Final Project Assessment Report Hastings Zone Substation 22 kV Switchgear Condition

Project No. UE-RCA-U-26-001

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Document Control

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1	Initial Version

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1. Executive Summary

1.1 Summary

United Energy (**UE**) is a regulated Victorian electricity distribution business. UE distributes electricity to more than 720,000 customers across Melbourne's east and south-east metropolitan area, and the Mornington Peninsula. The UE network consists of more than 202,000 poles and over 13,500 kilometres of overhead lines and underground cables. Electricity is received via 92 sub-transmission lines at 47 zone substations, where it is transformed from sub-transmission voltages down to distribution voltages.

The area of the UE network that is the subject of this *Regulatory Investment Test for Distribution* (**RIT-D**) is the Hastings Zone Substation (**HGS**) supply area that spans the areas of Hastings, Merricks, Somerville and Tyabb. HGS is owned and operated by UE, providing power to approximately 17,208 customers, comprising mainly residential customers, with commercial/light industrial customers located near Western Port Bay.

The condition of the 22 kV switchgear[1] at HGS, necessary for the provision of a safe and reliable power supply to customers within the HGS supply area, is deteriorating and technically obsolete, unsupported by the original equipment manufacturers, and with no spares available.

UE has assessed for this RIT-D, credible options to address the asset condition risks at HGS and has confirmed the preferred option to address this identified need being replacement of the existing outdoor 22 kV switchyard with a new indoor switchroom building. This option has a total capital cost of $9.67 million (real, 2026), with $2.43 million present value of net benefits and an optimum practical timing of 2028.

1.2 Purpose

This *Final Project Assessment Report* (**FPAR**) has been prepared by UE in accordance with the requirements of clause 5.17.4, paragraph (r) of the *National Electricity Rules* (**NER**)[2] version 248.

The purpose of this report is to identify the preferred option to address the HGS 22 kV switchgear condition identified need, associated with the network safety and reliability limitations within the HGS supply area.

This report has been prepared following the publication of the *Notice of Determination* and represents the final stage of the RIT-D process.

1.3 Notice of Determination Report

On 24 July 2026, UE published a *Notice of Determination* in accordance with clause 5.17.4, paragraphs (c) and (d) of the NER. The purpose of that report was to present the potential credible options considered, and to explain the reasons for concluding that there would unlikely be any potential credible non-network or standalone power system (**SAPS**) options (or any combination of those options, or with a network option) that could adequately and economically address the identified need within the HGS supply area.

1.4 Draft Project Assessment Report

Given the total cost of the most expensive credible network option to address the HGS 22 kV switchgear condition identified need, is lower than the trigger threshold of $14 million[3] for the publication of and consultation on a *Draft Project Assessment Report* (**DPAR**), UE did not publish and consult on a DPAR for this RIT-D.

1.5 Final Project Assessment Report

Following publication of the *Notice of Determination*, UE is required to prepare and publish a FPAR, as required under NER clause 5.17.4, paragraph (o). The NER requires that the FPAR includes matters detailed in NER clause 5.17.4, paragraph (r)(1), summarised as follows:

- provide background information on the network servicing the HGS supply area and its limitations
- describe the need which UE is seeking to address, together with the assumptions used in identifying that need

[1] Includes all 22 kV switchyard equipment including circuit breakers, current and voltage transformers, buses, isolators, insulators and control cables.
[2] National Electricity Rules (NER), Australian Energy Market Commission (AEMC), 2026.
[3] 2024 cost thresholds review for the Regulatory Investment Test, Australian Energy Regulator (AER), 2024.

- describe the credible options that are considered in this RIT-D assessment
- explain the materiality of each class of market benefit and the methods used in quantifying material market benefits
- quantify costs, high-level cost breakdowns, and material market benefits for each of the credible options
- present the results of a net present value (**NPV**) analysis, with explanatory statements regarding the results
- identify the preferred option, its costs, optimum timing and its technical characteristics.
- summarise submissions received on the DPAR and the responses to those submissions[4].

1.6 The Identified Need

The AEI LG1C 22 kV outdoor bulk-oil circuit breakers at HGS are at end-of-life. HGS is the only zone substation on the UE network with this type of circuit breaker, with the equipment experiencing an increasing number of outstanding defects.

There are nine circuit breakers of this type installed at HGS, with defects detected in their bushings, mechanisms, current transformers, contacts (high resistance), terminations (thermal hotspot), insulation (partial discharge) and tanks/gauges (leaking oil).

These defects cannot be effectively repaired given the lack of spares and equipment obsolescence, putting at risk the ongoing safe and reliable operation of this zone substation. As an interim measure, UE has imposed operational constraints on HGS to minimise the safety risk for personnel working on site, by activating instantaneous protection settings and disabling auto-reclose functionality for risk mitigation.

The identified need at HGS is to:

i) protect power sector workers and members of the public from harm caused by equipment failure (safety); and

ii) continue to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network (reliability).

Solutions to the identified need shall manage and mitigate the increasing risk of 22 kV switchgear defects, to maintain the safety and reliability of electricity supply to UE's customers and workforce within the HGS supply area.

Table 1 summarises the forecast total financial impact of the identified need for customers within the HGS supply area from deterioration in reliability and safety of our network assets.

Table 1: Forecast impact of the identified need on customers ($'000, real 2026)

Year	Total risk cost
2026	1,171
2027	1,188
2028	1,195
2029	1,203
2030	1,193
2031	1,189
2032	1,196
2033	1,201
2034	1,197
2035 - 2047	1,197 p.a.

For the purposes of this RIT-D, economic evaluations are undertaken over a 20-year period with the risk costs held constant beyond the 10-year forecast period.

Table 2 provides a summary of the base case option, using the risk costs presented in Table 1.

[4] Not applicable for this RIT-D.

Table 2: Base case

Option	Description
Do nothing (status quo)	This base case option involves running the HGS 22 kV switchgear to failure. That is, continue with existing maintenance of this equipment, coupled with replacement upon failure. This option does not address the identified need as it does not address the network reliability and safety risks. The present value of all costs (reliability and safety risk) is $14.13 million (real, 2026).

1.7 Credible Options for Addressing the Identified Need

The following options in Table 3 have been included as credible options in the RIT-D assessment.

Table 3: Credible options assessed in this RIT-D

Option	Description
1) Replace existing outdoor 22 kV switchyard with a new indoor switchroom building	This option involves retiring the existing 22 kV switchyard and establishing a pre-fabricated building with 2 indoor 22 kV buses, 10 feeder, 2 transformer, and 2 bus-tie circuit breakers with 500 m of underground 22 kV cable connections. It addresses network reliability risk and safety risk. The total capital cost of this option is $9.67 million (real, 2026) which includes 18.5 per cent overheads. The present value of all costs (capital, O&M, residual risk) is $11.70 million (real, 2026).
2) Replace existing outdoor 22 kV switchgear in situ	This option involves replacing 5 feeder, 2 transformer and 1 bus-tie circuit breakers, and all existing 22 kV current and voltage transformers in situ. The existing 22 kV bus, connections, isolators, insulators and control cabling in the switchyard will also be replaced. It addresses network reliability risk and safety risk. The total capital cost of this option is $10.17 million (real, 2026) which includes 18.5 per cent overheads. The present value of all costs (capital, O&M, residual risk) is $12.17 million (real, 2026).

1.8 Scenarios and Sensitivities Considered

In order to test the robustness of the RIT-D preferred option to changes in assumptions, a set of sensitivities to key input variables of the analysis has been applied. Table 4 lists the variables and respective ranges adopted for the purpose of defining sensitivities.

Table 4: Sensitivity analysis variables

Sensitivity Testing	Lower Bound	Base value	Upper bound
Capital and operational costs	70%	100%	130%
Reliability risk	80%	100%	120%
Safety risk	80%	100%	120%
Discount rate	4.73%	7.0%	10.0%
Assessment period	15 years	20 years	25 years

The NER stipulates that the RIT-D must be based on a cost-benefit analysis that considers a number of reasonable scenarios of future supply and demand [5]. For the identified need in this RIT-D assessment, the major input variables that impact future reliability and safety outcomes within the HGS supply area, are changes in the demand for electricity and changes in the asset failure rates. The scenarios and their weightings that are used in the economic evaluation to identify the preferred option, are summarised in Table 5.

Table 5: Scenario variables and weightings

Scenario Definition	Low Scenario	Central Scenario	High Scenario
Weighting	25%	50%	25%
Reliability risk	80%	100%	120%
Safety risk	80%	100%	120%

Four scenarios are considered:

- Central scenario (reliability and safety risk set to the base values in Table 4).
- Low scenario (reliability and safety risk set to the lower bound values in Table 4).
- High scenario (reliability and safety risk set to the upper bound values in Table 4).
- Weighted scenario (25% low scenario; 50% central scenario; and 25% scenario).

1.9 Net Present Value Analysis Results

The purpose of the RIT-D is to identify the preferred option, being the credible option that maximises the present value of net market benefit. Table 6 sets out a comparison of the present value of net market benefits of each option under all reasonable scenarios, over a 20-year period.

Table 6: Present value of net market benefits of credible options - scenarios ($'000, real 2026)

Scenario	Do nothing		Option 1		Option 2	
	Net market benefit	Ranking	Net market benefit	Ranking	Net market benefit	Ranking
Weighted	0	3	2,428	1	1,964	2
Central	0	3	2,428	1	1,964	2
Low	0	2	175	1	(289)	3
High	0	3	4,681	1	4,217	2

The RIT-D assessment summarised in Table 6, demonstrates that Option 1 maximises the present value of net market benefits under the Weighted Scenario (i.e. a weighting of the Central, Low and High Scenarios).

For all reasonable scenarios considered, Option 1 maximises the present value of net market benefits for all scenarios.

Based on the Weighted Scenario, the preferred option for investment in the HGS supply area is therefore Option 1 (i.e. the replacement of the existing outdoor 22 kV switchyard with a new indoor switchroom building at HGS).

Option 1 satisfies the requirements of the RIT-D.

The robustness of the preferred option to credible changes in input variables is summarised in the sensitivity analysis results of Table 7.

[5] NER: clause 5.17.1(c) paragraph 1.

Table 7: Present net market benefits of credible options - sensitivities ($'000, real 2026)

Sensitivity for Central Scenario	Option 1	Option 2
All Variables: Base values	2,428	1,964
Capital and operational costs: Lower bound	5,079	4,754
Capital and operational costs: Upper bound	(223)	(826)
Reliability and safety risk: Lower bound	175	(289)
Reliability and safety risk: Upper bound	4,681	4,217
Discount rate: Lower bound	4,764	4,289
Discount rate: Upper bound	295	(155)
Assessment period: Lower bound	847	383
Assessment period: Upper bound	3,555	3,091

Option 1 has a present value of net market benefit that remains positive under all but one credible sensitivity, and when compared with Option 2, clearly maintains its status as the preferred option.

The economic timing of the preferred option is when the annualised value of avoided risk cost exceeds the annualised investment cost of the preferred option. Table 8 shows the expected optimum timing of the preferred option.

Table 8: Expected timing of the preferred option ($'000, real 2026)

Annualised investment cost	Annualised cost of avoided risk				Optimum timing
	2027	2028	2029	2030	
677	1,129	1,137	1,144	1,134	2027

Although the optimum timing is identified as 2027, it is not practical to complete the works by this time. Therefore, considering the practical completion time of 1-2 years, the optimum practical timing of Option 1 is 2028.

1.10 Preferred Option

The preferred option is Option 1 as it maximises the present value of the net economic benefit, considering a set of reasonable state-of-the-world scenarios and their weightings.

The preferred option was tested under a range of sensitivities. In most cases, Option 1 provides positive economic benefits and is the highest-ranked option under all sensitivities.

The optimum practical timing for completing the preferred option is 2028.

The preferred option has a capital cost of $9.67 million (real, 2026).

The 20-year present value of net market benefits associated with the preferred option is $2.43 million (real, 2026).

1.11 Next Steps

This FPAR represents the final stage of the RIT-D process.

In accordance with the provisions set out in clause 5.17.5, paragraph (c) of the NER, Registered Participants or interested parties may, within 30 days after the publication of this report, dispute the conclusions made by UE in this report with the Australian Energy Regulator (**AER**).

Accordingly, Registered Participants and interested parties who wish to dispute the recommendation outlined in this report must do so by 28 August 2026. Any parties raising such a dispute are also required to notify UE at planning@ue.com.au. If no formal dispute is raised, UE will commence with the investment activities necessary to proceed with the implementation of the preferred option.

For the purposes of referencing this RIT-D, this RIT-D shall refer to the "*Hastings Zone Substation 22 kV Switchgear Condition*" identified need.

2. Definitions

Table 9: Terms and definitions

Term	Definition
AEI	American Electrical Inc.
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFAP	As Far As Practicable
CPI	Consumer Price Index
DAPR	Distribution Annual Planning Report
DPAR	Draft Project Assessment Report
EUE	Expected Unserved Energy (MWh pa)
FPAR	Final Project Assessment Report
FSH	Frankston South Zone Substation
HGS	Hastings Zone Substation
IASR	Inputs, Assumptions and Scenarios Report
LWN	Langwarrin Zone Substation
LTI	Lost Time Injury
MWp	Megawatt peak
MTN	Mornington Zone Substation
NCC	Network Control Centre
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
O&M	Operating and Maintenance
PoE	Probability of Exceedance
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
SAPS	Stand-alone Power System
SCADA	Supervisory Control and Data Acquisition
TBTS	Tyabb Terminal Station
UE	United Energy
VCR	Value of Customer Reliability ($/MWh)
VSL	Value of Statistical Life

Term	Definition
50% PoE	The forecast maximum demand has a 50% probability of exceedance (PoE). That is, the forecast maximum demand is expected, on average, to be exceeded once in two years.
10% PoE	The forecast maximum demand has a 10% probability of exceedance (PoE). That is, the forecast maximum demand is expected, on average, to be exceeded once in ten years.
Credible option	An option that addresses the 'identified need', is commercially and technically feasible, and can be implemented in sufficient time to meet the 'identified need'.
Identified need	Any capacity, voltage, or safety limitation on the distribution system.
Limitation	Any limitations on the operation of the distribution system that will give rise to Expected Unserved Energy or safety risk consequences.
Network option	A means by which an 'identified need' can be fully or partly addressed by expenditure on distribution network assets.
Non-network or SAPS option	A means by which an 'identified need' can be fully or partially addressed other than by a network option.
Non-network service provider	A party who provides a non-network or SAPS option.
Potential credible option	An option has the potential to be a credible option based on an initial assessment of its ability to address the 'identified need'.
Preferred network option	A credible network option that maximises the present value of net economic benefit. The preferred network option can be a network option, or do nothing (i.e. status quo).
Preferred option	A credible option that maximises the present value of net economic benefit. The preferred option can be a network option, non-network or SAPS option, combination of both, or do nothing (status quo).

3. Referenced Documents

Table 10: Referenced UE Documents

Title	Document No.
UE Asset Risk Quantification Guide	UE-GU-2011

4. Introduction

This FPAR has been prepared by UE in accordance with the requirements of clause 5.17.4, paragraph (r) of the NER[6] version 248 and is consistent with the *Regulatory Investment Test for Distribution (RIT-D) Application Guidelines*[7] and *Industry Practice Application Note for Asset Replacement Planning*[8].

The FPAR represents the final stage of the consultation process to support the RIT-D as required under clause 5.17.4(o) of the NER, for addressing the identified need, associated with the network safety and reliability risks within the HGS supply area.

This FPAR sets out the matters detailed in NER clause 5.17.4, paragraph (r)(1), summarised as follows:

- provide background information on the network servicing the HGS supply area and its limitations
- describe the need which UE is seeking to address, together with the assumptions used in identifying that need
- describe the credible options that are considered in this RIT-D assessment
- explain the materiality of each class of market benefit and the methods used in quantifying material market benefits
- quantify costs, high-level cost breakdowns, and material market benefits for each of the credible options
- present the results of a NPV analysis, with explanatory statements regarding the results
- identify the preferred option, its costs, optimum timing and its technical characteristics
- summarise submissions received on the DPAR and the responses to those submissions[9].

[6] National Electricity Rules (NER), Australian Energy Market Commission (AEMC), 2026.
[7] RIT-D Application Guidelines, Australian Energy Regulator (AER), 2024.
[8] Industry Practice Application Note – Asset Replacement Planning, Australian Energy Regulator (AER), 2019
[9] Not applicable for this RIT-D.

5. Identified Need

5.1 Network Overview

The area of the UE network that is the subject of this RIT-D is the HGS supply area that spans the areas of Hastings, Merricks, Somerville and Tyabb.

HGS is owned and operated by UE, providing power to approximately 17,208 customers, comprising mainly residential customers, with commercial/light industrial customers located near Western Port Bay.

HGS is bounded in the north by adjacent 22 kV zone substations Frankston South (**FSH**) and Langwarrin (**LWN**), and in the west by Mornington (**MTN**), providing load transfer capacity to reduce load on the zone substation in the event of an emergency (such as a major asset failure, for example). The load transfer capability away from HGS is 14.6 MVA.

HGS zone substation is served by two 66 kV sub-transmission lines from the Tyabb Terminal Station (**TBTS**) and transforms electricity down to 22 kV via two 20/33 MVA transformers.

The cyclic rating of HGS with all transformers in service is 77.7 MVA (summer) 90.4 MVA (winter), and with one transformer out of service the rating reduces to 38.9 MVA (summer) 45.2 MVA (winter). This compares to a forecast 10% PoE maximum demand of 66.7 MVA for summer 2029/30.

The electrical single line diagram for HGS, showing the 66 kV assets (in red), 66/22 kV transformers, and 22 kV assets (in blue, including distribution feeder exits) is illustrated in Figure 1.

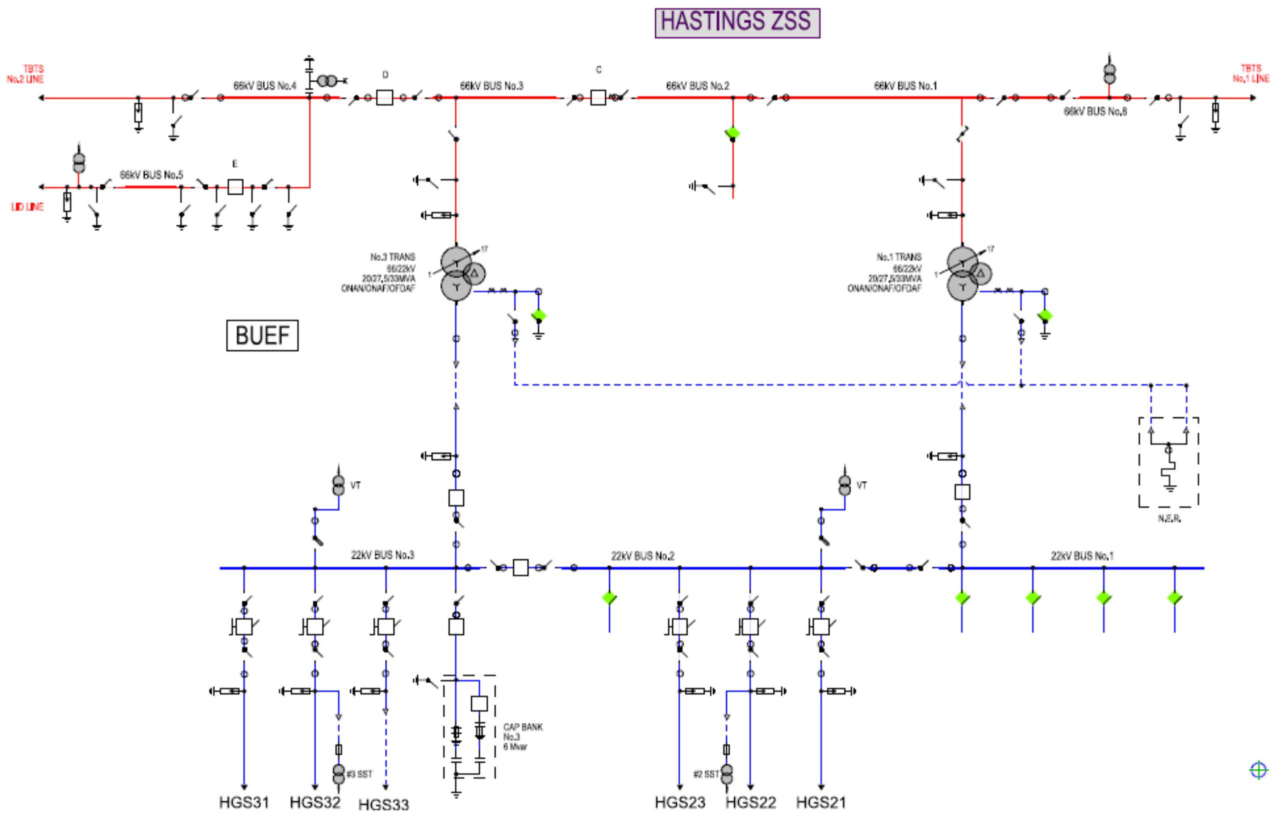

Figure 1: HGS electrical single line diagram

The aerial view of HGS showing the existing 22 kV switchyard is illustrated in Figure 2.

Figure 2: HGS aerial view

The power supply coverage of HGS relative to the supply area of adjacent zone substations FSH, LWN and MTN, and to TBTS, is illustrated in Figure 3.

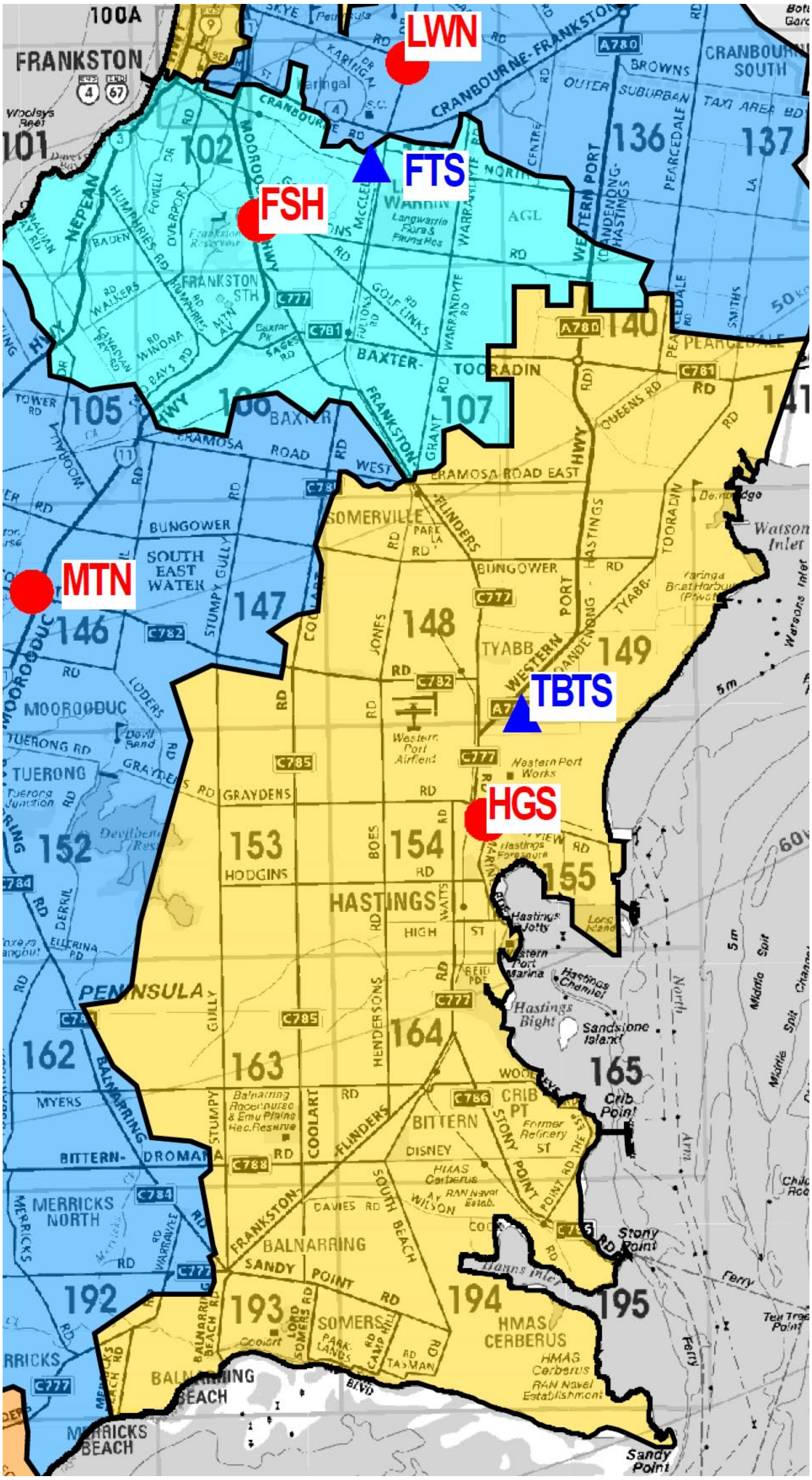

Figure 3: HGS supply area and surrounding areas

5.2 Description of the Identified Need

The identified need at HGS is to:

i) protect power sector workers and members of the public from harm caused by equipment failure (safety) and

ii) continue to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network (reliability).

The condition of the 22 kV switchgear [10] at HGS, necessary for the provision of a safe and reliable power supply to customers within the HGS supply area, is deteriorating and technically obsolete, unsupported by the original equipment manufacturers, and with no spares available.

The American Electrical Inc.(AEI) LG1C 22 kV outdoor bulk-oil circuit breakers at HGS are at end-of-life. HGS is the only zone substation on the UE network with this type of circuit breaker, with the equipment experiencing an increasing number of outstanding defects.

There are nine circuit breakers of this type installed at HGS, with defects detected in their bushings, mechanisms, current transformers, contacts (high resistance), terminations (thermal hotspot), insulation (partial discharge) and tanks/gauges (leaking oil).

These defects cannot be effectively repaired given the lack of spares and equipment obsolescence, putting at risk the ongoing safe and reliable operation of this zone substation. As an interim measure, UE has imposed operational constraints on HGS to minimise the safety risk for personnel working on site, by activating instantaneous protection settings and disabling auto-reclose functionality for risk mitigation.

Solutions to the identified need shall manage and mitigate the increasing risk of 22 kV switchgear defects, to maintain the safety and reliability of electricity supply to UE's customers and workforce within the HGS supply area.

Recent 22 kV switchgear defects experienced at HGS are listed in Table 11. Photographs of those assets are presented in Appendix A.

Table 11: 22 kV switchgear defects

Year	22 kV circuit breaker(s)	Defective component	Identified issue
2025	HGS32, HGS22, HGS21 HGS31	Bushings Contacts	Low oil level High contact resistance
2024	HGS23	Bushings Mechanism Contacts	Low oil level, gauge cracked glass Interruption assembly broken High contact resistance
2023	HGS31, HGS32 HGS23, HGS21 HGS22	Bushings Terminations Contacts	Cracked bushings, gauge oil leak Thermal hot spot detection - poor connection Worn contacts
2022	HGS32 HGS23, HGS21	Terminations Contacts	Thermal hot spot detection - poor connection Worn contacts
2021	No.1 Transformer HGS23, HGS21, HGS31 No. 2-3 Bus Tie	Terminations Terminations Insulation	Thermal hot spot detection - poor connection Thermal hot spot detection - poor connection Failed megger reading - insulation breakdown
2020	HGS31 HGS32, HGS21 HGS21	Bushings Terminations Tank & Mechanism	Partial discharge - insulation breakdown Thermal hot spot detection - poor connection Low oil level, interruption assembly broken

[10] Includes all 22 kV switchyard equipment including circuit breakers, current and voltage transformers, buses, isolators, insulators and control cables.

5.3 Quantification of the Identified Need

Table 12 summarises the forecast impact of the identified network need discussed in Section 5.2. The table shows over a 10-year forecasting period, the total risk costs comprising:

- reliability risk cost, being the value of expected unserved energy (**EUE**), which is the customer value of the energy at risk after accounting for the probability of asset failures or malfunctions at HGS, representing the deterioration in supply reliability within the HGS supply area.
- safety risk cost, which is the cost of harm to UE's staff and/or the public resulting from anticipated safety incidents caused by asset failures or malfunctions at HGS.

Table 12: HGS risk quantification ($'000, real 2026)

Year	Total risk cost
2026	1,171
2027	1,188
2028	1,195
2029	1,203
2030	1,193
2031	1,189
2032	1,196
2033	1,201
2034	1,197
2035 - 2047	1,197 pa

For the purposes of this RIT-D, economic evaluations are undertaken over a 20-year period, commensurate with the long life nature of the asset, with the risk costs held constant beyond the 10-year forecast period.

Table 13 provides a summary of the base case option, using the risk costs presented above.

Table 13: Base case

Option	Description
Do nothing (status quo)	This base case option involves running the HGS 22 kV switchgear to failure. That is, continue with existing maintenance of this equipment, coupled with replacement upon failure. This option does not address the identified need as it does not address the network reliability and safety risks. The present value of all costs (reliability and safety risk) is $14.13 million (real, 2026).

6. Key Assumptions in Relation to the Identified Need

6.1 Method for Quantifying the Identified Need

UE adopts its *Asset Risk Quantification Guide* (UE-GU-2011) in quantifying safety and reliability risks associated with asset condition failures and their consequences. This modelling is based on Weibull distribution parameters for each asset class and a probabilistic planning approach.

6.1.1 Safety

The safety risk to UE employees and the general public, arising from potential failure or malfunction of network assets is quantified by UE using an annualised safety risk cost, based on the asset conditions. The safety risk cost provides a measure of the expected financial value of the safety risk event. The safety risk cost is defined as the probability weighted cost of consequences, with the likelihood of consequences being the moderating factor in quantifying the risk.

The *Electricity Safety Act*[11] requires UE to design, construct, operate, maintain, and decommission its network to minimise hazards and risks to the safety of any person as far as reasonably practicable, or until the costs become disproportionate to the benefits from managing those risks. As such, UE's approach to safety risk is based on the as far as practicable (**AFAP**) principle.

In implementing this principle for assessing safety risks from asset condition failures, UE uses a value of statistical life (**VSL**) to estimate the benefits of reducing the risk of death, a value of lost time injury (**LTI**) to estimate the benefits of reducing the risk of injury, and a disproportionality factor. UE notes that this approach, including the use of a disproportionality factor, is consistent with practice notes provided by the AER[12], and is the approach taken by other network service providers.

The AFAP principle recommends safety risk reduction measures be implemented unless the cost, time or form of the risk reduction measure is grossly disproportionate to the benefit gained from the reduced risk. A "Do nothing" (or "run to failure") approach would result in the poor condition assets remaining in service, deteriorating further, and completely failing to address any safety concerns.

6.1.2 Reliability

UE's reliability planning standard for its zone substation assets is based on a probabilistic planning approach which quantifies EUE defined in terms of megawatt hours (MWh) per annum of energy not supplied, taking into account the unavailability of an asset due to a failure or malfunction and any shortfalls in capacity, and monetises this by applying a locational VCR ($/MWh)[13].

6.2 Forecast Maximum Demand

Forecasts of the 10 per cent PoE and 50 per cent PoE summer maximum demand and power factor at HGS are presented. These forecasts are based on an expected economic growth scenario.

Table 14: HGS maximum demand forecast

Time period	Power Factor	10% PoE (MVA)	50% PoE (MVA)
2026	1.00	66.0	51.1
2027	1.00	66.7	51.4
2028	1.00	66.9	51.6
2029	1.00	67.1	51.7
2030	1.00	66.7	51.6

[11] Electricity Safety Act, Victorian State Government, Victorian Legislation and Parliamentary Documents, 1998..
[12] Industry Practice Application Note – Asset Replacement Planning, Australian Energy Regulator (AER), 2019.
[13] Values of Customer Reliability, Australian Energy Regulator (AER), 2025.

6.3 Characteristic of Load Profile

UE has presented load profiles that are characterised by the use of profiles from the most recent 50 per cent PoE year. The coincident maximum demand of the customers within the HGS supply area occurs during days of extreme ambient temperature, particularly for hot weather.

The annual demand profile at HGS expressed as a percentage of the 50 per cent PoE maximum demand listed in Table 14, is illustrated in Figure 4.

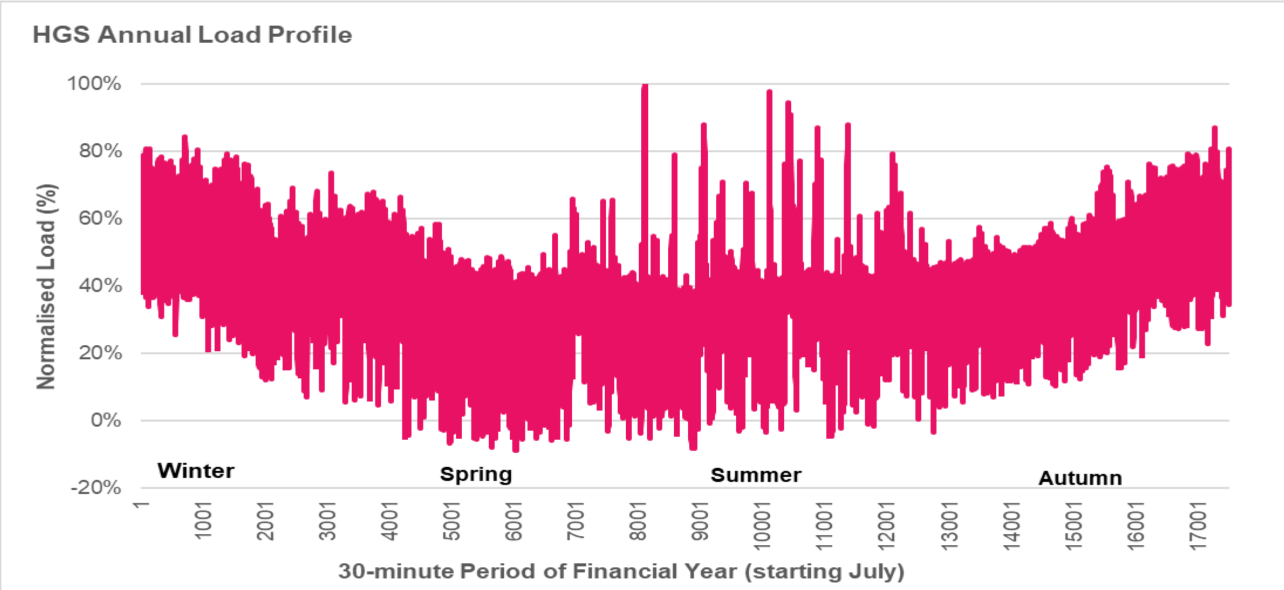

Figure 4: Annual load profile at HGS

The load profile on the day of a 50 per cent PoE summer maximum demand is illustrated in Figure 5. The prominence of air-conditioning load within the HGS supply area, results in a maximum demand occurring during the early evening as the solar PV output subsides. Embedded solar PV generation depresses the demand during daylight hours illustrated by the difference in gross (underlying) and net (observed) demand.

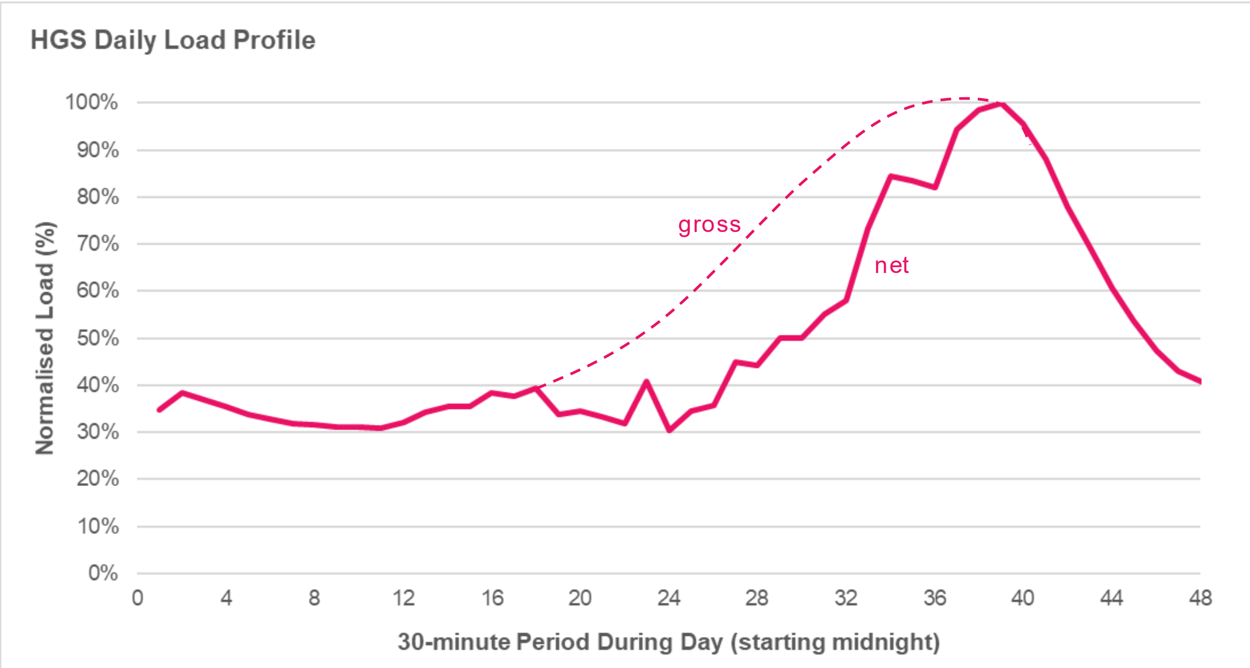

Figure 5: Load profile on day of summer maximum demand at HGS

Figure 6 shows the normalised annual load-duration curve at HGS for a 50 per cent PoE summer maximum demand year.

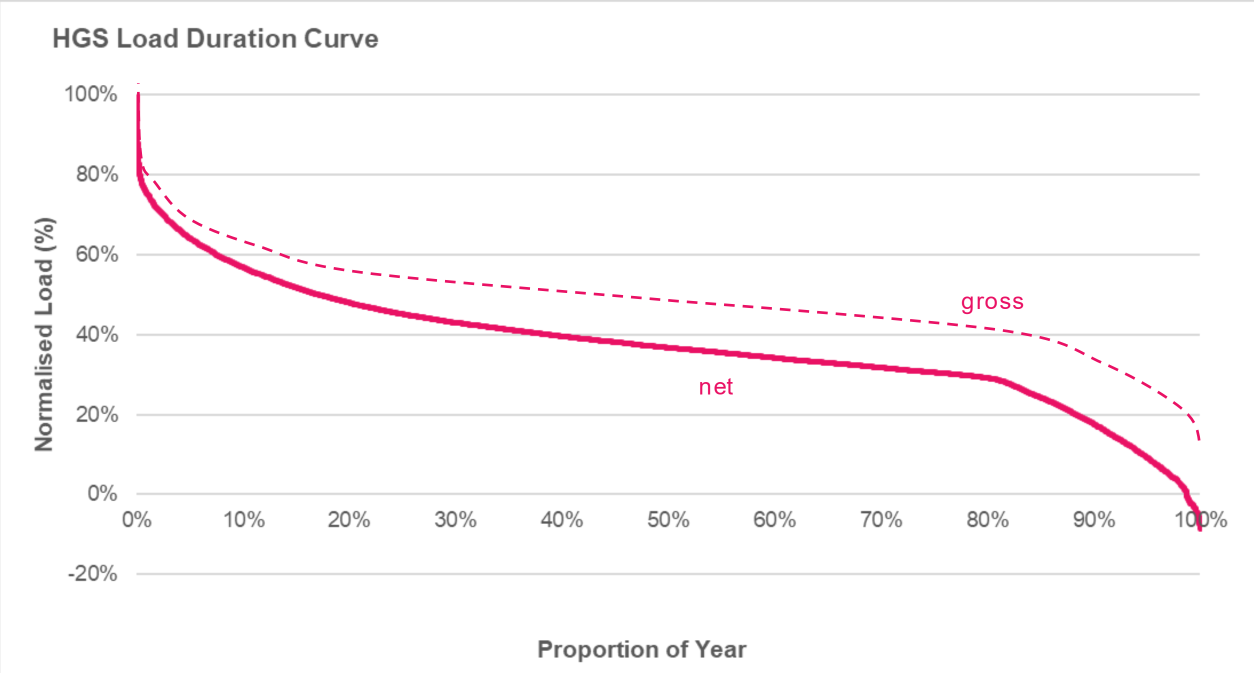

Figure 6: Annual load-duration curve at HGS

The load characteristics can vary marginally from year to year due to changes in weather, solar PV generation and storage systems growth, and underlying changes in the customers' load usage. Figure 6 shows that load more than 80 per cent of the maximum demand lasts for less than 1 per cent of the year. It also indicates that HGS has a high penetration of air conditioning which operates for a very small fraction of the year.

6.4 Load Transfer Capacity and Supply Restoration Times

The load transfer capability between HGS and the neighbouring networks of FSH, LWN and MTN is 14.6 MVA for 2026. Future load transfer capability levels between HGS and the neighbouring network are expected to remain relatively constant. Customers' supply is normally restored within 60 minutes following the loss of a major plant item (i.e. a zone substation transformer, or distribution feeder).

6.5 Asset Ratings

The existing capabilities of HGS zone substation for summer and winter are presented in Table 15 for all transformers in service (**N**), and for one transformer out of service (**N-1**).

Table 15: Summary of HGS ratings (MVA)

Zone Substation	Summer cyclic rating at 40°C		Winter cyclic rating at 10°C	
	N	N-1	N	N-1
HGS import[14]	77.7	38.9	90.4	45.2
HGS export[15]	-66.0	-33.0	-66.0	-33.0

[14] Power flow towards customer load.
[15] Power flow towards the transmission network.

6.6 Asset Failure Rates

The base (average) reliability and safety consequence data adopted in this assessment is presented in Table 16, Table 17 and Table 18 below. The data is based on observed UE asset failure rates.

Table 16: Summary of asset failure rates and hazard function (Weibull distribution parameters)

Equipment	α parameter	β parameter
Electro-mechanical Relay (failure to operate)	6.0	75
Analogue Relay (failure to operate)	4.0	56
Digital / Numerical Relay (failure to operate)	3.0	36
22 kV switchgear (failure)	6.8	69

Table 17: Summary of asset reliability consequence probability

Equipment	Consequence	Probability
Electro-mechanical Relay (reliability)	Bus outage Feeder outage	37% 16%
Analogue relay (reliability)	Bus outage Feeder outage	32% 16%
Digital / numerical relay (reliability)	Bus outage Feeder outage	21% 9%

Table 18: Summary of asset safety consequence probability

Equipment	Consequence	Probability
All protection relays (safety)	Injury Death – public Death – staff	0.0260% 0.0115% 0.1960%

7. Credible Options

UE presented seven options (network, non-network and standalone power system) in the *Notice of Determination* for the HGS 22 kV switchgear condition identified need. Only two network options were regarded as being credible for the reasons set out in that report. Details of those credible options assessed in this RIT-D against the base case are presented in Table 19.

Table 19: Credible options assessed in this RIT-D

Option	Description
1) Replace existing outdoor 22 kV switchyard with a new indoor switchroom building	This option involves retiring the existing 22 kV switchyard and establishing a pre-fabricated building with 2 indoor 22 kV buses, 10 feeder, 2 transformer, and 2 bus-tie circuit breakers with 500 m of underground 22 kV cable connections. It addresses network reliability risk and safety risk. The total capital cost of this option is $9.67 million (Real, 2026) which includes 18.5% overheads. The present value of all costs (capital, O&M, residual risk) is $11.70 million (Real, 2026).
2) Replace existing outdoor 22 kV switchgear in situ	This option involves replacing 5 feeder, 2 transformer and 1 bus-tie circuit breakers, and all existing 22 kV current and voltage transformers in situ. The existing 22 kV bus, connections, isolators, insulators and control cabling in the switchyard will also be replaced. It addresses network reliability risk and safety risk. The total capital cost of this option is $10.17 million (Real, 2026) which includes 18.5% overheads. The present value of all costs (capital, O&M, residual risk) is $12.17 million (Real, 2026).

8. Submissions to the DPAR

Given the total cost of the most expensive credible network option to address the HGS 22 kV switchgear condition identified need, is lower than the trigger threshold of $14 million [16] for the publication of and consultation on a DPAR, UE did not publish and consult on a DPAR for this RIT-D.

[16] 2024 cost thresholds review for the Regulatory Investment Test, Australian Energy Regulator (AER), 2024.

9. Market Modelling Methodology

The RIT-D requires market benefits identified to be material, to be calculated by comparing the state-of-the-world in the base case (where no action is undertaken by UE), against each of the credible options in place.

The states-of-the-world are a range of reasonable and mutually consistent scenarios of credible supply and demand characteristics and conditions that may affect the calculation of the market benefits over the period of assessment. The selection of the preferred option is informed by a weighting of all the reasonable scenarios.

Furthermore, a set of sensitivity studies is undertaken on the preferred option by varying key input variables, to test the economic viability and rank of the preferred option against other options and the base case, for all credible changes in assumptions.

9.1 Key Parameters

9.1.1 Discount Rates

To compare cash flows of options with different time profiles, it is necessary to use a discount rate to express future costs and benefits in present value terms. The choice of discount rate will impact on the estimated present value of net market benefits and may affect the ranking of alternative options.

UE uses the commercial discount rates in the Australian Energy Market Operator's (**AEMO**) *2025 Inputs, Assumptions and Scenarios Report*[17], being 7.0 per cent for the base case and 10.0 per cent for the upper bound values. For the lower bound value UE uses a regulatory discount rate of 4.73 per cent.

9.1.2 Value of Customer Reliability

Location-specific VCR is used to value reliability of supply. The locational VCR for the HGS supply area was derived from the published sector VCR estimates[18], weighted in accordance with the composition of the load, by sector. This is summarised in Table 20.

Table 20: Summary of location specific VCR

Zone Substation	VCR ($ per MWh, real 2026)
HGS	42,259

9.1.3 Value of Safety Consequence

Values of safety consequence used in this RIT-D are derived from various sources including Safe Work Australia[19] for LTI, and the Department of Prime Minister and Cabinet, *Best Practice Regulation Guidance Note*[20] for VSL, adjusted for CPI. The values of safety consequence are summarised in Table 21.

Table 21: Summary of safety consequence values

Safety Consequence	Value of safety consequence ($'000, real 2026)
Injury (LTI)	235
Death (VSL)	5,870
Disproportionality factor	3

[17] 2025-26 Inputs, Assumptions and Scenarios Report (IASR), Australian Energy Market Operator (AEMO), 2025.
[18] Values of Customer Reliability, Australian Energy Regulator (AER), 2025.
[19] The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community, Safe Work Australia, 2015.
[20] Best Practice Regulation Guidance Note: Value of statistical life, Department of the Prime Minister and Cabinet, Australian Government, 2026.

9.1.4 Assessment Period

The RIT-D economic analysis has been undertaken over a 20-year period, commensurate with the long-lived nature of the investments considered in this RIT-D assessment. For simplicity, the risk modelling for calculation of market benefits is calculated across a forecast horizon up to ten-years. The market benefits calculated in final forecast year has been applied as the assumed annual market benefit that would continue to arise until the end of the analysis period.

9.2 Approach to Estimating Costs

UE has estimated the capital costs of the credible options, based on actual costs from previous projects of a similar nature. They have been developed in-house by project estimators. UE estimates that the actual cost is within ±30 per cent of the capital cost used within this RIT-D.

Capital costs presented in this RIT-D are fully loaded including escalations, overheads and management reserve.

Only incremental operating and maintenance (**O&M**) costs are included in the assessment annually from the year after the capital investment.

All cost estimates are prepared in real 2026 dollars based on the information available at the time of preparing this FPAR.

9.3 Classes of Market Benefits Considered Material

The purpose of the RIT-D is to identify the credible option that maximises the present value of net market benefit. In order to measure the increase in net market benefit, UE has analysed the classes of market benefits required to be considered by the RIT-D.[21] The classes of market benefits that are considered material and have been quantified in this RIT-D assessment are:

- changes in safety risk costs[22] and
- changes in involuntary load shedding.

9.3.1 Changes in Safety Risk Cost

Reducing the likelihood of asset failure by addressing poor condition assets provides a better safety outcome for the supply area, by reducing potential safety incidents and the consequential risk of harm to UE's personnel and the wider community. At HGS, the safety risk cost is considered to be material. The method used by UE in quantifying changes in safety risk cost is described in Section 6.1.1.

9.3.2 Changes in Involuntary Load Shedding

Reducing the likelihood of asset failure by addressing poor condition assets provides a greater reliability for the supply area, by reducing potential supply interruptions and the consequential risk of involuntary load shedding. At HGS, the reliability risk cost (expressed as the value of EUE) is considered to be material. The method used by UE in quantifying changes in involuntary load shedding is described in Section 6.1.2.

9.4 Classes of Market Benefits Not Expected to be Material

UE considers that the following classes of market benefit are not likely to be material for this RIT-D assessment:

- changes in load transfer capacity and the capacity of embedded generating units to take up load
- changes in electrical energy losses
- changes in voluntary load curtailment
- changes in costs to other parties
- changes in greenhouse gas emissions
- difference in timing of expenditure
- additional option value.

[21] NER: clause 5.17.1(c) paragraph 4.

[22] UE notes that use of a safety risk cost as a class of market benefit is consistent with practice notes provided by the AER, and is the approach taken by other network service providers. Refer to: Industry Practice Application Note – Asset Replacement Planning, AER, 2019.

9.4.1 Changes in Load Transfer Capacity and the Capacity of Embedded Generating Units

The modelling undertaken in Section 9.3.2 considers load transfer that may be expected to occur with each of the credible options in place. Changes in load transfer capability is not expected to be materially different between any of the credible options considered, or with the base case. Furthermore, changes in the capacity of embedded generating units to take up load is not expected to be materially different between any of the credible options considered, or with the base case.

9.4.2 Changes in Electrical Energy Losses

The differences in electrical energy losses between credible options and with the base case is considered to be negligible.

9.4.3 Changes in Voluntary Load Curtailment

Voluntary load curtailment is where customers agree to voluntarily curtail their electricity under certain circumstances, such as during a network asset outage event. The customer will typically receive an agreed payment for making load available for curtailment, and for actually having it curtailed during a network event. A credible demand-side reduction option leads to a change in the amount of voluntary load curtailment.

In its Notice of Determination, UE assessed the potential for voluntary load curtailment within the HGS supply area. It was identified from that report that the potential for voluntary load curtailment was immaterial to address the identified need. Therefore, this market benefit is not quantified for this RIT-D, as it was considered to be not material to differentiate between credible options, or with the base case.

9.4.4 Changes in Costs to Other Parties

There are no material market benefits (or costs) associated with changes in costs to other parties in this instance.

9.4.5 Changes in Greenhouse Gas Emissions

The credible options are not expected to create any material difference in Australia's greenhouse gas emissions. The rationale for there being no impact on greenhouse gas emissions is that the options are not expected to have an impact on wholesale market generation dispatch, renewable energy curtailment or levels of SF_6 emissions from high-voltage switchgear. with the new and existing switchgear not containing SF_6 gas and not expected to alter HGS export ratings.

9.4.6 Difference in Timing of Expenditure

UE has determined that the timing of other unrelated expenditure is not impacted by the options considered in this assessment. Therefore, this market benefit is not quantified, as it was not considered to be relevant to differentiate between options that address the need within the HGS supply area.

9.4.7 Additional Option Value

Additional option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and if the credible options considered by UE are sufficiently flexible to respond to that change.

In the context of the HGS supply area, it is noted that a key identified need relates to safety. As there is virtually no uncertainty in the condition of the assets further deteriorating over time, and that the current condition of the assets is not tenable under the AFAP principle, there is little value in retaining flexibility.

UE considers that the estimation of any option value benefits captured via the scenario analysis and comparison of the credible option under those scenarios would be adequate to meet the NER requirements to consider option value as a class of market benefit.

UE therefore does not propose to estimate any additional option value market benefit for this RIT-D assessment.

9.5 Costs of Credible Options

The capital and incremental operating cost assumptions for each credible option considered in this RIT-D assessment are summarised in Table 22.

Table 22: Capital and operating costs of credible options ($'000, real 2026)

Option	Capital cost	Incremental operational cost (p.a.)
Base case - Do nothing	0	0
1 - Replace existing outdoor 22 kV switchyard with a new indoor switchroom building	9,666	0
2 - Replace existing outdoor 22 kV switchgear in situ	10,168	0

The 20-year present value of capital, operating and risk costs for each credible option considered in this RIT-D assessment are summarised in Table 23.

Table 23: Present value of costs of credible options ($'000, real 2026)

Option	Capital cost	Operational cost	Investment cost (Net)	Risk cost	Total cost
Base case - Do nothing	0	0	0	14,129	14,129
1 - Replace existing outdoor 22 kV switchyard with a new indoor switchroom building	8,836	0	8,366	2,865	11,701
2 - Replace existing outdoor 22 kV switchgear in situ	9,300	0	9,300	2,865	12,165

9.6 Scenarios

Clause 5.17.1 paragraph (c)(1) of the NER requires the RIT-D to be based on a cost-benefit analysis that considers a number of reasonable state-of-the-world scenarios of future supply and demand.

The development of additional reasonable scenarios applied by UE for this RIT-D involved a process of applying a credible sensitivity on key input variables around a Central Scenario, to identify a credible Low Scenario and a credible High Scenario. A weighting is then assigned to each of the three scenarios, representing the likelihood of each of these state-of-the-world scenarios materialising. The Weighted Scenario is then used to identify the preferred option, as it inherently takes into account the uncertainty associated with different future states-of-the-world.

For the identified need in this RIT-D assessment, the major input variables that impact future reliability and safety outcomes within the HGS supply area, are changes in the demand for electricity and changes in the asset failure rates. The scenarios and their weightings that are used in the economic evaluation to identify the preferred option, are summarised in Table 24.

Table 24: Scenario variables and weightings

Scenario Definition	Low scenario	Central scenario	High scenario
Weighting	25%	50%	25%
Reliability risk	80%	100%	120%
Safety risk	80%	100%	120%

9.7 Sensitivities

In order to test the robustness of the RIT-D preferred option to changes in assumptions, a set of sensitivities to key input variables to the analysis has been applied. Table 25 lists the variables and ranges adopted for the purpose of informing sensitivity analysis.

Table 25: Sensitivity analysis variables

Sensitivity testing	Lower bound	Base value	Upper bound
Capital and operational costs	70%	100%	130%
Reliability risk	80%	100%	120%
Safety risk	80%	100%	120%
Discount rate	4.73%	7.0%	10.0%
Assessment period	15 years	20 years	25 years

10. Results of Analysis

The results of the Net Present Value (NPV) cost-benefit analysis for each of the credible options considered in this RIT-D assessment, for each scenario are detailed below.

10.1 Gross Market Benefits

The gross market benefit is the sum of each of the individual categories of material market benefit, as quantified based on the approach set out in Section 9 expressed in present value terms over the analysis period.

Table 26 summarises the present value of gross market benefits of Option 1 and Option 2 relative to the base case (Do Nothing).

Table 26: Gross market benefits

Scenario	Present value of gross market benefit ('000, real 2026)		
	Do Nothing	Option 1	Option 2
Weighted	0	11,264	11,264
Central	0	11,264	11,264
Low	0	9,011	9,011
High	0	13,516	13,516

10.2 Net Market Benefits

Table 27 summarises the net market benefit in present value terms for each credible option over the analysis period, relative to the base case (Do nothing). The net market benefit for Option 1 and Option 2 is the present value of gross market benefits, under the Weighted Scenario (as set out in Table 26), minus the present value of total investment costs of each option (as set out in Table 23).

The table also shows the corresponding ranking of each option under the RIT-D, with options ranked in the order of descending net market benefit.

Table 27: Net market benefits of credible options for the Weighted Scenario

Options	Present Value ('000, Real 2026)			
	Investment cost	Gross market benefits	Net market benefits	Ranking under RIT-D
Do nothing	0	0	0	3
Option 1	8,366	11,264	2,428	1
Option 2	9,300	11,264	1,964	2

This RIT-D assessment demonstrates that Option 1 has the highest net market benefit under the Weighted Scenario.

10.3 Sensitivity Assessment

UE has tested the robustness of the RIT-D assessment to the inclusion of a number of sensitivity tests around the input assumptions adopted. These sensitivities were presented in Table 25. Table 28 shows the results of these sensitivity studies.

Table 28: Present net market benefits of credible options - Sensitivities ($'000, real 2026)

Sensitivity for Central Scenario	Option 1	Option 2
All variables: Base values	2,428	1,964
Capital and operational costs: Lower bound	5,079	4,754
Capital and operational costs: Upper bound	(223)	(826)
Reliability and safety risk: Lower bound	175	(289)
Reliability and safety risk: Upper bound	4,681	4,217
Discount rate: Lower bound	4,764	4,289
Discount rate: Upper bound	295	(155)
Assessment period: Lower bound	847	383
Assessment period: Upper bound	3,555	3,091

Option 1 has a present value of net market benefit that remains positive under all but one credible sensitivity, and when compared with Option 2, clearly maintains its status as the preferred option under all credible sensitivities.

Table 29 presents the net market benefits in NPV terms for each option across all reasonable scenarios considered.

Table 29: Present value of net market benefits of credible options - Scenarios ($'000, real 2026)

Scenario	Do nothing		Option 1		Option 2	
	Net market benefit	Ranking	Net market benefit	Ranking	Net market benefit	Ranking
Weighted	0	3	2,428	1	1,964	2
Central	0	3	2,428	1	1,964	2
Low	0	2	175	1	(289)	3
High	0	3	4,681	1	4,217	2

For all reasonable scenarios considered, Option 1 maximises the present value of net market benefits for all scenarios, including under the Weighted Scenario (i.e. a weighting of the Central, Low and High Scenarios).

Under the RIT-D, the preferred option should maximise the present value of the net market benefits when compared to other credible options and the base case. This RIT-D assessment, based on the sensitivity results in Table 28 and the scenario results in Table 29, demonstrates that Option 1 maximises the present value of net market benefits under all reasonable sensitivities and scenarios considered.

The preferred option for investment for the HGS supply area is therefore Option 1 - Replace existing outdoor 22 kV switchyard with a new indoor switchroom building. This option satisfies the requirements of the RIT-D.

10.4 Economic Timing

The previous Sections 10.2 and 10.3 demonstrate Option 1 to be the preferred option to address the identified need. The economic timing of the preferred option is when the annualised value of avoided risk cost exceeds the annualised investment cost of the preferred option. Table 30 shows the expected timing of the preferred option.

Table 30: Expected timing of the preferred option ($'000, real 2026)

Annualised investment cost	Annualised cost of avoided risk				Optimum timing
	2027	2028	2029	2030	
677	1,129	1,137	1,144	1,134	2027

Although the optimum timing is identified as 2027, it is not practical to complete the works by this time. Therefore, considering the practical completion time of 1-2 years, the optimum practical timing of Option 1 is 2028.

11. Preferred Option

Section 10 has presented the results of the NPV analysis conducted for this RIT-D assessment. This RIT-D assessment has demonstrated that Option 1 maximises the present value of net market benefits under all reasonable sensitivities and scenarios considered.

The preferred option for investment is therefore Option 1. This option involves retiring the existing 22 kV switchyard and establishing a pre-fabricated building with two indoor 22 kV buses, ten feeder, two transformer, and two bus-tie circuit breakers with 500 m of underground 22 kV cable connections.

This option addresses both the safety need and reliability need and maximises the present value of the net economic benefit, considering a set of reasonable state-of-the-world scenarios and their weightings.

The preferred option was tested under a range of sensitivities. In each case, Option 1 was confirmed to provide positive economic benefits under the majority of sensitivities and is the highest-ranked option under all sensitivities.

This option has a total capital cost of $9.67 million (real, 2026), with a $2,43 million present value of net benefits and an optimum practical timing of 2028.

12. Next Steps

This FPAR represents the final stage of the RIT-D process.

In accordance with the provisions set out in clause 5.17.5, paragraph (c) of the NER, Registered Participants or interested parties may, within 30 days after the publication of this report, dispute the conclusions made by UE in this report with the AER.

Accordingly, Registered Participants and interested parties who wish to dispute the recommendation outlined in this report must do so by 28 August 2026. Any parties raising such a dispute are also required to notify UE at ritdenquiriesue@ue.com.au. If no formal dispute is raised, UE will commence with the investment activities necessary to proceed with the implementation of the preferred option.

For the purposes of referencing this RIT-D, this RIT-D shall refer to the "*Hastings Zone Substation 22 kV Switchgear Condition*" identified need.

13. Checklist of Compliance with NER Clauses

This Section 13 sets out a compliance checklist which demonstrates the compliance of this FPAR with the requirements of clause 5.17.4, paragraph (r)(1) of the NER in Table 31.

Table 31: NER requirements checklist

NER clause	Summary of requirements	Relevant section DPAR
5.17.4(j)(1)	A description of the identified need for investment.	Section 5.2
5.17.4(j)(2)	The assumptions used in identifying the need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary).	Section 6
5.17.4(j)(3)	A summary of, and commentary on, the submissions on the options screening report.	Not Applicable
5.17.4(j)(4)	A description of each credible option assessed.	Section 7
5.17.4(j)(5)	Where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option.	Section 10.1
5.17.4(j)(6)	A quantification of each applicable cost for each credible option, including breakdown of operating and capital expenditure.	Section 9.5
5.17.4(j)(7)	A detailed description of methodologies used in quantifying each class of cost and market benefit.	Section 9
5.17.4(j)(8)	Where relevant, the reasons why UE has determined that a class or classes of market benefits do not apply to a credible option.	Section 9.4
5.17.4(j)(9)	The results of a net present value analysis for each option and accompanying explanatory statements regarding the results.	Section 10.2 Section 10.3
5.17.4(j)(10)	The identification of the preferred option.	Section 11
5.17.4(j)(11)	Details of the preferred option including technical characteristics, construction timetable and commissioning date, the indicative capital and operating cost (where relevant), a statement and accompanying detailed analysis that the proposed preferred option satisfies the RIT-D, if the proposed preferred option is for reliability corrective action and that option has a proponent and the name of the proponent.	Section 11
5.17.4(j)(12)	Contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	Section 12
5.17.4(r)(1)(ii)	Summary of, and commentary on, the submissions on the Draft Project Assessment Report.	Section 8

14. Appendix A: 22 kV switchgear photos

The 22 kV outdoor bulk-oil AEI LG1C circuit breakers at HGS are in a poor condition and technically obsolete (with no vendor support and limited to no spares). UE has assessed there is now an unacceptable risk of asset failure, with significant consequences for safety, and for the reliability of electricity supply to UE's customers within the HGS supply area.

Figure 7: Existing outdoor 22 kV circuit breakers at HGS

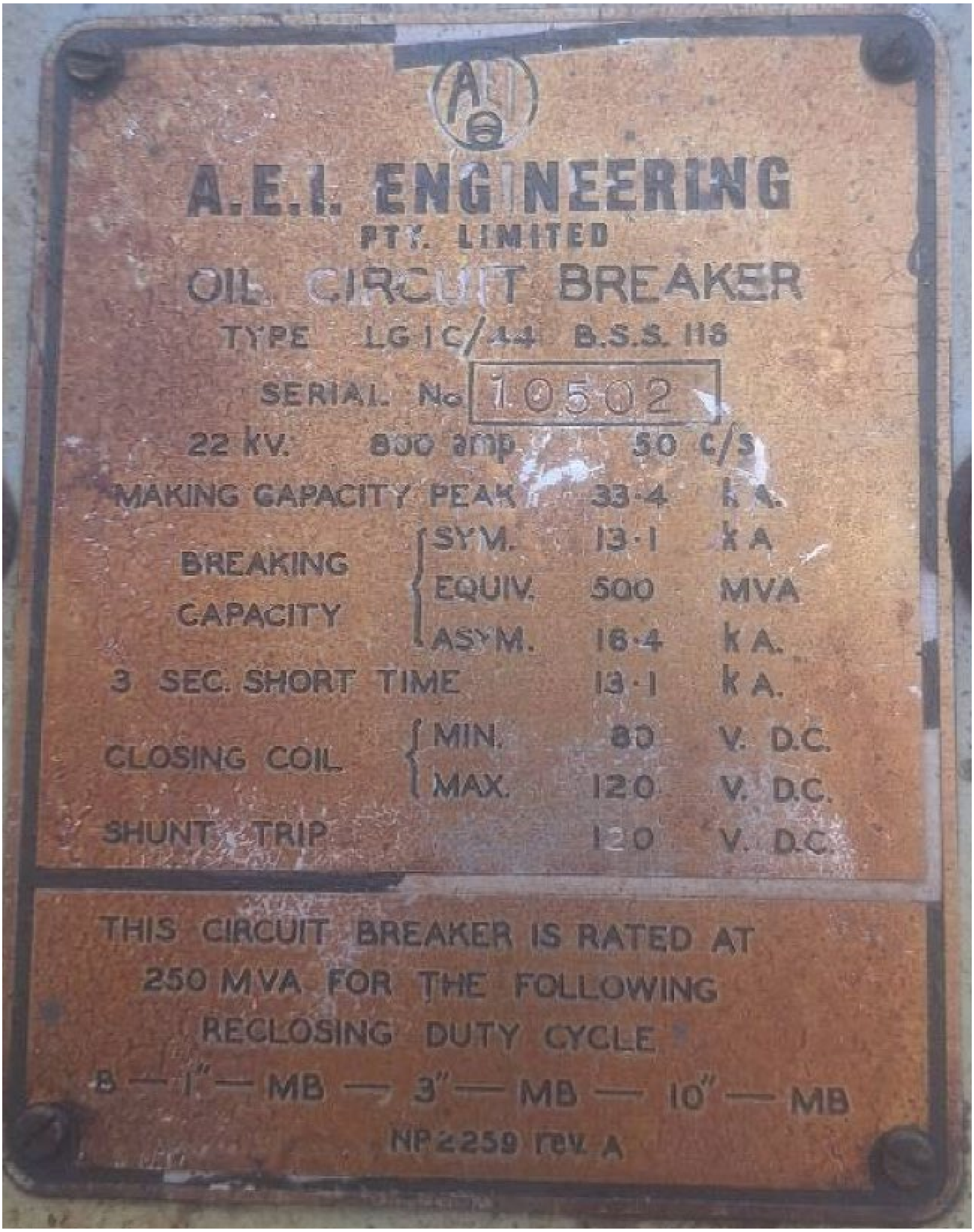

Figure 8: Nameplate of 22 kV circuit breakers at HGS