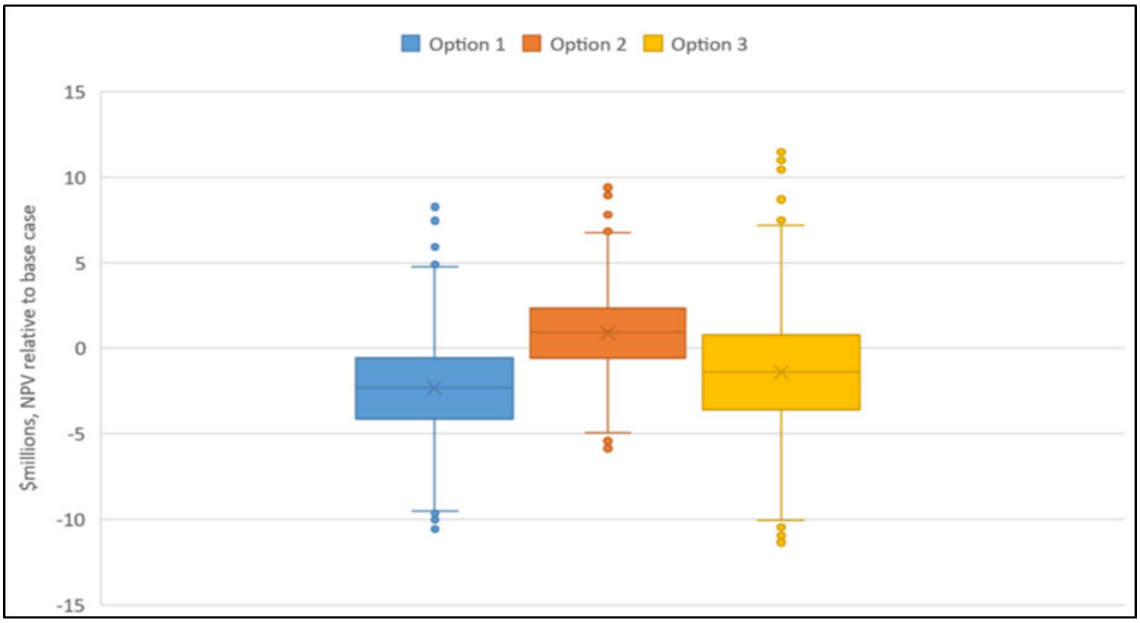
- a range from 3.47% to 8.33% for discount rate.
- a range from 75% to 125% of base capital expenditure estimates.
- a range from 75% to 125% of operational maintenance expenditure estimates.
- a range from 75% to 125% of total risk cost estimates.

Sensitivity analysis for the NPV relative to the Base Case shows that varying the discount rate, capital expenditure, operational maintenance expenditure and total risk costs has no impact on the option rank and the identification of the preferred option.

9.2.1 Sensitivity to multiple parameters

A Monte Carlo simulation was performed with multiple input parameters (including capital cost, discount rate, operational maintenance cost and total risk cost) generated for the calculation of NPV for each option. This process is repeated over 5000 iterations, each time using a different set of random variables from the probability function. The sensitivity analysis output is presented as a distribution of possible NPVs for each option, as illustrated in Figure 9.2.

Figure 9.2 NPV sensitivity analysis of multiple key assumptions relative to the Base Case



The Monte Carlo simulation results identify that Option 2 has the highest mean and median compared to the other credible options, while also exhibiting less statistical dispersion. This confirms Option 2 as the preferred option and shows it to be robust over a range of input parameters in combination.

10. Preferred option

Based on the conclusions drawn from the NPV analysis and the Rules requirements relating to the proposed replacement of transmission network assets, it is recommended that Option 2 be implemented to address the risks associated with the deteriorated condition of the two ageing 132/66/11kV 80MVA transformers at Blackwater Substation. Implementing this option will provide an ongoing safe and reliable electricity supply to customers in the area and ensure continued compliance with applicable regulatory instruments and the Rules.

The result of the cost benefit analysis indicates that Option 2 has the highest net economic benefit over the 20-year analysis period. Sensitivity testing shows that the analysis is robust to variations in the capital cost, operational maintenance cost, discount rate and risk cost assumptions. Option 2 is therefore considered to satisfy the requirements of the RIT-T and is the preferred option.

11. Conclusions

The following conclusions have been drawn from the analysis presented in this report:

- Powerlink has identified condition risks arising from the two ageing 80MVA transformers at Blackwater Substation.
- TNSPs must maintain (including repair and replace if necessary) their transmission network to ensure the adequate, economic, reliable and safe transmission of electricity, including the ability to meet peak demand if a major element of the network was to fail.
- The increasing likelihood of faults associated with the condition of the ageing 80MVA transformers compels Powerlink to undertake reliability corrective actions at Blackwater Substation if it is to continue meeting the reliability standards set out in its Transmission Authority and to ensure ongoing compliance with the Rules and relevant jurisdictional obligations.

- Studies were undertaken to evaluate three credible options. The three credible options were evaluated in accordance with the AER's RIT-T.
- Powerlink published a PSCR in May 2019 requesting submissions from Registered Participants, AEMO and interested parties on the credible options presented, including alternative credible non-network options, which could address the condition risks associated with the 80MVA transformers at Blackwater Substation.
- The PSCR also identified the preferred option and that Powerlink was adopting the expedited process for this RIT-T, claiming exemption from producing a PADR as allowed for under the Rules Clause 5.16.4(z1) for investments of this nature.
- There were no submissions received in response to the PSCR, which was open for consultation until 27 August 2019. As a result, no additional credible options that could deliver a material market benefit have been identified as part of this RIT-T consultation. The conditions specified under the Rules for exemption have now been fulfilled.
- The result of the cost-benefit analysis under the RIT-T identified that Option 2 is the least cost solution, providing the greatest economic benefit, over the 20 year analysis period. Sensitivity testing showed the analysis is robust to variations in discount rate, capital expenditure, operational maintenance expenditure and risk cost assumptions. As a result, Option 2 is considered to satisfy the RIT-T.
- The outcomes of the economic analysis contained in this PACR remain unchanged from those published in the PSCR. Consequently, the draft recommendation has been adopted without change as the final recommendation and will now be implemented.

12. Final Recommendation

Based on the conclusions drawn from the NPV analysis and the Rules requirements relating to the proposed replacement of transmission network assets, it is recommended that Option 2 be implemented to address the risks associated with the condition of the ageing 80MVA transformers at Blackwater Substation. Option 2 allows Powerlink to continue to maintain compliance with Powerlink's Transmission Authority, Schedule 5.1 of the Rules and other applicable regulatory instruments.

Option 2 involves replacing both 132/66/11kV 80MVA transformers with one new 160MVA transformer by June 2022. This option minimises the number of outages and mobilisation costs, and reduces the overall future operational maintenance costs, as there are less transformers to maintain in the final substation configuration.

The indicative capital cost of the RIT-T project for Option 2 is $6.16 million in 2018/19 prices. Powerlink is the proponent of this network solution.

Design and procurement activities will commence in late 2019, with the RIT-T project works to be completed by June 2022.

Powerlink will now proceed with the necessary processes to implement this recommendation.

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