OPTIONS EVALUATION REPORT (OER)

Tamworth Transformer Renewals

OER- N2422 revision 1.0

Ellipse project no(s):
TRIM file: [TRIM No]

Project reason: Capability - Asset Replacement for end of life condition
Project category: Prescribed - Security/ Compliance

Approvals

Author	Sam Murali	Substation Asset Strategist
Endorsed	Evan Lamplough	Substations Asset Manager
	Debashis Dutta	Asset Analytics & Insights Manager
Approved	Andrew McAlpine	A/Head of Asset Management
Date submitted for approval	8 November 2021	

Change history

Revision	Date	Amendment
00	28/10/2021	Initial
01	08/11/2021	Minor update

Executive summary

Power transformers are essential for the safe and reliable transmission of electricity by enabling different voltage levels throughout the transmission and distribution networks. The condition assessment and health index methodology has identified the Tamworth No.1 and No.2 330kV transformer as reaching end of life and having an increasing risk of failure. The is an economic benefits need, with risks to be considered for remediation within the 2023 – 2028 regulatory period.

Tamworth 330kV substation is located in TransGrid's Northern NSW network. It connects to Transgrid's 330kV Armidale, Liddell and Muswellbrook substations as well as Transgrid's 132kV Narrabri, Tamworth and Gunnedah substation, which all support Essential Energy's 66kV network.

There are three transformers at Tamworth's 330kV substation. The No.1 and No.2 transformers were commissioned along with the substation in 1966 and the No.3 transformer was commissioned in 1998.

The health index considers natural age, dissolved gas analysis (DGA), oil quality (OQ), Bushing DDF, defects, load and corrosive oil. The No.1 and No.2 transformers are approaching the end of their serviceable lives and showing signs of deterioration due to the following key factors:

> Natural Age: The transformers will be 57 years in 2022/23. This is well above the 45-year expected useful life of a power transformer.
> Corrosive Sulphur: The insulating oil has corrosive sulphur, which can form conductive compounds on the insulation paper and tap changer contacts. This can cause an internal flashover and could lead to a catastrophic failure.
> Oil leaks: There are leaks from the bushings, pumps, valves, main tank and tap changer allowing moisture ingress and oxygen into the main insulation.
> Corrosion: The paint and galvanic protection on the transformer has failed resulting in rusting and deterioration.

These condition issues have been evaluated through the transformer health index methodology to give an effective age of 56 years (2022/23, No.1 and 2), which is only slightly below its chronological age. These condition issues, if not remediated, increase the probability of transformer failure.

The No.3 transformer is in satisfactory condition and not part of this Need.

Replacement of the Tamworth transformers will significantly reduce the likelihood of prolonged and involuntary load shedding in the Northern region, and help Transgrid manage its safety obligations.

The key economic benefits associated with addressing this need are summarised as:

> Reduction of risk as valued as direct impact to Transgrid and consumers including:
  – Changes in involuntary load shedding
  – Safety and environmental hazards associated with a catastrophic failure.
> Avoided operating expenditure related to an escalation of corrective maintenance;

Two options have been considered to address the increasing risk of failure of the Tamworth Transformers as shown in Table 1 below. These options are the complete replacement of the transformers with new units (option A) and refurbishment of the existing transformers attempting to address the identified condition issues (option B).

The preferred option is replacement of the Tamworth No.1 and No.2 transformers (Option A). This option is technically feasible and has the highest Net Present Value. The option is optimally timed to be completed within the 2023-2028 regulatory period.

Table 1 - Evaluated options

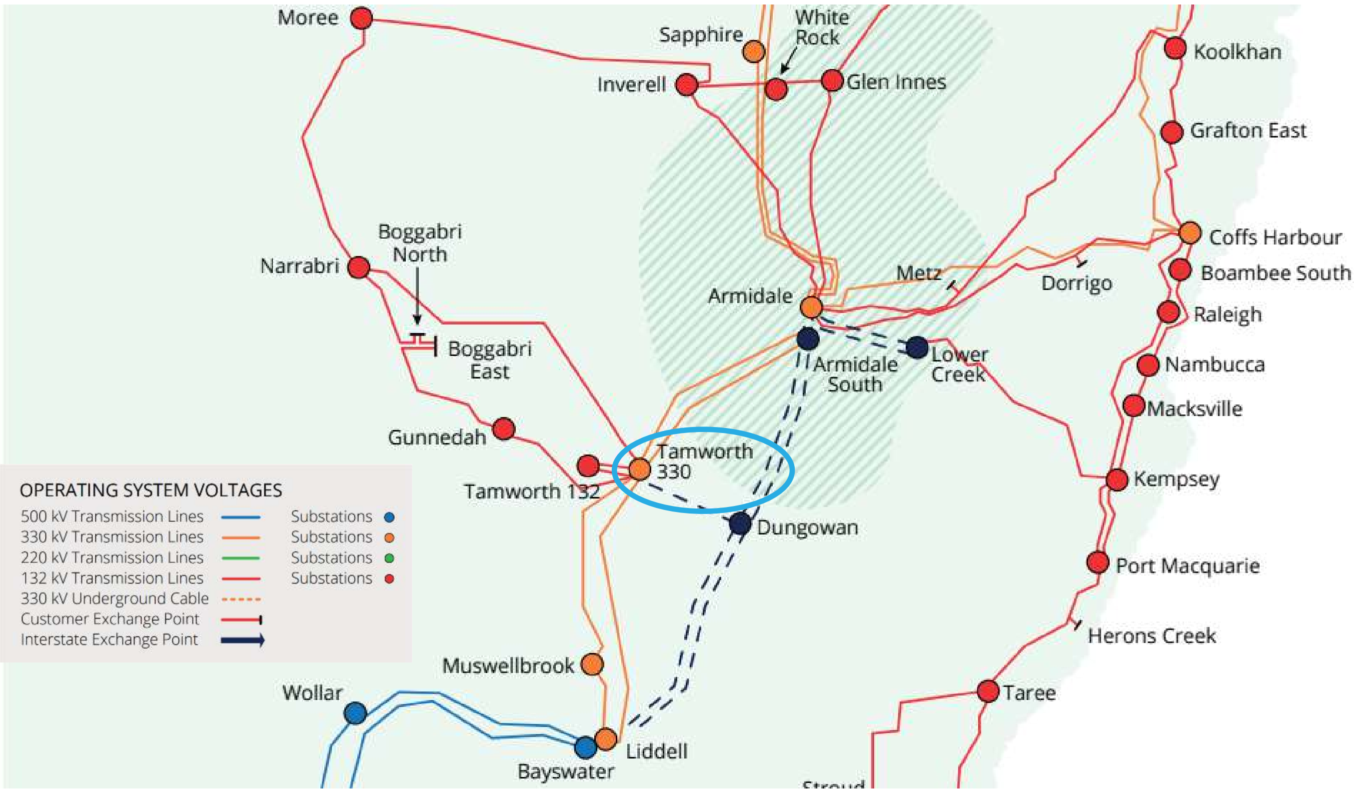
Option	Description	Direct capital cost ($m)	Network and corporate overheads ($m)	Total capital cost[1] ($m)	Weighted NPV (PV, $m)	Rank
Option A	Replacement	12.0	0.8	12.8	137.6	1
Option B	Refurbishment	1.7	0.5	2.2	24.1	2

1. Need/opportunity

Tamworth 330kV substation was commissioned in 1966 and forms a part of Transgrid's network that serves the Northern region of NSW. Tamworth 330kV substation connects to Transgrid's 330kV Armidale, Liddell and Muswellbrook substations as well as Transgrid's 132kV Narrabri, Tamworth and Gunnedah substation.

The location of Tamworth 330kV substation and supply arrangements for the Northern NSW network is provided in Figure 1 below.

Figure 1: Northern NSW transmission network



---

[1] Total capital cost is the sum of the direct capital cost and network and corporate overheads. Total capital cost is used in this OER for all analysis.

The Tamworth 330/132kV transformers play an essential role in the suppling Transgrid's 132kV network in the northern region, which supply Essential Energy's customer connection points in the Tamworth, Gunnedah, Moree and Inverell area.

Transgrid's Northern NSW network which is part of the New England Renewable Energy Zone connects approximately 460 MW of renewable generation. It is also an area of interest for new renewable generation projects. Tamworth 330kV substation will continue to play a central role in the safe and reliable operation of the power system, and the region is expected to enable at least 2,000 MW of new electricity capacity in the future.

The No.1 and No.2 transformer (330/132kV,150MVA) were commissioned in 1966 during the initial construction of Tamworth 330kV substation and have now reached the end of its serviceable life. The No.3 transformer which was commissioned in 1998 is in satisfactory condition and not part of this need. The three transformers at the substation play a central role in supplying electricity to the distribution network in the northern region.

Condition assessment of the No.1 and No.2 Transformer at Tamworth 330kV substation using Transgrid's Network Asset Risk Assessment Methodology (RAM) has noted signs of deterioration, primarily due to condition issues set out in below.

Issue	Potential impact
Corrosive Sulphur	Corrosive sulphur can form conductive compounds on insulating paper. Disrupting the integrity of the paper leading to thermal insulation failure or electrical breakdown between adjacent conductors. Sulphur compounds can also attack the silver coating on selector switching contacts, creating loose sections of conductive silver sulphide. This can result in a catastrophic failure of the tap changer and/or transformer.
Corrosion resulting in loss of oil due to leaks	Corrosion resulting in leaks or leaking gaskets can cause loss of oil within the Transformer resulting in a catastrophic failure. Moisture and oxygen can also enter the transformer resulting in accelerated aging of the insulation resulting in failure.

If the deteriorating asset condition is not addressed by a technically and commercially feasible option, the likelihood of prolonged and involuntary load shedding in the Northern region will increase.

In addition, the increased risk of failure presents a safety risk which Transgrid is obligated to manage. Rectifying the worsening condition of the transformer will reduce safety risks, as well as lower planned and unplanned corrective maintenance costs.

The key economic benefits associated with addressing this need are summarised as:

- Reduction of risk as valued as a direct impact to Transgrid and consumers including:
  - Changes in involuntary load shedding
  - Safety and environmental hazards associated with a catastrophic failure.
- Avoided operating expenditure related to corrective maintenance;

2. Options

Under the 'Base Case' scenario, there is no consideration for planned replacement of the transformer. This is a 'run to fail' scenario and will lead to an increase in the identified risks, the transformer's eventual failure, and the materialisation of the expected consequences. This case shall only be considered as a last resort should no option be deemed viable through the economic evaluation process.

Replacement of a failed transformer is expensive and requires significant time to restore capacity. Key considerations against the base case are:

> Transgrid holds an onsite like-for-like spare for the Tamworth No.1 and No.2 transformer.
> Due to the condition of the spare transformer, the transformer will require major refurbishment:
  – Leak repairs, major maintenance and corrosion treatment.
  – Replacement of out of tolerance bushings prior to energisation.
  – A major overhaul of the tap changer and selector to confirm that the unit is in serviceable condition.
  – Oil treatment and/or replacement based on moisture content
> If the failure is catastrophic, there is substantial clean up and disposal costs and likely to take 1-2 weeks.
> The spare transformer will need to undergo high voltage testing and commissioning works.

2.1 Options evaluated

Option A — Replacement of the Tamworth 330kV No.1 and No.2 Transformer [NOSA N2422, OFS-N2422A]

This option replaces the No.1 and No.2 transformer with two new 330/132 kV 150 MVA transformers. The option will address the identified need by installing new transformers with a very low probability of failure, associated risks and lower operating costs.

This option involves:

> Installation of two 150MVA power transformers;
> Modification of associated switchgear, protection and control systems (secondary systems);
> Civil works.

The transformer will be installed in-situ, during shoulder periods to maintain reliability during construction.

The estimated Capex with this option is $12.76 million with an expected asset life of 45 years. The expected project timeframe from Decision Gate 1 (DG1) is 37 months.

Option B — Refurbishment of the Tamworth 330kV No.1 and No.2 Transformer [NOSA N2422, OFS-N2422B]

This option consists of an in-situ refurbishment of the No.1 and No.2 330/132 kV transformers according to the recommended scope in Network Asset Condition Assessment (NACA):

> Oil treatment and/or replacement
> Corrosion repair, leak repair and repainting
> Major overhaul of the tap changer and selector
> Conservator modifications and/or repairs.

The No.1 and No.2 transformers have undergone major refurbishment in 2006 and 2001, the refurbishment under this need is only expected to result in a reduction in the effective age of five years, limited by the natural age of the transformer. While refurbishment will remediate some of the condition issues, it will not improve the quality of the paper insulation and ageing in the core of the transformer.

The majority of reliability, safety and environmental risk will remain even after the refurbishment and will only be addressed by replacement. The refurbishment option will essentially delay the transformer replacement into 2028 – 2033 regulatory period.

The estimated Capex with this option is $2.24 million with an expected improvement of asset life of 5 years. The expected project timeframe from DG1 is 21 months.

2.2 Options considered and not progressed

The following options were considered but not progressed:

Table 2 - Options not progressed

Option	Reason for not progressing
Increased maintenance or inspections	The condition issues have already been identified and cannot be rectified through increased maintenance or inspections, and therefore is not technically feasible to address the need.
Elimination of all associated risk	This can only be achieved by retiring the assets, which is not technically feasible due to the requirement to maintain the existing network reliability.
Non-network solutions	Transgrid does not consider non-network options to be commercially feasible to assist with meeting the identified need.

3. Evaluation

3.1 Commercial evaluation methodology

The economic assessment undertaken for this project includes three scenarios that reflect a central set of assumptions based on current information that is most likely to eventuate (central scenario), a set of assumptions that give rise to a lower bound for net benefits (lower bound scenario), and a set of assumptions that give rise to an upper bound on benefits (higher bound scenario).

Assumptions for each scenario are set out in Table 3.

Table 3 - Scenario assumptions

Parameter	Central scenario	Lower bound scenario	Higher bound scenario
Discount rate	4.8%	7.37%	2.23%
Capital cost	100%	125%	75%
Operating expenditure benefit	100%	75%	125%
Risk cost benefits	100%	75%	125%
Other Benefits	Not applicable in this assessment		
Scenario weighting	**50%**	**25%**	**25%**

Parameters used in this commercial evaluation are in Table 4

Table 4 - Commercial evaluation parameters

Parameter	Parameter Description	Value used for this evaluation
Discount year	The year that dollar values are discounted to	2020/21
Base year	The year that dollar value outputs are expressed in real terms	2020/21 dollars
Period of analysis	The number of years included in economic analysis with remaining capital value included as terminal value at the end of the analysis period.	25 years
ALARP disproportionality	Multiplier of the environmental and safety related risk cost included in NPV analysis to demonstrate implementation of the obligation to reduce to ALARP.	Refer to section 3.3 for details.

The capex figures in this OER do not include any real cost escalation.

3.2 Commercial evaluation results

The commercial evaluation of the technically feasible options is set out in Table 5. Details appear in Appendix A.

Table 5 - Commercial evaluation (PV, $ million)

Option	Capital Cost PV	OPEX Cost PV	Central scenario NPV	Lower bound scenario NPV	Higher bound scenario NPV	Weighted NPV	Ranking
Option A	10.6	0	126.0	61.0	237.6	137.6	1
Option B	1.9	0	22.1	10.8	41.4	24.1	2

3.3 ALARP evaluation

Transgrid manages and mitigates bushfire and safety risk to ensure they are below risk tolerance levels or 'As Low As Reasonably Practicable' ('ALARP'), in accordance with the regulation obligations and Transgrid's business risk appetite. Under the Electricity Supply (Safety and Network Management) Regulation 2014 Section 5 'A network operator must take all reasonable steps to ensure that the design, construction, commissioning, operation and decommissioning of its network (or any part of its network) is safe.' Transgrid maintains an Electricity Network Safety Management System (ENSMS) to meet this obligation.[2]

In its Network Risk Assessment Methodology, under the ALARP test with the application of a gross disproportionate factor[3], the weighted benefits are expected to exceed the cost. Transgrid's analysis concludes that

[2] TransGrid's ENSMS follows the International Organization for Standardization's ISO31000 risk management framework which requires following hierarchy of hazard mitigation approach

[3] The values of the disproportionality factors were determined through a review of practises and legal interpretations across multiple industries, with particular reference to the works of the UK Health and Safety Executive. The methodology used to determine the disproportionality factors in this document is in line with the principles and examples presented in the AER Replacement Planning Guidelines and is consistent with TransGrid's Revised Revenue Proposal 2023/24-2027/28.

the costs are less than the weighted benefits from mitigating bushfire and safety risks. The proposed investment will enable Transgrid to continue to manage and operate this part of the network to a safety and risk mitigation level of ALARP.

Evaluation of the above options has been completed in accordance with As Low As Reasonably Practicable (ALARP) obligations. The Network Safety Risk Reduction is calculated as 6 x Bushfire Risk Reduction + 3 x Safety Risk Reduction + 3 x Other Environmental Risks + 0.1 x Reliability Risk Reduction.

Results of the ALARP evaluation are set out in Table 6.

Table 6 - Reasonably practicable test ($ million)

Option	Network Safety Risk Reduction	Annualised Capex	Reasonably Practicable?[4]
A	0.09	0.70	No
B	0.03	0.21	No

The result of the ALARP evaluation is that all options lie under the ALARP threshold.

3.4 Preferred option

The preferred option is replacement (Option A) of the Tamworth 330kV No.1 and No.2 Transformers, as this is technically feasible and has the highest positive NPV. This option addresses the need by achieving the largest risk reduction. The new transformers have a relatively low probability of failure (PoF) and corresponding post-investment risk.

Capital and Operating Expenditure

Opex benefits associated with avoided corrective and reduced routine expenditure have been included in the business case NPV and optimal timing evaluation.

There are no capex to opex trade-offs considered in this evaluation.

Regulatory Investment Test

A Regulatory Investment Test for Transmission (RIT-T) is expected to be required as the preferred option is above $6 million.

[4] Reasonably practicable is defined as whether the annualised CAPEX is less than the Network Safety Risk Reduction.

4. Optimal Timing

The test for optimal timing of the preferred option has been undertaken. The approach taken is to identify the optimal commissioning year for the preferred option where net benefits (including avoided costs and safety disproportionality tests) of the preferred option exceeds the annualised costs of the option. The commencement year is determined based on the required project disbursement to meet the commissioning year based on the OFS.

The results of optimal timing analysis are:

> Optimal commissioning year: 2023/24. This is the earliest feasible commissioning year due to the significant lead time required to design, procure and commission a transformer replacement.
> Commissioning year annual benefit: $0.94 million
> Annualised cost: $0.7 million

Based on the optimal timing, the project is expected to be completed within the 2023-2028 Regulatory Period

5. Recommendation

It is recommended that Option A for the replacement of the transformers be scoped in detail.

The total project cost is $12.76 million, including $1 million to progress the project from DG1 to DG2.

Appendix A – Option Summaries

Project Description	Tamworth Transformer Renewals		
Option Description	Option A - Transformer Replacement		
Project Summary			
Option Rank	*1*	Investment Assessment Period	*25*
Asset Life	*45*	NPV Year	*2021*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	[Net Present Value (Standard - OER)] *125.95*	Annualised CAPEX ($m)	Annualised Capex - Standard (Business Case) *0.70*
NPV @ Lower Bound Scenario (PV, $m)	[Net Present Value (Upper Bound)] *61.01*	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction *0.09*
NPV @ Higher Bound Scenario (PV, $m)	[Net Present Value (Lower Bound)] *237.56*	ALARP	ALARP Compliant? *No*
NPV Weighted (PV, $m)	[Net Present Value (Weighted)] *137.62*	Optimal Timing	Optimal timing (Business Case) *2022*
Cost			
Direct Capex ($m)		Network and Corporate Overheads ($m)	
Total Capex ($m)	12.76	Cost Capex (PV,$m)	10.57
Terminal Value ($m)	5.39	Terminal Value (PV,$m)	1.38
Risk (central scenario)	**Pre**	**Post**	**Benefit**
Reliability (PV,$m)	Reliability Risk (Pre) *149.10*	Reliability Risk (Post) *15.91*	Pre – Post *133.19*
Financial (PV,$m)	Financial Risk (Pre) *1.28*	Financial Risk (Post) *0.16*	Pre – Post *1.12*
Operational/Compliance (PV,$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) *0.00*	Pre – Post *0.00*
Safety (PV,$m)	Safety Risk (Pre) *0.80*	Safety Risk (Post) *0.10*	Pre – Post *0.70*
Environmental (PV,$m)	Environmental Risk (Pre) *0.05*	Environmental Risk (Post) *0.01*	Pre – Post *0.04*
Reputational ($m)	Reputational Risk (Pre) 0.08	Reputational Risk (Post) *0.01*	Pre – Post *0.07*
Total Risk Benefit (PV,$m)	Total Risk (Pre) *151.31*	Total Risk (Post) *16.18*	Pre – Post *135.13*
OPEX Benefit (PV,$m)			*OPEX Benefit* *0.01*
Other benefit (PV,$m)			*Incremental Net Benefit* *0.00*
Total Benefit (PV,$m)			*Business Case Total Benefit* *135.15*

Project Description	**Tamworth Transformer Renewals**		
Option Description	Option B - Transformer Refurbishment		
Project Summary			
Option Rank	*2*	Investment Assessment Period	*25*
Asset Life	*15*	NPV Year	*2021*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	[Net Present Value (Standard - OER)] *22.11*	Annualised CAPEX ($m)	Annualised Capex - Standard (Business Case) *0.21*
NPV @ Lower Bound Scenario (PV, $m)	[Net Present Value (Upper Bound)] *10.76*	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction *0.03*
NPV @ Higher Bound Scenario (PV, $m)	[Net Present Value (Lower Bound)] *41.39*	ALARP	ALARP Compliant? *No*
NPV Weighted (PV, $m)	[Net Present Value (Weighted)] *24.09*	Optimal Timing	Optimal timing (Business Case) *2023*
Cost			
Direct Capex ($m)		Network and Corporate Overheads ($m)	
Total Capex ($m)	2.24	Cost Capex (PV,$m)	1.90
Terminal Value ($m)	0.00	Terminal Value (PV,$m)	0.00
Risk (central scenario)	Pre	Post	Benefit
Reliability (PV,$m)	Reliability Risk (Pre) *149.10*	Reliability Risk (Post) *125.46*	Pre – Post *23.64*
Financial (PV,$m)	Financial Risk (Pre) *1.28*	Financial Risk (Post) *1.07*	Pre – Post *0.21*
Operational/Compliance (PV,$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) *0.00*	Pre – Post *0.00*
Safety (PV,$m)	Safety Risk (Pre) *0.80*	Safety Risk (Post) *0.67*	Pre – Post *0.13*
Environmental (PV,$m)	Environmental Risk (Pre) *0.05*	Environmental Risk (Post) *0.04*	Pre – Post *0.01*
Reputational ($m)	Reputational Risk (Pre) 0.08	Reputational Risk (Post) *0.06*	Pre – Post *0.02*
Total Risk Benefit (PV,$m)	Total Risk (Pre) *151.31*	Total Risk (Post) *127.31*	Pre – Post *24.00*
OPEX Benefit (PV,$m)			*OPEX Benefit* *0.01*
Other benefit (PV,$m)			*Incremental Net Benefit* 0.00
Total Benefit (PV,$m)			*Business Case Total Benefit* 24.01