energy market consulting associates

TransGrid Revenue Proposal 2023-28

# REVIEW OF RIT-T PROJECT: IMPROVING STABILITY IN SOUTH-WESTERN 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 31 May 2022 and any information provided subsequent to this time has been taken into account only where specifically 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 |
| 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 |
| NEM | National Electricity Market |
| NEMDE | NEM Dispatch Engine |
| 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 |
| --- | --- |
| RP | Revenue Proposal |
| RRP | Revised Revenue Proposal |
| 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 to improve stability in south-western NSW.

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

4. Transgrid has identified a potential need to upgrade the network in the south-western area of NSW, principally relating to the 330 kV transmission line between Darlington Point and Wagga Wagga (Line 63) and surrounding 220kV and 132kV network due to emergence of stability issues.

5. Transgrid states that its planning studies have identified that the 132kV system in south-western NSW can experience stability issues during an outage of Line 63. Transgrid states that the stability issues are currently managed operationally through measures such as:[1]

   - power flow constraints;
   - transfer tripping Line X5 for a trip of Line 63; and
   - splitting 132kV parallels to Line 63 pre-contingency.

6. The stability issues under a Line 63 outage contingency are further exacerbated by the introduction of new generation west of Darlington Point as a result of higher power flows east towards Wagga Wagga from mid-2020. Under these conditions, the power system risks include fast voltage collapse, thermal overload and under-voltage.

7. In its RP submitted to the AER in January 2022, Transgrid has referred to this project as a major project undergoing RIT-T, at a total cost of $175.3m (real 2022-23). On the basis of the information in its RP, Transgrid would propose $127.1m (real 2022-23) to be included in the next RCP based on its preferred network option.

8. Transgrid's PADR published in September 2021 included the network cost of the preferred option at $211m ($2020/21).

## Summary of our review findings

9. Transgrid has substantially updated its PADR in its draft PACR provided to us in response to our request for information, and which we have considered in our review. Whereas in its PADR Transgrid had found that its Option 1A was the only option with positive net benefits across all scenarios, Transgrid has now nominated its preferred option as Option 4 being

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[1] Transgrid RIT-T PADR, Improving stability in south-western NSW, page 15

provision of a 3-year interim network support solution using a BESS followed by establishment of a new Darlington Point to Dinawan 330 kV transmission line at a total network cost of $166m.

10. Transgrid presents the preferred option as delivering a scenario weighted NPV of $91m. If the currently in-service temporary SPS is included, the weighted NPV decreases to $82m.

11. The selection of Option 4 as the preferred option was appropriate based on the assumptions applied by Transgrid. However, there are plausible risks to some of the underlying assumptions that would reduce the NPV, and we consider that the option of extending an SPS and network support arrangements from the BESS in order to cover the years when the majority of the benefit is assumed to occur, has been too readily dismissed by Transgrid.

12. Further, we consider that the NPV is overstated by inclusion of significant benefits prior to the proposed network project being commissioned. This seems implausible and the reason for these benefits, or at least, attributing these benefits to the network project, is not satisfactorily explained. Removing these benefits results in a negative NPV.

13. We consider that more rigorous assessment of options, assumptions and benefits is likely to find that the network project as proposed does not have a positive net market benefit. We consider that Transgrid's PACR analysis also exhibits a degree of optimism with regard to construction timing and the ability to quantify long-term market benefits. It is instructive in this regard, and it is to the credit of the RIT-T process, that Transgrid's preferred option has changed between its PADR and its PACR.

## Implications for proposed expenditure

14. As currently presented, we consider that Transgrid has not adequately demonstrated the value of proceeding with the proposed 330kV line build and associated works.

# 1 INTRODUCTION

## 1.1 Purpose and scope

### 1.1.1 Purpose of this report

15. The purpose of this report is to provide the AER with an expert review of the RIT-T project to improve stability in south-western NSW.

### 1.1.2 Scope of requested work

16. 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), and 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 RRP.

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

- The need for the project –assessing the 'identified need' described by Transgrid;
- The options Transgrid has considered and whether its options analysis is robust;
- The timing of the proposed solution – cognisant of our assessment of the prudency of the selected option, we consider the basis for Transgrid's proposed timing of the work; and
- The reasonableness of the cost estimate for the proposed option, including by considering Transgrid's application of its cost estimation methodology.

18. 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, and which for this RIT-T project includes a draft PACR. Transgrid has now finalised and published its PACR.

## 1.2 Approach and context

### 1.2.1 Our approach

19. 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

20. 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.

21. 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.

22. 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.

23. 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

24. 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.

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

## 1.3 This report

### 1.3.1 Structure of this report

26. 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.

27. 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

28. 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.

29. 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.

30. 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 contained in its draft PACR that would result in a material change to the opinion contained in our report.

### 1.3.3 Presentation of expenditure amounts

31. 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

32. The project identified as "Improving stability in south western NSW" is listed in Transgrid's Revenue Proposal as a major project undergoing RIT-T as shown in Table 2.1.

*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 |
|---|---|---|---|
| Improving stability in south western NSW | $127.1 | $175.3 | 2024-25 |

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

33. 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.'*

34. 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.'*

35. 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]

36. 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.'*

37. 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

38. Transgrid is applying the Regulatory Investment Test for Transmission (RIT-T) to options for improving stability in the south-western New South Wales (NSW) power system. 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.
- Project Assessment Draft Report (PADR) released in September 2021.
- Project Specification Consultation Report (PSCR) released in July 2020.

39. We understand that the information provided in the draft PACR for the purposes of our review, 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. Our assessment was completed prior to release of a final PACR, however we have since had the opportunity to review the final PACR and we consider that it does not result in any material change to the opinion contained in our report.

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

40. 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.'*

41. 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.)

42. 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.

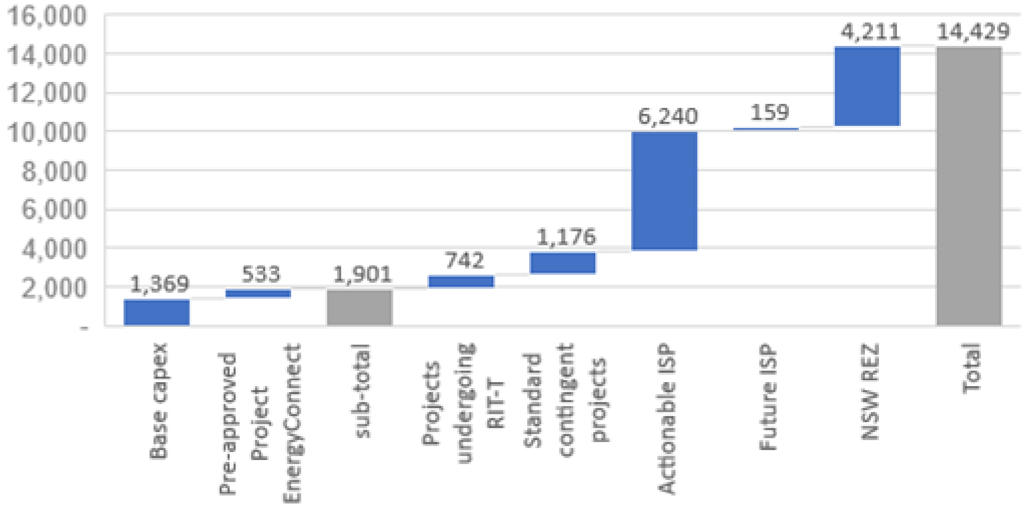
43. Transgrid has separately identified this tranche of additional projects in its Revenue Proposal. A further tranche of projects is also flagged associated with implementing Renewable Energy Zones in NSW.

44. As shown in Figure 2.1, 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, real 2022-23)*




45. 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 them 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 for improving the stability of the south western NSW system. Our review is based on the published PADR and a draft PACR provided by Transgrid.

We have focussed our review on whether the preferred option identified by Transgrid is likely to be the option that maximises a positive net economic benefit. We considered the reasonableness of the inputs, assumptions and methodologies applied to identify the preferred option.

We consider that the selection of Option 4 as the preferred option was appropriate based on the assumptions applied by Transgrid. However, there are plausible risks to some of the underlying assumptions, and when adjusting for a range of reasonable modelling assumptions, the benefits of the preferred option are materially reduced. Taking account of a combination of these factors, we consider that it is not reasonable to conclude that the project has a positive net market benefit.

There is potential for technology and market framework changes over the modelling horizon to disrupt the planning assumptions applied for this project, and market modelling it is inevitably based on. Whilst we do not seek to quantify these changes, we consider that there is a mismatch between the period for which market benefits are likely to exist and the asset life assumed for a new transmission line, and which should favour selection of shorter term options.

Accordingly, we consider that the option of extending an SPS and network support arrangements from the BESS in order to cover the years when the majority of the benefit is assumed to occur, has been too readily dismissed by Transgrid.

## 3.1 Introduction

46. In assessing the project justification, 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 draft PACR;
- 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.

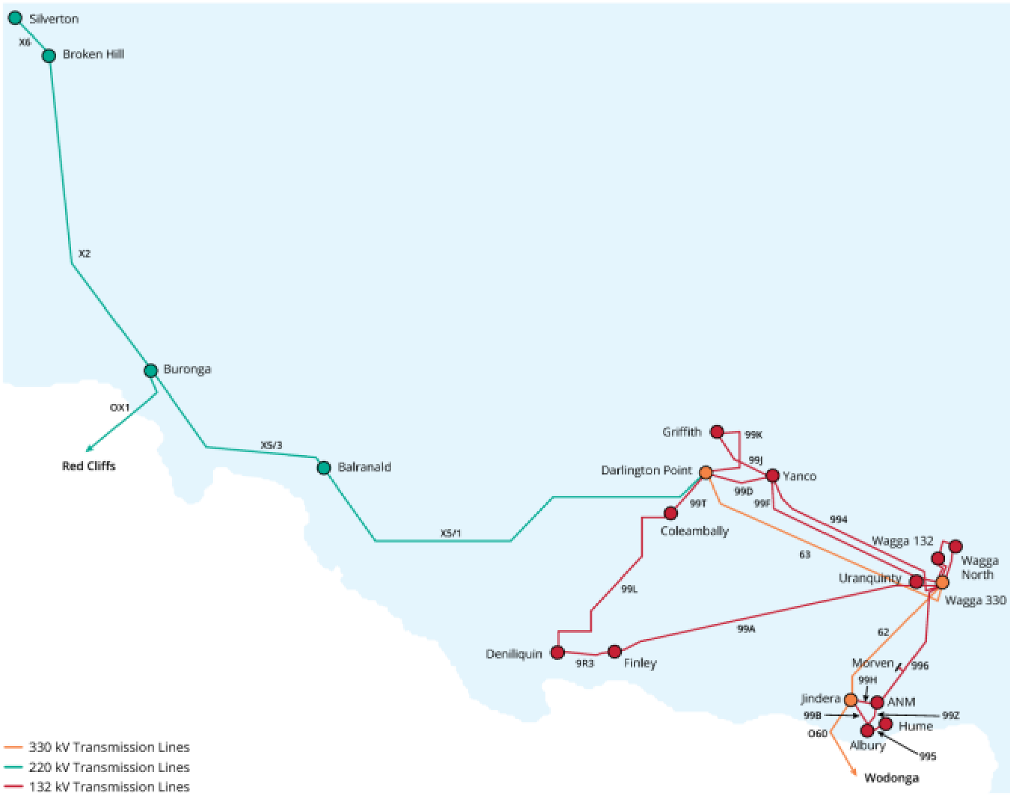
## 3.2 Identified potential need

### 3.2.1 Summary of Transgrid's PADR

47. The network arrangement in south-western NSW is shown in Figure 3.1 below. The primary network elements consist of one 330 kV transmission line between Darlington Point and

Wagga Wagga (Line 63) and 220 kV transmission lines west of Darlington Point (including Line X5). A system of 132kV lines connect into Darlington point and Wagga Wagga, and which Transgrid describe as providing supply to regional towns.

*Figure 3.1: Overview of south-western NSW transmission network*




*Source: PADR, Improving stability in south western NSW, Appendix B, Figure 8-1*

48. Transgrid system studies identified that the 132kV system in south-western NSW can experience stability issues during an outage of Line 63, a 330kV line between Wagga Wagga and Darlington Point.

49. Transgrid states that the stability issues are currently managed operationally through measures such as:[7]

- power flow constraints;
- transfer tripping Line X5 for a trip of Line 63; and
- splitting 132kV parallels to Line 63 pre-contingency.

50. The stability issues under a Line 63 outage contingency are further exacerbated by the introduction of new generation west of Darlington Point as a result of higher power flows east towards Wagga Wagga from mid-2020. Under these conditions, the power system risks include fast voltage collapse, thermal overload and under-voltage.

51. Based on advice from Transgrid, in May 2020, AEMO implemented a constraint equation in the NEM dispatch engine (NEMDE) to limit power flows on Line 63 in order to maintain system stability under contingency conditions.[8] This effectively limits the power transfer capability of Line 63 to approximately 300MW.[9]

7 Transgrid RIT-T PADR, Improving stability in south-western NSW, page 15

8 Transgrid RIT-T PADR, Improving stability in south-western NSW, page 15

9 The power flow limit will vary slightly with power system conditions

52. Transgrid states that the current operational measures and constraint equation result in material constraints to some generators in the region. Accordingly, Transgrid describes the identified need to:[10]

> *'..increase overall net market benefits in the NEM through relieving existing and forecast constraints on generation connecting to the transmission network in south-western NSW.'*

### 3.2.2 Summary of Transgrid's draft PACR

53. In the draft PACR, Transgrid added the following information on the system configuration:

- A proponent-funded temporary special protection scheme (SPS) had been commissioned; and
- the NEMDE constraint equation was updated in December 2021.

54. Transgrid's characterisation of the identified need was unchanged from that published in the PADR.

### 3.2.3 Our assessment

#### The constraint is currently binding

55. We requested information from Transgrid to determine how often the constraint was binding on generators in the region. From Transgrid's response,[11] we understand that the constraint is regularly binding, and that connection of new renewable energy in South Western NSW[12] would be limited and/or would have the effect of further limiting transfer of existing renewable generation from this region.

#### Submissions to the PADR confirm the constraint is binding

56. In the draft PACR, Transgrid confirms that the impact of the constraint was reflected in submissions, where it states:[13]

> *'Many of the submitters to the PADR highlighted the impact of the constraint on generation in the NEM. All of the existing or new renewable generators in south-western NSW that submitted to the PADR commented on the impact of the constraint.'*

57. We have not specifically assessed the submissions to the PADR, however it is clear both from Transgrid's assessment and from submissions that the constraint is already impacting existing renewable generation in the region.

#### Temporary SPS has already reduced constraint by 200MW

58. In its draft PACR, Transgrid states that the implementation of a SPS in December 2021 has reduced the constraint by around 200MW[14] and that the number of dispatch intervals impacted reduced from 1,115 per month to 410 per month.[15] However, the stated level of constraint is still material and will increase substantially when the 580MW of renewable generation (all solar farms) currently being commissioned in the region comes into service, if no mitigating action was taken.

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10 Transgrid RIT-T PADR, Improving stability in south-western NSW, page 16

11 Transgrid's response to information request AER IR018, Question 2

12 *'More than 790 MW of renewable generation has connected in South-western NSW since December 2015 and approximately 580 MW of renewable generation is currently in the process of being commissioned.'* Draft PACR, page 4

13 Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 6

14 Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 52

15 Based on 12,263 dispatch intervals impacted over 11 months and 821 in the 2 months since the SPS installed. Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 16

### BESS is now a committed project

59. The proponent of the BESS in option 4 (Edify) has advised Transgrid that it will proceed with commissioning of the battery solution. The proponent has advised that the full capacity of the BESS will be available for trading in the wholesale market while also providing interim network support services.

60. Transgrid advised that it now considers that the BESS meets the definition of 'committed' status under the RIT-T. Accordingly it is now treated as forming part of its base case.[16]

61. In discussions with Transgrid, we understand that the BESS, once configured to provide a network support service, allows the constraint to be reduced by approximately 120MW. The network support capability will be available from July 2023.

### Identification of potential investment need is reasonable

62. Given the present scale of the constraint on 790MW of lower cost renewable generators in south-western NSW, the identified need to consider options to relieve this constraint appears reasonable. Whether the proposed project is justified therefore depends on whether it can reasonably be considered to have a positive net market benefit. We provide our assessment of Transgrid's economic analysis in section 3.7.

### Investment need has been identified in related planning information

63. The stability issues in south-western NSW are referenced in Transgrid's 2021 TAPR. As noted earlier in our report, the RIT-T process was commenced in July 2020.

64. The stability issues which this project is targeting, and specifically the constraint on Line 63, are not mentioned in AEMOs draft 2022 Integrated System Plan. Transgrid has advised that these issues are considered local planning issues, which AEMO expects Network Service Providers (NSPs) to investigate and identify measures to address.

# 3.3 Credible options

## 3.3.1 Summary of Transgrid's PADR

65. Transgrid has assessed five types of credible options, with two variations to option 1 as shown in Table 3.1.

*Table 3.1: Summary of the credible options (PADR)*

| Option | Description | Estimated capital cost | Expected Delivery date |
|---|---|---|---|
| 1A | 330 kV transmission line between Darlington Point and the new Dinawan substation being constructed for EnergyConnect:<br>• (new line) Establish a new Darlington Point to Dinawan 330kV transmission line | $211m | 4-5 years |
| 1B | 330 kV transmission line between Darlington Point and the new Dinawan substation being constructed for EnergyConnect:<br>• (rebuilt line) Rebuild the existing 99T Darlington Point to Coleambally and 99L Coleambally to Deniliquan as 330kV to Dinawan | $303m | 4-5 years |
| 2 | Establish a new Wagga Wagga to Darlington Point 330kV transmission line | $393m | 4-5 years |

[16] Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 20

| Option | Description | Estimated capital cost | Expected Delivery date |
|---|---|---|---|
| 3 | Establish a static synchronous compensator (STATCOM) solution at the Darlington Point substation, 100MVAr | $50m | 3-4 years |
| 4 | Option 1A + 3-year interim network support solution using a battery (proposed by a confidential submitter) | $211m (network component)<br>$[redacted] for BESS | 4-5 years for network component<br>Network support from battery available [redacted] |
| 5 | A standalone battery solution (proposed by a confidential submitter) | $[redacted] for BESS[17] | [redacted] commissioning |

*Source: Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, Table 4-1*

66. In its PADR, Transgrid introduced Option 4 and Option 5 which were proposed in submissions to the PSCR. These comprise a 3-year interim network support contract provided via a battery solution prior to the construction of a network solution (i.e., Option 4) and a stand-alone battery solution (Option 5).

67. Transgrid included a network diagram for each option. We have not reproduced this information or other technical information relevant to the options in our report.

68. A brief discussion on two options that Transgrid considered and did not progress was included in the PADR and is reproduced in Table 3.2.

*Table 3.2: Summary of the options considered and not progressed*

| Option | Transgrid's Description |
|---|---|
| Rebuild Line 63 as double circuit 330kV transmission line | This option would be considerably more expensive than the other network options outlined above (due to it being double-circuit and also requiring significant demolition costs) and would require extended outage of Line 63 (which would exacerbate the effects of the generation constraints in the area).<br>This option is therefore considered inferior to the credible network options outlined above and not commercially feasible under the RIT-T. |
| Synchronous condensers | Synchronous condensers are not considered able to respond fast enough to meet the identified need. They are therefore not considered technically feasible since they cannot meet the identified need. |

*Source: Transgrid RIT-T PADR, Improving stability in south-western NSW, Table 4-2*

### 3.3.2 Summary of Transgrid's draft PACR

69. In the draft PACR, Transgrid has retained all options. However, it notes that the third-party proponent for a stand-alone BESS solution (Option 5) had withdrawn their offer. Transgrid has referred to this as an option considered but no longer progressed.

70. As a result, Transgrid retained the option to assess a stand-alone BESS solution for completeness but now assumes that it would be Transgrid-owned. This option is retained as Option 5.

71. The revised costs are as shown in Table 3.3 and reflect a reduction in costs compared with the PADR.

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17 Comprising $[redacted] for BESS in [redacted] and a further $[redacted] for replacement BESS in [redacted]

*Table 3.3: Summary of the credible options (PADR and PACR)*

| Option | PADR Estimated capital cost | Draft PACR Estimated capital cost | Draft PACR Expected Delivery date |
|---|---|---|---|
| 1A | $211m | $166.9m | 2025/26 |
| 1B | $303m | $222.2m | 2025/26 |
| 2 | $393m | $285.4m | 2026/27 |
| 3 | $50m | $33.2m | 2025/26 |
| 4 | $211m (network component) | $166.9m for the network component<br>The network support component has no incremental capital costs compared to the base case (since it is considered 'committed').<br>The proposed annual network support cost (opex) is $3.25m per year for the three years of support. | 2025/26 for the network component<br>2023/24 for the network support from the BESS |
| 5 | n/a | $216.0m (initial)<br>$102.1m (reinvestment) | 2024/25 (initial)<br>2044/45 (reinvestment) |

*Source: PADR, Table 4-1 and draft PACR, Table E-1*

## 3.3.3 Our assessment

### Transgrid has updated its options to reflect new information

72. There were three key changes from the PADR options in the Draft PACR. Firstly, as noted above, the third party that was previously providing the BESS withdrew its offer, however Transgrid has instead estimated its own BESS at what appears to be the same costs used in the PADR modelling.

73. Secondly, the BESS for the short-term network support solution is now deemed a committed project so, as is appropriate in an economic analysis, the cost to Transgrid for the network support nets off the charge received by the BESS owner. And lastly, some option delivery timeframes have changed and which we assume is for the same reasons as the cost changes (ie detailed scope review, learnings from recent projects, market trends).

### Credible options are consistent with a reasonable range of potential solutions

74. The investment need is to reduce the risk of a fast voltage stability and thermal constraint resulting from generation greater than the capacity of the network in the case of a contingency. In principle, this can be resolved by increasing network capacity, installing fast acting voltage support (including fast generation runback schemes) or increasing demand behind the constraint. As such the credible options assessed by Transgrid in its draft PACR and the additional options considered are consistent with available potential solutions.

75. We sought additional information to understand the extent to which Transgrid has reviewed a number of alternative options that are present across the NEM. These are summarised in Table 3.4.

*Table 3.4: Consideration of alternative options*

| Option | Transgrid's response |
|---|---|
| Changes to various generator control systems to make them assist or at least reduce the impact such as improving ability to ride through the low voltage or reduce output quickly following loss of Line 63 such as the generator control system changes undertaken in Western Victoria. | We undertook significant analysis to assess the ability of the renewable generators in the area to relieve the Line 63 constraint. Based on the analysis undertaken, we introduced an extra positive term to the RHS of the constraint to recognise the positive contribution by the Darlington Point Solar Farm inverter controls. We also assessed the controls of the other solar farms in the area, however, found that inverter controls available with these solar farms (e.g. Coleambally Solar Farm, Finley Solar Farm, etc.) do not possess the control characteristics (called inverter QV controls) required to provide such benefits via fast inverter voltage controls.<br>Please note that the issues in Western Victoria were due to the control interactions between a number of solar farms that have the same manufacturer inverters. It was possible to overcome this issue by tuning the settings of this particular manufacturer inverter controls. In this case, the issue is primarily a network limitation due to high levels of renewable generation in the area. Hence, ability of further tuning control systems to relieve the constraint is limited. |
| Augmentation of the existing network (other than that included in Option 1B) that would reduce the amount and extent of constraint binding. For example augmentation at 132kV, use of dynamic ratings etc. | We considered many options to relieve the constraint. The primary limitation in this case is due to voltage collapse that can occur in the event Line 63 trips. Augmentation of the 132 kV network has very little contribution to relieving voltage issues at Darlington Point due to high impedance associated with long lines from the next strong transmission node, Wagga. Since the primary limitation is voltage collapse, dynamic line ratings have limited benefits in this situation.<br>We also considered generator runback and transfer trip schemes to remove the excess MWs from the Darlington Point 132 kV subsystem (when 330kV line trips). This provided limited benefit due to speed of response that can be achieved and the fast nature of voltage collapse. |
| Use of staging options to defer the timing of the preferred option. For example, installation of a 'transportable' STATCOM. | Since the existing renewable generation is already significantly constrained, the optimal timing for implementing a solution is as soon as possible. The solutions such as STATCOMS, Battery Systems and Special Protection Schemes cannot fully relieve the constraint due to the technical limitations of the network and limited capability of these options. |

*Source: Transgrid's response to information request AER IR018, Question 19*

76. Following our enquiry, we are satisfied that Transgrid has explored a reasonable range of potential options.

77. The specifications of the various options that Transgrid has defined are also those most likely to cost-effectively resolve the need in the south-western NSW system. For example, examining a 330kV line option matches approximately the capacity of renewable generation that will be connecting and also is the highest voltage used in the area.

### Line route assumptions of option 1 not sufficiently defined in the draft PACR

78. From our reading of the draft PACR description and diagram for Option 1A[18] the line route for the new 330kV line Darlington Point to Dinawan proposed by Transgrid appears to assume the same line route (and corresponding line length) as the rebuild of existing 132kV

18 Option 1A scope is stated as one single line length, whilst 1B is provided in sections and add up to approximately the same length.

lines to 330kV (option 1B). We understand that Transgrid proposes a line easement adjacent to the existing 132kV lines in Option 1A.

79. Whilst there is limited information to make an accurate assessment, this appears to add at least 25% to the route length compared with a direct line route. Whilst the draft PACR states that the RIT-T does not address line route specifics for the preferred option[19], we found that the Option Feasibility Study for Option 1A states that a shorter route was investigated and was found not to be feasible.[20]

80. Given the materiality of the difference in line length and cost, a more detailed examination of a shorter line route would be prudent if the project was to progress, as it would correspond to a material reduction in the cost of the transmission line. We expect that this would need to be balanced against the additional time and effort required for community engagement and environmental approval.

### Nominated delivery dates for the transmission line may be overly optimistic

81. Given the current status of the RIT-T process, some of the commissioning dates proposed by Transgrid in its draft PACR appear optimistic. Recent community challenges with construction of new transmission lines and specifically around Darlington point[21], disruption to supply chains from COVID-19 and the Russian invasion of Ukraine, the dependency of some options on other projects and the scale of transmission build in Australia are all likely to negatively impact delivery timing.

82. The option delivery dates are provided in somewhat unspecific financial years, so it is also unclear within a financial year when a particular option is assumed to come on line. It appears from the market modelling that the end of the financial year (e.g. June 30) is assumed for commissioning of each option, and we consider this to be a more reasonable assumption than early in each year.

83. We examine the implications of the delivery dates on the optimal timing in subsequent sections of our report.

### Temporary schemes were not adequately assessed

84. Transgrid has assumed that both the SPS (which is a new scheme implemented since the PADR) and a BESS providing network support have limited lifetimes. Transgrid states that it considers that extension of the BESS is impracticable[22] and extension of the SPS is not viable.[23]

85. We asked Transgrid to explain the feasibility of extending the proposed Special Protection Scheme and the BESS Network Support service beyond the three years presently assumed (and which Transgrid considers to be the shortest timeframe before the new 330kV line is built). Specifically, we sought to understand the impacts on the market modelling if the SPS and BESS could be extended and construction of the 330kV line deferred.

86. Transgrid stated that the SPS was accepted and implemented as a temporary measure only (i.e., until a longer-term solution can be commissioned) as it considered that the SPS did not meet long-term network design standards:

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19 Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 5

20 Transgrid Option 1A Option Feasibility Study, page 5

21 The original line route for Project Energy Connect was via Darlington Point however was diverted to Dinawan *'to secure the necessary transmission line corridor.'* ElectraNet Project Energy Connect, CPA Submission Summary 2020 (electranet.com.au accessed 17 June 2022).

22 Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 34 "preliminary assessments indicate that it is impractical to reconfigure the BESS controls to continue to provide the identified benefits when more new generators connect to the network due to BESS system technical limitations such as the limit to system strength contribution (i.e.,fault current limitations) and the need to satisfy its performance standard for normal market operation".

23 Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 21 "it is not considered to meet long-term network design standard … incorporates a delay to the controlled opening of Line 63 … requiring a longer than normal time if Line 63 needs to be taken out of service by AEMO in an emergency".

*'Specifically, the scheme involves tripping/disconnecting a number of renewable generators in the area (amounting to about 947 MW, all of which benefit from relieving the Line 63 constraint) and incorporates a delay to the controlled opening of Line 63 circuit breakers at Darlington Point and Wagga, requiring a longer than normal time if Line 63 needs to be taken out of service by AEMO in an emergency. These arrangements are not considered to be viable in the long-term.'*

87. Transgrid stated that:[24]

*'..we do not consider that extending this SPS beyond the presently assumed timeframe is feasible and a longer-term SPS is not considered a credible option in the PACR as it does not have a proponent.'*

88. We made a similar request of Transgrid in relation to extending operation of the BESS, beyond the initial 3-year period, and until such time as transmission investments in the region are developed as predicted by Transgrid. Transgrid stated that it did not consider extending the BESS as feasible, referring to the need to regularly update settings:[25]

*'Specifically, while the BESS can relieve the constraint for current existing and committed generators in the region, our preliminary assessments indicate that it is impractical to reconfigure the BESS controls to continue to provide the identified benefits when more new generators connect to the network due to BESS system technical limitations such as the limit to system strength contribution (i.e., fault current limitations) and the need to satisfy its performance standard for normal market operation. Consequently, the BESS component has been included as an interim measure for the three years only (as proposed by the proponent) and extending it is considered infeasible.'*

89. Whilst challenges to extending the operation of schemes such as these would reasonably be expected, further assessments of feasibility appear justified given the scale of the benefits achieved by these schemes. For example, while the BESS network support service requires full technical feasibility to be confirmed and agreed with AEMO,[26] we consider it (Option 4) to be a 'no regrets' option at this stage.

90. We consider that there is merit in Transgrid more robustly examining the feasibility of extending the SPS and BESS network support service and undertaking economic modelling and NPV analysis on this as an additional option. We consider this further in section 3.7, and as described there, we consider that the lack of rigorous exploration of these options is a significant factor leading us to conclude that the transmission line option that Transgrid proposes, is not justified on information currently presented to us.

## 3.4 Input assumptions and scenarios

### 3.4.1 Summary of Transgrid's PADR

91. The base case is described as the current network configuration in which the current constraint remains in-place going forward.[27]

92. Transgrid commissioned EY to produce a separate market modelling report that was published alongside the PADR. The market modelling was based on the final 2020 ISP and input assumptions, making adjustments for a small number of assumptions.[28]

24 Transgrid's response to information request Aer IR018, Question from 18 May meeting, Item 3

25 Transgrid's response to information request Aer IR018, Question from 18 May meeting, Item 3

26 Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 4

27 Transgrid RIT-T PADR, Improving stability in south-western NSW, page 16

28 Transgrid RIT-T PADR, Improving stability in south-western NSW, page 29

93. Transgrid assessed the credible options against four scenarios as part of this PADR assessment, corresponding with the four 2020 ISP scenarios:[29]

- central;
- slow-change;
- step-change; and
- fast-change.

94. Transgrid did not model the high DER scenario from the 2020 ISP as it considered that the variations in the assumptions these scenarios embody are already reflected in the four that it did model.[30]

95. Transgrid has weighted each of the four scenarios equally (i.e., 25 per cent each).

### 3.4.2 Summary of Transgrid's draft PACR

96. As discussed in the previous section, the committed status of the BESS for option 4, means the costs of the BESS component now feature in both the base case and the Option 4 case. Because they then net out, they effectively have no bearing in the RIT-T assessment.

97. Transgrid has also updated the level of committed generation. In its draft PACR, Transgrid states that an additional 200MW of renewable generation has connected in the area since the PADR.[31]

98. Transgrid again commissioned EY to produce a separate market modelling report for the PACR. The market modelling is now based on the draft 2022 ISP and input assumptions with the only changes to ISP assumptions being inclusion of recent announcements of coal plant closure dates.[32]

99. Transgrid has utilised the same scenarios as deployed in AEMOs 2022 Draft ISP, other than excluding the Slow Change scenario: [33]

> *'The slow-change scenario from the 2022 ISP scenarios has not been modelled given the low likelihood ascribed to this scenario in the draft 2022 ISP (i.e., the 4 per cent weighting AEMO gave this scenario).'*

100. Transgrid has given a weighting to each of the scenarios based on the draft 2022 ISP weightings, as shown in Table 3.5.

*Table 3.5: Summary of scenarios*

| Scenario | AEMO Description | Weighting |
|---|---|---|
| Step Change | Rapid consumer-led transformation of the energy sector and coordinated economy-wide action | 52% |
| Progressive Change | Pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time | 30% |
| Hydrogen Superpower | Strong global action and significant technological breakthroughs | 18% |

*Source: Draft RIT-T PACR, Improving stability in south-western NSW*

29 Transgrid RIT-T PADR, Improving stability in south-western NSW, page 29

30 Transgrid RIT-T PADR, Improving stability in south-western NSW, page 29

31 Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 20

32 Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 20

33 Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 36

### 3.4.3 Our assessment

#### Market benefits assumptions were updated with the latest available information

101. Transgrid, and its market modelling consultant EY, applied a large number of changes to the final 2020 ISP assumptions used for the PADR such as different coal outage rates and renewables pipeline.

102. In its draft PACR, Transgrid has updated the modelling to utilise the latest AEMO assumptions and scenarios, being those underpinning the 2022 draft ISP.[34] In addition, Transgrid has updated assumptions for more recent announcements on coal closures, and in the future market modelling has allowed for further earlier coal plant retirements where these are indicated by the economic assumptions.

#### Base case updated to reflect committed BESS

103. Transgrid's updated modelling now treats the Edify BESS as committed. The consequence of this is that the direct wholesale market benefits of the BESS are now ignored, since they arise under all options and therefore 'cancel out' in the options analysis. Under each of the options, however, indirect wholesale market benefits are accounted for, through relieving the constraint on Line 63.

#### Temporary SPS not included in base case

104. Transgrid has not included the temporary SPS in the base case despite that scheme being in service since December 2021, instead using a sensitivity to examine the impacts of the scheme.

105. Excluding the SPS from the base case is questionable given the scheme is in service and working, albeit Transgrid has examined a sensitivity on the SPS. This assumption is relevant to our consideration of the overall net market benefits of Transgrid's proposal, and which we describe in section 3.7.

#### Committed generation only considered

106. Transgrid has only included existing and in-commissioning renewables projects in the market modelling. Potentially this is conservative (i.e. understates potential benefits) given another 560MW in projects in south-western NSW has been publicly announced and there is another 200MW connection enquiry.[35]

#### Scenarios were updated in the draft PACR with the latest available information

107. With the release of the draft 2022 ISP in December 2021, Transgrid has now utilised the latest AEMO scenarios and applied the new weightings. The timing of key outcomes from the ISP such as the build times for new major transmission augmentations have also been utilised. Transgrid's choice of these scenarios is appropriate.

## 3.5 Quantification of costs

### 3.5.1 Summary of Transgrid's PADR

108. The PADR included a total estimate for each of the options. No greater detail of the cost estimates or independent assessment of the robustness of the estimates was provided.

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[34] This is different to the PACR where more changes were implemented. Transgrid advised they have utilised AEMOs ISP renewable generation and load forecasts which are both important to the Line 63 constraint.

[35] Transgrid Draft RIT-T PACR, Improving stability in south-western NSW, page 20

### 3.5.2 Summary of Transgrid's draft PACR

109. The draft PACR included a total estimate and breakdown for each of the options.

### 3.5.3 Our assessment

#### Transgrid's cost estimation methodology is reasonable

110. 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.

111. Transgrid engaged Aurecon to provide a technical assurance report on key revenue proposal inputs, tools and processes, including cost estimates. Aurecon found that Transgrid's cost estimates benchmark closely with Aurecon's independently derived cost estimates for the same scopes.[36] No specific reference was made to the accuracy of the south-western NSW stability project estimate in this high-level assurance report.

112. From our high-level review, the general Transgrid estimating approach[37] appears reasonable and is supported by external review of the forecast costs.

113. 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.

#### Cost estimate accuracy is reasonable

114. The draft PACR provides high level estimates of the various options, with a breakdown of the major components of the cost estimate for substation, lines, land and batteries. Transgrid provided a south-western NSW Basis of Estimate document which outlined the high-level scopes of the options and a summary of the bottom up build cost estimates with an accuracy of +/-25%.[38] Transgrid states that the estimation accuracy is aligned with its governance process for the stage of the project.

#### Cost estimates have been reduced since the PADR

115. There was no change to the draft PACR project option costs since the Revenue Proposal. However, the cost estimates for the network options have decreased by a range of 21%-34% since the PADR.

116. Transgrid explains the reason for the reductions as being the result of estimate reviews taking into account current market trends, recent project experience and detailed review of the scope of each option.

117. From the information we were provided, we were unable to establish a clear link between these claimed drivers and the change in cost estimate. This was complicated somewhat by inconsistencies between documents, revision commentary (or lack thereof) and apparent mismatches between dates of documents.

#### Inclusion of some cost allowances requires greater justification

118. In reviewing the cost build-up model we did not see sufficient justification for

- Remote allowances (on construction costs) and which include a 15.5% premium at Darlington Point in the Option Feasibility Studies. We consider this is on the high side, however it was not clear from the information provided how this has been applied to the cost build-up and what proportion of costs this may have been applied to.
- Inclusion of a Transgrid allowance of $17.5m in the Option Feasibility Study was not broken down or adequately explained.

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36 Aurecon Transgrid 2023-29 Repex Proposal Technical Assurance Report Page 1

37 TransGrid Expenditure Forecasting Methodology Page 16.

38 TransGrid South Western NSW Basis of Estimate, page 9

119. Given the sensitivity of the NPV results to the network costs, we expected to see better-substantiated cost information provided. However, based on the broad scope of constructing 85km[39] of single circuit 330kV line with 330kV substation connection works at both ends in a regional area, we consider from our experience that Transgrid's cost estimate is within reasonable bounds.

## 3.6 Quantification of benefits

### 3.6.1 Summary of Transgrid's PADR

120. The key sources of benefits described by Transgrid in the PADR are:

- ***Avoided and deferred capital costs of new generation and storage:*** Relieving the existing constraint on generation in south-western NSW and enabling existing and new renewable generation in the area to dispatch more is expected to affect the pattern of new generation and storage build in the NEM going forward. The avoided and deferred capital cost of new capacity in the NEM is a key modelled benefit of the options considered in the PADR.
- ***Avoided generator dispatch costs:*** The wholesale market modelling undertaken in the PADR finds that the avoided dispatch costs of these higher cost generators is a significant market benefit category for the preferred option due to the system constraints on the operation of renewable generation. These cost savings are expected to accrue as soon as the constraint can be relieved and increase until the late-2030s.
- ***Lower transmission costs associated with connecting REZ:*** The market modelling finds that there are avoided transmission costs associated with connecting REZ to the NEM for the preferred option under all scenarios, especially the step-change and fast-change scenarios.

121. The modelling did not include changes in competition benefits nor did it consider option value.

### 3.6.2 Summary of Transgrid's draft PACR

122. Transgrid has updated its market modelling and provided an updated market modelling report for our review. All outputs were subsequently updated in the NPV model provided for our review.

123. The key sources of benefits described were unchanged from the PADR.

### 3.6.3 Our assessment

#### Major source of benefits is associated with savings in generation development costs

124. The dominant source of benefits quantified in EY's modelling for Transgrid, arises from savings in 'costs for non-RIT-T proponent parties'. These essentially represent savings in the capital cost of the modelled generation development path to meet the assumed forecast of demand. The weighted average of these benefits as presented in the EY modelling is $220m for Option 4 and $194m for Option 1A.

125. Other benefits are minimal by comparison – for example for Option 4 a 'fuel saving' benefit of $3.6m is calculated, however this is significantly offset by an assumed increased risk-cost of $2.4m in involuntary load shedding.

39 '*90km of line however as the Line Route is following the same route as Option 1B which provides a more detailed breakdown of the line sections which add up to 85km. Other documents provided by TransGrid refer to Option 1A line length as 80-90km.*' Transgrid RIT-T Draft PACR, Improving stability in south-western NSW, page 30

### Method used for modelling market benefits appears reasonable

126. EY states that it utilises a Time Sequential Integrated Resource Planning (TSIRP) model. This is based on modelling hourly trading intervals with the goal of producing a least-cost generation development and operational cost path over the modelled period. This comprises modelling of capital costs for new generation, fixed and variable operating costs, fuel costs, voluntary and involuntary load curtailment costs and the costs of transmission expansions associated with REZ developments.

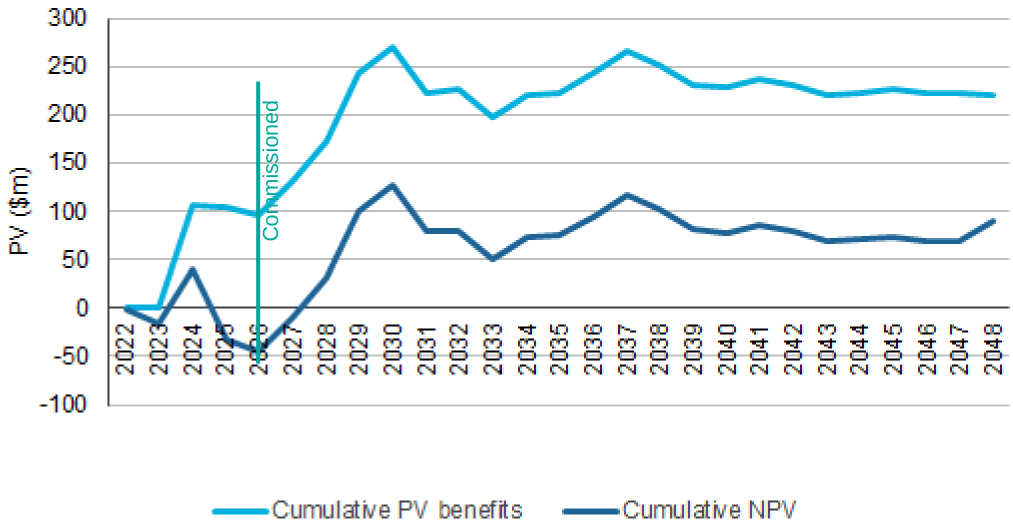
127. It is not feasible to independently verify the quantification of benefits, other than by fully independent modelling. However, the modelling methodology is consistent with what we would expect to find and EY states that it is consistent with the AER's RIT-T guidelines. As stated earlier, EY has also essentially utilised the AEMO Draft 2022 ISP scenarios in its modelling.

### The benefits largely accrue through the period to 2030, after which they are negative before stabilising close to zero

128. As with any modelling involving forecasts, our caution would relate to the modelling assumptions, with increasing uncertainty further into the future. As shown in Figure 3.2, the Houston Kemp NPV model that Transgrid provided shows the cost and benefit profile which, for Option 4 under a weighted average of the scenarios, shows benefits accumulating steeply over the period to around 2030. Beyond this time, however, there is a period for which the benefits are negative, before essentially settling to zero (i.e. in cumulative terms, they no longer increase).

129. This profile raises significant questions regarding the terminal value ascribed in the modelling, and which implies benefits continuing even beyond the modelled period. The impact of the terminal value can be seen in Figure 3.2 as the 'kick up' in the NPV in the cumulative final year of the modelled period and which, we consider, artificially increases the presented NPV of the project. We explore the question of terminal value further in section 3.7.

*Figure 3.2: Cumulative benefits and NPV for Option 4, weighted average scenario, as presented by Transgrid*




*Source: Transgrid draft PACR NPV model, provided in response to AER IR018*

### The modelling attributes significant benefits to the project before it is commissioned

130. Of significant concern in seeking to interpret the modelling of benefits is that, as can be seen in Figure 3.2, around $100m of the benefits (in PV terms) is accrued before the project is commissioned. We infer that this could reflect the benefits resulting from the BESS, which is to be commissioned in 2024. All of the Transgrid costs of the project, however, are network costs (i.e. for the new 330kV line and substation costs) in which case the

incremental benefits resulting from the network investment are represented only by benefits after it is commissioned in 2026.

131. We draw two implications from this:

- Firstly, that there may be significant benefits available at low cost to Transgrid from continuing a network support arrangement from the BESS beyond the 3-year agreement proposed, with the BESS essentially already committed to providing a non-network solution to the same technical issues that the network solution that Transgrid proposes is also seeking to address; and
- Secondly, that the incremental benefits from the proposed network investment may be significantly overstated.

132. We consider both of these issues further in section 3.7.

## 3.7 Economic analysis

### 3.7.1 Summary of Transgrid's PADR

133. Transgrid has utilised a CBA model developed for it by its consultants in seeking to demonstrate that the proposed project is economically viable, to demonstrate optimal timing and in support of 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.

134. Transgrid has provided a copy of its NPV model, which presents the NPV analysis for each of the options and scenarios.[40]

135. Transgrid also undertook sensitivity testing in addition to the scenario analysis in the PADR. The range of factors tested as part of the sensitivity analysis in the PADR are: (i) changes in the network capital costs of the credible options; (ii) alternate discount rate assumptions; (iii) increasing the weighting of the step-change scenario, in line with recent commentary from the ESB; and (iv) alignment with the 2020 ISP assumptions (and recent AEMO gas price forecasts).

136. The results of the PADR assessment identifies Option 1A as the preferred option to deliver the greatest net benefits on a weighted basis across the four scenarios considered. Option 1A was found to deliver an estimated net benefit of approximately $33 million overall relative to the base case.

137. Option 1A involves the establishment of a greenfield transmission line between Darlington Point and the proposed Dinawan substation with an estimated capital cost of $211m. Transgrid stated that delivery was expected to take 4-5 years, with this model assumed commissioning in 2024/25.

### 3.7.2 Summary of Transgrid's draft PACR

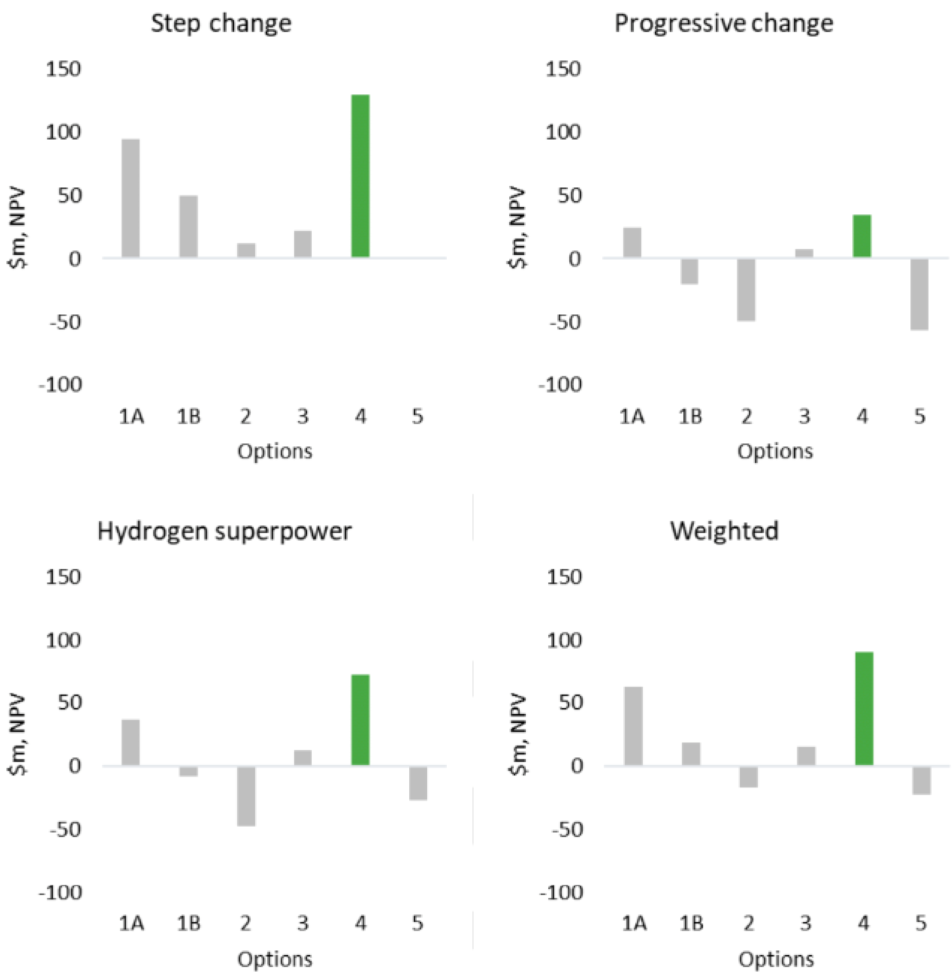
138. Transgrid has updated its CBA and provided an updated NPV model for our review.[41] In this model, the commissioning timing is pushed out to 2025/26 for all options except option 5 (network battery only).

139. A summary of Transgrid's NPV analysis for each of the 6 options assessed, for the 3 ISP scenarios and the weighted scenario is provided in Figure 3.3.

[40] Transgrid's model was developed by its consultants, Houston Kemp and is dated 23rd September 2021.

[41] Transgrid provided this model in response to our information request IR018, From the file name, we infer that the version provided to us is dated 4th May 2022. Transgrid also provided a variant of the model, used for a sensitivity analysis involving the Special Protection Scheme

*Figure 3.3: Transgrid's assessed net present value for each scenario*




*Source: Transgrid RIT-T Draft PACR, Improving stability in south-western NSW, Figure E-1*

140. Transgrid undertook sensitivity testing in addition to the scenario analysis in the PACR. This included testing a range of factors including: (i) the impact of the temporary SPS funded by a proponent; (ii) changes in the capital costs of the credible options; and (iii) alternate discount rate assumptions.

141. The draft PACR now identifies Option 4 as Transgrid's preferred option, on the basis of its analysis that it would deliver a positive NPV and that it has the highest NPV of the investment options both on a weighted basis and in each of the scenarios.

142. From Transgrid's PACR modelling, Option 4 is assessed as delivering an estimated net present value of $91m (on a scenario-weighted basis). Option 4 involves utilising a BESS development that is currently going ahead independent of this RIT-T (i.e., it is considered 'committed' under the RIT-T) to provide interim network support from 2023-24 and the establishment of a new greenfield transmission line between Darlington Point and the new Dinawan substation (that will be developed as part of EnergyConnect), with an estimated capital cost of $166.9m.

143. Transgrid states that the BESS is expected to provide network support from 2023/24 to 2025/26 (when the new line is expected to be commissioned).

## 3.7.3 Our assessment of Transgrid's economic analysis results

### Updated input assumptions have resulted in a change to Transgrid's preferred option

144. There have been substantial changes in the NPVs in the draft PACR from the PADR due to the change to the 2022 Draft ISP assumptions, scenarios and weightings, as well as

changes to cost estimates. No detailed examination of the PADR results is outlined here given the magnitude of these changes.

145. Consequently, Transgrid's preferred option changed from Option 1A in the PADR to Option 4 in the draft PACR. We understand this is primarily due to the commitment of the BESS project in the region (which was the primary difference between the options) and assuming a network support service can technically be provided by this BESS. The BESS provides a short term, relatively low cost means of partially reducing the Line 63 constraint.

146. We consider that the change of preferred option is appropriate, based on Option 4 resulting in a higher benefit than the PADR preferred Option 1A.

#### Benefits favour options that can be implemented earlier than others

147. Given that stability issues are being managed largely through a constraint equation, and that the constraint is currently binding, a faster implementation of a solution improves the market benefits.

148. As we showed in Figure 3.2, the main sources of benefit for this project are realised in the first few years of the assessment period, primarily as a result of deferred generation. This places a higher value on delivering potential solutions as early as possible, noting that any investment needs to be considered over its full economic life.

149. Almost all benefits are from avoided generation/storage costs with some minor impacts in avoided fuel costs. Other benefits are immaterial.

150. The cumulative gross benefits rise rapidly from avoided generation costs until around 2029-30 in both the Step Change and Hydrogen Superpower scenario before dropping and then flattening out. A similar pattern occurs in the Progressive scenario although the peak benefits occur in 2036-37. From Transgrid's PACR model, we find that it calculates market benefits with a PV of $175m in the 4 years from 2027 to 2030 on scenario weighted average basis and the benefits calculated in these years are what drives Transgrid's positive modelled NPV for the project.

#### Transgrid's sensitivity analysis retains Option 4 as the preferred option

151. Each of the three sensitivity analyses that Transgrid undertook retains Option 4 with the highest NPV. Transgrid's analysis taking account of the temporary SPS being in service, results in a $16m[42] reduction in benefits in the weighted case.

### 3.7.4 Aspects of the economic analysis that we consider to be overstated

152. We consider that the following four aspects of Transgrid's economic analysis represent an overstatement of the economic net benefits of this project. The aspects considered here also reflect consideration of the option value inherent in shorter-term solutions and the significant potential regret inherent in locking in a capital-intensive line-build solution, in the absence of a compelling economic case.

#### Sensitivity adjustment 1: Temporary SPS should be assumed in the modelled option(s)

153. From the information that Transgrid has provided, the temporary SPS should be assumed. As above, Transgrid has modelled this as reducing the NPV by $16m.

#### Sensitivity adjustment 2: The assumed terminal value is not supportable and should be removed

154. Transgrid has included a terminal value of approximately $100.1m for the new 330kV transmission line at the end of the modelling period. This presumes that the investment will continue to provide a benefit over the remaining years of its assumed asset life (i.e. beyond the analysis period), that at least exceeds the terminal value.

[42] Transgrid RIT-T Draft PACR, Improving stability in south-western NSW, NPV model. Comparing the 'core result' and the 'SPS sensitivity' in the SPS version of the model supplied by Transgrid.

155. In its draft PACR, Transgrid states:[43]

> *'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. We note that for this RIT-T, the terminal value assumption is not material in terms of the outcome, with the benefits generated by the preferred option exceeding the total estimated project costs well before the end of the assessment.'*

156. On reviewing the cumulative benefits of Option 4 in all scenarios, we observe that the cumulative benefits have a flat trend at the end of the modelling period, corresponding with no further increase in benefits arising from this investment. For example, the average of the scenario-weighted benefits over the last 5 years modelled is approximately zero.

157. In the model provided, we observe that the terminal value is modelled as an offset to the capital cost. That is, the terminal value is accounted for in the NPV modelling as a 'negative cost' and it therefore has the effect of depressing the apparent 'capital cost' in the NPV modelling. Furthermore, we observe that the $25.9m land component of the capital cost is assumed to have a terminal value in 2047/48 equal to its original cost, implying that the land can be 'released' at this time. The effect of this in Transgrid's modelling is that the land effectively has no cost other than the 'time value of money' during the analysis period.

158. We consider that allocation of a terminal value is not appropriate in this case and, from the Houston Kemp model, we have calculated that the impact of removing the terminal value will decrease the NPV by $24m.

### Sensitivity adjustment 3: It is not reasonable to dismiss the option that Transgrid could extend network support arrangements from the SPS and BESS

159. As outlined in the discussion of credible options, Transgrid has limited its assessment of the BESS network support service and the SPS on the basis of these options having limited life spans. However, if these schemes could remain in service then these options are likely to continue to provide material benefits to the region by reducing the constraint.

160. Importantly, as operational solutions, these options provide 'option value' through their flexibility to be retained or superseded as market needs in this region evolve and alternative technologies arise. We are cognisant, for example of the ESB's recognition, in exploring an improved congestion management regime in the NEM, of instances where new renewable generation can be crowding out existing renewable generation, with no net gain to the system. We are also cognisant of the NSW REZ scheme, and that the region in which Transgrid is seeking to address constraints is not a REZ.

161. We expect that extending the life of these schemes will likely result in higher operating costs for regularly having to update the schemes and for the impacts on SPS tripping of solar farms. However, these additional costs are likely to be materially lower than the proposed capital expenditure and the impact of building a new 330kV line and associated substation works.

162. Extending the SPS and BESS network support arrangement provides a 320MW reduction in the existing Line 63 constraint compared with the 1,000MW extra capacity provided by the new 330kV line. As a first approximation, if the benefits are assumed to be proportional to the available capacity, then these scheme extensions would reduce the new line benefits by the order of one third, or $74m. Market modelling with SPS and BESS network support arrangements continuing in service would need to be undertaken to determine a more accurate figure.

### Sensitivity adjustment 4: Benefits commencing only after commissioning

163. The fast ramp up of benefits over the first years of the study period results in relatively fast apparent pay back periods in the modelling that Transgrid has presented. However, as we noted in section 3.6, we find that the market modelling that Transgrid relies on has derived a

[43] Transgrid RIT-T Draft PACR, Improving stability in south-western NSW

benefit with a PV of $107m in 2024, which is two years before Transgrid's project is assumed to be commissioned. While it is not totally implausible that a market model that assumes a degree of foresight amongst generation developers could ascribe a benefit in advance of commissioning, this result stands out as being considerably higher than the benefit of the project in any subsequent year. Moreover, this single year's modelled benefit is sufficient in itself to make the difference between the project having a positive or a negative NPV.

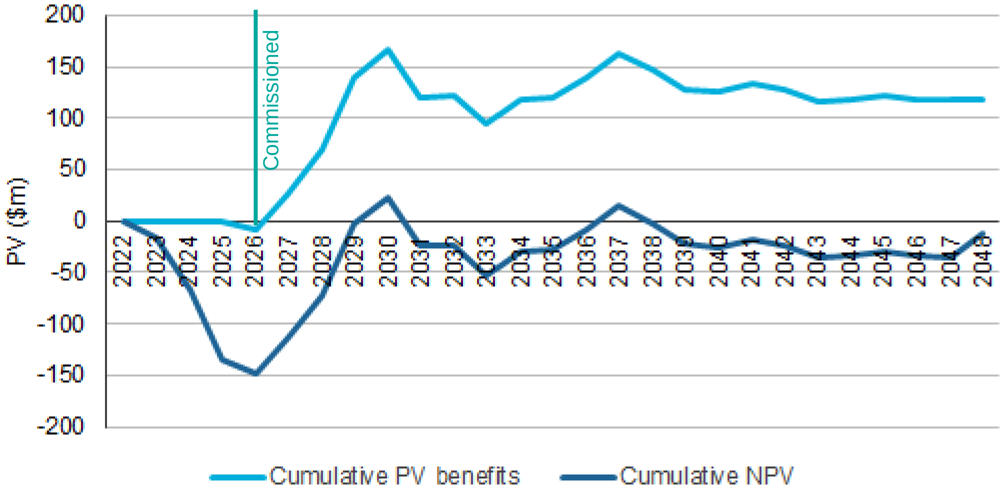
164. As we discuss in section 3.6, we consider it also possible that the benefit prior to commissioning the network (in 2026) is attributable to the BESS.

165. We consider it unlikely that a benefit of this magnitude two years in advance of commissioning, can be plausibly ascribed to the commissioned network project. At a minimum, given its decisive impact, the driver calculations behind this would need to be investigated and 'sense checked' for plausibility.

166. The dominance of this value also raises the question of the impact of a project construction delay of, say, one year – which we would classify as a likely scenario. Transgrid's modelled benefits in 2027 are (in PV terms) $35m, and in 2028 $43m, suggesting that delays of one to two years would negate benefits of this order.

167. In Figure 3.4, we show the cumulative PV of benefits and of the project NPV, if we attribute benefits to the project only after it is commissioned. With this assumption, there is essentially no payback and the overall NPV is negative.[44]

*Figure 3.4: Cumulative PV of benefits and of NPV, with benefits commencing only after commissioning of the network project*




*Source: EMCa analysis from Houston Kemp PACR NPV model, as supplied by Transgrid in response to IR018*

### Combined application of sensitivity adjustments results in a negative NPV

168. In Table 3.6 we show the combined effects of the sensitivity adjustments described above. While each of the adjustments is an approximation, we have investigated the impact of a number of likely alternate assumptions by way of making adjustments to the weighted NPV in Transgrid's NPV model. These are shown in Table 3.6.

[44] This model run removes only benefits prior to 2026. Benefits from this date are as modelled in the Houston Kemp model. The results are for Option 4, from the weighted average of the scenarios, as determined in the model supplied to us. For clarity, this model run includes consideration of this factor only, and does not include removal of the terminal value or the impact of the SPS nor does it assume continuation of the BESS or SPS arrangements.

*Table 3.6: Sensitivity analysis of likely alternate assumptions*

| Item | Potential PV adjustment | Weighted NPV result |
|---|---|---|
| Option 4 (preferred option: Transgrid analysis) | n/a | +$91m |
| Sensitivity adjustment 1: Exclusion of terminal value of line (cumulative benefits flat by 2047/48) | - $24m | +$67m |
| Sensitivity adjustment 2: Install SPS for 3-years (Transgrid has applied as a sensitivity only) | - $16m | +$51m |
| Sensitivity adjustment 3: SPS & BESS Network Support extended over the life of the analysis (based on weighted benefit reduction).<br>*Alternatively, the benefit of the BESS may be implied the PV of benefits prior to commissioning of the new network, and appear to be of the order of $100m in that period.* | - $74m | - $23m |
| Sensitivity adjustment 4: Assuming benefits commence only on commissioning of the project (i.e. from 2026).<br>Alternatively, a commissioning delay of 1 year would indicatively reduce the PV of benefits (and therefore the NPV) by $35m, and a delay of 2 years would reduce the PV of benefits by $78m) | - $103m | -$126m |

*Source: EMCa analysis*

169. We do not consider that these are all independent factors and can necessarily be stacked to reduce the benefits of the preferred option to the level shown above. However, taking account of a combination of these factors, we consider that on a reasonable balance of probabilities and from the information provided by Transgrid to date, it is not reasonable to conclude that the project as proposed by Transgrid has a positive net market benefit.

## 3.8 Summary of our finding

170. We consider that Transgrid's conclusion that this project has a positive economic benefit is undermined by having too-readily dismissed alternative options. We consider that Transgrid's PACR analysis also exhibits a degree of optimism with regard to construction timing and the ability to quantify long-term market benefits. It is instructive in this regard, and it is to the credit of the RIT-T process, that Transgrid's preferred option has changed between its PADR and its PACR.

171. As currently presented, we consider that Transgrid has not adequately demonstrated the value of proceeding with the proposed 330kV line build and associated works.

172. While we have not sought to explicitly quantify this, we are also minded to consider the likely impact of technology and market framework changes over the modelling horizon and the extent to which they are likely to disrupt current forecast assumptions that market modelling is inevitably based on. In essence, Transgrid is proposing to construct assets with a 40 to 50-year technical life, in order to provide a market benefit that it estimates will predominantly occur only for around 4 years from 2027 to 2030. There is an inherent mismatch with this, which we consider renders shorter term solutions more appropriate.

173. Finally, we make note of the deliberations of the ESB and of the NSW regime for facilitating renewables development through REZs and other measures, and which are intended to provide for well-placed network developments that will provide optimal locations for renewable energy resources.

# APPENDIX A – CONTEXTUAL INFORMATION ON NEM PLANNING AND REGULATORY FRAMEWORK

## A.1 Industry in transition

174. 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.

175. 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.

176. 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.

177. 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.

178. 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.

179. 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.

180. 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.

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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

181. 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.

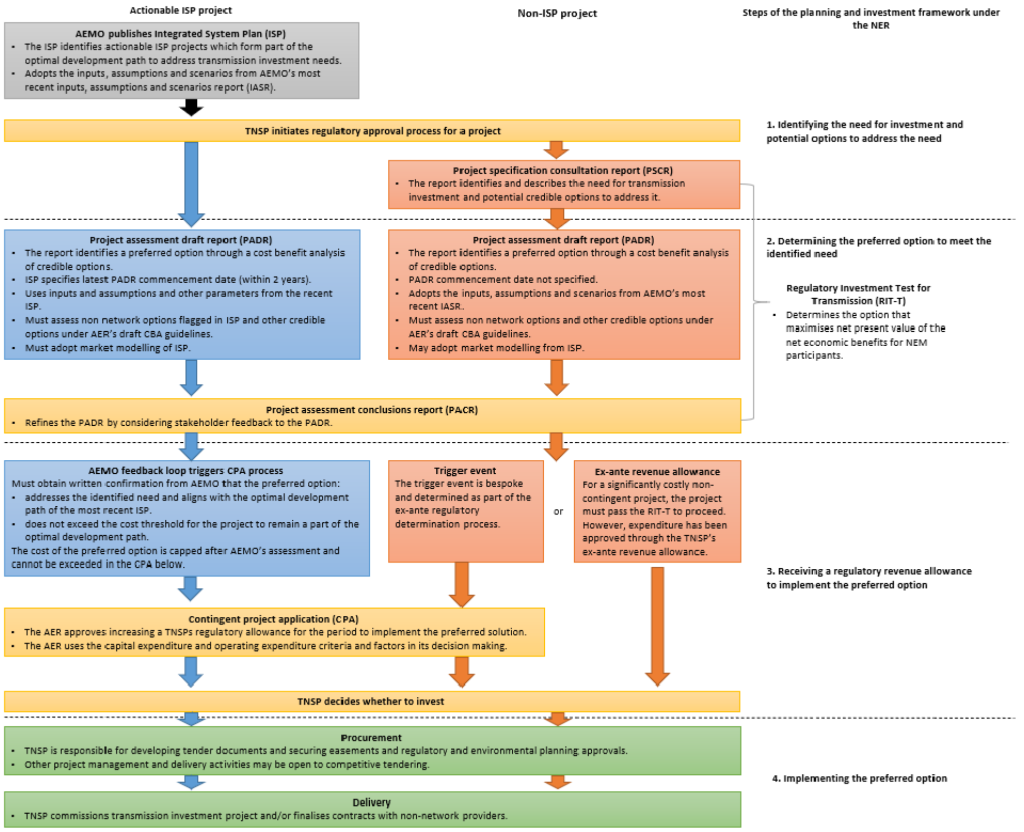
182. TNSPs are regulated on an ex-ante basis, with the governing National Electricity Rules (NER) requiring the determination of a revenue cap, being the result of a building block assessment. The components of the building block model include providing for a return on and return of capital, and which 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.

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

184. 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.

185. 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*

186. 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

187. 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.

188. 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.

189. 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

190. 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

191. 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

192. 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]

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

193. 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. '*

194. 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

195. 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]

196. 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.

197. 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.

198. 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.'*

199. 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.'*