REGIONAL VICTORIAN THERMAL CAPACITY UPGRADE RIT-T PROJECT ASSESSMENT CONCLUSION REPORT

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Executive summary

AEMO has prepared this Regulatory Investment Test for Transmission (RIT-T) to address emerging limitations in the Victorian regional transmission network.

Identified need

Electricity supply security for customers in the north-west of Victoria (also known as regional Victoria) may be at risk due to potential overload on the existing Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line under a combination of the following conditions:

- High ambient temperature leading to a 1-in-10-year maximum demand occurrence.
- Low wind speed affecting the ability of the transmission lines into Ballarat and Bendigo to transmit the required energy.
- Constrained import into Victoria across the Murraylink Interconnector due to limitations on South Australia’s Riverland network.
- Constrained import into Victoria across the New South Wales interconnectors.

While these events are unlikely, the consequence should they occur may result in the requirement to reduce demand by up to 251 MW in 2013–14.

Based on all available information, AEMO proposes the following three stage solution as the preferred option:

- Stage 1 - Install a wind monitoring facility on the Ballarat–Bendigo 220 kV line in 2015–16.
- Stage 2 - String a new line on the vacant side of the existing towers on the Moorabool–Ballarat No.2 220 kV line in 2017–18.
- Stage 3 - Replace the towers to up-rate the existing Ballarat–Bendigo 220 kV line to a maximum operating temperature of 82 ºC in 2019–20.

The total cost of this option, including operating costs, is estimated to be $126.2 million (in present value terms). The estimated capital cost of stages 1, 2 and 3 are $0.6 million, $27.8 million, and $77.2 million respectively. The lead time for stage 1 is expected to be one year and two months; for stage 2, three years and two months; and for stage 3, four years and nine months.

Stages 1, 2 and 3 are forecast to deliver a positive net market benefit of $317.4 million (in present value terms), commencing from the first year of operation (2015–16) over the assumed life of the assets (40 years).

Before the preferred option can be completed, involuntary load reduction under certain conditions may be required to maintain power system security.

Automatic control schemes have been implemented to reduce existing risk of pre-contingent load shedding. These schemes enable the use of higher short-term (5-minute) ratings on the Ballarat–Bendigo 220 kV line and Moorabool–Ballarat No.1 220 kV line.

Subsequent to the issue of the Project Assessment Draft Report (PADR), AEMO received proposals from EnerNoc, NovaPower, and Transmission Operations Australia (TOA) to minimise the potential load at risk in the form of demand management and embedded generation. AEMO has discussed the proposals with these entities but notes that it has insufficient information to consider these to be credible options at this time.

To maximise the net market benefit from the investment, AEMO proposes to commit to stages 1 and 2 of the preferred option. AEMO recommends that stage 3 be placed on hold, and that the need and timing for this stage be further assessed against recent proposals received from non-network service providers.

Next steps

If no dispute is raised under NER clause 5.16.5(a), AEMO will proceed with procuring services to implement stages 1 and 2 of the preferred option.

AEMO will undertake a further assessment to identify whether the proposals for demand management and embedded generation are justified as interim or longer-term solutions that could defer or replace the need for stage 3. If economically justified, AEMO may issue a Request for Information or an Invitation to Tender to procure this service from potential non-network service providers.

Changes from the PADR

Key changes to the Project Assessment Conclusion Report (PACR) include the following:

- AEMO recommends a construction outage window between April and October, which it found to have no load at risk when implementing the preferred option. This was assessed in response to the PADR submission from SP AusNet.
- A recall time of six hours is required to switch the Ballarat–Bendigo 220 kV line and Moorabool–Ballarat No.1 220 kV line back into service during the required outages for construction. This was assessed in response to the PADR submission from SP AusNet.
- AEMO found the augmentation outage market impact cost to be minimal when implementing the preferred option. Re-dispatch of generation is valued using the short-run marginal cost (SRMC) of generation, including a price on carbon. This was assessed in response to the PADR submission from SP AusNet.
- AEMO revised the estimated project lead time of ten credible network options (including the preferred option) to reflect the latest information from SP AusNet. This resulted in updated net market benefits for each credible network option. In addition, the net market benefit results for the sensitivity analysis on discount rates, capital costs, value of customer reliability, and scenario weightings were updated accordingly.
- AEMO proposes committing to implementation of stage 1 and 2 of the preferred option but recommends that stage 3 be placed on hold. AEMO recommends the need and timing for stage 3 be further assessed against recent proposals received from non-network service providers.

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1 Introduction

1.1 Overview

This Project Assessment Conclusion Report (PACR) has been prepared by the Australian Energy Market Operator (AEMO) under clause 5.16.4(t) of the National Electricity Rules (NER).

The PACR represents the final stage of a formal consultation process set out in the NER in relation to the Regional Victorian Thermal Capacity Regulatory Investment Test for Transmission (RIT-T).

The first stage of the RIT-T was the release of the Project Specification Consultation Report (PSCR). In April 2012, AEMO published a PSCR addressing limitation on the Moorabool–Ballarat No.1 220 kV line[1] and in August 2012 published a PSCR addressing limitation on the Ballarat–Bendigo 220 kV line.[2]

The second stage was the release of the Project Assessment Draft Report (PADR) in March 2013 addressing limitations on both lines.

This PACR evaluates both limitations together to identify investment options that maximise the net market benefit in the National Electricity Market (NEM).

This PACR:

- Describes the identified need that AEMO is seeking to address, namely supply security of customers in north-west Victoria. This is at risk due to potential overload on the existing Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line under a combination of weather and operational conditions.
- Describes the credible options AEMO has assessed to address the identified need.
- Summarises and responds to the submissions received on the PSCRs and PADR previously published.
- Quantifies costs (including a breakdown of operating and maintenance, and capital expenditure) and classes of material market benefits for each credible option, and describes the methodologies adopted by AEMO in quantifying these.
- Explains why differences in changes to ancillary services costs, option value, competition benefits, and changes in costs for parties other than AEMO are not material to this RIT-T assessment.
- Provides the results of the net present value (NPV) analysis for each credible option assessed, and includes explanations of the results.
- Identifies AEMO's preferred option for investment, including the technical characteristics, estimated project lead time, and noting that it satisfies the RIT-T.
- Concludes the RIT-T with the decision to progress the preferred option.

1.2 Background to the RIT-T

The purpose, principles, and procedures of the RIT-T are set out in NER clause 5.16 and the published RIT-T document by the Australian Energy Regulator (AER).

The purpose of the RIT-T is stated in NER clause 5.16.1(b):

> The purpose of the *regulatory investment test for transmission* is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the *market* (the preferred option). For the avoidance of

[1] Regional Victorian Thermal Capacity – Ballarat Supply – Project Specification Consultation Report, April 2012. http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Regional-Victorian-Thermal-Capacity-Upgrade.

[2] Regional Victorian Thermal Capacity – Bendigo Supply – Project Specification Consultation Report, August 2012. http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Regional-Victorian-Thermal-Capacity-Upgrade.

doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.

As part of the PADR and the PACR, the transmission network service provider (TNSP) must present the results of the RIT-T analysis. This analysis is based on quantifying various categories of costs and benefits arising in the NEM. Both positive and negative market impacts must be included.

Chapter 6 of this PACR provides a detailed description of the methodology underlying the RIT-T assessment.

Most importantly, AEMO's assessment considers the relative costs and benefits[3] of alternative options in order to identify the option that maximises the present value of net economic benefit to all those who produce, consume, and transport electricity in the market. As such, the materiality of assumptions underlying the cost and benefit quantification depends on the extent to which changes in those assumptions are expected to affect the ranking of the options assessed.

Variations in assumptions resulting in a change to the net market benefit value calculated for a particular option, but that leave the net benefit of that option unchanged relative to alternative options, are not considered as material in this RIT-T assessment.

1.3 Next steps

NER clause 5.16.5(a) states that any of a number of specified parties may dispute:

1. The application of the regulatory investment test for transmission;
2. The basis on which [AEMO] has classified the preferred option as being for reliability corrective action; or
3. [AEMO's] assessment regarding whether the preferred option will have a material inter-network impact, in accordance with any criteria for a material inter-network impact that are in force at the time of the preparation of the PACR.

It states that disputes must be raised with the AER by notice within 30 days of the publication date of this PACR; that is, by 9 November 2013. If a dispute is raised, the AER will review this PACR and make a determination in accordance with NER clause 5.16.(d). If the AER rejects the dispute, AEMO will either proceed with implementing the preferred option, or—if the AER requires amendments—AEMO will review this PACR.

If no dispute is raised in accordance with NER clause 5.16.5(a), AEMO will implement stage 1 and stage 2 of the preferred option.

AEMO will review whether the proposal for demand management, embedded generation, or a combination of the two may defer or replace the need for stage 3. If economically justified, AEMO may issue an Invitation to Tender to procure this service from potential non-network service providers.

1.3.1 Interim solutions

Prior to final practical completion of the preferred option, involuntary load reduction in the regional Victorian area may be required to maintain power system security. The amount of load reduction required depends on weather conditions (wind speed and ambient temperature) and power system operating conditions, including:

- Demand level and loading level on critical transmission lines.
- Import from South Australia via the Murraylink Interconnector.

[3] Note that different categories of market benefit may be positive or negative, for each option assessed.

- Import from New South Wales via the Buronga – Red Cliffs 220 kV line.
- Status of the 5-minute rating automatic load shedding schemes on the Moorabool–Ballarat No.1 220 kV line and Ballarat–Bendigo 220kV line.

With the existing 15-minute rating[4], the expected unserved energy (USE) is between 133 MWh and 594 MWh from 2013–14 to 2018–19 under a set of conservative power system conditions.

Historical maximum demand snapshots in the last four years show that relatively low ambient temperatures (maximum ambient temperature of 41 ºC) and high wind-speeds (above 2.3 m/s) have coincided with maximum demand days, resulting in higher line ratings than assumed in AEMO's assessment. (The assessment assumes a maximum ambient temperature of 45 ºC and wind speeds of 0.6 m/s for the Ballarat–Bendigo 220 kV line and 1 m/s for the Moorabool–Ballarat No.1 220 kV line.)

As a result of the higher line ratings, there has been no USE in the last four years.

Line ratings assumed for planning purposes are typically more conservative than those observed under actual conditions; this has resulted in the difference between the USE during the last four years and that forecast under AEMO's assessment.

However, AEMO considered that the magnitude of expected USE identified warrants investigation of an interim solution to manage the expected USE prior to practical completion of the preferred option.

AEMO recently received proposals from EnerNoc, NovaPower, and Transmission Operations Australia (TOA) on possible interim solutions to minimise the potential USE by using demand management and embedded generation. AEMO has discussed these proposals with all three entities but notes that it has insufficient information to consider these to be credible options at this time.

AEMO will undertake a further assessment to identify whether the non-network options would be justified as interim or longer term solutions that could defer or replace the need for stage 3. If economically justified, AEMO may issue a Request for Information or an Invitation to Tender to procure this service from potential non-network service providers.

Further details in relation to this project can be obtained from:

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4 With existing 5-minute rating with automatic load shedding schemes armed, the expected USE can be reduced from 570 MWh to 356 MWh in 2013–14.

2 Shared network planning criteria

AEMO undertakes shared network planning in Victoria on the basis that any project must maximise the net present value of market benefits, in accordance with the Regulatory Investment Test for Transmission (RIT-T).

In applying a probabilistic approach to shared network planning, AEMO does not plan the network to provide 100% reliability after a single credible contingency. Instead, AEMO accounts for the probability of an event's occurrence and determines an "expected value" of the network limitations using the value of customer reliability (VCR) of $61,950 per MWh (in 2013–14 Australian dollars). The expected value is then compared with the total cost of the network options to determine whether the project will proceed.

A project will only proceed if:

- Market benefits of the project exceed the project cost.
- The project maximises net market benefits compared with alternative credible options.

In applying a probabilistic approach, AEMO also considers the need to maintain the system in both a satisfactory and a secure operating state, as required by the National Electricity Rules (NER).

AEMO's planning adopts a 15-minute short-term rating for critical transmission lines based on the response time required after a contingency to facilitate manual intervention.

Shorter timeframes are used in real-time operations as temporary measures to manage limitations until augmentations are economically justified and implemented. This only occurs if automatic control schemes are designed and implemented to respond after a contingency.

3 Identified need

3.1 Background

AEMO's 2011, 2012 and 2013 Victorian Annual Planning Reports[5,6,7] (VAPR) and 2011 and 2012 National Transmission Network Development Plans[8,9] (NTNDP) identified that action will be required to prevent loading of the Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line beyond their thermal capability due to continued demand growth in regional Victoria.

The 2011 VAPR[5] highlighted the possibility of positive net market benefits by increasing supply capability to regional Victoria; this triggered a detailed assessment.

To further investigate the costs associated with regional Victorian thermal limitations and the benefits of taking action to mitigate reaching these limitations, AEMO commenced a Regulatory Investment Test for Transmission (RIT-T).

In April 2012, AEMO published the first stage of the RIT-T— the Project Specification Consultation Report (PSCR)—addressing limitations on the Moorabool–Ballarat No.1 220 kV line. One submission was received, from ATA/EnerNOC.

In August 2012, AEMO published the PSCR addressing limitations on the Ballarat–Bendigo 220 kV line. No submission was received.

In March 2013, AEMO published the Project Assessment Draft Report (PADR) addressing limitations on both lines. One submission was received, from SP AusNet.

AEMO has proceeded with this RIT-T assessment on the basis that:

- Although the 2013 National Electricity Forecasting Report[10] (NEFR) demand forecasts show that overall Victorian demand growth has reduced compared to the 2012 NEFR[11] forecasts used in the PADR, AEMO does not expect this to affect the augmentation requirement identified in this PACR.
- The cost-benefit assessment of each option considered was based on robust and realistic assumptions.

3.2 Description of identified need

3.2.1 Overview

The Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat 220 kV lines form one of the key supply routes into regional Victoria and South Australia's Riverland area (via the Murraylink high voltage direct current (HVDC) Interconnector at Red Cliffs Terminal Station).

Regional Victoria includes load at the Ballarat, Bendigo, Fosterville, Glenrowan, Horsham, Kerang, Red Cliffs, Shepparton, and Wemen terminal stations and is supplied from:

- The 220 kV system via two 500/220 kV transformers at Moorabool Terminal Station.

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5 AEMO. 2011 Victorian Annual Planning Report. Available: http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2011-Victorian-Annual-Planning-.Report/~/media/Files/Other/planning/vapr2012/VAPR2011/documents/VAPR2011%20pdf.ashx.

6 AEMO. 2012 Victorian Annual Planning Report. Available: http://aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/2012_Victorian_Annual_Planning_Report.

7 AEMO. 2013 Victorian Annual Planning Report. Available: http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/VAPR2013/Victorian_Annual_Planning_Report_2013_v2.ashx.

8 AEMO. 2011 National Transmission Network Development Plan. Available: http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2011-National-Transmission-Network-Development-Plan.

9 AEMO. 2012 National Transmission Network Development Plan. Available: http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/2011-National-Transmission-Network-Development-Plan.

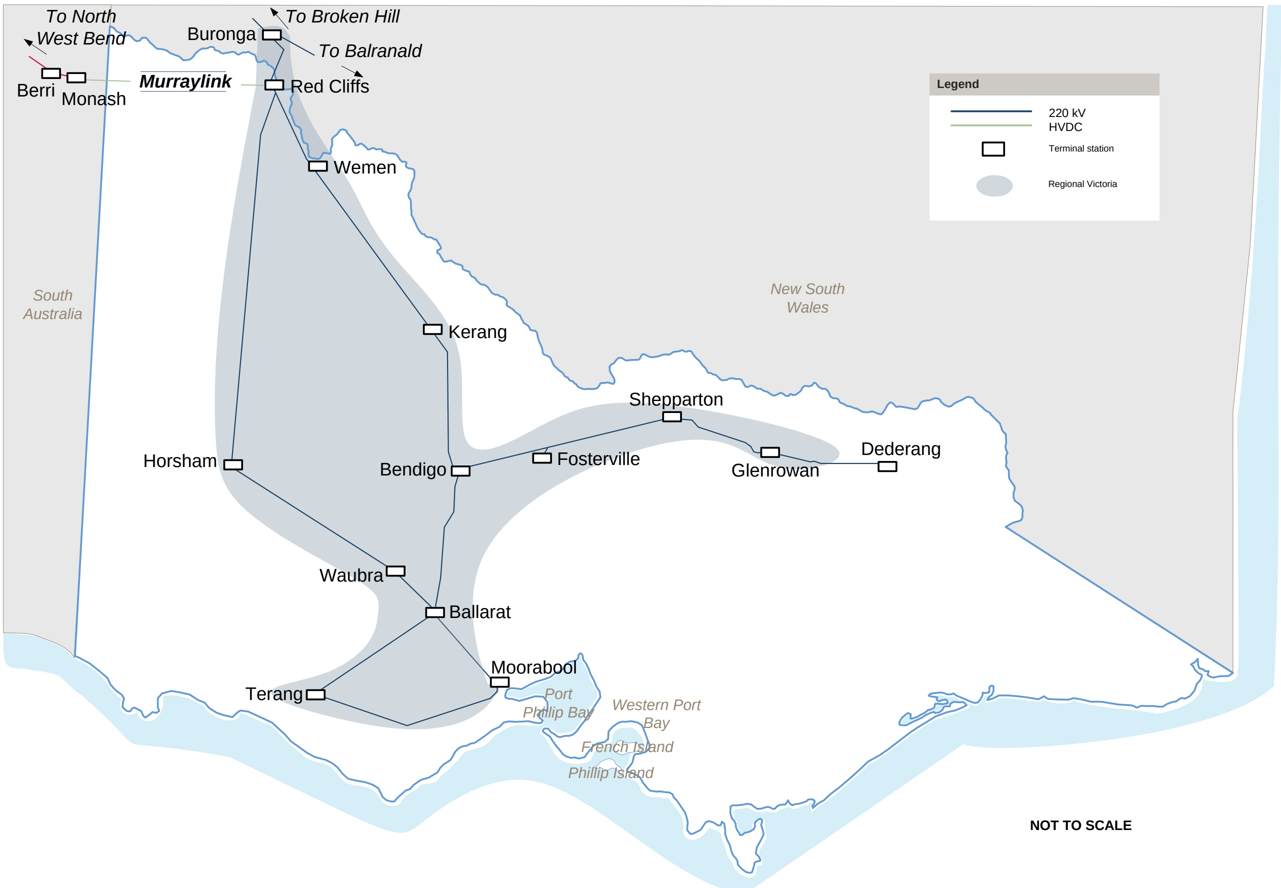
10 AEMO. 2013 National Electricity Forecasting Report. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013.

11 AEMO. 2012 National Electricity Forecasting Report. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012.

- The 220 kV system via three 330/220 kV transformers at Dederang Terminal Station.
- The NSW–VIC Interconnector (Buronga – Red Cliffs 220 kV line) at Red Cliffs Terminal Station.
- The VIC–SA Murraylink Interconnector at Red Cliffs Terminal Station.

Figure 1 is a geographical representation of the terminal stations affected by the forecast network limitations on the Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line.

Figure 1 – Geographical representation of terminal stations affected by the forecast network limitations



3.2.2 Interaction with Murraylink Interconnector

Transmission limitations in regional Victoria have a major influence on Murraylink Interconnector capability between Red Cliffs Terminal Station in Victoria and Monash Substation in South Australia. Murraylink's ability to transfer power between Victoria and South Australia is limited by the following factors:

- The design capability of the Murraylink Interconnector (nominal ± 220 MW).
- The transmission network capability in regional Victoria and South Australia's Riverland region.
- The availability of surplus generating capacity in the exporting region.
- The status of various runback control schemes.

A number of Murraylink runback schemes have been implemented to manage network limitations in Victoria and South Australia. These are outlined in Appendix A.

The Very Fast Runback Scheme (VFRB) allows higher export to South Australia by initiating rapid reduction in Murraylink power flow following a number of critical contingencies within Victoria.

However, due to demand growth in regional Victoria, loading on critical transmission lines (including the Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220kV line) has increased such that import into Victoria via Murraylink is forecast to be required to avoid pre-contingent load shedding during maximum demand periods in regional Victoria. This required import into Victoria via Murraylink cannot be met due to transmission limitations in the South Australia's Riverland region.

Table 1 lists and describes the constraint equations that restrict Murraylink transfer capability during maximum demand periods.

Table 1 – Constraint equations that restrict Murraylink transfer capability

Region	Constraint	Description
Victoria	V>>SML_NIL_1	Thermal limit for the Moorabool–Ballarat No.1 220 kV line, for loss of the Moorabool–Ballarat No.2 220 kV line.
	V>>SML_NIL_7A	Thermal limit for the Ballarat North–Buangor 66 kV line, for loss of the Ballarat–Waubra–Horsham 220 kV line.
	V>>SML_NIL_7B	Thermal limit for the Buangor–Ararat 66 kV line, for loss of the Ballarat–Waubra–Horsham 220 kV line.
	V>>SML_NIL_7C	Thermal limit for the Ararat–Stawell 66 kV line, for loss of the Ballarat–Waubra–Horsham 220 kV line.
	V>>SML_NIL_8	Thermal limit for the Ballarat–Bendigo 220 kV line, for loss of the Bendigo– Fosterville–Shepparton 220 kV line.
	V>SML_NSWRB_9	Thermal limit for the Bendigo–Kerang 220 kV line, for loss of the Balranald–Darlington Point (X5/1) 220 kV line, for loss of NSW Murraylink runback scheme.[a]
	V>SML_NSWRB_10	Thermal limit for the Kerang–Wemen 220 kV line, for loss of the Balranald–Darlington Point (X5/1) 220 kV line.[b]
	V^SML_NSWRB_2	Voltage stability limit to cater for the loss of the Darlington Point – Buronga (X5) 220 kV line.
South Australia	S>V_NIL_NIL_ RBNW_1	Thermal limit for the parallel Robertstown–North West Bend 132 kV line, for loss of the parallel line.

Note a: There are no commissioned runback schemes in NSW that allow for higher transfer on Murraylink by initiating rapid reduction in Murraylink power flow following the loss of critical contingencies within NSW.
Note b: An automatic load-shedding scheme was commissioned in 2012 to manage constraints on the Ballarat–Bendigo 220 kV line. Once this scheme is armed, the line can be operated to five-minute rating, and customer loads will be disconnected automatically after a contingency to prevent loading the line above its thermal capability.

Table 1 highlights that although the limitations on the Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line are addressed by this RIT-T assessment, Murraylink's transfer capability from Victoria to South Australia will still be constrained due to other existing underlying limitations in regional Victoria, most notably:

- Thermal limit on the Ballarat North – Buangor 66 kV line.
- Thermal limit on the Buangor–Ararat 66 kV line.
- Thermal limit on the Ararat–Stawell 66 kV line.

AEMO notes that removing the limitations on the Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line could lead to a potential deferral of augmentations in South Australia's Riverland region, provided the limitations on the three 66 kV lines detailed above are addressed.

AEMO will undertake joint planning with Powercor (the relevant distribution network service provider) to address the three 66 kV network limitations listed above. While solutions are yet to be identified, AEMO notes that there are potential market benefits arising from potentially deferred expenditure in the Riverland region.

AEMO did not include the potential benefits associated with this deferral in this RIT-T because the net market benefits will linearly increase for each credible option considered; the need to augment and the credible option rankings are not likely to change.

3.2.3 Emerging limitation on the Ballarat–Bendigo 220 kV line

3.2.3.1 Background

The Ballarat–Bendigo 220 kV line is designed to a maximum conductor operating temperature of 65 ºC. No wind monitoring facility is installed on this line; however, ambient temperature is monitored to enable dynamic adjustment of the line's rating. The line's 15-minute rating is calculated based on its pre-contingent loading level and ambient temperature.[12]

3.2.3.2 Forecast limitation

During maximum demand periods in regional Victoria, an unplanned outage of the most severe credible contingency event is for a trip of the Bendigo–Fosterville–Shepparton 220 kV line. In this situation, the loading on the Ballarat–Bendigo 220 kV line is forecast to be above the 15-minute line rating. This overload cannot be alleviated by the Murraylink runback schemes outlined in Table 2.

The results presented in Table 2 assume:

- A 10% probability of exceedance (POE) summer demand in regional Victoria.
- Thermal ratings are applied at an effective wind speed of 0.6 m/s.
- Wind generator contribution to maximum demand is 6.5% of maximum installed capacity.
- Murraylink runback schemes are in operation.
- No import from South Australia via the Murraylink interconnector.
- Import from New South Wales via Buronga – Red Cliffs Interconnector between 120 to 170 MW.

Table 2 shows the forecast loading of the Ballarat–Bendigo 220 kV line under system normal and N-1 conditions. System normal loading is compared to the line's continuous rating while N-1 loading levels have been compared to the line's 15-minute rating.

The forecast loading is based on AEMO's 2012 Terminal Station Demand Forecasts. AEMO's 2013 NEFR[13] indicates reduced regional demand forecasts for Victoria; this in turn has reduced the forecast overloading of the Ballarat–Bendigo 220 kV line. However, AEMO considers this forecast reduction to be insignificant as it will not affect the overall conclusion, so the results presented in Table 2 do not differ to those in the PADR.

Table 2 – Forecast Ballarat–Bendigo 220 kV line loading

Critical condition	Year	Ambient temperature (ºC)		
		35 ºC	40 ºC	45 ºC
System normal	2013–14	43%	48%	57%
	2014–15	45%	51%	60%
	2015–16	48%	54%	64%
	2016–17	50%	56%	66%
Bendigo–Fosterville–Shepparton 220 kV line outage	2013–14	101%	113%	139%
	2014–15	103%	116%	143%
	2015–16	105%	120%	146%
	2016–17	107%	122%	148%

12 An automatic load-shedding scheme was commissioned in 2012 to manage constraints on the Ballarat–Bendigo 220 kV line. Once this scheme is armed, the line can be operated to five-minute rating, and customer loads will be disconnected automatically after a contingency to prevent loading the line above its thermal capability.

13 AEMO. 2013 National Electricity Forecasting Report. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013.

Under system normal conditions, loading of the Ballarat–Bendigo 220 kV line is forecast to remain within its continuous rating.

Under N-1 conditions, loading of the Ballarat–Bendigo 220 kV line is forecast to exceed its 15-minute rating given coincident maximum demand in regional Victoria and high ambient temperature in the Ballarat and Bendigo areas.

3.2.4 Emerging limitation on the Moorabool–Ballarat No.1 220 kV line

3.2.4.1 Background

The two Moorabool–Ballarat 220 kV lines are constructed on individual towers. The Moorabool–Ballarat No.1 220 kV line is strung on a single-circuit tower line and is designed to a maximum conductor operating temperature of 65 ºC. The Moorabool–Ballarat No.2 220 kV line is strung on one side of a double-circuit tower line and is designed to a maximum operating temperature of 82 ºC. Load sharing between the two lines is not equal. The Moorabool–Ballarat No.2 220 kV line carries approximately 60% of the total power flow during maximum demand periods.

Dynamic wind monitoring facilities are installed on both Moorabool–Ballarat 220 kV lines. This enables dynamic adjustment of the lines' rating based on ambient temperature and effective wind speed. AEMO has deduced that an effective wind speed of 1.0 m/s is most appropriate for the Moorabool–Ballarat 220 kV lines at times of coincident maximum demand and high ambient temperature periods in regional Victoria.

A 15-minute rating is calculated based on the line's pre-contingent loading level, ambient temperature, and effective wind speed.[14]

3.2.4.2 Description of the limitation

During maximum demand periods in regional Victoria, if there is an unplanned outage of the most severe credible contingency event—a trip of the Moorabool–Ballarat No.2 220 kV line—the loading on the Moorabool–Ballarat No.1 220 kV line is forecast to be above the 15-minute rating under the conditions set out below. This overload cannot be alleviated by the Murraylink runback schemes outlined shown in Table 3.

The results presented in Table 3 assume:

- 10% probability of exceedance (POE) summer demand in regional Victoria.
- Thermal ratings applied at an effective wind speed of 1.0 m/s.
- Wind generator contribution to maximum demand is 6.5% of maximum installed capacity.
- Murraylink runback schemes are in operation.
- No import from South Australia via the Murraylink Interconnector.
- Import from New South Wales via Buronga – Red Cliffs Interconnector between 120 to 170 MW.

Table 3 shows the forecast loading of the Moorabool–Ballarat No.1 220 kV line under system normal and N-1 conditions. System normal loading is compared to the line's continuous rating while N-1 loading levels have been compared to the line's 15-minute rating.

The forecast loading is based on AEMO's 2012 Terminal Station Demand Forecasts. The reduced regional demand forecasts for Victoria indicated in AEMO's 2013 NEFR have reduced the forecast overloading of the Moorabool–Ballarat No.1 220 kV line. However, AEMO considered this forecast reduction to be insignificant, so the results presented in Table 3 do not differ to those in the PADR.

[14] An automatic load-shedding scheme was commissioned in 2012 to manage constraints on the Moorabool–Ballarat No.1 line. Once this scheme is armed, the line can be operated to five-minute rating, and customer loads will be disconnected automatically after a contingency to prevent loading the line above its thermal capability.

Table 3 – Forecast Moorabool–Ballarat No.1 220 kV line loading

Critical condition	Year	Ambient temperature (ºC)		
		35 ºC	40 ºC	45 ºC
System normal	2013–14	68%	77%	91%
	2014–15	69%	77%	91%
	2015–16	69%	77%	91%
	2016–17	70%	79%	92%
Moorabool–Ballarat No.2 220 kV line outage	2013–14	112%	130%	160%
	2014–15	112%	130%	161%
	2015–16	112%	130%	161%
	2016–17	114%	132%	164%

Under system normal conditions, loading of the Moorabool–Ballarat No.1 220 kV line is forecast to remain within its continuous rating.

Under N-1 and 1 m/s effective wind speed conditions, loading of the Moorabool–Ballarat No.1 220 kV line is forecast to exceed its 15-minute rating given coincident maximum demand in regional Victoria with high ambient temperature in the Ballarat and Moorabool areas.

However, under N-1 and wind speed conditions higher than 2.3 m/s, loading of the Moorabool–Ballarat No.1 220 kV line may not exceed its 15-minute rating given coincident maximum demand in regional Victoria with high ambient temperature in the Ballarat and Moorabool areas.

3.2.5 Expected impact of limitations

Base case – Do Nothing

Clause 5.16.1(c)(1) of the NER requires that RIT-Ts are based on a cost-benefit analysis that includes an assessment of reasonable scenarios of future supply and demand if each credible option were implemented. This must be compared to the situation where no option is implemented; the “Do Nothing” base case.

The Do Nothing option provides a basis for comparing the cost-benefit assessment of each credible option.

Under the Do Nothing option, the action required to ensure that network loading levels remain within transmission network equipment thermal limits is involuntary load shedding. The cost of involuntary load shedding is calculated using the value of customer reliability (VCR) index. This value is equivalent to the cost to consumers of having their electricity supply interrupted for a short time. The VCR applied in this RIT-T PACR is $61,950/MWh (in 2013–14 Australian dollars).

The forecast market impact under the Do Nothing option is presented in Table 4. Note that the “maximum load at risk” is defined as the highest load at risk out of all five scenarios considered, and the “maximum energy at risk” is the highest energy at risk of all five scenarios considered (Refer to Section 6.4.1 for description of scenarios considered).

“Expected unserved energy” is defined as the weighted (equal for all the scenarios at 20%) unserved energy based on the five scenarios considered. The five scenarios are described in Table 10. The “limitation cost” is calculated as the expected unserved energy is multiplied by the VCR.

Table 4 – Forecast market impact under the Do Nothing option

Year	Maximum load at risk (MW)	Maximum energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ million)
2013–14	251	1,480	570	35.3
2014–15	253	1,387	586	36.3
2015–16	278	1,538	616	38.2
2016–17	305	2,037	751	46.6
2017–18	331	2,126	814	50.5
2018–19	280	2,379	825	51.1
2019–20	285	2,366	954	59.1
2020–21	298	2,976	1,062	65.8
2021–22	285	3,451	995	61.6
2022–23	330	4,822	1,240	76.8

4 Network options for removal of constraints

4.1 Potential network options identified in this RIT-T

Table 5 lists the estimated capital costs of all the potential network options identified to address the forecast limitations on the Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line.

These costs exclude easement and/or land acquisition. A new easement is not required to install the third Moorabool–Ballarat 220 kV line, as it will be strung on the vacant side of the existing Moorabool–Ballarat No.2 220 kV double-circuit tower line.

Table 5 – List of potential network options, and capital costs (2013–14 $M)

Option	Ballarat–Bendigo 220 kV line options				Moorabool–Ballarat No.1 220 kV line options					Capital costs ($M)
	Up-rate to 82 ºC	Up-rate to 90 ºC	High temperature conductor	New DC line	Up-rate to 82 ºC	Up-rate to 90 ºC	High temperature conductor	Third circuit	New DC line	
1	✓				✓					125.5
2		✓			✓					130.7
3			✓		✓					157.4
4	✓					✓				127.6
5		✓				✓				132.7
6			✓			✓				159.5
7	✓						✓			150.2
8		✓					✓			155.4
9			✓				✓			182.1
10	✓							✓		105.0
11		✓						✓		110.1
12			✓					✓		136.9
13	✓								✓	171.8
14		✓							✓	177.0
15			✓						✓	203.7
16				✓	✓					220.2
17				✓		✓				222.3
18				✓			✓			244.9
19				✓				✓		199.6
20				✓					✓	266.5

4.1.1 Elimination of potential network options

AEMO undertook market modelling for a 10-year period (2013–14 to 2022–23). To calculate the end-effect associated with the life of network assets beyond 2022–23, the market benefits calculated for the final year were held constant and applied as the assumed annual market benefits that would continue for the remainder of the assumed asset life of each credible option. The assumed asset life is 40 years.

The following section describes the process used to select the credible options considered in this RIT-T assessment.

- Options 1 to 9 remove the forecast limitations by increasing thermal capability of the existing Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line over the modelling period without adversely increasing loading of other transmission circuits. As a result, the expected market benefits of these options 1 to 9 are similar. For this reason, only the least-cost options are considered in this RIT-T assessment to ensure the net present value (NPV) of the market benefits are maximised; namely options 1 and 4.
- The core investment element common to options 10 to 12 is installing the third Moorabool–Ballarat 220 kV circuit. This increases loading of other critical transmission plants in regional Victoria, including the Ballarat–Bendigo 220 kV line and the Ballarat–Horsham 66 kV tie lines. As a result, the expected market benefits of these options were marginally lower than options 1 to 9. All three options are forecast to remove the limitation over the modelling period, with similar market benefits. To maximise the net market benefit, the cheapest options are considered in this RIT-T assessment; namely options 10 and 11.
- Replacing the existing Moorabool–Ballarat No.1 220 kV line with a new double-circuit line is common to options 13 to 15. Replacing the existing Ballarat–Bendigo 220 kV line with a new double-circuit line is common to options 16 to 18. Options 13 to 15 increase loading of other critical transmission plant, including the Ballarat–Horsham 66 kV tie lines and the Moorabool–Ballarat 220 kV lines. Similarly, options 16 to 18 increase the loading of Ballarat–Bendigo and the Ballarat–Horsham 66 kV tie lines. The market modelling assessment indicated that the expected market benefits associated with these options are sufficient to justify augmentations. Although these options provide increased supply capability into regional Victoria, they are considerably more expensive than all the options listed above, and are not expected to maximise the net market benefit under AEMO's cost-benefit assessment methodology (see Chapter 6). For completeness, this RIT-T considers options 13 and 16.
- Options 19 and 20 involve installing new 220 kV circuits between Moorabool and Bendigo terminal stations. These options provide the highest supply capability to regional Victoria, but have high associated costs. Under AEMO's cost-benefit assessment methodology, these options are unlikely to maximise the net market benefits compared with other options. For completeness, this RIT-T assessment considers option 19 as a credible network option.

4.2 Credible network options eliminated from the PSCR

Installing a wind monitoring facility on the Ballarat–Bendigo 220 kV line to take advantage of higher wind speeds on hot summer days does not completely remove the forecast constraint on the Ballarat–Bendigo 220 kV line.

As a result, a wind monitoring facility was included with credible options that are expected to maximise the net present value of market benefits (i.e., options with higher expected market benefits and lower costs), as outlined in Section 4.1.1.

4.3 Credible network options included in this RIT-T

Following consideration of all the above options, Table 6 lists the credible options considered in this assessment.

Table 6 – Credible network options considered in this RIT-T, and capital costs (2013–14, $M)

Options	Ballarat–Bendigo 220 kV line options				Moorabool–Ballarat No.1 220 kV line options				Capital costs ($M)
	Wind monitoring scheme	Up-rate to 82 ºC	Up-rate to 90 ºC	New DC line	Up-rate to 82 ºC	Up-rate to 90 ºC	Third circuit	New DC line	
1a		✓			✓				125.6
1b	✓	✓			✓				126.2
2		✓				✓			127.6
3a		✓					✓		105.0
3b	✓	✓					✓		105.6
4a			✓				✓		110.1
4b	✓		✓				✓		110.7
5		✓						✓	171.9
6				✓	✓				220.2
7				✓			✓		199.6

4.3.1 Description of credible network options assessed

This section provides a description of each credible network option in this assessment, including:

- The technical characteristics of the option.
- The estimated construction timetable and commissioning date.
- The estimated capital and operating cost.

For all credible network options:

- Annual operating costs are estimated at 2% of their capital cost.
- Estimated project lead time includes the time required to acquire relevant property rights, design and construction activities.

Option 1a

Option 1a is depicted in Figure 2. The proposed scope of works for option 1a includes:

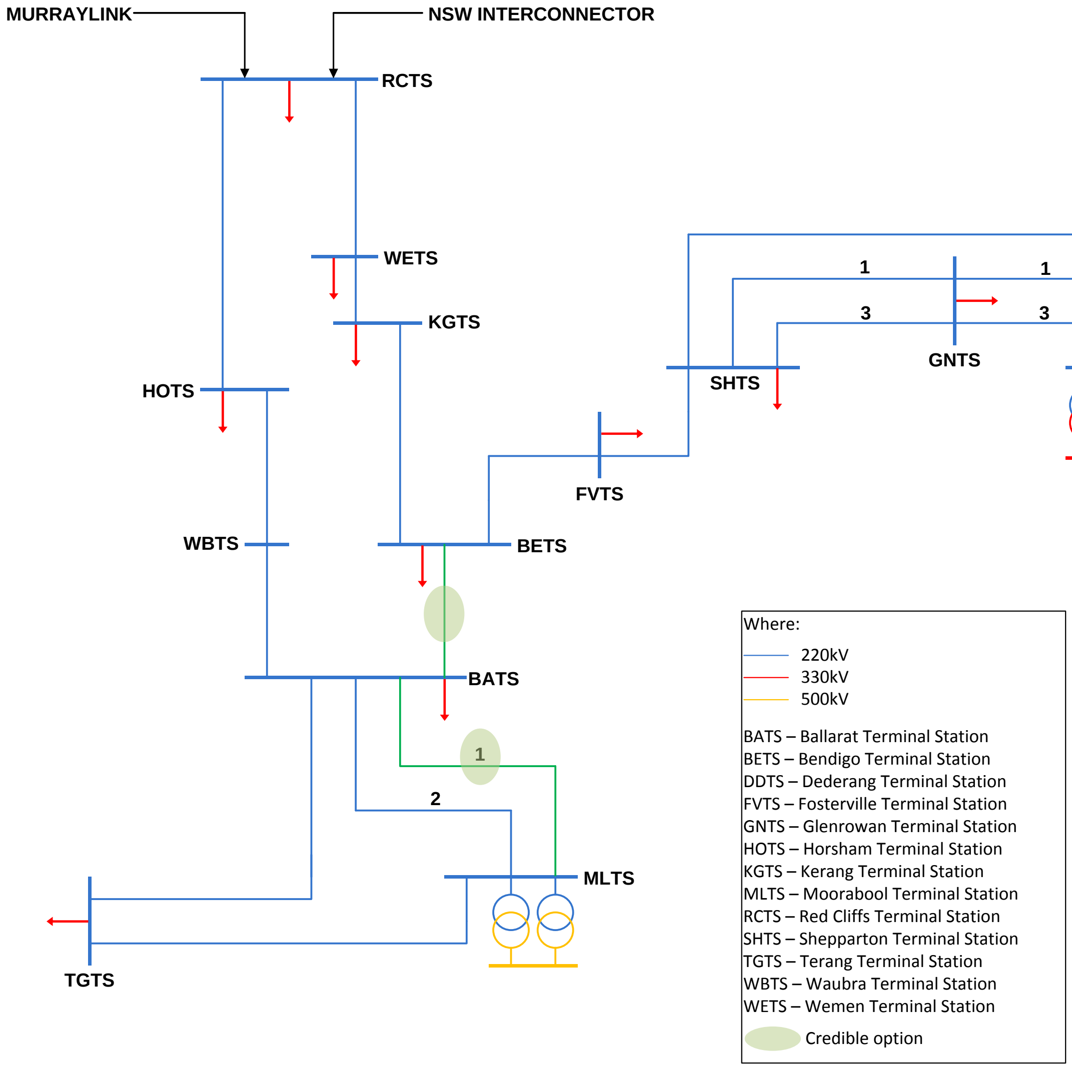
- Up-rating the existing Ballarat–Bendigo 220 kV line to a maximum conductor operating temperature of 82 ºC. This involves replacing approximately 56% of the existing towers to maintain the minimum ground clearance at the new rated conductor temperature as specified in AS/NZS 7000. This increases the line's continuous rating from 240 MVA at 40 ºC to 330 MVA at 40 ºC.
- Up-rating the existing Moorabool–Ballarat No.1 220 kV line to a maximum conductor operating temperature of 82 ºC. This involves replacing approximately 34% of the existing towers to maintain the minimum ground clearance at the new rated conductor temperature as specified in the AS/NZS 7000. This increases the line's continuous rating from 265 MVA at 40 ºC to 370 MVA at 40 ºC.[15]

The estimated capital cost of this option is $125.6 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

[15] The continuous rating is based on an effective wind speed of 1.0 m/s.

- Up-rating the Ballarat–Bendigo 220 kV line to 82 ºC: $77.2 million; four years, nine months.
- Up-rating the Moorabool–Ballarat No.1 220 kV line to 82 ºC: $48.4 million; four years, nine months

Figure 2 – Option 1a: Up-rate the existing Ballarat–Bendigo 220 kV line and Moorabool–Ballarat No.1 220 kV line to a maximum operating temperature of 82 ºC



Option 1b

Option 1b includes installing a wind monitoring facility on the Ballarat–Bendigo 220 kV line, together with the works set out under option 1a.

Option 1b increases the Ballarat–Bendigo 220 kV line's continuous rating from 240 MVA at 40 ºC to 370 MVA at 40 ºC.[16]

The total capital cost of this option is $126.2 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

- Installing a wind monitoring facility on the Ballarat–Bendigo 220 kV line: $0.6 million; one year, two months.
- Up-rating the Ballarat–Bendigo 220 kV line to 82 ºC: $77.2 million; four years, nine months.
- Up-rating the Moorabool–Ballarat 220 kV line to 82 ºC: $48.4 million; four years, nine months.

16 Based on an effective wind speed of 1.0 m/s.

Option 2

The proposed scope of works for option 2 includes:

- Up-rating the existing Ballarat–Bendigo 220 kV line to a maximum conductor operating temperature of 82 ºC by replacing approximately 56% of existing towers to maintain the minimum ground clearance at the new rated conductor temperature as specified in AS/NZS 7000. This increases the line's continuous rating from 240 MVA at 40 ºC to 330 MVA at 40 ºC.
- Up-rating the existing Moorabool–Ballarat No.1 220 kV line to a maximum conductor operating temperature of 90 ºC by replacing approximately 46% of existing towers to maintain the minimum ground clearance at the new rated conductor temperature as specified in AS/NZS 7000. This increases the line's continuous rating from 265 MVA at 40 ºC to 400 MVA at 40 ºC.[17]

The estimated capital cost of this option is $127.6 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

- Up-rating the Ballarat–Bendigo 220 kV line to 82 ºC: $77.2 million; four years, nine months.
- Up-rating the Moorabool–Ballarat No.1 220 kV line to 90 ºC: $50.4 million; four years, nine months.

Option 3a

Option 3a is depicted in Figure 3. The proposed scope of works for option 3a includes:

- Stringing a third Moorabool–Ballarat 220 kV circuit on the vacant side of the existing Moorabool–Ballarat No.2 220 kV double-circuit tower line. The continuous rating of the new circuit will be 420 MVA at 40 ºC.

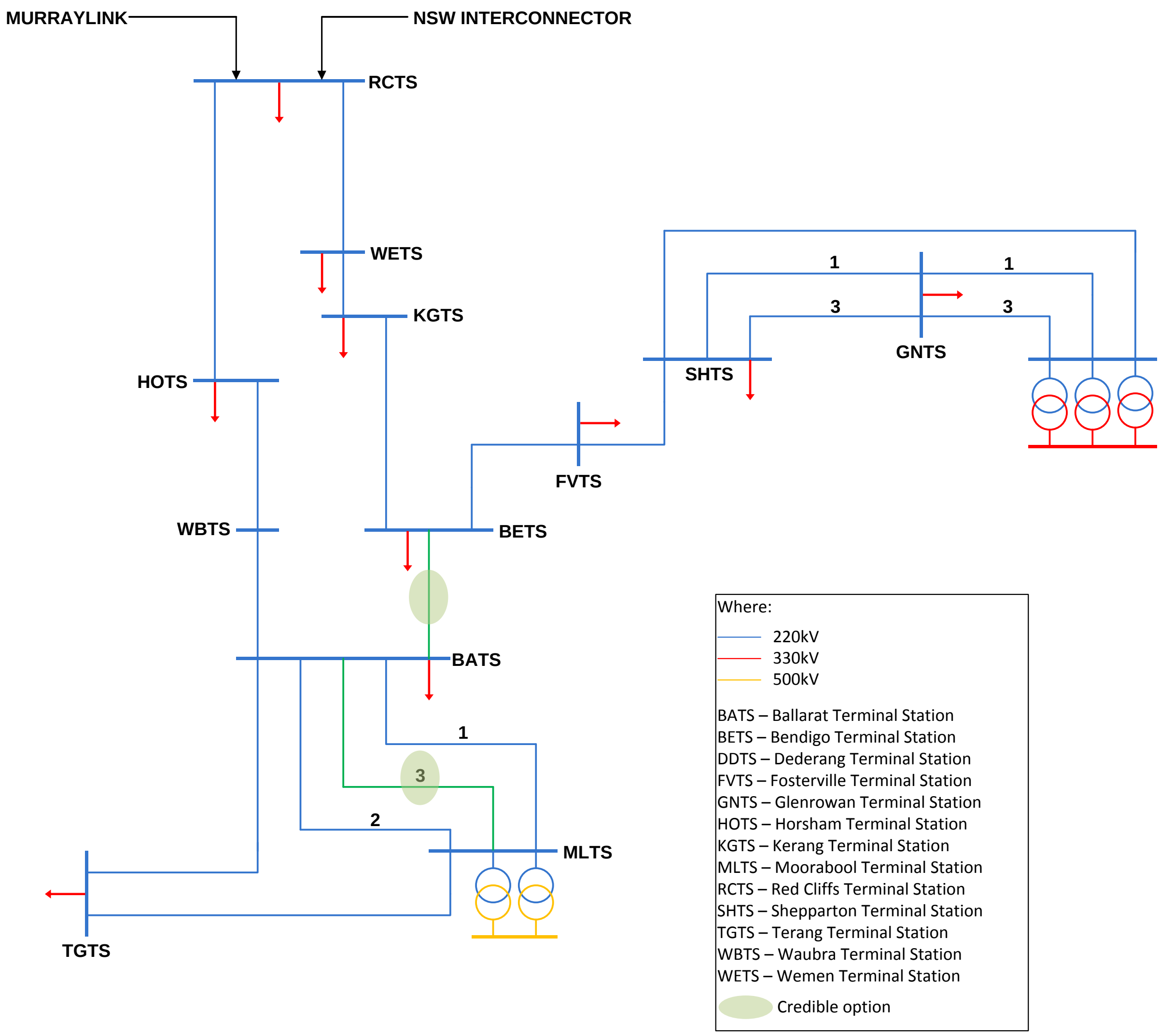
  Up-rating the existing Ballarat–Bendigo 220 kV line to a maximum conductor operating temperature of 82 ºC by replacing approximately 56% of existing towers to maintain the minimum ground clearance at the new rated conductor temperature as specified in AS/NZS 7000. This increases the line's continuous rating from 240 MVA at 40 ºC to 330 MVA at 40 ºC.

The estimated capital cost of this option is $105.0 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

- Installing the third Moorabool–Ballarat 220 kV circuit: $27.8 million; three years, two months.
- Up-rating the Ballarat–Bendigo 220 kV line to 82 ºC: $77.2 million; four years, nine months.

[17] Based on an effective wind speed of 1.0 m/s.

Figure 3 – Option 3a: Up-rate the existing Ballarat–Bendigo 220 kV to a maximum operating temperature of 82 ºC and install the third Moorabool–Ballarat 220 kV circuit



Option 3b

Option 3b includes the installation of a wind monitoring facility on the Ballarat–Bendigo 220 kV line, together with the works set out under option 3a.

Option 3b increases the Ballarat–Bendigo 220 kV line's continuous rating from 240 MVA at 40 ºC to 370 MVA at 40 ºC.[18]

The total capital cost of this option is $105.6 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

- Installing a wind monitoring facility on the Ballarat–Bendigo 220 kV line: $0.6 million; one year, two months.
- Installing the third Moorabool–Ballarat 220 kV circuit: $27.8 million; three years, two months.
- Up-rating the Ballarat–Bendigo 220 kV line to 82 ºC: $77.2 million; four years, nine months.

[18] Based on an effective wind speed of 1.0 m/s.

Option 4a

The proposed scope of works for option 4a includes:

- Stringing the third Moorabool–Ballarat 220 kV circuit on the vacant side of the existing Moorabool–Ballarat No.2 220 kV double-circuit tower line. The continuous rating of the new circuit will be 420 MVA at 40 ºC.
- Up-rating the existing Ballarat–Bendigo 220 kV line to a maximum conductor operating temperature of 90 ºC by replacing approximately 60% of existing towers to maintain the minimum ground clearance at the new rated conductor temperature as specified in AS/NZS 7000. This increases the line's continuous rating from 240 MVA at 40 ºC to 400 MVA at 40 ºC.

The estimated capital cost of this option is $110.1 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

- Installing the third Moorabool–Ballarat 220 kV circuit: $27.8 million; three years, two months.
- Up-rating the existing Ballarat–Bendigo 220 kV line to 90 ºC: $82.3 million; four years, nine months.

Option 4b

Option 4b includes the installation of a wind monitoring facility on the Ballarat–Bendigo 220 kV line, together with the works set out under option 4a.

Option 4b increases the Ballarat–Bendigo 220 kV line's continuous rating from 240 MVA at 40 ºC to 400 MVA at 40 ºC.[19]

The total capital cost of this option is $110.7 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

- Installing wind monitoring facility on the Ballarat–Bendigo 220 kV line: $0.6 million, one year, two months.
- Installing the third Moorabool–Ballarat 220 kV circuit: $27.8 million, three years, two months.
- Up-rating the existing Ballarat–Bendigo 220 kV line to 90 ºC: $82.3 million, four years, nine months.

Option 5

Option 5 is depicted in Figure 4. The proposed scope of works for option 5 includes:

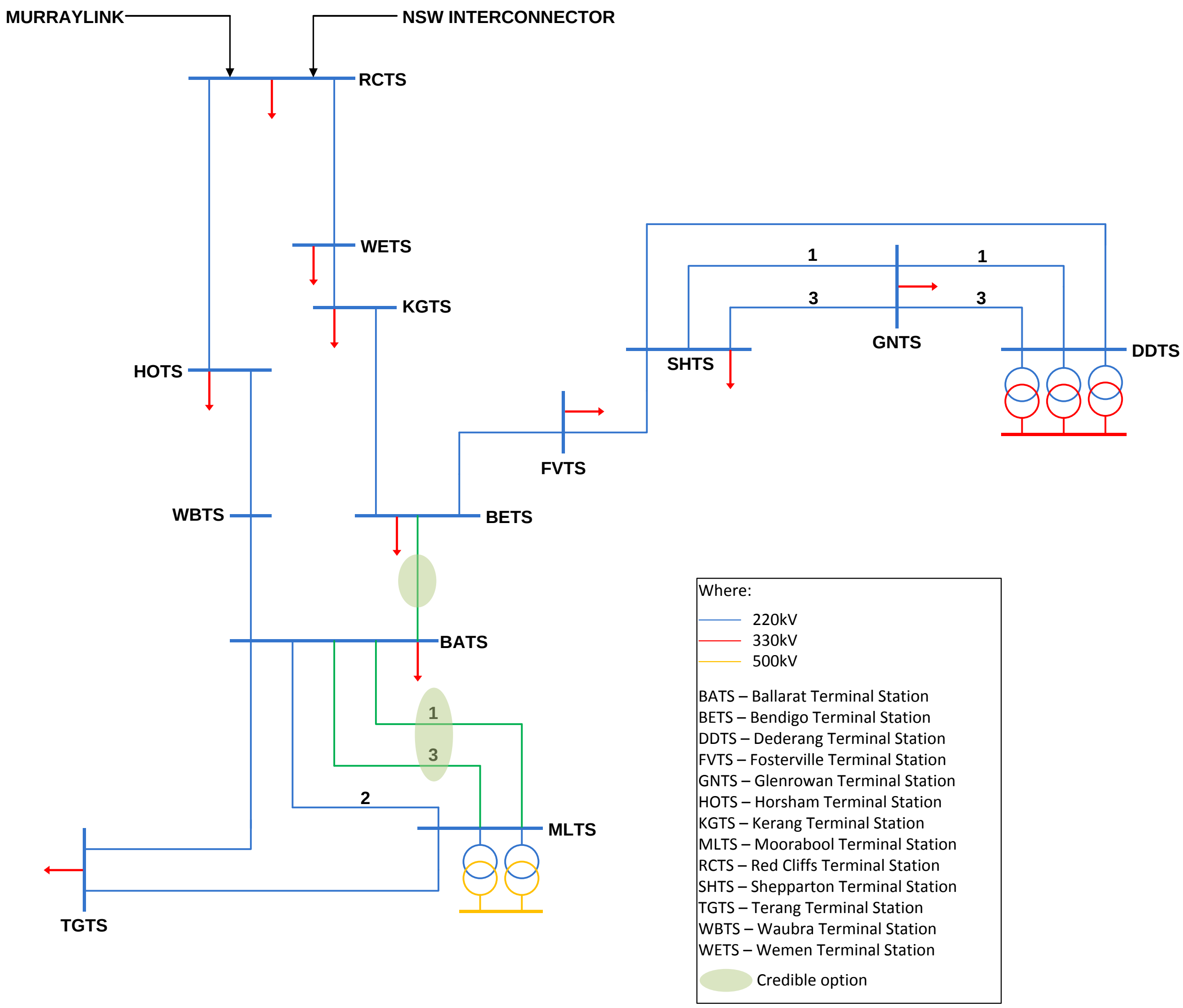
- Up-rating the existing Ballarat–Bendigo 220 kV line to a maximum conductor operating temperature of 82 ºC by replacing approximately 56% of existing towers to maintain the minimum ground clearance at the new rated conductor temperature as specified in AS/NZS 7000. This increases the line's continuous rating from 240 MVA at 40 ºC to 330 MVA at 40 ºC.
- Dismantling the existing Moorabool–Ballarat 220 kV No.1 line and replacing with a new 220 kV double-circuit line, in a new easement corridor. The continuous rating of each new circuit will be 420 MVA at 40 ºC.

The estimated capital cost of this option is $171.9 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

- Up-rating the Ballarat–Bendigo 220 kV line to 82 ºC: $77.2 million; four years, nine months.
- Replacing the Moorabool–Ballarat No.1 220 kV with a new 220 kV double-circuit line: $94.7 million; four years, nine months.

[19] Based on an effective wind speed of 1.0 m/s.

Figure 4 – Option 5: Up-rate the existing Ballarat–Bendigo 220 kV to a maximum operating temperature of 82 ºC and replace the existing Moorabool–Ballarat No.1 220 kV line with a new 220 kV double-circuit line



Option 6

Option 6 is depicted in Figure 5. The proposed scope of works for option 6 involves:

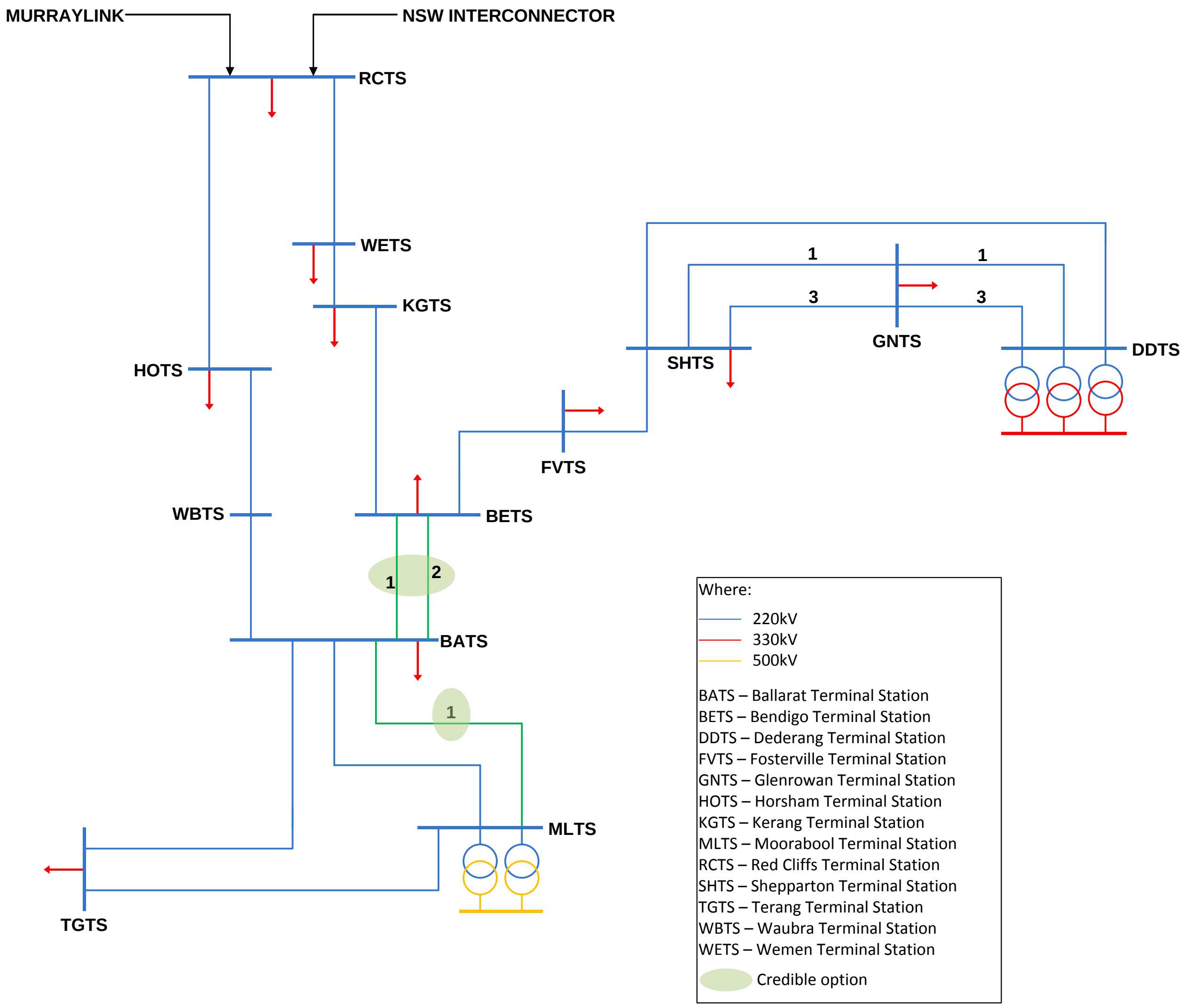
- Up-rating the existing Moorabool–Ballarat No.1 220 kV line to a maximum conductor operating temperature of 82 ºC by replacing approximately 34% of existing towers to maintain the minimum ground clearance at the new rated conductor temperature as specified in the AS/NZS 7000 standard. This increases the line's continuous rating from 265 MVA at 40 ºC to 370 MVA at 40 ºC.[20]
- Dismantling the existing Ballarat–Bendigo 220 kV single-circuit line and replacing with a new 220 kV double-circuit line. The continuous rating of this new line will be 660 MVA at 40 ºC.

The estimated capital cost of this option is $220.2 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

- Up-rating the Moorabool–Ballarat 220 kV line to 82 ºC: $48.4 million; four years, nine months.
- Replacing the Ballarat–Bendigo 220 kV with a new 220 kV double-circuit line: $171.8 million; five years, nine months.

[20] The continuous rating is based on an effective wind speed of 1.0 m/s.

Figure 5 – Option 6: Replace the existing Ballarat–Bendigo 220 kV line with a new 220 kV double-circuit line and up-rate the existing Moorabool–Ballarat No.1 220 kV line to maximum operating temperature of 82 ºC



Option 7

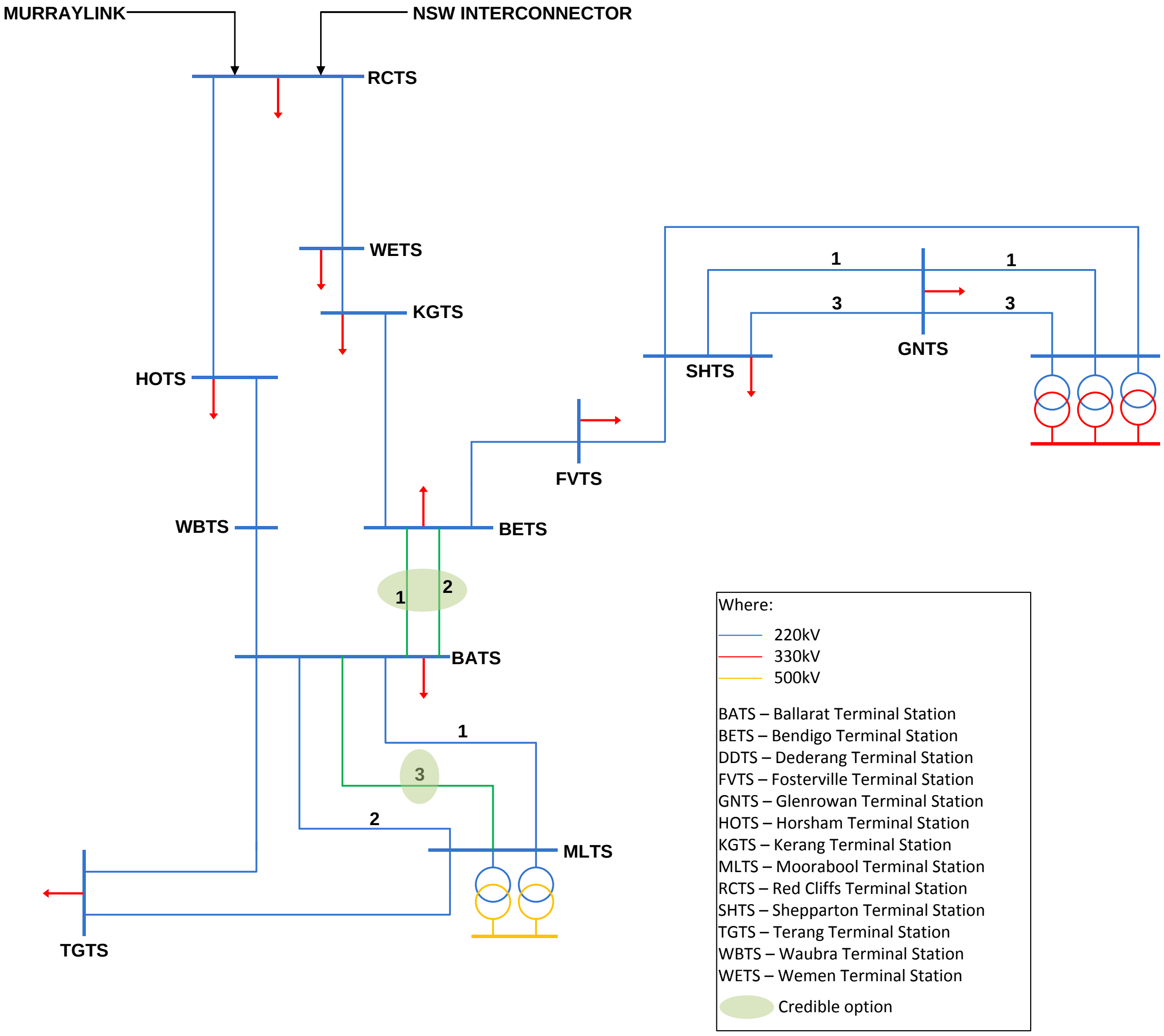
Option 7 is depicted in Figure 6. The proposed scope of works for option 7 involves:

- Stringing the third Moorabool–Ballarat 220 kV circuit on the vacant side of the existing Moorabool–Ballarat No.2 220 kV double-circuit tower line. The continuous rating of the new circuit will be 420 MVA at 40 ºC.
- Dismantling the existing Ballarat–Bendigo 220 kV single circuit line and replacing with a new 220 kV double-circuit line. The continuous rating of each new circuit will be 660 MVA at 40 ºC.

The estimated capital cost of this option is $199.6 million (in 2013–14 dollars). The estimated project lead time and capital cost breakdown is:

- Installing the third Moorabool–Ballarat 220 kV circuit: $27.8 million; three years, two months.
- Replacing the Ballarat–Bendigo 220 kV with a new 220 kV double-circuit line: $171.8 million; five years, nine months.

Figure 6 – Option 7: Replace the existing Ballarat–Bendigo 220 kV line with a new 220 kV double-circuit line and install the third Moorabool–Ballarat 220 kV circuit



4.4 Credible non-network options assessed

AEMO has not undertaken any additional analysis to determine the technical feasibility of non-network options. AEMO did not receive any proposals to the Project Specification Consultation Reports (PSCRs) and Project Assessment Draft Report (PADR) suggesting a credible non-network option approach to address the identified need.

AEMO did not receive any submissions regarding embedded generation, but did receive a submission on the Ballarat Supply PSCR recommending demand-side management. No proposal was included, however, AEMO assessed the commercial feasibility utilising the non-network cost assumptions it developed.

These cost assumptions are based on general industry knowledge available to AEMO, and information gathered from non-network service providers for similar demand-management (DM) assessments that AEMO has been party to.

Option 8: Demand management

Demand management, in the form of voluntary load curtailment, has the potential to decrease the involuntary load shedding that would otherwise be required during maximum demand periods.

AEMO has assumed that the non-network DM is spread between the two terminal station connection points that presented the highest expected load shedding (MWh) in the base case (Do

Nothing option). AEMO assumed the available non-network DM support to be at Ballarat and Bendigo terminal stations, where it could be effective and optimised.

AEMO assumed the available non-network DM support to be 5% of the 2013–14 10% probability of exceedance forecast demand under the medium demand growth scenario at the two chosen terminal station transmission connection points. The 5% availability estimate is based on optimistic DM contributions identified in similar projects that AEMO has contributed to.

Table 7 presents the available DM location and support assumed as part of the option 8 assessment.

Table 7 – Available demand management location and support

Location	Demand reduction available (MW)
Ballarat	9
Bendigo	12

AEMO based DM cost assumptions on general industry knowledge available, and information gathered from non-network service providers for similar DM assessments that AEMO has been party to.

Table 8 describes and estimates the costs associated with DM.

Table 8 – Costs associated with demand management

Cost Type	Description	Cost
Establishment cost	One-off cost for implementing this option. The cost includes consultancy services to investigate the potential for DM, prepare plans, arrange support contracts, and set up any systems to trigger and coordinate demand response when it is required.	$80,000 per MW of capacity required.
Availability charge	Regular payment to the DM provider for having support services in place, regardless of utilisation. The amount paid will depend on the type of customers involved in the arrangement (i.e., whether the service is provided by a small number of large customers, or many small-to-medium customers).	AEMO expects a typical payment to be around $60,000 to $120,000/MW/year. In the absence of a DM submission to the PSCR, or further information from potential providers, AEMO estimated a regular payment cost of $90,000/MW/year.
Dispatch fee	Payment to the provider for reducing demand when requested.	$900/MWh.

5 Submissions

5.1 Submission on the Project Specification Consultation Reports

In April 2012, AEMO published the Ballarat Supply Project Specification Consultation Report (PSCR) addressing limitations on the Moorabool–Ballarat No.1 220 kV line. The Bendigo Supply PSCR addressing limitations on the Ballarat–Bendigo 220 kV line followed in August 2012.

AEMO received one submission on the Ballarat supply PSCR. This was from ATA/EnerNOC in July 2012.

In its submission, ATA/EnerNOC expressed interest in providing a demand-management (DM) option. ATA/EnerNOC requested additional details about the characteristics a DM option would require for both limitations. This information would enable them to estimate the details and cost of their DM proposal, which they intended to submit during the Bendigo PSCR consultation phase.

ATA/EnerNOC did not submit a proposal in response to the Bendigo Supply PSCR; however, AEMO has included a DM option in the RIT-T assessment.

5.2 Submission on the Project Assessment Draft Report

In March 2013, AEMO published the Project Assessment Draft Report (PADR) addressing limitations on the Moorabool–Ballarat No.1 220 kV line and Ballarat–Bendigo 220 kV line. AEMO received one submission. This was from SP AusNet in May 2013.

In April 2013, AEMO and SP AusNet met to discuss SP AusNet's intention to provide a submission. In the submission, SP AusNet requested the augmentation outage market impact costs which were not quantified in the PADR to be included in the AEMO's assessment for the PACR.

SP AusNet requested details on the time of the year when construction outage windows would have lower market impacts, and on expected recall times required for both the Ballarat–Bendigo 220 kV line and Moorabool–Ballarat No.2 220 kV line for the purpose of the proposed augmentation.

Following this request, AEMO conducted further assessments on the augmentation outage market impact costs. AEMO found an outage of either line during the construction outage window between April and October results in no unserved energy (USE) being simulated, and a marginal increase in the dispatch price. The assessment concludes that the augmentation outage market impact cost is insignificant during these construction outage windows.

AEMO has addressed SP AusNet requests for information on recall times. AEMO advised that it requires six hours of recall time to enable either line to return to service to maintain power system security. AEMO determined this by conducting further assessments to address the submission, and also held discussions with SP AusNet at two meetings in June and July 2013.

6 Description of methodology

This section provides a summary of the methodology adopted for this RIT-T assessment. It includes a description of the approach used for the market dispatch modelling; a description of the reasonable scenarios considered; and a summary of the key assumptions.

6.1 Analysis period

Market modelling was undertaken for the period 2013–14 to 2022–23. AEMO considered this period as being sufficiently lengthy to:

- Cover the impact of large-scale wind generation developments in regional Victoria that could affect the timing and ranking of a preferred option.
- Reduce the impact of limitations (other than those associated with the identified need) that could skew future market modelling results.
- Minimise uncertainty around demand forecasts, and new development projects that could otherwise skew market modelling results.

To capture the "end effects" associated with the life of the network assets extending beyond 2022–23, the market benefits calculated for the final year (2022–23) were held constant and applied as the assumed annual market benefit that would continue under the credible option in the future.

This is an approach AEMO commonly adopts in similar assessments. It was applied to each credible option in this RIT-T assessment. For each credible option assessed, the assumed asset life is 40 years.

Note that where options rank closely in terms of net market benefits and the differences fall within the resolution of the market simulation tools, the options were considered as equal and further considerations were required to determine the preferred option.

6.2 Market modelling

The RIT-T process requires a market dispatch modelling methodology be used in estimating the magnitude of market benefits, unless the transmission network service provider (TNSP) provides reasons why this methodology is not relevant.[21] AEMO considers that a market dispatch modelling methodology is relevant for this RIT-T application, and adopted this approach.

The RIT-T process requires the calculation of many of the market benefit categories by comparing the "state of the world" in the base case (where AEMO takes no action) with a state of the world where each of the credible options is in place.

In this RIT-T assessment, the impact of each credible option on National Electricity Market (NEM) operation outcomes is such that relevant comparisons between the states of the world with and without each option were able to be appropriately estimated using market dispatch modelling.

The RIT-T considers several "reasonable scenarios" to address uncertainties associated with future NEM development, and the consequent uncertainties in estimating the future state of the world for each credible option. (See Section 6.4 for more information).

6.2.1 Market dispatch model

To calculate dispatch outcomes in the state of the world scenario, AEMO undertook market simulations using a market model that incorporates generation dispatch and market clearing processes to replicate NEM operation. AEMO used the PROPHET model for this RIT-T.[22]

The market dispatch modelling methodology adopted is consistent with the further RIT-T requirement that the model must incorporate a realistic treatment of both:

[21] AER. Final Regulatory Investment Test for Transmission. June 2010, version 1, paragraph 11, p.6.
[22] For details of the PROPHET model see: http://www.iesys.com/ies/ProductsandServices/Prophetsuite.aspx. Accessed February 2013.

- Plant characteristics, such as minimum generation levels and variable operating costs.
- Network constraints and losses.

The modelling uses a database which individually models each Victorian load and generator transmission connection point. This allows load shedding requirements to be attributed to the specific transmission connection point(s) that will best offload the limiting element. It is represented by a constraint equation with the minimum amount of load shedding required.

The level of load shedding required to maintain power system security is calculated using the plant rating traces developed by AEMO. These were based on the 2009–10 temperature trace; effective wind speeds[23]; and estimated pre-contingent loading levels based on the maximum demand load flow base cases AEMO developed. Table 9 presents a snapshot of the 15-minute ratings of critical 220 kV transmission circuits.

The modelling incorporates expected changes in involuntary load shedding, generation fuel consumption, and network losses expected to occur as a result of implementing any of the credible options. The impact of changes in involuntary load shedding is calculated by comparing the expected unserved energy (USE) under the base case with each credible option in place.

The level of USE is estimated by calculating the USE in each trading interval over the modelling period, and applying a value of customer reliability (VCR, expressed in $/MWh).

The impact of changes in generation fuel consumption is calculated by comparing the generation dispatch cost under the base case with each credible option in place.

The impact of changes in network losses is inherently included in the market modelling results. An increase in network losses represents a negative market benefit (market cost) while a reduction in losses represent a positive market benefit.

Expected changes in load shedding, generation fuel consumption, and network losses of each credible option are realised by the change in constraint equations modelled for each option.

The model includes a limited set of National Electricity Market Dispatch Engine (NEMDE) pre-dispatch system normal constraints so that the model considers inter-regional limitations. AEMO developed and modelled separate intra-regional constraints, specifically around regional Victorian and Metropolitan Melbourne areas, for each credible option assessed.

As described in Section 3.2, AEMO included key constraint equations in the model to represent the following thermal loading limits:

- Ballarat–Bendigo 220 kV line loading.
- Bendigo–Fosterville–Shepparton 220 kV line loading.
- Dederang–Shepparton 220 kV line loading.
- Kerang – Wemen – Red Cliffs 220 kV line loading.
- Moorabool–Ballarat No.1 220 kV line loading.
- Moorabool A1 and A2 500/220 kV transformer loadings.
- South Morang – Thomastown 220 kV line loading.
- South Morang H1 and H2 330/220 kV transformer loadings.
- Voltage stability limit equations in regional Victoria.
- Murraylink runback scheme for relevant equations.
- Ballarat–Horsham 66 kV tie line loadings.[24]

23 AEMO adopted higher effective wind speeds for transmission lines with monitoring facilities, based on its own studies. Otherwise, 0.6 m/s is used.

24 These thermal limit equations were incorporated in the database.

- Thermal limit equations in South Australia's Riverland network.[25]

AEMO ran the PROPHET model based on wind and temperature traces from 2009–10 data; demand traces grown from 2009–10 data; plant thermal rating traces; and assuming that generators follow short-run marginal cost (SRMC) bidding behaviour.

6.3 Key assumptions that drive market benefits

The following categories of key assumptions drive the market benefits expected from relieving the supply capability limitations to regional Victoria.

- Discount rate.
- Value of customer reliability (VCR).
- Wind contribution to maximum demand.
- Characteristics of load profile.
- Forecast demand growth.
- Generation re-dispatch cost.
- Plant thermal ratings.

This section describes each of the above key assumption categories used in the analysis undertaken for this Project Assessment Conclusion Report (PACR). AEMO also considered sensitivities of discount rate, VCRs, and capital costs in the analysis. The cost-benefit analysis undertaken to determine the preferred option incorporated a range of scenarios outlined in Section 6.4.

6.3.1 Discount rate

AEMO adopted a discount rate of 10% (real, pre-tax) in undertaking the net present value (NPV) analysis for all credible options. This represents a reasonable commercial discount rate, appropriate to the analysis of a private enterprise investment in the electricity sector, as required by paragraph 14 of the RIT-T.[26]

6.3.2 Value of customer reliability

The cost of USE is calculated using the VCR, which is an estimate of the value that electricity consumers place on a reliable electricity supply. This value is equivalent to the cost to consumers of having their electricity supply interrupted for a short time.

The forecast Victorian VCR has recently been updated to $61,950/MWh (in 2013–14 Australian dollars), and AEMO used this rate to calculate the cost of expected USE for this RIT-T assessment.

6.3.3 Wind contribution to maximum demand

The capacity factor of existing and new wind generation during maximum demands can affect transmission network loading levels by replacing other generation and altering network power flow patterns.

To account for the impact of wind generation on transmission loading levels, AEMO considers two alternative assumptions in this RIT-T assessment. The first assumption applies a 6.5% capacity factor during maximum demand periods in each of the scenarios assessed.[27] The second uses a

25 Thermal limit equations relating to Robertstown 275/132 kV transformer loading, Robertstown – North West Bend 132 kV line loading, North West Bend – Monash 132 kV line loading equations were incorporated in the database.

26 AER. Final Regulatory Investment Test for Transmission. June 2010, version 1, paragraph 14, p. 6.

27 AEMO. 2012 National Transmission Network Development Plan. Available: http://aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~/media/Files/Other/ntndp/2012NTNDP.

capacity factor of 33% during maximum demand periods; this was based on the actual wind generation utilisation recorded during the 2009–10 Victorian summer maximum demand.

6.3.4 Characteristic of load profile

The regional Victorian area (Ballarat, Bendigo, Fosterville, Glenrowan, Horsham, Kerang, Red Cliffs, Shepparton, and Wemen) has agricultural, commercial and residential loads.

Annual maximum demand for regional Victoria generally occurs on hot summer afternoons.

Figure 7 shows the load duration curve for the critical regional Victorian loads for summer 2009–10.

Figure 7 – Historical regional Victoria load duration curve for summer 2009–10

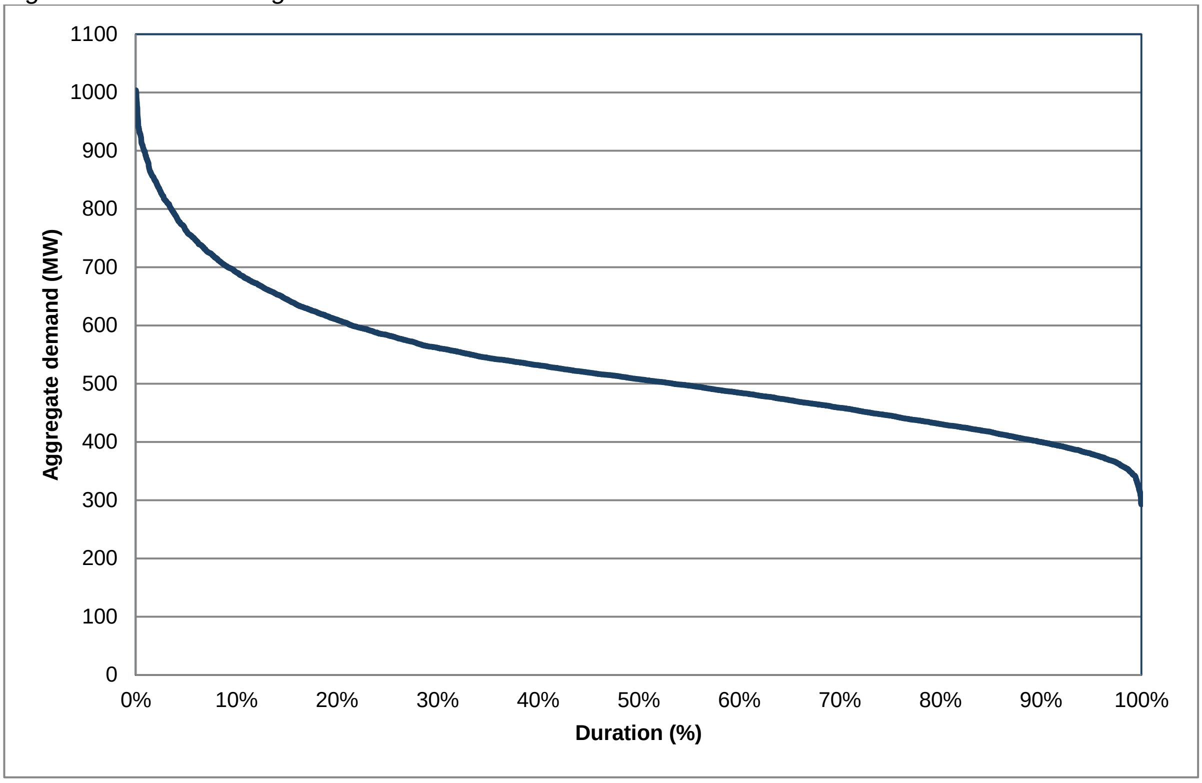


Figure 7 shows a sharp peak of a short duration, and average-to-low demand for most of the summer, with around 70% of the maximum demand lasting less than 10% of the time.

This implies that although the probability of reaching high demand levels is reasonably low, not having sufficient capability (be it network capability or non-network support) can result in significant involuntary load shedding to maintain a secure operating state.

AEMO prepared terminal station demand traces based on the load shape of the historical base-year trace from 2009–10. The expected USE presented in Section 3.2.5 was calculated using these demand traces.

6.3.5 Forecast demand growth

Although recent demand forecasts show a slower growth rate than previously experienced, electricity demand in regional Victoria is still continuing to grow.

Figure 8 shows that the forecast maximum demand growth for regional Victorian loads is about 1.6% per year. These forecasts are based on AEMO's medium economic growth scenario and represent the 10% probability of exceedance (POE) demand levels, as presented in AEMO's Victorian Terminal Station Demand Forecasts 2012.[28] These forecasts are represented as

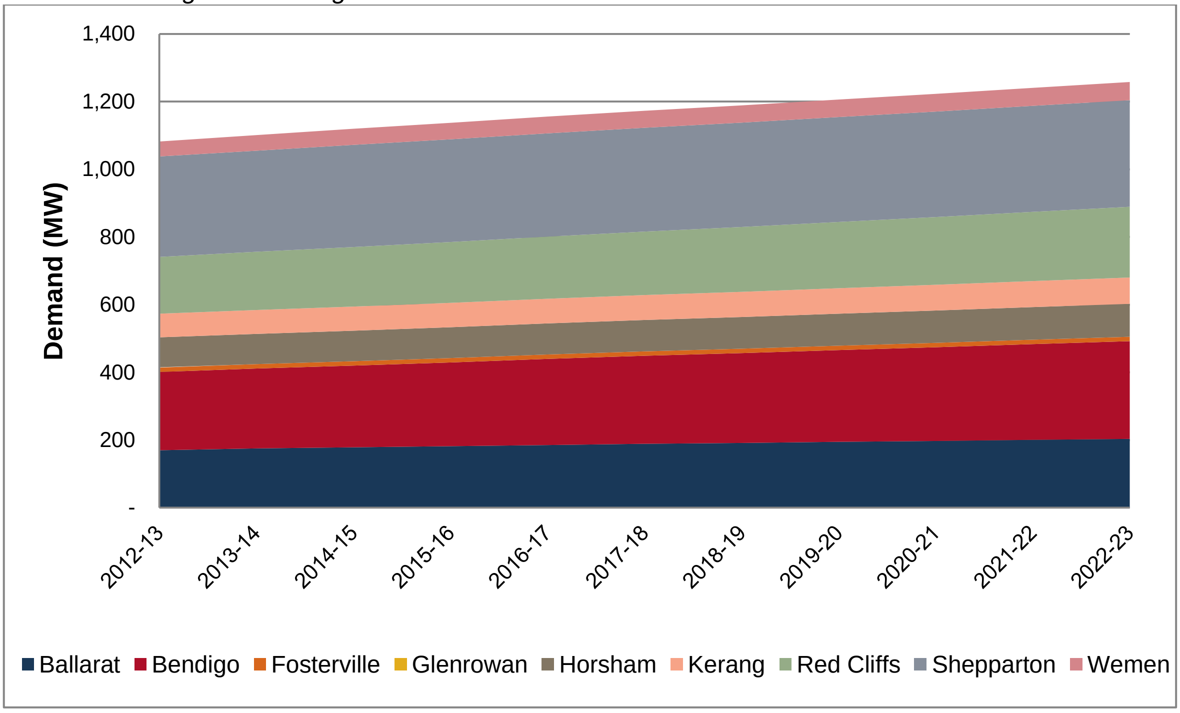
[28] AEMO. "Victorian Terminal Station Demand Forecasts 2012". Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria.

undiversified maximum demand, which assumes that maximum demand at all connection points occurs simultaneously.

AEMO scaled down the terminal station demand forecasts to align with the Victorian region's system maximum demand and annual energy forecasts presented in AEMO's 2012 National Electricity Forecasting Report.[29]

The demand forecasts applied under each demand scenario are presented in Appendix B.1.

Figure 8 – Demand growth for regional Victorian loads over 10% POE summer demand levels



AEMO accounts for demand forecast uncertainty by applying a 10% POE demand forecast and a 50% POE demand forecast and weighting them 30% and 70% respectively to calculate the expected USE and generation dispatch variations.

6.3.6 Modelling hydroelectric generation

AEMO models Victorian hydroelectric generation by time-of-day bids based on a historical profile of Victorian hydroelectric dispatch for a typical year.

AEMO analysed historical data and determined that the average annual cost for all NEM hydroelectric units was approximately $25 per MWh. To calculate the future annual cost of hydroelectric generation, AEMO increased the average annual cost for all NEM hydroelectric units ($25) by 80% of the carbon price each year.

This escalation reflects that following the introduction of a carbon price, the hydroelectric units in the NEM continued to operate to maintain about the same reservoir levels as prior to the carbon price introduction.

The increase also reflects that the average hydroelectric cost was higher with carbon pricing, as the hydroelectric units may incur higher electricity costs to pump water.

AEMO calculated the annual hydro generation cost as follows:

$$Annual\ hydroelectric\ generation\ cost = Annual\ hydroelectric\ generation\ \times hydro\ cost$$

Where:

[29] AEMO. "2012 National Electricity Forecasting Report". Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012.

Annual hydroelectric generation is the total output from all NEM hydroelectric generating units for a year (in megawatt hours).

Hydroelectric cost is the annual average cost incurred from all NEM hydroelectric generation producing one additional megawatt hour. This is approximated as $25 + (80% x carbon price that year).

6.3.7 Generation re-dispatch costs

Re-dispatch of generation is valued using SRMC of generation, including any price on carbon. AEMO derived the SRMC of generation applied for this RIT-T assessment from fuel cost projections prepared for the 2012 NTNDP.[30]

6.3.8 Plant thermal ratings

The 220 kV transmission line ratings vary with ambient temperature, effective wind speeds (if a wind monitoring facility is installed), and each line's pre-contingent loading level.

A snapshot of the 15-minute ratings of critical 220 kV transmission circuits modelled for this RIT-T assessment is presented in Table 9.

Table 9 – Thermal ratings of existing transmission circuits

Circuit	Indicative 15-minute rating at 40 °C ambient temperature (MVA)
Ballarat–Bendigo 220 kV line	279
Bendigo–Fosterville–Shepparton 220 kV line	355
Dederang–Shepparton 220 kV line	269
Moorabool–Ballarat No.1 220 kV line	299
Kerang – Wemen – Red Cliffs	219
South Morang – Thomastown	649

6.3.9 Sensitivities

6.3.9.1 Capital costs

SP AusNet provided budget estimates for the augmentation works associated with each network option. These are subject to a range of ± 30%.

Accordingly, for the purpose of sensitivity testing, a range of ± 30% around the budget estimate is assumed to define the upper and lower bounds of the capital costs of all network options.

6.3.9.2 Discount rates

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

The RIT-T requires that any present value calculations be carried out using a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.

AEMO applied a real pre-tax discount rate of 10% for this analysis. For the sensitivity testing, a lower bound real discount rate of 6% and an upper bound rate of 12% were applied.

[30] ACIL Tasman. Fuel cost projections – Updated natural gas and coal outlook for AEMO modelling. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/2012-Planning-Assumptions. Accessed March 2013.

6.3.9.3 Value of customer reliability

This RIT-T assessment adopts a value of USE of $61,950 per MWh. For the purpose of sensitivity testing, this value is varied within limits of ± 20%, resulting in an upper bound value of $74,340 per MWh, and a lower bound value of $49,560 per MWh.

6.4 Reasonable scenarios

6.4.1 Description of reasonable scenarios

The RIT-T analysis needs to incorporate several different reasonable scenarios; these are used to estimate the market benefits associated with each credible option. The RIT-T application guide states that the number and choice of reasonable scenarios must be appropriate to the credible options under consideration. The choice of reasonable scenarios must reflect any variables or parameters that are likely to affect:

- The ranking of the credible options, where the identified need is reliability corrective action.
- The ranking of the credible options, or the sign of the net economic benefits of any of the credible options, for all other identified needs.

To consider the identified key factors that drive market benefits, AEMO adopted the following five scenarios in undertaking the RIT-T analysis presented in this PACR:

- Scenario 1: Medium demand growth scenario.
- Scenario 2: Alternative generation placement medium demand growth scenario.
- Scenario 3: Low demand growth scenario.
- Scenario 4: Alternative generation placement low demand growth scenario.
- Scenario 5: Medium demand growth scenario with high wind generator contributions during maximum demand periods.

Table 10 provides a summary of the parameters adopted under each scenario.

Of particular note:

- **Scenario 1** is considered the base case scenario. It assumes medium economic and population growth, with Victorian summer 10% POE and 50% POE demands forecast to increase over the next 10 years at annual rates of 1.6%.

  Scenario 1 also includes treasury's core carbon price trajectory, which is most similar to the Australian Governments' carbon price modelling[31], and uses the 2012 NTNDP wind contribution to maximum demand assumptions.[32]

  Several large-scale wind generation developments are proposed in regional and south-west Victoria; these will affect the market modelling outcomes. This scenario assumes a supply development scenario based on connection enquiry and connection applications submitted to AEMO by industry participants.[33]

- **Scenario 2** reflects parameters that would be associated with a medium rate of economic development outlined in scenario 1, but includes all new generation developments on the 500 kV network in Victoria's south-west corridor.

  Although this supply development scenario is not likely, AEMO considers this to be an appropriate scenario for inclusion due to the high number of connection applications in

[31] Australian Government Treasury. Strong Growth, Low Pollution – Modelling a Carbon Price. Available: http://archive.treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp. Accessed March 2013.

[32] AEMO. 2012 National Electricity Forecasting Report. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012. Accessed March 2013.

[33] AEMO. Generation Information. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information.

south-west Victoria, and the high level of supply that can be provided to regional Victoria via the 500 kV network at Moorabool.

- **Scenario 3** reflects parameters that would be associated with a slower rate of economic development than in scenario 1, with Victorian summer 10% POE and 50% POE demands forecast to increase over the next 10 years at annual rates of 1.2%.
- **Scenario 4** reflects parameters that would be associated with a slower rate of economic development outlined in scenario 3, but includes all new generation developments on the 500 kV network in south-west Victoria.
- **Scenario 5** reflects parameters that would be associated with the medium rate of economic development outlined in scenario 1, but with higher contribution from wind generators during maximum demand periods.[34]

Table 10 – Summary of parameters under each reasonable scenario

Drivers	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Economic growth	Medium	Medium	Low	Low	Medium
Demand growth	Medium	Medium	Low	Low	Medium
Carbon price	Treasury-core	Treasury-core	Treasury-core	Treasury-core	Treasury-core
Rooftop PV	Moderate	Moderate	Moderate	Moderate	Moderate
Wind contribution to maximum demand	6.5%	6.5%	6.5%	6.5%	33.0%
New generation development connections	220 kV & 500 kV	500 kV	220 kV & 500 kV	500 kV	220 kV & 500 kV
Weighting	20%	20%	20%	20%	20%

The carbon price assumed is based on the Federal Government's Clean Energy Policy, adjusted for CPI. Rooftop PV contribution is derived from AEMO's National Electricity Forecasting Report.[35]

6.4.2 Generation expansion plan

Table 11 shows the generation expansion plan modelled under each scenario. This is based on connection enquiry and connection application information submitted to AEMO.[36]

All five scenarios assume that the committed Macarthur Wind Farm (420 MW) and Mt Mercer Wind Farm (131 MW) are in service from 2013–14 and 2014–15 respectively.

Table 11 – Generation expansion plan modelled (Victoria)

Year	Project	Fuel Type	Capacity (MW)	SC 1	SC 2	SC 3	SC 4	SC 5
2013–14	Macarthur	Wind	420	✓	✓	✓	✓	✓
2014–15	Mt Gellibrand	Wind	232	✓	×	✓	×	✓
	Mt Mercer	Wind	131	✓	✓	✓	✓	✓
	Ryan Corner & Hawkesdale	Wind	234	✓	✓	✓	✓	✓
2015–16	Ararat	Wind	247	✓	×	✓	×	✓
2016–17	Ben More	Wind	120	✓	×	✓	×	✓
	Red Cliffs	Wind	201	✓	×	✓	×	✓
	Stockyard Hill	Wind	400	✓	✓	✓	✓	✓

34 Based on actual wind generation utilisation recorded at Victorian summer maximum demand during the 2009–10 year.

35 AEMO. 2012 National Electricity Forecasting Report. Table 2-1, p 2–9. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012. Accessed March 2013.

36 See footnote 31.

Year	Project	Fuel Type	Capacity (MW)	SC 1	SC 2	SC 3	SC 4	SC 5
	Penshurst	Wind	600	✓	✓	✓	✓	✓
2017–18	Lexton	Wind	47	✓	×	✓	×	✓
	Lal Lal (Yendon end)	Wind	80	✓	×	✓	×	✓
	Lal Lal (Elaine end)	Wind	48	✓	×	✓	×	✓
	Dundonnell	Wind	270	✓	✓	✓	✓	✓
	Darlington	Wind	350	✓	✓	✓	✓	✓
2018–19	Berry Bank	Wind	180	✓	×	✓	×	✓
	Crowlands	Wind	123	✓	×	✓	×	✓
	Moorabool	Wind	320	✓	×	✓	×	✓
	Mortlake and Minjah	Wind	485	✓	✓	✓	✓	✓
2019–20	Shaw River (Stage 1)	Gas	500	✓	✓	✓	✓	✓
2020–21	Tarrone	Gas	512	✓	✓	✓	✓	✓
2021–22	Mallee solar park	Solar	180	✓	×	✓	×	✓

6.4.3 Generation retirement plan

Table 12 shows the generation retirement plan modelled under each scenario.

Table 12 – Generation retirement plan modelled (Victoria)

Year	Station	SC 1	SC 2	SC 3	SC 4	SC 5
2014–15	Morwell G1	✓	✓	✓	✓	✓
	Morwell G2	✓	✓	✓	✓	✓
2015–16	Morwell G3	✓	✓	✓	✓	✓

6.5 Classes of market benefits not expected to be material

In the PSCRs and PADR, AEMO noted that the following classes of market benefit are unlikely to be material for this assessment:

- Changes in ancillary services costs.
- Competition benefits.
- Option value.

AEMO notes that one PSCR submission was received and has been adequately addressed; no party disputed the identification of these three market benefit categories as being not material.

AEMO notes that SP AusNet provided a PADR submission in relation to the market impact cost. AEMO conducted further assessment and addressed SP AusNet's submission in the RIT-T PACR assessment.

In addition to these categories, AEMO also identified that changes in costs for parties other than the TNSP are not a material market benefit category for the purposes of this assessment.

AEMO's rational for considering these classes of market benefits as not material are set out below:

- Changes in ancillary services costs

  There is no expected change to costs of Frequency Control Ancillary Services (FCAS), Network Support Control Ancillary Services (NSCAS), or System Restart Ancillary Services

(SRAS) as a result of the options considered. These costs are therefore not material to the RIT-T assessment outcome.

- Competition benefits

  Increasing supply capability to regional Victoria will reduce reliance on local generation and increase the ability of generation from the rest of the NEM to supply the bulk demand areas around regional Victoria. The extent that this increase in competition results in market benefits over and above those already identified under “changes in fuel consumption arising through different patterns of generation dispatch” is expected to be negligible.

  Further assessment of competition benefits would also require additional modelling, such as the inclusion of game theory bidding or similar, which would lead to substantial increases in the complexity and cost of this RIT-T assessment. Such increased complexity is not warranted given the negligible market benefits expected from any additional market competition realised.

  Given that AEMO considers this class of benefit not to be material, it has not attempted to estimate any additional market competition benefit for this RIT-T assessment.

- Option value

  AEMO notes the RIT-T Application Guidelines stage that “option value” is likely to arise where there is uncertainty regarding future outcomes; where the information that is available in the future is likely to change; and where the credible options considered by the RIT-T Proponent are sufficiently flexible to respond to that change.[37]

  AEMO also notes that the appropriate identification of credible options and reasonable scenarios capture any option value, thereby meeting the requirement under NER clause 5.16.1(c)(4)(ix) to consider option value as a class of market benefit under the RIT-T.

  For this RIT-T assessment, estimating any option value benefit over and above that already captured in the scenario analysis would require significant additional modelling assessment. This would be disproportionate to any additional option value benefit that may be identified for this specific RIT-T assessment. AEMO does not propose to estimate any additional option value market benefit for this RIT-T assessment.

- Changes in costs for parties, other than the TNSP, due to differences in timing of new plant, capital and operating and maintenance costs
- Increasing the thermal capability of the Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line may lead to deferral of network augmentations in South Australia’s Riverland region, provided other existing limitations in regional Victoria are addressed (see Section 3.2.2).
- AEMO and Powercor will undertake a joint planning assessment with a view to addressing the identified limitations on the 66 kV lines. AEMO did not include potential benefits associated with the deferral of investment in the Riverland region because the net market benefits of each credible option will increase linearly. For this reason, the requirement to augment and ranking of credible options is not likely to change.

[37] AER. Final Regulatory Investment Test for Transmission Application Guidelines, p.39 and p.75. Available: http://www.aer.gov.au. Accessed November 2011.

7 Detailed option assessment

This section sets out the results of the net present value (NPV) analysis for each credible option discussed in sections 4.3 and 4.4. The National Electricity Rules (NER) requires that the Project Assessment Conclusion Report (PACR) set out a detailed description of the methodologies used in quantifying each class of material market benefit and cost, together with the results of the NPV analysis, and explanatory statements regarding the results.

This section outlines how AEMO calculated each of the costs and material categories of market benefits, and presents the market benefit results across each credible option.

7.1 Quantifying costs for each credible option

The network option capital costs are based on cost estimates provided by SP AusNet, prepared using their in-house estimation tool. The costs are indexed according to Melbourne CPI to represent them in 2013–14 dollars.

Network option operating costs were assumed to be 2% of each option's annual capital cost. The accuracy range of these estimates is ± 30%, and they exclude land easement costs and augmentation outage market impact costs.

AEMO estimated the indicative costs for the demand-management provisions in option 8 based on general industry knowledge available, including submissions to other RIT-T assessments and discussions with non-network providers.

Table 13 presents the total cost of each credible network option.

Table 13 – Total cost of credible network options (2013–14 $M)

Option	Component	Capital cost ($M)	Operating cost ($M)	Total project cost ($M)
1a	Up-rate the existing Ballarat–Bendigo 220 kV line to maximum operating temperature of 82 ºC. Up-rate the existing Moorabool–Ballarat 220 kV line to maximum operating temperature of 82 ºC.	77.2 48.4	15.1 9.5	150.2
1b	Install wind monitoring facility on Ballarat–Bendigo 220 kV line. Up-rate the existing Ballarat–Bendigo 220 kV line to maximum operating temperature of 82 ºC. Up-rate the existing Moorabool–Ballarat 220 kV line to maximum operating temperature of 82 ºC.	0.6 77.2 48.4	0.1 15.1 9.5	150.9
2	Up-rate the existing Ballarat–Bendigo 220 kV line to maximum operating temperature of 82 ºC. Up-rate the existing Moorabool–Ballarat 220 kV line to maximum operating temperature of 90 ºC.	77.2 50.4	15.1 9.9	152.6
3a	Install a third Moorabool–Ballarat 220 kV circuit. Up-rate the existing Ballarat–Bendigo 220 kV line to maximum operating temperature of 82 ºC.	27.8 77.2	5.4 15.1	125.5
3b	Install wind monitoring facility on Ballarat–Bendigo 220 kV line. Install a third Moorabool–Ballarat 220 kV circuit. Up-rate the existing Ballarat–Bendigo 220 kV line to maximum operating temperature of 82 ºC.	0.6 27.8 77.2	0.1 5.4 15.1	126.2
4a	Install a third Moorabool–Ballarat 220 kV circuit. Up-rate the existing Ballarat–Bendigo 220 kV line to maximum operating temperature of 90 ºC.	27.8 82.3	5.4 16.1	131.6

Option	Component	Capital cost ($M)	Operating cost ($M)	Total project cost ($M)
4b	Install wind monitoring facility on Ballarat–Bendigo 220 kV line. Install a third Moorabool–Ballarat 220 kV circuit. Up-rate the existing Ballarat–Bendigo 220 kV line to maximum operating temperature of 90 ºC.	0.6 27.8 82.3	0.1 5.4 16.1	132.4
5	Up-rate the existing Ballarat–Bendigo 220 kV line to maximum operating temperature of 82 ºC. Replace the existing Moorabool–Ballarat 220 kV line with a new double-circuit 220 kV line.	77.2 94.7	15.1 18.5	205.5
6	Up-rate the existing Moorabool–Ballarat 220 kV line to maximum operating temperature of 82 ºC. Replace the existing Ballarat–Bendigo 220 kV line with a new double-circuit 220 kV line.	48.4 171.8	9.5 33.6	263.3
7	Install a third Moorabool–Ballarat 220 kV circuit. Replace the existing Ballarat–Bendigo 220 kV line with a new double-circuit 220 kV line.	27.8 171.8	5.4 33.6	238.6

Table 14 presents the total cost of credible non-network option.

Table 14 – Total cost of the credible non-network option (2013–14 $M)

Option	Component	Establishment cost ($/MW)	Availability charge ($/MW/year)	Dispatch fee ($/MWh)	Total project cost ($M)[38]
8	Non-network demand-side management	80,000	90,000	900	18.2

7.2 Fault level assessment

Table 15 highlights the short-circuit levels at Ballarat, Bendigo, and Moorabool terminal stations under each option considered in this RIT-T assessment.

Table 15 – Short-circuit levels at Ballarat, Bendigo, and Moorabool in 2016–17

Option	Ballarat Terminal Station		Bendigo Terminal Station		Moorabool Terminal Station	
	Short-circuit level (kA)	Short-circuit limit (kA)	Short-circuit level (kA)	Short-circuit limit (kA)	Short-circuit level (kA)	Short-circuit limit (kA)
Do Nothing	12.0	26.2	5.8	26.2	26.6	26.2
1a	12.0	26.2	5.8	26.2	26.6	26.2
1b	12.0	26.2	5.8	26.2	26.6	26.2
2	12.0	26.2	5.8	26.2	26.6	26.2
3a	14.2	26.2	6.0	26.2	27.0	26.2
3b	14.2	26.2	6.0	26.2	27.0	26.2
4a	14.2	26.2	6.0	26.2	27.0	26.2
4b	14.2	26.2	6.0	26.2	27.0	26.2
5	12.6	26.2	5.9	26.2	26.7	26.2
6	12.4	26.2	8.3	26.2	26.8	26.2
7	14.7	26.2	8.7	26.2	27.2	26.2
8	12.0	26.2	5.8	26.2	26.6	26.2

38 This includes the establishment cost and availability cost.

The 2012 Annual Victorian Short-circuit Level Review[39] indicates that the short-circuit levels at the Moorabool 220 kV bus may reach the NER limit of 26.2 kA in 2014–15.

AEMO is currently working with SP AusNet to increase the NER limit at Moorabool Terminal Station to an acceptable limit based on the station's design capability. AEMO assumes that any additional costs associated with increased short-circuit levels at Moorabool Terminal Station are considered outside this RIT-T assessment.

AEMO notes that if additional costs to manage the short-circuit levels at Moorabool Terminal Station were to be considered within this RIT-T, the timing or ranking of the preferred option is not likely to change as these costs are common to all options.

7.3 Classes of market benefits expected to be material

The purpose of the RIT-T is to identify the credible option that maximises the present value of net benefit to all persons who produce, consume, and transport electricity in the market.[40]

To measure the increase in net market benefit, AEMO has analysed the classes of market benefit required for consideration under the RIT-T. AEMO believes that the classes of market benefits most likely to change as a result of reducing limitations on the Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220kV lines are:

- Involuntary load shedding.
- Voluntary load curtailment.
- Generator fuel consumption arising through different patterns of generation dispatch.
- Network losses.

7.3.1 Changes in involuntary load shedding

During periods of high demand in regional Victoria, increased available supply capability will reduce the potential for supply shortages and consequent risk of involuntary load shedding in regional Victoria.

Similarly, voluntary load curtailment, through non-network demand-management, reduces the amount of load shedding required.

7.3.2 Changes in voluntary load shedding

Voluntary load curtailment is when customers agree to reduce their load once pool prices in the National Electricity Market (NEM) reach a certain threshold. Customers usually receive a payment for this.

Where implementing a credible option affects pool price outcomes—particularly when pool prices reach higher levels in some trading intervals than in the base case—this may affect the extent of voluntary load curtailment.

The PROPHET modelling incorporates voluntary load curtailment as part of its suite of dispatch options in accordance with the assumptions in 2012 NEFR. Under credible option 8, demand-side management was assessed in addition to voluntary load curtailment. As a consequence, the market benefit associated with changes in voluntary load curtailment is already reflected in the difference in dispatch cost outcomes outlined in Section 7.3.3.

AEMO notes that the level of voluntary load curtailment currently present in the NEM is limited.

[39] AEMO. Short-circuit Levels for Victorian Electricity Transmission: 2013–17. Available: http://www.aemo.com.au/Electricity/Planning/Victorian-Annual-Planning-Report-2013/Victorian-Short-Circuit-Level-Review.

[40] AEMC. National Electricity Rules. Version 54, Clause 5.16. Available: http://www.aemc.gov.au.

Additionally, a demand-side reduction credible option would lead to increased voluntary load curtailment in place of involuntary load shedding. Costs associated with this are presented as increased dispatch costs.

7.3.3 Changes in generator fuel consumption

The network limitations identified are predominantly driven by increasing demand. However, new generation developments connected within the 220 kV network, north of Ballarat and Bendigo terminal stations, can offload the transmission assets of concern.

The PROPHET modelling incorporates the expected changes in generator fuel consumption associated with each credible option by calculating the total dispatch cost under each state of the world. Specifically, the generation dispatch cost under each credible option and state of the world is compared with the generation dispatch cost under the base case, and included in the total cost of constraint to quantify the market benefit associated with changes in generation fuel consumption.

AEMO also expects a non-network option to lead to differences in fuel consumption by displacing scheduled generation at the time of operation. This may lead to an increase or decrease in market benefits depending on the fuel cost of the non-network option.

7.3.4 Changes in network losses

Increasing supply capability to regional Victoria can lead to reduced network losses as additional supplies in regional Victoria are established.

Similarly, a non-network option, such as new local generation in close proximity to the bulk demand area, could also be expected to reduce network losses.

AEMO's market modelling took into account the change in network losses that may occur as a result of implementing any of the credible options, compared with base case network losses, for each scenario.

An increase in network losses represents a negative market benefit (a market cost); a reduction in losses represents a positive market benefit.

7.4 Net present value results

This section summarises the results of the NPV analysis. It first summarises the gross market benefits and then presents the net market benefits of each credible option. This is followed by a sensitivity assessment of key assumptions including discount rate, capital option cost, VCR, and scenario weights.

The spreadsheet in Appendix D presents a full set of results, including the annual market impact of each credible option assessed.

7.4.1 Gross market benefits

Table 16 summarises the gross market benefit, in NPV terms, for each of the 11 credible options included in the RIT-T analysis. The gross market benefit is the sum of each individual category of material market benefit (both positive and negative) as quantified using the approach set out in Chapter 6.

AEMO calculated the gross market benefit of each option for five reasonable scenarios. The results for each option under each scenario were then weighted together to derive the overall market benefit for each option.

Table 16 – Gross market benefits for each credible option (NPV, $M)

Options	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Weighted gross market benefits
Scenario weights	20%	20%	20%	20%	20%	
1a	291.5	794.8	235.1	540.7	150.5	402.5
1b	314.6	809.6	256.0	556.7	188.3	425.0
2	293.2	796.7	235.5	540.7	150.1	403.2
3a	289.1	795.7	293.2	550.9	167.2	419.2
3b	312.1	814.3	314.5	571.0	206.2	443.6
4a	289.1	795.2	293.2	551.0	167.6	419.2
4b	312.1	814.3	314.5	571.0	206.2	443.6
5	271.1	754.9	236.1	526.0	129.9	383.6
6	210.2	630.5	218.3	459.2	141.8	332.0
7	228.1	722.0	260.8	490.0	164.4	373.1
8	64.9	202.7	59.9	126.3	44.5	99.7

Table 16 highlights that the market benefits of all options considered in this RIT-T are sensitive to the scenarios modelled.

The market benefits are significantly higher under scenarios 2 and 4 as new generation developments north of Ballarat and Bendigo are not modelled; this can offset the identified network limitations. The market benefits for all options under scenario 2 are the highest because higher (i.e., medium) demand levels are assumed.

Table 16 also shows that the market benefits for all options considered are the lowest under scenario 5. This scenario assumes a higher capacity factor for existing and new wind generators during maximum demand periods.

7.4.2 Net market benefits

Table 17 summarises the net market benefit in NPV terms for each credible option. The net market benefit is the gross market benefit, weighted across all scenarios (as set out in Table 16), minus the costs of each option, all in present value terms.

The table also shows the corresponding ranking of each option under the RIT-T. The options are ranked from one to 11 in order of descending net market benefit.

Table 17 – Net market benefits for each credible option (PV, $M)

Option	Project cost	Weighted gross market benefit	Net market benefit	Ranking under RIT-T
1a	150.2	402.5	252.4	6
1b	150.9	425.0	274.1	5
2	152.6	403.2	250.7	7
3a	125.5	419.2	293.7	3
3b	126.2	443.6	317.4	1
4a	131.6	419.2	287.6	4
4b	132.4	443.6	311.3	2
5	205.5	383.6	178.1	8
6	263.3	332.0	68.7	11
7	238.6	373.1	134.4	9

8	18.2	99.7	81.5	10

Table 17 shows that all credible options have positive net market benefits in the form of large reductions in expected USE. As a consequence, all credible options are ranked higher than the "Do Nothing" option.

The results demonstrate that the incremental costs of adding the wind monitoring facility under options 1b, 3b and 4b are offset by additional market benefits compared to options without the wind monitoring facility (options 1a, 3a and 4a). This results in materially higher net market benefits for options 1b, 3b and 4b.

The RIT-T assessment shows that options 3a, 3b and 4b have the three highest net market benefits. Although option 3b has the greatest net market benefit, the difference between this and option 4b is only $6.1 million, or 1.9%. This small difference is within the resolution of the market simulation tools, requiring further sensitivity analysis to decide the preferred option.

7.5 Sensitivity analysis

AEMO performed a series of sensitivity studies on the base results presented above for all the options. The sensitivity analyses consider and allow for changes in relation to:

- The discount rate applied.
- The value of customer reliability.
- Network capital costs.

Table 18 presents the NPV of each credible option, relative to the Do Nothing option, under each sensitivity considered.

Table 18 – Net present value of net market benefits (NPV, $M)

Sensitivity	Discount rate		Capital cost		VCR	
	6%	12%	+30%	-30%	+20%	-20%
Option 1a	635.2	152.1	207.3	297.4	332.9	171.9
Option 1b	643.6	174.2	228.9	319.4	359.1	189.1
Option 2	634.3	150.2	204.9	296.4	331.3	170.0
Option 3a	659.4	195.5	256.0	331.3	377.5	209.8
Option 3b	678.8	218.3	279.5	355.2	406.1	228.6
Option 4a	653.4	189.4	248.1	327.1	371.4	203.7
Option 4b	672.7	212.2	271.6	351.0	400.0	222.5
Option 5	540.2	83.1	116.4	239.8	254.8	101.4
Option 6	394.2	-15.9	-10.2	147.7	135.1	2.3
Option 7	463.5	46.3	62.8	206.0	209.0	59.8
Option 8	153.9	61.3	76.0	86.9	101.7	61.2

All options are sensitive to changes in the discount rates applied, capital costs, and VCR weightings. However, the three top-ranking options are not sensitive to these changes, and in no case are other credible options found to have higher net market benefits than options 3a, 3b and 4b.

Table 19 shows the net market benefit (in NPV terms) of options 3a, 3b and 4b under alternative scenario weightings.

Table 19 – Net market benefits under different scenario weightings (NPV, $M)

Description	Net market benefit ($M)			Scenario weighting				
	Option 3a	Option 3b	Option 4b	SC 1	SC 2	SC 3	SC 4	SC 5
Under current scenario weightings.	293.7	317.4	311.3	20.0%	20.0%	20.0%	20.0%	20.0%
Weightings of medium demand scenarios reduced.	294.3	317.2	311.1	15.8%	15.8%	26.3%	26.3%	15.8%
Weightings of medium demand scenarios increased.	293.1	317.5	311.4	23.8%	23.8%	14.3%	14.3%	23.8%
Weightings of 500 kV generation placement scenarios reduced.	245.4	270.1	264.0	23.8%	14.3%	23.8%	14.3%	23.8%
Weightings of 500 kV generation placement scenarios increased.	347.0	369.7	363.6	15.8%	26.3%	15.8%	26.3%	15.8%
Weightings of high wind generator contribution to maximum demand scenario reduced.	314.8	337.1	331.0	21.7%	21.7%	21.7%	21.7%	13.0%
Weightings of high wind generator contribution to maximum demand scenario increased.	263.1	288.5	282.4	17.6%	17.6%	17.6%	17.6%	29.4%

The net market benefits of options 3a, 3b, and 4b also depend on the scenario weightings adopted. For this reason, AEMO assessed different weights taking into consideration the likelihood of:

- Demand levels.
- Generation development.
- Wind generator contribution levels during maximum demand periods.

The results in Table 19 show that option 3b maximises the net market benefits under a wide-range of alternative scenario weightings.

7.6 Selection of preferred option

The market costs associated with outage requirements of each network option were not considered in the cost-benefit assessment (see Table 16). SP AusNet provided these requirements, which were prepared using their in-house estimation tools. Table 20 highlights the estimated outage requirements of major investment elements for the top three credible options.

This shows that the number and duration of outages associated with increasing thermal capability of existing lines are significantly higher compared with installing new circuits.[41]

[41] The outage requirements associated with up-rating the existing lines are larger due to installation of new towers to maintain adequate ground clearance. AEMO estimated that 130 to 140 towers would need to be replaced to up-rate the Ballarat–Bendigo 220 kV line from maximum operating temperature of 65 ºC to 82 ºC and 90 ºC respectively.

Table 20 – Estimated outage requirements of major works associated with top three credible options

Option	Option description	Number of outages	Duration (hours)	Total duration (hours)
3a	Install a third Moorabool–Ballarat 220 kV circuit. Up-rate the existing Ballarat–Bendigo line to maximum operating temperature of 82 ºC.	9 166	216 2016	2232
3b	Install a wind monitoring facility on the Ballarat–Bendigo 220 kV line. Install a third Moorabool–Ballarat 220 kV circuit. Up-rate the existing Ballarat–Bendigo line to maximum operating temperature of 82 ºC.	0 9 166	0 216 2016	2232
4b	Install a wind monitoring facility on the Ballarat–Bendigo 220 kV line. Install a third Moorabool–Ballarat 220 kV circuit. Up-rate the existing Ballarat–Bendigo line to maximum operating temperature of 90 ºC.	0 9 169	0 216 2052	2268

Option 3a is ruled out, as the only difference between option 3a and 3b is the wind monitoring facility, which has been shown as effective in maximising net market benefit.

AEMO notes that there are core investment elements common to both options 3b and 4b. These are installing a wind monitoring facility on the Ballarat–Bendigo 220 kV line, and installing the third Moorabool–Ballarat 220 kV circuit.

For this reason, these common investment elements will be part of the preferred option, irrespective of which one is selected.

AEMO proposed option 3b as the preferred option, as this option:

- Maximises the net market benefits under all credible sensitivities considered.
- Has the lowest outage requirements.

8 Proposed preferred option

The previous section presented the results of the net present value (NPV) analysis conducted for this RIT-T assessment.

The National Electricity Rules (NER) requires the Project Assessment Conclusion Report (PACR) to identify the preferred option under the RIT-T.[42] This should be the option with the greatest net market benefit, and which is therefore expected to maximise the present value of the net economic benefit to all who produce, consume and transport electricity in the market.

The RIT-T analysis outlined in sections 7.4 and 7.5 indicates that the following three credible options have the three highest net market benefits, and are ranked ahead of all other credible options:

- Option 3a – Installing the third Moorabool–Ballarat 220 kV circuit and up-rating the Ballarat–Bendigo 220 kV line to a maximum conductor temperature of 82 ºC.
- Option 3b – Installing wind monitoring facility on the Ballarat–Bendigo 220 kV line followed by installing the third Moorabool–Ballarat 220 kV circuit and up-rating the Ballarat–Bendigo 220 kV line to a maximum conductor temperature of 82 ºC.
- Option 4b – Installing wind monitoring facility on the Ballarat–Bendigo 220 kV line followed by installing the third Moorabool–Ballarat 220 kV circuit and up-rating the Ballarat–Bendigo 220 kV line to a maximum conductor temperature of 90 ºC.

As outlined in Section 7.6, AEMO determined that the preferred option for investment is option 3b. This option maximises the net market benefits under sensitivities of discount rates, value of customer reliability (VCR), network capital costs, and scenario weightings. It also has the lowest outage requirements.

This option's positive net market benefit is $317.4 million under an equal-weighted scenario, which satisfies the RIT-T.

Given that the estimated project lead time for stage 1 (installing a wind monitoring facility) is one year and two months, stage 2 (installing a third Moorabool–Ballarat line) is three years and two months, and stage 3 (up-rating the Ballarat–Bendigo line to 82ºC) is four years and nine months, positive net market benefits are expected from the first year of operation, which is 2015–16. .

Table 21 presents the annualised cost-benefit assessment of the preferred option, for the 10-year period from 2013–14. This shows that the optimal time for augmentation is before 2013–14, being the year when the annualised gross market benefits associated with augmenting begin to outweigh the annualised cost to implement.

Table 21 – Annualised cost-benefit assessment of preferred option

Year	Market impact of Do Nothing base case		Market impact of the preferred option from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0.0	0.0	0.0
2014–15	586	36.3	0	0.0	0.0	0.0
2015–16	616	38.2	108	6.7	0.1	6.6
2016–17	751	46.6	157	9.7	0.1	9.7
2017–18	814	50.5	631	39.1	3.5	35.6
2018–19	825	51.1	691	42.8	3.5	39.4
2019–20	954	59.1	955	59.2	12.9	46.2

42 NER 5.6.6 (c)(8).

Year	Market impact of Do Nothing base case		Market impact of the preferred option from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2020–21	1,062	65.8	1,059	65.6	12.9	52.7
2021–22	995	61.6	985	61.0	12.9	48.1
2022–23	1,240	76.8	1,180	73.1	12.9	60.2

The preferred option total cost contains capital operating costs. The total capital cost is estimated at $105.6 million (in present value terms) and the operating cost, assuming 2% of the annual capital cost, is $20.6 million (in present value terms).

The total project cost is $126.2 million (in present value terms).

The technical characteristics of this option are set out in Section 4.3.

Before the preferred option can be completed, involuntary load reduction under certain conditions may be required to maintain power system security.

Automatic control schemes have been implemented to reduce existing risk of pre-contingent load shedding. These schemes enable the use of higher short-term (5-minute) ratings on the Ballarat–Bendigo 220 kV line and Moorabool–Ballarat No.1 220 kV line.

Subsequent to the issue of the Project Assessment Draft Report (PADR), AEMO received proposals from EnerNoc, NovaPower and Transmission Operations Australia (TOA) to minimise the potential load at risk in the form of demand management and embedded generation. AEMO has discussed the proposals with these entities but notes that it currently has insufficient information to consider these to be credible options at this time.

To maximise the net market benefit from the investment, AEMO proposes to commit to stages 1 and 2 of the preferred option, but that stage 3 be placed on hold and the need and timing for this stage be further assessed against recent proposals received from non-network service providers.

Appendix A Murraylink runback schemes

A number of runback schemes have been implemented to allow for higher transfers on the Murraylink Interconnector. These schemes allow higher pre-contingency flows on Murraylink due to automatic post-contingency action returning the network to a secure operating state.

A fast runback scheme was also installed for some network elements in New South Wales; however, this scheme has not yet been placed into service due to communication problems.

Without the New South Wales runback scheme enabled, Murraylink transfer to South Australia may be limited to near zero under high demand conditions in New South Wales. Investigations are ongoing to get this runback scheme operational.

A.1 Murraylink automatic slow runback control (Victoria)

This automatic slow runback control scheme is required to prevent power flows exceeding the thermal limits in the Victorian transmission system for contingent loss of one several critical 220 kV circuits. The scheme continuously monitors the loading of critical circuits within Victoria and will reduce Murraylink transfer if overloads become apparent.

The slow runback scheme operates only with Murraylink transfer from Victoria to South Australia.

The monitored circuits are (dynamic line ratings are used for all lines):

- Bendigo–Shepparton 220 kV line.
- Moorabool–Ballarat 220 kV No.1 line.
- Ballarat–Bendigo 220 kV line.
- Dederang–Shepparton 220 kV line.
- Dederang–Glenrowan 220 kV No.1 line.
- Dederang–Glenrowan 220 kV No.3 line.

If the scheme is triggered it will reduce Murraylink to South Australia flow by 110 MW, or to 0 MW if the initial transfer is less than 110 MW. This will relieve the overloaded transmission circuit.

A.2 Murraylink Very Fast Runback Scheme (Victoria)

The Very Fast Runback (VFRB) Scheme allows higher transfers on Murraylink by initiating rapid reduction in Murraylink power flow following critical contingencies in Victoria.

The VFRB scheme operates only with Murraylink transfer from Victoria to South Australia.

Murraylink transfer to South Australia is reduced to below 20 MW following the trip of any of the following monitored transmission elements:

- Bendigo–Fosterville–Shepparton 220 kV line.
- Bendigo–Kerang 220 kV line.
- Kerang – Red Cliffs 220 kV line.
- Ballarat–Horsham 220 kV line.
- Horsham – Red Cliffs 220 kV line.
- Ballarat–Bendigo 220 kV line.
- Moorabool–Ballarat 220 kV No.1 line.
- Moorabool–Ballarat 220 kV No.2 line.

- Moorabool 500/220 kV No.1 transformer (VFRB not enabled for Moorabool No.2 transformer).
- Dederang 330 kV bus tie.

A.3 Automatic sever trip (South Australia)

As the existing North West Bend (NWB), Monash and Berri substations can be supplied through a radial system, it is possible for the system to be "severed" from the South Australian network, either momentarily or permanently.

The automatic sever trip scheme is required to identify the "islanding" of the NWB, Monash and Berri substations from the South Australian network, and to trip the connecting circuit breakers to the Murraylink Berri converter. This prevents the possibility of load connected to NWB or Monash and Berri being supplied by Murraylink in isolation.

A.4 Automatic runback scheme (South Australia)

This runback scheme permits increased power flow across Murraylink through supervision of selected network conditions and automatic control of power flow to prevent network thermal overload conditions.

When a contingency occurs, runback will not only reduce the real power flow through Murraylink but will also increase the reactive power capability of Murraylink.

Such increased reactive capability is especially useful in improving voltage stability following network contingencies. The automatic runback control scheme is designed to prevent exceeding the thermal limits in the South Australian transmission system.

The scheme reduces the import/export of Murraylink to a secure operating level within five seconds from receipt of the runback signal.

The following lines are monitored by the automatic runback control scheme:

- Robertstown–NWB 132 kV No.1 line.
- Robertstown–NWB 132 kV No.2 line.
- NWB–Monash 132 kV No.1 line.
- NWB–Monash 132 kV No.2 line.

Appendix B Market modelling inputs

B.1 Demand forecasts

Table 22 and Table 23 present the maximum demand adopted under the medium demand scenario at critical regional Victorian terminal station connection points.

Table 22 – 10% POE maximum demand adopted under the medium demand scenarios (MW)

Connection point	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23
Ballarat	182.7	186.0	189.5	192.9	196.9	199.4	202.9	205.5	209.0	211.9
Bendigo	237.4	242.9	248.9	256.2	261.6	267.1	272.7	278.6	284.5	290.5
Fosterville	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Horsham	91.4	92.2	93.1	94.0	94.9	95.8	96.7	97.7	98.6	99.6
Kerang	70.7	71.4	72.2	72.9	73.7	74.5	75.4	76.2	77.0	77.9
Red Cliffs	188.6	192.8	196.9	201.2	205.5	210.0	214.6	219.3	224.1	229.1
Shepparton	299.8	303.2	304.8	306.4	308.0	309.6	311.3	312.9	314.6	316.3
Terang	185.9	187.8	189.2	191.0	192.5	194.0	195.5	197.0	198.5	200.0
Wemen	55.4	57.2	58.5	59.6	60.4	61.2	62.1	62.9	63.8	64.7

Table 23 – 50% POE maximum demands adopted under the medium demand scenarios (MW)

Connection point	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23
Ballarat	176.2	179.4	182.8	186.0	189.9	192.3	195.7	198.2	201.6	204.3
Bendigo	222.1	227.3	232.9	239.8	244.8	249.9	255.2	260.8	266.3	271.9
Fosterville	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Horsham	85.6	86.3	87.2	88.0	88.9	89.7	90.6	91.5	92.4	93.2
Kerang	66.9	67.6	68.3	69.0	69.8	70.6	71.3	72.1	72.9	73.7
Red Cliffs	178.2	182.16	186.07	190.1	194.22	198.45	202.8	207.27	211.85	216.6
Shepparton	281.7	284.9	286.4	287.9	289.5	291.0	292.6	294.1	295.7	297.2
Terang	178.3	180.1	181.4	183.2	184.6	186.0	187.5	188.9	190.4	191.8
Wemen	53.6	55.2	56.5	57.6	58.4	59.2	60.0	60.8	61.6	62.5

Table 24 and Table 25 present the maximum demand adopted under the low demand scenario, at critical regional Victorian terminal station connection points.

Table 24 – 10% POE maximum demands adopted under the low demand scenarios (MW)

Connection point	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23
Ballarat	178.7	181.2	183.6	186.2	189.6	191.3	193.7	195.3	197.8	200.5
Bendigo	232.5	236.8	241.5	247.6	252.2	256.5	260.6	265.0	269.4	275.1
Fosterville	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Horsham	89.5	89.9	90.3	90.8	91.5	92.0	92.5	93.0	93.4	94.3
Kerang	69.2	69.6	70.0	70.5	71.1	71.6	72.0	72.5	73.0	73.8
Red Cliffs	184.2	187.4	190.4	193.7	197.4	201.1	204.5	208.0	211.6	216.3
Shepparton	293.1	295.2	295.2	295.7	296.5	296.9	297.1	297.3	297.6	299.2
Terang	191.8	192.8	188.9	194.2	195.2	195.8	196.3	196.8	197.4	198.9
Wemen	54.3	55.7	56.7	57.5	58.2	58.7	59.2	59.8	60.3	61.2

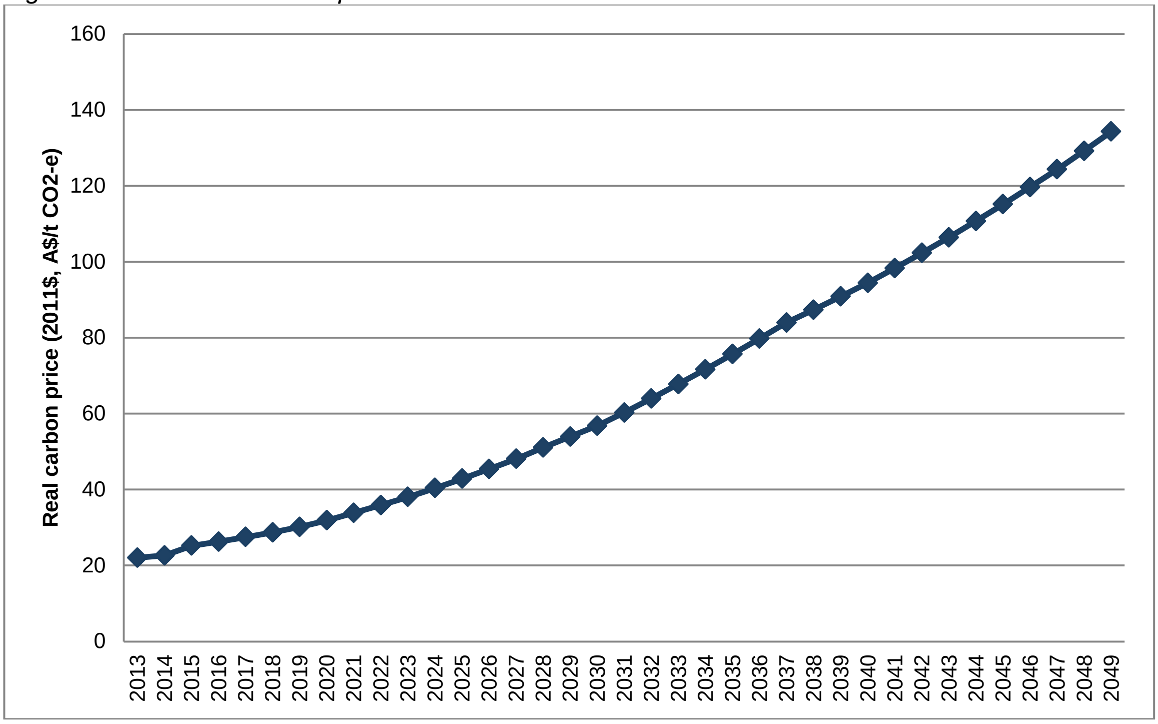
Table 25 – 50% POE maximum demands adopted under the low demand scenarios (MW)

Connection point	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23
Ballarat	172.2	174.6	176.9	179.4	182.7	184.3	186.6	188.2	190.6	193.1
Bendigo	217.3	221.5	225.8	231.5	235.8	239.8	243.7	247.9	252.0	257.4
Fosterville	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Horsham	83.7	84.1	84.5	85.0	85.6	86.0	86.5	87.0	87.4	88.2
Kerang	65.4	65.9	66.2	66.7	67.2	67.7	68.1	68.6	69.0	69.8
Red Cliffs	173.9	177.0	179.8	182.9	186.4	189.7	193.1	196.4	199.8	204.3
Shepparton	275.2	277.2	277.2	277.6	278.4	278.8	278.9	279.2	279.4	280.9
Terang	184.2	185.1	181.3	186.5	187.4	188.0	188.5	189.0	189.5	191.0
Wemen	52.4	53.8	54.8	55.5	56.2	56.7	57.2	57.7	58.2	59.0

B.2 Carbon price

Figure 9 presents the carbon price adopted in this RIT-T assessment.

Figure 9 – Assumed carbon price



Appendix C Annual market impact

This section shows the forecast market impact and classes of market benefits expected under each option assessed.

For detailed net present value (NPV) analysis, including sensitivity and weighted scenario results, refer to the Appendix D Excel file located on the same webpage as this PACR in AEMO's website.

C.1 Option 1a

Table 26 present the forecast market impact under option 1a.

Table 26 – Forecast market impact under option 1a

Year	Market impact of Do Nothing base case		Market impact of option 1a from implementation in accordance with the respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0.0	0.0	0.0
2014–15	586	36.3	0	0.0	0.0	0.0
2015–16	616	38.2	0	0.0	0.0	0.0
2016–17	751	46.6	0	0.0	0.0	0.0
2017–18	814	50.5	0	0.0	0.0	0.0
2018–19	825	51.1	0	0.0	0.0	0.0
2019–20	954	59.1	954	59.1	15.4	43.7
2020–21	1,062	65.8	1,061	65.7	15.4	50.4
2021–22	995	61.6	994	61.6	15.4	46.2
2022–23	1,240	76.8	1,237	76.6	15.4	61.3

Given the estimated project lead time is four years and nine months (up-rate Ballarat–Bendigo and Moorabool–Ballarat No.1 lines to 82 ºC), positive net benefits are expected from the first year of operation, being 2019–20.

Option 1a reduces the amount of involuntary load shedding by providing additional network capacity.

C.2 Option 1b

Table 27 presents the forecast market impact under option 1b.

Table 27 – Forecast market impact under option 1b

Year	Market impact of Do Nothing base case		Market impact of option 1b from implementation in accordance with the respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0.0	0.0	0.0
2014–15	586	36.3	0	0.0	0.0	0.0
2015–16	616	38.2	108	6.7	0.1	6.6
2016–17	751	46.6	157	9.7	0.1	9.7
2017–18	814	50.5	183	11.3	0.1	11.2

Year	Market impact of Do Nothing base case		Market impact of option 1b from implementation in accordance with the respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2018–19	825	51.1	237	14.7	0.1	14.6
2019–20	954	59.1	952	59.0	15.4	43.5
2020–21	1,062	65.8	1,062	65.8	15.4	50.4
2021–22	995	61.6	994	61.6	15.4	46.1
2022–23	1,240	76.8	1,237	76.6	15.4	61.2

Given the estimated project lead time for stage 1 (installation of wind monitoring facility) is one year and two months, and for stage 2 (up-rate Ballarat–Bendigo and Moorabool–Ballarat No.1 lines to 82 ºC) is four years and nine months, positive net benefits are expected from the first year of operation, being 2015–16.

Option 1b reduces the amount of involuntary load shedding by providing additional network capacity.

C.3 Option 2

Table 28 presents the forecast market impact under option 2.

Table 28 – Forecast market impact under option 2

Year	Market impact of Do Nothing base case		Market impact of option 2 from implementation in accordance with the respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0	0.0	0.0
2014–15	586	36.3	0	0	0.0	0.0
2015–16	616	38.2	0	0	0.0	0.0
2016–17	751	46.6	0	0	0.0	0.0
2017–18	814	50.5	0	0	0.0	0.0
2018–19	825	51.1	0	0	0.0	0.0
2019–20	954	59.1	951	58.9	15.6	43.3
2020–21	1,062	65.8	1,062	65.8	15.6	50.2
2021–22	995	61.6	996	61.7	15.6	46.1
2022–23	1,240	76.8	1,240	76.8	15.6	61.2

Given the estimated project lead time is four years and nine months (up-rate Ballarat–Bendigo and Moorabool–Ballarat No.1 lines to 82 ºC and 90 ºC respectively), positive net benefits are expected from the first year of operation, being 2019–20.

Option 2 reduces the amount of involuntary load shedding by providing additional network capacity.

C.4 Option 3a

Table 29 presents the forecast market impact under option 3a.

Table 29 – Forecast market impact under option 3a

Year	Market impact of Do Nothing base case		Market impact of option 3a from implementation in accordance with the respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0.0	0.0	0.0
2014–15	586	36.3	0	0.0	0.0	0.0
2015–16	616	38.2	0	0.0	0.0	0.0
2016–17	751	46.6	0	0.0	0.0	0.0
2017–18	814	50.5	449	27.8	3.4	24.4
2018–19	825	51.1	455	28.2	3.4	24.8
2019–20	954	59.1	956	59.2	12.8	46.4
2020–21	1,062	65.8	1,061	65.7	12.8	52.9
2021–22	995	61.6	985	61.0	12.8	48.2
2022–23	1,240	76.8	1,181	73.1	12.8	60.3

Given the estimated project lead time for stage 1 (install a third Moorabool–Ballarat line) is three years and two months, and stage 2 (up-rate Ballarat–Bendigo line to 82 ºC) is four years and nine months, positive net benefits are expected from the first year of operation, being 2017–18.

Option 3a reduces the amount of involuntary load shedding by providing additional network capacity.

C.5 Option 3b

The forecast market impact under option 3b is presented in Table 30.

Table 30 – Forecast market impact under option 3b

Year	Market impact of Do Nothing base case		Market impact of option 3b (preferred option) from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0.0	0.0	0.0
2014–15	586	36.3	0	0.0	0.0	0.0
2015–16	616	38.2	108	6.7	0.1	6.6
2016–17	751	46.6	157	9.7	0.1	9.7
2017–18	814	50.5	631	39.1	3.5	35.6
2018–19	825	51.1	691	42.8	3.5	39.4
2019–20	954	59.1	955	59.2	12.9	46.2
2020–21	1,062	65.8	1,059	65.6	12.9	52.7
2021–22	995	61.6	985	61.0	12.9	48.1
2022–23	1,240	76.8	1,180	73.1	12.9	60.2

Given the estimated project lead time for stage 1 (installation of wind monitoring facility) is one year and two months stage 2 (install a third Moorabool–Ballarat line) is three years and two months, and stage 3 (up-rate Ballarat–Bendigo line to 82 ºC) is four years and nine months, positive net benefits are expected from the first year of operation, being 2015–16.

Option 3b reduces the amount of involuntary load shedding by providing additional network capacity.

C.6 Option 4a

The forecast market impact under option 4a is presented in Table 31.

Table 31 – Forecast market impact under option 4a

Year	Market impact of Do Nothing base case		Market impact of option 4a from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0	0.0	0.0
2014–15	586	36.3	0	0	0.0	0.0
2015–16	616	38.2	0	0	0.0	0.0
2016–17	751	46.6	0	0	0.0	0.0
2017–18	814	50.5	449	27.8	3.4	24.4
2018–19	825	51.1	455	28.2	3.4	24.8
2019–20	954	59.1	956	59.2	13.5	45.8
2020–21	1,062	65.8	1,061	65.7	13.5	52.3
2021–22	995	61.6	984	61.0	13.5	47.5
2022–23	1,240	76.8	1,181	73.1	13.5	59.7

Given the estimated project lead time for stage 1 (install a third Moorabool–Ballarat line) is three years and two months, and stage 2 (up-rate Ballarat–Bendigo line to 82 ºC) is four years and nine months, positive net benefits are expected from the first year of operation, being 2017–18.

Option 4a reduces the amount of involuntary load shedding by providing additional network capacity.

C.7 Option 4b

The forecast market impact under option 4b is presented in Table 32.

Table 32 – Forecast market impact under option 4b

Year	Market impact of Do Nothing base case”		Market impact of option 4b from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0	0.0	0.0
2014–15	586	36.3	0	0	0.0	0.0
2015–16	616	38.2	108	6.7	0.1	6.6
2016–17	751	46.6	157	9.7	0.1	9.7
2017–18	814	50.5	449	39.1	3.5	35.6

Year	Market impact of Do Nothing base case”		Market impact of option 4b from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2018–19	825	51.1	455	42.8	3.5	39.4
2019–20	954	59.1	955	59.2	13.5	45.6
2020–21	1,062	65.8	1,059	65.6	13.5	52.1
2021–22	995	61.6	985	61.0	13.5	47.5
2022–23	1,240	76.8	1,180	73.1	13.5	59.6

Given the estimated project lead time for stage 1 (installation of wind monitoring facility) is one year and months, stage 2 (install a third Moorabool–Ballarat line) is three years and two months, and stage 3 (up-rate Ballarat–Bendigo line to 90 ºC) is four years and nine months, positive net benefits are expected from the first year of operation, being 2015–16.

Option 4b reduces the amount of involuntary load shedding by providing additional network capacity.

C.8 Option 5

The forecast market impact under option 5 is presented in Table 33.

Table 33 – Forecast market impact under option 5

Year	Market impact of Do Nothing base case		Market impact of option 5 from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0	0.0	0.0
2014–15	586	36.3	0	0	0.0	0.0
2015–16	616	38.2	0	0	0.0	0.0
2016–17	751	46.6	0	0	0.0	0.0
2017–18	814	50.5	0	0	0.0	0.0
2018–19	825	51.1	0	0	0.0	0.0
2019–20	954	59.1	955	59.1	21.0	38.1
2020–21	1,062	65.8	1,059	65.6	21.0	44.6
2021–22	995	61.6	973	60.3	21.0	39.3
2022–23	1,240	76.8	1,165	72.2	21.0	51.2

Given the estimated project lead time is four years and nine months (up-rating the Ballarat–Bendigo to 82 ºC line and a new Moorabool–Ballarat 220 kV double-circuit line), positive net benefits are expected from the first year of operation, being 2019–20.

Option 5 reduces the amount of involuntary load shedding by providing additional network capacity.

C.9 Option 6

The forecast market impact under option 6 is presented in Table 34.

Table 34 – Forecast market impact under option 6

Year	Market impact of Do Nothing base case		Market impact of option 6 from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0	0.0	0.0
2014–15	586	36.3	0	0	0.0	0.0
2015–16	616	38.2	0	0	0.0	0.0
2016–17	751	46.6	0	0	0.0	0.0
2017–18	814	50.5	0	0	0.0	0.0
2018–19	825	51.1	0	0	0.0	0.0
2019–20	954	59.1	250	15.5	5.9	9.6
2020–21	1,062	65.8	966	59.8	26.9	32.9
2021–22	995	61.6	942	58.4	26.9	31.4
2022–23	1,240	76.8	1,064	65.9	26.9	39.0

Given the estimated project lead time for stage 1 (up-rating the Moorabool–Ballarat No.1 line to 82 ºC) is four years and nine months, and stage 2 (a new Ballarat–Bendigo 220 kV double-circuit line) is five years and nine months, positive net benefits are expected from the first year of operation, being 2019–20.

Option 6 reduces the amount of involuntary load shedding by providing additional network capacity.

C.10 Option 7

The forecast market impact under option 7 is presented in Table 35.

Table 35 – Forecast market impact under option 7

Year	Market impact of Do Nothing base case		Market impact of option 7 from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0	0.0	0.0
2014–15	586	36.3	0	0	0.0	0.0
2015–16	616	38.2	0	0	0.0	0.0
2016–17	751	46.6	0	0	0.0	0.0
2017–18	814	50.5	449	27.8	3.4	24.4
2018–19	825	51.1	455	28.2	3.4	24.8
2019–20	954	59.1	568	35.2	3.4	31.8
2020–21	1,062	65.8	921	57.1	24.4	32.7
2021–22	995	61.6	927	57.5	24.4	33.0
2022–23	1,240	76.8	1,069	66.2	24.4	41.8

Given the estimated project lead time for stage 1 (installing a new third Moorabool–Ballarat line) is three years and two months, and stage 2 (installing a new Ballarat–Bendigo double-circuit line) is five years and nine months, positive net benefits are expected from the first year of operation, being 2017–18.

Option 7 reduces the amount of involuntary load shedding by providing additional network capacity.

C.11 Option 8

The available non-network DM support is assumed to be 5% of Bendigo and Ballarat connection point's 10% POE terminal station demand forecast.

The utilisation payment (dispatch fee) to the DM service provider is incorporated in the dispatch cost (see Appendix D), thereby increasing the total dispatch cost compared to the base case but reducing the reported expected unserved energy, which only includes involuntary load shedding resulting under this option.

Table 36 – Forecast market impact under option 8

Year	Market impact of Do Nothing base case		Market impact of option 8 from implementation in accordance with respective stages			
	Expected unserved energy (MWh)	Limitation cost ($ million)	Expected unserved energy reduction (MWh)	Gross market benefit ($ million)	Annualised cost ($ million)	Annualised net market benefit ($ million)
2013–14	570	35.3	0	0	0.00	0.0
2014–15	586	36.3	90	5.5	3.57	2.0
2015–16	616	38.2	105	6.4	1.89	4.5
2016–17	751	46.6	129	7.9	1.89	6.0
2017–18	814	50.5	134	8.2	1.89	6.3
2018–19	825	51.1	147	9.0	1.89	7.1
2019–20	954	59.1	163	9.9	1.89	8.1
2020–21	1,062	65.8	190	11.6	1.89	9.7
2021–22	995	61.6	196	12.0	1.89	10.1
2022–23	1,240	76.8	240	14.6	1.89	12.8

It is assumed the earliest this option can be implemented is 2014–15 due to lead time required to procure non-network support.

This option reduces the amount of involuntary load shedding and replaces it with lower cost voluntary load curtailment.

Appendix D Detailed net present value analysis

A detailed net present value analysis is presented in Excel as an attachment to this Project Assessment Conclusion Report (PACR) on AEMO's website.

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