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Increasing capacity for generation in the Molong and Parkes area

RIT-T Project Assessment Draft Report

Region: Central West NSW

Date of issue: 16 June 2023

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for improving capacity for renewable generation in the Molong and Parkes area. Publication of this Project Assessment Draft Report (PADR) represents the second step in the RIT-T process following the Project Specification Consultation Report (PSCR) we published on 29 July 2022.

The Molong and Parkes area has seen significant growth in renewable generation connections to the transmission network, as part of the wider energy market transition. New renewable generators have connected or are planning to connect to the network west of our Molong 132/66 kV substation. Nineteen solar and wind generation farms in the area with a combined output of 1,273 MW are already in service, with a further 1,148 MW of generation committed or in advanced stage.

Line 94T plays a central role in transmitting the electricity from these renewable generators in the Molong and Parkes area to the load in Orange. It connects Molong substation to Orange North switching station, which in turn supplies Orange city, Cadia Mine and surrounding areas.

The current rating of Line 94T is constraining renewable generation in the Molong and Parkes area. The Australian Energy Market Operator's (AEMO's) Monthly Constraint Reports since September 2021 have consistently identified Line 94T as a top 10 constraint on the National Electricity Market (NEM). AEMO's latest Annual NEM Constraint Report for 2022 identified the Line 94T constraint as the second highest binding impact network constraint.[1]

Network modelling shows thermal overloading of Line 94T is expected under normal system conditions with current levels of in-service and committed generation dispatched to their maximum capacities. Hence, we have identified the opportunity to strengthen the transmission network to relieve this constraint and realise net market benefits by avoiding curtailment of low-cost renewable generation in the Molong and Parkes area.

Benefits from improving capacity and relieving existing constraints in the Molong and Parkes area

The identified need for this RIT-T is to increase overall net market benefits in the NEM through improving capacity and relieving existing constraints on renewable generation in the Molong and Parkes area. This will enable greater output from renewable generation in this region of the NEM.

Within the context of the RIT-T assessment, greater output from renewable generation is expected to deliver market benefits primarily through reductions in total dispatch costs from:

- lower fuel costs, by enabling low-cost renewable generation to displace higher cost conventional generation elsewhere; and
- lower capital costs, by reducing (or deferring) the need for new investment in generation plants.

1 AEMO, *NEM Constraint Report 2022 summary data*, 24 May 2023.

We consider this a 'market benefits' driven RIT-T as opposed to a 'reliability corrective action' driven RIT-T. The additional wholesale market benefits associated with each credible option have been estimated using market modelling as part of this PADR.

The PADR analysis has benefited from stakeholder consultation

We published a PSCR on 29 July 2022 and invited written submissions on the material presented within the document. In the PSCR, we noted that non-network options may be able to assist with meeting the identified need.

Five submissions were received in response to the PSCR which can be grouped into three categories:

- existing renewable generators in central west NSW
- a conductor manufacturer, and
- a power flow controller manufacturer.

The submissions raised a number of alternative options that we have assessed in addition the options presented in the PSCR. We have also presented additional sensitivity analysis in response to the issues raised by stakeholders. These submissions have been summarised and responded to in this PADR.

We held bilateral meetings with each of the submitters in order for them to further understand the RIT-T assessment and the option requirements in the Molong and Parkes area, as well as how proposed solutions are expected to be able to assist with meeting the identified need. These discussions have played a key role in developing the PADR and we thank all parties for their time and effort to-date.

Key developments since the PSCR have been reflected in the PADR

There have been a number of key developments since the PSCR was released, which impact the analysis in this RIT-T. In particular we have included:

- an additional four options based on stakeholder submissions to the PSCR;
- Stage 1 of the preferred option from the Maintaining Reliable Supply to Bathurst, Orange and Parkes RIT-T in the assessment base case, to ensure benefits quantified in that RIT-T aren't double counted; and
- additional in-service, committed and advanced renewable generation in the Wellington, Molong and Parkes area based on AEMO's latest generation information.

The credible options have been refined since the PSCR

The credible options assessed involve relieving the existing constraint through different means. Three broad types of credible options have been assessed which involve:

- increasing the capacity of the existing Line 94T (Molong – Orange North) (Option 1, 2, 2A and 3)
- installing power flow controllers in combination with increasing the capacity of the existing Line 94T (Option 2B), and
- installing a Battery Energy Storage System (BESS) (Option 4).

Table E-1 below summarises each of the credible options assessed in the PADR.

Table E-1: Summary of the credible options

Option	Description	Estimated capex ($M, Real 2021-22)
1	Increase transmission line design temperature of Line 94T	1.4
2	Restring Line 94T with higher rated 'Flicker/ACSS' conductor on existing structures	7.5
2A	Restring Line 94T with higher rated 'Partridge/ACSS/HS285' conductor on existing structures	8.2
2B	Implementing Option 2 together with power flow controllers	26.0
3	Replacing Line 94T with a double circuit transmission line	38.5
4	Installation of a 50MW/300MWh BESS at Molong substation	185.7

Note: All estimated capex is an accuracy level of +/- 25%.

Uncertainty has been captured by way of three scenarios

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option. The credible options have been assessed under three scenarios as part of this PADR assessment, which reflect the scenarios from AEMO's 2022 ISP.

Table E-2 summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered.

Table E-2: Summary of scenarios

Variable	Step Change	Progressive change	Hydrogen Superpower
Capital costs	Base estimate	Base estimate	Base estimate
Demand	Central demand forecast (ISP POE10 and Orange North POE50, as outlined in section 2.2.2)	Central demand forecast (ISP POE10 and Orange North POE50, as outlined in section 2.2.2)	High demand forecast (ISP POE10 and Orange North POE10, as outlined in section 2.2.2)
Renewable generation in the area	All in-service, committed and advanced generators (as outlined in section 2.2.1)	All in-service, committed and advanced generators (as outlined in section 2.2.1)	All in-service, committed and advanced generators (as outlined in section 2.2.1)
Wholesale market benefits estimated	EY estimate based on the 'step change' 2022 ISP scenario	EY estimate based on the 'progressive change' 2022 ISP scenario	EY estimate based on the 'hydrogen superpower' 2022 ISP scenario
Discount rate	5.50%	5.50%	5.50%

The three scenarios have been weighted based on the ISP weightings:

- 52 per cent to the Step Change scenario
- 30 per cent to the Progressive Change scenario; and
- 18 per cent to the Hydrogen Superpower scenario.

Option 2 and 2A are the preferred options

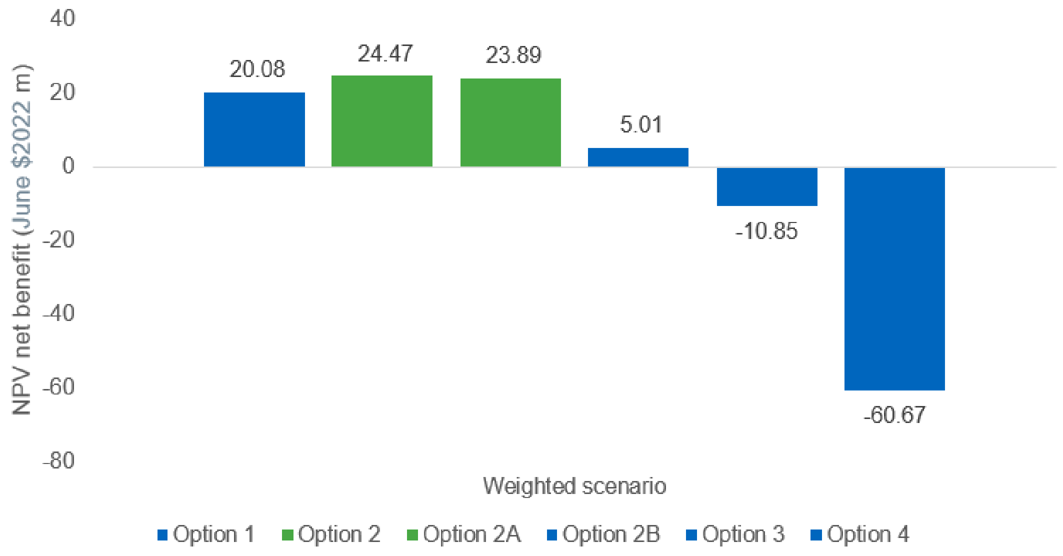
Options 2 and 2A produce the highest net benefits under each of the three ISP scenarios. While Option 2 produces the largest net benefit under each scenario, the net benefits produced by Option 2A are only marginally lower. Given the similarities between the builds of the two options (both require restringing Line 94T with higher rated conductors), as well as the similar gross market benefits produced by both options, we consider both options to be the preferred options.

While other options, such as Option 4, are able to generate additional gross market benefits compared to Option 2 and 2A, the build costs of these options are significantly higher and result in lower net benefits under all scenarios.

Table E-3: NPV of net economic benefits relative to the base case – Weighted scenario (June $2022 million)

Option	Weighted scenario
Option 1	20.1
Option 2	24.5
Option 2A	23.9
Option 2B	5.0
Option 3	-10.9
Option 4	-60.7

Figure E-1 NPV of net economic benefits relative to the base case (Weighted scenario)



For the next stage of the RIT-T process, we intend to undertake more detailed analysis on which of Option 2 or 2A are likely to deliver greater cost efficiencies and, therefore, which will be the preferred option.

Next steps

We welcome written submissions on this PADR. Submissions are due on 2 August 2023. Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[2] In the subject field, please reference 'Increasing capacity for generation in the Molong and Parkes area PADR'.

At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the publication of a PACR. The PACR is expected to be published in December 2023.

[2] Transgrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

Contents

1. Introduction

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for improving capacity for renewable generation in the Molong and Parkes area. Publication of this Project Assessment Draft Report (PADR) represents the second step in the RIT-T process following the Project Specification Consultation Report (PSCR) we published on 29 July 2022.

The Molong and Parkes area has seen significant growth in renewable generation connections to the transmission network, as part of the wider energy market transition. New renewable generators have connected or are planning to connect to the network west of our Molong 132/66 kV substation. Nineteen solar and wind generation farms in the area with a combined output of 1,273 MW are already in service, with a further 1,148 MW of generation committed or in an advanced stage.

Line 94T plays a central role in transmitting electricity from renewable generators in the Molong and Parkes area to the load in and around Orange. It is a 132 kV line that connects Molong substation to Orange North switching station, which in turn supplies Orange city, Cadia Mine and surrounding areas.

The current rating of Line 94T is constraining renewable generation in the Molong and Parkes area. The Australian Energy Market Operator's (AEMO's) Monthly Constraint Reports since September 2021 have consistently identified Line 94T as a top 10 constraint on the National Electricity Market (NEM). AEMO's latest Annual NEM Constraint Report for 2022 identified the Line 94T constraint as the second highest binding impact network constraint[3]. Network modelling shows thermal overloading of Line 94T is expected under normal system conditions with current levels of in-service and committed generation dispatched to their maximum capacities.

We have identified the opportunity to realise net market benefits in the NEM by relieving this constraint and avoiding curtailment of low-cost renewable generation in the Molong and Parkes area. We consider this a 'market benefits' driven RIT-T and expect the preferred option to have positive net market benefits.

1.1. Purpose of this report

The purpose of this PADR is to:

- confirm the identified need for the investment, and describe the assumptions underlying this need, including any changes to these assumptions since the PSCR;
- summarise the consultation undertaken since the PSCR and highlight how it has been reflected in the RIT-T analysis;
- describe the options being assessed under this RIT-T, including how these have been shaped as part of the PSCR consultation and the additional options proposed in submissions.
- identify and confirm the market benefits expected from the various credible options;
- summarise our approach to modelling the net market benefits for each credible option assessed, and present the results of this analysis;
- describe the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
- identify the preferred option at this stage of the RIT-T, i.e., the option that is expected to maximise net market benefits.

3 AEMO, *NEM Constraint Report 2022 summary data*, 24 May 2023.

Overall, this report provides transparency into the planning considerations for investment options to relieve generation constraints in the central west NSW power system, and the associated market benefits. A key purpose of this PADR, and the RIT-T more broadly, is to provide interested stakeholders the opportunity to review the analysis and assumptions, provide input to the process, and have certainty and confidence that the preferred option has been robustly identified as optimal.

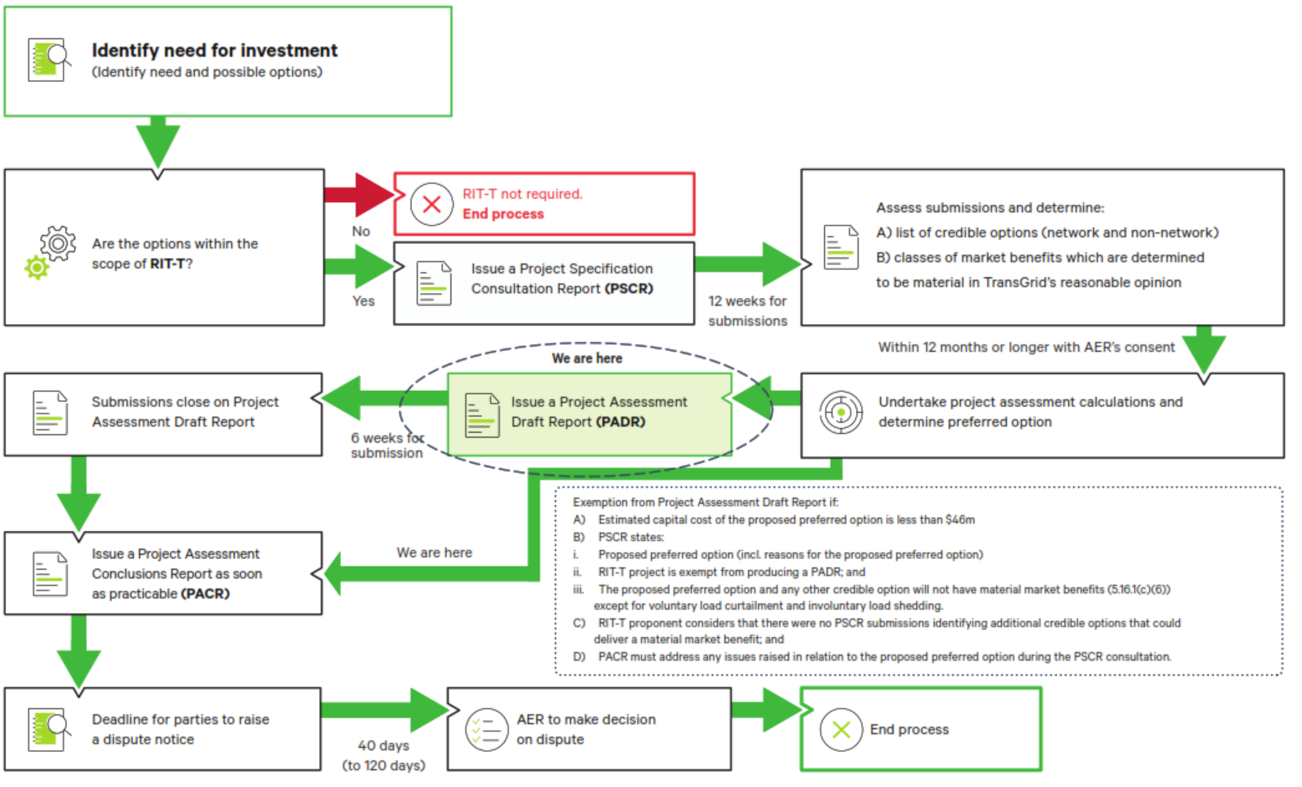
1.2. Next steps

We welcome written submissions on this PADR. Submissions are due on 2 August 2023 2023. Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au.[4] In the subject field, please reference ‘Increasing capacity for generation in the Molong and Parkes area’.

At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the publication of a PACR. The PACR is expected to be published in December 2023.

Figure 1-1 This PADR is the second stage of the RIT-T process



[4] Transgrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

2. Benefits from increasing capacity in the Molong and Parkes area

This section discusses the 'identified need' for this RIT-T, before outlining the key developments that have occurred since the PSCR was released in July 2022.

2.1. Summary of the identified need

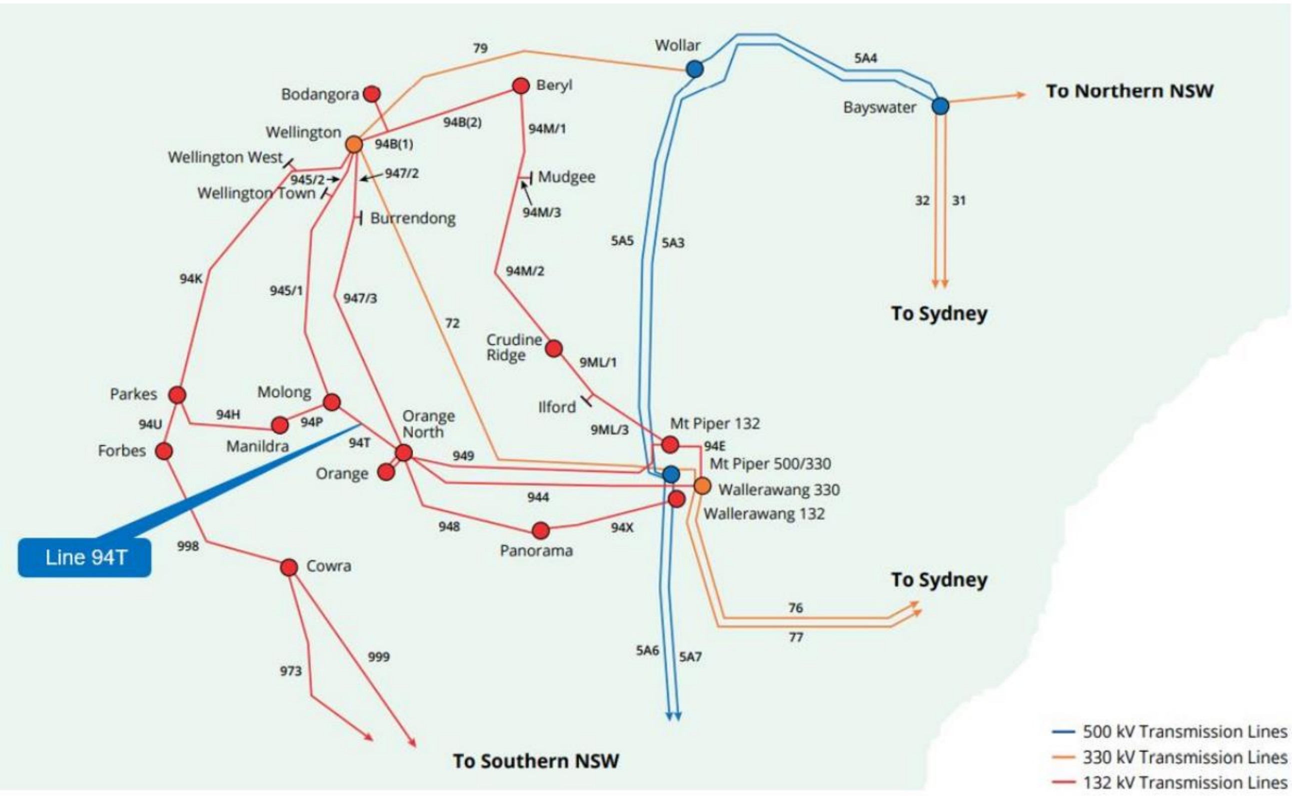
The identified need for this RIT-T is to increase consumer and producer surplus in the NEM through relieving network constraints on the supply of renewable generation from the Molong and Parkes area. This will enable a greater amount of renewable generation produced in the Molong and Parkes area to be supplied to customers in the NEM.

Within the context of the RIT-T assessment, greater supply of renewable generation is expected to deliver market benefits primarily through reductions in total dispatch costs from:

- lower fuel costs, by enabling lower cost renewable generation to displace higher cost conventional generation elsewhere in the NEM; and
- lower capital costs, by reducing (or deferring) the need for new investment in generation plants to meet growing electricity demand in the future.

Line 94T is a 132 kV transmission line which connects our Molong 132/66 kV substation to our Orange North 132 kV switching station. It plays a central role in transmitting electricity from renewable generators in the Molong and Parkes area to load in and around Orange.

Figure 2-1 Location of Line 94T on our Central West transmission network



However, the combination of increasing demand in the Orange area and increasing renewable generation west of Molong substation is giving rise to binding constraints on the line. The constraint is caused by the existing 112 MVA (summer daytime) thermal capacity limit of Line 94T being reached during times of high renewable generation output. In these situations, thermal overloading of the 132 kV Line 94T can occur which constrains the amount of renewable generation that can be supplied from the Molong and Parkes area to load in the Orange area. Expected increases in renewable generation capacity in the Molong and Parkes area, and expected growth in demand in the Orange area, will result in the network constraint binding more often and to a greater extent.

This resulted in AEMO introducing operational constraints in the NEM Dispatch Engine (NEMDE) to limit power flows in order to manage the risk of thermal overload on Line 94T. AEMO's Monthly Constraint reports since September 2021 have consistently identified Line 94T as a top 10 constraint on the National Electricity Market (NEM), and AEMO's latest Annual NEM Constraint Report for 2022 identified the Line 94T constraint as the second highest binding impact network.[5]

If the constraint caused by the existing 112 MVA (summer daytime) thermal capacity limit of Line 94T is not addressed by a technically and commercially feasible credible option, the output curtailment of low-cost renewable generation in the Molong and Parkes area will increase. This curtailment will mean that a substantial quantity of low-cost renewable energy will not be available to displace higher-cost alternative energy generation within the NEM. It may also require additional generation capacity to be installed to meet demand growth in the Orange area, imposing additional costs on users.

2.2. Developments since the PSCR

2.2.1. Renewable generation forecasts

Since publication of the PSCR, we have included additional renewable generation that is either in service, committed or anticipated in the Molong and Parkes area. The renewable generation projects are taken from AEMO's NEM Generation Information as of January 2023. The additional renewable generation includes the:

- 280 MW Wollar solar farm;
- 145 MW Flyers Creek wind farm;
- 138 MW Crudine Ridge wind farm; and
- 210 MW Orana BESS.[6]

In total, our market modelling assumes that renewable generation with a combined output of 1,273 MW is in-service in the region, and a further 1,148 MW of renewable generation is planned. A summary of these projects is provided in Table 2-1.

5 AEMO, *NEM Constraint Report 2022 summary data*, 24 May 2023

6 210MW/800MWh Orana BESS is based on AEMO's May 2022 Generation Information. Orana BESS has been updated to 407/1MW/1600MWh in AEMO's January 2023 Generator Information however was not captured in the change log and therefore not reflected in EY's market modelling. The increase in Orana BESS is not expected to be material to the PADR outcome and will be investigated further in the PACR.

Table 2-1: Current and planned renewable generation in the Molong/Parkes/Wellington area

Generating System	Connection location	Capacity (MW)	Status
Bango wind farm	Line 973	155 MW	In service
Beryl solar farm	Beryl substation	89 MW	In service
Bodangora wind farm	Line 94B	113 MW	In service
Crudine wind farm	Between Mudgee and Ilford	138 MW	In service
Jemalong solar farm	West Jemalong substation	50 MW	In service
Manildra solar farm	Manildra substation	50 MW	In service
Molong solar farm	Molong substation	30 MW	In service
Parkes solar farm	Parkes substation	51 MW	In service
Goonumbla solar farm	Parkes substation	70 MW	In service
Nyngan solar farm	Nyngan SF substation	102 MW	In service
Nevertire solar farm	Line 94W	105 MW	In service
Wellington solar farm	Wellington substation	170 MW	In service
Suntop solar farm	Line 94K	150 MW	In service
Bango wind farm	Line 973 and Line 999	83 MW	Committed
Wollar solar farm	Line 75	280 MW	Committed
Flyers Creek wind farm	Essential Energy Line 9MC	145 MW	Advanced
Quorn Park solar farm	Line 300	80 MW	Advanced
Orana BESS	Wellington substation	210 MW[7]	Advanced
Aspley BESS	Line 945	160 MW	Advanced

In addition to the named generation above, our market modelling undertaken for this RIT-T has indicated that additional renewable capacity will be built in the Central West Orana Renewable Energy Zone (CWO REZ). This varies with the ISP scenario being modelled and is summarised in Table 2-2.

Table 2-2: Additional renewable generation built by the modelling associated with this RIT-T

ISP scenario	Additional capacity built in the CWO REZ
Step Change	5.6 GW of wind and 5.3 GW of solar
Progressive Change	5.4 GW of wind and 4.5 GW of solar
Hydrogen Superpower	4.8 GW of wind and 4.8 GW of solar

[7] Ibid.

2.2.2. Demand and spot load forecasts

Demand forecast data used in the model is based on AEMO's ISP 2022 forecast data. We use AEMO peak demand forecast for POE10 for each of the three ISP scenarios based on ISP methodology.

We have applied the load forecasts from our 2022 Transmission Annual Planning Report (TAPR) for Orange North 132kV to capture the spot load forecasts in the Orange area.[8] We use POE10 forecasts for the Hydrogen Superpower scenario and POE50 forecasts for the Step Change and Progressive Change scenarios.

2.2.3. Interaction with the Bathurst, Orange and Parkes RIT-T

We recently published our Amended PACR for our 'Maintaining reliable supply to the Bathurst, Orange and Parkes areas RIT-T' (BOP RIT-T).[9] The BOP RIT-T examined options for addressing voltage constraints associated with forecast load growth in the Orange and Parkes areas, as well as the expansion of existing large mine loads in the area, the planned connection of new mine / industrial loads and general load growth around Parkes, including from the NSW government's Parkes Special Activation Precinct.

The PACR identified two preferred non-network solutions for Stage 1 that involve the use of non-network Battery Energy Storage Systems (BESS) in the short term coupled with network investment as demand grows. These were referred to as Option 7D and Option 7E – both options ranked closely in terms of their estimate of net economic benefits. We are entering into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract.

We have considered the interaction between the BOP RIT-T and the options considered in this PADR and in particular whether the preferred option from the BOP RIT-T should be captured in the market modelling being conducted for this RIT-T.

The RIT-T defines a 'committed project' as a project that meets the following criteria:

- the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement;
- construction has either commenced or a firm commencement date has been set;
- the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction;
- contracts for supply and construction of the major components of the necessary plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments; and
- the necessary financing arrangements, including any debt plans, have been finalised and contracts executed.

The RIT-T defines an 'anticipated project' as a project which does not meet all of the criteria of a committed project as defined above and is in the process of meeting at least three of the criteria for a committed project.

The preferred solutions in the BOP RIT-T do not meet the definition of either a committed project or an anticipated project. We note however that the RIT-T requires a proponent to develop 'reasonable'

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8 Transgrid, *Transmission Annual Planning Report 2022*, August 2022

9 Transgrid, Maintaining reliable supply to Bathurst, Orange and Parkes areas - Amended Project Assessment Conclusions Report, January 2023

scenarios, and to consider states of the world that reflect 'reasonable' and mutually consistent demand and supply characteristics. In our view, given that the BOP RIT-T is reliability corrective action, a 'do nothing' approach (i.e., to not include any solution from the BOP RIT-T) would not be reasonable as it would result in Transgrid breaching its obligations under the NER – an outcome which will not eventuate. The inclusion of the preferred option is also likely to remove the possibility of double counting benefits in this RIT-T that would likely be met by the BOP RIT-T solution.

On this basis, we think it reasonable to include one of Option 7D or Option 7E in the base case for this PADR. This is because these two options were assessed as having higher net benefits than any of the other options considered, and were identified as preferred options in the BOP RIT-T. The choice of which specific option to include in the base case is not directly addressed by the RIT-T or the RIT-T Guideline.

However, in our view, guidance may be taken from the principles of best practice cost-benefit analysis. Specifically, we think it is reasonable to include in the base case the option that would result in a more conservative estimate of the net benefit for this RIT-T, where conservative is defined as the option that is likely to reduce the net benefit under this RIT-T the most (as compared to other options). We have therefore included Option 7D from the BOP RIT-T in the core scenarios due its marginally higher net benefit under the weighted scenario. Option 7D involves developing BESSs at Parkes and Panorama along with the installation of static synchronous compensators. We have also modelled a sensitivity that includes no Option from the BOP RIT-T in the base case, which demonstrates that the removal of Option 7D does not have an impact on the outcomes of this RIT-T - refer to Section 7.5.3.

The BOP RIT-T also considered a Stage 2, which involves construction of a new Wellington to Parkes 132 kV line, with the date for developing this line depending on outturn demand forecasts. This has been accepted by the AER as a contingent project as part of our 2023-28 Regulatory Determination. Given there is a level of uncertainty associated with whether Stage 2 will be progressed, it has not been included in the analysis. However, we have modelled a sensitivity that includes developing the new Wellington to Parkes line in 2030/31 – refer to Section 7.5.4.

3. Consultation on the PSCR

The PSCR was released in July 2022. We received submissions from five parties to the PSCR. Submissions from AMP Power Australia and Smart Wires have been published on our website.[10] The remaining three submitters requested confidentiality and so the details of these submissions have not been included in this PADR or published on our website.

We have outlined the key themes of these submissions below.

Stakeholders agreed with the identified need but consider the proposed network options in the PSCR may not relieve generation constraints in the area

In response to feedback suggesting that the proposed solutions in the PSCR may not relieve generation constraints in the area, we have re-examined the additional renewable generation that is expected to be commissioned in the area and have included additional generation in our modelling – refer to Section 2.2.1.

We have also modelled a sensitivity that includes an additional three generators that do not currently meet the requirements for inclusion in the base case to demonstrate the impact of including additional renewable generation – refer to Section 7.5.6.

Stakeholders provided a number of alternative solutions to meet the identified need

Based on these proposed solutions we have modelled additional options that include:

- Restringing Line 94T with the proposed 'Partridge/ACSS/HS285' conductor on existing structures
- Restringing Line 94T as per Option 2 in our PSCR and installing power flow controllers
- Rebuilding Line 94T as a double circuit transmission line
- Building a battery energy storage system (BESS) to deliver thermal overload contingency

We have assessed these options alongside the credible options identified in the PSCR – refer to Section 4.

Stakeholders consider the biggest market benefit to be the increase in low cost renewable generation entering the NEM

We have included benefits associated with an increase in renewable generation entering the NEM in our market modelling. This will ensure that the gross market benefits associated with the additional renewable generation will be captured in the cost benefit analysis.

We held bilateral meetings with each submitter in order for them to further understand the RIT-T assessment and the option requirements in Central West NSW, as well as how proposed solutions are expected to be able to assist with meeting the identified need. These discussions have played a key role in being able to define and include the four additional credible options assessed in this PADR and we thank all parties for their time and effort to-date.

The key matters raised in submissions relevant to the RIT-T assessment, as well as our responses and how the matters raised have been reflected in the PADR assessment are summarised in Appendix B.

[10] Refer to: https://www.transgrid.com.au/about-us/regulatory-framework/regulatory-investment-test-for-transmission-rit-t

4. Credible options assessed

We considered credible options in this RIT-T assessment as those that would meet the identified need from a technical, commercial, and project delivery perspective.[11] This includes the two options originally proposed in the PSCR, and four new credible options provided by stakeholders in response to the PSCR.

Table 4-1 summarises each of the credible options we considered to address the identified need.

Table 4-1: Summary of the credible options

Option	Description	Estimated capex ($M, Real $2021-22)	Expected commissioning year
1	Increase transmission line design temperature of Line 94T	1.41	2024/25
2	Restring Line 94T with higher rated 'Flicker/ACSS' conductor on existing structures	7.50	2025/26
2A	Restring Line 94T with higher rated 'Partridge/ACSS/HS285' conductor on existing structures	8.16	2025/26
2B	Implementing Option 2 together with power flow controllers	25.97	2025/26
3	Replacing Line 94T with a double circuit transmission line	38.54	2026/27
4	Installation of a 50MW/300MWh BESS at Molong substation	185.69	2025/26

Note: All estimated capex is an accuracy level of +/- 25%.

The remainder of this section provides further detail on each of these credible options.

4.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken will compare the costs and benefits of each option to a base case. The base case is the projected case where no action is taken to address the identified need as per section 3.3 of the RIT-T Application Guidelines, which is extracted below[12].

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

Under the base case, no investments are made to meet the identified need to improve capacity for renewable generation in the Molong and Parkes area. However, we have included the preferred option

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

[12] As per the RIT-T Application Guidelines, the base case provides a clear reference point for comparing the performance of different credible options. Australian Energy Regulator, *Application guidelines Regulatory Investment Test for Transmission - August 2020,* August 2020

(Option 7D) from the BOP RIT-T in the base case. Details regarding this option as well as the explanation for its inclusion are provided in section 2.2.3.

This will result in curtailment of renewable generation to avoid thermal overloading of Line 94T. The forecasted curtailment on the NEM will increase from approximately 130,000 MWh per annum in 2022 to 142,000 MWh per annum by 2030. As a result of the curtailment, reliance on existing higher cost generation and investment in new generation in other parts of the NEM will be required to meet expected load forecasts.

The assessment uses this base case as a common point of reference when estimating the net benefits of each credible option.

4.2. Option 1 – Increase transmission line design temperature of Line 94T

Option 1 involves increasing Line 94T's summer daytime thermal rating from 112 MVA to 125 MVA by increasing the maximum design temperature of the existing Wolf conductor from 85°C to 100°C and Neon conductor from 85°C to 92°C.

This is achieved by:

- replacing one structure; and
- converting insulator arrangements of 18 structures.

While this option will increase the thermal rating of Line 94T, it will not completely relieve renewable generation curtailment in the Molong and Parkes area.

The estimated capital cost of this option is approximately $1.41m (June $2022) +/-25 per cent. Table 4-2 shows the expected expenditure profile of this option. This option is expected to take 21 months to deliver, with commissioning possible in 2024/25.

Table 4-2 Option 1 Capital Cost (June $2022 million)

Item	Capital expenditure (June $2022 million)
FY24	0.24
FY25	1.16
Total capital cost	**1.41 (+/- 25%)**

4.3. Option 2 – Restring Line 94T with higher rated 'Flicker/ACSS' conductor on existing structures

Option 2 involves increasing Line 94T's summer daytime thermal rating from 112 MVA to at least 150 MVA by restringing Line 94T with a higher capacity conductor (i.e., Flicker conductor).

This is achieved by:

- replacing the existing conductor between structures 1 and 95 with a new Flicker ACSS conductor (approximate circuit length of 27.04 kilometres);

- replacing the existing conductor between structure 96 and the gantry of Molong substation with a new Linnet ACSS conductor (approximately circuit length of 1.85 kilometres);
- replacing 11 structures; and
- converting three suspension structures to tension structures.

The final configuration of Line 94T would be as follows:

Table 4-3 Configuration of Line 94T with Option 2

Structure Range	Three Phase Single Circuit Length (km)	Conductor	Maximum Operating Temperature (C)	Thermal Rating (MVA)
From Orange North Gantry to Str. 1 Back Span	0.127	Existing Oxygen AAAC/1120	85	169
From Str. 1 Ahead Span to Str. 95 Back Span	27.04	New Flicker ACSS/TW/HS285	80	150
From Str. 95 Back Span to Molong Gantry	1.85	New Linnet ACSS	90	150

The estimated capital cost for the option is approximately $7.50 million (June $2022) +/-25 per cent. Table 4-4 shows the expected expenditure profile of this option. This option is expected to take 28 months to deliver, with commissioning possible in 2025/26.

Table 4-4 Option 2 Capital Cost ($M, Real $2021-22)

Item	Capital expenditure ($M, Real $2021-22)
FY24	0.45
FY25	4.75
FY26	2.30
Total capital cost	**7.50 (+/- 25%)**

4.4. Option 2A – Restring Line 94T with higher rated ‘Partridge/ACSS/HS285’ conductor on existing structures

Option 2A involves increasing Line 94T’s summer daytime thermal rating from 112 MVA to at least 152 MVA by restringing Line 94T with a higher capacity conductor than Option 2 (i.e., a Partridge conductor).

This is achieved by:

- replacing the existing conductor between structure 1 and the gantry of Molong substation with a new Partridge ACSS conductor (approximate circuit length of 28.89 kilometres);
- replacing 11 structures; and
- converting three suspension structures to tension structures.

The final configuration of Line 94T would be as follows:

Table 4-5 Configuration of Line 94T with Option 2A

Structure Range	Three Phase Single Circuit Length (km)	Conductor	Maximum Operating Temperature (C)	Thermal Rating (MVA)
From Orange North Gantry to Str. 1 Back Span	0.127	Existing Oxygen AAAC/1120	85	169
From Str. 1 Ahead Span to Molong Gantry	28.89	New Partridge ACSS/HS285	250	152

The estimated capital cost for the option is approximately $8.16 million (June $2022) +/-25 per cent. Table 4-6 shows the expected expenditure profile of this option. This option is expected to take 28 months to deliver, with commissioning possible in 2025/26.

Table 4-6 Option 2A Capital Cost ($M, Real $2021-22)

Item	Capital expenditure ($M, Real $2021-22)
FY24	0.50
FY25	5.17
FY26	2.49
Total capital cost	**8.16 (+/- 25%)**

4.5. Option 2B – Option 2 with Power Flow Controllers

Option 2B involves implementing Option 2 (i.e., increasing Line 94T summer daytime thermal rating from 112 MVA to at least 150 MVA by restringing Line 94T with a higher capacity conductor) as well as installing power flow controllers. Specifically, this option involves installing one unit of SmartValve SV10-1800 model at Molong substation, which can increase or decrease the reactance of Line 94T. This has the effect of diverting power away or drawing more power towards a circuit on which this capability is available. Diverting power away from Line 94T during peak solar generation periods would help in avoiding circuit overloads. For the purpose of market modelling, the power flow controller is assumed to increase the reactance of Line 94T by approximately 0.05 per unit throughout the modelling period.

This is achieved by:

- replacing the existing conductor between structures 1 and 95 with a new Flicker ACSS conductor (approximate circuit length of 27.04 kilometres);
- replacing the existing conductor between structure 96 and the gantry of Molong substation with a new Linnet ACSS conductor (approximately circuit length of 1.85 kilometres);
- replacing 11 structures;
- converting three suspension structures to tension structures; and
- installing one unit of SmartValve SV10-1800 model at Molong substation.

The final configuration of Line 94T would be similar to Option 2, as set out in Table 4-3.

The estimated capital cost for the option is approximately $25.97 million (June $2022) +/-25 per cent. Table 4-7 shows the expected expenditure profile of this option. This option is expected to take 28 months to deliver, with commissioning possible in 2025/26.

Table 4-7 Option 2B Capital Cost ($M, Real $2021-22)

Item	Capital expenditure ($M, Real $2021-22)
FY24	1.58
FY25	16.45
FY26	7.94
Total capital cost	**25.97 (+/- 25%)**

4.6. Option 3 – Double circuit transmission line

Option 3 involves removing the existing structures and conductors of Line 94T and replacing them with new dual circuit towers and dual conductors with higher ratings.

This is achieved by:

- removal of the 106 pole structures along the entire length of Line 94T;
- construction of 59 double circuit suspension structures;
- converting three suspension structures to tension structures; and
- stringing of dual circuit towers with higher rated conductors (principally Flicker conductors)

The estimated capital cost for the option is approximately $38.54 million (June $2022) +/-25 per cent. Table 4-8 shows the expected expenditure profile of this option. This option is expected to take 30 months to deliver, with commissioning possible in 2026/27.

Table 4-8 Option 3 Capital Cost ($M, Real $2021-22)

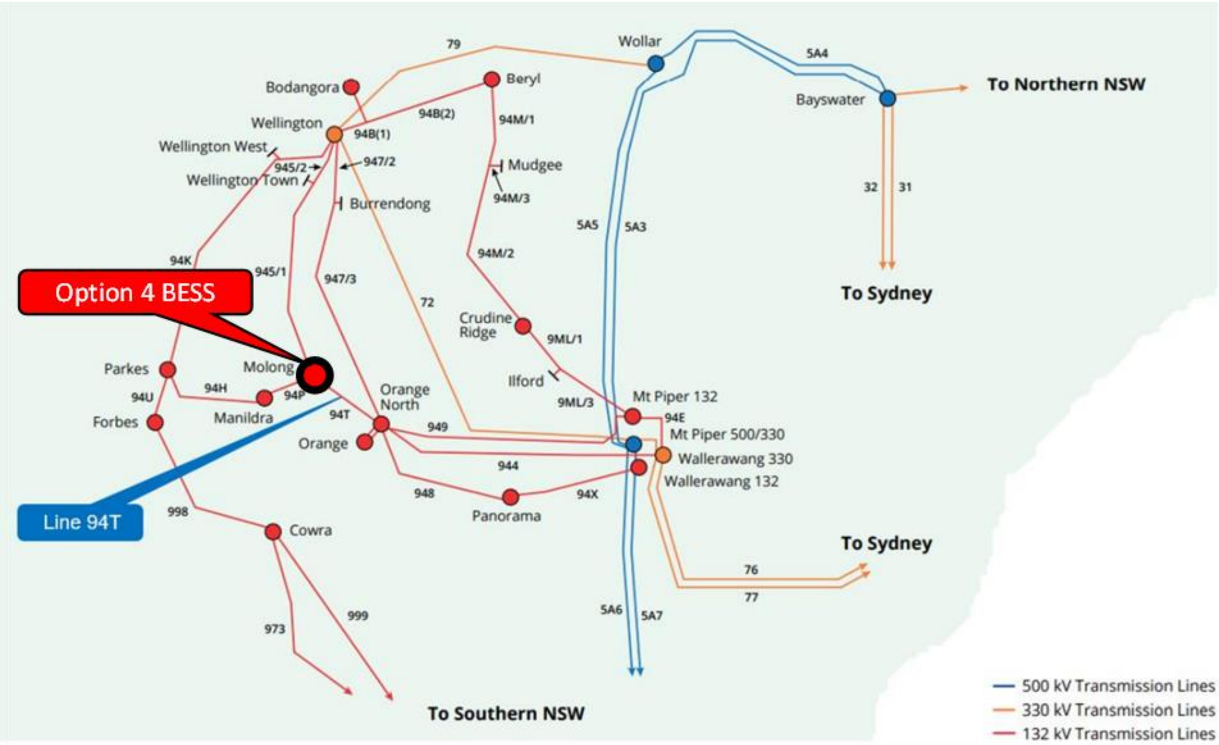
Item	Capital expenditure ($M, Real $2021-22)
FY24	1.98
FY25	23.98
FY26	12.58
Total capital cost	**38.54 (+/- 25%)**

4.7. Option 4 – Install a 50MW/300MWh BESS

Option 4 involves installing a 50MW/300MWh BESS at Molong substation. Based on our load low studies, we have determined that a 50MW battery with 6 hour duration (i.e. the time when solar generation is highest) is required to address the constraint on Line 94T. This is achieved by:

- Installation of a 50MW/300 MWh BESS at Molong substation;
- Construction of a new 132kV switchbay; and
- Laying of approximately 110m underground 132kV cable.

Figure 4-1 Location of BESS under Option 4



The estimated capital cost for the option is approximately $185.69 million (June $2022) +/-25 per cent. Table 4-9 shows the expected expenditure profile of this option. We have estimated possible commissioning of this Option in 2025/26, however detailed timing and cost analysis of this option has not been undertaken at this stage of the RIT-T process as the costs are significantly more than other options. However, we do not anticipate that the relative timing of this option is material to the outcome.

Table 4-9 Option 4 Capital Cost ($M, Real $2021-22)

Item	Capital expenditure ($M, Real $2021-22)
FY24	18.76
FY25	98.47
FY26	68.46
Total capital cost	**185.69 (+/- 25%)**

4.8. Options considered but not progressed

We have also considered whether other options could meet the identified need. These options have not changed since the publication of the PSCR. The reasons these options were not progressed are summarised in Table 4-10.

Table 4-10: Options considered but not progressed

Option	Reason(s) for not progressing
Increase Line 94T conductor rating to 138MVA for contingency events only	This option increases the contingency rating for Line 94T to 138 MVA. How ever, it does not increase the continuous rating of Line 94T. Network modelling show s thermal overloading of Line 94T is expected under normal system conditions. Hence, achieving a higher rating for contingency situations only, which enables overloading for approximately 30 minutes, will not address the identified need and therefore is not technically feasible.
Rebuild Line 94T as a higher rated single circuit transmission line	This option involves removing the existing structures and conductors of Line 94T and replacing it with new single circuit towers and conductors with higher ratings. This option would be considerably more expensive than the similar other network options and is not expected to deliver significantly higher benefits. This option will also need significant outage of existing Line 94T which will lead to more generation curtailment during the construction period. Therefore, this option is considered not commercially feasible under the RIT-T.
New transmission line parallel to existing Line 94T	This option involves building a new single circuit transmission line parallel to the existing Line 94T is similar to Option 3 and may require widening of the existing Line 94T easement. This option would be considerably more expensive than the other similar network options and is not expected to deliver significantly higher benefits. Therefore, this option is considered not commercially feasible under the RIT-T.
Implement Stage 2 of the Maintaining Reliable Supply to Bathurst, Orange and Parkes area project	This option would bring forward the timing for Stage 2 of this project. The preferred option for Stage 2 in the Maintaining Reliable Supply to Bathurst, Orange, and Parkes area RIT-T PACR is establishing a Wellington to Parkes 132 kV transmission line. Establishing this transmission line will not address the identified need in this RIT-T as it will not relieve the constraints on Line 94T and is therefore considered not technically feasible under this RIT- T. Alternate Stage 2 options, such as establishing a 330/132 kV supply point at Orange will cost substantially more than other network options considered. The timing of Stage 2 is also uncertain, and it will take significantly longer to implement. Therefore, this option is considered not commercially feasible under this RIT-T.

4.9. No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact[13]. A 'material inter-network impact' is defined in the NER as:

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

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

AEMO's suggested screening test to indicate that a transmission augmentation has no material inter-network impact is that it satisfies the following[14]:

- a decrease in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW
- an increase in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW
- an increase in fault level by less than 10 MVA at any substation in another TNSP's network; and
- the investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

We consider that each credible option satisfies these conditions. By reference to AEMO's screening criteria, there is no material inter-network impacts associated with any of the credible options considered.

[14] Inter-Regional Planning Committee. "*Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentations*." Melbourne: Australian Energy Market Operator, 2004. Appendix 2 and 3. Accessed 23 June 2021. https://aemo.com.au/-/media/files/electricity/nem/network_connections/transmission-and-distribution/170-0035-pdf.pdf

5. Ensuring the robustness of the analysis

This section outlines the approach that we have undertaken to assess the net benefits associated with each of the credible options against the base case.

The investments considered as part of this RIT-T involve long-lived assets, and it is important that the recommended preferred option does not depend on a narrow view of future outcomes, given that the future is inherently uncertain. Uncertainty is captured under the RIT-T framework through the use of reasonable scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered. The adoption of different scenarios tests the robustness of the RIT-T assessment to different assumptions about how the energy sector may develop in the future.

The robustness of the outcome is also investigated through two other means. First, we have undertaken sensitivity analysis to determine how the net benefits change in relation to changes in key input assumptions. Second, we have identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change.

5.1. The assessment considers three 'reasonable scenarios'

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit.[31] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The RIT-T must include any of the ISP scenarios from the most recent IASR that are relevant unless:[15]

- the RIT–T proponent demonstrates why it is necessary to vary, omit or add a reasonable scenario to what was in the most recent IASR, and
- the new or varied reasonable scenarios are consistent with the requirements for reasonable scenarios set out in the RIT–T instrument.

AEMO's latest ISP (2022) includes four scenarios – the Slow Change scenario, Step Change scenario, Progressive Change scenario, and Hydrogen Superpower scenario.[16] AEMO has identified that the Slow Change scenario has a very low probability of occurring (approximately 4%). We have excluded this scenario as it does not have a reasonable likelihood of arising. For the purposes of this RIT-T, we have modelled outcomes under the remaining three scenarios from AEMO's latest ISP, i.e., the Step Change scenario, Progressive Change scenario, and the Hydrogen Superpower scenario.

[15] AER, *Regulatory investment test for transmission*, August 2020, clause 20(b).
[16] AEMO, 2022 Integrated System Plan, June 2022, p.30-31.

The scenarios also vary by local spot load forecast , which are not parameters included in the ISP but which can be expected to have a material impact on the options considered in this RIT-T (see Section 2.2.2)

The table below summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered.

Table 5-1 Summary of the scenarios

Variable	Step Change	Progressive change	Hydrogen Superpower
Capital costs	Base estimate	Base estimate	Base estimate
Demand	Central demand forecast (ISP POE10 and Orange North POE50, as outlined in section 2.2.2)	Central demand forecast (ISP POE10 and Orange North POE50, as outlined in section 2.2.2)	High demand forecast (ISP POE10 and Orange North POE10, as outlined in section 2.2.2)
Renewable generation in the area	All in-service, committed and advanced generators (as outlined in section 2.2.1)	All in-service, committed and advanced generators (as outlined in section 2.2.1)	All in-service, committed and advanced generators (as outlined in section 2.2.1)
Wholesale market benefits	EY estimate based on the 'step change' 2022 ISP scenario	EY estimate based on the 'progressive change' 2022 ISP scenario	EY estimate based on the 'hydrogen superpower' 2022 ISP scenario
Discount rate	5.50%	5.50%	5.50%

5.2. Weighting the reasonable scenarios

We have weighted each of the scenarios for this RIT-T based on the 2022 ISP weightings for the underlying wholesale market scenarios. Specifically, we have given each scenario a weighting based on the proportion its weighting in the 2022 ISP makes up of the cumulative 96 per cent given to these three scenarios, i.e.:

- 52 per cent to the Step Change scenario;
- 30 per cent to the Progressive Change scenario; and
- 18 per cent to the Hydrogen Superpower scenario.

The results are calculated for each scenario, as well as on a weighted basis.

5.3. Sensitivity and threshold analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing.

The factors tested as part of the sensitivity analysis in this PADR are:

- higher and lower capital cost assumptions for the credible options;
- alternate commercial discount rate assumptions;
- excluding stage 1 of the preferred option from the BOP RIT-T

- including stage 2 of the preferred option from the BOP RIT-T
- higher load forecasts for the Orange area; and
- higher forecast renewable generation capacity in the Molong and Parkes area

The results of the sensitivity tests are discussed in section 7.5. The sensitivity testing also includes ‘boundary testing’, where relevant, to investigate what key variables would need to change by in order to change the identified preferred option.

6. Estimating the market benefits

6.1. Assessment against the base case

Consistent with the RIT-T requirements, the assessment undertaken in the PADR compares the costs and benefits of each option to a base case 'do nothing' option. The base case is the (hypothetical) projected case if no action is taken, i.e.,[17]

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

Under the base case, thermal limitations on Line 94T will continue to constrain the amount of renewable generation that can be supplied from the Molong and Parkes area to load in the Orange area. Expected increases in renewable generation capacity in the Molong and Parkes area, and expected growth in demand in the Orange area, will result in the network constraint binding more often and to a greater extent, which in turn will increase the volume of renewable generation curtailed. As a result of these constraints binding, residual load in the Orange area must be supplied from other parts of the NEM. This would increase reliance on existing conventional generation connected to other parts of our network, which would impose higher fuel costs on customers, and increase the need for additional generation capacity to be installed to meet demand growth in the Orange area.

The assessment uses this base case as a common point of reference when estimating the net benefits of each credible option.

6.2. Options uprating Line 94T would avoid future replacement costs

Under the base case, we expect to remediate low clearance conductors which pose a public safety risk on Line 94T in the next five to ten years at an estimated cost of $1.3 million ($Real 2020-21). Options 2, 2A, 2B and 3 are expected to avoid this future remediation cost (and so provide an economic benefit). While we recognise this will lead to a cost saving under the proposed options, given the relatively small value of remediating low clearance conductors when discounted back over a five-to-ten-year period, and the fact that this will apply to options 2, 2A, 2B and 3 equally meaning the relative rankings of the options will not be altered, we have not included this cost as part of the cost benefit analysis in the PADR. We may re-assess this for inclusion in the PACR.

6.3. Wholesale market benefits

As outlined in section 4, the options considered in this PADR involve either increasing the capacity of Line 94T or installing and operating a BESS to dispatch to the wholesale market. These options can offset more costly generation that would otherwise operate in the NEM, and therefore provide wholesale market benefits. These benefits are outlined in Table 6-1.

[17] AER, *Regulatory Investment Test for Transmission Application Guidelines*, August 2020, p. 21.

Table 6-1 Categories of wholesale market benefit under the RIT-T that have been modelled as part of this PADR

Market benefit	Overview
Changes in costs for parties, other than the RIT–T proponent, due to differences in the timing of new plant, capital costs, and operating and maintenance costs	This category of market benefit is expected where credible options result in different investment patterns of generators and large-scale storage across the NEM, compared to the base case. Removing thermal constraints on Line 94T will allow additional solar generation to be built. Solar generation has lower capital expenditure compared to thermal and wind generators, lowering the capital expenditure required to service the NEM.
Changes in fuel consumption arising through different patterns of generation dispatch	This category of market benefit is expected where credible options result in different patterns of generation and storage dispatch across the NEM, compared to the base case. Removing thermal constraints on Line 94T will allow additional solar generation to enter the NEM, replacing more expensive thermal and wind generation. This will bring down the overall cost of generation in the NEM.
Changes in the timing of unrelated expenditure	This category of market benefit is expected where credible options may delay the need for additional expenditure, such as planned transmission investment.
Changes in voluntary load curtailment	This category of market benefit is expected where credible options allow for additional generation to be dispatched due to the relieving of existing Line 94T constraints. Removing thermal constraints on Line 94T will allow additional solar generation to enter the NEM that may have otherwise been curtailed.
Changes in involuntary load shedding	As the identified need for this RIT-T is to increase overall net market benefits in the NEM by relieving existing Line 94T constraints on renewable generation in the Molong and Parkes area, it will have an immaterial impact on load, however small instances of load shedding may be avoided.

These wider benefits have been estimated by way of wholesale market modelling conducted by EY. As outlined in section 5.1, these benefits have been modelled under the 'step change' scenario, 'progressive change' scenario, and 'hydrogen superpower' scenario identified by AEMO in the 2022 ISP.

To simplify the wholesale market modelling, EY have not included the impact of outages on Line 94T during the construction period for each option. We do not believe that accounting for these outages will change the ranking of the options. The outages will affect generators around the Molong and Parkes area, but the impact of this on the wholesale market is expected to be limited considering the generation capacity available elsewhere in the region. Further, outages will be arranged at shoulder periods or during periods of high generation reserve to minimise the impact to the market wholesale price. Outages will also be arranged to avoid high market price period (i.e., during peak or high demand times).

An overview of the modelling conducted by EY is presented in Appendix C.

6.4. General modelling parameters adopted

The RIT-T analysis spans a 25-year assessment period from 2022/23 to 2047/28.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period and can be interpreted as a conservative estimate for benefits (net of operating costs) arising after the analysis period.

A real, pre-tax discount rate of 5.50 per cent has been adopted as the central assumption for the NPV analysis presented in this PADR, consistent with the assumptions adopted in the 2021 IASR. The RIT-T also requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 3.21%,[18] and an upper bound discount rate of 7.50 per cent (i.e., the upper bounds in the 2021 IASR[19]).

6.5. Classes of market benefit not considered material

In addition to the classes of market benefits listed above, NER clause 5.15A.2(b)(4) requires Transgrid to consider the following classes of market benefits, arising from each credible option. We consider that none of the classes of market benefits listed in Table 6-2 are material for this RIT-T assessment for the reasons provided.

Table 6-2 Reasons non-wholesale electricity market benefits are considered immaterial

Market benefits	Reason
Changes in network losses	There is not expected to be any material difference in transmission losses between options.
Changes in ancillary service costs	While the cost of Frequency Control Ancillary Services (FCAS) may change because of changed generation dispatch patterns and changed generation development following any increase to transfer capacity, we consider that changes in FCAS costs are not likely to be materially different between options and are not expected to be material in the selection of the preferred option. There is no expected change to the costs of Network Control Ancillary Services (NCAS), or System Restart Ancillary Services (SRAS) as a result of the options being considered. These costs are therefore not considered material to the outcome of the RIT-T assessment.
Competition benefit	Competition benefits under the RIT-T relate to net changes in market benefits, arising from the impact of the credible option on the bidding behaviour of market participants in the wholesale market. While each of the credible options considered is designed to address network constraint, we consider that competition benefits are unlikely to be material and do not intend to estimate them as part of this RIT-T. This is due to all options being expected to have a similar effect on the wholesale market through relieving the existing constraint of Line 94T in Central NSW. In addition, the calculation of competition benefits requires substantial additional market modelling. We consider that this modelling exercise would be disproportionate to any competition benefits that may be

[18] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: AER, *Transgrid 2023-28 – Final Decision – PTRM – April 2023.xlsx*), 'WACC' sheet, cell R23.
[19] AEMO, 2021 Inputs, Assumptions and Scenarios Report, July 2021, p. 105.

	identified for this specific RIT-T assessment, particularly the difference between options in terms of competition benefits
Option value	Option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change. We note that no credible option identified is sufficiently flexible to respond to change or uncertainty. Additionally, a significant modelling assessment would be required to estimate the option value benefit, but it would be disproportionate to potential additional benefits for this RIT-T. Therefore, we have not estimated any additional option value benefit.

6.6. Approach to estimating option costs

We have estimated the capital and operating costs of the options based on the scope of works necessary together with costing experience from previous projects of a similar nature.

The cost estimates are developed using our 'MTWO' cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (i.e., there is an equal likelihood of over- or under-spending the estimate total).

We estimate that the actual cost is within +/- 25 per cent of the central capital cost. An accuracy of +/-25 per cent is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the Association for the Advancement of Cost Engineering (AACE) classification system.

All cost estimates are prepared in real dollars based on the information and pricing history available at the time that they were estimated. The cost estimates do not include or forecast any real cost escalation for materials.

Routine operating and maintenance costs are based on works of similar nature.

7. Net present value results

This section outlines the assessment we have undertaken of the credible options. The assessment compares the costs and benefits of the options to the base case.

The accompanying market modelling report prepared by EY provides additional detail in terms of the modelled wholesale market impacts for each option modelled.

7.1. Step Change scenario

This scenario includes EY's market modelling of the wholesale market benefits for the options based on the 'Step Change' scenario from the 2022 ISP. It also assumes the Orange North demand forecasts (as outlined in section 2.2.2) and all in-service, committed and advanced renewable generators (as outlined in section 2.2.1). Under this scenario, both Options 2 and 2A are the highest ranked options and are expected to deliver very similar net market benefits (approximately $19 million in June $2022).

In comparison to Option 1, Options 2 and 2A are expected to provide higher gross benefits. Both options alleviate thermal constraints on Line 94T, allowing for an increase in the supply of solar generation in the Molong and Parkes area to the Orange area. This avoids the need to build and operate more expensive generators, such as wind or thermal generators, generating savings in capital costs and fixed operating costs. Option 1's lower thermal rating alleviates less thermal constraint on Line 94T compared to the top ranked options, producing lower gross benefits. The higher gross benefits of the top ranked options offset the relatively higher cost of these options compared to Option 1.

While Options 2B and 3 are expected to provide similar gross benefits to Options 2 and 2A, they are both more expensive to implement. Likewise, Option 4 is expected to yield the greatest gross benefits of all the options considered but will also involve significantly higher cost than any of the other options. Our analysis indicates that the higher costs of implementing Options 2B, 3 and 4 outweigh the market benefits that each option is expected to deliver and therefore impose net costs on the market.

7.1.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. The principal driver of market benefits is the extent to which each of the options allows for reduced network congestion and consequently less renewable energy spill. The gross benefits associated with Options 2, 2A, 2B and 3 are fairly similar, albeit higher for Options 2 and 2A. The reason for lower benefits of Option 2B and Option 3 is forecast to relate to their impact on the power flow of the network due to different Line 94T parameters in these options.

For Option 2B, it is forecast that with the power flow controller in place, power flow in the direction towards Molong reduces and is diverted to other nearby lines causing congestion in other parts of the nearby network. This is forecast to result in lower level of avoided renewable spill compared to Option 2, resulting in lower gross benefits in this option. Note that the power flow controller is assumed to increase the reactance of Line 94T throughout the modelling period. In reality, it could be controlled dynamically, however this assumption is not expected to have a material impact on the modelling outcomes.

Option 3 is forecast to result in a lower equivalent impedance in the Molong and Orange transmission lines, and in transmission corridors through this flow path towards the Sydney West. As a result the flow on the lines in this direction is forecast to increase relative to other options (although a significantly higher flow is still forecast on the higher voltage network). In particular, flow on the Wellington to Wellington Town line is forecast to increase, resulting in congestion on this line, which is mostly during the evening. This is forecast to become a limiting factor for wind generation in the central west NSW, resulting in the need to supply the demand using other more expensive generation which is expected to partly erode the benefits of this option.

Option 4 produces the highest gross benefit compared to the other Options. The use of a BESS allows for renewable generation to be stored and exported to the grid at times when it will provide the greatest benefit (which may differ from the times when renewable generators are producing).

Table 7-1: NPV of gross economic benefits relative to the base case – Step Change scenario (June $2022 million)

Option	Step Change scenario
Option 1	18.72
Option 2	25.44
Option 2A	25.31
Option 2B	23.14
Option 3	22.07
Option 4	107.77

7.1.2. Estimated costs

The table below summarises the present value of capital costs and operating and maintenance costs of each credible option relative to the base case. Options 1, 2 and 2A can be delivered at a lower cost than the other Options. Given the similarity in build specifications, the expected cost of implementing Option 2 and 2A are not expected to be materially different. In contrast, the expected cost of implementing Options 2B, 3 and 4 are considerably higher than the other options, i.e., in comparison to Option 2, Option 2B is more than three times the cost, Option 3 is more than five times the cost, while Option 4 is more than 24 times the cost).

Table 7-2: NPV of costs relative to the base case – Step Change scenario (June $2022 million)

Option	Step Change scenario
Option 1	1.44
Option 2	7.46
Option 2A	8.11
Option 2B	25.82
Option 3	38.26
Option 4	184.46

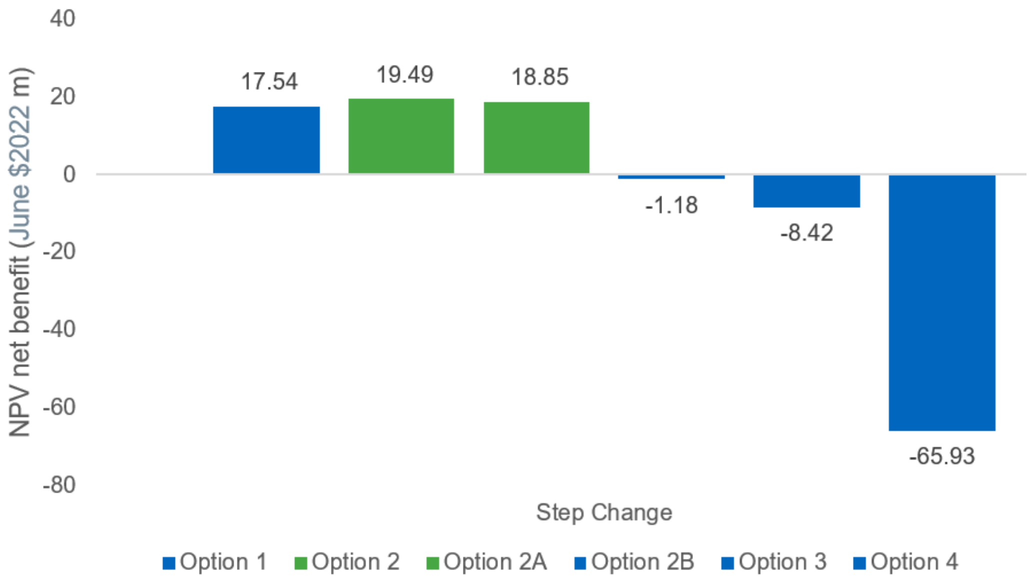
7.1.3. Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option. The net economic benefits are calculated as the estimated gross benefits less the estimated costs. The results show that Option 2 has the greatest net market benefit of all the options considered, while Option 2A produces a net market benefit only marginally lower.

Table 7-3: NPV of net economic benefits relative to the base case – Step Change scenario (June $2022 million)

Option	Step Change scenario
Option 1	17.54
Option 2	19.49
Option 2A	18.85
Option 2B	-1.18
Option 3	-8.42
Option 4	-65.93

Figure 7-1 NPV of net economic benefits relative to the base case – Step Change scenario (June $2022 million)



7.2. Progressive Change scenario

This scenario includes EY's market modelling of the wholesale market benefits for the options based on the 'Progressive Change' scenario from the 2022 ISP. It also assumes the Orange North demand forecasts (as outlined in section 2.2.2) and all in-service, committed and advanced renewable generators (as outlined in section 2.2.1).

The outcomes under this scenario are broadly similar to the Step Change scenario. In particular, Options 2 and 2A are the highest ranked options and are expected to deliver very similar net market benefits (approximately $15 million in $June 2022). Option 1 is also expected to produce a net benefit under this scenario, while Options 2B, 3 and 4 all expected to generate net costs. In comparison to the Step Change scenario, all options with positive net market benefits are expected to generate relatively lower net benefits. However, the relative ranking of the options does not change.

The lower net benefits under this scenario are driven by lower gross benefits. Under the Progressive Change scenario, demand growth is assumed to be lower and carbon budgets are assumed to be less restrictive than the Step Change scenario. This result in a lower rate of congestion on Line 94T in the base case, meaning that the benefits associated with relieving congestion are also commensurately lower.

Given that the costs of the options are unchanged compared with the Step Change scenario, we have only set out the results for the gross benefits and net market benefits.

7.2.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. As with the Step Change scenario, the gross benefits associated with Options 2, 2A, 2B and 3 are fairly similar, albeit higher for Options 2 and 2A, while Option 4 produces the highest gross benefit compared to the other options given its capability to store and export low-cost renewable generation to the grid at times when it will provide the greatest benefit.

Table 7-4: NPV of gross economic benefits relative to the base case – Progressive Change scenario (June $2022 million)

Option	Progressive Change scenario
Option 1	14.55
Option 2	21.42
Option 2A	21.45
Option 2B	20.35
Option 3	16.94
Option 4	114.19

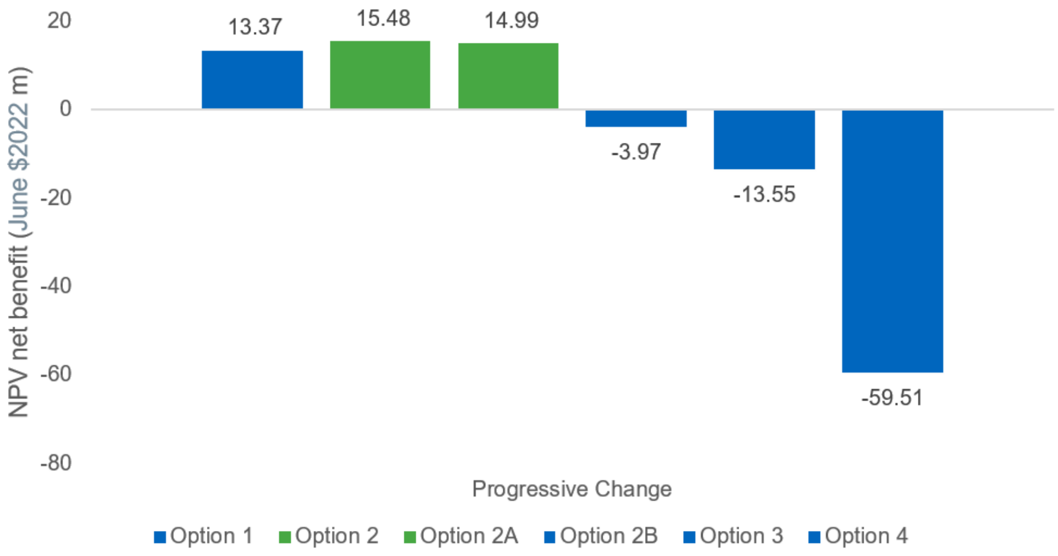
7.2.2. Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option. The net economic benefits are calculated as the estimated gross benefits less the estimated costs. Similar to the Step Change scenario, the results show that Option 2 has the greatest net market benefit of all the options considered, while Option 2A produces a net market benefit only marginally lower.

Table 7-5: NPV of net economic benefits relative to the base case – Progressive Change scenario (June $2022 million)

Option	Progressive Change scenario
Option 1	13.37
Option 2	15.48
Option 2A	14.99
Option 2B	-3.97
Option 3	-13.55
Option 4	-59.51

Figure 7-2 NPV of net economic benefits relative to the base case – Progressive Change scenario (June $2022 million)



7.3. Hydrogen Superpower scenario

This scenario includes EY's market modelling of the wholesale market benefits for the options based on the 'Hydrogen Superpower' scenario from the 2022 ISP. It also assumes the high Orange North demand forecasts (as outlined in section 2.2.2) and all in-service, committed and advanced renewable generators (as outlined in section 2.2.1).

The outcomes under this scenario are broadly similar to the other scenarios. In particular, Options 2 and 2A are the highest ranked options and are expected to deliver very similar net market benefits (approximately $53 million in June $2022). Options 1 and 2B are also expected to produce net benefits under this scenario, while Options 3 and 4 are expected to generate net costs. In comparison to the Step Change scenario, all options generate higher net benefits except for Option 3. The relative ranking of the options does not change.

The Hydrogen Superpower scenario is forecast to have the highest benefits among all scenarios, due to the assumptions of higher demand growth, combined with a more restrictive carbon budget. This results in more renewable energy and hydrogen turbine capacity being built in the base case. Similar to the other scenarios, solar capacity is forecast to be the main technology which is avoided with all options. However, in this scenario, network options are forecast to defer some hydrogen turbine capacity. Overall, fuel cost savings are expected in this scenario.

Given that the costs of the options are unchanged compared with the Step Change scenario, we have only set out the results for the gross benefits and net market benefits.

7.3.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. As with the Step Change scenario, the gross benefits associated with Options 2, 2A, and 2B are fairly similar, although Option 2B now has the highest gross benefits of the three options. The gross benefits associated with Option 3 are lower compared to the other two scenarios. Option 4 produces the largest gross benefit compared to the other options given its capability to store and export low-cost renewable generation to the grid at times when it will provide the greatest benefit.

Option 2B's marginally higher gross benefits is due to the power flow controllers reducing the level of congestion on the Wellington to Wellington Town line during evening peaks. For further details, refer to the market modelling report.

Gross market benefits for Option 3 are similar to the Step Change scenario, which is a marked contrast to outcomes for the other options.

Option 3 is forecast to result in a lower equivalent impedance in the Molong and Orange transmission lines, and in transmission corridors through this flow path towards the Sydney West. As a result, the flow on the lines in this direction is forecast to increase relative to other options (although a significantly higher flow is still forecast on the higher voltage network). In particular, flow on the Wellington to Wellington Town line is forecast to increase, resulting in congestion on this line, mostly during the evening. This is forecast to become a limiting factor for wind generation in the central west NSW, resulting in the need to supply the demand using other generation such as hydrogen turbine generation in the Hydrogen Superpower scenario. The forecast increase in the fuel costs in this scenario is expected to reduce the overall benefits of this option.

Table 7-6: NPV of gross economic benefits relative to the base case – Hydrogen Superpower scenario (June $2022 million)

Option	Hydrogen Superpower scenario
Option 1	39.74
Option 2	59.76
Option 2A	59.77
Option 2B	62.17
Option 3	17.15
Option 4	126.34

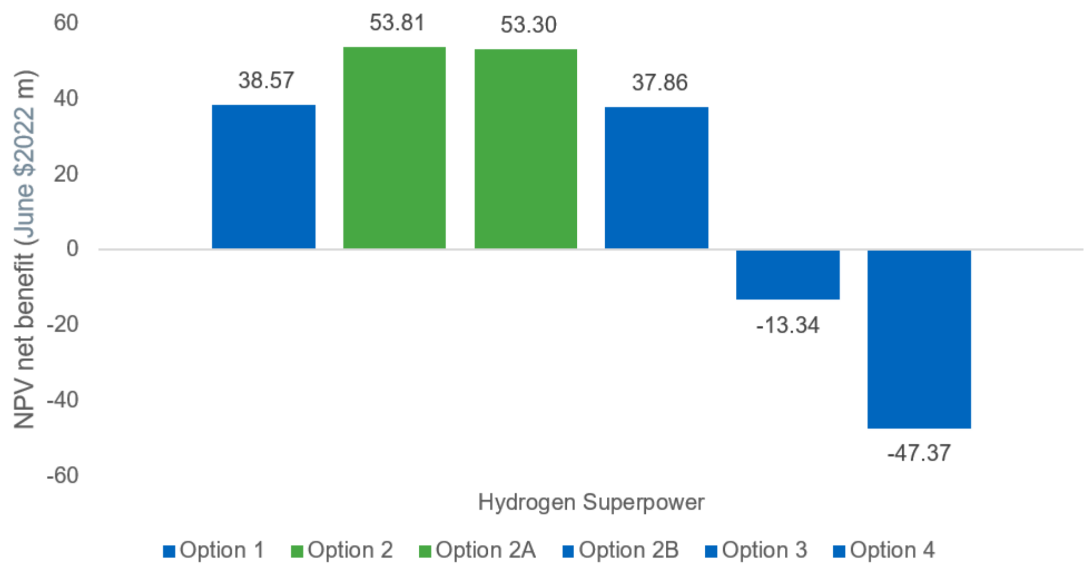
7.3.2. Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option. The net economic benefits are calculated as the estimated gross benefits less the estimated costs. The results show that Option 2 has the greatest net market benefit of all the options considered, while Option 2A produces a net market benefit only marginally lower.

Table 7-7: NPV of net economic benefits relative to the base case – Hydrogen Superpower scenario (June $2022 million)

Option	Hydrogen Superpower scenario
Option 1	38.57
Option 2	53.81
Option 2A	53.30
Option 2B	37.86
Option 3	-13.34
Option 4	-47.37

Figure 7-3 NPV of net economic benefits relative to the base case – Hydrogen Superpower scenario (June $2022 million)



7.4. Weighted net benefits

As outlined in section 5.2, we have weighted each of the scenarios for this RIT-T based on the 2022 ISP weightings for the underlying wholesale market scenarios. Given that the costs of the options are unchanged compared with the Step Change scenario, we have only set out the results for the gross benefits and net market benefits.

7.4.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. Consistent with the results above, Option 4 is expected to produce the largest gross benefit compared to the other options given its capability to store and export low-cost renewable generation to the grid at times when it will provide the greatest benefit, followed by Options 2 and 2A which are expected to generate a very similar level of benefits.

Table 7-8: NPV of gross economic benefits relative to the base case – Weighted scenario (June $2022 million)

Option	Weighted scenario
Option 1	21.25
Option 2	30.41
Option 2A	30.36
Option 2B	29.33
Option 3	19.64
Option 4	113.04

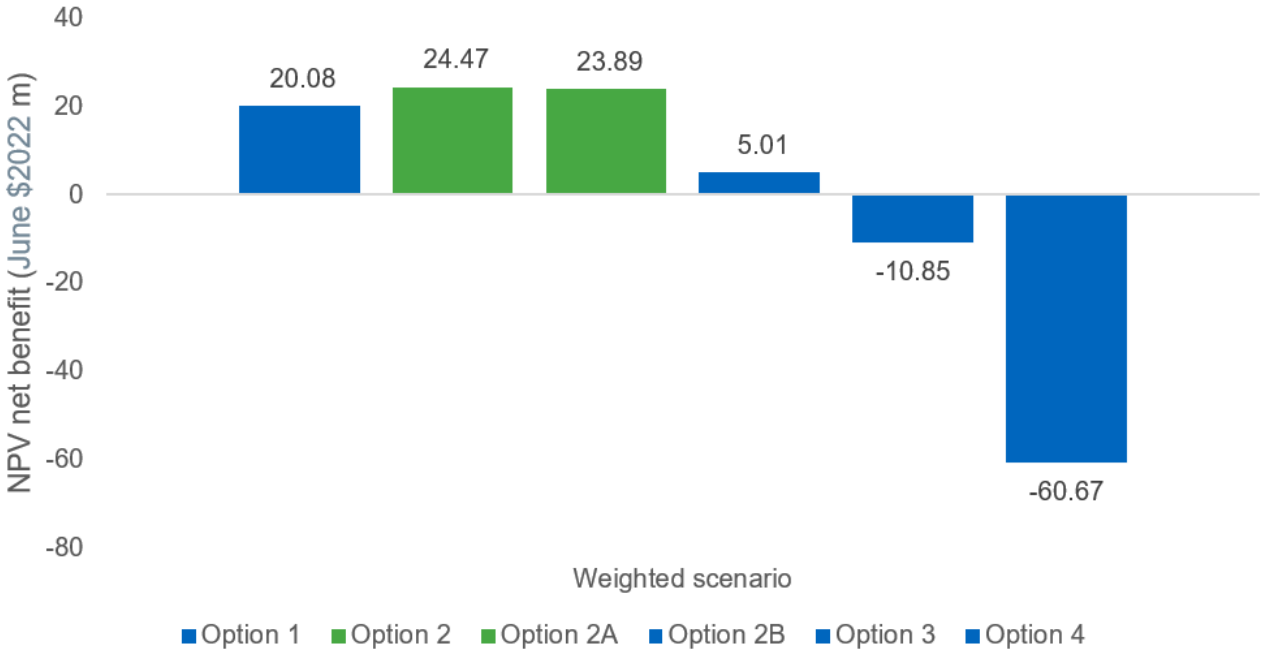
7.4.2. Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option. The net economic benefits are calculated as the estimated gross benefits less the estimated costs. The results shows that Option 2 has the greatest net market benefit of all the options considered, while Option 2A produces a net market benefit only marginally lower. The net benefit of Option 2B is much lower, while Options 3 and 4 are expected to impose net costs on the market, due principally to the higher cost of implementing these options in comparison to Options 2 and 2A.

Table 7-9: NPV of net economic benefits relative to the base case – Weighted scenario (June $2022 million)

Option	Weighted scenario
Option 1	20.08
Option 2	24.47
Option 2A	23.89
Option 2B	5.01
Option 3	-10.85
Option 4	-60.67

Figure 7-4 NPV of net economic benefits relative to the base case – Weighted scenario (June $2022 million)



7.5. Sensitivity testing

We have undertaken sensitivity testing to examine how the net economic benefit of the credible options changes with respect to changes in key modelling assumptions.

The factors tested as part of the sensitivity analysis in this PADR are:

- higher and lower capital cost assumptions for the credible options (undertaken on the weighted scenario);
- alternate commercial discount rate assumptions (undertaken on the weighted scenario);

- excluding stage 1 of the preferred option from the BOP RIT-T (undertaken on all scenarios);
- including stage 2 of the preferred option from the BOP RIT-T (undertaken on the Step Change scenario);
- higher load forecasts in the Orange area (undertaken on the Step Change scenario); and
- higher forecast renewable generation capacity in the Molong and Parkes area

In each case, we individually varied each factor identified above and estimated the net economic benefit in the scenario relative to the base case while holding all other assumptions constant. The results of the sensitivity tests are set out in the sections below.

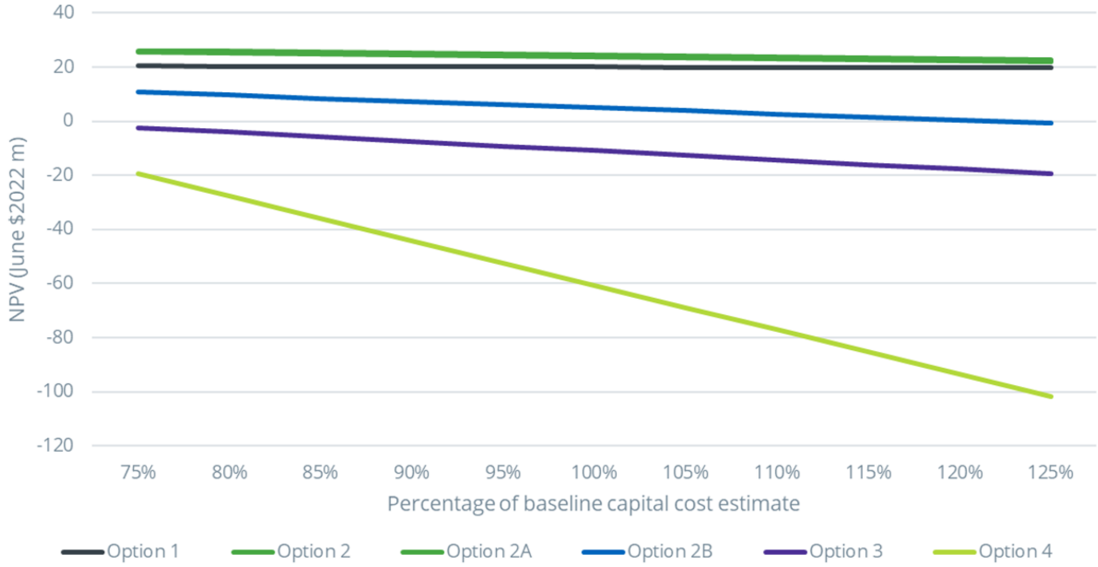
7.5.1. Sensitivity analysis on capital costs

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting capital costs that are 25% higher (the 'High capex' scenario) and 25% lower (the 'Low capex' scenario) than the estimate of capital costs adopted in our scenarios. Under both the low capex and high capex scenarios the relative rankings of the Options do not change.

Table 7-10: NPV of net economic benefits relative to the base case under lower and higher capital costs (June $2022 million)

Option/scenario	Low capex	High capex	Ranking
Sensitivity	*Estimate - 25%*	*Estimate + 25%*	
Option 1	20.40	19.76	3
Option 2	26.13	22.80	1
Option 2A	25.70	22.08	2
Option 2B	10.77	-0.75	4
Option 3	-2.31	-19.38	5
Option 4	-19.53	-101.81	6

Figure 7-5 NPV of net economic benefits relative to the base case under lower and higher capital costs (June $2022 million)



We have also undertaken a threshold analysis to identify whether a change in capital cost estimates would change the RIT-T outcome. Specifically, we considered whether an increase or decrease in the capital costs of one option (while holding the capital costs of the other options constant) would change the RIT-T outcome.

Our findings show that if Option 2's costs were only 8.6% higher that our current forecasts then Option 2A would be the preferred option. This relatively small change in capital costs is one of the key reasons for progressing both Options 2 and 2A. We also conducted analysis on the required increase in Option 2's capital cost for Option 1 to produce a higher net benefit. Our findings show that Option 2's capital costs would need to increase by more than 66.0% in order for its net benefit to decrease below that of Option 1.

7.5.2. Sensitivity analysis on the discount rate

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting alternative discount rates. Specifically, we considered a low discount rate of 3.21%[20] and a high discount rate of 7.5% which aligns with the discount rate scenarios in the 2021 IASR.[21] Under both the low and high discount rate scenarios the relative rankings of the Options do not change.

Table 7-11: NPV of net economic benefits relative to the base case under lower and higher discount rates (June $2022 million)

Option/scenario	Low discount rate	High discount rate	Ranking
Sensitivity	*3.21%*	*7.5%*	
Option 1	27.76	15.46	3
Option 2	36.14	17.59	1
Option 2A	35.67	16.98	2
Option 2B	15.17	-0.71	4
Option 3	-2.37	-15.27	5
Option 4	-32.49	-75.70	6

[20] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: AER, *Transgrid 2023-28 – Final Decision – PTRM – April 2023.xlsx*), 'WACC' sheet, cell R23.

[21] AEMO, 2021 Inputs, Assumptions and Scenarios Report, July 2021, p. 105.

Figure 7-6 NPV of net economic benefits relative to the base case with lower and higher discount rates (June $2022 million)

We have also undertaken a threshold analysis to identify whether a change in the discount rate would change the RIT-T outcome. Our approach involved solving for the discount rate that would result in Option 2 not being the preferred option. Our findings suggest that there are no positive discount rates that would result in Option 2A surpassing Option 2 as the preferred option. However, at a discount rate of 10.55% or higher Option 1 would become the preferred option.

7.5.3. Excluding stage 1 of the preferred option from the BOP RIT-T

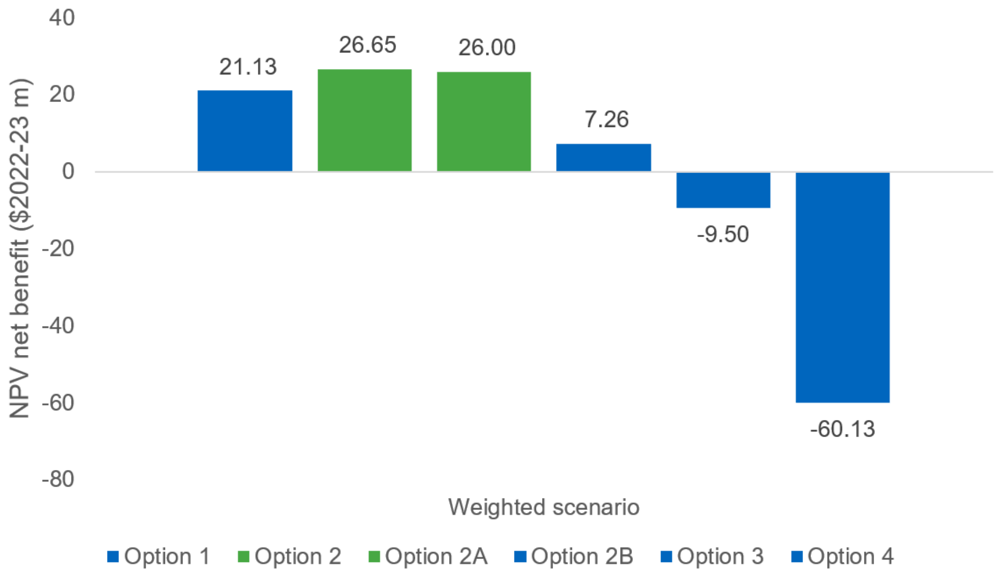
As outlined in Section 2.2.3, our central analysis has included the preferred option for Stage 1 of the BOP RIT-T (i.e., Option 7D, which involves installation of a BESS and STATCOM at Parkes and Panorama). In this sensitivity, we have excluded the preferred option from the BOP RIT-T and modelled the credible options under each of the Step Change, Progressive Change and Hydrogen Superpower scenarios.

The figure and table below set out the net economic benefits estimated for each credible option relative to the base case. Option 2 and 2A remain the preferred options under all scenarios, with net economic benefits for all Options increasing compared to the central analysis. The removal of the BESSs at Panorama and Parkes increases the congestion on the network in the base case and allows the Line 94T options to alleviate more of the congestion, generating higher gross market benefits.

Table 7-12: NPV of net economic benefits relative to the base case after excluding the preferred BOP option (June $2022 million)

Option/scenario	Step Change	Progressive Change	Hydrogen Superpower	Weighted
Option 1	18.30	13.94	41.29	21.13
Option 2	21.20	16.78	58.85	26.65
Option 2A	20.55	16.30	57.94	26.00
Option 2B	0.50	-2.62	43.26	7.26
Option 3	-6.95	-12.74	-11.47	-9.50
Option 4	-65.41	-59.09	-46.61	-60.13

Figure 7-7 NPV of net economic benefits relative to the base case after excluding the preferred BOP option (Weighted scenario, June $2022 million)



7.5.4. Including stage 2 of the preferred option from the BOP RIT-T

As outlined in Section 2.2.3, our central analysis has excluded the preferred option for Stage 2 of the BOP RIT-T, which involves building a 132kV line between Wellington and Parkes. This sensitivity assumes that Stage 2 of the BOP RIT-T is developed and commences operation from 2031-32.

The figure and table below set out the net economic benefits estimated for each credible option relative to the base case. Under this sensitivity, Option 1 becomes the preferred option while Option 2 and 2A remain closely ranked as the next best alternatives. The construction of the Wellington to Parkes line will add additional transmission capacity to the region, and in turn lessen constraints on existing lines in the region such as Line 94T. This reduces the expected gross market benefits of all the Options considered in this RIT-T, and means that Option 1, which can be delivered at considerably lower cost, will provide the highest net benefit.

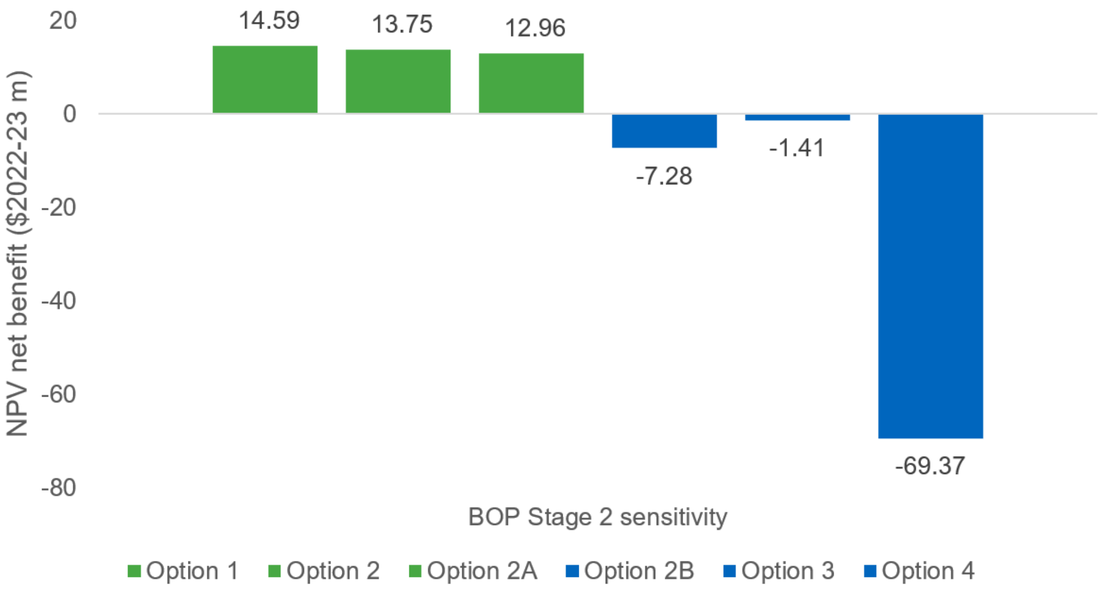
Unlike the other options, Option 3 has increased gross market benefits This is due to Option 3 further benefiting from the reduced impedance of the Wellington to Parkes line, which avoids/reduces the congestion in the area compared to the central analysis.

As the timing of Stage 2 is dependant on outturn demand forecasts, some uncertainty as to its future development remains, and Options 2 offers only marginally lower net benefits than Option 1 in this sensitivity, we believe that the ranking of the options under the core scenarios remain robust.

Table 7-13: NPV of net economic benefits relative to the base case when including Stage 2 of the BOP RIT-T (June $2022 million)

Option	Step Change scenario
Option 1	14.59
Option 2	13.75
Option 2A	12.96
Option 2B	-7.28
Option 3	-1.41
Option 4	-69.37

Figure 7-8 NPV of net economic benefits relative to the base case when including Stage 2 of the BOP RIT-T (June $2022 million)



7.5.5. Higher load forecasts in the Orange area

We have considered a sensitivity that increases the forecast demand in the Orange area due to spot loads in the region. Additional demand from this region would be expected to lead to further constraining of Line 94T under the base case scenario, meaning that credible options that reduce this constraint would create additional gross market benefits.

The figure and table below set out the net economic benefits estimated for each credible option relative to the base case. Under this sensitivity, the relative rankings of the Options are unchanged. In comparison to our central analysis, all of the Options are expected to produce higher net economic benefits, except for Option 4 which experiences a minor decrease. Option 3 generates only a marginally higher gross market benefit but remains net negative, while all other Options generate higher positive net economic benefits.

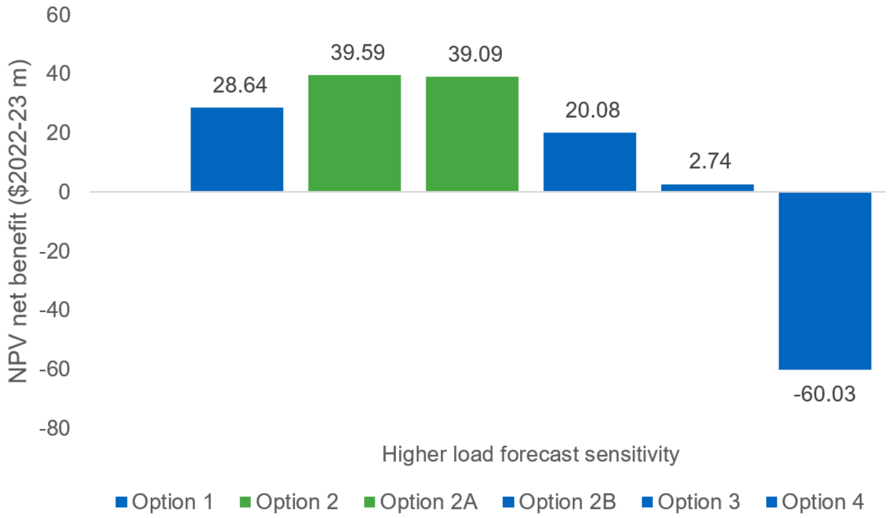
Option 1's relatively lower increase in gross market benefits compared to the Option 2 variants is due to lower thermal rating of Line 94T in this option, which limits the level of alleviated constraint bindings and gross benefits of the option.

Option 3 also delivers lower benefits compared to Option 2 variants for the same reason as the central analysis.

Table 7-14: NPV of net economic benefits relative to the base case with a larger demand forecast for the Orange area (June $2022 million)

Option	Step Change scenario
Option 1	28.64
Option 2	39.59
Option 2A	39.09
Option 2B	20.08
Option 3	2.74
Option 4	-60.03

Figure 7-9 NPV of net economic benefits relative to the base case with a larger demand forecast in the Orange area (June $2022 million)



7.5.6. Including three additional generators

We have considered a sensitivity that further increases renewable generation in the Molong and Parkes area. Under this sensitivity we include in the base case an additional three generators that are advanced but do not currently meet the requirements for an anticipated project in AEMO's generator information. The additional generators and assumed connection locations and commissioning dates are:

- 330 MW Wellington North Solar Farm connected at Wellington 330 kV substation to be commissioned on 1 January 2025.
- 400 MW Stubbo Solar Farm connected at Uungula 330 kV substation to be commissioned on 1 July 2025.
- 400 MW Uungula Wind Farm connected at Uungula 330 kV substation to be commissioned on 1 October 2025.

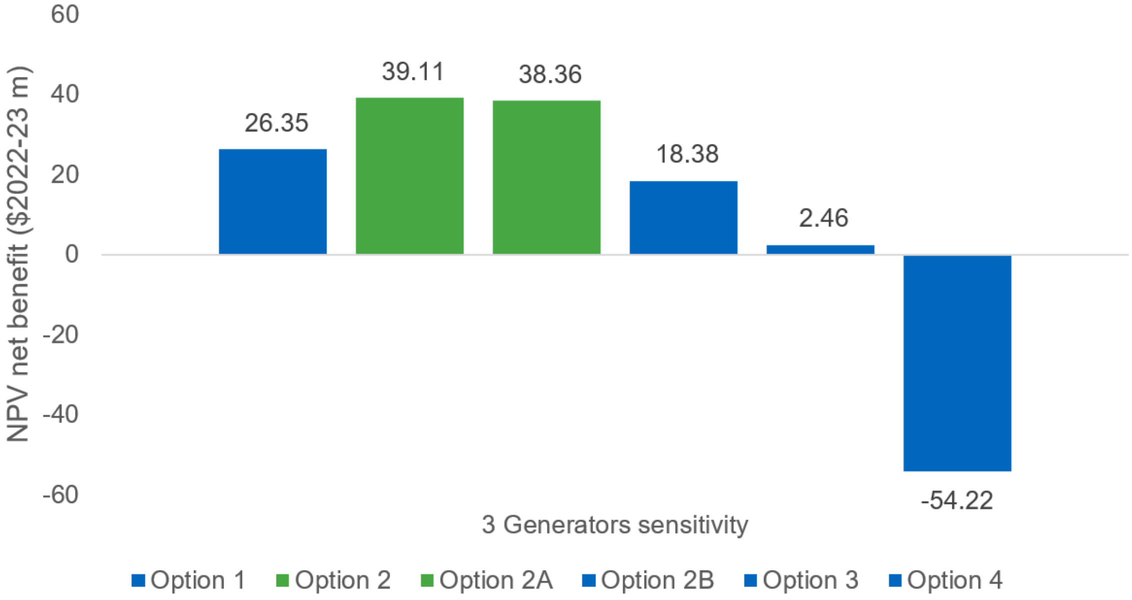
The addition of these three generators is likely to lead to further constraining of Line 94T under the base case as more renewable generation is available to be dispatched, meaning that credible options that reduce this constraint should create additional gross market benefits.

The figure and table below set out the net economic benefits estimated for each credible option relative to the base case. Under this sensitivity, the relative rankings of the Options are unchanged. In comparison to our central analysis, all of the Options are expected to produce higher net economic benefits. Option 3 and 4 generate only marginally higher gross market benefits but remain net negative, while all other Options generate higher positive net economic benefits.

Table 7-15: NPV of net economic benefits relative to the base case with additional renewable generation (June $2022 million)

Option	Step Change scenario
Option 1	26.35
Option 2	39.11
Option 2A	38.36
Option 2B	18.38
Option 3	2.46
Option 4	-54.22

Figure 7-10 NPV of net economic benefits relative to the base case with additional renewable generation (June $2022 million)



8. Conclusion

This PADR finds that Options 2 and 2A are the highest ranked options and are expected to deliver very similar net market benefits. These options involve increasing Line 94T's summer daytime thermal rating by restringing Line 94T with a higher capacity conductor. The thermal rating of the new conductor would increase to 177 MVA under Option 2 and 152 MVA under Option 2A, with commissioning of either option expected in 2025/26.

We consider Options 2 and 2A satisfy the RIT-T at this draft stage. A summary of the preferred options is set out in the table below.

Table 8-1 Summary of the preferred options

Option	Description	Estimated capex ($M, Real 2021-22)
2	Restring Line 94T with higher rated 'Flicker/ACSS' conductor on existing structures	7.50
2A	Restring Line 94T with higher rated 'Partridge/ACSS/HS285' conductor on existing structures	8.16

Note: All estimated capex is an accuracy level of +/- 25%.

The estimated net benefits of each option are approximately $24 million (June $2022) relative to a 'do nothing' base case, under the weighted scenario. While Option 2 produces the (strictly) largest net benefit under each scenario, the net benefits produced by Option 2A are only marginally lower. Given the similarities between the builds of the two options (both require restringing Line 94T with higher rated conductors), as well as the similar gross market benefits produced by both options, we consider both options to be the preferred options.

A key determinant of the overall preferred option is the capital costs. For the next stage of the RIT-T process, we intend to undertake more detailed analysis on which of Option 2 or 2A are likely to deliver greater cost efficiencies and, therefore, which will be the preferred option.

Appendix A Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4 of the National Electricity Rules version 200.

Rules clause	Summary of requirements	Relevant section(s) in the PACR
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	-
	(1) a description of each credible option assessed;	4
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	3 & Appendix B
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	6 & 7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	5 & 6
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	6.5
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	7
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7
	(8) the identification of the proposed preferred option;	7 & 8
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	4 & 8

Appendix B Summary of consultation on the PSCR

This appendix provides a summary of points raised by stakeholders during the PSCR consultation process, besides those comments considered confidential. Where elements of confidential submissions have been included, the stakeholders are referred to as Conductor manufacturer, Generator 1 and Generator 2.

The points raised are grouped by topic and a response is provided to the points raised. All section references are to this PADR, unless otherwise stated.

Table 8-2 Summary of consultation on the PSCR

Summary of comment(s)	Submitter(s)	Our response
Stakeholders agreed with the identified need but believe Transgrid may have underestimated the problem		
AMP agreed with the identified need outlined in the PSCR and provided evidence of expected significant Generator curtailment in the future based on committed Generator coming to the area.	AMP Power Australia p.2	We have re-examined the additional renewable generation that is expected to be commissioned in the area and have included additional generation into our modelling – refer to Section 2.2.1. We have also modelled a sensitivity that includes an additional three generators – refer to Section 7.5.6.
Other generators in the region agreed with the identified need outlined in the PSCR. One considered that Transgrid have underestimated the problem by underestimating forecast renewable Generator in the region. Another expects that constraints on Line 94T will result in over 30GWh of renewal Generator being lost.	Confidential	
Smart Wires agreed with the identified need outlined in the PSCR	Smart Wires p.3	
Stakeholders considered the proposed network options in the PSCR may not relieve generation constraints in the area		
AMP considers Option 1 would not provide a sufficient increase in line rating to meet generation and load growths in the region. AMP supports Option 2 from the PSCR but considers it might not completely remove the generation curtailment risk in the area.	AMP Power Australia p.2-3	We have included a number of additional options in the assessment that have been compared against the original two options from the PSCR in response to the submissions – refer to Section 4.
A generator considered that Option 1 and Option 2 in the PSCR would only temporarily relieve congestion and curtailment and are not viable in the	Confidential	

long term due to the large pipeline of new renewable energy projects that are intended to connect to the network.		
A generator considered that Option 1 in the PSCR is unlikely to make any real impact on reducing curtailment of renewable generation. It supported Option 2 and considered that this option should allow existing and new connecting renewable generation without increasing the existing levels of constraints.	Confidential	
Smart Wires considered the options proposed in the PSCR are not expected to fully relieve the generation constraints in the Molong and Parkes area	Smart Wires p.3	
Stakeholders provided alternative solutions to the proposed solutions		
A conductor manufacturer proposed two alternative conductors for restringing Line 94T.	Confidential	We have modelled an additional option (Option 2A) that includes restringing with the proposed Partridge/ACSS/HS285 conductor – refer to Section 4.4.
Other generators proposed alternate options, including that: • Line 94T should be rebuilt as a double-circuit transmission line and that Transgrid should consider interim solutions to ease curtailment while a permanent solution is selected • A BESS to deliver thermal overload contingency for Line 94T	Confidential	We have modelled an additional option (Option 3) that replaces Line 94T as a double-circuit transmission line – refer to Section 4.6. We have modelled an additional option (Option 4) that includes a BESS – refer to Section 4.7.

Smart Wires puts forward alternative solutions, which involve installing and operating Modular Power Flow Controllers on Line 94T. It considers deployment of these devices can be undertaken faster than the proposed network options to deliver constraint relief.	Smart Wires p.3	We have modelled an additional option (2B) that includes both the proposed Option 2 plus the inclusion of power flow controllers – refer to Section 4.5.
Stakeholders consider the biggest market benefit to be the increase in low cost renewable generation entering the NEM		
AMP considered that reducing curtailment would provide energy consumers with access to lowest cost renewable generation and maintain power system security during generation shortfall periods, such as during the exit of coal-fired generators.	AMP Power Australia p.4	We have included benefits associated with an increase in renewable generation entering the NEM in our market modelling – refer to Section 6, Appendix C and the EY report.
A generator identified that the current constraints on Line 94T are resulting in a significant volume of low-cost renewable energy being lost and supplied instead by more expensive thermal generation, leading to high prices for end consumers.	Confidential	
Stakeholders did not comment on our assessment approach		
N/A		

Appendix C Overview of the wholesale market modelling undertaken

As outlined in the body of this PADR, we have engaged EY to undertake the wholesale market modelling as part of this PADR.

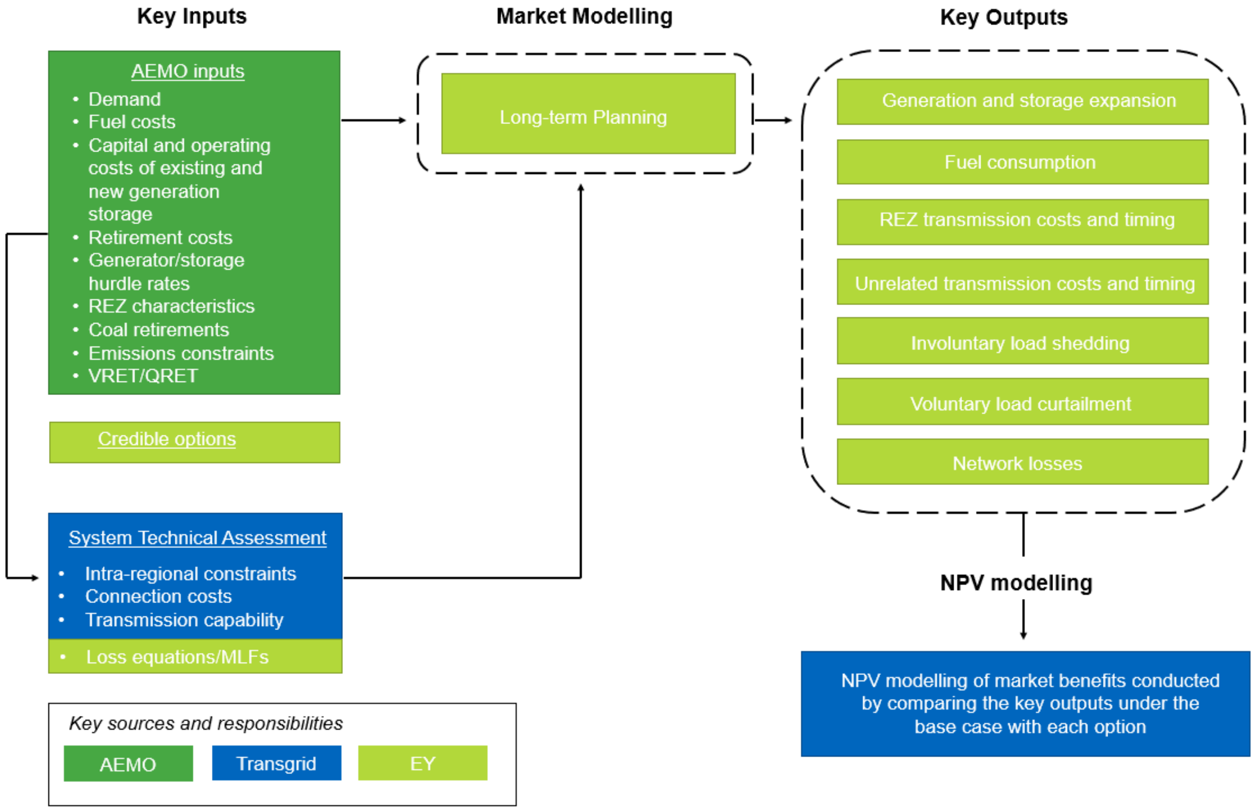
EY has applied a linear optimisation model and performed hourly, time-sequential, long-term market modelling for the NEM to estimate categories of wholesale market benefits expected under the options that affect the wholesale market. Specifically, EY has undertaken market simulation exercise involving long-term investment planning, which identifies the optimum generation (including storage) and unrelated transmission infrastructure development schedule, while meeting policy objectives, and technical generator and network performance limitations. This solves for the least-cost generation and transmission infrastructure development across the assessment period.

We have undertaken a detailed System Technical Assessment, which evaluates the power system behaviour and performance under each credible option and ensures market modelling outcomes are physically plausible, follow the operation of the NEM, and that the benefits of credible options align with the changes to the power system under each credible option. This assessment serves as an input to the wholesale market modelling exercises EY has undertaken (as outlined above).

These exercises are consistent with an industry-accepted methodology, including within AEMO's ISP. For further detail, refer to the EY market modelling report.

Figure 8-1 illustrates the interactions between the key modelling exercises, as well as the primary party responsible for each exercise and/or where the key assumptions have been sourced.

Figure 8-1 Overview of the market modelling process and methodologies



The sub-sections below provide additional detail on the key wholesale market modelling exercises EY have undertaken as part of this PADR assessment.

Long-term Investment Planning

The Long-term Investment Planning's function is to develop generation (including storage) and unrelated transmission infrastructure forecasts over the assessment period for each of the credible options and base cases.

This exercise determines the least-cost development schedule for each credible option drawing on assumptions regarding demand, emissions budget and renewable energy targets, reservoir inflows, generator outages, wind and solar generation profiles, and maintenance over the assessment period.

The generation and transmission infrastructure development schedule resulting from the Long-term Investment Planning is determined such that:

- it economically meets hourly regional and system-wide demand while accounting for network losses;
- it builds sufficient generation capacity to meet demand when economic while considering potential generator unplanned and planned outages;
- the cost of unserved energy is balanced with the cost of new generation investment to supply any potential shortfall;
- generator's technical specifications such as minimum stable loading, and maximum capacity are observed;
- notional interconnector flows do not breach technical limits and interconnector losses are accounted for;
- hydro storage levels and battery storage state of charge do not breach maximum and minimum values and cyclic losses are accounted for;
- new generation capacity is connected to locations in the network where it is most economical from a whole of system cost;
- NEM-wide emissions constraints are adhered to;
- NEM-wide and state-wide renewable energy targets are met;
- regional and mainland reserve requirements are met;
- energy-limited generators such as Tasmanian hydro-electric generators, Snowy Hydro-scheme and grid-scale batteries are scheduled to minimise system costs; and
- the overall system cost spanning the whole outlook period is optimised whilst adhering to constraints.

The Long-term Investment Planning adopts the same commercial discount rate as used in the NPV discounting calculation in the cost benefit analysis. This is consistent with the approach being taken in the 2022 ISP.[22]

Coal-fired and gas-fired generation is treated as dispatchable between its minimum load and its maximum load in the modelling. Coal-fired 'must run' generation is dispatched whenever available at least at its

[22] AEMO, *Planning and Forecasting 2019 Consultation Process Briefing Webinar*, Wednesday 3 April 2019, slide 21.

minimum load. Open cycle gas turbines are typically bid at their short run marginal cost with a zero minimum load level, and started and operated whenever the price is above that level.

The Long-term Investment Planning model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, plus a reserve level sufficient to allow for generation or transmission contingences which can occur at any time, regardless of the present dispatch conditions.

Due to load diversity and sharing of reserve across the NEM, the reserve to be carried is minimised at times of peak and provided from the lowest cost providers of reserve including allowing for each region to contribute to its neighbours reserve requirements through interconnectors.

Modelling of diversity in peak demand

The market modelling accounts for peak period diversification across regions by basing the overall shape of hourly demand on nine historical years ranging from 2010/11 to 2018/19.

Specifically, the key steps to accounting for this diversification are as follows:

- the historical underlying demand has been calculated as the sum of historical metered demand and the estimated rooftop PV generation based on historical rooftop PV capacity and solar insolation;
- the nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region;
- the nine reference years are repeated sequentially throughout the modelling horizon; and
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

This method ensures the timing of peak demand across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the diversity of timing.

Modelling of intra-regional constraints

The wholesale market simulations include models for intra-regional constraints in addition to the inter-regional transfer limits.

Key intra-regional transmission constraints in New South Wales have been captured by splitting NSW into zones (NNS, NCEN, CAN and SWNSW), and explicitly modelling intra-regional connectors across boundaries or cut-sets between these zones. Bi-directional flow limits and dynamic loss equations were formulated for each intra-regional connector.

In addition, loss factors for each generator were applied. These were computed from an AC power flow programme interfaced with the Long-term Investment Planning model.

Summary of the key assumptions feeding into the wholesale market exercise

The table below summarises the key assumptions that the market modelling exercise draws upon.

Table 8-3 Summary of the credible options

Key drivers input parameters	Step Change	Progressive Change	Hydrogen Superpower
Underlying consumption	ISP 2022 – Step Change	ISP 2022 – Progressive Change	ISP 2022 – Hydrogen Superpower
Committed and anticipated generation	AEMO Generation information data as of January 2023		
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PSH, and large-scale batteries	2021 Inputs and Assumptions Workbook – Step Change	2021 Inputs and Assumptions Workbook – Progressive Change	2021 Inputs and Assumptions Workbook – Hydrogen Superpower
Retirements of coal-fired power stations	Coal retirement is based on EY market modelling outcomes	Coal retirement is based on EY market modelling outcomes	Coal retirement is based on EY market modelling outcomes
Gas fuel cost	2021 Inputs and Assumptions Workbook - Step Change	2021 Inputs and Assumptions Workbook - Progressive Change	2021 Inputs and Assumptions Workbook – Hydrogen Superpower
Coal fuel cost	2021 Inputs and Assumptions Workbook - Step Change	2021 Inputs and Assumptions Workbook - Progressive Change	2021 Inputs and Assumptions Workbook – Hydrogen Superpower
NEM carbon budget	2021 Inputs and Assumptions Workbook - Step Change: 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook - Progressive Change: 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook – Hydrogen Superpower: 453 Mt CO_2-e 2023-24 to 2050-51
Victoria Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030 VRET2 including 600 MW of renewable capacity by 2025		
Queensland Renewable Energy Target (QRET)	50% by 2030		
Tasmanian Renewable Energy Target (TRET)	100% by 2022, 150% by 2030 and 200% Renewable generation by 2040, excluding hydro		
NSW Electricity Infrastructure Roadmap	12 GW NSW Roadmap, with 3 GW in the Central West Orana REZ, modelled as generation constraint per 2022 ISP and 2 GW of long duration storage (8 hrs or more) by 2029-30		
EnergyConnect	2022 ISP: EnergyConnect commissioned by July 2026		
Western Renewable Link	Western Renewables Link commissioned by July 2026		
HumeLink	2022 ISP outcome – Step Change: HumeLink commissioned by July 2028	2022 ISP. outcome – Progressive Change: HumeLink commissioned by July 2035	2022 ISP. outcome – Hydrogen Superpower: HumeLink commissioned by July 2027
Marinus Link 1	2022 ISP outcome:1st cable commissioned by July 2029 and 2nd cable by July 2031		
Victoria to NSW Interconnector Upgrade (VNI Minor)	VNI Minor commissioned by December 2022		
NSW to QLD Interconnector Upgrade (QNI Minor)	QNI minor commissioned by July 2022		
QNI Connect	2022 ISP outcome – Step Change: QNI Connect commissioned by July 2032	2022 ISP outcome – Progressive Change: QNI Connect commissioned by July 2036	2022 ISP outcome – Hydrogen Superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030
VNI West	2022 ISP outcome – Step Change: VNI West commissioned by July 2031	2022 ISP outcome – Progressive Change: VNI West commissioned by July 2038	2022 ISP outcome – Hydrogen Superpower: VNI West commissioned by July 2030

Victorian SIPS	300 MW/450 MWh, 250 MW for SIPS service during summer. In the summer months the remaining 50 MW can be deployed in the market on a commercial basis, in the winter months the full capacity is available. From April 2032 the full capacity is available to the market.		
New England REZ Transmission	2022 ISP outcome – Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	2022 ISP outcome – Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	2022 ISP outcome – Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031, and stage 2 by July 2042
Snowy 2.0	Snowy 2.0 is commissioned by December 2027		