Jemena Electricity Networks (Vic) Ltd

2026-31 - Electricity Distribution Price Review - Revised Regulatory Proposal

Supporting justification document

North Heidelberg ZSS Redevelopment Business Case

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1. Executive Summary

This business case details Jemena Electricity Networks (Vic) (JEN's) revised economic assessment of options for addressing reliability and safety risks caused by age-related condition issues of the primary and secondary assets at the North Heidelberg zone substation (NH ZSS). The revised analysis in this report addresses the concerns raised by the Australian Energy Regulator (AER) and its consultant EMC[a] that our zone substation (ZSS) replacement projects have not been sufficiently justified in line with AER guidance. The principal critiques raised as part of the draft determination are that:

- risk has not been modelled consistent with AER guidance or industry practice
- the cost of consequence is overstated, which is driven by two factors:
  - an overstated probability of failure due to risk not being modelled consistent with AER guidance or industry practice
  - an assumption that the outage occurs at the time of peak load and extends for 12 hours
- a common value of customer reliability (VCR) has been applied, but should instead be calibrated for the study area and based on the 2024 AER updated VCR estimates
- no assessment of optimal timing was undertaken for the proposed ZSS replacement projects.

To address the above issues, we have revised our analysis to:

- model risk consistent with AER guidance and industry practice. We estimated probability of failures by reference to Weibull distributions and parameters appropriate for the primary and secondary equipment at NH ZSS, drawing on advice from a technical expert and parameters previously applied by Distribution Network Service Providers (DNSPs) to similar assets
- develop a more rigorous cost of consequence by:
  - modelling risk consistent with AER guidance and industry practice
  - adopting an estimate of load at risk by reference to forecast average MWh load at NH ZSS over the assessment period, derived using load duration curves for NH ZSS
  - assuming conservative outage lengths of 90 minutes, noting that we do not consider that it is feasible to restore supply in this timeframe across all failure modes, such as where excess capacity of NH ZSS has been consumed and load transfers to adjacent networks have been exhausted
- apply a load-weighted VCR based on the AER's 2024 updated VCR estimates and the proportion of consumption (measured in MWh) of customer types at NH ZSS
- assess the optimal timing of replacing NH ZSS consistent with the AER's guidance, through a comparison of the annualised benefits with the annualised costs of the proposed investment.

We have applied this revised modelling framework to four options for addressing the reliability and safety risks at NH ZSS:

- Option 1 – do nothing (base case)
- Option 2 – increased maintenance and monitoring,
- Option 3 – develop the zone substation,
- Option 4 – staged replacement of zone substation assets.

These options are consistent with those assessed in our original business case submitted as part of our initial regulatory proposal.[1]

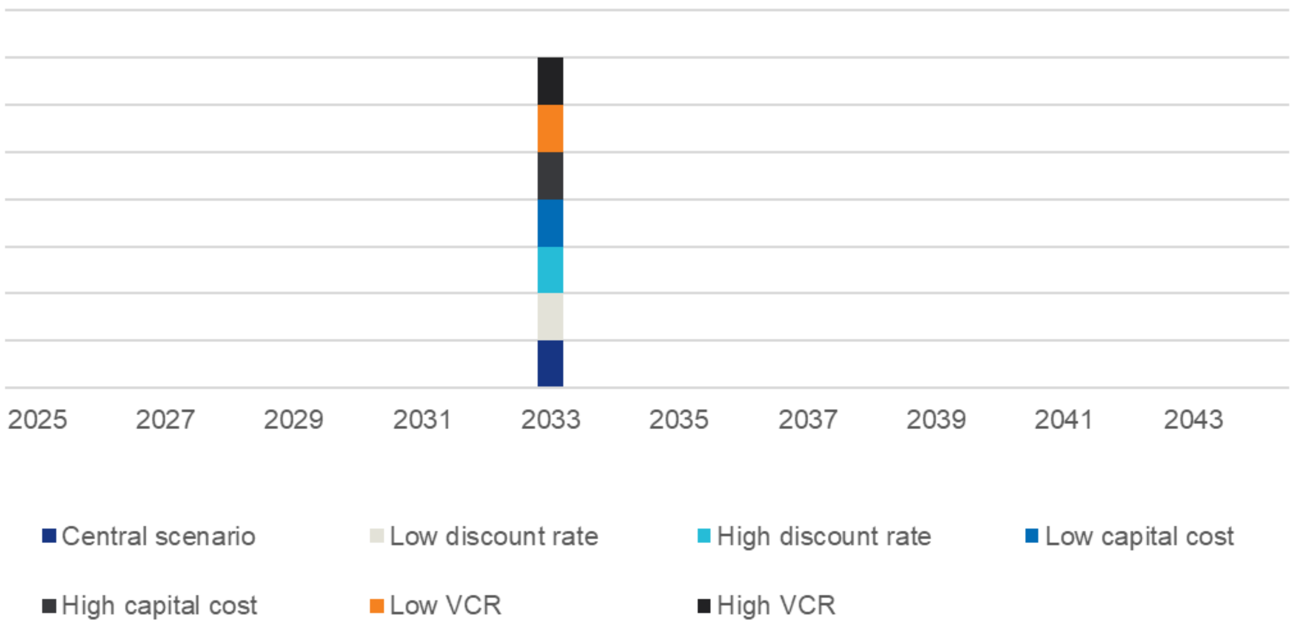
Table 1-1 shows that Option 3 and Option 4 are found to have positive net benefits relative to the base case (Option 1). Option 3 has the greatest net economic benefits of all the options assessed and is therefore the preferred option at this stage of our planning process.

Table 1-1 Net economic benefits for options relative to Option 1 (the base case) ($m, net present value (NPV))

Option	Gross benefits ($m)	Gross costs ($m)	Net benefits ($m)
Option 2	0.0	0.6	-0.6
Option 3	**78.2**	**16.1**	**62.1**
Option 4	60.1	16.5	43.6

We have undertaken sensitivity testing to understand the robustness of the economic assessment to underlying assumptions including the impact on the optimal timing. Across all sensitivities we have investigated, the optimal timing of Option 3, where the annualised benefits exceed the annualised costs, is FY33 (figure 1-1).[2] Figures illustrating the cross-over point between annualised benefits and annualised costs under each of these sensitivities are set out in **Error! Reference source not found.**.

Figure 1-1 Optimal timing for Option 3



We consider that replacing NH ZSS in the next regulatory period is prudent and efficient. Based on our analysis, replacing the entire ZSS at once delivers the highest net benefits to our customers. We note that this investment will be subject to the formal regulatory investment test for distribution (RIT-D) consultation process, ensuring transparency and providing an opportunity for stakeholder engagement.

[1] JEN – RIN – Support – North Heidelberg ZSS Redevelopment – Business Case.

[2] This is consistent with our proposal that works are to take place between FY30 and FY32, with practical completion and commissioning in the first half of FY33.

2. Introduction

This business case details Jemena Electricity Networks (Vic) (JEN's) revised economic assessment of options for addressing reliability and safety risks caused by age-related condition issues of the primary and secondary assets at the North Heidelberg zone substation (NH ZSS). Its purpose is to provide supporting evidence as to the prudence and efficiency of redeveloping NH ZSS in the next regulatory period. It presents the quantitative cost-benefit analysis that demonstrates redeveloping NH ZSS is optimally timed in the next regulatory period and is the option that will deliver the highest net benefits to our customers.

NH ZSS was commissioned in 1973 and most of the primary and secondary equipment have reached or are nearing the end of their technical lives. Consistent with assets that have reached or are nearing the end of their technical lives, their health-based assessment utilising JEN's Condition Based Risk Modelling (CBRM) rates the assets as poor with increasing asset risk. JEN also engaged a technical expert to undertake an independent review of the asset condition data, with the conclusion that NH ZSS is an appropriate candidate for replacement due to the condition issues of the primary and secondary equipment.

These asset conditions pose a risk to the reliability of supply to the approximately 16,000 customers served by NH ZSS because:

- circuit breakers are used to automatically disconnect faulty sections to prevent damage spreading through the network
- secondary systems are needed to isolate network faults (therefore avoiding wider damage) and prevent correctly operating circuits from incorrectly tripping.

As a consequence, failure of the primary and secondary equipment due to asset condition is expected to lead to unserved energy for customers who are supplied via NH ZSS. The nature of the primary and secondary equipment being at end-of-life also poses safety risks due to the potential for explosive failures of bushings, insulators, tank ruptures, and uncleared network faults.

JEN is therefore examining options for addressing the age-related condition issues of the primary and secondary equipment at NH ZSS in the next regulatory period so that it continues to operate in a safe and reliable manner. This is consistent with the conclusion of the technical expert's report, which recommends replacing the aged equipment before failures start affecting the safety of our staff and community and the reliability of supply to customers.[3]

The remainder of this business case:

- explains how we have addressed the concerns raised in the Australian Energy Regulator's (AER's) draft decision regarding the justification of replacing NH ZSS in the next regulatory period
- provides background to the inputs and assumptions underpinning the identified need
- presents the options that we have considered as part of meeting the identified need
- outlines our assessment of whether non-network options would be able to meet the identified need (either in whole or in part)
- presents the economic assessment of all options, as well as the assumptions feeding into the analysis, and identifies the preferred option at this stage of our planning process
- presents the results of our optimal timing analysis for the preferred option.

We note that this investment will be subject to the regulatory investment test for distribution (RIT-D) prior to being initiated, ensuring transparency and providing an opportunity for further stakeholder consultation.

[3] JEN – K-BIK Power – RP – Support – Review of substation replacements – Report – 20251120.

3. How this business case addresses concerns raised in the AER's draft decision

The cost-benefit analysis detailed in this revised business case addresses the factors underpinning the AER's and its consultant EMCᵃ's assessment that our zone substation (ZSS) replacement projects were not sufficiently justified in line with AER guidance , as provided in the materials accompanying our initial. The principal critiques raised as part of the draft determination are that:

- risk has not been modelled consistent with AER guidance or industry practice
- the cost of consequence is overstated, which is driven by two factors:
  - an overstated probability of failure due to risk not being modelled consistent with AER guidance or industry practice
  - an assumption that the outage occurs at the time of peak load and extends for 12 hours
- a common value of customer reliability (VCR) has been applied, but should instead be calibrated for the study area and based on the 2024 AER updated VCR estimates
- no assessment of optimal timing was undertaken for the proposed ZSS replacement projects.

The following sections briefly summarise the issues raised by the AER and its consultant and how we have addressed each in this revised business case.

3.1 Risk is now modelled consistent with AER guidance and industry practice

EMCᵃ found that we did not model risk in accordance with AER guidance or industry practice. EMCᵃ explains that it is common practice for asset replacement planning to assume that the probability of failure increases over time with the rate of increase being correlated with the condition of the asset.[4] EMCᵃ also highlights that it is common to use Weibull functions for this purpose and, when applied to risk-cost analysis, this results in an increasing cost function that can be compared with the cost of intervention to address the risk.[5] EMCᵃ highlighted that common Weibull functions and parameters are available from industry sources and other Distribution Network Services Providers (DNSPs) that can be applied to JEN's network and compared with our own observed experience.

To address this issue, we engaged a technical expert to advise us on an appropriate Weibull distribution and parameters for the primary equipment, that is transformers and circuit breakers, at each ZSS proposed for replacement. For secondary equipment, we have adopted the Weibull distribution underpinning the protection relay program business case submitted by Ergon Energy as part of its most recent revenue proposal, which was accepted by the AER.[6] We consider use of Ergon Energy's Weibull distribution appropriate because Ergon Energy also operates in the Australian National Electricity Market (NEM) and is therefore likely to be a closer comparator to JEN's assets relative to international evidence.

Sections 4.3 and 6.3.1 explain how we have used the Weibull curves to estimate the probability of failure of each asset given its age and condition, which in turn underpins the estimated cost of consequence under the base and option cases.

3.2 Load duration curve underpins estimate of load at risk

EMCᵃ found that our estimated cost of consequence for an outage was overstated due to two factors:[7]

[4] EMCᵃ, *Review of aspects of proposed network related expenditures*, JEN Services 2026-2031 regulatory proposal, August 2025, p 15.

[5] EMCᵃ, *Review of aspects of proposed network related expenditures*, JEN Services 2026-2031 regulatory proposal, August 2025, p 15.

[6] Ergon Energy, *Protection relay replacements business case*, 25 January 2024; and AER, *Ergon Energy electricity distribution determination 2025 to* 2030, Attachment 5, Capital expenditure, p 62.

[7] EMCᵃ, *Review of aspects of proposed network related expenditures*, JEN Services 2026-2031 regulatory proposal, August 2025, p 46.

- an overstated probability of failure due to risk not being modelled consistent with AER guidance or industry practice
- an assumption that the outage occurs at the time of peak load and extends for 12 hours.

The previous section explains how we have revised our estimate of the probability of failure to address the concern that the cost of consequence is overstated.

Turning to the second point, EMCª suggests that energy at risk is more reasonably determined by estimating the average load or by using a load duration curve, rather than assuming that the event occurs at the time of peak load.[8] Section 6.3.2 explains that we have now adopted EMCª's recommendation by estimating load at risk by reference to the 50th and 10th percentile of the forecast load duration curve of NH ZSS over the 20-year assessment period. Specifically, we estimate the energy at risk by applying a 70 per cent weighting to the 50th percentile forecast load duration curve and 30 per cent weighting to the 10th percentile load duration curve.

Finally, we now assume that fully restoring supply to customers in the distribution network would take 90 minutes for the scenarios that we have developed. We consider this length of outage to be a very conservative assumption. Our experience with the time it takes to undertake the onsite inspection and investigate in the case of an outage, which is a combination of remote and manual switching and transferring load to the adjacent network suggests that restoring supply would take considerably longer. However, we have adopted this conservative approach to mitigate concerns that the benefits of replacing the primary and secondary assets at the NH ZSS are overstated.

3.3 A load-weighted VCR based on the 2024 AER update is used

EMCª recommended that the VCR be calibrated for the study area based on the 2024 AER update.[9] Section 6.3.3 presents our calculation of a load-weighted VCR for the HN ZSS based on the AER's 2024 update of the VCR estimates.

3.4 Optimal timing of the proposed investment has been assessed

The final concern raised by EMCª in the context of the ZSS replacement business cases is that there was no evidence of an assessment of optimal timing.[10] Section 7.4.1 contains our assessment of optimal timing consistent with the AER's guidance, that is, comparing the annualised benefits with the annualised costs of the proposed investment.

[8] EMCª, *Review of aspects of proposed network related expenditures*, JEN Services 2026-2031 regulatory proposal, August 2025, p 46.

[9] EMCª, *Review of aspects of proposed network related expenditures*, JEN Services 2026-2031 regulatory proposal, August 2025, p 15.

[10] EMCª, *Review of aspects of proposed network related expenditures*, JEN Services 2026-2031 regulatory proposal, August 2025, p 46.

4. Background to the identified need

This section sets out the identified need for the investment assessed in this business case, as well as the assumptions and data underpinning it. It first sets out background information related to NH ZSS and the relevant primary and secondary equipment.

4.1 Primary and secondary equipment at NH ZSS have reached end-of-life

NH ZSS was commissioned in 1973 and is located 13km to the Northeast of the Melbourne CBD. The zone substation supplies approximately 16,000 customers in the Yallambie, Viewbank, Macleod, Rosanna, Heidelberg Heights and Heidelberg West areas. The substation comprises:

- Three 66/22kV power transformers
- Two 66kV circuit breakers
- Two capacitor banks
- Ten 22kV feeders.

The operation of this primary equipment is supported by secondary assets that are designed to detect the presence of faults or other abnormal operating conditions and to automatically isolate the faulted network by opening appropriate high voltage circuit breakers.

Figure 4.1 provides an overview of the layout of NH ZSS.

Figure 4.1 North Heidelberg Zone Substation Layout

Most of the primary and secondary equipment at NH ZSS have reached or are nearing the end of their technical lives. JEN is therefore examining options for addressing the age-related condition issues of the primary and secondary equipment at NH ZSS in the next regulatory period so that it continues to operate in a safe and reliable manner. This is consistent with the conclusion of JEN's technical expert, who recommends replacing the aged equipment before failures start affecting safety for our staff and community and the reliability of supply to customers.

4.2 Ageing assets pose reliability and safety risks

JEN has undertaken a network asset risk assessment for both the primary and secondary assets installed at NH ZSS. The results of this risk assessment illustrate that the current assets are in poor condition, consistent with nearing or having reached the end of their technical lives. Refer to JEN – Support – North Heildeberg ZSS Redevelopment – Risk Register – 20251201 for details.

JEN also engaged a technical expert to undertake an independent review of the asset condition data, with the conclusion that NH ZSS is an appropriate candidate for replacement due to the condition issues of the primary equipment.[11] JEN's own assessment has reached the same conclusion for secondary equipment.

[11] JEN – K-BIK Power – RP – Support – Review of substation replacements – Report – 20251120.

4.2.1 Risk assessment of primary equipment

For switchgear and transformer assets, JEN applies Condition Based Risk Modelling (CBRM) to assist in developing asset investment plans using existing asset data and other information. A detailed description of how the CBRM model works can be found in the Guideline – Condition Based Risk Management (CBRM).[12]

The key element of the CBRM model is the health index that it outputs for each asset. Values greater than seven represent serious deterioration and the need to plan for replacement before failure occurs.

The CBRM modelling results for NH ZSS as of 2024 are summarised in table 4-1. The results indicate that all primary equipment is in a severely deteriorated condition.

Table 4-1 Primary equipment CBRM as of 2024

Primary Equipment	Average	Maximum
66kV Bus Tie CB	4.65	7.81
22kV CBs	7.01	9.21

We explain in section 4.3.1 below that we engaged an independent technical expert to undertake an expert review of the condition-based data of the primary assets at NH ZSS. The expert also concludes that the current condition of the assets means that they are appropriate candidates for replacement.

Failure of the primary equipment may lead to unserved energy because circuit breakers are used to automatically disconnect faulty sections to prevent damage spreading through the network. When a feeder, bus tie or transformer incomer circuit breaker fails, the protection system will operate to isolate and de-energise the effected bus. All customers who are fed by that bus will be without power leading to unserved energy. Further, the nature of the primary equipment being at end-of-life also poses safety risks due to the potential for explosive failures of bushings, insulators and tank ruptures.

4.2.2 Secondary equipment

Protection and control systems are designed to detect the presence of faults or other abnormal operating conditions and to automatically isolate the faulted network by opening appropriate high voltage circuit breakers. The major primary plant at NH ZSS is mostly protected by legacy, electromechanical protection relays that do not have real-time monitoring. Specifically, the electromechanical relays at NH ZSS are 50 years old with a design life of 40 years. Without monitoring, failure of these relays can remain undetected, exposing the network to reliability and safety risks.

4.3 Probability of failure increases over time as asset condition worsens

As explained in section 3.1, a key issue raised by EMC[a] following its review of our original business case is that we did not model risk in accordance with AER guidance or industry practice. The particular concern was that we neither:

- assumed that the probability of failure increases over time, with the rate of increase being correlated with the condition of the asset; nor
- used Weibull curves for the purpose of estimating the increasing probability of failure over time.

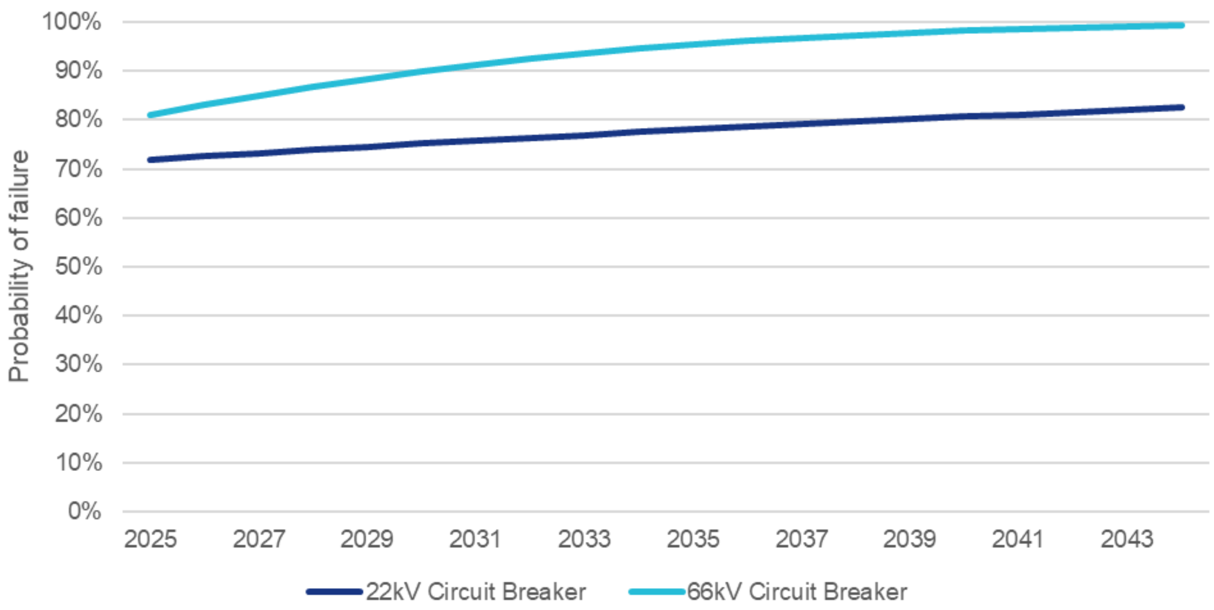
[12] JEN – RIN – Support – Condition Based Risk Management (CBRM) Guideline – 20250131.

To address these concerns, we have updated our business case to include probabilities of failure for primary and secondary equipment that are based on appropriate Weibull distributions. We discuss our revised probability of failure analysis in greater detail below.

4.3.1 Technical expert advice on the probability of failure for primary equipment

JEN engaged Dr Kerry Williams, Director and Principal Engineer at K-BIK Power Pty Ltd, to undertake an expert review of the condition-based data associated with the proposed replacement of NH ZSS. As part of the scope of work, we requested that Dr Williams provide a Weibull style analysis of the probability of failure of the primary equipment at NH ZSS, that is the switchgear. Dr Williams' report sets out the appropriate parameters for the Weibull distribution, which underpin our revised estimates of the probability of failure for the primary equipment.[13] Figure 4-2 shows that, under our revised analysis, the probability of failure of the primary equipment increases over time as further asset deterioration occurs.

Figure 4-2 Primary equipment probability of failure based on Weibull distribution



Refer to Attachment JEN – K-BIK Power – RP – Support – Review of substation replacements – Report – 20251120 and JEN – RP – Support – North Heidelberg ZSS – PoF and Quantified risks – Primary equipment – 20251201 for more details on how the probability of failure for primary equipment was calculated.

4.3.2 Probability of failure for secondary equipment draws on work from other DNSPs

To estimate the probability of failure of the secondary systems at NH ZSS using a Weibull distribution, JEN conducted a literature review to understand how this a methodology has been previously applied to protection relays of varying types. JEN adopted a literature review approach because of insufficient relay failures on our network, likely due to our proactive replacement strategy of these devices. Low volumes of sample data from our network have the potential to skew the results of statistical analysis, reducing reliability.

Our review process identified several studies that included various parameters for protection relay Weibull distributions. For the purpose of the analysis set out in this business case, we have adopted the Weibull curve parameters set out in Ergon Energy's 2024 business case for protection relay replacements.[14] We have adopted these parameters out of the studies we reviewed on the basis that Ergon Energy also operates in the Australian NEM and is therefore likely to be a closer comparator to JEN's assets relative to international evidence.

[13] JEN – K-BIK Power – RP – Support – Review of substation replacements – Report – 20251120.

[14] Ergon Energy, *Protection relay replacements business case*, 25 January 2024.

We consider that the above approach is consistent with EMCa's suggestion that Weibull functions and parameters are available from other DNSPs that can be applied to our network. Further, we note that the AER accepted Ergon Energy's forecast expenditure relating to protection relays, which was underpinned by this Weibull function.[15]

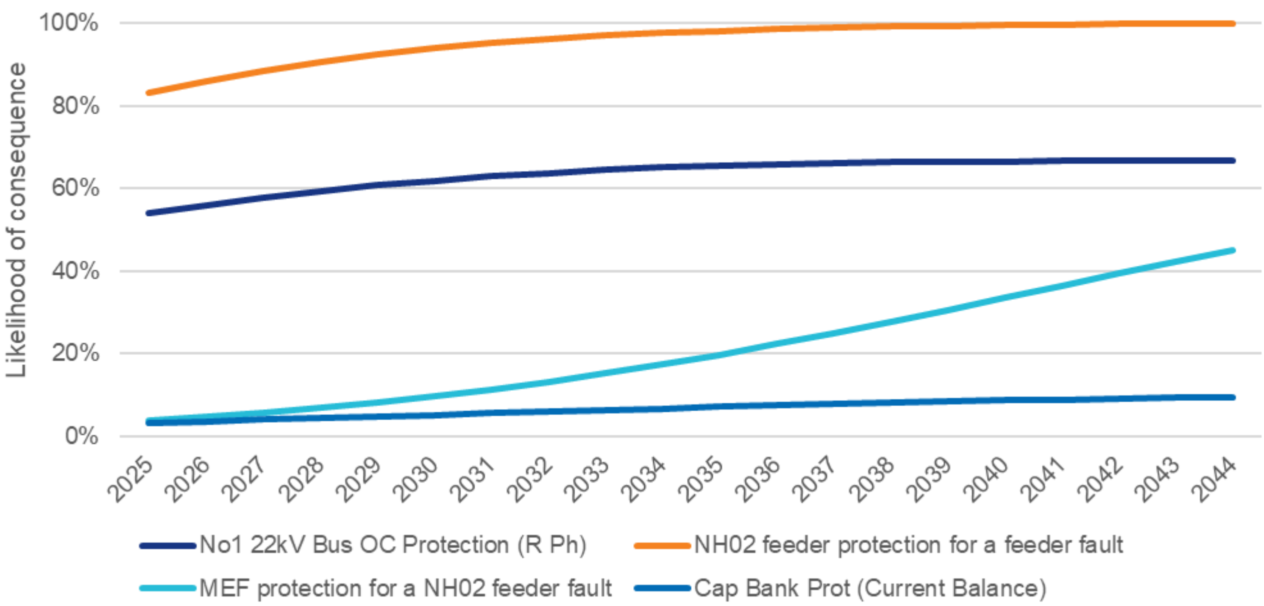
Many of the legacy electromechanical and digital protection relays installed at NH ZSS have been in service for considerably longer than their technical asset lives. As a consequence, the relevant Weibull distribution leads to an annual asset probability of failure of between 70-95 per cent for the majority of relays, which increases over time. Given that an outage associated with a protection relays failure occurs only during a network fault, we estimate the likelihood of consequence for each type of protection relay using the following equation:

$$\mathrm{LoC} = \mathrm{PoF}^{X} \times \text{observed frequency of fault}$$

Where LoC is the expected likelihood of consequence used in our assessment, PoF is the probability of failure estimated using a Weibull distribution, X is the number of protection relays that need to fail before an outage occurs, which in most circumstances is one, and $\text{observed frequency of fault}$ is the observed frequency of feeder fault on the network over the past four years that would be addressed by each relay type, that is, the average number of feeder faults per year divided by the number of feeders from the NH ZSS.

Figure 4-3 shows that, under this analysis, the likelihood of consequence of the secondary equipment increases over time as further asset deterioration occurs. Note that the figure only shows the likelihood of consequence for a subset of the protection relays at NH ZSS to illustrate the outcomes of the analysis. We have examined failure modes for each of the 47 protection relays at NH ZSS and it is this aggregated analysis that underpins the economic assessment.

Figure 4-3 Secondary equipment likelihood of consequence based on Weibull distribution



Refer to JEN – RP – Support - Attachment JEN – RP – CN, CS, NH ZSS – PoF and quantified risks – Secondary equipment – 20251201 for more details on how the likelihood of consequence for secondary equipment was calculated.

[15] AER, *Ergon Energy electricity distribution determination 2025 to* 2030, Attachment 5, Capital expenditure, p 62.

4.4 Investment will address reliability and safety risks and is consistent with our customers' feedback and regulatory obligations

The investment outlined in this business case seeks to address the reliability and safety risks posed by the age-related condition issues of the primary and secondary equipment at NH ZSS.

Section 2 of our original business case[16] sets out how such an investment is consistent with JEN's consumer engagement, regulatory considerations and objectives and strategies.

[16] *JEN – RIN – Support – North Heidelberg ZSS Redevelopment – Business Case.*

5. Four options have been assessed

The following options have been identified to address the reliability and safety risks posed by the condition of assets at Coburg South zone substation:

- Option 1 – do nothing (base case)
- Option 2 – increased maintenance and monitoring
- Option 3 – redevelop the zone substation
- Option 4 – staged replacement of zone substation assets.

The above options are consistent with those assessed in our original business case.

We have also had regard to the potential for a non-network or stand-alone power system (SAPS) solution to address the reliability and safety risks. A preliminary assessment determined that such options are unlikely to be viable to address the asset related concerns at NH ZSS, and so are not considered further, because they do not address the underlying condition issues driving the identified need. We note that this conclusion will be tested again in the RIT-D process.

5.1 Option 1 – Do nothing

The costs and benefits of each option in this business case are compared against those of a 'do nothing' base case. This base case assumes the continuation of business-as-usual maintenance activities such as the current frequency of inspections, condition monitoring, preventative maintenance and defect repairs. Operating expenditure in the base case is assumed to be $75,000 per year based on a 'rule of thumb' percentage of capital expenditure.

Under this base case, no proactive capital investment is made to remediate the deterioration of assets at NH ZSS. Instead, the assets at NH ZSS are left in service until they fail and require reactive replacement. JEN would then be forced to replace the assets under emergency conditions. While the base case is not in line with our asset class strategies and is a situation we plan to encounter, we use this base case as a common point of reference when estimating the net benefits of each option.

Option 1 does not address any of the risks of failure associated with the current condition of assets at NH ZSS.

5.2 Option 2 – Increased maintenance and monitoring

Option 2 involves closer monitoring of the primary assets at NH ZSS with a doubling in the frequency of condition testing. Under Option 2, no refurbishment occurs at NH ZSS and so increased monitoring is necessary as the primary equipment continues to deteriorate. More frequent maintenance and testing is required for aged assets to monitor the increasing risk of asset failure and the associated reliability and safety consequences.

To double the monitoring and testing of the primary assets at NH ZSS JEN would incur operating expenditure of $150,000 per year from FY30 (that is, twice the operating expenditure under Option 1).

Option 2 does not address any of the risks of failure associated with the current condition of assets at NH ZSS.

5.3 Option 3 – Redevelop the zone substation

Option 3 involves the redevelopment of NH ZSS all at once in the next regulatory period. It comprises the decommissioning of legacy items and deteriorated assets and sees most of the ZSS equipment replaced with new standardised equipment. The major assets to be installed include:

- new 66kV modular GIS equipment: busbars, insulators, circuit breakers, voltage transformers, current transformers, motorised double break disconnectors, earth switches and surge arrestors

- three sets of transformer bushings
- a new earth management system including arc suppression coil (ASC), ASC bypass CB, neutral earthing resistor and associated secondary systems
- two new 22kV/433V station service transformers (kiosk type)
- three new modular indoor 22kV switchboards consisting of busbars, insulators, circuit breakers, voltage transformers, current transformers, disconnectors, earth switches and surge arrestors
- two new 22kV containerised capacitor banks. The Cap Banks shall have floating neutrals with VAr control and neutral earth switch
- civil and structural works associated with new or decommissioned equipment including earth grid works
- new secondary equipment required to complete protection, control, communications and auxiliary supply functions required for the zone substation.

To redevelop the ZSS, JEN would incur $4.5 million in capital expenditure in FY30, $11.3 million in FY31, and $20.0 million in FY32 for commissioning in FY33. The total cost is $35.8 million.

Option 3 fully addresses the risks of failure associated with the current condition of assets at NH ZSS.

5.4 Option 4 – Staged replacement of zone substation assets

Option 4 involves the redevelopment of NH ZSS in a staged manner. The staged approach would see most of the NH ZSS equipment replaced with new, standardised equipment over two regulatory periods. The staged replacement approach prioritises the resolution of issues based on the condition and criticality of the assets.

The first stage will be completed in the next regulatory period and will involve the installation of three new modular indoor 22kV switchboards, as well as civil and structural works associated with new or decommissioned equipment. The second stage will be completed in the 2031 to 2036 regulatory period and involves the remainder of the works set out in the scope of Option 3.

The estimated capital cost of Option 4 is $42.9 million, which is comprised of the following:

- $17.2 million for the first stage, incurred in FY30 prior to commissioning in 2031
- $25.7 million for the second stage, incurred in FY35 prior to commissioning in 2036.

In estimating the capital costs for Option 4, we have applied a 20 per cent uplift to the capital costs of Option 3 due to the additional costs associated with staging the replacement, which arise from:

- the new primary plant needing to be wired to the existing secondary equipment and then later re-wired to the new secondary equipment. This will also result in complexities with interfacing legacy secondary equipment to modern switchgear
- testing and commissioning the new secondary systems and primary plant would need to be performed twice rather than once had all of the assets been replaced at the same time
- two instances of site mobilisation / demobilisation rather than one which involves site construction facilities, inductions, project management establishment
- two sets of review of the secondary design drawings and protection settings rather than one
- twice as many planned outages to be planned, scheduled and switched out.

    Option 4 addresses the risk of failure associated with the current condition of the 22kV switchboards in the first stage, however it does not address the risks of failure associated with the remainder of the assets until the second stage.

5.5 Options considered but not progressed

JEN has considered whether a non-network or SAPS solution could assist in the context of this investment need. Non-network and SAPS solutions could be delivered through embedded generation, storage, or demand-side management programs (or combination thereof), to defer or reduce in scope, traditional network augmentation solutions or asset replacement. Such solutions need to have a sufficient number of proponents participating, to provide the aggregate level of dispatchable capacity needed. This could then mitigate the consequential risks of continuing to operate ‘at risk’ assets.

The extent of reliability risk may be reduced if the load is reduced through non-network options or SAPS. However, the identified safety risks are, for the most part, not load dependent and so would not be reduced by a non-network options or SAPS. It is therefore not likely that the risk costs will be sufficiently reduced to make the non-network or SAPS options more cost effective overall, irrespective of their type, size, operating profile and location.

We have undertaken a high-level assessment of non-network options by considering the benefits of deferring expenditure by one year against a plausible alternative of procuring capacity from the market based on recent RIT-D responses. Applying this methodology to distributed storage solutions, we determined that the installed costs[17] of $50.0 million is greater than the $35.8 million installed costs of the preferred option identified from the economic assessment (Option 3). Therefore, a non-network option is not the preferred approach based on program-wide network benefits alone and because it would not address the underlying condition issues driving the identified need.

The potential role of non-network or SAPS solutions will be further considered as part of the RIT-D for this investment.

[17] Installed cost of $500/kWh x $78.9M present value reliability benefit ÷ $39.44/kWh VCR ÷ 20 years analysis period = $50.0M.

6. How the options have been assessed

6.1 General overview of the assessment framework

All costs and benefits for each option have been measured against a ‘do nothing’ base case (Option 1). This base case assumes the continuation of business-as-usual maintenance activities such as the current frequency of inspections, condition monitoring, preventative maintenance and defect repairs. These business-as-usual activities do not address any of the identified condition issues, particularly with respect to the switchgear and protection relays. The probability of failure would continue to increase over time, potentially leading to catastrophic failure while in service. While the base case is not a situation JEN plans to encounter, and this business case actively examines options to avoid it, the cost benefit analysis requires the use of a base case as a common point of reference when estimating the net benefits of each option.

The business case analysis has been undertaken over a 20-year period, from 2024-25 to 2043-44. JEN considers that a 20-year period takes into account the size, complexity and expected life of the relevant options to provide a reasonable indication of the market benefits and costs of the options.

Where the capital components of the options have asset lives extending beyond the end of the assessment period, the net present value (NPV) modelling includes a terminal value to capture the remaining functional asset life. Inclusion of a terminal value ensures that the capital cost of long-lived assets over the assessment period are appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or serviceable asset life. The terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period.

JEN has adopted a real, pre-tax discount rate of 5.28 per cent for the NPV analysis. We have also tested the sensitivity of the results to a lower bound discount rate of 2.3 per cent and an upper bound discount rate of 7.5 per cent.

6.2 JEN’s approach to estimating project costs

We have estimated the capital costs of the options based on the scope of works necessary, together

using a mix of current and historical information from similar projects that were adjusted to reflect the requirements of the proposed works, location and market conditions.

In line with JEN’s Cost Estimation Methodology (ELE-999-PR-CE-001) a top-down technique and Project Estimation Model (PEM) tool was utilised to develop the capital cost estimate. Inputs such as scope definition, asset strategy requirements, site information, standard rates, lessons learned, vendor pricing, design considerations, delivery strategy and network asset risk assessments were considered when forming inputs into the PEM

Project costs remain unchanged from those in the original business case submitted with the initial regulatory proposal.

6.3 Market benefits are expected from reduced involuntary load shedding

The primary benefits expected from the redevelopment of NH ZSS are expected to arise from reduced involuntary load shedding.

We estimate the value of expected involuntary load shedding under each option as the sum of the value of expected involuntary load shedding for each asset. For each asset we estimate the value of expected involuntary load shedding based on the following equation:

$$\text{LoC x USE x VCR}$$

Where:

- LoC is the likelihood of consequence of each relevant asset at the zone substation, which, for primary equipment, is equivalent to the probability of failure
- USE is the expected unserved energy at risk if there were to be an asset failure
- VCR is the value of customer reliability.

The probability of failure for each asset is based on its condition, and therefore changes under each option following works to improve or replace the asset. The expected unserved energy at risk and VCR are the same across all options.

We explain our approach to estimating each of the above parameters in turn below.

6.3.1 Probability of failure

JEN has estimated the probability of failure for each relevant asset at NH ZSS using a Weibull curve.

Electricity network operators commonly use the Weibull distribution to model the likelihood of asset failure based on asset age. By fitting historical failure data to a Weibull distribution, network operators can estimate the probability that a particular asset will fail within a given timeframe, enabling more informed decisions about maintenance scheduling, asset replacement programs, and capital expenditure planning.

We provide a more detailed explanation of our approach to estimating the probability of failure and likelihood of consequence for each relevant asset in section 4.3 above.

6.3.2 Energy at risk

The energy at risk is the expected load at NH ZSS at the time of an asset failure. We estimate the energy at risk using the 50th and 10th percentile of the forecast load duration curve of NH ZSS over the 20-year assessment period to approximate average MWh load (average load). Specifically, we estimate the energy at risk by applying a 70 per cent weighting to the 50th percentile forecast load duration curve and 30 per cent weighting to the 10th percentile load duration curve.

In the circumstance where certain circuit breakers fail, we assume that two-thirds of the average load will be lost for each hour of the outage. This indicates that these asset failures would result in the loss of supply to two of the three busses at NH ZSS. In contrast, where other circuit breakers fail, only one of the three busses at NH ZSS will lose supply. It follows that we assume that these asset failures would result in one-third of the average load being lost for each hour of the outage. A protection relay failure may result in one, two or three buses losing supply. To be conservative, we assume the energy at risk for protection relay failures is one-third of the average load being lost for each hour of the outage.

Across each failure mode, that is, switchgear and protection relay, we have assumed that fully restoring supply to customers in the distribution network would take 90 minutes. We consider this length of outage to be a very conservative assumption. Our experience of the time taken to undertake the onsite inspection and investigation in the case of an outage, a combination of remote and manual switching and transferring load to adjacent network suggests that restoring supply would take considerably longer.

Further, where excess capacity of the NH ZSS has been consumed and load transfers to adjacent networks have been exhausted, we expect that there may be unserved energy for several days until JEN is able to install temporary infrastructure to allow additional load switching to an adjacent network or deploy a temporary generator on the network. We have adopted a conservative approach of assuming a 90-minute outage for all failure types to mitigate concerns that the benefits of replacing the primary and secondary assets at the NH ZSS are overstated.

6.3.3 Value of customer reliability

Reductions in the expected involuntary load shedding arising from the redevelopment of the NH ZSS are valued using the AER's 2024 estimated value of customer reliability (VCR) for Victoria,[18] weighted by the proportion of demand (in MWh) attributable to each customer type at NH ZSS.

Table 6-1 summarises the calculation of the load weighted VCR used in our analysis.

Table 6-1 Calculation of load weighted VCR

Load type	VCR ($/kWh)	Weighting (%)
Commercial	34.39	39.0%
Industrial	33.49	25.4%
Residential	49.23	35.6%
Weighted VCR	**39.44**	

6.4 Reduction in risk costs are not quantified

While we expect that redeveloping NH ZSS will result in a reduction in safety and fire risk costs, we have not quantified these as part of this business case.

It follows that the NPV of each option presented in section 7 are understated. In addition, we do not expect that the inclusion of safety and fire risk costs would change the preferred option for addressing reliability and safety risks at NH ZSS because:

- the avoided safety and fire risk costs are expected to be small compared to the expected involuntary load shedding
- the timing of the avoided safety and fire risk costs aligns with the timing of the avoided expected involuntary load shedding benefits, that is all occur when assets are replaced.

Our expectation is therefore that inclusion of safety and fire risk costs would be expected to increase the NPV of the options while not altering each option's ranking.

6.5 Sensitivity analysis

We model one scenario as part of the assessment and consider the robustness of the outcome of the cost benefit analysis through undertaking various sensitivity testing. The range of factors tested as part of the sensitivity analysis in this business case are as follows:

- lower and higher assumed capital costs
- lower and higher weighted VCR
- alternate commercial discount rate assumptions**.**

The above list of sensitivities focuses on the key variables that could impact the identified preferred option. The results of the sensitivity tests are set out as part of the following section.

We have also sought to identify the 'boundary value' for key variables beyond which the outcome of the analysis would change, including the amount by which capital costs would need to increase for the preferred option to no longer be preferred.

[18] AER, *Values of customer reliability,* Final report on VCR values, December 2024.

7. Assessment of options

This section outlines the assessment we have undertaken of the network options. The assessment compares the costs and benefits of options 2 through 5 to Option 1 (the 'do nothing' base case). The benefits of each option are represented by a reduction in risk costs compared to the base case.

7.1 Gross market benefit estimated for each option

Table 7-1 below summarises the present value of the gross benefit estimates for each option relative to the base case. The benefits included in this assessment consist of reduced expected involuntary load shedding. We explain in section 6.4 that we also expect some benefits from reduced safety and fire risk costs, however these have not been quantified as part of this assessment.

Table 7-1 Estimated gross benefits from credible options relative to Option 1 (the base case) ($2024m, present value (PV))

Option	Gross benefits ($m)
Option 2	0.0
Option 3	78.2
Option 4	60.1

7.2 Estimated costs for each option

Table 7-2 summarises the costs of the options, relative to the base case, in present value terms.
The costs consist of the refurbishment costs and direct capital costs for each option, relative to the base case.

Table 7-2 Costs of credible options relative to Option 1 (the base case) ($2024m, PV)

Option	Gross costs ($m)
Option 2	0.6
Option 3	16.1
Option 4	16.5

7.3 Net present value assessment outcomes

The net economic benefits are the differences between the estimated gross benefits less the estimated costs. Table 7-3 below summarises the present value of the net economic benefits for each option.

Table 7-3 Net economic benefits for options relative to Option 1 (the base case) ($2024m, NPV)

Option	Net benefits ($m)
Option 2	-0.6
Option 3	62.1
Option 4	43.6

Options 3 and 4 are found to have positive net benefits. Option 3 has the greatest net economic benefits of all the options assessed and is therefore the preferred option at this stage of our planning process.

7.4 Sensitivity analysis results

We have undertaken sensitivity testing to understand the robustness of the economic assessment to underlying assumptions about key variables. In particular, we have undertaken two sets of sensitivity tests:

- Step 1 – testing the sensitivity of the optimal timing of the project to different assumptions in relation to key variables; and
- Step 2 – once the optimal timing has been determined, testing the sensitivity of the total NPV benefit associated with the investment proceeding in that year, in the event that actual circumstances turn out to be different. Step 2 includes boundary testing, which assesses what would need to occur for Option 3 to have negative expected net benefits.

The application of the two steps to test the sensitivity of the key findings are outlined below.

7.4.1 Step 1 – Sensitivity testing of the assumed optimal timing

This section outlines the sensitivity of the identification of the commissioning year to changes in the underlying assumptions. This assessment addresses EMCᵃ's concern that optimal timing analysis had not been included in the original business case. The optimal timing is determined to be where the annualised benefits of the proposed investment exceed the annualised costs, consistent with AER guidance.[19]

The optimal timing of Option 3 is found to be invariant to the assumptions of:

- a 30 per cent increase/decrease in the assumed network capital costs
- a 30 per cent increase/decrease in the weighted average VCR
- lower discount rate of 2.30 per cent as well as a higher rate of 7.50 per cent.

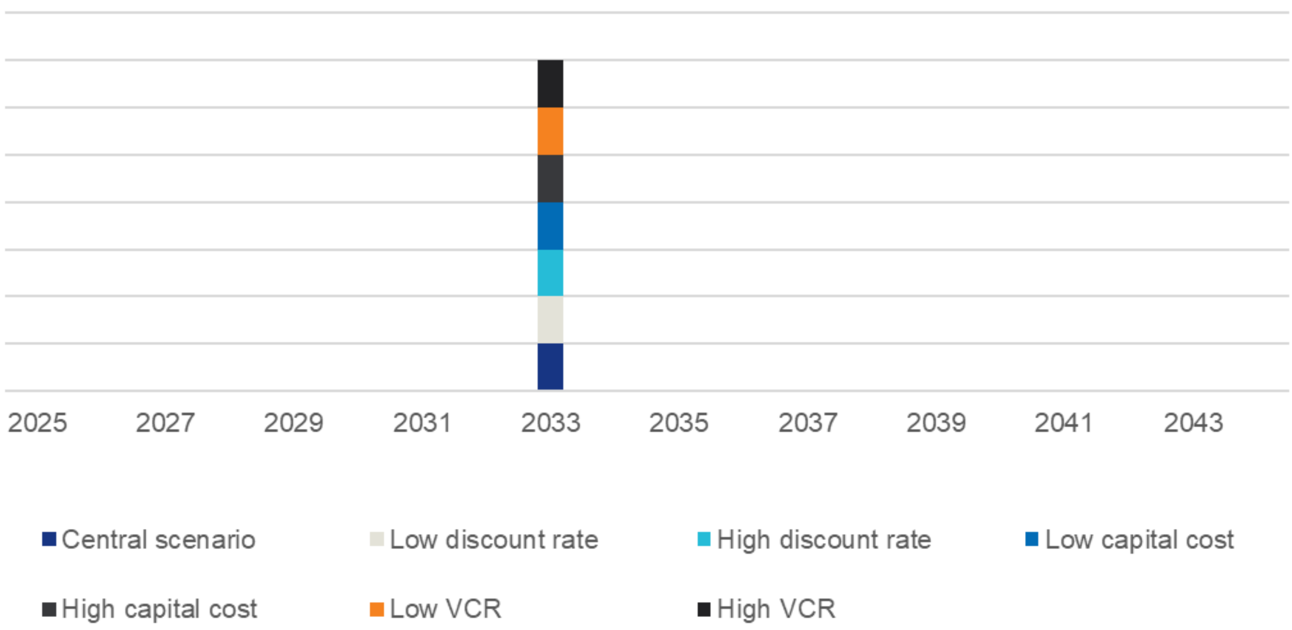
Figure 7-1 below outlines the impact on the optimal commissioning year for Option 3 under a range of alternate assumptions. It demonstrates that the optimal timing for Option 3 is FY33.[20]

We include figures that show the annualised benefits of Option 3 exceed the annualised costs from FY33 for each of the sensitivities included in Figure 7-1 in Appendix A.

[19] AER, *Asset replacement planning,* Industry practice application note, July 2024, p 36.

[20] This is consistent with our proposal that works are to take place between FY30 and FY32, with practical completion and commissioning in the first half of FY33.

Figure 7-1 Optimal timing for Option 3



7.4.2 Step 2 – Sensitivity of the overall net market benefit

We have conducted sensitivity analysis on the present value of the net economic benefit, based on undertaking the project in FY27 and FY28 and commissioning in FY29. Specifically, we have investigated the following same sensitivities under this step as in the first step:

- a 30 per cent increase/decrease in the assumed network capital costs;
- a 30 per cent increase/decrease in the weighted average VCR; and
- lower discount rate of 2.30 per cent as well as a higher rate of 7.50 per cent.

All of the above sensitivities investigate the consequences of having committed to a certain investment decision under different conditions to those assumed in this business case. The figures below illustrate the estimated net economic benefits for each option if separate key assumptions in the central scenario are varied individually.

Figure 7-2 shows that Option 3 delivers higher expected benefits than the other three options for all sensitivities of capital costs within 30 per cent of the expected capital cost (that is, 70 per cent to 130 per cent of estimated capital costs).

Figure 7-2 Capital costs sensitivity testing

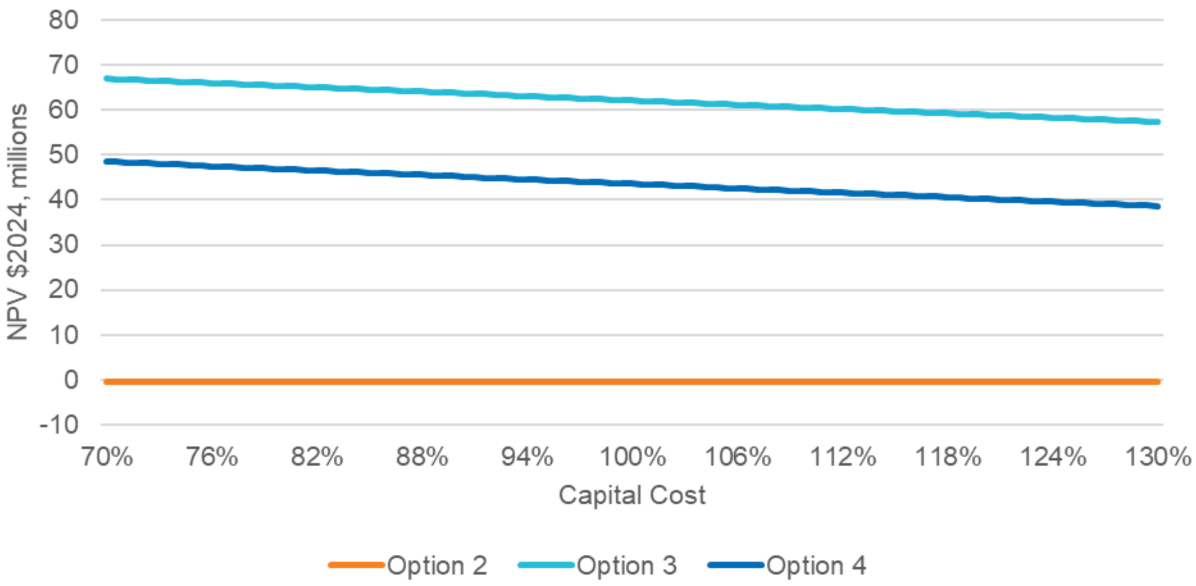


Figure 7-3 shows that Option 3 delivers higher expected benefits than the other three options for all sensitivities of VCR within 30 per cent of the weighted average VCR based on the proportion of demand (in MWh) attributable to each customer type at NH ZSS (that is, $27.61/kWh to $51.27/kWh).

Figure 7-3 VCR sensitivity testing

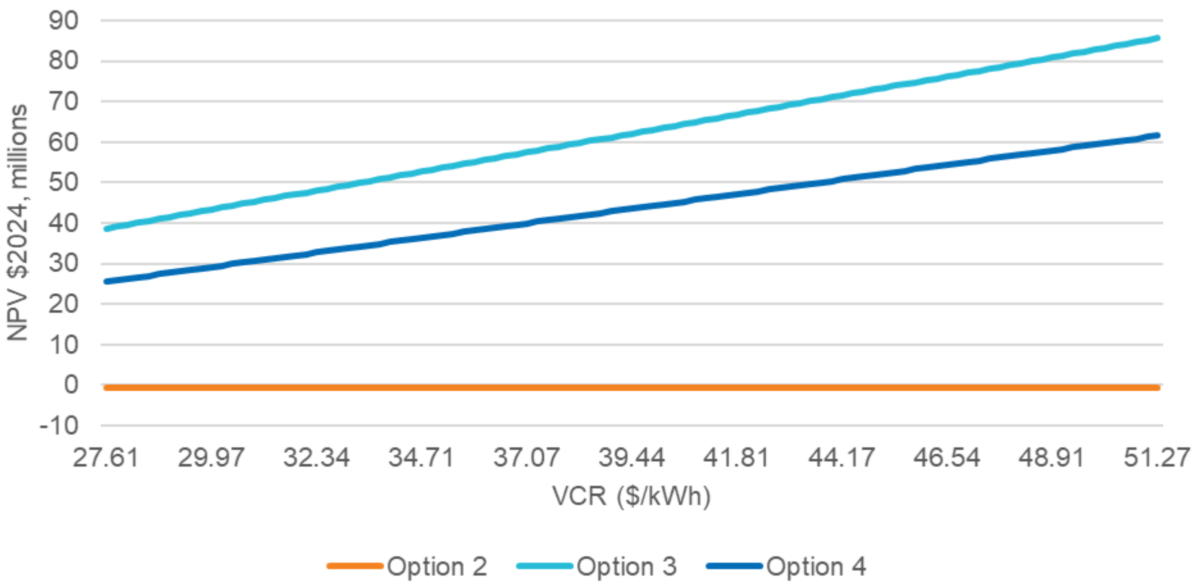
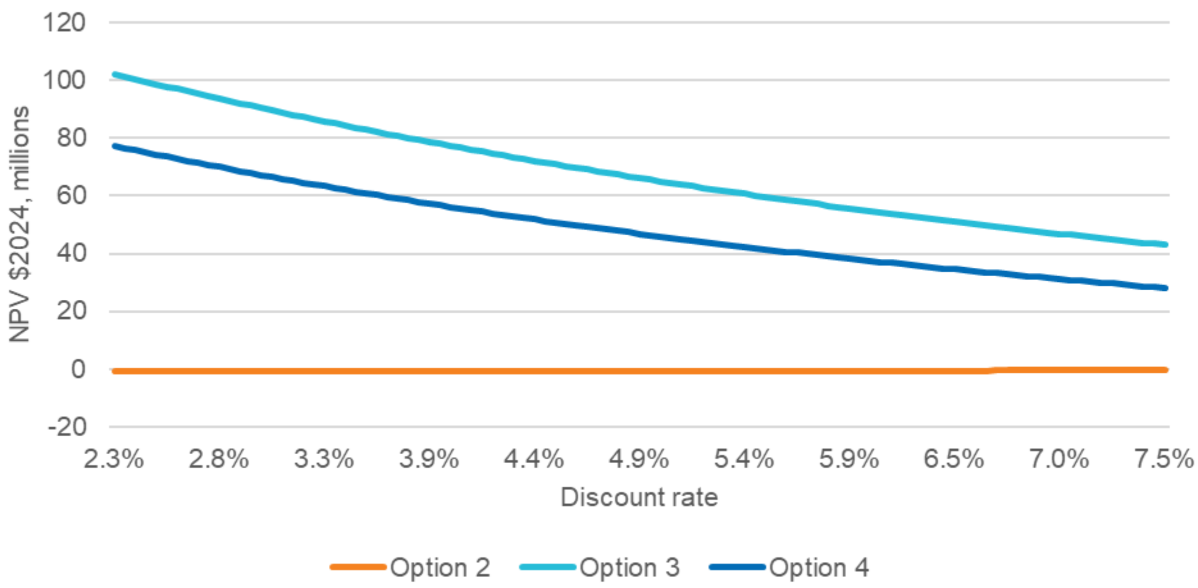


Figure 7-4 shows that Option 3 delivers higher expected benefits than the other three options for all sensitivities of the discount rate (that is, 2.3 per cent to 7.5 per cent).

Figure 7-4 Discount rate sensitivity testing



In terms of boundary testing, we find that the following would need to occur for Option 3 to have negative expected net benefits:

- assumed network capital costs would need to increase by approximately 387 per cent
- the VCR would need to decrease by approximately 79.4 per cent to below $8.10/kWh, which is substantially below the lowest VCR of any load type currently served by NH ZSS substation (industrial customers with a VCR of $33.49 /kWh) or
- a discount rate of over 30.3 per cent.

We therefore consider the finding that Option 3 being the preferred option is robust to the key underlying assumptions.

8. Recommendation

This business case has found that Option 3 is the preferred option. Option 3 involves the simultaneous replacement of the transformers, switchgears, and protection relays at NH ZSS in the upcoming regulatory period.

The estimated capital expenditure associated with Option 3 is $35.8 million (in FY24 dollars).

The works are planned to take place between FY30 and FY32, with practical completion and commissioning in the first half of FY33.

JEN notes that a RIT-D will be applied to this investment, in line with the National Electricity Rule requirements, prior to its commencement.

Appendix A
Option 3

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A1. Option 3

In this appendix we provide figures detailing the annualised costs and benefits of Option 3 for each of the sensitivities included in Figure 7-1. This appendix shows that that under all sensitvities detailed in section 7.4.1 the optimal timing of Option 3 is FY33.

Figure A 1 Optimal timing of Option 3 - Discount rate sensitivities

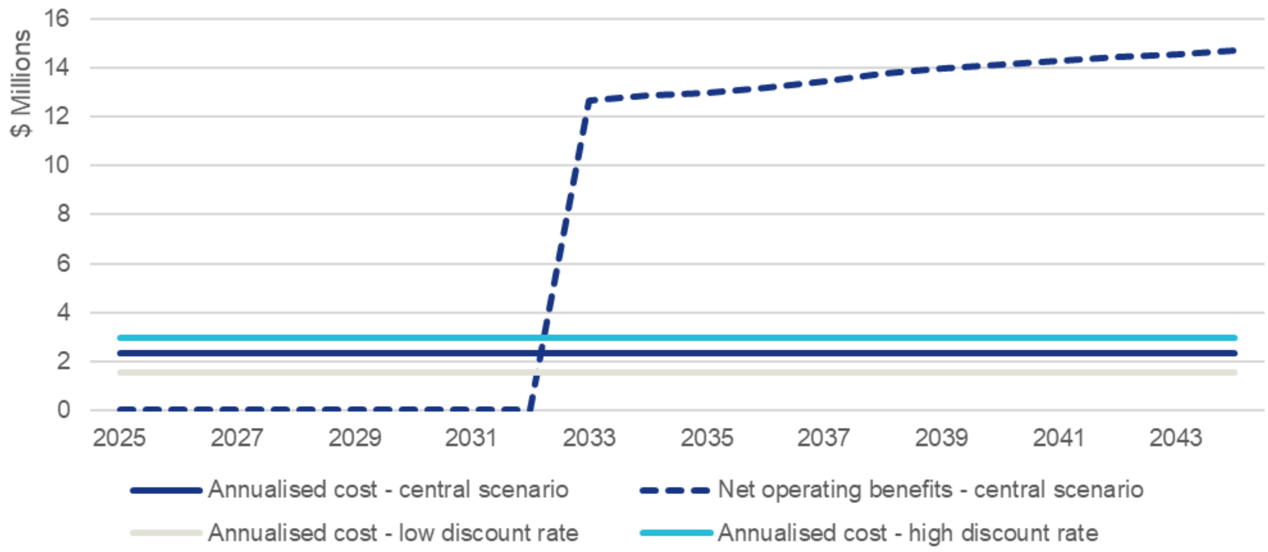

Figure A 2 Optimal timing of Option 3 – Capital cost sensitivities

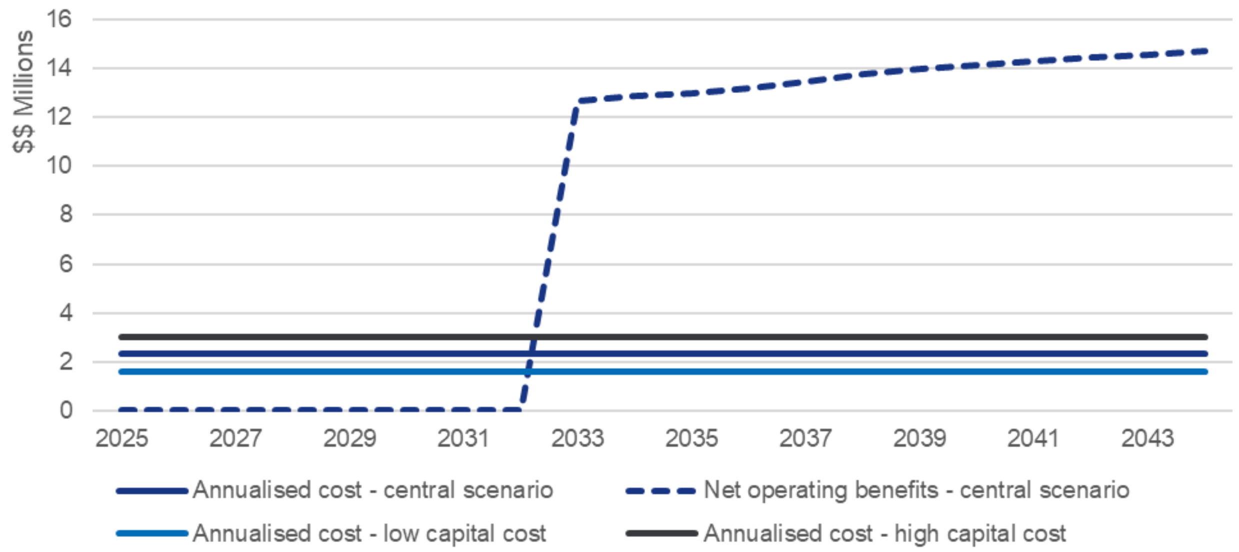

Figure A 3 Optimal timing of Option 3 - VCR sensitivities