Options Evaluation Report (OER)

Regentville No.1 Transformer Refurbishment Program
OER- **N2404** revision **4.0**

Ellipse project no(s):

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Project reason: Capability - Asset Replacement for end of life condition

Project category: Prescribed - Asset Renewal Strategies

Approvals

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Change history

Revision	Date	Amendment
00	05/11/2021	Initial
01	12/11/2021	Minor formatting
02	14/11/2021	Reissue PDF (no other change)
03	21/10/2022	Updated analysis and evaluation including: • Analysis updated with FY22 values • Amendment of environmental disproportionality factors • Removal of reputational risk • Technical feasibility of refurbishment
04	31/10/2022	Version history added

Executive summary

Power transformers are essential for the safe and reliable electricity transmission as they enable different voltage levels throughout the transmission and distribution networks. As part of the condition assessment and health index methodology, Regentville No.1 330/132kV transformer has been identified as a transformer which is reaching end of life and with an increasing risk of failure. The need of this project is economic benefit, with risks which will require remediation within the 2023 – 2028 regulatory period.

Regentville 330/132kV Substation is located in Transgrid's central NSW network. It connects to Transgrid's 330kV Bayswater and Sydney West substations. It also connects to Endeavour Energy's 132kV distribution network which supplies industrial and residential loads in the Western Sydney region.

There are two 330/132kV transformers at Regentville substation. The No.1 transformer was manufactured in 1984 and installed at Regentville substation in 1997 during the commissioning of the substation. The No.2 transformer was commissioned in 2000.

The health index considers natural age, dissolved gas analysis (DGA), oil quality (OQ), Bushing DDF, defects, load and corrosive oil.

The No.1 transformer is approaching the end of its serviceable life and showing signs of deterioration due to the following key factors:

- Natural Age: The transformer will be 39 years in 2022/23 and will be approaching its 45-year expected useful life by the end of 2023-2028 regulatory period.
- Aged Oil Impregnated Paper (OIP) Bushings: The 330kV & 132kV OIP bushings were originally installed in 1984 and are over the 30-year useful life of high voltage bushings.
- Paper moisture: Moisture acts to increase the rate of degradation of the paper insulating system. At high levels, it may compromise the insulation reducing the dielectric strength.
- Oil leaks: There are leaks from the bushings, valves, pipework flanges, and main tank lid gasket, allowing moisture ingress and oxygen into the main insulation.

These condition issues have been evaluated through the transformer health index methodology to give an effective age for the transformer of 41 years (2022/23), which slightly above its chronological age. These condition issues, if not remediated, increase the probability of transformer failure.

The No.2 transformer at Regentville substation is in satisfactory condition with an effective age of 26 years (2022/23) which is lower than its chronological age by four years, and not part of this need.

Replacement of the Regentville No.1 Transformer would significantly reduce the likelihood of prolonged and involuntary load shedding in the Central 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 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;

Two options have been considered to address the increasing risk of failure of the Regentville No.1 Transformer, as shown in Table 1 below. These options are the complete replacement of the transformer with a new unit (option A) and refurbishment of the existing transformer attempting to address the identified condition issues (option B).

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	Replacement of the No.1 Regentville Transformer	9.0	0.7	9.73	63.90	1
Option B – Refurbishment	Refurbishment of the No.1 Regentville Transformer	1.5	0.4	1.9	19.50	2

The preferred option from the economic evaluation is replacement (Option A).

However, refurbishment (Option B) has been determined to be technically feasible and has been selected to meet the overall objective to reduce capex for the transformer program. The option is optimally timed to be completed within the 2023-2028 regulatory period. Therefore, it is recommended that the refurbishment (Option B) be progressed.

1. Need/opportunity

Regentville 330/132 kV Substation was commissioned in 1997 and forms a part of Transgrid's network that serves the Central region of NSW. It connects to Transgrid's 330kV Bayswater and Sydney West substations. It also connects to Endeavour Energy's 132kV distribution network which supplies industrial and residential loads in the Western Sydney region.

The location of Regentville substation and transmission supply arrangements for the Central NSW network is provided in Figure 1 below.

[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.

Figure 1: Central NSW transmission network

Note: The 132kV Endeavour Energy network that Regentville No.1 and No.2 transformer supplies are not shown in Figure 1.

The No.1 transformer (330/132kV, 375MVA) was initially commissioned in 1984 at Sydney South substation as a system spare. The transformer has been installed at Regentville substation since 1997 since the commissioning of the substation. The transformers at the substation play a central role in supplying electricity to the distribution network in the Western Sydney region.

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

Table 2 - Condition Issues

Issue	Potential impact
Oil Impregnated Paper (OIP) Bushings	The No.1 transformer 330kV & 132kV OIP bushings were installed in 1984, and are equipped with porcelain insulators and a condenser based core. Their advanced age makes them susceptible to failures from high over voltages and thermal stresses and humidity ingress.

Paper insulation moisture	The transformer insulation system is based on special papers impregnated with insulating oil. Moisture acts to increase the rate of degradation of the paper insulating system. At high levels, it may compromise the insulation. The papers provided insulation and also support the structure of the transformer winding. Over time and with load and the presence of moisture, the paper becomes brittle. This may progress to the point where a mechanical shock caused by a through fault can result in electrical failure.
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 Central 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. Related needs/opportunities

- N2427 – Regentville Secondary Systems Renewal

3. Options

3.1. Base case

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 with a strategic spare is expensive and requires significant time to restore capacity. Key considerations against the base case are:

- Transgrid holds a similar spare for the Regentville No.1 transformer.
- Primary and secondary asset modifications will also be required at Regentville substation to adapt the spare unit.

- If the failure is catastrophic, there is substantial clean up and disposal costs and likely to take 1-2 weeks.
- As there are no spares on site, a spare transformer will need to be dismantled and transported from another depot/substation and assembled at Regentville.
- Transportation permits will likely be required due to the physical size and weight of the spare transformer.
- The spare transformer will need to undergo high voltage testing and commissioning works.

3.2. Options evaluated

Option A — Replacement of the Regentville No.1 Transformer [NOSA N2404, OFS N2404-RGVA]

This option replaces the No.1 transformer with a new 330/132kV 375MVA transformer. The option will address the identified need by installing a new transformer with a very low probability of failure, associated risks and lower operating costs.

This option involves:

- Installation of a new 375MVA power transformer;
- Modification of transformer compound walls;
- Modification of associated switchgear, protection and control systems (secondary systems);

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

The estimated Capex with this option is $9.73 million with an expected asset life of 45 years. The expected project timeframe from Decision Gate 1 (DG1) is 29 months.

Option B — Refurbishment of the Regentville No.1 Transformer [NOSA N2404, OFS N2404B]

This option consists of an in-situ refurbishment of the No.1 330/132kV 375MVA transformer according to the recommended scope in Network Asset Condition Assessment (NACA):

- Replacement of high voltage, low voltage and tertiary voltage bushings.
- Oil filtering & degassing.
- Moisture removal.
- Corrosion repair, leak repair and repainting.
- Major overhaul of the tap changer
- Conservator modifications and/or repairs.

The refurbishment is expected to result in a reduction in the effective age of seven years, limited by the natural age of the transformer.

Consideration of Refurbishment

Refurbishment is expected to improve condition issues associated with the bushings, insulating oil quality, gasket leaks and tap changer components. It cannot address or improve the quality of the paper insulation, eliminate gas generation, ageing in the core or improve winding clamping pressure.

The natural age of the transformer at the end of the 2023-28 regulatory period is 44 years and will be refurbished within its useful life, which is when it is most effective from a technical perspective.

The technical benefits of refurbishment are further increased as the transformer has operated as a strategic spare during its early life and has likely experienced reduced asset degradation until it was commissioned in Regentville. The refurbishment option will also meet the overall objective to reduce capex for the transformer program.

The estimated Capex with this option is $1.88 million with an expected improvement of asset life of seven years. The expected project timeframe from DG1 is 21 months.

3.3. Options considered and not progressed

The following options were considered but not progressed:

Table 3 - 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.

4. Evaluation

4.1. Commercial evaluation methodology

The economic assessment undertaken for this project includes three scenarios that reflect a central set 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 the table below.

Parameter	Central scenario	Lower bound scenario	Higher bound scenario
Discount rate	5.5%	7.5%	2.3%
Capital cost	100%	125%	75%
Operating expenditure	100%	75%	125%

Parameter	Central scenario	Lower bound scenario	Higher bound scenario
Risk costs	100%	75%	125%
Benefits	100%	75%	125%
Scenario weighting	50%	25%	25%

Parameters used in this commercial evaluation:

Parameter	Parameter Description	Value used for this evaluation
Discount year	Year that dollar values are discounted to	2021/22
Base year	The year that dollar value outputs are expressed in real terms	2021/22
Period of analysis	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 obligation to reduce to ALARP.	Refer to section 4.3 for details.

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

4.2. Commercial evaluation results

The commercial evaluation of the technically feasible options is set out in Table 2. Details appear in Appendix A.

Table 4 - 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	8.75	0.01	52.19	22.43	128.82	63.90	1
Option B	1.69	0.01	16.17	7.67	37.98	19.50	2

4.3. 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].

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

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 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 1 x Bushfire Risk Reduction + 1 x Other Environmental Risks + 3 x Safety Risk Reduction + 0.1 x Reliability Risk Reduction.

Results of the ALARP evaluation are set out in Table 5.

Table 5 - Reasonably practicable test ($ million)

Option	Network Safety Risk Reduction	Annualised Capex	Reasonably Practicable?[4]
A	0.09	0.59	No
B	0.03	0.19	No

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

4.4. Preferred option

The preferred option is the replacement (Option A) of the Regentville No.1 Transformer, as this is technically feasible and has the highest positive NPV. This option addresses the need by achieving the largest risk reduction. A new transformer has a relatively low probability of failure 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 required as one of the evaluated options is above $7 million.

[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.

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

5. 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: $0.83 million
- Annualised cost: $0.59 million

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

6. Recommendation

Although Option A provides the highest positive NPV, it is recommended that the transformer refurbishment (Option B) be scoped in detail to meet the overall objective to reduce capex for the transformer program.

The total project cost is $1.88 million, including $0.6 million to progress the project from DG1 to DG2.

Appendix A – Option Summaries

Project Description	Regentville Transformer Renewal		
Option Description	Option A - Transformer Replacement		
Project Summary			
Option Rank	*1*	Investment Assessment Period	*25*
Asset Life	*45*	NPV Year	*2022*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	[Net Present Value (Standard - OER)] *52.19*	Annualised CAPEX ($m)	Annualised Capex - Standard (Business Case) *0.59*
NPV @ Lower Bound Scenario (PV, $m)	[Net Present Value (Upper Bound)] *22.43*	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction *0.09*
NPV @ Higher Bound Scenario (PV, $m)	[Net Present Value (Lower Bound)] *128.82*	ALARP	ALARP Compliant? No
NPV Weighted (PV, $m)	[Net Present Value (Weighted)] *63.90*	Optimal Timing	Optimal timing (Business Case) *2023*
Cost			
Direct Capex ($m)	*9.05*	Network and Corporate Overheads ($m)	*0.68*
Total Capex ($m)	*9.73*	Cost Capex (PV,$m)	*8.75*
Terminal Value ($m)	*4.32*	Terminal Value (PV,$m)	*0.97*
Risk (central scenario)	Pre	Post	Benefit
Reliability (PV,$m)	Reliability Risk (Pre) *63.57*	Reliability Risk (Post) *4.15*	Pre – Post *59.42*
Financial (PV,$m)	Financial Risk (Pre) *0.66*	Financial Risk (Post) *0.24*	Pre – Post *0.42*
Operational/Compliance (PV,$m)	Operational Risk (Pre) *0.00*	Operational Risk (Post) *0.00*	Pre – Post *0.00*
Safety (PV,$m)	Safety Risk (Pre) *0.16*	Safety Risk (Post) *0.06*	Pre – Post *0.10*
Environmental (PV,$m)	Environmental Risk (Pre) *0.09*	Environmental Risk (Post) *0.09*	Pre – Post *0.00*
Reputational ($m)	Reputational Risk (Pre) *0.00*	Reputational Risk (Post) *0.00*	Pre – Post *0.00*
Total Risk Benefit (PV,$m)	Total Risk (Pre) *64.49*	Total Risk (Post) *4.53*	Pre – Post *59.95*
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 *59.96*

Project Description	Regentville Transformer Renewal		
Option Description	Option B - Transformer Refurbishment		
Project Summary			
Option Rank	*2*	Investment Assessment Period	*25*
Asset Life	*15*	NPV Year	*2022*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	[Net Present Value (Standard - OER)] *16.17*	Annualised CAPEX ($m)	Annualised Capex - Standard (Business Case) *0.19*
NPV @ Lower Bound Scenario (PV, $m)	[Net Present Value (Upper Bound)] *7.67*	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction *0.03*
NPV @ Higher Bound Scenario (PV, $m)	[Net Present Value (Lower Bound)] *37.98*	ALARP	ALARP Compliant? No
NPV Weighted (PV, $m)	[Net Present Value (Weighted)] *19.50*	Optimal Timing	Optimal timing (Business Case) *2023*
Cost			
Direct Capex ($m)	*1.45*	Network and Corporate Overheads ($m)	*0.42*
Total Capex ($m)	*1.88*	Cost Capex (PV,$m)	*1.69*
Terminal Value ($m)	*0.00*	Terminal Value (PV,$m)	*0.00*
Risk (central scenario)	Pre	Post	Benefit
Reliability (PV,$m)	Reliability Risk (Pre) *63.57*	Reliability Risk (Post) *45.89*	Pre – Post *17.68*
Financial (PV,$m)	Financial Risk (Pre) *0.66*	Financial Risk (Post) *0.53*	Pre – Post *0.13*
Operational/Compliance (PV,$m)	Operational Risk (Pre) *0.00*	Operational Risk (Post) *0.00*	Pre – Post *0.00*
Safety (PV,$m)	Safety Risk (Pre) *0.16*	Safety Risk (Post) *0.13*	Pre – Post *0.03*
Environmental (PV,$m)	Environmental Risk (Pre) *0.09*	Environmental Risk (Post) *0.09*	Pre – Post *0.00*
Reputational ($m)	Reputational Risk (Pre) *0.00*	Reputational Risk (Post) *0.00*	Pre – Post *0.00*
Total Risk Benefit (PV,$m)	Total Risk (Pre) *64.49*	Total Risk (Post) *46.64*	Pre – Post *17.85*
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 *17.85*

Approval Record

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