

Options Evaluation Report (OER)

Inverell No. 2 Transformer
OER- N2404 revision 2.0

Ellipse project no(s):

TRIM file: [TRIM No]

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	08/11/2021	Initial
01	21/10/2022	Updated analysis and evaluation including: <ul style="list-style-type: none">Analysis updated with FY22 valuesAmendment of environmental disproportionality factorRemoval of reputational riskConsideration of in-situ replacement scope and technical feasibility of refurbishment
02	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, Inverell No.2 132/66kV 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.

Inverell 132/66kV Substation is located in Transgrid's northern NSW network. It connects to Transgrid's 132kV Moree, White Rock and Armidale substations. It also connects to Essential Energy's 66kV distribution network which supplies industrial and residential loads in the Inverell region.

There are two 132/66kV transformers at Inverell substation which were both commissioned in 1983, this need only considers the No.2 transformer. The health index considers natural age, dissolved gas analysis (DGA), oil quality (OQ), Bushing DDF, defects, load and corrosive oil.

The No.2 transformer is approaching the end of its serviceable life and showing signs of deterioration due to the following key factors:

- **Natural Age:** The transformer was manufactured and commissioned in 1983. The transformer will be 40 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 132kV and 66kV OIP bushings were originally installed in 1983 and are over the 30-year useful life of high voltage bushings.
- **Internal Arcing:** Dissolved Gas Analysis (DGA) shows high levels of acetylene in the main tank of the transformer. This typically indicates arcing in the paper or oil at high temperatures.
- **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 No.2 transformer of 51 years (2022/23), which is significantly above its chronological age. These condition issues, if not remediated, increase the probability of transformer failure.

The No.1 transformer at Inverell substation is in satisfactory condition with an effective age of 41 years (2022/23), which is above its chronological age by one year, and not part of this need. The main drivers for a lower effective age when compared to the No.2 transformer is lower acetylene, ethylene and ethane gas levels and improved 66kV bushing condition.

Replacement of the Inverell No.2 Transformer would 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 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 Inverell No.2 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).

The preferred option is the replacement of the Inverell No.2 transformer (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	Replacement of the No.2 Inverell Transformer	0.8	10.0	10.8	22.9	1
Option B – Refurbishment	Refurbishment of the No.2 Inverell Transformer	1.0	0.3	1.3	6.9	2

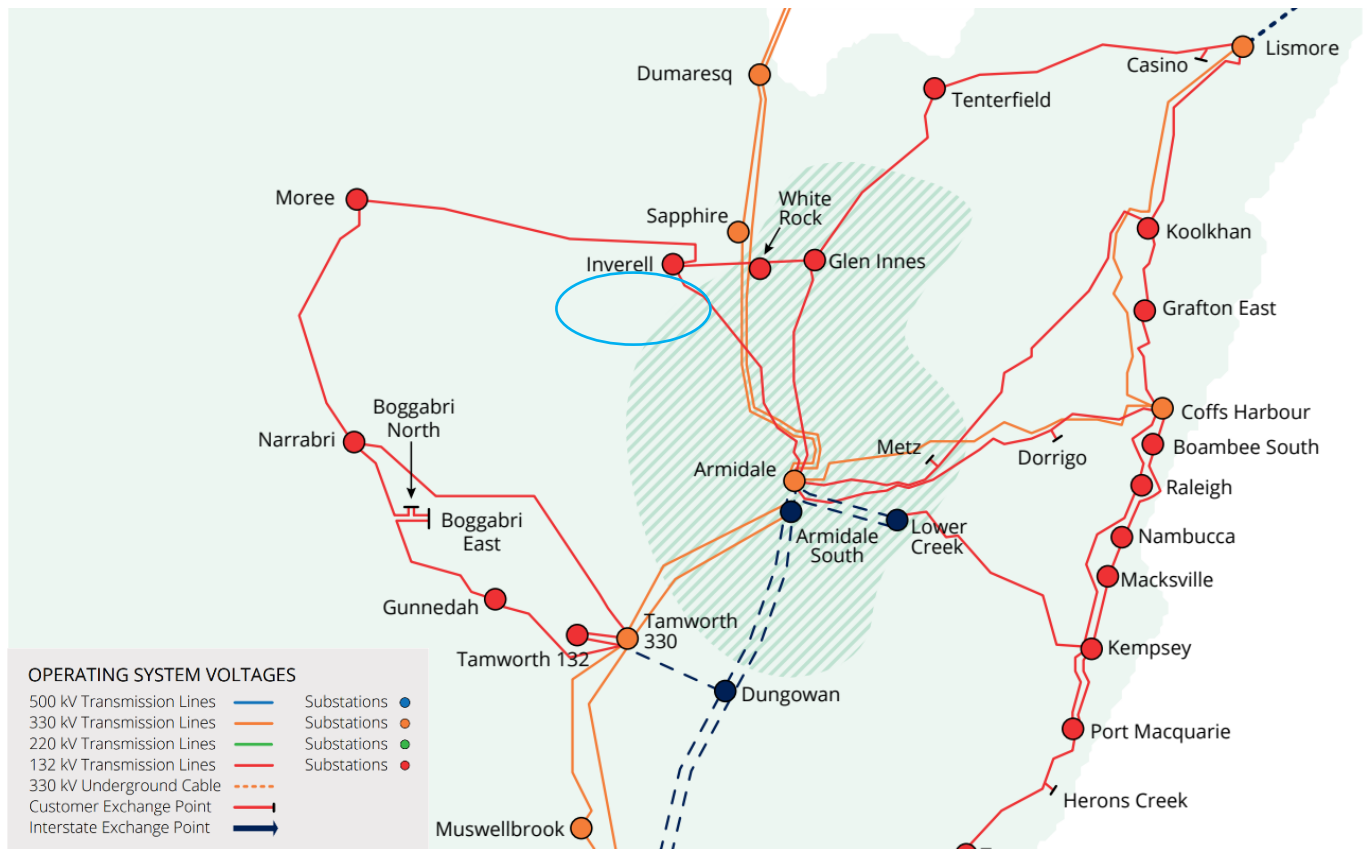
1. Need/opportunity

Inverell 132/66 kV Substation was commissioned in 1983 and forms a part of Transgrid's network that serves the Northern region of NSW. It connects to Transgrid's 132kV Moree, White Rock and Armidale substations. It also connects to Essential Energy's 66kV distribution network which supplies industrial and residential loads in the Inverell region.

The location of Inverell substation and transmission supply arrangements for the Northern 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: Northern NSW transmission network



Note: The 66kV Essential Energy network that Inverell No.1 and No.2 transformer supplies are not shown in Figure 1.

The Inverell No.1 and No.2 Transformers (132/66kV, 120MVA each) were both commissioned in 1983 during the initial construction of Inverell Substation. The transformers at the substation plays a central role in supplying electricity to the Essential Energy distribution network.

The two transformer arrangement allows for an N-1 contingency during planned and unplanned outages. Transgrid does not have an agreed back up arrangement for the Inverell load with Essential Energy network.

Condition Assessment of the No.2 Transformer at Inverell 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	<p>The 132kV and 66kV OIP bushings were installed in 1983, and are equipped with porcelain insulators and a condenser based core.</p> <p>Their advanced age makes them susceptible to failures from high over voltages and thermal stresses and humidity ingress.</p>
Internal Arcing	<p>Dissolved Gas Analysis (DGA) shows high levels of acetylene (C₂H₂) in the main tank of the transformer. This typically indicates arcing in the paper or oil at high temperatures above 1000 °C.</p> <p>Leakage from the tap changer compartment to the main tank can also cause elevated levels of acetylene. The transformer would require a major overhaul to investigate the cross contamination between the tank and tap changer.</p> <p>Lighter combustible gases are relatively low, indicating losses to the atmosphere through leaks. Long term trending and analysis is ineffective as the oil has been filtered and treated during previous maintenance activities.</p>
Corrosion resulting in loss of oil due to leaks	<p>Corrosion resulting in leaks or leaking gaskets can cause loss of oil within the Transformer resulting in a catastrophic failure.</p> <p>Moisture and oxygen can also enter the transformer resulting in accelerated aging of the insulation resulting in failure.</p>

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. Related needs/opportunities

- N2436 – FY24-28 Inverell 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 Inverell No.2 transformer.
- Primary and secondary asset modifications will also be required at Inverell 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 Inverell.
- 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.

The base case assumes the failed transformer can be replaced with a strategic spare in a much shorter time frame than replacing the transformer with a new asset. Where a spare transformer is not available due to concurrent failures the design, procurement and installation time for new transformer is expected to be at least 12 months. The probability and likelihood of expected unserved energy under this scenario has been excluded from the base case risk modelling.

3.2. Options evaluated

Option A — Replacement of the Inverell No.2 Transformer [[NOSA N2404](#), [OFS N2404-INVA](#)]

This option replaces the No.2 transformer with a new 132/66kV 120MVA 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 120MVA power transformer.
- Installation of new switch bays, gantries, busbar extension, protection and control systems (secondary systems).
- Installation of an auxiliary transformer.
- Bench extension and modification of the palisade fencing.
- Construction of new firewalls.

The new No.2 transformer will be installed in a new compound with associated bays to maintain reliability during construction. The old No.2 transformer will then be decommissioned and disposed of once the new No.2 transformer is in-service. The final transformer configuration at Inverell substation will remain as two transformers to meet the NSW Electricity Transmission Reliability and Performance Standard.

Consideration of In-Situ Replacement

Transgrid has evaluated the option of undertaking an in-situ transformer replacement at Inverell Substation. This would require a 12-16 week outage of the No.2 transformer, during this period 20 - 30 MW of load would be radial supplied via the No.1 transformer. Essential Energy have limited load transfer capability (less than 10 MVA) during non-peak demand period by energising Essential Energy's 6AB transmission line between Ashford and Borthwick Street substations..

The outage risk of undertaking an in-situ transformer replacement is considered unacceptable as there would be significant load shedding in the event of an unplanned outage of the No.1 transformer. The transformer recall period during construction is also expected to be weeks unlike maintenance or refurbishment activities which is typically within 24-48 hours.

During the in-situ construction Transgrid would not be compliant under the obligations set out in the NSW Electricity Transmission Reliability and Performance Standard to maintain a reliability of 2 (Redundancy Level of N-1) at Inverell substation.

The estimated Capex with this option is \$10.82 million with an expected asset life of 45 years. The expected project timeframe from Decision Gate 1 (DG1) is 34 months.

Option B — Refurbishment of the Inverell No.2 Transformer [[NOSA N2404](#), [OFS N2404B](#)]

This option consists of an in-situ refurbishment of the No.2 132/66kV 120MVA transformer according to the recommended scope in Network Asset Condition Assessment (NACA):

- Replacement of high voltage, low voltage and tertiary voltage bushings.
- Oil filtering and degassing.
- Moisture removal.
- Corrosion repair, leak repair and repainting.
- Conservator modifications.

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

Limitations 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 45 years and will be refurbished within its useful life, which provides the largest economic benefit and reduction in effective age provided by the option. However, refurbishment (Option B) of the Inverell No.2 transformer does not provide the highest economic value when compared to replacement of the transformer (Option A). The refurbishment option will essentially delay the transformer replacement into 2028 – 2033 regulatory period and result in a higher lifecycle capex investment.

The majority of reliability, safety and environmental risk will remain even after the refurbishment and will only be addressed by replacement.

The estimated Capex with this option is \$1.31 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:

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%
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 3 - 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	9.72	0.01	18.08	3.82	51.76	22.94	1
Option B	1.17	0.01	5.72	2.43	13.68	6.89	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 obligation².

In its Network Risk Assessment Methodology, under the ALARP test with the application of a gross disproportionate factor³, 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.

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.

Results of the ALARP evaluation are set out in Table 4.

Table 4 - Reasonably practicable test (\$ million)

Option	Network Safety Risk Reduction	Annualised Capex	Reasonably Practicable? ⁴
A	0.08	0.65	No
B	0.02	0.13	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 Inverell No.2 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 the preferred option is above \$7 million.

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: \$0.65 million
- Annualised cost: \$0.65 million

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

6. Recommendation

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

The total project cost is \$10.82 million, including \$1 million to progress the project from DG1 to DG2.

Appendix A – Option Summaries

Project Description		Inverell 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)] 18.08	Annualised CAPEX (\$m)	Annualised Capex - Standard (Business Case) 0.65
NPV @ Lower Bound Scenario (PV, \$m)	[Net Present Value (Upper Bound)] 3.82	Network Safety Risk Reduction (\$m)	Network Safety Risk Reduction 0.08
NPV @ Higher Bound Scenario (PV, \$m)	[Net Present Value (Lower Bound)] 51.76	ALARP	ALARP Compliant? No
NPV Weighted (PV, \$m)	[Net Present Value (Weighted)] 22.94	Optimal Timing	Optimal timing (Business Case) 2024
Cost			
Direct Capex (\$m)	10.06	Network and Corporate Overheads (\$m)	0.76
Total Capex (\$m)	10.82	Cost Capex (PV,\$m)	9.72
Terminal Value (\$m)	4.81	Terminal Value (PV,\$m)	1.07
Risk (central scenario)	Pre	Post	Benefit
Reliability (PV,\$m)	Reliability Risk (Pre) 27.18	Reliability Risk (Post) 1.500	Pre – Post 25.68
Financial (PV,\$m)	Financial Risk (Pre) 1.24	Financial Risk (Post) 0.50	Pre – Post 0.74
Operational/Compliance (PV,\$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) 0.00	Pre – Post 0.00
Safety (PV,\$m)	Safety Risk (Pre) 0.35	Safety Risk (Post) 0.15	Pre – Post 0.20
Environmental (PV,\$m)	Environmental Risk (Pre) 0.15	Environmental Risk (Post) 0.05	Pre – Post 0.10
Reputational (\$m)	Reputational Risk (Pre) 0.00	Reputational Risk (Post) 0.00	Pre – Post 0.00
Total Risk Benefit (PV,\$m)	Total Risk (Pre) 28.91	Total Risk (Post) 2.19	Pre – Post 29.72
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 26.73

Project Description	Inverell 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)] 5.72	Annualised CAPEX (\$m)	Annualised Capex - Standard (Business Case) 0.13
NPV @ Lower Bound Scenario (PV, \$m)	[Net Present Value (Upper Bound)] 2.43	Network Safety Risk Reduction (\$m)	Network Safety Risk Reduction 0.02
NPV @ Higher Bound Scenario (PV, \$m)	[Net Present Value (Lower Bound)] 13.68	ALARP	ALARP Compliant? No
NPV Weighted (PV, \$m)	[Net Present Value (Weighted)] 6.89	Optimal Timing	Optimal timing (Business Case) 2023
Cost			
Direct Capex (\$m)	0.96	Network and Corporate Overheads (\$m)	0.35
Total Capex (\$m)	1.31	Cost Capex (PV,\$m)	1.17
Terminal Value (\$m)	0.00	Terminal Value (PV,\$m)	0.00
Risk (central scenario)	Pre	Post	Benefit
Reliability (PV,\$m)	Reliability Risk (Pre) 27.18	Reliability Risk (Post) 20.57	Pre – Post 6.61
Financial (PV,\$m)	Financial Risk (Pre) 1.24	Financial Risk (Post) 1.04	Pre – Post 0.20
Operational/Compliance (PV,\$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) 0.00	Pre – Post 0.00
Safety (PV,\$m)	Safety Risk (Pre) 0.35	Safety Risk (Post) 0.29	Pre – Post 0.06
Environmental (PV,\$m)	Environmental Risk (Pre) 0.15	Environmental Risk (Post) 0.12	Pre – Post 0.03
Reputational (\$m)	Reputational Risk (Pre) 0.00	Reputational Risk (Post) 0.00	Pre – Post 0.00
Total Risk Benefit (PV,\$m)	Total Risk (Pre) 28.91	Total Risk (Post) 22.03	Pre – Post 6.89
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 6.89

Approval Record

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205846	Document Review	Lamplough Evan	Reviewed		09-11-2021
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