AUSTRALIAN ENERGY MARKET OPERATOR

Victorian Planning

Eastern Victoria Grid Reinforcement

November 2024

Regulatory Investment Test for Transmission (RIT-T)

Project Specification Consultation Report (PSCR)

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

The purpose of this publication is to, among other things, provide information about certain network limitations and potential options to address these limitations.

AEMO publishes this Project Specification Consultation Report in accordance with clause 5.16 of the National Electricity Rules (NER). This publication is generally based on information available to AEMO as at October 2024 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts, and assumptions are accurate, complete, or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results because events and circumstances frequently do not occur as expected, and those differences may be material.

This publication does not include all of the information that an investor, participant or potential participant in the national electricity market might require and does not amount to a recommendation of any investment.

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Executive summary

AEMO Victorian Planning (AVP) is undertaking this Eastern Victoria Grid Reinforcement regulatory investment test for transmission (RIT-T) to assess investment options required to maintain reliable and secure supply to consumers in the eastern metropolitan Melbourne network as demand increases and electricity supplies transition from fossil fuels to renewable sources. This Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

Demand in the eastern metropolitan Melbourne area is forecast to increase over the next 10 years by 21.8%[1]. This increased demand is expected to exceed the existing network capacity, which may require operational measures such as dispatch constraints or load shedding in the eastern metropolitan Melbourne area to maintain loading within network limits unless alternative action is taken.

A separate investment is planned which will reconfigure the Latrobe Valley following the retirement of Yallourn W Power Station (YWPS). The reconfiguration will enhance the utilisation of the 220 kilovolts (kV) network between Latrobe Valley and Melbourne and ensure the network capacity is preserved post YWPS retirement. However, thermal limitations on assets used to supply the eastern metropolitan Melbourne area are still expected to be present with those investments in place, due to the forecast increasing demand in eastern metropolitan Melbourne, so further investment under this RIT-T is required to remediate these thermal limitations.

The 2024 *Integrated System Plan* (ISP) identified the ‘Eastern Victoria Grid Reinforcement’ as a future ISP project to increase the transfer capacity between Hazelwood and Melbourne so increased onshore and new offshore wind generation in Eastern Victoria can be accommodated[2]. Currently the high capacity on the existing 500 kV lines between Hazelwood and Melbourne is being restricted by thermal limitations of 500/220 kV transformers used to supply the eastern metropolitan Melbourne area. Therefore, the investment considered under this RIT-T to resolve these thermal limitations will have the added benefit of increasing the transfer capacity between Hazelwood and Melbourne to accommodate the planned projects in Eastern Victoria.

Regulatory investment test for transmission (RIT-T)

The RIT-T is an economic cost-benefit test used to assess and rank different options that address an identified need. This process establishes the business case for investment and confirms the option, ultimately paid for by consumers, that will maximise net economic benefits.

In response to expected demand increases, AVP is undertaking this Eastern Victoria Grid Reinforcement RIT-T to assess options that are considered technically and economically feasible to meet the identified need described below. Through the assessment of credible options, the RIT-T process will identify a proposed preferred option, then ultimately a preferred option and its optimal timing.

This PSCR is the first stage of the RIT-T process, and includes:

- a description of the identified need and the assumptions used in identifying that need;

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[1] This is based on 10% probability of exceedance (POE) forecast demand growth from 2024-25 to 2033-34. The assumptions behind these forecasts and the sites included in the eastern Melbourne area are set out in Section 2.3.1

[2] See section A5.4.2 at https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a5-network-investments.pdf?la=en

- the technical characteristics and performance requirements that a non-network option would have to deliver to meet the identified need;
- a description of all credible options which AVP is aware of that address the identified need;
- the classes of market benefits AVP considers not likely to be material (and why), along with the classes of market benefits that AVP considers likely to be material; and
- an overview of the proposed assessment approach for this RIT-T.

Identified need

AVP has identified a need to support forecast demand growth beyond the existing capacity of the eastern metropolitan Melbourne network. This is a market benefits-driven RIT-T, thereby requiring any proposed investment to deliver positive net market benefits. It is expected that market benefits of this RIT-T will primarily come from avoided unserved energy.

Maximum operational electricity demand in Victoria is forecast to grow steadily over the next 10 years[3], including in metropolitan Melbourne[4]. Figure 1 shows the 10% and 50% POE demand forecast for the eastern metropolitan Melbourne area compared with the approximate existing network supply capacity. Under 50% probability of exceedance (POE) demand forecast (1 in 2 year), there is a risk that demand could exceed network capacity from summer 2028-29, the risk increases under 10% POE demand forecasts (1 in 10 year), which show there is a risk demand could exceed the network capacity from summer 2024-25[5]. This highlights that there is a relatively small risk from summer 2024-25 which steadily increases over the next 10 years.

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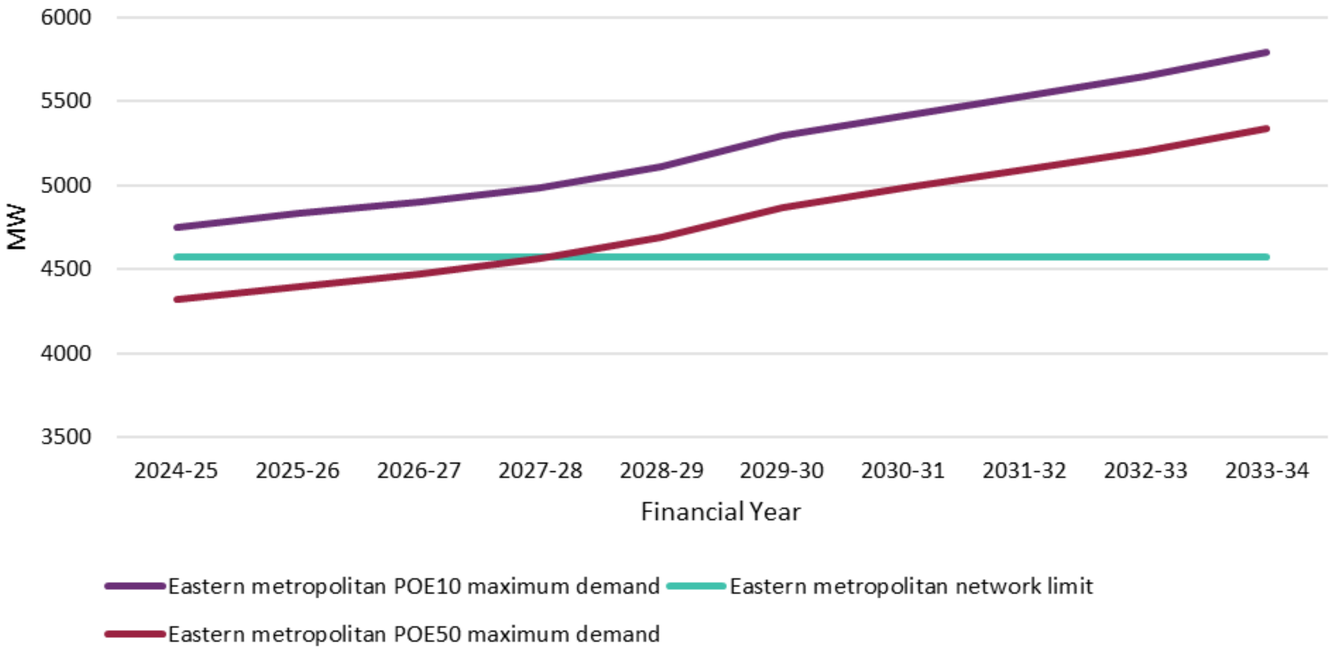
[3] AEMO, *2023 Electricity Statement of Opportunities*, August 2023, p 36; and AEMO, *2024 Electricity Statement of Opportunities*, August 2024, pp 158-159. AVP expects to update its modelling for this project to reflect the 2024 ESOO and 2024 VAPR as part of its assessment in the PADR, as explained in section 2.3.1.

[4] AEMO, 2023 Victorian Connection Point Demand Forecast, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report

[5] The assumptions behind these forecasts are set out in Section 2.3.1 below.

Figure 1 Eastern metropolitan Melbourne approximate network capacity versus maximum demand forecast, 2024-25 to 2033-34 (MW)[6]



If no action is taken to increase the eastern metropolitan Melbourne network capacity, then operational measures may be required to manage network loading within the thermal limits of the following assets (noting that timings are indicative and assume 10% POE peak demand conditions):

- Rowville 500/220 kV A1 transformer loading is forecast to exceed its system normal (N) continuous rating in summer 2028-29.
- Eildon – Thomastown 220 kV line loading is forecast to exceed its system normal (N) continuous rating in summer 2028-29.
- Following contingent loss of the Rowville 500/220 kV A1 transformer:
  - Ringwood – Thomastown 220 kV line loading is forecast to exceed its N-1 short-term rating in summer 2024-25.
  - Rowville – Yallourn 220 kV lines' loadings are forecast to exceed their N-1 short-term ratings in summer 2028-29.

If the 10% POE demand forecasts eventuate, there is a risk that operational measures such as load shedding or dispatch constraints may be required from summer 2024-25 to manage network loading so that the Ringwood – Thomastown 220 kV line's short-term rating is not exceeded for a contingency loss of the Rowville 500/220 kV A1 transformer. The risk increases from summer 2028-29 when loading is forecast to exceed the rating of several network assets listed above and loading is forecast to exceed the rating of network assets assuming a 50% POE demand forecast.

[6] The assumptions behind these forecasts and the sites included in the eastern Melbourne area are set out in Section 2.3.1

Credible options

Non-network options may be able to meet (or partially meet) the identified need, including:

- Demand response and decentralised storage.
- Grid-connected generators and battery energy storage systems (BESS).

While AVP expects that the extent to which forecast demand exceeds existing network supply capacity cannot be fully addressed by a non-network option on its own, there is a possibility for a non-network solution to defer the need for network investment by addressing the need during the early years of the assessment period. As part of the Project Assessment Draft Report (PADR, the next stage of the RIT-T process), AVP will carefully review all submissions regarding possible non-network options and assess whether combinations of network and non-network components could form credible options.

AVP has identified two credible network options to address the identified need which are canvassed in this PSCR. Both options consist of several of the same augmentations, with the variation of a transformer at Rowville for Option 1 or a transformer at Cranbourne with some switching at Rowville for Option 2. These represent different approaches to addressing thermal limitations associated with the Rowville A1 transformer. Both options include other components necessary to mitigate fault level increases, and to address thermal limitations on the Eildon – Thomastown 220 kV line.

The components of both credible options are detailed in Table 1 with indicative cost estimates (+/-50% accuracy) in real 2024 terms. Total capital costs are expected to be $121 million for Option 1, and $122.9 million for Option 2.

Table 1 Credible option components and capital cost estimates

Element/s of identified need	Option 1 component	Option 2 component	Cost estimate ($ million, real 2024)
Eildon – Thomastown 220 kV line will exceed N (continuous) rating	Bring forward the component of the VNI West project which addresses overloading on the existing VNI East circuits, including the Eildon - Thomastown 220kV circuit (power flow controllers or alternative)	Bring forward the component of the VNI West project which addresses overloading on the existing VNI East circuits, including the Eildon - Thomastown 220kV circuit (power flow controllers or alternative)	3.5 for both options
Rowville A1 Transformer will exceed N (continuous) rating **Contingency loss of Rowville A1 transformer means that Ringwood – Thomastown and Rowville – Yallourn 220 kV lines will exceed their short-term rating**	Install third 500 kV/220 kV transformer at Rowville to provide backup to the existing Rowville 500/220 kV A1 transformer and supply to the Rowville No. 3-4 220kV bus group	Transfer the Rowville 500/220 kV A2 transformer from the Rowville No. 1-2 220 kV bus group to the Rowville No. 3-4 220 kV bus group, to provide backup to the 500/220 kV A1 transformer. Install a second 500/220 kV transformer at Cranbourne to provide backup to the existing Cranbourne 500/220 kV A1 transformer and supply to the Rowville No. 1-2 220 kV bus group.	76.4 for both options
Fault level mitigation	Equipment replacements at stations that have fault level exceedances – expected to be Keilor and Rowville 220 kV buses and Templestowe and Thomastown 66 kV buses	Equipment replacements at stations that have fault level exceedances – expected to be Rowville, South Morang and Thomastown 220 kV buses	41.1 for Option 1 43.0 for Option 2

Further details regarding AVP's approach to estimating costs (and how AVP intends to estimate costs at the PADR stage) are in Section 5.3.

At this stage AVP estimates annual operating expenditure to be 1% of total capex for network components, for both credible options.

The options, including their costs and optimal timing, will be refined at the PADR stage based on further investigations by AVP, including in relation to:

- Any practicality issues, such as site-specific requirements at the relevant location.
- Combinations of network and non-network solutions to determine the combination that maximises net market benefit for consumers.
- The potential impact that currently uncommitted connection applications for generation and storage in the metropolitan Melbourne area may have on the need being addressed by this RIT-T, if they become committed during the RIT-T process.

Submissions

AVP welcomes written submissions on this PSCR, particularly from potential proponents of non-network options. All feedback will be considered and will help refine the proposed preferred option to be published in the PADR.

Submissions should be emailed to AVP_RIT-T@aemo.com.au with subject title 'Eastern Victoria Grid Reinforcement PSCR' and are due on or before 5.00 pm on 7 February 2025.

At the conclusion of the consultation process, all non-confidential submissions received will be published on AEMO's website. If you do not wish for your submission to be made public, please clearly stipulate this at the time of lodgement.

Next steps

Following consultation on this PSCR, the next stage of the RIT-T process, in accordance with the requirements of National Electricity Rules (NER) 5.16.4, is a full options analysis and publication of the PADR.

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1 Introduction

AEMO Victorian Planning (AVP) is undertaking this Eastern Victoria Grid Reinforcement regulatory investment test for transmission (RIT-T) to assess investment options required to maintain reliable and secure supply to consumers in the eastern metropolitan Melbourne network as demand increases and electricity supplies transition from fossil fuels to renewable sources.

Demand in the eastern metropolitan Melbourne area is forecast to increase over the next 10 years by 21.8%[7]. This increased load is expected to exceed the existing network capacity, which may require operational measures such as dispatch constraints or load shedding in the eastern metropolitan Melbourne area to maintain loading within network limits unless alternative action is taken.

This Project Specification Consultation Report (PSCR) has been prepared by AVP in accordance with the requirements of National Electricity Rules (NER) 5.16.4 for a RIT-T. It represents the first step in the RIT-T process.

In line with NER requirements, this PSCR provides:

- A description of the identified need and the assumptions used in identifying that identified need.
- The technical characteristics and performance requirements that a non-network option would have to deliver to meet the identified need.
- A description of credible options considered by AVP to address the identified need including, for each credible option:
  - Technical characteristics.
  - Estimated construction timeline and commissioning date.
  - Indicative capital, operating and maintenance costs.
  - Whether the option is reasonably likely to have a material inter-network impact.
- The classes of market benefits AVP considers not likely to be material (and why), along with the classes of market benefits that AVP considers likely to be material.
- An overview of the proposed assessment approach for this RIT-T.

The next stage of the RIT-T process is the publication of a Project Assessment Draft Report (PADR). The PADR will address submissions received on this PSCR.

[7] This is based on 10% probability of exceedance (POE) forecast demand growth from 2024-25 to 2033-34. The assumptions behind these forecasts and the sites included in the eastern Melbourne area are set out in Section 2.3.1

2 Identified need

Forecast demand growth driven by increasing electrification and urban sprawl, coupled with changing power flow patterns as thermal generators retire and are replaced by renewable energy sources and new interconnectors, is expected to result in future loading that exceeds the existing eastern metropolitan Melbourne network thermal capacity.

To maintain secure supply under these changing power system conditions, AVP has identified a need to invest and is undertaking this market benefits-driven RIT-T to identify the option that maximises net economic benefits for Victorian electricity consumers.

2.1 Background

Maximum demand in the eastern metropolitan Melbourne area is forecast to grow steadily over the next 10 years, with an average annual growth rate of 2.2%[8]. This demand growth is driven by electrification of both business and residential sectors and the electrification of transport, primarily via electric vehicles (EVs).

Additionally, forecast maximum demand periods continue to occur outside daylight hours in Victoria, removing the ability of distributed photovoltaics (PV) systems to dampen transmission network maximum demand growth, relative to other fundamental drivers of growth such as new connections or appliance uptake[9].

The Victorian power system, like the National Electricity Market (NEM) more generally, is undergoing transformational changes with the withdrawal of several existing thermal power stations coupled with significant increases in renewable generation, battery energy storage systems (BESS) and consumer energy resources (CER).

Generation in the Latrobe Valley is currently a key source of electricity supply to metropolitan Melbourne, and although the existing coal generators are expected to retire over the coming decade, the Latrobe Valley is expected to continue as a key source of electricity with thermal generation being replaced by an abundance of onshore and offshore wind, grid-scale solar and a new interconnection to Tasmania via the proposed Marinus Link subsea cable.

Yallourn W Power Station (YWPS) in the Latrobe Valley is scheduled to retire in 2028. While YWPS remains in service it will continue providing a supply to Melbourne via the 220 kilovolts (kV) network, which is in parallel to the other Latrobe Valley generators that provide supply via the 500 kV network. When YWPS retires, if supply from the other generators in the Latrobe Valley to the eastern metropolitan Melbourne area were to remain solely via the 500 kV network, there is a risk that existing assets would be loaded beyond their capability, under both in pre- and post-contingent conditions, which may require operational measures such as pre- and post-contingent load shedding to manage this risk.

[8] The assumptions behind these forecasts and the sites included in the eastern Melbourne area are set out in Section 2.3.1

[9] See Section 2.1 of AEMO's 2024 *Electricity Statement of Opportunities* (ESOO), at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf?la=en&hash=2B6B6AB803D0C5F626A90CF0D60F6374

In the 2023 *Victorian Annual Planning Report* (VAPR), AVP identified a minor augmentation project – the Latrobe Valley reconfiguration project – involving switching works at Hazlewood Power Station[10]. This involves changing to a new switching configuration, referred to as 'modified parallel mode'. The Latrobe Valley reconfiguration project is progressing separately to the investments contemplated under this RIT-T, and will preserve the eastern metropolitan network supply capacity at existing levels during peak demand conditions post YWPS retirement. It does this by redirecting power from some Latrobe Valley generators off the 500 kV Latrobe Valley to Melbourne network and on to the 220 kV Latrobe Valley to Melbourne network. This rebalancing of generator supply between the 500 kV and 200 kV parallel networks helps maximise utilisation of the existing network capacity.

While the switch to modified parallel mode will mitigate network loading risks following retirement of YWPS, it does not completely address the expected unserved energy (EUSE), and further investment is therefore being considered under this RIT-T.

2.2 Description of the identified need

AVP has identified a need to support forecast demand growth beyond the existing capacity of the eastern metropolitan Melbourne network. This is a market benefits-driven RIT-T, thereby requiring any proposed investment to deliver positive net market benefits. Market benefits are primarily expected from avoided unserved energy but may also include changes in fuel costs as retiring thermal units are replaced with renewable resources and the new interconnection with Tasmania via Marinus Link.

Maximum operational electricity demand in Victoria is forecast to grow steadily over the next 10 years[11], including in metropolitan Melbourne[12].

The eastern metropolitan Melbourne network is currently capable of supplying approximately 4,570 megawatts (MW) of demand during summer peak demand conditions[13] which is expected to be maintained following the retirement of YWPS with the implementation of modified parallel mode operation. Under 50% probability of exceedance (POE) demand forecast (1 in 2 year), there is a risk that demand could exceed network capacity from summer 2028-29, the risk increases under 10% POE demand forecasts (1 in 10 year), which show there is a risk demand could exceed the network capacity from summer 2024-25[14]. If no action is taken to increase the eastern metropolitan Melbourne network capacity, then operational measures may be required to manage network loading during peak demand periods as maximum demand in the area continues to grow.

[10] AEMO, *2023 Victorian Annual Planning Report*, October 2023, pp 8, 64. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

[11] AEMO, 2023 ESOO, August 2023, p 36; and AEMO, 2024 ESOO, August 2024, pp 158-159. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.AVP expects to update its modelling for this project to reflect the 2024 ESOO and 2024 VAPR as part of its assessment in the PADR, as explained in Section 2.3.1.

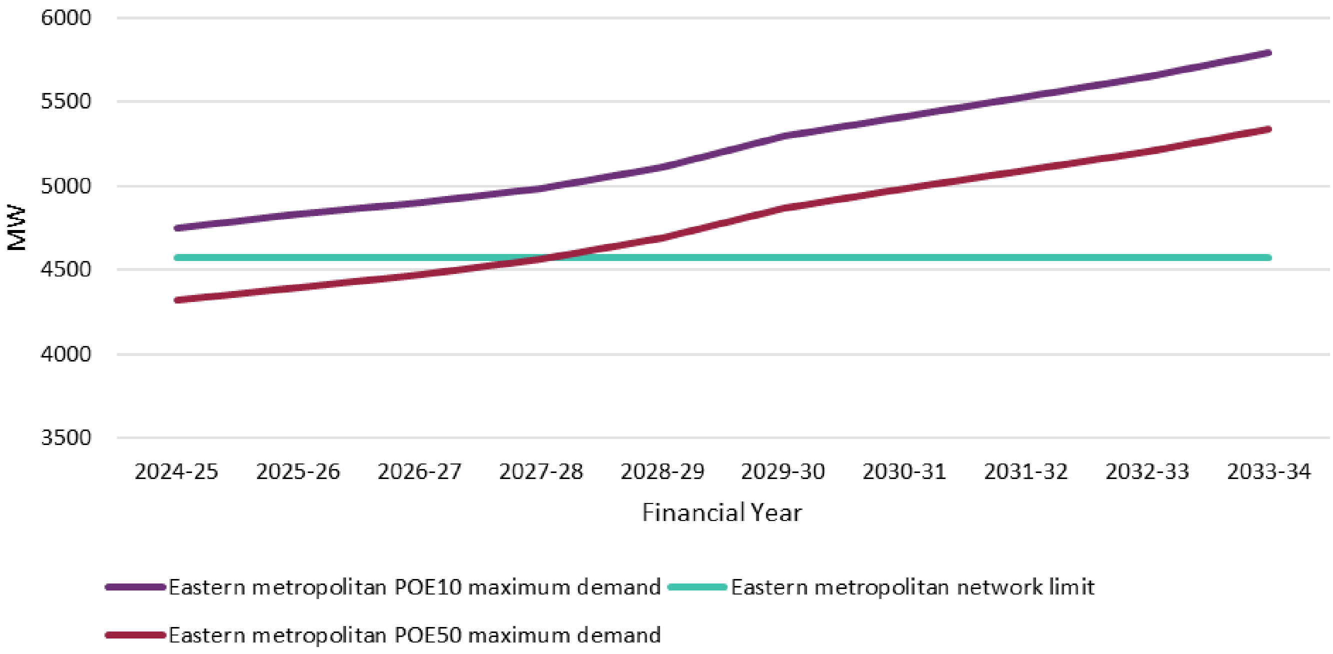
[12] AEMO, *2023 Victorian Connection Point Demand Forecast*, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report

[13] Summer peak demand conditions assume 45-degree equipment ratings which reduces the network supply capacity. This assumption has been made because high temperatures are a driver of high demand in summer and peak demand days typical coincide with high ambient temperatures.

[14] The assumptions behind these forecasts are set out in Section 2.3.1 below.

Figure 2 shows the 10% and 50% POE demand forecast for the eastern metropolitan Melbourne area compared with the approximate existing network supply capacity. This figure highlights that there is a relatively small risk from summer 2024-25 which steadily increases over the next 10 years.

Figure 2 Eastern metropolitan Melbourne approximate network capacity versus maximum demand forecast, 2024-25 to 2033-34 (MW)[15]



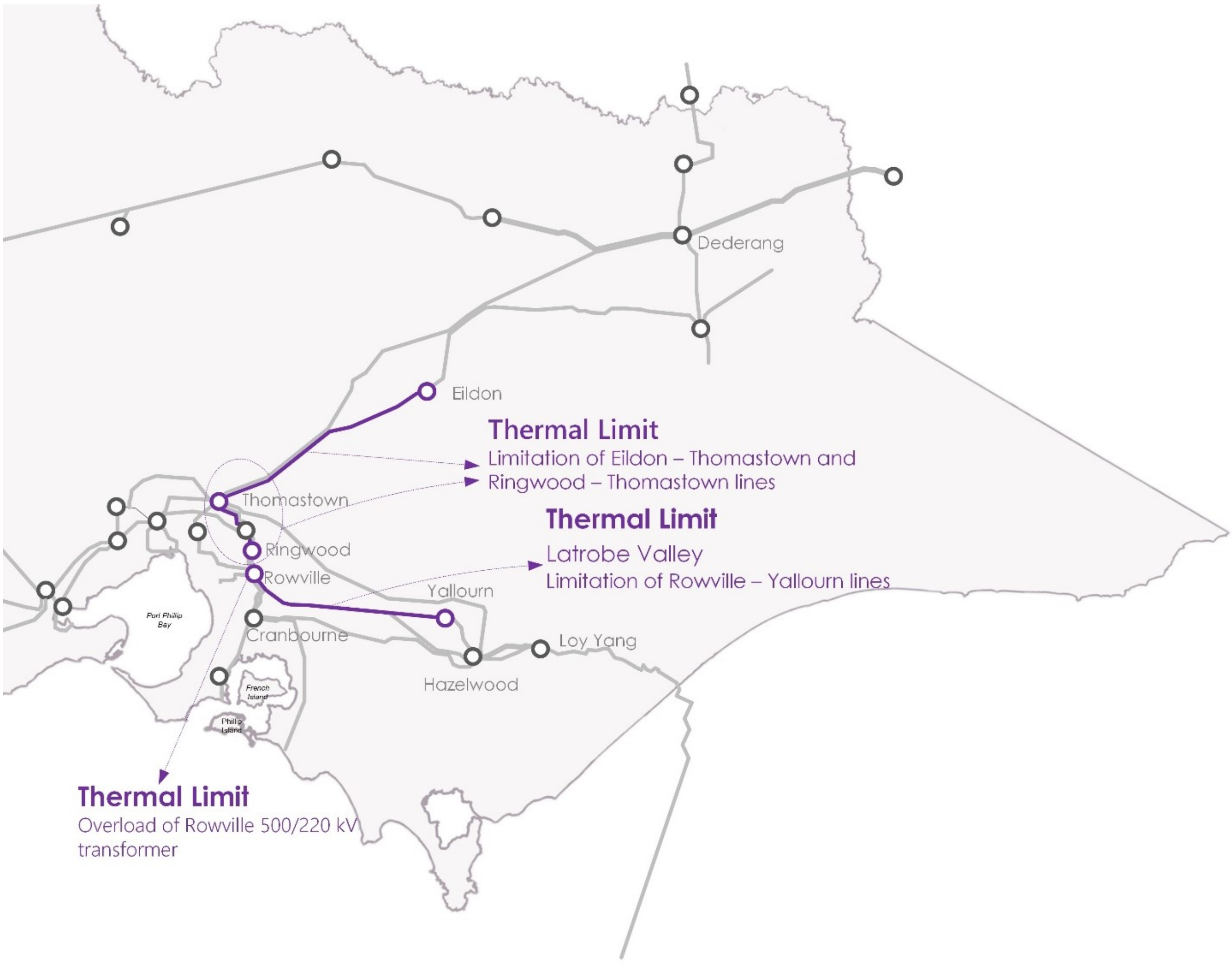
As a result of the forecast maximum demand growth in the eastern metropolitan Melbourne several thermal limitations have been identified and will be addressed through additional investment under this RIT-T. Addressing these limitations will increase the supply capacity of the eastern metropolitan Melbourne network in peak demand conditions and ensure reliable and secure supply to consumers. The assets that have been identified are listed below, including the year that these limitations first occur under 10% POE peak demand conditions:

- Rowville 500/220 kV A1 Transformer loading is forecast to exceed its system normal (N) continuous rating in summer 2028-29.
- Eildon – Thomastown 220 kV line loading is forecast to exceed its system normal (N) continuous rating in summer 2028-29.
- For contingent loss of the Rowville 500/220 kV A1 transformer:
  - Ringwood – Thomastown 220 kV line loading is forecast to exceed its short-term rating in summer 2024-25.
  - Rowville – Yallourn 220 kV lines' loadings are forecast to exceed their short-term ratings in summer 2028-29.

Figure 3 shows the location of key network assets and related thermal limitations impacting supply capability to the eastern metropolitan Melbourne area.

[15] The assumptions behind these forecasts and the sites included in the eastern Melbourne area are set out in Section 2.3.1

Figure 3 Network assets and related thermal limitations impacting eastern metropolitan Melbourne supply



If the 10% POE demand forecasts eventuate, there is a risk that operational measures such as load shedding or dispatch constraints may be required from summer 2024-25 to manage network loading so that the Ringwood – Thomastown 220 kV line's short-term rating is not exceeded for a contingency loss of the Rowville 500/220 kV A1 transformer. The risk increases from summer 2028-29 when loading is forecast to exceed the rating of the other network assets listed above and loading is forecast to exceed the rating of network assets assuming a 50% POE demand forecast.

Estimates of the extent of involuntary load curtailment, required to maintain loading within network limits, under the base case are in Section 3.5.

This RIT-T is focused on reducing the cost of EUSE that would otherwise be required to prevent thermal limitations associated with demand exceeding the rating of the existing network assets in the eastern metropolitan Melbourne area. However, AVP notes that the credible network options identified as capable of addressing these thermal limitations will contribute to increasing the transfer capacity between generators in the Latrobe Valley and the bulk load centre in metropolitan Melbourne. Transfer capacity from the Latrobe Valley is expected to be constrained during periods of high demand and very high temperatures in the future if no action is taken.

The 2024 *Integrated System Plan* (ISP) identified the 'Eastern Victoria Grid Reinforcement' as a future ISP project, expected to be required from 2035-36 under the ISP *Step Change* scenario to accommodate increased onshore and new offshore wind generation in Eastern Victoria[16].

Despite the high capacity of the existing 500 kV network between Hazelwood and Melbourne, the transfer capacity between the 500 kV network and Melbourne major load centres is restricted by the existing capacity of 500/220 kV transformers in the eastern metropolitan Melbourne area. By resolving these limitations, this RIT-T will help maximise utilisation of the existing transmission lines between the Latrobe Valley and Melbourne, thereby catering for future onshore and offshore wind generation, grid-scale solar projects and increased interconnection with Tasmania via Marinus Link.

2.3 Assumptions used in identifying the identified need

This section sets out the assumptions underpinning the identified need, including:

- Demand forecasts.
- Generation and dispatch forecasts.

2.3.1 Demand forecasts

AVP performed studies using the models developed for the 2023 VAPR to estimate the level of unserved energy required to maintain loading within network limits. These models have been updated to incorporate the 2023 AEMO connection point forecasts for coincident maximum demand in Victoria[17] which were developed after publication of the 2023 VAPR. AVP has updated all VAPR models to incorporate these updated demand forecasts at the transmission connection point level across Victoria.

After applying the updated connection point forecasts, AVP reconciled demand at a regional level with the 2023 *Electricity Statement of Opportunities* (ESOO) regional demand forecast[18]. A 45° ambient temperature rating has been applied to all equipment in the model and all EUSE has been calculated using weightings consistent with the ESOO and Reliability Forecast Methodology[19].

Due to a low risk of EUSE in the eastern metropolitan Melbourne network under 90% POE demand conditions, studies have only been performed for 10% POE and 50% POE demand forecasts. The 10% POE and 50% POE outcomes were weighted at 30.4% and 39.2% respectively, with the remaining 30.4% weighting assigned to 90% POE outcomes with zero EUSE assumed. See Section 5.6 for more details on the EUSE weighting.

As there is significant interconnection between the terminal stations supplied from the Latrobe Valley, the risk has been calculated across the entire eastern metropolitan Melbourne area, which includes terminal stations

[16] See Section A5.4.2 at https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a5-network-investments.pdf?la=en.

[17] AEMO, 2023 Victorian Connection Point Demand Forecast, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report

[18] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal .

[19] See Section 5.2.2 at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

located at Brunswick, Cranbourne, East Rowville, Heatherton, Malvern, South Morang, Springvale, Richmond, Ringwood, Rowville, Templestowe, Thomastown and Tyabb.

AVP expects to receive updated connection point forecasts in January 2025, and intends to use these for the PADR assessment. Additionally, it is intended that the studies completed as part of the PADR assessment will incorporate a regional demand that reflects the latest forecasts set out in the 2024 ESOO.

2.3.2 Generation and dispatch assumptions

Studies performed by AVP to identify the need for investment covered by this PSCR took into account the following publications for the development of power system models which align with those used for the 2023 VAPR[20]:

- Offshore wind targets based on AEMO's 2023 *Inputs, Assumptions and Scenarios Report*[21].
- All committed, anticipated, and actionable ISP projects impacting the Victorian region from the July 2023 update on AEMO's NEM Transmission Augmentation Information web page[22].
- Generation plant and retirement information based on the July 2023 update on AEMO's Generation Information web page[23].

Table 2 summarises the dispatch assumptions for the power system studies which align with those utilised for the maximum demand scenario modelled as part of the 2023 VAPR studies.

Table 2 Dispatch assumptions

Generation type	Dispatch assumption for maximum demand scenario
Grid-scale solar	Offline[A]
Wind farms	Online with output up to 50% of maximum capacity[B]
BESS	Online with output at 50% capacity
Synchronous generation (coal, gas, and hydro)	Online with output up to maximum rated capacity
Interconnectors	The inter-regional flows are set to be consistent with the FY2022-23 historical year with a demand level close to 10% POE conditions and adjusted if necessary to accommodate the recent changes in operating conditions (such as any change in interconnector limits, demand and generation)[C]

A. Given that maximum demand is forecast to occur in the early evening, around sunset, the PSCR studies have assumed that solar farms would be offline at peak demand. However, studies for the PADR are expected to include time-sequential data including typical solar generation dispatch traces aligned with the ISP.
B. Studies performed from year 5-10 assumed above average capacity factors for wind farms during periods of maximum demand. This resulted due to no planting of additional generation to support increasing demand forecasts as is done in the ISP. Studies performed for the PADR will incorporate additional planted generation and follow the optimal development path from the ISP.
C. For the PSCR, new interconnectors have assumed flow rates consistent with existing interconnectors of relevant regions. However, PADR studies are expected to include time-sequential data aligned to the ISP.

[20] AEMO, 2023 VAPR, October 2023, pp 13.

[21] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[22] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[23] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

All studies completed as part of the PADR assessment are expected to incorporate the latest publications on the AEMO Generation Information and the NEM Transmission Augmentation Information web pages.

3 Credible options

This section provides detail on each of the credible options considered capable of addressing the identified need, outlining their estimated capital and operational and maintenance costs, land, environment and social considerations, earliest delivery timing and consideration of any material inter-network impact.

This section also outlines the technical characteristics that a non-network solution would need to provide to meet the identified need.

3.1 Development of credible options

The process for developing the credible options is summarised below;

1. Identify network limitations → 2. Identify set of possible solutions to network limitations → 3. Identify fault level mitigation required following implementation of solutions → 4. Consider the commercial and technically feasibility possible solutions forming an option

For each of the eastern metropolitan Melbourne network assets at risk of exceeding their thermal capability, as set out in Section 2.2, AVP has identified possible solutions that, combined with each other, form credible options that are expected to be capable of meeting the identified need. These possible solutions are summarised in Table 3, and are used as components of the credible network options set out in Section 3.2.

Table 3 Solutions to manage thermal limitations

Thermal limitation	Possible solutions
Eildon – Thomastown 220 kV line will exceed its system normal (N) continuous rating	• Bring forward the component of the VNI West project which addresses overloading on the existing VNI East circuits, including the Eildon - Thomastown 220kV circuit (power flow controllers or alternative)
Rowville 500/220 kV A1 Transformer will exceed its system normal (N) continuous rating **Following contingent loss of Rowville 500/220 kV A1 transformer:** • **Forecast Ringwood – Thomastown 220 kV line loading exceeds its short-term rating** • **Forecast Rowville – Yallourn 220 kV line loadings exceed their short-term ratings**	• Install additional 500/220 kV transformation in the eastern metropolitan Melbourne area; and/or • Increase supply to Rowville 220 kV by undertaking switching rearrangements at Rowville and supplying Rowville No.1-2 220 kV bus group from Cranbourne.

AVP has also identified that the possible solutions set out above are expected to lead to fault level increases. Potential strategies to mitigate the fault level increases include:

- opening Bus ties at affected terminal stations, to operate certain stations in a split-bus arrangement.
- Rearranging the network to tie stations together via different lines.

- Installing fault level mitigation equipment such as series or neutral earth reactors/resistors.
- Replacing low fault current rated assets with higher capacity assets.

These fault level mitigation strategies have been included as components of the credible options set out below. The specific fault level mitigation action that would be adopted will be considered in more detail as part of the PADR and PACR assessments, which will also allow AVP to further refine the indicative fault level mitigation cost estimates included in this PSCR.

3.2 Network options

This section describes the two credible network options that AVP has identified to meet the identified need using the process and considerations set out above. It also outlines seven other network options that have been considered but will not be progressed to the next stage of the RIT-T process as they are not considered to meet the identified need from a technical or commercial perspective[24].

The options, including their costs and optimal timing, will be refined at the PADR stage based on further investigations. At the PADR stage, AVP intends to further investigate:

- Any practicality issues, such as site-specific constraints.
- Combinations of network and non-network solutions to determine the option or hybrid option that maximises net market benefit for consumers.
- The potential impact that a change in status of currently uncommitted connection applications for generation and storage in the metropolitan Melbourne area may have on the identified need being addressed by this RIT-T.

3.2.1 Option 1 – additional transformation at Rowville

Option 1 involves establishing additional 500/220 kV transformation at Rowville Terminal Station.

The Rowville 500/220 kV A1 transformer is responsible for transferring supply from the 500 kV lines from the Latrobe Valley into supply at 220 kV for the eastern metropolitan Melbourne terminal stations connected to the Rowville No. 3-4 220 kV bus group. This includes supplying the terminal stations at Heatherton, Malvern, Ringwood, Springvale and Templestowe, and for some supply to Thomastown. Following reconfiguration of the network to 'modified parallel mode' operation, there is still forecast loading beyond the Rowville 500/220 kV A1 transformer's capacity. This option proposes the installation of an additional transformer at Rowville to address this forecast loading issue.

Further, AVP has identified that VNI West project works which address overloading on the existing VNI East circuits, including the Eildon - Thomastown 220kV circuit, will assist in resolving the thermal limitations on the Eildon – Thomastown 220 kV line. These works involve the installation of modular power flow controllers or other equipment to divert power flow away from Eildon – Thomastown 220 kV line and onto the parallel South Morang – Dederang 330 kV circuits. Under the VNI West project, these works are currently anticipated to be completed by

[24] As per clause 5.15.2(a) of the NER.

December 2028[25]. Therefore, Option 1 proposes bringing forward those works to be completed prior to summer 2028/29.

Fault level increases are expected to occur with this option because installing an additional transformer will reduce the impedance of the network and thereby increase fault currents. AVP has included an estimate of fault level mitigation works within the components for Option 1. This cost estimate has been developed based on the assumption that site equipment is replaced, which is likely to be the cheapest solution to increase the fault current rating. The precise nature of the works that will be undertaken to mitigate fault level increases will be refined ahead of the PADR. Alternative fault mitigation options, such as line cut-ins and opening bus ties to operate certain stations in a split bus configuration, will also be considered, with the lowest cost option to be adopted.

The components of Option 1 are summarised in Table 4.

Table 4 Option 1 capital cost components

Option 1 component	Element/s of identified need	Cost estimate ($ million, real 2024)
Bring forward the component of the VNI West project which addresses overloading on the existing VNI East circuits, including the Eildon - Thomastown 220kV circuit (power flow controllers or alternative)	Eildon – Thomastown 220 kV line loading forecast to exceed its N (continuous) rating	3.5
Install third 500/220 kV transformer at Rowville to back up the A1 transformer providing supply to the Rowville No. 3-4 220 kV bus group	Rowville 500/220 kV A1 transformer loading forecast to exceed its N (continuous) rating For contingent loss of the Rowville 500/220 kV A1 transformer, Ringwood – Thomastown and Rowville – Yallourn 220 kV lines are forecast to exceed their short-term ratings	76.4
Equipment replacements at stations that have fault level exceedances – expected to be Keilor and Rowville 220 kV assets and Templestowe and Thomastown 66 kV assets	Fault level mitigation	41.1
Total		**121[A]**

A. Total includes known and unknown risk allowances of approximately 25.9

At this stage AVP estimates the annual operating and maintenance expenditure for Option 1 to be 1% of the total capex of network components, which is aligned with the 2023 *Transmission Expansion Options Report*[26].

Option 1 is expected to address the identified need by increasing the network limit in the eastern metropolitan Melbourne area above that required to maintain reliable and secure supply under 10% POE demand forecasts beyond the 10-year planning horizon. The benefits associated with Option 1 will be assessed in detail as part of the PADR.

[25] For more information on the VNI West program, see https://www.aemo.com.au/initiatives/major-programs/vni-west. The December 2029 date for capacity release of VNI West was sourced from the August 2024 publication on AEMO transmission augmentation information webpage, see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information

[26] Section 5.3 discusses the Transmission Cost Database (TCD), which was updated as part of the 2023 *Transmission Expansion Options Report*. At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

3.2.2 Option 2 – new transformer at Cranbourne

Option 2 involves transferring the existing Rowville 500/220 kV A2 transformer from the No. 1-2 220 kV bus group to the No.3-4 220 kV bus group at Rowville, and installing a new 500/220 kV transformer at Cranbourne to ensure secure supply is maintained for the Rowville No. 1-2 220 kV bus group.

Transferring the Rowville 500/220 kV A2 transformer to the Rowville No.3-4 220 kV bus group will address the thermal limitation on the Rowville 500/220 kV A1 transformer under system normal conditions and the thermal limitations on 220 kV lines for the contingent loss of the Rowville 500/220 kV A1 transformer. Installing the new transformer at Cranbourne, which will then supply power to the Rowville No. 1-2 220 kV bus group, will replace the lost capacity on the Rowville No. 1-2 220 kV bus group resulting from the transfer of the Rowville 500/220 kV A2 transformer to the alternative bus group.

In a similar manner to Option 1, Option 2 also includes bringing forward components of the VNI West project to address Eildon – Thomastown 220 kV limitations to be completed prior to summer 2028/29.

As for Option 1, Option 2 also includes an estimate of works required to mitigate fault level increases, and similarly assumes the equipment replacements will be the lowest cost option. There is an estimated $1.9 million difference in the cost of these works between the two options resulting from the different transformer locations impacting network impedances, fault current increases and expected equipment replacements differently.

The components of Option 2 are summarised in Table 5.

Table 5 Option 2 capital components

Option 2 component	Element/s of identified need	Cost estimate ($ million, real 2024)
Bring forward the component of the VNI West project which addresses overloading on the existing VNI East circuits, including the Eildon - Thomastown 220kV circuit (power flow controllers or alternative)	Eildon – Thomastown 220 kV line loading forecast to exceed its N (continuous) rating	3.5
Transfer the Rowville 500/220 kV A2 transformer to the Rowville No. 3-4 220 kV bus group to back up the Rowville 500/220 kV A1 transformer	Rowville 500/220 kV A1 transformer is forecast to exceed its system normal continuous rating For the contingent loss of Rowville 500/220 kV A1 transformer, Ringwood – Thomastown and Rowville – Yallourn 220 kV lines are forecast to exceed their short-term rating	0
Install a second 500/220 kV transformer at Cranbourne to provide backup to the existing transformer and to provide supply to the Rowville No. 1-2 220 kV bus group	Rowville 500/220 kV A1 transformer is forecast to exceed its system normal continuous rating For the contingent loss of Rowville 500/220 kV A1 transformer, the Ringwood – Thomastown and Rowville – Yallourn 220 kV lines are forecast to exceed their N-1 short-term rating	76.4
Equipment replacements at stations that have fault level exceedances – expected to be Rowville, South Morang and Thomastown 220 kV assets	Fault level mitigation	43.0

Option 2 component	Element/s of identified need	Cost estimate ($ million, real 2024)
Total		**122.9[A]**

A. Total includes known and unknown risk allowances of approximately 25.4

At this stage AVP estimates the annual operating expenditure for Option 2 to be 1% of the total capex of network components, which is aligned with the 2023 *Transmission Expansion Options Report*[27].

Option 2 is expected to address the identified need by increasing the network limit in the eastern metropolitan Melbourne area above that required to maintain reliable and secure supply under 10% POE demand forecasts beyond the 10-year planning horizon. The benefits associated with Option 2 will be assessed in detail as part of the PADR.

The base case is discussed in Section 5.1 and further details regarding AVP's approach to estimating costs, and how AVP intends to estimate costs at the PADR stage, are detailed in Section 5.3.

3.2.3 Indicative construction time and earliest possible commission dates

Table 6 sets out the estimated construction time and earliest possible commissioning date for each option, based on AVP's observations and experience in similar projects. AVP will undertake further analysis as part of the PADR to determine the optimal commissioning dates, based on economic timing, for each option and its solution components, which may result in changes to the information presented in Table 6.

Table 6 Indicative construction timelines and potential commissioning dates (task complete by dates)

Task description	New transformer	Fault mitigation works	VNI West project components which address Eildon-Thomastown 220kV line limitations
Regulatory investment test process	Q4-2024 to Q3-2025		
Contract negotiation	Q4-2025 to Q4-2026		
Design, approvals and long lead procurement	Q1-2027 to Q2-2029	Q1-2027 to Q4-2028	Q4-2026 to Q3-2027
Construction	Q2-2029 to Q2-2030	Q1-2029 to Q3-2029	Q4-2027 to Q1-2028
Commissioning	Q3-2030 to Q2-2031	Q4-2029 to Q2-2030	Q2-2028

3.2.4 Options considered but not progressed

Table 7 summarises the network options that AVP considered during the feasibility studies undertaken for this RIT-T but have not been included in this PSCR, together with the reasons why AVP considers those options not to be commercially feasible and/or technically feasible[28]. For each of the augmentations listed in the table below it was assumed that the following works would still be required (as is the case with the credible options):

- Bring forward the component of the VNI West project which addresses overloading on the existing VNI East circuits, including the Eildon - Thomastown 220kV circuit (power flow controllers or alternative)

[27] Section 5.3 discusses the Transmission Cost Database (TCD), which was updated as part of the 2023 *Transmission Expansion Options Report*. At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[28] As per clause 5.15.2(a) of the NER.

- Equipment replacements at stations forecast to have fault level exceedances.

Table 7 Options considered but not progressed

Description	Reason(s) for not progressing
Complete Option 1 or Option 2 with a different size transformer	The 1,000 megavolt-amperes (MVA) transformer size has been considered optimal for both Option 1 and Option 2 due to this size matching the already existing transformers at Cranbourne and Rowville. Installing a smaller size transformer would result in it reaching its rating prior to the existing transformer, reducing the utilisation of the existing equipment and the expected market benefits. Similarly, a larger size transformer could not be fully utilised as the existing transformer would become the limiting equipment, resulting in the larger transformer adding additional cost with no additional expected market benefits. Therefore, completing Option 1 or Option 2 with a different size transformer is not considered. Additionally, aligning common size transformers across the Victorian Declared Shared Network reduces the need for multiple spare asset holding to cover the unlikely but possible failure of a transformer.
Install extra 500/220kV transformer at Rowville on hot standby to switch in for the loss of either transformer	This option would reduce the fault level mitigation that is required when compared with Option 1 or Option 2, due to it not impacting network impedances. However, due to the system normal rating being reached on the Rowville 500/220 kV A1 transformer, this option is not considered capable of meeting the identified need.
Install a second Rowville – Thomastown circuit (making it a double circuit line)	This option would resolve the limitation on the Ringwood – Thomastown 220 kV line for the contingent loss of the Rowville 500/220 kV A1 transformer but would not resolve the system normal continuous rating limitation on the Rowville 500/220 kV A1 transformer, and is therefore not capable of meeting the identified need on its own. The option is not considered commercially feasible to be included with the Option 1 or Option 2 augmentations because both those options mitigate the Ringwood – Thomastown 220 kV line limitation under contingency events.
Establish a new 500 kV terminal station at Templestowe or Ringwood by cutting into the existing South Morang – Rowville No.3 5,000 kV line	While this option is considered technically feasible, it is not considered commercially feasible. Specifically, it is expected to cost significantly more than Option 1 and Option 2 (approximately $200 million to develop the new terminal station plus any costs for fault level mitigation works) and is not expected to provide sufficient additional expected market benefits to cover the higher cost.
Connecting the 220 kV Rowville No. 1-2 and No. 3-4 buses by a tie-line	This option was considered not technically feasible as it would result in the fault current at Rowville exceeding the planning limits set out in section 9.3A of the NER for the metropolitan Melbourne area (40.0 kilo-amperes (kA) at 220 kV).
Install two additional 500/220 kV transformers, one at Rowville connected to the No.1-2 bus group and another at either Rowville of Cranbourne connecting to the No. 3-4 bus group	This option was considered not commercially feasible as it provided only a marginal increase in capacity (~300 MW) with significant additional cost ($76.4 million each plus costs for any fault level mitigation works) when compared to Option 1 and Option 2.
Develop a new 220 kV line between Hazelwood Power Station and Yallourn Power Station using the existing easement	It was observed that although connecting a third 220 kV line from Hazelwood to Yallourn increasing the line rating between Hazelwood to Yallourn, it reduced the impedance of the 220 kV corridor so much that it resulted in loading on the Hazelwood Terminal Station transformers exceeding their capacity. This impacted the sharing between the 220 kV and 500 kV lines in such a way that the 500 kV share was reduced, resulting in an overall lower transfer capacity from the Latrobe Valley into the eastern metropolitan Melbourne area. Due to the reduced capacity, this option on its own was not considered technically feasible to meet the identified need. When combined with the augmentations in Option 1 or Option 2, the same result of reduced transfer capacity from Latrobe Valley into the eastern metropolitan Melbourne area was observed. As a result, combining this option with Option 1 or Option 2 wasnot considered commercially feasible to meet the identified need under this RIT-T as it would increase the cost of the options and reduce the expected market benefits.

3.3 Non-network options

3.3.1 Description of credible non-network options

A suite of non-network options may be capable of meeting or partially meeting the identified need, including:

- Demand response and decentralised storage.
- Grid-connected generators and BESS.

While AVP expects that the extent to which forecast demand exceeds network limits could not be fully addressed by a non-network option on its own, it is considered possible for a non-network solution to defer the need for network investment by addressing the identified need during the early years of the assessment period.

As such, AVP will carefully review all submissions regarding possible non-network options and assess how combinations of network and non-network components could form credible options as part of the PADR.

Demand response and decentralised storage

The demand level can be reduced during high demand periods by encouraging and promoting demand response, load shifting, coordinated discharging of decentralised storage, and contracted discharging of grid-scale storage. It is conceptually possible to alter the demand during high demand periods, when network capacity is expected to be exceeded, by utilising flexible loads such as hot water and pool pumps or certain industrial loads in addition to emerging flexible loads such as EVs and distributed storage.

An effective load shift at times of high demand is an alternative to increasing the network limit in addressing the identified need. AVP is seeking information from potential providers that may have sufficient capability to decrease load on the network, such as large pump loads or batteries, during periods of high demand. See Section 3.3.2 below for details of the technical characteristics required of a non-network solution, including the times at which the solution would need to reduce load, and Section 3.3.3 for details of the information that AVP is seeking from potential non-network solution providers.

Grid connected generators and BESS

As described in Section 2.2, the earliest network asset reaching its rated capacity in the eastern metropolitan Melbourne network is the thermal limitation of the Ringwood – Thomastown 220 kV line for the contingent loss of the Rowville 500/220 kV A1 transformer. A generator or BESS providing supply into the Rowville No. 3-4 220 kV bus group, to obtain sufficient net peak demand reduction, can manage the load at risk and defer the network option of installing a new 500/220 kV transformer. Therefore, projects that connect into the Rowville, Ringwood, Templestowe, Malvern, Springvale, or Heatherton terminal stations have potential to defer the transformer component of the network options for several years.

AVP is seeking submissions from generator or BESS proponents with a connection in an appropriate location who have the potential to defer the identified need and who are a potential proponent of a non-network solution. See Section 3.3.2 below for details of the technical characteristics required of a non-network solution, including the times at which the solution would need to reduce load, and Section 3.3.3 for details of the information that AVP is seeking from potential non-network solution providers.

3.3.2 Technical characteristics required of a network or non-network option

Table 8 summarises the size, operating profile and timing requirements for non-network solutions connected at the Rowville No. 3-4 220 kV bus group, which is the optimal location for a non-network solution. Non-network solutions at other locations are less effective at relieving the eastern metropolitan Melbourne network limitations and therefore require a larger size MW support level. The operating profile and timing requirements will not change at different locations.

AVP encourages applications for non-network solutions at other nearby locations, which will also be reviewed for their ability to meet the identified need. Additional sites that are effective at relieving the eastern metropolitan Melbourne network limitations include, but are not limited to, Ringwood, Templestowe, Malvern, Springvale, or Heatherton.

Table 8 Summary of technical requirements for non-network solutions connecting at the Rowville No. 3-4 220 kV bus group

Financial year	Size (MW)[A]	Time of day[B]	Period of availability	Maximum consecutive hours of dispatch[C]
2024-25	70	Evening Peak	December to February	1
2025-26	100	Evening peak	December to February	2.5
2026-27	120	Evening peak	December to February	3
2027-28	140	Evening peak	December to February	3.5
2028-29	350	Evening peak	December to February	4
2029-30	400	Evening peak	December to February	4.5
2030-31	550	Evening peak	December to February	4.5
2031-32	650	Evening peak	December to February	4.5
2032-33	800	Evening peak	December to February	5.5
2033-34	950	Evening peak	December to February	5.5

A. MW power injection required at the Rowville No. 3-4 220 kV bus group to resolve eastern metropolitan Melbourne network limitations based on a 10% POE maximum demand forecast.
B. Evening peak refers to the hours between 3.00 pm and 9.00 pm.
C. Maximum consecutive duration where network support would be required based on 10% POE demand forecast, noting that additional smaller durations may also occur in any given year. For example, the table shows at that a 350 MW/1,400 megawatt hour (MWh) BESS connected at the Rowville No. 3-4 220 kV bus group would be required to fully meet the identified need in 2028-29.

3.3.3 Information to be provided by proponents of a non-network option

The above is not an exhaustive list of potential non-network services. AVP welcomes proponents of potential non-network solutions to make submissions on any non-market ancillary services (NMAS) they can provide to address the identified need outlined in this PSCR. Submissions should include details on:

- Organisational information.
- Relevant experience.
- Details of the service, including size (MW and megawatt hour (MWh) capacities), connection point location and any restrictions on how often and when the service can be called upon.
- Cost of service, separating capital and operational expenditure.
- Confirmation of timelines in providing the service.

- Details of the proposed solutions commitment status against the RIT-T glossary definitions of Committed Project and Anticipated Project[29].

3.4 Material inter-network impact

AVP considered whether the credible options are expected to have a material inter-regional impact[30].

A 'material inter-network impact' is defined in the NER[31] as:

> *a material impact on another Transmission Network Service Provider's network, which may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network.*

In its Inter-Network Test Guidelines[32], AEMO suggests a screening test to indicate whether or not a transmission augmentation has a material inter-network impact. Applying this screening test, no material inter-network impact can be assumed if the transmission augmentation satisfies any of the following:

- A decrease in power transfer capability between transmission networks or in another transmission network service provider's (TNSP's) network of no more than the minimum of 3% of the maximum transfer capability and 50 MW.
- An increase in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW.
- An increase in fault level by less than 10 megavolt amperes (MVA) at any substation in another TNSP's network.
- The investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

AVP considers that the credible options presented in this PSCR satisfy these conditions, as they will only have localised effects around the eastern metropolitan Melbourne region of Victoria. By reference to AEMO's screening criteria, there is no material inter-network impact associated with any of the credible options identified.

3.5 Land, environmental and social considerations

Section 3.2 of this PSCR outlined cost factors and indicative construction and commissioning timeframes for network options. It should be noted that information presented in the PSCR is at a point in time and is subject to change.

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[29] AER, Regulatory Investment Test for Transmission, August 2020, p.13, at https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

[30] As per clause 5.16.4(b)(6)(ii) of the NER.

[31] See Chapter 10 of the NER.

[32] See AEMO, *Inter-Network Test Guidelines*, October 2022.

AVP intends to investigate and consider the potential impacts of constructing and operating credible options identified in this PSCR. Priority actions AVP plans to commence now and into the development of the PADR include:

- Engaging with landholders of nominated host brownfield terminal station locations to verify land availability to construct and install credible options and any required connection arrangement/s.
- Completing desktop analysis to better understand matters[33] that may have the potential to cause significant impact to communities or the environment in constructing or operating credible options.
- Preparing a stakeholder engagement plan to be enacted when the preferred option is identified.
- Documenting likely planning and environment approval obligations.
- Considering any issue/s arising from stakeholder feedback presented in submissions to the PSCR, including potential non-network solutions that may contribute to meeting the identified need presented in Section 2.2.

AVP plans to develop the PADR with updated information about land assembly options, environment, planning and social constraints for credible options. This information will contribute to refinements to relevant cost factors and time allowances for obtaining planning and environment approval prior to the construction of credible options.

[33] As a guide, AVP plans to undertake desktop investigations into potential for impacts to vegetation, land use planning, cultural heritage, historic heritage and any other matter that may arise.

4 Materiality of market benefits

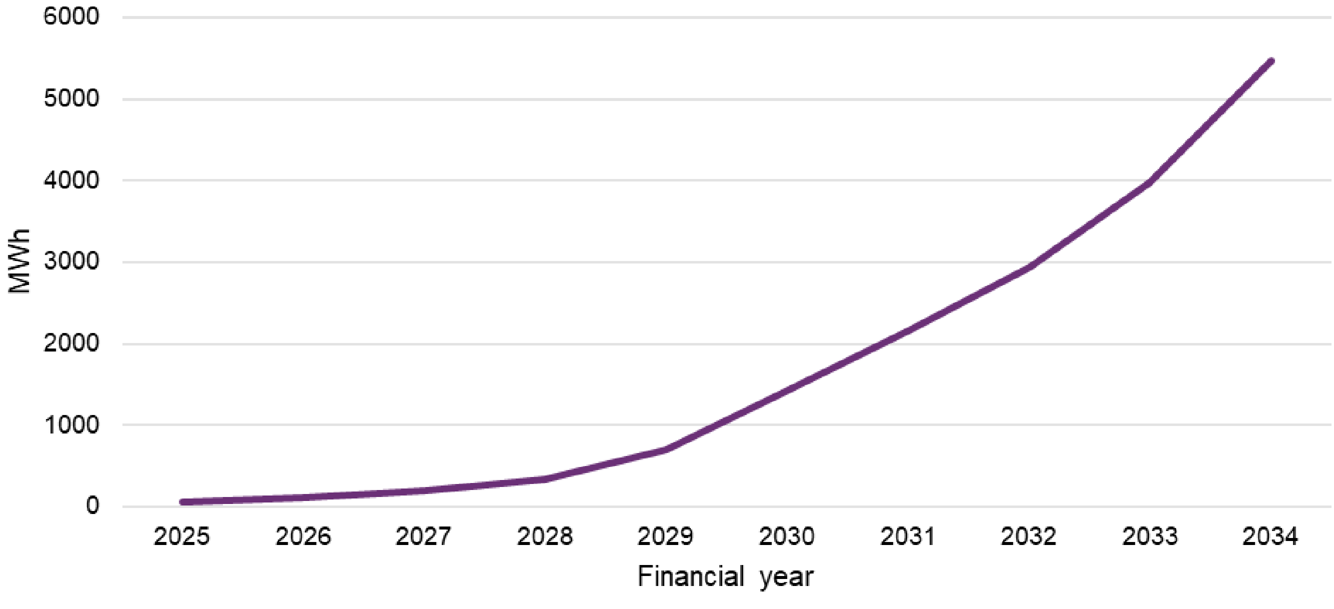
AVP notes the NER requirement that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the RIT-T proponent can demonstrate that:

- a particular class (or classes) of market benefit is unlikely to be material in relation to the RIT-T assessment for a specific option, or
- the estimated cost of undertaking the analysis to quantify that benefit would likely be disproportionate to the "scale, size and potential benefits of each credible option being considered in the report".

Material class of market benefits: involuntary load curtailment

AVP considers that changes in involuntary load curtailment will be material to the RIT-T assessment. Significant involuntary load shedding is expected to occur under the base case because demand is expected to exceed the capacity of the eastern metropolitan Melbourne network. Figure 4 provides an indicative estimate of forecast involuntary load shedding under the base case.

Figure 4 Indicative estimate of forecast expected unserved energy under the base case, 2024-25 to 2033-34 (MWh)



As part of the PADR assessment, AVP intends to estimate the value of avoided EUSE under each of the credible options, compared to the base case. This will be valued using the Value of Customer Reliability (VCR) published by the Australian Energy Regulator (AER), as described in Section 5.5.

Classes of market benefit that may be material: wholesale market benefits

AVP will further investigate whether wholesale market benefits are likely to be material to the RIT-T assessment. This investigation will consider the following categories of market benefits:

- Changes in fuel consumption arising through different patterns of generation dispatch.
- Changes in Australian greenhouse gas emissions.
- Changes in voluntary load curtailment.
- Changes in costs for parties other than AVP.

AVP expects that the options may have some impact on NEM dispatch. However, it is not clear at this stage whether that impact will be material to the outcome of this RIT-T. A proportionality and materiality assessment will be undertaken ahead of the PADR to determine whether wholesale market modelling, using software such as PLEXOS, will be valuable for this RIT-T. This assessment will take account of submissions to the PSCR, particularly regarding any non-network options and our assessment of credible options including a non-network component.

Depending on the expected materiality of any wholesale market benefits, a proportionate approach may be taken to estimating them (rather than full wholesale market modelling across all ISP scenarios). However, as discussed in Section 5.6 below, AVP will test the sensitivity of net present value (NPV) results to different demand scenarios in the PADR, regardless of whether wholesale market modelling is undertaken.

Other classes of market benefits not likely to be material

AVP considers that the following classes of market benefits are not material to the RIT-T assessment for any of the credible options:

- **Differences in timing of expenditure**, as the credible options are not expected to impact the timing of unrelated network expenditure.
- **Changes in network losses**, as any network losses outside of those that inherently captured through the change in transmission capacity representing the benefit of each credible option are not expected to be material to the ranking of options.
- **Option value**, as at this stage, AVP does not expect there to be any option value outside of anything captured in the scenario analysis (to the extent that timing or scope of options components, including any non-network components, varies across reasonable scenarios). AVP also notes that a significant modelling exercise would be required to estimate option value benefits, and that such an exercise would be disproportionate to the potential additional benefits for this RIT-T.
- **Changes in ancillary services costs**, as the estimated cost of undertaking the analysis to quantify these changes would likely be disproportionate to the scale of the credible options being considered in this report.
- **Competition benefits**, because the estimated cost of undertaking the analysis to quantify competition benefits would likely be disproportionate to the scale of the credible options being considered in this report.

5 Overview of proposed assessment approach

This section sets out AVP's proposed assessment approach to credible options in the PADR.

It also provides more detail in Section 5.1 on the base case for the assessment of these options (the 'do nothing' reference point that all option portfolios are assessed against under the RIT-T).

5.1 The base case

Consistent with the RIT-T requirements, AVP intends to compare the costs and benefits of each portfolio option to a 'do nothing' base case for each scenario. The base case is the projected case if no credible option investment is taken[34]:

> *"The base case is where the RIT-T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. 'BAU activities' are ongoing, economically prudent activities that occur in absence of a credible option being implemented"*

For this RIT-T, business as usual (BAU) activities are forecast to lead to significant unserved energy. While these are not situations that AVP plans to encounter, and this RIT-T has been initiated in order to avoid it, it is plausible that a small amount of load shedding might be required in periods prior to an investment option becoming economically feasible. The RIT-T assessment is required under the NER to consider this base case as a common point of reference when estimating the net benefits of each credible option and, for a market benefit driven RIT-T, the base case is also considered a credible option.

In this RIT-T the base case includes modified parallel operation of the Latrobe Valley network, as this investment is currently in progress and is separate to the identified need in this RIT-T, as discussed in Section 2.1.

Under the base case, the network supply capacity in the eastern metropolitan Melbourne area will remain at approximately 4,570 MW under peak demand conditions throughout the assessment period. Although retirement of YWPS in 2028 negatively impacts this network capacity limit, this impact is entirely offset by implementation of modified parallel mode operation (see Section 2.2) so, for the purpose of this RIT-T, a consistent network capacity limit of 4,570 MW has been applied.

5.2 Assessment parameters

AVP intends to adopt a 10-year assessment period from FY2024-25 to FY2033-34 for this RIT-T analysis. AVP considers this timeframe to be appropriate given the size and complexity of the proposed options and the increasing uncertainty associated with supply in eastern Victoria to support the energy transition from the mid-2030s.

[34] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, p. 22.

Where the capital components of the options considered have an asset life extending beyond the end of the assessment period, the NPV modelling will include a terminal value to capture the remaining functional asset life. This ensures that the capital cost of long-lived assets over the assessment period is appropriately captured, and that all assets have their costs assessed over a consistent period irrespective of type, technology or serviceable asset life. The terminal values will be calculated based on the undepreciated value of capital costs at the end of the analysis period and expected operating and maintenance cost for the remaining asset life.

A real, pre-tax discount rate of 7% will be adopted as the central assumption for the NPV analysis, consistent with AEMO's latest *Inputs, Assumptions and Scenarios Report* (IASR)[35]. The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. The PADR will therefore test the sensitivity of the results to a lower bound discount rate equal to the WACC (pre-tax, real) in the latest final decision by the AER for a transmission business in the NEM as of the date of the analysis. AVP will also adopt an upper bound discount rate of 10.5% (the upper bound in the latest IASR)[26].

5.3 Approach to estimating option costs

The capital costs quoted in this PSCR have been developed to a class 5B (+/- 50% accuracy) estimate using AEMO's latest Transmission Cost Database (TCD) and have been escalated to June 2024 dollar terms based on CPI[36]. The TCD is substantially based on the Association for Advancement of Cost Engineering (AACE) international classification system commonly used in many industries[37].

Desktop site assessments were undertaken to inform the likely build component for each option and, where relevant, the connection arrangement equipment costs have also been included. The cost of each option includes the following components:

- Project management.
- Engineering support.
- Equipment and services procurement.
- Installation.
- Commissioning and testing.
- Known and unknown risk allowances, in line with the TCD, which is presented as a proportion ($ million) of the total costs for credible options in Table 6 and Table 7 in Section 3.2 and is considered a contingency in line with AEMO's Mott MacDonald: Transmission Cost Database Update final report released in July 2023[38].

The TCD enables the selection of known and unknown risks for each build component to reflect the level of project complexity and risks that will or could arise during further development of credible options:

[35] AEMO, 2023 IASR, September 2023, p 123.

[36] AEMO, 2023 IASR, September 2023, pp 23-24; Transmission Cost Database version 4-0, March 2023.

[37] The approach taken in the TCD differs from the AACE system in two superficial ways – see: AEMO, *2023 Transmission Expansion Options Report*, September 2023, p 21.

[38] As referenced in AEMO Transmission Cost Database, Building Blocks Costs and Risk Factors Update Final Report, 24 July 2023 prepared by Mott MacDonald, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios/transmission-cost-database.

- Known risks:
  - Compulsory acquisition.
  - Cultural heritage.
  - Environmental offset risks.
  - Macroeconomic influences.
  - Market activity.
  - Geotechnical conditions.
  - Outage restrictions.
  - Weather delays.
- Unknown risks:
  - Productivity and labour cost.
  - Plant procurement costs.
  - Project overheads.
  - Scope and technology.

Known and unknown risks will be refined as AVP completes further investigations into the constructability and operation of each credible option. AVP notes that the estimates of fault level mitigation costs will be further refined as the RIT-T progresses because the precise nature of the works is not yet known.

AVP intends to further refine costs for credible options as the RIT-T progresses and plans to develop class 5A (+/-30% accuracy) estimates for the PADR using AEMO's latest TCD[39].

5.4 Estimation of market benefits

Section 4 explains that wholesale market benefits may be material for this RIT-T, and the need to undertake wholesale market modelling will be considered in preparing the PADR, in view of both the network and non-network options that are being considered.

If any wholesale electricity market benefits are expected to be materially different between options, AVP expects to undertake wholesale electricity market modelling to estimate them. However, if this is not the case, then AVP will likely apply a proportionate approach to estimating these benefits, which may include not estimating them at all where there is a strong case for them not affecting the ranking of the options, or whether the options have a positive net market benefit.

Changes in unserved energy is expected to be a key source of benefits for the options, so the sensitivity of the NPV results to the demand forecast adopted, and hence the EUSE, will be tested as part of this RIT-T.

[39] Transmission Cost Database version 4-0, March 2023.

5.5 Value of Customer reliability

AVP intends to value avoided unserved energy using the AER's most recent customer load-weighted state VCR for Victoria. The AER releases annual updates to its VCRs based on the Consumer Price Index (CPI) for that year, with the most recent adjustment being published in December 2023[40]. The latest IASR uses the 2023 update to the VCR with a customer load-weighted state value for Victoria of 48,152 per MWh. AVP intends to use the AER's 2024 updated VCR, which is expected to be published on 31 December 2024, for the PADR assessment. The updated VCR applies the CPI adjustments published on the AER website to the customer load-weighted state VCRs that were published by the AER in December 2019[41].

5.6 Reasonable scenarios

AVP intends to use the ISP scenarios and associated weightings if it determines that wholesale market modelling is necessary for this RIT-T (see Section 5.4).

However, if modelling each ISP scenario is determined to be disproportionate to scale, size and potential benefits of each credible options, AVP will adopt reasonable scenarios that vary based on the demand forecast. This may involve the demand breakdown set out in Table 9.

Table 9 Proposed parameters for scenarios in RIT-T assessment

Parameter	Low	Central	High
Weighting	30.4%	39.2%	30.4%
Demand forecast	Zero EUSE is assumed for low demand conditions	50% POE	10% POE
ISP scenario	*Step Change*		
Discount rate	7%		
VCR	$48,152/MWh[A]		
Network capital cost	Base estimate		
Operating and maintenance costs	Base estimate		

A. This is the 2023 value for VCR which will be escalated to the 2024 value for the PADR assessment as detailed in section 5.5

Initial analysis has determined that the risk of EUSE in the eastern metropolitan Melbourne network under 90% POE demand conditions is very low and the work required to model this scenario would be disproportionate to the potential benefits. Therefore, AVP intends to limit the studies to 10% POE and 50% POE demand forecasts only and assume the EUSE under 90% POE demand conditions is zero.

[40] At https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2019/update.

[41] See Table 5.22 at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf.

AVP intends to base the weightings for EUSE on analysis performed for the ESOO which found that weightings for 10% POE, 50% POE, and 90% POE of 30.4%, 39. 2%, and 30.4% respectively, are an appropriate approximation across the different years[42]. The intended approach is as follows:

- Determine EUSE in each financial year for each demand POE level.
- Assume the EUSE is zero in the 90% POE case.
- Weight the average EUSE across the three POE cases to determine the expected EUSE value.

If multiple ISP scenarios are modelled these will have weightings aligned to the ISP scenario weighting of 43% for *Step Change*, 42% for the similar *Progressive Change* and 15% for *Green Energy Exports*.

AVP intends to conduct sensitivity analysis to test the sensitivity of the results to the following parameters:

- Discount rate (see Section 5.2).
- Capital costs (+/- 30 per cent, in line with the expected accuracy of the costs at the PADR stage (that is, class 5A)).
- VCR +/- 30%.

AVP will review its approach to reasonable scenarios and sensitivities ahead of the PADR, taking into account any stakeholder responses to this PSCR.

[42] See Section 5.2.2 at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

6 Next steps

AVP welcomes written submissions on this PSCR, particularly in relation to non-network options, to be provided to AVP_RIT-T@aemo.com.au, with subject title 'Eastern Victoria Grid Reinforcement PSCR', by 5.00 pm on 7 February 2025.

Following conclusion of the PSCR consultation process, all submissions received will be published on AEMO's website. If you do not wish for your submission to be made public, please clearly stipulate this at the time of lodgement.

All feedback will be considered in preparing the PADR. AVP strongly encourages all interested non-network proponents to make submissions to the PSCR to ensure that a comprehensive suite of options is considered in the PADR to meet the identified need.

A1. Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PSCR with the requirements of the National Electricity Rules version 216.

Rules clause	Summary of requirements	Relevant section(s) in the PSCR
5.16.4(b)	A RIT-T proponent must prepare a PSCR, which must include:	-
	(1) a description of the identified need;	2
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	2.3
	(3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; and (iii) operating profile;	3.3
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan;	NA
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alternative transmission options, interconnectors, generation, system strength services, demand side management, market network services or other network options;	3
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefits are not likely to be material (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	3 and 3.5

In addition, the table below outlines a separate compliance checklist demonstrating compliance with the binding guidance in the latest AER RIT-T guidelines.

Guidelines section	Summary of the requirements	Relevant section(s) in the PSCR
3.5A.1	Where the estimated capital costs of the preferred option exceeds $100 million (as varied in accordance with a cost threshold determination), a RIT-T proponent must, in a RIT-T application: • outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T • for all credible options (including the preferred option), either – apply the cost estimate classification system published by the AACE, or – if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more	5.3

Guidelines section	Summary of the requirements	Relevant section(s) in the PSCR
	appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate.	
3.5A.2	For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T: • all key inputs and assumptions adopted in deriving the cost estimate • a breakdown of the main components of the cost estimate • the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) • the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied • the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance	5.3
3.9.4	If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: • the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and • how the level or quantum of the contingency allowance was determined.	3.2 and 5.4