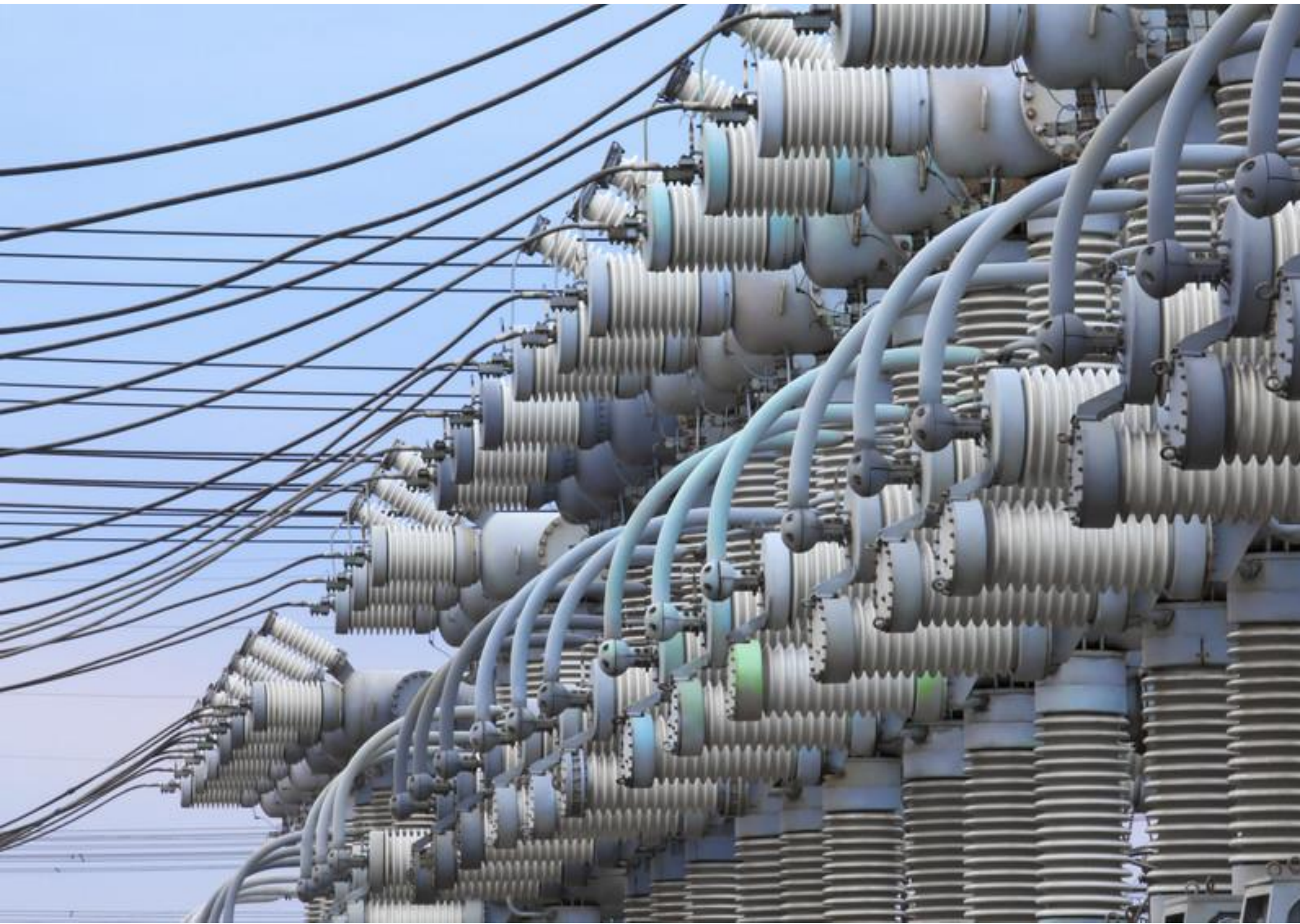
Transformer Renewals

2023-28 Revenue Proposal

Transgrid

7 November 2022

→ **The Power of Commitment**



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The Power of Commitment

Executive summary

The original Transgrid proposal for the 2023-2028 regulatory period planned to replace 11 transformers on the basis that their Net Present Value (NPV) options analysis supported this path as the preferred option. The Australian Energy Regulator (AER) observed that Transgrid has historically refurbished (rather than replaced) about 90% of its transformers. This observation questions whether there has been a change to the asset management strategy from previous periods.

The AER's Draft Determination has reduced Transgrid's proposed transformers Repex program from $64.4M to $24.9M representing a 61% reduction.

This report provides an independent assessment of Option Evaluation Reports (OER)s – N2404, N2421, N2422, N2423 and N2424 that have been updated based upon the feedback detailed in AER's Draft Determination.

The AER's Draft Determination included several observations regarding Transgrid's OERs covering transformers. These included the following which has been summarised:

- Transgrid provided condition reports, which indicate that most of its transformers can be returned to service with minor refurbishment (for less than $1 million in many cases).

  From GHD's perspective the AER's Asset Replacement Planning Note[1] promotes the use of NPV to support long term decision making. The view that refurbishment may see transformers returned to service is a short-term perspective which addresses some issues identified in condition reports but may not address all the longer-term transformer asset failure risks. Note – Based upon the updated OER's, only the Yass transformer is below $1M.

- In some cases, Transgrid's proposed replacement approach is overly risk averse and is not required to maintain current risk or service levels.

  Transgrid has used a standard risk-based approach to consider replacement v refurbishment options.

- Transgrid uses its Health Index Formula to calculate the probability of failure. For transformer age, the formula uses manufacturing year rather than commissioning year.

  As indicated in the body of this report, these small differences are unlikely to influence the preferred option outcome given the slope of the Probability of Failure (PoF) curve and the differentials in the NPVs calculated between replacement v refurbishments. Note the "effective transformer age" is a term that is used to indicate the condition of the transformer, and therefore indicates its probability of failure. Transformers are not replaced because they have reached a certain chronological age, they are replaced because their effective age i.e. condition is at a point where the cost of the probability of failure is higher than the replacement cost. In addition, Transgrid have indicated to GHD that except for Regentville the difference is 0 to 2 years between manufacturing and commissioning years.

[1] Industry practice application note, Asset replacement planning, January 2019, AER

– Transgrid overstates unserved energy by assuming a repair time of 10-weeks for subsequent transformer failures (i.e. N-2 events), whereas service can usually be restored (e.g. by mobilising a spare transformer) well before permanent repairs are completed

  Based upon an analysis of the tasks required to replace a transformer following an event, the location and condition of current spares, a 10-week assumption is considered prudent when calculating NPVs.

– Probability and consequence of failure risks appear to be overstated and not supported by evidence.

  As indicated above, the PoF is based upon failure data and the consequences have been based upon a methodology that is common to the sector.

Our analysis indicates that Transgrid has commissioned a large number of transformers in the first half of the 1980s. By the end of the next Regulatory Period a number of these transformers will be at or beyond their natural or effective asset lives. The analysis detailed in CIGRE's Transformer Reliability Survey 2015 (refer *Figure 2*) supports this view noting that the average effective age of transformers Transgrid is seeking to replace is 55 years.

The decision to replace v refurbishment is supported by a NPV analysis that considers incremental cash flows against a base case of doing nothing. The most influential factors in the NPV analysis relate to the capital costs, PoF and unserved energy which includes an assumption that 10-weeks would be required to effectively replace a transformer following an event. For clarity purposes, the calculation represents the risk of unserved energy, rather than the cost of unserved energy.

Transgrid's capital costs are based upon past experience, their PoF curve is based upon event data with the assumptions detailed in section 3.3. The calculation of unserved energy, further detailed in Appendix A-1 is based upon industry practice and the assumption of a 10-week replacement period appears to be reasonable based upon a risk assessment of spares availability and spares conditions detailed in section 3.2.2.

Considering CIGRE's Transformer Reliability Survey 2015, an average effective transformer age of 55 places these transformers to the right tail of the bell curve of the in-service industry-wide database for transmission substation power transformers. This indicates that it is an appropriate time to consider replacement v refurbishment options. The analysis detailed in Transgrid's OERs covering transformers is backed by sufficient analysis based upon event data and industry practice.

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1. Introduction

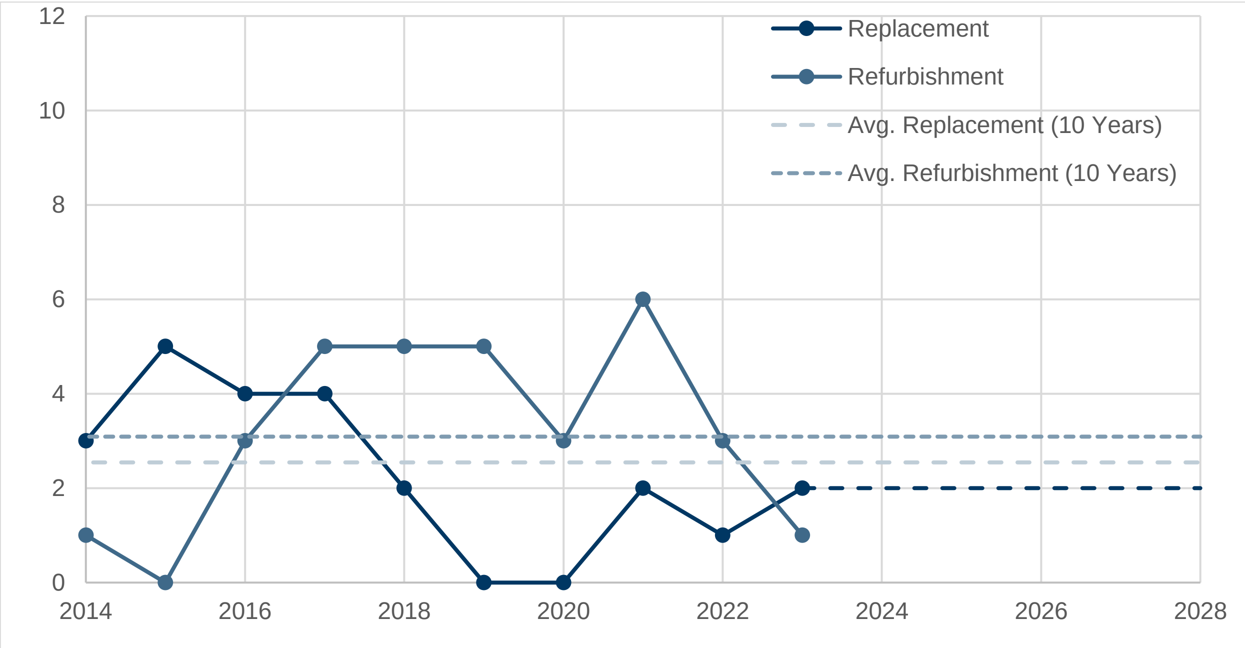
The original Transgrid proposal planned to replace 11 transformers on the basis that their NPV analysis of options supported this path as the preferred option. The AER observed that Transgrid has historically refurbished (rather than replaced) about 90% of its transformers. This observation questions whether there has been a change to the asset management strategy from previous periods.

The AER's Draft Determination has reduced Transgrid's proposed transformers Repex program from $64.4M to $24.9M representing a 61% reduction.

Transgrid have indicated that the previous regulatory period was a combination of bushing replacement and refurbishment. There were several transformers during this period that were replaced (as replacement yielded a higher NPV than refurbishment). The same Transgrid power transformer asset renewal strategy has been utilised for the development of the proposed repex program with the NPV result driving the outcome in accord with the AER's Asset Replacement Planning Note[2].

Analysing the history of Transgrid's previous transformers renewals over the last ten years reveals that on average Transgrid have been replacing about 2.5 transformers per year and refurbishing approximately 3 transformers per year. Therefore, the rate of proposed replacement of 2 transformers (10 over a 5-year period) is similar to the 10-year trend.

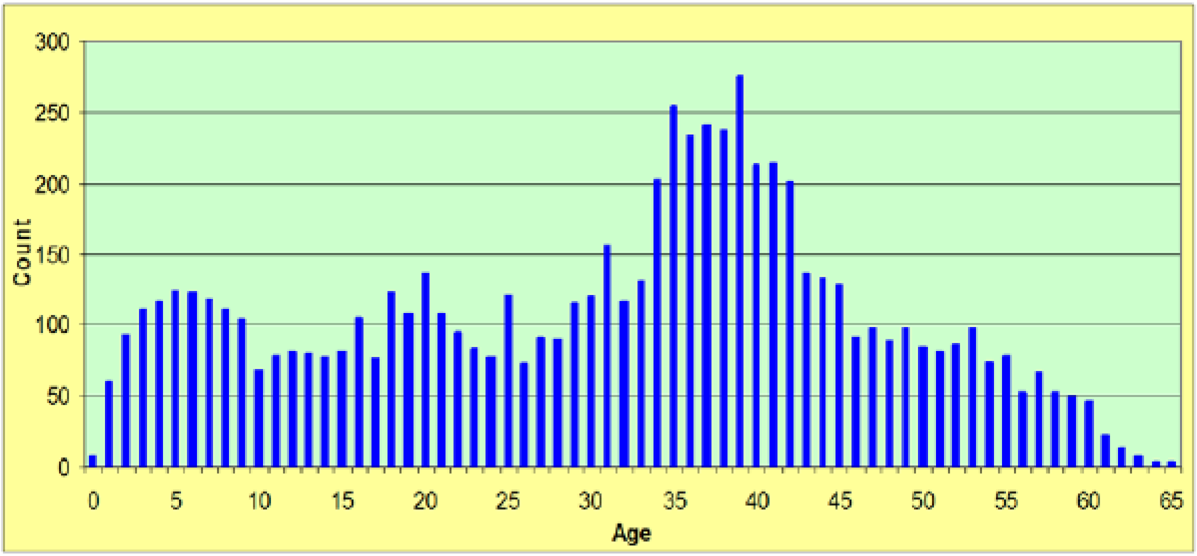
Figure 1 ***Historical transformer replacements and refurbishment***



[2] Industry practice application note, Asset replacement planning, January 2019, AER

Figure 2 details the typical age profile of transformers, noting that the average effective age of the transformers Transgrid seeks to replace is 55 years.

Figure 2 ***Typical age profile – in-service industry-wide database for transmission substation power transformers***



Source CIGRE Transformer Reliability Survey 2015

Powerlink as part of its 2023-27 regulatory period includes the replacement of nine power transformers and the refurbishment of a further four. The four transformers to be refurbished were between 35 and 39 years of age and the transformers to be replaced were aged between 37 and 44 years of age. This compares with 39 to 63 years (effective age of 41 to 61 years) for the proposed transformers to be replaced by Transgrid. Whilst the condition and asset health of each transformer is different the comparison with Powerlink indicates that Transgrid is at a portfolio level replacing their transformers on average later than Powerlink.

From a high-level perspective, there are a number of factors that drive the NPV outcome. These include the capital costs of replacement and refurbishment and the resulting risk reduction achieved through delivery. The risk reduction is a function of probability and consequence, with probability being driven by the PoF.

Transformer replacement resets the PoF to the bottom end of the curve (approximately a 6.9% reduction based upon Transgrid's PoF curve assuming an average replacement point at 55 years), whereas refurbishment may see a 2.8% reduction (based upon Transgrid's PoF curve assuming a refresh of 10 years as a result of the refurbishment). These probability differentials drive replacement v refurbishment option considerations, only triggered for assessment as the transformers reaches the end of its service life.

In this case the transformers have an average life of 55 years.

Consequence is a function of impact and duration. In this area unserved energy has the most material impact upon the NPV calculation. The calculation is complex and is based upon the individual substation configuration which can have several transformers potentially providing redundancy. The unserved energy calculation is based upon the risk of unserved energy and is further detailed in Appendix A-1.

As highlighted by the AER, the calculation is based upon a 10-week period, which is the risk of unserved energy across this period.

Based upon a bottom-up review performed by the AER, they indicate that Transgrid has not adequately demonstrated why its forecast should differ substantially from its historical practices detailing the following concerns with Transgrid's transformer Repex forecast:

- Transgrid provided condition reports, which indicate that most of its transformers can be returned to service with minor refurbishment (for less than $1 million in many cases)

  From GHD's perspective the AER's Asset Replacement Planning Note[3] promotes the use of NPV to support long term decision making. The view that refurbishment can see transformers can be returned to service returned to service is a short-term perspective which may address some of the issues identified in condition reports but not necessarily address all of the longer-term transformer asset failure risks. Transgrid's business cases indicate that it only a few cases could the transformers be refurbished for less than $1 million.

- In some cases, Transgrid's proposed replacement approach is overly risk averse and is not required to maintain current risk or service levels

  As indicated above, Transgrid has used an industry accepted methodology to perform the risk assessment.

- Transgrid uses its Health Index Formula to calculate the probability of failure. For transformer age, the formula uses manufacturing year rather than commissioning year

  As indicated above, given the differentials of the NPV calculations, the slope of the PoF curve, these small differences are unlikely to drive different preferred options. Transgrid have indicated to GHD that except for Regentville the difference is 0 to 2 years between manufacturing and commissioning years.

- Transgrid overstates unserved energy by assuming a repair time of 10 weeks for subsequent transformer failures (i.e. N-2 events), whereas service can usually be restored (e.g. by mobilising a spare transformer) well before permanent repairs are completed

  As indicated above and supported by additional analysis performed in section 3.2 the 10-week replacement assumption is considered a realistic timeframe.

- Probability and consequence of failure risks appear to be overstated and not supported by evidence.

  As indicated above and supported by additional analysis performed in section 3.3 the probabilities used have support and the calculation of consequences in based upon accepted industry practice.

Transgrid has updated the relevant OER's to address the above feedback.

1.1 Purpose of this report

This report provides an independent assessment of OERs – N2404, N2421, N2422, N2423 and N2424 that have been updated based upon the feedback detailed in AER's Draft Determination.

This report may be used to support Transgrid's Revised Revenue Proposal to be submitted to the AER.

[3] Industry practice application note, Asset replacement planning, January 2019, AER

1.2 Scope and limitations

GHD has been engaged by Transgrid to provide an independent assessment of the revised OERs prepared to support the funding request for the remediation of transformers. Our review has considered whether the:

- Assessment of options follows the AER's Asset Replacement Planning Note[4]
- Updated OER's include appropriate consideration of the transformer issues raised by the AER in their Draft Determination
- Decisions with regards the preferred option reached in the updated OER are supported by the analysis performed.

Additional details of our assessment methodology are detailed in section 2.

This report has been prepared by GHD for Transgrid and may only be used and relied on by Transgrid for the purpose agreed between GHD and Transgrid as set out in section 1.1 of this report.

GHD otherwise disclaims responsibility to any person other than Transgrid arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD described in this report. GHD disclaims liability arising from any of the assumptions being incorrect.

2. Transformer OER assessment methodology

Our assessment includes several elements that support transformer risk assessment and specific tests designed to determine if the AER's feedback on the original transformer OERs have been appropriately considered. This includes a review of:

- The health index methodology to determine if it represents an appropriate tool to support effective age estimation
- Whether the calculation of unserved energy (10-week repair time following a transformer failure) is reasonable.
- Whether the probability and consequence of failure risks are considered reasonable though a review of incidents or through considering wider industry data.

[4] Industry practice application note, Asset replacement planning, January 2019, AER

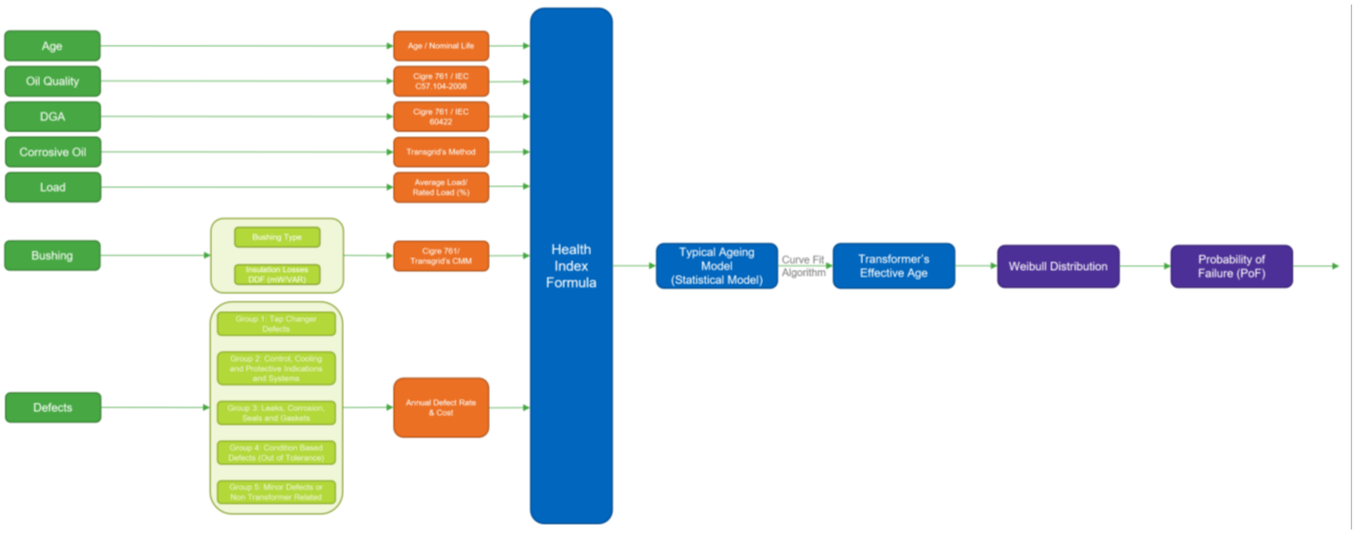
- Whether the option analysis follows the AER's Asset Replacement Planning Note[5] with appropriate Disproportionality Factors (DF) being applied in NPV calculations used to support decision making.
- Whether the selected preferred option is supportable by the analysis performed.

3. Transformer OER assessment

3.1 Transgrid's health index methodology

The asset health index methodology for transformers considers natural age, oil quality, dissolved gas analysis, corrosive oil, load, bushing condition and defects (cost and frequency). A health index score is calculated based on weighting of each of these parameters and converted to an effective age using Transgrid's typical aging model. Linked to the above, the effective age drive the PoF used in the NPV analysis. This approach is considered to be similar to approaches adopted by other Australian and overseas transmission networks with respect to power transformers.

Figure 3 Transformer health index



Transgrid's analysis of its transformers has identified several current or emerging issues in these transformers:

- Accelerated deterioration of insulating paper quality
- Combustible gases in oil
- Tap-changer condition or type faults
- Bushing failures
- Corrosion (including paint system)

[5] Industry practice application note, Asset replacement planning, January 2019, AER

- Oil leaks
- Corrosive Oil
- Worn ancillary components

3.2 Transgrid's unserved energy calculation

The unserved energy calculation methodology is detailed in Appendix 0. This includes an assumption allowing for a 10-week repair time following a transformer failure. There are several elements that support the reasonableness of this assumption, including:

1. A breakdown of transformer replacement tasks supplied by Transgrid (Table 1)
2. An analysis of spare locations and conditions (Table 2)
3. The physical size of the transformers (Figure 4)

3.2.1 Tasks involved in transformer replacement

The table below includes critical path tasks which Transgrid would be required to undertake in order to utilise a spare transformer at a substation after a transformer failure as well as the timeframe for each task. Each transformer emergency replacement would be different based on the extent of damage, the size and type of transformer as well as site and outage constraints. Weather, natural disasters (especially floods and bushfires) and the availability of specialist staff and equipment when the emergency occurs would also be relevant in terms of the timeframe to replace the transformers.

Table 1 Critical Path Transgrid provided breakdown of transformer replacement tasks

Task	Weeks
Manage emergency response, ensure fire extinguished (or for non-fire complete investigation, complete diagnostic HV testing to confirm irreparable)	1
Make failed transformer area safe, manage investigation for root cause analysis and regulatory reporting requirement	1
Establish safe construction site, Principal Contractor requirements, clean up debris. Commence engagement of transformer disassembly contractor, transport company and initiate transport approvals.	1
Complete testing of the spare transformer and start disassembling to prepare for transport (radiators, pipework, bushings conductors, fire walls)	1
Transport spare transformer and in parallel make repairs to compound (e.g., concrete topping compounds, bund wall repairs, old structure holding down bolts), fire walls ready for spare transformer (including cooler wall penetrations)	2
Spare transformer arrives, assemble transformer (radiators, pipework, bushings) (assumes contractor available), vacuum oil filling	2
Connect high voltage, low voltage terminations, assemble surge arrester supports, overhead connections	2
Transformer high voltage testing, commission transformer (including any other damaged equipment)	1

3.2.2 Location and condition of spares

The following information that provides insights into the potential duration of events has been extracted from the OERs. The duration of an event is dependent upon whether a spare is held, the condition of the spare, whether the spare is available on site or requires transport and whether civil and primary and secondary asset modifications are required to accommodate the replacement.

The heat map presented below supports at least 10-week assumption.

Table 2 Information regarding the duration of events

Substation	Spare held on site	Spare requires transport	Spare requires remediation	Civil and primary and secondary asset modifications required	No spare held
Tenterfield	Yes	-	Yes	-	-
Yass	No	Yes	-	Yes	-
Murray 330kV	No	Yes	-	Yes	-
Panorama	No	Yes	-	Yes	-
Regentville	No	Yes	-	Yes	-
Molong	No	Yes	-	Yes	No like for like replacement but a larger unit may be useable
Tamworth	Yes	-	Yes	-	-
Inverell	No	Yes	-	-	-

3.2.3 Transport of transformers

The transport of large power transformers is a complex process involving a range of important and specialist activities. Each transformer may weight approximately 300 tonnes and contain up to 100,000L of oil. Before a transformer is able to be transported in must appropriately disassembled, packed and loaded onto specialised transport. Transport permits and route selection (to comply with road width and weight limits and bridge clearances) will need to be determined prior to commencing the transport. Vicinity access permits and potentially outages may be needed before the transformer can be transported inside the new substation.

The following figure provides some context as to the size of transformers.

Figure 4 Assembled and disassembled transformers

Assembled	Cooling system
	
Turrets	**Bushings**
	

3.3 Risk of transformer failure

Transgrid's PoF is based upon:

- PoF curve modelled using a 2 Parameter Weibull Distribution
- Transformer and reactor failures from infant mortalities that are less than 16 years have been excluded
- Bushing failures from type faults have been excluded
- Failure data set includes transformers and reactor failures from 1979 (>40 years)
- Includes failures modes from bushings, windings and tap changers in the PoF model

3.4 NPV calculation

Examination of the NPV spreadsheets used to support the identification of the preferred option indicates that:

- The refurbishment case reflects the cost of the refurbishment followed by marginally lower reliability benefits projected out 25 years. This assessment assumes the transformers are fit for purpose for another 25 years after refurbishment.
- An alternative analysis in the NPV spreadsheet treats the refurbishment as a deferred replacement, initially including cost of the refurbishment followed by marginally lower reliability benefits projected out to the point of replacement, then including replacement costs a marginally higher reliability benefit.

  The table presented below illustrates that this alternative analysis continues to support replacement as the preferred option.

Table 3 Results of alternative deferred replacement analysis

Substation	Deferment case replaces transformer in year	Replacement results	Refurbishment results	Deferred replacement results	Preferred option still replacement
Tenterfield OER – N2424 R2	5	Cost $ 12.1M NPV $5.2M	Cost $1.7M NPV $1.8M	Cost $16.4M NPV $3.3M	Yes
Yass OER – N2423 R3	5	Cost $4.1M NPV $946.6M	Cost $1.0M NPV $175.2M	Cost $5.9M NPV $782.5M	Yes
Murray 330kV OER – N2404 R3	5	Cost $11.5M NPV $442.2M	Cost $3.0M NPV $76.5M	Cost $16.8M NPV $371.2M	Yes
Panorama OER – N2404 R4	7	Cost $9.9M NPV $78.8M	Cost $1.3M NPV 21.0M	Cost $14.4M NPV 69.4M	Yes
Regentville OER – N2404 R4	7	Cost $9.7M NPV $63.9M	Cost $1.9M NPV $ 19.5M	Cost $14.8M NPV $61.0M	Yes
Molong OER – N2421 R4	5	Cost $6.4M NPV $429.4M	Cost $1.3M NPV $72.1M	Cost $9.0M NPV $359.9M	Yes
Tamworth OER – N2422 R3	5	Cost $13.6M NPV $197.1M	Cost $2.3M NPV $33.9M	Cost $18.8M NPV $183.3M	Yes
Inverell OER – N2404 R2	7	Cost $10.8M NPV $22.9M	Cost $1.3M NPV $6.9M	Cost $15.6 NPV $20.4M	Yes

Transgrid's spreadsheets that supports the option analysis contain a number of factors that materially drive the NPV result and manual links between their risk model spreadsheets and the NPV spreadsheet. The following table contains the material factors and manual links driving the NPV calculation used to support decision making.

Table 4 ***Material factors and links between spreadsheets driving the NPV calculation***

Substation	Tx #	Correct DF used in NPV	Reputation risk excluded	Input from risk model aligned with NPV model	Condition summary	Transformer age 2022/23	Life used for PoF NPV Calculation	OER Replace	OER Refurb	Agreed cost and NPV to supporting NPV analysis spreadsheet	Replacement type
Tenterfield	1 2	Yes	Yes	Yes	Natural Age Corrosive Sulphur Internal Arcing Oil Leaks	Natural age 55 Effective age 61	58 Ave of natural & effective age	Cost $12.1M NPV $5.2M	Cost $1.7M NPV $1.8M	Yes	One tx in situ and one in new bay
Yass	3	Yes	Yes		Natural Age Corrosive Sulphur Internal Arcing Oil Leaks	Natural age 57 Effective age 55	51 Younger age which would favor refurbishment. Impact does not influence outcome.	Cost $4.1M NPV $946.6M	Cost $1.0M NPV $175.3M	Yes	Replaced in-situ
Murray 330kV	1	Yes	Yes	Yes	Natural Age Aged Synthetic Resin Bonded (SRBP) OIP Bushings Paper Ins moisture Oil Leaks	Natural age 56 Effective age 59	55	Cost $11.5M NPV $442.2M	Cost $3.0M NPV $76.5M	Yes	Both transformers are replaced in-situ
	2				Lack of Voltage Control	Natural age 60 Effective age 60	56 Younger age which would favor refurbishment. Impact does not influence outcome				
Panorama	1	-	-	-	Satisfactory	-	-	-	-	-	-

Substation	Tx #	Correct DF used in NPV	Reputation risk excluded	Input from risk model aligned with NPV model	Condition summary	Transformer age 2022/23	Life used for PoF NPV Calculation	OER Replace	OER Refurb	Agreed cost and NPV to supporting NPV analysis spreadsheet	Replacement type
	2	Yes	Yes	Yes	Natural Age SRBP Corrosive Sulphur Oil Leaks Corrosion	Natural age 43 Effective age 50	44 Younger age which would favor refurbishment. Impact does not influence outcome	Cost $9.9M NPV $78.8	Cost $1.3M NPV $21.0M	Yes	Not in situ, new bay, benching etc
Regentville	1	Yes	Yes	Yes	Natural Age OIP Bushings Paper Ins moisture Oil Leaks caused by corrosion	Natural age 39 Effective age 41	35 Younger age which would favor refurbishment. Impact does not influence outcome	Cost $9.7M NPV $63.9M	Cost $1.9M NPV $19.5M	Yes	Replaced in-situ
	2	-	-	-	Satisfactory	-	-	-	-	-	-
Molong	1	Yes	Yes	Yes	Natural Age OIP 132 kV Bushings Corrosive sulphur Moisture Oil Leaks Corrosion Control Cubicles	Natural age 63 Effective age 61	57 Younger age which would favor refurbishment. Impact does not influence outcome	Cost $6.4M NPV $429.4M	Cost $1.3M NPV $72.1M	Yes	Not in situ, new bay, benching etc
Tamworth	1	Yes	Yes	Yes	Natural Age Corrosive sulphur Oil Leaks Corrosion	Natural age 57 Effective age 56	54 Younger age which would favor refurbishment. Impact does not influence outcome	Cost $13.6M NPV $197.1M	Cost $2.3M NPV $33.9M	Yes	Both No.1 and No.2 Transformers are to be replaced in situ.
	2				Natural Age Corrosive sulphur Oil Leaks Corrosion						
	3	-	-	-	Satisfactory	-	-	-	-	-	-
Inverell	1	-	-	-	Satisfactory	-	-	-	-	-	-

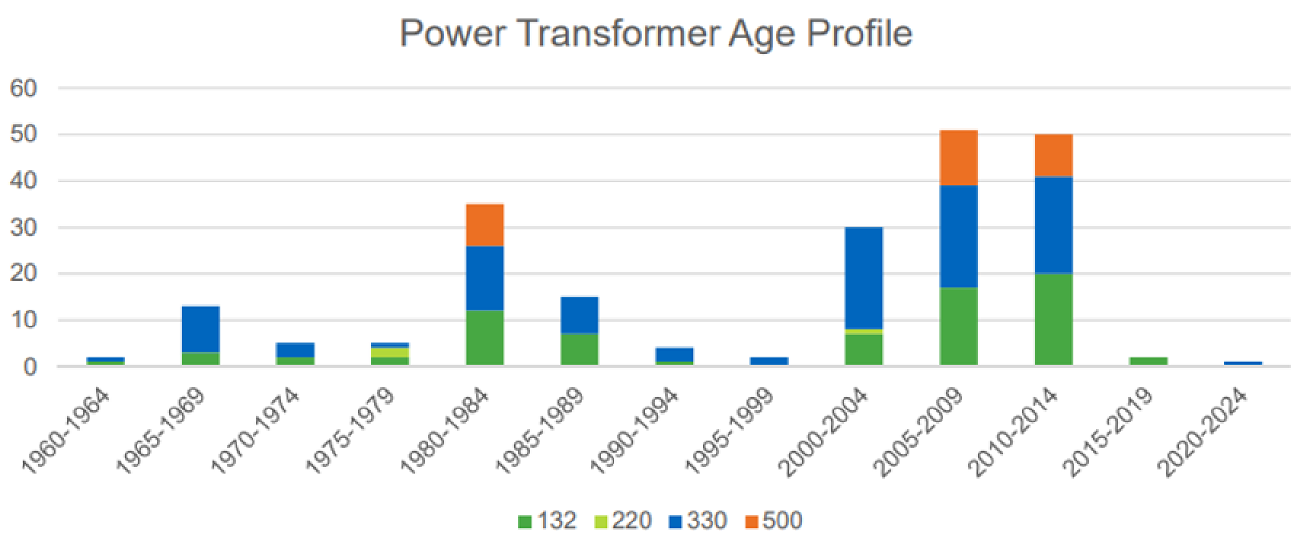
Substation	Tx #	Correct DF used in NPV	Reputation risk excluded	Input from risk model aligned with NPV model	Condition summary	Transformer age 2022/23	Life used for PoF NPV Calculation	OER Replace	OER Refurb	Agreed cost and NPV to supporting NPV analysis spreadsheet	Replacement type
	2	Yes	Yes	Yes	Natural Age OIP Bushings Internal Arcing Oil Leaks	Natural age 40 Effective age 51	40	Cost $10.8M NPV $22.9M	Cost $1.3M NPV $6.9M	Yes	Not in situ, new bay, benching etc

3.5 Transformer age and life cycle risks

Whilst a small percentage of power transformers in the current reset period (2018-23) have already exceeded their nominal asset life of 45 years, a large number of transformers will reach this age and the risk of failure over the next two reset periods. Should Transgrid refurbish rather than replace transformers during the 2023-28 regulatory period then this would reduce the immediate capital expenditure in the 2023-28 regulatory period at the expense of an increase in the risks and the future expenditure required in future regulatory periods.

As shown in the graph below from the Substation Renewals and Maintenance Strategy 2021/22 this is due to approximately 35 transformers being commissioned during the 1980-1984 period (as well as approximately 15 transformers from 1985-89).

Figure 5 ***Transformer age profile***



This means that by the end of the 2023-2028 regulatory period in addition to pre 1979 commissioned transformers (approximately 30) Transgrid will have an additional up to 50 transformers of at least 40 years of age which will need to be considered for asset renewal.

3.6 Replacement type and influence on cost

When considering whether the proposed transformer replacement capex is efficient the scope of works for each replacement needs to be assessed. The most efficient approach is to replace the transformer in situ with only the necessary civil works, bay modifications and outage necessary to be undertaken. Transgrid is proposing in-situ replacement for seven of the eleven transformers to be replaced.

The remaining four transformer replacements would involve new transformer foundations and bunds as well as new switch bays. These transformers are not able to be replaced in situ due to the length of time required for outages which would impact reliability (risk of unserved energy) during construction. This is a common approach which other transmission and distribution networks utilise and is consistent with previous regulatory periods. An example of this is the new transformer No.3 at Tenterfield substation which is required to be installed in a new foundation with a new switchbay. Once this transformer has been commissioned the old transformer foundation is able to be used for the second transformer to be replaced (reducing the capex cost of the second transformer to be replaced).

The capital cost for the Powerlink transformer replacements, with the exception of the Nebo substation, ranges from $5.1M to $7.9M. The Nebo substation project is replacing two small 5MVA 132/11kV transformers for $2.8M each. The capital cost for the Transgrid transformers to be replaced from 3.9M to 9.6M. The average capital cost for Transgrid transformer replacement of $6.68M is slightly higher than Powerlink at $6.29M (an approx. 6% difference). The capital works associated with each transformer project for each TNSP is different however the different is in part explained by the higher operating voltages of Transgrid (330kV) compared to Powerlink (275kV) and the submission being one year earlier than Transgrid's.

A-1 Transformer unavailability and unserved energy

Asset unavailability

A specific unavailability (expressed as percentage time per year) has been applied for each asset considered in the capacity analysis. This has been based on the outage duration multiplied by frequency, observed from historical failures (failure model). The contingency states applied will be tested across a range of coincident conditions, ranging from (n-1) to (n-2). The equations used were:

$$U = \frac{f * MTTR}{365}$$

where:

U is the asset unavailability

$MTTR$ is the mean time to repair (days/repair)

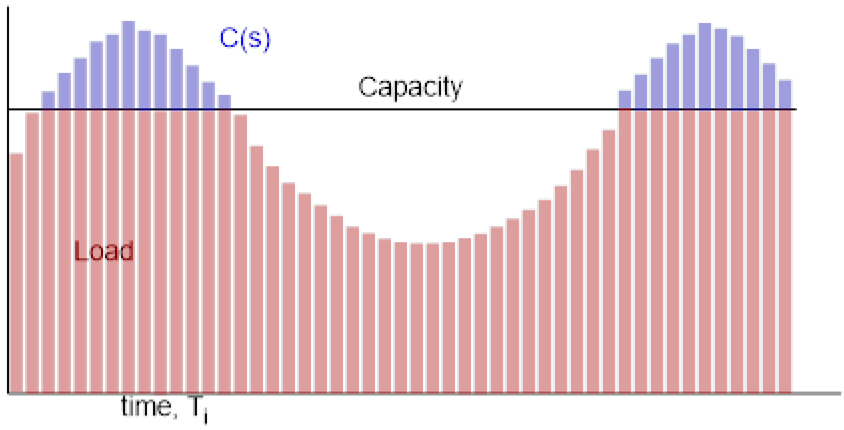
Unserved energy calculation

Unserved energy has been calculated by tallying selected critical system states that resulted in the inability of the network to service the load. This calculation has been done for half hourly load intervals during a financial year, then scaled by the medium POE 50 maximum demand forecast to evaluate future load.

For each system state, the unserved energy has been determined based on the network topology, equipment availability, load level and system capacity.

The figure below shows a simplified illustration of how unserved energy has been calculated.

Figure 6 Illustrative figure of how unserved energy is calculated



The probability of residing in each state is calculated from the unavailability of each component. Therefore, the probability of residing in each state is given by the equation below.

$$P(s) = \prod_{i=1}^{N_d} PF_i \prod_{i=1}^{N-N_d} (1 - PF_i)$$

Where:

N is the total number of components

N_d is the number of failed components

PF_i is the unavailability of the ith component

The total annual expected unserved energy for each year is calculated by weighting each system state load curtailment by the probability of residing in that state and the duration of the load level. The expected unserved energy is given by equation below.

$$EUE = \sum_{i=1}^{NL}\left(\sum_{s\in F_i} P(s) \cdot C(s)\right) \cdot T_i$$

Where:

NL is the number of load levels

F_i is the set of all system states with load curtailment

T_i

A-2 Documentation considered

The following documentation was considered during our independent assessment:

- AER - Transgrid 2023-28 - Draft Decision - Attachment 5 - Capital expenditure - September 2022 (002).pdf
- Australian Energy Regulator, “Industry practice application note, Asset replacement planning”, January 2019
- Transgrid - OER-N2404 Rev 4 FY24-28 RGV Transformer Program - 31 Oct 2022 - PUBLIC.pdf
- Transgrid - OER-N2404 Rev 4 FY24-28 PMA Transformer Program - 31 Oct 2022 - PUBLIC.pdf
- Transgrid - OER-N2404 Rev 3 FY24-28 MUR Transformer Program - 31 Oct 2022 - PUBLIC.pdf
- Transgrid - OER-N2404 Rev 2 FY24-28 INV Transformer Program - 31 Oct 2022 - PUBLIC.pdf
- Transgrid - OER-N2424 Rev 2 Tenterfield Transformer Renewals - 31 Oct 2022 - PUBLIC.pdf
- Transgrid - OER-N2423 Rev 4 Yass No3 Transformer Renewal - 31 Oct 2022 - PUBLIC.pdf
- Transgrid - OER-N2422 Rev 3 Tamworth Transformer Renewals - 31 Oct 2022 - PUBLIC.pdf
- Transgrid - OER-N2421 Rev 4 Molong No1 Transformer Renewal - 31 Oct 2022 - PUBLIC.pdf
- oer-n2404-mur rev 0 - fy24-28 transformer refurb program.pdf
- oer-n2404-inv rev 0 - fy24-28 transformer refurb program.pdf
- oer-n2422 rev 0 - Tamworth transformer renewals.pdf
- oer-n2423 rev 0 - yass no3 transformer renewal.pdf
- oer-n2424 rev 0 - tenterfield transformer renewals.pdf
- oer-n2404-rgv rev 0 - fy24-28 transformer refurb program.pdf
- oer-n2421 rev 0 - molong no1 transformer renewal.pdf
- Copy of NPV Analysis Tool - N2404 MUR - Rev1.0_20221004
- Copy of NPV Analysis Tool - N2404 INV- Rev1.0_20221004
- Copy of NPV Analysis Tool - N2404 - RGV - Rev1.0_20221004
- Copy of Summary TTF Transformers-20221007
- Copy of Summary RGV Transformers-20221007
- Copy of Summary PMA Transformers-20221007
- Copy of NPV Analysis Tool - N2404 PMA - Rev1.0_20221004
- Copy of Summary MUR Transformers-20221007
- Copy of Summary MOL Transformers-20221007
- Copy of Summary INV Transformers-20221007
- Copy of Summary YSN Transformers-20221007
- Copy of NPV Analysis Tool - N2424 - TTF - Rev1.0_20221004
- Copy of NPV Analysis Tool - N2423 - YSN - Rev1.0_20221004
- Copy of NPV Analysis Tool - N2422 TA1 - Rev1.0_20221004

- Copy of NPV Analysis Tool - N2421 - MOL - Rev1.0_20221004
- Copy of transformer restoration time v0.0
- N2404 Panorama No.2 Transformer - Condition Assessment 2021-PUBLIC.pdf
- N2404 Inverell No.2 Transformer - Condition Assessment 2021-PUBLIC.pdf
- N2404 Regentville No.1 Transformer - Condition Assessment 2021-PUBLIC.pdf
- OER-N2290 Rev 2 Fit OLCM to OIP Bushing – 12 November 2021.pdf
- OER-N2404 Rev 0 FY24-28 INV Transformer Refurb Program – 8 November 2021.pdf
- OER-N2404 Rev 1 FY24-28 MUR Transformer Refurb Program – 8 November 2021.pdf
- OER-N2404 Rev 2 FY24-28 PMA Transformer Refurb Program – 14 November 2021.pdf
- OER-N2404 Rev 2 FY24-28 RGV Transformer Refurb Program – 14 November 2021.pdf
- OER-N2421 Rev 1 FY24-28 Molong No1 Transformer Renewal – 8 November 2021.pdf
- OER-N2422 Rev 1 FY24-28 Tamworth Transformer Renewal – 8 November 2021.pdf
- OER-N2423 Rev 2 FY24-28 Yass No3 Transformer Renewal – 14 November 2021.pdf
- OER-N2424 Rev 0 FY24-28 Tenterfield Transformer Renewals – 10 November 2021.pdf
- Transgrid – Substations Renewal and Maintenance Strategy – 30 Nov 2021 – PUBLIC.pdf

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