Transgrid

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# System Security Roadmap Operational Technology Upgrades

RIT-T Project Assessment Conclusions Report

Date of issue: 8 October 2025

# 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.[1]

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) and Australian Capital Territory (ACT) transmission network. Publication of this Project Assessment Conclusions Report (PACR) is the final step in the application of the RIT-T. It follows the publication of the Project Assessment Draft Report (PADR) on 12 May 2025.

The PADR received one submission, from the Justice and Equity Centre (JEC). Transgrid has engaged with JEC on the matters raised in its submission in preparing this PACR, to ensure that we understand their concerns. We have also refined the costs presented in the PADR, and the timing of some initiatives, through an independent assessment by DGA Consulting as well as further detailed planning by Transgrid's internal team. This has resulted in some minor changes in the costs and timing of the options since the PADR. The benefits have also changed slightly due to changes in timing of various initiatives. In addition, we have continued to engage with the Transgrid Advisory Council (TAC) in progressing and testing the assessment in this PACR.


**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.

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, 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. Further, as synchronous coal generation retires, the grid is losing the 'buffer' in the power system and will operate closer to the edge of the secure operating envelope. This means the power system could cascade faster in response to contingency events.

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

Whilst these developments will ultimately benefit consumers through increased access to lower cost, zero-emission energy sources 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 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 limits for inverters across the network in order to have sufficient confidence that the system will remain within its required operating envelope, these inverter limits will bind more frequently. This may limit the capacity of low marginal cost inverter-base renewable generation that can be utilised on the grid.
- there is an increased likelihood of emergency outages or disruptions when our operators are overburdened from needing to access and correlate 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 proactively address these potential adverse outcomes and this RIT-T is being carried out to provide Transgrid 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 static limits on the operation of inverter-based generators connected to our system going forward to ensure the system remains within its required operating envelope, and instead being able to utilise dynamic inverter limits reflecting real time conditions. 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., 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 (through providing real-time fault levels and inverter limits); 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 Advanced Energy Management System (AEMS) and 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 PADR**

There have been a number of important developments since the publication of the PADR.

- We have obtained an independent cost review by DGA Consulting, as well as undertaken further, detailed internal planning. This resulted in a number of refinements to the costs and implementation timings of the various initiatives included in each of the options. Benefits have also changed slightly due to changes in implementation timing.
- Overall, the initial costs of both options has been subject to some minor changes since the PADR, and the costs associated with the refresh of technologies later in the assessment period (when the initial investment has reached end-of-life) has reduced, reflecting reduced effort on data cleansing and configuration in refresh projects compared with the initial implementation.
- We have also obtained an additional independent technical verification from the Electric Power Research Institute (EPRI), that the control room investments we are proposing under Option 2 are judicious and align with EPRI's recommendations and their experience of global power system developments.
- EPRI highlights that Option 1 has basic capability uplift but has in-built constraints. The limitations in scope and investment under Option 1 would almost certainly require inefficiently adding additional piecemeal investment to address gaps in operability in the medium term.
- Lastly, the Australian Energy Market Operator (AEMO) has provided a letter of confirmation supporting the preferred option in this PACR, which we are publishing on our website alongside this PACR. This letter reconfirms the importance and urgency for investment in Operational Technologies by NSPs and that the Option 2 investments by Transgrid are complementary to AEMO's investments.
- AEMO and Transgrid have validated alignment of our respective technology roadmaps, which is a key prerequisite to realising the benefits estimated by Transgrid in this RIT-T assessment.

We have continued to adopt AEMO's 2023 Input, Assumptions and Scenarios Report (IASR) and the 2024 Integrated System Plan (ISP) for the benefit quantification in this PACR, as reflecting the most up to date, consistent set of assumptions at the time that the assessment was undertaken. We note that AEMO's final 2025 IASR was published on 31 July 2025. We have undertaken a high-level comparison with the IASR inputs used in our quantification, and found that the changes are unlikely to materially affect our benefit calculations and therefore the outcome of this RIT-T.

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.

**Submission received in response to the PADR**

Transgrid received one submission in response to the PADR, from the Justice and Equity Centre (JEC).

The JEC expressed concern that, whilst Transgrid has articulated why changes in the energy system have caused an increase in complexity of operations, Transgrid has not established a particular threshold to demonstrate that this increasing complexity requires extra investment to manage and cannot be acceptably managed with increased operating expenditure.

Transgrid's view is that there would be substantial, practical difficulties involved in quantifying operational complexity thresholds, and there are currently no established industry methodologies to draw on. As a consequence, we have not adopted a 'complexity threshold' approach as suggested by JEC. However, we have endeavoured to ensure that our case study assessment is as transparent as possible, including through highlighting the extent of constraints that may be imposed to address system complexity concerns in the absence of the investment. We have also provided further substantiation for our conclusion that hiring additional staff cannot substitute for operational tools in grid management, including that personnel cannot substitute for certain tool capabilities (e.g., real-time visibility and advanced alarm management).

We also note that evaluating investments in relation to the threshold is generally more applicable for reliability corrective action RIT-Ts (where there is often a threshold set out in an obligation on Transgrid, which cannot be breached), rather than for market benefit RIT-Ts.

JEC also considered that, to the degree that the need to invest can be established, Option 1 would be preferable as it would ensure 'minimum standards are met at least cost' and would therefore minimise the risk that consumers will bear unnecessary excess costs, whilst not precluding Transgrid's operational capabilities being further uplifted if needed in future.

Transgrid has obtained further independent technical verification from EPRI. EPRI highlights that Option 1 would not maximise the net economic benefit resulting from fully mitigating the potential reliability risks driven by likely growth patterns, and would require further investment in the short-medium term, duplicating expenditure and introducing uncertainty and delays.

Further, AEMO has provided its support for Option 2, as representing capabilities that are required now, and are complementary to the operability initiatives AEMO is also progressing.[2]

In line with the RIT-T requirements, Transgrid has continued to identify the preferred option under this RIT-T as the option that has the greatest expected net economic benefit, which is Option 2.

**Two credible options have been assessed in the PACR**

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 (EPRI and GHD Advisory). It has also been informed and refined through a comprehensive market testing process, centred on a Request for Information (RFI) process conducted ahead of the PADR.

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

[2] *AEMO, Update support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices*, 15 September 2025.

- 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. Option 2 includes initiatives out to 2030, but does not also include longer-term initiatives which may be added in 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 was tested and refined in the light of responses to the RFI. Since the PADR, the options have been subject to additional independent assessment by DGA Consulting and further planning by the internal Transgrid team. This has led to some changes in the assumed implementation timing for initiatives, as well as to minor scope refinements to both options – we discuss this further in section 4.1.2.

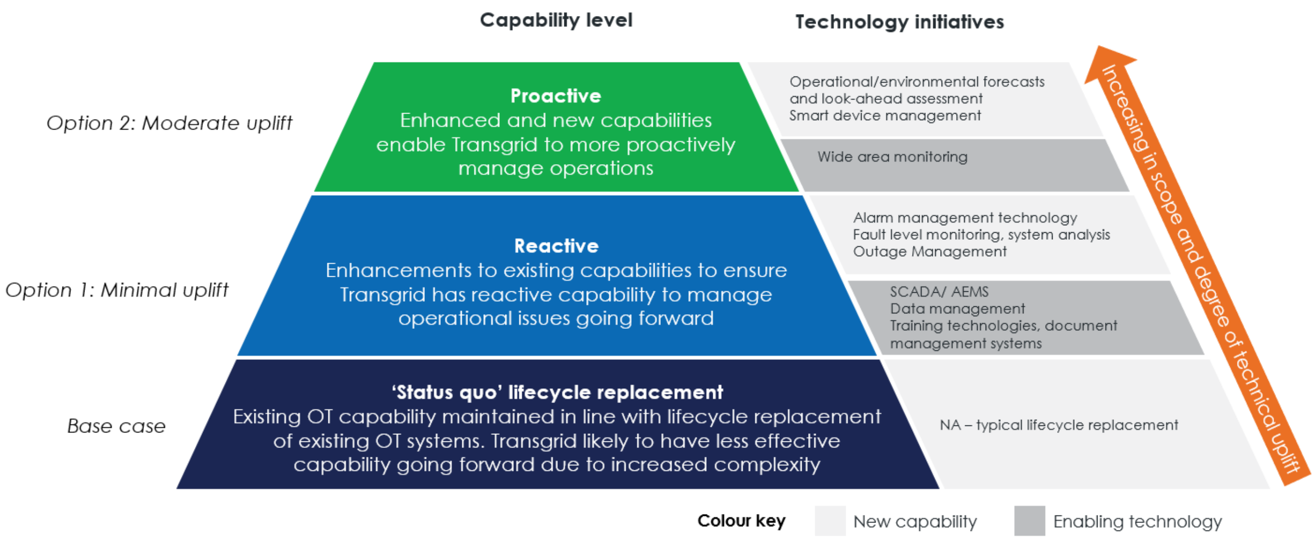
In the PSCR, we also identified a third option, i.e., Option 3: **Predictive capability** – this option would have provided a suite of advanced enhancements to existing capabilities, as well as adding advanced new capabilities, to enable Transgrid to employ a predictive approach to operations in our control room and corporate offices. Option 3 would provide a degree of future-proofing for longer-term functionalities which are expected to be required. 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, and it has not been assessed in the PADR or this PACR. 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. This capital expenditure reflects a 6.8 per cent decrease compared to the PADR for Option 2, and a 0.3 per cent decrease for Option 1, resulting from a range of scope and cost refinements following the independent assessment by DGA Consulting and further planning by Transgrid – discussed further in section 5.2. DGA supports Transgrid's revised capex estimates as representing an efficient level of costs to deliver the scope of the proposed capability.[3]

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

| | Estimated capital expenditure |
|---|---|
| Option 1 | 122.7 |
| Option 2 | 167.1 |

As Transgrid is undertaking this RIT-T over a 15-year assessment period, to capture the full benefit realisation period for operational technologies and tools which reach the end of their economic life prior to the end of the period, we have included indicative refresh costs in both the base case and option cases. For the purposes of this PACR, Transgrid has generally assumed the indicative replacement costs in real terms are 20 per cent less than the initial costs at the end of the economic life of the assets. This discount (which was not applied in the PADR assessment), reflects the independent advice received from DGA Consulting that a like-for-like refresh is likely to be less expensive than a new build, given the learnings and

[3] DGA Consulting, *Independent Review of System Security Operability Costs – Option 2*, 30 September 2025, version 1.2, p 6 and DGA Consulting, *Independent Review of System Security Operability Costs – Option 1*, 30 September 2025, version 1.2, p 6.

labour cost saving opportunities compared to the original build.[4] We continue to believe that our approach reflects a conservatively high estimate of the refresh costs. This is consistent with DGA Consulting's finding that there is potential for some refresh costs to be less than 80 per cent of original costs.[5]

We considered five additional options, including the potential for non-network options, to meet the identified need during the course of 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 4.5).

**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.

4 The exception is the refresh costs of the incremental facilities associated with the SCADA/AEMS system, where we continue to assume that future refresh costs remain the same in real terms.

5 DGA Consulting, *Independent Review of System Security Operability Costs – Option 2*, 30 September 2025, version 1.2, p 6 and DGA Consulting, *Independent Review of System Security Operability Costs – Option 1*, 30 September 2025, version 1.2, p 6.

We have estimated benefits under three case studies, which are summarised in Table E.2.

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 | 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.<br>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. |
| Case study 2 | Increase in network utilisation | Alleviating pre-emptive and conservative static limits on inverter-based generation, through real-time and near-term network analysis replacing static scenario measurements. This facilitates less conservative network asset utilisation by enabling dynamically changing inverter 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 automation of planned generator inverter changes. |

We have estimated the gross market benefit for each option under each case study for each of the 2024 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 | 103.5 | 160.5 |
| Increased network utilisation | 10.9 | 61.5 |
| Reduced duration of switching operations | 74.8 | 74.8 |
| Total | 189.3 | 296.8 |

**The net present value analysis confirms 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 Business As Usual (BAU) activities to best maintain our control room capabilities required for compliance with the National Electricity Rules (NER) until the end of the assessment period will occur, including a lifecycle, non-enhanced replacement of our SCADA/AEMS system by June 2031. Because we have undertaken a 15-year assessment for this RIT-T to capture the full benefit realisation period, these options include refresh costs where required for technologies to 2039.

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

| | Capital costs | Operating costs | Total costs |
|---|---|---|---|
| Option 1 | 104.1 | 33.1 | 137.2 |
| Option 2 | 133.8 | 44.2 | 177.9 |

In Table E.5 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 $118.9 million, compared with $52.0 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 | 40.0 | 47.9 | 97.8 | 52.0 | 2 |
| Option 2 | 73.6 | 135.5 | 198.1 | 118.9 | 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. We also find that a 1 year delay in the delivery of the preferred option (Option 2) would result in a $6.5 million decrease in net market benefits.[6]

Given the above and consistent with the findings of the PADR, Option 2 is confirmed as the preferred option for this RIT-T as it is the credible option that maximises the NPV of the net economic benefit (in accordance with NER clause 5.15A.2(b)(12)).

## Next steps

This PACR represents the final step of the consultation process in relation to the application of the RIT-T process undertaken by Transgrid.

Parties wishing to lodge a dispute notice with the AER may do so prior fto 7 November 2025 (30 days after publication of this PACR). Any dispute notices raised during this period will be addressed by the AER.

Following completion of this RIT-T, and the written support received from AEMO, Transgrid now intends to submit a CPA to the AER so that we are able to progress with this key investment.

[6] We discuss this in further detail in section 7.4.

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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.

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# 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 Conclusions Report (PACR) represents the final step in the application of the RIT-T. It follows the publication of the Project Assessment Draft Report (PADR) on 12 May 2025.

## 1.1 Context and AEMO support

We are currently in a period of transformation for the electricity system in NSW, with multiple 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:[7]

- 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.

Transgrid has been 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.

Following publication of the Project Specification Consultation Report (PSCR), AEMO 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:[8]

> *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.*

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

8 *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.*

AEMO also noted that the options identified in the PSCR were ‘fully aligned’ with AEMO’s Operational Technology and Engineering Roadmaps,[9] which outline the emerging operational and engineering challenges emerging from the transition to higher levels of renewable generation while maintaining reliability, security and resilience.[10] In particular AEMO highlighted that:[11]

> *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 has now sought AEMO’s formal written support for the specific operational technologies and tools proposed in the preferred option (ie, Option 2) in this PACR (in accordance with the CPA trigger requirement), to support the submission of the CPA following publication of the PACR and the completion of the RIT-T. Transgrid has published the letter received from AEMO alongside this PACR.

In its most recent letter, AEMO has:[12]

- reconfirmed that the urgency for investment in Operational Technologies by NSPs remains;
- reconfirmed that the Option 2 investments by Transgrid are complementary to AEMO’s investments;
- confirmed that AEMO and Transgrid have validated the technology roadmap alignment required to realise benefits; and
- confirmed that it supports Option 2 as the preferred option.

AEMO highlights in its most recent letter that:

> *[..] to continue progressing through upcoming energy transition challenges, new operational technology and tools are required by Transgrid, that are new, different and in addition to current tool capability.*

## 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 inverter-based 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

9 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.

10 *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.*

11 *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.*

12 *AEMO, Update support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices*, 15 September 2025.

- 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).

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 completed 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 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. The project was completed on time and within budget and is already providing material benefits. We have incorporated the expenditure associated with this project as part of both options considered in this RIT-T.

Except for the investment in alarm rationalisation, 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 PACR[13] is to:

- confirm the identified need for the investment and describe the assumptions underlying this need;
- summarise points raised in submissions to the PADR, and highlight how these have been taken into account in the RIT-T analysis;
- describe the credible options being assessed under this RIT-T, which remain broadly the same as in the PADR (with some minor refinements in scope and timing following additional analysis);
- set out the basis on which the costs of the credible options have been estimated, which includes an independent review and confirmation since the PADR;
- summarise the methodology used to model the net market benefits for the credible options assessed, including the case study approach adopted, and present the updated results of this analysis since the PADR;

[13] See Appendix A for the NER requirements.

- 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 preferred option to meet the identified need confirmed in this PACR; and
- set out the 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.

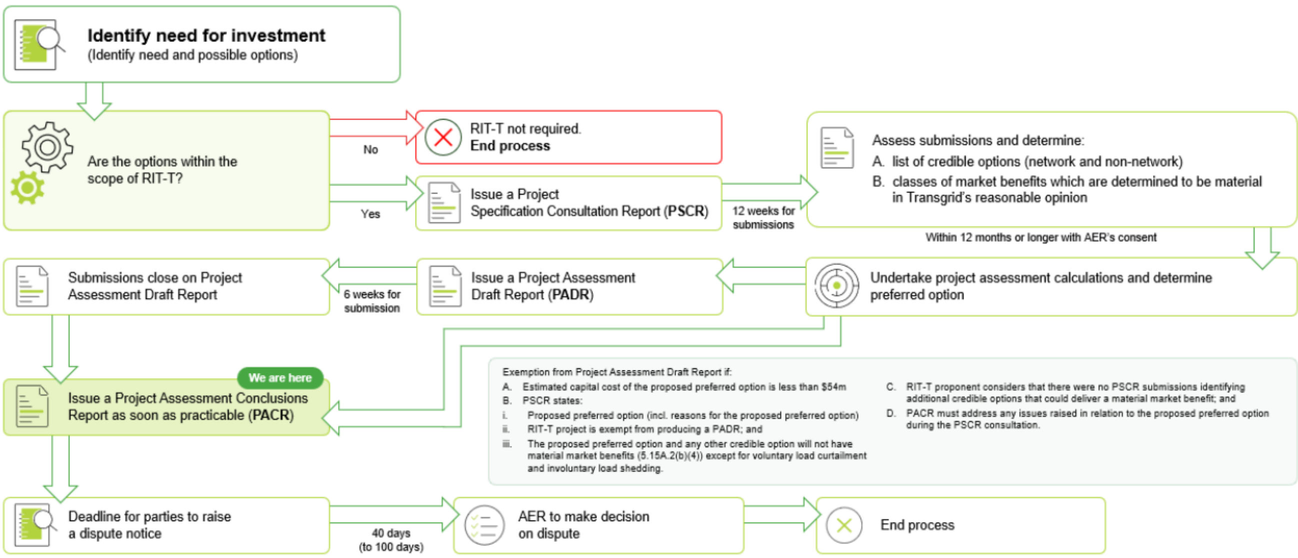
Overall, this report provides transparency into the planning considerations for investment options to enhance our capabilities to securely operate, plan, and manage the NSW/ACT power system during a period of unprecedented change and rapidly increasing system complexity.

A key purpose of this PACR is to provide certainty and confidence to stakeholders that our proposed investments into operational technologies and tools should be undertaken, and that the preferred option has been robustly identified as optimal.

## 1.4 Next steps

This PACR represents the final step of the consultation process in relation to the application of the RIT-T process undertaken by Transgrid for upgrading Transgrid's operational technology and tools.

Figure 1.1 This PACR is the final stage of the RIT-T process[14]




Parties wishing to raise a dispute notice with the AER may do so prior to 7 November 2025 (30 days after publication of this PACR). Any dispute notices raised during this period will be considered by the AER.

Further details on the RIT-T can be obtained from Transgrid's Regulation team via regulatory.consultation@transgrid.com.au. In the subject field, please reference 'System Security Roadmap Operational Technology upgrades PACR'.

[14] Australian Energy Market Commission. "*Replacement expenditure planning arrangements, Rule determination*". Sydney: AEMC, 18 July 2017.

Following completion of this RIT-T, and the written support received from AEMO, Transgrid now intends to submit a CPA to the AER so that we are able to progress this key investment.

# 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 PADR, and so has been summarised here. Further details are set out in section 2 of the PSCR.[15]

## 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 National Electricity Market (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:[16]

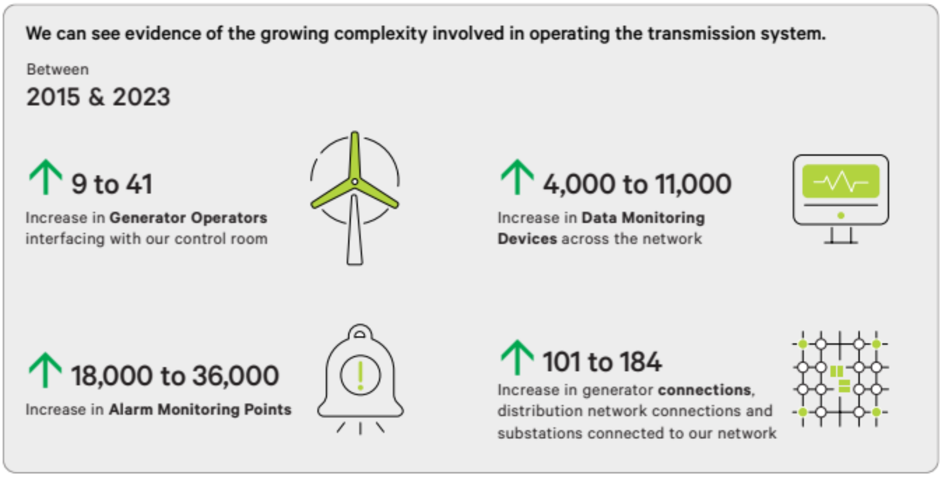
- **system monitoring and control**: continuous, real-time surveillance of the entire network; essential for effective network management and rapid response to changes;
- **fault detection and response**: when system faults occur, the control centre assesses the cause and impact, implements corrective 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.

EPRI highlighted that these capabilities will allow Transgrid to operate the network as efficiently and cost-effectively as possible, by reducing consumer costs from constraints while maintaining reliability.

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 for Transgrid's network 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.

[15] Transgrid, *System Security Roadmap Operational Technology Upgrades*, RIT-T PSCR, 14 October 2024.
[16] EPRI report, April 2025, 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 increased to 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 pre-emptively impose static limits  on the operation of invertor-based generators connected to our system to ensure the system remains within its required operating envelope. This includes through real-time and near-term network analysis enabling dynamically changing inverter limits and providing the ability to operate closer to the power system's technical envelope, including 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 a 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 PACR 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 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 network 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[17] that need to be maintained as system complexity increases.

## 2.3 AEMO has provided written support for the options proposed under this RIT-T

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.[18] 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:[19]

> *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.

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[17] 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.

[18] *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.*

[19] *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.*

AEMO 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.[20]

We have continued to work closely with AEMO during the RIT-T process, and have now received AEMO's formal written support for the specific operational technologies and tools proposed in the preferred option (ie, Option 2) in this PACR. AEMO's support is part of the CPA trigger requirement determined by the AER, and supports the submission of the CPA following publication of the PACR and the completion of the RIT-T. Transgrid has published the letter we received from AEMO alongside this PACR.

In its most recent letter, AEMO has:[21]

- reconfirmed that the urgency for investment in Operational Technologies by NSPs remains;
- reconfirmed that the Option 2 investments by Transgrid are complementary to AEMO's investments;
- confirmed that AEMO and Transgrid have validated the technology roadmap alignment, which is a key prerequisite to realising benefits; and
- confirmed that it supports Option 2 as the preferred option.

AEMO highlights that:

> *[..] to continue progressing through upcoming energy transition challenges, new operational technology and tools are required by Transgrid, that are new, different and in addition to current tool capability.*

[20] *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.*

[21] *AEMO, Update support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices*, 15 September 2025.

# 3 Consultation on the PADR

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

## 3.1 Submissions to the PADR

Transgrid received one submission in response to the PADR. It was made by the Justice and Equity Centre (JEC) and is available on our website here.

The key themes from JEC's submission are set out below. Transgrid met with JEC on 4 July 2025 to discuss their concerns with the PADR, and how these could be addressed.

**The need for additional investment should be assessed relative to a system complexity 'threshold'**

In the submission, the JEC expressed concern that, whilst Transgrid has articulated why changes in the energy system have caused an increase in complexity of operations, Transgrid has not established a particular threshold to demonstrate that this increasing complexity:

- requires extra investment to manage; or
- cannot be acceptably managed with increased operating expenditure.

JEC recommended creating a threshold in the form of a point at which failure to uplift operational capacities would result in a number of constraints being imposed that would lift outages for consumers above an acceptable level.

To estimate the market benefits from a reduction in unserved energy, we have utilised a case study where we assume that there is a critical threshold of alarms per operator per day, and once this 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. This threshold is a proxy for network complexity – it is based on a relative increase in the current volume of alarms operators face and is a proxy for the additional network complexity each operator is likely to be able to handle.

Developing a threshold for the additional operational constraints that are expected to be imposed on the network would be complex. A meaningful threshold would require establishing a causal relationship between specific levels of operational complexity and the frequency/severity of operational constraints likely to be imposed.

This represents a highly complex analytical challenge. Unlike traditional network capacity thresholds that can be measured through physical parameters (such as thermal or voltage limits), an operational complexity threshold would need to quantify the human and technological capacity to process information and make decisions under increasing system complexity.

The absence of established industry methodologies for quantifying operational complexity thresholds reflects the inherent difficulty in establishing such metrics.

As a consequence of the practical difficulties involved, we have not adopted a 'complexity threshold' approach as suggested by JEC in assessing the identified need for investment in this PACR. Evaluating investments in relation to the threshold is generally more applicable for reliability corrective action RIT-Ts (where there is often a threshold set out in an obligation on Transgrid, which cannot be breached), rather than for market benefit RIT-Ts.

We have instead endeavoured to ensure that our case study assessment is as transparent as possible, including through highlighting the extent of constraints that may be imposed to address system complexity concerns in the absence of the investment, and the realisable benefits we expect to result from the proposed investment.

**JEC also considered that Transgrid had not established that the increasing system complexity cannot be addressed with increased operating expenditure (ie, staffing levels)**

In the PADR, we investigated the potential to achieve the outcomes in this RIT-T through additional staffing levels, rather than through capital expenditure. We concluded that staff cannot substitute for operational tools in grid management, since personnel cannot substitute for certain tool capabilities (e.g., real-time visibility and advanced alarm management).[22] In addition, while adding human resources is necessary, it is only impactful up to a point before operations become significantly segmented – adding more personnel may lead to reduced situational awareness and a reduced ability to process data and analysis quickly.[23]

In response to JEC's submission, we considered this issue further.

Whilst additional staff may be able to contribute towards managing an increasing quantity of alarms, they cannot provide Transgrid with improved understanding of actual network conditions so to allow us to operate the network less conservatively, nor improve our ability to reduce switching time.

Even if staff could effectively contribute to addressing the identified need, the skill sets required are specialised and are in high demand in the employment market, and so it is unlikely that we would be able to recruit, develop, and train a sufficient number of staff within a sufficient timeframe to address the identified need. By way of example, in absence of the control room investments we are proposing in this RIT-T, by 2030 we would need sufficient staff to cover:

- two additional 24/7 shifts to manage the increasing quantity and complexity of alarms; and
- at least one additional 24/7 shift to manage smaller areas of the network and maintain situational awareness.

This represents recruiting at least 21 additional staff, as each 24/7 shift requires at least seven staff to manage. Given the highly specialised skills required and tight employment market, it would be a complex, high risk and time consuming task for Transgrid to recruit, develop and train this increased quantity of staff, which would ultimately be expected to result in poorer quality outcomes and not negate the need for investment in new technologies.

Accordingly, we continue to conclude that an opex solution involving additional staff alone cannot unlock a significant proportion of the benefits from operational technology upgrades quantified in this RIT-T. This is also consistent with the adoption by other TNSPs and market operators, both in Australia and globally, of operational technology programs to address the complexity challenges they face with operating networks with increased renewable penetration.

22 PADR, p 34.
23 EPRI report, April 2025, p 12.

**Selection of the preferred option**

JEC's submission also considered that, to the degree that the need to invest can be established, Option 1 would be preferable as it would ensure 'minimum standards are met at least cost' rather than seeking to maximise net benefits. In the context of what JEC describes as a 'messy' transition in which consumers face persistently high energy prices, JEC considered that Option 1 should be selected to minimise the risk that consumers will bear unnecessary, excess costs, whilst not precluding Transgrid's operational capabilities being further uplifted if needed in future.

Under the NER, the purpose of the RIT-T is to identify the credible option that maximises the present value of net economic benefit (the 'preferred option').[24] This purpose is not dependent on whether the identified need for the investment is classified as a 'market benefit' RIT-T or a 'reliability corrective action'.

The focus of the RIT-T on net benefits reduces the risk that consumers will pay for inefficient investments.[25] A focus on minimising costs that did not also take account on the benefits from an investment may result in investments that would provide a greater benefit to consumers not being progressed.

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 In line with the NER, we have identified Option 2 as the preferred option under this RIT-T, as it provides a greater net benefit compared to Option 1.

Transgrid appreciates JEC's concerns around consumers incurring unnecessary, excess costs due to the uncertainty of the transition. Transgrid has aimed to address such concerns earlier in this RIT-T process, through refining the scope of Option 2 from that initially presented in the PSCR, and discontinuing its consideration of more advanced capabilities under Option 3 ('Predictive capability'), following market testing of the expected costs and delivery risks.

Following publication of the PADR, Transgrid has obtained independent technical verification from EPRI that the control room investments we are proposing under Option 2 are judicious and align with EPRI's recommendations and their experience of global power system developments.

Relevant to the concerns raised by JEC, EPRI highlights that Option 1:[26]

> *has basic capability uplift, but has in-built constraints and limitations in scope and investment that would almost certainly require inefficiently allocating additional piecemeal investment to address gaps in operability in the medium term.*

Specifically, EPRI highlights that Option 1 would limit Transgrid's capability as it would not go far enough to fully mitigate the potential reliability risks given likely growth patterns and would require further investment in the short-medium term, duplicating expenditure and introducing uncertainty and delays.[27]

[24] NER 5.15A.1(c).
[25] AER, *RIT-T Application Guidelines*, version 6, November 2024, p. 8.
[26] EPRI, *Evolving Transgrid's Operational Technology (OT) Capability - Addendum to April 2025 EPRI Report*, June 2025, p 2.
[27] EPRI, *Evolving Transgrid's Operational Technology (OT) Capability - Addendum to April 2025 EPRI Report*, June 2025, p 2.

EPRI has endorsed Transgrid's approach to proceed with Option 2, and considers that it aligns well with the recommendations from EPRI's original Evolving Transgrid's Operational Technology (OT) Capability report.[28]

The 'messy' nature of the energy transition is also increasing the complexity of maintaining reliability of supply, as the system is increasingly operating closer to its limits, and the control room is the 'last line of defense' to be able to react quickly to prevent or recover from high risk situations. Option 2 incorporates proactive capabilities, whereas Option 1 remains reactive, with the risk that a major outage may occur, resulting in a much greater impact on consumers.

In its additional report, EPRI highlights that:[29]

> *The goal for all system operators is move to proactive management from reactive, addressing controlling and mitigating risks before they manifest.*

The time required to upgrade capabilities from Option 1 to Option 2 once the need has emerged as acute is likely to be in the range of 2-3 years, from the point of approved funding, which would again exposure consumers to a high degree of risk.

In addition to EPRI's technical verification, Transgrid has also received formal endorsement from AEMO for progressing with investment in Option 2. AEMO has confirmed that the capabilities that form Option 2 are needed now, and will complement the operability initiatives AEMO is itself undertaking as system operator, which is a key prerequisite to ensuring realisable benefits for consumers.[30] Further, AEMO highlights EPRI's conclusion that an option with more basic capability uplift would be:

> *too limited in scope and has built in constraints which would not go far enough in mitigating potential reliability risks given growth patterns.*

As a consequence, Transgrid has continued to identify the preferred option under this RIT-T as the option that has the greatest expected net economic benefit, and this continues to be Option 2 .

## 3.2 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 on Transgrid's regulatory proposal, 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.[25]

In light of this concern, Transgrid has focused on undertaking ongoing and meaningful consultation with the TAC as part of this RIT-T assessment, focusing on the scope and range of investment options

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[28] EPRI, *Evolving Transgrid's Operational Technology (OT) Capability - Addendum to April 2025 EPRI Report*, June 2025, p 2.

[29] EPRI, *Evolving Transgrid's Operational Technology (OT) Capability - Addendum to April 2025 EPRI Report*, June 2025, p 2.

[30] AEMO, *Update support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices*, 15 September 2025.

under consideration and the methodology being used to quantify the benefits associated with the proposed investments.

The TAC was engaged early and consulted during the planning and development of this RIT-T. The TAC has heard from EPRI about the need for enhanced operability capabilities (both local and global) and have been taken through Transgrid's specific capabilities needs and the urgency of these being addressed. TAC members have also toured the control room, hearing first-hand from Transgrid's control room staff about some of the challenges the increase in complexity is posing.

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 has ensured that the investment proposal has been clearly presented to and examined by the TAC.

Transgrid 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, Request for Information process (RFI) and approach to developing cost estimates and the benefits quantification approach; and
- deep dive 4 – April 2025: control room tour and PADR briefing session.

In parallel to the drafting of this PACR, Transgrid and the TAC co-drafted a brief explanatory document which described how the proposed investment would meet the identified need, and the indicative impact it is expected to have on customer bills. This explainer is now available on Transgrid's website here. This explainer has been recently held up by consumer advocates as a positive initiative encouraged by the TAC.[31]

The operability technology upgrade project has continued to be a regular item included in Transgrid's quarterly update to the TAC. Transgrid also briefed the TAC on the outcome of this PACR analysis, to obtain any feedback specifically on this section prior to publication.

Overall, engagement with the TAC has been positive and has provided Transgrid with feedback that has been incorporated in articulating the need, developing the cost estimates, quantifying the benefits, and assessing the options. Feedback from the TAC members is that they have valued the depth of engagement and analysis presented to them, and felt they were brought along the journey. This is

[31] Gavin Dufty (St Vincent de Paul National Director Energy Policy and research) and Louise Benjamin (Independent Customer Advocate), *Reflection to the AER - Transgrid 2026-31 Revenue proposal enabling CWO REZ and the energy transition,* p. 5.

reflected in the engagement surveys undertaken at the end of each TAC session, the results of which have averaged greater than 4.5 out of 5.

Importantly, a key outcome from our engagement is that the TAC is supportive of the identified need.

## 3.3 Ongoing engagement with AEMO

Transgrid is collaborating actively with AEMO to identify the operational technologies and tools required to manage the future power system, as outlined in sections 1.1 and 2.3, as well as in AEMO's letter of support.

Transgrid's and AEMO's roles, capabilities and systems have significant interdependencies. Recognising this, we have continued 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.[32]

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 4.

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 global 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.

Transgrid has continued to engage with AEMO since the PADR. Technical specialists from both Transgrid and AEMO held several deep dive workshops to discuss in detail the capabilities of Transgrid's proposed investments and how the enhanced capabilities would interact with AEMO 's systems. These workshops confirmed that the benefits Transgrid is estimating from the improved capabilities allowing the network to be operated in a less conservative manner are expected to be realisable in practice, as AEMO's systems are able to take advantage of the changes in system constraints that would be notified by Transgrid as a consequence of these capabilities.

[32] AEMO, *2024 General Power System Risk Review – Report*, Final report, July 2024, p 109.

Transgrid has continued to keep AEMO informed on the detail of the initiatives being assessed in this RIT-T, and has ensured that AEMO is comfortable to formally support the preferred option in this PACR. This formal support has been provided in a recent letter from AEMO which has highlighted both the importance and urgency of the investments, and also the validation of the technology roadmap alignment between AEMO and Transgrid, to ensure benefits are realisable.[33]

[33] AEMO, *Update support for Transgrid's proposed investment to upgrade operational technology and tools for use in its control room and corporate offices*, 15 September 2025.

# 4 Credible options assessed

This section describes the options assessed in this PACR to address the identified need, including the changes to the scope of each option - between the initial PSCR and the PADR (resulting from the RFI process), and the minor refinement to the scope of Option 2 made in this PACR. It also presents the updated estimate of capital and operating costs since the PADR.

All costs presented in this PACR 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 obtained at the PADR stage;
- refinements in cost estimates following an external review by independent experts DGA Consulting, including allowances for expected customisation of functionalities under each option;
- refinements in scope arising from further planning works by Transgrid since the PADR;
- an updated RFI on refined scope items to the two preferred vendors; and
- the inclusion of additional staff to allow for regular support and updating of the technologies in line with vendor expectations (ie, an 'evergreen' support approach), consistent with the assumed economic life of the assets in the option cases (which has been extended since the PADR).

We have adopted the average cost across the two responses to the updated RFI, which were much closer than the initial RFI responses.

We have also obtained an independent review by an industry expert (DGA Consulting), to further refine the market-based cost estimates. This has resulted in some changes to the costs of the options (including a downward adjustment to some items quoted by the vendors which were above DGA Consulting's expectations), as well as an adjustment to the timing of various elements within each option.

DGA Consulting supports the revised capex cost estimates as representing an efficient level of costs to deliver the scope of the proposed capability. [34] We have not added an additional contingency amount to the vendor's RFI cost (but have added a separate contingency to overall costings based on a P50 approach, as discussed further below).

We consider this to be the maximum refinement to the cost estimates possible at this stage (as well as the subsequent CPA stage), as vendors would not hold prices for the full duration of the relevant regulatory processes, nor agree to fixed prices for this length or complexity of project.

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 5.1). We have assumed indicative refresh costs for initiatives that reach the end of their economic life before the end of the assessment period in both the base case and option cases.

[34] DGA Consulting, *Independent Review of System Security Operability Costs – Option 2*, 30 September 2025, version 1.2, p 6 and DGA Consulting, *Independent Review of System Security Operability Costs – Option 1*, 30 September 2025, version 1.2, p 6.

## 4.1 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.[35]

Transgrid has investigated and considered a number of alternative options for improving our control systems and corporate office capabilities. As described in the PSCR and PADR, 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 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.

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

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

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. Each option also includes an increase in associated personnel levels, to augment the capability of the technology solutions.

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

- 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.

[35] AER, *Transgrid transmission determination – 1 July 2023 to 30 June 2028 – Attachment 5: Capital expenditure*, Final decision, p. 27.

### 4.1.2 The option specifications were refined in the PADR based on responses to the RFI

In sections 3.2 and 5.1 of the PADR, we discussed in detail how our option specifications were refined as part of the RFI process. We summarise this process here.

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

- it will be more efficient to leverage the SCADA/AEMS system that were commissioned in 2022;
- the existing software remains commonplace in the industry; and
- the software vendor has made available new features to support renewable resources.

We consider that our RFI process was comprehensive and allowed us to challenge the scope and costs of each of the options. Our RFI process involved four steps, ie:

- an initial RFI process which was similar to a request for tender, where we liaised with vendors to ensure alignment on scope and need, and formally assessment of technical and commercial terms;
- detailed one on one sessions with all four respondents, followed by a blind evaluation of these responses – we found two responses had not demonstrated adequate technical ability to meet the identified need;
- a process of Transgrid challenging and refining the scope of the options, incorporating lessons from responses to the initial RFI; and
- a revised RFI and evaluation, where Transgrid went back to the two technically feasible respondents with the refined scope of the options to obtain updated cost estimates.

The PADR presented cost estimates for the options that were substantially refined from those in the PSCR through a comprehensive market testing process. Between the PSCR and PADR, 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.

After receipt of the RFI responses, we challenged the scope of the options. In particular, we refined the technology initiatives included in Option 2 for the PADR assessment based on this market feedback, to lower the option costs and remove scope where successful delivery was not assured.

Through the responses to the initial RFI, valuable insights emerged from vendors' with 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).

Accordingly, Transgrid did not consider Option 3 was technically and commercially feasible at the PADR 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.

Since the PADR, we have obtained an independent assessment of our cost estimates from DGA Consulting and undertaken additional planning works. This has resulted in minor refinements to the scope of works for both Option 1 and Option 2, and general refinement of the quantum and timing of costs, based on industry expertise. The adjustment in timing has also led to minor changes in the benefit numbers. We went back to the two preferred vendors from the earlier RFI stage to request updated cost estimates for initiatives where the scope of works has been revised. DGA Consulting reviewed the resulting updated cost estimates and highlighted where it considered there to be a divergence from what it considered would be the reasonably expected opex and capex costs for that initiative. DGA Consulting has concluded that:

- our revised capex estimates represent an efficient level of costs to deliver the scope of the proposed capacity;[36]
- our revised opex estimates are reasonable; [37] and
- our revised refresh costs have reduced significantly but are still conservative.[38]

We discuss the specific refinements to the cost of the options that have been made in response to DGA Consulting's feedback in the remainder of this section. DGA Consulting's report has been released alongside this PACR.

### 4.1.3 Summary of the credible options assessed in this PACR

Figure 4.1 summarises the key characteristics of the credible options assessed in this PACR, in terms of the capabilities, associated technology and the extent of technical uplift. These options remain substantially unchanged since the PADR (with the exception of merging real-time asset health monitoring systems requirement with Data Management from the scope of Option 2 – discussed further below).[39] Some of these technologies relate to our corporate offices, including operational planning software which will be used be staff outside the control room, and elements of data management and sharing with asset management systems.

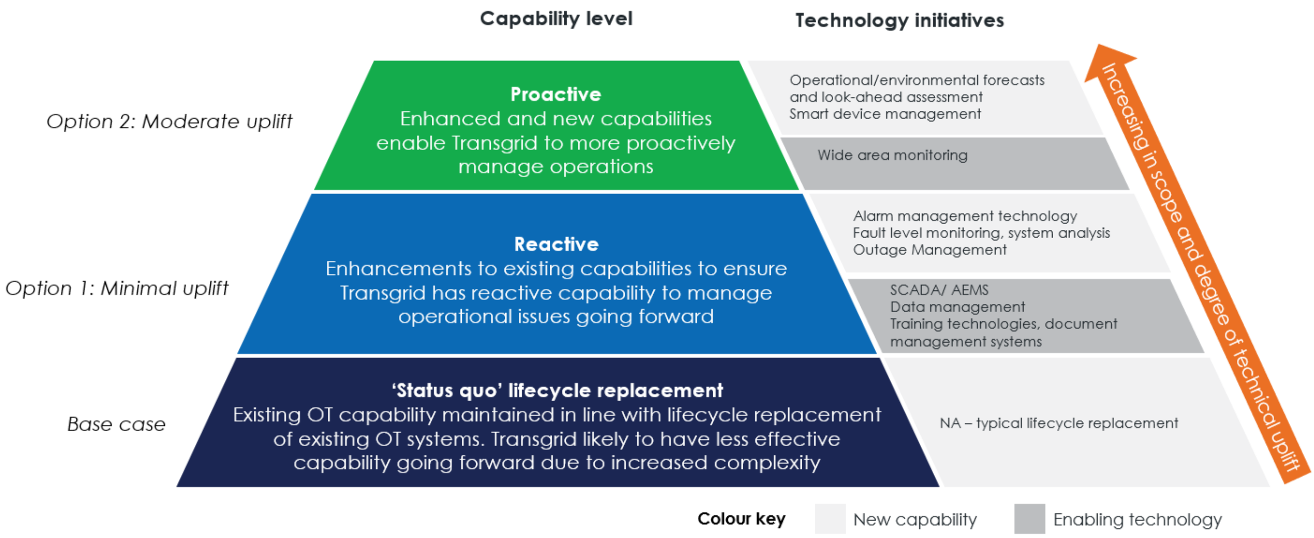
[36] DGA Consulting, *Independent Review of System Security Operability Costs – Option 2*, 30 September 2025, version 1.2, p 6 and DGA Consulting, *Independent Review of System Security Operability Costs – Option 1*, 30 September 2025, version 1.2, p 6.

[37] DGA Consulting, *Independent Review of System Security Operability Costs – Option 2*, 30 September 2025, version 1.2, p 57 and DGA Consulting, *Independent Review of System Security Operability Costs – Option 1*, 30 September 2025, version 1.2, p 56.

[38] DGA Consulting, *Independent Review of System Security Operability Costs – Option 2*, 30 September 2025, version 1.2, p 6 and DGA Consulting, *Independent Review of System Security Operability Costs – Option 1*, 30 September 2025, version 1.2, p 6.

[39] Some initiatives have been renamed since the PADR. In particular, the Energy Management System (EMS) is now referred to as the Advanced Energy Management System (AEMS) and the outage management system is now referred to as simply Outage Management. There have been no scope changes to either of these initiatives since the PADR. We have also corrected the labelling of the wide- area high speed monitoring to be wide area monitoring, noting that the removal of the high speed capability occurred as part of the Option 2 scope refinement prior to the PADR.

Figure 4.1: Option capability-technology pyramid for operational tools




Note: In addition to the technology initiatives identified above, operational planning and facilities 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 4.2 below, which demonstrates that the options are increasing both in scope and technical maturity. Since the PADR, we have identified that implementation of new visualisation tools, new training technologies and adopting an evergreen support approach will require some minor enabling facilities modifications, discussed further in section 4.3 below. We have therefore included a new scope item for 'facilities' in the table below.

Figure 4.2: Difference in extent of technical uplift between options

| Technology initiatives | Option 1 | Option 2 |
|---|---|---|
| Data management and network modelling systems | △ | O |
| SCADA/ Advanced Energy Management System (AEMS) | △ | O |
| Outage management – Inverter switching | △ | △ |
| Operational forecasts and look-ahead contingency assessment | | O |
| Wide Area Monitoring System (WAMS) | | O |
| Smart transmission device management | | O |
| Fault level and system parameter monitoring, power system analysis | △ | O |
| Alarm management, visualisation and situational awareness enhancements | △ | O |
| Training technologies and operational document management systems | O | O |
| Operational planning | △ | △* |
| Control Room facilities | △* | △* |

* Refined since PADR    △ Minimal    O 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 AEMS/SCADA systems, where that investment is a prerequisite to other capabilities such as alarm visualisation or wide area monitoring;
- data management and network modelling systems;
- training technologies and operational document management systems;
- operational planning functions; and
- the provision of minor facility changes to support new visualisation tools, new training technologies and the ever-green maintenance of solutions in line with vendor expectations.

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 monitoring without prior investments in our SCADA and AEMS systems (and associated facilities).

We have initiated and recently completed an alarm rationalisation project of $2.99 million ('alarm rationalisation early works') to help offset increases in alarm volumes arising from increases in alarm monitoring points associated with new connections.[40] This project was urgently required to handle the rapid increase in the number of alarms 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 completed this work ahead of the operational tools RIT-T and submission of the CPA, and have started to realise material benefits from these systems. We note that the alarm rationalisation project was delivered on time and on budget, and has reduced the need for immediate investment in alarm technologies that would otherwise be required.

We have continued to assess the alarm 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.

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 from this RIT-T process. 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 4.5.

## 4.2 Base case

Consistent with the RIT-T requirements, the PACR 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.:[41]

[40] The alarm 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.

[41] AER, *Regulatory investment test for transmission application guidelines – October 2023*, p 22.

*"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, including the alarm rationalisation project. 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 non-enhanced replacement of our SCADA/AEMS system by December 2030,[42] and additional operating expenditure for extended support of the existing SCADA/AEMS system from 2028 to its replacement in December 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:

- 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 $30 million of capital expenditure will be incurred under the base case in the two and a half years to December 2030, in order to upgrade our SCADA/AEMS system. This has been refined downwards from $40 million in the PADR assessment, and spread across two and a half years, based on DGA Consulting's recommended refinements to the estimated cost of the SCADA/AEMS system in the option cases, and the implementation timeframe.

The base case also includes an indicative refresh of the SCADA/AEMS system after seven years, consistent with the PADR. We note that the assumed asset life of OT assets in the option cases has been extended to 10 years, to align with the AER's post tax revenue model (PTRM). However this longer asset life requires the adoption of an evergreen approach to system support, which incurs an additional operating cost, and has not been assumed for the base case SCADA/AEMS system.

[42] Transgrid's SCADA/AEMS system will reach end of life in 2029, as it will be unable to handle additional network complexity in absence of operational tools investments. 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 December 2030. The cost of this life-cycle replacement is brought forward under the option cases.

We have also assumed that the hardware associated with the SCADA/AEMS system has an asset life of four years, resulting in the need to refresh the hardware part way through the seven-year period at a cost of $10 million. This is consistent with the latest advice we have obtained from DGA Consulting.

As this project is going through the CPA process, we present the expected capital expenditure by component by regulatory period for the base case in Table 6, which shows that all of the expenditure on the initial SCADA/AEMS system will occur in the next regulatory period.

Table 6: Breakdown of capital cost under the base case by regulatory period ($m $2024/25)

| Technology initiative | 2023-28 | 2028-33 | 2033-38 | Total |
|---|---|---|---|---|
| SCADA/AEMS system | 0.0 | 30.0 | 40.0 | 70.0 |

*Note: The initial expenditure is assumed to occur across two and a half years: $10 million in 2028/29, $15 million in 2029/30, and $5 million in 2030/31.*

### Operating expenditure

Under the base case, we have assumed that $250,000 per annum will be required to extend support for the existing SCADA/AEMS system across the two and a half years to December 2030. We have conservatively assumed no further operating expenditure in the base case.[43] 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 7. These base case operating costs reflect higher vendor support costs in the years prior to the initial replacement, which are avoided under the option cases.

Table 7: 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/AEMS system | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 0.3 | 0.1 | 0.0 |

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

[43] This is a conservative approach, as including additional cost in the base case would increase the net benefits of each option.

**Description of capabilities**

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 - inverter switching**:[44] augmenting our outage management capability to reduce the market impact of planned 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;[45] and
- **Fault level and system parameter monitoring and power system analysis**: partially deploying an AEMS 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/AEMS**: upgrading our SCADA/AEMS 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. weather data, forecasts, network model management and the asset management systems);
- **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 and maintain control room staff experience 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.

[44] We note that the expenditure proposed under this option represents an additional upgrade to our outage management capability (i.e., above that of lifecycle replacement), beyond expenditure included in Transgrid's 2023-28 regulatory determination.

[45] This also includes the alarm rationalisation project that has already occurred.

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

We have refined the cost and timing of initiatives based on an independent review by DGA Consulting. In particular, DGA Consulting recommended:

- allowing more time for procurement, and so pushing back the timing of delivery;
- aggregating the roll-out of initiatives into major releases, rather than having multiple discrete release dates; and
- refining the costs of several initiatives, to remove any duplication and improve the accuracy of the estimates (through, for example, recognising the likelihood of additional costs being incurred for customisations).

DGA Consulting also identified that our cost estimate for the SCADA/AEMS system and the training technologies at the PADR stage were higher than they expected, given the scope of items included.

Following DGA Consulting's findings, we went back to the two preferred vendors from the initial RFI process with a range of clarifying questions to confirm their cost estimates. We also made some minor revisions to the scope of the options, following additional planning works. This process resulted in an update to the vendor costings.

We subsequently also applied a downwards adjustment (of $3.2 million) to the average vendor costing for the SCADA/AEMS system and the fault level and system parameter monitoring, to bring them within the range that DGA Consulting advised us it considered reasonable. We expect that this adjusted cost better reflects the likely price we could obtain for these initiatives through a competitive tender process.

Otherwise, we have adopted the average vendor costs from the updated RFI estimates, noting that the updated vendor costings were relatively close to each other and in line with DGA Consulting's independent view of the reasonable costs of these initiatives.

Since the PADR, we have identified that we will require some minor facilities modifications. This includes new operator consoles in the control room, and accommodating the new visualisation functionality and training tools. It also includes additional desks for staff associated with the 'evergreen' system support approach underpinning the extended asset life assumptions (see below). These modifications are required to enable the Option 1 benefits, and so have been included in the PACR assessment. These incremental facilities modifications are separate from, and consistent with, longer term, more extensive changes to control room infrastructure, which Transgrid expects to progress as a separate need within the 2028-2033 regulatory period. We have captured all facilities costs in a separate line item in Table 9.1 8 below.

Since the PADR, we have also revised our approach to reporting the internal resources required for options 1 and 2. At the PADR stage, these resources were spread out across the relevant initiatives each year in alignment with the vendor's program. However, at the PACR stage, we have:

- mapped these costs to a particular initiative where they are directly attributable to that initiative; and
- split these out into program implementation costs where they are not directly attributable to a particular initiative, e.g., because they relate to more than one initiative or general program implementation.

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

**Capital expenditure**

We estimate that the capital expenditure for Option 1 will be $122.7 million – see Table 8Table E.1 below.

Table 8: Breakdown of Option 1's estimated capital expenditure ($m $2024/25)

| Technology initiative | Estimated capital expenditure |
|---|---:|
| Outage management | 1.5 |
| Alarm management, visualisation and situation awareness enhancement | 26.4 |
| Fault level and system parameter monitoring and power system analysis capability | 3.4 |
| SCADA/AEMS system | 30.5 |
| Facilities | 5.2 |
| Data management and network modelling system | 21.1 |
| Training technologies, operational document management system and operational planning systems | 13.9 |
| CPA submission | 6.2 |
| Program implementation | 14.5 |
| **Total** | **122.7** |

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 4 and 10 years,[46] we have assumed indicative refresh costs for initiatives that reach the end of their economic life before the end of the assessment period in both the base case and option cases.

There is significant uncertainty regarding the estimate for future refresh costs. At the PADR stage, we conservatively assumed equal costs of replacement in real terms at the end of the economic life of the assets. DGA Consulting identified that the refresh costs should be lower than the initial costs, and there should be a shorter project duration for a refresh given the step change in capability delivered from each option. Accordingly, we have adopted an indicative discount of 20 per cent of the initial costs in estimating the refresh costs. The exception is the incremental facilities costs, where we have continued to assume that future refresh costs will be the same as the initial cost, as DGA Consulting's advice did not cover these types of costs. We have applied an indicative proportional program implementation cost for refreshing initiatives, which is based on the proportion of program implementation costs to initial costs, noting that these also attract a 20 per cent discount. We summarise the indicative refresh costs for Option 1 in Table 9 below.

[46] These asset lives have been refined since the PADR to align with the economic lives of OT and IT assets in the AER's PTRM. A 10 year asset life for OT assets can be achieved with the identified uplift in operating expenditure for evergreen support, discussed as part of the opex for Option 1.

Table 9: Breakdown of Option 1's assumed indicative refresh cost ($m $2024/25)

| Technology initiative | Indicative refresh cost |
|---|---|
| Outage management | 2.4* |
| SCADA/AEMS system | 22.2 |
| Facilities | 5.2 |
| Data management and network modelling system | 33.7* |
| Training technologies, operational document management system and operational planning systems | 11.7* |
| Project implementation | 8.5 |
| **Total** | **83.7** |

**The indicative refresh costs are higher than initial expenditure for some technologies because one or more components only have a 4 year asset life, and so are assumed to be replaced twice during the assessment period.*

*The indicative refresh costs are zero for some initiatives (ie, those that do not appear in Table 9) because the initial expenditure for those technologies is assumed to have a 10 year asset life and occurs with less than 10 years left in the assessment period. We explain in section 5.1 that 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.*

We present the estimated capital expenditure across the whole 15-year assessment period by initiative and by regulatory period in Table 10 below. We note that the initial capital expenditure is incurred from 2024/25 to 2029/30, which means that approximately $36.7 million of the $122.7 million in initial expenditure under Option 1 would be incurred in the 2028-33 regulatory period.

Table 10: 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 | 1.5 | 1.2 | 1.2 | 3.8 |
| Alarm management, visualisation and situation awareness enhancement | 14.2 | 12.2 | 0.0 | 26.4 |
| Fault level and system parameter monitoring and power system analysis capability | 0.0 | 3.4 | 0.0 | 3.4 |
| SCADA/AEMS system | 21.0 | 15.1 | 16.7 | 52.7 |
| Facilities | 4.8 | 0.5 | 5.2 | 10.5 |
| Data management and network modelling system | 21.1 | 16.9 | 16.9 | 54.8 |

| | | | | |
|---|---|---|---|---|
| Training technologies, operational document management system and operational planning systems | 11.1 | 8.7 | 5.8 | 25.6 |
| CPA submission | 6.2 | 0.0 | 0.0 | 6.2 |
| Program implementation | 6.1 | 11.6 | 5.2 | 22.9 |
| **Total** | **85.9** | **69.5** | **50.9** | **206.3** |

Table 11 shows the profile of estimated capital expenditure for Option 1 for the current regulatory period.

Table 11: Annual breakdown of Option 1's estimated capital expenditure for the current regulatory period. ($m $2024/25)

| | 2024/25 | 2025/26 | 2026/27 | 2027/28 |
|---|---|---|---|---|
| Capital expenditure | 8.2 | 1.7 | 28.9 | 47.1 |

**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/AEMS system will cost $1.0 million per year;
- data network hardware support will cost $1.0 million per year;
- data modelling and network management will cost $0.6 million per year; and
- the operational planning system and training LMS will cost $0.4 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 maintain and support the systems. Specifically, we have estimated that an additional 12 full time equivalent (FTE) staff[47] will be required to maintain and support new technologies by 2030, ie:

- one additional full time equivalent (FTE) to maintain the training simulator software and configurations;
- four additional FTEs to maintain SCADA/AEMS modules to vendors' recommended versions (under the evergreen system support approach which underpins the longer assumed asset life), maintain and update alarm handling business rules and maintain and update test automation tools;
- one additional FTE for network model management; and

[47] 1 FTE represents one full-time worker's standard workload.

- 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 also expect that approximately $0.4 million per year in 2028/29 and 2029/30 only will be required for training attendance during the OT uplift program.

We present the expected annual operating expenditure associated with Option 1 between 2025/26 and 2031/32 in Table 12. These operating costs follow a similar trend throughout the remainder of the assessment period (ie, the total operating costs in 2031/32 will be the same each year through to the end of the assessment period).

Table 12: Annual breakdown of Option 1's expected operating cost ($m $2024/25)

| | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 |
|---|---|---|---|---|---|---|---|
| SCADA/AEMS system | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 1.0 | 1.0 |
| Data modelling and network management | 0.0 | 0.0 | 0.0 | 0.6 | 0.6 | 0.6 | 0.6 |
| Operational planning system and training LMS | 0.0 | 0.0 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 |
| Hardware support | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 1.0 | 1.0 |
| Training attendance | 0.0 | 0.0 | 0.0 | 0.4 | 0.4 | 0.0 | 0.0 |
| Internal staffing – SCADA/AEMS system | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 1.0 | 1.0 |
| Internal staffing – training simulator maintenance | 0.0 | 0.0 | 0.0 | 0.1 | 0.3 | 0.3 | 0.3 |
| Internal staffing – network model management | 0.0 | 0.0 | 0.0 | 0.3 | 0.3 | 0.3 | 0.3 |
| Internal staffing – planning operations | 0.0 | 0.0 | 0.5 | 0.8 | 1.3 | 1.5 | 1.5 |
| Total operating expenditure | **0.0** | **0.0** | **0.8** | **2.5** | **4.1** | **6.0** | **6.0** |

## 4.4 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.

**Description of capabilities**

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:
  - 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 transmission outages.

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:

- **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 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.

We have not included proactive uplifts to outage management in Option 2, because Transgrid's SCADA/AEMS outage management vendor does not currently have safe switching execution software 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 capabilities between Option 1 and Option 2.

In addition to the general refinements based on our review process with DGA Consulting that we discuss in section 4.3 above in relation to Option 1 (which also apply to Option 2), our review process identified optimised delivery by merging the real-time asset health system initiative with the data management initiative. We have now removed real-time asset health system as a standalone initiative.

Following DGA Consulting's findings, we went back to the two preferred vendors from the initial RFI process with a range of clarifying questions to confirm their cost estimates for Option 2. We have generally adopted the average vendor costs from the updated RFI estimates.  The exception is for the costs associated with AEMS/SCADA, fault level and system parameter monitoring, smart transmission device management, wide area monitoring and forecasting, where DGA Consulting's conclusion was that the average cost was above what they would expect based on their experience. We have therefore applied an adjustment to decrease the cost of these components of Option 2 by $12.5 million (in total), compared to the average vendor cost. We expect that this better reflects the likely price we could obtain through a competitive tender process.

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 be otherwise be incurred by building Option 1 now and Option 2 at a later date.

As with Option 1, we have extended the timing for delivery of Option 2, based on advice from DGA Consulting. The scope of works for this option is now expected to be carried out between 2025 and 2031, with the expected in-service date for the technology initiatives of this option being rolled out in stages until May 2031.

**Capital expenditure**

We estimate that the capital expenditure for Option 2 is $167.1 million. We present a breakdown of this estimated capital expenditure in Table 13 below.

Table 13: Breakdown of Option 2's estimated capital expenditure ($m $2024/25)

| Technology initiative | Estimated capital expenditure |
|---|---|
| Outage management | 1.5 |
| Alarm management, visualisation and situation awareness enhancement | 35.3 |
| Fault level and system parameter monitoring and power system analysis capability | 7.2 |
| SCADA/AEMS system | 34.7 |
| Facilities | 5.3 |
| Data management and network modelling system | 28.1 |
| Training technologies, operational document management system and operational planning systems | 13.9 |
| Operational forecasts and look-ahead contingency assessment | 4.2 |
| Wide area monitoring | 6.7 |
| Smart Transmission Device Management | 4.0 |
| CPA submission | 6.2 |
| Program implementation | 20.0 |
| **Total** | **167.1** |

As discussed in section 4.3, Transgrid has assumed indicative refresh costs for each of the initiatives at the end of their economic life in both the base case and option cases. Transgrid has assumed a 20 per cent reduction in the costs of replacement in real terms at the end of the economic life of the assets for all initiatives, with the exception of the refresh of the incremental facilities investment, where we have continued to assume that the refresh cost will be the same as the initial cost in real terms. We have applied an indicative proportional program implementation cost for refreshing initiatives, which is based on the proportion of program implementation costs to initial costs, noting that these also attract a 20 per cent discount. We summarise the indicative refresh costs for Option 2 in Table 14 below.

Table 14: Breakdown of Option 2's assumed indicative refresh cost ($m $2024/25)

| Technology initiative | Indicative refresh cost |
|---|---|
| Outage management | 2.4* |
| SCADA/AEMS system | 22.2 |
| Facilities | 5.3 |
| Data management and network modelling system | 45.0* |
| Training technologies, operational document management system and operational planning systems | 11.7* |
| Program implementation | 9.9 |
| **Total** | **96.4** |

**The indicative refresh costs are higher than initial expenditure for some technologies because one or more components only have a 4 year asset life, and so are assumed to be replaced twice during the assessment period.*

*The indicative refresh costs are zero for some initiatives (ie, those that do not appear in Table 14) because the initial expenditure for those technologies is assumed to have a 10 year asset life and occurs with less than 10 years left in the assessment period. We explain in section 5.1 that 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.*

We present the estimated capital expenditure across the entire 15-year assessment period by initiative by regulatory period in Table 15 below. We note that the initial capital expenditure is incurred from 2024/25 to 2030/31 under this option, which means that approximately $84.8 million of the $167.1 million in initial capital expenditure will be incurred in the 2028-33 regulatory period.

Table 15: 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 | 1.5 | 1.2 | 1.2 | **3.8** |
| Alarm management, visualisation and situation awareness enhancement | 10.1 | 25.2 | 0.0 | **35.3** |
| Fault level and system parameter monitoring and power system analysis capability | 0.0 | 7.2 | 0.0 | **7.2** |
| SCADA/AEMS system | 19.9 | 25.9 | 11.1 | **56.9** |
| Facilities | 4.8 | 0.5 | 5.3 | **10.6** |
| Data management and network modelling system | 19.2 | 31.4 | 22.5 | **73.1** |
| Training technologies, operational document management system and operational planning systems | 11.1 | 8.7 | 5.8 | **25.6** |

| | | | | |
|---|---|---|---|---|
| Operational forecasts and look-ahead contingency assessment | 0.0 | 4.2 | 0.0 | **4.2** |
| Wide area monitoring | 0.0 | 6.7 | 0.0 | **6.7** |
| Smart transmission device management | 0.0 | 4.0 | 0.0 | **4.0** |
| CPA submission | 6.2 | 0.0 | 0.0 | **6.2** |
| Program implementation | 9.6 | 15.0 | 5.2 | **29.9** |
| **Total** | **82.3** | **130.0** | **51.2** | **263.5** |

Table 16 shows the profile of estimated capital expenditure for Option 2 for the current regulatory period.

Table 16: Annual breakdown of Option 2's estimated capital expenditure for the current regulatory period ($m $2024/25)

| | 2024/25 | 2025/26 | 2026/27 | 2027/28 |
|---|---|---|---|---|
| Capital expenditure | 8.2 | 2.2 | 24.3 | 47.6 |

**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 SCADA/AEMS system will cost $1.0 million per year (which the same as Option 1);
- operating costs for data modelling and network management, the operational planning system, training LMS and hardware maintenance will cost $2.0 million per year in total, (the same as Option 1);
- operating costs for wide area monitoring will be $0.6 million per year; and
- additional software/licensing for alarm management technologies will be required that costs $0.8 million per year.

We note that individual categories of opex above have changed since the PADR based on a more granular identification of activities following DGA Consulting's review (eg, an increase in software requirements for wide area monitoring). Estimated opex has increased by approximately $0.9 million in total since the PADR.

In addition to the 12 FTEs that we expect will be required to achieve reactive capabilities under Option 1, we estimate that three 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 also expect that approximately $0.6 million per year in 2028/29 and 2030/31 only will be required for training attendance during the OT uplift program.

We present expected annual operating expenditure associated with Option 2 in Table 17 below. These operating costs follow a similar trend throughout the remainder of the assessment period (ie, the total operating costs in 2031/32 will be the same each year through to the end of the assessment period).

Table 17: Annual breakdown of Option 2's expected operating cost ($m $2024/25)

| | 2025/26 | 2026/27 | 2027/28 | 2028/29 | 2029/30 | 2030/31 | 2031/32 |
|---|---|---|---|---|---|---|---|
| SCADA/AEMS system | 0.0 | 0.0 | 0.0 | 0.3 | 1.0 | 1.0 | 1.0 |
| Data modelling and network management | 0.0 | 0.0 | 0.0 | 0.6 | 0.6 | 0.6 | 0.6 |
| Operational planning system and training LMS | 0.0 | 0.0 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 |
| Hardware support | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 1.0 | 1.0 |
| Wide area monitoring | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 0.6 |
| Alarm management technologies – software/licensing | 0.0 | 0.0 | 0.0 | 0.0 | 0.8 | 0.8 | 0.8 |
| Internal staffing – SCADA/AEMS system | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 1.3 | 1.3 |
| Internal staffing – training simulator maintenance | 0.0 | 0.0 | 0.0 | 0.1 | 0.3 | 0.3 | 0.3 |
| Internal staffing – network model management | 0.0 | 0.0 | 0.0 | 0.3 | 0.3 | 0.3 | 0.3 |
| Internal staffing – planning operations | 0.0 | 0.0 | 0.5 | 0.8 | 1.3 | 1.5 | 1.5 |
| Internal staffing – control room/forecasting[48] | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 0.5 |
| Total operating expenditure | **0.0** | **0.0** | **0.8** | **2.9** | **5.3** | **8.0** | **8.2** |

[48] Note that this excludes any additional control room operators that may be required as a consequence of network growth, which are outside the scope of the investments being considered in this RIT-T.

## 4.5 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. There were no submissions to the PADR by non-network proponents. Table 18 summarises the reasons the following options were not progressed further.

Table 18: Options considered but not progressed

| Description | Reason(s) for not progressing |
|---|---|
| Option 3: Predictive capability. Option 2, plus artificial intelligence, machine learning and advanced wide areas monitoring systems (ie, WAMSPAC) to enable predictive and automated operations throughout key parts of Transgrid's operational control systems and operational planning technology stack | This option was considered under the PSCR, but was no longer considered commercially feasible at the PADR stage, given costs that were significantly higher than originally expected obtained from vendor responses to the RFI and deliverability challenges in the given timeframe.<br>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. |
| A significant uplift in staffing levels and training, without the introduction of new technology and tools. | 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. This would ultimately be expected to result in poorer quality outcomes and not negate the need for investment in new technologies. |
| A fully automated technology solution that could be implemented without an uplift in human resourcing. | 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. |
| Impose additional operating requirements on generators (potential non-network solution) | 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.<br>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. |

| | |
|---|---|
| Other non-network solutions | 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.<br>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.<br>Further, the RFI process conducted with potential vendors prior to the PADR confirmed that technologies are to be hosted on-premises to meet our security and operating license data classification requirements. It follows that any non-network solution that involve hosting of technologies off-premises would not be a credible option. |

# 5 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 6 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 7 sets out the results of our net market benefits assessment.

## 5.1 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 four and ten 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.

We have updated the asset lives assumed in this PACR compared to the earlier PADR, to align with the OT and IT asset life assumptions in the AER's PTRM. In particular:

- The assumed life of OT assets has been extended from 7 years to 10 years; and
- The assumed life of IT assets has been shortened from 5 years to 4 years.

These changes in asset lives have implications for the timing of refresh costs for each initiative, and in particular whether a refresh of the initiative is required within the assessment period.

For the specific OT assets included in the options in this RIT-T, the extension of the functional asset life to 10 years requires the adoption of an evergreen system support approach, which will require additional FTEs to implement. We have included these additional operating costs as part of the scope of each option. We have also undertaken a sensitivity assessment which adopts the earlier 7 year asset life assumption for OT assets, to confirm that this change in assumption is not material to the outcome of this RIT-T.

We have adopted a real, pre-tax discount rate of 7 per cent as the central assumption for the NPV analysis presented in the PACR, consistent with AEMO's most recent final Input Assumptions and Scenarios Report (IASR), which was published on 31 July 2025.[49] 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

[49] AEMO, *2025 Inputs, Assumptions and Scenarios Report*, Final report, July 2025, p. 159.

bound. We have tested the sensitivity of the results to a lower bound discount rate of 4.18 per cent,[50] as well as an upper bound discount rate of 10.0 per cent (i.e., the upper bound in the latest IASR).[51]

## 5.2 Approach to estimating option costs

As outlined in section 4.1.2, we have undertaken comprehensive market testing with vendors to refine the specifications and obtain market-based cost estimates for the options assessed in this PACR. We also obtained an independent assessment of costs and schedule of work from DGA Consulting, and went back to technically compliant vendors with a range of clarifying questions, and obtained updated costings.

**Capital cost estimates have decreased since the PADR, including due to lower refresh costs**

Initial project capital costs have remained steady for Option 1 and slightly decreased for Option 2 since the PADR.

Specifically, in real terms, compared to the PADR, the initial project cost estimates in this PACR are 0.3 per cent lower for Option 1 and 6.8 per cent lower for Option 2. For both options:

- there has been a reduction in the SCADA/AEMS system and fault level and system parameter monitoring costs, as an outturn of the review by DGA Consulting, and a deferral of project costs for many initiatives to a later year, to reflect more realistic implementation timeframes (which results in a decrease in costs in real terms);
- there has been a removal of year 1 support costs that were incorrectly embedded within the vendors' project costs;
- there has been an increase in scope with the addition of essential minor facility modifications, customisations and test automation capabilities following further assessment with DGA Consulting across the program of initiatives.

For Option 2, we have also refined the costs of some initiatives, in particular the alarm management, visualisation and situation awareness enhancement, wide area monitoring, smart transmission device, operational forecasts and look ahead contingency, which has resulted in an overall decrease in costs.

Refresh costs have fallen materially for both options, leading to an overall decrease in the capital costs assumed over the assessment period for both options since the PADR. In real terms, compared to the PADR, the indicative refresh costs in this PACR are 41.3 per cent lower for Option 1 and 53.0 per cent lower for Option 2. These significant reductions are principally driven by an extension of the asset lives for OT assets from 7 years in the PADR to 10 years in the PACR (to align with the asset lives used in the AER's PTRM model), which reduces the number of initiatives that need refreshing during the assessment period. Another material driver is the 20 per cent discount on non-facilities refreshes, which we discuss in section 4.3.

DGA Consulting has concluded that:

[50] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (Directlink) as of the date of this analysis, see: AER, *Directlink – 2025-30 – Final decision – PTRM*, April 2025, WACC sheet.
[51] AEMO, *2025 Inputs, Assumptions and Scenarios Report*, Final Report, July 2023, p. 159.

- the revised capex estimates represent an efficient level of costs to deliver the scope of the proposed capacity;[52]
- the revised opex estimates are reasonable; [53] and
- the revised refresh costs have reduced significantly but are still conservative.[54]

**Approach to estimating capital costs**

We have generally adopted the average of the technically compliant vendor cost estimates for each option, following the second RFI that was conducted with vendors following the PADR. The exceptions are the SCADA/AEMS system and fault level and system parameter monitoring cost estimates (for both Options 1 and 2) and the wide area monitoring, smart transmission device management and forecasting capability costs (Option 2), where we have adjusted the average vendor costs to align with DGA Consulting's independent cost estimates. We discuss this further in section 4.3. We have not included an additional contingency amount as part of the vendor cost estimate (but have instead considered the risks associated with vendor cost outcomes in arriving at our P50 cost estimate, discussed further below).

We note that the two options assessed reflect a programme of works, for which Transgrid currently expects it may contract with multiple vendors within a System Integrator delivery model 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.

Transgrid has also developed an estimate of the internal resources required for Options 1 and 2. This has been based on responses to the second RFI, and the overall option scope and program schedule, drawing on costing experience from previous similar projects, using a bottom-up approach. These resources have been mapped to each initiative being delivered under the vendor's program where they can be directly attributed to that initiative. Where they cannot be directly attributed to an initiative (e.g., because they relate to multiple initiatives or general program implementation costs), we have separated these costs out as program implementation costs. These program implementation costs extend from project initiation to close-out and are reported in a separate line item throughout the costs section.

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 this annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.

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52 DGA Consulting, *Independent Review of System Security Operability Costs – Option 2*, 30 September 2025, version 1.2, p 6 and DGA Consulting, *Independent Review of System Security Operability Costs – Option 1*, 30 September 2025, version 1.2, p 6.

53 DGA Consulting, *Independent Review of System Security Operability Costs – Option 2*, 30 September 2025, version 1.2, p 57 and DGA Consulting*, Independent Review of System Security Operability Costs – Option 1*, 30 September 2025, version 1.2, p 56.

54 DGA Consulting, *Independent Review of System Security Operability Costs – Option 2*, 30 September 2025, version 1.2, p 6 and DGA Consulting*, Independent Review of System Security Operability Costs – Option 1*, 30 September 2025, version 1.2, p 6.

Overall, the cost estimates are P50 using Transgrid's standard process to determine P50 cost estimates, with the risks and cost impacts been refined in some areas since the PADR to reflect independent feedback from DGA Consulting. In particular, the feedback has resulted in:

- a refinement in the methodology by considering risks at an individual project level rather than for the program as a whole;
- focusing on a subset of high value risks and reducing the number of risks considered in the analysis – the number of risks considered has gone from 13 to seven (five at project level and two at the program level). These risks are considered to be beyond Transgrid's control; and
- some changes to the application of likelihood and consequence.

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 using a bottom up approach that actual costs will be within -10 to +25 per cent of the central capital cost estimate presented in this PACR. While we have not explicitly applied the AACE cost estimate classification system, we note that an accuracy range between -20 to +30 per cent for cost estimates is consistent with industry best practice and aligns with the accuracy range of a 'Class 3' estimate, as defined in the AACE classification system. The cost estimates in this PACR are therefor at a greater accuracy range than AACE Class 3.

**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 reviewed by DGA Consulting. 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.

## 5.3 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 6 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.

### 5.3.1 Changes in involuntary load curtailment

As outlined in section 4.2, 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,[55] Transgrid has adopted VCR estimates that are based on the latest estimates published by the AER.[56]

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,[57] inflated to 2024/25 dollars using Consumer price index (CPI) data.[58]

### 5.3.2 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.

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 6.4.3.

### 5.3.3 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 2023 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.[59] We summarise our methodology to calculating avoided greenhouse gas emissions in further detail in section 6.4.3.

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[55] AER, Regulatory investment test for transmission, Application guidelines, November 2024, p 25.
[56] AER, Values of customer reliability, Final report, December 2024.
[57] AER, Values of customer reliability, Final report, December 2024, p 62.
[58] 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.
[59] AER, Valuing emissions reduction – AER guidance and explanatory statement, May 2024, pp 5-6.

### 5.3.4 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.

### 5.3.5 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 19 are material for this RIT-T assessment for the reasons provided.

Table 19: 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. |
| Option value | While the options can be scaled up over time (e.g., from Option 1 to Option 2), the scenario analysis in the PACR 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. |

## 5.4 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 PACR assessment. Specifically, we have adopted different forecast renewable generator growth, generation mix and retirement dates based on the 2024 ISP Progressive Change, Step Change and Green Energy Exports scenarios. We have weighted the market benefit outcomes under the three scenarios based on the ISP scenario weightings.

Table 20 below summarises the scenarios we have adopted to assess options in this RIT-T.

Table 20: Summary of scenarios

| ISP scenario (demand growth and renewable generation projections) | Progressive Change | Step Change | Green Energy Exports |
|---|---|---|---|
| *Scenario weighting* | *42%* | *43%* | *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.

We have adopted the scenarios in the 2024 ISP because we used data and assumptions from the 2023 IASR and the 2024 ISP for our analysis, as reflecting the most up to date, consistent set of assumptions at the time that the assessment for this PACR was undertaken. We explain in section 6.1 below that we do not expect adopting the 2025 IASR (including the updated parameters in the most recent ISP scenarios) would materially affect the benefit calculation.

## 5.5 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.

### 5.5.1 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 PACR 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;

- shorter economic lives; and
- optimal timing analysis, based on a one year delay to the rollout.

We discuss the rationale behind these sensitivities and the results in section 7.4 below.

### 5.5.2 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 7.5 below.

# 6 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 note that we have not made any changes to our methodology for calculating benefits since the PADR, aside from updating the timing of benefits to match the revised timing of initiatives following the DGA Consulting review.

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 7. Detailed assumptions used to calculate the benefits are set out in Appendix B.

## 6.1 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 is 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 have used the 2023 IASR and the 2024 ISP, as reflecting the most up to date, consistent set of assumptions at the time that the assessment for this PACR was undertaken.

We do not expect that updating our benefit inputs to incorporate the 2025 IASR published on 31st July 2025 would make a material difference to the benefit calculations (and we consider the effort to do so would be disproportionate to the likely change in net benefits and the outcome of this RIT-T). We have undertaken a high-level comparison of IASR inputs used in our quantification, ie, fuel costs, variable operating maintenance (VOM), emissions intensity of generation and marginal loss factors. We found that:

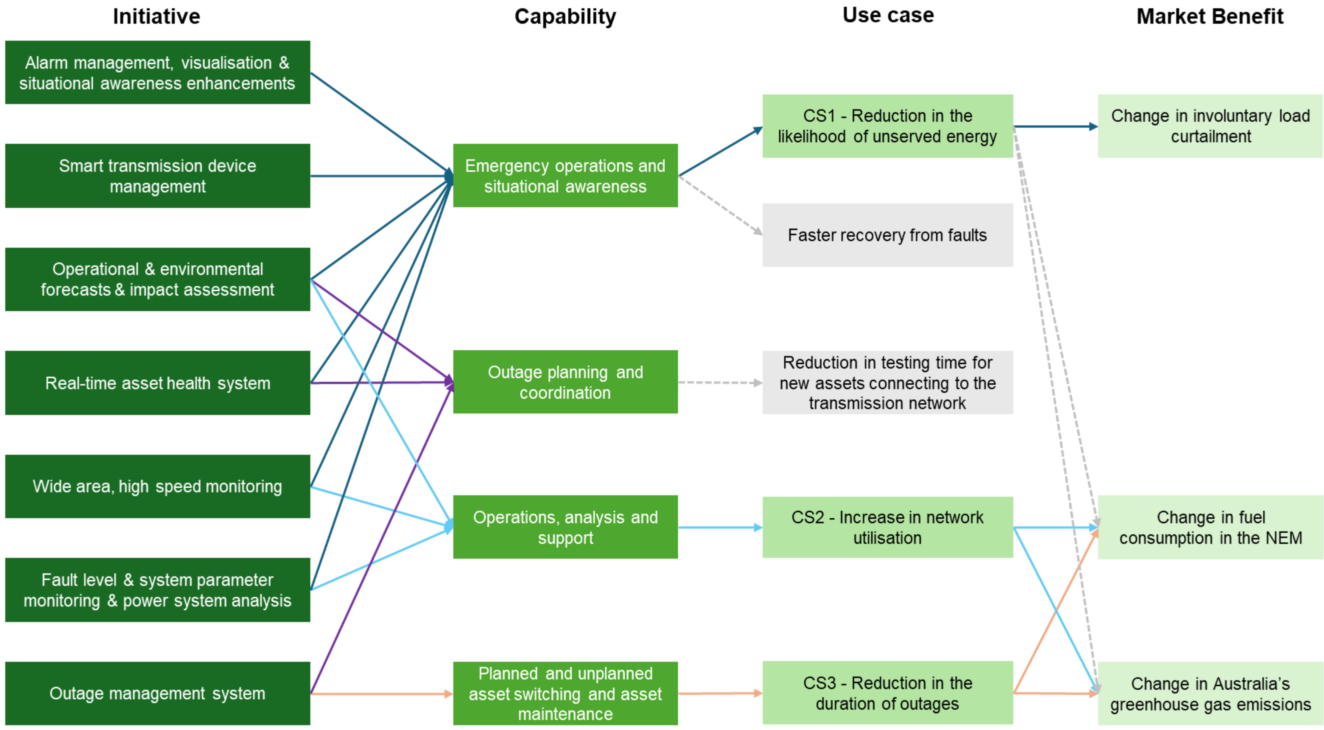
- fuel costs and VOM have increased by slightly more than CPI for the majority of relevant generators, such that updating the IASR inputs are likely to result in a minor increase in benefits; and
- changes to emissions intensity of generation and marginal loss factors were minimal, and are unlikely to materially affect our benefit calculations.

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 6.1 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 6.1: 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). CS1, CS2 and CS3 refer to the three use cases quantified in this RIT-T (ie, Case Study 1, Case Study 2 and Case Study 3), which are described further in this section.

## 6.2 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, by moving from static limits on inverter-based generation to dynamically changing inverter limits; and
- **Case study 3**: reduced duration of outages from having improved outage management.

We summarise these three case studies in Table 21 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, as quantifying the benefits from the above three use cases was sufficient to demonstrate positive net market benefits and identify a preferred option.

Table 21: 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 | 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 | 6.3 |

| ID | Case study | Benefit driver | Section |
|---|---|---|---|
| | | making, which together reduces the cognitive load on control room operators in a complex operating environment.<br>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. | |
| Case study 2 | Increase in network utilisation | Alleviating pre-emptive and conservative static limits on inverter-based generation through real-time and near-term network analysis replacing static scenario measurements. This facilitates less conservative network asset utilisation by enabling dynamically changing inverter limits and providing the ability to operate closer to the power system's technical envelope. | 6.4 |
| 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 | 6.5 |

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.

## 6.3 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.

### 6.3.1 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 6.2, 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 6.2: 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.

### 6.3.2 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.

In line with our revisions to the timing of initiatives in this PACR, we have updated the timing of capability improvements (and so benefits). Specifically, we have aggregated many of the initiatives into one major release in FY2030 for Option 1, and two major releases in FY2030 and FY2031 for Option 2. The two options provide different levels of capability improvements, as shown in Table 22. We expect wide area monitoring to deliver additional benefits for case study 2 beyond those quantified in our analysis. We have not quantified these benefits in this PACR.

Table 22: 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 1/2, FY 2025 |
| | Ability to manage versions of alarm/SCADA point configurations, import and export alarm configurations | Option 1/2, FY 2027 |
| | Uplift in capability of AEMS/SCADA to import configurations, to report on alarm performance, create single parent alarm and include view on technical envelope boundaries | Option 1, FY 2030<br>Option 2, 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 2029 |
| Operational forecasts and look ahead contingency analysis | Uplift to AEMS to provide persistent access to AEMO forecast data, establishing a forecasting system integrated with the AEMS and uplift to AEMS contingency Analysis tool for day-ahead decision support. | Option 2, FY 2031 |
| Fault level & system parameter monitoring & power system analysis | Uplift to improve accuracy of calculations application on an AEMS for impedances, mutual coupling data, ratings, and fault definition cases | Option 1, FY 2030<br>Option 2, FY 2029 |
| | AEMS Fault Level Calculation (FLC) application to enable real-time FLC execution, with updated modelling parameters | Option 1, FY 2030<br>Option 2, FY 2029 |
| | Uplift to AEMS capability, incorporating fault level calculation, harmonics and EMT technical envelope data | Option 2, FY 2029 |
| | Implementation of the AEMS time domain capabilities | Option 2, FY 2029 |
| Smart Transmission Device | Uplift capability of AEMS network applications and to receive SCADA points | Option 2, FY 2031 |

### 6.3.3 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 × estimated size of the event in that year (in MWh) × VCR ($/MWh).

We summarise our key assumptions and calculations in Table 23 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 scenario.

Table 23: 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<br>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.[60] | Transgrid's historical alarm data<br>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. |
| | 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 |

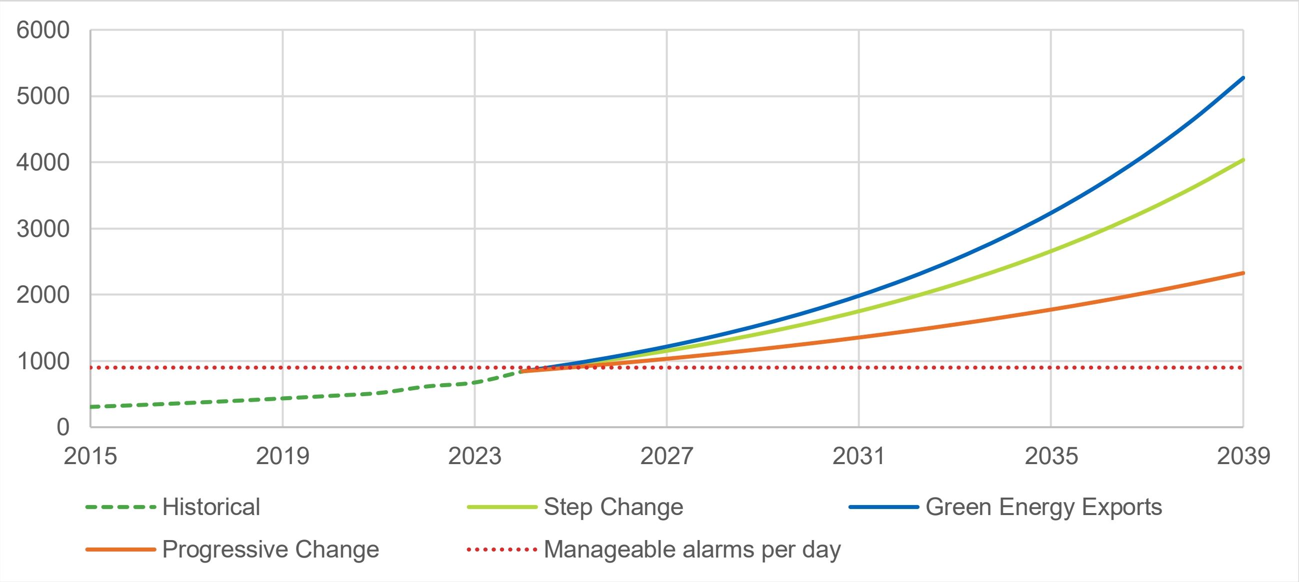
[60] This assumption is explained in Appendix B.

| | | |
|---|---|---|
| Benefits | Calculated as reduction in number of 'EUE events' in that year × estimated size of event in that year × the value of customer reliability (VCR) of $31,604/MWh ($2025) | AER data on VCR in NSW – December 2024, adjusted to 2025 using Australian Bureau of Statistics (ABS) CPI data and Reserve Bank of Australia (RBA) forecast CPI. |
| | Option 1 will lead to a 46 per cent reduction in alarm volumes by 2029<br>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 6.3 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 6.3: 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.

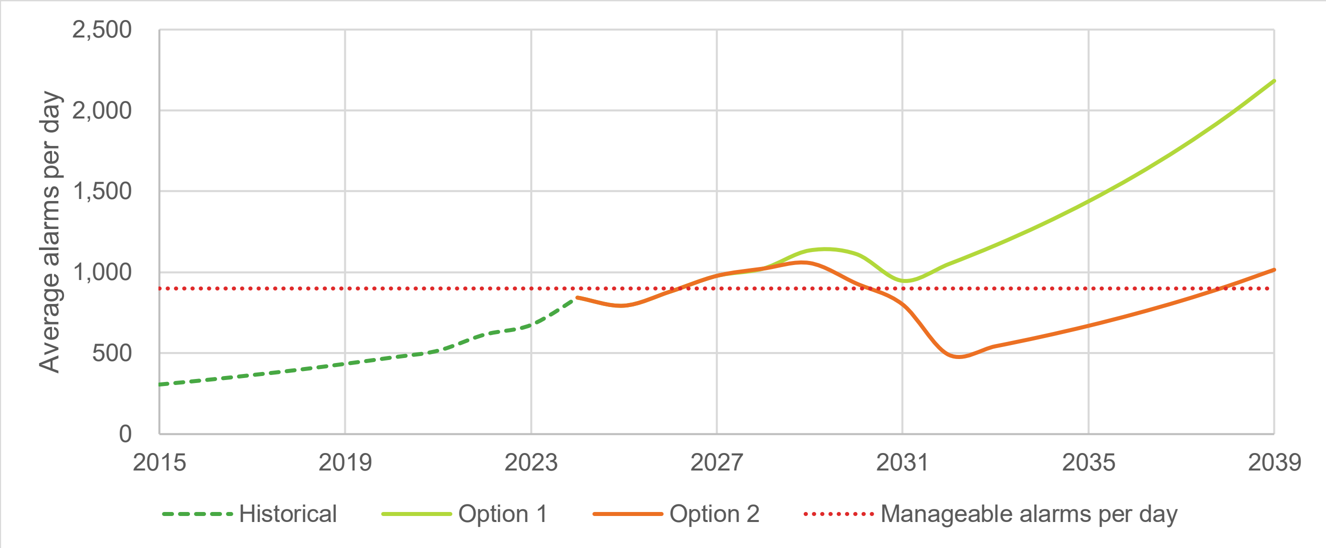
Table 24 below sets out the assumed reduction in alarm numbers by option. The assumed reduction is based on our assessment of capability gained and potential improvement in the control room's ability to manage alarms under each option. Alarm reductions are based on detailed analysis, practical experience, extrapolated to benefits of further capabilities, workshopped 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 24: 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 increases from 15% in 2026 (following delivery of the alarm rationalisation project) to 46% from 2031 following full implementation of option 1. |
| | Uplift in capability of AEMS/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 AEMS for impedances, mutual coupling data, ratings, and fault definition cases | |
| | AEMS 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 between 2029 and 2031 will mean alarm reductions reaches 75% from 2032 onwards in the year following option 2's full implementation. |
| | Implement processing of alarm flood suppression conditions and of abnormal alarm detection and identification | |
| | Alarm analysis & response automation tool & defect management system & alarm integration | |
| | AEMS capability, incorporating fault level calculation, harmonics and EMT technical envelope data | |
| | Implementation of AEMS time domain capabilities | |
| | Uplift in AEMS to provide persistent access to AEMO forecast data, establishing a forecasting system integrated with the AEMS and uplift in EMS contingency Analysis tool for day-ahead decision support | |
| | Uplift capability of AEMS network applications and to receive SCADA points | |

Figure 6.4 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 from 2027 for Option 1 and between 2027 and 2030, then from 2038 for Option 2. The exceedance of the threshold reflects the later timing of when the initiatives are expected to be able to be put in place, based on the independent advice received from DGA Consulting. When the number of alarms is above the threshold this increases the risk of an EUE event. The expected exceedance of the threshold even as the options are rolled out highlights the urgent nature of the investment. Further, 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 6.4: 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 2030-31 under the ISP step change scenario for Option 2, i.e.:

- under the base case, the number of alarms in the year (1.60 million) is higher than the threshold (0.8 million), leading to an increase of 1.60 EUE events for the year (assumed to occur at a rate of one per million alarms above the threshold);
- under Option 2, the number of alarms in the year (0.73 million, calculated as 1.60 million multiplied by (1 - 54%) 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 2 is expected to have 1.60 fewer EUE events when compared to the base case;
- the size of a EUE in the year is 376 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 (1.60 EUE events) × expected size of EUE event (376 MWh) × VCR ($31,604 per MWh) = $19.0 million.

### 6.3.4 Gross market benefits for case study 1

Table 25 presents the gross market benefits for case study 1 and shows that gross market benefits are expected to range between $103.5 million and $160.5 million between the options, weighted across the scenarios.

Table 25: Gross market benefits under case study 1 ($ millions, PV)[61]

| Option | Progressive Change | Step Change | Green Energy Exports | Weighted |
|---|---|---|---|---|
| Option 1 | 112.8 | 94.6 | 103.1 | 103.5 |
| Option 2 | 150.7 | 166.0 | 172.1 | 160.5 |

While we believe our estimates are conservative, we have also included a sensitivity analysis in section 7.4 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).

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

The inverter-based constraints that effect wind and solar generation are currently operated based on static 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.

### 6.4.1 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 static limits based on 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

[61] The equivalent table (as well as the results tables for case studies 2 and 3) in the final PADR issued 12 May 2025 contained a transposition error, with the values for the progressive change and green energy exports scenarios presented in the wrong columns. This error was presentational only, with the weighted results in the PADR and the accompanying NPV model being correct.

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.

### 6.4.2 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 inverter-based limits based on real data, enabling them to be more dynamic and less conservative in nature.

The uplift in wide area 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 and measured and analysed. These are summarised in Table 26.

Table 26: 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 to AEMS to provide persistent access to AEMO forecast data, establishing a forecasting system integrated with the AEMS and uplift in AEMS contingency Analysis tool for day-ahead decision support | Option 2, FY 2031 |
| Wide area monitoring | Uplift in the existing Phasor Measurement Unit (PMU) central processor to tool to securely pass PMU data to Transgrid's AEMS to support wide area monitoring 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 AEMS for impedances, mutual coupling data, ratings, and fault definition cases | Option 1, FY 2030 |
| | AEMS Fault Level Calculation (FLC) application to enable real-time FLC execution, with updated modelling parameters | Option 1, FY 2030 |
| | AEMS capability, incorporating fault level calculation, harmonics and EMT technical envelope data | Option 2, FY 2031 |
| | Implementation of AEMS time domain capabilities | Option 2, FY 2031 |

### 6.4.3 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 27.

Table 27: 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 | Transgrid data on causes of constraints |

| | | |
|---|---|---|
| | would result in 5 constraint hours. We have included only NSW related constraints and daytime constraints in our analysis, which is conservative.<br>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. | |
| | Relevant constraint hours are assumed to increase with renewable generator capacity growth in NSW.[62] 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 per relevant constraint hour | Uplift in fault level monitoring , wide area monitoring and forecasting tools will progressively unlock 2 MW of renewable generation capacity per relevant constraint hour for Option 2 by 2032. Option 1 involves partial uplift in fault level monitoring and is assumed to progressively unlock 0.33 MW per relevant constraint hour by 2031. | Transgrid assumption |
| | 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 MWh = 2 (MW) x 0.57 (daytime renewable capacity factor) x 0.913 (renewable energy loss factor) / 0.959 (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<br>CSIRO Gencost 2023-2024[63]<br>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 Market Management System (MMS) data for marginal generator analysis<br>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<br>IASR data for emissions intensity |
| | Economic savings for a given year is calculated as number of relevant constraint hours (hours) × reduction in thermal generation per hour (MWh per hour) × SRMC ($/MWh).<br>Emission reduction savings for a given year is calculated as relevant constraint hours (hours) × reduction in thermal generation per hour (MWh per hour) × emission intensity (tonnes/MWh) × value of emission reduction ($/tonne)<br>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

[62] We discuss this assumption in Appendix B.
[63] We discuss the application of this dataset in in Appendix B.

generator could be constrained. Given this, the total number of constraint hours in a year exceeds the total number of hours in a year.

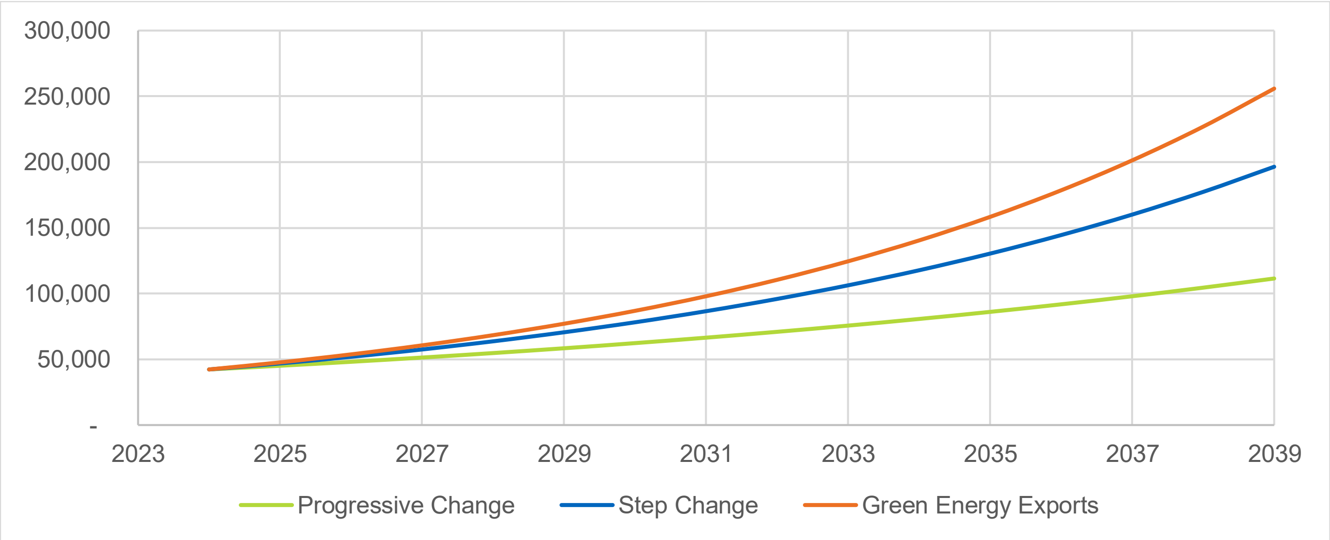
Uplift in operational tools alleviates inverter-based stability and security-related constraints. We have identified the number of relevant constraint hours for FY2024 (i.e. inverter-based stability and security-related constraints). Further, we have conservatively:

- 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
- 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 6.5 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 6.5: 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 2032 (i.e., we have assumed that fault monitoring and system parameter modelling, wide area 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 MWh = 2 (MW) x 0.57 (capacity factor) x 0.913 (renewable energy loss factor) / 0.959 (thermal generation loss factor). Option 1 is calculated similarly.

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

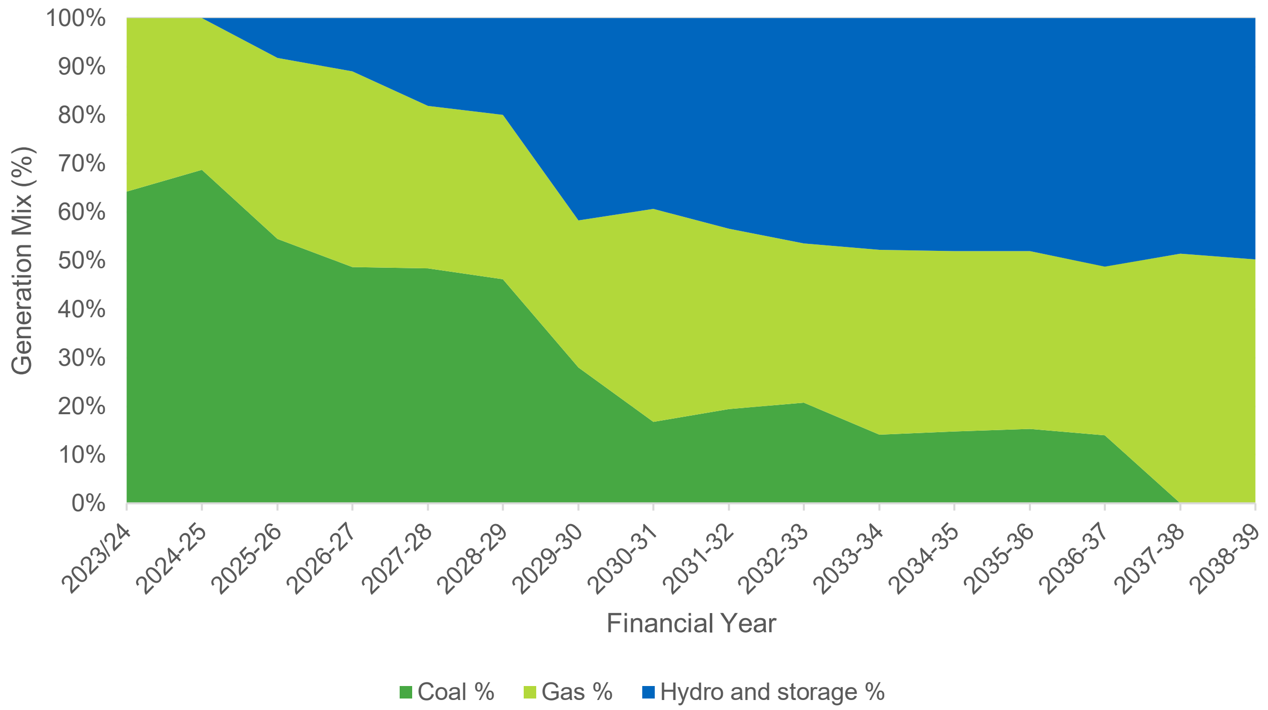
The saving that arises from a 1 MWh reduction in thermal generation depends on the marginal generator in the relevant period. To understand the potential SRMC and emission savings, we need to identify the marginal generator at the time, and the fuel consumption and emission intensity of the marginal 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 6.6 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 6.6: Change in marginal generator during relevant constraint period by fuel mix under Step Change scenario – 2023/24 to 2038/39




Data from AEMO's 2023 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 2030-31

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 86,607 by 2030-31, 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 2030-31) = 0.18 MWh; and
- reduction in thermal generation, which is calculated as 86,607 (constraint hours) × 0.18 (MWh savings per constraint hour) = 15,669 MWh.

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

- avoided fuel cost: 15,669 MWh × $59.80 ($/MWh, which represents the weighed SRMC of the marginal generators) = $0.9 million in 2030-31; and
- reduction in greenhouse gas emissions: 15,669 MWh × 0.37 (weighted emission intensity of the marginal generators, measured in tonnes/MWh) × $116 (value of emission reductions, measured in $/tonne) = $0.7 million in 2030-31.

In total, the gross market benefit in 2030-31 is $1.6 million, or $18.60 per relevant constraint hour.

### 6.4.4 Gross market benefits of case study 2

Table 28 presents the gross market benefits for case study 2 and shows that gross benefits for the options are expected to range between $10.9 million and $61.5 million between the options, weighted across the ISP scenarios.

Table 28: Gross benefits under case study 2 ($ millions, PV)

| Option | Progressive Change | Step Change | Green Energy Exports | Weighted |
|---|---|---|---|---|
| Option 1 | 7.9 | 12.2 | 15.6 | 10.9 |
| Option 2 | 44.3 | 69.2 | 87.6 | 61.5 |

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 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.

## 6.5 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.

### 6.5.1 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, we expect 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 29 compares two similar outages, one occurring in 2015 and one occurring in 2025.[64] 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

[64] 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 29: 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% |
| **Total coordination time** | 32 mins | 174 mins | 544% |
| Total number of steps for switching | 113 | 302 | 267% |

### 6.5.2 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 enhanced outage management. 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 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 30 breaks down the technology initiative implemented, and shows that there are no enhancements in proposed outage management between Option 1 and Option 2. As such, the quantified benefits are the same for each option.

Table 30: Capability enhancement matrix short term operational planning under each option

| Initiatives | Requirement | Option and timing |
|---|---|---|
| Outage management and Switching execution | Uplift outage management functionality 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 invertor 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 |

### 6.5.3 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 31.

Table 31: 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.<br>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 |

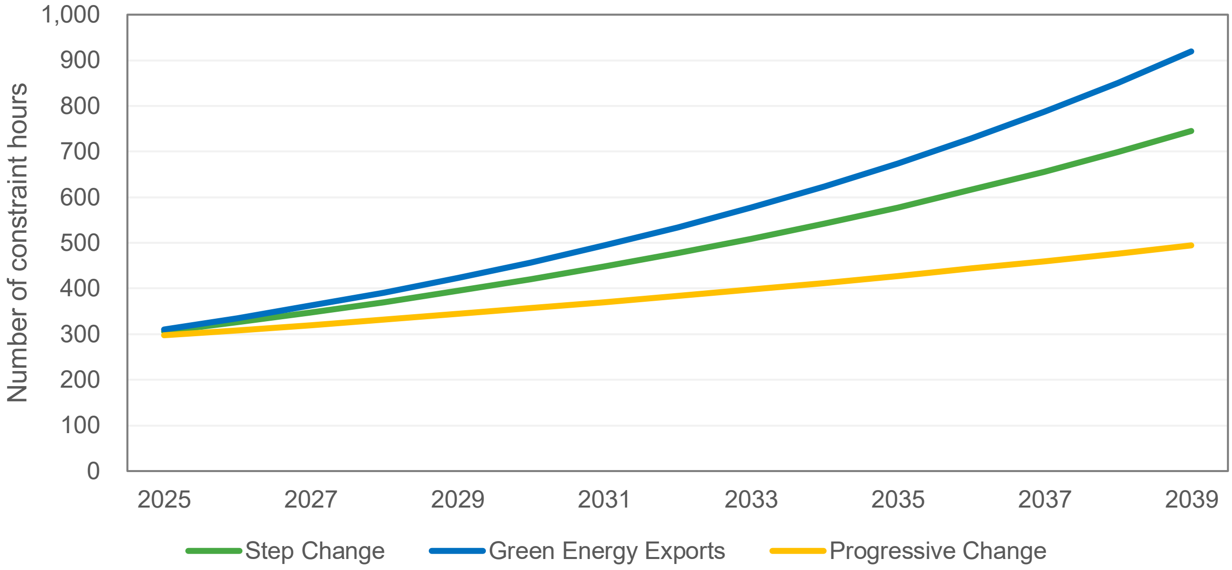
| | | |
|---|---|---|
| | 1 July 2023 to 31 December 2023. That is, we have only included half a year of outages in our benefit calculations. | |
| | Average outage time varies by number of renewable generators affected and is weighted by the size of the outage. We have assumed that switching time will 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<br>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<br>AEMO marginal loss factor values |
| Benefits | Marginal generators identified using same approach as case study 2. | AEMO's MMS data for marginal generator analysis<br>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<br>IASR data for emissions intensity |
| | Fuel cost savings for a given year is calculated as number of relevant outages (number of outages) × reduction in switching time per outage (hours per outage) × reduction in thermal generation per hour (MWh per hour) × SRMC ($/MWh).<br>Reduction in greenhouse gas emissions for a given year is calculated as relevant outage (number of outages) × reduction in switching time per outage (hours per outage) × reduction in thermal generation per hour (MWh per hour) × emission intensity (tonnes/MWh) × value of emission reduction ($/tonne). | |

### Relevant outages

We discuss our methodology for identifying relevant constraint hours in section 6.4.3. 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 6.7 sets out our forecast growth in relevant outages under different ISP scenarios. [65] Number of relevant outages are assumed to grow in line with renewable generator capacity growth in NSW, excluding estimated REZ capacity.

Figure 6.7: 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 MWh = 342.5 MWh (average curtailment of renewable energy per hour in FY2024) x 0.913 (renewable energy loss factor) / 0.959 (thermal generation loss factor).

Table 32 sets out the assumed time saving per outage by number of generators involved.

Table 32: 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 |

[65] 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.

| | | | | |
|---|---|---|---|---|
| 10 or more | 28% | 280 minutes | 30% | 84 minutes |
| 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.

### 6.5.4 Gross market benefits of case study 3

The gross benefit for each option by scenario is set out in Table 33 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 33: Gross benefits under 'reduced duration of switching operations' use case ($ millions, PV)

| Option | Progressive Change | Step Change | Green Energy Exports | Weighted |
|---|---|---|---|---|
| Option 1 | 56.5 | 78.3 | 116.3 | 74.8 |
| Option 2 | 56.5 | 78.3 | 116.3 | 74.8 |

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

Table 34 presents each option's gross benefits by case study and ISP scenario, and on a weighted basis.

Table 34: Summary of option gross benefits by case study and ISP scenario, and on a weighted basis

| Option | Case Study | Progressive change | Step change | Green energy exports | Weighted |
|---|---|---|---|---|---|
| Option 1 | Reduction in the likelihood of unserved energy | 112.8 | 94.6 | 103.1 | 103.5 |
| | Increase in network utilisation | 7.9 | 12.2 | 15.6 | 10.9 |
| | Reduction in duration of outages | 56.5 | 78.3 | 116.3 | 74.8 |
| | Total | **177.2** | **185.1** | **235.0** | **189.3** |
| Option 2 | Reduction in the likelihood of unserved energy | 150.7 | 166.0 | 172.1 | 160.5 |
| | Increase in network utilisation | 44.3 | 69.2 | 87.6 | 61.5 |
| | Reduction in duration of outages | 56.5 | 78.3 | 116.3 | 74.8 |
| | Total | **251.5** | **313.5** | **376.0** | **296.8** |

# 7 Net present value analysis

This section outlines the NPV assessment we have undertaken for the two credible options. The NPV results have changed since the PADR based on changes to the timing of implementation of initiatives (and therefore the realisation of benefits) and the quantum of costs, following the independent review by DGA Consulting and further detailed planning works by Transgrid.

## 7.1 Present value of costs

Table 35 presents the capital, operating and total cost for each option in present value terms. Option 1 represents incremental capital and operating expenditure of $137.2 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 $177.9 million in present value terms. The cost of the options does not differ across the ISP scenarios considered.

Table 35: Present value of capital and operating costs by option (present value, $ millions)

| | Capital expenditure | Operating expenditure | Total |
|---|---|---|---|
| Option 1 | 104.1 | 33.1 | 137.2 |
| Option 2 | 133.8 | 44.2 | 177.9 |

## 7.2 Present value of gross market benefits

Table 36 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 36: Present value of gross market benefits by case study ($m, PV)

| Case study | Option 1 | Option 2 |
|---|---|---|
| Reduction in the likelihood of outages | 103.5 | 160.5 |
| Increased network utilisation | 10.9 | 61.5 |
| Reduced duration of switching operations | 74.8 | 74.8 |
| **Total** | **189.3** | **296.8** |

Table 37 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 37: Option gross benefits by type of market benefit, weighted basis ($m, PV)

| | Option 1 | Option 2 |
|---|---|---|
| Avoided EUE | 103.5 | 160.5 |

| | | |
|---|---|---|
| Avoided generation dispatch costs | 48.3 | 77.4 |
| Reduction in greenhouse gas emissions | 37.5 | 59.0 |
| **Total** | **189.3** | **296.8** |

## 7.3 Net present value

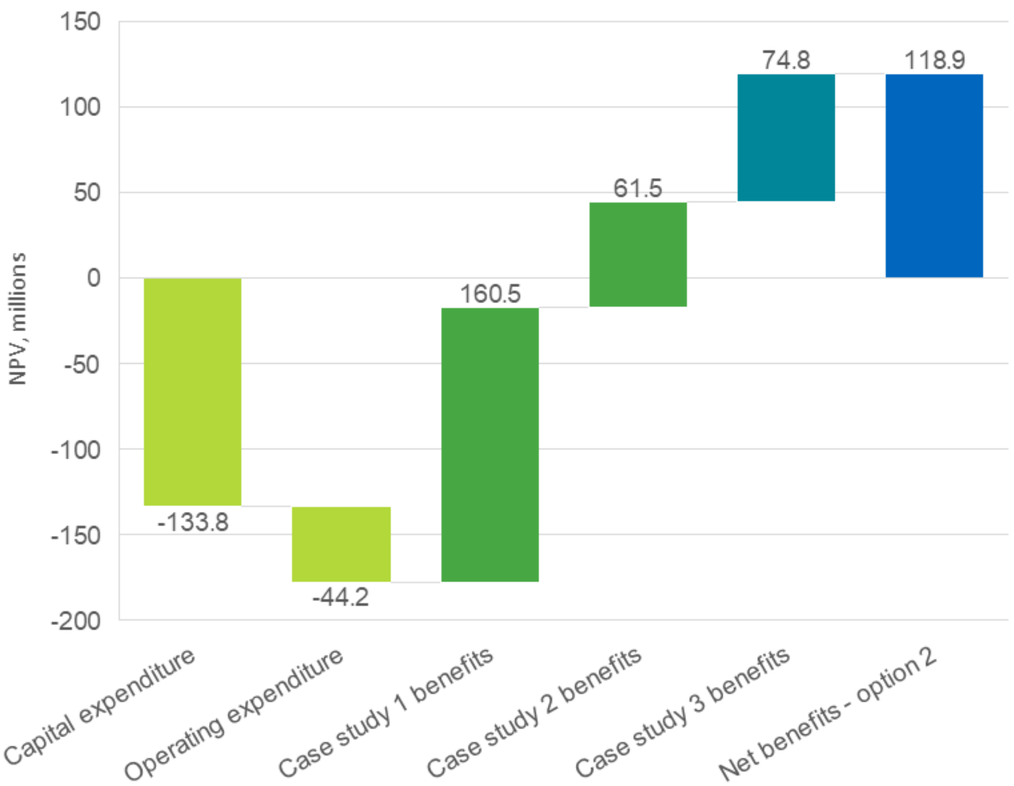
In Table 38, we set out the NPV for each option across the three ISP scenarios modelled, and on a weighted basis. This demonstrates that Option 2 has the highest net benefit, and is therefore the preferred option under the RIT-T, with $118.9 million in net benefits.

Table 38: NPV of options compared to base case (present value, $ millions)

| Option | Progressive change | Step change | Green energy exports | Weighted NPV | Rank |
|---|---|---|---|---|---|
| Option 1 | 40.0 | 47.9 | 97.8 | 52.0 | 2 |
| Option 2 | 73.6 | 135.5 | 198.1 | 118.9 | 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 7.1.

Figure 7.1: Drivers of net benefits for Option 2 – weighted across scenarios (NPV, $m)



## 7.4 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 by changing the relevant parameter in each scenario and reporting the weighted NPV outcome.

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 6.1, 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 39: Sensitivity analysis – Weighted results ($ millions, NPV)

| Sensitivity | | Option 1 | Option 2 |
|---|---|---|---|
| Capital cost | High (+25%) | 19.9 | 76.3 |
| | Low (-10%) | 65.0 | 135.0 |
| Operating cost | High (+25%) | 43.7 | 107.9 |
| | Low (-25%) | 60.3 | 129.9 |
| Discount rate | High (10.0%) | 30.7 | 77.0 |
| | Low (4.18%) | 80.9 | 175.8 |
| Value of customer reliability | High (+30%) | 83.1 | 167.0 |
| | Low (-30%) | 21.0 | 70.8 |
| Value of emissions reduction | High (+25%) | 61.4 | 133.7 |
| | Low (-25%) | 42.7 | 104.2 |
| Total gross benefits | High (+25%) | 99.3 | 193.1 |
| | Low (-25%) | 4.7 | 44.7 |
| Shorter economic lives | 7 years (for OT assets)[66] | 38.7 | 101.6 |
| Optimal timing | 1 year delay | 47.4 | 112.4 |

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 $6.5 million decrease in net market benefits.

[66] We have also removed 2.5 FTEs from Option 1 and 3.5 FTEs from Option 2 under this sensitivity. Those FTEs are used for the adoption of an evergreen system support approach to extend OT assets to 10 years in the core analysis, and so are not required in this 7 year economic life sensitivity.

## 7.5 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 40 below relative to the option that provides the greatest net benefit (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 40: 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 | 160% | 73% |
| Operating costs | 606% | 269% |
| Total costs | 128% | 56% |
| Gross benefits | -62% | -40% |

## 7.6 Proposed reopening triggers

We are required to set out 'reopening triggers' for this RIT-T since the estimated capital cost of the proposed preferred option is greater than $103 million.[67]

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 PACR, we consider that the following would form re-opening triggers for this RIT-T:

- AEMO withdrawing its support for the initiatives set out in Option 2;
- credible evidence that the capital cost of the preferred option has increased by more than 70 per cent compared to the costs used in this RIT-T analysis;[68]
- 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

[67] NER clause 5.16.4(k)(10).
[68] The boundary value testing above finds that there would need to be a 73 per cent increase in capital costs for Option 2 to no longer deliver positive net market benefits.

- credible evidence that another solution is likely to deliver higher net market benefits compared to the preferred option under this RIT-T.

Stakeholders did not comment on these proposed re-opening triggers in submissions to the PADR.

# 8 PACR conclusion

This PACR 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. This is consistent with the findings of the PADR.

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;
- alarm management, visualisation and situation awareness;
- fault level and system parameter monitoring and power system analysis capability;
- SCADA/AEMS system;
- control room facility configuration changes;
- data management and network modelling system;
- training technologies, operational document management system and operational planning systems;
- operational forecasts and look-ahead contingency assessment;
- wide area monitoring; and
- smart transmission device management.

We set out the scope of investments under Option 2 in section 4.4.

The preferred option, Option 2, has:

- estimated capital expenditure of $133.8 million (PV, 2024/25 dollars); and
- estimated incremental operating expenditure over the assessment period of $44.2 million (PV, 2024/25 dollars).

The new operational technologies and tools are expected be commissioned incrementally, beginning with the alarm rationalisation project (that was completed in April 2025), with full implementation by March 2031.

In the 2023-28 regulatory period Option 2 has:

- $82.3 million in capital expenditure ($2024/25); and
- $0.8 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 NPV of the net economic benefit. The key expected benefits include:

- reduced expected unserved energy through improved situational awareness and decision making; 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 PACR with the requirements of the National Electricity Rules version 235.

| Rules clause | Summary of requirements | Relevant section(s) |
|---|---|---|
| 5.16.4(v) | The project assessment conclusions report must set out: | |
| | (1) the matters detailed in the project assessment draft report as required under paragraph (k); and | See below. |
| | (2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought under paragraph (q). | 3.1 |
| 5.16.4(k) | A RIT-T proponent must prepare a report (the assessment draft report), which must include: | - |
| | (1) a description of each credible option assessed; | 4 |
| | (2) a summary of, and commentary on, the submissions to the PSCR; | 3.1 |
| | (3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option; | 4, 5 & 6 |
| | (4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost; | 5 & 6 |
| | (5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material; | 5.3.5 |
| | (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); | 5.3.4 |
| | (7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results; | 7 |
| | (8) the identification of the proposed preferred option; | 8 |
| | (9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide:<br>(i) details of the technical characteristics;<br>(ii) the estimated construction timetable and commissioning date;<br>(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<br>(iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission. | 8 |

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 | A RIT-T proponent must consider social licence issues in the identification of credible options.<br>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. | N/A[69] |
| 3.4.3 | The value of emissions reduction (VER), reported in dollars per tonne of emissions ($CO_2$ equivalent), is used to value emissions within a state of the world.<br>A RIT-T proponent is required to use the then prevailing VER under relevant legislation or, otherwise, in any administrative guidance. | 5.3.3 and Appendix B[70] |
| 3.5A.1 | 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:<br>• 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<br>• for all credible options (including the preferred option), either:<br>> apply the cost estimate classification system published by the AACE, or<br>> 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. | 5.2[71] |
| 3.5A.2 | 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:<br>• all key inputs and assumptions adopted in deriving the cost estimate<br>• a breakdown of the main components of the cost estimate<br>• the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates)<br>• the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied<br>• the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance | 4.1.2, 4 & 5 |
| 3.5 | In the RIT-T, costs must include the following classes:<br>• Costs incurred in constructing or providing the credible option<br>• Operating and maintenance costs over the credible option's operating life<br>• Costs of complying with relevant laws, regulations and administrative requirements<br>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 | 4 & 5 |

[69] 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 has 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 for this RIT-T was published prior to 21 November 2024, these new requirements are not applicable to this RIT-T.

[70] See previous footnote.

[71] The cost threshold of $103 million has been updated in the new guidelines from the previous value of $100 million. In accordance with footnote 69, 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[69] |
| 3.6 | RIT-T proponents are required to apply classes of market benefits consistently across all credible options. | 5[69] |
| 3.7.3 | When calculating the benefit from changes in Australia's greenhouse gas emissions, a RIT-T proponent is required to:<br>• include the following emissions scopes, unless the change relative to the base case can be demonstrated to be immaterial to the RIT outcome:<br>• direct emissions from generation<br>• direct emissions other than from generation<br>• 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 | 5.3.3[69] |
| 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. | 5.5 & 7.4[71] |
| 3.9.4 | If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain:<br>• the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and<br>• how the level or quantum of the contingency allowance was determined. | 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.<br>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[69] |
| 4.1 | RIT-T proponents are required to describe in each RIT-T report<br>• 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<br>• how they plan to engage with these stakeholder groups, or<br>• why this project does not require community engagement. | N/A[69] |

# 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 × the estimated size of the event in that year (in MWh) × 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.[72] 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.

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

[72] 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.

- 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 41 and discussed in further detail below.

Table 41: 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 this 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 fault level monitoring, wide area monitoring 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 fault level monitoring and is assumed to unlock 0.33 MW per relevant constraint hour by 2031 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%).[73] 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).[74] 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 (Gigajoule (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

[73] CSIRO 2023-2024 GenCost Report - CSIRO releases 2023-24 GenCost report - CSIRO

[74] 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

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[75]. AEMO's 2025 IASR report escalated these values to 2024/2025 dollars and interpolated to financial years.[76] The values used are taken from the 2025 IASR and reproduced in Table 42.

Table 42: 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 | 91 | 97 | 106 | 116 | 126 | 137 | 149 | 160 | 172 | 185 | 198 | 212 |

**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 2031 for Option 1 and by 2032 for Option 2, reflecting the full implementation of initiatives by those dates. Table 43 sets out the assumed benefit rollout profile used for CS2.

Table 43: 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 | 0 | 33 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |

[75] 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

[76] AEMO, 2025 Inputs, Assumptions and Scenarios Report, July 2025, p 160.

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Option 2 | 0 | 0 | 0 | 0 | 4 | 17 | 44 | 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 43 provides an overview of the key assumptions that feed into case study 3 only. We provide further information on these assumptions below.

Table 44: CS3 fuel cost NPV equation inputs and reference

| Input | Reference |
|---|---|
| **Outage** | The number of relevant outages that could benefit from operational uplift. These are related to inverter-based stability and security-related constraints |
| **Time saved per outage** | 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) |
| **rollout** | 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 45: 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 | 25 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 2 | 0 | 0 | 0 | 25 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |