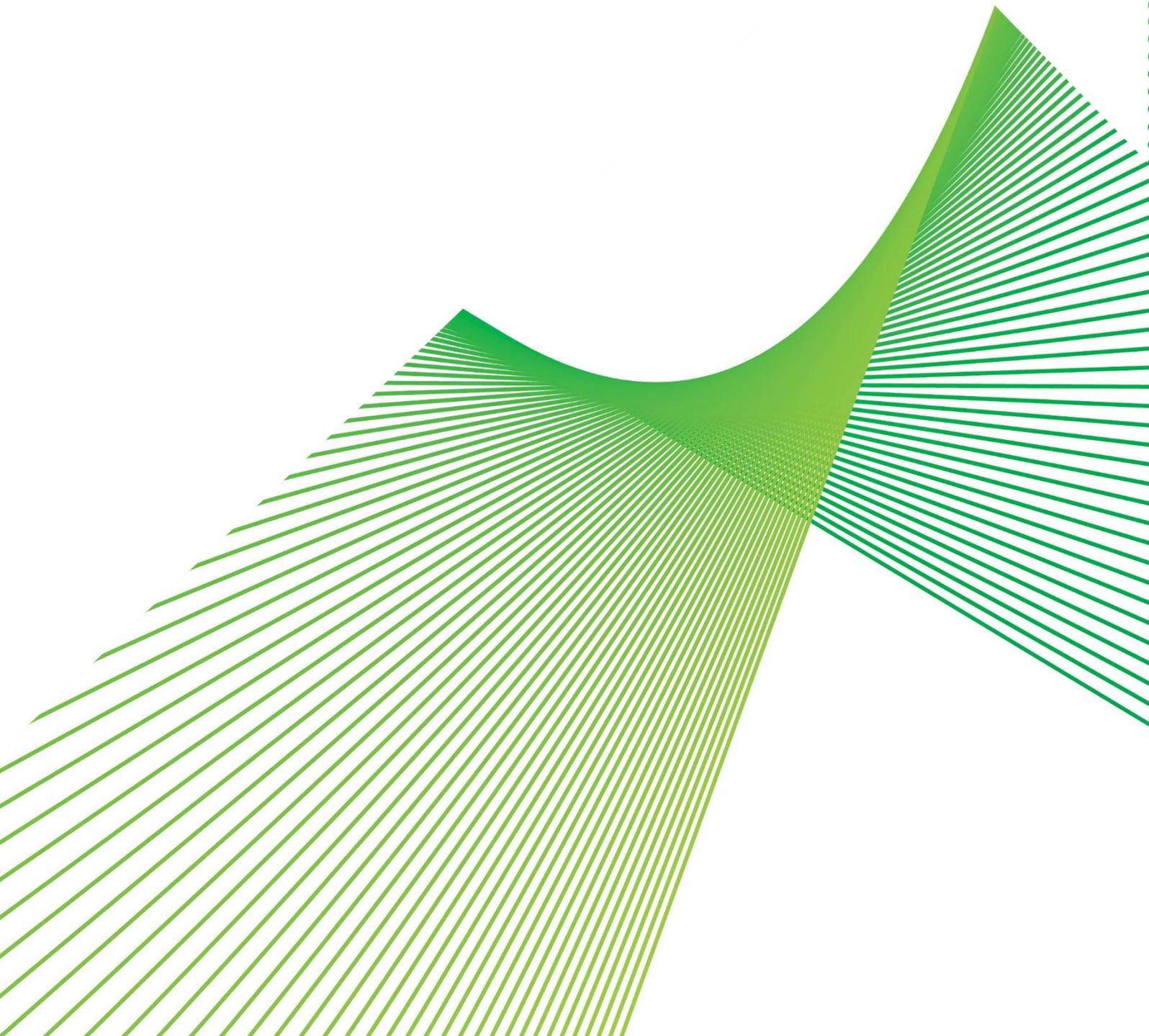


# System Security Roadmap Operational Technology Upgrades

RIT-T Project Assessment Draft Report

Date of issue: 12 May 2025



## Disclaimer

---

This suite of documents comprises Transgrid's application of the Regulatory Investment Test for Transmission (RIT-T) which has been prepared and made available solely for information purposes. It is made available on the understanding that Transgrid and/or its employees, agents and consultants are not engaged in rendering professional advice. Nothing in these documents is a recommendation in respect of any possible investment.

The information in these documents reflect the forecasts, proposals and opinions adopted by Transgrid at the time of publication, other than where otherwise specifically stated. Those forecasts, proposals and opinions may change at any time without warning. Anyone considering information provided in these documents, at any date, should independently seek the latest forecasts, proposals and opinions.

These documents include information obtained from the Australian Energy Market Operator (AEMO) and other sources. That information has been adopted in good faith without further enquiry or verification. The information in these documents should be read in the context of the Electricity Statement of Opportunities, the Integrated System Plan published by AEMO and other relevant regulatory consultation documents. It does not purport to contain all of the information that AEMO, a prospective investor, Registered Participant or potential participant in the National Electricity Market (NEM), or any other person may require for making decisions. In preparing these documents it is not possible, nor is it intended, for Transgrid to have regard to the investment objectives, financial situation and particular needs of each person or organisation which reads or uses this document. In all cases, anyone proposing to rely on or use the information in this document should:

1. Independently verify and check the currency, accuracy, completeness, reliability and suitability of that information
2. Independently verify and check the currency, accuracy, completeness, reliability and suitability of reports relied on by Transgrid in preparing these documents
3. Obtain independent and specific advice from appropriate experts or other sources.

Accordingly, Transgrid makes no representations or warranty as to the currency, accuracy, reliability, completeness or suitability for particular purposes of the information in this suite of documents.

Persons reading or utilising this suite of RIT-T-related documents acknowledge and accept that Transgrid and/or its employees, agents and consultants have no liability for any direct, indirect, special, incidental or consequential damage (including liability to any person by reason of negligence or negligent misstatement) for any damage resulting from, arising out of or in connection with, reliance upon statements, opinions, information or matter (expressed or implied) arising out of, contained in or derived from, or for any omissions from the information in this document, except insofar as liability under any New South Wales and Commonwealth statute cannot be excluded.

## Privacy notice

Transgrid is bound by the *Privacy Act 1988 (Cth)*. In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions.

Under the National Electricity Law, there are circumstances where Transgrid may be compelled to provide information to the Australian Energy Regulator (AER). Transgrid will advise you should this occur.

Transgrid's Privacy Policy sets out the approach to managing your personal information. In particular, it explains how you may seek to access or correct the personal information held about you, how to make a complaint about a breach of our obligations under the Privacy Act, and how Transgrid will deal with complaints. You can access the Privacy Policy here (<https://www.transgrid.com.au/Pages/Privacy.aspx>).

## Executive summary

---

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for Transgrid's System Security Roadmap Operational Technology contingent project to upgrade operational technologies and tools for use in our control rooms and corporate offices.

The Australian Energy Regulator (AER) accepted the System Security Roadmap Operational Technology project as a contingent project for Transgrid's 2023-28 regulatory period, subject to the successful completion of early works and fulfillment of specific trigger events.<sup>1</sup>

One of the trigger events identified by the AER for the Contingent Project Application (CPA) is the successful completion of a RIT-T. This RIT-T demonstrates that an investment in operational technology and tools is the preferred option to address the increasingly complex operational challenges faced by Transgrid as the owner and operator of the New South Wales (NSW)/Australian Capital Territory (ACT) transmission network. Publication of this Project Assessment Draft Report (PADR) is the second step in the RIT-T process. It follows the publication of the Project Specification Consultation Report (PSCR) on 14 October 2024.

The PSCR received one submission from Energy Consumers Australia (ECA). We have also sought responses from potential vendors in a request for information (RFI), which have informed refinements to the scope of the options and the cost estimates in this PADR. In addition, we have continued to engage closely with the Transgrid Advisory Council (TAC) in progressing and testing the assessment in this PADR.

### **Project context: operational challenges in a transitioning power system**

The electricity system in NSW is currently undergoing a period of transformation, with several factors driving increased complexity in power system planning and operations.

Historically, the consistent profile and flexible output of baseload generators allowed transmission network operators to quickly stabilise the technical operating envelope of the power system and return the system to secure operations following contingency incidents (generator trips, equipment failures, weather events, etc.). However, the NSW power system is undergoing a transition from a small number of large, centrally distributed thermal generators to many small, distributed, variable generator connections and storage resources. This results in a more complex and dynamic transmission network to manage, given the significant increase in the number of resources connected to the transmission network, more monitored points for the control room, new asset types and variable bi-directional power flows.

Whilst these developments will ultimately benefit consumers through increased access to lower cost, zero-emission energy sources and the ability for the network to operate more flexibly overall to meet demand, they also increase the complexity of the system Transgrid needs to manage.

This transition is driving a substantial increase in information and analysis requirements across our operational control and operational planning functions, which is exacerbated by an increase in the number of transmission assets and the new types of transmission assets, combined with unprecedented changes in generation and load interacting with our network. Additional complexity also arises from the more variable characteristics defining renewable generation and storage compared to retiring baseload generation. In the

---

<sup>1</sup> AER, *Transgrid transmission determination – 1 July 2023 to 30 June 2028 – Attachment 5: Capital expenditure*, Final decision, p. 47.

absence of an upgrade to the capabilities used in our control rooms and corporate offices, the increasing complexity of the NSW power system means that:

- it is likely that, as a result of Transgrid maintaining static operating limits, constraints will need to be imposed more frequently on the operation of the power system in NSW and the system will begin to be operated in a more conservative manner (which may require constraining the operation of low marginal cost renewable generators), to have sufficient confidence that the system will remain within its required operating envelope; and
- there is an increased likelihood of emergency outages or disruptions when our operators are overburdened from needing to access and confirm the accuracy of information from multiple sources following contingency events, which are expected to increase in frequency. Specifically, there is a greater risk of failure for operators to take required actions within the required time, in turn leading to an increased risk of expected unserved energy (EUE) to end consumers going forward.

Transgrid plans to address these potential adverse outcomes proactively and this RIT-T is being carried out to provide us with the tools to prevent such a situation from arising.

**Identified need: net market benefits arising from investment in operational technologies and tools for use in control rooms and corporate offices**

The identified need for this RIT-T is to increase overall net market benefits in the National Electricity Market (NEM) as the complexity of the electricity system increases, by:

- avoiding the need to impose more frequent constraints on the operation of generators connected to our system going forward to ensure the system remains within its required operating envelope. This includes reducing the need to impose constraints during periods of planned and unplanned transmission outages, including outages necessary to connect new generation and undertake network upgrades; and
- allowing our control system operators to better prepare for, and then assess information and respond to, contingency events in an increasingly complex operating environment with a substantial increase in information sources needing to be monitored, which, amongst other things, is expected to reduce the likelihood of load shedding (i.e., expected unserved energy (EUE)).

We expect market benefits will predominately arise from:

- reduced dispatch costs and greenhouse gas emissions, resulting from the ability to operate the system with fewer constraints on low marginal cost and low emissions renewable generation; and
- reduced expected EUE, resulting from a reduction in the risk of contingency events escalating to the point where load shedding is required.

Our assessment indicates that the market benefits from enhancing the capabilities of the operational technology and tools (including our Supervisory Control and Data Acquisition (SCADA) system) in our control room and corporate offices will exceed the costs of these investments. As such, we have identified this as a 'market benefits' driven RIT-T (i.e., as opposed to a 'reliability corrective action' to address regulatory or service standard obligations).

## Developments since the publication of the PSCR

There have been two important developments since the publication of the PSCR. The first is that in October 2024 AEMO provided a letter of written support for Transgrid's proposed upgrades to operational technology and tools for use in our control room and corporate offices.<sup>2</sup> The full letter has been published on our website.

In particular, AEMO acknowledged the urgent need for the investment to enhance Transgrid's capabilities to securely operate, plan and, manage the NSW/ACT power system. AEMO highlighted that Transgrid's proposed investments in operational technology and tools are:<sup>3</sup>

*consistent with the experience of system and network operators globally, which are undergoing similar shifts and are making equivalent investments in the architecture, data and tools required to operate, plan and manage the system of the future.*

AEMO also highlighted the interdependent roles, systems and capabilities between itself and Network Service Providers (NSPs), emphasising that investments in operational tools by AEMO alone are insufficient to ensure system security across the NEM during the energy transition.

AEMO has confirmed that the options outlined by Transgrid in the PSCR are 'fully aligned' and complementary to AEMO's Operational Technology and Engineering Roadmaps, which describe the emerging operational and engineering challenges from the transition to higher levels of renewable generation while maintaining reliability, security and resilience.<sup>4</sup>

The second development is Transgrid's market testing process, which, following consultation with TAC, was conducted to confirm the availability, capacity, solutions and expected cost to deliver the proposed levels of capability uplift. This process considered each option within the PSCR in light of retaining and building on our core SCADA/Emergency Management System (EMS).

Transgrid considers it prudent to retain, at the core, the existing software as it will be more efficient to leverage the SCADA/EMS asset that was commissioned in 2022. This software remains commonplace in the industry, and the software has been updated to support renewable resources. As such, responses were sought from all of the existing software's Australian-based System Integrators as part of a RFI to explore a range of solutions and attain latest market pricing. The System Integrator model was used as it offers cost efficiencies by reducing redundancies when delivering a program of technologies and reduces delivery risk through ensuring all components function together smoothly, with a focus on data and integration. Vendors were requested to submit proposals against requirements encompassing the three options defined within the PSCR (i.e., reactive, proactive and predictive).

Through this market testing process, valuable insights emerged from vendors' local and global experience with transmission and distribution network service providers. Notably, vendors indicated that the desired levels of capability uplift within Option 3, while well aligned with industry and vendor software product roadmaps, had high degrees of cost and functional uncertainty. Additionally, the RFI identified that Option 3 could not be delivered by the targeted date of 2030. As a result, Option 3 has now been excluded as a

---

<sup>2</sup> AEMO, *Support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices*, 15 October 2024.

<sup>3</sup> AEMO, *Support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices*, 15 October 2024.

<sup>4</sup> AEMO, *Support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices*, 15 October 2024.

credible option. The proposed technology architecture for Options 1 and 2 will enable Transgrid to readily scale and take advantage of new functionality sought within Option 3 at a future date, when there is greater certainty in relation to its cost and functionality, if there were benefits of doing so.

### **Consultation undertaken on the PSCR**

The PSCR was released in October 2024. We received 1 submission from ECA, which we have published on our website.<sup>5</sup>

The ECA is generally supportive of developing new capabilities to accommodate the demands of the energy transition but wants to see further evidence, such as through a cost-benefit analysis, demonstrating that the options have net benefits in the best interests of residential and small business energy consumers. The ECA also requested that the volatility of wholesale price should be part of this assessment, as well as estimating the likelihood that savings would be passed on to consumers.

Transgrid engaged with the ECA following its submission and discussed the types of consumer benefits delivered by the project along with the approach to quantifying the benefits. In addition, Transgrid notes that many of these benefits quantified under the case studies will accrue directly to consumers and small businesses – Transgrid and the TAC are developing a summary document that sets out these benefits, which will be released shortly after this PADR. This separate summary of the consumer benefits has been prepared as a direct result of the ECA request to make this information more transparent.<sup>6</sup>

On 21 November 2024, the requirements set out in the AER's RIT-T Application Guidelines were amended. The amended guidelines now expect a RIT-T proponent to explicitly consider community engagement and social licence during the RIT-T process.

Under the transitional provisions, the new guideline requirements do not apply to this RIT-T.<sup>7</sup> Notwithstanding, we note that community engagement and social licence considerations are not expected to be relevant to this project since the investments proposed will take place in Transgrid's control rooms and corporate offices. Accordingly, no specific community is expected to be affected by the proposed investments.

### **Two credible options have been assessed in the PADR**

Transgrid has investigated and considered alternative options for improving our control systems and corporate office capabilities. This has involved extensive investigation and planning by our internal teams, as well as the commissioning of expert input from independent international and Australian experts (Electric Power Research Institute (EPRI) and GHD Advisory). It has also been informed and refined through a comprehensive market testing process.

We have identified two credible options from a technical, commercial, and project delivery perspective, i.e.:

---

<sup>5</sup> ECA, *System Security Roadmap Operational Technology upgrades PSCR submission*, 15 January 2025, available at: <https://www.transgrid.com.au/media/aalnhz2i/system-security-roadmap-operational-technology-upgrades-pscr-submission-eca.pdf>

<sup>6</sup> The consumer benefits explainer is available on the consultation page, available at: <https://www.transgrid.com.au/projects-innovation/>.

<sup>7</sup> The new guidelines do not apply to any RIT-T project where a PSCR was published prior to 21 November 2024. The PSCR for this RIT-T was published on 14 October 2024.

- Option 1: **Reactive capability** – provides enhancements to Transgrid’s existing core operational technology and tools to improve the reactive capabilities of Transgrid’s control room and corporate offices; and
- Option 2: **Proactive capability** – provides further, moderate enhancements to Transgrid’s existing operational technology and tools, in addition to several new capabilities, so that Transgrid can proactively plan for, and respond to, operational issues across its control room and corporate offices.

Option 2 includes the initiatives and capabilities in Option 1, typically at a higher level of technical uplift. In other words, Option 2 increases in scope, capability and the degree of technical uplift for each of these capabilities. The implementation of technology initiatives under each option is staged to prioritise initiatives that deliver the highest immediate net benefits, and defer investments that can be implemented in the future.

The two options have been developed as packages to reflect the minimum incremental technology solution required to enable a defined level of capability (i.e., reactive or proactive). As a result, partial implementation of either option would not result in the intended capability uplift under each option being achieved, and so would not provide the benefits of avoided unserved energy, fuel costs and greenhouse gas emissions identified. The scope and timing of these two options has been further tested and refined in the light of responses to the RFI – we discuss this further in section 5.1.2.

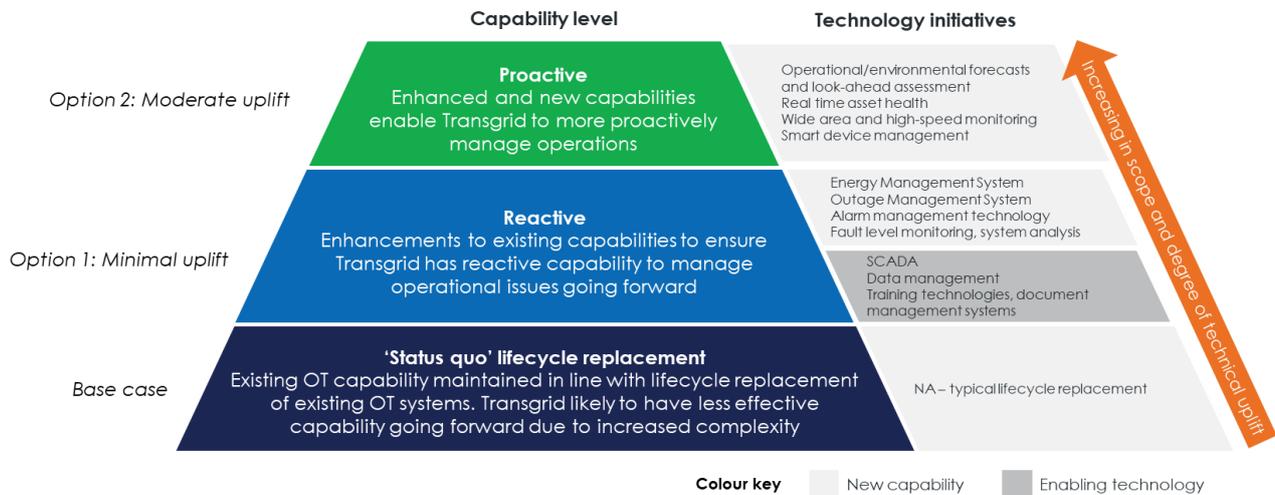
In the PSCR, we also identified a third option, i.e., Option 3: **Predictive capability** – this option would have provided a suite of advanced enhancements to existing capabilities, as well as adding advanced new capabilities, to enable Transgrid to employ a predictive approach to operations in our control room and corporate offices. However, in responses to the RFI, vendors indicated that the desired levels of capability uplift within Option 3:

- whilst well aligned with industry and software product roadmaps, had high degrees of cost and functional uncertainty;
- had significantly higher costs (i.e., more than triple) compared to Transgrid’s preliminary estimates in the PSCR and compared to the cost escalation for the other options between the PSCR and PADR; and
- could not be delivered in a similar timeframe to Option 2 (i.e., would take significantly longer to deliver).

Accordingly, Transgrid does not currently consider Option 3 technically and commercially feasible. However, because each option builds upon the previous option, the proposed technology architecture for Options 1 and 2 will still enable Transgrid to readily scale and take advantage of new functionality sought within Option 3 at a future date, if there are net market benefits in doing so.

The differing features of the two credible options are illustrated in Figure E-1.1 below, which summarises the key characteristics of the options, in terms of the capabilities, associated technology and the extent of technical uplift.

Figure E.1.1: Option capability-technology pyramid for operational tools



Note: In addition to the technology initiatives identified above, operational planning sits across several of the technology initiatives as an enabling and complementary function.

We present the estimated capital expenditure for upgrades to our operational technologies and tools under each option in Table E.1 below.

Table E.1 Summary of estimated capital expenditure (\$m \$2024/25).

	Estimated capital expenditure
Option 1	123.1
Option 2	179.2

As Transgrid is undertaking this RIT-T over a 15-year assessment period, to capture the full benefit realisation period, and because the economic life of operational technologies and tools is typically between 5 and 7 years, we have assumed indicative refresh costs for each of the initiatives at the end of their economic life in both the base case and option cases. There is significant uncertainty for the value of any refresh costs. For the purposes of this RIT-T, Transgrid has conservatively assumed equal costs of replacement in real terms at the end of the economic life of the assets. We considered five additional options, including the potential for non-network options, to meet the identified need in this RIT-T. However, these options were not progressed as they were not considered to be commercially and technically feasible to assist with meeting the identified need for this RIT-T (discussed further in section 5.5).

### Both options are expected to deliver significant economic benefits

Upgrades to Transgrid's operational tools represent a step change in control room capabilities, which is expected to provide a broad range of benefits that accrue to consumers.

The market benefits of operational technologies and tools are not typically quantified through the RIT-T process, and are difficult to measure. This is because, unlike the benefits from specific network augmentation or network replacement expenditure (which are the most typical investments subject to the RIT-T) which have a specific, traceable impact on electricity network operation, the benefits from operational technologies and tools accrue across the network through improved system reliability, market efficiency and utilisation.

Accordingly, the approach to quantifying the benefits from operational technologies and tools needs to be different to that taken for network investments. We have adopted a ‘case study’ approach to estimate a subset of the market benefits from each option compared to the base case to showcase the improved operational capability benefits from specific operational technologies and tools.

The case study approach is a transparent and tractable method of quantifying the market benefits from upgrades to Transgrid’s operational tools. The case studies link technology upgrades to specific, distinct outcomes and market benefits that result from that uplift in operational capabilities. Rather than attempt a broad calculation of all possible benefits, we’ve focused on three specific case studies where we can make transparent assumptions about the change in outcomes that we expect to be achieved under each option, and have estimated the benefits associated with these case studies.

Our case study approach represents a conservative approach to quantifying the market benefits, as we:

- only quantify a subset of the total market benefits that are likely to accrue from this project, focusing on case studies that result in market benefits that can be estimated simply and tractably using a set of transparent assumptions; and
- have made reasonable assumptions where there is uncertainty to ensure that we have not overestimated the benefits of these investments.

Whilst the full range of benefits associated with the options is difficult to measure in dollars, the options are expected to create real value through improved operations, enhanced staff capabilities and their contribution to meeting regulatory requirements.

We have estimated benefits under three case studies, i.e.:

- **Case study 1:** reduction in the likelihood of unserved energy compared to the base case, as a result of better situational awareness in the control room which we have quantified using alarm volumes and a cognitive load threshold for control room operators;
- **Case study 2:** increased network utilisation arising from less conservative operation of the network, which we have quantified based on a reduction in the impact of constraints applied on inverter constraints; and
- **Case study 3:** improved outage management through a reduction in switching time in the event that an outage occurs.

Table E.2 summaries these case studies.

Table E.2: Summary of market benefit case studies estimated in this RIT-T

ID	Case study	Benefit driver
Case study 1	Reduction in the likelihood of unserved energy	<p>Early detection and intervention for faults reduces the probability of an event escalating to an outage event with unserved energy, as well as the need to operate the network more conservatively and take assets offline. This outcome arises from better visibility of asset conditions and network fault levels, prioritisation of information and supported decision making, which together reduces the cognitive load on control room operators in a complex operating environment.</p> <p>This RIT-T only quantifies the benefits related to the reduction in the likelihood of unserved energy and does not quantify any additional benefits from reduced risk of asset failure or less conservative network operation.</p>

Case study 2	Increase in network utilisation	Alleviating pre-emptive and conservative constraints on generators through real-time and near-term network analysis replacing static scenario measurements. This facilitates less conservative network asset utilisation by updating operating limits and providing the ability to operate closer to the power system's technical envelope.
Case study 3	Reduction in the duration of outages	Reduction in planned outage duration associated with switching operations through enhanced ability to better coordinate switching operations and new tools to verify equipment/safety status.

We have estimated the gross market benefit for each option under each case study for each of the ISP scenarios. Table E.3 below presents the present value of the gross market benefits for each option under each case study, and in total, on a weighted basis across the three ISP scenarios. This shows that significant benefits for Option 2 are delivered under all three case studies, and in particular that the additional technologies enabling increased network utilisation under Option 2 deliver substantial additional benefits compared to Option 1.

Table E.3: Present value of gross market benefits by case study (\$m, PV)

Case study	Option 1	Option 2
Reduction in the likelihood of outages	123.2	180.3
Increased network utilisation	12.5	68.6
Reduced duration of switching operations	80.6	80.6
Total	216.2	329.5

### The net present value analysis identifies Option 2 as the preferred option

The present value of estimated costs for each option are summarised in Table E.4 below. We have assessed the options against a base case where no investment to improve Transgrid's operational technology and tools for use in its control rooms and corporate offices is undertaken. However, consistent with the base case under the RIT-T, we assume a range of economically prudent BAU activities to best maintain our control room capabilities required for compliance with the NER until the end of the assessment period will occur, including a lifecycle, non-enhanced replacement of our SCADA/EMS system by June 2030. Because we have undertaken a 15-year assessment for this RIT-T to capture the full benefit realisation period, these options include refresh costs for technologies to 2039.

Table E.4: Net Present value of capital and operating costs by option (present value, \$ millions)

	Capital costs	Operating costs	Total costs
Option 1	115.6	34.1	149.8
Option 2	169.4	48.8	218.2

In Table E.55 below, we set out the net present value (NPV) for each option across the three scenarios modelled, and on a weighted basis. The analysis shows that both options are expected to deliver net

benefits across all three ISP scenarios. On a weighted basis, Option 2 is expected to deliver a NPV of \$111.3 million, compared with \$66.5 million for Option 1.

Table E.5: Net present value of options compared to base case (present value, \$ millions)

	Progressive change	Step change	Green energy exports	Weighted NPV	Rank
Option 1	34.8	76.8	125.5	66.5	2
Option 2	43.0	140.8	218.1	111.3	1

We have also undertaken sensitivity testing to examine how the net economic benefit of the credible options changes with respect to changes in key assumptions, including changes to costs, the total amount of benefits realised, and the discount rate. The results of the sensitivity analysis show that no reasonable change in key assumptions would result in Option 2 no longer being the preferred option or failing to deliver positive net market benefits over the evaluation period. In particular, we find that a 1 year delay in the delivery of the preferred option (Option 2) would result in a \$19.4 million decrease in net market benefits.<sup>8</sup>

Given the above, Option 2 is the preferred option at this draft stage, because it is the credible option that maximises the net present value of the net economic benefit (in accordance with NER clause 5.15A.2(b)(12)).

### Submissions and next steps

We welcome written submissions on materials contained in this PADR. Submissions are due on 24 June 2025.

Submissions should be emailed to our Regulation team via [regulatory.consultation@transgrid.com.au](mailto:regulatory.consultation@transgrid.com.au).<sup>9</sup> In the subject field, please reference 'System Security Roadmap Operational Technology upgrades PADR'.

At the conclusion of the consultation process, all submissions received will be published on our website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. Subject to what is proposed in submissions to this PADR, we anticipate publication of a PACR by second half of 2025.

<sup>8</sup> We discuss this in further detail in section 8.4.

<sup>9</sup> Transgrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

## Contents

<b>Disclaimer .....</b>	<b>1</b>
Privacy notice .....	1
<b>Executive summary.....</b>	<b>3</b>
<b>1. Introduction .....</b>	<b>15</b>
1.1 Context and AEMO support.....	15
1.2 The initiatives being assessed will provide economic benefits.....	16
1.3 Purpose of this report.....	17
1.4 Submissions and next steps .....	18
<b>2 The identified need.....</b>	<b>19</b>
2.1 Background .....	19
2.2 Description of the identified need .....	20
<b>3 Developments since the PSCR .....</b>	<b>22</b>
3.1 AEMO has provided written support for the options outlined in the PSCR.....	22
3.2 Option specifications have been informed by responses to the RFI .....	22
<b>4 Consultation undertaken to date .....</b>	<b>25</b>
4.1 Submission to the PSCR .....	25
4.2 Ongoing engagement with the Transgrid Advisory Council .....	26
4.3 Ongoing engagement with AEMO .....	27
4.4 Update to the AER’s RIT-T guidelines.....	28
<b>5 Credible options assessed .....</b>	<b>29</b>
5.1 Approach to developing credible options.....	29
5.1.1 We identified three credible options in the PSCR.....	29
5.1.2 We have refined the scope and estimated cost of the options based on the detailed RFI ....	31
5.1.3 Summary of the credible options assessed in this PADR.....	32
5.2 Base case.....	34
5.3 Option 1 – Reactive capability: uplift of core operational technologies and tools only .....	35
5.4 Option 2 – Proactive capability: uplift across a portfolio of operational technologies and tools, plus essential new capabilities.....	39
5.5 Options considered but not progressed.....	43
<b>6 Overview of the assessment approach.....</b>	<b>45</b>
6.1 Assessment period and discount rate.....	45
6.2 Approach to estimating option costs.....	45

6.3	Classes of market benefit that are considered material .....	46
6.3.1	Changes in involuntary load curtailment .....	47
6.3.2	Changes in fuel consumption in the NEM .....	47
6.3.3	Changes in Australia’s greenhouse gas emissions .....	48
6.3.4	Market benefits expected to arise outside of NSW and the ACT .....	48
6.3.5	Classes of market benefit that are not considered material .....	48
6.4	Three different scenarios have been modelled to address uncertainty.....	49
6.5	Ensuring the robustness of the analysis.....	49
6.5.1	Sensitivity analysis .....	50
6.5.2	Threshold analysis .....	50
<b>7</b>	<b>Estimating the market benefits of the alternative options.....</b>	<b>51</b>
7.1	Benefits have been estimated using a case study approach .....	51
7.2	The three use cases quantified in this RIT-T.....	52
7.3	Case study 1 – Reduction in the likelihood of unserved energy .....	53
7.3.1	Background and driver of benefits under case study 1.....	53
7.3.2	Benefits and technology/capability uplift in case study 1 across options .....	55
7.3.3	Quantification approach for benefits under case study 1.....	56
7.3.4	Gross market benefits for case study 1 .....	61
7.4	Case study 2 – increased network utilisation through less conservative operation.....	61
7.4.1	Background and driver of benefits under case study 2.....	61
7.4.2	Benefits and technology/capability uplift in case study 2 across options .....	62
7.4.3	Quantification approach for case study 2.....	63
7.4.4	Gross market benefits of case study 2.....	68
7.5	Case study 3 – improved outage management through reduced switching time .....	68
7.5.1	Background and driver of benefits under case study 3.....	68
7.5.2	Benefits and technology/capability uplift in case study 3 under each option .....	70
7.5.3	Quantification approach for case study 3.....	71
7.5.4	Gross market benefits of case study 3.....	74
7.6	Summary of option gross benefits by case study and scenario .....	75
<b>8</b>	<b>Net present value analysis .....</b>	<b>76</b>
8.1	Present value of costs.....	76
8.2	Present value of gross market benefits .....	76
8.3	Net present value .....	77
8.4	Sensitivity analysis.....	78
8.5	Threshold analysis .....	79
8.6	Proposed reopening triggers.....	79
<b>9</b>	<b>PADR conclusion.....</b>	<b>81</b>

**Appendix A Compliance checklist..... 82**

**Appendix B Benefit Quantification Approach..... 85**

# 1. Introduction

---

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for Transgrid's System Security Roadmap Operational Technology contingent project, to upgrade operational technology and tools for use in our control rooms and corporate offices. This Project Assessment Draft Report (PADR) represents the second step in the application of the RIT-T and follows the Project Specification Consultation Report (PSCR) published on 14 October 2024.

## 1.1 Context and AEMO support

We are currently in a period of transformation for the electricity system in NSW, with several factors driving increased complexity in power system planning and operations.

The Australian Energy Regulator (AER) accepted the System Security Roadmap Operational Technology project as a contingent project for Transgrid's 2023-28 regulatory period. This allows Transgrid to submit a contingent project application (CPA) subject to the successful completion of early works and fulfilling specific trigger events, namely:<sup>10</sup>

- the Australian Energy Market Operator (AEMO)'s written support for the implementation of specific operational technology upgrades and tools for use in Transgrid's control rooms and corporate offices;
- successful completion of a RIT-T, if a RIT-T is required or equivalent economic evaluation, which demonstrates that the preferred option (or part of the preferred option) that maximises net economic benefits is the investment in technological upgrades and tools that has written support from AEMO; and
- Transgrid Board commitment to proceed with the development of the operational technology upgrades and tools (that has written support from AEMO), subject to the AER amending the Revenue Determination pursuant to the Rules.

Following publication of the PSCR, AEMO has provided a letter of written support for the options being considered by Transgrid and acknowledged the urgent need for investment to enhance Transgrid's capabilities to securely operate, plan and manage the New South Wales (NSW)/Australian Capital Territory (ACT) transmission network. In particular, AEMO highlighted that Transgrid's proposed investments in operational technology and tools are:<sup>11</sup>

*consistent with the experience of system and network operators globally, which are undergoing similar shifts and are making equivalent investments in the architecture, data and tools required to operate, plan and manage the system of the future.*

AEMO also noted that the options identified in the PSCR were 'fully aligned' with AEMO's Operational Technology and Engineering Roadmaps,<sup>12</sup> which outline the emerging operational and engineering

<sup>10</sup> AER, *Transgrid transmission determination – 1 July 2023 to 30 June 2028 – Attachment 5: Capital expenditure*, Final decision, p. 40.

<sup>11</sup> AEMO, *Support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices*, 15 October 2024.

<sup>12</sup> AEMO's Operational Technology and Engineering Roadmaps were discussed in section 2.3.1 of the PSCR for this RIT-T. The investment proposed in this RIT-T will deliver complementary benefits to AEMO's initiatives to prepare for higher levels of renewable integration in the NSW energy system.

challenges emerging from the transition to higher levels of renewable generation while maintaining reliability, security and resilience.<sup>13</sup> In particular AEMO highlighted that:<sup>14</sup>

*Investments by AEMO alone will not be sufficient; a capability uplift will also be needed by [Network Service Providers] for system security to be maintained across the National Electricity Market (NEM). These investments are urgently needed to manage the security of the power system and to complement investments AEMO is making under its own Operations Technology Roadmap and associated program.*

Transgrid is working collaboratively with AEMO during the RIT-T process to consider the interaction of our enhanced control room capabilities with the wider needs of the system and minimise unnecessary duplication of investment between organisations. Transgrid will be seeking AEMO's formal written support for the specific operational technologies and tools proposed (in accordance with the CPA trigger requirement), to support the submission of the CPA following publication of the Project Assessment Conclusions Report (PACR) and the completion of the RIT-T.

We also appreciate input from the Transgrid Advisory Council (TAC), which has informed and helped to shape the assessment presented in this PADR. We intend to continue working closely with AEMO and the TAC, as well as other interested stakeholders, in the lead up to the finalisation of this RIT-T and our subsequent CPA.

## 1.2 The initiatives being assessed will provide economic benefits

The increase in the complexity in power system planning and operations means that, in the absence of an upgrade to the capabilities used in our control rooms and corporate offices:

- it is likely that, as a result of Transgrid maintaining static operating limits, constraints will need to be imposed more frequently on the operation of the power system in NSW and the system will begin to operate in a more conservative manner (which may require constraining the operation of low marginal cost renewable generators), to have sufficient confidence that the system will remain within its required operating envelope; and
- there is an increased likelihood that contingency events may occur when our operators are overburdened from informational overload, arising from the additional complexity of the system, and are therefore less equipped to take the action required in response. In addition to a range of other consequences, this poses a greater risk of expected unserved energy (EUE) to end consumers going forward.

We have identified the opportunity to deliver significant market benefits from expanding the functionality of the operational technology and tools used in our control rooms and corporate offices to address these expected limitations in the way we operate the network going forward. The proposed project is expected to result in an overall increase in net economic benefits, as captured in the RIT-T. As such, we have identified this as a 'market benefits' driven RIT-T (i.e., as opposed to a 'reliability corrective action' to address regulatory or service standard obligations).

<sup>13</sup> AEMO, Support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices, 15 October 2024.

<sup>14</sup> AEMO, Support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices, 15 October 2024.

Notwithstanding the net economic benefits expected to arise from undertaking this investment, continued investment in operational technology tools is also likely to be integral to Transgrid continuing to meet our regulatory obligations under the National Electricity Rules (NER) in relation to the secure operation of the system under an increasingly complex operating environment.

We have already commenced work in relation to an alarm rationalisation project at a cost of \$2.99 million, to address the rapid increase in the volume of alarms in our control rooms. This project was urgently required to handle the rapid increase in the number of alarms and alarm monitoring points, which increased from 18,000 in 2015 to 36,000 in 2023 and 55,000 in February 2025. Accordingly, we have commenced this work ahead of completion of this RIT-T and submission of the associated CPA. This expenditure is above and beyond business as usual activities, and reflects the urgent need to ensure the continued function of the control room. We have incorporated the expenditure associated with this project as part of both of the options considered in this RIT-T.

Except for the investment in alarms rationalisation and expected expenditure on training technologies, we note that we will not proceed with the investment outlined in this RIT-T unless the associated revenue is approved by the AER in our CPA.

### 1.3 Purpose of this report

The purpose of this PADR<sup>15</sup> is to:

- confirm the identified need for the investment and describe the assumptions underlying this need;
- summarise points raised in submissions to the PSCR, and highlight how these have been taken into account in the RIT-T analysis;
- describe the credible options being assessed under this RIT-T (including our refinement of the number and scope of credible options since the PSCR);
- set out the basis on which the costs of the credible options have been estimated at this stage of the RIT-T process, including how the costs have been refined through market testing since the PSCR;
- summarise the methodology used to model the net market benefits for the credible options assessed, including the case study approach adopted, and present the results of this analysis;
- describe the key drivers of the net present value (NPV) results, as well as the assessment that has been undertaken to demonstrate the robustness of the conclusion, which we have done through undertaking a range of sensitivity and boundary tests;
- provide details of the overall proposed preferred option at this stage of the process to meet the identified need; and
- set out the proposed re-opening triggers, building on the sensitivity assessments undertaken, to provide transparency to stakeholders on what may constitute a later material change in circumstance for this RIT-T.

Overall, this report provides transparency into the planning considerations for investment options to enhance our capabilities to securely operate, plan, and manage the NSW/ACT power system during a period of unprecedented change and rapidly increasing system complexity.

---

<sup>15</sup> See Appendix A for the NER requirements.

## 1.4 Submissions and next steps

The purpose of this PADR, and the RIT-T more broadly, is to set out the reasons our proposed investments into operational technologies and tools should be undertaken, present options that address the identified need, summarise how these options have been assessed (as well as the results of this assessment), and allow interested parties to make submissions and provide input into the RIT-T assessment. A key purpose of this PADR is to provide certainty and confidence to stakeholders that the preferred option has been robustly identified as optimal.

We welcome written submissions on materials contained in this PADR, including on the proposed re-opening triggers.

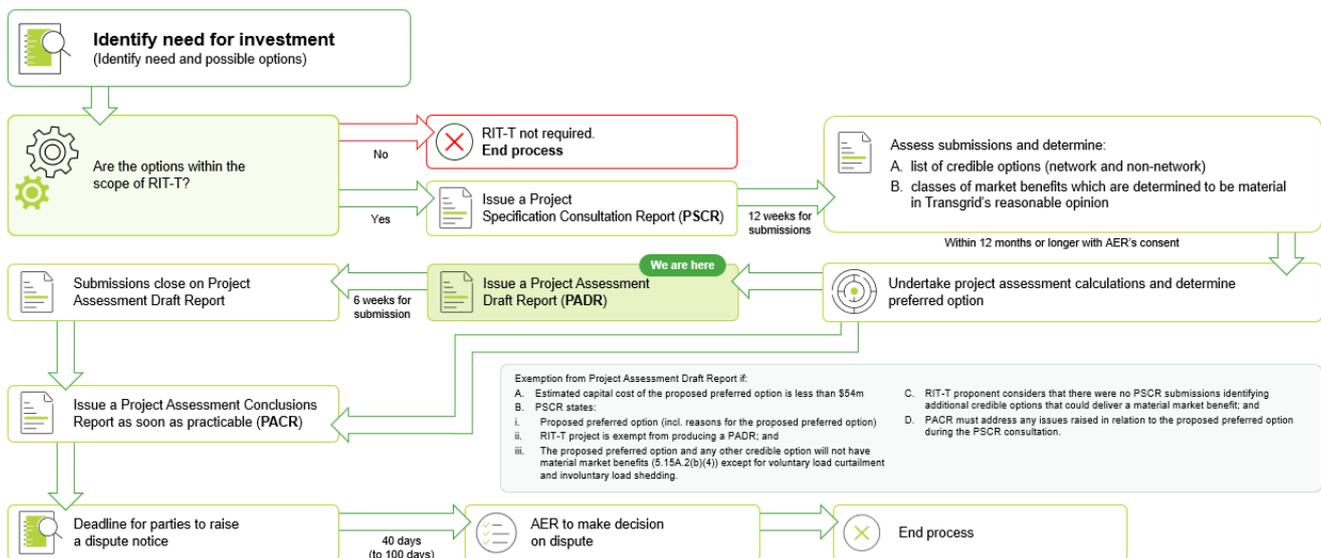
Submissions are due on 24 June 2025.<sup>16</sup>

Submissions should be emailed to our Regulation team via [regulatory.consultation@transgrid.com.au](mailto:regulatory.consultation@transgrid.com.au).<sup>17</sup> In the subject field, please reference 'System Security Roadmap Operational Technology upgrades PADR'.

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

The next formal stage of this RIT-T is the publication of a PACR. The PACR will address all submissions received, including any issues raised in relation to the proposed preferred option. Subject to what is received in submissions to this PADR, we anticipate publication of a PACR in July 2025.

Figure 1.1 This PADR is the second stage of the RIT-T process<sup>18</sup>



<sup>16</sup> Consultation period is for 6 weeks. Additional days have been added to cover public holidays.

<sup>17</sup> We are bound by the *Privacy Act 1988 (Cth)*. In making submissions in response to this consultation process, we will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.

<sup>18</sup> Australian Energy Market Commission. "Replacement expenditure planning arrangements, Rule determination". Sydney: AEMC, 18 July 2017.

## 2 The identified need

---

This section outlines the identified need for this RIT-T. The identified need, and the assumptions and data underpinning it, remains the same as in the PSCR, and so has been summarised here. Further details are set out in section 2 of the PSCR.<sup>19</sup>

### 2.1 Background

The energy transition in NSW/ACT is occurring at a rapid pace and is driving increased complexity in power system operations and operational planning. The next decade will be a period of profound transformation within the electricity system, in both NSW/ACT and across the NEM. In NSW/ACT, the power system is undergoing a transition from a small number of large, centrally distributed thermal generators to a large number of small, distributed, variable generator connections and storage resources.

The transmission control room is the nerve centre of the network, where operators work 24 hours per day each day of the year to monitor and manage the flow of power through the network through interaction with the assets on the network, in coordination with AEMO. Transgrid has already experienced a substantial increase in the complexity of its network operation, which is increasing the complexity of the activities for operators in our control room.

We engaged external experts the Electric Power Research Institute (EPRI) and GHD Advisory to independently assess Transgrid's control room and operational planning capabilities against future operational needs and international best practice. The critical functions of these capabilities encompass, but are not limited to:<sup>20</sup>

- **system monitoring and control:** continuous, real-time surveillance of the entire network: essential for effective network management and rapid response to changes;
- **fault detection and response:** when system faults occur, the control centre assesses the cause and impact, implements corrective measures, and manages power redirection to minimise service disruptions;
- **people and asset protection:** prevent overload of assets, which reduces risk of equipment failure and potential safety hazards; and
- **planned outage management and coordination:** manage planned outages to facilitate scheduled maintenance and connection of new assets.

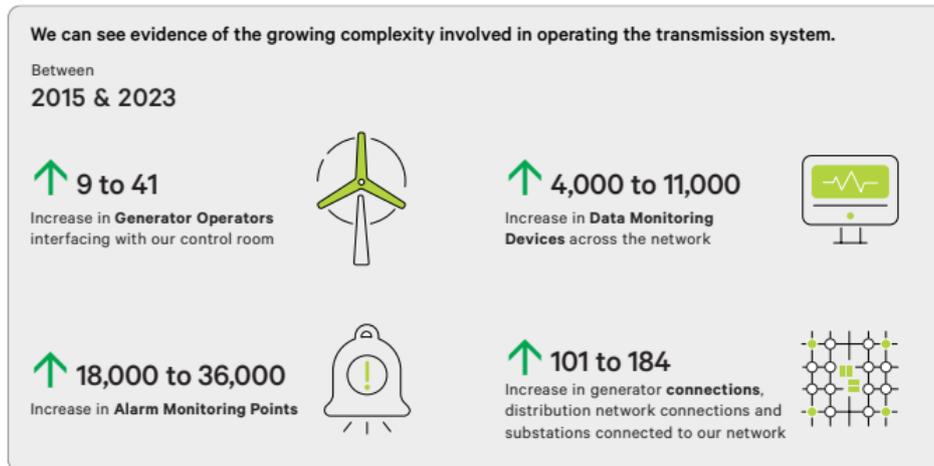
Although there is no single metric to characterise the increasing complexity being borne by network operators and operational planners, Figure 2.1 below presents key increases in network parameters between 2015 and 2023, which each contribute to complexity of control room operation. In particular, this shows that the number of alarm monitoring points doubled from 18,000 in 2015 to 36,000 in 2023.

---

<sup>19</sup> Transgrid, *System Security Roadmap Operational Technology Upgrades*, RIT-T PSCR, 14 October 2024.

<sup>20</sup> EPRI report, p 16.

Figure 2.1: Changes in operational parameters between 2015 and 2023



Source: Transgrid, *System Security Roadmap*, 21 June 2023, p 30.

All of the parameters in Figure 2.1 are forecast to increase further over the next decade, which will further increase the complexity of control room operation. For example, the number of alarm monitoring points is now 55,000 as of February 2025, which equates to a 52% increase over the last two years.

## 2.2 Description of the identified need

The identified need for this RIT-T is to increase overall net market benefits in the NEM as the complexity of the electricity system increases, by:

- avoiding the need to more frequently impose constraints on the operation of generators connected to our system in the future to ensure the system remains within its required operating envelope. This includes reducing the need to impose constraints during periods of planned and unplanned transmission outages, such as outages necessary to connect new generation and undertake network upgrades. Amongst other things, this is expected to reduce the curtailment of low marginal cost and low emissions renewable generation, which would offset the need to dispatch additional thermal generation; and
- allowing our control system operators to better prepare for, assess and respond to contingency events in an increasingly complex operating environment (including with a substantial increase in information sources needing to be monitored). This, amongst other things, is expected to reduce the likelihood of load shedding (including expected unserved energy (EUE)).

In particular, market benefits are expected to result from reduced EUE, reduced dispatch costs, and reduced greenhouse gas emissions, resulting from reduction in the risk of contingency events escalating to the point where load shedding is required, and the ability to operate the system with fewer constraints predominately on low marginal cost and low emissions renewable generation.

This PADR describes when and how market benefits are expected to arise as a result of our proposed investments in operational technologies and tools and presents a quantification of these market benefits. Our assessment finds that, compared to the base case, the market benefits from enhancing the capabilities of our operational technologies and tools (including the non-lifecycle upgrade of our supervisory control and data acquisition (SCADA) system) exceed the cost of our proposed investments. We have therefore

presented this as a ‘market benefits’ driven RIT-T (i.e., as opposed to a ‘reliability corrective action’ to address a prescribed regulatory obligation).

Notwithstanding the expected net market benefits, the proposed enhancements to our control room and corporate office capabilities are also integral to Transgrid continuing to meet our obligations under the National Electricity Rules (NER). Specifically, NER cl 4.3.4(a) sets out that Transgrid must use reasonable endeavours to exercise the rights and obligations in respect of our networks so as to co-operate with and assist AEMO in the proper discharge of AEMO’s power system security responsibilities.

Our ongoing compliance with our NER obligations is being challenged by the decentralisation of generation, a higher proportion of intermittent generation, and new network and non-network technologies interacting with our network.

The proposed investments align with the expectations of AEMO, which also faces increased operational complexity due to the energy transition. The investments proposed in this RIT-T are complementary to AEMO’s workstreams to improve its own ability to handle increased renewable penetration in the NEM, including its Engineering Roadmap and Operational Technology Roadmap (discussed further below). AEMO’s operations depend on Transgrid maintaining an appropriate level of operational capability, especially with regard to provision of real-time data from SCADA systems that interface directly with AEMO. As system complexity across the NEM grows, we anticipate AEMO’s reliance on Transgrid’s operational capability will continue to increase. In addition, Transgrid has broader operational responsibilities under the NER (i.e., NER cl 4.3.1) and outlined within the AEMO/Transgrid Schedule of Delegation<sup>21</sup> that need to be maintained as system complexity increases.

---

<sup>21</sup> AEMO, Schedule 1 – [https://aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/power\\_system\\_ops/schedules/schedule\\_1\\_extract\\_from\\_transgrid\\_instrument\\_of\\_delegation.pdf?la=en](https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/schedules/schedule_1_extract_from_transgrid_instrument_of_delegation.pdf?la=en).

### 3 Developments since the PSCR

---

In this section we outline developments that have occurred since publication of the PSCR.

#### 3.1 AEMO has provided written support for the options outlined in the PSCR

AEMO provided a letter of written support for Transgrid's proposed upgrades to operational technology and tools for use in its control room and corporate offices on 15 October 2024.<sup>22</sup> The full letter has been published on our website.

In particular, AEMO acknowledged the urgent need for the investment to enhance Transgrid's capabilities to securely operate, plan and, manage the NSW/ACT power system. AEMO highlighted that Transgrid's proposed investments in operational technology and tools are:<sup>23</sup>

*consistent with the experience of system and network operators globally, which are undergoing similar shifts and are making equivalent investments in the architecture, data and tools required to operate, plan and manage the system of the future.*

AEMO also highlighted the interdependent roles, systems and capabilities between itself and Network Service Providers (NSPs), emphasising that investments in operational tools by AEMO alone are insufficient to ensure system security across the NEM.

AEMO has confirmed that the options outlined by Transgrid in the PSCR are 'fully aligned' and complementary to AEMO's Operational Technology and Engineering Roadmaps, which describe the emerging operational and engineering challenges from the transition to higher levels of renewable generation while maintaining reliability, security and resilience.<sup>24</sup>

Transgrid will continue to engage with AEMO during the remainder of the RIT-T process and will be seeking AEMO's formal written support for the specific operational technologies and tools that form the preferred option identified under the RIT-T (in accordance with the CPA trigger events), following publication of the PACR.

#### 3.2 Option specifications have been informed by responses to the RFI

In the PSCR, we set out an initial scope and indicative cost estimate for each of the options being considered. The cost estimates for the options presented in the PSCR were built upon previous cost estimates developed for the System Security Roadmap Operational Technology project in Transgrid's 2023-28 regulatory submission, which were in turn based on a bottom-up assessment performed in 2022 of the labour, materials and expenses required for each option, considering the duration of work required.

We explained in the PSCR that the scope and cost estimates for each of the options would be refined in the PADR as part of an ongoing market testing process. Following the PSCR and in consultation with the TAC, Transgrid sought responses to a request for information (RFI) to confirm the availability of and

---

<sup>22</sup> AEMO, Support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices, 15 October 2024.

<sup>23</sup> AEMO, Support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices, 15 October 2024.

<sup>24</sup> AEMO, Support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices, 15 October 2024.

capacity to deliver solutions, and obtain market-based cost estimates for technology solutions required to achieve the levels of capability uplift proposed under each option.

We sought independent expert advice to work with Transgrid to ensure the technology solutions sought in the RFI process would deliver the required capability uplift under each option.

Our RFI process considered each option in the PSCR in light of retaining and building on our core SCADA/EMS software. Transgrid considers it prudent to retain our existing software as:

- it will be more efficient to leverage the SCADA/EMS asset that was commissioned in 2022;
- the existing software remains commonplace in the industry; and
- the software has been updated to support renewable resources.

As such, we sought responses from all of our existing SCADA/EMS software provider's approved Australian-based system integrators as part of our RFI.<sup>25</sup>

The initial RFI followed a process similar to a request for tender, as it included contract terms and conditions, functional and non-functional requirements for technologies, a site visit to our control room, workshops with all suppliers to ensure alignment on scope and the need, and formal evaluation criteria including of both technical and commercial terms.

We received expressions of interest from four system integrators (vendors). We undertook several pre-submission meetings including workshops and detailed one-on-ones with Transgrid subject matter experts, to provide clarifications and refine the system integrators' formal responses to the RFI.

Following formal receipt of the RFI, we held one-on-one sessions to vendors, to ask questions and present their responses to the RFI to us. Vendors were requested to submit responses to the RFI for each of the three options defined within the PSCR (i.e., reactive, proactive and predictive). Vendors were also encouraged to consider and propose alternative, innovative solutions that may offer better alignment with the identified need.

We received responses to the initial RFI containing detailed information on the cost of each technology, schedule for delivery of the package of technologies, concept designs, software products and version details. Through the responses to the RFI, valuable insights emerged from vendors' local and global experience with network operators. Notably, vendors indicated that the desired levels of capability uplift within Option 3 (predictive):

- whilst well aligned with industry and software product roadmaps, had high degrees of cost and functional uncertainty;
- had significantly higher costs (i.e., more than triple) compared to Transgrid's preliminary estimates in the PSCR and compared to the cost escalation for the other options between the PSCR and PADR; and
- could not be delivered in a similar timeframe to Option 2 (i.e., would take significantly longer to deliver).

---

<sup>25</sup> We used the System Integrator model as it offers cost efficiencies by reducing redundancies across the full program of operational technologies and tools, and reduces delivery risk by ensuring the integration of all components and their data.

Accordingly, Transgrid no longer considers that Option 3 is technically and commercially feasible at this stage. However, because each option builds upon the previous option, the proposed technology architecture for options 1 and 2 will enable Transgrid to readily scale and take advantage of the new functionality sought within Option 3 at a future date, if there were net market benefits in doing so.

Additionally, the capital and operating cost information received through the RFI process was also substantially higher on a per initiative basis than Transgrid's earlier indicative costings, across all of the vendors and for all of the options. These higher costs are an outturn of market testing, as the indicative costings presented in the PSCR were not market tested.

In response to the responses to the initial RFI, we reviewed the scope of each of the options, and then put out a revised scope in a secondary RFI to respondents that had demonstrated technical ability to meet the identified need. Specifically, following the receipt of the RFIs, we undertook a blind evaluation of proposed solutions with Transgrid subject matter experts. In addition, throughout January and February 2025, we reviewed and refined the scope of options 1 and 2 in light of responses to the RFI – in particular by challenging ourselves on which initiatives are required immediately to address the identified need, and which could be deferred or removed.

Accordingly, our evaluation and refinement process:

- involved us further challenging the scope of the options and initiatives in response to the market engagement, and particularly in decreasing the scope of Option 2 due to functional uncertainty, deliverability risk or cost savings opportunities; and
- confirmed that although we received innovative solutions from multiple vendors, none of them directly met Transgrid's needs as a standalone solution – nevertheless, we adopted several innovative components in refining the scope and set of functional uplifts of Option 2.

We consider that the revised option specifications:

- maintain the required level of capability uplift to meet future operational needs;
- reduce complexity of implementation (i.e., implementation risk);
- draw on vendors' experience in implementing operational technology and tools solutions globally; and
- deliver better value for money by focusing on a reduced set of functional uplifts.

Ahead of the PACR, we are intending to obtain an independent review by an industry expert, to further refine our market-based cost estimates.

We describe the key differences from the specification of options described in the PSCR in section 5.

## 4 Consultation undertaken to date

---

In this section we outline the key themes of the one submission received to the PSCR and describe our ongoing engagement with the TAC and AEMO in relation to investment in operational technology and tools.

### 4.1 Submission to the PSCR

The PSCR was released in October 2024. We received one submission from Energy Consumers Australia (ECA), which we have published on our website.<sup>26</sup>

The key themes from the ECA's submission are set out below. Transgrid met with the ECA on 3 February 2025 to discuss key changes between the PSCR and PADR, and how the ECA's submission would inform the development of the PADR.

The ECA is generally supportive of developing new capabilities to accommodate the demands of the energy transition, but want to see further evidence, such as a cost benefit analysis, demonstrating that the options have net benefits in the best interests of residential and small business energy consumers. The ECA also requested that the volatility of wholesale price should be part of this assessment, as well as estimating the likelihood that savings would be passed on to consumers.

Broadly the investments into operational technologies and tools proposed under this RIT-T are designed to:

- improve the control room's ability to respond to contingency events, thereby reducing the likelihood of an outage occurring; and
- increase the flexibility in operating the network during the periods of network constraints, thereby maximising the value of renewables by reducing the period where renewables are constrained.

We have undertaken a cost-benefit analysis using a case-study approach to quantifying the benefits under this RIT-T, which we describe in further detail in section 7. This case-study approach focuses on quantifying the benefits of avoided curtailment of large-scale inverter-based resources and the associated reduction in unserved energy, fuel costs and emissions, which are sufficient to generate positive net benefits for the preferred option. In addition, Transgrid notes that many of these benefits quantified under the case studies will accrue directly to consumers and small businesses – Transgrid and the TAC are developing a supporting document that sets out these benefits. This separate summary of the consumer benefits is being prepared as a direct result of the ECA request to make this information more transparent.

Our case study approach has considered wholesale market conditions where relevant. For example, both case study 2 and case study 3 consider whether a reduction in constraints on the operation of renewable generators will result in a decrease in output from a thermal generator, given the prevailing wholesale market conditions. However, we have not undertaken a wholesale market modelling exercise, as this would be unlikely to materially affect the outcome of the credible options assessment, would be difficult to undertake in a meaningful manner, and would be disproportionate given the scale, size and potential benefits of the credible options. We discussed our case study approach with the TAC, who supported our approach.

---

<sup>26</sup> ECA, *System Security Roadmap Operational Technology upgrades PSCR submission*, available at: <https://www.transgrid.com.au/media/aalnhz2i/system-security-roadmap-operational-technology-upgrades-pscr-submission-eca.pdf>

The ECA requested further evidence that the preferred option would assist with ensuring compliance with the NER, including the likelihood of failure to comply with the NER under status quo operating procedures.

The rapid growth and complexity of the evolving network increases the risk for Transgrid's operators to maintain situational awareness for sense and decision-making. This is essential to maintain obligations under the NER including:

- system security and reliability (cl 4.3): Transgrid must ensure the secure and reliable operation of the transmission network, including maintaining system security and managing the network to prevent and respond to incidents;
- compliance with operating procedures (cl 4.10): Transgrid must adhere to the operating procedures and standards set by AEMO, including following protocols for load shedding, system restoration, and emergency management; and
- coordination with AEMO (cl 4.9): Transgrid is required to coordinate with AEMO for the dispatch and operation of the transmission network, which involves real-time communication and collaboration to manage electricity flows and maintain system stability.

## 4.2 Ongoing engagement with the Transgrid Advisory Council

Transgrid initially engaged with the TAC regarding operational tools investments as part of the System Security Roadmap proposed in our 2023-28 revised regulatory proposal. In its final decision, the AER considered that the TAC had not yet reached a firm position in support of the proposed investments, noting that stakeholders desired clearer illustration of risks, benefits and assumptions.<sup>27</sup>

In light of this concern, Transgrid has focused on undertaking extensive and meaningful consultation with the TAC as part of this RIT-T assessment, focusing on the scope and range of investment options under consideration and the methodology being used to quantify the benefits associated with the proposed investments.

This engagement process has involved detailed technical discussions and clearer documentation of assumptions and methodologies. Through these collaborative sessions, Transgrid has worked to ensure that the TAC members are able to provide meaningful input and feedback into the assessment process for this RIT-T. Transgrid considers that its enhanced engagement with the TAC on the operability initiatives addresses the earlier concerns raised by the AER and will continue to ensure that all aspects of the investment proposal are clearly presented to and thoroughly examined by the TAC.

Transgrid has engaged the TAC through four deep dive workshops between April 2024 and April 2025. The key topics that the TAC were consulted and informed on through these workshops were as follows:

- deep dive 1 – April 2024: describe the need for investment including a presentation from EPRI;
- deep dive 2 – September 2024: discuss the scope, investment areas and proposed investment approach and programme;
- deep dive 3 – November 2024: discuss current operational challenges, the operability RIT-T and PSCR, RFI and approach to developing cost estimates and the benefits quantification approach; and

<sup>27</sup> AER, *Transgrid transmission determination – 1 July 2023 to 30 June 2028 – Attachment 5: Capital expenditure*, Final decision, p 28.

- deep dive 4 – April 2025: control room tour and PADR briefing session.

The TAC has been engaged early and consulted during the planning and development of the RIT-T. The TAC members have heard from EPRI about the need (both local and global), taken through Transgrid's need and the urgency, the process and methodologies used as part of the cost and benefits estimations and toured the control room hearing firsthand from Transgrid's control room staff. The engagement has been positive and provided Transgrid with feedback that has been incorporated within the PADR.

### 4.3 Ongoing engagement with AEMO

As described in sections 1.1 and 3.1, and as documented in AEMO's letter of support, Transgrid is collaborating actively with AEMO to identify the operational technologies and tools required to manage the future power system.

Transgrid's and AEMO's roles, capabilities and systems have significant interdependencies. Recognising this, we will continue to engage with AEMO to:

- minimise unnecessary duplication of investment (and efforts between our organisations); and
- ensure our investment complements AEMO's operational capabilities and responsibilities.

Our proposed investments are consistent with AEMO's recommendations in its General Power System Risk Review, which aims to support the industry's ability to review and plan for resilient power systems into the future. Specifically, in the context of the evolving power system and changing risk profile of the NEM, AEMO recommends that all NSPs, where not already doing so, evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training.<sup>28</sup>

Consistent with AEMO's recommendations in its Risk Review, we engaged EPRI to assess our operational technology capabilities and gaps, to support our investment under this RIT-T. The EPRI report has been instrumental in informing the options and technologies assessed as part of this RIT-T, as discussed further in section 5.

AEMO provided input into the independent assessment conducted by EPRI to validate and prioritise the operational capabilities and tools we require to meet the evolving operational needs of the control room. The engagement between Transgrid, EPRI and AEMO has ensured the operational technologies and tools we have proposed under this RIT-T are sufficient to achieve each level of capability uplift, and reflect industry best practice to achieve a resilient future power system.

We also briefed AEMO's National Electricity Market Operations Committee on our alarm rationalisation project that we have undertaken ahead of completing this RIT-T. The committee supported the value and benefits of this project, agreeing that it is foundational to further investment in alarm rationalisation initiatives.

---

<sup>28</sup> AEMO, *2024 General Power System Risk Review – Report*, Final report, July 2024, p 109.

#### 4.4 Update to the AER's RIT-T guidelines

On 21 November 2024, the AER published its final decision on its review of the RIT-T guidelines. The guidelines have been updated and now require a RIT-T proponent to consider social licence issues in the consideration of credible options.<sup>29</sup>

We note that these updated guidelines do not formally apply to this RIT-T since the PSCR was published before the AER's final decision. Notwithstanding, we note that social licence considerations are not expected to be relevant to this project since the investments proposed will take place in Transgrid's control rooms and corporate offices. Accordingly, no specific community is expected to be affected by the proposed investments.

---

<sup>29</sup> AER, *Regulatory investment test for transmission application guidelines*, November 2024, p 20.

## 5 Credible options assessed

---

This section describes the options assessed in this PADR to address the identified need, including the changes to the scope of each option since the PSCR and the updated estimate of capital and operating costs.

All costs presented in this PADR are in 2024/25 dollars unless otherwise stated. The cost estimates used in this analysis are based on vendor responses to the requirements for each option set out in the RFI. We consider this to be a reliable source of cost information for this stage of the RIT-T process, and the maximum refinement possible at this stage, as vendors would not hold prices nor agree to fixed prices for this length or complexity of project at the RFI stage. We understand that suppliers have not incorporated contingency costs into cost estimates in response to the RFI. This budget estimation approach is common practice for multi-year technology investments.

We have adopted an average cost approach for responses to the RFI, as opposed to a lowest cost approach. We expect this approach will better reflect the level of contingency cost that the lowest cost vendor would likely include at the procurement stage. Ahead of the PACR, we are intending to obtain an independent review by an industry expert, to further refine our market-based cost estimates.

The costs for each option represent incremental expenditure relative to the base case. Both the base case and option case expenditure is in addition to the expenditure allowance approved in the current 2023-28 regulated revenue determination.

Transgrid is undertaking this RIT-T over a 15-year assessment period, to capture the full benefit realisation period (as discussed in section 6.1). Because the economic life of operational technologies and tools is typically between 5 and 7 years, we have therefore assumed indicative refresh costs for each of the initiatives at the end of their economic life in both the base case and option cases. These refresh costs are indicative only, and reflect a CPI adjustment to market tested results, with slightly lower assumed costs for procurement.

### 5.1 Approach to developing credible options

In its final decision on Transgrid's revised regulatory submission, the AER considered that Transgrid's System Security Roadmap Operational Technology project would need to explore a reasonable range of options to demonstrate that the project is prudent and efficient under the expenditure objectives and criteria in the NER.<sup>30</sup>

We set out the process we have undertaken to identify the range and scope of potential credible options in the remainder of this subsection.

#### 5.1.1 We identified three credible options in the PSCR

Transgrid has investigated and considered a number of alternative options for improving our control systems and corporate office capabilities. As described in the PSCR, this has involved both extensive investigation and planning by our internal teams, collaboration with AEMO, and the commissioning of expert input from independent international and Australian experts (EPRI and GHD Advisory) to

---

<sup>30</sup> AER, *Transgrid transmission determination – 1 July 2023 to 30 June 2028 – Attachment 5: Capital expenditure*, Final decision, p. 27.

independently assess Transgrid's control room and operational planning capabilities against future operational needs and international best practice.

The independent assessments pointed to the need for a staged approach to investment to deliver incremental improvements in the operational technology capabilities to a pace commensurate with the rate of decarbonisation of the electricity network.

In the PSCR, we identified what we considered to be three feasible options from a technical, commercial, and project delivery perspective, ie:

- Option 1: **Reactive capability** - provides enhancements to Transgrid's existing core operating technology (OT) capabilities to improve the reactive capabilities of Transgrid's control room and corporate offices;
- Option 2: **Proactive capability** - provides further, moderate enhancements across a portfolio of Transgrid's existing OT capabilities, as well as additional new capabilities, so that Transgrid can proactively plan for, and respond to, operational issues across its control room and corporate offices; and
- Option 3: **Predictive capability** - provides a suite of advanced enhancements to existing capabilities, as well as adding advanced new capabilities, to enable Transgrid to employ a predictive approach to operations in our control room and corporate offices.

Each option included the initiatives and capabilities of the previous option, typically at a higher level of technical uplift. In other words, Option 2 increased in scope, capability and the degree of technical uplift compared to Option 1. For example, while enhancements to data management and network modelling systems featured across both options, the technical capability of this solution was higher under Option 2 than Option 1 (where technologies are integrated across more systems and reflect a higher degree of technical sophistication). The proposed schedule in the PSCR for implementation of technology initiatives under each option was also staged to prioritise the initiatives required most urgently to meet the needs of an evolving power system.

Each option was developed as a package to reflect the minimum incremental technology solution required to enable a defined level of capability (i.e., reactive, proactive or predictive). Additionally, each option builds on the preceding option.

For example, under Option 1, the alarm management technology and energy management system (EMS) rely on data and functionality from the enhanced SCADA system to function effectively. Modern alarm management and EMS technologies uses data available from the latest versions of Transgrid's SCADA to monitor the network in real-time. This supports greater situational awareness and swift decision-making, to minimise outage duration and customer impact. Likewise, the EMS relies on the enhanced SCADA data to maintain system stability and optimise power flows. As a result, partial implementation of an option would not result in the intended capability being achieved.

We also considered two additional options as part of the PSCR that we did not consider technically feasible, ie:

- a significant uplift in human resources, without investing in operational technologies and tools; and
- a fully automated technology solution that could be implemented without additional staffing.

These options have not been progressed for the reasons outlined in Table 19.

### 5.1.2 We have refined the scope and estimated cost of the options based on the detailed RFI

Subsequent to the PSCR, we undertook a comprehensive market testing process through a detailed RFI to confirm the availability and costing of the proposed options being considered, and to test whether there are any other credible options that should be considered as part of this RIT-T. We also used the RFI process to further refine the scope of the options assessed in this PADR. We describe this process in detail in section 3.2.

We have undertaken further vendor assessments of technology architecture to validate the technical capabilities and implementation feasibility for each technology initiative. The deliverability risk is primarily driven by the technology vendor landscape, as some software solutions are in their infancy.

We consider that it is prudent to exclude technologies that are not within vendor product roadmaps, given the present deliverability and cost uncertainty. For this reason, we no longer consider Option 3 (predictive capability) as a credible option during this regulatory period. We discuss this further in section 5.5.

As we describe above in section 3.2, the PSCR presented initial scoping and high-level cost estimates for options. The cost estimates for the options presented in the PSCR were built upon previous cost estimates developed for the System Security Roadmap Operational Technology project in Transgrid's 2023-28 regulatory submission, which were in turn based on a bottom-up assessment performed in 2022 of the labour, materials and expenses required for each option, considering the duration of work required.

We have now substantially refined these initial scoping and high-level cost estimates through our comprehensive market testing process. Vendor feedback collected through responses to the RFI revealed that:

- the broad capability improvements can be achieved through investment in slightly fewer technology initiatives, while maintaining similar capability enhancement outcomes; but
- the capital and operating cost was substantially higher on a per initiative basis than our earlier indicative costings, across all of the vendors and for all of the options.

Subsequent to receipt of the RFI responses, we challenged the scope of the options. We have refined the technology initiatives included in each option for the PADR assessment based on this market feedback. We summarise some of the key differences in the specification of each option compared to the PSCR in Table 6 below, noting that further, minor refinements have been made to the scope of each technology initiative.

Table 6: Summary of scope refinement between the PSCR and PADR

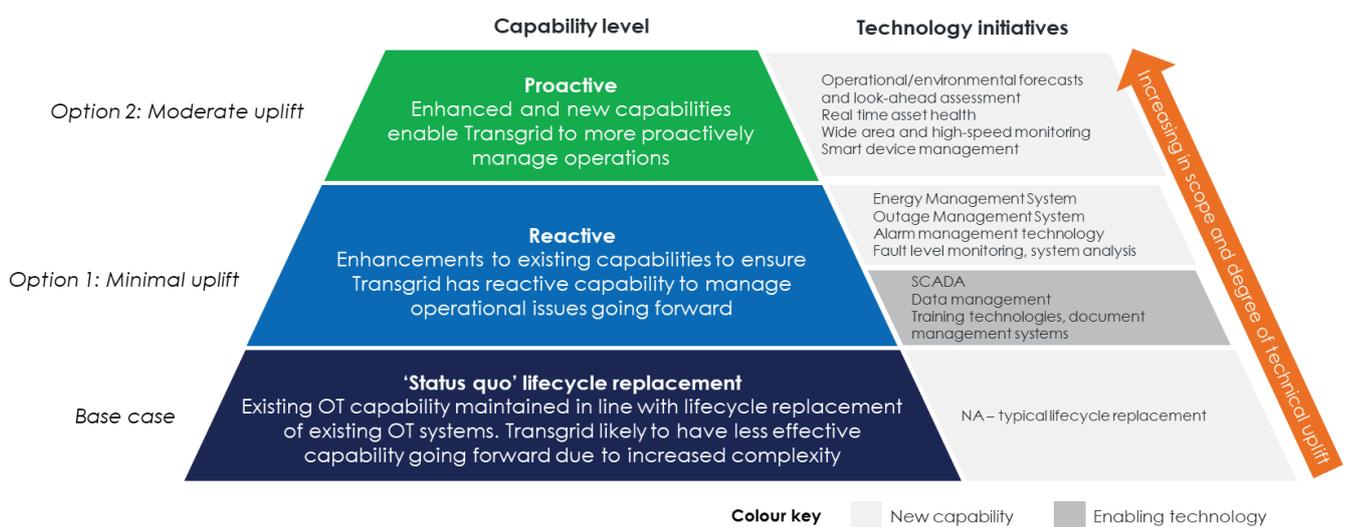
Technology initiative	Scope refinement	Option
Real time asset health monitoring system	Removed a range of automation and integration capabilities as a result of challenging the scope of technologies required	Option 2
Outage management system	Removed some automated data management capabilities as a result of challenging the scope of technologies required	Option 1
Outage management system	Removed all components to support proactive uplift, as they rely on safe switching capabilities which the existing SCADA/EMS product does not currently provide	Option 2

Operational forecasts and look-ahead contingency assessment	Removed geospatial and visualisation capabilities as a result of challenging the scope of technologies required	Option 2
Wide area and high speed monitoring	Removed several tools that support data collection and visualisation as a result of challenging the scope of technologies required	Option 2
Smart transmission device management	Removed uplift in capabilities as technology not provided by the market.	Option 2
Operational visualisation and situation awareness	Replaced several technologies with alternative vendor proposed solutions	Option 1
Operational visualisation and situation awareness	Removed several visualisation capabilities as a result of challenging the scope of technologies required	Option 2
Operational documentation management system	Removed several capabilities which were related to a higher level of uplift than reactive capabilities.	Option 1

### 5.1.3 Summary of the credible options assessed in this PADR

Figure 5.1 summarises the key characteristics of the credible options assessed in this PADR, in terms of the capabilities, associated technology and the extent of technical uplift. Some of these technologies relate to our corporate offices, including operational planning software which will be used by staff outside the control room, and elements of data management and sharing with asset management systems.

Figure 5.1: Option capability-technology pyramid for operational tools



Note: In addition to the technology initiatives identified above, operational planning sits across several of the technology initiatives as an enabling and complementary function.

The extent of technical uplift of the two options is presented in Figure 5.2 below, which demonstrates that the options are increasing both in scope and technical maturity. We also highlight areas where more significant scope refinement has occurred since the PSCR – we note that minor refinements to the scope of

technologies under each initiative has also been undertaken since the PSCR, which has not resulted in a change in the extent of technical uplift.

Figure 5.2: Difference in extent of technical uplift between options

Technology initiatives	Option 1	Option 2
Data management and network modelling systems	△	○
Energy management system (EMS)	△	○
SCADA enhancements	△	○
Enhanced outage management system (OMS)	△	△*
Real-time asset health monitoring system		△*
Operational forecasts and look-ahead contingency assessment		○
Wide area, high speed monitoring (WAMS)		○
Smart transmission device management		○
Fault level and system parameter monitoring, power system analysis	△	○
Alarm management, visualisation and situational awareness enhancements	△	○
Training technologies and operational document management systems	○*	○
Operational planning	△	○

\* Refined since PSCR    △ Minimal    ○ Moderate

We note that some of the technologies and tools considered are ‘enabling’ for the purposes of operational capability, since they provide foundational data or technologies and do not provide direct operational benefits in themselves but are necessary to realise the benefits of new capabilities. These enabling technologies include:

- enhancements to SCADA systems, where that investment is a prerequisite to enabling other capabilities such as alarm visualisation or wide area, high speed monitoring;
- data management and network modelling systems;
- training technologies and operational document management systems; and
- operational planning functions.

There are significant interactions and interdependencies between the investments in technology systems reflected in the options being considered in this RIT-T. In addition, the enabling capabilities and systems above are required to underpin the implementation of additional new capabilities. By way of example, we cannot implement any of our proposed investments in operational forecasting, fault level and system parameter modelling or wide area high speed monitoring without prior investments in our SCADA and EMS systems.

We have initiated an alarm rationalisation project of \$2.99 million (‘alarms rationalisation early works’) to help offset increases in alarm volumes arising from increases in alarm monitoring points associated with new connections.<sup>31</sup> This project was urgently required to handle the rapid increase in the number of alarms

<sup>31</sup> The alarms rationalisation project includes standardising alarm data including futureproofing for new generators, reprioritising and reducing the number of alarms presented to control room operators, and updating the screens for rapid alarm filtering.

and alarm monitoring points, which have increased from 18,000 in 2015 to 36,000 in 2023 and 55,000 in February 2025. Accordingly, we have commenced the initial phases of this work ahead of the operational tools RIT-T and submission of the CPA. We note that the alarms rationalisation project has reduced the need for immediate investment in alarm technologies that would otherwise be required.

We have continued to assess the alarms rationalisation project as part of the option cases (rather than including it in the base case), since the investments are part of all options and required now to address the expected unserved energy risk as outlined in case study 1. Transgrid intends to recover these costs as part of the CPA.

In addition to the two options we considered not credible at the PSCR stage, we have considered the potential for non-network solutions to assist in meeting the identified need. We did not receive any proposals from non-network proponents. We also do not consider that non-network solutions could assist (including imposing additional operating requirements on generators) for the reasons we set out in section 5.5.

## 5.2 Base case

Consistent with the RIT-T requirements, the PADR assessment compares the costs and benefits of each option to a base case. The base case is the (hypothetical) projected case if no action is taken, i.e.:<sup>32</sup>

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

Under the base case, no investment to improve Transgrid’s operational technology and tools for use in its control rooms and corporate offices is undertaken. However, consistent with the base case under the RIT-T, we assume a range of economically prudent BAU activities to best maintain our control room capabilities required for compliance with the NER until the end of the assessment period will occur, which are incremental to Transgrid’s existing services and 2023-28 regulatory revenue determination.

Specifically, we assume a lifecycle, non-enhanced replacement of our SCADA/EMS system by June 2030,<sup>33</sup> and additional operating expenditure for extended support of the existing SCADA/EMS system from 2028 to its replacement in June 2030.

We have not assumed additional staffing in the BAU base case. Staff cannot substitute for operational tools in grid management with growing system complexity, since personnel cannot substitute for certain tool capabilities (e.g., real-time visibility and advanced alarm management). Accordingly, the base case (which does not have any investment in additional operational technology and tools) reflects:

<sup>32</sup> AER, *Regulatory investment test for transmission application guidelines – October 2023*, p 22.

<sup>33</sup> Transgrid's SCADA/EMS system will reach end of life in 2029, having served its 7-year asset life. A SCADA upgrade will be necessary at this point for which Transgrid would seek lifecycle replacement funding during the next regulatory period, in the absence of investment under this RIT-T. We expect that this life-cycle replacement would take two years to deliver, and could be delivered by June 2030 (i.e., six months after the end of asset life). The cost of this life-cycle replacement is brought forward under the option cases. We assume a further replacement at the end of its 7-year asset life in June 2037, with the same two year rollout profile.

- a higher risk that we may need to load shed during system normal conditions and contingency events, as human capability to respond to the increased complexity in the control room environment will be limited; and
- higher fuel costs associated with NEM generator dispatch, as well as higher levels of greenhouse gas emissions associated with fossil-fuel generation, due to Transgrid having to manage its transmission network more conservatively in the future as system complexity increases, without the benefit of upgraded technology and tools in the regular operation and planning of network operations.

### Capital expenditure

We assume that approximately \$40 million of capital expenditure will be incurred under the base case in the two years to June 2030, in order to upgrade our SCADA/EMS system. We also assume an indicative refresh of this system at the end of its 7-year asset life by June 2037. As this project is going through the contingent project application process, we present the expected capital expenditure by component by regulatory period for the base case in Table 7, which shows that all of the expenditure on the initial SCADA/EMS investment will occur in the next regulatory period.

Table 7: Breakdown of capital cost under the base case by regulatory period (\$m \$2024/25)

Technology initiative	2023-28	2028-33	2033-38	Total
SCADA/EMS	0.0	40.0	40.0	80.0

Note: This expenditure is assumed to occur equally in 2028/29 and 2029/30 for the initial expenditure, and in 2036/37 and 2037/28 for the indicative refresh cost.

### Operating expenditure

Under the base case, we have assumed that \$250,000 per annum will be required to extend support for the existing SCADA system from 2028/29 to 2029/30. We have conservatively assumed no further operating expenditure in the base case.<sup>34</sup> Whilst we have not assessed any additional material operating costs in the base case, we note the potential for additional, immaterial operating costs to exist in the base case.

We present the annual breakdown of additional base case operating expenditure between 2024/25 and 2031/32 in Table 8. These base case operating costs are avoided under the option cases.

Table 8: Annual breakdown of expected operating cost under the base case (\$m \$2024/25)

	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
SCADA/EMS system	0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.0

## 5.3 Option 1 – Reactive capability: uplift of core operational technologies and tools only

Option 1 – reactive capability, ensures that we can continue to respond to operational incidents and operational planning needs in a reactive capacity. This includes our ability to effectively manage control

<sup>34</sup> This is a conservative approach, as including additional cost in the base case would increase the net benefits of each option.

room operations and optimise operational planning (e.g., by optimising the duration of outages) in an increasingly complex operating environment.

## Capital expenditure

Option 1 involves upgrades and augmentations to several of our core existing operational technologies and tools, beyond the scope of the typical lifecycle replacement reflected in the base case (i.e., the upgrades enable new functionalities), including:

- **Outage management system enhancements:**<sup>35</sup> enhancing our outage management system to reduce outage times, co-ordinate a greater number of outages, and improve our ability to assess the combined effect of a greater number of parallel outages;
- **Alarm management, visualisation and situation awareness enhancements:** reducing the number of alarms and providing more informative alarms, thereby reducing operators' cognitive load and enabling faster triage to improve monitoring of dynamic system conditions; and
- **Fault level and system parameter monitoring and power system analysis:** deploying an EMS fault level and system parameter monitoring application to provide real-time visibility of how close the system is to its operational limits. This will help define new technical operating envelopes and supporting secure operations, dynamic voltage control, and various operational support activities.

Option 1 also includes enhancements to our foundational capabilities that are required to establish the base level of reactive capability required. Put another way, these investments are required to enable the benefits from other operational technologies and tools to be unlocked. Specifically, enhancements to enable the capabilities expected from Option 1 include:

- **SCADA/EMS enhancements:** upgrading our SCADA/EMS system providing modern functionality used for system modelling, distributed energy resource management, enhanced contingency analysis, smart alarm management and visualisation. These enhancements will provide a platform that enables improved data sharing with other external and internal systems (i.e., the outage management system, network model management and the asset ratings team);
- **Data management and network modelling systems:** upgrading our data management tools to integrate operational planning data, operational electrical network model data and asset ratings data, to provide a 'single version of truth' for power system modelling and network model management;
- **Training technologies and operational document management systems:** establishing an advanced simulator-based training environment to upskill control room staff for a variety of scenarios under different power system conditions, and streamlining information access for control room operators, increasing the efficiency of operators when responding to network incidents; and
- **Operational planning system:** uplifting software and establishing new roles to define the increasing range of scenarios and technical limits applicable to the operation of the NSW/ACT network, managing risks to network integrity and operability associated with planned and unplanned network events and outages.

---

<sup>35</sup> We note that the expenditure proposed under this option represents an additional upgrade to our outage management system (i.e., above that of lifecycle replacement), beyond expenditure included in Transgrid's 2023-28 regulatory determination.

The SCADA/EMS enhancements in the option cases represent the 'bring forward' cost of an earlier replacement of our SCADA/EMS system, which is otherwise assumed to be replaced at its end of life in the base case.

The scope of works for this option are expected to be carried out between 2025 and 2029, with the expected in-service date for the technology initiatives in this option being incrementally rolled out until March 2029.

We estimate that the capital expenditure for Option 1 will be \$123.1 million – see Table 9.1 99.1 below.

Table 9.1 9: Breakdown of Option 1’s estimated capital expenditure (\$m \$2024/25)

Technology initiative	Estimated capital expenditure
Outage management system	1.8
Alarm management, visualisation and situation awareness enhancement	29.0
Fault level and system parameter monitoring and power system analysis capability	6.1
SCADA/EMS system enhancements	46.2
Data management and network modelling system	19.5
Training technologies, operational document management system and operational planning systems	14.3
CPA submission	6.2
<b>Total</b>	<b>123.1</b>

As Transgrid is undertaking this RIT-T over a 15-year assessment period, to capture the full benefit realisation period, and because the economic life of operational technologies and tools is typically between 5 and 7 years, we have assumed indicative refresh costs for each of the initiatives at the end of their economic life in both the base case and option cases. There is significant uncertainty for the value of any refresh costs. For the purposes of this RIT-T, Transgrid has conservatively assumed equal costs of replacement in real terms at the end of the economic life of the assets. We summarise the indicative refresh costs for Option 1 in Table 10 below.

Table 10: Breakdown of Option 1’s assumed indicative refresh cost (\$m \$2024/25)

Technology initiative	Indicative refresh cost
Outage management system	3.6*
Alarm management, visualisation and situation awareness enhancement	26.0
Fault level and system parameter monitoring and power system analysis capability	6.1
SCADA/EMS system enhancements	46.2

Data management and network modelling system	39.1*
Training technologies, operational document management system and operational planning systems	21.7*
<b>Total</b>	<b>142.6</b>

\*The indicative refresh costs are higher than initial expenditure for some technologies because one or more components only have a 5 year asset life, and so are assumed to be replaced twice during the assessment period.

We present the estimated capital expenditure across the whole 15-year assessment period by initiative and by regulatory period in Table 11 below. We note that the estimated capital expenditure is incurred from 2024/25 to 2028/29, which means that approximately \$16.4 million of the \$123.1 million in initial expenditure under Option 1 would be incurred in the 2028-33 regulatory period.

Table 11: Breakdown of Option 1's estimated capital expenditure by regulatory period (\$m \$2024/25)

Technology initiative	2023-28	2028-33	2033-38	Total
Outage management system	1.8	1.8	1.8	5.4
Alarm management, visualisation and situation awareness enhancement	21.2	10.0	23.8	55.0
Fault level and system parameter monitoring and power system analysis capability	4.3	1.8	6.1	12.1
EMS/SCADA system enhancements	39.4	14.3	38.7	92.4
Data management and network modelling system	19.5	19.5	19.5	58.6
Training technologies, operational document management system and operational planning systems	14.3	7.4	14.3	36.0
<b>CPA submission</b>	<b>6.2</b>	<b>0</b>	<b>0</b>	<b>6.2</b>
<b>Total</b>	<b>106.7</b>	<b>54.9</b>	<b>104.1</b>	<b>265.7</b>

Table 12 shows the profile of estimated capital expenditure for Option 1.

Table 12: Annual breakdown of Option 1's estimated capital expenditure (\$m \$2024/25)

	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Capital expenditure	8.2	15.6	58.0	24.9	16.4	0.0

## Operating expenditure

The delivery of new operational tools and systems will necessitate an increase of vendor software and hardware maintenance to ensure these tools deliver the required level of capabilities. Specifically, we estimate that maintenance for:

- the enhanced SCADA/EMS system will cost between \$1.0 and \$1.2 million per year; and

- the operational planning system will cost between \$0.9 and \$1.4 million per year.

In addition, Option 1 will require a direct increase in Transgrid’s resourcing, which is essential to facilitate the operation of these tools, as additional staff will be required to handle the new processes, provide training, and maintain the systems. Specifically, we have estimated that an additional 12 FTEs<sup>36</sup> will be required to maintain and support new technologies by 2030, ie:

- six additional FTEs to maintain SCADA/EMS modules to vendors’ recommended versions, maintain and update the SCADA/EMS training simulator and maintain and update alarm handling business rules; and
- six additional FTEs to support planning operations by maintaining the quality of power system modelling for operations planning and maintaining and updating the common information data model for operational data.

We present the expected annual operating expenditure associated with Option 1 between 2024/25 and 2031/32 in Table 13. These operating costs follow a similar trend throughout the remainder of the assessment period.

Table 13: Annual breakdown of Option 1’s expected operating cost (\$m \$2024/25)

	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
SCADA/EMS system	0.0	0.0	1.0	1.0	1.0	1.0	1.1	1.1
Operational planning system	0.0	0.0	0.0	0.9	0.8	1.2	1.2	1.3
Internal staffing – SCADA/EMS system	0.0	0.1	0.5	1.5	1.5	1.5	1.5	1.5
Internal staffing – planning operations	0.0	0.0	0.8	1.0	1.0	1.0	1.0	1.0
<b>Total operating expenditure</b>	<b>0.0</b>	<b>0.1</b>	<b>2.2</b>	<b>4.3</b>	<b>4.3</b>	<b>4.7</b>	<b>4.7</b>	<b>4.9</b>

#### 5.4 Option 2 – Proactive capability: uplift across a portfolio of operational technologies and tools, plus essential new capabilities

Option 2 – proactive capability, builds on Option 1 but involves a greater level and scope of technical upgrades across Transgrid’s portfolio of operational technology and tools (rather than just Transgrid’s core tools). In addition, Option 2 includes establishing new functionality to underpin proactive capabilities for Transgrid’s control rooms operators and operational planners.

Transgrid expects that the additional initiatives delivered by Option 2 will, amongst other things:

- improve the outcomes of operational incidents as system complexity increases by:

<sup>36</sup> 1 FTE represents one full-time worker’s standard workload.

- > facilitating more proactive monitoring of power system conditions, supporting real-time decision making; and
- > further enhancing situational awareness and reducing cognitive load on control room operators;
- provide improved network visibility and modelling capabilities through automated measurement of real-time network characteristics, enabling a reduction in network constraints; and
- enable Transgrid’s control room operators to reduce the duration and scope of planned and unplanned transmission outages, including during critical contingencies.

Option 2 includes the same core technology upgrades as Option 1 but at a higher level of technical uplift. In addition, Option 2 includes several new operational technologies and tools which underpin the ‘proactive’ capabilities under Option 2, including:

- **Real-time asset health system:** integration of real-time data with asset management systems to provide greater insights into asset health;
- **Operational and environmental forecasts and impact assessment:** systems to provide early warnings and alarms to control room operators, asset monitoring and maintenance teams, which provides short-term forecast decision support for contingency analysis to support network operation including voltage control, outage switching and emergency management;
- **Wide area, high speed monitoring:** provides real-time monitoring of the transmission network, helping to detect potential issues before they lead to outages and maintain grid stability by quickly identifying and addressing disturbances; and
- **Smart transmission device management:** technical capability to increase the prevalence and effectiveness of Special Protection Schemes, which facilitate increasing levels of variable renewable energy.

Since the PSCR, we have removed proactive uplifts to the outage management system from Option 2, because the existing outage management solution does not currently have safe switching execution functionality available, and RFI responses for this functionality indicated that desired levels of capability could not be delivered in a suitable timeframe. Therefore, there are no enhancements in our proposed outage management system between Option 1 and Option 2.

Whilst Option 2 builds on the capabilities of Option 1, its delivery as a single package reduces duplication of planning and delivery costs that would otherwise be incurred by building Option 1 now and Option 2 at a later date.

The scope of works for this option is expected to be carried out between 2025 and 2030, with the expected in-service date for the technology initiatives of this option being incrementally rolled out until March 2030.

### Capital expenditure

We estimate that the capital expenditure for Option 2 is \$179.2 million. We present a breakdown of this estimated capital expenditure in Table 14 below.

Table 14: Breakdown of Option 2’s estimated capital expenditure (\$m \$2024/25)

Technology initiative	Estimated capital expenditure
Outage management system	1.8

Alarm management, visualisation and situation awareness enhancement	41.0
Fault level and system parameter monitoring and power system analysis capability	9.6
EMS/SCADA system enhancements	56.0
Data management and network modelling system	26.3
Training technologies, operational document management system and operational planning systems	14.3
Real-Time Asset Health Monitoring	0.6
Operational forecasts and look-ahead contingency assessment	6.3
Wide Area and High-Speed Monitoring	11.4
Smart Transmission Device Management	5.9
CPA submission	6.2
<b>Total</b>	<b>179.2</b>

As Transgrid is undertaking this RIT-T over a 15-year assessment period, to capture the full benefit realisation period, and because the economic life of operational technologies and tools is typically between 5 and 7 years, we have assumed indicative refresh costs for each of the initiatives at the end of their economic life in both the base case and option cases. There is significant uncertainty for the value of any refresh costs. For the purposes of this RIT-T, Transgrid has conservatively assumed equal costs of replacement in real terms at the end of the economic life of the assets. We summarise the indicative refresh costs for Option 2 in Table 15 below.

Table 15: Breakdown of Option 2's assumed indicative refresh cost (\$m \$2024/25)

Technology initiative	Indicative refresh cost
Outage management system	3.6*
Alarm management, visualisation and situation awareness enhancement	38.0
Fault level and system parameter monitoring and power system analysis capability	9.6
EMS/SCADA system enhancements	56.0
Data management and network modelling system	52.3*
Training technologies, operational document management system and operational planning systems	21.7*
Real-Time Asset Health Monitoring	0.6
Operational forecasts and look-ahead contingency assessment	6.3
Wide Area and High-Speed Monitoring	11.4

Smart Transmission Device Management	5.9
<b>Total</b>	<b>205.3</b>

\*The indicative refresh costs are higher than initial expenditure for some technologies because one or more components only have a 5 year asset life, and so are assumed to be replaced twice during the assessment period.

We present the estimated capital expenditure across the entire 15-year assessment period by initiative by regulatory period in Table 16 below. We note that the capital expenditure is incurred from 2024/25 to 2029/30 under this option, which means that approximately \$50.4 million of the \$179.2 million in capital expenditure will be incurred in the 2028-33 regulatory period (and so asked for in Transgrid's next regulatory revenue determination, not in the CPA process).

Table 16: Breakdown of Option 2's estimated capital expenditure by regulatory period (\$m \$2024/25)

Technology initiative	2023-28	2028-33	2033-38	Total
Outage management system	1.8	1.8	1.8	5.4
Alarm management, visualisation and situation awareness enhancement	28.7	15.4	34.8	78.9
Fault level and system parameter monitoring and power system analysis capability	6.5	3.0	9.6	19.2
EMS/SCADA system enhancements	39.7	24.8	47.5	112.0
Data management and network modelling system	26.2	26.3	26.1	78.5
Training technologies, operational document management system and operational planning systems	14.3	7.4	14.3	36.0
Real-time asset health monitoring system	0.0	0.6	0.6	1.1
Operational forecasts and look-ahead contingency assessment	2.2	4.0	6.3	12.6
Wide area and high-speed monitoring	3.2	8.2	11.4	22.8
Smart transmission device management	0.0	5.9	5.9	11.8
CPA submission	6.2	0	0	6.2
<b>Total</b>	<b>128.8</b>	<b>97.4</b>	<b>158.2</b>	<b>384.5</b>

Table 17 shows the profile of estimated capital expenditure for Option 2.

Table 17: Annual breakdown of Option 2's estimated capital expenditure (\$m \$2024/25)

	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Capital expenditure	8.2	19.5	68.8	32.3	35.0	15.4

## Operating expenditure

The uplift of new operational tools and systems from reactive to proactive capabilities under Option 2 is expected to necessitate an incremental increase in maintenance costs compared to under Option 1. We assume that:

- maintenance for the enhanced SCADA/EMS system will cost between \$1.5 and \$1.9 million per year (which is approximately 50 per cent more than under Option 1); and
- additional software/licensing will be required that costs \$500,000 per year.

In addition to the 12 additional FTEs that we expect will be required to achieve reactive capabilities under Option 1, we estimate that four further FTEs will be required by 2030 under Option 2 to operate the additional systems required to achieve proactive capabilities. Specifically, the proactive capabilities under Option 2 involve moving from maintaining and utilising a real-time dataset (Option 1) to maintaining and leveraging both real-time and forecasting datasets for operational forecasting, which will require additional FTEs to manage.

We present expected annual operating expenditure associated with Option 2 in Table 18 below. These operating costs follow a similar trend throughout the remainder of the assessment period.

Table 18: Annual breakdown of Option 2's expected operating cost (\$m \$2024/25)

	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
SCADA/EMS system	0.0	0.0	1.5	1.5	1.6	1.6	1.7	1.7
External software/licensing	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5
Operational planning system	0.0	0.0	0.0	0.9	0.8	1.2	1.2	1.3
Internal staffing - SCADA/EMS system	0.0	0.1	0.5	1.5	1.5	1.5	1.5	1.5
Internal staffing – control room	0.0	0.0	0.0	0.0	0.0	0.3	0.5	0.5
Internal staffing – planning operations	0.0	0.0	0.8	1.5	1.5	1.5	1.5	1.5
<b>Total operating expenditure</b>	<b>0.0</b>	<b>0.1</b>	<b>3.3</b>	<b>5.9</b>	<b>5.9</b>	<b>6.5</b>	<b>6.8</b>	<b>7.0</b>

## 5.5 Options considered but not progressed

We considered five additional options, including the potential of non-network options, to meet the identified need in this RIT-T. Table 19 summarises the reasons the following options were not progressed further.

Table 19: Options considered but not progressed

Description	Reason(s) for not progressing
<p>Option 3: Predictive capability. Option 2, plus artificial intelligence, machine learning and advanced WAMS to enable predictive and automated operations throughout key parts of Transgrid's operational control systems and operational planning technology stack</p>	<p>This option was considered under the PSCR, but is no longer considered commercially feasible at this time, given costs that were significantly higher than originally expected obtained from vendor responses to the RFI and deliverability challenges in the given timeframe.</p> <p>Transgrid notes that, because this option builds upon Option 2, this option, or part thereof, may be explored in a future regulatory period as technology matures, if there were net benefits of doing so.</p>
<p>A significant uplift in staffing levels and training, without the introduction of new technology and tools.</p>	<p>This option is not considered technically feasible. The near-exponential increases in data management, analysis and decision-making required over the next decade mean that system risks cannot be effectively managed with additional human resources alone. Furthermore, the skill sets required are specialised and are in high demand in the employment market, so it would be highly challenging to recruit, develop, train and retain staff in the numbers and timeframe that would be required. Increased staff would also require managing the network in smaller segments, thus reducing overall network situational awareness.</p>
<p>A fully automated technology solution that could be implemented without an uplift in human resourcing.</p>	<p>This option is not considered to be technically feasible because such tools are not available 'off the shelf' and the solution could not be fully developed and implemented within the timeframes required.</p>
<p>Impose additional operating requirements on generators (potential non-network solution)</p>	<p>This option involves imposing additional information collection and operating requirements on generators. For example, this would require generators to self-collect information on network conditions and self-curtail under certain network conditions.</p> <p>We do not consider this option to be commercially feasible as this would require generators to invest in duplicative systems and would lead to a higher degree of curtailment given the lack of coordination between generators. Further, this option would not address the identified need, and so is also not considered technically feasible.</p>
<p>Other non-network solutions</p>	<p>We have not identified any other non-network solutions that are commercially and technically feasible to assist with meeting the identified need for this RIT-T.</p> <p>Non-network options are unable to contribute towards meeting the identified need for this RIT-T, as non-network options cannot affect the capabilities of Transgrid's control rooms or corporate offices.</p> <p>Further, the RFI process has also confirmed that technologies are to be hosted on-premises to meet our security and operating license data classification requirements. It follows that any network solutions that involve hosting of technologies off-premises would not be a credible option.</p>

## 6 Overview of the assessment approach

---

This section outlines the overall approach we have applied in assessing the net benefits associated with each of the credible options against the base case, and ensuring the robustness of our analysis. Section 7 then provides further detail on the case study approach that we use to quantify the gross market benefits from investments in operational technologies and tools, and section 8 sets out the results of our net market benefits assessment.

### 6.1 Assessment period and discount rate

We have adopted a 15-year assessment period from 2024/25 to 2038/39 for this RIT-T analysis. This assessment period was selected to reflect the relatively shorter asset lives of operational technologies and tools compared to network infrastructure assets, but also to fully capture the benefit realisation period from our proposed staged delivery of these investments. Staging is required for some technology initiatives, since they depend on enabling technologies that must be implemented first. We have also considered the likely need to refresh assets during the assessment period under both the base case and option cases, given these assets typically have useful lives of between five and seven years.

Where capital components of the options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining functional asset life. This ensures that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or serviceable asset life. The terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period.

A real, pre-tax discount rate of 7 per cent has been adopted as the central assumption for the NPV analysis presented in the PADR, consistent with AEMO's most recent final Input Assumptions and Scenarios Report (IASR).<sup>37</sup> The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have tested the sensitivity of the results to a lower bound discount rate of 3.63 per cent,<sup>38</sup> as well as an upper bound discount rate of 10.5 per cent (i.e., the upper bound in the latest IASR).<sup>39</sup>

### 6.2 Approach to estimating option costs

As outlined in section 3.2, we have undertaken comprehensive market testing with vendors to refine the specifications and obtain market-based cost estimates for the options assessed in this PADR. We have used the average of the technically compliant vendor cost estimates for each option. We expect this approach will better reflect the level of contingency cost that the lowest cost vendor would likely include at the procurement stage. Ahead of the PACR, we are intending to obtain an independent review by an industry expert, to further refine our market-based cost estimates.

We note that the two options being assessed reflect a programme of works, for which Transgrid currently expects it may contract with multiple vendors at different future points in time, in order to achieve the most cost-efficient outcome for consumers and take advantage of the most recent technologies. The final cost

<sup>37</sup> AEMO, *2023 Inputs, Assumptions and Scenarios Report*, Final report, July 2023, p 123.

<sup>38</sup> This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (TasNetworks) as of the date of this analysis, see: AER, *TasNetworks – 2024-29 – Final decision – PTRM*, April 2024, WACC sheet.

<sup>39</sup> AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, Final Report, p. 123.

estimate, together with the selected vendor/s for the near-term option components will be detailed in the CPA.

We set out in section 3.2 that Transgrid conducted a RFI process to obtain external vendor costs for the three options mentioned in the PSCR. Based on the RFI responses, Transgrid considered that Option 3 was not technically or commercially feasible at this time. The vendors set out the overall project timeline for all options. Based on the scope and program schedule, Transgrid developed the internal resources required for options 1 and 2. The resources have been spread out across each year in alignment with the vendor's program. A risk factor is also included in the overall cost estimate based on an assessment of the expected risks, which is based on Transgrid's standard process to determine P50 cost estimates.

The overall project cost estimates have increased in comparison to the estimates in the PSCR. The reason for this increase is the external vendor costs received, which reflect realistic market testing. As the external vendor cost has increased, it has also driven an increase in the internal cost and risk factors, which in total have increased the overall project cost.

Transgrid has estimated the internal costs of the options based on the RFI responses and costing experience from previous similar projects, using a bottom-up approach. All costs estimated by Transgrid's project development team use the estimating tool 'MTWO'. The MTWO cost estimating database reflects actual outturn costs built up over more than 10 years from labour quantities from recently completed projects.

The MTWO estimating database is reviewed annually to reflect the latest outturn costs and confirm that estimates are within their stated accuracy range and represent the most likely expected cost of delivery (P50 costs). As part of annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.

Transgrid does not generally apply the Association for the Advancement of Cost Engineering (AACE) international cost estimate classification system to classify cost estimates. Doing so for this RIT-T would involve significant additional costs, which would not provide a corresponding increase in benefits compared with market-based cost estimates and so this has not been undertaken.

We estimate that actual costs will be within +/- 25 per cent of the central capital cost estimate. While we have not explicitly applied the AACE cost estimate classification system, we note that an accuracy of +/- 25 per cent for cost estimates is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the AACE classification system.

### **Operating costs directly associated with the capital investment**

Annual operating costs associated with additional personnel, where required to support and maintain proposed new technologies, are based on estimated labour rates from the MTWO cost estimating tool. The estimating tool considers a blend of internal resourcing and external service providers. In addition to labour, the Original Equipment Manufacturer (OEM) hardware and software maintenance costs have been estimated based on market estimates derived within the RFI process.

### **6.3 Classes of market benefit that are considered material**

Three categories of market benefit are considered material for this RIT-T:

- **changes in involuntary load curtailment** – the proposed investments are expected to materially reduce expected unserved energy (EUE) compared to the base case;
- **changes in fuel consumption in the NEM** – the proposed investments are expected to reduce the quantity and duration of constraints on renewable generators, thereby affecting generator dispatch patterns and associated fuel consumption; and
- **changes in Australia’s greenhouse gas emissions** – resulting from the changes in fuel consumption and generation dispatch patterns, material changes in Australia’s greenhouse gas emissions from NEM generators are expected compared to the base case.

Section 7 presents our estimate of these market benefit categories, across three case studies. The remainder of this sub-section describes at a high level the key parameters we have adopted in this assessment to evaluate each category of market benefit.

### 6.3.1 Changes in involuntary load curtailment

As outlined in section 5.2, the base case will increasingly result in expected unserved energy as the cognitive load on control room operators increases. Transgrid has valued the differences in EUE between the base case and the option cases using the Value of Customer Reliability (VCR).

Consistent with the AER’s RIT-T Guidelines,<sup>40</sup> Transgrid has adopted VCR estimates that are based on the latest estimates published by the AER.<sup>41</sup>

The options considered have benefits which arise across our network. As a result, we consider that a state-wide VCR is likely to reflect the weighted mix of customers that will be affected by these options. We have adopted the customer load weighted VCR for NSW published by AEMO in its December 2024 final report on the values of customer reliability,<sup>42</sup> inflated to 2024/25 dollars using CPI data.<sup>43</sup>

### 6.3.2 Changes in fuel consumption in the NEM

We have estimated fuel cost changes using a traceable and simple set of assumptions to provide transparency and reflect a proportionate approach to estimating this benefit category for this RIT-T.

The options identified in this RIT-T are expected to affect wholesale market dispatch outcomes, since the proposed investments are expected to decrease the likelihood and duration of constraints on renewable generators, thereby reducing the quantity of thermal generation dispatched.

We consider that full-scale wholesale market modelling would be disproportionate to the scale, size and potential benefits expected. In addition, we expect that a wholesale market modelling exercise would itself be largely assumptions-driven, given the number of assumptions that would be required to generate outputs, which likely results in false precision for any conclusions drawn, and would provide less transparency than Transgrid’s case study approach.

<sup>40</sup> AER, Regulatory investment test for transmission, Application guidelines, November 2024, p 25.

<sup>41</sup> AER, Values of customer reliability, Final report, December 2024.

<sup>42</sup> AER, Values of customer reliability, Final report, December 2024, p 62.

<sup>43</sup> The VCR values published by AEMO are in September 2024 dollars. We deflate these to 2023/24 dollars using actual CPI data published by the Australian Bureau of Statistics, and then inflate them to 2024/25 dollars using the forecast CPI published by the Reserve Bank of Australia.

Instead, we have quantified avoided fuel costs under two case studies, based on the avoided fuel costs of the marginal generator as the network moves from a constrained to less-constrained state, or during an outage. We summarise our methodology to calculating avoided fuel costs in further detail in section 7.4.3.

### 6.3.3 Changes in Australia’s greenhouse gas emissions

Consistent with the approach taken to estimating the change in thermal generation dispatched, we have calculated the associated change in greenhouse gas emissions based on the change in the marginal generator, and the generator emissions intensity factors published in the latest IASR.

We calculate the benefit as the change in the quantity of emissions between the base case and option case, multiplied by the annual value of emissions reduction (VER), based on those determined by the Energy Ministers and set out in the AER guidance and explanatory statement published in May 2024.<sup>44</sup> We summarise our methodology to calculating avoided greenhouse gas emissions in further detail in section 7.4.3.

### 6.3.4 Market benefits expected to arise outside of NSW and the ACT

We expect that investments in Transgrid’s control room will reduce the curtailment of renewable generators in NSW and the ACT. This may have material market benefits in regions other than NSW and the ACT, as a reduction in constraints on renewable generators connected to Transgrid’s network may increase the supply of renewable generation to and decrease the marginal cost of generation in other regions.

Under our case study approach, we have conservatively only quantified the benefits of operational technology investments in NSW and the ACT. This is because considering interconnector constraints and inter-state marginal costs would add additional complexity to the analysis, which would be disproportionate to the size, scale and expected benefits of this quantification exercise.

### 6.3.5 Classes of market benefit that are not considered material

In addition to the classes of market benefits listed above, NER clause 5.15A.2(b)(4) requires Transgrid to consider the following classes of market benefits, arising from each credible option. We consider that none of the classes of market benefits listed in table 20 are material for this RIT-T assessment for the reasons provided.

Table 20: Reasons market benefits are considered immaterial

Market benefits	Reason
Changes in costs for other parties in the NEM	The options are not expected to require other parties in the NEM to make material investments or incur additional operating costs. While the improved operational capabilities may benefit other parties through more efficient network operations, these benefits are captured through other market benefit categories like reduced dispatch costs and reduced unserved energy.
Changes in network losses	The investments are not expected to materially affect network losses.
Changes in ancillary service costs	While better visibility and control may help manage ancillary services, material changes to ancillary service costs are not expected.
Competition benefits	The operational technology investments are internal to Transgrid’s capabilities and not expected to materially impact competition in generation markets. While improved network operations may enable more efficient dispatch, this benefit is captured under other categories.

<sup>44</sup> AER, Valuing emissions reduction – AER guidance and explanatory statement, May 2024, pp 5-6.

Option value	While the options can be scaled up over time (e.g., from Option 1 to Option 2), the scenario analysis in the PADR captures differences in the timing of renewable energy integration. No additional option value beyond what is captured in the scenario analysis is expected to be material.
--------------	---

## 6.4 Three different scenarios have been modelled to address uncertainty

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future ‘states of the world’). For the operability investments being assessed in this RIT-T, the key uncertainties relate to the future complexity of the energy market, which will be impacted by the number and timing of new generation and storage connecting to our network, as well as future demand increases.

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each ISP scenario to determine a weighted (‘expected’) net benefit.

For each ISP scenario, the RIT-T requires categories of market benefits to be calculated by comparing the ‘state of the world’ in the base case where no action is undertaken, with the ‘state of the world’ with each of the credible portfolio options in place, separately. The ‘state of the world’ is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity and timing of future generation and storage investment as well as unrelated future transmission investment (for example, that is required to connect REZs). It is this ‘expected’ net benefit that is used to rank credible options and identify the preferred option.

We have assessed the options across three scenarios as part of the PADR assessment. Specifically, we have adopted different forecast renewable generator growth, generation mix and retirement dates based on the 2024 ISP Step Change, Progressive Change and Green Energy Exports scenarios. We have weighted the market benefit outcomes under the three scenarios based on the ISP scenario weightings.

Table 21 below summarises the scenarios we have adopted to assess options in this RIT-T.

Table 21: Summary of scenarios

ISP scenario (demand growth and renewable generation projections)	Step Change	Progressive Change	Green Energy Exports
<i>Scenario weighting</i>	43%	42%	15%
Discount rate	7.0%	7.0%	7.0%
Network capital costs	Base estimate	Base estimate	Base estimate
Operating costs	Base estimate	Base estimate	Base estimate

The effect of changes to other variables (including the discount rate and capital costs) on the NPV results have been investigated in sensitivity analysis, rather than through the scenarios.

## 6.5 Ensuring the robustness of the analysis

In addition to the scenario analysis, we have considered the robustness of the outcome of the cost benefit analysis through undertaking various sensitivity tests and threshold analysis.

### 6.5.1 Sensitivity analysis

Sensitivity testing demonstrates how robust the preferred option is by testing different key assumptions and scenarios. Sensitivity testing shows the variables that most affect the outcomes and accounts for uncertainty in long-term forecasts.

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

- lower and higher assumed capital costs;
- lower and higher assumed operating costs;
- lower and higher assumed discount rates;
- lower and higher value of customer reliability;
- lower and higher total gross benefits;
- longer economic lives; and
- optimal timing analysis, based on a one year delay/acceleration of the rollout.

We discuss the rationale behind these sensitivities and the results in section 8.4 below.

### 6.5.2 Threshold analysis

We have also undertaken threshold analysis to show at what point options change in rank or provide negative market benefits compared to the base case, for capital cost, operating costs, and total gross benefits. We present the results from this analysis in section 8.5 below.

## 7 Estimating the market benefits of the alternative options

---

This section outlines our case study approach for calculating gross market benefits for each of the credible options identified in this RIT-T, compared to the base case, across the three ISP scenarios. It also presents the outcome of that calculation.

We present gross market benefits only (i.e., exclusive of investment cost) in this section, for each of the case studies and under each of the ISP scenarios. The costs and net benefits of each option are detailed in section 8. Detailed assumptions used to calculate the benefits are set out in Appendix B.

### 7.1 Benefits have been estimated using a case study approach

The RIT-T process requires us to quantify the market benefits associated with addressing the identified need. There are several challenges with quantifying these market benefits, including:

- it is atypical for the benefits from investments in operational technologies and tools to be quantified under the RIT-T process, and how benefits arise from these types of projects is different to network augmentation and replacement expenditure – this has required us to develop a bespoke quantification framework that is different to a typical asset upgrade;
- the problems that investments in operational technologies and tools are designed to address are emerging – existing data and trends provide limited insight into the nature and future scale of the problem; and
- the benefits from upgrades to operational technologies and tools are far reaching – making it harder to articulate all of the benefits that arise from addressing the identified need.

Given the above challenges, we have adopted a ‘case study’ approach to quantify the benefits arising from each credible option. A case study approach provides stakeholders with a clear understanding of the capability gained from the initiatives, the identified use case for different capabilities, and the associated benefits for each use case. This provides a clear understanding of the investment logic associated with addressing the identified need. We have explained our case study approach to the TAC, who support our approach.

We have identified five use cases that arise from upgrades to operational technologies and tools. To provide a conservative estimate of benefits of each credible option, we have:

- only quantified three out of the five use cases identified – the three case studies quantified are the ones that we could most readily quantify and are sufficient to demonstrate positive net market benefits and identify a preferred option;
- only quantified a subset of associated benefits for the three use cases quantified, to ensure our analysis remains conservative, tractable and does not double count benefits across use cases; and
- used conservative or reasonable assumptions to quantify benefits. For example, we have conservatively excluded ‘system restart’ events from case study 1.

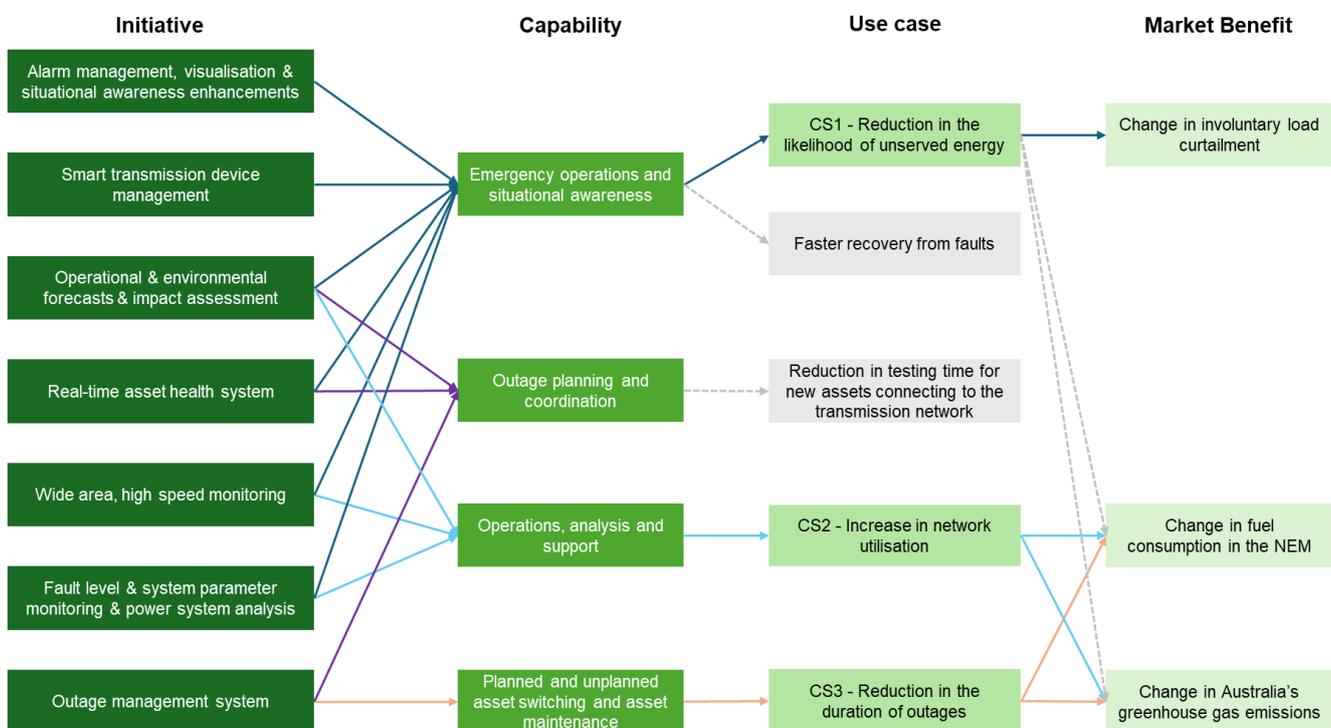
As such, the benefits quantified in this RIT-T are conservative but sufficient to identify a preferred option and demonstrate that the preferred option generates positive net market benefits. Where relevant, we have used data from AEMO’s ISP and IASR as inputs into our analysis, including to inform how benefits are expected to change over time and the implications of different ISP scenarios.

We consider that a more complex market modelling exercise would be inappropriate for this project, given the number of assumptions that would be required to generate outputs, which would likely result in false precision for any conclusions drawn. In addition, Transgrid believes that market modelling would be disproportionate to scale, size and potential benefits of the credible options being considered, particularly given the lack of additional accuracy expected compared with the case study approach.

Figure 7.1 provides an overview of:

- the initiatives that we will invest in as part of the options considered in this RIT-T;
- the corresponding capability improvement arising from the initiatives;
- the use cases we have identified from the improvements in capability; and
- the associated market benefits for the use cases we have quantified using a case study approach.

Figure 7.1: Benefits expected to accrue from control room investments



Note: we have not quantified all benefits expected to accrue from control room investments (denoted in grey).

## 7.2 The three use cases quantified in this RIT-T

We have quantified the following use cases in this RIT-T:

- **Case study 1:** reduction in the likelihood of unserved energy compared to the base case, as better situational awareness and decision making in the control room to maintain network reliability and security;
- **Case study 2:** reduced curtailment of renewable energy when network is constrained, as improved understanding of actual network conditions allows us to operate the network less conservatively; and
- **Case study 3:** reduced duration of outages from having an improved outage management system.

We summarise these three case studies in Table 22 below. We have also identified two other use cases, i.e., faster recovery from faults and reduction in testing time for new assets connecting to the network. We have not quantified the benefits from these two use cases at this stage, as quantifying the benefits from the above three use cases was sufficient to demonstrate positive net market benefits and identify a preferred option.

Table 22: Summary of market benefit case studies estimated in this RIT-T

ID	Case study	Benefit driver	Section
Case study 1	Reduction in the likelihood of unserved energy	<p>Early detection and intervention for faults reduces probability of event escalating to an outage event with unserved energy, as well as the need to operate the network more conservatively and take assets offline. This outcome arises from better visibility of asset conditions and network fault levels, prioritisation of information and supported decision making, which together reduces the cognitive load on control room operators in a complex operating environment.</p> <p>This RIT-T only quantifies the benefits related to reduction in the likelihood of unserved energy and does not quantify benefits from reduced risk of asset failure or less conservative network operation.</p>	7.3
Case study 2	Increase in network utilisation	Alleviating pre-emptive and conservative generator constraints through real-time and near-term network analysis replacing static scenario measurements. This facilitates less conservative network asset utilisation by updating operating limits and ability to operate closer to the technical envelope.	7.4
Case study 3	Reduction in the duration of outages	Reduction in planned outage duration associated with switching operations through enhanced ability to better coordinate switching operations and new tools to verify equipment/safety status	7.5

In the remainder of this section we set out, for each case study:

- the background and drivers of benefits;
- the benefits and technology/capability uplift under each option;
- the quantification approach taken to estimate the benefits for each option; and
- the results of the gross benefit modelling for that case study.

Additional details on data sources and modelling assumptions for each case study is provided in Appendix B.

### 7.3 Case study 1 – Reduction in the likelihood of unserved energy

Case study 1 evaluates the reduction in the likelihood of outages arising from an improvement to situational awareness and decision making. Situational awareness and decision making refers to the control room operator's ability to sense, understand and respond to issues in the power system in real-time.

#### 7.3.1 Background and driver of benefits under case study 1

Control room operators must undertake a range of time-critical actions to maintain the network within a safe operating envelope, either ahead of or following a range of real-time events occurring on our network, including:

- performing network control actions to secure the network post trip of an asset;
- preparing contingency management plans to manage potential loss of assets;

- performing network control actions to remove equipment from service to prevent critical failure of an asset; and
- assessing potential risks in collaboration with other operations teams (e.g. asset management and field staff) to prepare for potential faults based on early indicators of compromised operations.

The rapid transformation of NSW's electricity grid is testing the limitations of our existing control room capabilities. Increasing power system complexity has resulted in operators needing to process more information and manage situations that have not occurred historically. It follows that operators will need more time and effort to make decisions, while using tools that are not designed to for this level of complexity or alarm volumes.

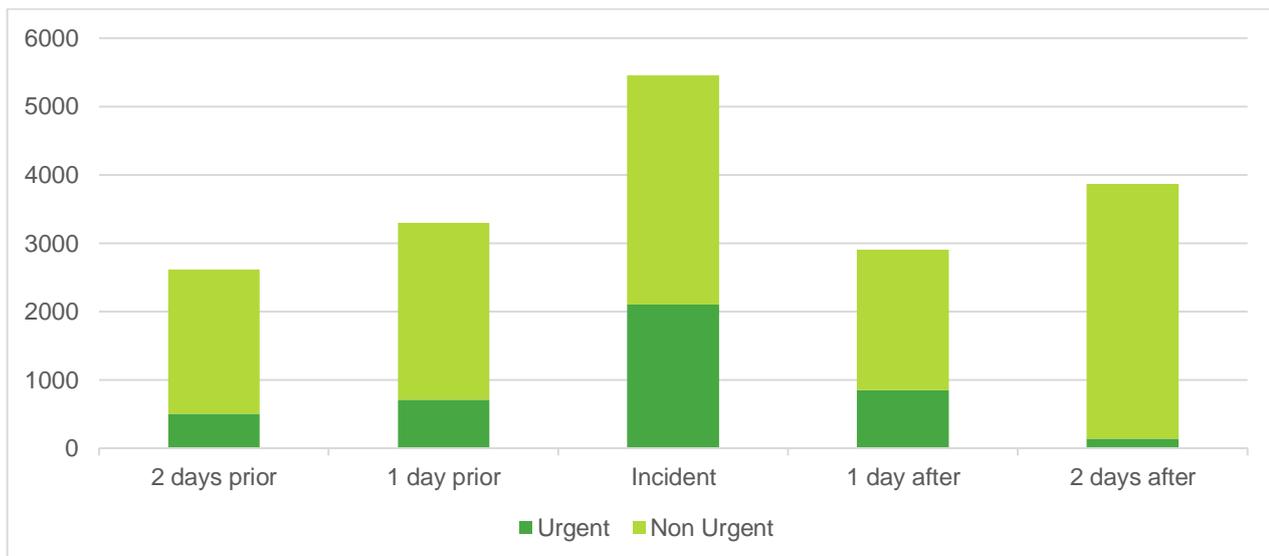
A key driver of this challenge is the growing volume of alarms in our control rooms. Alarms are increasing in both volume and complexity as grid transformation continues, creating difficulties in daily alarm management and handling "alarm floods" – a situation where numerous alarms occur within a short timeframe. The fragmented nature of legacy systems compounds this problem, limiting operators' ability to effectively monitor and respond to changing network conditions.

An example of an alarm flood caused by a network incident in 2024 is shown in figure 7.2, which details the number of alarms (classified as urgent and non-urgent), that operators had to respond to in the days leading up to, during, and after an incident. It shows that:

- total alarm volumes before and after the incident were around 3,000 per day, increasing to around 5,500 on the day of the incident; and
- volumes of urgent alarms before and after the incident ranged from 100 to 800 per day, increasing to 2,100 on the day of the incident.

Current tools in the control room do not aggregate based on priority or parent-child relationships, leading to a significant increase in volume of alarms that the operators must identify, validate and then resolve.

Figure 7.2: Volume of alarms before, during and after a network incident in 2024



When operating under a high volume of alarms, operators may struggle to distinguish genuine alarms requiring immediate action from non-genuine alarms (often related to maintenance work), significantly reducing their ability to identify and respond to critical events. Excessive alarms also create a risk of 'alarm

fatigue', where operators may become conditioned to dismiss alarms as likely invalid, potentially missing crucial warnings that could prevent outages.

The increase in complexity and volume of alarm increases will mean that operators are likely to:

- struggle to process information efficiently, leading to delays in critical decision-making;
- have insufficient or limited data to inform their decision-making;
- misinterpret data due to fragmented information systems, leading to potential operational mistakes and increasing the risk of errors; and
- take overly cautious and conservative measures to avoid errors and maintain system security, reducing network efficiency and capacity utilisation.

The outcomes above can lead to the following negative impacts on consumers, including:

- more conservative operation of the network, leading to curtailment of renewable generation output;
- increasing the need to take assets offline to protect them from overloading and asset failure; and
- load shedding to secure the network, resulting in unserved energy.

Upgrades to the control room tools aim to reduce all these outcomes, including reducing risk of an EUE event occurring. We have only quantified the reduction in an EUE event occurring in this case study.

There is an urgent need to address the increasing number of alarms faced by our control room operators, to reduce the risk of an EUE event occurring. Alarm volumes have increased almost threefold over the past 10 years, increasing from around 920 per day (or 38 per hour) in 2015 to around 2,530 per day (or 105 per hour) in 2024.

We have already begun addressing concerns that the control room would not be able to manage further increases in workload without an increased risk of an EUE event occurring through our investment in the alarm rationalisation project, which aims to help reduce cognitive load for operators through improved alarm prioritisation. The alarm rationalisation project is a foundation requirement for future upgrades to the alarm management capabilities and is expected to provide sufficient capabilities until the end of 2026 or 2028, depending on the growth rate in alarm volumes.

### 7.3.2 Benefits and technology/capability uplift in case study 1 across options

Case study 1 evaluates the benefits of a reduction in the likelihood of outages arising from an improvement to situational awareness, relative to the 'do nothing' base case. These benefits derived from an uplift in control room capability and enhanced alarm management systems arise from:

- **improved alarm management** – reduced alarm overload through smart filtering and categorisation of alarms to reduce unnecessary noise, helping to ensure that operators only respond to critical or actionable issues. Faster response times allow operators to respond to critical or actionable issues more efficiently; and
- **proactive monitoring and enhanced forecasting** – with upgraded data measurement, visualisation and forecasting systems, the control room can be more proactive in identifying risks and anomalies that could lead to equipment failures or operational hazards.

The options proposed as part of this RIT-T will equip Transgrid's control room operators with operational technologies and tools that provide relevant information, in a timelier way, with intelligent applications to

support decision making. The two options provide different levels of capability improvements, as shown in Table 23.

Table 23: Uplift requirements across each option contributing to the benefit case study 1

Initiatives	Requirement	Option and timing
Alarm management, visualisation & situational awareness enhancements	Master alarm/SCADA point source, naming configuration rules, standard templates, grouping rule templates	Option 1, FY 2025
	Ability to manage versions of alarm/SCADA point configurations, import and export alarm configurations	Option 1, FY 2027
	Uplift in capability of EMS/SCADA to import configurations, to report on alarm performance, create single parent alarm and include view on technical envelope boundaries	Option 1, FY 2029
	Implement processing of alarm flood suppression conditions and of abnormal alarm detection and identification	Option 2, FY 2029
	Alarm analysis & response automation tool & defect management system & alarm integration	Option 2, FY 2030
Real-time asset health system	Access to the Operational Asset Ratings and Network Technical Envelope Data	Option 2, FY 2029
Operational forecasts and look ahead contingency analysis	Uplift in EMS to provide persistent access to AEMO forecast data, establishing a forecasting system integrated with the EMS and uplift in EMS contingency Analysis tool for day-ahead decision support.	Option 2, FY 2029
Wide area, high speed monitoring	Uplift in EMS capability to ingest Phase angle differences as SCADA points for use by State Estimator and other User interfaces	Option 2, FY 2030
Fault level & system parameter monitoring & power system analysis	Uplift to improve accuracy of calculations application on the EMS for impedances, mutual coupling data, ratings, and fault definition cases	Option 1, FY 2029
	Enhanced EMS Fault Level Calculation (FLC) application to enable real-time FLC execution, with updated modelling parameters	Option 1, FY 2029
	Uplift EMS capability, incorporating fault level calculation, harmonics and EMT technical envelope data	Option 2, FY 2030
	Implementation of all EMS time domain capabilities	Option 2, FY 2030
Smart Transmission Device	Uplift capability of EMS network applications and to receive SCADA points	Option 2, FY 2030

### 7.3.3 Quantification approach for benefits under case study 1

Case study 1 evaluates how enhanced operability tools improve the control room’s ability to manage the increasing complexity and volume of alarms, and corresponding decrease in expected unserved energy.

The transition towards renewable energy means that operators are dealing with a significant increase in number of alarms as well as an increase in complexity of decision making for each alarm. The increase in complexity is driven by increased diversity in the types of alarms, variability of power flows, and increased network size. However, a single metric to measure this increase in complexity does not exist. Accordingly, our analysis has only considered how increases in number of alarms will lead to an increase in EUE, which we consider to be conservative.

While not every alarm indicates that there is a risk to system security, more alarms make it harder to react to important alarms related to system security. In addition, an increased volume of alarms indicates that

certain typical system safety thresholds are being breached more frequently (i.e., the physical triggers that set off alarms).

To estimate market benefits for this case study, we have assumed that:

- the volume of forecast alarms is an appropriate indication of how the complexity of the power system will increase over time, and hence the level of risk the control room must manage;
- once a critical threshold of alarms per operator per day is breached, operators are likely to be dealing with a volume of complexity and information that exceeds their capacity to maintain situational awareness of the grid at large;
- when the number of alarms is above this threshold, then there is an increased risk of an EUE event occurring (assumed to be 1 EUE event per 1 million alarms) – we consider this to be a reasonable assumption that illustrates that even a very small increase in risk can lead to significant economic costs;
- EUE events arising from missed alarms will be similar to system security events that have occurred historically, noting that system restart events have been excluded from the analysis; and
- the economic cost of outages for a given year is calculated as reduction in EUE events by option  $\times$  estimated size of the event in that year (in MWh)  $\times$  VCR (\$/MWh).

We summarise our key assumptions and calculations in Table 24 below, which are discussed in greater detail in Appendix B. Under this methodology the number of EUE events and size of EUE event changes over time and by ISP scenarios.

Table 24: Key assumptions and calculations for case study 1

Parameter	Assumption	Data/basis for assumption
Reduction in EUE event per year	Control room operators can handle 900 alarms per operator per day and there is an increased risk of an EUE event occurring if alarms exceed this threshold. This equates to 2,500 alarms per day threshold (or 820,000 alarms per year), given current staffing levels of 2.5 operators per day.	Transgrid assumption, based on our assessment that alarms would exceed threshold in 2025  Transgrid has an average of 2 control room operators per day who handle the majority of alarms and one network control manager per day, who spends around half their time on managing alarms.
	Control room operators handled approximately 850 alarms per operator per day in FY2024, which equates to approximately 770,000 alarms per year. Number of alarms is assumed to increase in line with generator capacity growth in NSW. <sup>45</sup>	Transgrid's historical alarm data ISP scenario data on forecast renewable generator growth
	The risk of an EUE event when alarms exceed the threshold is one event per one million alarms.	Transgrid assumption. This demonstrates that even a very small reduction in risk can lead to significant economic benefits.
Size of an EUE event	Outage event caused by missed alarms will be an intermediate outage (100 MWh to 1,000 MWh of expected USE) and related to system security. Outage size assumed to be 320 MWh in 2025. Catastrophic events are by definition system security events but have been excluded from the analysis.	320 MWh is the average size of intermediate-sized, system security related outages between 2004 and 2024.

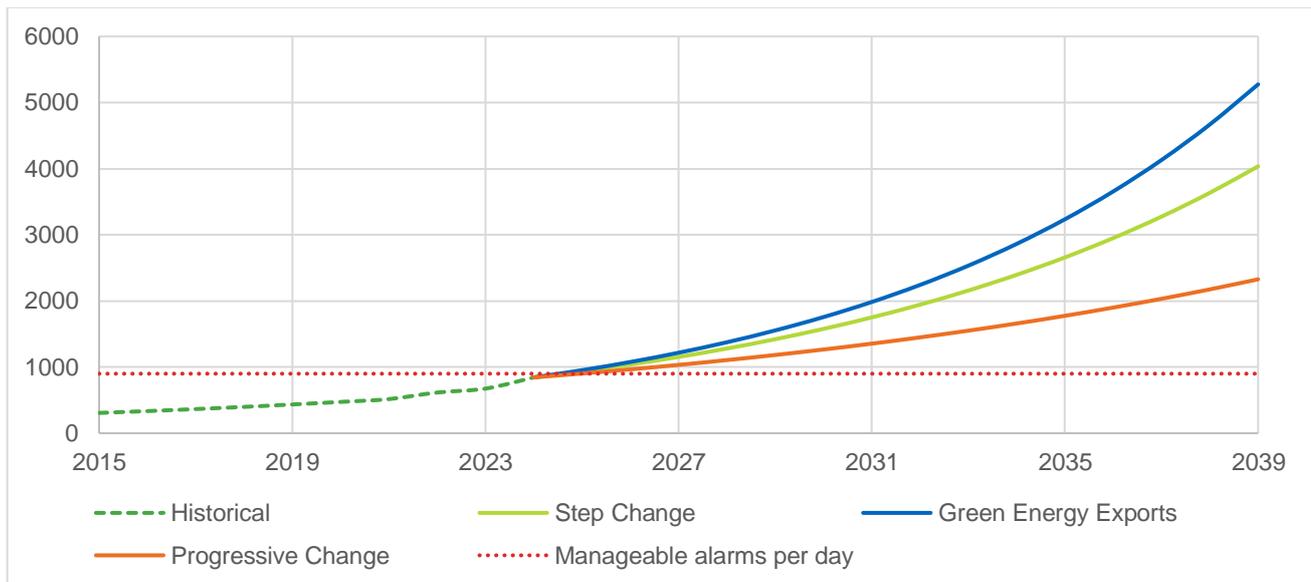
<sup>45</sup> This assumption is explained in Appendix B.

	Size of EUE event grows in line with number of substations (2.9% per year)	Linear forecast based on historical growth rate between 2016 and 2024
Benefits	Calculated as reduction in number of 'EUE events' in that year x estimated size of event in that year x the value of customer reliability (VCR) of \$31,604/MWh (\$2025)	AER data on VCR in NSW – December 2024, adjusted to 2025 using ABS CPI data and RBA forecast CPI.
	Option 1 will lead to a 46 per cent reduction in alarm volumes by 2029 Option 2 will lead to a 74 per cent reduction in alarm volumes by 2031	Assessed based on the level of capability uplift and resultant complexity reduction achieved under each option

### Increase in EUE event per year

Figure 7.3 presents actual alarm volume per operator per day between 2015 and 2024 and forecast alarm volumes per operator per day between 2024 and 2039 by ISP scenario in the base case, and in comparison, to the critical threshold established above. This shows that the number of alarms per operator per day breaches the critical threshold of 900 alarms per operator per day by 2025 under all three ISP scenarios.

Figure 7.3: Historical and forecast alarms per operator per day across ISP scenarios between 2015 and 2039 – base case scenario



When the number of alarms per day exceed the critical threshold, the increased number of EUE events is then calculated as the number of alarms per year /1 million. For example, if the number of alarms per year is 1 million, then the expected increase in EUE event is 1 per year.

Table 25 below sets out the assumed reduction in alarm numbers by option. The assumed reduction is based on our assessment of capability gained and potential improvement in the control room’s ability to manage alarms under each option. Alarm reductions are based on detailed analysis, practical experience, extrapolated to benefits of further capabilities, workshoped the thought process and reduction with internal subject matter experts from a range of functions, got independently reviewed by external experts. We recognise it is difficult to be exact and have strived to be conservative.

Table 25: Reduction in alarm volumes by option

Option	Driver of improved capability	Assumed reduction in volume of alarms
Option 1	Master alarm/SCADA point source, naming configuration rules, standard templates, grouping rule templates	Alarm reductions commence from 2025 when first capability is rolled out. Reduction in alarms is 46% from 2029 onwards when option 1 is fully implemented.
	Uplift in capability of EMS/SCADA to import configurations, to report on alarm performance, create single parent alarm and include view on technical envelope boundaries	
	Uplift to improve accuracy of calculations application on the EMS for impedances, mutual coupling data, ratings, and fault definition cases	
	Enhanced EMS Fault Level Calculation (FLC) application to enable real-time FLC execution, with updated modelling parameters	
Option 2	Option 1 capabilities	Same as option 1 between 2025 and 2028. Additional capabilities implemented in 2029 and 2030 will mean alarm reductions reaches 74% from 2030 onwards when option 2 is fully implemented.
	Implement processing of alarm flood suppression conditions and of abnormal alarm detection and identification	
	Alarm analysis & response automation tool & defect management system & alarm integration	
	Uplift EMS capability, incorporating fault level calculation, harmonics and EMT technical envelope data	
	Implementation of all EMS time domain capabilities	
	Uplift in EMS to provide persistent access to AEMO forecast data, establishing a forecasting system integrated with the EMS and uplift in EMS contingency Analysis tool for day-ahead decision support	
	Uplift capability of EMS network applications and to receive SCADA points	

Figure 7.4 below shows the number of alarms under Option 1 and 2 for the ISP step change scenario, compared to the critical threshold. The analysis suggests that the critical threshold is exceeded in 2031 for Option 1 and 2038 for Option 2. The need to have further investment in the future is consistent with advice from EPRI that further investment in operational tools above and beyond Option 2 will be required to manage the grid in the future as the complexity and size of the grid increases over time.

Figure 7.4: Forecast alarms per operator per day for Option 1 and 2 under the step change scenario



## Size of EUE events

To estimate an appropriate size of EUE events, we have conducted an analysis of unserved energy events since 2004. We have identified EUE events that could potentially arise because of a missed alarm. That is, system security events which may have been avoided if the control room operators were equipped with the tools and capabilities associated with this uplift, such as improved network visibility and analysis.

Our analysis focused on intermediate events, as system security event that could be avoided by an uplift in operational tools have historically been these intermediate events. The average size of historical events that could be avoided by an uplift in operational tools is approximately 320 MWh, which equates to a cost of \$10.1 million (\$2024/25), assuming a VCR of \$31,604/MWh. The size of the outage is assumed to grow over time in line with the historical growth in number of substations in our network (2.9% per year).

## Case study 1 – worked example

A worked example is shown below to demonstrate how gross market benefits have been calculated, which calculates the annual benefit for 2029-30 under the ISP step change scenario for Option 1, i.e.:

- under the base case, the number of alarms in the year (1.44 million) is higher than the threshold (0.8 million), leading to an increase of 1.44 EUE events for the year (assumed to occur at a rate of one per million alarms above the threshold);
- under Option 1, the number of alarms in the year (0.78 million, calculated as 1.44 million multiplied by (1 - 46%) to reflect the reduction in number of alarms) is below the threshold (0.8 million) and so there is no increased risk of an EUE event occurring in the year – it follows that Option 1 is expected to have 1.44 fewer EUE events when compared to the base case;
- the size of a EUE in the year is 367 MWh, which reflects the average size of historical events (320 MWh) growing in line with expected growth number of substations on our network; and
- benefits for the year are then calculated as reduction in EUE events (1.44 EUE events) x expected size of EUE event (367 MWh) x VCR (\$31,604 per MWh) = \$16.7 million.

### 7.3.4 Gross market benefits for case study 1

Table 26 presents the gross market benefits for case study 1 and shows that gross benefits for the options are expected to range between \$123.2 million and \$180.3 million between the options, weighted across the scenarios.

Table 26: Gross market benefits under case study 1 (\$ millions, PV)

Option	Step Change	Green Energy Exports	Progressive Change	Weighted
Option 1	128.3	114.4	132.9	123.2
Option 2	197.8	150.7	213.3	180.3

While we believe our estimates are conservative, we have also included a sensitivity analysis in section 8.4 that tests whether the options continue to have positive net market benefits with a 25 per cent reduction in gross benefits (across all case studies).

## 7.4 Case study 2 – increased network utilisation through less conservative operation

The network is currently operated based on conservative limits, due to limitations on existing capability and capacity of monitoring systems, network analysis and forecasts. Case study 2 evaluates the benefits from an increase in network utilisation arising from improvements to the capability and capacity of monitoring and analysis systems, which reduces the number of binding inverter-based constraints across the network.

### 7.4.1 Background and driver of benefits under case study 2

We operate our network safely and securely. Doing so requires us to monitor the network and advise AEMO on network capability for the application of system security constraints to ensure network stability, sufficient system strength, and regulatory compliance.

However, our existing legacy systems are not able to accurately measure and analyse network conditions. In absence of a full and accurate view of network operating conditions, we adopt conservative assumptions about network conditions to ensure system stability and prevent load shedding and unserved energy.

One example of existing limitations of our current tools is that we are unable to incorporate inverter-based generation into fault level models. This reduces the accuracy of the model, creating more uncertainty on when the network is approaching system strength limits. We therefore adopt conservative, static fault level assumptions when operating the network to ensure there are sufficient contingency margins and operating limits are not breached. This conservatism often results in the curtailment of renewable energy, as inverter-based generators are instructed to reduce generation when certain network constraints are potentially binding. This leads to increased dispatch of thermal generation to meet the needs of electricity consumers and higher wholesale electricity prices.

The economic costs of making conservative, static fault level assumptions are expected to increase over time as the network size and complexity grows over time. This is because the need to set binding constraints will increase over time as we transition towards a system with more renewable energy.

Uplifting our operational technologies and tools will improve our ability to more efficiently operate the network, thereby increasing network utilisation through reduced curtailment of renewable energy. The purpose of operational tools is to reduce the size of network constraints, noting that some level of network

constraints will be prudent and efficient as the costs of removing all network constraints will be too high, and may not be possible.

#### 7.4.2 Benefits and technology/capability uplift in case study 2 across options

This uplift will improve the accuracy and granularity of real-time network measurements and analysis to enable improved decision making. The benefit of increased network utilisation is derived from recalculating operating limits based on real data, enabling them to be less conservative in nature.

The uplift in wide area high speed monitoring systems, fault level and system parameter modelling and forecasting capabilities will enable modelling of inverter-based generation and a wide range of fault level calculations and contingency analysis. Doing so improves our understanding of when the network is approaching system strength limits, reducing the need for overly conservative margins.

The benefits of this technological uplift will emerge across multiple timeframes. In the near term, technology uplift will improve outcomes during outages. Currently, our legacy systems cannot deliver sufficient confidence in forecasted contingencies, forcing us to establish constraints based on worst-case or conservative assumptions. This upgrade will enhance certainty around forecasted fault levels, allowing us to operate the network closer to capacity limits.

In the medium term, operational uplift will enhance the quality of information we provide to AEMO regarding network limits. As our real-time operational awareness improves, the accuracy of our modelling and forecasting capabilities will correspondingly increase, enabling us to supply AEMO with more precise network capability data.

These benefits are distinct to the benefits delivered by synchronous condensers and other ongoing infrastructure projects. The objective of those capital projects is to fundamentally improve the stability, capacity, and resilience of the network by increasing the capability of our network for a given set of network conditions. However, network conditions are not static and shift with changing generation, demand and unplanned transmission outages. Enhanced operability capabilities from the proposed uplift in this RIT-T will enable continuous assessment of system strength and stability, ensuring network infrastructure is not just built, but operated efficiently, in a rapidly evolving grid environment.

Each option provides different levels of uplift to initiatives in relation to how network parameters are measured and analysed. These are summarised in Table 27.

Table 27: Uplift requirements across each option contributing to the benefit case study 2

Initiatives	Requirement	Option and timing
Operational forecasts and look ahead contingency analysis	Uplift in EMS to provide persistent access to AEMO forecast data, establishing a forecasting system integrated with the EMS and uplift in EMS contingency Analysis tool for day-ahead decision support	Option 2, FY 2030
Wide area, high speed monitoring	Uplift in the existing PMU central processor to tool to securely pass PMU data to Transgrid's EMS to support WAMs input and Phase angle differences as SCADA points	Option 2, FY 2031
Fault level & system parameter monitoring & power system analysis	Uplift to improve accuracy of calculations application on the EMS for impedances, mutual coupling data, ratings, and fault definition cases	Option 1, FY 2028
	Enhanced EMS Fault Level Calculation (FLC) application to enable real-time FLC execution, with updated modelling parameters	Option 1, FY 2028

Uplift EMS capability, incorporating fault level calculation, harmonics and EMT technical envelope data	Option 2, FY 2030
Implementation of all EMS time domain capabilities	Option 2, FY 2030

### 7.4.3 Quantification approach for case study 2

Case study 2 quantifies the benefits from a reduction in inverter-related constraints on our network over the evaluation period. At a high level, the approach to quantifying the benefits are as follows:

- **Determine the number of relevant constraint hours (number of hours)** – uplift in operational tools alleviates the impact of generator constraints, thereby increasing the utilisation of renewable energy generation in certain circumstances. This increased utilisation of renewable energy will reduce the need for thermal generation;
- **Calculate the reduction in thermal generation per relevant constraint hour (MWh per relevant constraint hour)** – the potential reduction in thermal generation depends on the increase in renewable energy generation, which in turn depends on the alleviation in renewable energy capacity curtailment (in MWs), the capacity factor of renewable energy at the time, and relative lost factor of renewable energy when compared to thermal generation; and
- **Savings in short run marginal costs (SRMC) and emissions reductions (\$ per MWh)** – SRMC savings arise from reduction in fuel consumption and variable operating and maintenance costs of the marginal thermal generator. Emission savings arises from the reduced carbon emissions (measured in tonnes per MWh), which are calculated using forecast emission intensity factors of the marginal generator and value of emission reduction (VER) published by the AER (\$ per tonne).

Assumptions are based on detailed analysis of historical constraint data, extrapolated to benefits of further capabilities, practical experience, workshopped the thought process and reduction with internal subject matter experts from a range of functions. We recognise it is difficult to be exact and have strived to be conservative. We set out the key assumptions that feed into this quantification in Table 28.

Table 28: Quantification methodology – case study 2

Parameter	Assumption	Data/basis for assumption
Number of relevant constraint hours	Relevant constraint hours are constraints that occur due to inverter-based stability and security-related constraints. One constraint hour is one inverter based generator being constrained by one hour. A network constraint that lasts for 1 hour and constrains 5 inverter-based generators would result in 5 constraint hours. We have included only NSW related constraints and daytime constraints in our analysis, which is conservative.  We have excluded hours where from renewable energy has been constrained to zero and hours where fuel costs of the marginal generator are lower than the wholesale market price. We have identified 42,299 constraint hours that meet the criteria above in FY2024.	Transgrid data on causes of constraints
	Relevant constraint hours are assumed to increase with renewable generator capacity growth in NSW. <sup>46</sup> This is estimated to be 7% in the progressive change scenario, 11% in the step change scenario, and 13% in green energy exports scenario.	ISP scenario data on forecast renewable generator growth
Reduction in thermal generation	Uplift in FLM, WAMS and forecasting tools will unlock 2 MW of renewable generation capacity per relevant constraint hour for Option 2 by 3031. Option	Transgrid assumption

<sup>46</sup> We discuss this assumption in Appendix **Error! Reference source not found.**

per relevant constraint hour	1 involves partial uplift in FLM and is assumed to unlock 0.33 MW per relevant constraint hour by 2029.	
	Under Option 2, 1.09 MWh of thermal generation will be displaced by renewable generation for each relevant constraint hour. This is calculated as $1.09 \text{ MWh} = 2 \text{ (MW)} \times 0.57 \text{ (daytime renewable capacity factor)} \times 0.913 \text{ (renewable energy loss factor)} / 0.959 \text{ (thermal generation loss factor)}$ . Under Option 1, 0.18 MWh of thermal generation will be displaced for each relevant constraint hour, calculated using the same methodology.	Transgrid assumption CSIRO Gencost 2023-2024 <sup>47</sup> AEMO Marginal Loss factor 2024
Savings in SRMC and emissions for thermal generator	Marginal generators identified using 2023-24 data and trended forward in line with ISP scenarios on generation and capacity forecasts by fuel source.	AEMO's MMS data for marginal generator analysis ISP scenario data on generation mix and retirement dates
	AEMO SRMC forecasts are used to determine economic savings (fuel plus variable operating and maintenance costs) across the evaluation period.	IASR data for fuel costs
	AEMO emission intensity forecasts are used to determine reduction in greenhouse gas emissions over the evaluation period. Value of emission reductions as published by the AER is used to quantify benefits associated with reduction in greenhouse gas emissions.	AER value of emissions reduction IASR data for emissions intensity
	Economic savings for a given year is calculated as $\text{number of relevant constraint hours (hours)} \times \text{reduction in thermal generation per hour (MWh per hour)} \times \text{SRMC (\$/MWh)}$ . Emission reduction savings for a given year is calculated as $\text{relevant constraint hours (hours)} \times \text{reduction in thermal generation per hour (MWh per hour)} \times \text{emission intensity (tonnes/MWh)} \times \text{value of emission reduction (\$/tonne)}$ . Further, benefits vary by option, increasing over time to reflect rollout of various initiatives.	

## Number of relevant constraint hours

Constraint hours measure the level of constraint on our network in terms of hours and number of inverters being constrained. The network could have multiple constraints in an hour as more than one inverter based generator could be constrained. Given this, the total number of constraint hours in a year exceeds the total number of hours in a year.

Uplift in operational tools alleviates inverter-based stability and security-related constraints. We have identified the number of relevant constraint hours for FY2024 (i.e. inverter-based stability and security-related constraints). Further, we have conservatively:

- included NSW related constraints only, noting that operational uplift could also help with constraints in other parts of the NEM;
- excluded instances where a renewable connection is constrained to zero as these can often be attributed to anti-islanding measures rather than due to system strength or instability conditions;
- included daytime constraints only as this is when most inverter-based constraints occur. However, uplift in operational tools will also alleviate nighttime constraints; and

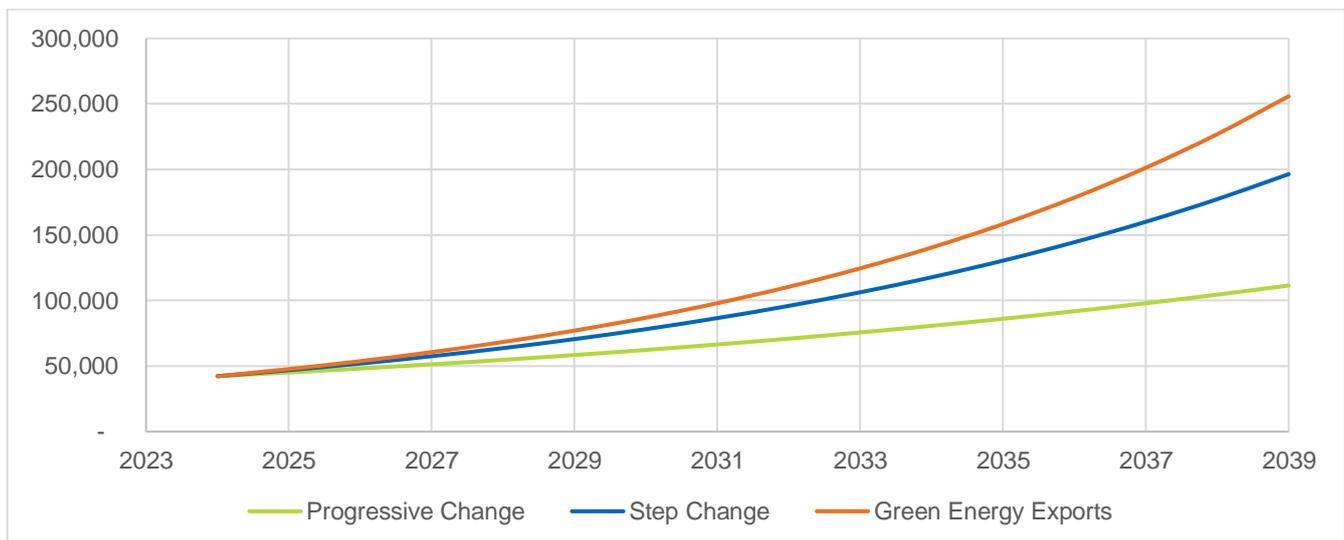
<sup>47</sup> We discuss the application of this dataset in in Appendix B.

- excluded hours where wholesale market prices are lower than the fuel costs of the marginal generator, as that marginal generator may be generating for reasons other than to support wholesale market outcomes (e.g., ramping up or to meet minimum generation requirements). However, renewable generation may still displace this thermal generation if constraints were avoided.

The number of relevant constraint hours has increased exponentially since 2016, increasing from around 5,500 hours per year in 2016 to around 42,300 in 2024. We expect that constraint hours will continue to increase over time due to incoming ISP projects and renewable energy zones, which will lead to greater meshing of the network across the NEM, thereby leading to changing power system dynamics and increase the challenge of identifying and mitigating new modes of instability.

Figure 7.5 shows that the forecast number of relevant constraint hours under different ISP scenarios. We have assumed that relevant constraint hours will grow in line with renewable generation capacity in NSW, which varies by ISP scenario.

Figure 7.5: Number of relevant constraint hours under ISP scenarios from 2024 to 2039



### Reduction in thermal generation

Reduction in thermal generation is the key driver of the market benefits quantified in case study 2. The reduction in thermal generation has been calculated using the following assumptions:

- The proposed uplift in operational tools will alleviate 2 MW of renewable energy constraints per relevant constraint hour for Option 2 by 2031 (i.e., we have assumed that fault monitoring and system parameter modelling, wide area speed monitoring, and improved operational forecasting will each alleviate 0.67 MW of constraints per relevant constraint hour);
- Option 1 is assumed to alleviate 0.33 MW of constraints per relevant constraint hour as it involves partial delivery of fault monitoring and system parameter modelling when compared to Option 2;
- the average capacity factor for renewable energy during relevant daytime constraint hours is 57 per cent, determined using CSIRO GenCost 2023-2024 values; and

- the average loss factor for renewable energy is 0.913 versus an assumed average loss factor of 0.959 for thermal sources. These are consistent with AEMO's 2023 IASR.

In summary, the assumptions above mean that 0.18 MWh and 1.09 MWh of thermal generation will be displaced by renewable generation for each relevant network constraint hour for Option 1 and Option 2 respectively. For Option 2, this is calculated as  $1.09 \text{ MWh} = 2 \text{ (MW)} \times 0.57 \text{ (capacity factor)} \times 0.913 \text{ (renewable energy loss factor)} / 0.959 \text{ (thermal generation loss factor)}$ . Option 1 is calculated similarly.

### **Savings in SRMC and emissions for thermal generator**

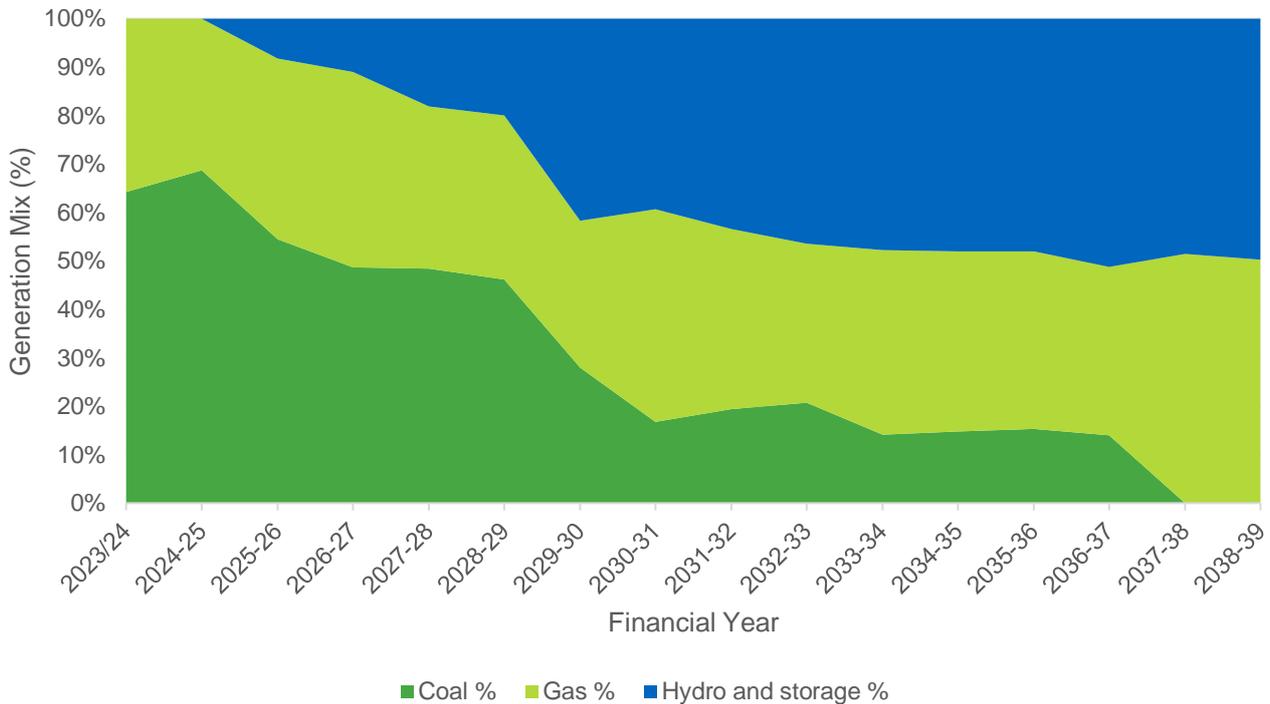
The saving that arises from a 1 MWh reduction in thermal generation depends on the marginal generator in the relevant period. To understand the potential SRMC and emission savings, we need to identify the marginal generator at the time, and the fuel consumption and emission intensity of the marginal generator.

Our analysis of identifying the relevant marginal generator involved the following steps:

- use 2023-24 data to identify the coal or gas marginal generator in the relevant constraint hour – this identified the proportion of times where each existing coal or gas plant was the marginal generator during 2023-24;
- assume that proportion of time where dispatchable storage (hydro and storage) is the marginal generator increases from zero in FY2024 to reflecting the proportion of energy sent out by dispatchable storage compared to other dispatchable sources (i.e., generator from coal, gas, hydro and dispatchable storage) by 2038-39 – for example, under the step change scenario, we assume that dispatchable storage will be the marginal generator for 50% of intervals by 2038-39 as energy sent out from hydro and storage represents 50% of energy sent out from all dispatchable sources; and
- assume that gas and coal will be the marginal generator for the remaining time intervals, factoring in forecast changes in capacity and energy sent out by gas and coal over time – for example, when output sent out by coal becomes zero then the proportion of time intervals where coal is the marginal generator is also zero.

Figure 7.6 below shows how the marginal generator is projected to change over time given the assumptions above under the Step Change scenario. This projection varies by ISP scenario. The decline of coal as the marginal generator reflects the reduction in output and eventual retirement of coal plants, in line with AEMO ISP scenarios. Similarly, the increasing role of hydro and storage as the marginal generator where it was previously from coal or gas reflects the increase in energy sent out expected from these energy sources.

Figure 7.6: Change in marginal generator during relevant constraint period by fuel mix under Step Change scenario – 2023/24 to 2038/39



Data from AEMO’s IASR allows us to forecast the SRMC and emission intensity for each marginal generator over the evaluation period. We use this to calculate the change in SRMC over the evaluation period and emissions avoided reduced energy produced by the marginal generators. We have used the VER as published by the AER to quantify benefits associated with reduced carbon emissions. We note that SRMC and emission for hydro and storage have been assumed to be zero.

### Case study 2 – worked example

To illustrate our quantification methodology, we present a worked example showing the annual gross market benefits for Option 1 under the step change scenario for 2029-2030.

We first calculate reduction in output required from the marginal generator, which is calculated as follows:

- the number of constraint hours that would benefit from the uplift – assumed to increase from around 42,300 in 2023-24 to 78,180 by 2029-30, in line with expected capacity growth for renewable energy and battery;
- amount of thermal generation avoided per constraint hour for the year – calculated as capacity alleviated (0.33 MW for Option 1) × capacity factor (0.57) × adjustments for loss factors (0.95) × rollout of initiative in the year (100% in 2030) = 0.18 MWh; and
- reduction in thermal generation, which is calculated as 78,180 (constraint hours) × 0.18 (MWh savings per constraint hour) = 14,144 MWh.

Gross market benefit is then calculated as avoided fuel cost + emission savings, which is in turn calculated as:

- avoided fuel cost: 14,144 MWh × \$47.05 (\$/MWh, which represents the weighed SRMC of the marginal generators) = \$0.7 million in 2029-30; and
- reduction in greenhouse gas emissions: 14,144 MWh × 0.39 (weighted emission intensity of the marginal generators, measured in tonnes/MWh) × \$106 (value of emission reductions, measured in \$/tonne) = \$0.6 million in 2029-30.

In total, the gross market benefit in 2029-30 is \$1.3 million, or \$16 per relevant constraint hour.

#### 7.4.4 Gross market benefits of case study 2

Table 29 presents the gross market benefits for case study 2 and shows that gross benefits for the options are expected to range between \$12.5 million and \$68.6 million between the options, weighted across the ISP scenarios.

Table 29: Gross benefits under case study 2 (\$ millions, PV)

Option	Step Change	Green Energy Exports	Progressive Change	Weighted
Option 1	14.0	9.0	17.9	12.5
Option 2	77.0	49.2	98.6	68.6

The main driver of differences between the gross market benefits under this case study for Option 1 and Option 2 is the reduction in thermal generation achieved under each of the options. Option 2 unlocks the full 2 MW inverter constraints per relevant constraint hour, as it has full investment in fault monitoring and system parameter modelling, wide area, high speed monitoring, and operational forecasting tools. In contrast, Option 1 only unlocks 0.33 MW as it only has partial investment in fault monitoring and system parameter modelling.

### 7.5 Case study 3 – improved outage management through reduced switching time

This case study analyses the economic benefits of improving operational outage planning through a reduction in the duration of switching time. Switching time refers to the time taken to transition network assets from one configuration to another during an outage or system change. Reducing switching time enables faster recovery from faults, more efficient maintenance operations, and reduction in service interruptions.

Reduction in switching time reduces the time in which parts of the network are derated or disconnected. As derating or closing parts of the network leads to network constraints, reducing outage time can lead to a reduction in inverter-based constraints in the network, enabling more renewable energy to flow in the network. This in turn decreases the need to dispatch thermal energy, a similar (but distinct) outcome to case study 2.

#### 7.5.1 Background and driver of benefits under case study 3

A key function of the control room is to manage planned transmission outages, which are scheduled and coordinated temporary disconnections or deratings of network assets. Planned outages are required to facilitate scheduled maintenance and connection of new assets. Effective outage management will also help the network to recover quickly and safely from any unplanned transmission outages.

The number of planned outages on our network is expected to increase over time. One key driver is the shift towards a higher share of renewable energy, which will require connection of smaller, dispersed renewable generation to be brought online to replace aging thermal generation. Other important drivers include:

- the increasing expected of the size of our network, which will lead to more planned outages to accommodate maintenance requirements and grid upgrades, and facilitate system reliability;
- accommodating major ISP projects, including renewable energy zones; and
- accommodating new loads, such as data centres.

Unplanned transmission outages are also expected to increase with high renewable penetration due to an increase in grid challenges including voltage instability, bidirectional power flow disrupting protection systems, and overloaded local circuits.

Planned transmission outages are typically scheduled with a significant notice period, and require:

- outage preparation, including an assessment of network conditions and scheduling of appropriate time and duration of outage, based on the scope of work to be undertaken; and
- coordination with affected parties, e.g., outages require de-energisation of the network and often AEMO approval.

To facilitate an outage, operators must run through a sequential process of operating electrical switches, circuit breakers and network equipment to isolate or reconnect sections of the network (a process referred to as ‘switching’). This process is critical for both system stability and worker safety. Switching involves coordination with third parties to ensure that generators have disconnected (and have subsequently reconnected), which operators must verify before planned works can proceed.

Growing system complexity has made it more challenging to schedule and manage planned transmission outages and undertake switching, from initial planning through to implementation, to network de- and re-energisation. Historically, the capabilities of operational technologies and tools have been focused on managing voltage levels during planned transmission outages over a relatively predictable daily load profile where conditions were relatively stable.

The increased complexity involved with present-day outage planning has increased the number of steps and complexity of facilitating an outage. A key driver of this is the increase in the number of third parties to coordinate with during de- and re-energisation.

In the absence of enhancements to our outage planning capabilities, there will likely be an increase in the length of time to undertake switching operations – due to the need to coordinate with an increasing number of generators, which increases time involved with switching on and switching off.

Table 30 compares two similar outages, one occurring in 2015 and one occurring in 2025.<sup>48</sup> It shows the significant increase in the number of steps required and the time taken to carry out switching before and after an outage. The coordination time increase is attributed to the growth number of third parties who need to be individually contacted. The increase in the number of steps is due to growth in the number of

---

<sup>48</sup> We consider these two outages as being similar since they involved similar scope of works, similar number of assets, and the same geographic area. The key difference is the number of generators that we are required to coordinate with.

generator inverter/turbine constraints that need to be applied and the increased number of tripping schemes that also need to be armed and disarmed.

Table 30: Comparison of switching time and steps for a similar planned outage, 2015 and 2025

	2015	2025	Increase
Coordination before outage	23 mins	64 mins	278%
Coordination after outage	9 mins	110 mins	1220%
<b>Total coordination time</b>	32 mins	174 mins	544%
Total number of steps for switching	113	302	267%

### 7.5.2 Benefits and technology/capability uplift in case study 3 under each option

Case study 3 evaluates the benefits of a reduction in switching time arising from an enhanced outage management system. Reducing switching time will deliver significant market benefits. Currently, switching to disconnect generators to isolate the line takes between 30 minutes and three hours, and to reconnect takes between 20 minutes and an hour and 40 minutes, depending on the number of generators affected.

On a weighted average basis, total switching time is around 140 minutes on average (around 92 minutes to disconnect and around 48 minutes to reconnect). The manual generator coordination step, which involves making phone calls to each impacted third party, takes up to one third of this time, which equates to on average, 47 minutes per outage.

Reducing the time spent on equipment isolation and removal from service can directly impact the period of network constraint. It follows that reducing switching time improves grid efficiency as the duration of network constraint means less curtailment of generation, including from renewable sources. Automating and streamlining coordination can significantly reduce switching time through:

- **Reduced time required for generator coordination** – automated systems eliminate manual calls, ensuring instant updates and confirmations;
- **Quicker response to system constraints** – standardised process enables real-time adjustments without back-and-forth discussions between generators and AEMO;
- **Reduced switching delays**– predefined and consolidated and/or automated sequences, scenarios and live data sharing allow for smoother transitions, cutting down manual coordination time; and
- **More efficient decision-making** – virtual coordination tools facilitate rapid data sharing and issue resolution, reducing overall outage duration.

Table 31 breaks down the technology initiative implemented for Option 1. Since the PSCR, we have removed proactive uplifts to the outage management system from Option 2, because the existing outage management solution does not currently have safe switching execution functionality available (which would be required to achieve uplift to proactive capabilities), and pricing provided by RFI responses for this functionality was speculative. Therefore, there are no enhancements in our proposed outage management system between Option 1 and Option 2. As such, the quantified benefits are the same for each option.

Table 31: Capability enhancement matrix short term operational planning under each option

Initiatives	Requirement	Option and timing
Outage Management System and Switching execution	Uplift functionality of OMS to automate customer notifications and workflow to accommodate new outage planning scenarios	Option 1/2, FY 2028
	Visualisation of planned outage requests and the automated inverter runback during switching	Option 1/2, FY 2028
	Creation of SPS schemes to automate inverter runback and return during switching	Option 1/2, FY 2028
	Implement self-service web-browser capability – for both internal and external users, to perform enquiries and updates, plus download and upload required documentation.	Option 1/2, FY 2028

### 7.5.3 Quantification approach for case study 3

To quantify the benefits of a reduction in switching time, case study 3 quantifies the benefits from a reduction in switching time for historical daytime outage hours with inverter-related constraints on our network.

At a high level, the approach to quantifying the benefits for case study 3 are as follows:

- **Determine the hours of switching time saved (hours)** – with uplift in operational tools, we can reduce the switching time during relevant outages. The number of hours saved will depend on number of relevant outages and savings per outage;
- **Calculate the reduction in thermal generation per hour of switching time saved (MWh per relevant outage hour)** – the potential reduction in thermal generation depends on the increase in renewable energy generation. This depends on the time saving from switching (in hours) (which in turn is based on the number of renewable generators affected by a particular outage) and the size of the constraint on renewable generation (in MWh); and
- **Savings in SRMC and emissions (\$ per MWh)**– benefits arise from the reduction in fuel consumption and emissions of the marginal thermal generator. The marginal generator will vary depending on wholesale market conditions.

Assumptions are based on detailed analysis of historical outage data, extrapolated to benefits of further capabilities, practical experience, workshopped the thought process and reduction with internal subject matter experts from a range of functions. We recognise it is difficult to be exact and have strived to be conservative. We set out the key assumptions that feed into this quantification in Table 32.

Table 32: Quantification methodology – case study 3

Parameter	Assumption	Data/basis for assumption
Determining the hours of switching time saved	Relevant outages are related to inverter-based stability and security-related constraints. Similar to case study 2, we have only included outages which occur during NSW related, daytime constraints. We are only considering outages relating to lines and transformers to avoid any duplication of benefits. We consider our approach to identifying relevant outages to be conservative.  In total 287 outages have been included in our analysis, which represents number of relevant outages for the 6 month period between	Transgrid data on causes of constraints

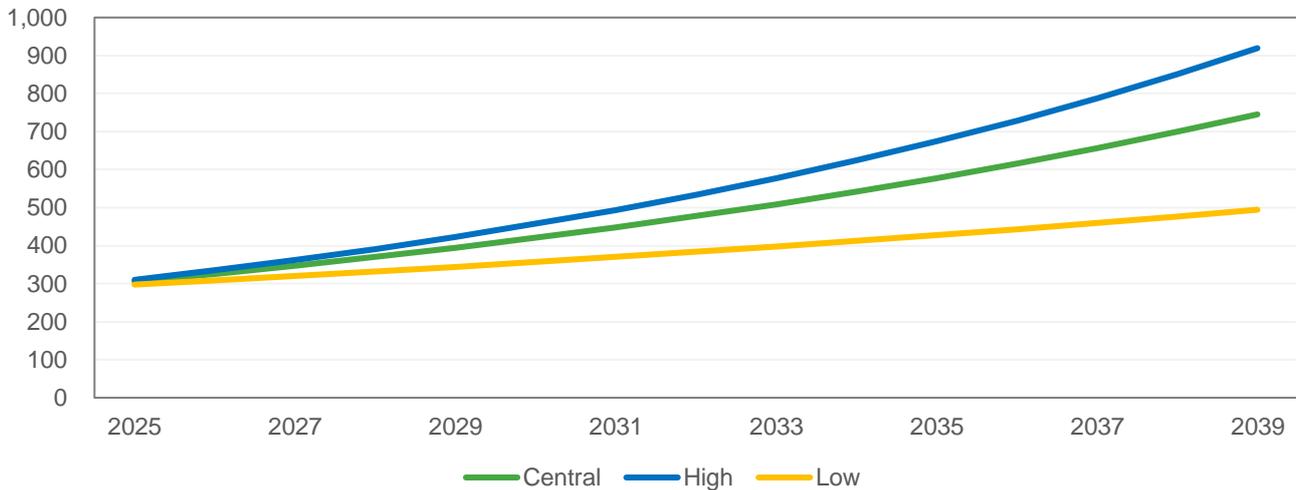
	1 July 2023 to 31 December 2023. That is, we have only included half a year of outages in our benefit calculations.	
	Average outage time varies by number of renewable generators affected and is weighted by the size of the outage. We have assumed that switching time will reduce by 20% for outages involving 4 generators or less and 30% when more than 4 generators are involved.	Historical data of Transgrid's network Transgrid assumption based on capability gained
	Number of relevant outages grows in line with renewable generator capacity growth in NSW, excluding estimated REZ capacity. Relevant outages are assumed to grow by 4% in progressive change scenario, 7% in step change scenario, and 8% in green energy export scenario.	ISP scenario data on forecast renewable generator growth
Reduction in thermal generation per hour of switching time saved	326 MWh per hour of thermal generation will be displaced by renewable generation. This is calculated as 342.5 MWh (average curtailment of renewable energy per relevant outage hour in FY2024) x 0.913 (renewable energy loss factor) / 0.959 (thermal generation loss factor).	Average quantity of renewable generation constrained during relevant outage hours in 2023-24 AEMO marginal loss factor values
Benefits	Marginal generators identified using same approach as case study 2.	AEMO's MMS data for marginal generator analysis ISP scenario data on generation mix and retirement dates
	SRMC and avoided emissions from reduced use of marginal generator calculated using same approach as case study 2.	IASR data for fuel costs
	Value of emission reduction published by AER used to quantify carbon emission reductions.	Value of emissions reduction published by AER IASR data for emissions intensity
	Fuel cost savings for a given year is calculated as number of relevant outages (number of outages) x reduction in switching time per outage (hours per outage) x reduction in thermal generation per hour (MWh per hour) x SRMC (\$/MWh). Reduction in greenhouse gas emissions for a given year is calculated as relevant outage (number of outages) x reduction in switching time per outage (hours per outage) x reduction in thermal generation per hour (MWh per hour) x emission intensity (tonnes/MWh) x value of emission reduction (\$/tonne).	

## Relevant outages

We discuss our methodology for identifying relevant constraint hours in section 7.4.3. Similar principles are applied here but rather than employing the total hours of constraint to estimate the benefit, we instead identify the number of relevant outages which occur throughout a year. We have only daytime outages that are related to inverter-based stability and security-related constraints. Further, we are only considering outages relating to lines and transformers to avoid any duplication of benefits.

Figure 7.7 sets out our forecast growth in relevant outages under different ISP scenarios. <sup>49</sup> Number of relevant outages are assumed to grow in line with renewable generator capacity growth in NSW, excluding estimated REZ capacity.

Figure 7.7: Relevant outage hours projected to 2039 under each ISP scenario



### Switching time saving and reduction in thermal generation

To calculate switching time saving and the associated reduction in thermal generation, we assume that:

- the number of renewable generators affected by an individual outage remains constant over time. This is a conservative assumption, as the number of renewable generators affected by an individual outage is likely to increase over time, as the total number of renewable generators increases;
- the potential switching time savings arising from automation of running back generator’s invertors to meet the agreed threshold sets within the approved outage, thus avoiding multiple phone calls. These will be scripted into the switching instructions ensuring there is compliance with this new process; and
- 326 MWh of thermal generation will be displaced by renewable generation per hour saved. This is calculated as  $326 \text{ MWh} = 342.5 \text{ MWh}$  (average curtailment of renewable energy per hour in FY2024)  $\times 0.913$  (renewable energy loss factor) /  $0.959$  (thermal generation loss factor).

Table 33 sets out the assumed time saving per outage by number of generators involved.

Table 33: Savings per relevant outage hour

Number of generators	Distribution of the number of generators per outage	Total switching time before uplift	Reduction in switching time based on uplift	Reduction in total switching time based on uplift
1-4	41%	57 minutes	20%	11 minutes
5-9	32%	130 minutes	30%	39 minutes
10 or more	28%	280 minutes	30%	84 minutes

<sup>49</sup> Our approach to managing outages has changed over time, moving from a more siloed, ad hoc approach to consolidating planned works to reduce the number of outages required. As such, historical trends in number of outages do not provide meaningful insight into likely future growth.

Weighted average		141 minutes	28%	40 minutes
------------------	--	-------------	-----	------------

### Case study 3 – worked example

To illustrate our quantification methodology, we present a worked example showing the annual gross market benefits for Option 1 (and Option 2, which has the same capability uplift) under the step change scenario for 2029-2030.

We first calculate reduction in output required from the marginal generator, which is calculated as follows:

- the number of outages that would benefit from the uplift – assumed to increase from 287 in 2023-24 to 420 by 2029-30;
- hours saved per outage – calculated to be 0.67 hours based actual switching time in FY2023-24 and assumed saving of 20% for outages involving 1 to 4 generators and 30% for outages involving more than 4 generators;
- reduction in greenhouse gas emissions per outage hour saved – calculated as increase in renewable energy generation per hour (342.5 MWh based on outcomes in FY2023-24) × adjustments for loss factors (0.95) × rollout of initiatives in the year (100% in 2030) = 326 MWh; and
- reduction in thermal generation – calculated as 420 (number of outages) × 0.67 (hours saved per outage) × 326 MWh (thermal generation avoided per outage saved = 91,388 MWh).

Gross market benefit is then calculated as avoided SRMC + emission savings, which is in turn calculated as:

- reduction in SRMC: 91,388 MWh × \$47.41 (\$/MWh, which represents the weighed SRMC of the marginal generators) = \$4.3 million in 2029-30; and
- reduction in greenhouse gas emissions: 91,388 MWh × 0.39 (weighted emission intensity of the marginal generators, measured in tonnes/MWh) × \$106 (value of emission reductions, measured in \$/tonne) = \$3.8 million in 2029-30.

In total, the gross market benefit in 2029-30 is \$8.1 million, or \$89 per MWh considered in the analysis.

#### 7.5.4 Gross market benefits of case study 3

The gross benefit for each option by scenario is set out in Table 34 below, based on the forecast of number of assumed switching operations under each scenario, and the reduction in the duration of each of these events that is expected under each of the options. As noted above, these benefits are the same for both options, as they have an identical capability uplift in this area (i.e., both options are reactive).

Table 34: Gross benefits under 'reduced duration of switching operations' use case (\$ millions, PV)

Option	Step Change	Green Energy Exports	Progressive Change	Weighted
Option 1	84.2	61.3	124.4	80.6
Option 2	84.2	61.3	124.4	80.6

## 7.6 Summary of option gross benefits by case study and scenario

Table 35 presents each option's gross benefits by case study and ISP scenario, and on a weighted basis.

Table 35: Summary of option gross benefits by case study and ISP scenario, and on a weighted basis

		Step change	Progressive change	Green energy exports	Weighted
Option 1	Reduction in the likelihood of unserved energy	128.3	114.4	132.9	123.2
	Increase in network utilisation	14.0	9.0	17.9	12.5
	Reduction in duration of outages	84.2	61.3	124.4	80.6
	<b>Total</b>	<b>226.5</b>	<b>184.6</b>	<b>275.2</b>	<b>216.2</b>
Option 2	Reduction in the likelihood of unserved energy	197.8	150.7	213.3	180.3
	Increase in network utilisation	77.0	49.2	98.6	68.6
	Reduction in duration of outages	84.2	61.3	124.4	80.6
	<b>Total</b>	<b>359.0</b>	<b>261.2</b>	<b>436.3</b>	<b>329.5</b>

## 8 Net present value analysis

This section outlines the NPV assessment we have undertaken for the two credible options.

### 8.1 Present value of costs

Table 36 presents the capital, operating and total cost for each option in present value terms. Option 1 represents incremental capital and operating expenditure of \$149.8 million in present value terms relative to the base case. Option 2 represents incremental capital and operating expenditure relative to the base case of approximately \$218.2 million in present value terms. The cost of the options does not differ across the ISP scenarios considered.

Table 36: Present value of capital and operating costs by option (present value, \$ millions)

	Capital expenditure	Operating expenditure	Total
Option 1	115.6	34.1	149.8
Option 2	169.4	48.8	218.2

### 8.2 Present value of gross market benefits

Table 37 presents the total gross market benefits for each option and under each case study on a weighted basis across the three ISP scenarios considered, as estimated from the methodology described elsewhere in this document. This shows that significant benefits under Option 2 are derived under all three case studies, and that the additional technologies enabling increased network utilisation under Option 2 deliver substantial additional benefits compared to Option 1.

Table 37: Present value of gross market benefits by case study (\$m, PV)

Case study	Option 1	Option 2
Reduction in the likelihood of outages	123.2	180.3
Increased network utilisation	12.5	68.6
Reduced duration of switching operations	80.6	80.6
<b>Total</b>	<b>216.2</b>	<b>329.5</b>

Table 38 presents gross benefits by option by category of RIT-T market benefit on a weighted basis. The table shows that most benefits across both options arise from avoided EUE and the value of avoided emissions compared to the base case.

Table 38: Option gross benefits by type of market benefit, weighted basis (\$m, PV)

	Option 1	Option 2
Avoided EUE	123.2	180.3
Avoided generation dispatch costs	52.3	84.8

Reduction in greenhouse gas emissions	40.8	64.4
<b>Total</b>	<b>216.2</b>	<b>329.5</b>

### 8.3 Net present value

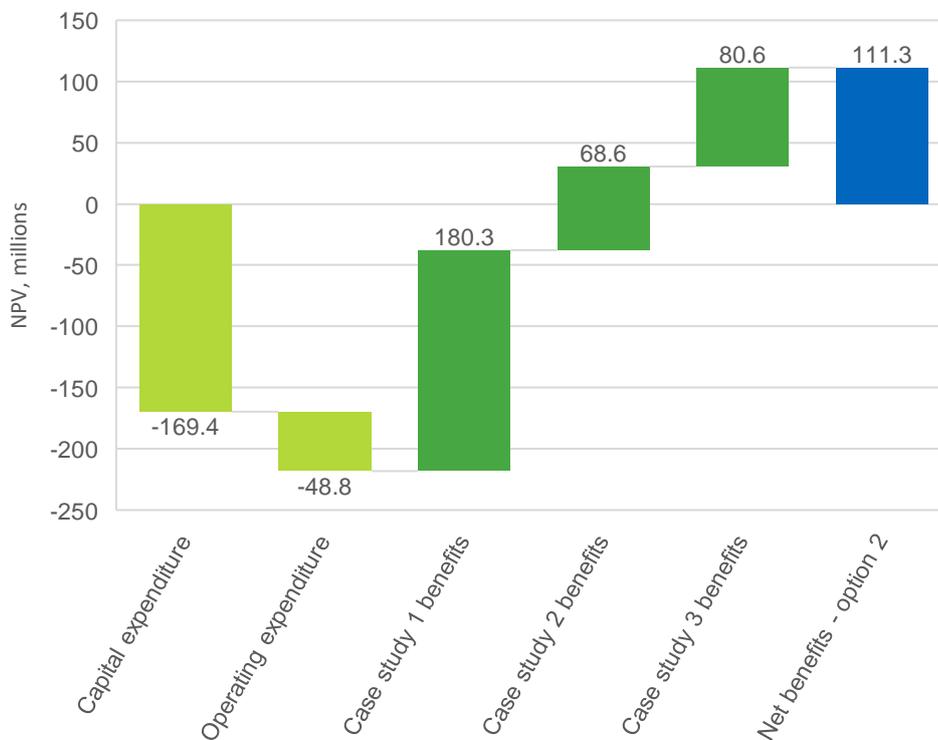
In Table 39, we set out the net present value for each option across the three ISP scenarios modelled, and on a weighted basis. This demonstrates that Option 2 has the highest net benefit, and is therefore the preferred option under the RIT-T, with \$111.3 million in net benefits.

Table 39: Net present value of options compared to base case (present value, \$ millions)

Option	Progressive change	Step change	Green energy exports	Weighted NPV	Rank
Option 1	34.8	76.8	125.5	66.5	2
Option 2	43.0	140.8	218.1	111.3	1

We set out the drivers of the net benefits of the preferred option (Option 2) on a weighted basis across the three ISP scenarios in Figure 8.1.

Figure 8.1: Drivers of net benefits for Option 2 – weighted across scenarios (NPV, \$m)



## 8.4 Sensitivity analysis

We have undertaken sensitivity testing to examine how the net economic benefit of the credible options changes with respect to changes in key assumptions. The sensitivity testing was undertaken for the Step Change scenario only.

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

As discussed in section 7.1, the estimation of gross benefits under the case studies has been developed using conservative assumptions. However, to further test the robustness of our findings we have also undertaken a sensitivity analysis that varies the gross benefits for each option by +/- 25 per cent relative to the core benefit estimate to test whether the ranking of options changes in response to lower or higher than expected gross benefits.

Table 40: Sensitivity analysis – Step Change scenario (\$ millions, Net Present Value)

Sensitivity		Option 1	Option 2
Capital cost	High (+25%)	34.4	62.6
	Low (-25%)	99.0	161.4
Operating cost	High (+25%)	57.9	99.1
	Low (-25%)	75.0	123.5
Discount rate	High (10.5%)	38.8	60.9
	Low (3.63%)	107.3	187.0
Value of customer reliability	High (+30%)	103.4	165.4
	Low (-30%)	29.5	57.2
Value of emissions reduction	High (+25%)	76.6	127.4
	Low (-25%)	56.3	95.2
Total gross benefits	High (+25%)	120.5	193.7
	Low (-25%)	12.4	29.0
Longer economic lives	+5 years	108.8	171.5
Optimal timing	1 year delay	44.6	91.9
	1 year acceleration	62.2	102.4

We find that there is no reasonable change in the parameters under these sensitivity tests that result in either the ranking of the options changing, or the preferred option (Option 2) not having positive net market benefits. In particular, we find that a 1 year delay in the delivery of the preferred option (Option 2) would result in a \$19.4 million decrease in net market benefits.

## 8.5 Threshold analysis

We have also undertaken threshold analysis to show at what point options would change in rank or provide negative net market benefits compared to the base case. We have undertaken threshold analysis on the percentage change that would lead to a change in option ranking (or the option to not provide positive net market benefits) for:

- capital costs;
- operating costs;
- total costs, i.e., capital and operating costs; and
- gross benefits.

The results from the threshold analysis are set out in Table 41 below relative to the option that provides the greatest net benefit at the PADR stage (i.e., Option 2). This threshold analysis demonstrates that there is no reasonable value which would result in Option 2 not being the preferred option or having a positive NPV. In addition, there is no reasonable value that would result in Option 1 being ranked above Option 2 whilst still delivering positive net market benefits.

Table 41: Option result threshold analysis (% change in variable for preferred option to change) – weighted scenario

	Option 2 no longer preferred	Option 2 to have zero NPV
Capital costs	72%	57%
Operating costs	306%	228%
Total costs	58%	46%
Gross benefits	-40%	-34%

## 8.6 Proposed reopening triggers

We are required to set out in the PADR, for consultation and confirmation in the PACR, ‘reopening triggers’ for this RIT-T since the estimated capital cost of the proposed preferred option is greater than \$103 million.<sup>50</sup>

Consistent with these requirements and drawing on the results of the sensitivity assessments outlined above, we have considered the impact of changes in key underlying assumptions to identify re-opening triggers. Specifically, based on the sensitivity assessment included in this PADR, we consider that the following are expected to form re-opening triggers for this RIT-T:

- AEMO withdrawing its support for the initiatives set out in Option 2;
- credible evidence that the cost of the preferred option has increased by more than 50 per cent compared to the costs used in this RIT-T analysis;<sup>51</sup>

<sup>50</sup> NER clause 5.16.4(k)(10).

<sup>51</sup> The boundary value testing above finds that there would need to be a 57 per cent increase in capital costs for Option 2 to no longer deliver positive net market benefits.

- vendors being unwilling to provide the capability uplift identified under Option 2, within the timeframes set out in this RIT-T (such that Option 2 is no longer credible); and
- credible evidence that another solution is likely to deliver higher net market benefits compared to the preferred option under this RIT-T.

We would be interested to hear from stakeholders on whether there are any additional factors that we should consider as re-opening triggers for this RIT-T.

## 9 PADR conclusion

---

This PADR has found that Option 2 (proactive investment in operational tools) is the preferred option under this RIT-T to enhance Transgrid's operational technology and tools capabilities for use in control rooms and corporate offices.

Option 2 involves upgrading Transgrid's operational technologies and tools to establish new functionalities and underpin proactive capabilities for Transgrid's control rooms operators and operational planners, including the following technology initiatives:

- outage management system;
- alarm management, visualisation and situation awareness enhancement;
- fault level and system parameter monitoring and power system analysis capability;
- EMS/SCADA system enhancements;
- data management and network modelling system;
- training technologies, operational document management system and operational planning systems;
- real-time asset health monitoring;
- operational forecasts and look-ahead contingency assessment;
- wide area and high-speed monitoring; and
- smart transmission device management.

We set out the scope of investments under Option 2 in section 5.4.

The preferred option, Option 2, has:

- estimated capital expenditure of \$169.4 million (PV, 2024/25 dollars); and
- estimated incremental operating expenditure of \$48.8 million (PV, 2024/25 dollars).

The new operational technologies and tools are expected be commissioned incrementally, beginning with the alarm rationalisation project in 2025, with full implementation of Option 2 by March 2030.

In the 2023-28 regulatory period, i.e., the period for which the contingent project application would apply, Option 2 has:

- \$122.7 million in capital expenditure (\$2024/25); and
- \$9.3 million in operating expenditure (\$2024/25).

Option 2 is the preferred option in accordance with NER clause 5.15A.2(b)(12) because it is the credible option that maximises the net present value of the net economic benefit. The key expected benefits include:

- reduced expected unserved energy through improved situational awareness; and
- reduced dispatch costs and greenhouse gas emissions through improved network utilisation and reduced switching time.

The analysis undertaken and the identification of Option 2 as the preferred option satisfies the RIT-T.

## Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PADR with the requirements of the National Electricity Rules version 227.

Rules clause	Summary of requirements	Relevant section(s)
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	-
	(1) a description of each credible option assessed;	5
	(2) a summary of, and commentary on, the submissions to the PSCR;	4.1
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	5, 6 & 7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	6 & 7
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	6.3.5
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	6.3.4
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	8
	(8) the identification of the proposed preferred option;	9
(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide:	9	
(i) details of the technical characteristics;		
(ii) the estimated construction timetable and commissioning date;		
(iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and		
(iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.		

In addition, the table below outlines a separate compliance checklist demonstrating compliance with the binding guidance in the latest AER RIT-T guidelines.

Guidelines section	Summary of the requirements	Relevant section(s)
3.2.5	<p>A RIT-T proponent must consider social licence issues in the identification of credible options.</p> <p>A RIT proponent should include information in its RIT reports about when and how social licence considerations have affected the identification and selection of credible options.</p>	N/A <sup>52</sup>
3.4.3	<p>The value of emissions reduction (VER), reported in dollars per tonne of emissions (CO<sub>2</sub> equivalent), is used to value emissions within a state of the world.</p> <p>A RIT-T proponent is required to use the then prevailing VER under relevant legislation or, otherwise, in any administrative guidance.</p>	6.3.2 <sup>52</sup>
3.5A.1	<p>Where the estimated capital costs of the preferred option exceeds \$103 million (as varied in accordance with a cost threshold determination), a RIT-T proponent must, in a RIT-T application:</p> <ul style="list-style-type: none"> <li>● outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T</li> <li>● for all credible options (including the preferred option), either: <ul style="list-style-type: none"> <li>&gt; apply the cost estimate classification system published by the AACE, or</li> <li>&gt; if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate.</li> </ul> </li> </ul>	6.2 <sup>53</sup>
3.5A.2	<p>For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T:</p> <ul style="list-style-type: none"> <li>● all key inputs and assumptions adopted in deriving the cost estimate</li> <li>● a breakdown of the main components of the cost estimate</li> <li>● the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates)</li> <li>● the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied</li> <li>● the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance</li> </ul>	3.2, 5 & 6
3.5	<p>In the RIT-T, costs must include the following classes:</p> <ul style="list-style-type: none"> <li>● Costs incurred in constructing or providing the credible option</li> <li>● Operating and maintenance costs over the credible option's operating life</li> <li>● Costs of complying with relevant laws, regulations and administrative requirements</li> </ul> <p>For, asset replacement projects or programs, there are costs resulting from removing and disposing of existing assets, which a RIT-T assessment should recognise. RIT-T proponents should include these costs in the costs of all credible options that require</p>	5 & 6

<sup>52</sup> These are new requirements stipulated in revised RIT-T Application Guidelines released by the AER, which came into effect on 21 November 2024. For compliance purposes, the AER only have regard to the guidance that was in effect when Transgrid initiated the RIT-T in question. In this context, initiated means from the publication of a PSCR. As the PSCR was published prior to 21 November 2024, these new requirements are not applicable to this RIT-T.

<sup>53</sup> The cost threshold of \$103 million has been updated in the new guidelines from the previous value of \$100 million. In accordance with footnote 52, the previous cost threshold applies.

	removing and disposing of retired assets. For completeness, the RIT-T proponent would exclude these costs from the 'BAU' base case.	
3.5.3	The RIT-T proponent is required to provide the basis for any social licence costs in its RIT-T reports and may choose to refer to best practice from a reputable, independent and verifiable source.	N/A <sup>52</sup>
3.6	RIT-T proponents are required to apply classes of market benefits consistently across all credible options.	6 <sup>52</sup>
3.7.3	When calculating the benefit from changes in Australia's greenhouse gas emissions, a RIT-T proponent is required to: <ul style="list-style-type: none"> <li>include the following emissions scopes, unless the change relative to the base case can be demonstrated to be immaterial to the RIT outcome:</li> <li>direct emissions from generation</li> <li>direct emissions other than from generation</li> <li>estimate the change in annual emissions (once identified in accordance with this Guideline) between the base case and the credible option, and multiplying this change by the annual VER to arrive at the annual benefit from changes in Australia's greenhouse gas emissions</li> </ul>	6.3.3 <sup>52</sup>
3.8.2	Where the estimated capital cost of the preferred option exceeds \$103 million (as varied in accordance with an applicable cost threshold determination), a RIT-T proponent must undertake sensitivity analysis on all credible options, by varying one or more inputs and/or assumptions.	6.5 & 8.4 <sup>53</sup>
3.9.4	If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: <ul style="list-style-type: none"> <li>the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and</li> <li>how the level or quantum of the contingency allowance was determined.</li> </ul>	N/A
3.11.2	Where a concessional finance agreement is included, the RIT-T proponent is required to provide sufficient detail about the concessional finance agreement to justify an agreement's inclusion and such that it can articulate how the value of the concession is to or would be shared with consumers.  If a proponent seeks to include an unexecuted concessional finance agreement in the RIT-T, they must undertake sensitivity testing for the scenario the agreement doesn't eventuate.	N/A <sup>52</sup>
4.1	RIT-T proponents are required to describe in each RIT-T report <ul style="list-style-type: none"> <li>how they have engaged with local landowners, local council, local community members, local environmental groups or traditional owners and sought to address any relevant concerns identified through this engagement</li> <li>how they plan to engage with these stakeholder groups, or</li> <li>why this project does not require community engagement.</li> </ul>	N/A <sup>52</sup>

## Appendix B Benefit Quantification Approach

### B.1 Case Study 1 – Reduction in likelihood of unserved energy

The benefits for case study 1 are calculated as the reduction in EUE events for that year by option  $\times$  the estimated size of the event in that year (in MWh)  $\times$  the VCR (\$/MWh). We describe the key assumptions that are used to calculate the benefits for case study 1 below.

#### Number of EUE events

For this analysis, we have implicitly assumed that the increase in the number of alarms is a reasonable proxy for the increase in the complexity of operating the control room, and hence the level of risk that the control room must mitigate over time. An example of the relationship between the number of alarms and complexity can be seen in the increase in the alarm points associated with newer assets (such as grid forming batteries in Transgrid's network) compared to the traditional generators connected to the network. The rate of connection of these newer assets is increasing, with a resultant exponential increase in the alarm points.

We have estimated the forecast number of alarms going forward under each of the ISP scenarios based on the level of increase in generation in NSW. We consider that this is appropriate there is a strong relationship between the number of alarm monitoring points (and so number of alarms) with renewable energy capacity growth.

We assume that once a critical threshold of 900 alarms per operator per day is breached, operators are likely to be dealing with a volume of information and complexity that exceeds their capacity to maintain situational awareness of the grid at large. The 900 alarms per operator per day threshold is around 300 per cent and 7 per cent above FY2015 and FY2024 alarm volumes, respectively.<sup>54</sup> The threshold is assumed to be 900 per operator per day based on our assessment that our control room would have trouble maintaining situational awareness of the grid at large by 2025 without upgrades to operational tools.

We note that analysis of historical data provides limited insight on the potential risk of operating above a critical threshold, since we have not exceeded this threshold in the past. As a result, a forward-looking assessment of risk (based on forecast alarms) has been adopted to estimate the impacts of breaching this threshold. The risk escalates significantly above this threshold because the high volume of alarms increases the complexity of information analysis, potentially leading to longer outages (due to extended resolution times) and more frequent incidents (as triggering conditions become more common).

#### Size of an EUE event

To estimate an appropriate size of EUE events, we have conducted an analysis of unserved energy events between 2004 and 2024. We have identified EUE events that could potentially arise because of a missed alarm.

---

<sup>54</sup> We have assumed that there are 2.5 operators per day. This represents an average of two operators managing all incoming alarms, aside from voltage regulation alarms on the main grid apparatus, which are the responsibility of the Network Control Manager and equates approximately 0.5 of an operator.

EUE events are classified based on the volume of lost load, into either minor, intermediate or catastrophic, where:

- minor refers to an event impacting a limited geographic region for a short period of time and resulting in less than 100 MWh of lost load – only a very small proportion of minor events are related to system security incidents (around 3%);
- intermediate refers to larger and/or more complex system events resulting in more than 100 MWh of lost load – around half of these events are system security related; and
- catastrophic relates to a black start event covering the full NSW region, which are by definition system security incidents because the loss of generation and load occurs as a results of insecure power system conditions.

Our analysis focused on intermediate events, as system security events that could be avoided by an uplift in operational tools have historically been these types of events. Further, we have conservatively excluded catastrophic events.

The impact of a missed alarm is expected to grow as the network becomes larger and more complicated, thereby taking more time to resolve any issues identified. EUE event size is assumed to grow over time in line with the number of substations on our network, since this provides a reasonable proxy of increases in complexity and network size. Since 2016, there has been a 2.9% per year growth rate in substations added to our asset base. This growth rate has been used to project the average annual event size over the evaluation period.

## B.2 Case Study 2 – Increased network utilisation

The economic benefits for case study 2 include SRMC savings and emission reduction benefits. The following formulas are used to calculate benefits for a given year and given option:

SRMC savings = number of relevant constraint hours (hours) × change in constraint (MW per hour) × capacity factor (MWh per MW) × loss factor ratio (%) × weighted average SRMC of marginal generators (\$/MWh) × benefit rollout (%).

Emission reduction benefits = number of constraint hours (hours) × change in constraint (MW per hour) × capacity factor (MWh per MW) × loss factor ratio (%) × weighted average emission intensity of marginal generators (tonnes per MWh) × value of emission reductions (\$ per tonne) × benefit rollout (%).

A summary of key inputs and assumptions for case study 2 is set out in table 42 and discussed in further detail below.

Table 42: CS2 SRMC inputs and definitions

Input	Definition
Relevant constraint hours	Relevant constraint hours are constraints that occur due to inverter-based stability and security-related constraints. We have excluded hours where output of renewable energy has been constrained to zero and hours where wholesale market price is lower than fuel costs of the marginal generator.
Change in constraint	The alleviation in generator constraints that is assumed to arise from uplift in operational tools.

Capacity factor	The average capacity factor of renewable generators during daytime periods (%)
Loss factor ratio	The ratio of energy lost as electricity is transmitted from renewable generation site to consumer versus the energy lost from thermal generator
Weighted average SRMC of marginal generators	The weighted average SRMC of dispatching the marginal generator. This is used to calculate reduction in SRMC that arises from reducing the marginal generator's output.
Benefit rollout	The benefits achieved each year, based on the deployment of the initiatives over evaluation period
Value of emission reductions (VER)	The value of emissions reduction for each tonne of emissions avoided
Weighted average emission intensity of marginal generators	The weighted average emission intensity of dispatching the marginal generator. This is used to calculate reduction in emissions that arises from reducing the marginal generator's output.

## Constraint hours

The constraint hours included in the benefit calculation represent a subset of total constraint hours across our network. Our analysis only includes inverter-base inverter-based stability and security-related constraints. We have only included NSW-related and day time constraints, where day time is defined as being from 5:30 am to 5:30 pm. We consider this to be conservative as uplift in operational tools will also likely benefit night time constraints and non-NSW related constraints.

Further, we have excluded the following constraints from our analysis of case study 2 benefits:

- constraints where renewable connection is constrained to since these can often be attributed to anti-islanding measures rather than based on system strength or instability conditions/assumptions – we consider this conservative as operational tools could help alleviate these constraints; and
- constraints that occur during periods when the Regional Reference Price (RRP) is less than the fuel costs of the marginal generator to avoid capturing periods where marginal generator was dispatching for reasons other than serving electricity demand – we consider this conservative as it is possible that increase in renewable energy during these periods could still reduce output from thermal generators.

We consider that it is reasonable to assume that constraint hours will increase in line with renewable energy capacity in NSW. Constraint hours are expected to continue to rise due to the oncoming ISP projects and renewable energy zones. These will lead to greater meshing of the network across the NEM and subsequently change power system dynamics and increase the challenge of identifying and mitigating new modes of instability.

## Change in constraints

Uplift in operational tools will reduce curtailment of renewable generation capacity. We have considered how different initiatives could alleviate curtailment under each option. We have assumed that uplift in FLM, WAMS and forecasting tools will unlock 2 MW of renewable generation capacity per relevant constraint hour for Option 2 when fully implemented, i.e. each initiative would unlock 0.66 MW of renewable generation capacity.

Option 1 involves partial uplift in FLM and is assumed to unlock 0.33 MW per relevant constraint hour by 2029 when fully implemented.

### Capacity factor

A capacity factor measures how much energy is generated when compared to its maximum capacity. The capacity factor for renewable energy depends on the weather condition at the time. For example, the capacity factor for solar energy is zero at nighttime when there is no sunlight.

We have assumed a capacity factor of 57 per cent. This has been estimated using the low assumption capacity factors in CSIRO GenCost report for 'Onshore Wind' (48%) and 'Large Scale Solar' (32%).<sup>55</sup> Low assumption is considered reasonable as inverter-based constraints typically occur when output from renewable generation is higher and this calculation has excluded any increase contributed by offshore wind. The daytime capacity factor of solar is assumed to be around two times the total capacity factor of 32 percent, or 64 per cent.

### Loss factor

A loss factor ratio of 0.95 is calculated based on the average loss factor for the NSW marginal generators (0.96) versus the average loss factor for the alternative NSW renewable generators (0.91).<sup>56</sup> This accounts for the energy lost as electricity is transmitted from generation site to consumer with renewables typically incurring more losses due to the remoteness of renewable generators. These loss factors are based on the AEMO 2023-24 marginal loss factors (with the regional reference node at Sydney West 330 kV).

### SRMC savings

SRMC is defined as follows:

SRMC = Variable operating and maintenance costs (VOM, \$ per MWh) + heat rate (GJ/MWh) × fuel costs (\$/GJ)

AEMO's IASR provides VOM and heat rate for each generator in NSW, including new entrant generators, and forecast fuel costs under different ISP scenarios. These have been used to calculate SRMC for each generator over the evaluation period.

The approach to identifying the marginal generator is described in section 7.4.3 of the report. By way of summary, we have identified the proportion of time each existing generator is the marginal generator, which we then project forward based on AEMO forecast change in capacity and energy sent out by ISP scenario. A weighted average SRMC is then calculated for each year based on the SRMC of each generator and proportion of time that each generator is the marginal generator.

We have assumed that the SRMC for hydro and storage is zero. In other words, we have assumed that there are no economic benefits from alleviating renewable energy curtailment when the marginal generator is hydro or storage. We consider this assumption to be conservative as there are likely to be economic

<sup>55</sup> CSIRO 2023-2024 GenCost Report - [CSIRO releases 2023-24 GenCost report - CSIRO](#)

<sup>56</sup> AEMO, Marginal Loss Factors for the 2024-25 Financial Year, Nov 2024, [https://aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/loss\\_factors\\_and\\_regional\\_boundaries/2024-25-financial-year/mlfs-for-the-2024-25-financial-year.pdf?la=en](https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2024-25-financial-year/mlfs-for-the-2024-25-financial-year.pdf?la=en)

benefits in these circumstances, e.g. hydro and storage could be dispatched during other time intervals instead and reducing the need to invest in renewable energy capacity.

The SRMC is expected to decrease over time across all ISP scenarios, as the proportion of intervals where hydro and storage is the marginal generator increases over time.

### Emission intensity

Emission intensity is used to calculate the reduction in greenhouse gas emissions arising from reduced thermal generation from the marginal generator. We have sourced emission intensity factors from AEMO’s IASR, which provides emission intensity by generator and under different ISP scenarios.

The approach to identifying the marginal generator is described in section 7.4.3 of the report and is the same approach used to identify marginal generator to calculate SRMC savings. A weighted average emission intensity is calculated for each year based on the emission intensity of each generator and proportion of time that each generator is then marginal generator for each constraint hour.

The weighted average emissions intensity is expected to decrease over time under all ISP scenarios, as the grid transitions away from thermal energy sources.

### VER cost

The value of emissions reduction (VER) applied to the benefit calculations are derived from the AER’s interim VERs as of May 2024<sup>57</sup>. The values have been escalated to 2024/2025 dollars using the ABS CPI to FY2024 values and then to FY2025 using RBA forecast inflation rate between FY2024-25. These values have been converted from calendar year to financial year, taking the average of the two calendar years (as per Table 43).

Table 43: VERs applied to benefit calculations for each FY (\$/tonne)

FY	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
VER (\$/tonne)	77	82	87	92	98	106	116	127	138	149	161	173	186	199	213

### Benefit rollout

We have assessed how benefits are likely to arise over time by option. This assessment is based on the deployment of the initiatives over the evaluation period. 100% of benefits are achieved by 2029 for Option 1 and by 2031 for Option 2, reflecting the full implementation of initiatives by those dates. Table 44 sets out the assumed benefit rollout profile used for CS2.

Table 44: Assumed benefit profile from 2024-25 to 2038-39 for CS2 (%)

Option	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
Option 1	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100

<sup>57</sup> AER, Valuing emissions reduction – AER guidance and explanatory statement, May 2024, <https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf>

Option 2	0	0	0	0	17	75	100	100	100	100	100	100	100	100	100
----------	---	---	---	---	----	----	-----	-----	-----	-----	-----	-----	-----	-----	-----

### B.3 Case Study 3 – Improved outage management

Similar to case study 2, the economic benefits for case study 3 includes SRMC savings and emission reduction benefits. The following formulas are used to calculate benefits for a given year and given option:

SRMC savings = number of relevant outages (number) × time saved per hour (hours per outage) × reduction in thermal generation (MWh per hour) × loss factor ratio (%) × weighted average SRMC of marginal generators (\$/MWh) × benefit rollout (%).

Emission reduction benefits = number of relevant outages (number) × time saved per hour (hours per outage) × reduction in thermal generation (MWh per hour) × loss factor ratio (%) × weighted average emission intensity of marginal generators (tonnes per MWh) × value of emission reductions (\$ per tonne) × benefit rollout (%).

Case study 2 and 3 are quantified using a similar approach. As such, the same assumptions and approach is adopted across these two studies. Table 44 provides an overview of the key assumptions that feed into case study 3 only. We provide further information on these assumptions below.

Table 45: CS3 fuel cost NPV equation inputs and reference

Input	Reference
<b>Outage</b>	The number of relevant outages that could benefit from operational uplift. These are related to inverter-based stability and security-related constraints
<b>Time saved per outage</b>	The average time predicted to be saved per outage and is estimated based on historical approximations of switching times per number of generators and estimated time savings across the options (hours)
<b>rollout</b>	The percentage used to quantify the realisation of benefits based on the deployment of the initiatives over program period (%)

#### Relevant outages

Relevant outages are related to inverter-based stability and security-related constraints. Similar to case study 2, we have only included outages which occur during NSW related, daytime constraints. We are only considering outages relating to lines and transformers to avoid any duplication of benefits. We consider our approach to identifying relevant outages to be conservative as other outages, including unplanned outages will also benefit from this initiative. Further, we have only included outages for the six month period between 1 July 2023 to 31 December 2023. Expanding the analysis to include a full year would increase the benefits that arise from case study 3.

The growth rate used is based on the rate of renewable generator capacity in NSW under each ISP scenario, excluding the estimated proportion of generation in REZs.

#### Reduction in thermal generation

To understand the change in renewable energy that arises from reduced switching time, we have assessed renewable energy output during normal system conditions and when there is a relevant outage. Our analysis indicates that renewable energy output is higher in system normal conditions (155 MWh per five minute interval) when compared to output when there is a relevant outage (184 MWh per five minute interval). This equates to around 29 MWh per five minute interval, or 342.5 MWh per hour. We have therefore assumed that reducing duration of switching time would increase renewable energy generation by 342.5 MWh per hour.

The reduction in thermal generation is assumed to remain the same across the evaluation period. We consider this to be a conservative assumption as this will likely increase over time with increased uptake of renewable energy generation.

### Time saved per outage

The time saved per outage is based on our analysis of average switching time for each outage and estimated time savings per outage. This analysis is done by number of generators involved, as higher number of generators increases the switching time required.

We have assumed that time saved per outage remains constant across the evaluation period. This implicitly assumes that the number of generators involved with each outage will remain constant, which we consider to be conservative as this will increase as more renewable energy comes onto our grid.

### Benefit rollout

We have assessed how benefits are likely to arise over time by option. The benefit rollout does not change by option as option 1 and 2 are the same for case study 3.

Table 46: Rollout plan from 2024-25 to 2038-39 for CS3 (%)

Option	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39
1	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
2	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100