Victorian Reactive Power Support

June 2019

Regulatory Investment Test for Transmission
Project Assessment Draft Report

Important notice

PURPOSE

AEMO has prepared this Project Assessment Draft Report to meet the consultation requirements of clause 5.16.4(j) – (s) of the National Electricity Rules.

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VERSION CONTROL

Version	Release date	Changes
1	28/6/2019	Initial release

Executive summary

The energy landscape in Victoria is changing rapidly. Strong investor interest in western parts of the state continues to shift the geography of supply sources away from the Latrobe Valley, while an increasing penetration of non-synchronous generation is changing the technical characteristics of the system. Overlaid on this, consumer response through distributed energy resources (DER) is impacting the very nature of demand and raising new challenges in operating the transmission network.

During minimum demand conditions, high voltages can occur in Victoria following credible contingencies, and in some cases under normal (pre-contingent) operation. Short-term operational measures, such as network reconfiguration or direct intervention, have become increasingly necessary to maintain voltages during these critical periods. In November 2018, AEMO was required to concurrently de-energise three 500 kilovolt (kV) lines and direct generators online in response to high voltages.

The frequency and severity of these interventions has increased rapidly, and operators are reaching the limit of available real-time options. Continued reliance on generator directions or increasingly onerous network reconfiguration will result in higher market costs, reduced system resilience, and higher system security risks.

AEMO's latest demand forecasts project that operational minimum demand may fall by as much as 1,185 megawatts (MW), or 40%, over the next 10 years. This forecast change is primarily driven by projections of increasing rooftop solar photovoltaic (PV) installation and energy efficiency improvements, and will only exacerbate the issues now being observed.

The 2018 National Transmission Network Development Plan (NTNDP)[1] identified an immediate Network Support and Control Ancillary Service (NSCAS) gap for voltage control in Victoria, and AEMO has subsequently entered a short-term contractual arrangement for Non-Market Ancillary Services (NMAS) while a more efficient long-term solution is progressed.

In mid-2018, AEMO initiated a Regulatory Investment Test for Transmission (RIT-T) to assess the technical and economic benefits of delivering additional reactive power support in Victoria. In May 2018, AEMO published a Project Specification Consultation Report (PSCR)[2], which identified the need for up to 800 megavolt amperes reactive (MVAr) of additional reactive support by 2028 to maintain voltages within operational design limits.

Following that publication, AEMO sought feedback from stakeholders on the identified need, and on the range of credible options being considered. AEMO also sought information from providers of potential non-network solutions capable of providing voltage support during low demand periods.

AEMO has now assessed these credible options (as described in Section 3.2), and has identified the optimal size, technology, location, and investment staging that is projected to meet the identified need while maximising net economic benefits.

This Project Assessment Draft Report (PADR) marks step two of the RIT-T process[3]. The report reconfirms the nature of the identified need, summarises AEMO's technical and economic assessment of the credible options, and justifies selection of the preferred option.

[1] AEMO. 2018 National Transmission Network Development Plan, at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf.

[2] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victorian-reactive-power-support-RIT-T-PSCR.pdf.

[3] As specified by Clause 5.16.6(j) – (s) of the National Electricity Rules, at https://www.aemc.gov.au/sites/default/files/2019-05/NER%20-%20v122.pdf.

The preferred option

The preferred option identified in this PADR (and shown in Figure 1) is to install:

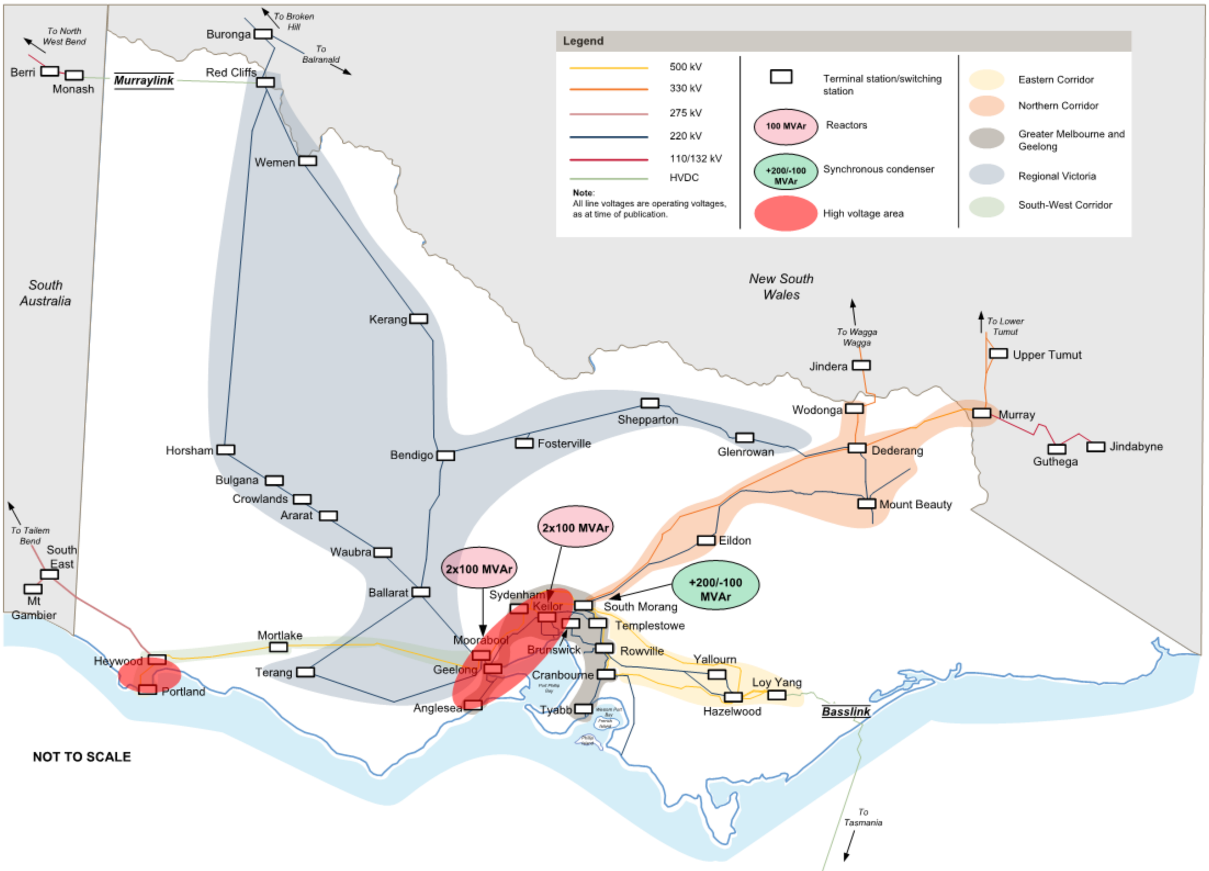
- Two 100 MVAr shunt reactors at Keilor Terminal Station in 2021 and 2022 respectively.
- One 330 kV +200/-100 MVAr synchronous condenser at South Morang Terminal Station in 2022.
- Two 220 kV 100 MVAr shunt reactors at Moorabool Terminal Station in 2023.

The preferred option has a capital cost of approximately $72 million (in present value terms), and yields the highest net market benefits when weighted across all reasonable scenarios and sensitivities.

The PADR analysis identifies that investing in this option will deliver a net present economic benefit of approximately $89 million, by:

- Reducing market costs associated with dispatching generators that are normally offline during light load periods to maintain voltages within operational and design limits.
- Reducing market costs associated with dispatching generators for system strength.
- Increasing the Victoria to New South Wales export interconnector transient stability limit by approximately 150 MW, and the voltage stability limit by approximately 30 MW.

Figure 1 Preferred option of four 100 MVAr reactors and one +200/-100 MVAr synchronous condenser



Other credible options

AEMO considered a range of credible options with the capability to manage high voltages on the Victorian transmission network during low demand periods.

All credible network options involved the installation of reactive power devices, such as reactors, Static VAr Compensators (SVCs), and synchronous condensers. These components are relatively modular, and therefore credible options were formed from assets across a combination of location, voltage level, technology, capacity, and connection arrangements.

Performing detailed network and economic studies against all possible permutations of these parameters would be impractical, and AEMO refined these combinations based on technical feasibility, relative effectiveness, investment cost, and local site restrictions. While AEMO also sought feedback from potential non-network providers, no submissions were received.

Table 1 Credible options tested in detail through the PADR analysis

Option	Description	Estimated Cost ($M)
1A	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 1 x 100 MVAr Shunt Reactor at Moorabool	19
1B	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 2 x 100 MVAr Shunt Reactor at Moorabool	25
1C	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 3 x 100 MVAr Shunt Reactor at Moorabool	32
1D	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 4 x 100 MVAr Shunt Reactor at Moorabool	39
2 (preferred option)	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 2 x 100 MVAr Shunt Reactor at Moorabool 330 kV 1 X +200/-100 MVAr Synchronous Condenser at South Morang	85

Scenarios and sensitivities analysed

The RIT-T requires cost-benefit analysis that considers reasonable scenarios of future supply and demand under conditions where each credible option is implemented, and compared against conditions where no option is implemented.

A reasonable scenario represents a set of variables or parameters that are not expected to change across each of the credible options or the base case.

This RIT-T considers three reasonable future scenarios:

- Neutral – central projections of economic growth, future demand growth, fuel costs, technology cost reductions, and DER aggregation growth.
- Slow change – compared with the Neutral scenario, assumed weaker economic and demand growth, lower levels of investment in energy efficiency, slower uptake of electric vehicles, slower cost reductions in renewable generation technologies, and greater aggregation of DER.
- Fast change – compared with the Neutral scenario, assumed stronger economic and demand growth, higher levels of investment in energy efficiency, faster update of electric vehicles, faster cost reductions in renewable generation technologies, and less aggregation of DER.

Additional sensitivity analysis was carried out for the PADR on the above results, by varying the assumed option cost, discount rate, and scenario weightings.

Market benefits

The primary source of market benefits quantified in this RIT-T relates to fuel and operating cost savings associated with avoided market intervention, avoided reliance on non-market ancillary services, and increases to the Victoria to New South Wales export stability limits.

Table 2 summarises the weighted net market benefit in net present value (NPV) terms[4] for each credible option. The net market benefit for each option reflects the weighted benefit across the three reasonable scenarios considered.

While Option 2 has a higher capital cost, it also captures additional market benefits through the inclusion of a synchronous condenser. Option 2 also provides the highest net benefit under all reasonable scenarios and sensitivities tested.

Table 2 Weighted net market benefits NPV ($M)

Option	1A	1B	1C	1D	2 (preferred option)
Cost ($)	19.1	25.4	31.7	38.8	84.7
NPV ($M)	63.9	71.7	74.9	74.7	89.2

Next steps

The publication of this PADR commences the next phase of the RIT-T process. Following submissions on this PADR, a Project Assessment Conclusions Report (PACR) will be published in accordance with Clause 5.16.4 of the National Electricity Rules (NER).

Submissions

AEMO welcomes written submissions from stakeholders on this PADR, including comments on the inputs, analysis, and choice of preferred option.

Submissions should be emailed to planning@aemo.com.au and are due on or before 9 August 2019.

Submissions will be published on the AEMO website. If you do not want your submission to be publicly available, please clearly stipulate this at the time of lodgement.

[4] Net Present Value (NPV) is the value of all future cash flows (both positive and negative) over the outlook period when discounted to the present. NPV analysis is a form of valuation used extensively across finance and accounting to determine the value of a long-term investment.

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1. Introduction

The Regulatory Investment Test for Transmission (RIT-T) is an economic cost-benefit test used to assess and rank different investment options that address an identified need. This Project Assessment Draft Report (PADR) represents step two of the consultation process in relation to the Victorian Reactive Power Support RIT-T.

1.1 Background to the RIT-T process

Under the National Electricity Law, AEMO is responsible for planning and directing augmentation on the Victorian electricity transmission Declared Shared Network (DSN).

In deciding whether a proposed augmentation to the DSN should proceed, AEMO is required to undertake a cost-benefit analysis. As the credible options (identified in this report) all involve augmentation to the DSN, the RIT-T process meets AEMO's requirements for cost-benefit analysis.

The purpose of a RIT-T is to identify the investment option which meets an identified need while maximising the present value of net economic market benefits to all those who produce, consume, and transport electricity in the market.

The RIT-T process involves the publication of three reports:

- The Project Specification Consultation Report (PSCR), which seeks feedback on the identified need and credible options to address that need.
- The PADR, which identifies and seeks feedback on the RIT-T analysis and on the selection of a preferred option that delivers the highest net market benefit.
- The Project Assessment Conclusions Report (PACR), which presents final RIT-T analysis and makes a conclusion on the preferred option.

The procedures for conducting a RIT-T are defined in Clause 5.16.4 of the National Electricity Rules (NER).

1.2 Overview of this report

- In May 2018, AEMO published a PSCR[5] which identified a need for additional reactive support to maintain transmission system voltages in the Victoria region, and outlined potential investment options to address this need.
- This PADR represents step two of the RIT-T process[6], and provides:
- A description of the identified need for investment, in Chapter 2.
- A description of each credible option assessed, in Chapter 3.
- A summary of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option, in Chapter 3.

A summary of, and commentary on, the submissions to the PSCR, in Chapter 4.

A detailed description of the methodologies and assumptions used in quantifying each class of material market benefit and cost, in Chapter 5.

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[5] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victorian-reactive-power-support-RIT-T-PSCR.pdf.

[6] As specified by Clause 5.16.6(j) – (s) of the National Electricity Rules, at https://www.aemc.gov.au/sites/default/files/2019-05/NER%20-%20v122.pdf.

Identification of all material classes of market benefits that arise both within Victoria and within other National Electricity Market (NEM) regions, in Chapter 6.

- Reasons why some classes of market benefit have not been considered as material, in Section 6.1.
- Results from a net present value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results, in Section 6.3.

The identified preferred option, in Chapter 7.

For the proposed preferred option, this PADR also provides:

- Details of its technical characteristics.
- The estimated construction commissioning date (year).
- If the proposed preferred option is likely to have a material inter-network impact and, if the transmission network service provider (TNSP) affected by the RIT-T project has received an augmentation technical report, that report.
- A statement and accompanying detailed analysis showing that the preferred option satisfies the RIT-T.

1.3 Stakeholder submissions

AEMO invites written submissions on this PADR from registered participants and interested parties.

Submissions are due on or before 9 August 2019, and should be emailed to planning@aemo.com.au.

Submissions will be published on the AEMO website. AEMO would prefer public submissions, however if you do not want your submission to be publicly available, please clearly stipulate this at the time of lodgement.

1.4 Next steps

The publication of this PADR commences the next phase of the RIT-T process.

Following consultation, a PACR will be published to finalise the RIT-T assessment process. The PACR will draw a conclusion on the preferred option, and provide consideration to any submissions made in response to this PADR.

For further details about this project, please e-mail planning@aemo.com.au.

2. Identified need

The identified need for investment is to maintain voltages within operational and design limits in the South-West transmission corridor around Geelong, Keilor, Moorabool, and Portland – particularly during low demand periods. This will:

- Address an emerging Network Support and Control Ancillary Service (NSCAS) gap.
- Ensure the power system remains in a satisfactory and secure operating state.
- Maximise net market benefits through reduced costs of market intervention and non-market ancillary services.

2.1 Description of the identified need

The identified need was described in Chapter 2 of the PSCR[7], which stated that investment in additional reactive support is required to maintain transmission system voltages within operational and equipment design limits during minimum demand periods, and to realise market benefits through reduced reliability risk and market intervention costs.

Lightly loaded transmission lines produce reactive power, and the higher the line voltage or the longer the transmission line, the higher the level of reactive power produced. Excessive levels of reactive power can cause over-voltages that damage equipment and jeopardise the security of the transmission system.

Transmission lines are most lightly loaded during low demand periods, which may also correspond to times where large thermal generating units are offline. These units, when running, are typically able to absorb reactive power and reduce voltages.

The driver of identified need in this RIT-T is a continued decline in minimum demand. Over the last five years, minimum operational demand has declined more rapidly than ever before, with minimum demand reducing by 520 megawatts (MW), or 15%. AEMO's latest demand forecasts project that operational minimum demand may fall by as much as 1,185 MW (40%) over the next 10 years[8].

This forecast change is primarily driven by projections of increasing rooftop photovoltaic (PV) installation and energy efficiency improvements. The projected reduction in minimum demand will only exacerbate the issues currently being observed in Victoria.

Because lightly loaded transmission lines produce reactive power, AEMO has used de-energisation of long, high-voltage lines as a short-term operational measure to manage high transmission system voltages. This approach is used only after all standard practices have been exhausted (such as utilising the reactive capabilities of online generation, changing transformer taps, and switching out capacitors).

In some cases, AEMO may also intervene directly in the market to bring units online and access their reactive capabilities. In November 2018, AEMO was required to concurrently de-energise three 500 kilovolt (kV) lines and direct generators online in response to high voltages.

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[7] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victorian-reactive-power-support-RIT-T-PSCR.pdf.

[8] See 2018 Electricity Statement of Opportunities (ESOO) forecasts at http://forecasting.aemo.com.au/.

The frequency and severity of these interventions has increased rapidly, and operators are reaching the limit of available real-time options. Continued reliance on generator directions or increasingly onerous network reconfiguration will result in higher market costs, reduced system resilience, and higher system security risks.

While the identified need for investment remains largely the same as described in the PSCR, new information has become available since the PSCR was published in May 2018.

AEMO has refined some aspects of the identified need, as described in the following sections. In particular, more recent demand forecasts, updated trends in operator actions, and the identification of a NSCAS gap have all impacted the scale and urgency of investment required.

2.2 New information since the PSCR

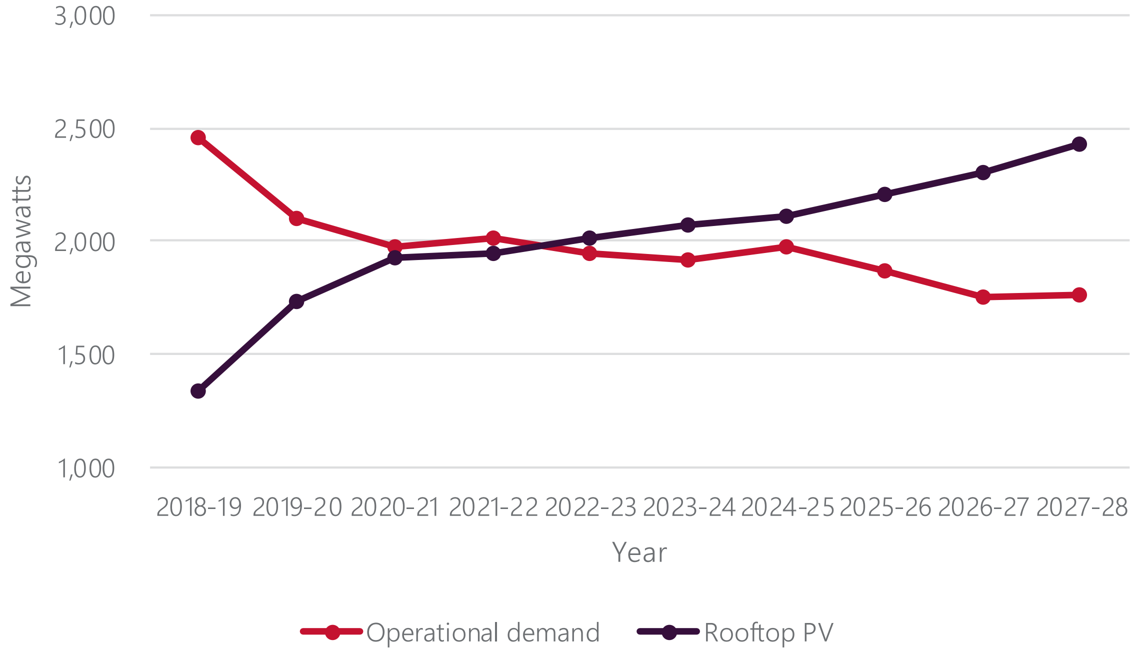
2.2.1 Updated demand forecasts

Since publication of the PSCR, AEMO has produced an updated set of minimum demand forecasts[9] as part of the 2018 Electricity Statement of Opportunities (ESOO) for the NEM. The assessment in this PADR has used these updated demand forecasts.

As shown in Figure 2 and Table 3, minimum operational demand forecasts are expected to reduce significantly in Victoria over the next 10 years. Under the Neutral 90% probability of exceedance (POE) scenario[10], minimum demand is projected to fall from approximately 2,460 MW in 2018-19 to 1,763 MW in 2027-28. This reduction is primarily driven by increases in rooftop PV installation (included for comparison on Figure 2).

While these forecasts show a strong downward trend, they do not decline to the same extent as projected in the PSCR. In particular, the 2027-28 minimum demand forecast from the 2018 ESOO is 840 MW higher than that used in the PSCR. While this does not reduce the urgency of the identified need, it has put downward pressure on the scale (which was expected to be up to 800 megavolt amperes reactive [MVAr] in the PSCR).

Figure 2 Minimum demand and rooftop PV forecast



[9] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[10] POE means the probability, as a percentage, that a maximum demand forecast will be met or exceeded (for example, due to weather conditions). For example, a 10% POE forecast is expected to be met or exceeded, on average, only one year in 10, so considers more extreme weather than a 50% POE forecast, which is expected to be met or exceeded, on average, one year in two. See AEMO's 2018 ESOO for more on forecast and scenarios, at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf.

Table 3 Minimum demand and rooftop PV forecast

Year	Forecast minimum operational demand (MW)	Forecast rooftop PV (MW)
2018-19	2,460	1,336
2019-20	2,097	1,732
2020-21	1,973	1,930
2021-22	2,013	1,944
2022-23	1,950	2,017
2023-24	1,916	2,069
2024-25	1,971	2,108
2025-26	1,864	2,212
2026-27	1,757	2,308
2027-28	1,763	2,430

2.2.2 Trends in requirements for operator action

The frequency and severity of voltage control interventions has increased more rapidly than previously anticipated. Since the PSCR was published in May 2018, AEMO has been required to switch out 500 kV transmission assets on 57 separate occasions, and for a total duration of 610 hours. This compares to the equivalent period prior to the PSCR, where lines were switched for only 344 hours.

This increase is despite the introduction of a Non-Market Ancillary Service (NMAS) contract in March 2019 (see Section 2.2.3).

The most severe operator action was necessary in November 2018, when AEMO was required to concurrently de-energise three 500 kV lines and direct a generator online on to maintain Victorian voltages.

Continued reliance on generator directions and increasingly onerous network reconfiguration will result in higher market costs, reduced system resilience, and higher system security risks.

These trends further support the identified need for additional reactive power investment in Victoria.

In addition, AEMO (as system operator) has amended operating practices in response to further network studies and a system security risk assessment. Operating practice now permits the switching of a single 500 kV line during high voltage periods, and only after all other standard options for suppressing high voltage have been exhausted.

Activation of NMAS services or direct market interventions are now likely to occur before switching a second 500 kV line. This operating practise has been reflected in the PADR market benefit assessment, and while it decreases the expected reliability benefits associated with multiple line-switching events, it increases the benefits associated with avoiding NMAS and market intervention costs.

2.2.3 Network Support and Control Ancillary Services Gap

NSCAS is a non-market ancillary service that may be procured by AEMO or TNSPs to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network.

Each year, AEMO's National Transmission Network Development Plan (NTNDP) assesses all NEM regions and identifies gaps that should be resolved by an NSCAS arrangement. For Victoria, the 2018 NTNDP[11] identified an immediate NSCAS gap for voltage control in Victoria under low demand conditions.

To address this gap, in March 2019, AEMO entered into a short-term NMAS agreement with a service provider for a six-month period. In the three months to 13 June 2019, this contract was invoked on 11 occasions to supress high voltages in Victoria, with each activation lasting for approximately six hours. This contract has typically been activated overnight, where demands are often lowest.

AEMO is currently tendering for further interim NMAS services, to take effect following conclusion of the original contract in September 2019.

The frequency, duration, and market cost of these NMAS activations further support the urgency and potential benefit associated with the identified need for reactive support in Victoria.

2.2.4 Intervention for system strength

In June 2018, AEMO published the System Strength Impact Assessment Guidelines[12], which detail the system strength assessment methods used to determine any adverse system strength impacts. The 2018 System Strength Requirements and Fault Level Shortfalls report[13] uses the concept of three phase fault level to quantify regional system strength requirements.

Based on AEMO's system strength requirements and 2018 Integrated System Plan (ISP) projections, the Victorian grid meets the minimum requirements under system normal conditions, and no fault level shortfalls have been declared in Victoria.

However, under certain dispatch conditions, fault levels can fall below the minimum requirements. AEMO was required to direct a generating unit to remain online on 17 November 2018 to manage system strength requirements[14] following multiple outages in the system.

AEMO is conducting detailed studies to review and refine the minimum requirement definitions, and to consider how this requirement might be impacted when 500 kV lines are switched out of service for voltage control purposes. AEMO plans to publish an update of the minimum system strength requirement at the end of 2019.

This PADR assessment considers the circumstances under which directions for system strength would be required when determining the benefits of the credible options proposed.

2.2.5 New committed generation in Victoria

Since the publication of the PSCR, several new renewable generator projects in Victoria have reached the committed stage[15]. Committed projects are those that have advanced to the point where proponents have secured land and planning approvals, entered into contracts for supply of major components and financing arrangements, and either started construction or set a firm date. Approximately 2,000 MW of new renewable generation will be built in Victoria by 2020.

In some cases, these new renewable projects can deliver additional reactive support at times of low demand, provided they are synchronised and generating. This puts downward pressure on the scale of the identified need (described as up to 800 MVAr in the PSCR).

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[11] AEMO. 2018 National Transmission Network Development Plan, at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf.

[12] AEMO, System Strength Assessment Guidelines, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

[13] AEMO, System Strength Requirements, at www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[14] At www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/2018/Intervention-pricing-for-system-security-directions.pdf.

[15] Generation information page, Victoria Region, May 2019, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

The PADR analysis includes the impact of these committed projects when determining the need and net market benefits associated with each credible option.

2.3 Refinements to the identified need

AEMO has used the updated information described in Section 2.2 and assessed the voltage performance of the Victorian transmission system, based on a range of credible scenarios, and identified the locations where voltages exceed operational limits. AEMO then modelled reactive power plant with a range of capacities at selected terminal stations to identify the most effective combination of locations/capacities.

This analysis indicates that:

- Under most scenarios, additional absorbing reactive power support of approximately 400-500 MVAr is required, with a single 500 kV line de-energised to maintain voltages within limits.
- The most effective locations for installing the additional reactive power support include the existing Geelong, Moorabool, South Morang, Keilor, and Sydenham terminal stations.

3. Credible options included in the RIT-T analysis

Analysis has considered all credible network and non-network options to address the identified need. The options described cover a range of potential solution sizes, technologies, locations, and timings. These combinations have been refined to identify those likely to maximise the net market benefits through a full cost-benefit assessment.

3.1 Refinement of potential options

As described in Chapter 4 of the PSCR, a credible network option in this RIT-T should have the capability to suppress high voltages on the Victorian transmission network, especially during low demand periods.

Following the PSCR, AEMO issued a Request for Information (RFI) seeking submissions from providers of potential non-network options with these capabilities. No submissions were received, and the assessment of credible options has therefore focused on combinations of network assets.

Credible network options all include the installation of reactive power devices, including reactors, Static VAr Compensators (SVCs), or synchronous condensers. These components are relatively modular, and therefore credible options are formed from a combination of location, voltage level, technology, capacity, and connection arrangements. In addition, credible options can be formed from a combination of assets with differing parameters.

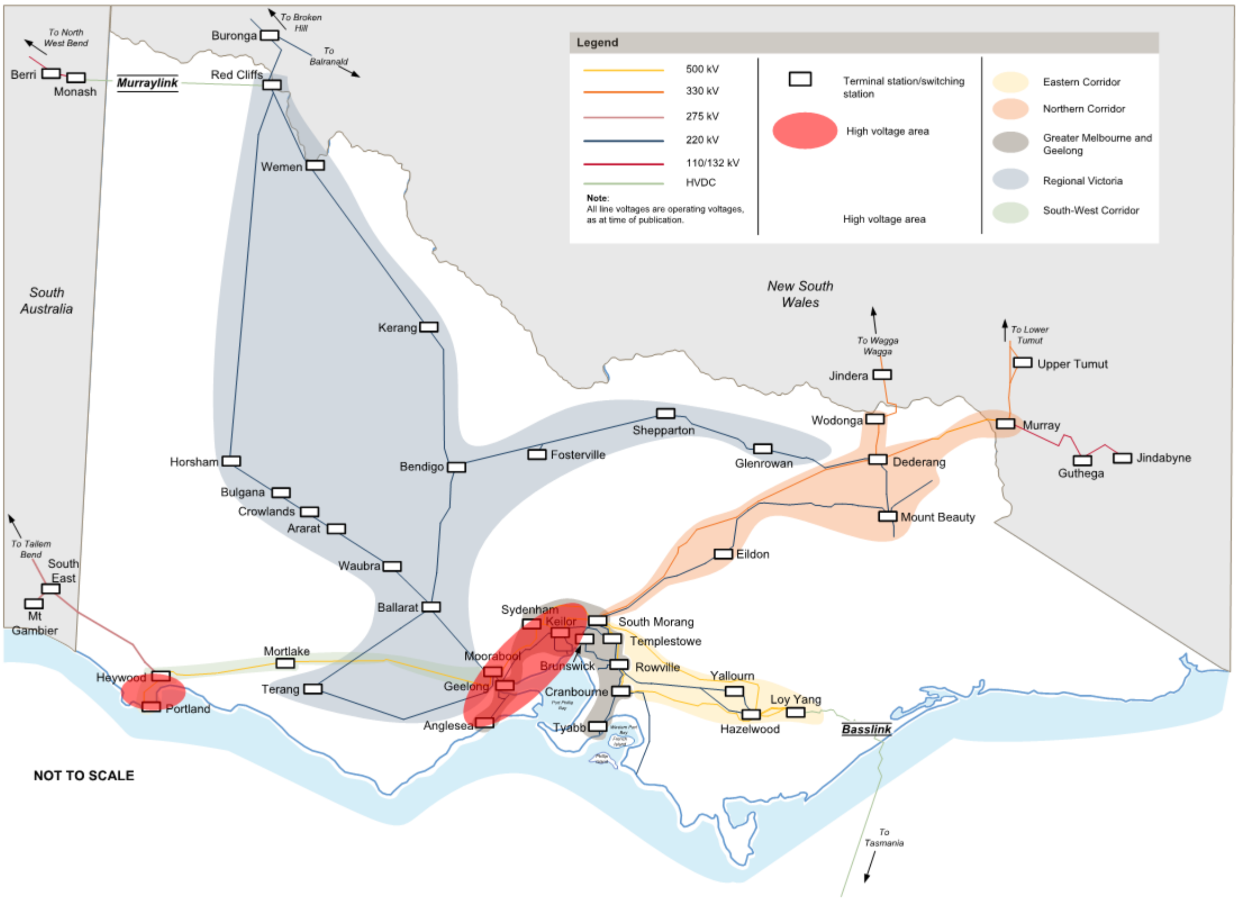
The identification and refinement of these credible options is discussed in the following sections.

Electrical location

As described in the 2018 VAPR, and confirmed through power system modelling for the PSCR, the most limiting high voltage issues occur along the south-west transmission corridor near Geelong, Keilor, Moorabool, and Portland terminal stations (refer to Figure 3).

The more electrically separated reactive support devices are from the high voltage conditions, the less effective they are. As such, power system studies for the PADR have identified that the most effective locations to install additional absorbing reactive support devices are at Moorabool, Keilor, Geelong, South Morang, and Sydenham terminal stations.

Figure 3 Area of high voltages that are being addressed



Site-specific constraints and costs

In addition to the electrical considerations above, local site constraints (and associated cost increases) as presented in Table 4 make Geelong Terminal Station unlikely to pass economic testing in preference to Moorabool, Keilor, and South Morang. Sydenham Terminal Station is a 500 kV station, and the cost of installing a reactor at 500 kV is more expensive than installing at 220 kV.

Table 4 Cost estimates for selected 220 kV terminal stations

	Shunt reactor at 220 kV	Site constraints
Moorabool	$6.3 M	Beyond two shunt reactors are possible with negligible impact on site ultimate.
Keilor	$6.4 M	Beyond two shunt reactors impact on site ultimate and likely to be more expensive.
South Morang	$7.1 M	A single 220 kV reactor can be accommodated on site. Lines within the terminal station site may need to be relocated to make space for a 2nd 220 kV reactor.
Geelong	$11.1	Connection required via 220 kV cable due to physical space constraints and existing 220 kV line entries.

As noted in Table 4, site constraints and build cost estimates restrict the feasible number of new reactive assets that can be installed at each of these locations. Build beyond these limits is possible, but comes at a cost premium that would prevent these combinations from becoming the preferred option.

As a result, only options involving these three locations, and that remain under these build limits, have been considered through full cost-benefit assessment.

Voltage level

Power flow analysis has been performed for the PADR to confirm the most effective voltage connection levels to address over-voltages in Victoria. Table 5 shows the effective contribution factor for different voltages and at different credible locations within the south-west transmission corridor.

Table 5 Location contribution for absorbing reactive power[A]

Location	Keilor 500 kV	Keilor 220 kV	Moorabool 500 kV	Moorabool 220 kV	Geelong 220 kV	South Morang 500 kV	South Morang 220 kV	South Morang 330 kV
Percentage	100%	99%	100%	96%	96%	100%	93%	93%

A. Average percentage contributed to high voltage areas (e.g. a 100 MVAr reactor at Geelong 220 kV is equivalent to a 96 MVAr reactor located at the Keilor 500 kV).

While connection to the 500 kV network delivers the highest contribution factor, incremental costs are also much higher when installing shunt reactors at the 500 kV and 330 kV locations. As such, only 220 kV options were considered when assessing shunt reactor credible options in this PADR.

With respect to synchronous condensers, although connection to South Morang 330 kV provides a lower contribution factor, an investment in this location may carry additional market benefits by relaxing transient and stability limits on the Victoria to New South Wales interconnector. As a result, connection of a synchronous condenser at South Morang 330 kV was also tested in the PADR credible options.

Technology type

Both static reactors and dynamic reactive plant can be used to meet the identified need. Dynamic plant includes SVCs, synchronous condensers, and any other plant that can provide continuously varying reactive power output.

Dynamic reactive plant is more expensive than static reactors, but may also provide additional benefits, such as improving transient and voltage stability, increasing system strength, and providing system inertia.

Static synchronous compensators (STATCOMs) and SVCs were not considered as suitable dynamic plant options, due to their inability to provide system strength and inertia benefits. Battery storage systems were also considered, but due to cost and product life they were not included as a credible option in the market benefit analysis.

This PADR considers an option that combines shunt reactors and a synchronous condenser to deliver the benefits of both static and dynamic reactive response.

Capacity (MVAr) of reactive power plant

Based on discussions with suppliers about construction efficiencies, incremental costs implications, experience with existing plant in the system, and network studies on the impact of reactor switching, this PADR considers the optimal individual unit sizes to be:

- 100 MVAr for static reactors.
- +200/-100 MVAr for dynamic plant.

For example, the switching impact of a single 200 MVAr reactor, especially at light load conditions, could result in voltage step changes of greater than 3%. This is outside the permitted limits for rapid voltage changes[16]. Selecting multiple smaller unit sizes (less than 100 MVAr) begins to unduly increase the cost per MVAr of each solution.

Connection arrangements

Several connection arrangements have also been considered (consistent with those discussed in the PSCR):

- **Standard arrangement (single-switching).**
  - The standard arrangement for connecting reactive plant to the Victorian transmission network is a single-switched arrangement, where the reactive power plant is connected to a bus with a single circuit breaker.
- **'Line shunt' arrangement (where a new reactive power plant is connected to one or both ends of a line behind the line circuit breaker).**
  - With this special arrangement, no new circuit breaker will be required for the new reactor, because the reactor will share the line circuit breaker. This special arrangement is typically used to compensate line charging during light load periods for long transmission lines, and can also be considered for connecting reactive plant.
  - While this arrangement can reduce costs associated with new circuit breakers, the loss or outage of the transmission line will lead to the reactive plant not being available. Major line maintenance is normally scheduled during light load periods where the reactive plant is most needed. The concurrent outage of line/reactive plant under this special arrangement will also incur operational cost and reliability impacts. As a result, this option was not pursued further in this PADR.
- **'Bus-shunt' arrangement.**
  - Two 100 MVAr line reactors are associated with the Tarrone – Alcoa Portland (APD) and Mortlake – APD 500 kV lines. Each of these reactors will trip together with its associated 500 kV line which also leads to a trip of the connected APD load. Power system studies have indicated that if the reactor remains in service following a 500 kV line tripping, the additional absorbing reactive power requirement could be reduced by approximately 60-70 MVAr for the scenarios with APD load in service. This is because the trip of these two 500 kV lines together with APD load is a critical contingency associated with the identified need for this RIT-T.
  - A potential special arrangement for additional absorbing reactive power is to change the existing arrangement of connecting 500 kV APD reactors from 'line shunt' to 'bus shunt' by installing two new 500 kV circuit breakers. To implement the proposed change with existing switchgear is technically challenging and costly.
  - This option was considered but not pursued further in this PADR.

For this PADR, only standard single-switching connection arrangements have been considered.

3.2 Description of the credible options assessed

The previous section detailed AEMO's assessment of reactive plant characteristics and limitations with respect to meeting the identified need of this RIT-T. This assessment is necessary, because performing detailed network and economic studies against all possible permutations of size, voltage, technology, location, and connection arrangements would be impractical.

Based on the above assessment, credible combinations of the following parameters have been investigated in detail through the PADR process:

- Plant located at Moorabool, Keilor, or South Morang terminal stations.
- Static reactors (at 220 kV) and synchronous condensers (at South Morang 330 kV).

[16] AS/NZS 61000.3.7:2001.

- Static plant in multiples of 100 MVAr, and dynamic plant in multiples of +200/-100 MVAr.

The explicit combinations tested are described in the remainder of this section.

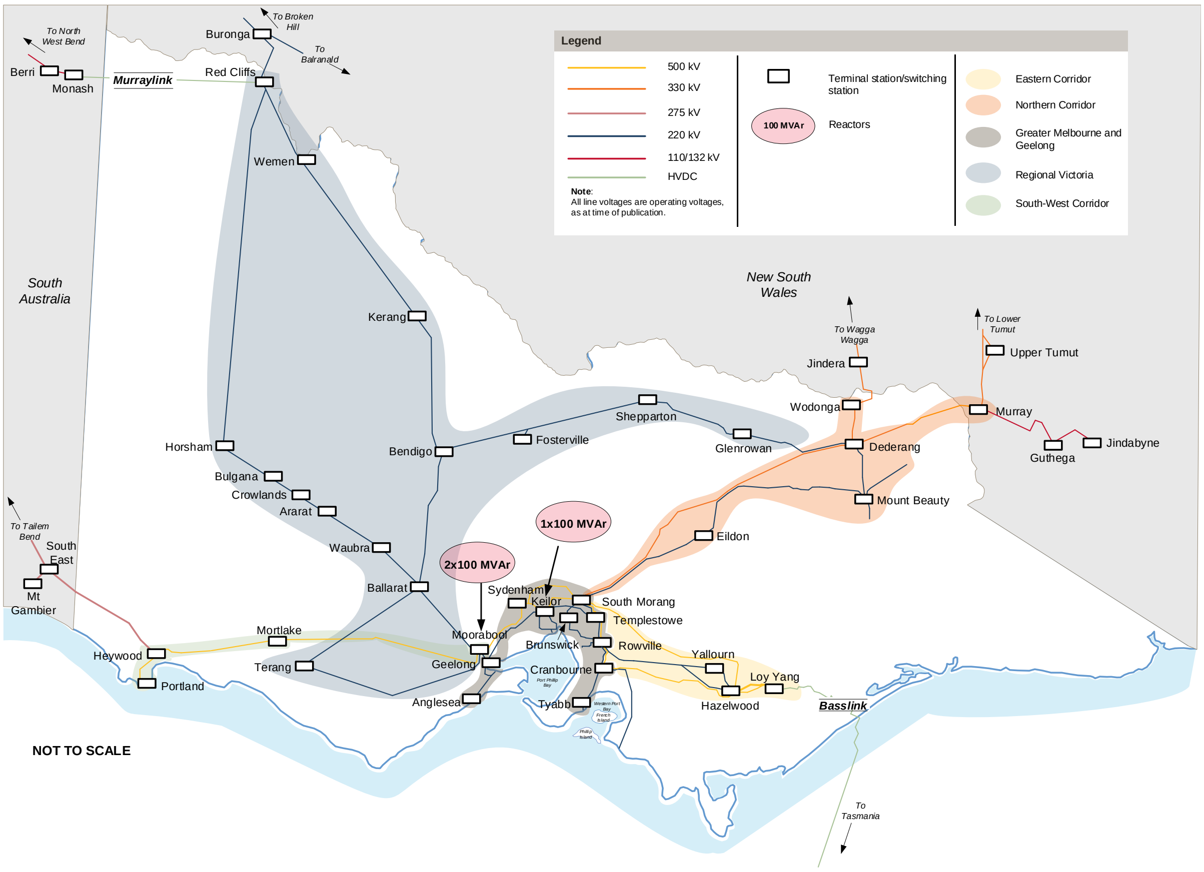
Option 1 – Combination of shunt reactors at various 220 kV locations

As noted in the previous section, taking account of the contributing factors, build costs, and site constraints, Option 1 consists of four separate sub-options testing combinations of 100 MVAr shunt reactors installed in the 220 kV network at Keilor, Moorabool, and South Morang. A combination of options sizes, with 100 MVAr increments (starting from 300 MVAr), were tested to determine which combination of shunt reactors provided the greatest net market benefit. The timing of the investments was determined by the cost-benefit analysis, which generally showed that the optimal timing was a soon as possible (see Section 5.5).

Option 1A – Combination of 3 x 100 MVAr shunt reactors

Figure 4 presents Option 1A, which consists of three 220 kV 100 MVAR shunt reactors.

Figure 4 Combination of three 100 MVAr reactors (Option 1A)



In this option:

- The initial 100 MVAr shunt reactor is installed at Keilor Terminal Station in 2021.
- Two 100 MVAr shunt reactors are installed at Moorabool Terminal Station in 2022.

Keilor and Moorabool terminal stations were preferred for the initial investment option because this provides the least-cost locations and the largest contributing factors (at 220 kV). It also provides diversity, instead of installing all shunt reactors at a single location. Having two 100 MVAr shunt reactors at Keilor and one at Moorabool terminal stations would provide similar benefits.

The estimated capital cost of this option is $19.1 million.

Option 1B – Combination of 4 x 100 MVAr shunt reactors

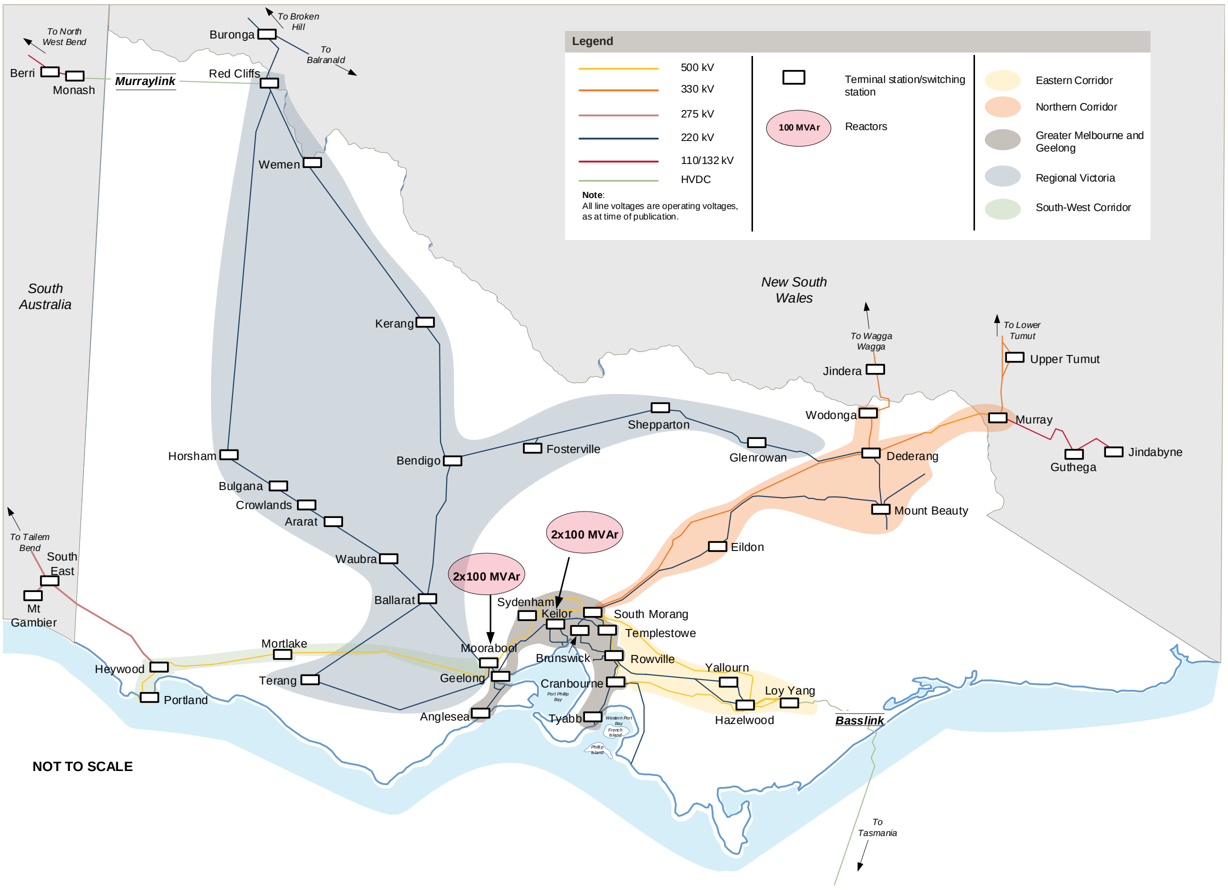
Figure 5 presents Option 1B, which consist of four 220 kV 100 MVAR shunt reactors. In this option:

- Two 100 MVAr shunt reactors are installed at Keilor Terminal Station, in 2021 and 2022.
- Two more 100 MVAr shunt reactors are installed at Moorabool Terminal Station in 2023.

As in Option 1A, Keilor and Moorabool terminal stations were preferred for the initial investment option because this provides the least-cost locations and the largest contributing factors (at 220 kV). It also provides diversity, instead of installing all shunt reactors at a single location.

The estimated capital cost of this option is $25.4 million.

Figure 5 Combination of four 100 MVAr reactors (Option 1B)



Option 1C – Combination of 5 x 100 MVAr shunt reactors

Figure 6 presents Option 1C, which consists of five 220 kV 100 MVAR shunt reactors. In this option:

- The initial 100 MVAr shunt reactor is installed at Keilor Terminal Station in 2021.
- Two 100 MVAr shunt reactors are installed in 2022, one at Keilor Terminal Station and the other at Moorabool Terminal Station.
- Two 220 kV 100 MVAr shunt reactors are installed at Moorabool Terminal Station in 2023.

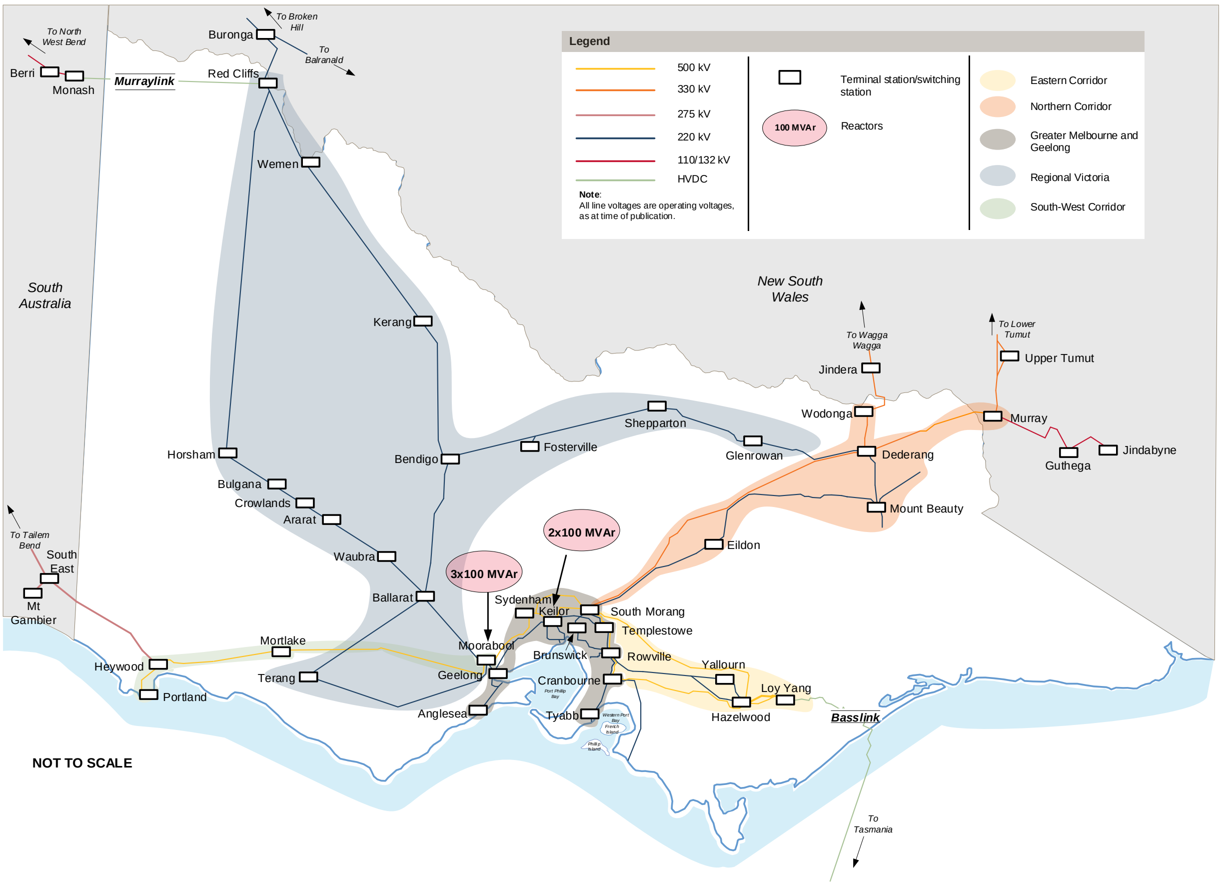
Keilor and Moorabool terminal stations were preferred for the initial investment option because this provides the least-cost locations and the largest contributing factors (at 220 kV). It also provides diversity, instead of installing all shunt reactors at a single location.

Due to additional site availability, in this option three shunt reactors are installed at Moorabool.

South Morang Terminal Station was not considered in this option as an alternative location, due to its incremental cost, but it was considered in Option 1D.

The estimated capital cost of this option is $31.7 million.

Figure 6 Combination of five 100 MVAr reactors (Option 1C)



Option 1D – Combination of 6 x 100 MVAr shunt reactors

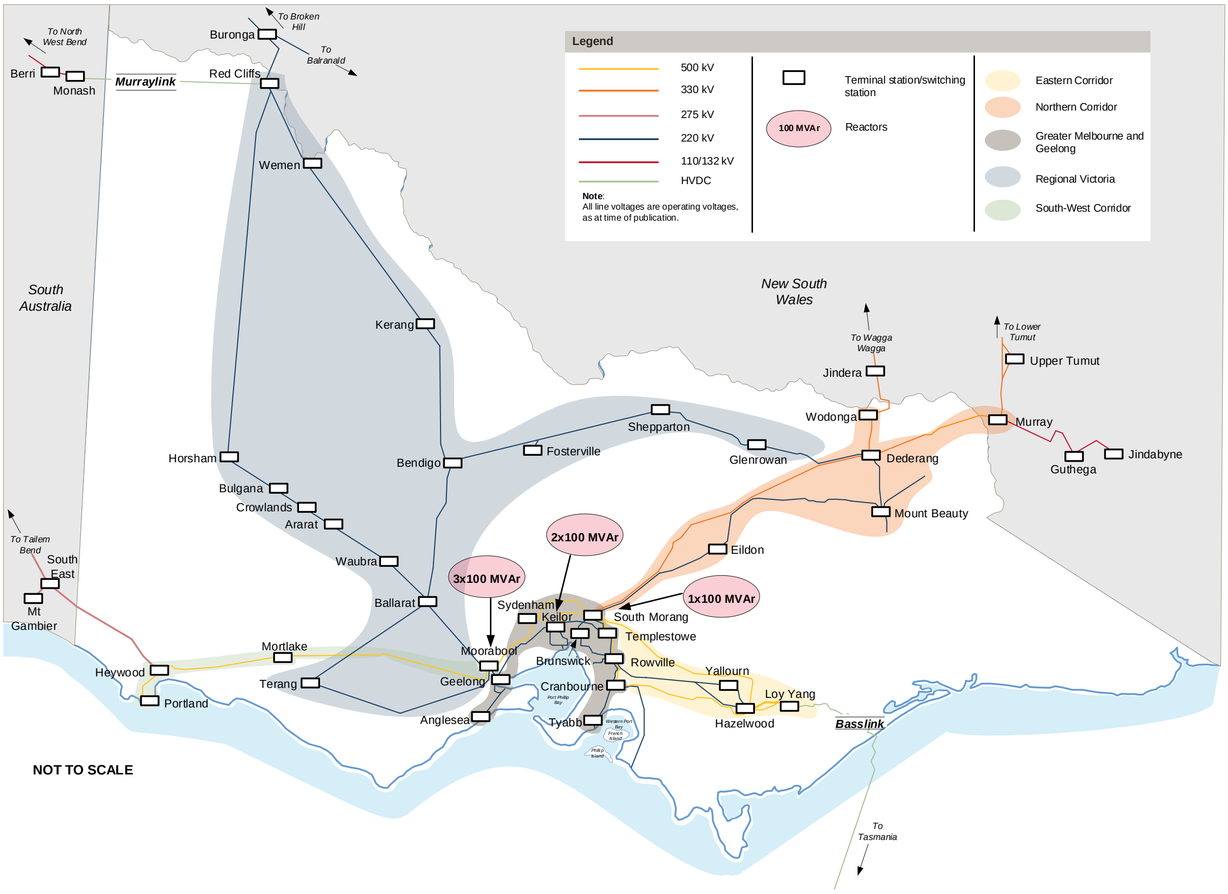
Figure 7 presents Option 1D, which consists of six 220 kV 100 MVAR shunt reactors. In this option:

- The initial 100 MVAr shunt reactor is installed at Keilor Terminal Station in 2021.
- Two 100 MVAr shunt reactors are installed in 2022, one at Keilor Terminal Station and the other at Moorabool Terminal Station.
- Two more 100 MVAr shunt reactors are installed at Moorabool Terminal Station in 2023.
- A 220 kV shunt reactor is installed at South Morang Terminal Station in 2024.

This option is similar to Option 1C, but with an additional shunt reactor installed at South Morang. South Morang was selected instead of including another shunt reactor at Moorabool for further site diversity and flexibility.

The estimated capital cost of this option is $38.8 million.

Figure 7 Combination of six 100 MVAr reactors (Option 1D)



Option 2 – Combination of reactors with a single dynamic reactive plant

Option 2 is a variation of option 1C, where a single 100 MVAR shunt reactor replaced by a +200/-100 MVAr synchronous condenser. The timing of the investments was determined by the cost benefit analysis (see Section 6.3.4). In this option:

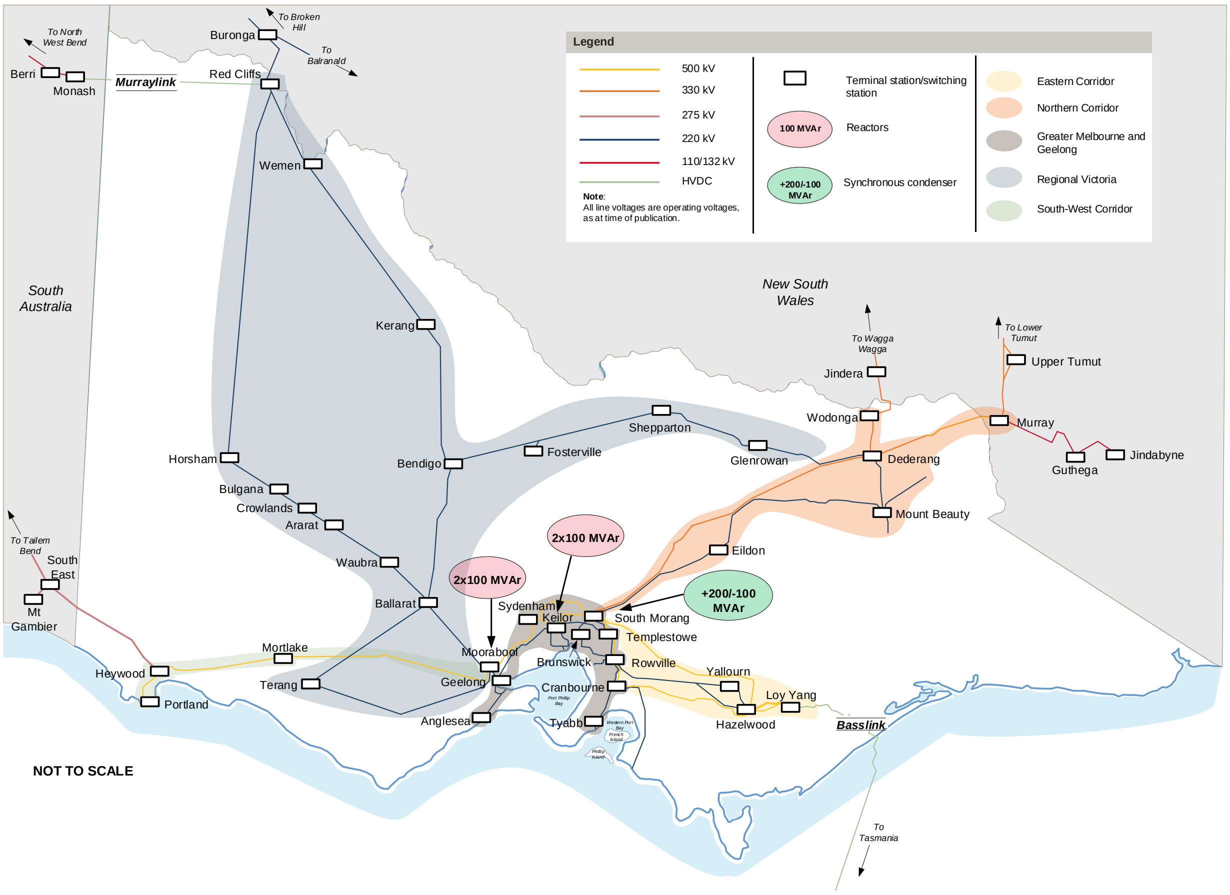
- Two 100 MVAr shunt reactors are installed at Keilor Terminal Station, in 2021 and the other in 2022.
- A 330 kV +200/-100 MVAr synchronous condenser is installed at South Morang Terminal Station in 2022.
- Two more 220 kV 100 MVAr shunt reactors are installed at Moorabool Terminal Station in 2023.

Although the cost of a synchronous condenser is significantly higher than a reactor, this option was included to test for possible additional market benefits through increasing the Victoria to New South Wales export limits (transient and voltage stability).

The estimated capital cost of this option is $84.7 million.

AEMO also considered testing combinations with even higher numbers of dynamic reactive plant, however initial studies showed that the increased benefit of these options was not sufficient to justify the increased costs.

Figure 8 Combination of four 100 MVAr reactors and one +200/-100 MVAr synchronous condenser (Option 2)



3.3 Cost estimates of credible options

Cost estimates for each of the above network options are presented in Table 6, based on information provided by AusNet Services. Costs were provided on a P50[17] basis, and do not include finance charges, overheads, or management reserve risk costs. Operational cost was assumed to be 2% of the capital cost.

The cost of each option includes the following components:

- Project management.
- Engineering support.
- Equipment and services procurement.
- Installation.
- Commissioning and testing.
- Project management risk allowance.

Cost estimates are based on standard capacities of reactive power plant and standard connection arrangements (as described in Section 3.1).

The typical lead time assumed is 12-18 months for installing reactors, and 18-36 months for installing synchronous condensers. The actual time required will depend on factors such as the location of the manufacturer, whether they are off-the-shelf products, and the location of the installations.

[17] An estimate prepared at any stage of a project which has a 50% confidence factor of not being exceeded by cost at completion.

Table 6 Cost estimates of credible network options

Option	Description	Total MVAr (absorbing)	Estimated capital cost ($M 2019-20)	Estimated operational cost ($M 2019-20)
1A	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 1 x 100 MVAr Shunt Reactor at Moorabool	300	19.1	0.38
1B	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 2 x 100 MVAr Shunt Reactor at Moorabool	400	25.4	0.51
1C	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 3 x 100 MVAr Shunt Reactor at Moorabool	500	31.7	0.63
1D	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 3 x 100 MVAr Shunt Reactor at Moorabool 220 kV 1 x 100 MVAr Shunt Reactor at South Morang	600	38.8	0.78
2	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 2 x 100 MVAr Shunt Reactor at Moorabool 330 kV 1 X +200/-100 MVAr Synchronous Condenser at South Morang	500	84.7	1.69

3.4 Description of the credible non-network options assessed

The PSCR listed three alternative non-network options that may meet the identified need:

- Demand response and decentralised storage.
- Additional absorbing reactive power capability from grid-connected generators.
- Solar rooftop PV reactive power support.

In July 2018, AEMO issued a Request for Information (RFI)[18] seeking submissions from generators, loads, and other parties that may have the capability to suppress high voltages during low demand periods in Victoria. Submissions closed on 13 August 2018.

AEMO did not receive any such submissions through the PSCR consultation, or through the RFI.

AEMO currently has a six-month NMAS agreement in place to manage high voltages in Victoria. AEMO has commenced an open tender for an alternative NMAS provider to commence when the existing contract concludes. These NMAS contracts are in response to a NSCAS gap, identified in the 2018 NTNDP. As such, they are effectively considered in the base case, against which the network options are assessed (refer to Section 6.3.1).

3.5 Material inter-network impact

Options 1A-1D do not have a material inter-network impact, since they do not materially impact interconnector limits.

Option 2 would increase the Victoria to New South Wales transient and voltage stability export interconnector limits. The potential benefits of this are included in the market benefit assessment.

[18] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Request-for-Information-for-reactive-power-Non-market-Ancillary-Services-in-VIC.

3.6 Other options considered

AEMO also gave due consideration to the following potential options, but for the reasons summarised below they were considered unlikely to become the preferred option and therefore not assessed further:

- Dynamic reactive power devices other than synchronous condensers.
  - Dynamic devices such as SVCs and STATCOMs can control voltage but are significantly more expensive than reactors. Since the primary issue that is being addressed is a steady state voltage issue and not a dynamic issue, no dynamic devices other than synchronous condensers were assessed in the PADR.
- Other combinations of capacity, voltage, location, technology, and connection arrangements.
  - Credible network options all comprise the installation of reactive power devices. These components are relatively modular, and therefore credible options are formed from a combination of capacity, voltage, technology, and connection arrangements. In addition, credible options can be formed from a combination of assets with differing parameters.
  - Performing detailed network and economic studies against all possible combinations would be impractical and unnecessary. As described in Section 3.1, AEMO has assessed the relative merits of these technical parameter combinations when identifying credible options, discussed in Section 3.2.

4. Submissions to the PSCR

4.1 Stakeholder submissions to the PSCR

The Victorian Reactive Support PSCR was published on 15 May 2018[19], and stakeholder submissions closed on 7 August 2018.

No submissions were received.

4.2 Request for information from non-network options

In July 2018, AEMO also issued an RFI[20] seeking information from generators, loads, and other parties that may have capability to suppress high voltages during low demand periods in Victoria.

Submissions closed on 13 August 2018.

No submissions were received.

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[19] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victorian-reactive-power-support-RIT-T-PSCR.pdf.

[20] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Request-for-Information-for-reactive-power-Non-market-Ancillary-Services-in-VIC.

5. Description of methodology and assumptions

The modelling carried out in this RIT-T is based on detailed power flow studies to estimate the impact of credible options in meeting the identified need, and economic modelling to rank credible options and identify the preferred option that delivers the highest net economic benefit. Where possible, all input assumptions have been based on AEMO's most recently published planning datasets.

5.1 Overview

The assessments in this PADR are based on the RIT-T application guidelines published in December 2018[21] by the Australian Energy Regulator (AER).

This chapter describes the key assumptions and methodologies applied in this RIT-T.

5.2 Assumptions

5.2.1 Analysis period

The RIT-T analysis has been undertaken over the period from 2019-20 to 2027-28.

To capture the overall market benefits of a credible option with asset life extending past 2027-28, the market dispatch benefits calculated for the final three years of the modelling period have been averaged, and this average value has been assumed to be indicative of the annual market dispatch benefit that would continue to arise under that credible option in the future.

Terminal values[22] have been used to capture the remaining asset life of the credible options.

5.2.2 Discount rate

The RIT-T requires the base discount rate used in the NPV analysis to be the commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.

A base discount rate of 6% (real, pre-tax) has been used in the NPV analysis. This discount rate is consistent with the 5.90% (real, pre-tax) commercial discount rate calculated in Energy Network Australia's RIT-T Economic Assessment Handbook[23]. This calculation assumes that a private investment in the electricity sector has a return on equity, and a debt gearing ratio, equal to an average firm on the Australian stock exchange as of 15 March 2019.

[21] At https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018.

[22] The value of an asset at the end of the modelled horizon.

[23] At https://www.energynetworks.com.au/rit-t-economic-assessment-handbook.

Sensitivity testing has been conducted on the base discount rate, with a lower bound discount rate of 3.5% and an upper bound discount rate of 8.5%.

5.2.3 Reasonable scenarios

The RIT-T requires a cost-benefit analysis that includes an assessment of reasonable scenarios of future supply and demand if each credible option were implemented, compared to the situation where no option is implemented.

A reasonable scenario represents a set of variables or parameters that are not expected to change across each of the credible options or the base case.

This RIT-T analysis included three reasonable scenarios:

- Neutral – central projections of economic growth, future demand growth, fuel costs, technology cost reductions, and distributed energy resources (DER) aggregation growth.
- Slow change – compared with the Neutral scenario, assumed weaker economic and demand growth, lower levels of investment in energy efficiency, slower uptake of electric vehicles, slower cost reductions in renewable generation technologies, and greater aggregation of DER.
- Fast change – compared with the Neutral scenario, assumed stronger economic and demand growth, higher levels of investment in energy efficiency, faster update of electric vehicles, faster cost reductions in renewable generation technologies, and less aggregation of DER.

All scenarios assumed the following market and policy settings:

- Emissions trajectories – reduce emissions to 28% on 2005 levels by 2030.
- Victorian Renewable Energy Target (VRET) – 25% renewables by 2020 and 50% by 2030.
- Queensland Renewable Energy Target (QRET) – 50% renewables by 2030.

5.2.4 Weightings applied to each scenario

The cost benefit analysis in this RIT-T has applied a 50% weighting to the Neutral scenario with the Fast change and Slow change scenario each weighted at 25%.

Sensitivity studies were undertaken with:

- Slow weighting – 50% weighting for the Slow change scenario, and 25% for the Neutral and Fast change scenarios.
- Fast weighting – 50% weighting for the Fast change scenario, and 25% for the Neutral and Slow change scenarios.

5.2.5 Demand and rooftop PV

The RIT-T PADR analysis applied the demand forecasts from the 2018 ESOO[24].

Rooftop PV forecasts and half-hourly traces for each scenario were also based on the 2018 ESOO.

Half-hourly demand traces used included the 50% POE, 90% POE, and 10% POE minimum demand conditions with weightings of 39.2%, 30.4% and 30.4% respectively[25].

5.2.6 Generator assumptions

The RIT-T analysis assumptions included:

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[24] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

[25] The methodology used to determine these weightings is at http://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/ESOO-Methodology-Document-v2---draft-2019.pdf.

- Committed generator projects from the January 2019 Generation Information update[26].
- Modelled generator projects obtained from the capacity outlook model described in Section 5.3.3.
- Renewable generator output traces from the 2018 ESOO.
- Generator build costs, fuel costs, and variable and fixed operating and maintenance costs (OPEX) from the 2019 Planning and Forecasting consultation[27].
- Assumptions of reactive power capability from agreed performance standards[28].
- Minimum generation levels based on historical generator performance.
- Start-up times estimated based on operational experience.
- Start-up fuel usage at 10% of fuel usage at full generator capacity.

5.2.7 Transmission development

Studies performed for this PADR included transmission developments proposed in the 2018 ISP and currently progressing through the RIT-T process, including existing interconnector augmentations and new interconnector developments.

The impacts of these interconnector developments on the Victoria to New South Wales transient and voltage stability limits were assumed to occur in both the 'do nothing' and upgraded case alike. The inclusion of these transmission developments is a conservative assumption, as each of the below listed developments increases the stability limits and therefore reduces the benefit of further increasing these limits through this RIT-T.

The Victoria to New South Wales transient and voltage stability limits were developed assuming:

- South Australia to New South Wales augmentation – preferred option from the RIT-T PACR from 2023[29].
- Victoria to New South Wales – Option 1 from the RIT-T PSCR from 2022[30].
- Western Victoria – preferred option (C2) from the RIT-T PADR from 2024[31].

If these projects are deferred or do not ultimately proceed, stability limit improvements due to options tested in this RIT-T will increase (as these limits will not have already been addressed by other network projects).

5.3 Market benefit methodology

AEMO used a combination of power systems studies and market modelling to estimate the market benefits associated with each credible option.

5.3.1 Power system studies

Power system studies were undertaken with a PSS®E[32] model to determine the Victorian reactive requirements under a range of scenarios, and to quantify the sensitivity of reactive requirements to the following factors:

- Operational demand level.
- Number of coal units online.

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[26] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[27] At http://www.aemo.com.au/Stakeholder-Consultation/Consultations/2019-Planning-and-Forecasting-Consultation.

[28] Future renewable generation reactive contribution was assumed at 25% of their maximum active power contribution as an average.

[29] At https://www.electranet.com.au/projects/south-australian-energy-transformation/.

[30] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PSCR.pdf.

[31] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Western-Victoria-Renewable-Integration-RIT-T-PADR.PDF.

[32] Description of software at https://www.siemens.com/global/en/home/products/energy/services/transmission-distribution-smart-grid/consulting-and-planning/pss-software/pss-e.html.

- Location and output of renewable generators.
- Critical contingencies.
- Location of credible options.
- 500 kV line switching.

The aim of the power system analysis was to determine the reactive requirements to maintain voltage limits under a range of low demand conditions, taking account of potential de-energisation of a single 500 kV line. These reactive requirements were then used as the inputs into the reactive modelling.

As Option 2 includes a dynamic reactive component, AEMO also studied the impact of this option on the Victoria to New South Wales transient and voltage stability limits, under periods of high Victoria to New South Wales export. Multiple snapshots representing different network operating conditions were studied using PSS®E dynamic simulations.

This study identified that a +200/-100 MVAr synchronous condenser at South Morang 330 kV will increase the Victoria to New South Wales export interconnector transient stability limit by approximately 150 MW, and the voltage stability limit by approximately 30 MW.

Additionally, studies have been undertaken to identify possible combinations of synchronous generating units that can provide adequate system strength to ensure secure operation of the Victorian power system[33].

5.3.2 Market modelling methodology

AEMO used market dispatch modelling to estimate the market benefits associated with the credible options. This estimation was done by comparing the 'state of the world' in the base case (or 'do nothing' case) with the 'state of the world' with each of the credible options in place. The 'state of the world' is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity, and timing of future generation, storage, and transmission investment, as well as the market dispatch outcomes over the modelling period.

This PADR used the following market models:

- Capacity outlook long-term (LT) model – determines the most cost-efficient long-term trajectory of generator, storage, transmission investments and retirements to maintain power system reliability.
- Time-sequential short-term (ST) model – carries out an hourly simulation of generation dispatch and regional demand while considering various power system limitations, generator forced outages, variable generation availability and bidding models.

Model inputs for both models, including demand levels and generator fuel and capital cost assumptions, are as described in Section 5.2 above.

5.3.3 Capacity outlook model

'Least- cost'[34] market development modelling was undertaken, according to the RIT-T and the application guidelines. The least-cost market development model used was the PLEXOS® long-term optimisation model.

The same capacity outlook model was used for the 'do nothing' case and the upgrade cases. Only the credible option with dynamic reactive plant (Option 2) is expected to have any inter-regional impact, and even this option was not expected to have a significant enough impact to change the capacity outlook. The capacity outlook model uses notional interconnector limits, and while Option 2 increases the Victorian to New South Wales transient and voltage stability export limits, these limits are not the only network limits impacting the overall export limit.

[33] The methodology used is at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[34] This means the modelling is orientated towards minimising the cost of serving load (or allowing load to remain unserved if that is least-cost) while meeting minimum reserve levels.

5.3.4 Time sequential model

The time sequential modelling aims to dispatch the least-cost generation to meet customer demand, mandatory service standards, and the various carbon abatement targets that have been assumed, while remaining within the technical parameters of the electricity transmission network.

Detailed market modelling was undertaken with the PLEXOS® short-term dispatch model.

Model parameters

- Generation and interconnector expansion plans were obtained from the Capacity outlook model described in Section 5.3.3.
- Generation and demand side resources are dispatched to meet load in order from lowest to highest short-run marginal cost.
- Transmission network parameters included in the modelling are described in Section 5.3.5.

Model outputs

This model produced an hourly pricing and dispatch solution for generation, which was used to calculate operational benefits (reduction in fuel and operation and maintenance costs). These benefits primarily stem from a reduction in dispatch costs from New South Wales and Queensland black coal generation due to an increase in export from Victoria.

5.3.5 Transmission network parameters

Constraint equations are a key input to the time sequential model. Constraint equations are a mathematical representation of transmission network parameters that AEMO uses to manage power system limitations, generation dispatch, and FCAS requirements.

In general, the following types of constraints were considered:

- Thermal – for managing the power flow on a transmission element so that it does not exceed a rating (either continuous or short term) under normal conditions or following a credible contingency.
- Voltage stability – for managing transmission voltages and reactive power margin so that they remain at acceptable levels after a credible contingency.
- Transient stability – for managing network flows to ensure the continued synchronism of all generators on the power system following a credible contingency.
- Oscillatory stability – for managing network flows to ensure the damping of power system oscillations is adequate under system normal and following a credible contingency.

Refer to AEMO's Constraint Formulation Guidelines[35] for more information on constraint equations. FCAS constraints were not modelled in this RIT-T, since they are not expected to materially impact market benefits.

The power system studies in Section 5.3.1, were used to apply offsets to the voltage and transient stability export limit constraint equations for the market modelling cases for the 'state of the world' with the credible option involving dynamic reactive plant (Option 2).

5.3.6 Market costs of maintaining system security

During low demand periods, AEMO's system operator may need to intervene in the market to maintain voltages within operational and design limits or to maintain adequate system strength. This intervention, via a direction or via the activation of a NMAS contract, involves AEMO dispatching a generator online 'out-of-merit' order, or in other words running a more expensive generator than would be dispatched without the intervention.

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[35] See http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2016/Constraint_Formulation_Guidelines_v10_1.pdf.

To capture the market cost of this intervention in the market modelling, the following steps were undertaken for each hour in the modelling period with and without the credible options in place:

- Step 1 – determine if the combination of synchronous generators online in Victoria provide adequate system strength to the power system. If not, bring additional synchronous generators online as required.
- Step 2 – calculate the reactive power shortfall using operational demand and renewable and thermal generation online (including the synchronous generators brought online in Step 1). For a non-zero reactive power shortfall, determine the number of additional generators required to be online to remove the reactive power shortfall.
- Step 3 – calculate the additional market cost of starting-up and dispatching the additional generators brought online in Step 1 and 2.

Representative generators

Combinations of Victorian grid connected generators that could deliver at least 100 MVAr absorbing reactive capability and meet system strength need were developed to form a representative generator with average:

- Absorbing reactive capability.
- Minimum dispatch levels.
- Dispatch costs (fuel plus variable OPEX).
- Start-up hours.
- Start-up cost.

These representative generators were then dispatched as required to remove the reactive power and system strength need.

Market cost of dispatching representative generators

The market cost of dispatching the representative generators was calculated using the following:

(Generator start-up costs + minimum generation x generator dispatch cost) – (minimum generation x displaced generator cost)

The dispatch cost includes the fuel costs and the variable OPEX.

Gross market benefits

The gross market benefits of each credible option were calculated by comparing the market cost of dispatching the representative generators with the credible option in place with the market cost of dispatching the representative generators in the 'do-nothing' case (no credible options in place).

5.4 Cost estimate methodology

Cost estimates for each network location and technology type are based on information provided by AusNet Services. Costs were provided on a P50[36] basis, and do not include finance charges, overheads, or management reserve risk costs. Operational cost was assumed to be 2% of the capital cost.

The cost of each option includes the following components:

- Project management.
- Engineering support.
- Equipment and services procurement.
- Installation.

[36] An estimate prepared at any stage of a project which has a 50% confidence factor of not being exceeded by cost at completion.

- Commissioning and testing.
- Project management risk allowance.

Cost estimates are based on assumed standard capacities of reactive power plant (100 MVAr) and standard connection arrangements (single-switching).

The typical lead time assumed is 12-18 months for installing reactors, and 18-36 months for installing synchronous condensers. The actual time required will depend on factors such as the location of the manufacturer, whether they are off-the-shelf products, and the location of the installations.

5.5 Investment timing methodology

The timing of the individual components in each of the credible options was developed by using the lead times discussed above and then shifting out the individual components by one-year increments until the net market benefits decreased.

For credible options with more than one component at the same terminal station, the investments were timed together if the increase in net benefits from staging was less than $0.5 million, due to expected efficiencies in combining the components.

The first proposed 100 MVAr reactor at Keilor Terminal Station in 2021 may be undertaken as part of a Network Capability Incentive Parameter Action Plan (NCIPAP) project by AusNet Services[37], and if approved, this would be removed from the final preferred option presented in the PACR.

Additional investigation on the cost of staging will be undertaken for the PACR assessment.

[37] AusNet Services owns and operates the majority of Victoria's electricity transmission network. See https://www.ausnetservices.com.au/.

6. Detailed option assessment

The primary source of market benefits is fuel and operating cost savings associated with avoided market intervention, avoided use of non-market ancillary services, and potential increases to the Victoria to New South Wales export stability limits.

6.1 Classes of market benefits not expected to be material

Chapter 5 of the PSCR identified classes of market benefits that were not expected to be material. A class of market benefit is considered immaterial if either:

- The class is likely not to affect materially the assessment outcome of the credible options for this RIT-T, or
- The estimated cost of undertaking the analysis to quantify market benefits of the class is likely to be disproportionate to the scale, size, and potential benefits of each credible option being considered.

AEMO did not receive any PSCR submissions on the materiality of the market benefits listed below, and therefore has continued to exclude them in this PADR assessment.

The following classes of market benefits are not expected to be material to this RIT-T:

- Network losses – the identified need of this RIT-T is related to suppression of high voltages during light load periods. While augmentation options to suppress high voltages could marginally increase network losses, it is not expected the increase will be material in relation to the RIT-T assessment for a specific option, as all options which can suppress high voltage will have similar (small) impact on network losses.
- Changes in ancillary services costs – there is no expected change to the costs of Frequency Control Ancillary Services (FCAS), Network Control Ancillary Services (NCAS), or System Restart Ancillary Services[38] (SRAS) because of the options being considered. These costs are therefore not material to the outcome of the RIT-T assessment.
- Differences in timing of transmission investment – investments to address the identified need of this RIT-T could postpone other transmission investments. Although it is likely that additional synchronous condensers will be required in Victoria after the retirement of brown coal generators in the 2030s, this benefit has not been included in this RIT-T, because it will not change the sign or the ranking of the credible options.
- Competition benefits – competition benefits are not expected to be material to the outcome of this RIT-T assessment. The high voltages are localised in nature and have a limited impact on spot market outcomes, except when line de-energisation is used to manage the issue. It is expected that all options which can suppress high voltage will have a similar (small) impact on spot market outcomes. The estimation of any competition benefit in this RIT-T assessment would require significant modelling which would be disproportionate to any competition benefits arising from any of the credible options in this RIT-T.

[38] All though not quantified, a synchronous condenser will provide greater flexibility during system restart process and enable a broader range of SRAS providers.

- Option value – for this RIT-T assessment, the estimation of any option value benefit over and above that already captured via the scenario analysis in the RIT-T would require significant modelling, which would be disproportionate to any additional option value benefit that may be identified for this specific RIT-T assessment. In this case, appropriate identification of credible options and reasonable scenarios should capture any option value. AEMO does not therefore propose to estimate any additional option value market benefit for this RIT-T assessment.

6.1.1 Classes of market benefit that are no longer material in the PADR

This section describes the classes of market benefits that were initially assumed to be material in the PSCR, but have subsequently been identified as immaterial through the PADR analysis:

- Changes in voluntary/involuntary load curtailment – without additional reactive power support, there still may be high-impact low-probability reliability risk associated with de-energisation of multiple 500 kV lines under extreme conditions, like what happened on 17 November 2018, and thus market benefits can be captured by additional reactive support for mitigating this risk. However, these market benefits are not considered material for the purposes of this RIT-T, because any such benefits would be common to all credible options and would therefore not influence the selection of a preferred option.

6.2 Quantification of classes of material market benefit for each credible option

The classes of market benefits/costs that are material in the case of this RIT-T are:

- Changes in fuel consumption arising through different patterns of generation dispatch.
- Changes in costs to parties other than the TNSP, due to differences in the operational and maintenance costs of different plant.

The next sections further describe the main market benefits of each credible option.

6.2.1 Changes in fuel consumption

Changes in fuel consumption through different patterns of generation dispatch are the primary source of market benefits identified in this RIT-T.

For all credible options the reduction in the need for AEMO's system operator to intervene in the market via either directing generators online or by calling on an NMAS contract has been captured by reduction in:

- Fuel costs of generators dispatched through market intervention.
- Start-up fuel costs of generators dispatched through market intervention.

Additionally, as noted in the previous section, dynamic plant such as synchronous condensers can meet the identified need under this RIT-T and have other benefits such as improving system strength and voltage stability in an area. Studies indicate installation of a synchronous condensers to address the identified need would also increase the Victoria to New South Wales transient and voltage stability limits, under periods of high Victoria to New South Wales export.

AEMO calculated the difference in total fuel costs between the 'do nothing' base case and the case with the credible option involving dynamic reactive plant (Option 2) to capture any reduction in total fuel costs due to the increased stability limit. Fuel costs are calculated for the entire NEM and will therefore capture benefits to states other than Victoria.

6.2.2 Changes in costs for other parties

Changes in costs for other parties is the other class of market benefits quantified in this RIT-T. 'Other parties' in this context refers to costs incurred by market participants due to:

- Differences in variable operating and maintenance costs of generators dispatched through market intervention.
- Start-up operating and maintenance costs of generators dispatched through market intervention.
- Differences in variable operating and maintenance cost of generators due to different market dispatch patterns due to the increased Victoria to New South Wales export stability limits.

6.2.3 Other benefits not quantified in this RIT-T

The PSCR also included the reduction in market costs during periods of de-energisation of 500 kV lines as a potential market benefit. This is because the de-energisation of 500 kV lines can reduce Victoria's ability to export, and create a market impact through the use of higher marginal cost generation in other regions. This potential market benefit has not been calculated in this PADR, because the cost from reducing export limits in these periods is significantly smaller than the cost of the market intervention required in these periods. This minor benefit will not affect the ranking of credible options.

Option 2 will also provide additional benefits compared to the other credible options that were not quantified in the market benefits assessment, including the ability of the synchronous condenser to:

- Improve voltage control and voltage stability during high demand periods where necessary, which could delay the need for future voltage control devices such as capacitors.
- Facilitate system restart by providing stability. It will enable a broader range of SRAS providers and provide greater operational flexibility during the restart process.
- Provide dynamic voltage support after the retirement of brown coal generation in Victoria.

These benefits were not quantified because they would not change the ranking of the credible options or result in negative net market benefits for the preferred option. As such, they would not affect the outcome of the PADR assessment.

6.3 Net market benefit assessment

6.3.1 The 'do nothing' base case and non-network NMAS option

The 'do nothing' base case is defined in the RIT-T guidelines as the case where the RIT-T proponent does not implement a credible option to meet the identified need. For this RIT-T, if AEMO as TNSP does not implement a credible option, then AEMO as system operator would be required to intervene in the market either by directing generators or entering into, and activating, a NMAS contract, to maintain the power system in a satisfactory and secure operating state.

The underlying cost of directing generators, or a NMAS contract, has been calculated using generator fuel costs and operating and maintenance costs, as discussed in Section 5.3.6.

A non-network option in the form of AEMO's current NMAS contract[39] is assumed to have the same underlying costs (based on fuel and operating and maintenance cost) as either directing generators or a system operator NMAS contract.

6.3.2 Net market benefits of network augmentations

Table 7 presents the gross and net market benefits for each augmentation option. Refer to Attachment A for more details on the net present value calculations.

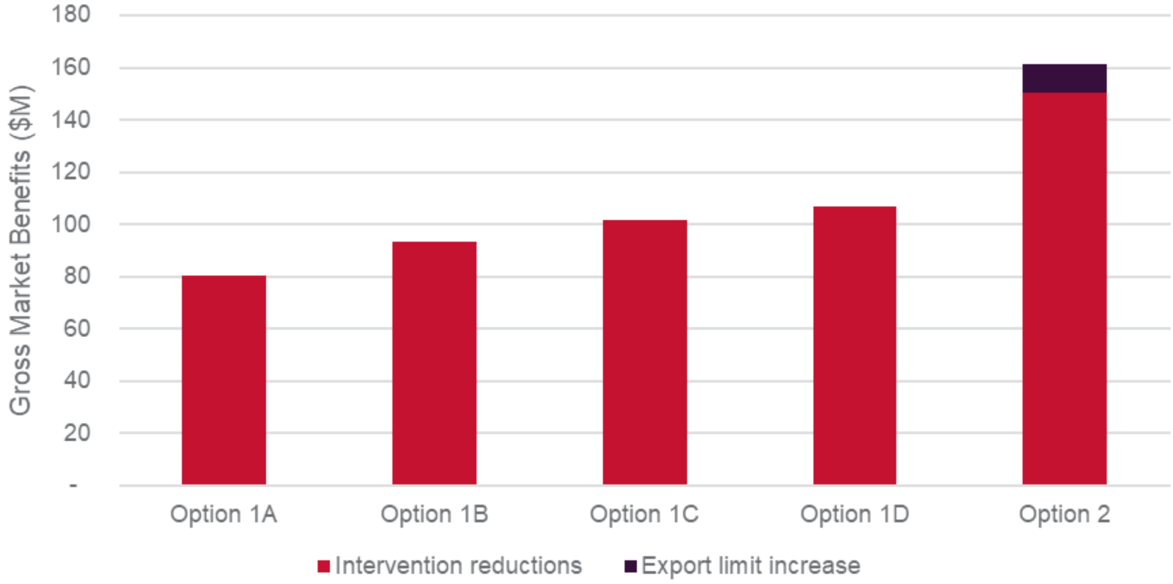
[39] In December 2018, AEMO's NTNDP identified an NSCAS gap for voltage control in Victoria, and AEMO has subsequently entered an NMAS contract as an interim measure to resolve this gap while the reactive power support RIT-T investigates a permanent solution.

Table 7 Weighted net market benefits for each augmentation option

Option	Description	Capital cost, $M (2019-20)	Capital cost, $M (NPV)	Neutral – net market benefit, $M (NPV)	Fast change – net market benefit, $M (NPV)	Slow change – net market benefit, $M (NPV)	Weighted – net market benefit, $M (NPV)
1A	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 1 x 100 MVAr Shunt Reactor at Moorabool	19.1	16.7	48.2	14.9	144.1	63.9
1B	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 2 x 100 MVAr Shunt Reactor at Moorabool	25.4	21.5	53.0	15.1	165.4	71.7
1C	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 3 x 100 MVAr Shunt Reactor at Moorabool	31.7	26.9	53.5	13.8	178.9	74.9
1D	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 4 x 100 MVAr Shunt Reactor at Moorabool	38.8	32.3	51.4	10.8	185.2	74.7
2 (preferred option)	220 kV 2 x 100 MVAr Shunt Reactor at Keilor 220 kV 2 x 100 MVAr Shunt Reactor at Moorabool 330 kV 1 X +200/-100 MVAr Synchronous Condenser at South Morang	**84.7**	**72.3**	**64.9**	**18.5**	**208.7**	**89.2**

Figure 9 shows the weighted gross market benefits for each augmentation option, highlighting that all market benefits for Options 1A to 1D, and most of the market benefits for Option 2, arise from a reduction in market costs associated with the market interventions that would otherwise be required to maintain system security.

Figure 9 Weighted gross market benefits for each augmentation option



Market intervention outcomes

Figure 10 shows the projected annual hours of market intervention under each credible option, and Figure 11 shows the number of start-ups required each year, for the 'do nothing' base case and for each credible option. The number of start-ups represent the number of times a generator was brought online to provide reactive support or to fulfil system strength requirements, and the annual hours of market intervention represent the total running hours of generators brought online to provide reactive support or to fulfil system strength requirements (as described in Section 5.3.6).

Figure 10 Annual hours of intervention

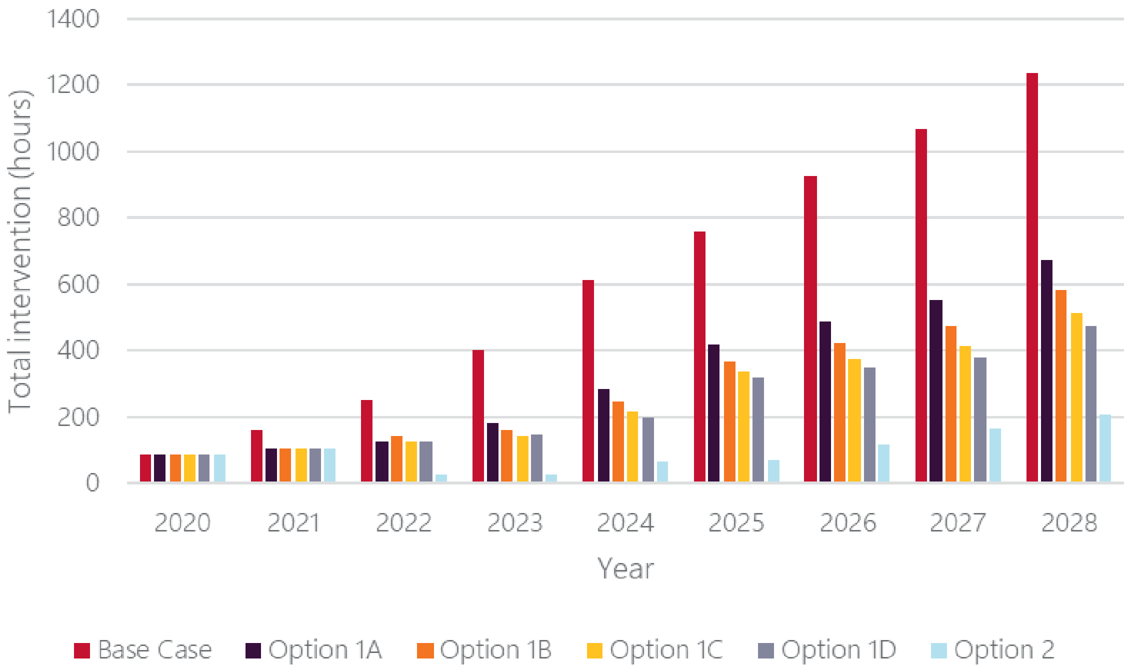
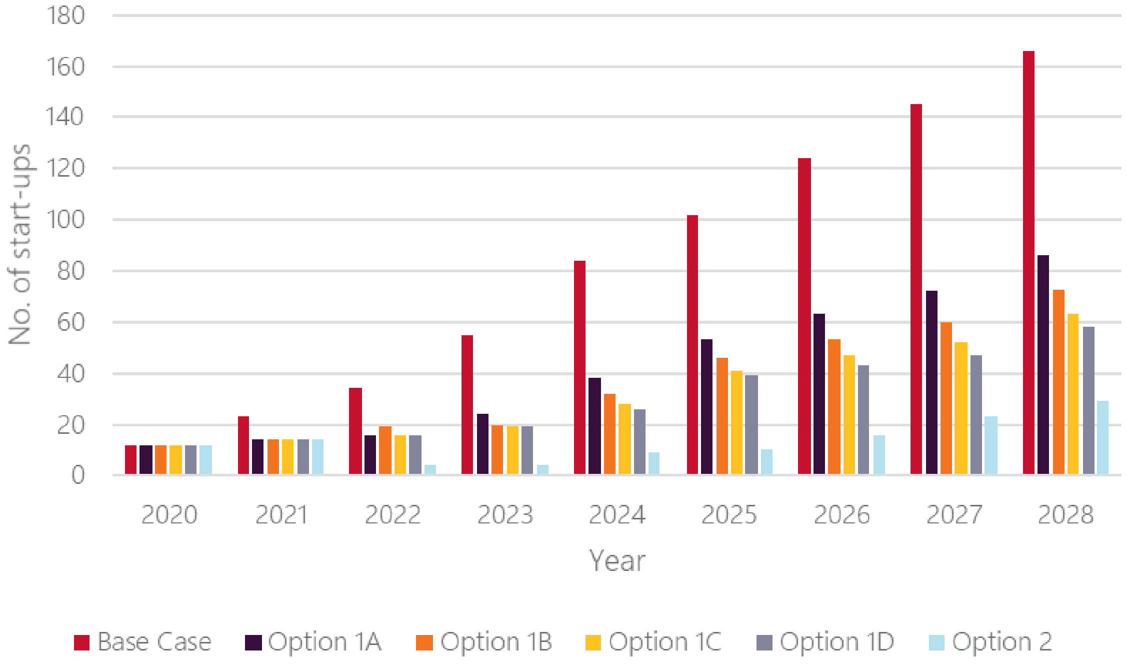


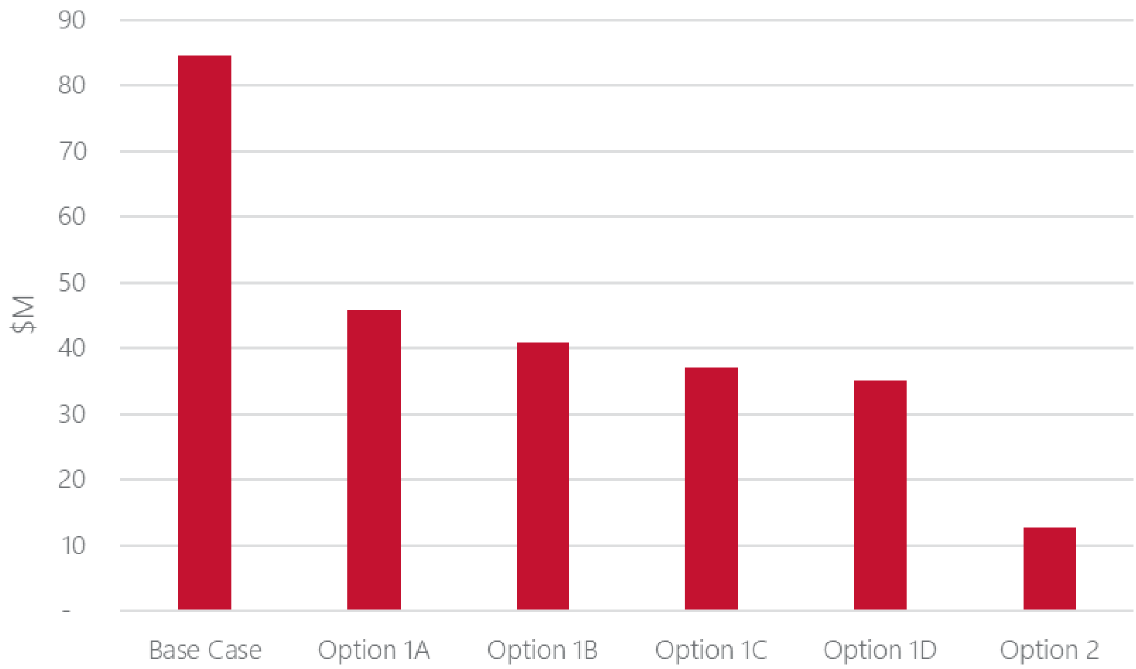
Figure 11 Annual number of start-ups



Credible options 1A to 1D deliver increasing levels of reactive support (from 300 MVAr to 600 MVAr). As the reactive support increases, the extent of market intervention required to remove reactive shortfalls decreases. Option 2 also reduces the need for market intervention to maintain system strength, and this option has the greatest decrease in market intervention incidents.

Figure 12 shows the total cost of market intervention between 2020 and 2028 for the 'do nothing' base case and for each credible option.

Figure 12 Cost of market intervention from 2020 to 2028 ($M)



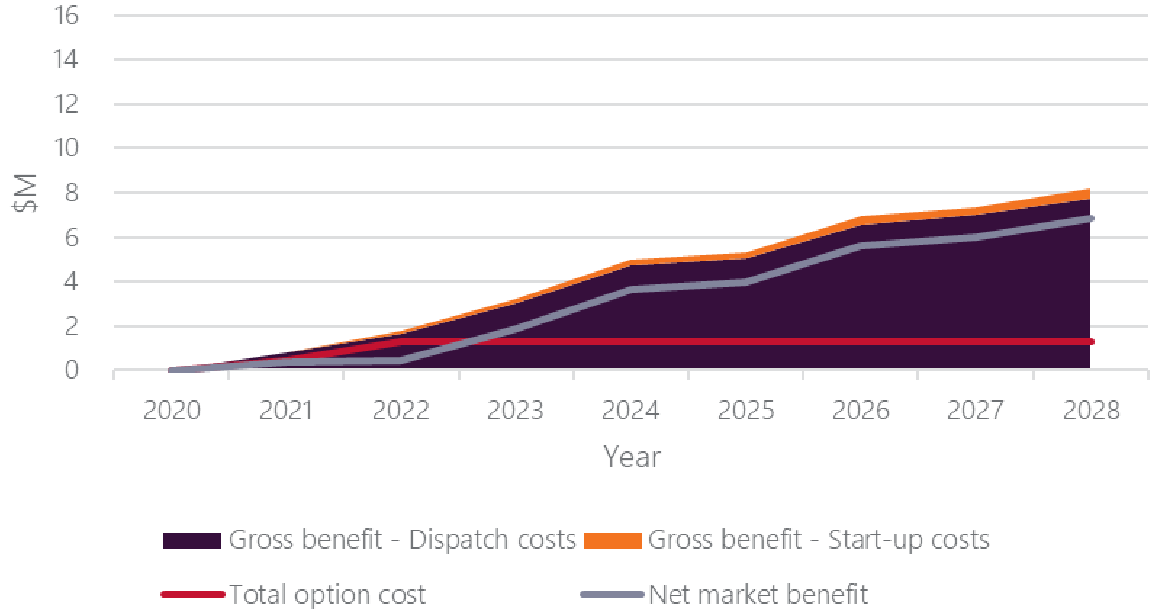
Option 1A,1B,1C, and 1D

Options 1A-1D have a combination of 100 MVAr additional reactors installed in the network between Keilor, Moorabool, and South Morang terminal stations. For these options, all quantified market benefits arise from the reduction of market intervention for reactive shortfalls.

Figure 13 to Figure 16 show the annual gross benefits and the investment cost for each of Options 1A to 1D. The net market benefit is positive from the first year of investment (2021) for all options and increases steadily from 2023 onwards as minimum demand continues to decline.

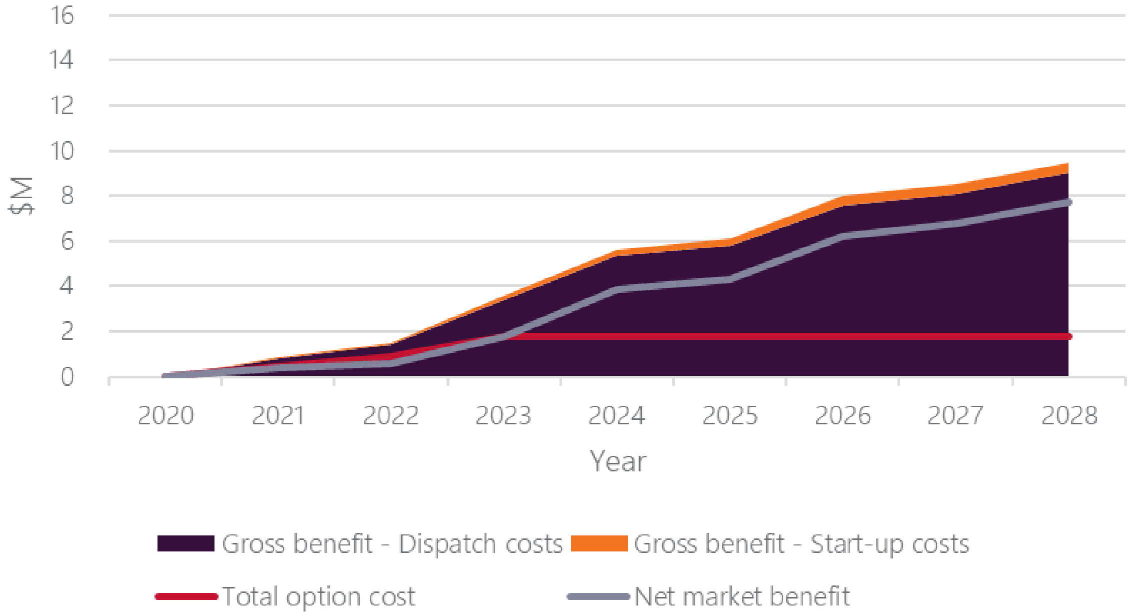
Option 1A, with 300 MVAr of new reactors, has the lowest investment cost but also the lowest gross benefits and lowest net market benefits out of the Option 1 variants. This shows that at 300 MVAr, the benefits of additional reactive support would outweigh the increase in investment cost.

Figure 13 Option 1A gross benefits and investment costs



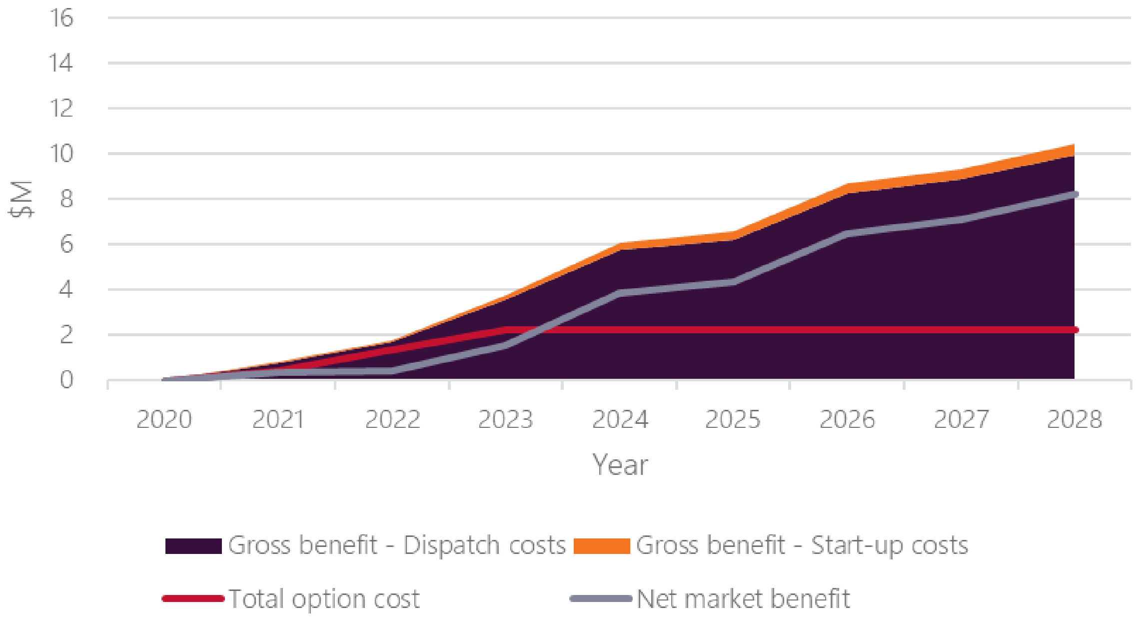
Option 1B, with 400 MVAr of reactive support, has higher investment costs but also delivers higher net market benefits than Option 1A.

Figure 14 Option 1B gross benefits and investment costs



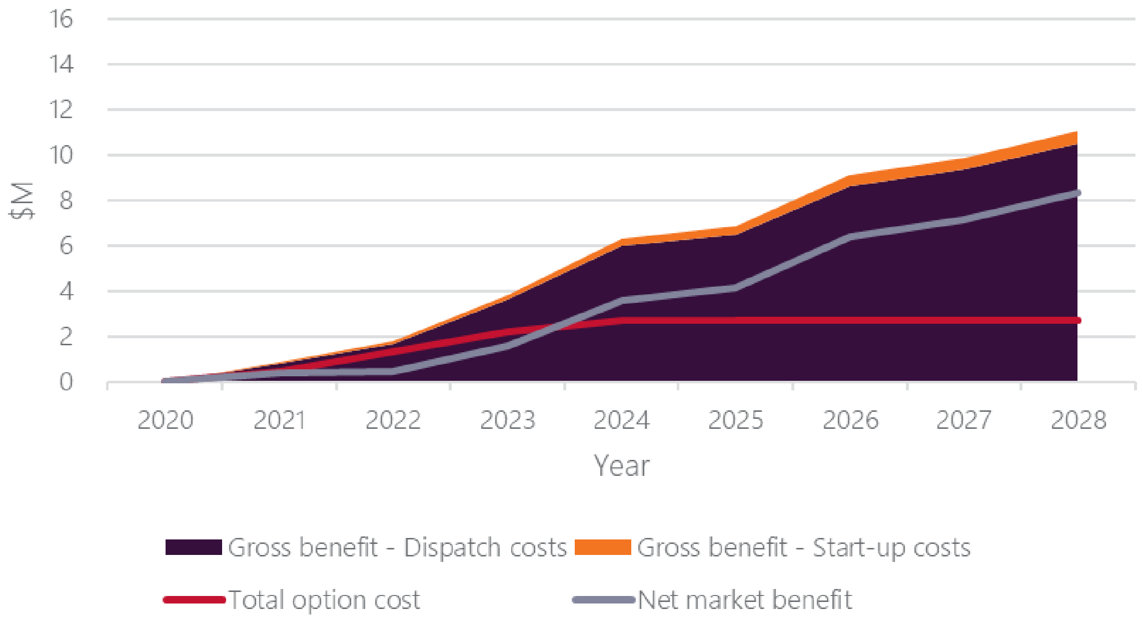
Option 1C, with 500 MVAr of reactive support, has higher investment costs than Option 1A and 1B but also higher net market benefits. This option has the highest net market benefits out of the Option 1 variants, showing that after 500 MVAr the incremental value of additional reactive support does not outweigh the additional investment cost.

Figure 15 Option 1C gross benefits and investment costs



Option 1D, with 600 MVAr of reactive support, has the highest investment cost out of all the Option 1 variants, and the highest gross market benefits. The net market benefit for Option 1D is slightly less than for Option 1C, because its higher investment cost was only partially offset by the additional market benefits under this option.

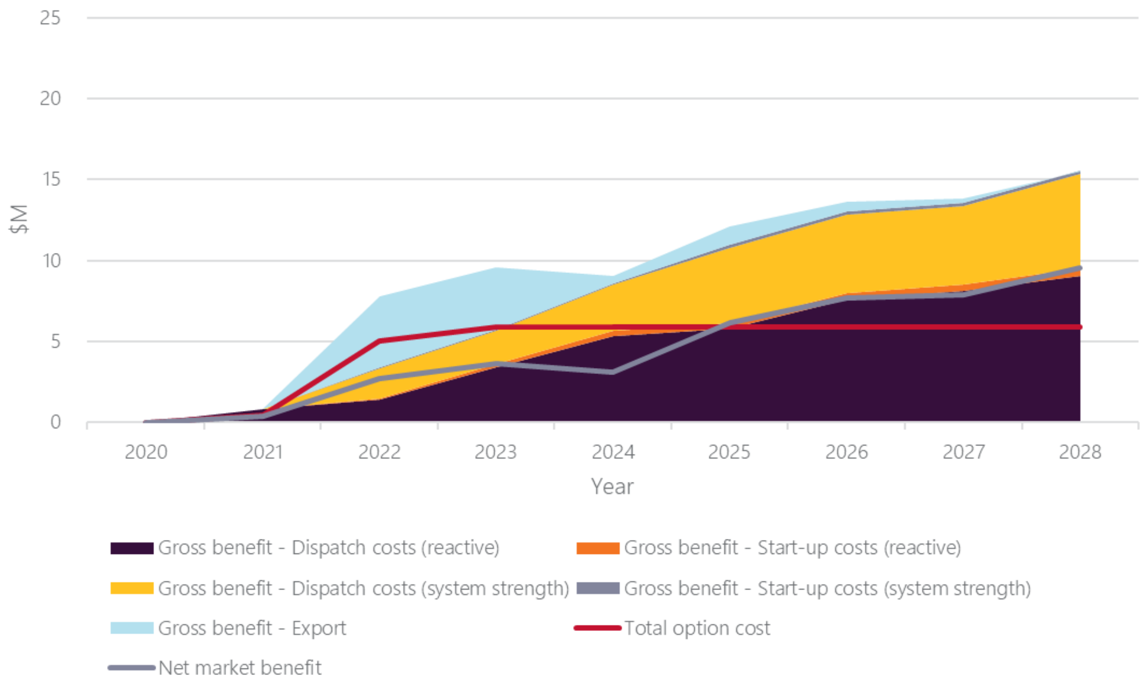
Figure 16 Option 1D gross benefits and investment costs



Option 2

Option 2 has a total of 500 MVAr of reactive support – 400 MVAr of reactors and one +200/ 100 MVAr synchronous condenser. Figure 17 shows the annual gross benefits and investment cost for this option.

Figure 17 Option 2 gross benefits and investment costs



The Option 2 gross market benefits include the additional benefits from increasing the Victoria to New South Wales export limit. These benefits are highest in 2022 and 2023 and decrease from 2024 onwards as additional investment in the transmission network (see Section 5.2.7) increase the export limit in the 'do nothing' base case.

Option 2 also captures additional benefits from reducing the need for market intervention to maintain system strength. These benefits are projected to commence from 2022 and continue to increase as minimum demand decreases.

Option 2 has the highest cost, and highest net market benefits, out of all the credible options assessed.

Preferred option

Table 8 compares the weighted net market benefits (NPV) across all credible options considered. This shows that all credible options provide positive net market benefits, with Option 2 providing the highest net market benefits at $89.2 million.

Table 8 Weighted net market benefits NPV ($M)

Option	1A	1B	1C	1D	2 (preferred option)
NPV ($M)	63.9	71.7	74.9	74.7	89.2

As discussed above, Option 2 captures higher benefits because it includes additional benefits from increasing the Victoria to New South Wales export limit and reducing the need for market intervention to maintain system strength.

Option 2 will also provide additional benefits compared to other options that were not quantified in the market benefits assessment. These include the ability of the synchronous condenser to:

- Improve voltage control and voltage stability during high demand periods where necessary, which could delay the need for future voltage control devices such as capacitors.
- Facilitate system restart by providing stability. It will enable a broader range of SRAS providers and provide greater operational flexibility during the restart process.
- Provide dynamic voltage support after the retirement of brown coal generation in Victoria.

6.3.3 Sensitivity studies

Sensitivity analysis was carried out to test the robustness of the analysis resulting in the preferred option and to determine if any factors will change the order of the credible options assessed:

- Change in scenario weightings – scenario weightings:
  - Slow change scenario weighted to 50%, with Neutral and Fast change scenarios at 25% each.
  - Fast change scenario weighted to 50% and Neutral and Slow change scenarios at 25% each.
- Change in cost – costs were changed by ±30%.
- Change in discount rate – sensitivity testing has been conducted on the base discount rate, with a lower bound discount rate of 3.5% and an upper bound discount rate of 8.5%.

Table 9 compares the weighted net market benefits delivered by each credible option. Option 2 provides the highest net market benefits under all scenarios and sensitivities.

Table 9 Sensitivity studies – weighted net market benefits NPV ($M)

Option	Base	High cost	Low cost	High discount rate	Low discount rate	Slow weighting	Fast weighting
1A	63.9	58.9	68.9	42.7	98.1	87.8	55.6
1B	71.7	65.2	78.1	47.2	111.6	99.8	62.2
1C	74.9	66.9	83.0	48.4	118.4	106.3	65.0
1D	74.7	65.0	84.4	47.1	120.3	108.2	64.6
2	89.2	67.6	110.9	50.7	153.1	125.2	77.6

6.3.4 Timing of preferred option

The proposed timing of the preferred network option is staged between 2021-23, with the option having positive net market benefits from 2021 onwards.

A number of sensitivities were undertaken to determine the optimal timing, as shown in Table 10. These sensitivities involved delaying components of the preferred solution by one year.

The results showed that one-year delays decreased the net benefits, with the exception of delaying one of the two reactors at Moorabool Terminal Station. A one-year delay of one reactor increased the net benefits by $0.4 million, but a one-year delay of both reactors decreased the net benefits by $0.5 million.

Table 10 Timing sensitivities

Timing sensitivity	Weighted net benefit ($M)	Difference from preferred option ($M)
Proposed timing	89.2	
Delay first 100 MVAr at Keilor from 2021 to 2022	88.9	-0.4
Delay second 100 MVAr at Keilor from 2022 to 2024	88.8	-0.5
Delay synchronous condenser at South Morang from 2022 to 2023	87.7	-1.5
Delay 100 MVAr at Moorabool from 2023 to 2024	89.6	0.4
Delay 200 MVAr at Moorabool from 2023 to 2024	88.7	-0.5

As Table 10 shows, further staging of the transmission investment by separating the installation of the two reactors at Moorabool may have a market benefit, but it is believed the overall net benefit may not be significant when considering the incremental costs of staging the project (project management costs, contract costs, tender process, and construction costs). These incremental costs have not been considered in this PADR and will be further investigated in the PACR to finalise the optimal timing.

7. Proposed preferred option

The preferred option is to install 400 MVAr of static reactive plant across Keilor and Moorabool Terminal Stations, and a +200/-100 MVAr synchronous condenser at South Morang Terminal Station.

7.1 Preferred option

The NER requires the PADR to identify the preferred option under the RIT-T, which is the investment option that meets an identified need, while maximising the present value of net economic market benefits to all those who produce, consume, and transport electricity in the market.

The RIT-T analysis (discussed in Chapter 6) indicates that the preferred option identified in this PADR (and shown in Figure 18) is to install:

- Two 100 MVAr shunt reactors at Keilor Terminal Station in 2021 and 2022 respectively.
- One 330 kV +200/-100 MVAr synchronous condenser at South Morang Terminal Station in 2022.
- Two 220 kV 100 MVAr shunt reactors at Moorabool Terminal Station in 2023.

The preferred option has a capital cost of approximately $72 million (in present value terms), and yields the highest net market benefits when weighted across all reasonable scenarios and sensitivities.

The PADR analysis identifies that investing in this option will deliver a net present economic benefit of approximately $89 million, by:

- Reducing market costs associated with dispatching generators that are normally offline during light load periods to maintain voltages within operational and design limits.
- Reducing market costs associated with dispatching generators for system strength.
- Increasing the Victoria to New South Wales export interconnector transient stability limit by approximately 150 MW, and the voltage stability limit by approximately 30 MW.

Together, the above listed augmentations constitute the proposed preferred option and satisfy the regulatory investment test for transmission.

Figure 18 Preferred option of four 100 MVAr reactors and one +200/-100 MVAr synchronous condenser