energy market consulting associates

TransGrid Revenue Proposal 2023-28

REVIEW OF RIT-T PROJECT: MAINTAIN RELIABLE SUPPLY TO NORTHWEST SLOPES AREA NSW (PUBLIC VERSION)

Report prepared for:

AUSTRALIAN ENERGY REGULATOR

August 2022

Preface

This report has been prepared to assist the Australian Energy Regulator (AER) with its determination of the appropriate revenues to be applied to the prescribed transmission services of TransGrid from 1st July 2023 to 30th June 2028. The AER's determination is conducted in accordance with its responsibilities under the National Electricity Rules (NER).

This report covers a particular and limited scope as defined by the AER and should not be read as a comprehensive assessment of proposed expenditure that has been conducted making use of all available assessment methods. This report relies on information provided to EMCa by Transgrid. EMCa disclaims liability for any errors or omissions, for the validity of information provided to EMCa by other parties, for the use of any information in this report by any party other than the AER and for the use of this report for any purpose other than the intended purpose. In particular, this report is not intended to be used to support business cases or business investment decisions nor is this report intended to be read as an interpretation of the application of the NER or other legal instruments.

EMCa's opinions in this report include considerations of materiality to the requirements of the AER and opinions stated or inferred in this report should be read in relation to this over-arching purpose.

Except where specifically noted, this report was prepared based on information provided by AER staff prior to 29 May 2022 and any information provided and utilised subsequent to this time has been explicitly referenced. Some numbers in this report may differ from those shown in Transgrid's regulatory submission or other documents due to rounding.

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ABBREVIATIONS

Term	Definition
AER	Australian Energy Regulator
AEMC	Australian Energy market Commission
AEMO	Australian Energy Market Operator
augex	Augmentation capital expenditure
BESS	Battery Energy Storage System
BSP	Bulk Supply Point
Capex	Capital expenditure
CBA	Cost Benefit Analysis
CPI	Consumer Price Index
CAPEX	Capital Expenditure
DNSP	Distribution Network Service Provider
ENA	Electricity Networks Association
EMCa	Energy Market Consulting associates
FCAS	Frequency Control Ancillary Service
IGF	Investment Governance Framework
ISP	Integrated System Plan
LDC	Load Duration Curve
NER	National Electricity Rules
NNS	Non-network solution / support
NPC	Net Present Cost
NPV	Net Present Value
NSW	New South Wales
opex	Operating expenditure
PEC	Project Energy Connect
PACR	Project Assessment Conclusion Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PoE	Probability of Exceedance
RCP	Regulatory Control Period
repex	Replacement (capital) expenditure
RIN	Regulatory Information Notice
RIT-T	Regulatory Investment Test

Term	Definition
SME	Subject Matter Experts
SPS	Special Protection Scheme
STATCOM	Static Synchronous Compensator
VCR	Value of Customer Reliability

EXECUTIVE SUMMARY

Scope and purpose of this report

1. The purpose of this report is to provide the AER with an expert review of Transgrid's RIT-T project for supply to the NW slopes area.
2. Transgrid has not as yet included this project in its proposed capex allowance for the next RCP. In its Revenue Proposal (RP), it referred to this as a project currently undergoing a RIT-T and, in separate correspondence with the AER, Transgrid indicated that it intended for it to be considered as part of its Revised Revenue Proposal (RRP). The assessment contained in this report is therefore intended to assist the AER in its own analysis of the capex allowance as an input to a Decision on Transgrid's revenue requirements for the period 2023-28, in the event that Transgrid subsequently proposes it.
3. At the time of our engagement, our assessment was to be limited to published materials and which for this RIT-T project was the Project Assessment Draft Report (PADR). By agreement with the AER, we agreed to consider updated materials provided to us prior to 29 May 2022.

Summary of proposed RIT-T project

Identified need is based on assumed load growth

4. Transgrid has identified a potential need to upgrade the network in the northwest slopes area of NSW, which currently comprise a ring of 132kV lines supporting loads in the Narrabri and Gunnedah load areas, supplied from two 330kV systems located at Armidale and Tamworth.
5. Transgrid forecasts load in the area to increase significantly over the next ten years, primarily due to planned connections of new mining and industrial loads. Transgrid states that its planning studies show that the network will not be capable of supplying the forecast increases in load in the area without breaching NER requirements.
6. There are two relevant constraints that will apply if action is not taken:
    - Thermal constraints on line 969 under system normal conditions; [1] and
    - Voltage stability constraints between Gunnedah and Narrabri for a contingent outage of line 969 or 968.
7. Transgrid has raised this project as it considers it necessary to ensure that its network meets NER requirements in the northwest slopes area in light of the forecast demand increases.

Transgrid has identified a preferred option (Option 5B), with its cost now estimated as $140.3m

8. In its RP submitted to the AER in January 2022, Transgrid has included the RIT-T project as a major project undergoing RIT-T, at a total cost of $168.3m (real 2022-23). On the basis of the information in its RP, Transgrid would propose $166.3m (real 2022-23) to be included in the next RCP based on its preferred network option.
9. The PADR published in February 2022 included the network cost of the preferred option of as $140.3m ($2020/21).
10. Transgrid has nominated its preferred option as Option 5B comprising

[1] particularly during times of low renewable generation dispatch in the region

i. a BESS installed immediately by proponent at a location close-by to Gunnedah,

ii. Transgrid to install a third Narrabri transformer in time for the initial Narrabri Gas Project load in 2025/26, and

iii. the remaining components (969 line rebuilt as double circuit, 9UH line upgraded) built in time for the increased load in 2029/30.

11. The proposed network cost of Option 5B is $140.3m to be incurred over two RCPs. Transgrid has grouped this into Stage 1 comprising parts (i) and (ii), and Stage 2 comprising the line rebuilds in part (iii) above.

Summary of our review findings

Transgrid's NPV estimate is not relevant to confirming the need

12. The preferred option is presented as providing a weighted NPV of $540m (and $567m under the central scenario). However, this is predicated on what we consider to be an invalid assumption in which the short-term 'VCR' value is applied to an assessed counterfactual inability to supply the new loads. However, the NPV does not influence our assessment of need, which is based solely on the obligation that Transgrid has to meet reasonable expectations of load growth.

The proposed option is appropriate, however only 'Stage 1' needs to be committed at this time, retaining the option of a future stage if and when required

13. We consider that Transgrid's selection of Option 5B as the preferred option is appropriate based on the assumptions applied by Transgrid. However, we consider that Stage 2 need not be included in a regulatory determination at this time, noting that under Transgrid's demand forecast assumptions it is not required until 2030 under a central demand scenario, and is not required at all under a low demand scenario. A likely trigger for this need will be once there is sufficient certainty associated with commitment of the Narrabri Gas Project. Until this time, we consider it is prudent to defer consideration of Stage 2, in order to utilise information on confirmed need prior to commitment to the associated substantial network cost.

14. We consider that:

- Stage 1 is reasonable and is the option that best satisfies the NER at this stage of the RIT-T process for proceeding with the known loads being proposed for connection to the northwest slopes area. The associated work for Stage 1 is required as soon as possible, and with the inclusion of the transformer at Narrabri represents a low regret cost until such time as other loads in the region are committed, particularly given the extent of loads forecast to develop in the Narrabri area.
- Stage 2 should be revisited as a future CPA once loads are committed and other developments in the area are known with greater certainty. Options for network rebuilds are likely to be necessary if load growth eventuates, however the growth is not certain and therefore the timing of the investments cannot currently be reasonably determined. Further options may also arise in this time and there is value in the flexibility presented by staging this project.

Implications for proposed expenditure

15. We consider that the proposed expenditure of $8.2m ($20/21) corresponding with Stage 1 of Transgrid's preferred Option 5B is likely to represent a prudent and efficient level. Based on the identified need, the proposed expenditure of Stage 1 is required within the next RCP.

16. The proposed expenditure of Stage 2 should be revisited as a future CPA once loads are committed and other developments in the area are known with greater certainty, so as to determine the prudent and efficient option at that time.

1 INTRODUCTION

1.1 Purpose and scope

1.1.1 Purpose of this report

17. The purpose of this report is to provide the AER with an expert review of Transgrid's RIT-T project for the supply to the NW slopes area.

1.1.2 Scope of requested work

18. The AER is seeking an expert review of capex forecasts proposed to be included in TransGrid's transmission revenue allowance for the next Regulatory Control Period (RCP), which was submitted to the AER in January 2022. Transgrid did not include this project in its proposed capex allowance for the next RCP. In its regulatory submission, it referred to this as a project currently undergoing a RIT-T and, in separate correspondence with the AER, Transgrid indicated that it intended for it to be considered as part of its Revised Revenue Proposal (RRP).

19. The scope of this review covers the prudency and efficiency of the proposed project and specifically to review:

- The 'identified need' for the project described by Transgrid;
- The options Transgrid has considered and whether its options analysis is robust;
- The timing of the proposed solution; and
- The reasonableness of the cost estimate for the proposed option, including by considering Transgrid's application of its cost estimation methodology.

20. At the time of our engagement, our assessment was to be limited to published materials and which for this RIT-T project was the PADR. By agreement with the AER, we agreed to consider updated materials provided to us prior to 29 May 2022. Transgrid has since finalised and published its Project Assessment Conclusion Report (PACR).

1.2 Approach and context

1.2.1 Our approach

21. In undertaking our review, we:

- completed a desktop review of the information provided to us by the AER followed by preparing requests for information to Transgrid;
- undertook a virtual review meeting with Transgrid, to ensure we suitably understood the methodology and assumptions being applied to the expenditure requirements and justification in accordance with the NER for RIT-T projects and the stage of development of this RIT-T project; and
- documented our findings in the current report.

1.2.2 Scope limitations

22. We have not been requested to undertake a compliance assessment of the RIT-T project to the AER RIT-T guideline or to consider all aspects of the NER and therefore in this report we do not explicitly consider all matters including those raised through public consultation.

23. To the extent that Transgrid's proposed justification for this project is based on electricity market modelling, we have reviewed the process and methodologies applied, as described in documentation and models that Transgrid has provided. Our review does not encompass independent market modelling. While we have sought to identify the source of assumptions made by Transgrid and its consultants, our review should not be construed as an independent critique of all assumptions inherent in the modelling provided.

24. As stated above, Transgrid has not included this RIT-T project in its Revenue Proposal as a part of its augex forecast for revenue determination purposes. Transgrid states that it included this project as a 'contingent project' although to our knowledge Transgrid has not made a Contingent Project Application (CPA) for it. Transgrid also states that it intends to propose this project as part of its RRP. We have not been requested to consider the regulatory treatment of this RIT-T project, including whether it qualifies as a contingent project under the NER.

25. The limited nature of our review does not extend to advising on all options and alternatives that may be reasonably considered by Transgrid, or on all parts of the capex forecast. We have included additional observations in some areas that we trust may assist the AER with its own assessment.

1.2.3 Regulatory and planning context for this assessment

26. The NEM is currently in the midst of a significant transition towards increased renewable sources, with greater dispersion of generation. We have necessarily undertaken our assessment of the required project based on the current planning and regulatory framework, but cognisant of changes in this framework that are underway. Changes in this framework, and in the electricity market itself, may significantly and rapidly affect the technical and economic requirements for any transmission investment, including the assessment in the current report.

27. We provide further information on these contextual aspects in Appendix A.

1.3 This report

1.3.1 Structure of this report

28. The following sections of our report include the following:

- In section 2, we present background information to provide context to our review; and
- In section 3, we describe our assessment of Transgrid's RIT-T project.

29. In Appendix A, we provide a summary of the current planning and regulatory framework, current reviews underway in response to the energy transition and the impact of these on assessments of transmission projects in the NEM.

1.3.2 Information sources

30. We have examined relevant documents provided by Transgrid in support of the RIT-T project that the AER has designated for review. Transgrid provided further information at the on-site meetings and further documents in response to our information requests. These documents are referenced directly where they are relevant to our findings.

31. Except where specifically noted, this report was prepared based on information provided by AER staff prior to 29 May 2022 and any information provided subsequent to this time may not have been taken into account. We recognise that Transgrid's own assessment may continue beyond the time of our review, as it considers additional information and proceeds through the remainder of the RIT-T process, including consultation with stakeholders. Material changes that result from this process would require reassessment of our analysis and findings.

32. Since we undertook our primary assessment, and prior to finalisation of this report, Transgrid has published its PACR for this project. We have not identified material differences in its final PACR from the information provided to us as the basis for our assessment, and which would result in a material change to the opinion contained in our report.

1.3.3 Presentation of expenditure amounts

33. Expenditure is presented in this report in $2021 real terms, unless stated otherwise.

2 BACKGROUND

2.1 Summary of Transgrid's RIT-T project

2.1.1 Expenditure summary

34. The project identified as "Maintaining reliable supply to the north west slopes area" is listed in Transgrid's Revenue Proposal as a major project undergoing RIT-T as shown in Table 2.1 below.

Table 2.1: Major project summary included in Transgrid's RP ($m, real 2022-23)

Major project undergoing RIT-T	2023-28 estimated cost	Total estimated cost	Expected completion
Supply to North West Slopes	$166.3	$168.4	2027-28

Source: Transgrid 2023-28 Revenue Proposal, Table 17-1

35. In its RP, Transgrid states that

'..for the purpose of this Revenue Proposal we have also treated projects currently undergoing a RIT-T as contingent projects where we expect the outcome of the RIT-T to be identified prior to submitting our Revised Regulatory Proposal to the AER in November 2022.'

36. In relation to the four major projects undergoing RIT-T named in the RP, Transgrid confirmed its intention to submit these projects as part of its RRP in correspondence with the AER in February 2022:[2]

'As noted in our Revenue Proposal, we did not include the indicative costs of major Augex projects undergoing RIT-Ts in our capex forecast in our Revenue Proposal given the current uncertainty and the potential size of these projects. We propose to include the costs of any network solutions arising from the RIT-T process in our Revised Revenue Proposal, which is due to the AER in November 2022.'

37. We understand that Transgrid considers that it had insufficient information available to it at the then-current stage of the RIT-T process to reasonably cost any network solutions, should they be the preferred options.[3]

38. We note that in its Issues Paper, the AER stated:[4]

'While we appreciate that Transgrid's 2023–28 proposal may need to change due to circumstances outside of a business's control, the revised proposal should only include changes required by, or to address matters raised in, the draft decision. Furthermore, our expectation would be that consumers are properly consulted on any such changes.'

39. While noting uncertainty regarding the regulatory status of this project, we have undertaken our assessment as if the project had been proposed for inclusion in a capital allowance and based on the information provided by Transgrid.

[2] Transgrid letter to the AER, 10 February 2022

[3] Transgrid letter to the AER, 10 February 2022

[4] AER Issues Paper, 2023-2028 Revenue Proposal

2.1.2 Current stage of consultation

40. Transgrid is applying the Regulatory Investment Test for Transmission (RIT-T) to maintain reliable supply to the northwest slopes area of New South Wales (NSW). In accordance with the transmission planning and investment framework, the current stage of consultation of this project is as follows:

- PACR released in June 2022.
- PADR released in February 2022.
- PSCR released in April 2021.

41. Our assessment has been completed based on the PADR, and in accordance with the scope of review, reflects the forecasts, proposals and opinions adopted by Transgrid as at 29th May 2022 other than where otherwise specifically stated.

2.2 Transgrid's RIT-T projects in the context of its other planned projects

42. Our reading of Transgrid's RP is that due to the uncertainty associated with major augmentation projects, Transgrid has included many of its major transmission projects as contingent projects:[5]

> *'...so that customers only pay for them if and when they proceed. The costs of these contingent projects are not included in our capex forecast and are therefore not reflected in our forecast revenues or prices.'*

43. We understand Transgrid has included two categories of contingent projects:[6]

- Projects undergoing a RIT-T (comprising four projects that have an indicative cost in the 2023-28 regulatory period of $741.9 million and a total estimated cost of $792.2 million.)
- Standard contingent projects (eight projects that have an indicative cost in the 2023-28 regulatory period of $1,175.9 million and a total estimated cost of $2,142.3 million.)

44. In addition to the contingent projects, a number of additional actionable projects are nominated in the Integrated System Plan (ISP) published by AEMO. The ISP is principally an engineering-economic assessment that determines the least cost combination of network and supply side resources to meet forecast demand within the parameters of government policy. It is used to trigger transmission investment, whereas the market is relied upon to deliver generation investment. Importantly, the ISP identifies an investment need with potential market benefits, not a preferred solution.

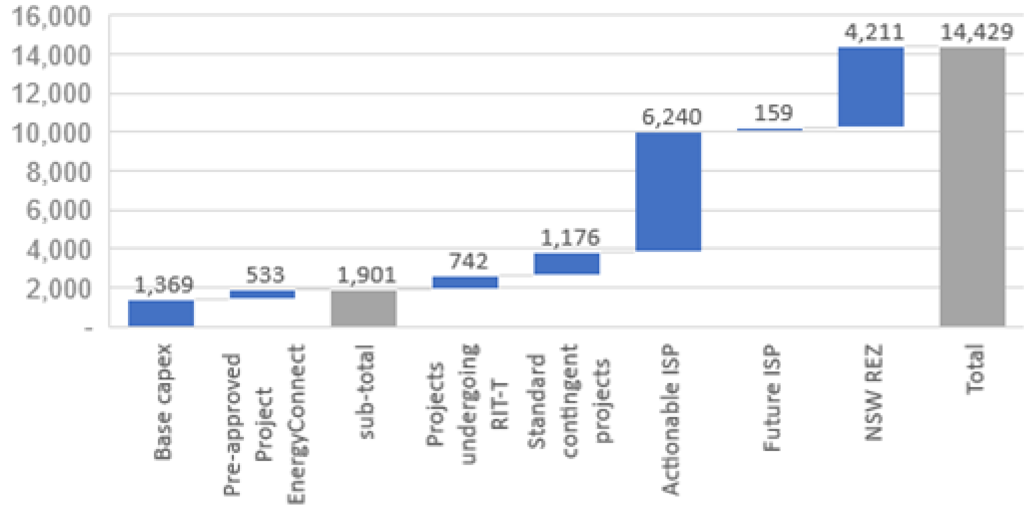
45. Transgrid has separately identified this tranche of additional projects in its Revenue Proposal. A further tranche of projects is also flagged associated with implementing Renewable Energy Zones in NSW.

46. As shown in Figure 2.1 below, collectively this has the potential for $14billion of capital investment within the next 5 years. This is far in excess of the $1.9billion currently proposed in Transgrid's submission.

[5] Transgrid 2023-28 Revenue Proposal, page 163

[6] Transgrid 2023-28 Revenue Proposal, page 163

Figure 2.1: Total planned capex, including contingent ISP and NSW REZ projects ($m, 2022-23)



47. The energy transition has been and is expected to be rapid. Whilst it is appropriate for TNSPs to be guided by the assumptions included in the ISP and other sources, and to plan and engage with local communities at a regional level, this does not insulate it from change. Accordingly, regular and ongoing review of market changes is required to build option value and minimise regret cost.

3 REVIEW OF PROJECT JUSTIFICATION

In this section we provide the findings from our review of the expenditure proposed for the RIT-T project to maintain reliable supply to the north west slopes area in NSW.

We have focussed our review on whether the project is justified, whether the preferred option identified by Transgrid is likely to be the option that maximises a positive net economic benefit, and whether Transgrid's proposed cost represents an efficient estimate. We considered the reasonableness of the inputs, assumptions and methodologies applied by Transgrid to identify the preferred option.

We consider that a project is justified to address the identified need and that Transgrid's selection of Option 5B as the preferred option is appropriate. However, based on the assumptions applied by Transgrid, there remains material uncertainty associated with the commitment of the Narrabri Gas Project as the dominant spot load driving a material component of the scope and proposed expenditure.

Transgrid has identified that this project naturally has two stages, and we consider it is prudent to defer a regulatory decision on stage 2, which comprises the majority of the proposed network investment, to take account of updated information prior to commitment of the full expenditure.

Accordingly, the Stage 1 works defined by Transgrid as comprising the BESS and new transformer at Narrabri is reasonable and is the option that best satisfies the RIT-T at this stage. The associated work for Stage 1 is required as soon as possible. The inclusion of the transformer at Narrabri represents a low regret cost until such time as other loads in the region are committed, particularly given the extent of loads forecast to develop in the Narrabri area. We consider that Transgrid's cost for this work represents an efficient estimate.

The Stage 2 works associated with the line rebuilds should be revisited as a future CPA once loads are committed and other developments in the area are known with greater certainty. Options for network rebuilds are likely to be necessary if load growth eventuates, however the growth is not certain and therefore the timing of the investments cannot be reasonably determined. Transgrid's current planning estimate is that these works will need to be commissioned by 2030.

3.1 Introduction

48. For our assessment, we considered:

- Transgrid's identification of a potential need;
- Transgrid's identification of the set of credible options to address that need, including the basis for excluding some options from the analysis presented in the PADR;
- the reasonableness of the input assumptions and scenarios applied to assess the net economic benefits of credible options;
- Transgrid's and its consultants' estimation of costs and benefits; and
- The reasonableness of the resulting assessment of market economic benefits, including sensitivity analysis, to test whether the identification of the preferred option is robust to changes in key parameters.

3.2 Identified potential need

3.2.1 Summary of Transgrid's PADR

49. The network arrangement in the northwest slopes area of NSW comprises a ring of 132kV lines supporting loads in the Narrabri and Gunnedah load areas, supplied from two 330kV systems located at Armidale and Tamworth as shown in Figure 3.1 below.

Figure 3.1: Northern NSW systems showing north west slopes load area

Source: PADR, Maintaining reliable supply to north west slopes area, Figure B-1

50. The area is primarily supplied by 132 kV lines from the Tamworth 330/132 kV substation:

- Line 968 – Tamworth to Narrabri; and
- Line 969 – Tamworth to Gunnedah.

51. The Narrabri and Gunnedah 132/66 kV substations supply Essential Energy loads in the area, with each substation having two 60 MVA 132/66 kV transformers. The Boggabri Coal and Maules Creek mines are also connected to the TransGrid 132 kV network via the Boggabri East and Boggabri North switching stations.

52. Transgrid has undertaken planning studies for the north west slopes area that show that the network will not be capable of supplying the forecast increases in load in the area without breaching the NER requirements. There are two relevant constraints that will apply if action is not taken:

- Thermal constraints on line 969 under system normal conditions; [7] and
- Voltage stability constraints between Gunnedah and Narrabri for a contingent outage of line 969 or 968.

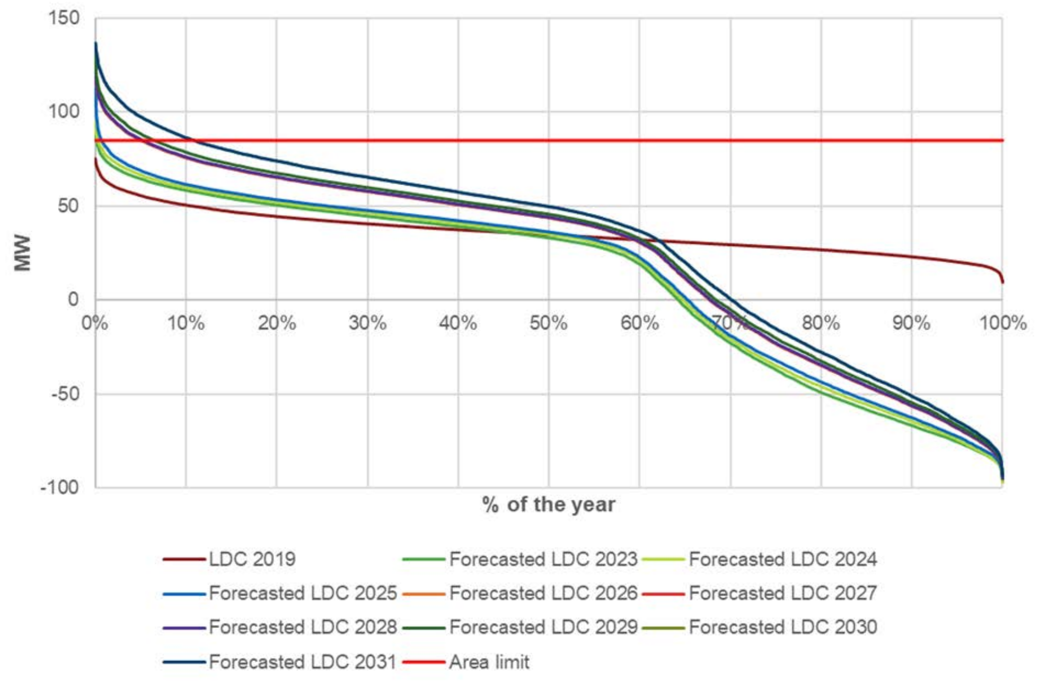
[7] particularly during times of low renewable generation dispatch in the region

53. In its PADR, Transgrid describes the forecast load increases in the area in addition to underlying general load growth in Narrabri and Gunnedah as follows:[8]

'Electricity demand in the North West Slopes is forecast to increase significantly over the next ten years, primarily due to planned connections of new mining and industrial loads in the area.'

54. The load duration curves (LDCs) and demand limits for the Narrabri and Gunnedah 66 kV Bulk Supply Points (BSP) along with the existing and forecast mining loads under the central scenario are shown in Figure 3.2 below. This provides a representation of the load that could be at risk during a calendar year under the central scenario if action is not taken.

Figure 3.2: Actual and forecast LDCs and demand limits for the north west slopes under central demand scenarios[9]



Source: PADR, Maintaining reliable supply to north west slopes area, Figure 8-2

55. Transgrid describes the identified need as:[10]

'... to ensure the above NER requirements continue to be met in the North West Slopes area in light of the forecast demand increases. We consider this a 'reliability corrective action' under the RIT-T as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards, i.e., Schedule 5.1.4 of the NER.'

3.2.2 Our assessment

The north west slopes area is supported by low rated transmission lines that cover long distances

56. Based on the current network configuration, the loss of Line 969 between Tamworth and Gunnedah will require the area to be fed back from Tamworth via Line 968. The latter line is

8 PADR, page 60

9 The data shown in these LDCs is the aggregate of the load at Narrabri 66 kV, Boggabri North 132 kV, Boggabri East 132 kV and Gunnedah 66 kV, less the Gunnedah Solar Farm generation.

10 PADR, page 18

approximately 174km in length, which leads to a material reduction in voltages along the path to Gunnedah. As the loading level increases, voltage stability is at risk leading to risk of voltage collapse and loss of load.

57. The existing 132kV lines are of an older design and have a thermal limit of 73MVA from Tamworth to Gunnedah and Gunnedah to Narrabri. Typical 132kV lines are rated at 100MVA. The system is currently operating without material spare capacity to accommodate new connections.

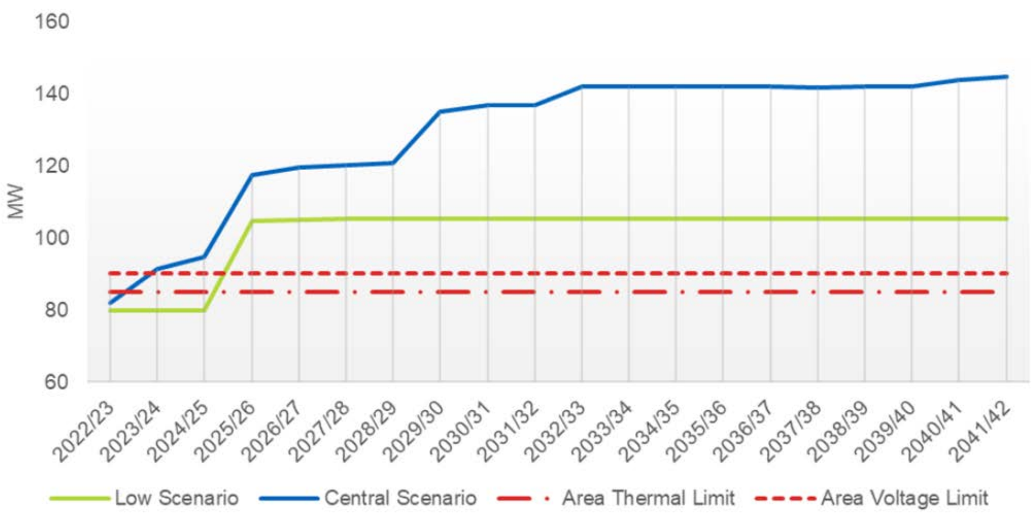
58. The forecast increases in demand will require investment in some form to resolve forecast voltage and thermal limitations.

Demand forecasts have been updated, deferring some of the previously assumed increase

59. Since the PSCR was published in April 2021, demand forecasts for the area have reduced due to an update from Essential Energy in terms of load in its network as well as a specific spot load forecast no longer being expected to proceed. As a result, Transgrid removed consideration of the 'high' demand forecast in its PADR assessment and made minor revisions to its central and low demand forecasts.[11]

60. We understand that the demand forecasts published in the PADR are based on those provided in Transgrid's 2021 Transmission Annual Planning Report and which was based on Essential Energy's forecast. This is shown in Figure 3.3 below with the 'low' and 'central' scenario forecasts assumed in the analysis.

Figure 3.3: Peak demand forecast with voltage and thermal limits



Source: Transgrid RIT-T PADR Maintaining reliable supply to NW slopes area, Figure 2-3

61. Since the PADR was published in February 2022, further changes have been made as detailed in Table 3.1.

[11] PADR, page 4

Table 3.1: Changes in demand forecast assumptions 2022/23 to 2029/30

Source	Location	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
PADR	Gunnedah 66kV	30	42	42	42	42	42	42	42
	Narrabri 66kV	53	53	53	81	82	82	85	101
	Total	**83**	**95**	**95**	**123**	**124**	**124**	**127**	**143**
Latest information	Gunnedah 66kV	27	30	42	42	42	42	42	42
	Narrabri 66kV	53	53	53	81	82	82	85	101
	Total	**80**	**83**	**95**	**123**	**124**	**124**	**127**	**143**
Variance	*Total*	*-3*	*-12*	-	-	-	-	-	-

Source: Adapted from information contained in the PADR and NOSA

62. The changes can be summarised as a delay of 1 year for Carroll Cotton ([redacted]) and also for Vickery coal mine [redacted]). Introduction of new load from 2024/25 for Narrabri coal mine expansion Stage 3 and from the Narrabri Special Activation Precinct (SAP) were not included due to the high level of uncertainty in them proceeding. The demand forecast also excludes load and generation at other locations, including Boggabri.

63. The updated demand forecast and contribution of the Narrabri gas project is shown in Figure 3.4 below.

Figure 3.4: Peak demand forecast showing Narrabri gas project timing (to 2029/30 only)

Peak demand forecast showing Total and Narrabri gas project

[redacted]

Source: EMCa analysis

64. Given the current voltage and thermal limits on this network, Transgrid has demonstrated that it is required to address network constraints assuming the increasing demand forecast. However, as this diagram shows, the demand profile, and the timing as to when thermal and voltage limits are reached under contingency conditions, is highly sensitive to the timing of the Narrabri gas project.

3.3 Credible options

3.3.1 Summary of Transgrid's PADR

65. Transgrid has assessed five types of credible options, noting that one of the options (option 4 has been removed) with variations to each of the options as shown in Table 3.2.

Table 3.2: Summary of the credible options for central scenario

Option	Description	Estimated capital cost ($m, 2020/21)	Expected Delivery date (central)
1	Uprating the existing line 969 from Tamworth to Gunnedah with two variants (Option 1A and Option 1B) for different line augmentations and dynamic reactive support levels at Narrabri and Gunnedah	1A: $284.2 1B: $218.3	2029/30
2	Installing new single or double circuit transmission lines between the Tamworth 330 kV substation and Gunnedah with three variants (Option 2A, Option 2B and Option 2C) for different line augmentations.	2A: $164.0 2B: $128.2 2C: $173.2 2D: $243.9	2029/30
3	Rebuilding line 969 to be a double circuit line with the three variants (Option 3A, Option 3B and Option 3C) for different line augmentations and dynamic reactive support levels.	3A: $160.0 3B: $316.2 3C: $169.1	2029/30
5	Two non-network options, Option 5A and Option 5B, initially use BESS to provide a network support service (Stage 1). Option 5A and Option 5B vary by the size, number and location of the BESS. Stage 2 would involve rebuilding line 969 as double circuit and upgrading line 9UH to 100MVA.	5A: $140.3 plus $[redacted] for BESS[12] 5B: $140.3 plus $[redacted] for BESS[13]	2029/30

Source: PADR, Maintaining reliable to supply to the north west slopes area, NPV model

66. With the exception of removal of Option 4, the network options have remained the same as those presented in the PSCR. Transgrid also states that:[14]

> *'Each of the credible network options requires the installation of a third 60 MVA 132/66 kV transformer at Narrabri due to the firm supply capacity of the existing transformers at this location being exceeded under both demand forecasts and to ensure the reliability standard set by IPART is met for Narrabri in the short-term.'*

67. A brief discussion on the options that Transgrid considered and did not progress was included in the PADR and is reproduced in Table 3.3.

[12] Including connection costs and excluding reinvestment costs for [redacted]

[13] Excluding reinvestment costs for BESS [redacted]

[14] Transgrid PADR, Maintaining reliable to supply to the north west slopes area, page 24

Table 3.3: Summary of the options considered and not progressed

Option	Transgrid's Description
Capacitor banks/ switched capacitors	Not technically feasible. Transgrid conclude that its studies show that due to the expected extensive load growth in the Narrabri and Gunnedah areas, adding a number of additional capacitor banks or switched capacitors in the area is a non-credible solution since step changes in voltages caused by their switching would lead to voltage excursions outside NER requirements. This remains unchanged since the PSCR.
Connection to the New England Transmission Infrastructure (NETI) project	This option was presented in the PSCR (as Option 4) and involves connecting to a potential new non-prescribed project in the Gunnedah area called the NETI (a potential 330 kV transmission line between Tamworth 330/132 kV substation and a new 330 kV substation between Tamworth and Gunnedah with the aim of unlocking new renewable energy investment in the New England area of NSW). Transgrid claims that whilst ARENA has provided funding to assess the feasibility of an innovative commercial model to develop the NETI, Transgrid has removed the option of connecting to the potential NETI from the PADR assessment given the uncertainty involved (particularly around the timing). Transgrid conclude that this option is not technically feasible at this stage of the RIT-T but may revisit it as part of the PACR (particularly if a connection enquiry is made).

Source: PADR, Maintaining reliable to supply to the north west slopes area, Table 4-9

3.3.2 Our assessment

The options reflect staging of investment

68. In its PADR, Transgrid states that:[15]

> *'The timing of the initial stage for all options has been fixed across the two demand forecasts (since these stages effectively need to be committed to now to ensure commissioning in time under the central forecast), while the timing of the later stages varies by forecast depending on when they are required (since they do not yet need to be committed to).'*

69. We consider that the staging of network investment is a critical determinant to a reasonable forecast of the prudent and efficient level of capex. Transgrid's 'stage 2', which comprises almost all of the network investment component, is required by 2030 in the central demand forecast scenario, but is not required under Transgrid's low demand forecast scenario.

Non-network options assist in deferring or avoiding line rebuilds

70. Transgrid has considered two variants of non-network options (i.e. 5A and 5B) in its PADR following submissions received since the PSCR. Transgrid states that non-network solutions in the PADR have been refined following:[16]

- Submissions to the EOI, resulting in two new options being included that utilise BESS; and
- Revised demand forecasts since the PSCR, which has led to elements of the non-network options being resized and rescoped.

71. We consider that these non-network options are appropriate and reasonable credible options.

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15 Transgrid PADR, Maintaining reliable to supply to the north west slopes area

16 Transgrid PADR, Maintaining reliable to supply to the north west slopes area, page 25

72. In its PADR, Transgrid states that:[17]

> *'...both of the non-network solutions have been modelled in terms of their ability to efficiently defer or avoid the rebuilding of line 969 as a double-circuit line when the Narrabri Gas Project comes online, which is part of the preferred network option at this stage of the RIT-T (Option 3A).'*

73. We consider that the use of non-network options to defer or avoid network investment is appropriate and provides option value flexibility with regard to any subsequent need for and scope of network investment.

Options for local supply not explicitly considered

74. We asked Transgrid whether local supply options such as onsite generation had been considered for supply of the forecast mining loads as an alternative to network connection and triggering network investment. We understand from Transgrid's response, that it relies on the processes of the TAPR and RIT-T to solicit non-network options from proponents to meet constraints, including those triggered by new loads.

75. We understand that generation capacity is currently installed at Wilga Park by Santos for its own use at the Narrabri Gas Project. Whilst we are not aware of plans by Santos or by Transgrid to extend the capacity of the installed generation at Wilga Park or at another location to meet future demand, the presence of the onsite generation would appear to be both technically and commercially prudent.

76. Based on information provided by Transgrid,[18] there does not appear to have been consideration of the contribution (if any) of the local generation installed at Wilga Park in the proposed demand profile for the Narrabri gas project. The demand profile commences in [redacted] with no indication of power required for development purposes or staged commissioning of plant leading up to this time.[19] The demand profile is shown in Figure 3.5 below. We expect that local generation options would be considered by mining loads, particularly in development phases, and that they may result in deferring the need for network investment.

Figure 3.5: Narrabri Gas project estimated demand forecast

[redacted]

Source: Transgrid NOSA provided in its response to information request AER IR018

[17] Transgrid PADR, Maintaining reliable to supply to the north west slopes area

[18] Transgrid's response to information request AER IR018, Santos NGP Power Profile 20211027

[19] The exception is the progressive ramp up of demand under the heading of "compression" whereas all other loads are constant and which we expect correspond to installed maximum demand before diversity

3.4 Input assumptions and scenarios

3.4.1 Summary of Transgrid's PADR

77. Transgrid describes the base case as the (hypothetical) projected case if no action is taken, and refers to this as the 'do nothing' option:[20]

> *'Under the base case, where the longer-term constraints associated with load growth in the North West Slopes area is unresolved, significant interruption of supply to loads in the area under normal and contingency conditions would be expected, due to voltage limitations and/or voltage collapse in the local supply network.'*

78. Transgrid describes the use of the base case as a common point of reference when estimating the benefits for each option, specifically in relation to the level of unserved energy if the new demand cannot be met:[21]

> *'We have not quantified the avoided expected involuntary load shedding after 2028/29 as part of the PADR analysis since each option will address all constraints equally from then and avoid the same amount of unserved energy thereafter. Quantifying the full extent of avoided involuntary load shedding under each option after 2028/29 will therefore not assist in identifying the preferred option under the RIT-T. Moreover, the levels of unserved energy under the base case are expected to be extremely high and so will dwarf the other quantified costs and benefits if this approach is not applied (e.g., we estimate that these will exceed $600 million/year by 2029/30 under the central demand forecasts and increase thereafter).'*

79. In the draft PADR, Transgrid has undertaken its analysis across three scenarios, which differ in terms of the key drivers of the estimated net market benefits (including the expected impact on the wholesale market).

80. The three alternative scenarios are characterised as follows:

- A 'low net economic benefits' scenario, involving a number of assumptions that gives a lower bound and conservative estimate of net present value of net economic benefits;
- A 'central' scenario which consists of assumptions that reflect the central set of variable estimates that provides the most likely scenario; and
- A 'high net economic benefits' scenario that reflects a set of assumptions which have been selected to investigate an upper bound of net economic benefits.

81. A summary of the assessment scenarios is shown in Table 3.4.

[20] Transgrid PADR, Maintaining reliable to supply to the north west slopes area, page 40

[21] Transgrid PADR, Maintaining reliable to supply to the north west slopes area

Table 3.4: Assessment scenarios

Variable	Central (S1)	Low net economic benefits (S2)	High net economic benefits (S3)
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Demand	Central demand forecast	Low demand forecast	Central demand forecast
New renewable generation in the area	In-service and committed generators from Appendix B	All in-service, committed and advanced generators from Appendix B.	In-service and committed generators from Appendix B.
Wholesale market benefits estimated	Estimated based on 'progressive change' 2022 ISP scenario	30 per cent lower than central scenario estimate	30 per cent higher than central scenario estimate
VCR	$46.93/kWh	$32.85/kWh	$61.01/kWh
Discount rate	5.50%	7.50%	1.96%

Source: PADR, Maintaining reliable to supply to the north west slopes area Table 5-1

82. In determining the weighted NPV, Transgrid has applied weightings to the three scenarios as follows:

- 52 per cent to central scenario;
- 30 per cent to the low economic benefits scenario; and
- 18 per cent to the high economic benefits scenario.

3.4.2 Our assessment

Assumption that new block loads will be interrupted overstates the benefits

83. Under the base case, and where the identified constraints are not resolved, Transgrid assumes that the new block loads are connected to the network but subsequently subject to regular interruptions under normal and contingency conditions to meet the requirement of the NER.

84. Transgrid has an obligation under the NER to ensure that it complies with the performance standards nominated in the NER for the connection of new loads. However we consider this method of valuing the benefit grossly inflates the benefits of the project required to meet the load. VCR was designed for determining the value of short-term interruptions, and not valuing the benefits to society (or potential new customers) of supplying new loads or industries. In these cases, determination of benefits using GDP or similar may be a more appropriate measure of benefit.

85. While the approach applied by Transgrid is also applied by other NSPs in the NEM, we consider it more appropriate to effectively disregard the calculated benefit, noting that (i) TNSPs have an obligation to supply such loads and (ii), as stated by Transgrid, the 'benefits' of supplying the load dwarf differences in economic benefits between the options and do not assist in distinguishing between them.

Key market modelling assumptions

86. We understand that Transgrid has made modelling assumptions, which include:

- The 'entire' capacity of the BESS is able to be dispatched to the NEM, and which can offset more costly generation that would otherwise operate in the NEM. In reality a portion of capacity would typically be reserved for provision of the network support service;

- No material wholesale market benefits are associated with the network options, as the primary benefit is the provision of greater network capacity and system strength to the north west slopes area; and
- Assessment against a single market modelling assumption based on the AEMO ISP 'progressive change' scenario, with a proportionate approach to assessment of benefits for the low and high net economic benefits scenarios. However, Transgrid indicated that its analysis was to be updated to reflect the more likely 'step change' ISP scenario in its PACR.

87. The above assumptions have been deemed reasonable by Transgrid on the basis that its results indicate that: [22]

> *'..the wholesale market benefits do not have a bearing on the identification of the preferred option, with the ranking instead being driven by the timing, and so avoided unserved energy, differences across the options…'*

88. We similarly observe that the unserved energy is the primary source of benefit, such that a change in the wholesale market assumptions is unlikely to have a bearing on the selection of the preferred option.

All demand forecasts include the Narrabri gas project

89. As described earlier in this report, Transgrid removed the high demand forecast, and replaced this with the central demand forecast for the high net economic benefits scenario. The demand forecasts differ as follows:

- Central demand forecast: assumes that both the Vickery Coal Mine (VCM) and the Narrabri Gas Project connect; and includes the full forecast for the Narrabri Gas Project (Stages 1 and 2).
- Low demand forecast: assumes that VCM does not connect; only Stage 1 of the Narrabri Gas Project is assumed to connect

90. Both demand forecasts include the Narrabri Gas Project, and which Transgrid states does not achieve Final Investment Decision until early 2023 and cannot be considered committed until that time. We consider the reasonableness of the demand assumptions in our assessment of the economic analysis below.

Inclusion of varying discount rates in the weighted scenarios

91. A weighted scenario approach can be appropriate in assessing relative NPV outcomes where there are uncertain parameters. For this reason, the AER RIT-T guidelines refers to weighting of costs and benefits.[23]

92. The AER Guideline and the AEMO Inputs Assumptions and Scenarios report refer to considering different discount rates in project assessments.[24] AEMO refers to doing so as a sensitivity analysis, and we consider this to be appropriate. However, we do not consider it valid to weight together 'scenarios' that contain 'all low' and 'all high' exogenous cost and benefit parameters, with different discount rates applied to the low and high scenarios, noting that different discount rates differentially affect project options depending on the extent to which their costs and benefits are in the near term of further into the future.

Application of weighted scenarios

93. Whilst we support the use of scenario analysis and sensitivity analysis, it is problematic that scenarios with 'all low' and 'all high' parameter values have been weighted together with the 'base' parameter NPVs, with each of the low and high scenarios ascribed probabilities of 25%. Whilst Transgrid has not stated this directly, we would expect that each of the low and high parameters may have a probability of 25%, but the combined probability of 'all low' and

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22 PADR, page 42

23 RIT-T guidelines, August 2020, paragraphs 6 and 7b.

24 RIT-T guidelines, August 2020, paragraph 22(g)

'all high' parameters is the product of the individual probabilities (assuming each is independent) and is therefore very small.

94. Because of the potential for an excessive weighting of a low probability outcome to bias the weighted average, we tend to pay attention to the central, low and high NPV outcomes in their own right, in forming conclusions drawn from the economic analysis.

3.5 Quantification of costs

3.5.1 Summary of Transgrid's PADR

95. The PADR included a total estimate for each of the options and no other information was provided that provided greater detail of the cost estimates or independent assessment of the robustness of the estimates.

3.5.2 Our assessment

Transgrid's cost estimation methodology is reasonable

96. Transgrid provided its CAPEX Estimating Database Administration Procedure which outlined how major project cost estimation is kept accurate and uses the most up to date information, including how it applies escalation.

97. Transgrid engaged Aurecon to provide a technical assurance report on key revenue proposal inputs, tools and processes, including cost estimates and found that the cost estimates benchmark closely with Aurecon's independently derived cost estimates for the same scopes.[25] No specific reference was made to the accuracy of the cost estimate for maintaining a reliable supply to northwest slopes in this high-level assurance report.

98. From our high-level review, the general Transgrid estimating approach[26] appears reasonable and is supported by external review of the forecast costs. However, we note that in response to our request for further information on the development of the cost estimate, Transgrid stated that it did not include any escalation for materials and that this decision is being further reviewed ahead of submission of its RRP for capex that falls within the next RCP. At the current time, therefore, no escalation basis has been provided for review.

No material cost estimate issues identified

99. Transgrid has provided copies of its cost estimates produced for the four options considered in the PSCR, and also included in the OFS documents. In June 2021, Transgrid also commissioned AECOM to produce a Class 4 cost estimate based on high-level design of transmission infrastructure for the north west slopes area based on the four options included in the PSCR. The costs of the non-network options are based on submissions by proponents.

100. Transgrid noted in its response to an information request that it is working through the submissions received on the PADR and additional information requested from non-network proponents, which will inform development of the PACR. We have not identified any material issues with the development of the cost estimate at this stage of the RIT-T process.

Transgrid has already applied staging to its option costs

101. As identified in our assessment of the credible options, Transgrid has effectively separated the costs of its options into two distinct stages that reflect the timing of demand under the central demand forecast. Based on this assessment, we can clearly separate the costs associated with its preferred option as shown in Table 3.5.

[25] Aurecon Transgrid 2023-29 Repex Proposal Technical Assurance Report Page 1

[26] TransGrid Expenditure Forecasting Methodology Page 16.

Table 3.5: Summary of costs for preferred Option 5B under the central scenario,[27] $m real 20/21

Option 5B	Network cost	Total economic cost
Stage 1: BESS by 2025 (BESS is not included as a network cost) and Transformer by 2026	$8.2m	$102.6m[28]
Stage 2: Line upgrade 9UH by 2030, line rebuild 969 by 2030	$132.1m	$132.1m
Total	**$140.3m**	**$234.7m**

102. Of the network cost, Transgrid has indicated in the CBA model that $49.3m ($real 20/21) will be incurred in the next RCP, corresponding with the 3rd transformer at Narrabri and commencement of the rebuild for line 969 and upgrade of line 9UH.

103. A project delivery plan was not available for the preferred Option 5B. Transgrid advised that the corresponding OFS is currently being developed, and which will identify the specific activities relating to this option and will include portions of Option 3A within it.[29]

Transgrid determines that new transformer capacity is required all demand scenarios

104. Due to the firm supply capacity of the existing transformers at Narrabri being exceeded under all scenarios, Transgrid considers that each of the credible network options requires the installation of a third 60 MVA 132/66 kV transformer at Narrabri. We understand that this is primarily driven by inclusion of stage 1 of the Narrabri Gas Project, which results in an increase of the load at Narrabri 66 kV to above 80 MW, and which exceeds the firm capacity of 60MVA and the IPART reliability standard limit of 72MVA.[30]

105. Based on our understanding of the demand forecast, we consider it reasonable to include the cost of the transformer for each of the credible options.

Deferral of some of the demand increase may support the lower cost option

106. We note that Transgrid identified Option 3A as the preferred network option in the PSCR, and this has continued as the preferred 'network' option in the PADR and was the basis for the cost estimate included in the RP. In fact, the network components of Option 5B are based on the design and cost estimate of Option 3A.

107. Option 3A was preferred over the lower cost Option 2B due to the earlier achievable timing. In a scenario where some of the demand increase is deferred, Transgrid may reconsider Option 2B as its preferred option.[31]

3.6 Quantification of benefits

3.6.1 Summary of Transgrid's PADR

108. Transgrid engaged a consultant to undertake its market modelling. Transgrid has provided a copy of its market modelling report, and the results of each of the modelled benefit streams are captured in the NPV model for each option and scenario considered.

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27 We were not able to reconcile the cost provided in the PADR and CBA model of $140m ($20/21) with the $157.3m ($22/23) provided in AER IR18.

28 Excluding estimated reinvestment costs of [redacted] for the BESS proposed at the end of its economic life, assumed to be [redacted]

29 Transgrid's response to information request AER IR018, question 16

30 Presentation to AER and EMCa

31 Option 2B includes a new double circuit 132kV line between Tamworth and Gunnedah ($89m) in place of the rebuild as double circuit option at a higher cost ($94m) in Option 3A.

109. Transgrid describes the main sources of benefits as:[32]

'The benefits for all options, under all scenarios, is primarily comprised of avoided EUE, relative to the base case of no investment for the load growth, valued using estimated VCRs published by the AER. Specifically a load weighted VCR for the central scenario using the AER VCR values for the customer groups relevant to the region.'

3.6.2 Our assessment

Primary benefit is driven by expected unserved energy

110. Transgrid has run system studies to estimate the Expected Unserved Energy (EUE) in the north west slopes area under the base case for each credible option and valued the avoided EUE using a load-weighted VCR[33] based on the 2019 AER report.

111. We understand that the unserved energy has been calculated from 2019 historical data for the Narrabri, Gunnedah and Boggabri areas, and which was summated and scaled for every year of the forecast load growth. An approximation of the Gunnedah East Solar Farm 110 MW export over a 12-month period was then removed from the summed loads to estimate the yearly profile for the net demand in the north west slopes area. The profiles were then compared to the thermal and voltage limits for the area to determine when load shedding would be required, which equated to the unserved energy expected over the study period.

112. As stated earlier in our assessment, the use of VCR to value the energy unserved is likely to result in an overstatement of benefits. However, there is a need to invest to meet the increase in demand, regardless of the way in which the 'benefits' of meeting that demand have been modelled. Our review has therefore focussed on the reasonableness of the proposed timing of the demand increase.

Wholesale market benefits are not material

113. Transgrid has determined that the wholesale market benefits are not material overall in its assessment. For the central scenario, Transgrid concludes that market benefits comprise approximately 10 per cent of the total estimated gross benefit for both of the non-network options, and do not affect the ranking of the options.[34]

Uncertain loads not included in the assessment

114. Several proposed loads that were considered as not yet being fully committed developments were not included in the assessment of unserved energy. These include:

- Narrabri SAP initially at [redacted] and increasing to [redacted];
- Narrabri Coal Stage 3 Expansion Project initially at [redacted] and increasing to [redacted]; and
- Solarig Australia, investigating the inclusion of a Green Hydrogen Production Facility in the order of [redacted] into the region

115. We consider that it is reasonable to exclude these loads from the assessment until such time as greater certainty is provided. With the exception of the Solarig proposal, the other loads are small.

Narrabri gas project remains uncertain

116. Transgrid reviewed the likelihood of the Narrabri gas project proceeding, along with other spot loads, via an independent review by Aurecon. Aurecon assigned a score of '2.0 – most

32 Transgrid PADR, Maintaining reliable to supply to the north west slopes area

33 Includes an estimated composition of loads at Gunnedah, Narrabri and Boggabri (100% industrial) in 2020

34 Transgrid PADR, Maintaining reliable to supply to the north west slopes area, page 47

issues resolved' out of a possible 3.0 to the point load. The study had assumed that [redacted] would be required by [redacted], and this has more recently been revised to [redacted].

117. The information relied upon in Transgrid's NOSA is dated November and December 2020 and was sourced from the Santos Narrabri Gas Project website and NSW planning portal website.[35]

118. In its May update to the Community Consultative Committee Meeting, Santos stated that it will undertake a 12 to 18 month appraisal program ahead of a Final Investment Decision for the next phase of project development, and based on its presentation, this would appear to be no earlier than Q4 2023.[36]

119. We also understand that the Narrabri Gas Project is currently subject to a decision from the native title tribunal, for a future act determination.[37] Based on publicly available information, we found that:

- *'Gomeroi traditional owners have voted overwhelmingly against entering into an agreement with Santos for its Narrabri gas project on the eve of a court hearing to decide if the project can go ahead without their consent. Santos has launched proceedings in the national native title tribunal to progress the 850-well coal seam gas project in north-west New South Wales without agreement from the Gomeroi People.'*[38]
- *'The project is currently waiting on results from a challenge under native title legislation as well as environmental regulatory checks.'*[39]

120. In our opinion this adds further uncertainty as to whether this project will proceed and undermines committing to the full network investment to meet the Narrabri Gas project demand until such time as the project demand is committed.

Timing of Narrabri gas project demand forecast is the key determinant of investment

121. The timing of the Narrabri gas project is a key determinant of the timing of required network investments, particularly those designated by Transgrid as forming part of stage 2. Statements provided in Transgrid's NOSA confirm this:[40]

> *'The available capacity in the Gunnedah and Narrabri area is limited following connection of NGP by thermal constraints on 969 Line under system normal and for a contingent outage of 968 Line, and voltage stability constraints between Gunnedah and Narrabri.'*

122. Also, when reviewing the demand assumptions, the increases at Narrabri substation, and corresponding drivers for network investment at Narrabri appear dependent on the introduction of Narrabri gas project stage 1:[41]

> *'Under all scenarios, the load increase at Narrabri Substation leads to the firm supply capacity for the transformers at this location being exceeded. These constraints are*

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35 Transgrid NOSA, page 4

36 Viewed at https://narrabrigasproject.com.au/wp-content/uploads/2022/06/220517_NGP-CCC_Santos-Presentation-May-22.pdf on 21 June 2022

37 A future act determination is a decision made by the Tribunal about whether a future act that has gone through the right to negotiate process may be done, may be done subject to conditions, or must not be done. When a negotiation party applies for a future act determination, the Tribunal will conduct an inquiry into whether the future act can proceed. In making a determination, the Tribunal must take into account the matters set out in s 39 of the Native Title Act. The parties have the opportunity to produce evidence and make submissions to the Tribunal on those matters. The Tribunal must not make a determination about the future act if it is satisfied that either the grantee party or the Government party has failed to negotiate in good faith with any of the native title parties. (viewed at http://www.nntt.gov.au/futureacts/Pages/Future-act-Determination-Applications.aspx on 21 June 2022)

38 Viewed at https://www.theguardian.com/australia-news/2022/apr/08/gomeroi-traditional-owners-vote-against-agreement-with-santos-for-narrabri-gas-project on 21 June 2022

39 Viewed at https://nirs.org.au/news/labors-support-of-narrabri-gas-project-slammed/ on 21 June 2022

40 Transgrid, NOSA

41 Transgrid, NOSA

required to be addressed through network or non-network solutions with sufficient timing to be ready for the provision of supply to the NGP stage 1.'

Inability to connect additional solar to meet new demand

123. In response to our request for information relating to the role of additional solar generation connecting to the area to meet forecast demand, Transgrid advised that there was insufficient system capacity to connect new generation.[42]

'We have also investigated the impact of additional solar generation connecting into the North West Slopes area. Due to the relatively large connection of the 110 MW Gunnedah East Solar Farm, the Expected Unserved Energy (EUE) during core solar hours has already been removed from the calculated EUE. Hence, additional new solar farms in the area will not materially affect the EUE calculated for the project. Existing solar farm connection enquiries for the area have not progressed once the Gunnedah East Solar Farm connection was committed due to thermal constraints in the area. The solutions identified for the North West Slopes project will enable additional new renewable generation to connect.'

3.7 Economic analysis (including sensitivity analysis and timing)

3.7.1 Summary of Transgrid's PADR

124. Transgrid has utilised a CBA model developed for it by its consultants in seeking to demonstrate that the proposed project is economically viable and to demonstrate optimal timing and its preferred option. The analysis compares the incremental costs and incremental benefits of the proposed option with a base case (or business as usual) counterfactual.

125. Transgrid has provided a copy of its CBA model, which presents the NPV analysis for each of the options and scenarios.

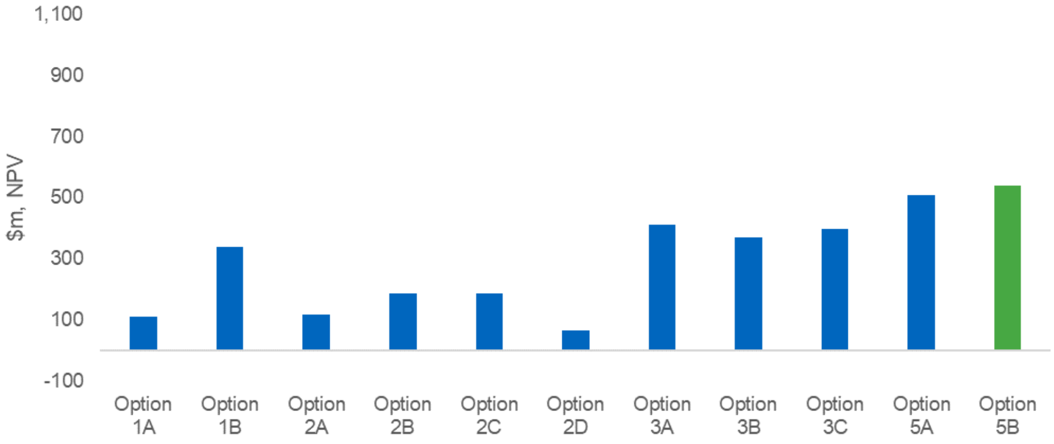
126. Transgrid also undertook sensitivity testing in addition to the scenario analysis in the PADR across a range of factors. Transgrid describes the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for key variables beyond which the outcome of the analysis would change.

127. The results of the draft PADR assessment identifies Option 5B as the preferred option to deliver approximately $540m in net benefits under the weighted scenario.

128. A summary of the NPV analysis for the central scenario is provided in Figure 3.6.

42 Transgrid's response to information request AER IR018, Question 4

Figure 3.6: Summary of the estimated net benefits, weighted across the three scenarios (weighted)



Source: Transgrid PADR Maintaining reliable supply to the north west slopes area, Figure 7-7

3.7.2 Our assessment

Key determinant of the preferred option is assumptions around build times and commissioning dates

129. Options that can be commissioned sooner allow for a substantial amount of unserved energy to be avoided in earlier years. Transgrid's sensitivity analysis of commissioning dates for the top-ranked options indicate that:

- The preferred option is changed to Option 3A if Option 5B (by shifting the commissioning date of the BESS only) is delayed by at least 2 years. The benefits increase if Option 3A can be delivered earlier by up to 2 years; and
- The benefits of Option 5B are within 5% of Option 3A for a number of scenarios including where Option 3A can be brought forward by 1 or 2 years, including a potential 1-year delay to Option 5B.

130. Accordingly, the rankings are sensitive to the timing of investments included in the analysis.

131. Transgrid has also tested the sensitivity of demand forecast, assuming the low demand forecast (excluding Vickery Coal) for the central scenario. Under these assumptions most options have net costs, and the estimated net benefits of Option 5B reduce from $567m to $22m.[43] However, this analysis further demonstrates how sensitive the option is to the timing of the spot loads in the preceding years.

Transgrid has identified the need for further analysis of the preferred option as a part of the PACR

132. We note that Transgrid has stated that it will continue to firm up key assumptions that drive the timing and therefore selection of the preferred option:[44]

> *'…[we] will therefore be focussing, internally and with third party proponents of non-network solutions, to firm up the assumed commissioning dates (and costs) for all options between now and the PACR, and to ensure that the assumed option timing is realistic in all cases. We expect that factors such as the assumed timing of land acquisition and planning approvals will be key to firm up and note that the current proposals display some diversity across these assumptions. It is expected that the*

43 Because of the dominance of VCR-based benefits, Transgrid's consultants' model artificially truncates these benefits in 2029/30. Its reasons for doing so are essentially the same as the reasons why we consider it invalid to rely on such benefits in considering the need for the project, noting that the benefits are the same for all options and therefore do not assist in distinguishing between them.

44 Transgrid PADR, Maintaining reliable to supply to the north west slopes area Page 57

assumed option timings in the PACR will reflect what option proponents are willing to commit to.'

133. We understand that in other submissions, BESS proponents have indicated a delivery timeframe of approximately 12-months and that construction of transmission lines is more likely than not to be delayed. Accordingly, this indicates to us that a non-network solution is likely to continue to be the preferred option.

134. Option 5A and Option 5B vary by the size, number and location of the BESS whilst the benefits are within 6% of each other. Further discussions with the proponents will be key to secure the optimal solution, together with confirming configuration of the network support service.

3.8 Summary of our finding

135. The RIT-T process has revealed a non-network option, involving a BESS, which largely obviates the need for the major part of the network project that Transgrid initially proposed.

136. Proceeding with the proposed transformer upgrade is a low-regret investment that is supportable, in conjunction with utilising services from the BESS. This represents 'Stage 1' of Transgrid's preferred option.

137. Further investment in network development (such as Stage 2 of Transgrid's proposed project) cannot be supported at this stage.

APPENDIX A – CONTEXTUAL INFORMATION ON NEM PLANNING AND REGULATORY FRAMEWORK

A.1 Industry in transition

138. In keeping with electricity systems globally, the National Electricity Market (NEM) is experiencing a significant transition away from reliance on thermal generation towards renewable generation and storage. As a result, the location of these energy sources is also shifting to be more geographically distributed and diverse. This will require a substantial investment in transmission infrastructure to enable connection of these new technologies and to facilitate benefits for consumers by way of a lower cost of electricity.

139. Major transmission investment is required to facilitate Australia's energy transition in line with the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) and beyond. Further, jurisdictions are identifying and planning Renewable Energy Zones (REZs), with major transmission required to support and bring this energy to consumers.

140. At the same time, there has been a move to centralise certain elements of planning of the energy system. Examples of this shift to centralised planning include the development of the ISP by AEMO, and establishment of jurisdictional specific planning arrangements, particularly in relation to the development of REZs, to meet renewable energy targets.[45] Additional planning and regulatory mechanisms, and changes to the mechanisms described above, may also result from implementing the federal government's announced policy of 'rewiring the nation' to support the continued transition to renewables.

141. In this context, the Energy Security Board (ESB) has commenced work on transmission access reform for the NEM, with a view to facilitating connection of '*new generators and storage in places that facilitate the full benefit of all these resources coming into the national power system'.*[46] We summarise the issues that the ESB review seeks to address and its relevance to our assessment of the current RIT-T project, in section A.2.3.

142. We recognise the importance of the energy transition, and the role of all participants including the network service providers including Transgrid. We have necessarily undertaken our review in accordance with the current planning and regulatory framework. Nevertheless, to the extent that 'market benefit'-related projects rely on future assessments, it is necessary to consider the likelihood of continuing changes to technologies and changes to the regulatory and planning framework that affect justification for projects of this type.

143. Given the factors described above, and the reality that transmission projects tend to be both lumpy and capital-intensive, it is particularly necessary to consider option value in assessing major transmission projects. Considerations of option value and the timeframe over which market benefits are adequately able to be modelled, can help to ensure that any transmission investment is prudent and efficient in accordance with the regulatory objectives. This in turn helps in meeting the objective of ensuring that consumers do not end up paying the risk costs of transmission projects that are developed earlier than required or which become stranded or 'regretted' due to changes in the electricity market and the technologies deployed there.

144. While we have taken the factors above into account in our assessment, we also caution that our assessment of the proposed RIT-T project is of this project alone. No inference from our assessment of this project should be drawn on the need for or benefit of transmission projects generally or their role in facilitating the transition to renewables.

45 AEMC Consultation paper, TPI Review, 19 August 2021, page 9

46 Energy Security Board, Transmission access reform, Consultation paper, May 2022, page 5

A.2 Current regulatory arrangements

A.2.1 Overview of planning and investment framework

145. The current regulatory arrangements provide for TNSPs to invest in the transmission network to promote the long-term interest of consumers. This is achieved by an independent regulator, the AER regulating revenues and prices.

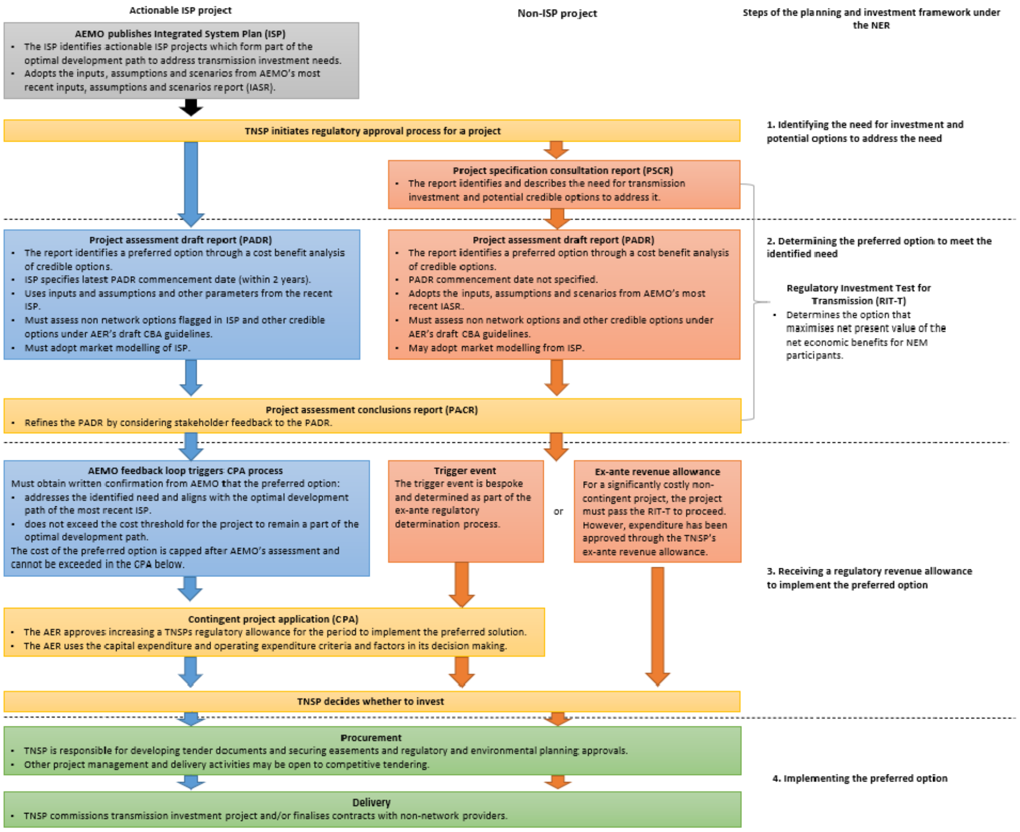
146. TNSPs are regulated on an ex-ante basis, with the governing National Electricity Rules (NER) requiring the determination of a revenue cap, being the result of a building block assessment. The components of the building block model include providing for a return on and return of capital, and which requires the AER to determine a prudent and efficient level of capital expenditure (referred to as the capital expenditure allowance) for each regulatory control period.

147. TNSPs are also subject to efficiency schemes to encourage efficient investment in capital expenditure, the benefits of which are shared with consumers.

148. In addition to the determination of a capital expenditure allowance as part of the regulatory determination cycle for each Regulatory Control Period (RCP), TNSPs are provided with a ‘contingent project' mechanism. Contingent projects are significant network augmentation projects that may arise during a regulatory control period, but the need, timing and/or cost of the project is uncertain. As such, project costs are not provided for in expenditure forecasts for a regulatory control period. Rather, contingent projects are linked to specific investment drivers, which are defined by a 'trigger event'. When a trigger event occurs, the proponent is able to submit a CPA to seek an increase to the revenue allowance to fund the project.

149. An overview of the planning framework is provided in Figure A.1 below.

Figure A.1: Overview of key steps in the transmission planning and investment framework



Source: AEMC, Consultation paper transmission planning and investment review

150. The NER requires also that transmission projects that have a capital expenditure above a pre-determined cost threshold are also subject to the requirements of the Regulatory Investment Test for Transmission (RIT-T). The cost threshold is currently $6 million.

A.2.2 RIT-T assessment

Purpose of the RIT-T

151. The RIT–T aims to promote efficient transmission investment in the national electricity market (the NEM) by promoting greater consistency, transparency and predictability in transmission investment decision making.

152. RIT–T proponents must apply the RIT–T in accordance with the procedures under NER clause 5.16.4 to assess the economic efficiency of proposed investment options.

153. NER clause 5.15A.1(c) states that the purpose of the RIT–T is to:

> *'… identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is a net economic cost) to the extent the identified need is for reliability corrective action or the provision of inertia network services required under clause 5.20B.4 or the provision of system strength services required under clause 5.20C.3.'*

RIT-T guidelines

154. The NER requires that the AER publish guidelines for application of a RIT-T. As set out in the RIT-T application guidelines, the broad steps involved in applying the RIT-T are:

- Identify the need for investment. The identified need may be for reliability corrective action or to increase the sum of consumer and producer surplus in the NEM.
- Identify the base case and a set of credible options to address the identified need.
- Identify a set of reasonable scenarios that are appropriate to the credible options under consideration. A reasonable scenario is a set of variables or parameters that are not expected to change across each of the credible options or base case.
- Quantify the expected costs of each credible option.
- Quantify the expected market benefits of each credible option.
- Quantify the expected net economic benefit of each credible option and identify the preferred option as the option with the highest expected net economic benefit.

A.2.3 Current reviews will provide additional guidance

155. There are two key reviews currently underway that will provide important guidance to the market and regulatory bodies and which seek to address some immediate issues facing the industry transition.

AEMC review of Transmission planning and investment

156. The AEMC has initiated a review of the transmission planning and investment framework to (i) identify issues with the existing regulatory frameworks in relation to the timely and efficient delivery of major transmission projects, (ii) explore options for reform of or improvements to the existing regulatory frameworks, and (iii) recommend possible changes to the National Electricity Rules (NER) and other regulatory instruments (if required) to support frameworks that are fit-for-purpose and promote the timely and efficient delivery of transmission services. [47]

[47] AEMC Consultation paper, TPI Review, 19 August 2021, page 1

157. The AEMC describes the objective of the review as:[48]

'..to ensure that the regulatory frameworks strike an appropriate balance between requiring rigorous assessment, to mitigate the risk of inefficient transmission investment, and the need to facilitate timely investments that deliver beneficial outcomes. Consumers will be paying for these projects for decades into the future and it is therefore important that they are in the long term interest of consumers. As such, it is imperative that the regulatory framework for assessing and approving them remains fit-for-purpose.'

158. Amongst the reasons for this review given in the consultation paper, the AEMC states:[49]

'The magnitude of anticipated investment brings into focus the need for the regulatory framework to accommodate the substantial investment and effectively manage the uncertainty of the transition, as such major discrete projects have a greater degree of uncertainty than business-as-usual (BAU) transmission investment. For the purposes of this consultation paper, the Commission considers major transmission projects to be projects of a significant size, scale and scope such that they are associated with greater uncertainty relative to BAU investments. These can be ISP or non-ISP projects.'

ESB review of congestion management

159. National Cabinet has instructed the ESB to progress detailed design work on transmission access reform and to propose a rule change to Energy Ministers by December 2022.[50]

160. The ESB initiated a project to:[51] (i) address the problems that prompted National Cabinet to ask the ESB to conduct the review, namely, the problems associated with the current access regime; (ii) work with stakeholders to understand their concerns and respond to them where appropriate, including by considering alternative mechanisms proposed by stakeholders, and (iii) ensure sufficient flexibility for jurisdictional differences.

161. The latest deliverable from this project is a consultation paper to seek feedback on four model options to guide the design of solutions for congestion management.

162. The ESB describes the current arrangements for provision of transmission access as follows:[52]

'The NEM has a transmission access regime whereby parties may connect to the grid at any point (subject to meeting technical requirements) and fund only the cost of the assets required to connect to the shared grid. Generators are not required to contribute towards the cost of the shared transmission network, and they receive no assurance that the transmission network will be capable of transporting their output to load centres.'

163. Amongst the reasons provided in the consultation paper for this project, the ESB states:[53]

'The energy transition can be delivered more cheaply and quickly if new generators and storage connect in places that facilitate the full benefit of all these resources coming into the national power system.

In some cases, generators are connecting in locations where, a lot of the time, they are not adding new renewable energy to the power system. Instead, they are displacing the existing renewable generators. If we don't change the access regime, we are likely to end up with a larger generation and storage fleet and transmission network than necessary to achieve the same decarbonisation and reliability outcomes (see Figure 1).

[48] AEMC Consultation paper, TPI Review, 19 August 2021, page 2

[49] AEMC Consultation paper, TPI Review, 19 August 2021, page 2

[50] ESB consultation paper Transmission access reform Consultation paper, page 8

[51] ESB consultation paper Transmission access reform Consultation paper, page 8

[52] ESB consultation paper Transmission access reform Consultation paper, page 15

[53] ESB consultation paper Transmission access reform Consultation paper, page 5

These issues are being recognised by some State governments who have sought to progress reforms to implement renewable energy zones (REZ) within their regions. The work of the Energy Security Board (ESB) aims to support and dovetail with these initiatives.'