Victoria to New South Wales Interconnector Upgrade – Project Assessment Draft Report

August 2019

Important notice

PURPOSE

AEMO and TransGrid have 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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Note that equipment locations identified in this document are indicative only. The actual locations will be determined as required during the detailed design and route assessment phase, after conclusion of the RIT-T process.

VERSION CONTROL

Version	Release date	Changes
1	August 2019	First release.

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Executive summary

The energy landscape across the National Electricity Market (NEM) is changing rapidly. Strong investor interest in renewable generation continues to shift the geography and technical characteristics of supply, while it is anticipated that an aging fleet of existing conventional generators will progressively withdraw from the market over the coming decades. Furthermore, consumer behaviour is evolving and the increasing penetration of distributed energy resources (DER) is changing the nature of 'demand' while also providing new opportunities to address Australia's energy transformation.

This energy transformation is already having a dramatic impact on the utilisation of the existing power system. It is, for instance, increasing network congestion in some areas, while also increasing the system's reliance on interconnections between regions. Well-targeted and timely investment in the transmission network is required to keep pace with these changes and provide consumers with the most cost-effective energy outcomes.

AEMO's 2018 Integrated System Plan[1] (ISP) sets out an optimised national pathway for development of the power system that would maximise the value from new and existing resources across the NEM, while delivering energy reliability at the lowest cost to consumers.

The ISP identified that immediate action was required on several fronts, and designated these as priority 'Group 1' projects. This group included the need for increases to the transfer capability between Victoria and New South Wales.

Transfer between these two states is currently restricted by thermal, voltage stability, and transient stability limitations. Without investment, these limitations will result in the northern states having limited access to lower-cost generation from the southern states, preventing reductions in the underlying economic cost of generating electricity across the NEM, and increasing the requirement for new generation investment to maintain adequate supplies.

In mid-2018, AEMO and TransGrid jointly initiated a Regulatory Investment Test for Transmission (RIT-T) to assess network and non-network options to increase the capacity to transfer electricity from Victoria to New South Wales. In November 2018, AEMO and TransGrid published a Project Specification Consultation Report (PSCR), which identified the need for additional export capability from Victoria.

Following the publication of the PSCR, AEMO and TransGrid sought feedback from stakeholders on the identified need, and on the range of credible options being considered. Information was sought from providers of potential non-network solutions capable of relieving congestion and improving the associated network limitations.

Feedback from stakeholders has now been incorporated, and extensive market modelling has been undertaken to assess all credible options, to identify the optimal size, technology, location, and staging that is projected to meet the identified need while maximising the present value of net economic benefits to all those who produce, consume, and transport electricity in the market (referred to as 'net market benefits').

This Project Assessment Draft Report (PADR) marks step two of the RIT-T process[2]. The report reconfirms the nature of the identified need, summarises the technical and economic assessment of the credible options, and justifies selection of the proposed preferred option.

[1] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[2] 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 proposed preferred option

The proposed preferred option identified in this PADR (as shown in Figure 1) is to implement the following augmentations by 2022-23:

- Install a second 500/330 kilovolt (kV) transformer at South Morang Terminal Station.
- Re-tension the 330 kV South Morang – Dederang transmission lines, as well as associated works (including uprating of series capacitors), to allow operation at thermal rating.
- Install modular power flow controllers on the 330 kV Upper Tumut – Canberra and Upper Tumut – Yass lines to balance power flows and increase transfer capability.

The proposed preferred option will increase export capability from Victoria to New South Wales by approximately 170 megawatts (MW), and has a capital cost of approximately $68 million (in present value terms). This option yields the highest net market benefits under all the future scenarios and sensitivities assessed.

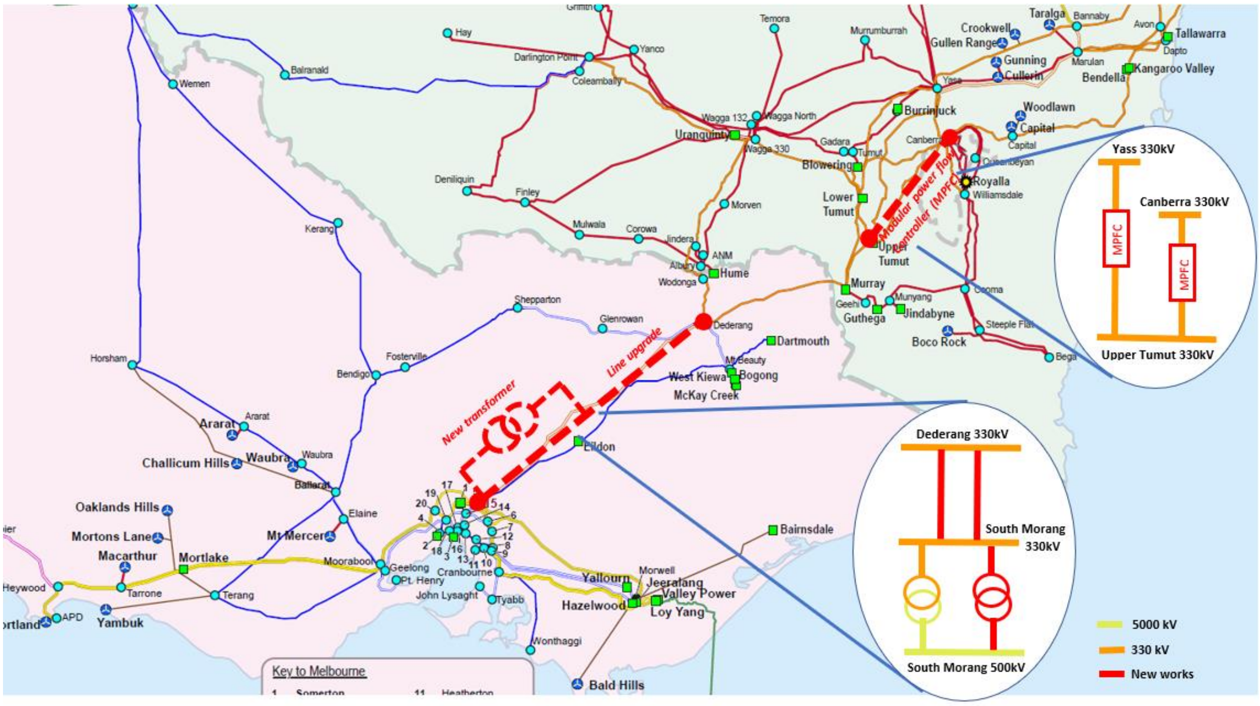
The PADR analysis identifies that this option will deliver a net present economic benefit of approximately $286 million, by:

- Reducing dispatch costs, through more efficient dispatch of generation in Victoria and New South Wales.
- Reducing capital costs associated with new generation build in New South Wales.

This preferred option is consistent with the project identified as a Group 1 priority project in AEMO's 2018 ISP.

The proposed preferred option is shown in Figure 1 below.

Figure 1 Proposed preferred option (Option 2 from PADR)



Joint RIT-T approach

AEMO and TransGrid are jointly progressing this RIT-T to assess the technical and economic viability of increasing the transfer capacity between Victoria and New South Wales, aimed at reducing the market costs across the NEM.

This PADR has been jointly prepared by AEMO and TransGrid for consultation in accordance with the requirements of the RIT-T process set out in the National Electricity Rules (NER) clause 5.16. The PADR is the second public consultation stage of the RIT-T process.

Credible options included in the assessment

A range of credible options for increasing the Victoria to New South Wales export capability were considered, as detailed in Table 1 below. The assessment of these options also considered any potential benefit to the import capabilities from New South Wales to Victoria.

These credible options are consistent with those proposed in the PSCR, except that the component to increase stability limits has been excluded.

This is because detailed studies found that the required increase in stability limits would be achieved through options to address thermal limitations under this RIT-T and other RIT-Ts (Victorian Reactive Power Support, Western Victoria Renewable Integration, and Project EnergyConnect) currently underway, as detailed in Section 2.2.2 of this report. The status of these other RIT-Ts will be monitored closely, and the proposed preferred option of this RIT-T updated if necessary during the PACR stage. In particular, the PACR may assess a variant of the proposed preferred option which includes a component to increase stability limits, if the preferred options under the other RIT-Ts do not become committed.

The PADR assessment included a credible option with modular power flow controllers (see Option 2) in response to stakeholder feedback. The PADR assessment did not identify any technical issues with these modular power flow controllers and is subject to further modelling in the PACR stage to assess the potential for control interactions between the modular power flow controllers and nearby generators.

Table 1 Credible options tested in detail through the PADR analysis

Option [A] (PSCR reference)	Description	Capital cost, $M, (2019-20)
Option 1 (equivalent to Option 1 of PSCR)	**ISP base option** • One new 500/330 kV transformer at South Morang Terminal Station. • Re-tensioning the 330 kV South Morang – Dederang transmission lines, as well as associated works (including uprating of series capacitors) to allow operation at thermal rating. • 330 kV Upper Tumut - Canberra line upgrade	97.5
Proposed preferred option Option 2[B] (equivalent to Option 1 of PSCR)	**ISP base option with modular power flow controllers** • One new 500/330 kV transformer at South Morang Terminal Station. • Re-tensioning the 330 kV South Morang – Dederang transmission lines, as well as associated works (including uprating of series capacitors) to allow operation at thermal rating. • Install modular power flow controllers on both 330 kV Upper Tumut – Canberra and 330 kV Upper Tumut - Yass lines.	80.5
Option 3 (equivalent to Option 2a of PSCR)	**Additional higher capacity upgrades in New South Wales** • One new 500/330 kV transformer at South Morang Terminal Station. • Re-tensioning the 330 kV South Morang – Dederang transmission lines, as well as associated works (including uprating of series capacitors) to allow operation at thermal rating. • Bring forward one leg of HumeLink, a new 500 kV line between Snowy and Bannaby including connection into existing 330 kV network, as proposed under TransGrid's RIT-T for reinforcing Southern New South Wales[C].	609.5 (102 in bring-forward cost terms)[D]
Option 4 (equivalent to combination of Option 3a and 3b of PSCR)	**Additional higher capacity upgrades in New South Wales and Victoria** • Two new 500/330 kV transformers at South Morang Terminal Station. • New 330 kV South Morang - Dederang line • Bring forward one leg of HumeLink, a new 500 kV line between Snowy and Bannaby including connection into existing 330 kV network, as proposed under TransGrid's RIT-T for reinforcing Southern New South Wales[C].	1,042 (534 in bring-forward cost terms)[D]

A. The PSCR proposed options to improve stability limits, however this PADR does not propose specific investment to improve stability limits as the improvements will be achieved through the proposed preferred option in this PADR and options proposed in other RIT-Ts currently underway, as detailed in Sections 2.2.2 and 5.4.4 of this report.

B. The PSCR proposed upgrading the 330 kV Upper Tumut – Canberra line to increase the transmission capacity between Snowy and load centres in New South Wales. However, a similar increase in transfer capacity can be achieved for a lower cost with modular power flow controllers. As such, the PADR proposes modular power flow controllers to increase utilisation of the 330 kV cut set between Snowy and Yass/Canberra.

C. At https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network/Documents/TransGrid%20PSCR_Reinforcing%20NSW%20Southern%20Shared%20Network.pdf

D. The bring-forward cost represents the cost of moving the HumeLink component forward from 2026-26 to 2024-25. This cost is effectively used in the cost-benefit assessment in the Neutral and Fast change scenario, and the full cost is effectively used in the Slow change scenario.

Scenarios and sensitivities analysed

The RIT-T requires a 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. They are intended to reflect a wide range of variations to the variables that may materially affect the relative benefits of the RIT-T credible options.

This RIT-T considers three reasonable future scenarios, based on the 2019 Planning and Forecasting Consultation Paper[3]:

1. **Neutral** – a future where modest economic and population growth is experienced, and existing policies are delivered. Consequently, grid demand is relatively static, and change in the large-scale generation mix is largely driven by the timing of coal-fired generation retirements.
2. **Slow change** – a future where Australia's economic and population growth is weaker, the life of existing power stations could be extended, households and commercial businesses install rooftop photovoltaic (PV) systems to help reduce energy costs, and the transition towards zero emission vehicles is slower, as people have less disposable income and are buying new vehicles less often. Consequently, grid demand is in decline and the change in large-scale generation mix over time is less pronounced.
3. **Fast change** – a future where Australia's economy is booming, population growth is strong, and emission reduction targets are aggressive, leading to rapid decarbonisation of both the stationary energy sector and the transport sector. Consequently, growth in grid demand is relatively strong and there is a material change in the large-scale generation mix over time.

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

Market benefits

The PADR assessment for this RIT-T has involved detailed market modelling using a capacity outlook model and a market dispatch model. The results of the assessment highlight that the key categories of market benefit for this RIT-T are:

- Changes in fuel and operating costs arising from the offset of more expensive New South Wales generation with cheaper Victorian generation; and
- Changes in generation investment costs, as there is a decreased need to build new generation in New South Wales.

Table 2 below 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 net market benefit across the three reasonable scenarios considered.

The proposed preferred option will increase export capability from Victoria to New South Wales by approximately 170 MW, and has a cost of approximately $68 million (in present value terms). This option yields the highest net market benefits under all the future scenarios and sensitivities assessed.

[3] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Planning-and-Forecasting-Consultation-Paper.pdf.

[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.

Table 2 Weighted net market benefit (NPV terms)

Option	Option Cost ($M) – NPV	Gross market benefit ($M) – NPV	Weighted net market benefit ($M) – NPV
Option 1 – ISP base option	84	354	270
Proposed preferred option Option 2 – ISP base option with modular power flow controllers	68	354	286
Option 3 – Additional higher capacity upgrades in New South Wales	447	634	187
Option 4 – Additional higher capacity upgrades in New South Wales and Victoria	763	711	-53

Next steps

The publication of this PADR commences the next phase of the RIT-T process. The PADR modelling assumptions will be reviewed and updated based on any material change in assumptions, and having regard to the submissions received, ahead of the Project Assessment Conclusions Report (PACR). Following submissions on this PADR, a PACR will be published in accordance with clause 5.16.4 of the NER.

Submissions

AEMO and TransGrid welcome written submissions from stakeholders on the proposed preferred option presented, and the issues addressed in this PADR.

Submissions are due on or **before 11 October 2019, and should be emailed to** planning@aemo.com.au.

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

AEMO and TransGrid will have regard to submissions in preparing the PACR.

Contents

Tables

Figures

1. Introduction

The Regulatory Investment Test for Transmission (RIT-T) is an economic cost-benefit test used to assess and rank different options that address an identified need. This Project Assessment Draft Report (PADR) represents stage two of the consultation process in relation to the Victoria to New South Wales Interconnector (VNI) Upgrade RIT-T.

1.1 Background to the RIT-T process

Under the National Electricity Law, AEMO is responsible for planning and authorising augmentation on the Victorian electricity transmission Declared Shared Network (DSN). TransGrid is the Transmission Network Service Provider (TNSP) in New South Wales, responsible for planning and augmenting the New South Wales electricity transmission network.

In deciding whether a proposed augmentation to the transmission network should proceed, TNSPs are required to undertake a RIT-T. The purpose of a RIT-T is to identify the credible option that addresses an identified need, while maximising the present value of net economic benefits to all those who produce, consume, and transport electricity in the market (referred to as 'net market benefits').

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 Project Assessment Draft Report (PADR), which identifies and seeks feedback on the RIT-T analysis and on the selection of a proposed preferred option that maximises net market benefit.
- The Project Assessment Conclusions Report (PACR), which presents the final RIT-T analysis and makes a conclusion on the preferred option.

The procedures for conducting a RIT-T are set out in clause 5.16.4 of the National Electricity Rules (NER). As part of the PADR and the PACR stages, the TNSP must publish the results of the RIT-T analysis based on a quantification of various categories of costs and benefits.

1.2 Overview of this report

In November 2018, AEMO and TransGrid published a PSCR[5] that described the need for investment to increase the Victorian transfer capacity to New South Wales, to capture potential positive net market benefits through more efficient sharing of generation resources between states. The purpose of the PSCR was to consult on the identified need and credible options. The PSCR received submissions from 10 stakeholders.

This PADR represents stage 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.

[5] At https://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

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

- A detailed description of the methodologies and assumptions used in quantifying each class of material market benefit and cost, in Chapter 5.
- Identification of all material classes of market benefits that arise from within Victoria, New South Wales and 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 identification of the proposed 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 TNSP affected by the RIT-T project has received an augmentation technical report, that report.
- A statement and accompanying detailed analysis that the proposed preferred option satisfies the RIT-T.

1.3 Victorian Declared Shared Network

In deciding whether a proposed augmentation to the Victorian DSN should proceed, AEMO is required to undertake a cost benefit analysis. As the proposed preferred option involves a number of augmentations to the Victorian DSN, the RIT-T meets this requirement in relation to those augmentations.

1.4 Stakeholder submissions

AEMO and TransGrid invite written submissions on the proposed preferred option presented, and the issues addressed in this PADR.

Submissions are due on or before 11 October 2019, and should be emailed to planning@aemo.com.au.

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

1.5 Next steps

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

Following consultation, and after having regard to the submissions received, 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 realise net market benefits by increasing the power transfer capability from Victoria to New South Wales. Alleviating current and projected limitations on this transfer corridor will reduce market costs, through more efficient sharing of generation resources between states, and greater access to diverse supply sources.

2.1 Description of the identified need

The identified need for investment was described in Chapter 2 of the PSCR[7]. It stated that increasing Victorian transfer capability to New South Wales by approximately 170 megawatts (MW) could capture positive net market benefits, that is, an increase in the sum of consumer and producer surplus, through more efficient sharing of generation resources between states. While the identified need for investment remains the same, additional information is provided in this section to address feedback received through submissions to the PSCR and to highlight changes since the PSCR.

2.1.1 Current limitations

The transfer capability from Victoria to New South Wales is currently limited by the following Victorian DSN limitations:

- Thermal capacity of the 500/330 kilovolt (kV) transformer at South Morang Terminal Station.
- Thermal capacity of the 330 kV transmission lines between South Morang and Dederang Terminal Stations.
- A transient stability limitation on transfers to provide for the potential loss of a 500 kV Hazelwood to South Morang line.
- A voltage stability limitation on transfers to provide for the potential loss of Alcoa Portland Potline (APD) potlines.

Apart from the Victorian DSN limitations, the transfer capability from Victoria to New South can also be limited by thermal capacity of the transmission lines between southern New South Wales and load centres in Canberra and Sydney, particularly the 330 kV line between Canberra and Upper Tumut. This is because output from existing and new generators in southern New South Wales will compete with imports from Victoria for access to the transmission capacity between this area and the load centres.

While the main driver of this RIT-T is to increase the Victoria to New South Wales export capability, some options considered also improve New South Wales to Victoria import capability. The RIT-T analysis considers the overall net benefit of increased transfer capability in both directions, therefore this RIT-T considered the benefits of increased New South Wales to Victoria transfer capability. Refer to Section 2.3 for details on imports from New South Wales to Victoria. Section 4.2.1 outlines projects being progressed to improve import capability into Victoria.

2.1.2 Historical constraint impacts

The Victoria to New South Wales transfer capability has been constrained by transient stability and thermal limitations for many years. More recently, it has also been constrained by a newly introduced voltage stability limitation to avoid voltage collapse around the Murray region for loss of APD. Table 3 below provides a summary of binding hours of the relevant constraints in the past five years.

[7] 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.

Table 3 Historical binding hours of relevant constraints

Limitations	2014	2015	2016	2017	2018	Total
South Morang 500/330 kV Transformer	844	951	1,015	312	208	3,330
Victoria to New South Wales transient stability	317	1,091	1,054	625	270	3,357
Victoria to New South Wales voltage stability	N/A	N/A	N/A	N/A	75	75
New South Wales to Victoria voltage stability	210	212	82	1806	1,118	3,428
330 kV South Morang – Dederang	23	1	0	0	0	24
330 kV Murray – Dederang	0	0	3	1	11	15
330 kV Upper Tumut – Canberra	0	0	0.2	5.3	0	5.5

On the Victorian side, Table 3 shows that the South Morang 500/330 kV transformer thermal limitation and Victoria to New South Wales export transient stability limitation have been the most binding constraints impacting Victoria to New South Wales transfer capability. The drop in binding hours in 2017 and 2018 was mainly due to a reduction in the level of export capability from Victoria to New South Wales following the closure of Hazelwood Power Station in Victoria in March 2017. It is expected that binding hours will increase with the connection of approximately 2,000 MW of proposed renewable generation projects in Victoria.

Conversely, Table 3 shows that the New South Wales to Victoria voltage stability constraint bound more in 2017 and 2018, reflecting the need for increased imports due to the closure of Hazelwood Power Station. It is expected that this voltage stability constraint binding hours will decrease in future, with additional generation connection in Victoria, combined with the fact that AEMO is updating this constraint as detailed in Section 4.2.1.

The 330 kV South Morang – Dederang line limitation only has a limited number of binding constraint hours, because the South Morang 500/330 kV transformer constraint typically binds first before the line constraint when transferring power from Victoria to New South Wales. Technical studies have indicated that the binding hours of the 330 kV South Morang – Dederang line limitation would significantly increase if the South Morang 500/330 kV transformer limitation was relieved by augmentation, and therefore augmenting the transformer alone will not be effective.

On the New South Wales side, Table 3 shows that the Upper Tumut – Canberra line limitation has a limited number of binding constraint hours. This is because the constraints on this line have historically bound during peak New South Wales demand periods, and occur for a limited number of periods during a year, when the lines were heavily loaded. The loading of these lines is projected to increase in future, with increased import capability from Victoria, combined with significant levels of new generator connections in Victoria and Southern New South Wales. There is 650 MW renewable generation in service, a further 466 MW of committed renewable connections, and approximately 2,000 MW wind and 5,200 MW solar connection enquiries in southern New South Wales.

2.1.3 Forecast constraint impacts

Table 4 below shows the forecast binding hours of the relevant constraints from the modelling study under the 'do nothing' scenario, which excludes the credible options being considered in this RIT-T. The 'do nothing' scenario assumes transmission development such as augmenting existing interconnectors and building new interconnectors based on the modelled outcome identified in the 2018 ISP, and associated RIT-T processes, where available (refer Section 5.2.10 for detail).

Table 4 Forecast binding hours of relevant constraints, Neutral scenario (No VNI upgrade)

Limitations	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Sum
South Morang 500/330 kV Transformer	2,124	2,154	681	1,382	2,083	3,815	4,103	4,523	1,941	2,031	2,084	1,346	1,374	29,641
Victoria to NSW transient stability	3,549	3,572	2,356	2,041	1,997	887	789	656	251	188	173	181	185	16,825
Victoria to NSW voltage stability	0	0	91	102	174	50	66	160	267	263	295	58	53	1,579
NSW to Victoria voltage stability	311	207	10	3	8	52	66	34	0	1	3	27	20	742
South Morang – Dederang	134	93	75	98	73	74	99	51	1	0	0	0	0	698
Murray – Dederang	58	40	15	17	16	0	0	0	0	0	0	0	0	146
Upper Tumut – Canberra	7	8	24	3	14	0	5	9	17	16	14	9	9	135

Table 4 shows that the forecast constraint binding hours are higher than historical binding hours, reflecting increases in network congestion due to additional new generator connections in the future, especially in Victoria and southern New South Wales. It is also noted that the forecast binding hours for the New South Wales to Victoria voltage stability constraint decrease in future, reflecting a reduction in the need for imports as additional generation connects in Victoria.

In 2023-24, the connection of Project EnergyConnect[8] and new transmission lines in Western Victoria are projected to improve network resilience, resulting in a decrease in stability constraint binding activity.

In 2026-27, the connection of new 500 kV lines in southern New South Wales[9] is also projected to improve network resilience, again leading to a decrease in stability constraint binding activity and decrease in thermal constraints in the southern New South Wales network, while increasing thermal constraint binding activity, more notably on the South Morang 500/330 kV transformers, which did not bind as much previously due to stability constraints binding first.

2.1.4 Previous investigations

As stated in the 2018 Victorian Annual Planning Report (VAPR)[10], any project designed to improve the Victoria to New South Wales export capability will need to collectively address the limitations on the South Morang F2 transformer, South Morang – Dederang 330 kV lines, and the stability limit, because they all play a critical role in limiting the transfer from Victoria to New South Wales. Augmentation solutions which only address

[8] The South Australia Energy Transformation RIT-T, for interconnection between South Australia and New South Wales, with added connection to Victoria, is now referred to as Project EnergyConnect. For more, see http://projectenergyconnect.com.au/.

[9] Part of a Group 2 project as identified in the 2018 ISP.

[10] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2018/2018-Victorian-Annual-Planning-Report.pdf.

individual components of the project need are unlikely to be effective, because the increase in transfer limit could be cramped by the other limitations.

AEMO has been monitoring the Victorian side limitations for years, and has assessed their market impact in recent VAPRs. In the 2017 VAPR, AEMO concluded that the upper bound of gross market benefits from alleviating the thermal capacity and transient stability limitations were likely sufficient to justify augmentations. Subsequently, a pre-feasibility study on the need to improve Victoria to New South Wales export capability was carried out as part of the 2018 VAPR, considering the latest developments including:

- The preferred options from the Western Victoria Renewable Integration RIT-T and Project EnergyConnect.
- The retirement of Hazelwood Power Station in March 2017.
- The Victorian Government's storage initiative and new generation development.

Based on the results of this pre-feasibility study, the 2018 VAPR[11] confirmed that the upper bound of forecast gross market benefits of relieving the thermal capacity and transient stability limitations impacting Victoria to New South Wales export would likely be sufficient to justify augmentations under the Slow change, Central, and Fast change scenarios which were considered. The 2018 VAPR concluded there was sufficient justification to commence a RIT-T to identify the preferred option for increasing the Victoria to New South Wales export capability.

2.1.5 Confirmation of the need

The transfer capacity limitation from Victoria to New South Wales has resulted in market impacts, and adds to reliability risk, increasing capital costs associated with new generation build in New South Wales, or a need for greater interconnection to New South Wales from other states following the planned closure of Liddell Power Station. Therefore, the gross market benefits of relieving the limitations could come from more efficient sharing of generation resources between states, which could capture the following:

- Reduced variable operating and maintenance costs through better utilisation of lower-cost fuel sources.
- Reduced capital costs associated with new generation build, as increased access to generation resources between states avoids or defers the need for new generation to maintain the same level of reliability. Some option components (such as new lines or transformers) can improve voltage control and system strength, avoiding or deferring the need for investment by other parties.
- Reduced investment costs in other transmission assets or services, as some option components to relieve the limitations impacting Victoria to New South Wales export may also relieve other transmission network limitations (such as those impacting Victoria to New South Wales import), avoiding or deferring other transmission investments.
- Reduced voluntary load curtailment and involuntary load shedding by improving reliability, particularly in New South Wales following the retirement of Liddell Power Station. This is also relevant in Victoria during high demand and low renewable generation periods, or periods with unexpected generation outages or unavailability[12].

Detail on the class of market benefits expected to be material and not-material for the RIT-T can be found in Sections 6.1 and 6.2.

[11] Refer to Section 3.8 of AEMO's 2018 VAPR, at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2018/2018-Victorian-Annual-Planning-Report.pdf.

[12] AEMO, Load Shedding in Victoria on 24 and 25 January 2019, April 2019, at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf.

2.2 New information since the PSCR

2.2.1 Regulatory changes

The augmentation options outlined in this RIT-T are broadly aligned with AEMO's 2018 Integrated System Plan[13] (ISP) recommendations, including an option which the ISP identified as a priority Group 1 project.

In December 2018, the Energy Security Board[14] (ESB) made the following recommendations in relation to the ISP[15]:

- All Group 1 projects should be fast tracked to allow the projects to be implemented in time to meet their identified need.
- A rule change was proposed to speed up the post-RIT-T regulatory processes for TNSPs which would allow the Group 1 projects (initially) to potentially be delivered 6-8 months earlier.
- The ISP should be converted into an actionable strategic plan.

A consultation paper on converting the Integrated System Plan into action has now been published[16].

This work reinforces the identified need and timing for increasing the Victoria to New South Wales interconnection capability.

2.2.2 Recent studies on the need for solutions

The PSCR indicated that there is a need to increase the Victoria – New South Wales export capability through development options which address transient stability, voltage stability, and thermal limitations. Detailed power system studies have been undertaken to assess potential long-term solutions to meet the identified need. These studies assessed the performance of the existing and future transmission system with a number of credible options.

The studies have found that installing a second South Morang transformer alone is not sufficient to increase the Victoria to New South Wales transfer capability. The 330 kV South Morang – Dederang lines are the next limiting constraint, and will need to be upgraded to utilise the capacity of two 500/330 kV transformers at South Morang Terminal Station.

The studies also found that:

- The Victoria to New South Wales interconnector transient and voltage stability limitations will be improved by the proposed preferred options under other RIT-Ts currently in progress (Victorian Reactive Power Support[17], Western Victoria Renewable Integration, Project EnergyConnect, and HumeLink).
- The second South Morang transformer – which is common to all options being considered in this RIT-T – will also improve stability limitations, because it reduces the effective impedance of the network and increases power system resilience through stability limit improvements (refer to Section 5.4.4 for detail).

As such, the analysis concluded that the augmentations through these RIT-Ts would deliver the stability limit improvements to achieve the 170 MW increase in transfer capability.

However, the staging and risks associated with the other RIT-T projects may result in a gap between delivery of the second South Morang transformer and full resolution of the stability limits. The status of these other RIT-Ts will be monitored closely, and the proposed preferred option of this RIT-T updated if necessary during the PACR stage. In particular, the PACR may assess a variant of the proposed preferred option including a

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[13] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[14] For information about the Energy Security Board, see http://www.coagenergycouncil.gov.au/market-bodies/energy-security-board.

[15] Full recommendations at http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/isp%20action%20plan.pdf.

[16] At http://www.coagenergycouncil.gov.au/publications/energy-security-board-%E2%80%93-converting-integrated-system-plan-action-consultation-paper.

[17] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/Victorian-Reactive-Power-Support-PADR.pdf.

component to increase stability limits, if the preferred options under the other RIT-Ts do not become committed.

2.2.3 Newly committed projects and other changes

The energy landscape is changing rapidly, and a number of changes have occurred since the PADR modelling, as discussed in Section 5.2:

- The number of committed generation projects continues to increase, as detailed in AEMO's Generation Information web page[18]. This includes Snowy 2.0 becoming committed (additional 2,040 MW of capacity in New South Wales).
- Some generator retirement timing has changed, such as Liddell Power Station.
- Other RIT-T projects are progressing closer to their respective preferred options, with PACRs being published for the Project EnergyConnect and Western Victoria Renewable Integration RIT-Ts, a PADR being published for the Victorian Reactive Power Support RIT-T, and a PSCR being published for the RIT-T to reinforce the New South Wales Southern Shared Network to increase transfer capacity to New South Wales demand centres.
- Updated demand forecasts were published by AEMO as part of the 2019 ESOO[19]. The updated forecasts show an overall reduction in energy consumption across the NEM, aligning closer to the Slow change scenario assessed in this PADR. Victorian energy consumption is forecast to reduce further than New South Wales energy consumption, which is expected to increase the net market benefits presented in this PADR. Table 19 (in Section 6.3.3) demonstrates that the proposed preferred option does not change with a higher weighting for the Slow scenario.

Further refinements and improvements will be undertaken as part of the PACR stage, incorporating the latest available information as well as stakeholder feedback on the PADR.

2.3 Imports into Victoria

As discussed in the 2019 VAPR, the supply-demand balance remained tight in Victoria during 2018-19, with both Reliability and Emergency Reserve Trader (RERT) and load shedding activated to maintain system security in January 2019. While these events were the result of extreme weather conditions and unplanned generator outages, further increases to Victorian import capabilities would enable better utilisation of spare reserves in neighbouring regions during such events.

The Victoria to New South Wales import capability is constrained by thermal capacity limitations near Dederang, and by a voltage stability limitation that typically binds during periods of reduced availability of generating units in the Murray area. While there is a short-term driver to improve import capabilities into Victoria to support peak demand periods, this need is likely to erode as new renewable generation is installed in Victoria, in line with Victorian Government renewable energy policy targets. AEMO continues to monitor transmission network limitations that may result in supply interruptions or constrain generation, as reported in the 2019 VAPR.

In 2018, AEMO investigated the feasibility and economic merits of non-network options with short lead times to improve capabilities into Victoria, including a process to seek offers from potential service providers through a formal Expression of Interest and Invitation to Tender process. These investigations did not identify any suitable economic solutions.

In the longer term, the 2018 ISP identified a need for large-scale network investment to strengthen transfer capabilities in both directions between Victoria and New South Wales. Victorian import limitations are projected to become critical following closure of further coal-fired generators in the Latrobe Valley. The most

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[18] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. AEMO"s commitment criteria are listed under the background information tab on each update spreadsheet.

[19] Published August 2019, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities. Full updated forecasting data is at http://forecasting.aemo.com.au/.

recently published information indicates an expected staged retirement of Yallourn Power Station between 2029 and 2032. AEMO has already commenced preliminary technical studies on options to further improve transfer capability with New South Wales and provide resilience against uncertain future step changes in supply. AEMO expects to build on these studies to commence another RIT-T process in the near future, to identify the most economic option to meet future interconnector needs with New South Wales.

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 options have been refined to identify those most likely to maximise the net market benefits through a full cost-benefit assessment.

3.1 Refinement of credible options in the PACR

Chapter 4 of the PSCR described three credible options (with several sub-options) capable of meeting the identified need for this RIT-T[20]:

1. **ISP Group 1** – this option is consistent with the scope of augmentation recommended by the 2018 ISP. It represents a near-term and modest cost option, with the potential to capture market benefits from as early as 2022-23.
   - The reactive component for increasing stability limits aspect of this option has not been included in the PADR analysis. This is because the increase in stability limits can be achieved through augmentations being considered through this RIT-T and other RIT-Ts currently under way, as detailed in Section 2.2.2. There are risks associated with this approach of relying on the implementation of the preferred options identified in other RIT-Ts, and this will be reviewed as part of the PACR stage of this process, considering the latest available information. In particular, the PACR may assess a variant of the proposed preferred option which includes a component to increase stability limits, if the preferred options under the other RIT-Ts do not become committed.
   - A variant of this option, considering modular power flow controllers as an alternative to upgrading the Upper Tumut – Canberra 330 kV line, has also been assessed in the PADR.
2. **Additional higher capacity upgrades in New South Wales** – this option represents larger augmentations in New South Wales which are also capable of meeting the identified need. These higher capacity options would need to deliver significant additional benefits to cover their higher costs and longer lead times.
   - This option included upgrading selected existing 330 kV lines between Snowy and Sydney in addition to the 330 kV Upper Tumut – Canberra line upgrade. The additional upgrades have not been progressed, as the PADR analysis did not identify any significant incremental benefits in relation to the existing network that warranted further investigation.
   - This PADR analysis did however note potential congestion associated with the future HumeLink project which is being investigated as part of TransGrid's Reinforcing the New South Wales Southern Shared Network RIT-T. Potential congestion could occur if the New South Wales network is not reinforced north of Bannaby, and would need to be investigated as part of that RIT-T[21].

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[20] At https://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.

[21] At https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network/Documents/TransGrid%20PSCR_Reinforcing%20NSW%20Southern%20Shared%20Network.pdf.

- A variant under this option is to bring forward one leg of HumeLink, a new 500 kV line between Snowy and Bannaby (as proposed under TransGrid's RIT-T for reinforcing Southern New South Wales), as an alternative to upgrading the Upper Tumut – Canberra 330 kV line. One of the benefits of this option is that it would bypass the need for lengthy outages associated with line upgrades. The option has been assessed in the PADR. Refer to Option 3 under Section 3.2.3 for detail.

3. **Additional higher capacity upgrades in Victoria and New South Wales** – this option represents larger augmentations in Victoria as well as New South Wales, which are also capable of meeting the identified need. These higher capacity options would need to deliver significant additional benefits to cover their higher costs and longer lead times.
   - Options include re-conductoring the 330 kV South Morang – Dederang line or building a third 330 kV South Morang – Dederang line as an alternative to upgrading the existing lines, and bringing forward the Bannaby leg of HumeLink. The option of re-conductoring the 330 kV South Morang – Dederang line has been ruled out in this PADR, because it is more costly than building the third line (see Section 3.5 for detail).
   - The additional upgrades to selected existing 330 kV lines between Snowy and Sydney have not been progressed in the PADR, as explained above.
   - The variant under this option is to bring forward one leg of HumeLink and complement this with a large upgrade in Victoria, which has been assessed in the PADR. Refer to Option 4 under Section 3.2.4 for detail.

The PSCR also noted that **non-network options** to increase transfer capability will need to minimise the impact of thermal limitations by allowing lines to operate at a higher rating for a prolonged or short duration. One credible non-network option of a Battery Energy Storage System (BESS) was identified, based on a confidential submission to the PSCR, and has been assessed (refer to Section 3.3 for detail).

Each of the broad options above have been further divided into sub-options which were considered credible. These are described in Section 3.2, along with how they compare with the options presented in the PSCR.

Credible options that were not further assessed are described in Section 3.5.

3.2 Description of the credible network options assessed

This section presents the credible options that were assessed in the detailed PADR economic modelling.

The cost estimates provided in this Section 3.2 have an accuracy of ±30%. Refer to Section 5.5 for the methodology applied for developing cost estimates.

3.2.1 Option 1: ISP base option

This option is consistent with "Option 1 – ISP base case" as presented in the PSCR, excluding the reactive component, as discussed in Section 3.1.

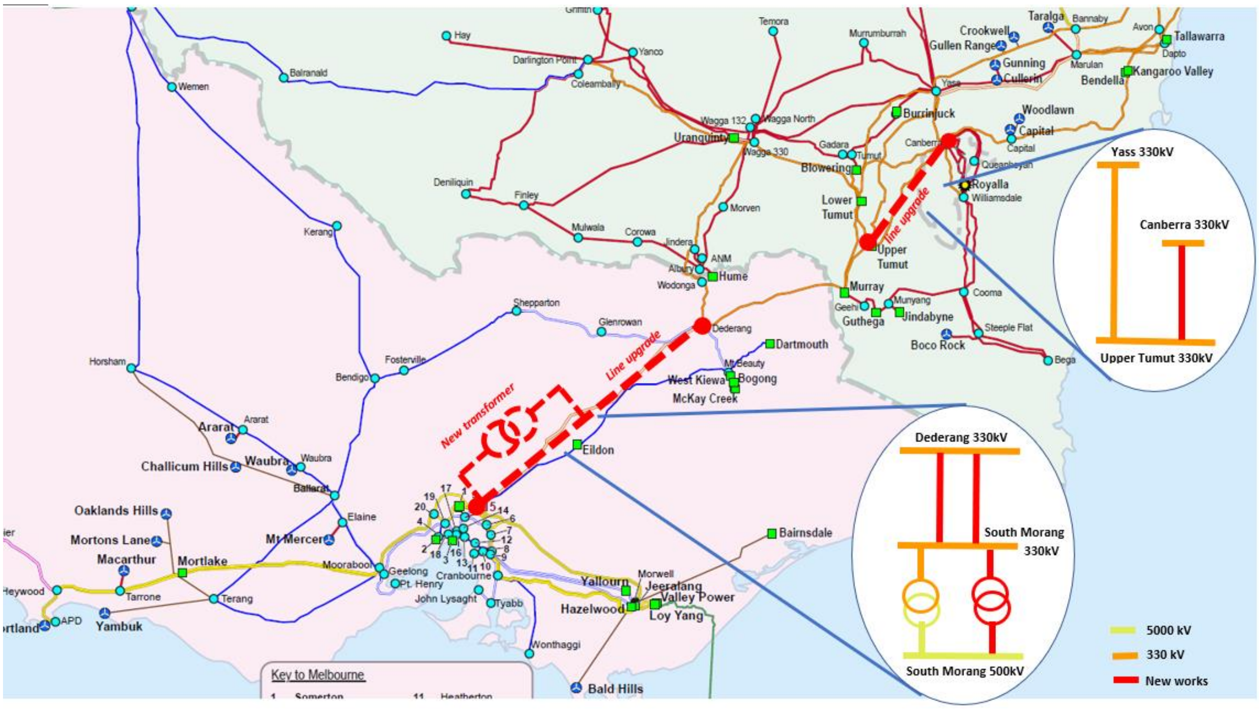
Table 5 below provides a summary of the augmentations comprising this option.

Table 5 Option 1 – ISP base option

	Description	Estimated cost ($M)	Estimated lead time (months) A
1	Installation of a new 1,000 megavolt amperes (MVA) 500/330 kV transformer at South Morang Terminal Station	38.5	24
	Re-tensioning the South Morang – Dederang 330 kV lines and associated works (including uprating of series capacitors) to allow the line to run to thermal rating of 1,038 megavolt amperes (MVA)B (or to 82 C)	21	21
	Uprating of the Upper Tumut – Canberra 330 kV line to 1132 MVAB (or to 100C)	38	27
Total		**97.5**	**-**

A. AEMO and TransGrid are reviewing the lead times to maximise efficiency, allowing for the delivery of preferred option within optimal lead times.
B. Post-contingent summer rating.

Figure 2 Option 1 – ISP base option



3.2.2 Option 2: ISP base option with modular power flow controllers

This option is consistent with "Option 1 – ISP base case" as presented in the PSCR, excluding the reactive component and with modular power flow controllers instead of upgrading the Upper Tumut – Canberra 330 kV line. Refer to Section 3.1 for detail.

Table 6 below provides a summary of the augmentations comprising this option.

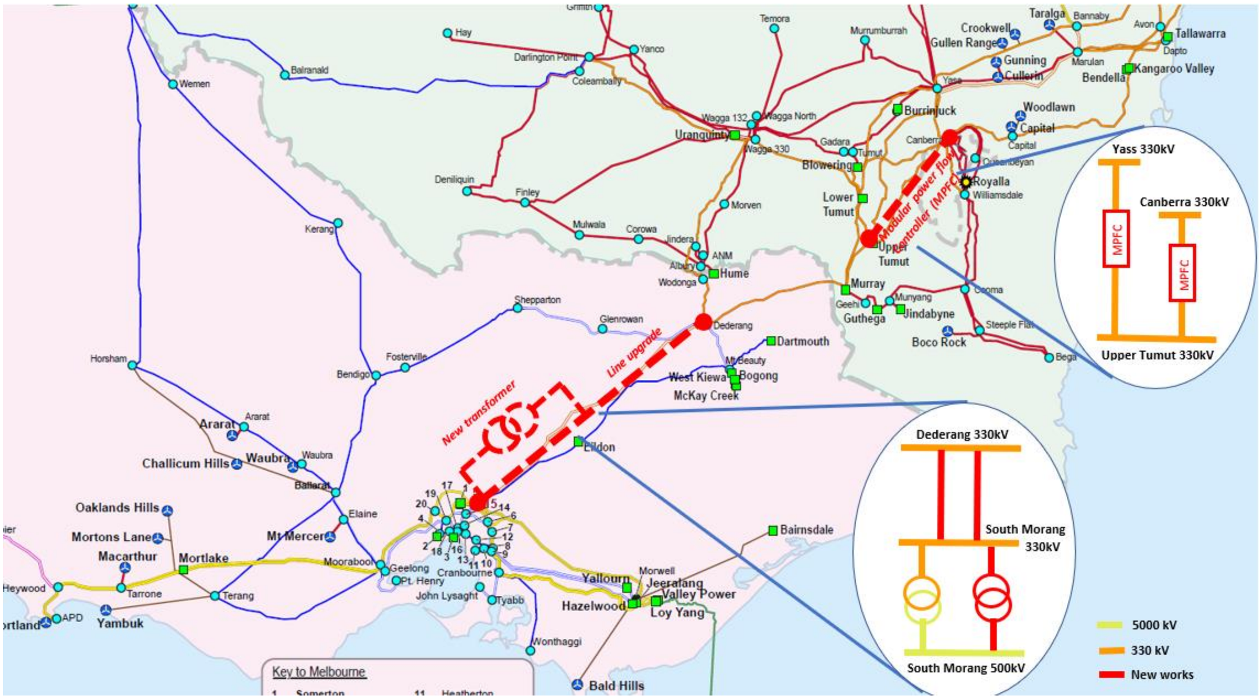
Table 6 Option 2 – ISP base option with modular power flow controllers

	Description	Estimated cost ($M)	Estimated lead time (months) A
2	Installation of a new 1,000 MVA 500/330 kV transformer at South Morang Terminal Station	38.5	24
	Re-tensioning the South Morang – Dederang 330 kV lines and associated works (including uprating of series capacitors) to allow the line to run to thermal rating of 1,038 MVA[B] (or to 82 C)	21	21
	Installation of modular power flow controllers on the 330 kV Upper Tumut - Canberra line and 330 kV Upper Tumut – Yass line to increase the transfer capacity on Lower Tumut / Upper Tumut – Canberra/Yass cut-set by 170 MW to 220 MW.	21	24
Total		**80.5**	**-**

A. AEMO and TransGrid are reviewing the lead times to maximise efficiency, allowing for the delivery of preferred option within optimal lead times.

B. Post-contingent summer rating.

Figure 3 Option 2 – ISP base option with modular power flow controller



Modular power flow controller

Investigations were conducted into the feasibility of modular power flow controllers on the 330 kV Upper Tumut – Canberra line and 330 kV Upper Tumut – Yass line as an alternative to upgrading the 330 kV Upper Tumut – Canberra line.

The modular power flow controllers could effectively increase or decrease the reactance of a given circuit through lagging or leading constant voltage injection. It enables the real-time control of power flow within the Upper Tumut/Lower Tumut – Yass/Canberra cut-set by increasing or decreasing the transmission line reactance, either pulling more current into the least loaded Upper Tumut – Yass line (capacitive mode) or pushing current away from the most loaded Upper Tumut – Canberra line (inductive mode) onto parallel underutilised lines. Steady state power system assessment confirmed that the modular power flow controllers would be capable of balancing and increasing the transfer capacity on Lower Tumut/Upper Tumut – Canberra/Yass cut-set by 170 to 220 MW depending on the operating conditions.

The modular power flow controller is subject to further modelling during the PACR stage, with more detailed Root Mean Square (RMS) and Electro Magnetic Transient (EMT) type modelling to assess the potential for control interactions between the modular power flow controllers and nearby generators. Detailed site-specific installation requirements and operational implementation will also be further reviewed during the PACR stage.

3.2.3 Option 3: Additional higher capacity upgrades in New South Wales

This option is consistent with "Option 2 – Additional higher capacity upgrades in New South Wales" as presented in the PSCR, and investigates the benefits of bringing forward a 500 kV line from Snowy to Bannaby from 2026-27 to 2024-25 in the Neutral and Fast change scenarios. In the Slow change scenario, the HumeLink component of this option is assumed to not proceed in 2026-27 and the evaluation considers the full cost of the line.

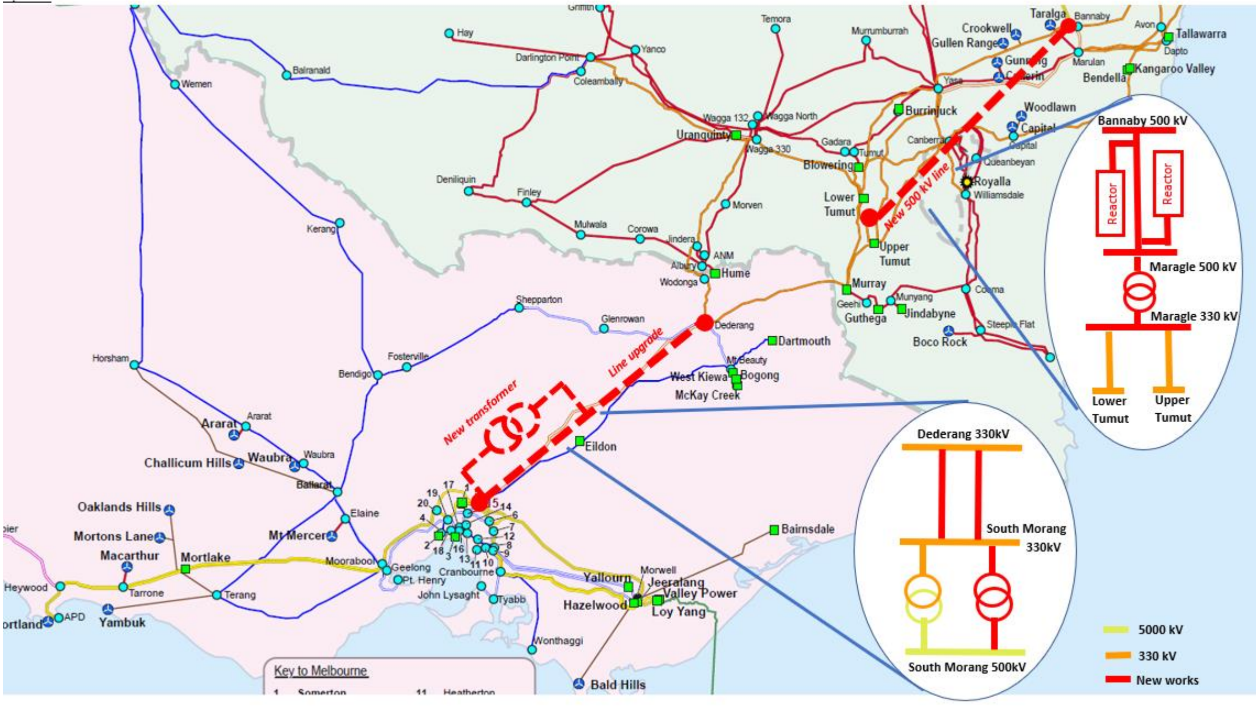
Table 7 below provides a summary of the augmentations comprising this option.

Table 7 Option 3 – Additional higher capacity upgrades in New South Wales

	Description	Estimated cost ($M)	Estimated lead time (months) [A]
3	Installation of a new 1000 MVA 500/330 kV transformer at South Morang Terminal Station	38.5	24
	Re-tensioning the South Morang – Dederang 330 kV lines and associated works (including uprating of series capacitors) to allow the line to run to thermal rating of 1,038 MVA[B] (or to 82 C)	21	21
	Bring forward one leg of HumeLink, a new 500 kV line between Snowy and Bannaby including connection into existing 330 kV network, as proposed under TransGrid's RIT-T for reinforcing Southern New South Wales[C], rated at 3,300 MVA .	550	47
Total		**610**	**-**

A. AEMO and TransGrid are reviewing the lead times to maximise efficiency, allowing for the delivery of preferred option within optimal lead times.
B. Post-contingent summer rating.
C. At https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network/Documents/TransGrid%20PSCR_Reinforcing%20NSW%20Southern%20Shared%20Network.pdf.

Figure 4 Option 3 – Additional higher capacity upgrades in New South Wales



3.2.4 Option 4: Additional higher capacity upgrades in New South Wales and Victoria.

This option is consistent with "Option 3 – Additional higher capacity upgrades in Victoria and New South Wales" as presented in the PSCR, and investigates the benefits of bringing forward the 500 kV line from Snowy to Bannaby from 2026-27 to 2024-25[22] and larger upgrades in Victoria.

Table 8 below provides a summary of the augmentations comprising this option.

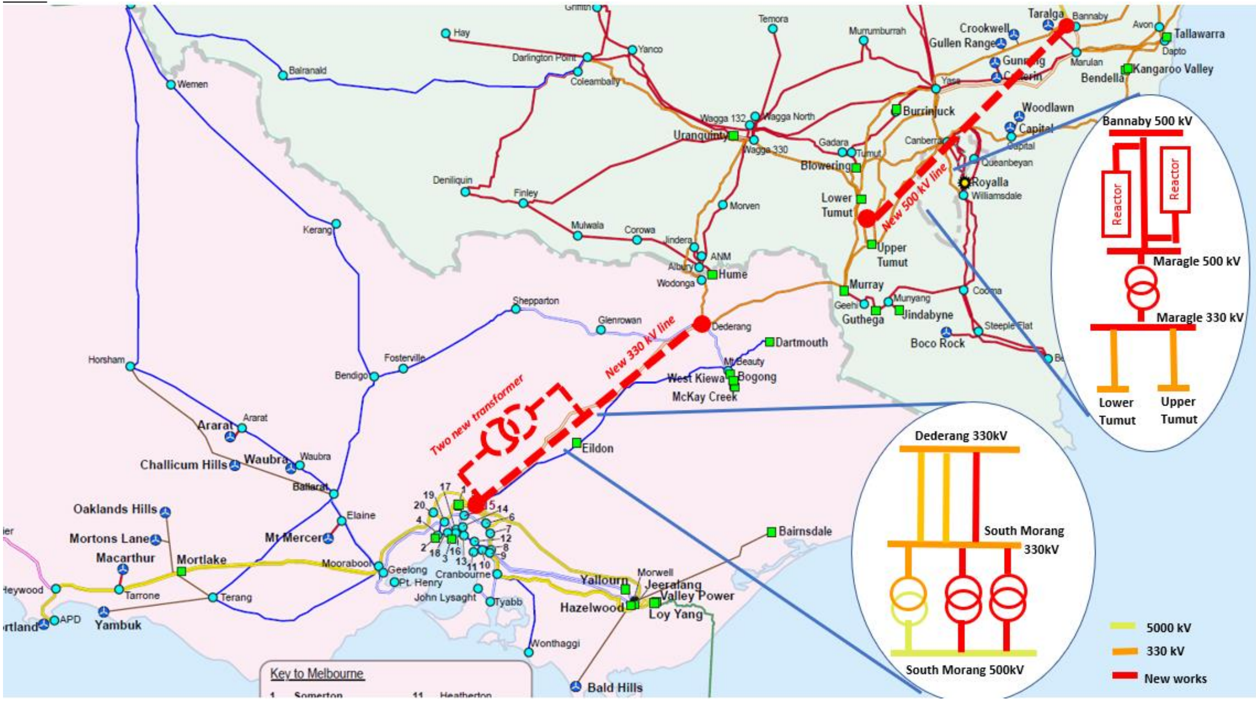
Table 8 Option 4 – Additional higher capacity upgrades in New South Wales and Victoria

	Description	Estimated cost ($M)	Estimated lead time (months) [A]
4	Installation of two new 1000 MVA 500/330 kV transformers at South Morang Terminal Station	77	24
	New 330 kV single circuit line rated at 1,038 MVA[B] in parallel with the existing South Morang – Dederang 330 kV lines.	415	48
	Bring forward one leg of HumeLink, a new 500 kV line between Snowy and Bannaby including connection into existing 330 kV network, as proposed under TransGrid's RIT-T for reinforcing Southern New South Wales[C], rated at 3,300 MVA.	550	47
Total		**1,042**	

A. AEMO and TransGrid are reviewing the lead times to maximise efficiency, allowing for the delivery of preferred option within optimal lead times.
B. Post-contingent summer rating.
C. At https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network/Documents/TransGrid%20PSCR_Reinforcing%20NSW%20Southern%20Shared%20Network.pdf.

[22] The HumeLink component is assessed as a bring-forward in the Neutral and Fast change scenarios only.

Figure 5 Option 4 – Additional higher capacity upgrades in New South Wales and Victoria



3.3 Description of the credible non-network options assessed

To be considered credible, any non-network options would need to be capable of increasing the stability limitation and/or thermal capacity of the transmission network.

One credible non-network option of a BESS was identified, based on a confidential submission to the PSCR, and has been assessed.

3.3.1 Battery Energy Storage System (BESS)

The key benefit of the BESS, in relation to this RIT-T's identified need, is its ability to improve stability limits. In addition, the BESS has the potential to provide other benefits such as generation and storage. As detailed in Section 2.2.2, the improvements in stability limit increases can be achieved through augmentations being proposed through this and other RIT-Ts.

The BESS option was assessed as part of the PADR analysis and found not to return a positive net market benefit, due to the stability limit improvements being delivered through this and other RIT-Ts. Further details have not been published in this report, due to the confidential nature of the submission.

3.4 Material inter-network impact

The options assessed in this RIT-T will have a material inter-network impact, because they increase transmission network capacity on critical flow paths between Victoria and New South Wales by more than 50 MW[23]. It should be noted that AEMO and TransGrid have confirmed that the options assessed in this RIT-T are not expected to introduce any adverse material inter-network impacts, and have agreed that an augmentation technical report is not required for the proposed preferred option.

[23] Criteria for assessing whether a proposed augmentation has a material inter-network impact, at http://www.aemo.com.au/-/media/Files/PDF/170-0035-pdf.pdf.

3.5 Other options considered

A number of other options were identified as possibly meeting the identified need, but were not assessed in the market modelling in preparing this PADR because preliminary analysis indicated that the options referred to above are more likely to deliver higher net market benefits. These other options include:

- The option of re-conductoring the existing South Morang – Dederang 330 kV lines is significantly more expensive from a cost ($547 million) and outage (620 days) perspective than the higher capacity option of building a third South Morang – Dederang 330 kV line, at a cost of $415 million, requiring a 31-day outage.
- The option of a new Bendigo to Shepparton 220 kV line, at a cost of $64 million, was considered. Several potential benefits were identified, such as the ability to export additional renewable generation and to facilitate connection of additional renewable generation locally. However, the investigations found that the second 500/330 kV South Morang transformer option would be more effective at meeting the identified need of increasing the Victoria – New South Wales interconnector capability.
- A range of options to increase the stability limitations were investigated, including Synchronous Condenser, Static Var Compensator, braking resistor, and network augmentations. The investigations found that the increase in stability limits can be achieved through augmentations being proposed through this and other RIT-Ts currently under way, as detailed in Section 2.2.2.
- Option 2 of the PSCR also considered upgrading existing 330 kV lines between Snowy and Sydney in addition to the 330 kV Upper Tumut – Canberra upgrade. This option has not been progressed, because the PADR analysis did not identify significant incremental benefits in relation to the existing network that warranted further investigation.
- The option of installing a phase shifting transformer at Canberra to increase the southern New South Wales transfer capability by 170 MW was considered, but ruled out due to the high cost and long lead time of phase shifting transformers. The option of modular power flow controllers or upgrading the Upper Tumut – Canberra line is more cost-effective than the phase shifting transformer.

4. Submissions to the Project Specification Consultation Report

The PSCR was published in November 2018, and stakeholder submissions closed in February 2019. AEMO and TransGrid received 10 submissions, which AEMO and TransGrid have had regard to when undertaking the PADR assessment and preparing this report.

4.1 Submissions

Nine public submissions were received, from the following:

- AusNet Services.
- Australian Energy Council (AEC).
- Energy Australia.
- ENGIE.
- ERM Power.
- Major Energy Users Inc (MEU).
- MEA Group (Meridian Energy Australia and Powershop).
- Smart Wires.
- Snowy Hydro.

One confidential submission was also received from a BESS provider.

The remainder of this chapter discusses the key issues raised in submissions.

4.2 Importance of interconnection capacity

The submissions generally supported the identified need of expanded interconnection in a system with increasing renewable generation, to provide diversity of supply and enable more efficient sharing of generation resources between states.

Stakeholders also highlighted the importance of non-network solutions as options to provide stability and support to the network.

4.2.1 Scope of the identified need

Submissions

AusNet Services, ERM Power, the MEU, and Snowy Hydro recommended that AEMO and TransGrid broaden the identified need to examine the benefits of expanded interconnection between Victoria and New South Wales in both directions.

ERM Power highlighted that it was critical for AEMO and TransGrid to assess options that increase transfer capacity in both directions, noting that historical demand outcomes indicate an ability for Queensland and

New South Wales supplies to support Victoria at times of maximum demand. ERM Power also recommended consideration of options to deliver the full benefits of the existing Snowy Hydro assets.

The MEU highlighted the importance of cost, reliability, quality, and long-term sustainability to electricity consumers, and noted their in-principle support for economically efficient investment in the transmission network to increase reliability of supply to consumers. The MEU submission included historical interconnector flows and constraints that highlighted times when flows from New South Wales to Victoria were constrained by the network, including during the Victorian load shedding that occurred in January 2019.

AusNet Services also raised the Victorian load shedding event in January 2019, and encouraged broadening the identified need to include an increase in interconnector capability from New South Wales to Victoria.

AEMO and TransGrid response

- The 2019 VAPR[24] also highlights the need to improve import capabilities into Victoria to support peak demand periods. However, this need is likely to erode quickly as new renewable generation is installed to meet renewable energy policy targets. In the long term, Victorian import limitations become critical only following closure of further coal-fired generation in the Latrobe Valley. AEMO has commenced preliminary studies on options to further expand import capabilities from New South Wales in the long term, and expects to commence a formal RIT-T process in the near future. Refer to Section 2.3 for detail.
- The options considered in this RIT-T do relieve network limitations in both directions, and the notional impact of the preferred option on interconnector limits is described in Sections 5.4.3 and 5.4.4.
- Import capability from New South Wales into Victoria can potentially be constrained by a number of limitations. The critical ones are thermal limitations on the 330 kV Murray – Dederang and South Morang – Dederang lines, and a voltage stability limitation that prevents voltage collapse in southern New South Wales for the loss of Basslink or the largest generator in Victoria.
  - The Murray – Dederang 330 kV thermal limitation is expected to bind under typical operating conditions. However, the South Morang – Dederang 330 kV line can be most limiting when temperatures in the Greater Melbourne and Geelong areas are significantly higher than those in the Snowy area. These are the conditions that contributed to the RERT events in Victoria on 24 and 25 January 2019. The proposed upgrade of the South Morang – Dederang 330 kV line will significantly relieve one of the two key thermal constraints for imports into Victoria, as described in Section 6.3.
  - The Victorian voltage stability limitation can bind ahead of the thermal limitations under some conditions, particularly during low availability of generation units in the Snowy area. AEMO is undertaking a review of the voltage stability limitation and expects that, once the constraint is updated, the thermal limitations will most likely bind before the voltage stability limitation during peak Victorian demand periods.
- Other relevant projects are also being progressed that would likely improve the New South Wales to Victoria limitations. These include two Network Capability Incentive Parameter Action Plan (NCIPAP) projects:
  - AusNet Services' NCIPAP project to install reactive power plant that can dynamically control the impedance of (and thus power flows across) the Jindera – Wodonga 330 kV line is expected to increase the New South Wales to Victoria import capability by up to 14.5 MW. This project is scheduled to be completed in 2019.
  - TransGrid's 2019 NCIPAP update proposes the installation of a 100 megavolt amperes reactive (MVAR) capacitor at Wagga. This project would relieve the voltage stability limit affecting the New South Wales to Victoria import capability by 30 MW. Refer to TransGrid's 2019 Annual Planning Report[25] for more information on this project.

[24] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2019/Victorian-Annual-Planning-Report-2019.pdf.

[25] TransGrid 2019 Transmission Annual Planning Report (TAPR), at https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2019%20Transmission%20Annual%20Planning%20Report.pdf.

- Another relevant project being progressed that may improve the Victoria to New South Wales limitations is TransGrid's NCIPAP project to install modular power flow controller to the Upper Tumut – Yass 330 kV line to increase the transfer capability of the Snowy network. This project is expected to increase the Victoria to New South Wales export capability by relieving the thermal constraints, and is scheduled to be completed in 2021.

4.2.2 Scale of interconnector options

Submissions

Snowy Hydro raised concerns that upgrades to the existing 330 KV network between Snowy and Sydney would not be sufficient to secure reliable supply in New South Wales and Victoria following the closure of Liddell Power Station.

These concerns were linked to the limited headroom available in related parts of the network, and the market disruption caused by any outages that might be required to support the network upgrades. Snowy Hydro also highlighted the importance of the RIT-T capturing all possible costs and benefits associated with incremental options, in light of the planned commissioning of Snowy 2.0 and the subsequent commissioning of the larger ISP Group 2 project to upgrade the 500 kV network between Snowy and Bannaby.

Snowy Hydro highlighted the potential benefits of the larger PSCR Options 2a/3a, which would advance parts of the future Group 2 project, providing up to 1,000 MW of supply into New South Wales, and delivering more access to generation in the Bannaby REZ.

Snowy Hydro also encouraged AEMO and TransGrid to consider new transmission lines between Murray and Dederang to achieve a significant increase in Victorian import capacity.

AEMO and TransGrid response

- AEMO and TransGrid have assessed a broad range of credible options, including non-network, incremental, and major new transmission infrastructure.
- The impact of network outages during upgrade works have been fully considered in the market benefit assessment for each credible option.
- The modular power flow controller option as an alternative to upgrading the 330 kV Upper Tumut – Canberra line has been assessed, subject to further studies to assess the potential for control interaction between the modular power flow controllers and nearby generators. Implementation of the modular power flow controller option would minimise outages on Upper Tumut – Canberra, reducing the outage duration (and subsequent market impacts), as detailed in Section 5.5.1.
- The timing of the 2018 ISP Group 2 500 kV lines between Snowy, Wagga, and Bannaby have been aligned with the timing of Snowy 2.0. Options 3 and 4 represent bringing forward the new 500 kV line between Snowy and Bannaby. As such, the PADR has tested the benefits of advancing these works by two years (to 2024-25), as an alternative to augmentations of the existing 330 kV network.
- This RIT-T primarily focuses on the need identified in the 2018 ISP to increase the export capacity from Victoria to New South Wales. While the proposed upgrades along the South Morang to Dederang path relieve one of the critical import constraints into Victoria, additional options to increase import capacity have not been included in this RIT-T. These options, including upgrades along the Murray to Dederang path, will be assessed in the next RIT-T process focusing on the identified need to improve interconnection between Victoria and New South Wales in the long term for northward[26] and southward flow.

[26] TransGrid Southern Shared Network PSCR, June 2019, at https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network/Documents/TransGrid%20PSCR_Reinforcing%20NSW%20Southern%20Shared%20Network.pdf.

4.2.3 Benefits of non-traditional and non-network solutions

Submissions

MEA Group noted that the VNI voltage stability limitation identified after the publication of the 2018 ISP highlights the rapidly changing nature of the power system. This reinforces the requirement for better interconnection between regions, and the importance of non-network solutions to provide stability and network support services.

The submission by Smart Wires proposed a solution to improve the transfer capability of the Snowy to Canberra/Yass transmission corridor using modular power flow equipment, while a confidential proposal was also received for a BESS.

AEMO and TransGrid response

- AEMO supports the importance of interconnection and the potential role that non-traditional and non-network solutions can play in a diverse system.
- The RIT-T modelling has assessed non-network options, as detailed in Section 3.3.
- Noting the importance of stability limitations, PADR analysis included detailed power system studies that focused on system stability and fully considered stability limitations. More detail is in Section 5.4.4.
- The proposed preferred option identified in this PADR includes a non-traditional modular power flow control device, in preference to traditional transmission line upgrade works, subject to further studies to assess the potential for control interaction between the modular power flow controllers and nearby generators.
- While BESS systems have also been considered through power system and economic studies, the assessment found that the BESS would not return a positive net market benefit, as detailed in Section 3.3.1.

4.3 Rapidly changing power system

Stakeholders highlighted changes in the energy sector since the preparation of the 2018 ISP, and urged AEMO and TransGrid to consider these when assessing the benefits of the proposed credible options.

4.3.1 Input assumptions

Submissions

AusNet Services supported the use of the 2018 ISP as a starting point for the analysis in this RIT-T, but highlighted the need for the RIT-T analysis to also consider a number of subsequent changes. These changes included movement in government policies, the decreasing cost of new generation, a decline in the reliability of thermal generation, and potential changes in the probability of system events that could lead to load shedding and separation of NEM jurisdictions.

EnergyAustralia also encouraged AEMO and TransGrid to use the latest input assumptions resulting from the 2019 Planning and Forecasting consultation, to the extent that timeframes allow.

AEMO and TransGrid response

The PADR analysis has used updated input assumptions from the 2019 Planning and Forecasting consultation[27], as discussed in Section 5.2. This consultation was still in progress at the time of preparing the PADR, and AEMO and TransGrid will assess the impact of any further material changes in the PACR.

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

4.3.2 Load growth assumptions

Submissions

ERM Power raised concerns that the 2018 Electricity Statement of Opportunities (ESOO) demand forecasts for the NEM, in particular those used in the Fast change scenario, may overstate future demand outcomes, and said AEMO and TransGrid should consider any updates to AEMO's 2018 ESOO forecasts prior to commencing the RIT-T modelling.

ENGIE encouraged the inclusion of a scenario that incorporates very low economic performance, or failing this, to weight the Slow change scenario more highly than usual.

AEMO and TransGrid response

- The RIT-T analysis for this PADR used the 2018 ESOO demand forecasts, which were the latest forecasts available at the time of modelling. As shown in Section 5.2.5, net market benefits have been calculated for scenarios with neutral, strong, and weak demand forecasts. Sensitivities have been included to vary the weightings of those scenarios, including a sensitivity with a higher weighting of the Slow change scenario, as proposed in feedback.
- The PACR will assess the impact of the updated demand forecasts from the 2019 ESOO on the market benefits assessment.

4.4 RIT-T process

Submissions affirmed the need for robust and transparent modelling under the RIT-T process to identify the most economically efficient option. They noted that consumers would bear the cost and risk of network investments, and therefore the importance of the RIT-T in ensuring consumers would benefit from any investment.

AEMO and TransGrid are adopting a robust and transparent approach to this RIT-T assessment, in accordance with the requirements of the NER and the RIT-T application guidelines[28] issued by the Australian Energy Regulator (AER).

4.4.1 Relationship between PSCR and ISP

Submissions

The AEC, Energy Australia, and ENGIE highlighted the importance of the PSCR phase of the RIT-T process, and their expectation that the PSCR document should provide detailed explanations and material in support of the RIT-T. They noted that the PSCR for this RIT-T made consistent references to the ISP for parts of this supporting detail, and raised concerns that the PSCR therefore did not provide all details required.

The AEC specifically highlighted their expectation that the PSCR would include diagrams of the affected network, the impact of different network options, and a summary of key data assumptions to be used in the RIT-T.

AEMO and TransGrid response

- The PSCR met all requirements under clause 5.16.4 of the NER.
- AEMO and TransGrid acknowledge that the PSCR is more succinct than previous PSCRs issued by AEMO because of the considerable modelling and detailed analysis work that had previously been published through the 2018 ISP.
- The AER's RIT-T application guidelines encourage proponents to consider external documents, and particularly the ISP, when undertaking RIT-Ts, including when forming identified needs, identifying credible

[28] At https://www.aer.gov.au/system/files/AER%20-%20Final%20RIT-T%20application%20guidelines%20-%2014%20December%202018_0.pdf.

options, developing reasonable scenarios, and developing assumptions and inputs for use in the modelling analysis.

- In all cases, the PSCR made specific references to where more detailed information had already been published in the ISP.
- AEMO and TransGrid have subsequently held stakeholder meetings to discuss the additional details that stakeholders would like to have seen included in the PSCR, and where appropriate have endeavoured to include this information in this PADR.

4.4.2 Discount rates

Submissions

ENGIE highlighted the importance of using a commercial discount rate in the RIT-T market benefit assessment where the outcomes are inherently more uncertain over the modelling horizon.

AEMO and TransGrid response

- As noted in Section 5.2.2, a base discount rate of 5.9% (real, pre-tax) is used in the NPV analysis, which is consistent with the commercial discount rate calculated in the Energy Network Australia (ENA) RIT-T Economic Assessment Handbook[29].
- As shown in Section 6.3.3, sensitivities with higher and lower discount rates have been included, as well as an assessment of how high the discount rate would need to be before the preferred option changes (or becomes no longer justified).

4.4.3 Market benefits, costs, and network studies

Submissions

AusNet Services noted that the RIT-T analysis needs to value the market benefit categories of reduced voluntary load curtailment and involuntary load shedding for options that provide increased interconnector capacity in both directions between New South Wales and Victoria. Its submission also noted that the RIT-T analysis needs to include the benefits of devices that can provide additional services to the grid, such as system strength.

EnergyAustralia urged AEMO and TransGrid to ensure that the full impacts of stability limitations are captured in the RIT-T analysis, and to capture the potential for existing and new generation in southern New South Wales to limit the ability of any new interconnector capacity to reach the Sydney load centre.

EnergyAustralia encouraged AEMO and TransGrid to consider the availability of hedging contracts in the NEM, and the ability of an interconnector to provide additional firm capacity into a region, as opposed to access to generation.

EnergyAustralia also stated its view that RIT-T modelling needs to consider the economic viability of all existing power stations, instead of using fixed closure dates as an assumption.

Snowy Hydro and EnergyAustralia noted the importance of including the market impacts of transmission outages required to complete any network upgrades. MEA Group Asset also stated that any impacts on the replacement of aging assets such as conductors and transformers need to be included in the RIT-T analysis.

AEMO and TransGrid response

- The market benefits of reducing voluntary load curtailment and involuntary load shedding have been calculated for all credible options considered, as shown in Section 6.3.
- The full impacts of stability limitations have been modelled, and all transmission constraints include the impact of existing, committed, and modelled generation. Refer to Section 5.4 for more details on

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

transmission network representation in the market benefits assessment, and Attachment B: Market modelling results on AEMO's website[30] for the generation expansion plan, showing the total existing, committed, and modelled generation for each scenario.

- The impacts of hedging contracts have not been included. Section A2.1 has more details on the capital deferral benefits and the changes in generation under the proposed preferred option. The changes in firm capacity are generally minor, hence impacts on the hedging market would also be minor.
- The market impacts of outage costs have been assessed and included in the net market benefits assessment. These outage costs are shown in Section 5.5.1.
- The replacement of aging assets has been included in the cost estimates for each credible option.
- As discussed in Section 5.3.1, the RIT-T has undertaken least-cost modelling for generation expansion and retirement, where the model allows for existing generators to retire if the retirement minimises total system costs, or if a predefined technical age limit is met (typically up to 50-60 years), or if a generator has advised AEMO of its intention to decommission generation capacity.

4.4.4 RIT-T outputs

Submissions

ERM Power requested the inclusion of the expected range of transfer capability for each option, under a range of operational conditions, factors that will limit the transfer capability, and how the transfer capability will change for additional blocks of generation in northern Victoria and southern New South Wales.

AEMO and TransGrid response

- AEMO and TransGrid have endeavoured to include sufficient information in this PADR and associated attachments to provide transparency on the RIT-T assumptions, methodology, and outcomes.
- AEMO and TransGrid welcome submissions and requests for additional information following publication of this PADR report.
- Information sessions will be conducted after the PADR is published, to further engage with stakeholders.

[30] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

5. Description of methodology and assumptions

The modelling carried out in this RIT-T, consistent with the approach specified in the RIT-T application guidelines, includes:

- Detailed power flow studies to quantify the network impact of credible options, and
- Subsequent market modelling to assess the net economic benefits of the options under a least-cost national development pathway.

The assumptions used in this RIT-T are consistent with the 2019 Planning and Forecasting Consultation inputs.

5.1 Overview

The assessments in this PADR are based on AER's RIT-T application guidelines published in December 2018[31].

The assumptions used have been based on AEMO's 2019 Planning and Forecasting Consultation Paper[32] and input workbook, provided as Attachment A: Input assumptions on AEMO's website[33] and summarised in Appendix A. This consultation was in progress at the time of preparing this PADR, and the impact of any material changes resulting from the consultation will be assessed in the PACR stage.

The market modelled methodology used is consistent with AEMO's 2018 ISP approach, and further details are available in Section 5.3, and in AEMO's Market Modelling Methodologies paper[34].

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 2021-22 to 2033-34.

To capture the overall market benefits of a credible option with asset life or assumed network support arrangements extending past 2033-34, the market dispatch benefits calculated for the final year of the modelling period has been assumed to be indicative of the annual market dispatch benefit that would continue to arise under that credible option in the future. As such, this approach of using the final year is conservative and demonstrates the robustness of the preferred option as the market benefits are lower in the final year, compared to previous years (refer to Section 6.3.2 for detail).

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

[32] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[33] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

[34] AEMO, July 2018, at www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Market-Modelling-Methodology-Paper.pdf.

Terminal values[35] have been used to capture the remaining asset life[36] of the credible options and other investments in the market (generation plant).

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 5.9% (real, pre-tax) has been used in the NPV analysis. This discount rate is consistent with commercial discount rate calculated in the ENA RIT-T Economic Assessment Handbook[37]. 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.

The cost-benefit assessment has included sensitivity testing with a lower discount rate equal to the regulated weighted average cost of capital (WACC) of 3.2% based on the AER's most recent transmission determination[38], and a symmetrically higher rate of 8.6%.

5.2.3 Reasonable scenarios

Clause 5.16.1(c)(1) of the NER requires that the RIT-T is based on 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 has included three reasonable scenarios:

1. **Neutral** – a future where modest economic and population growth is experienced, and existing policies are delivered. Consequently, grid demand is relatively static, and change in the large-scale generation mix is largely driven by the timing of coal-fired generation retirements.
2. **Slow change** – a future where Australia's economic and population growth is weaker, the life of existing power stations could be extended, households and commercial businesses install rooftop photovoltaic (PV) systems to help reduce energy costs, and the transition towards zero emission vehicles is slower, as people have less disposable income and are buying new vehicles less often. Consequently, grid demand is in decline and the change in large-scale generation mix over time is less pronounced.
3. **Fast change** – a future where Australia's economy is booming, population growth is strong, and emission reduction targets are aggressive, leading to rapid decarbonisation of both the stationary energy sector and the transport sector. Consequently, growth in grid demand is relatively strong and there is a material change in the large-scale generation mix over time.

5.2.4 Policy settings

The following market and policy settings were applied as modelling constraints:

- Emissions trajectories – reduce emissions to 28% on 2005 levels by 2030 in the Neutral and Slow change scenarios, and reduce emissions to 52% on 2005 levels by 2050 in the Fast change scenario.
- Victorian Renewable Energy Target (VRET) – 25% renewables by 2020 and 50% by 2030[39].
- Queensland Renewable Energy Target (QRET) – 50% renewables by 2030[40].

A number of policies exist across NEM jurisdictions to support uptake of distributed energy resources (DER). These include:

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

[36] Based on ISP assumptions for various asset types.

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

[38] At https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24.

[39] Details at https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

[40] Details at https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland.

- South Australia – Home Battery Scheme[41].
- Victoria – Solar Homes Package[42].
- New South Wales – Clean Energy Initiatives[43].
- Queensland – Solar battery rebates[44].

The consumption forecasts used in this PADR do not include explicit representation of the above policies. AEMO intends to review and incorporate each of these schemes in the DER uptake and behavioural analysis performed within the 2019 demand forecasts for the ESOO. AEMO and TransGrid will assess the impact of these updated forecasts in the PACR stage.

5.2.5 Weightings applied to each scenario

Three separate weightings have been applied to the reasonable scenarios, to test if different weightings have an impact on the preferred option.

Table 9 Scenario weightings

Scenario weightings	Neutral	Slow change	Fast change
Set A – Base	50%	25%	25%
Set B – Slow	25%	50%	25%
Set C – Fast	25%	25%	50%

5.2.6 Energy consumption

This RIT-T applied the energy consumption and demand forecasts from the 2018 ESOO[45]. These forecasts include an integrated rooftop PV, energy storage system (ESS), and electric vehicle consumer update forecast, performed by CSIRO[46].

Both 10% and 50% probability of exceedance (POE) demand projections were used, with a weighting of 30% and 70%, respectively.

The 10% POE projections reflect an expectation of more extreme maximum demand conditions driven by variations in weather conditions, and the 50% POE projections reflect an expectation of typical maximum demand conditions.

5.2.7 Reference years

Time-sequential traces are used in the market modelling to represent consumption patterns, wind and solar generation output, and temperature-sensitive transmission line thermal ratings ('dynamic ratings'). These traces reflect the historical patterns observed in previous financial years, or 'reference years'. A consistent methodology is used to develop these reference years traces to ensure that weather patterns affecting energy consumption also affect available renewable energy generation and line ratings.

This RIT-T used the 2013-14 reference year for the 10% POE demand projection modelling runs, and the 2014-15 reference year for the 50% POE demand projections modelling runs. These reference years were selected based on load conditions seen in those years, where the 2013-14 year represented peaky demand

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[41] Details at https://homebatteryscheme.sa.gov.au/.

[42] Details at https://www.solar.vic.gov.au/.

[43] Details at https://energy.nsw.gov.au/renewables/clean-energy-initiatives.

[44] Details at https://www.qld.gov.au/community/cost-of-living-support/concessions/energy-concessions/solar-battery-rebate.

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

[46] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Projections-for-Small-Scale-Embedded-Technologies-Report-by-CSIRO.pdf.

conditions and the 2014-15 year represented more moderate demand conditions, representing demand conditions expected in a 10% POE and 50% POE year respectively.

5.2.8 Value of customer reliability

The value of customer reliability (VCR) represents a customer's willingness to pay for the reliable supply of electricity[47], and was used in this RIT-T to value any reductions in unserved energy.

Table 10 shows the VCR values used in this RIT-T. The values were based on the AEMO's Value of Customer Reliability Report prepared in September 2014[48], escalated to 2018-19 values using the national Consumer Price Index (CPI)[49].

Table 10 VCR $/MWh (2018-19)

	NSW	VIC	QLD	SA	TAS
VCR (including direct connect)	36,483	34,848	37,295	36,387	27,370

5.2.9 Generation expansion

Generation expansion (including the development of new generation and storage) and the closure of existing generation was obtained from the capacity outlook model described in Section 5.3.1 for each reasonable scenario.

Committed generation projects were taken from the January 2019 Generation Information update[50]. The VRET projects[51] (listed in the 2019 Forecasting and Planning – Input and Assumptions workbook[52]) and the Snowy 2.0 project were assumed to be committed in all reasonable scenarios.

Announced and end-of-technical life retirements were applied as outlined in the 2019 Forecasting and Planning – Input and Assumptions workbook. End-of-life retirement timings are determined according to equipment age, and units may be retired earlier in the capacity outlook model if this is determined as a least-cost outcome.

The output of the capacity outlook model can be found in Attachment B: Market modelling results.

5.2.10 Transmission development

Transmission development, including augmenting existing interconnectors and building new interconnectors, was based on the modelled outcome identified in the 2018 ISP, and associated RIT-T processes where available.

The timing and notional capacities of these interconnector developments are shown in Table 11 below. Note that the modelling for this PADR used constraint equations to represent network capability, as described in Section 5.4.1.

In addition to these interconnector developments, the 2018 ISP showed that a new link from Tumut to Bannaby, referred to as HumeLink as part of TransGrid's Reinforcing the New South Wales Southern Shared Network RIT-T (and called 'SnowyLink North' in the 2018 ISP), would provide benefits in the mid-2020s, supporting the development of the Snowy 2.0 project. This link was included as an anticipated project from 1 July 2026 to align with the timing for Snowy 2.0 in the Neutral and Fast change scenarios.

[47] For more, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

[48] At www.aemo.com.au/-/media/Files/PDF/VCR-final-report--PDF-update-27-Nov-14.pdf.

[49] For annual CPI adjustment methodology used, see http://www.aemo.com.au/-/media/Files/PDF/VCR-Application-Guide--Final-report.pdf, and for CPI values see Australian Bureau of Statistics https://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/6401.0Dec%202018?OpenDocument#Time.

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

[51] VRET projects refers to VRET Stage 1 auction winners. See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-auction-scheme.

[52] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

This PADR also assumed that the preferred option from the Western Victorian Renewable Integration RIT-T, an upgrade between Sydenham to Ballarat to Bulgana, was in place by 2025 across all scenarios.

Table 11 Interconnector developments assumed in this PADR

Interconnector	Date	Capacity, MW, forward direction	Capacity, MW, reverse direction
NSW–QLD[A]	2022-23	770 (increase of 460)	1,215 (increase of 190)
NSW–QLD[B]	2023-24	770 (increase of 460)	1,593 (increase of 568)
EnergyConnect (SA–NSW)[C]	2022-23	750	750

A. For details see RIT-T at https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity.
B. It is noted that this ISP "Group 2 – medium tern NSW to QLD upgrade", while assumed in this PADR modelling, is no longer part of the QNI RIT-T scope. This change is expected to increase the VNI RIT-T benefits and will be incorporated in the PACR stage.
C. For details see RIT-T at https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf.

The above transmission developments decrease the benefits of the preferred options assessed in this RIT-T, by:

- Relieving stability constraints limiting Victoria to New South Wales export (refer to Section 2.2.2 for detail) allowing for greater imports into New South Wales, hence less reliance on additional import from Victoria.
- Providing additional capacity into New South Wales via South Australia and Queensland, hence less reliance on import from Victoria.
- Providing additional capacity into Sydney via Tumut, hence less reliance on import from Victoria.

As these increases in capacity occur in the base case, they effectively compete with the credible options in this PADR, decreasing the incremental benefits of the credible option. This PADR has not included a scenario without any uncommitted transmission development.

5.3 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.

AEMO maintains four mutually-interacting planning models, shown in Figure 6. These models incorporate the assumptions about future development described by the scenarios and simulate the operation of energy networks to determine a reasonable view as to how those networks may develop under different demand, technology, policy, and environmental conditions.

This PADR primarily uses two of these market models to deliver its key outputs:

- **Capacity outlook model** – determines the most cost-efficient long-term trajectory of generator and transmission investments and retirements to maintain power system reliability. Two variants exist:
  - **Long Term Integrated model (IM)** – co-optimised model which considers interdependencies between gas and electricity markets to determine optimal thermal generation investments, retirements, transmission and pipeline investment plans, over the longest time horizon (25 years or beyond).
  - **Detailed Long Term (DLT) model** – optimisation model of the electricity system in isolation to the gas market, optimising new generation investments and sub-regional transmission developments, using inter-regional transmission and other long-lived thermal generation development decisions produced by the IM capacity outlook model. The DLT model is a more granular capacity outlook approach that

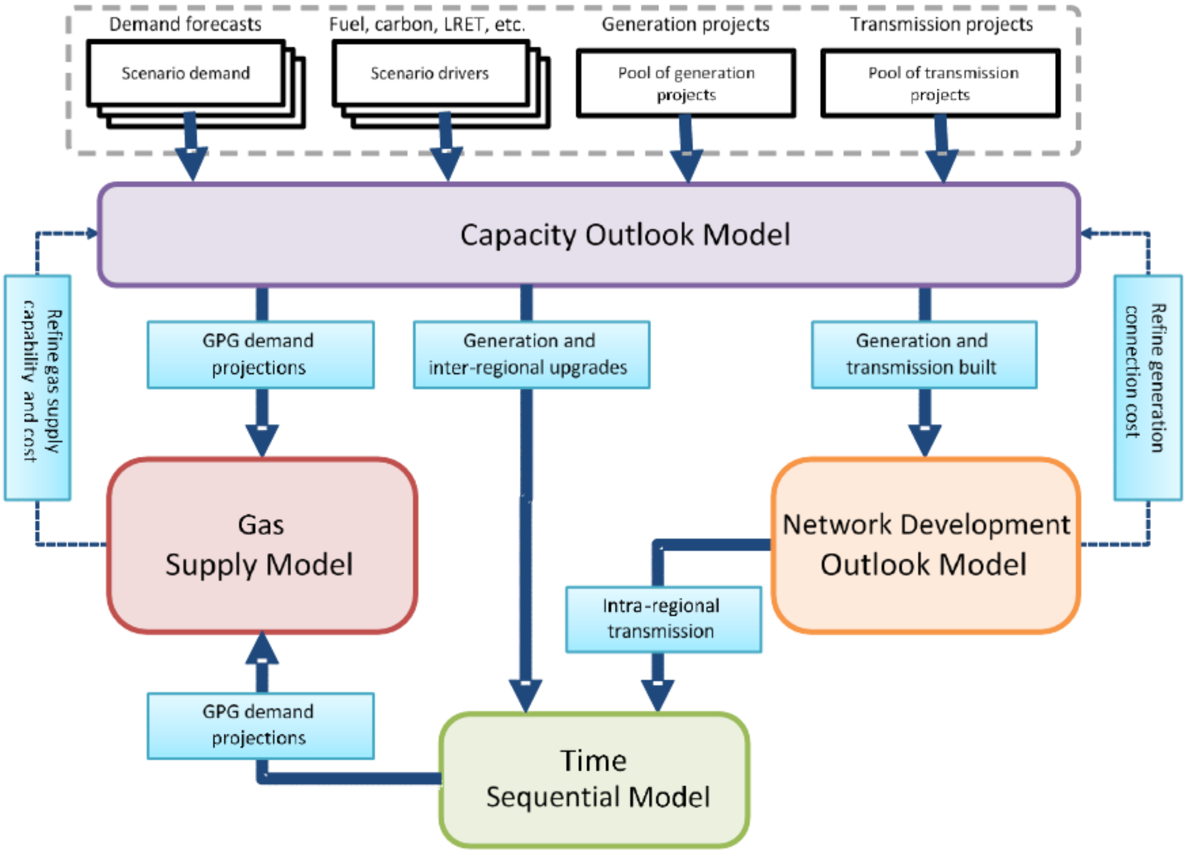
provides chronological, detailed representations of the long term via a multi-step solve, thus with reduced foresight relative to the IM.

- **Time-sequential 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. This model validates insights on power system reliability, available generation reserves, emerging network limitations, and other operational concerns. Depending on the study this model is used for, the generation and transmission outlook from the capacity outlook model may be incorporated.

The Network Development Outlook Model in Figure 6 is a PSS/e[53] model used to examine the engineering parameters of the identified need and the credible options.

The Gas Supply Model is used primarily in the Gas Statement of Opportunities (GSOO) and was not used in PADR studies.

Figure 6 Market modelling process



5.3.1 Capacity outlook model

A 'least-cost' market development modelling was undertaken, according to the RIT-T application guidelines. The least-cost model 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 and policy settings. The model can select between different generation and storage types, based on resource availability and transmission network capacity. The least-cost market development model used was the PLEXOS® long-term optimisation model.

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

The DLT model discussed above was used to develop a generation and storage expansion plan for each reasonable scenario with and without the credible options in place.

Following this, time-sequential modelling (described in the next section) was applied to assess the differences in market benefits for each credible option.

5.3.2 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 inputs

- Generation and interconnector expansion plans were obtained from the Capacity outlook model described in Section 5.3.1.
- Transmission network parameters that were included in the modelling are described in Section 5.4.
- Generation, storage, and demand side resource input assumptions are described in Appendix A1.

Model outputs

This model produces an hourly pricing and dispatch solution for generation, storage, and demand side resources, which is used to calculate operational benefits (reduction in fuel and variable operation and maintenance costs).

5.4 Transmission network parameters

Constraint equations and dynamic rating traces are two key inputs to the time-sequential model.

5.4.1 Constraint equations

Constraint equations are a mathematical representation of transmission network parameters AEMO uses to manage power system limitations, generation dispatch, and frequency control ancillary services (FCAS) requirements.

The constraint equations for network limitations were obtained from the 2018 ISP[54] and updated for each augmentation option described in Section 3.2 under system normal and contingency [(N-0)[55] and (N-1)[56]] conditions for all transmission lines with a voltage level of 220 kV and above. Constraint equations were validated against different demand, interconnector, and generation dispatch scenarios.

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[57].
- 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.

[54] 2018 ISP modelling database, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-database.

[55] Steady state operating condition with the power system in a secure operating state.

[56] The unexpected disconnection of one operating generating unit, or the unexpected disconnection of one major item of transmission plant (such as transmission line, transformer, or reactive plant).

[57] Based on ISP assumptions for various asset types.

- Oscillatory stability – for managing network flows to ensure the damping of power system oscillations is adequate under system normal and following a credible contingency.
- Rate of change of frequency (RoCoF) constraints – for managing the rate of change of frequency following a credible contingency.

Refer to AEMO's Constraint Formulation Guidelines[58] 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 (refer to Section 6.1 for further details).

5.4.2 Dynamic ratings traces

Dynamic transmission line ratings were modelled for critical transmission lines in Victoria, using thermal rating traces, which were developed using reference year ambient temperature traces. Some transmission lines are limited by substation equipment, or their protection settings.

AEMO used 15-minute short-term ratings for contingency constraint equations.

5.4.3 Thermal limits assessment

Studies were conducted to identify the impact of each credible option (see Section 3.2 for detail) on the Victoria to New South Wales interconnector transfer capacity. The studies were conducted on a single snapshot representing high export from Victoria to New South Wales. As such, the transfer capacities presented in this section serve to give an indication of the notional differences between the options, noting that transfer capacities can vary based on a number of factors including temperature and operating conditions.

It should be noted that the overall Victoria to New South Wales transfer capability can be limited by thermal or stability limitations (see Section 5.4.4 for detail) and the specific limitation at any point in time will depend on operational conditions.

Table 12 Improvement to Victoria to New South Wales interconnector export limit (thermal)

Option	Description	Indicative impact on transfer capacity
Option 1	ISP base option	+170 MW
Proposed preferred option – Option 2	ISP base option with modular power flow controllers	+170 MW
Option 3	Additional higher capacity upgrades in New South Wales	+300 MW
Option 4	Additional higher capacity upgrades in New South Wales and Victoria	+500 MW

5.4.4 Stability limits assessment

Studies were conducted to assess the impact of future network augmentations on the Victoria to New South Wales transient and voltage stability export limits, under periods of high Victoria to New South Wales export. Multiple high export snapshots representing a variety of different network operating conditions were used for the studies. The studies were carried out using PSS/E dynamic simulations.

In general, the following steps were taken:

- The study cases were modified to represent a scenario with no network augmentations, and each network augmentation.

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

- Victoria to New South Wales export was progressively increased in the study cases, to find the limit where the cases became unstable, based on the criteria described in the next sections.
- The maximum stable transfer limit was recorded for:
  - Scenario with no network augmentations.
  - Scenario with second South Morang transformer.
  - Scenario with addition of Project EnergyConnect preferred option and Western Victoria Renewable Integration RIT-T preferred option.
  - Scenario with addition of HumeLink.

Transient stability limit

A study case is considered unstable if one of the following criteria is met:

- There are more than four machines, with an individual maximum rotor angle swing deviation greater than 160^0.
- Rotor angle deviation spread between any two machines in the network is greater than 360^0.
- Out-of-step conditions are detected.

Voltage stability limit

NER S5.1.8 states that the reactive power margin (expressed as a capacitive reactive power (in MVAR) must not be less than one percent of the maximum fault level (in MVA) at any connection point.

A study case is considered stable if the following criteria are met:

- The minimum reactive power margin at every monitored bus is maintained.
- The pre-contingent and post-contingent minimum voltage at every monitored bus is within operating limits.

Improvement on interconnector export stability limit

Table 13 shows the improvement in Victoria to New South Wales export limit that has been assumed in market modelling, reflecting proposed network augmentations under the current RIT-T, and based on the assessment described above.

Table 13 Improvement to Victoria to New South Wales interconnector export limit (stability)

Augmentation	Impact on transient stability[A] (MW)	Impact on voltage stability[B] (MW)
Second South Morang transformer	+40	+6
Second South Morang transformer + Project EnergyConnect + Western Victoria Renewable Integration	+170	+122
Second South Morang transformer + Project EnergyConnect + Western Victoria Renewable Integration. + HumeLink	+220	+284

A. Prevent transient instability for a fault and trip of the Hazelwood to South Morang 500 kV transmission line.
B. Avoid voltage collapse around Murray for loss of APD potlines during light load conditions.

5.5 Cost estimate methodology

Cost estimates for the different types of credible options were estimated in several ways:

1. Network options in Victoria – costs were obtained from AusNet Services.

2. Network options in New South Wales – costs were developed by TransGrid.
3. Non-network options – costs were provided by vendors.

The cost estimates have an accuracy of ±30%. As such, the costs for each option were varied by ±30% to test the robustness of the market benefits. Operational cost was assumed to be 2% of the capital cost.

The cost of each option includes the following components:

- Project management.
- Contracts (sub-contracting).
- Administration and overheads.
- Equipment and services procurement.
- Installation.
- All station upgrade works, including:
  - Plant and equipment.
  - Civils.
  - Internal labour.

Estimated/typical lead times for components have been sourced in the same way as costs.

5.5.1 Cost estimate of outages

An assessment of the duration and costs of the outages required to implement the credible options is shown in Table 14.

The outage costs were assessed using market modelling, comparing the market costs in the 'do nothing' case with the market costs in a case with a network configuration matching that which would be required during the outage period.

This outage cost represents the cost to the market from losing access to cheaper generation sources, requiring replacement with more expensive generation.

Table 14 Outage cost for credible options

Outage	Outage duration	Outage cost, $M
330 kV South Morang – Dederang line upgrade	56 days[A]	1.3
330 kV Upper Tumut – Canberra line upgrade	6 months	4.6
Installation of modular power flow controllers on 330 kV Upper Tumut – Canberra and 330 kV Lower Tumut – Canberra line	50 days	1.4

A. For both lines (34 and 22 days for lines 1 and 2 respectively).

6. Detailed option assessment

The primary sources of market benefits are fuel cost savings associated with access to lower-cost generation in the southern states, and capital cost savings associated with deferred or avoided investment in additional generation capacity.

6.1 Classes of market benefits not expected to be material

Chapter 2 of the PSCR[59] identified classes of market benefits that were not expected to be material to this RIT-T. 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.

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

- Changes in ancillary services costs – there is no expected change to the costs of FCAS, Network Control Ancillary Services (NCAS), or System Restart Ancillary Services (SRAS) because of the options being considered. These costs are therefore not material to the outcome of the RIT-T assessment.
- Competition benefits – while increasing the ability for resource sharing between states is likely to increase competition and therefore provide a competition benefit, the estimated cost of the modelling and analysis to estimate this benefit is considered to be disproportionate to the size of the potential benefit itself.
- Option value – for this RIT-T, estimating any option value benefit over and above that already captured via the scenario analysis in this RIT-T and the 2018 ISP analysis would require a disproportionate level of investigation having regard to the cost of the analysis and the potential benefits. As such, additional option value market benefit estimates are not proposed as part of this RIT-T assessment.
- Negative of any penalty for not meeting the renewable energy target – the Federal Large-scale Renewable Energy Target (LRET), VRET, QRET, and 2030 climate change target were met in all scenarios, with and without the credible options in place. Therefore, this class of market benefit is not material to the PADR analysis.
- Changes in network losses – the PADR market modelling captures changes in inter-regional network losses due to changing dispatch patterns enabled by the credible options as part of the overall change to fuel consumption. Changes in intra-regional network losses due to the credible options have been captured in the constraint equations, as the equations were updated to reflect the impact of the options. As such, no separate category of changes in network losses is included in the PADR analysis.

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

[59] 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.

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 cost to parties other than the TNSPs, due to:
  - Differences in the timing of the installation of new plant.
  - Differences in capital costs of different plant.
  - Differences in the operating and maintenance costs of different plant.
- Differences in the timing of transmission investment.
- Reduced voluntary load curtailment and involuntary load shedding.

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

All classes of market benefits are calculated for the entire NEM and will therefore capture benefits arising in other regions, as well as Victoria and New South Wales.

6.2.1 Changes in fuel consumption

Changes in generation costs, where generation costs include fuel consumption cost, variable operation and maintenance (O&M) cost, and any emissions costs, are the primary source of market benefits in this RIT-T. These arise because the credible options promote more efficient sharing of generation resources between regions, enabling better utilisation of low-cost fuel sources, in particular renewable and brown coal generation in Victoria displacing black coal and gas generation in New South Wales and Queensland.

The market modelling for this PADR calculated the difference in total generation costs between the 'do nothing' base case and cases with each of the credible options in place. If cases with the credible option in place have a lower total generation cost than the 'do nothing' case, then the market benefit is positive.

The PLEXOS® model used for the market modelling is optimised to always identify the least-cost generation dispatch.

6.2.2 Changes in costs for other parties

Changes in costs for other parties are also a source of market benefits in this RIT-T. 'Other parties' in the context of this analysis refers mainly to costs incurred by market participants[60]. Market benefits arise due to better utilisation of existing plant, as the credible options allow for more efficient sharing of generation resources between regions.

The market modelling for this PADR developed a least-cost generation expansion required to meet customer demand under various scenarios, using the Capacity outlook model described in Section 5.3.1. The modelling showed that the credible options tended to result in a lower-cost generation expansion plan, due to:

- Deferral of new generation capacity built.
- Reducing the total megawatt capacity of new generation built.

The difference between capital costs under the 'do nothing' base case and the credible option cases represents the market benefits of the proposed option. Refer to Appendix A2.1 for further information on the capital cost savings identified in this PADR.

6.2.3 Differences in the timing of transmission investment

AEMO's 2018 ISP identified that transmission augmentation from Tumut to Bannaby (HumeLink) would provide system benefits once the Snowy 2.0 project is committed. Options 3 and 4 in this PADR consider the

[60] Parties other than AEMO in its capacity as one of the Victorian TNSPs and TransGrid as New South Wales TNSP.

benefits of reducing the future cost of HumeLink, compared to the other credible options, in meeting the identified need of this RIT-T.

This RIT-T does not preclude, or have any material impact on, known transmission network replacement projects in Victoria or New South Wales.

6.2.4 Reduced voluntary load curtailment and involuntary load shedding

Increasing transfer capacity between regions can improve the availability of supply at times of high demand if one of the regions has spare capacity. The market modelling for this PADR calculated the difference in voluntary load curtailment and involuntary load shedding between the 'do nothing' base case and cases with each of the credible options in place.

6.3 Net market benefit assessment

6.3.1 The 'do nothing' base case

The 'do nothing' base case is defined in the RIT-T and the application guidelines as the case where the RIT-T proponent does not implement an option to meet the identified need.

For the purposes of the net market benefits assessment, the market costs associated with each augmented case (credible option) are compared against the market cost in the base case to calculate a gross market benefit. This is subsequently compared against the cost of the credible option to determine and rank the net market benefits.

The same process is applied across each scenario and the results are weighted to provide an overall net market benefit result and option ranking.

6.3.2 Net market benefits across reasonable scenarios

Table 15 presents the net market benefits for each major credible option, under each reasonable scenario. The results presented in this chapter show the outcomes assuming the base scenario weighting.

Refer to Attachment C: Market benefits calculation on AEMO's website[61] for the gross and net market benefits under each assessed scenario and sensitivity. Refer to Appendix A2 for a more detailed breakdown of fuel and capital cost savings for each year for the proposed preferred option.

Table 15 Net market benefits for each credible option and reasonable scenario

Option	Capital cost, $M (2019-20)	Costs NPV $M	Neutral, $M	Slow change, $M	Fast change, $M	Weighted benefit, $M (NPV)
Scenario weighting			50%	25%	25%	
Option 1 – ISP base option	98	84	251	210	370	270
Proposed preferred option Option 2 – ISP base option with modular power flow controllers	81	68	267	226	386	286
Option 3 – Additional higher capacity upgrades in NSW	610	447	255	216	20	187
Option 4 – Additional higher capacity upgrades in NSW and Victoria	1,042	763	7	6	-231	-53

[61] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission.

Option 1 – ISP base option

This option consists of a new 500/330 kV transformer at South Morang Terminal Station, uprating of the South Morang – Dederang 330 kV lines and uprating of the Upper Tumut – Canberra 330 kV line by 2022-23.

Figure 7 provides a breakdown of the gross market benefits for this option under the Neutral scenario. This option reduces the costs of involuntary load shedding and voluntary load reduction from implementation until 2025-26.

From 2026-27, the commissioning of Snowy 2.0 reduces the amount of involuntary load shedding and voluntary load reduction in the base case. Gross market benefits then arise from reductions in fuel costs, with brown coal and renewable generation in Victoria displacing black coal and natural gas generation in New South Wales and Queensland.

Fuel cost savings increase over time as the supply-demand balance tightens, and reduce in 2033-34 with the assumed retirement of brown coal capacity in Victoria. From 2026-27 there are also reductions in generation capital costs in the augmented case, due to displacement of new capacity in New South Wales.

The net market benefits are positive from 2022-23 onwards indicating that the optimal timing for the augmentation is in 2022-23.

Figure 7 Option 1 gross and net market benefits in the Neutral scenario

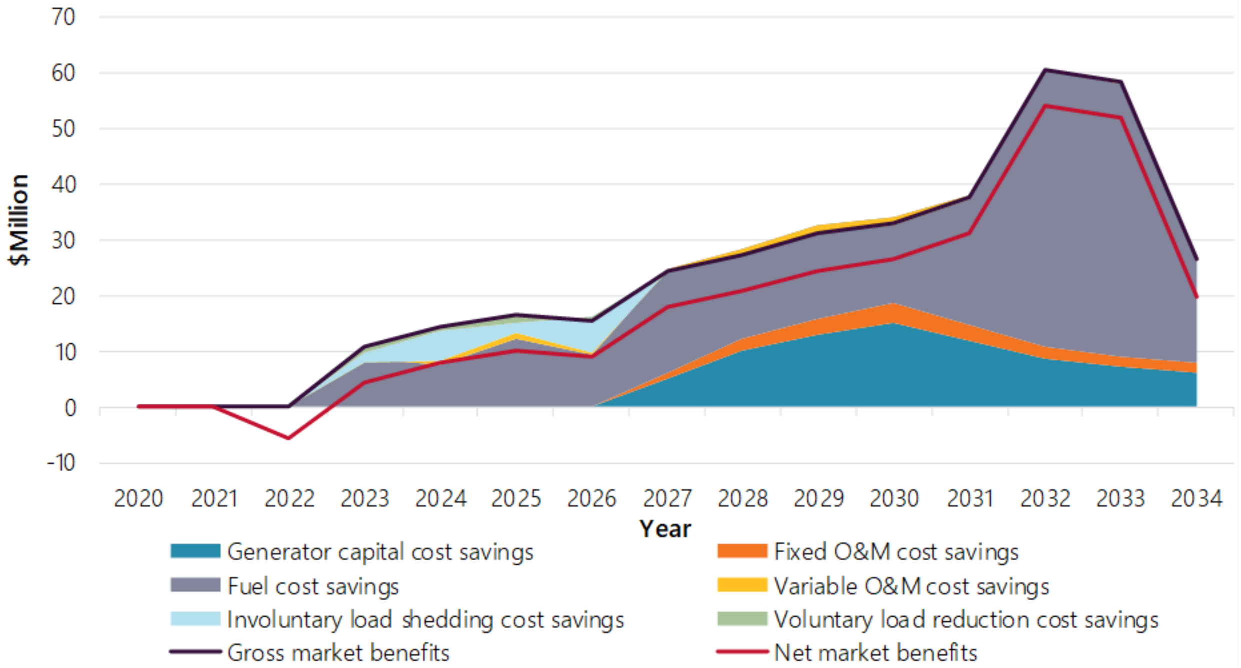


Table 16 below shows the forecast binding hours of the relevant constraints from the modelling study for this option.

The changes in constraint binding hours between this option and the 'do nothing' scenario reflect the interactions between the constraints. For example, in the 'do nothing' scenario the thermal constraints on the South Morang transformer had the greatest binding activity; the augmentations under this option relieve the thermal constraints resulting in increased binding activity on the stability constraints.

Table 16 Forecast binding hours of relevant constraints, Neutral scenario (Option1)

Limitations	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Sum
South Morang 500/330 kV Transformer	24	261	65	173	426	2,061	2,343	2,679	3,015	2,776	3,070	1,967	1,939	20,799
Victoria to NSW transient stability	4,050	2,868	1663	1,811	1,949	1,477	1345	1371	583	593	589	411	410	19,120
Victoria to NSW voltage stability	0	0	215	363	608	603	550	611	724	662	792	132	124	5,384
NSW to Victoria voltage stability	315	199	4	5	3	56	43	34	1	1	2	24	30	717
South Morang – Dederang	34	36	12	14	4	30	20	8	0	0	0	0	0	158
Murray – Dederang	137	96	55	60	58	8	3	0	0	0	0	0	0	417
Upper Tumut – Canberra	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Option 2 – ISP base option with modular power flow controllers

This option is consistent with Option 1 but proposes the installation of modular power flow controllers as an alternative option to increase transfer capacity on the 330 kV Upper Tumut – Canberra line by 2022-23.

This option has the highest net market benefits of all credible options.

Figure 8 provides a breakdown of the gross market benefits for this option under the Neutral scenario, and is consistent with Option 1 because both options provide the same increase in transfer capability.

Figure 8 Option 2 gross and net market benefits in the Neutral scenario

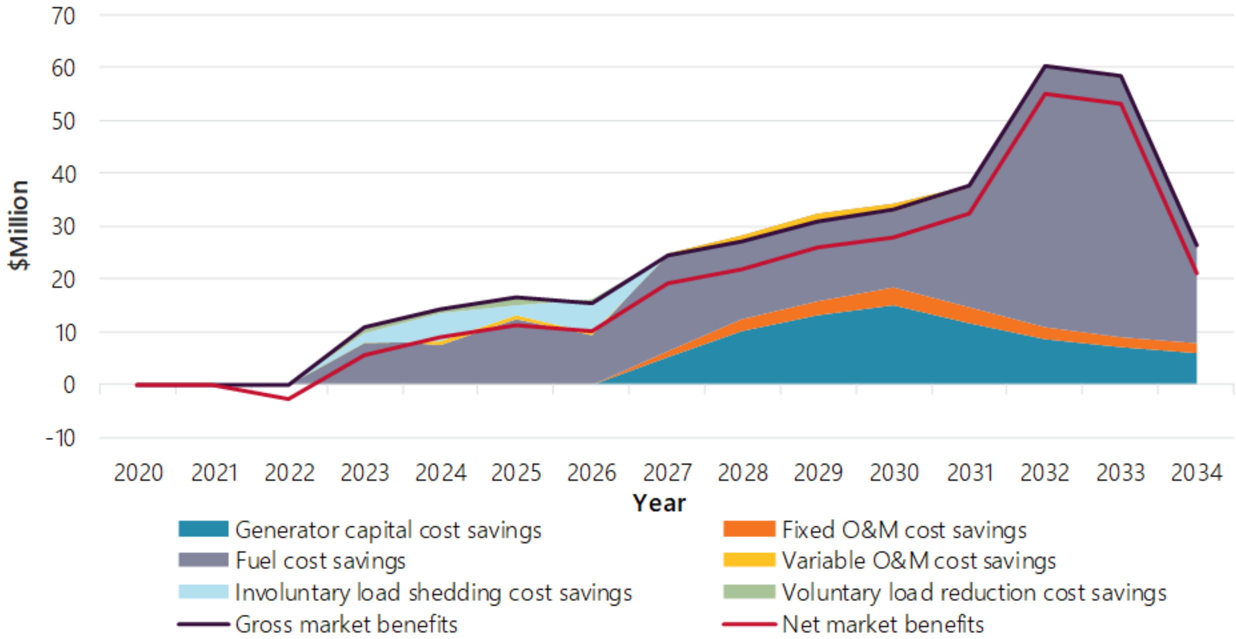


Table 17 shows the forecast binding hours of the relevant constraints from the modelling study for this option. The results are consistent with Option 1 because both options provide the same increase in transfer capability.

Table 17 Forecast binding hours of relevant constraints, Neutral scenario (Option2)

Limitations	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Sum
South Morang 500/330 kV Transformer	24	261	65	173	426	2,061	2,343	2,679	3,015	2,776	3,070	1,967	1,939	20,799
Victoria to NSW transient stability	4,050	2,868	1,663	1,811	1,949	1,477	1,345	1371	583	593	589	411	410	19,120
Victoria to NSW voltage stability	0	0	215	363	608	603	550	611	724	662	792	132	124	5,384
NSW to Victoria voltage stability	315	199	4	5	3	56	43	34	1	1	2	24	30	717
Murray – Dederang	137	96	55	60	58	8	3	0	0	0	0	0	0	417
South Morang – Dederang	34	36	12	14	4	30	20	8	0	0	0	0	0	158
Upper Tumut – Canberra	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Option 3 – Additional higher capacity upgrades in New South Wales

This option consists of the Victorian component of Option 1 (South Morang 500/330 kV transformer and uprating of the South Morang – Dederang 330 kV lines) in 2022-23, in addition to advancing a proposed Bannaby – Sydney 500 kV line from 2026-27 to 2024-25.

Figure 9 provides a breakdown of the gross market benefits for this option under the Neutral scenario.

Compared with Option 1, this option is less effective at reducing the costs of involuntary load shedding, voluntary load reduction, fuel costs, and variable O&M during 2022-23 to 2023-24. This is because this option does not include the Upper Tumut – Canberra line upgrade.

However, from 2025-26, this option has greater gross benefits than Option 1. Fuel cost savings increase from 2030-31 as the supply-demand balance tightens with retirements of black coal capacity in New South Wales and Queensland, although these savings reduce again from 2033 following assumed retirement of brown coal capacity in Victoria.

The transmission cost saving category represents that the 500 kV line investment proposed in this option is the advancement cost only of part of the investment currently being tested in TransGrid's RIT-T for reinforcing southern New South Wales.

Figure 9 Option 3 gross and net market benefits in the Neutral Scenario

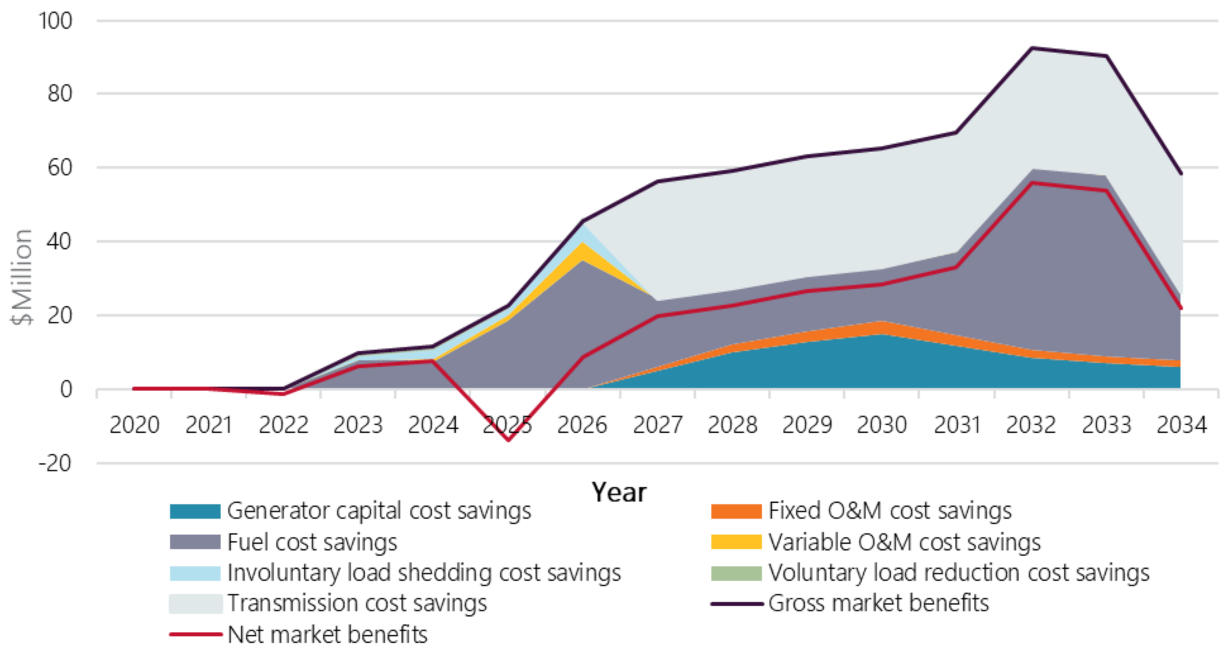


Table 18 shows the forecast binding hours of relevant constraints from the modelling study for Option 3.

Table 18 Forecast binding hours of relevant constraints, Neutral scenario (Option 3)

Limitations	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Sum
South Morang 500/330 kV Transformer	24	261	65	232	555	2,061	2,343	2,679	3,015	2,776	3,070	1,967	1,939	20,987
Victoria to NSW transient stability	4050	2,868	1,663	1,551	1,868	1,477	1,345	1,371	583	593	589	411	410	18,779
Victoria to NSW voltage stability	0	0	215	120	282	603	550	611	724	662	792	132	124	4,815
NSW to Victoria voltage stability	315	199	4	11	0	56	43	34	1	1	2	24	30	720
Murray – Dederang	137	96	55	53	54	8	3	0	0	0	0	0	0	406
South Morang – Dederang	34	36	12	15	6	30	20	8	0	0	0	0	0	161
Upper Tumut – Canberra	0	0	0	0	0	0	0	0	0	0	0	0	0	0

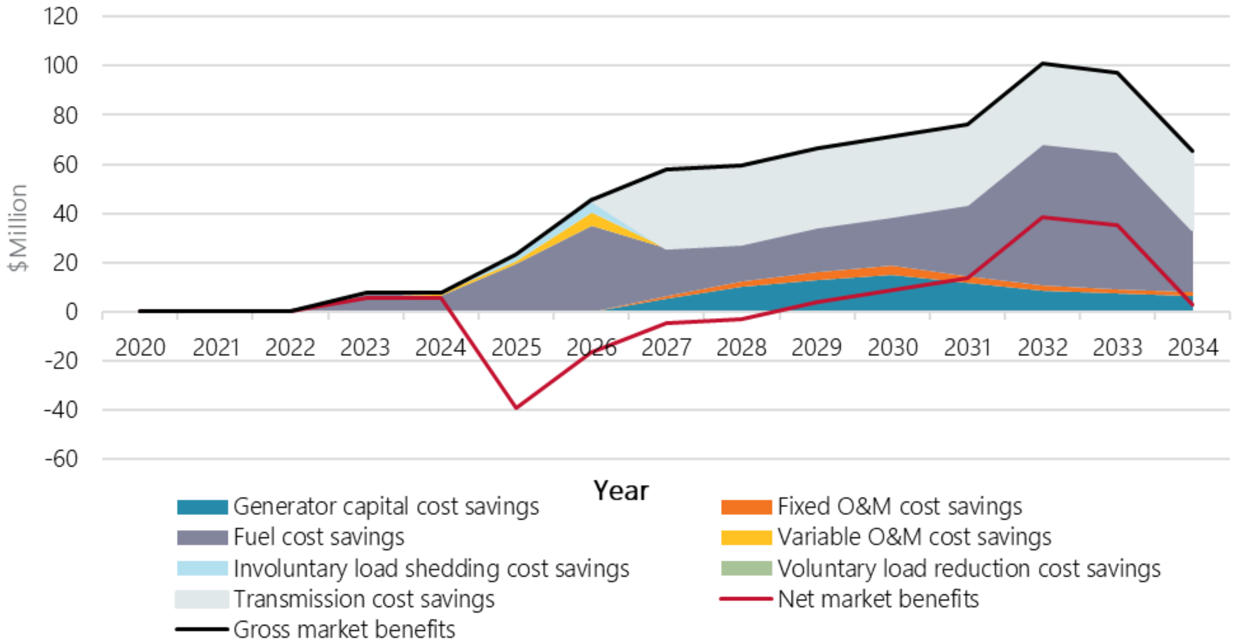
Option 4 – Additional higher capacity upgrades in New South Wales and Victoria

This option consists of a new third line between South Morang and Dederang and two new transformers at South Morang Terminal Station, in addition to the New South Wales investments proposed in Option 3.

Figure 10 provides a breakdown of the gross market benefits for this option under the Neutral scenario.

This option builds on Option 3 by including a new third line between South Morang and Dederang, and two new transformers at South Morang Terminal Station in Victoria. However, the gross market benefits show that the additional line does not provide sufficient market benefits to offset the additional cost involved.

Figure 10 Option 4 gross and net market benefits in the Neutral scenario



6.3.3 Sensitivity studies

The proposed preferred option is Option 2, with a gross market benefit of $354 million and a net market benefit of $286 million.

Sensitivity analysis was carried out to test the robustness of the choice of proposed preferred option and to determine if any factors that would change the order of the credible options assessed:

- Change in scenario weightings – scenario weightings were changed as described in Table 9 (Section 5.2.5). The ranking of the proposed preferred option does not change, and weighted net market benefits remain positive.
- Change in cost – costs were changed by ±30%. The ranking of the proposed preferred option does not change, and average weighted net market benefits remain positive.
- Change in discount rate – the discount rate was increased to 8.6% and decreased to 3.2%. Option 2 remains the proposed preferred option and the net market benefits remain positive for discount rates as low as 1% and as high as 20%.

Option 2 remains preferred under all sensitivities.

Table 19 Sensitivity results – net market benefits NPV ($M)

	Base	High discount rate	Low discount rate	High cost	Low cost	Slow weighting	Fast weighting
Option 1	270	157	485	247	294	300	260
Option 2 (proposed preferred option)	286	172	503	268	307	316	276
Option 3	187	76	399	131	243	128	177
Option 4	-53	-154	192	-204	99	-112	-53

6.3.4 Timing of preferred option

As shown in Figure 8, the net market benefits under Option 2 become positive from 2022-23 onwards.

The payback period for this option is six years, meaning the cost saving delivered through the option will exceed its cost after six years. Accordingly, the proposed preferred option is not exposed to longer-term uncertainty.

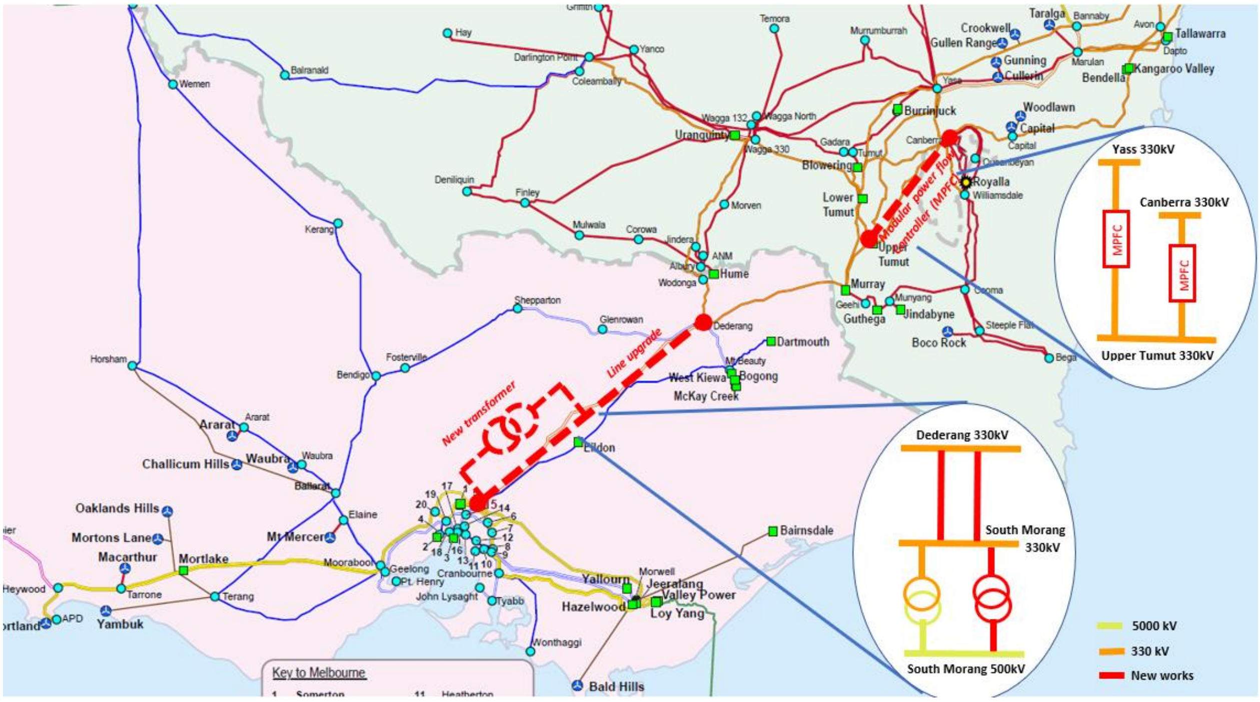
7. Proposed preferred option

The proposed preferred option is to implement the following augmentations with an optimal timing for delivery by 2022-23:

- Install a second 500/330 kV transformer at South Morang Terminal Station.
- Re-tension the 330 kV South Morang – Dederang transmission lines, as well as associated works (including uprating of series capacitors) to allow operation at thermal rating.
- Install modular power flow controllers on the 330 kV Upper Tumut – Canberra and Upper Tumut – Yass lines to balance power flows and increase the transfer capability.

This option returns the highest net market benefits under all assessed scenarios and all sensitivities.

Figure 11 Proposed preferred option (Option 2)



7.1 Preferred option

The NER requires the PADR to identify the proposed preferred option under the RIT-T, which is the option that meets the 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 Option 2 delivers the highest net market benefits when weighted across all reasonable scenarios, and also under all sensitivities considered.

Option 2 is shown in Figure 11 and consists of the following augmentations:

- Install a second 500/330 kilovolt (kV) transformer at South Morang Terminal Station.
- Re-tension the 330 kV South Morang – Dederang transmission lines, as well as associated works (including uprating of series capacitors) to allow operation at thermal rating.
- Install modular power flow controllers on the 330 kV Upper Tumut – Canberra and Upper Tumut – Yass lines to balance power flows and increase transfer capability.

Accordingly, this set of augmentations constitutes the proposed preferred option, and satisfies the *regulatory investment test for transmission*.

The technical characteristics of this option, and its constituent components, are set out in Appendix A3.

7.2 Considerations moving forward

The proposed preferred option includes a second transformer at South Morang Terminal Station that will address the identified thermal limitations, and partially address the identified stability limitations by reducing the effective impedance of the network.

The stability limitations will be further improved by augmentations being proposed outside this RIT-T, through the Western Victoria Renewable Integration RIT-T, Victorian Reactive Power Support RIT-T[62], Project EnergyConnect RIT-T, and HumeLink RIT-T. As such, investment to completely resolve the stability limits through this RIT-T is not proposed at this stage.

However, the staging and risks associated with the other RIT-T projects may result in a gap between delivery of the second South Morang transformer and full resolution of the stability limits. This will be reviewed as part of the PACR stage of this process, considering the latest available information. In particular, the PACR may assess a variant of the proposed preferred option which will include a component to increase stability limits, if the preferred options under the other RIT-Ts do not become committed.

The modular power flow controller is subject to further modelling during the PACR stage, with more detailed Root Mean Square (RMS) and Electro Magnetic Transient (EMT) type modelling to assess the potential for control interaction between the modular power flow controllers and nearby generators. Detailed site-specific installation requirements and detailed operational feasibility will also be further reviewed during the PACR stage.

These challenges and opportunities will be explored further as part of the next stage of this RIT-T, incorporating the latest available information as well as stakeholder feedback on this PADR.

[62] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victorian-Reactive-Power-Support-RITT.

A1. Market modelling inputs

A1.1 Overview

Modelling inputs to the Capacity outlook model described in Section 5.3.1 and the Time-sequential model described in Section 5.3.2 were based on AEMO's 2019 Planning and Forecasting Consultation Paper[63] and input workbook, and are discussed below. Further details are available on AEMO's website[64].

This consultation was ongoing at the time of preparing this PADR. AEMO and TransGrid will assess the impact of any material changes resulting from the consultation in the PACR stage.

A1.1.1 Technology build costs

As detailed in AEMO's Planning and Forecasting Consultation Paper, AEMO engaged GHD and CSIRO to review and update new entrant costs and technical parameters across a range of generation and storage technologies.

GHD provided AEMO with current technology costs and performance data for a range of candidate technology options[65]. CSIRO produced cost projections from GHD's current technology costs using their Global and Local Learning Model (GALLM)[66].

CSIRO's GALLM build costs projects are a function of global and local technology deployment. As the global technology deployment depends on the global climate policy, CSIRO GALLM build cost projections are given for two scenarios, termed '4-degrees' and '2-degrees'.

The capacity outlook model applied the '4-degree' build cost projections for the Neutral and Slow change scenario, and the '2-degree' build cost projections for the Fast change scenario.

A1.1.2 Generator technical parameters

The capacity outlook and time-sequential modelling used the technical parameters detailed in the 2019 Forecasting and Planning – Inputs and Assumptions workbook[67].

Generator unit capacity and seasonal ratings were taken from the January 2019 Generation Information update[68]. Generator operating limits and behaviours, including minimum load and capacity factor constraints, were based on GHD and AEMO analysis of historical generator performance.

Forced outages rates were applied on a fuel type basis, with outage rates for existing generators based on the most recent three years' outage data, and outage rates for new entrant technologies based on GHD data.

Generator O&M costs were based on GHD data and feedback from stakeholders. The fixed O&M costs for coal generators include an AEMO-developed estimate for fixed costs associated with adjacent mines.

Emission intensity factors for existing generators and new entrant technology were based on GHD data.

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[63] At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[64] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[65] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf.

[66] At https://publications.csiro.au/rpr/download?pid=csiro:EP189502&dsid=DS1.

[67] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook.xlsx.

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

A1.1.3 Fuel prices

This RIT-T's capacity outlook and time-sequential modelling used the fuel prices from the 2019 Planning and Forecasting Consultation. Gas prices were developed by AEMO in collaboration with consultant Core Energy & Resources Pty Limited (CORE)[69].

Coal prices were based on the 2016 Wood Mackenzie Coal Cost report for existing generators, and the Resources and Energy Quarterly (June 2018) report for new entrant technology.

A1.1.4 Storage technology modelling

The capacity outlook model considered a range of short and long storage options as build candidates. These were two-hour batteries, and pumped hydro storage of six hours, 12 hours, 24 hours, and 48 hours. Solar thermal technology with an eight-hour storage was also considered as a build candidate.

A1.1.5 Existing hydro generation modelling

As detailed in AEMO's Planning and Forecasting Consultation Paper, AEMO has collaborated with Snowy Hydro and Hydro Tasmania to improve the modelling of storage and generator topologies. These improvements were used in the capacity outlook and time-sequential modelling and included:

- Utilising historical hydro inflow data for historical years (aligned with the reference years used) to better capture the variability in production from Snowy Hydro and Hydro Tasmania.
- Improved cascaded topology of the Snowy Hydro scheme, including a representation of the interaction between the existing scheme and the Snowy 2.0 development.
- Adoption of a seven-pond model for the Hydro Tasmania generation assets.

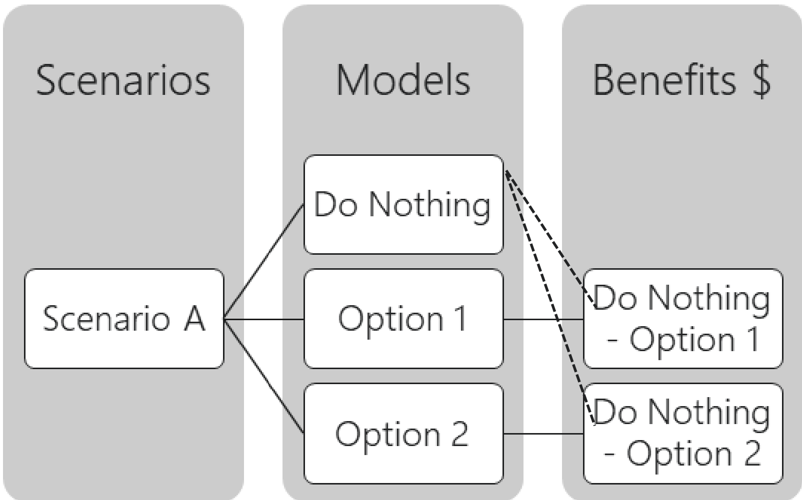
[69] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/CORE_Delivered-Wholesale-Gas-Price-Outlook_16-January-2019.pdf.

A2. Discussion of market benefits

The general process for identifying market benefits is shown in Figure 12 below. For each scenario, modelling is carried out for the base case and a credible option case. The difference in costs between the base case and credible option case represents the benefit of that credible option.

Capital deferral benefits have only been considered up to 2034, after which any differences in generation expansion are assumed to be independent of the augmentations described in this PADR.

Figure 12 Process for identifying market benefits



A2.1 Capital cost savings

Capital cost savings in this RIT-T have been derived from the capacity outlook model described in Section 5.3.1. The generation expansion plans derived from the capacity outlook modelling are provided in Attachment B: Market modelling results.

Figure 13 shows the changes in generation development with the proposed preferred option (Option 2) in place, compared to the base case under the Neutral scenario. A positive number indicated that installed generation capacity is higher when the proposed preferred option is applied, and a negative number indicates that installed generation capacity is lower.

The modelling showed that the primary changes between the generation development in the Neutral scenario with the proposed preferred option applied, compared to the base case, are reductions in utility solar in New South Wales from 2027, and pumped storage from 2029, due to the proposed upgrades allowing access to additional wind and brown coal generation from Victoria. By gaining access to the wind and brown coal resources in Victoria, the New South Wales region is able to reduce the need for a new entrant generation response to the retirement of Vales Point Power Station.

Figure 13 Changes in generation development (MW) – proposed preferred option, Neutral scenario

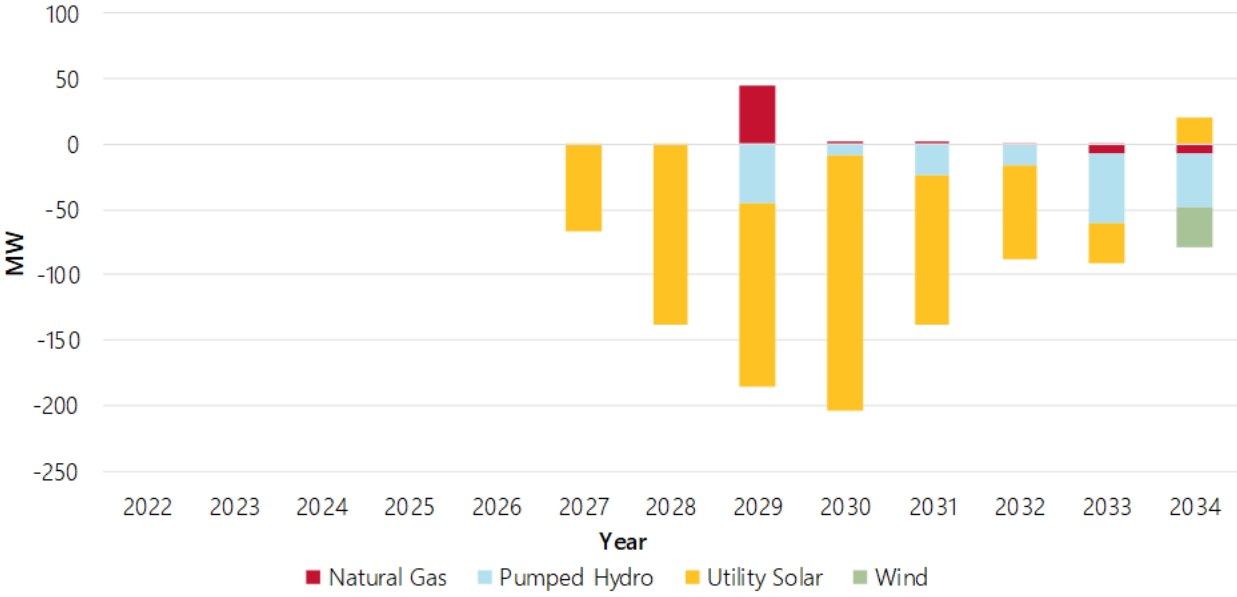


Figure 14 shows changes in generation development in the Fast change scenario with the proposed preferred option applied, compared to the base case. In this scenario, more changes in generation development occur in the early years than in the Neutral scenario, with peaking gas plant being deferred for one year (from 2023 to 2024) and solar generation moving forward one year (from 2024 to 2023). Overall, there is less solar capacity installed and more wind installed capacity with the proposed preferred option in place.

Figure 14 Changes in generation development (MW) – proposed preferred option, Fast change scenario

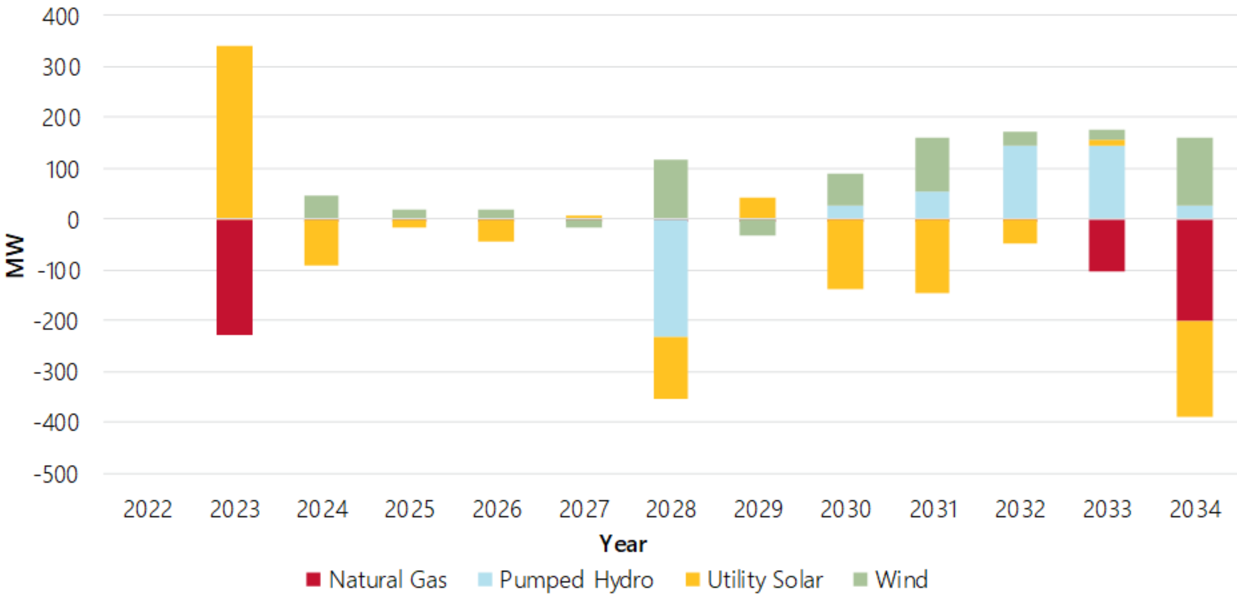


Figure 15 shows the changes in generation development in the Slow change scenario with the proposed preferred option applied, compared to the base case. In this scenario, a gas peaking capacity is deferred one year (2023 to 2024) and less solar capacity is installed up until 2033, as the proposed preferred option enables more efficient use of Victorian brown coal and wind generation as a response to New South Wales generation retirements. Additionally, gas peaking capacity is deferred from 2033, due to better sharing of generation capacity between regions as the rate of existing thermal retirements increases.

Figure 15 Changes in generation development (MW) – proposed preferred option, Slow change scenario

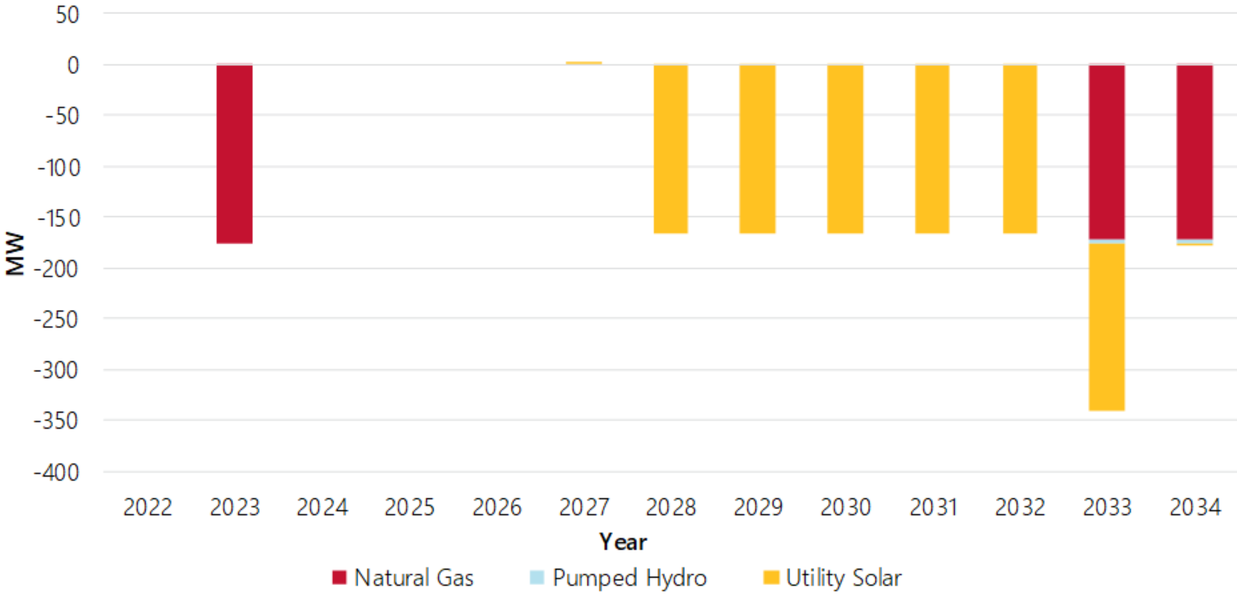
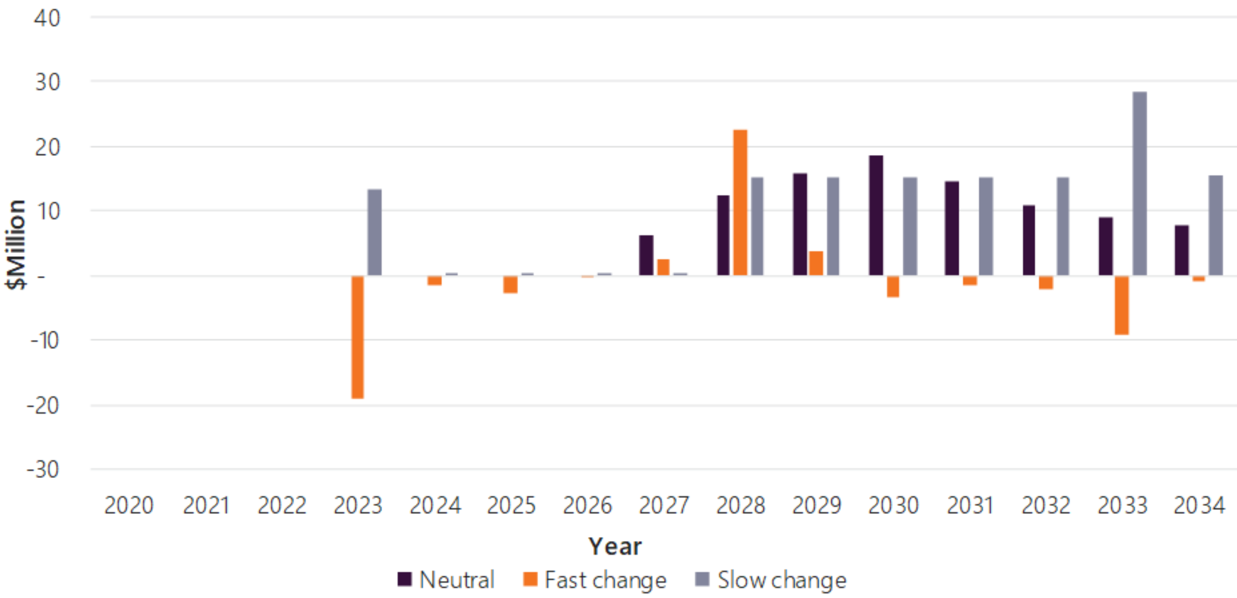


Figure 16 shows the capital cost savings for the proposed preferred option, compared to the base case across all reasonable scenarios. The capital cost savings in the Fast change scenario are negative in 2023, due to the higher cost of advancing the solar capacity installed in this year with the proposed preferred option applied, compared with the gas capacity in the base case. Overall, the capital cost savings are positive, as the proposed preferred option enables more efficient sharing of generation resources across regions.

Figure 16 Capital cost savings across all scenarios, proposed preferred option



A2.2 Generation cost savings

The time-sequential modelling described in Section 5.3.2 was carried out for the base case and each credible option identified in Section 3.2, for each reasonable scenario. Generation cost savings are derived from the fuel and variable O&M costs in the base case, minus the fuel cost and variable O&M for each credible option.

Generation levels and costs derived from the time-sequential modelling are in Attachment B: Market modelling results.

Figure 17 shows the difference in generation level with the proposed preferred option (Option 2) in place, compared to the base case under the Neutral scenario. A positive number indicates that generation has increased when the preferred option is applied, and a negative number indicates that generation has decreased.

The modelling shows that the proposed preferred option displaces black coal and natural gas generation and increases brown coal and wind generation. Solar generation is also lower under the proposed preferred option, due to the lower installed capacity of solar generation compared with the base case.

Figure 17 Changes in generation dispatch (GWh) – proposed preferred option, Neutral scenario

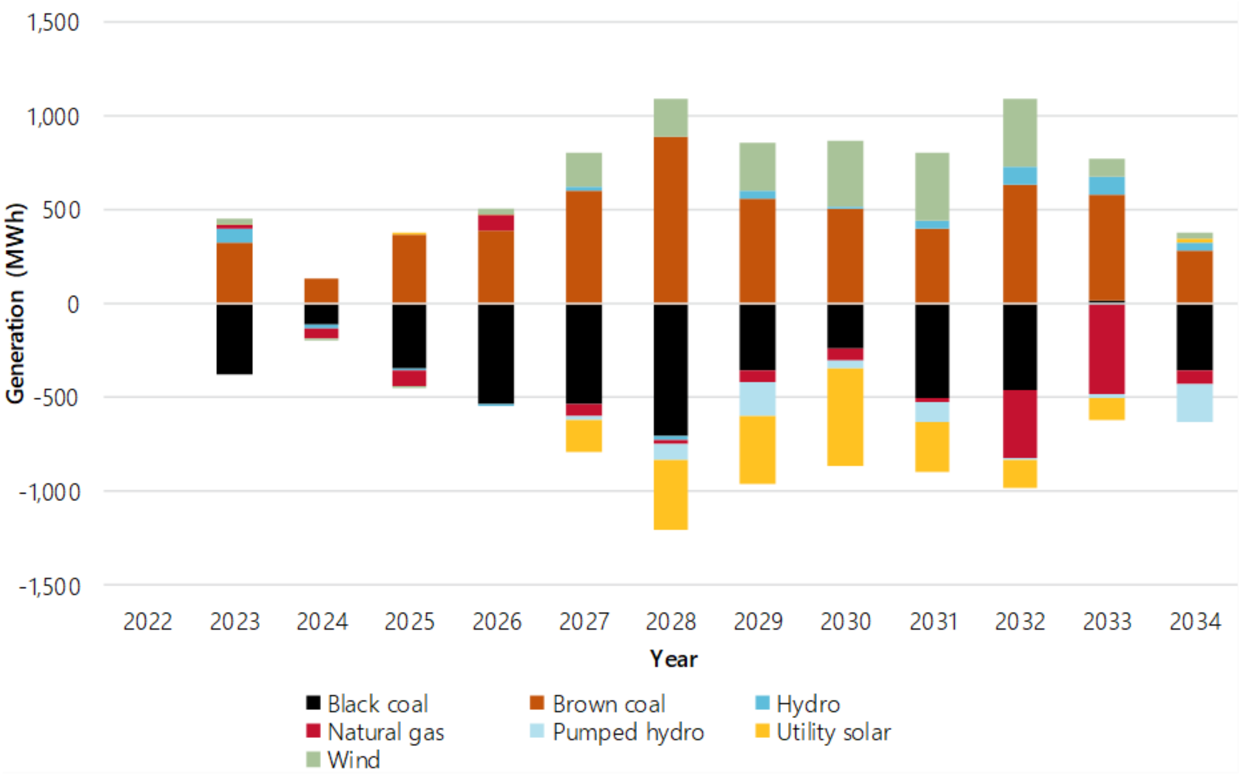
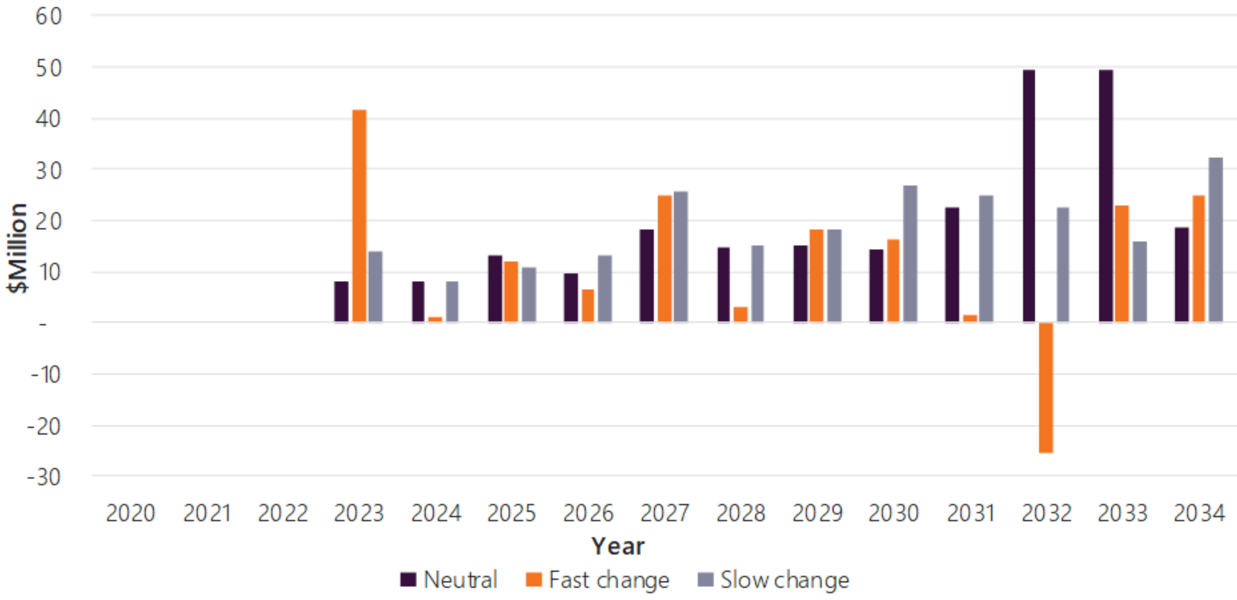


Figure 18 shows the generation cost savings for the proposed preferred option compared with the base case across all reasonable scenarios. The modelling shows that in the majority of years generation cost savings are positive, with the proposed preferred option enabling lower-priced generation to displace higher-priced generation.

The exception is in 2032 under the Fast change scenario, where more gas generation is dispatched due to there being less pumped hydro capacity installed with the preferred option in place. The large generation cost saving in 2023 under the Fast change scenario is due to fuel cost savings arising from the advancement of solar capacity, as shown in Figure 14.

Figure 18 Generator cost savings across all scenarios, proposed preferred option



A2.3 Load reduction cost savings

The time-sequential modelling described in Section 5.3.2 was carried out for the base case and each credible option identified in Section 3.2, for each reasonable scenario. Load reduction cost savings are derived from the voluntary load curtailment and involuntary load shedding costs in the base case, minus the voluntary load curtailment and involuntary load shedding for each credible option (credible option).

Voluntary load curtailment and involuntary load shedding levels and costs derived from the time-sequential modelling are provided in Attachment B: Market modelling results.

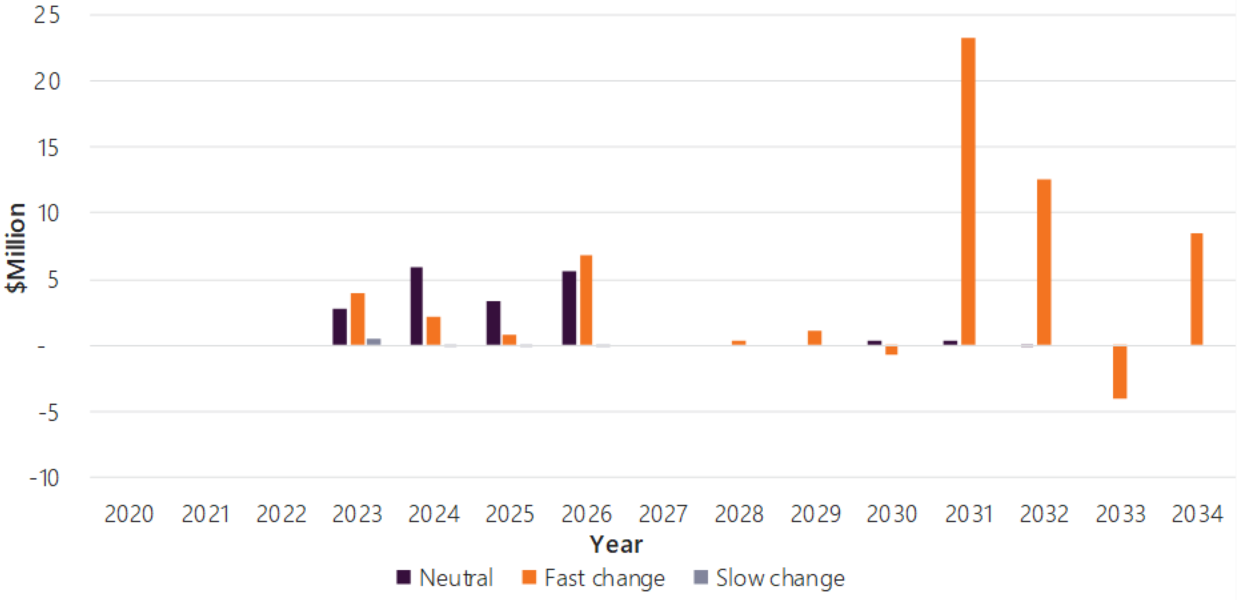
Figure 19 shows the load reduction cost savings for the proposed preferred option compared to the base case across all reasonable scenarios.

The proposed preferred option reduces voluntary load curtailment and involuntary load shedding in the Neutral and Fast change scenarios over the period from 2022 to 2026, up until the commissioning of Snowy 2.0. Reductions in voluntary load curtailment and involuntary load shedding are also identified in the later years in the Fast change scenario as demand growth increases.

These savings in voluntary load curtailment and involuntary load shedding are primarily a function of the ability of adjacent regions to share resources at times of non-coincident peak demand. The period after the Liddell Power Station retirement and before the commissioning of Snowy 2.0 presents additional opportunity for the proposed preferred option to mitigate the impact of these load reduction events by supplying generation from Victoria into New South Wales.

After the introduction of Snowy 2.0, New South Wales becomes more self-reliant during these periods of tightening supply-demand balance, ultimately reducing the opportunity for the proposed preferred option to demonstrate these benefits. However, from the 2030s as more generation in New South Wales and Queensland exit, savings are again identified under the Fast change scenario.

Figure 19 Load reduction cost savings across all scenarios, proposed preferred option



A3. Technical characteristics of proposed preferred option

A3.1 Variations

The 2018 ISP envisaged that investment in the following options were required to increase the transfer capability of the Victoria to New South Wales interconnector by approximately 170 MW:

- Second 500/330 kV South Morang transformer.
- 330 kV South Morang – Dederang line re-tensioning works and capacitor upgrade.
- Braking resistor to improve stability limitations.
- 330 kV Upper Tumut – Canberra line upgrade.

The proposed preferred option differs slightly from the proposal envisaged by the 2018 ISP. It does not include a braking resistor or any alternative options to increase stability limits, as discussed in Section 2.1.

A3.2 Indicative requirements for the proposed preferred option

The parameters of the proposed preferred option are subject to further detailed assessment and detailed design. The high-level functional requirements are:

- Install a second 1000 MVA 500/330 kV transformer in parallel to the existing F2 transformer at South Morang Terminal Station, connecting to the existing 500 kV and 330 kV switchyards.
- Carry out works to allow operation of the existing 330 kV South Morang – Dederang lines at 82^{0}C. This includes increasing conductor clearance at critical locations through re-tensioning or increasing tower height and uprating series compensation.
- Install modular power flow controllers on 330 kV Upper Tumut – Canberra line (likely at Stockdill 330 kV substation) and 330 kV Upper Tumut – Yass line (likely at Yass 330 kV substation) to increase the transfer capacity on Lower Tumut / Upper Tumut – Canberra / Yass cut-set by 170 MW to 220 MW. Bypass circuit will be installed in parallel with the modular power flow controllers.

Figure 20 below presents the high-level indicative project timeline, including construction and commissioning timeframes. The actual project timetable will depend on the approval and procurement process of each TNSP, but for these purposes is assumed to be consistent with enabling the proposed commissioning date to be achieved within optimal lead times. The timeframes presented in Figure 20 will be refined and updated during the PACR stage.

Figure 20 Indicative project timeline for the proposed preferred option