Transgrid

People. Power. Possibilities.

Meeting system strength requirements in NSW

Material Change in Circumstances assessment – Draft for consultation

Region: New South Wales

Date of issue: 1 July 2026

Executive Summary

In July 2025, Transgrid published its Project Assessment Conclusions Report (PACR), which identified the preferred portfolio of solutions for managing system strength in NSW. This report describes Transgrid's draft material changes in circumstances (MCC) assessment for the system strength portfolio.

This MCC assessment was triggered by an increase in the cost of synchronous condensers, which are part of the preferred portfolio. The assessment also incorporates changes to two key assumptions underpinning the PACR, including delayed coal unit retirement dates following the publication of the Australian Energy Market Operator's (AEMO) draft 2026 Integrated System Plan (ISP) and updated information on the delivery timing for synchronous condensers.

The result of this draft assessment is a reduction in the required number of Phase 2 synchronous condensers[1] on Transgrid's network from five to three, and an inclusion of 900 MW of grid-forming battery energy storage systems (BESS) for the minimum level of system strength, pending confirmation of their technical credibility for the minimum level.

The PACR identified that grid-forming BESS will form a core component of the efficient level system strength solution in NSW, with 5 GW of grid-forming BESS required by the early 2030s. Transgrid is currently evaluating responses to its initial tender for up to 2 GW of grid-forming BESS to support this need.

This draft MCC assessment expands the role that grid-forming BESS can play in supporting system strength in NSW, by providing a pathway for 900 MW of grid-forming BESS to contribute to meeting minimum level requirements, pending confirmation of technical credibility. To support this, Transgrid is engaging with industry, AEMO and other network service providers to validate the credibility of grid-forming BESS for the minimum level.

Purpose of this report

Transgrid published its final report in the Regulatory Investment Test for Transmission (RIT-T) in July 2025 for the *Meeting System Strength Requirements in NSW* project. The PACR identified a preferred portfolio of individual system strength solutions, including:

- ten network synchronous condensers at Transgrid substations;
- modifications to 650 MW of non-network synchronous machines to enable synchronous condenser mode;
- up to 5 GW of non-network grid-forming BESS to support a stable voltage waveform for future renewables; and
- contracts with non-network synchronous machines to fill gaps in system strength where required.

Transgrid provided notification to the Australian Energy Regulator (AER) in April 2026[2] that a reopening trigger specified in the PACR had been met, in line with Clause 5.16.4(z4)(2) of the National Electricity Rules (NER). In addition, there are changes to two other key assumptions which may also constitute an

[1] The PACR preferred option included network synchronous condensers at ten Transgrid substations. Synchronous condensers for the first five sites have been awarded to GE Vernova, who will deploy two smaller synchronous condenser units at each site to meet our specifications. These are labelled accelerated 'Phase 1' synchronous condensers. The additional synchronous condensers under assessment via this MCC are labelled 'Phase 2'.

[2] Meeting system strength requirements in NSW – Notification of Material Change in Circumstances Assessment, Transgrid, April 2026

MCC under NER 5.16.4(z4)(3). Transgrid's notification to the AER included a set of proposed actions to address the MCC and assumption changes.

In June 2026[3], the AER determined the following actions were required by Transgrid:

- Undertake a streamlined MCC assessment, drawing on existing PACR analysis, using updated inputs and assumptions based on the Australian Energy Market Operator's (AEMO) latest draft 2026 ISP Step Change scenario;
- Publish a draft statement on Transgrid's website setting out any changes to the PACR preferred option with supporting analysis and justification, on or before 24 June 2026;
- Undertake a one-month consultation period upon publishing of the draft statement; and
- Publish a final statement no later than 24 August 2026 which includes details of the submissions received during consultation and how they have been incorporated into the assessment.

Nature of the material changes in circumstance and changes to key assumptions

In April 2026, Transgrid submitted a revenue proposal[4] to the AER for the accelerated Phase 1 synchronous condensers project under the Electricity Infrastructure Investment (EII) Act, which includes the first five of the ten synchronous condensers identified in the PACR[5]. These synchronous condensers are required to close system strength gaps following the retirement of Eraring Power Station. The total cost of the project is $1.13 billion (in $FY25)[6], at an average cost of $225 million per site. This represents a 38% increase against the average cost of $163 million estimated and modelled in the PACR[7].

In light of this, Transgrid notified the AER in April 2026 that a RIT-T reopening trigger identified in the PACR had been met. Specifically, that the expected *"costs of synchronous condensers required for 2031/32 or after increase by significantly more than 30%"*.[8]

This increase in costs was driven by a significant escalation of global demand and supply constraints for both synchronous condensers and design and construction services. It is likely that costs will increase further for future synchronous condensers, due to additional supply chain impacts driven from the conflict in the Middle East. This has been incorporated into cost estimates for Phase 2 synchronous condensers within this draft MCC assessment, noting there is still considerable uncertainty in supply chain impacts.

This draft MCC assessment is focussed upon the remaining five synchronous condensers identified in the PACR, labelled 'Phase 2'. Phase 2 synchronous condensers are required to prepare the power system for the retirement of the remaining NSW coal generators. This need is recognised in AEMO's recent draft 2026 General Power System Risk Review (GPSRR) which stated *"further system strength support measures will*

[3] Material change in circumstances – Meeting system strength requirements in NSW – Determination, AER, June 2026
[4] Transgrid System Strength Project (hybrid), Transgrid, April 2026
[5] Note, Transgrid awarded a contract to GE Vernova for the supply and installation of accelerated Phase 1 synchronous condensers at five sites. Two smaller GE Vernova synchronous condensers will be deployed at each site to meet Transgrid's requirements, rather than one large synchronous condenser at each site as identified in the PACR. This draft MCC assessment maintains the same terminology as the PACR, in large-synchronous condensers-equivalent.
[6] The revenue proposal stated a cost of $1.19 billion, based on a dollar cost basis of September 2026 related to the regulatory year basis of that proposal. All costs for this MCC assessment are shown in 30 June 2025 dollars.
[7] The average cost presented in the PACR was $160 million, in $FY24, with actual costs estimated to be within -20% to +30% of the base capital cost estimate. This cost is adjusted for inflation to enable a comparison in $FY25.
[8] Meeting system strength requirements in NSW PACR, Transgrid, July 2025, Page 110

be needed to support future synchronous generation retirements or other scenarios resulting in unavailability of synchronous machines'[9].

Changes to two other key assumptions used within the PACR have also occurred. These changes may also constitute an MCC, and have been considered in this draft MCC assessment, namely:

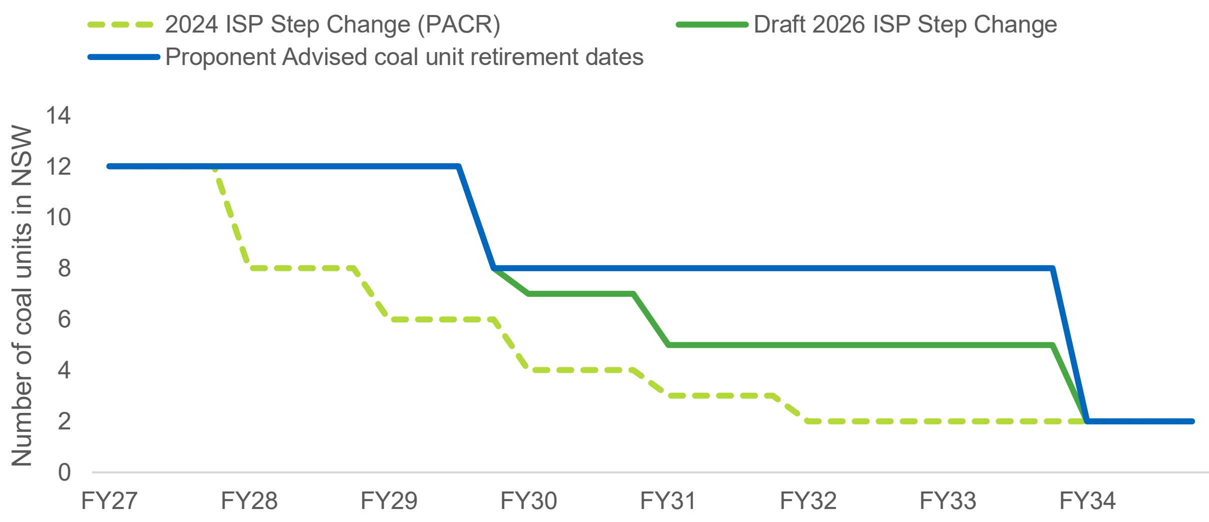
(i) The delivery timeline for Transgrid's Phase 2 synchronous condensers assumed in the PACR was between March 2029 and February 2030 for the first Phase 2 synchronous condenser. Given additional regulatory processes, including the dispute on Transgrid's PACR[10], this MCC assessment, the risk of further MCC assessments being required as well as increasing lead-times for available manufacturing slots ('length of the queue'), a delivery timeline of the beginning of FY34 was assumed in this assessment. This delivery timeline reflects the impact of uncertainties in factors external to Transgrid.

(ii) The projected retirement timing of NSW coal generator units has been deferred under AEMO's latest 2026 draft ISP Step Change scenario, compared with AEMO's 2024 ISP (which underpinned Transgrid's system strength PACR).

The delivery timing of synchronous condensers and the retirement dates of NSW coal generators remain uncertain. To reflect this uncertainty, Transgrid has opted to assess two synchronous condenser delivery timings and two coal unit retirement scenarios. These include:

- synchronous condensers modelled to be operational at the beginning of FY34 under an 'assumed' delivery timing, as well as the beginning of FY31 under an 'accelerated' delivery timing (which is not currently considered credible), reflecting an earlier contract award. Acceleration is expected to only be credible if procurement commences prior to AER's approval of a contingent project application; and
- coal unit retirement dates as per the 2026 draft ISP Step Change scenario, and as per Proponent Advised dates, creating two coal retirement scenarios. These scenarios are compared in Figure 1, in addition to the coal unit retirement scenario used within the PACR (from the 2024 ISP).

Figure 1. Comparison of NSW coal unit retirement schedule forecasts



[9] Draft 2026 General Power System Risk Review, AEMO, June 2026, Page 7

[10] Following the PACR publication, the AER received a notice of dispute on Transgrid's system strength PACR in August 2025 and published its determination on the dispute in December 2025.

Modelling approach and portfolio formation

The PACR identified that ten network synchronous condensers are required at Transgrid substations to address system strength requirements. The first five Phase 1 sites have already been awarded[11].

In this draft MCC assessment, Transgrid manually constructed five portfolio options to test the value of each Phase 2 synchronous condenser. Portfolio option 1a has one Phase 2 synchronous condenser, up to portfolio option 5a which has all five Phase 2 synchronous condensers identified in the PACR.

For each portfolio option, the deficit against minimum level system strength requirements was identified through power system modelling. This modelling included existing and committed sources of system strength and the additional Phase 2 synchronous condensers. The amount of re-dispatch[12] of synchronous machines required to meet (or attempting to meet) system strength requirements for each portfolio option was then identified.

Currently, grid-forming BESS are not considered credible to meet minimum system strength requirements. This is based on AEMO's public position[13], independent advice from Aurecon[14] to support Transgrid's system strength PACR and independent advice from ETIK for AEMO's Type 2 trials[15]. However, given the high likelihood that grid-forming BESS would form part of the preferred portfolio option if credibility was confirmed, Transgrid has included it as a solution for consideration from FY33 in this assessment (via a second set of portfolios, options 1b to 5b). The amount of grid-forming BESS was optimised to maximise net market benefits for each individual portfolio option. The assumed timing is based on the necessary steps for the technology to demonstrate credibility, as outlined in Section 3.3.1.

To manage the system security risk associated with the uncertainty of when, or if, grid-forming BESS will become a credible solution for the minimum level, Transgrid proposes to rely on grid-forming BESS for the minimum level only to the extent that there are sufficient alternative fallback solutions available to meet the need (i.e. gas and hydro re-dispatch). If grid-forming BESS credibility is not confirmed in time, hydro and gas re-dispatch would increase to meet system strength requirements. Where there are insufficient fallback solutions, i.e. infeasible[16] amounts of gas re-dispatch required to meet the need in the absence of grid-forming BESS, portfolio options were not deemed credible and were removed from further assessment.

Table 1 shows the years where a modelled risk of system strength gaps was observed under the Draft 2026 ISP Step Change scenario when grid-forming BESS for the minimum level are not included in the portfolio, under both assumed and accelerated synchronous condenser timing. A modelled risk of system strength gaps is identified when the level of gas re-dispatch is considered infeasible, due to modelled pipeline or supply constraints.

[11] Transgrid System Strength Project (hybrid), Transgrid, April 2026

[12] Transgrid defines 're-dispatch' as an increase in the operating hours of synchronous generators to provide system strength, in addition to their typical electricity market operations.

[13] AEMO, May 2024, Update to the 2023 Electricity Statement of Opportunities and more recently, AEMO's 2025 Transition plan for system security, December 2025, Page 135

[14] Advice on maturity of grid-forming inverter solutions for system strength, Aurecon, March 2024

[15] Grid-forming and grid-following fault current contribution, Etik Energy, November 2025

[16] This MCC assessment has included gas constraints to reflect pipeline and gas supply limitations which would limit the amount of gas re-dispatch available. Where gas re-dispatch exceeds these constraints, it is considered infeasible, leading to a modelled risk of system strength gaps. These gas constraints were informed by AEMO's 2026 Gas Statement of Opportunities and technical advice provided to Transgrid by GHD to support the PACR. AEMO was consulted during the development of these gas constraints.

Table 1. Draft 2026 ISP Step Change scenario. Modelled risk of system strength gaps when excluding grid-forming BESS

Assumed synchronous condenser timing (delivery in FY34)						
Portfolio option	Base case	1a	2a	3a	4a	5a
FY31	Risk	Risk	Risk	Risk	Risk	Risk
FY32	Risk	Risk	Risk	Risk	Risk	Risk
FY33	Risk	Risk	Risk	Risk	Risk	Risk
FY34	Risk	Risk	Risk	No risk	No risk	No risk
FY35+	Risk	Risk	Risk	No risk	No risk	No risk

Accelerated synchronous condenser timing (delivery in FY31)						
Portfolio option	Base case	1a	2a	3a	4a	5a
FY31	Risk	Risk	Risk	No risk	No risk	No risk
FY32	Risk	Risk	No risk	No risk	No risk	No risk
FY33	Risk	Risk	No risk	No risk	No risk	No risk
FY34	Risk	Risk	Risk	No risk	No risk	No risk
FY35+	Risk	Risk	Risk	No risk	No risk	No risk

Portfolio options 1a and 2a have a modelled risk of system strength gaps even after Phase 2 synchronous condensers are operational, indicating insufficient fall-back solutions if grid-forming BESS are not (yet) proven credible. These portfolio options were therefore not deemed credible. This result was similar under the Proponent Advised coal unit retirement scenario, as shown in section 6.

The tables also show a modelled risk of gaps in years FY31 – FY33 under the assumed synchronous condenser timing (FY34), before synchronous condensers or grid-forming BESS for the minimum level are available. This highlights the system security risk if coal units retire before replacement system strength solutions are delivered.

Net market benefit assessment

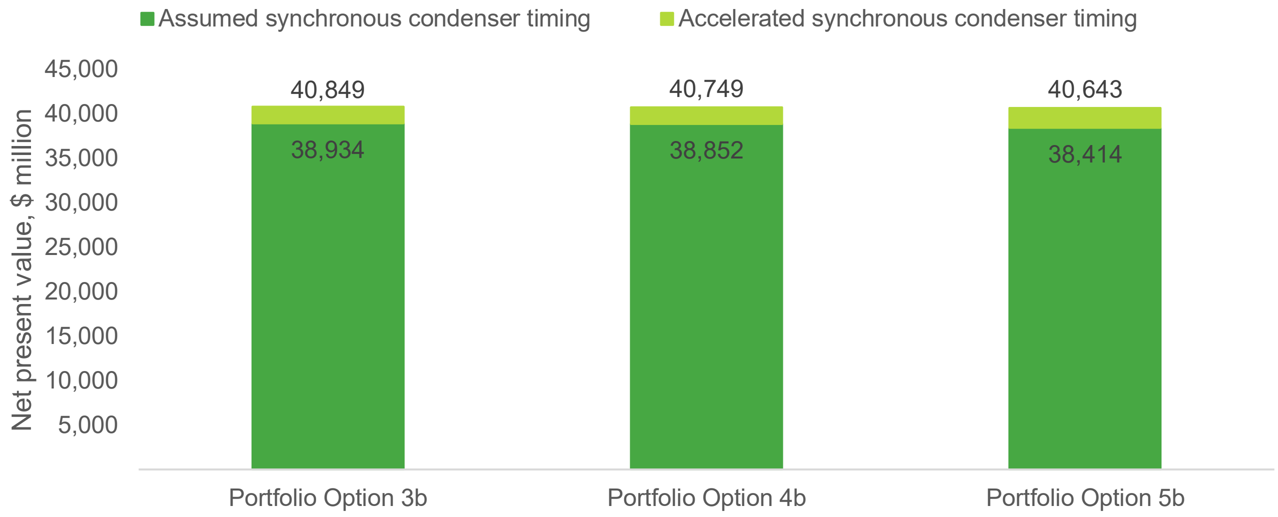
The net market benefit assessment was completed both with and without the contribution of grid-forming BESS, to assess if this effect changed the ranking of portfolio options.

Note that the results presented in this executive summary show the net present value assessment under the Draft 2026 ISP Step Change scenario only; similar analysis is also presented in Section 7 under the Proponent Advised coal unit retirement scenario.

Figure 2 shows the net present value assessment for each credible portfolio option, with grid-forming BESS included in the assessment, assuming credibility is proven for the minimum level and implemented by FY33. With grid-forming BESS included, the preferred portfolio option is portfolio option 3b, under all scenarios and synchronous condenser delivery timings.

Portfolio option 3b contains three Phase 2 synchronous condensers and 900 MW of grid-forming BESS for the minimum level (assuming credibility can be proven). This portfolio delivers $39 billion in net market benefits under the assumed synchronous condenser timing (FY34), and $41 billion under the accelerated synchronous condenser timing (FY31), when modelled under the Draft 2026 ISP Step Change scenario and compared to the base case. Portfolio option 3b delivers $100 million and $82 million more benefits than the next best portfolio option 4b, under the assumed and accelerated synchronous condenser timing, respectively.

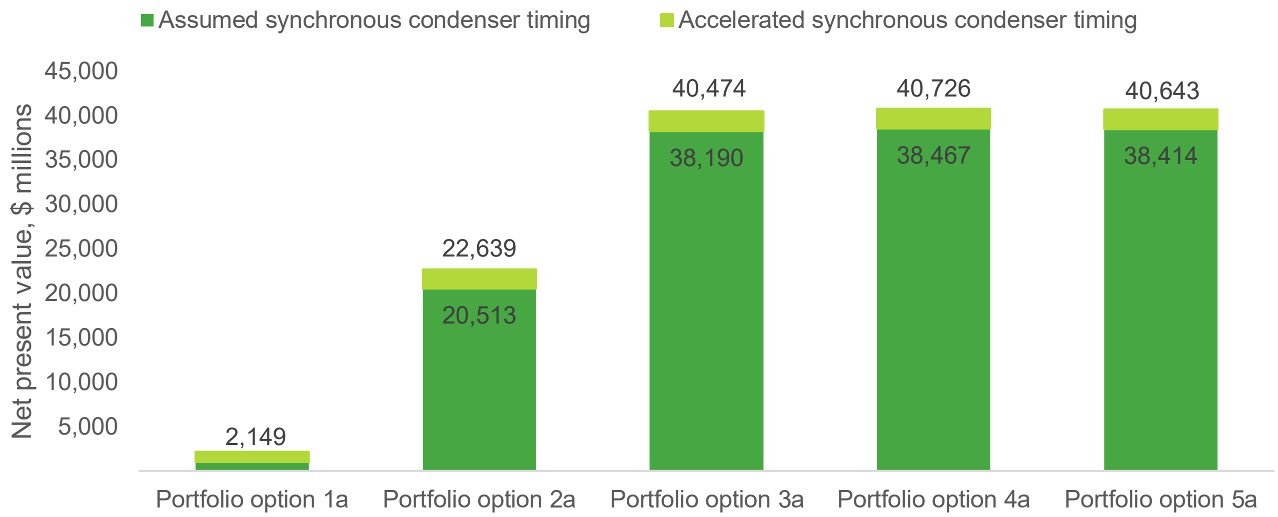
Figure 2. Draft 2026 ISP Step Change scenario. Net Present Value assessment including grid-forming BESS[17]



The accelerated synchronous condenser timing has a higher net present value for all portfolio options and under both coal unit retirement scenarios. For Portfolio option 3b under the Draft 2026 ISP Step Change scenario, the added benefit of acceleration is $1.9 billion. This increase in value is attributed to avoided involuntary load curtailment where a modelled risk of system strength gaps was observed. This highlights the benefit of earlier delivery of the identified solutions, if feasible.

Figure 3 shows the net present value for each portfolio option when excluding grid-forming BESS for the minimum level. Without grid-forming BESS, portfolio option 4a, with four Phase 2 synchronous condensers, maximises net market benefits and would be selected as the preferred portfolio under both the assumed (FY34) and accelerated (FY31) timing of synchronous condensers.

Figure 3. Draft 2026 ISP Step Change scenario. Net present value assessment when excluding grid-forming BESS



A significantly lower net present value is observed in Figure 3 for Portfolio option 1a and 2a, approximately $37 billion and $18 billion lower than portfolio option 4a, respectively. This outcome is primarily driven by

[17] To interpret the NPV charts, dark green bars represent benefits under the assumed delivery timing of Phase 2 synchronous condensers (in FY34). The benefits of accelerated synchronous condenser delivery (FY31) are represented as the summation of the benefits of the dark and light green bars (with the total noted above the light green bars).

the substantial costs associated with involuntary load curtailment, as Portfolio options 1a and 2a do not have sufficient solutions available to meet system strength requirements. Portfolio options 1a and 2a require infeasible levels of gas re-dispatch, so were not deemed credible portfolios and were removed from further analysis.

Portfolio option 3b (with grid-forming BESS included) has $467 million higher net benefits than the optimal portfolio without grid-forming BESS (portfolio option 4a), indicating the increased value of including grid-forming BESS in the portfolio. The increase in benefits is driven by the avoided capital and operating costs of the fourth synchronous condenser, as well as grid-forming BESS reducing the need and cost for gas and hydro re-dispatch. This justifies shifting from portfolio option 4a to portfolio option 3b as the preferred option, creating a pathway for grid-forming BESS to contribute.

Selection of the preferred portfolio of system strength solutions

This draft MCC assessment applies a structured decision framework to identify the preferred portfolio option. This framework integrates power systems modelling and a net present value assessment to manage key uncertainties of coal unit retirement dates, synchronous condenser delivery timing and the timing when the credibility of grid-forming BESS for the minimum level will be demonstrated. To manage these uncertainties, Transgrid:

- developed a two-stage process to exclude portfolio options which did not have sufficient fall-back solutions to meet minimum-level system strength requirements without grid-forming BESS. Based on this, portfolio options with fewer than three Phase 2 synchronous condensers were not deemed credible in this draft assessment.
- assessed the credible portfolio options under two coal unit retirement scenarios and two synchronous condenser delivery timings, in addition to sensitivities for New England Renewable Energy Zone (REZ) Stage 2 and for both higher and lower synchronous condenser costs.

Details of the preferred portfolio option 3b are listed in Table 2, relative to the PACR preferred option.

Table 2. Details of the preferred portfolio option in this MCC assessment

Technology	Number	Timing	Location
Phase 2 synchronous condensers	Three. Reduction from five in the PACR, to three.	To be delivered by FY31, if acceleration becomes credible, or as early as possible if not.	Sites of the three Phase 2 synchronous condensers are Dinawan, Munmorah and Newcastle[18].
Grid-forming BESS	900 MW for the minimum level of system strength (once credibility is confirmed). An increase from 0 MW for the minimum level, in addition to 5 GW for the efficient level that was identified in the PACR.	Modelled from FY33 based on independent advice from Aurecon, but if credibility can be proven earlier, this will increase benefits further.	Sydney West region – connected to the transmission network is considered most beneficial.

[18] Consistent with the PACR, the locations of synchronous condensers in the Sydney/Newcastle region may change as detailed site feasibility studies continue to ensure the optimal locations are progressed.

Technology	Number	Timing	Location
Modifications to synchronous machines to enable synchronous condenser mode	650 MW, as identified in the PACR.	From FY29	Projects located closer to the Sydney West node are considered more beneficial.

Consistent with the PACR, hydro and gas re-dispatch remains part of the preferred portfolio option, particularly in the early 2030s. The need for coal re-dispatch will be re-evaluated in the contracting timeframe. Transgrid will procure system security services from synchronous machines in the contracting timeframe based on latest information and unit availability from all technologies.

In comparison to the PACR, the reduced system strength need in years FY31-33 (due to delayed coal retirement) changed the preferred number of Phase 2 synchronous condensers from five to four. The delayed coal retirement timing coupled with the later delivery timing of synchronous condensers also provides additional time for grid-forming BESS to demonstrate credibility for the minimum level. We have opted to include grid-forming BESS for the minimum level (with sufficient fall-back solutions) to further reduce the number of Phase 2 synchronous condensers required from four to three.

This portfolio is the preferred option under both coal unit retirement scenarios, both synchronous condenser delivery timings, the New England REZ Stage 2 sensitivity and the higher and lower synchronous condenser cost sensitivity.

This assessment creates a pathway for grid-forming BESS to contribute to meeting minimum level system strength requirements, to the extent that the risk of not demonstrating their credibility can still be managed.

Additional non-network options could further change the optimal portfolio

Transgrid has identified that if additional, credible non-network options emerge, the optimal portfolio could be revised to further increase net market benefits. For this to occur, credible non-network options would need to be assessed and then selected within the preferred portfolio prior to Transgrid's lodgement of a contingent project application for Phase 2 synchronous condensers.

Transgrid has identified three changes which could lead to a reduction in the number of Phase 2 synchronous condensers within the preferred portfolio and lead to a higher market benefit outcome, subject to further criteria outlined in Section 11.

- If at least 500 MW of synchronous machines with synchronous condenser capability emerges in the Sydney / Newcastle region (or larger capacity but outside of the region). This is in addition to the 650 MW of synchronous machines with synchronous condenser capability across southern NSW that were identified in the PACR.
- If an additional 950 MW of grid-forming BESS for the minimum level (in addition to the 900MW already included in the preferred portfolio of this draft MCC assessment) emerges in the Sydney / Newcastle region and there is additional evidence to confirm their credibility such that fall-back solutions are not required.
- If sufficient coal generator units extend their Proponent Advised retirement dates beyond 2033 and this is expected to be included in the Step Change scenario in a subsequent AEMO Inputs, Assumptions and Scenarios Report (IASR) or ISP update.

Note that this list is not exhaustive. The exact amount required of a future solution will be dependent on its size, location on the grid, critical contingency and electrical characteristics.

Transgrid has explored different coal unit retirement assumptions during this assessment, even beyond Proponent Advised dates. If sufficient coal units were to extend their retirement dates beyond FY34, we expect the need for Phase 2 synchronous condensers will also be deferred commensurately, assuming a similar level of coal unit reliability and operational output could be maintained.

Deferred coal retirement dates in isolation are not expected to change the preferred portfolio composition, only the timing of the need for Phase 2 synchronous condensers and level of hydro and gas re-dispatch required. However, any delay in coal unit retirement that results in deferred investment provides more time for alternative solutions, including grid-forming BESS or emerging synchronous machines with synchronous condenser capability, to demonstrate credibility and/or become committed.

Transgrid will continue to monitor these changes (and others), which have the potential to change the preferred portfolio option.

Proposed next steps for system strength solutions

Synchronous condensers

Synchronous condensers for the first five sites have already been awarded (Phase 1). Transgrid is currently engaging with suppliers and collaborating with relevant stakeholders regarding the regulatory and procurement process to progress to deliver Phase 2 synchronous condensers, should these be identified in the preferred portfolio option in the final MCC assessment.

Grid-forming BESS

For the efficient level, Transgrid is currently evaluating responses to its initial tender for up to 2 GW of grid-forming BESS to support stable voltage waveform. Future tenders will occur as Transgrid progresses towards the PACR-identified portfolio of 5 GW; subject to holistic assessments of the need in the contracting timeframe.

For the minimum level, Transgrid is engaging with industry, AEMO and other network service providers to help progress the assessment and validation of the credibility of grid-forming BESS to provide protection quality fault current. Transgrid invites proponents of grid-forming BESS located in the Sydney West region interested in supporting the credibility assessment to contact Transgrid via email at systemstrength@transgrid.com.au, with a completed expression of interest (EOI) form accessible via Transgrid's website.

Re-dispatch of synchronous machines

Transgrid has completed its initial tranche of contracts for synchronous system security services. The timing for a second tranche of contracts will be informed by additional market modelling. Transgrid invites proponents to maintain an up-to-date EOI with Transgrid for system strength services.

Transgrid welcomes EOIs from parties with solutions that include modifications to existing or new synchronous machines, including hydro, coal and gas units, to enable their operation in synchronous condenser mode. The PACR identified upgrades to 650 MW of synchronous machines to enable synchronous condenser mode in southern NSW remains in the preferred portfolio.

Consultation on this draft MCC assessment

Noting the complexity of system strength planning and the revision of the preferred portfolio option in this assessment, it was determined appropriate to provide stakeholders an opportunity to provide submissions to this draft MCC assessment. As such, this draft MCC assessment will undergo a 1-month consultation period. Transgrid invites stakeholder submissions; submissions are due on 1 August 2026.

Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au[19]. In the subject field, please reference 'Meeting system strength requirements in NSW MCC assessment'.

Submissions will be used to inform the final MCC assessment, which is expected to be published by 24 August 2026, as stipulated by the AER.

The Final 2026 ISP was released on 25 June 2026. Transgrid intends to incorporate outcomes of the Final 2026 ISP in its final MCC assessment.

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

Contents

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1. Context and purpose

1.1. Purpose of this report

Transgrid completed a Regulatory Investment Test for Transmission (RIT-T) in July 2025 for the *Meeting System Strength Requirements in NSW* project. The Project Assessment Conclusions Report (PACR) identified a preferred portfolio option composed of:

- ten network synchronous condensers at Transgrid substations;
- modifications to 650 MW of non-network synchronous machines to enable synchronous condenser mode;
- up to 5 GW of non-network grid-forming battery energy storage systems (BESS) to support a stable voltage waveform for future renewables; and
- contracts with non-network synchronous machines to fill gaps in system strength where required.

This report presents Transgrid's draft assessment of material changes in circumstances (MCC) that have occurred since the publication of the PACR. The assessment has led to a refinement of the preferred option identified in the PACR, undertaken in accordance with clause 5.16.4(z4B) of the National Electricity Rules (NER).

Transgrid provided a notification to the Australian Energy Regulator (AER) in April 2026, to advise that a reopening trigger specified in the PACR had been met, in addition to changes to two other key assumptions[20]. Transgrid's notification to the AER included a set of proposed actions to address the MCC. In June 20256, the AER then determined the following actions were required[21]:

1. Undertake a streamlined cost benefit analysis, drawing on:
    a. the existing PACR analysis
    b. updated cost and timing information, and
    c. the most recent AEMO ISP-related inputs[22] and outputs and AEMO's 2025 Transition Plan for System Security, where relevant.
2. Transgrid must publish a draft statement on its website by 24 June 2026 which:
    a. sets out:
        i. a statement that the preferred option identified remains the preferred option, as well as any supporting information necessary to demonstrate that the preferred option identified remains the preferred option; or
        ii. a statement that the preferred option is no longer the preferred option and identifying the new preferred option, as well as any supporting information necessary to demonstrate that the preferred option is no longer the preferred option and the reasons the new preferred option is the preferred option,

[20] Meeting system strength requirements in NSW – Notification of Material Change in Circumstances Assessment, Transgrid, April 2026
[21] Material change in circumstances – Meeting system strength requirements in NSW – Determination, AER, June 2026
[22] The most recent AEMO ISP-related inputs are from the Draft 2026 ISP which has been used for this draft MCC assessment. The Final 2026 ISP was released on 25 June 2026 and will be incorporated into the final MCC assessment.

b. provides supporting information setting out the range of all potential solutions which could reasonably be expected to provide system strength, as well as reasons why any potential options were not considered credible or are considered to not form part of the preferred portfolio option,

c. provides a description of each of the changes in circumstances, including the changed operation of synchronous generation, and its materiality to the analysis, and

d. presents the updated cost benefit analysis developed under paragraph (1).

3. Transgrid must seek submissions from registered participants, AEMO and interested parties on the preferred option presented and the issues addressed in the draft statement. The period for submissions must be 1 month from the date Transgrid publishes the draft statement on its website.

4. Transgrid must publish a final statement which sets out the matters required under paragraph (2), incorporates feedback from submissions and provides a summary of, and response to, submissions received during the consultation period. The final statement must be published on Transgrid's website within 1 month of the closing date for submissions, at the latest by 24 August 2026.

This draft MCC assessment includes the outcomes of the updated assessment and details changes made to the preferred option. Appendix D provides a compliance checklist listing the relevant sections for each requirement outlined by the AER.

1.2. Transgrid's system strength obligations

System strength is a fundamental service required for the secure operation of the power system. System strength is the ability of the power system to maintain and control the voltage waveform, both during steady state operation and following a disturbance. Insufficient system strength can lead to instability, incorrect operation of protection systems, curtailment of inverter-based resources (IBR) and increased risk of widespread outages.

As the System Strength Service Provider (SSSP) for NSW, Transgrid is responsible to deliver both minimum and efficient levels of system strength. These levels are defined in AEMO's Transition Plan for System Security.[23]

Transgrid's system strength requirements are split into two components, being to:

- maintain the minimum three phase fault level specified by the AEMO for each system strength node in NSW – referred to as the minimum level.
- achieve stable voltage waveforms for the level and type of IBR and schedule 5.3a plant projected by AEMO – referred to as the efficient level.

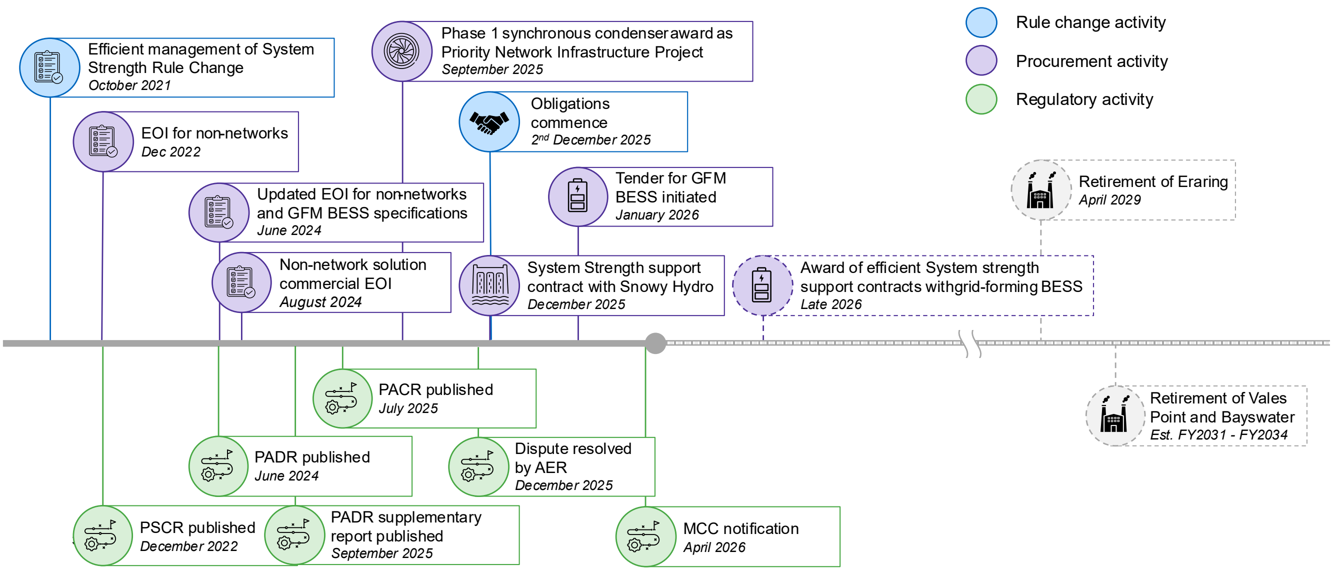
A detailed explanation of the identified need for system strength and obligations is outlined in section 2 of the PACR[24].

1.3. Timeline of activities to-date for managing system strength in NSW

Transgrid commenced activities to meet system strength requirements in NSW following introduction of the new system strength framework in 2021. A timeline of historical and selected forecast activities is shown in Figure 4.

[23] Transition Plan for System Security, AEMO, 2025
[24] Transgrid, 2025, Meeting system strength requirements in NSW PACR, page 22

Figure 4. Timeline of regulatory and procurement activities



In July 2025, the PACR concluded that the preferred option under the RIT-T was a portfolio of solutions, comprising ten synchronous condensers on Transgrid's transmission backbone, 5 GW of grid-forming BESS for the efficient level and re-dispatch of hydro, gas and coal generating units. This outcome was the result of extensive technical studies, stakeholder engagement and net economic benefit assessments across over 100 individual network and non-network solutions.

In August 2025, a dispute was raised regarding Transgrid's application of the RIT-T[25]. In December 2025, the AER published a determination[26], based on the grounds of the dispute, that Transgrid was not required to amend its PACR.

Following the completion of the PACR, Transgrid has commenced delivery of network and non-network solutions within the preferred portfolio option. Specifically, the following activities have been undertaken:

- Transgrid has awarded contracts for the first five synchronous condenser sites (labelled 'Phase 1' synchronous condensers). These are being procured under the direction of the NSW Energy minister[27] as a Priority Network Infrastructure Project (PNIP).
- Transgrid has contracted with SnowyHydro's Tumut 3 for system security services via operation in synchronous condenser mode, to be made available to AEMO and used when required; and
- Transgrid has initiated a tender process for up to 2 GW of grid-forming BESS for efficient level system security services.

[25] Notice of Dispute of Transgrid's RIT-T for Meeting system strength requirements in NSW, Centre for Independent Studies, August 2025
[26] Determination on RIT-T dispute – Meeting system strength requirements in NSW RIT-T, December 2025, AER
[27] Details of Priority Network Investment Projects and the NSW Government's direction can be found here

2. Nature of the material changes in circumstances

This section describes the MCC and changes to key assumptions that have been identified since publication of the PACR, and how they have been considered in this assessment.

2.1. MCC reopening trigger addressed in this assessment

Transgrid notified the AER on 29 April 2026 that a RIT-T reopening trigger identified in the PACR had been met, in line with Clause 5.16.4(z4)(2) of the NER. Specifically, that the expected *"costs of synchronous condensers required for 2031/32 or after increase by significantly more than 30%"*[28] .

Transgrid's assessment is that the expected costs for the deployment of the second five ('Phase 2') synchronous condensers are expected to meet this trigger threshold. This has been informed by the competitive procurement process for the accelerated 'Phase 1' synchronous condenser project[29], which was deemed by the AER to be the result of a genuine and appropriate procurement process[30] under the NSW EII Act. Further cost and supply chain pressures are forecast for Phase 2 synchronous condensers, due to a highly constrained market and impacts of the conflict in the Middle East. The combination of these drivers has been factored into the assessment in this report.

2.1.1. Increase in synchronous condenser capital costs

In October 2025, Transgrid signed a contract with GE Vernova to supply the first order of synchronous condensers required at five Transgrid sites (the 'Phase 1' synchronous condensers). Transgrid expects to sign contracts for site civil and balance of plant enabling works in mid-2026.

In April 2026, Transgrid submitted a revenue proposal[31] to the AER for its accelerated Phase 1 synchronous condensers project (the first five of the synchronous condensers identified in the PACR). The total cost of the project is $1.13 billion (in $FY25)[32], representing an average cost of $225 million ($FY25) per site. This compares to an estimated average cost of $163 million ($FY25) modelled in the PACR[33], equivalent to a 38% increase. This increase has been driven by the continued escalation of global demand and supply constraints for this equipment, as power systems worldwide transition away from fossil fuels to renewable energy.

Transgrid expects that the total project cost to deliver Phase 2 synchronous condensers (representing the remaining five of the synchronous condensers identified in the PACR) will increase beyond the cost of the accelerated Phase 1 synchronous condensers, due to ongoing market constraints and further supply chain impacts from the conflict in the Middle East. The expected average cost for Phase 2 synchronous condensers is $324 million ($FY25), based on a Class 4 estimate (-30%, +40%).

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[28] Meeting system strength requirements in NSW PACR, Transgrid, July 2025, Page 110
[29] Transgrid System Strength Project (hybrid), 22 April 2026, Revenue Submission to AER, https://www.aer.gov.au/industry/registers/determinations/system-strength-project-hybrid
[30] System strength project 2026-31 revenue proposal, Transgrid, April 2026, Page 49
[31] Transgrid System Strength Project (hybrid), Transgrid, April 2026
[32] Note a figure of $1.19 billion was provided in the revenue proposal based on a September 2026 dollar cost basis. All figures in this MCC report are based on 30 June 2025 dollars.
[33] The average cost presented in the PACR was $160 million, in $FY24, with actual costs estimated to be within -20% to +30% of the base capital cost estimate. Adjusted for inflation to enable a comparison to $FY25, this represents a cost of $163 million ($FY25) per site.

2.2. Other changes in key assumptions included in this assessment

Two other changes to key assumptions used to identify the preferred option in the PACR have occurred. These changes may also constitute an MCC under Clause 5.16.4(z4)(3) of the NER as they may affect the preferred option identified in the PACR[34]. These changes have been considered in this MCC assessment, namely:

- the potential for material increases in the delivery timeline for Transgrid's Phase 2 synchronous condensers, due to the time required to complete the regulatory process (including the dispute on Transgrid's PACR, this MCC assessment, the risk of further MCC assessments being required and a contingent project application under the NER) and increasing lead-times for available manufacturing slots ('length of the queue') for synchronous condensers due to tightening supply chains; and,
- changes to retirement dates and operational behaviour of NSW coal generation units, as forecast in AEMO's Draft 2026 ISP Step Change scenario and AEMO's 2025 Transition Plan for System Security.

These changes in key assumptions are expected to affect the preferred portfolio set out in the PACR, and therefore may constitute a MCC for the purposes of clause 5.16.4(z4).

The following sections describe the MCC key assumption changes since the PACR was published.

2.2.1. Timing of earliest synchronous condenser delivery

Estimated delivery timing for synchronous condensers is highly contingent on the time required for regulatory approvals, which then determines when manufacturing slots can be secured, in a context of sustained, heightened global demand for this equipment.

The delivery timeline for Transgrid's Phase 2 synchronous condensers has materially shifted from the timing assumed in the PACR (a range between March 2029 and February 2030 for the first synchronous condenser) to the beginning of FY34 for the first synchronous condenser. This is due to the time taken to resolve the dispute process on Transgrid's PACR[35] and this MCC process, as well as tightening supply chains due to rising global demand which is leading to increased lead times to obtain manufacturing slots.

This draft MCC assessment also considers an alternative synchronous condenser timing, from the beginning of FY31. This reflects an accelerated timeframe where early access to manufacturing slots with a shorter lead-time is possible. This timing is not currently considered credible. Acceleration is expected to only be credible if procurement commences prior to AER's approval of a contingent project application.

More detail on synchronous condenser timing is provided in Section 3.1.

2.2.2. Changes to coal unit retirement dates and operational assumptions

The projected retirement timing of NSW coal-fired generators has changed under AEMO's latest Draft 2026 ISP Step Change scenario, compared with AEMO's 2024 ISP (which informed Transgrid's system strength PACR). The retirement of both Vales Point units and a single Bayswater unit were deferred until FY34. Guidance provided by the AER is that SSSPs should use AEMO's latest Step Change scenario when applying the RIT-T[36].

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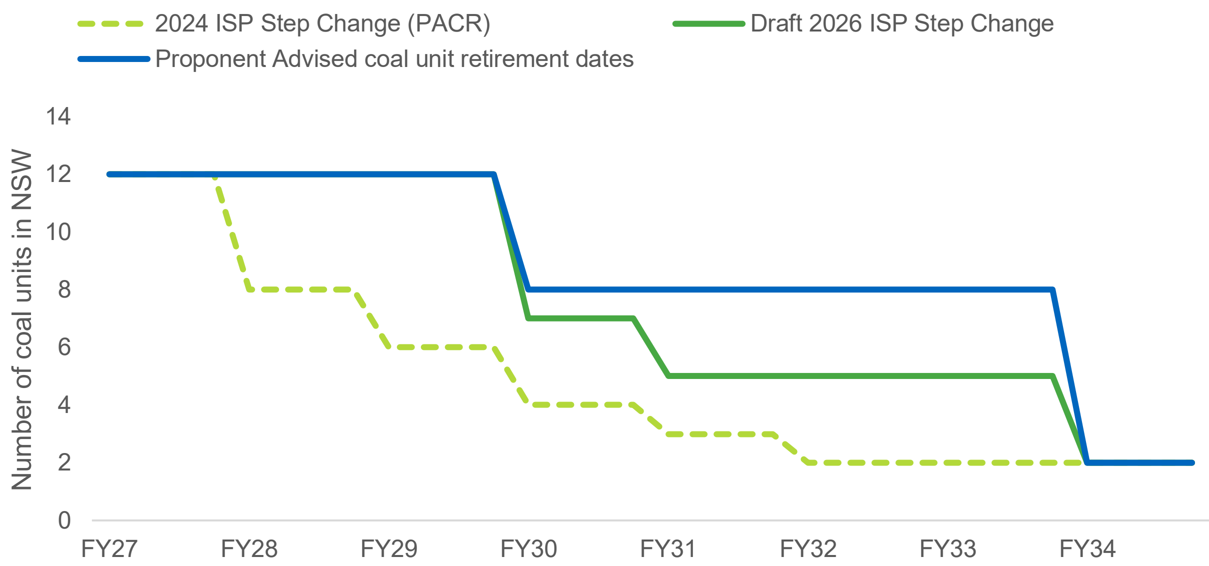
[34] Under NER 5.16.4(z4)(3), these changes in assumptions may constitute an MCC where, in the reasonable opinion of Transgrid, they may mean that the preferred option identified in the PACR may no longer be the preferred option.

[35] Following the PACR publication, the AER received a notice of dispute on Transgrid's system strength PACR in August 2025 and published its determination on the dispute in December 2025.

[36] The Efficient Management of System Strength Framework AER Guidance Note, AER, December 2024, Page 30.

The changes in coal retirement dates under the Draft 2026 ISP Step Change scenario are shown in Figure 5, in addition to Proponent Advised coal unit retirement dates[37].

Figure 5. Comparison of NSW coal unit retirement trajectory forecasts



The Draft 2026 ISP is the most recent publication of the ISP and has been used as the basis for the Step Change scenario for this assessment. The Final 2026 ISP was released on 25 June 2026 and will be considered in the final report of this MCC assessment.

Coal generator units provide system strength as a byproduct of their operation. Due to the ongoing operation of coal generators in the energy market associated with deferred retirement dates compared with the 2024 ISP (underpinning the PACR modelling), the need for additional system strength in the is reduced, particularly between FY28 and FY30.

Transgrid's power system modelling indicates that the Phase 1 synchronous condensers, along with non-network contracts for system security services, will be sufficient to meet system strength needs until FY31 under the Draft 2026 ISP Step Change scenario. From FY31, there will be five coal generator units remaining in NSW, at which time new sources of system strength will be required.

The Draft 2026 ISP and AEMO's December 2025 Transition Plan for System Security also forecast changes to the operating behaviours of coal generators, with coal generating units behaving more flexibly, to better align with market prices. These changes and their effects on system strength are tabulated below.

Table 3. Changes to coal operating behaviour and the associated effect on system strength provision

Change in behaviour	Effect on system strength provision
Introduction of two-shifting	Two-shifting reduces a coal generating unit's participation in the market by reducing generation output to zero (and desynchronising from the grid) for short periods of time, e.g. off in the morning and on again for the evening peak. During these periods, a coal unit does not provide any system

[37] As per AEMO's April 2026 Generating Unit Expected Closure Year file, which can be found here.

Change in behaviour	Effect on system strength provision
	strength. Bayswater units have exhibited two-shifting behaviour in the market[38].
Reduced minimum stable operating level (MSOL)	The MSOL for some NSW coal units has reduced since AEMO's 2024 ISP. This lowers the cost of coal unit 're-dispatch' (i.e. increased operating hours of a coal unit to meet system strength requirements).
Seasonal mothballing	AEMO's 2025 Transition Plan for System Security identified that some coal units in NSW may decommit from the market for months at a time (termed 'seasonal mothballing') as early as July 2028[39]. This is more likely to occur during shoulder periods when electricity prices are typically lower. This would reduce the system strength provided as a byproduct of typical energy market operation. The lead-time to ready a coal unit from this state to fill gaps in system strength can be prohibitively long.

AEMO has identified that ageing coal generators present an increasing risk of unavailability, as outlined in its 2025 Transition Plan for System Security, stating that "*statistically, failure rates increase as plants near the end of their planned operational life"*[40].

In the 2025 Thermal Audit[41], AEMO also stated that more flexible operating practices of coal units can accelerate equipment degradation by shifting the expected *"bathtub curve"* of failure rates forward and potentially introducing additional failure modes across the plant lifecycle.

Increased flexible operations, including those included in Table 3 above, may reduce the reliability of coal plants, compounding the risk to ageing assets. Decreased plant reliability impacts system strength availability and present risks to power system security unless appropriately managed. To assess how changing coal behaviour may affect the preferred portfolio option, we have conducted a case study (see section 8.2) with reduced coal availability due to early coal retirements, unexpected failure or seasonal mothballing.

We have also examined additional coal unit retirement dates beyond Proponent Advised coal unit retirement dates. Discussion of this is provided in Section 7.3.

2.3. Other changes to assumptions which are not material to this assessment

2.3.1. Eraring Power Station extension

Eraring Power Station has announced it will defer its retirement date from August 2027 to April 2029[42]. The additional system strength associated with Eraring's continued operation is expected to reduce the need for re-dispatch of other synchronous machines over this period. Transgrid will assess the impact of this change through its contracting process with synchronous machines, to ensure a prudent and efficient outcome.

[38] ASX & Media Release, AGL, 27 November 2025, AGL Bayswater Power Station site tour. *"We can now selectively two-shift Bayswater units, by shutting down and restarting units between demand peaks to optimise margin."*, p11.
[39] 2025 Transition Plan for System Security, AEMO, Page 60
[40] 2025 Transition Plan for System Security, AEMO, Page 21
[41] 2025 Thermal audit, AEMO, November 2025, Page 13
[42] Origin extends Eraring Power Station operations to 2029, Origin, January 2026

The delayed retirement date does not affect the outcome of this draft MCC assessment, as Eraring's deferred retirement date is still earlier than the earliest timing of Phase 2 synchronous condensers or grid-forming BESS for the minimum level.

2.3.2. Changes to Inverter-based resources (IBR) forecasts

In December 2025, AEMO published updated IBR forecasts in the 2025 Transition Plan for System Security, which sets Transgrid's efficient level requirements. These forecasts were derived from ongoing modelling being prepared for AEMO's draft 2026 ISP. Forecasts from the completed draft 2026 ISP is now available from AEMO's website.

Efficient level requirements are being addressed largely through non-network solutions (specifically grid-forming BESS), except for system strength needs within the South West REZ, which involves a combination of network and non-network solutions (see Section 4.3 for additional details).

For efficient level needs where non-network solutions formed part of the preferred portfolio, Transgrid will conduct a holistic assessment of non-network system strength needs in the contracting timeframe, to ensure prudency and efficiency. This includes assessment of Transgrid's connection pipeline to determine where the system strength need is arising.

3. Individual solutions assessed

This section summarises the individual system strength solutions available in the assessment which are combined to form portfolio options that meet the need. The following individual solutions have been considered:

- synchronous condensers
- 're-dispatch' (increase in operating hours) of synchronous machines (hydro, gas, coal)
- grid-forming BESS for the minimum level

The Phase 2 synchronous condensers identified in the PACR were required for the minimum level need in the Sydney West and Newcastle regions (with the exception of the Dinawan synchronous condenser). The minimum level requirements at other nodes will be met through Phase 1 synchronous condensers and other existing and committed sources of system strength.

The system strength contribution of solutions varies based on the electrical impedance from the solution to the point of the need. For this assessment, the need is focussed on the Sydney West/Newcastle region, so solutions located in this region will have a greater contribution.

3.1. Synchronous condensers

Synchronous condensers are large rotating machines that help manage voltage, inject synchronous fault current and improve the stability of the power system.

The PACR preferred option included network synchronous condensers at ten Transgrid substations. Synchronous condensers for the first five sites (Phase 1) have been awarded to GE Vernova, who will deploy two smaller synchronous condenser units at each site to meet Transgrid's specifications. Since Phase 1 synchronous condensers are committed assets, they are included in the base case of this analysis. The additional synchronous condensers under assessment via this MCC are labelled 'Phase 2'.

3.1.1. Drivers for cost and delivery timing assumption changes for synchronous condensers

Since the PACR, Transgrid has progressed procurement activities for Phase 1 synchronous condensers, and this process was used to inform the assumptions used in this draft MCC assessment for the remaining Phase 2 synchronous condensers. This section describes the key drivers affecting the cost and delivery timing assumptions of Phase 2 synchronous condensers, which include:

- extended regulatory processes;
- increased global demand for synchronous condensers; and
- tightening supply chains for synchronous condensers and design and construction services, in particular due to geopolitical factors.

Extended regulatory processes

The delivery timing for Phase 2 synchronous condensers has been revised, in part, due to additional regulatory processes required to be followed to enable the project to progress into the delivery stage. Specifically, the synchronous condenser timing assumed in the PACR did not include time to complete:

- The dispute process on Transgrid's system strength PACR[43]. The dispute process was initiated in August 2025 and was resolved in December 2025, when the AER determined that the PACR did not need to be amended.
- This MCC assessment. The MCC assessment commenced in December 2025 and will be completed with the publishing of the final MCC report by 24 August 2026.

Transgrid is obligated to monitor and assess further MCCs which may occur prior to submitting a regulatory proposal for a contingent project application under the NER. The potential for future MCCs creates uncertainty on the project scope and may delay the timing of contract award for the manufacture of synchronous condensers.

Due to increasing global demand, the queue for manufacturing slots is projected to increase over time. This means that delays to commencing procurement and regulatory approval processes creates a risk of extended delivery lead-time for this equipment, even if the time to manufacture the synchronous condensers does not change. Delays in commencing procurement would likely require a re-tendering for future synchronous condensers.

Increased global demand for synchronous condensers

Demand for synchronous condensers is increasing as power systems around the world transition from fossil fuels to renewables. The equipment is highly specialised, with a limited number of original equipment manufacturers globally. This can make securing manufacturing slots highly competitive. The table below shows recent international and domestic demand for this technology, noting that this list is not exhaustive.

Table 4. A sample of international and domestic demand for synchronous condensers

Location	Synchronous condensers	Timing of award
International demand for synchronous condensers		
United Kingdom[44]	4	April 2022
New York[45]	6	June 2024
Chile[46]	4	July 2024
Italy[47]	5	February 2025
Texas[48]	2	May 2025
Ireland[49]	4	October 2025
Saudi Arabia[50]	Nine sites	October 2025
Brazil[51]	6	January 2026
Domestic demand for synchronous condensers		

[43] Following the PACR publication, the AER received a notice of dispute on Transgrid's system strength PACR in August 2025 and published its determination on the dispute in December 2025.
[44] Quinbrook awarded four new contracts in Phase 2 of National Grid's pathfinder, Quinbrook, April 2022
[45] GE Vernova to build two turn-key synchronous condenser sites designed to improve grid stability in upstate New York, GE Vernova, June 2024
[46] GE Vernova to supply synchronous condensers equipment to help improve grid stability in Northern Chile, GE Vernova, July 2024
[47] Ansaldo Energia develops the grid with 5 new synchronous condensers, Ansaldo energy, February 2025
[48] Andritz to build synchronous condenser facilities to strengthen grid stability in Texas, Andritz, May 2025
[49] Renewable energy integration: Andritz to supply four synchronous condensers for Statkraft project in Ireland and Northern Ireland, Andritz, October 2025
[50] SEC awards synchronous condensers projects across Saudi Arabia, Saudi Golf Projects, October 2025
[51] Andritz to supply six synchronous condensers to stabilise Brazil's power grid, Andritz, January 2026

Location	Synchronous condensers	Timing of award
New South Wales – Central West Orana REZ[52]	7	May 2025
Queensland [53,54]	9	Four procured, with the remaining in planning
Victoria[55]	5	Upcoming procurement

Domestically, all eastern states completed their system strength RIT-Ts at similar times, with the outcomes for Queensland and Victoria also identifying synchronous condensers in their preferred portfolios. This may create further localised pressure on synchronous condenser delivery and installation.

Tightening supply chains for both synchronous condenser and design and construction services

Recent and ongoing geopolitical events continue to impact global supply chains. The conflicts in Ukraine, and the Middle East, are increasing costs across all infrastructure projects, as prices for inputs across the supply chain are impacted[56]. These pressures also have flow on impacts on domestic labour, particular in the energy sector[57]. These effects are expected to extend beyond the conflict itself.

These supply chain impacts have driven further increases in the cost estimate for Phase 2 synchronous condensers, beyond costs established through the accelerated Phase 1 procurement process. Ongoing geopolitical uncertainty, and associated supply chain impacts, have resulted in Transgrid widening the cost accuracy range for Phase 2 synchronous condensers to -30% to +40%, compared to -20% to +30% for the PACR.

3.1.2. Basis for assessing two synchronous condenser delivery timings

The timing of Phase 2 synchronous condensers is dependent on multiple factors, explained in Section 3.1.1, which creates uncertainty for the delivery timing to be assumed for this MCC assessment. As such, we have assessed two timings for Phase 2 synchronous condensers in this draft MCC assessment, similar to the approach taken in the PACR. The timings and key assumptions are listed in Table 5.

Table 5. Synchronous condenser delivery timing

Description	Timing	Key assumptions
Accelerated timing	July 2030 (FY31)	• Transgrid completes regulatory and procurement processes and award contracts before lead-times for available manufacturing slots increase. • Lead-time based on current Original Equipment Manufacturer (OEM) estimate. • Note that this timing is not currently considered credible. Acceleration is expected to only be feasible if procurement commences prior to AER's approval of a contingent project application.
Assumed timing	July 2033 (FY34)	• Longer regulatory approval processes (including potential for additional MCCs which require re-testing of project need and scope), delaying contract award.

[52] Siemens Energy partners with ACEREZ on NSW Renewable Energy Zone, Siemens Energy, May 2025
[53] Powerlink awards procurement for four synchronous condensers to Hitachi Energy, Powerlink, April 2026
[54] Meeting system strength requirements in Queensland PACR, Powerlink, June 2025
[55] Meeting system strength requirements in Victoria PACR, AEMO Victoria Planning, August 2025
[56] 2025 Electricity Network Options Report, AEMO, August 2025, Page 6
[57] 2025 Infrastructure Market Capacity Report, Infrastructure Australia, November 2025

Description	Timing	Key assumptions
		• Extended synchronous condenser procurement lead-times, including a likely need to re-tender for future synchronous condensers, due to growing international demand and tighter supply chains during extended regulatory and procurement processes.

While an delivery timing of FY34 has been modelled under the assumed timing, earlier delivery may be possible if contract award can occur faster than anticipated.

3.1.3. Revised assumptions for Phase 2 synchronous condensers

Changes to synchronous condenser cost assumptions for this draft MCC assessment compared to the PACR are presented in Table 6, reflecting latest information based on Phase 1 procurement and detailed feasibility studies for Phase 2 sites. Underlying drivers of cost increases are explained in sections 3.1.1 and 3.1.2, above.

Table 6. Summary of changes to synchronous condenser costs

Regulatory stage	Average cost per site & cost estimation range ($FY25)	Description
PACR, for Phase 1 and 2 synchronous condensers	$163 million [58] (-20%, +30%)	• PACR estimates were based on non-binding market sounding, completed in March 2025.
Revenue Proposal, for accelerated Phase 1 synchronous condensers[59]	$225 million [60]	• Includes contract costs with GE Vernova for the supply of synchronous condensers to each site as well as with design and construct partners. Each of these contracts were the result of competitive procurement processes that were deemed by the AER to be genuine and appropriate procurement processes[61], under the NSW EII Act.
MCC assessment, for Phase 2 synchronous condensers	$324 million (-30%, +40%)	• Updated costs for the draft MCC assessment are informed by contract costs for Phase 1 synchronous condensers, market escalation as well as supply chain impacts of the conflict in Middle East. • Inclusion of a single spare transformer across the fleet of Phase 2 synchronous condensers in this draft MCC assessment, to manage the high-impact low-probability risk of a transformer failure at a Phase 2 synchronous condenser location.

Changes to other assumptions for Phase 2 synchronous condensers are presented in Table 7, including fault current contribution, earliest delivery timing and preferred locations.

[58] The average cost presented in the PACR was $160 million, in $FY24, with actual costs estimated to be within -20% to +30% of the base capital cost estimate. This cost has been escalated by CPI to enable a comparison in $FY25.
[59] Transgrid System Strength Project (hybrid), Transgrid, April 2026
[60] The revenue proposal stated a cost of $1.19 billion for five sites, therefore averaging $238 million per site, based on a dollar cost basis of September 2026. All costs for this draft MCC assessment are shown in 30 June 2025 dollars. Transgrid System Strength Project (hybrid), Transgrid, April 2026
[61] Transgrid System Strength Project (hybrid), Transgrid, April 2026, Page 49

Table 7. Summary of changes to synchronous condenser assumptions

Assumption	PACR	MCC assessment	Reason for change
Fault current contribution per site[62]	1,050 MVA	927 MVA	• Based on contribution of awarded Phase 1 synchronous condensers.
Timing	FY30	FY31 and FY34 (two timings considered)	• See Table 5 above.
Preferred sites for Phase 2 synchronous condensers in order of preference			
Site 1	Dinawan	Dinawan	• Completion of detailed feasibility studies for Eraring, Liddell, Munmorah and Waratah West (in addition to previously completed feasibility studies for a second synchronous condenser at Newcastle and Kemps Creek).
Site 2	Kemps Creek	Munmorah	
Site 3	Newcastle	Newcastle	
Site 4	Eraring	Waratah West	
Site 5	Liddell	Kemps Creek	

The Dinawan synchronous condenser location is for remediation of inverter-based generation associated with the South West REZ. The remaining synchronous condensers are located in the Sydney/Newcastle region.

In the PACR, we identified that it may be necessary for Transgrid to re-evaluate and change the location of a network synchronous condenser to a different substation in the same region. This may occur if site constraints, unexpected costs or complexities are identified during the detailed design and procurement phases. This has occurred since the PACR, with Munmorah becoming the preferred site in the Sydney/Newcastle region while Eraring and Liddell have been removed. This change was driven by site suitability with Munmorah having a lower cost estimate than the alternative sites.

The benefits of synchronous condensers at Transgrid substations within the Sydney West, Newcastle or Hunter Valley regions are considered broadly interchangeable and would not materially affect the estimated net market benefits.

3.2. Re-dispatch of synchronous generators

Transgrid defines ‘re-dispatch’ as an increase in the operating hours of synchronous generators to provide system strength, in addition to their typical energy market operations.

3.2.1. Hydro

Hydro units provide system strength as a byproduct of their operation in either generating or pumping mode (where applicable). Some hydro units in NSW also have the capability to operate in ‘synchronous condenser mode’, where the turbine is de-watered, but remains synchronised to provide system strength without generating electricity. In this mode, the unit does not use water or require intervention in the electricity market beyond auxiliary power demand. This technology is well-suited to sustained operation. Transgrid has already contracted with SnowyHydro’s Tumut 3 units (which have synchronous condenser mode) for the provision of system strength.

[62] Fault current based on nominal unsaturated sub-transient reactance.

This MCC assessment included existing, committed and anticipated hydro units in NSW, similar to the PACR approach. As hydro re-dispatch is expected to be predominantly in synchronous condenser mode, the modelled cost is based solely on the additional maintenance costs from increased operation. There is no additional fuel usage or emissions production, so there are no associated costs. This is consistent with the PACR and RIT-T guidelines, where costs represent the underlying economic cost, rather than the expected cost to contract with the service provider.

3.2.2. Gas generators

Gas units are also assessed to be available for re-dispatch, up to a defined limit. There are no existing gas units in NSW with the capability for synchronous condenser mode, so this solution requires units to generate electricity to provide system strength, typically at a unit's minimum stable operating level. The cost of gas re-dispatch included in the MCC is dependent upon the fuel price, additional maintenance requirements and emissions production associated with generation.

Gas re-dispatch is not well-suited to sustained operation for system strength, due to pipeline and gas supply constraints limiting availability. Transgrid has developed two gas constraints for this analysis to reflect these considerations. These constraints are based on AEMO's assessment of gas supply via its latest Gas Statement of Opportunities (GSOO), released in March 2026[63], as well as from technical advice provided by GHD to support Transgrid's PACR. AEMO was consulted during the development of the gas constraints used in this MCC assessment. The two gas constraints are:

- Limiting coincident gas re-dispatch for system strength at any point in time, to reflect pipeline limitations on the Sydney–Newcastle line. This pipeline supplies gas to the bulk of the gas units in NSW which provide a material system strength contribution to the Sydney West and Newcastle regions.
- Limiting total annual gas re-dispatch based on a percentage of annual typical energy market dispatch, to reflect gas supply limitations. This constraint becomes more stringent from FY33 as southern production declines.

When gas re-dispatch exceeds the gas constraints in the model, it is considered a risk of a system strength gap and is quantified as involuntary load curtailment in the MCC assessment. Additional details of these constraints are provided in 0, including the results when the gas constraints are not included.

The PACR included a pipeline constraint on the Sydney-Newcastle pipeline, which limited coincident gas re-dispatch for units served by this pipeline. The PACR did not implement a total annual gas constraint as it was not expected to affect the ranking of portfolio options. This was because only the lowest-ranking option had a material amount of gas re-dispatch, and including the constraint would have lowered its net market benefits further. For this MCC assessment, the gas constraints are expected to affect the ranking of portfolio options, which is why they have now been included.

3.2.3. Coal generators

Coal unit re-dispatch was not included in this MCC assessment. Coal generator unit availability is highly uncertain given reliability, fuel supply, seasonal mothballing and potential early retirements. In addition, under the Improving Security Framework rule[64], AEMO is prevented from enabling a contract for security purposes more than 12 hours ahead of the trading interval; this potentially rules out coal re-dispatch from cold start.

[63] 2026 Gas Statement of Opportunities, AEMO, March 2026
[64] AEMC, March 2024, Improving security frameworks for the energy transition rule change

Finally, the modelling horizon commences in FY31 in this analysis and there is limited coal availability beyond FY34 after the retirements of Eraring, Vales Point and Bayswater units (unlike the PACR where the modelling horizon commenced in FY26). As such, including coal re-dispatch was not considered in this analysis.

Transgrid will procure system security services from synchronous machines in the contracting timeframe based on latest information and unit availability from all technologies.

3.3. Grid-forming BESS contribution towards minimum level requirements

Grid-forming BESS is considered mature for providing efficient level system security services. Transgrid's system strength PACR identified 5 GW of grid-forming BESS for the efficient level as part of the preferred portfolio of solutions by the early 2030s. Transgrid has initiated a tender for up to 2 GW of grid-forming BESS for the efficient level need[65]. Considering the ability of grid-forming BESS to 'value-stack' system security services with its other functions, including energy shifting and frequency control, its provision of efficient level services is expected to come at a low marginal cost.

However, grid-forming BESS are not currently considered credible for contributing towards the minimum level of system strength, as their capability to provide protection quality fault current has not yet been demonstrated. This was stated by AEMO in 2024[66] and re-confirmed in the 2025 Transition Plan for System Security, with AEMO noting that the *"provision of protection quality fault current remains a key limitation of GFM"*[67]. The key limitations of grid-forming BESS for protection quality fault current are detailed in a report commissioned by AEMO[68]. The report states *"grid-forming inverters offer improved stability and impedance control but still face limitations in fault current magnitude and consistency"*.

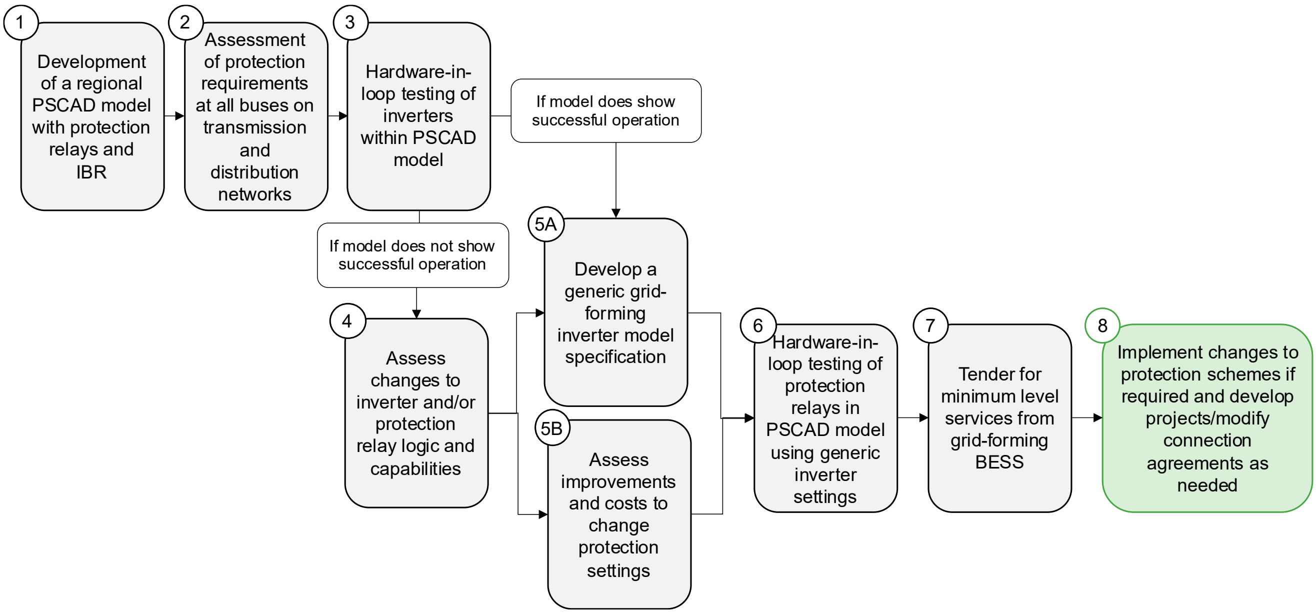
This creates challenges for the reliable operation of protection systems, because protection equipment has been designed and configured based on the fault response of synchronous machines and the fault current response of grid-forming BESS is inherently different to synchronous machines. This is a priority action listed in AEMO's Engineering roadmap[69] and Transgrid has commenced engagement with industry bodies to progress further research and trials of this technology.

3.3.1. Projected timing of credible grid-forming BESS contribution towards minimum level requirements

Transgrid's view on the steps anticipated to be required to demonstrate how grid-forming BESS can provide protection quality fault current is shown in Figure 6. Note these steps are indicative only, and will be further informed by industry including the status of AEMO's Type 2 trials.

[65] Transgrid, April 2026, Media release, Critical NSW grid stabilisation plans advance to final stages
[66] AEMO, May 2024, Update to the 2023 Electricity Statement of Opportunities
[67] 2025 Transition Plan for System Security, AEMO, December 2025, Page 135
[68] Grid-Forming and Grid-Following Inverter Fault Current Contribution, Etik Energy, November 2025
[69] Engineering roadmap FY2026 priority actions report, AEMO, July 2025, Page 40

Figure 6. Indicative steps to prove credibility of grid-forming BESS for the minimum level



An independent assessment completed by Aurecon[70] during Transgrid's system strength RIT-T estimated grid-forming BESS could be credible from FY33. A similar independent report commissioned by AEMO re-confirmed the limitations of the technology for providing protection-quality fault current[71]. This timing assumption was applied in the PACR, with grid-forming BESS available to be selected by the model from FY33. In the PACR, solutions for the minimum level were required well before FY33, given the earlier coal retirements, meaning that no grid-forming BESS for the minimum level were selected in the preferred portfolio.

Based on the time required to undertake the steps outlined above, and with consideration of industry updates including the status of AEMO's Type 2 trials, Transgrid does not consider any change to this FY33 time estimate is justified at this stage. There is still considerable uncertainty of the scope required to enable the technology, as outlined below:

- The availability and maturity of Electromagnetic Transient (EMT) models for protection relays, as EMT modelling on protection relays has not historically been required.
- The extent of potential change required to both protection relay and inverter capacities and operational logic.
- Time required and regulatory pathway to enable changes to protection schemes, if required.
- Availability and maturity of grid-forming BESS projects in the Sydney West region.

Transgrid has commenced work on the steps outlined above, and will continue to engage with industry and monitor updates for this technology.

Although not currently considered a credible solution, as a result of its strong potential to form part of the preferred portfolio option, Transgrid has included it as a solution for consideration in this assessment from FY33, rather than excluding it altogether. To manage the risk posed to system security associated with the uncertainty of when, or if, grid-forming BESS will provide protection quality fault current, Transgrid will only

[70] Advice on the maturity of grid forming inverter solutions for system strength, Aurecon, March 2024
[71] Grid-forming and grid-following fault current contribution, Etik Energy, November 2025

rely on this solution to the extent that there are sufficient alternative fall-back solutions available (i.e. gas and hydro re-dispatch). This is discussed further in Section 5.1.3.

3.3.2. Location of grid-forming BESS projects

During PACR and subsequent power systems modelling, Transgrid has assessed the largest minimum-level system strength needs to be surrounding the Sydney West, and then Newcastle, nodes. Requirements at other nodes are expected to be met by Phase 1 synchronous condensers and other existing/committed sources of system strength.

For this MCC assessment, the fault level contribution of theoretical grid-forming BESS from different locations on the 330 kV network within the Sydney West region has been calculated using power system modelling. A location 'de-rating' was then applied to capture the diminishing contribution of solutions located further from the system strength node, as it is unlikely a solution will connect directly to the Sydney West node. Only potential projects on the 330 kV or 500 kV networks were included in the assessment, as the relatively high impedance on lower-voltage networks results in materially lower, and in some cases negligible, system strength contribution, making them inefficient solutions for the purposes of this assessment.

3.3.3. Costs applied to grid-forming BESS solutions

BESS included under the Draft 2026 ISP Step Change scenario are modelled in this MCC assessment to have an incremental capital cost of only 5% of the total AEMO 2025 IASR project cost, to reflect the potential uplift required to enable protection quality fault current capability. The underlying capital cost and operating costs of the projects themselves are not included in the assessment, as these costs are already assumed to be incurred in the base case given the projects are forecast to enter the market under the Draft 2026 ISP Step Change scenario. This is consistent with the approach adopted in the PACR.

4. Modelling approach and assumptions

In Transgrid's MCC notice to the AER, we proposed a streamlined assessment rather than a re-application of the RIT-T. This recommendation was supported by the AER[72], with consideration to the likely high cost to the energy market, and ultimately consumers, that would result from the delay caused by the re-application of the RIT-T.

This section describes Transgrid's approach to the MCC assessment, including the scenarios modelled, characterisation of the base case and market benefit classes quantified.

4.1. Coal unit retirement dates

This MCC assessment considers a range of coal generator retirement dates, noting the uncertainty between and divergence of coal generator retirement dates projected under AEMO's Draft 2026 ISP Step Change scenario, and current Proponent Advised dates. Transgrid has tested this range of coal retirement dates to provide robustness to the analysis and to mitigate the need for further MCC assessments, if subsequent ISPs were to indicate delayed retirement schedules. Transgrid has assessed two coal retirement schedules, as per Table 8.

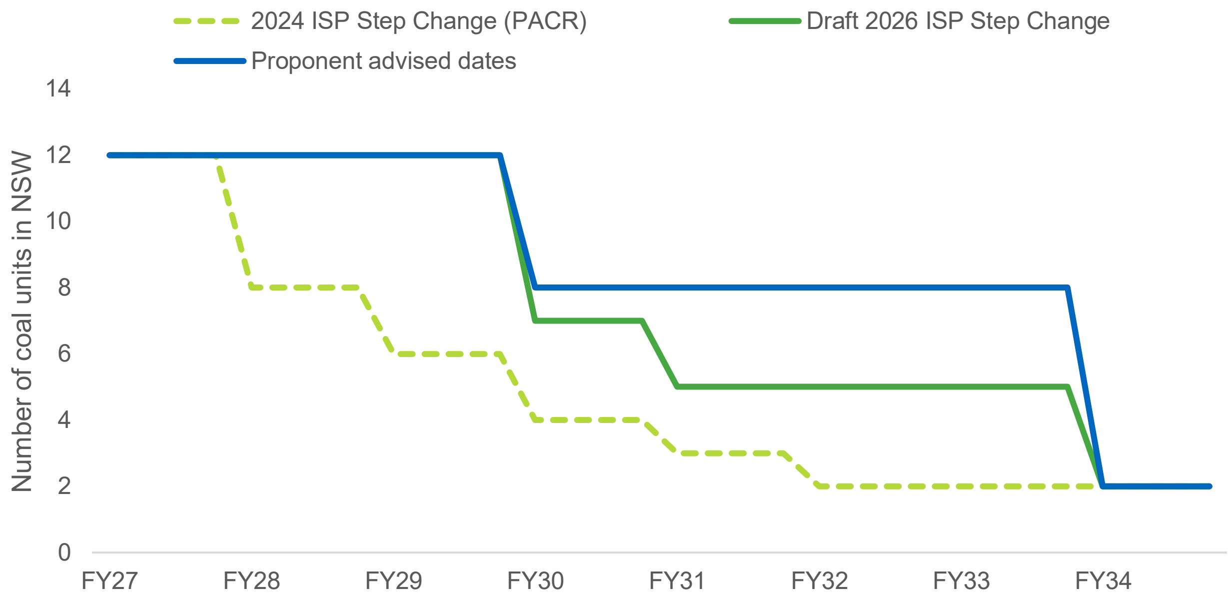
Table 8. Coal generator retirement scenarios modelled in this MCC assessment

Scenario	Description
Draft 2026 ISP Step Change	Coal retirement dates are taken as an output of AEMO's Draft 2026 ISP Step Change scenario. This represents the earliest coal unit retirement timing in this assessment.
Proponent Advised coal unit retirement dates	Coal retirement dates are based currently advised proponent timings, as published by AEMO[73].

The two coal generator unit retirement schedules modelled for this MCC assessment are shown in the graph below, along with the coal generator retirement schedule that underpinned the PACR analysis.

[72] Material change in circumstances – Meeting system strength requirements in NSW – Determination, AER, June 2026
[73] Generating Unit Expected Closure Year – Apr 2026, AEMO, April 2026

Figure 7. Coal generator retirement scenarios considered in this assessment



As shown in Figure 7, the two coal generator retirement schedules used in this MCC assessment diverge between FY30 and FY33, before converging in FY34 (and beyond). During the FY30-33 period, the provision of system strength associated with typical market dispatch of coal generators will differ. Under the Proponent Advised coal generator retirement dates, where coal units remain in the market for longer, there will be increased operation of coal units in the energy market and therefore higher system strength provision. Modelling both coal generator retirement scenarios enables us to understand if extensions to coal unit retirement dates out to proponent advised retirement dates are material to the ranking of portfolio options.

For each coal generator retirement schedule, Transgrid has assessed the optimal portfolio under both the accelerated (FY31) and assumed timing (FY34) of synchronous condenser deployment. No other changes to the Draft 2026 ISP Step Change scenario were included for the Proponent Advised coal unit retirement scenario.

We also assessed the implications of coal unit retirement dates beyond the Proponent Advised coal unit retirement scenarios. These are discussed in Section 7.3.

4.2. Treatment of New England Renewable Energy Zone

The system strength PACR identified seven synchronous condensers in the New England Renewable Energy Zone (REZ) were required to remediate the REZ as part of the preferred portfolio option, in addition to the ten synchronous condensers on Transgrid's transmission backbone. These solutions were separately itemised, as Transgrid stated that EnergyCo may adopt an approach outside of the NER framework, where central system strength remediation is the responsibility of a third-party network operator (rather than Transgrid as the SSSP for NSW). EnergyCo is now leading the design of system strength solution for the New England REZ. As such, Transgrid has excluded from this MCC assessment the identification of the portfolio of system strength solutions required for the New England REZ.

EnergyCo is exploring an approach where proponents largely self-remediate their system strength impact, either behind the connection point or 'in front of the meter'[74]. This would likely result in system strength remediation for the REZ being largely provided by grid-forming BESS. Transgrid is progressing joint planning with EnergyCo, including EMT studies, to support EnergyCo in confirming the efficient level requirement and the preferred system strength solutions for the REZ.

Based on experience from Transgrid's EMT studies completed for the PACR, we expect a grid-forming BESS solution will be capable of meeting the efficient level requirement for New England REZ Stage 1. However, synchronous condensers may be required for Stage 2 to complement the grid-forming BESS solution given the scale of renewables within the REZ (~10 GW). The flow of system strength from these potential New England REZ synchronous condensers could affect the ranking of portfolio options for Transgrid's transmission backbone. Stage 2 of New England REZ was not selected in the Optimal Development Path of AEMO's Draft 2026 ISP Step Change scenario, so these possible synchronous condensers have not been considered in the core MCC assessment.

However, while New England Stage 2 is not in the ODP of the Draft 2026 ISP, EnergyCo is actively planning its delivery. As such, Transgrid has undertaken a sensitivity in this MCC assessment where stage 2 of the REZ is progressed, and some synchronous condensers are required. Transgrid anticipate two synchronous condensers may be required for New England REZ Stage 2, if a grid-forming BESS solution is pursued. This sensitivity therefore includes two synchronous condensers installed for New England REZ Stage 2.

This sensitivity has been developed to test whether the fault current contribution from these New England REZ synchronous condensers, which would propagate into the broader NSW network, would change the composition of the preferred portfolio option. The sensitivity is helpful to manage the risk of a future MCC for a change to the system strength solution for New England REZ. Results to this sensitivity are outlined in Section 9.1.

4.3. Treatment of the Dinawan synchronous condenser

The South West REZ is being developed by EnergyCo, and Transgrid has maintained responsibility for system strength remediation as the System Strength Service Provider. The South West REZ is expected to host 3.56 GW of IBR[75] at or near Dinawan substation by the early 2030s.

As identified in the PACR, Dinawan is electrically distant from the nearest system strength nodes, which reduced the effectiveness of the available fault level methodology. Transgrid opted to complete a separate out-of-model assessment using EMT studies to assess solutions to meet the efficient level need and identify the cost impacts of any constraints on access rights projects in the REZ. This assessment identified one synchronous condenser at Dinawan was required within the preferred portfolio.

The need and analysis remain unchanged from the PACR (including when considering latest IBR forecasts from AEMO's draft 2026 ISP), but the same market benefits methodology has been applied for this assessment given the revised synchronous condenser timing. Transgrid is engaged in joint planning with EnergyCo for the delivery of the South West REZ.

Further details can be found in Appendix J of the PACR[76].

[74] EnergyCo, August 2025, New England Renewable Energy Zone Generation and Storage Consultation Paper
[75] South West Renewable Energy Zone, EnergyCo
[76] Meeting system strength requirements in NSW, Transgrid, July 2025, Appendix J

4.4. Representation of the base case

The purpose of the base case is to provide a baseline or 'do nothing' counterfactual against which different portfolio options and sensitivities can be compared. A 'do nothing' scenario would mean that Transgrid does not procure any additional system strength solutions to meet the minimum level need beyond what is already anticipated or committed to be deployed. This scenario would ultimately incur significant system strength violations and unserved energy for consumers. Net market benefits of each portfolio option are assessed against a 'do nothing' base case (or counterfactual scenario), in line with RIT-T requirements.

Over time, system strength gaps would be expected to occur as coal units increasingly decommit and retire. In real-time, AEMO would seek to close or reduce the impact of system strength gaps through recalling planned outages of transmission assets and generators or constraining output from IBR, with customer load shedding ultimately occurring.

Transgrid has used a modelling horizon from FY31 to FY45 for this assessment. Years before FY31 are not relevant to this assessment as they are before the earliest timing of new system strength solutions considered in this analysis. The system strength need is also lower before FY31, as under both coal retirement scenarios there are at least seven coal units in NSW, as well as Transgrid's Phase 1 synchronous condensers. Transgrid will continue to refine the optimal portfolio from the PACR in the contracting timeframe using non-network solutions. The year FY45 was selected for consistency to the PACR.

Each coal unit retirement scenario has its own base case, and forms a separate net market benefits assessment. The net market benefits between the two scenarios should not be compared, however the ranking of the portfolio options can be compared.

The table below summarises what is and is not included in the base case.

Table 9. Description of the base case

Treatment in base case	Components
Included	• Transgrid's Phase 1 synchronous condensers • ACEREZ synchronous condensers for Central West Orana REZ • Synchronous condensers deployed as part of Project EnergyConnect • Re-dispatch of existing, committed and anticipated synchronous machines (via directions in lieu of non-network contracts with Transgrid) • Transmission augmentations included in the Draft 2026 ISP Optimal Development Path
Excluded	• Phase 2 synchronous condensers • Grid-forming BESS contributions to the minimum level

4.5. Net market benefit assessment

Each identified portfolio option is assessed through a cost-benefit analysis against the base case, with the differences in each market benefit class calculated for each scenario, consistent with the PACR and RIT-T guidelines. The portfolio option which maximises net market benefits then becomes the preferred option. This assessment is provided in the accompanying workbook.

4.5.1. Types of market benefits

Market benefits are calculated by comparing the 'state of the world' in the base case, where no action to meet the need is taken, with the 'state of the world' with each of the portfolio options in place, consistent with the RIT-T guidelines[77].

The market benefit classes that have been modelled for this MCC are:

- changes in fuel consumption in the NEM arising through different patterns of generation dispatch;
- changes in Australia's greenhouse gas emissions;
- changes in involuntary load curtailment; and
- changes in costs for other parties.

This assessment did not rerun time-sequential market modelling, which was completed for the PACR. The effort and time to perform this modelling was not considered proportionate to the impact on the ranking of portfolio options, as the dispatch outcomes between portfolios is not expected to materially diverge since:

- Hydro re-dispatch hours occur primarily in synchronous condenser mode (i.e. no required pumping or generation of electricity which impacts energy market dispatch).
- Synchronous condensers do not participate in the energy market (the small auxiliary load would have an immaterial impact on energy market dispatch outcomes).
- There is no change to the generation and storage capacity outlook between portfolios (i.e. the solutions included in each portfolio option are also in the base case, and therefore the future generation mix does not vary between portfolio options).
- Gas re-dispatch is assumed to occur at minimum stable operating levels and used only as a last resort due to high marginal costs.

Each of the four key market benefit classes estimated are outlined in the sections below.

4.5.1.1. Changes in fuel consumption

Differences in fuel consumption between portfolio options reflect changes in the amount of synchronous machine dispatch required to meet system strength needs. Under portfolio options with more synchronous condensers and grid-forming batteries for the minimum level, less gas generation is re-dispatched, leading to reduced fuel consumption.

4.5.1.2. Changes in Australia's greenhouse gas emissions

Changes in Australia's greenhouse gas emissions were estimated based on the level of additional gas re-dispatch across each portfolio. The Value of Emissions Reduction (VER) adopted by Transgrid, consistent with AEMO's Draft 2026 ISP Inputs and Assumptions workbook[78], was then applied to the modelled level of re-dispatch, to quantify the associated emissions cost. This is consistent with the approach taken in the PACR.

4.5.1.3. Changes in involuntary load curtailment

If the minimum level of system strength is not met, voltage control and protection systems may not operate correctly, in the worst case leading to cascading failures in the transmission network and widespread power

[77] Regulatory investment test for transmission application guidelines, AER, November 2024, Section 3.7.1
[78] Draft 2026 ISP Inputs and Assumptions workbook, AEMO, December 2025

outages. As such, involuntary load curtailment is modelled where the minimum level of system strength is not met. While the portfolio options assessed are specifically designed to avoid these outcomes, a residual risk of involuntary load curtailment remains under some portfolio options, and, in particular, under the base case where no action to meet the need is taken.

This assessment quantifies involuntary load curtailment based on violations to minimum level requirements using the same methodology applied in the PACR[79]. The Value of Customer Reliability (VCR) is applied to quantify the estimated economic value of avoided involuntary load curtailment for each portfolio option. This value has been updated based on the latest AER estimate[80].

4.5.1.4. Changes in costs for other parties

For this assessment, changes in costs for other parties are tied to increases in variable operating and maintenance costs associated with the re-dispatch of hydro and gas units. These costs have been modelled using AEMO's Draft 2026 ISP Inputs and Assumptions workbook[81], consistent with section 3.4 of the RIT-T guidelines[82].

4.5.1.5. Other market benefits are considered immaterial

The PACR also considered two further categories of market benefit:

- changes in voluntary load curtailment; and
- changes in network losses.

These categories were both found to be immaterial in the PACR assessment[83]. We have therefore excluded them from this MCC assessment as we do not consider anything has changed that would alter this conclusion.

The remaining market benefit classes identified in the RIT-T guidelines[84], including competition benefits, option value and changes in ancillary service costs, were expected to be immaterial in the PACR and were excluded[85]. Transgrid have excluded these market benefit classes from this assessment as no change has occurred which would warrant a different approach.

4.5.2. Cost benefit analysis parameters adopted

This draft MCC assessment models a 20-year assessment period from FY31 to FY50, inclusive. FY31 is the earliest year that new solutions may be available, and so the approach to managing system strength solutions between FY26-30 will be common to all portfolio options.

A 20-year assessment period was selected to align to the duration of the modelling horizon in the system strength PACR. This period is commensurate to the size, complexity and expected lives of the assets delivered under the credible options assessed and provides for a reasonable indication of the costs and benefits over a long outlook period.

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79 Baringa, August 2025, PACR - Baringa Market Modelling Report, pg. 27
80 Value of customer reliability 2025 Annual Adjustment Summary, AER, December 2025
81 Draft 2026 ISP Inputs and Assumptions workbook, AEMO, December 2025
82 Regulatory Investment Test for Transmission application guidelines - Version 6, AER, November 2024
83 Meeting system strength requirements in NSW PACR, Transgrid, July 2025, Page 139
84 Regulatory investment test for transmission application guidelines, AER, November 2024, Section 3.6
85 Meeting system strength requirements in NSW PACR, Transgrid, July 2025, Appendix F.9

4.5.2.1. Annualised capital cost

Since the system strength PACR, Transgrid has aligned its approach to annualising and discounting costs with AEMO's ISP methodology[86]. Under this methodology, the capital investment is converted into an equivalent annual annuity to allow like-for-like comparison on assets with different economic lives and different commissioning dates. Transgrid is required to follow the assumptions used by AEMO[87] and has incorporated this methodology into this assessment.

In calculating this annuity, we have adopted the technology-specific real pre-tax weighted average cost of capital (WACC) estimates included in AEMO's 2025 IASR. Specifically, we have adopted an assumed three per cent WACC for regulated transmission investments and eight percent for battery projects in the Step Change scenario[88].

This methodology is different to the net market benefit assessment used in the PACR, which used a capitalised cost based on when it is incurred by Transgrid to deliver the solution (or procure the service for a non-network solution). The NPV workbooks for each assessment are provided on Transgrid's website.

Transgrid also completed the net present value assessment following the same methodology as the PACR to enable a like-for-like comparison, see Appendix C. This assessment showed the ranking of portfolio options is the same across both methodologies.

4.5.2.2. Discount rate

The AER Cost Benefit Analysis Guidelines require the discount rate used in the NPV analysis to be the commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. A central discount rate of seven per cent (real, pre-tax) has been used in the NPV analysis, consistent with the commercial discount rate in the 2025 IASR.

[86] ISP methodology June 2025, AEMO, June 2025, Page 94
[87] Regulatory investment test for transmission application guidelines, AER, December 2024, Section 3.4
[88] 2025 Inputs, Assumptions and Scenarios Report, AEMO, August 2025

5. Portfolio formation methodology

The following sections describe the methodology used in this MCC assessment to identify the composition of each system strength portfolio option.

Portfolio options were constructed to assess the need for each Phase 2 synchronous condenser, alongside re-dispatch of hydro and gas generators and grid-forming BESS towards the minimum level requirements.

5.1.1. Identifying the number of synchronous condensers

Five portfolio options were assessed, with each portfolio option including between one and five Phase 2 synchronous condensers, e.g. portfolio option 1a has one Phase 2 synchronous condenser, while portfolio option 5a has five Phase 2 synchronous condensers. The base case represents the portfolio option where zero Phase 2 synchronous condensers are included.

5.1.2. Identifying the amount of hydro and gas re-dispatch

For each portfolio option, power system studies were undertaken to assess the gap in system strength against Transgrid's minimum level system strength requirements[89]. The power system studies used coal duration curves derived from PACR market modelling to estimate the proportion of the year each number of coal units were online and then identified the residual system strength gap as a result. The coal duration curves did not consider material two-shifting or seasonal mothballing, as coal units which are offline due to economic decommitment are likely to be available for re-dispatch if this behaviour does occur, therefore having no net effect on the risk of system strength gaps. A case study has been considered where greater economic decommitment does reduce the availability of coal units in section 8.2.

In addition to the synchronous condenser(s) included in each portfolio option, hydro and then gas units were progressively added, in order of marginal cost between technologies, until the system strength requirements were met. The availability of hydro units was informed by recent procurement outcomes for re-dispatch. The availability of gas units was subject to modelled gas constraints based on practical supply and pipeline limitations. Further detail of the modelled constraints is provided in Section 3.2.2 and Appendix B.

Gas re-dispatch is the highest marginal cost system strength solution, therefore if gas constraints bind, there is limited alternative solutions available to meet system strength requirements. Where constraints were binding, a system strength gap was modelled. This gap was quantified as involuntary load curtailment for the net-market benefits assessment, following the same methodology applied in the PACR[90].

5.1.3. Identifying the amount of grid-forming BESS for the minimum level

Grid-forming BESS are not currently considered credible to meet minimum system strength requirements, as per the PACR, re-confirmed by AEMO's public position[91] and independent advice from Aurecon[92] for Transgrid's system strength PACR. Aurecon's advice stated that the credibility of grid-forming BESS for the minimum level was likely to be demonstrated by FY33.

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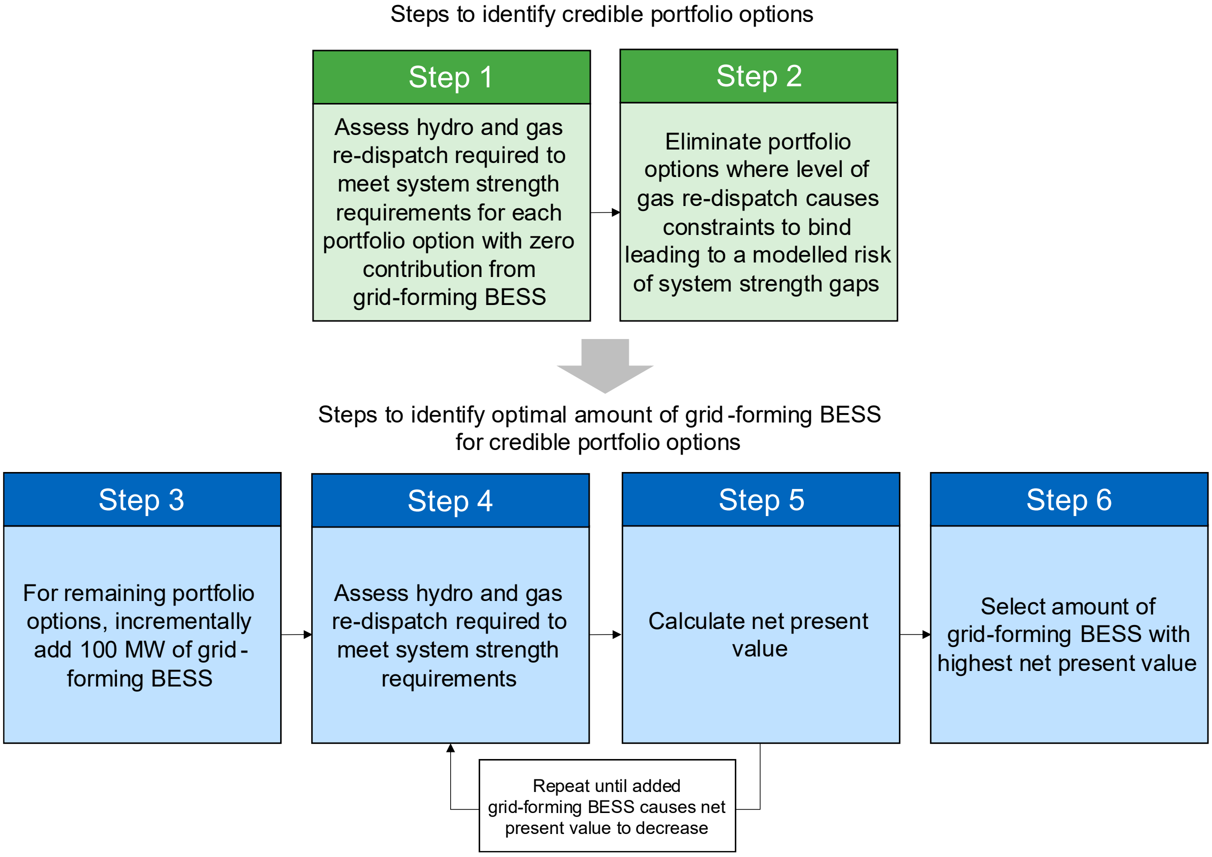
[89] Transgrid's system strength requirements are defined by AEMO in its Transition Plan for System Security as per Clause 5.20C.1 of the National Electricity Rules.
[90] System Strength PACR Modelling Report, Baringa, August 2025, Page 29
[91] Transition plan for system security, AEMO, December 2025, Page 135
[92] Advice on maturity of grid-forming inverter solutions for system strength, Aurecon, March 2024

If proven credible for the minimum level of system strength, and located in areas of need, grid-forming BESS could provide a low-cost system strength solution by value stacking minimum level system strength support with other energy, ancillary market and efficient level system strength services.

Noting that this technology is not yet credible, Transgrid has taken a risk-balanced approach to include grid-forming BESS as an available solution from FY33, to the extent that there are sufficient fall-back hydro and gas re-dispatch solutions available to meet the need. This mitigates the risk of grid-forming BESS not performing as intended, or if their credibility for the minimum level is not demonstrated in-time.

The methodology to identify the optimal amount of grid-forming BESS for each portfolio option is illustrated in the figure below.

Figure 8. Methodology to identify the optimal amount of grid-forming BESS for each portfolio option



Steps 1 and 2 are designed to manage the risk stemming from when grid-forming BESS will demonstrate its credibility for providing protection-quality fault current. Steps 1 and 2 identify if a portfolio option has sufficient fall-back solutions, by testing the portfolio option without grid-forming BESS. Portfolio options without sufficient fall-back solutions are removed from further analysis.

Transgrid's MCC assessment therefore provides a practical and prudent pathway for grid-forming BESS to contribute towards the minimum level of system strength requirements, while appropriately managing uncertainty and risk to the power system.

6. Portfolio options

This section outlines the outcomes of the portfolio formation process used to develop candidate portfolio options for net market benefit assessment. The portfolio formation process is undertaken in two-stages, involving:

1) identification of credible portfolio options to manage uncertainty of grid-forming BESS demonstrating credibility for the minimum level.
2) identification of the optimal amount of gas and hydro re-dispatch and grid-forming BESS for the minimum level, for each credible portfolio option.

As discussed in Section 5.1.3, this approach is used to ensure a secure and credible portfolio is maintained in the event that credibility of grid-forming BESS towards the minimum level is delayed or does not eventuate.

6.1. Identification of credible portfolio options to manage grid-forming BESS uncertainty

The first step in forming the portfolio options is to identify which portfolio options have sufficient fall-back solutions without the contribution of grid-forming BESS to the minimum level. Five portfolio options were considered. The initial portfolio options are denoted with ‘a’ (e.g. portfolio option 1a), to differentiate them from portfolio options in which grid-forming BESS are included. We later identify portfolio options with a ‘b’ where grid-forming BESS are included.

Table 10. Portfolio options excluding grid-forming BESS

Portfolio option	0 (base case)	1a	2a	3a	4a	5a
Phase 2 synchronous condensers						
Dinawan	-	1	1	1	1	1
Munmorah	-	-	1	1	1	1
Newcastle	-	-	-	1	1	1
Waratah West	-	-	-	-	1	1
Kemps Creek	-	-	-	-	-	1
Total	**-**	**1**	**2**	**3**	**4**	**5**
Re-dispatch of synchronous machines						
Hydro	Yes	Yes	Yes	Yes	Yes	Yes
Gas	Yes	Yes	Yes	Yes	Yes	Yes
Grid-forming BESS for minimum level						
Sydney West region (MW)	-	-	-	-	-	-

Figure 9 and Figure 10 show the hydro and gas re-dispatch hours required between FY31-41 for each portfolio option, under both coal unit retirement scenarios (i.e., the Draft 2026 ISP Step Change and Proponent Advised coal unit retirement scenarios). The modelling horizon extends to FY45, however there is minimal change for system strength in the power system beyond FY41, after all coal-fired power stations have retired in NSW. Accordingly, for readability, all graphs presented in this report end at FY41.

The gas re-dispatch graphs delineate between ‘feasible’ gas re-dispatch and ‘infeasible’ gas re-dispatch, which reflects where modelled gas constraints have been violated. Periods of infeasible gas re-dispatch indicate a risk of system strength gaps and are quantified as involuntary load curtailment for the net market benefits assessment.

The re-dispatch hours shown align to the accelerated synchronous condenser timing scenario (i.e. delivery in FY31). Under the assumed synchronous condenser timing scenario (i.e. delivery in FY34), the re-dispatch requirements for each portfolio option are identical to the base case (‘portfolio option 0’) from FY31 to FY33, prior to the deployment of Phase 2 synchronous condensers.

Figure 9. Draft 2026 ISP Step Change scenario. Hydro re-dispatch in years FY31 – 41, excluding grid-forming BESS

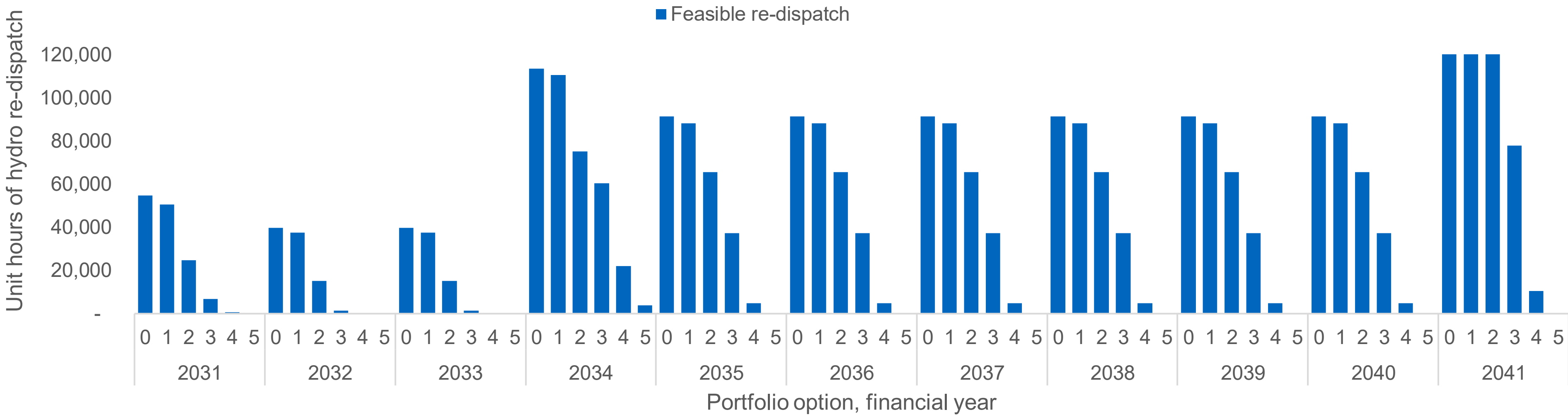


Figure 10. Draft 2026 ISP Step Change scenario. Gas re-dispatch in years FY31 – 41, excluding grid-forming BESS

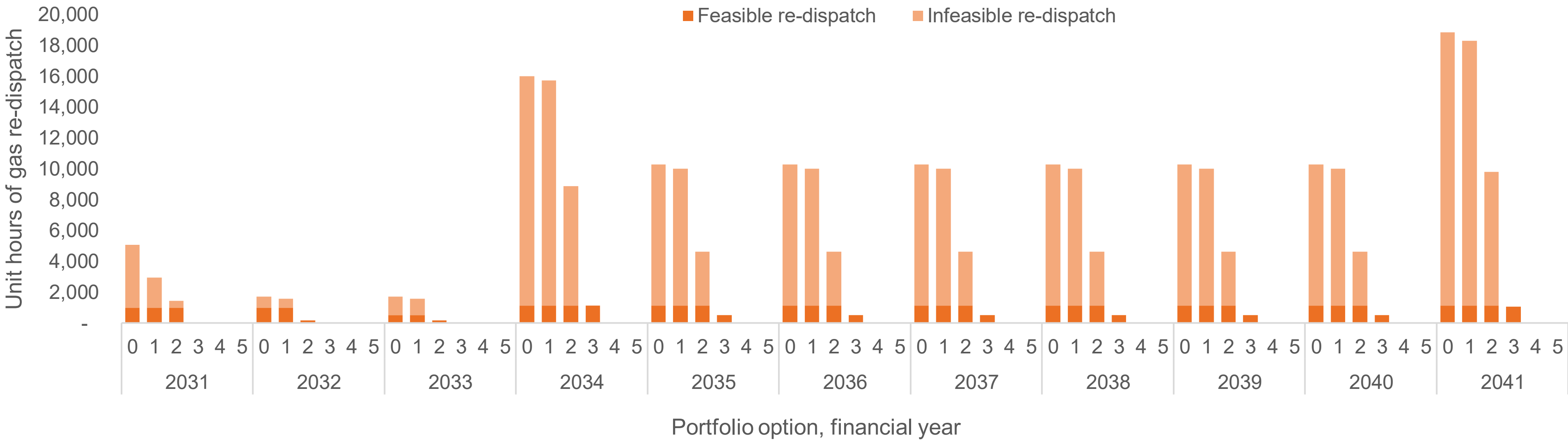


Figure 11. Proponent Advised coal unit retirement date scenario. Hydro re-dispatch in years FY31 – 41, excluding grid-forming BESS

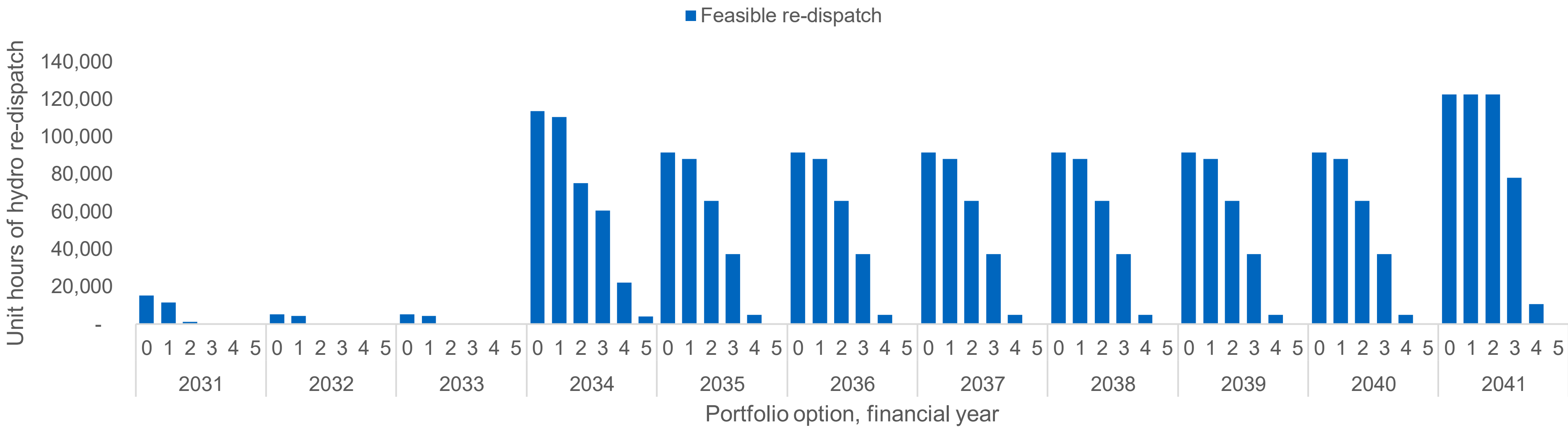
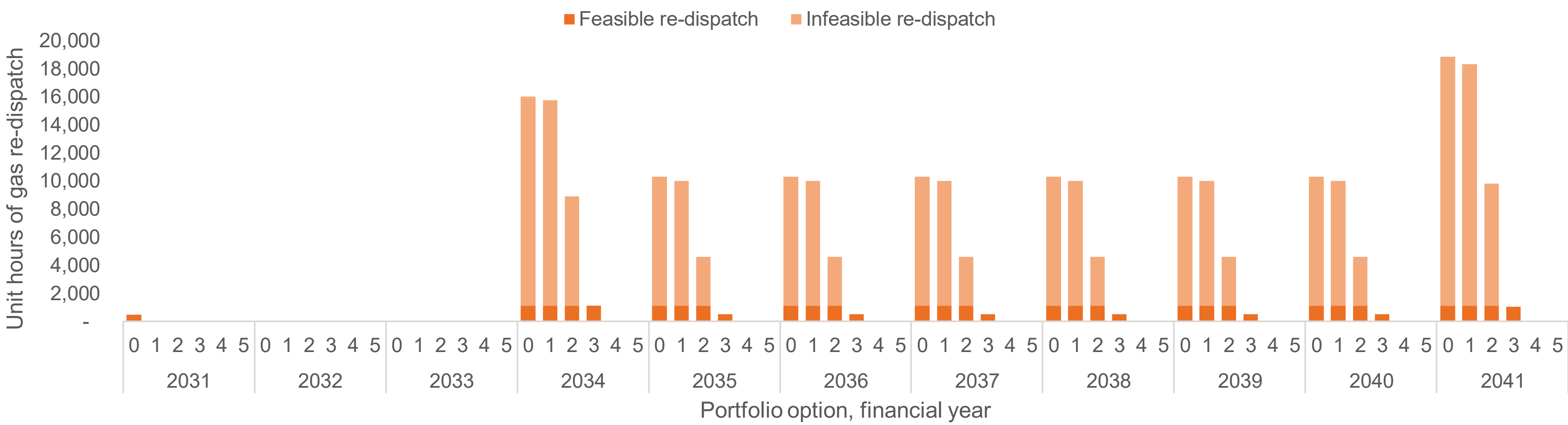


Figure 12. Proponent Advised coal unit retirement date scenario. Gas re-dispatch in years FY31 – 41, excluding grid-forming BESS



6.1.1. Difference in re-dispatch between Draft 2026 ISP Step Change and Proponent Advised coal unit retirement date scenarios

The above assessment shows a significant reliance on both hydro and gas re-dispatch from FY34 onwards in the base case and portfolio options 1a and 2a (i.e. with less than three Phase 2 synchronous condensers), under both coal unit retirement date scenarios.

In the Draft 2026 ISP Step Change coal retirement scenario, the assessment shows infeasible levels of gas re-dispatch is required from FY31 to FY33 under the assumed synchronous condenser delivery timing (FY34) for all portfolio options, denoted by Portfolio option 0 in the figures above for these years. Infeasible gas re-dispatch is also modelled for the base case, portfolio options 1a and 2a under the accelerated timing (FY31) in FY31 and from FY34 onwards. Infeasible levels of gas re-dispatch translate into a modelled risk of system strength gaps in these years.

Under the Proponent Advised coal unit retirement date scenario, there is more system strength provided by coal generators as a byproduct of their typical operation in the energy market, which reduces the need for re-dispatch of hydro and gas units from FY31 to FY33. No infeasible gas re-dispatch is observed between FY31 and FY33 under the Proponent Advised coal unit retirement scenario for either accelerated (FY31) or assumed synchronous condenser delivery timing (FY34). However, there is still a modelled risk of system strength gaps under the base case, portfolio option 1a and 2a from FY34 onwards.

6.1.2. Re-dispatch in FY34 and beyond, when the two scenarios converge

Gas and hydro re-dispatch hours significantly increase from FY34 in the base case, under both coal unit retirement date scenarios. This coincides with the full retirement of Vales Point and Bayswater Power Stations in both scenarios. At this point, only Mt Piper coal units remain operational in NSW, with the Mt Piper retirement date of FY41 consistent under the Draft 2026 ISP Step Change and Proponent Advised coal unit retirement dates.

Infeasible gas re-dispatch is observed from FY34 onwards in the base case, leading to the risk of gaps in system strength and associated involuntary load curtailment. Hydro re-dispatch, predominantly in synchronous condenser mode, plays a sustained role in meeting system strength requirements in portfolio options with four or less Phase 2 synchronous condensers.

Gas re-dispatch is required when hydro re-dispatch is insufficient to meet the need. With three or more Phase 2 synchronous condensers installed, gas re-dispatch typically only occurs for periods of synchronous condenser maintenance or critical planned outages of transmission lines. Portfolio options with less than three synchronous condensers require gas re-dispatch for sustained operation, exceeding modelled gas constraints. This indicates there is not sufficient fall-back system strength solutions to manage the risk of grid-forming BESS not performing.

6.1.3. Risk of system strength gaps

The tables below show the modelled risk of system strength gaps for each portfolio option (without grid-forming BESS), based on the range of coal retirement scenarios and synchronous condenser timing. Note ‘FY35+’ represents all years including and beyond FY35.

A modelled risk of system strength gaps is identified where the level of gas re-dispatch required exceeds the gas constraints.

Table 11. Draft 2026 ISP Step Change scenario. Modelled risk of system strength gaps

Assumed synchronous condenser timing (delivery in FY34)							Accelerated synchronous condenser timing (delivery in FY31)						
Portfolio option	Base case	1a	2a	3a	4a	5a	Portfolio option	Base case	1a	2a	3a	4a	5a
FY31	Risk	Risk	Risk	Risk	Risk	Risk	FY31	Risk	Risk	Risk	No risk	No risk	No risk
FY32	Risk	Risk	Risk	Risk	Risk	Risk	FY32	Risk	Risk	No risk	No risk	No risk	No risk
FY33	Risk	Risk	Risk	Risk	Risk	Risk	FY33	Risk	Risk	No risk	No risk	No risk	No risk
FY34	Risk	Risk	Risk	No risk	No risk	No risk	FY34	Risk	Risk	Risk	No risk	No risk	No risk
FY35+	Risk	Risk	Risk	No risk	No risk	No risk	FY35+	Risk	Risk	Risk	No risk	No risk	No risk

Table 12. Proponent Advised coal unit retirement scenario. Modelled risk of system strength gaps

Assumed synchronous condenser timing (delivery in FY34)							Accelerated synchronous condenser timing (delivery in FY31)						
Portfolio option	Base case	1a	2a	3a	4a	5a	Portfolio option	Base case	1a	2a	3a	4a	5a
FY31	No risk	No risk	No risk	No risk	No risk	No risk	FY31	No risk	No risk	No risk	No risk	No risk	No risk
FY32	No risk	No risk	No risk	No risk	No risk	No risk	FY32	No risk	No risk	No risk	No risk	No risk	No risk
FY33	No risk	No risk	No risk	No risk	No risk	No risk	FY33	No risk	No risk	No risk	No risk	No risk	No risk
FY34	Risk	Risk	Risk	No risk	No risk	No risk	FY34	Risk	Risk	Risk	No risk	No risk	No risk
FY35+	Risk	Risk	Risk	No risk	No risk	No risk	FY35+	Risk	Risk	Risk	No risk	No risk	No risk

The risk profile differs between the scenarios in years FY31 to FY33. Three synchronous condensers with an accelerated synchronous condenser timing (FY31) are required to mitigate the modelled risk of system strength gaps under the Draft 2026 ISP Step Change scenario. From FY34, the two scenarios converge and there is an ongoing modelled risk of system strength gaps for the base case, portfolio option 1a and portfolio option 2a. There is no modelled risk of system strength gaps for portfolio options 3a to 5a once Phase 2 synchronous condensers are delivered.

The objective of testing each portfolio option without grid-forming BESS is to identify which portfolio options have sufficient fall-back system strength solutions (i.e. hydro and gas). From this risk assessment, the base case, portfolio option 1a and portfolio option 2a have a modelled risk of system strength gaps shown by the infeasible gas re-dispatch between FY31-33 under the Draft 2026 ISP Step Change scenario and from FY34 onwards under both scenarios. Therefore, these portfolio options are not considered credible and have been excluded from further assessment.

For all portfolio options, the results indicate a modelled risk of system strength gaps between FY31 and FY33 under the Draft 2026 ISP Step Change scenario with assumed synchronous condenser timing (delivered in FY34). This analysis identifies a modelled gap in system strength that may also ultimately result in a reliability gap. Where 'no risk' is identified, this indicates a modelled outcome based on the scenario. Changes to key assumptions may increase or decrease the risk of system strength gaps, and this analysis does not consider non-credible contingencies.

There is more coal dispatch in the base case under the Proponent Advised coal unit retirement scenario in years FY31–33. This makes the system strength need more uncertain as two-shifting, seasonal mothballing and flexible coal unit operations is likely to become more frequent. Although we do not expect a risk of system strength gaps under this scenario, re-dispatch of coal may be required if economic decommitment of coal units continues to increase.

Note that this represents a modelled outcome in one potential state of the world. In the contracting timeframe, various aspects of the realised state of the world may diverge from the modelled state[93]. Transgrid will continue to apply reasonable endeavours to manage these risks through its procurement processes and collaborate with market and government bodies.

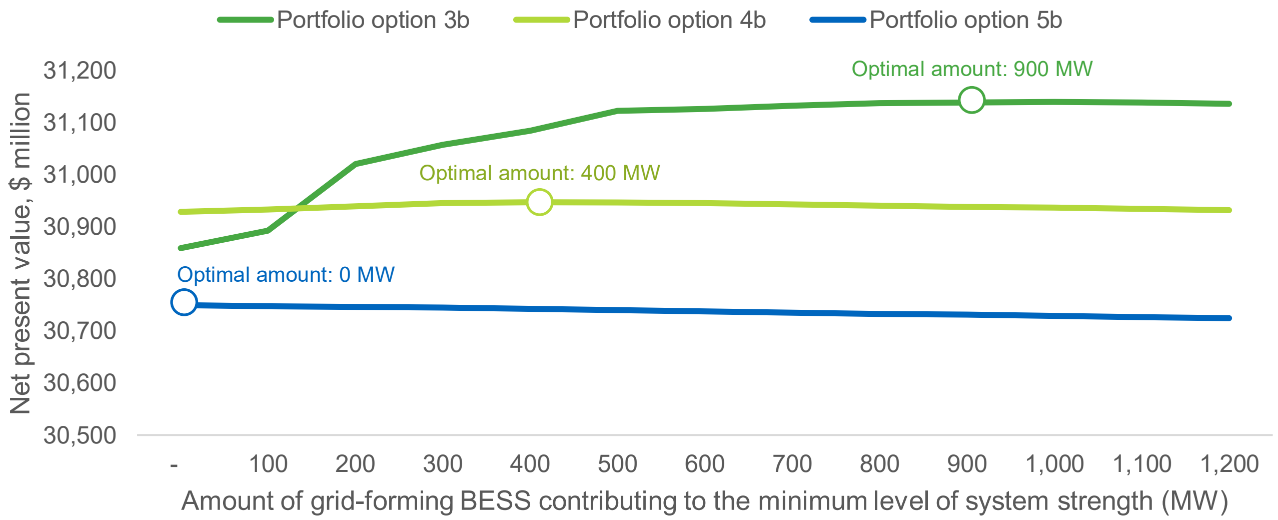
6.2. Identification of the optimal amount of grid-forming BESS for the minimum level

For credible portfolio options 3 to 5 (i.e., with three to five Phase 2 synchronous condensers), blocks of 100 MW of grid-forming BESS[94] located in the Sydney West region were progressively added, to identify the optimal amount which maximises net market benefits for each portfolio option.

To differentiate the three portfolio options from those without grid-forming BESS, these portfolio options are assigned the label ‘b’, e.g. ‘portfolio option 3b’ is the portfolio option which contains three Phase 2 synchronous condensers and grid-forming BESS contributing towards the minimum level.

Figure 13 shows how net market benefits vary as grid-forming BESS for the minimum level are progressively added to each of the portfolio options. The net market benefits of each portfolio option are discussed in detail in Section 7. The shape of the net market benefits curves below is similar across both coal unit retirement date scenarios and synchronous condenser timings. The optimal amount of grid-forming BESS for the minimum level of system strength is shown by a circle for each portfolio option.

Figure 13. Draft 2026 ISP Step Change coal retirement scenario. Identifying the optimal amount of grid-forming BESS for the minimum level of system strength



The benefit of adding grid-forming BESS to portfolio option 3b (containing three Phase 2 synchronous condensers) is significant, as it displaces higher-cost gas re-dispatch. For portfolio option 4b, there is a small added benefit from displacing hydro re-dispatch. There is no benefit for Portfolio Option 5b as the

[93] Due to differences compared to the modelled assumptions of for example IBR uptake, timing of the entry and exit of generation assets, the timing of transmission deployment etc. Note, this is a non-exhaustive list.
[94] Within the MCC analysis, these grid-forming BESS are considered as upgrades from generic BESS that are included within AEMO’s Draft 2026 ISP Step Change projections for the Sydney, Newcastle Wollongong region.

minimum level need is entirely met through synchronous condensers, so the net market benefits simply reduce by the added capital cost of the grid-forming BESS.

Note only 5% of the capital cost of grid-forming BESS is considered in this assessment consistent with the PACR (reflecting upgrade costs to enable grid-forming and protection quality fault current), as these BESS are already projected to enter the energy market under the Draft 2026 ISP Step Change scenario (discussed in Section 3.3.3). The optimal amount of grid-forming BESS was the same for both coal retirement scenarios.

Table 13 shows the components of each portfolio option which include grid-forming BESS. The amount of grid-forming BESS included is based on the amount of grid-forming BESS which maximises net market benefits.

Table 13. Portfolio options with grid-forming BESS

Portfolio option	Base case	3b	4b	5b
Phase 2 synchronous condensers				
Dinawan	0	1	1	1
Munmorah	0	1	1	1
Newcastle	0	1	1	1
Waratah West	0	0	1	1
Kemps Creek	0	0	0	1
Total	**0**	**3**	**4**	**5**
Re-dispatch of synchronous machines				
Hydro	Yes	Yes	Yes	Yes
Gas	Yes	Yes	Yes	Yes
Grid-forming BESS for the minimum level				
Sydney West region (MW)	0	900	400	0

7. Net market benefits assessment

The net market benefits for each portfolio option have been assessed for both coal unit retirement date scenarios (see Section 4.1) and for both synchronous condenser timings (See Section 3.1).

Note all values presented in this document are on 30 June 2025 dollar cost basis, unless stated otherwise.

7.1. Draft 2026 ISP Step Change coal unit retirement dates scenario

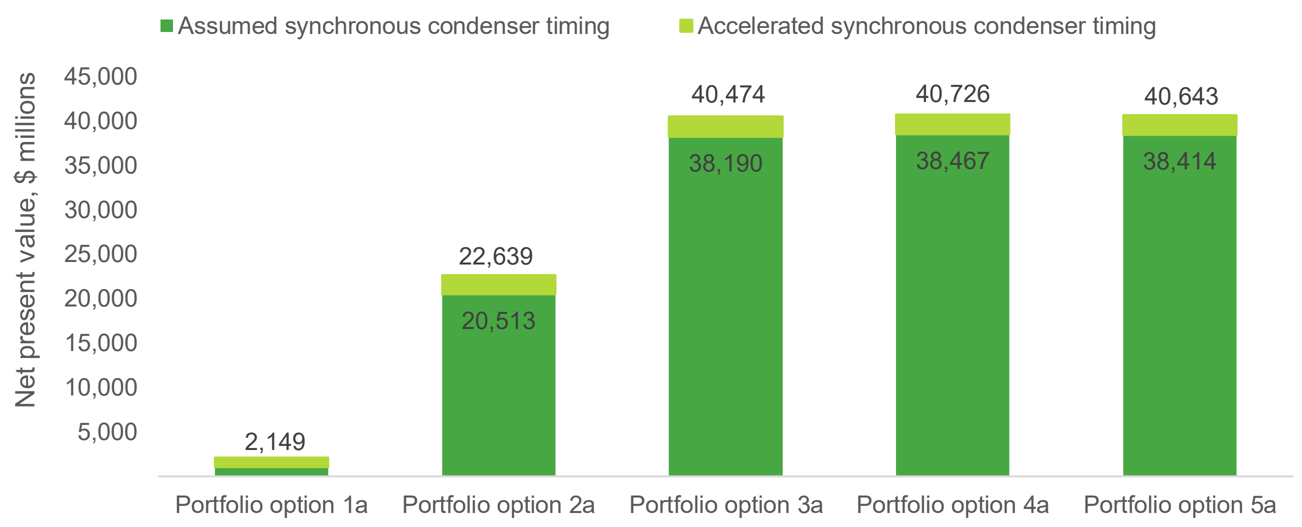
The following section details the net market benefits and costs of individual portfolio options for both accelerated (FY31) and assumed synchronous condenser delivery timing (FY34) under the Draft 2026 ISP Step Change scenario. This net present value assessment is undertaken for portfolio options excluding ('a' portfolio options) and then including ('b' portfolio options) grid-forming BESS for the minimum level, to enable the additional value generated by grid-forming BESS to be observed.

7.1.1. Net market benefits excluding grid-forming BESS for the minimum level

The net present value assessment for each portfolio option without grid-forming BESS contributing to the minimum level is shown in Figure 14.

To interpret this chart, dark green bars represent benefits under the assumed delivery timing of Phase 2 synchronous condensers (in FY34). The benefits of accelerated synchronous condenser delivery (FY31) are represented as the summation of the benefits of the dark and light green bars (with the total noted above the light green bars).

Figure 14. Draft 2026 Step Change coal retirement scenario. Net present value excluding grid-forming BESS in the portfolio



The magnitude of the benefits of each portfolio option indicates the severity of the risk to the power system under the base case, where gaps in system strength become increasingly apparent. The difference in present value between portfolio options 3a, 4a and 5a is relatively small compared to the total benefit each portfolio option provides.

Figure 14 identifies that portfolio option 4a maximises net market benefits (i.e. four Phase 2 synchronous condensers) under both the accelerated and assumed timing of synchronous condensers, and would be selected as the preferred portfolio where grid-forming BESS contributing to the minimum level of system strength is excluded. Portfolio option 5a and 3a have the second and third highest net market benefits ($83 million and $252 million lower than Portfolio option 4a under the accelerated synchronous condenser timing, respectively).

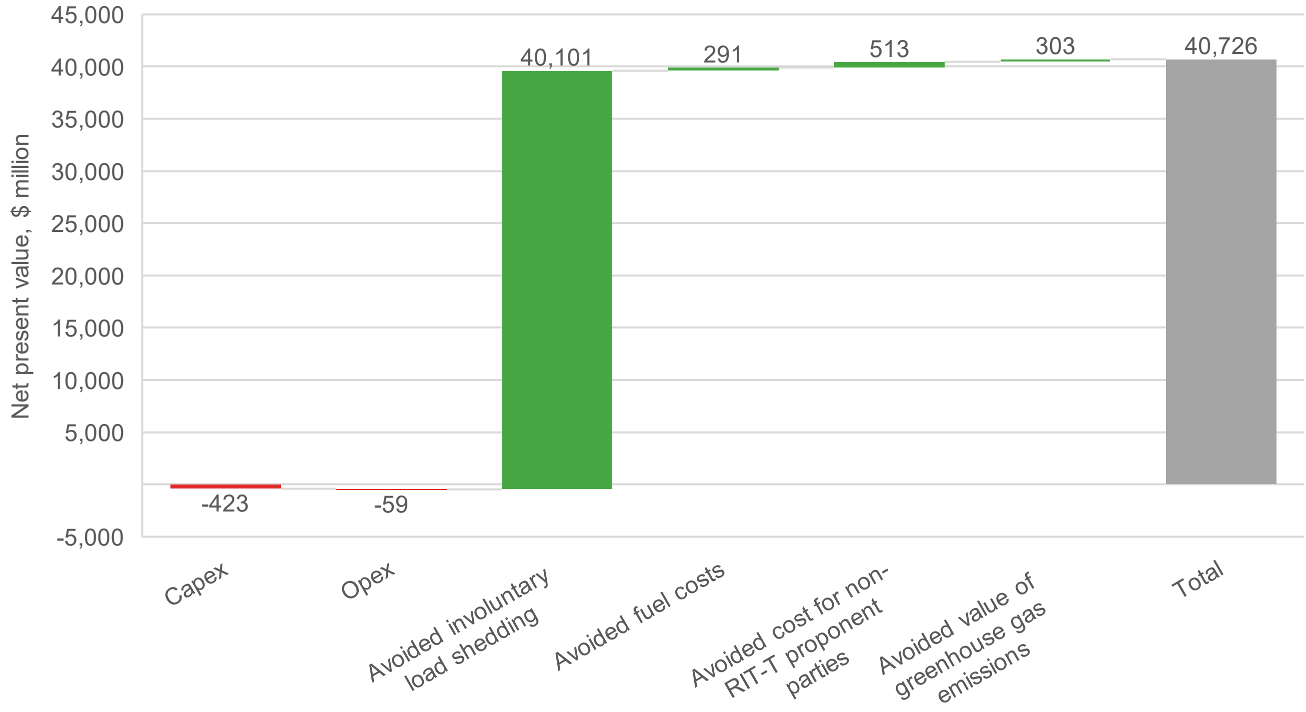
A significant reduction in net benefits is observed for portfolio options 1a and 2a, which are approximately $39 billion and $18 billion lower than portfolio option 4a under the accelerated synchronous condenser timing, respectively. This outcome is primarily driven by the substantial costs associated with involuntary load curtailment resulting from these portfolio options being unable to satisfy system strength requirements. In these cases, system strength gaps arise due to infeasible levels of gas generator re-dispatch hours. The net market benefits assessment was also calculated without application of the gas constraints, it did not change the ranking of options. These results are shown in 0.

While portfolio options 1a and 2a are not considered credible options, as they do not have sufficient fall-back solutions to meet the system strength need, they have been displayed to highlight the risk of under procurement of system strength solutions.

Figure 15 presents the composition of the estimated net market benefits for portfolio option 4a with the accelerated synchronous condenser timing, relative to the base case. Avoided involuntary load curtailment (unserved energy) represents by far the largest component of net market benefits, contributing approximately $31 billion. This highlights the importance of system strength and level of unserved energy that is expected without additional investment in system strength solutions.

The benefits associated with avoided fuel costs, avoided costs to non-RIT-T parties and avoided greenhouse gas emissions are comparatively smaller, contributing approximately $291 million, $513 million, and $303 million, respectively. These benefits are associated with avoided gas and hydro re-dispatch.

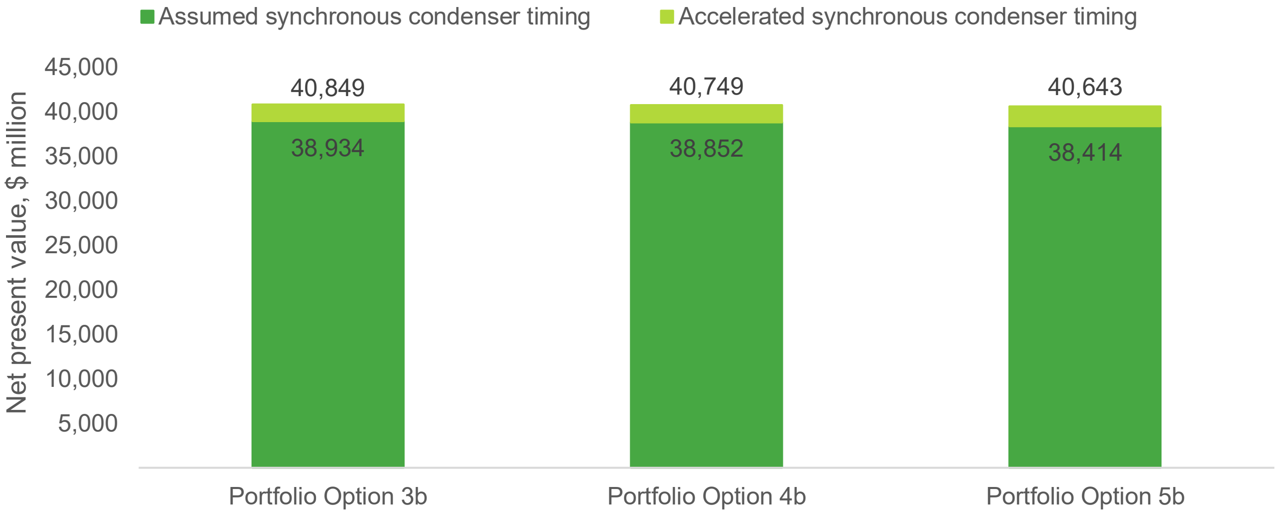
Figure 15. Draft 2026 ISP Step Change scenario. Composition of the estimated net market benefits for portfolio option 4a, relative to the base case



7.1.2. Net market benefits including grid-forming BESS for the minimum level

Figure 16 shows the net present value assessment for each technically credible portfolio option with grid-forming BESS for the minimum level included. This analysis assumes that their technical credibility for minimum level provision is confirmed.

Figure 16. Draft 2026 ISP Step Change scenario. Net present value assessment including grid-forming BESS

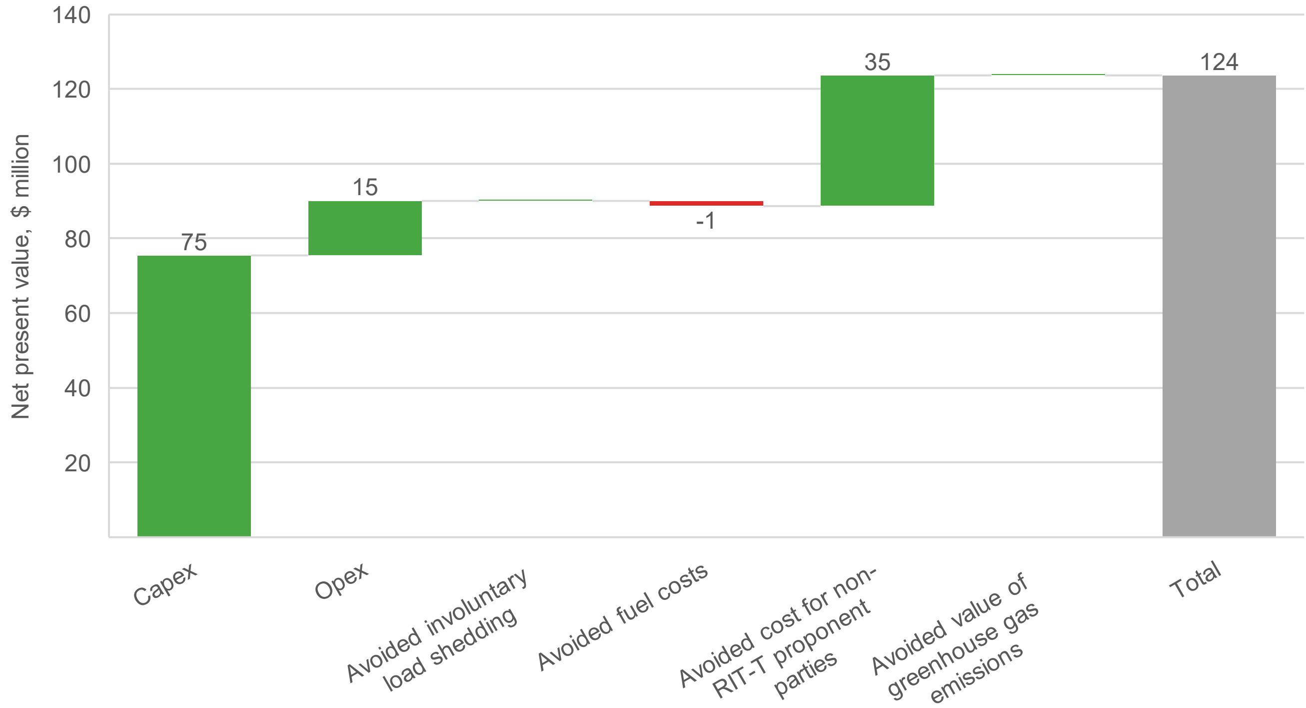


Under the assumed synchronous condenser timing, Portfolio option 3b has $467 million higher net present value benefits than the optimal portfolio without grid-forming BESS contributing to the minimum level (portfolio option 4a), indicating the increased value of grid-forming BESS in the portfolio. This increase is driven by low-cost grid-forming BESS upgrades avoiding the need for inclusion of a fourth Phase 2 synchronous condenser (reduced capital and operating costs) and gas re-dispatch (reduced fuel costs, variable operating costs, emissions costs). This justifies the shift from Portfolio Option 4a to Portfolio Option 3b, and creates a practical pathway for grid-forming BESS to contribute towards minimum level requirements.

The net market benefits for portfolio option 3b are approximately $1.9 billion higher if the three Phase 2 synchronous condensers are delivered at the accelerated identified timing (FY31) compared to the assumed timing (FY34). This benefit is driven by avoided involuntary load curtailment associated with infeasible levels of gas re-dispatch leading to a modelled risk of system strength gaps in years FY31-33, prior to delivery of Phase 2 synchronous condensers and projected proven credibility of grid-forming BESS.

The breakdown of net market benefits for the preferred option including grid-forming BESS (Portfolio option 3b) is compared to the preferred option excluding grid-forming BESS (Portfolio option 4a) under accelerated timing is shown in Figure 17. This highlights the benefits associated specifically to grid-forming BESS for the minimum level.

Figure 17. Draft 2026 ISP Step Change scenario. Key changes in the composition of the estimated net market benefits for portfolio option 3b, compared to portfolio option 4a under accelerated synchronous condenser timing



If portfolio option 3b is selected, but grid-forming BESS do not ultimately prove credible for the minimum level, then additional hydro and gas re-dispatch would be required to meet system strength requirements. This would result in a $252 million lower net market benefit compared to if Portfolio option 4a was originally selected, under the accelerated synchronous condenser timing. This could be considered the 'regret cost'.

A simple probabilistic assessment has been undertaken to determine the required probability for demonstrating credibility of grid-forming BESS which makes portfolio option 3b the preferred option over portfolio option 4b – this is termed the 'minimum required probability threshold'.

Table 14. Net present value comparison for Portfolio options 3b and 4b under accelerated synchronous condenser timing

	Net present value if grid-forming BESS do not demonstrate credibility for the minimum level ($m)	Net present value if GFM BESS do demonstrate credibility for the minimum level ($m)
Portfolio option 3b	38,934	38,190
Portfolio option 4b	38,852	38,467

The minimum required probability threshold of grid-forming BESS demonstrating capability and being delivered by FY33, 'X%', is determined using the equations below.

$$Expected\ NPV\ of\ 3b = (1 - X) * 38{,}190 + X * 38{,}934$$

$$Expected\ NPV\ of\ 4b = (1 - X) * 38{,}467 + X * 38{,}852$$

$$where\ X\ \geq 77\%, Expected\ NPV\ of\ 3b\ is\ higher\ than\ the\ expected\ NPV\ of\ 4b$$

It is challenging to determine the probability of grid-forming BESS proving credible; however this analysis indicates that the minimum required probability threshold is not unreasonably high, at above 77%, justifying selection of portfolio option 3b.

7.1.3. Portfolio costs including grid-forming BESS (assuming confirmed technical credibility for the minimum level)

The breakdown of costs by technology for each portfolio is tabulated below. All costs are presented in present value dollars ($FY25). Total expenditure is lowest for portfolio option 3b, under both the accelerated and assumed synchronous condenser delivery timings.

Table 15. Draft 2026 ISP Step Change scenario. Present value portfolio costs[95]

Portfolio	Portfolio option 3b		Portfolio option 4b		Portfolio option 5b	
Timing of synchronous condensers	Accelerated (FY31)	Assumed (FY34)	Accelerated (FY31)	Assumed (FY34)	Accelerated (FY31)	Assumed (FY34)
Network expenditure – Phase 2 synchronous condensers						
CAPEX ($m)	318	239	423	319	529	398
OPEX ($m)	44	33	59	44	73	55
Total ($m)	**362**	**272**	**482**	**363**	**603**	**453**
Non-network expenditure – grid-forming BESS						
CAPEX ($m)	30		14		0	
OPEX ($m)	0		0		0	
Total ($m)	**30**		**14**		**0**	
Non-network expenditure – Re-dispatch from synchronous generators						
CAPEX ($m)	0	0	0	0	0	0
OPEX ($m)	5	446	2	454	2	466
Total ($m)	**5**	**446**	**2**	**454**	**2**	**466**
Total expenditure						
CAPEX ($m)	348	269	437	332	529	398
OPEX ($m)	49	479	61	498	75	521
Total ($m)	**397**	**748**	**498**	**830**	**605**	**919**

Note that grid-forming BESS in this MCC assessment have an incremental capital cost of only 5% of the total AEMO 2025 IASR project cost, to reflect the potential uplift required to enable protection quality fault current capability. The underlying capital cost and operating costs of the projects themselves are not included in the assessment, as these costs are already assumed to be incurred in the base case given the projects are forecast to enter the market under the Draft 2026 ISP Step Change scenario. This is consistent with the approach adopted in the PACR.

[95] Note that this assessment (and Table 15) converted all capital costs into an equivalent annual annuity, consistent with the methodology employed by AEMO for the 2026 ISP, before discounting to a present value cost. This methodology is different to the net market benefit assessment used in the PACR, which used a capitalised cost. See Section 4.5.2 for additional details.

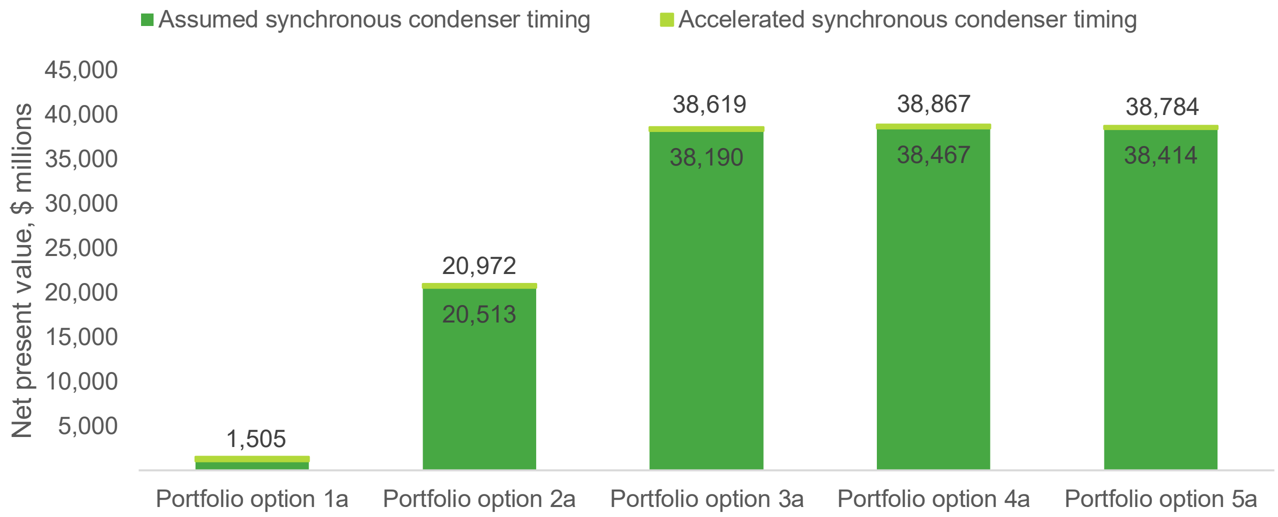
7.2. Proponent Advised coal unit retirement dates scenario

The following section details the net market benefits and costs of individual portfolio options for both accelerated (FY31) and assumed (FY34) synchronous condenser delivery dates under the Proponent Advised coal unit retirement scenario. The net present value assessment for portfolio options excluding and then including grid-forming BESS for the minimum level is shown in this section, to enable the additional value generated by grid-forming BESS to be observed.

7.2.1. Net market benefits excluding grid-forming BESS for the minimum level

The net present value assessment for each portfolio option excluding grid-forming BESS contributing to the minimum level is shown in Figure 18. The dark green bars represent net market benefits accrued under the assumed delivery timing of Phase 2 synchronous condensers (in FY34). The additional benefits associated with accelerated delivery of synchronous condensers (FY31) are in light green.

Figure 18. Proponent Advised coal unit retirement scenario. Net present value assessment excluding grid-forming BESS

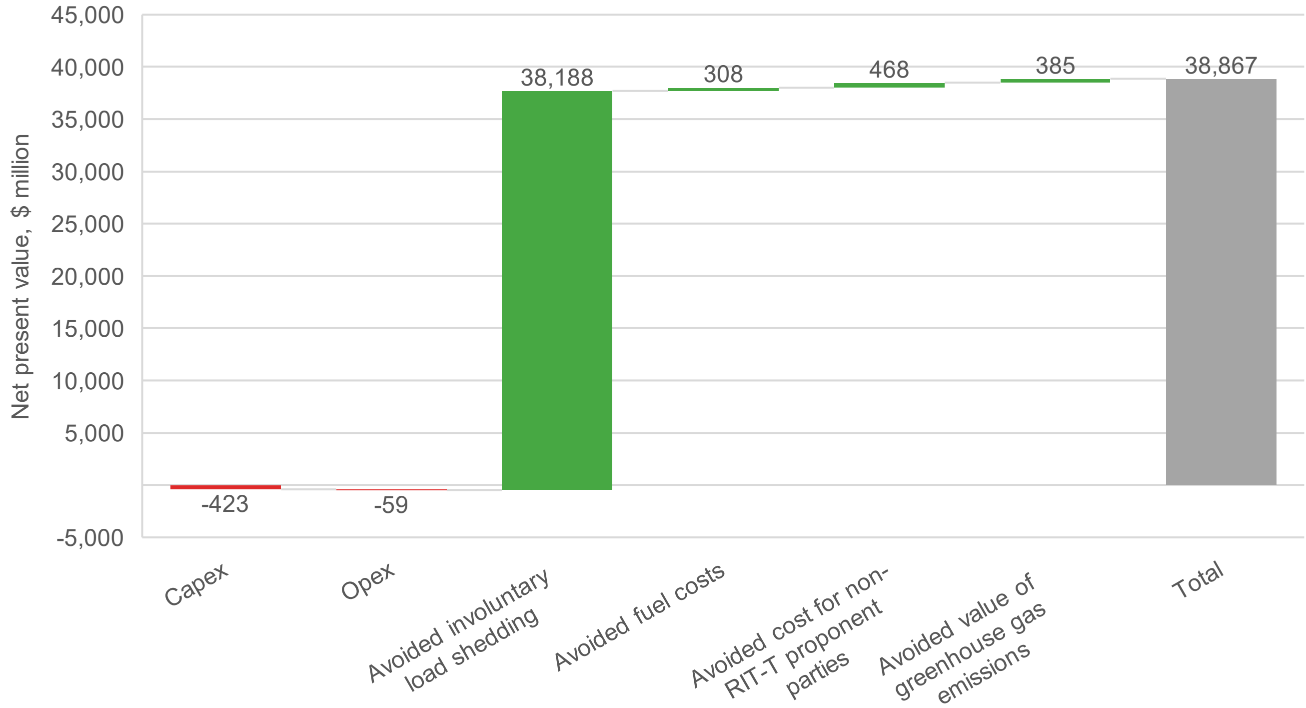


Portfolio option 4a, which includes four Phase 2 synchronous condensers, maximises the net market benefits. This is consistent with results under the Draft 2026 ISP Step Change scenario, however the difference between portfolio option 3a and 4a is reduced under this scenario. The benefit of accelerated delivery of synchronous condensers is also reduced. This is due to the later timing of coal generator retirements, which provide additional system strength during typical market operations in FY31 to FY33. As a result, the avoided levels of system strength gaps and associated involuntary load curtailment, fuel costs and emissions that synchronous condensers displace during this period is reduced relative to the scenario with earlier coal generator retirement dates.

Again, portfolio options 1a and 2a have significantly lower net market benefits than portfolio option 4a (i.e. approximately $37 billion and $18 billion lower, respectively). This is due to significant involuntary load curtailment occurring under these portfolio options without sufficient system strength solutions available. Portfolio option 2a does reduce the involuntary load curtailment observed under the base case and Portfolio option 1a but still maintains significant involuntary load curtailment.

The net present value assessment for portfolio option 4a under the accelerated synchronous condenser timing, compared to the base case is shown in Figure 19 broken down by market benefit class.

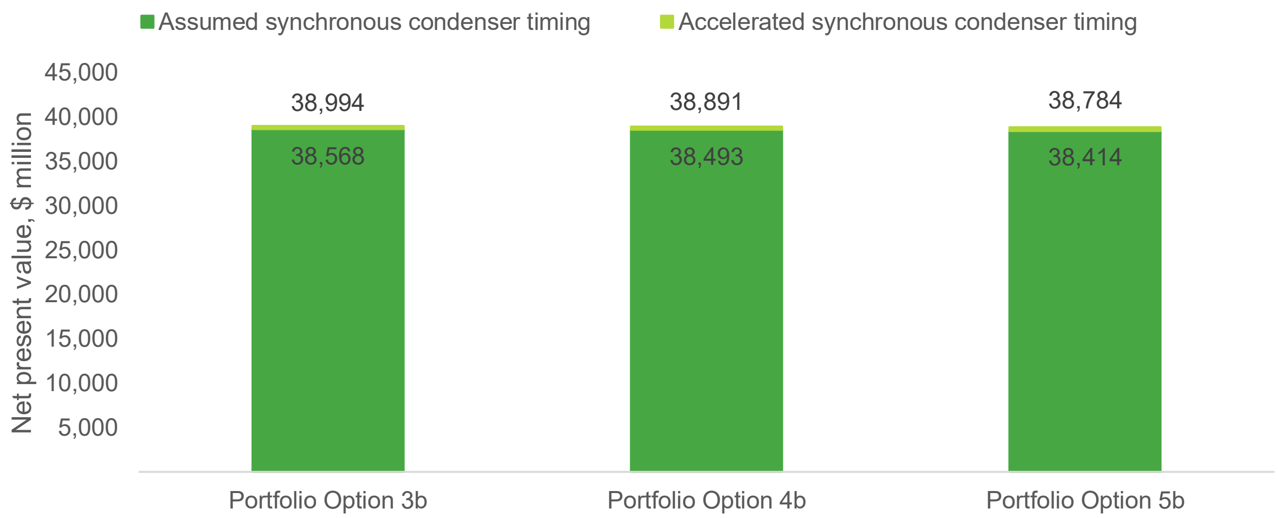
Figure 19. Composition of estimated net present value for portfolio option 4a in comparison to the base case under accelerated timing



7.2.2. Net market benefits including grid-forming BESS for the minimum level

The net market benefits for each portfolio option including grid-forming BESS are shown below. This analysis assumes that their technical credibility for minimum level provision is confirmed. Portfolio option 1b and portfolio option 2b are excluded from this analysis, as they do not sufficiently meet system strength requirements.

Figure 20. Proponent Advised coal retirement scenario. Net present value assessment with grid-forming BESS

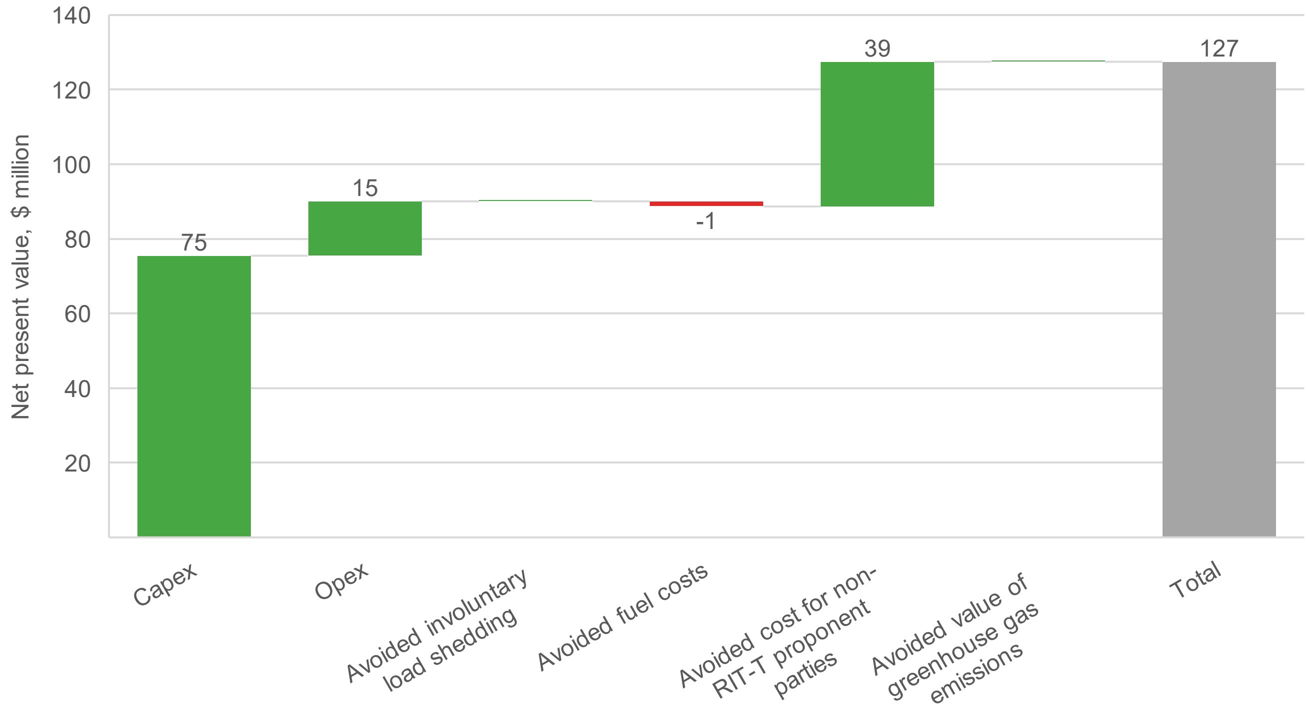


Portfolio option 3b, which includes three Phase 2 synchronous condensers and 900 MW of grid-forming BESS for the minimum level of system strength, is the portfolio option with the highest market benefit under the Proponent Advised coal unit retirement scenario. This is consistent with modelled outcomes of the Draft 2026 ISP Step Change scenario. This indicates that portfolio option 3b remains the preferred portfolio option across the range of coal generator retirement dates assessed, demonstrating its robustness to variations in retirement timing.

The increased benefit of accelerated synchronous condenser timing is smaller under the Proponent Advised coal unit retirement scenario compared to the Draft 2026 ISP Step Change scenario. This is due to the extended coal operation during FY31 to FY33, which reduces the avoided involuntary load curtailment, fuel costs and emissions benefits of accelerated synchronous condenser delivery.

The breakdown of net market benefits for the preferred option including grid-forming BESS (portfolio option 3b) to the preferred option excluding grid-forming BESS (portfolio option 4a) is compared in Figure 21 to demonstrate the benefits associated specifically with inclusion of grid forming BESS.

Figure 21. Proponent Advised coal retirement scenario. Key changes in the composition of the estimated net market benefits for portfolio option 3b, compared to portfolio option 4a under accelerated timing



7.3. Discussion of coal unit retirement dates

This draft MCC assessment has included two coal unit retirement scenarios:

- Under the Draft 2026 ISP Step Change coal retirement scenario, there is a modelled risk of system strength gaps from FY31 in the base case. Phase 2 synchronous condensers are required from FY31 to meet this need.
- The later Proponent Advised coal unit retirement scenario showed no modelled risk of system strength gaps in years FY31-33 (where the scenarios diverged), delaying the need for synchronous condensers until FY34.

Transgrid has explored other coal unit retirement assumptions during this assessment, even beyond Proponent Advised dates. If both Bayswater and Vales Point units were to delay their retirement dates beyond FY34, we expect the need for Phase 2 synchronous condensers will also be deferred commensurately.

Extended coal retirement dates are not expected to change the preferred portfolio composition in isolation, only the timing of the need for Phase 2 synchronous condensers and level of hydro and gas re-dispatch. However, deferred investment does provide more time for alternative solutions, including grid-forming BESS or emerging synchronous machines with synchronous condenser capability, to demonstrate credibility and/or become committed.

Importantly, this assessment assumes a similar level of coal unit reliability and operational output could be maintained if coal retirements extend. As noted in Section 2.2.2, AEMO has identified that ageing coal generators present an increasing risk of unavailability and that more flexible operating practices of coal units (expected as the penetration of renewables increase) can accelerate equipment degradation.

This reinforces the importance of maintaining a portfolio that is robust to both timing uncertainty and operational variability of coal units, rather than relying on any single retirement trajectory. In practical terms, the preferred portfolio in this draft MCC assessment reflects a balance between deferring system strength investment where possible, and ensuring sufficient system strength capability is available ahead of key transition points, where the risks of under-procurement are materially higher than the costs of early investment.

7.4. Inertia assessment

In the PACR, Transgrid identified the addition of flywheels to each synchronous condenser (for stable voltage waveform support) will enable inertia requirements in NSW to be met[96]. This analysis was repeated for Portfolio option 3b with assumed Phase 2 synchronous condenser delivery (FY34). The analysis validated that a reduction from five to three Phase 2 synchronous condensers is still forecast to meet NSW's inertia requirements.

Additional information on meeting inertia requirements can be found in the PACR[97].

[96] Meeting system strength requirements in NSW, Transgrid, July 2025, Page 71
[97] Meeting system strength requirements in NSW, Transgrid, July 2025, Pages 32-33, 69

8. Case studies

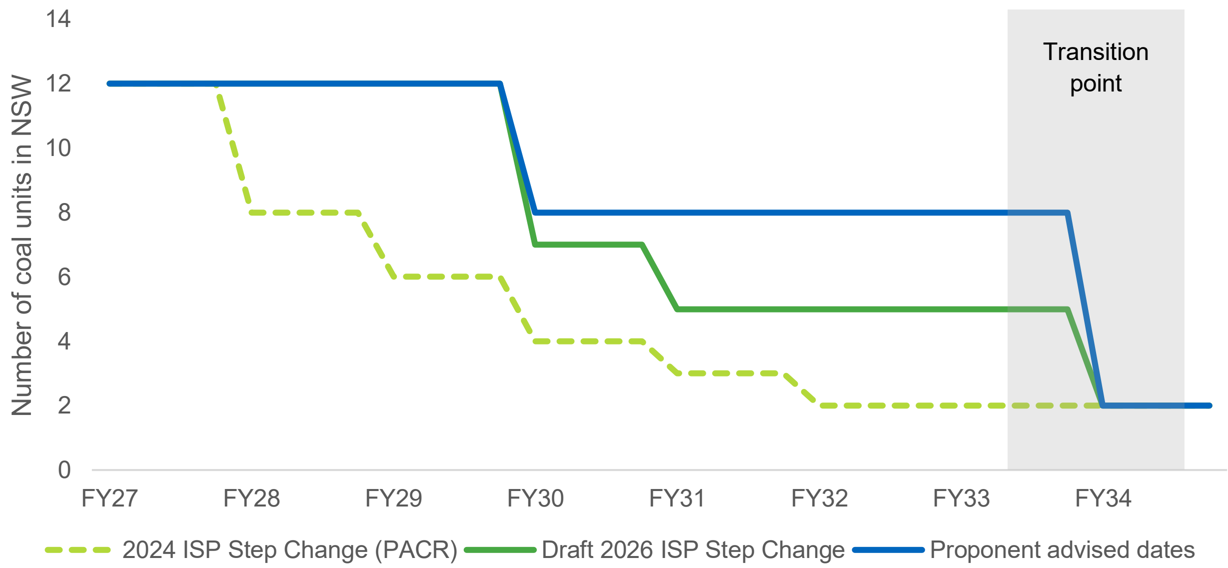
This section includes two case studies that explore specific uncertainties related to coal unit retirement timing and the timing of system strength solutions. The case studies examine:

- Asymmetric risk of system strength adequacy at transition points.
- System strength adequacy with reduced coal unit output.

8.1. Case study 1: Asymmetric risk of system strength adequacy at transition points

The retirement of each coal generator represents a key transition point for the power system. Based on Proponent Advised timing, both Vales Point and Bayswater are planned to retire in between late FY33 and early FY34, making this a critical period for managing system strength. Preparation is needed ahead of the transition point to ensure that any unexpected outcomes during commissioning or early operation of replacement system strength solutions are well-understood before the transition point occurs (including gaining experience in AEMO and Transgrid control rooms).

Figure 22. Key transition period for managing system strength in NSW



Under each of the two coal retirement scenarios modelled in this MCC assessment, grid-forming BESS and Phase 2 synchronous condensers are modelled to be delivered before the complete retirement of Bayswater and Vales Point units. However, in reality, there is uncertainty on the timing of coal generator retirements, synchronous condenser delivery and timing for the proven credibility of grid-forming BESS towards the minimum level requirements. Although not modelled in the two scenarios above, external factors could force a scenario where coal unit retirements may occur before replacement solutions are delivered. These factors could include:

- Catastrophic failure of one or more coal units as they approach end of technical life.
- Less favourable market conditions for coal generators incentivising early retirement.
- Extended duration of regulatory processes, including contingent project applications and MCC obligations, delaying the delivery of Phase 2 synchronous condensers.

- Disruptions to international supply chains, or unexpected delays during project delivery, delaying when Phase 2 synchronous condensers are operational.
- Credibility of grid-forming BESS for the minimum level requiring wide-spread changes to protection schemes or changes to inverter hardware.
- Grid-forming BESS projects in the Sydney West region fail to materialise or are delayed during project development or delivery.

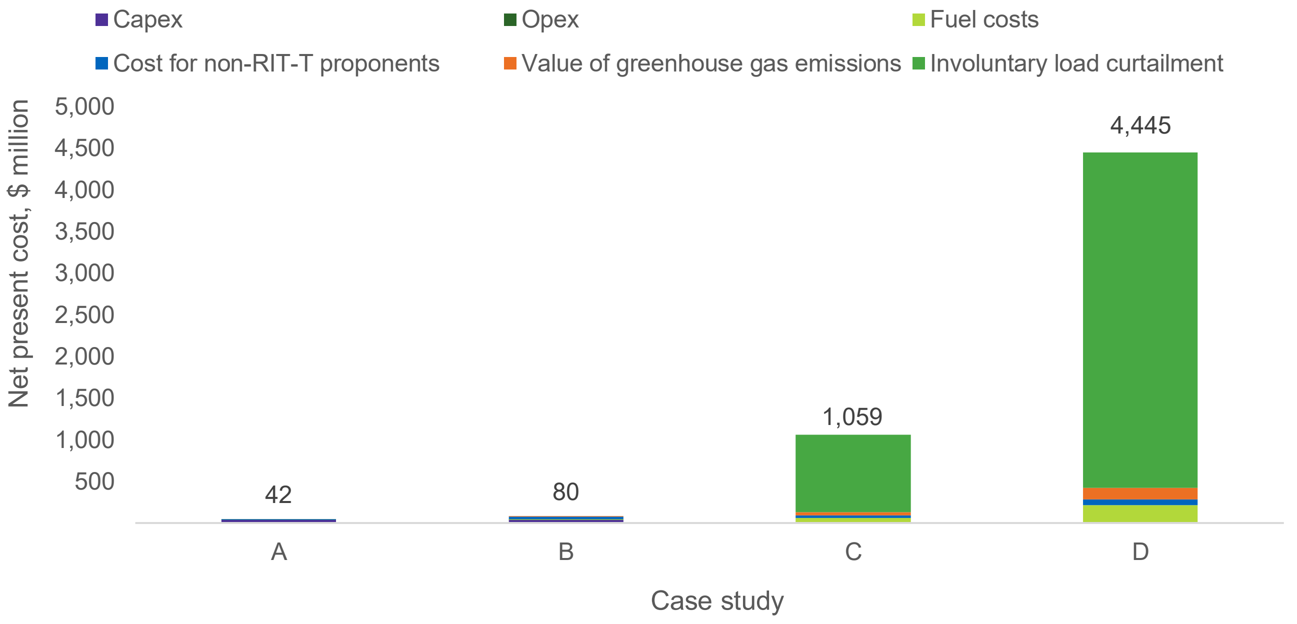
This case study assesses the cost of meeting minimum level system strength requirements if Vales Point and Bayswater retirements occur before replacement system strength solutions are in place. Four case studies have been explored on Portfolio Option 3b, with FY34 used as a reference year.

Table 16. Four case studies exploring the sequencing of system strength solutions and the retirement of Vales Point and Bayswater

#	Case study	Phase 2 synchronous condensers deployed	Grid-forming BESS deployed
A	Both replacement solutions are in place before coal retires	3	900 MW
B	Coal retires before grid-forming BESS are proven credible, but after Phase 2 synchronous condensers are in place	3	0
C	Coal retires before Phase 2 synchronous condensers, but after grid-forming BESS are proven credible	0	900 MW
D	Coal retires before both replacement solutions are in place	0	0

The net present cost of managing system strength following the retirement of Vales Point and Bayswater is shown for a single year in Figure 23, for each case study.

Figure 23. Cost to meet system strength requirements for a one-year period, following the retirement of Bayswater and Vales Point



If Bayswater and Vales Point retire before either replacement solution is delivered, there is a modelled risk of system strength gaps because of insufficient available system strength solutions. The cost associated with system strength for one year in this state of the world is $4.4 billion, with significant costs due to involuntary load curtailment.

If the 900 MW of grid-forming BESS for the minimum level component of the portfolio option is delivered, and found to be technically feasible, but not Phase 2 synchronous condensers, then the economic cost is reduced to approximately $1.1 billion. Involuntary load curtailment representing the largest cost component due to insufficient system strength solutions.

The cost to manage system strength with Phase 2 synchronous condensers deployed but no grid-forming BESS is $80 million, with no modelled risk of system strength gaps. Instead, the largest cost component relative to the other case studies is the annualised Capex and Opex for the Phase 2 synchronous condensers, totalling $39 million. This is followed by gas and hydro redispatch costs (costs for non-RIT-T proponents), which is required to ramp up in the absence of grid-forming BESS for the minimum level.

If grid-forming BESS are then added, the modelled economic cost is reduced to $42 million; this represents the core scenarios modelled in this MCC assessment. The difference with and without grid-forming BESS is $43 million, this represents the cost risk if grid-forming BESS are not proven credible on-time or do not perform as modelled.

Comparing the cost with and without system strength solutions highlights the asymmetric risk of system strength, particularly at key transition points such as coal retirements. As the AEMC Reliability Panel[98] stated in 2025, *"...the risks of over- and under-investment are asymmetric. The risk of over-investment in security services, or investment earlier than needed, comes with much lower costs than under-investment or investment that is too late. Under-investment could lead to periods when the NEM cannot be securely operated."*

This case study further reinforces the importance of timely delivery of system strength solutions ahead of key transition points, to enable key transition points to be appropriately managed.

[98] Letter to AEMO: Reliability Panel comments on AEMO's Transition Plan for System Security, AEMC Reliability Panel, April 2025

8.2. Case study 2: System strength adequacy with reduced coal unit output

This case study has assessed the modelled risk of system strength gaps in the hypothetical scenario where there are two less coal units available for system strength provision in each year, relative to each of the Draft 2026 ISP Step Change and Proponent Advised coal unit retirement scenarios. This may occur due to faster than anticipated coal unit retirements, unexpected failures, or material seasonal mothballing where units are unable to return to service in-time to address system strength gaps. Seasonal mothballing is likely to occur in spring and autumn, when wholesale electricity prices are typically lowest; this also coincides with the periods where the system strength need is greatest.

The methodology used for this case study is identical to the core methodology, with grid-forming BESS for the minimum level excluded from this assessment, and the modelled risk of system strength gaps identified in years where gas re-dispatch exceeded feasible levels. This case study (with two less coal units available) has been undertaken on both the Draft 2026 ISP Step Change scenario and the Proponent Advised coal unit retirement scenario.

Table 17. Draft 2026 ISP Step Change scenario. Risk of system strength gaps under case study 2

Assumed synchronous condenser timing (delivery in FY34)							Accelerated synchronous condenser timing (delivery in FY31)						
Portfolio option	Base case	1a	2a	3a	4a	5a	Portfolio option	Base case	1a	2a	3a	4a	5a
FY31	Risk	Risk	Risk	Risk	Risk	Risk	FY31	Risk	Risk	Risk	No risk	No risk	No risk
FY32	Risk	Risk	Risk	Risk	Risk	Risk	FY32	Risk	Risk	No risk	No risk	No risk	No risk
FY33	Risk	Risk	Risk	Risk	Risk	Risk	FY33	Risk	Risk	No risk	No risk	No risk	No risk
FY34	Risk	Risk	Risk	No risk	No risk	No risk	FY34	Risk	Risk	Risk	No risk	No risk	No risk
FY35+	Risk	Risk	Risk	No risk	No risk	No risk	FY35+	Risk	Risk	Risk	No risk	No risk	No risk

Table 18. Proponent Advised coal unit retirement scenario. Risk of system strength gaps under case study 2

Assumed synchronous condenser timing (delivery in FY34)							Accelerated synchronous condenser timing (delivery in FY31)						
Portfolio option	Base case	1a	2a	3a	4a	5a	Portfolio option	Base case	1a	2a	3a	4a	5a
FY31	Risk	Risk	Risk	Risk	Risk	Risk	FY31	Risk	Risk	Risk	No risk	No risk	No risk
FY32	Risk	Risk	Risk	Risk	Risk	Risk	FY32	Risk	No risk	No risk	No risk	No risk	No risk
FY33	Risk	Risk	Risk	Risk	Risk	Risk	FY33	Risk	Risk	No risk	No risk	No risk	No risk
FY34	Risk	Risk	Risk	No risk	No risk	No risk	FY34	Risk	Risk	Risk	No risk	No risk	No risk
FY35+	Risk	Risk	Risk	No risk	No risk	No risk	FY35+	Risk	Risk	Risk	No risk	No risk	No risk

The results show that a risk of system strength gaps is modelled to occur in the base case from FY31 onwards under both the Draft 2026 ISP Step Change scenario and the Proponent Advised scenario with two additional coal units unavailable. Gaps are also modelled to occur when less than three Phase 2 synchronous condensers are deployed.

Modelled risk of gaps are most significant under the Draft 2026 Step Change scenario in years FY31–33, under the assumed synchronous condenser timing (FY34), where the quantified cost of involuntary load curtailment rose from $1.9 billion to $4.9 billion across these years compared to the core analysis in Section 7 (and from $0 million to $476 million under the Proponent Announced scenario).

This analysis identifies modelled gaps in system strength that may ultimately result in a reliability gap.

The high economic cost associated with the modelled risk of system strength gaps under a reduced coal output Draft 2026 ISP Step Change scenario highlight the vulnerability of the system to changes in coal assumptions. This risk can be addressed through accelerated procurement of system strength solutions to increase the resilience of the power system, if feasible.

9. Sensitivity analysis

This section explores the impact on net benefits of changes two further assumptions; one being changes in the system strength solution for New England REZ and the other being synchronous condenser costs. By testing the robustness of the preferred portfolio to these changes, we can understand if these changes occur if they are likely to constitute a further MCC in line with Clause 5.1.6.4(z4)(3).

9.1. New England REZ sensitivity

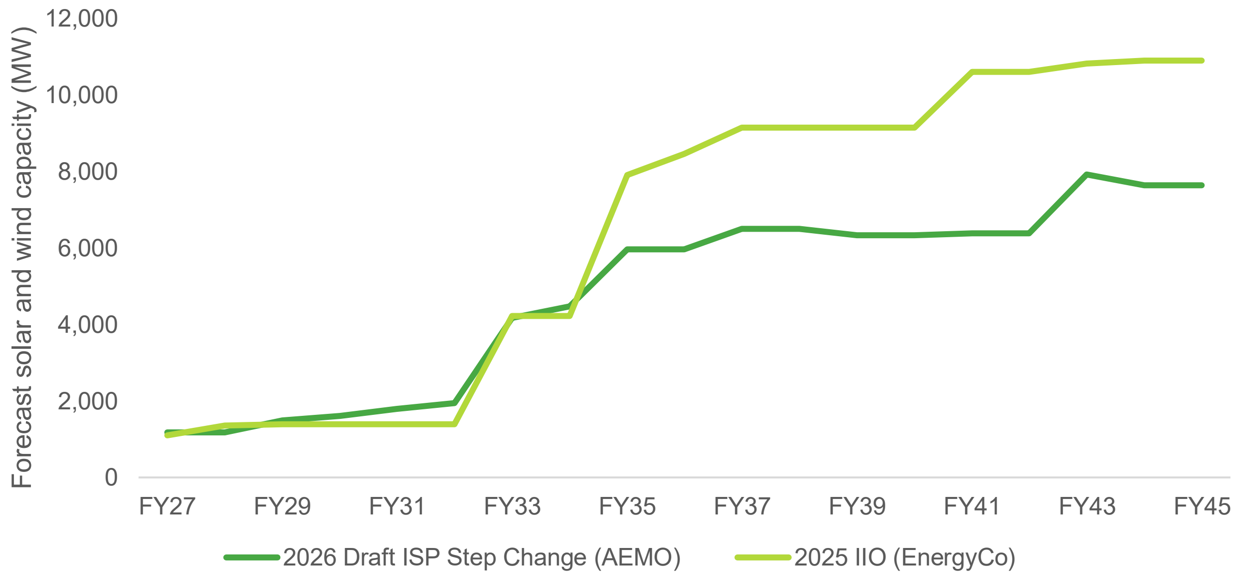
AEMO's Draft 2026 ISP Step Change scenario did not select Stage 2 of the New England REZ Network Infrastructure Project as an actionable ISP or future ISP project in the proposed optimal development path.[99] However, EnergyCo, the State Infrastructure Planner for NSW, has progressed planning for its development since the PACR[100].

Assumptions for New England REZ development in the core analysis of this MCC assessment is based on AEMO's latest published ISP (Draft 2026 ISP), as per the RIT-T guidelines, where Stage 2 of the REZ is not included (therefore nor are system strength solutions for generators in Stage 2). However, this sensitivity tests the impact of EnergyCo procuring synchronous condensers for New England REZ Stage 2 on the ranking of portfolio options to meet minimum system strength requirements on Transgrid's transmission backbone.

9.1.1. New England REZ planning uncertainty

EnergyCo has a higher forecasted uptake of solar and wind generation in New England REZ compared to AEMO's Draft 2026 ISP Step Change Scenario[101]. The difference is likely driven by the New England REZ Stage 2 not being in the Draft 2026 ISP optimal development path (compared to the 2024 ISP). The IBR planned for in the latest version of each report is shown in Figure 24.

Figure 24. Forecasted IBR for the New England REZ



[99] Draft 2026 Integrated System Plan, AEMO, December 2025
[100] 2025 Infrastructure Investment Objectives Report, AEMO Services Limited, 2025
[101] Information is based on 2025 Infrastructure Investment Objectives Report (IIO, Page 50) and via joint planning.

EnergyCo has signalled a requirement for prospective New England REZ projects to be capable of a withstand short circuit ratio of 1.2, met either behind-the-meter or via contracts in-front-of-the-meter[102]. At this SCR, a proponent's system strength charge is zero under the NER. Grid-forming BESS is expected to be the primary solution to enable projects to achieve this.

Grid-forming BESS alone (no synchronous condensers) may be sufficient to support the efficient level requirements for AEMO's planned level of solar and wind in the 2030s (~6.5 GW). However, there is uncertainty if grid-forming BESS alone can remediate the higher level of IBR planned for by EnergyCo (~9.1 GW as per the 2025 IIO Report). Transgrid and EnergyCo are undertaking joint planning to identify the optimal solution to support stable voltage waveforms.

9.1.2. Sensitivity assumptions

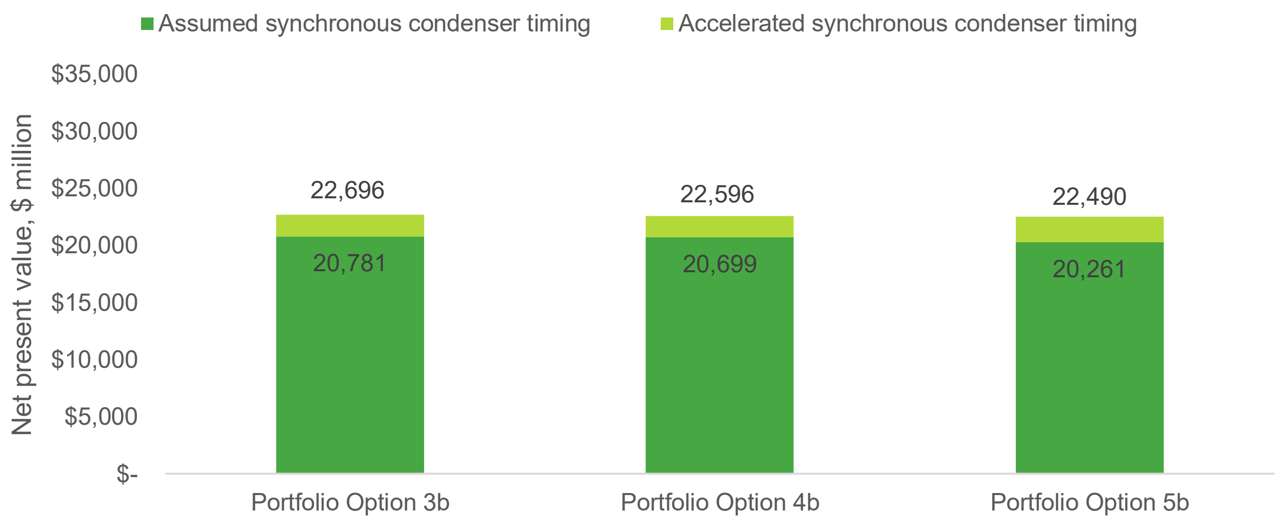
As the system strength solution for New England REZ is uncertain, Transgrid has included a sensitivity in this report which assesses the contribution from potential synchronous condensers in New England REZ to the rest of the transmission backbone (if deployed), to assess whether this would change the ranking of portfolio options for this MCC assessment.

For this sensitivity, Transgrid has modelled two synchronous condensers in the New England REZ from FY35. This timing is based on the Proponent Advised timing for Stage 2 of the REZ[103] when they would be required, and two synchronous condensers were estimated from insights gained through EMT modelling for the system strength PACR.

9.1.3. Sensitivity results

The net market benefits assessment is shown in Figure 25.

Figure 25. Draft 2026 ISP Step Change scenario. Net present value assessment for the New England REZ sensitivity



The net market benefits of portfolio options 3b to 5b are reduced by $18 billion compared to the core modelling (which assumes no synchronous condensers are deployed in New England REZ), however there is no change to the ranking of portfolio options, with 3b being the preferred portfolio option. This indicates

[102] Indicative Technical Requirements for generation and storage connections in New England Renewable Energy Zone, EnergyCo, December 2025, Page 8
[103] Draft 2026 ISP Appendix A5. Network Investments, AEMO, December 2025, Page 35

that the outcomes of Transgrid's MCC assessment is robust to synchronous condensers being installed for New England REZ.

9.2. Sensitivity on higher and lower Phase 2 synchronous condensers costs

This sensitivity assesses if the ranking of portfolio options change when there is a 40% increase, or a 30% decrease in synchronous condenser costs, relative to the central estimate within this MCC assessment. This percentage change has been selected as this is the current estimate accuracy range for the revised synchronous condenser cost. The net present value results for each portfolio option, including grid-forming BESS, are shown below.

Figure 26. Draft 2026 ISP Step Change scenario. Net present value including grid-forming BESS with 40% higher synchronous condenser costs

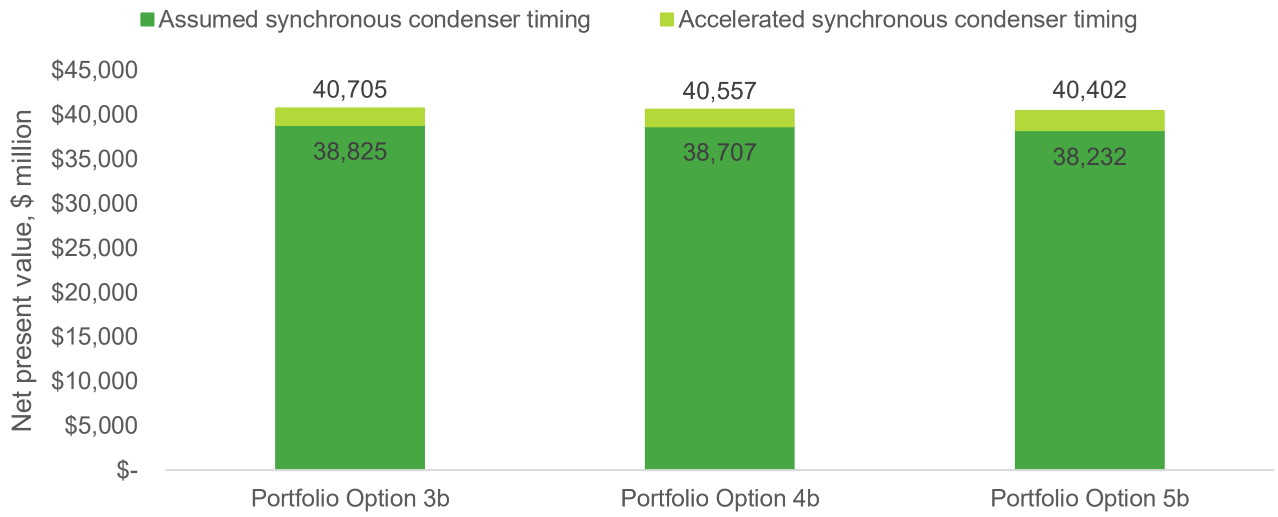
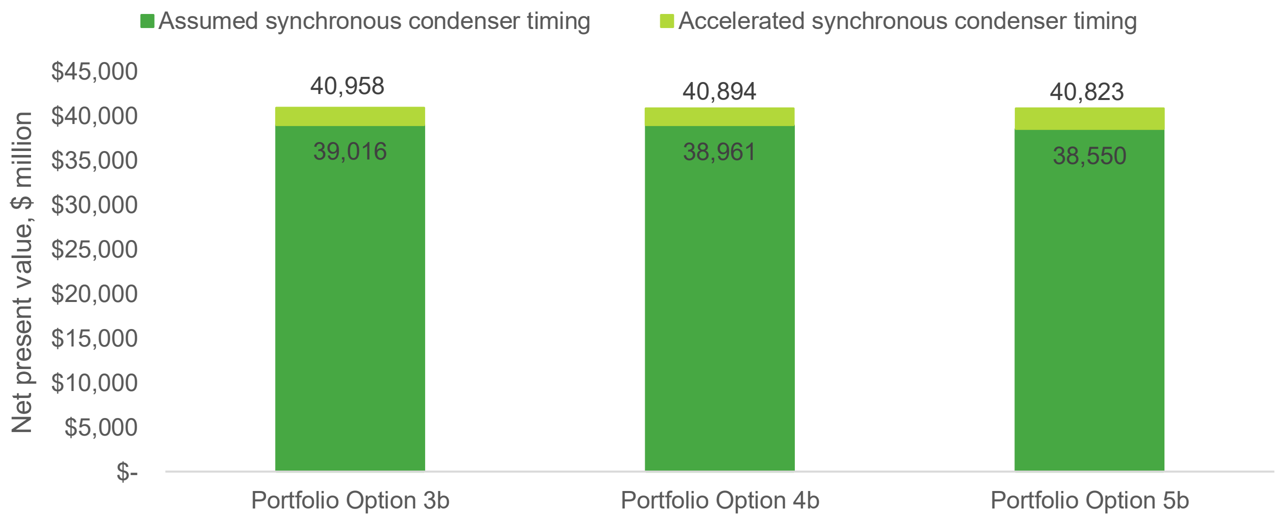


Figure 27. Draft 2026 ISP Step Change scenario. Net present value including grid-forming BESS with 30% lower synchronous condenser costs



The ranking of portfolio options (with portfolio option 3b being preferred) does not change under either the decreased or increased synchronous condenser cost sensitivity.

10. Selecting the preferred portfolio

This draft MCC assessment applies a structured decision framework to identify the preferred portfolio option. This framework integrates power systems modelling and a net present value assessment to manage key uncertainties of coal unit retirement dates, synchronous condenser delivery timing and the timing of demonstrating the credibility of grid-forming BESS for the minimum level.

To manage these uncertainties, Transgrid:

- developed a two-stage process to exclude portfolio options which did not have sufficient fall-back solutions to meet minimum-level system strength requirements without grid-forming BESS. Based on this, portfolio options with fewer than three Phase 2 synchronous condensers were not deemed credible based on the assumptions of this draft MCC assessment.
- assessed the credible portfolio options under two coal unit retirement scenarios and two synchronous condenser delivery timings.

This draft assessment identified portfolio option 3b as the preferred portfolio option to meet system strength requirements. This portfolio option is comprised of three Phase 2 synchronous condensers, 900 MW of additional grid-forming BESS for the minimum level and contracts with hydro and gas generators.

The introduction of grid-forming BESS for the minimum level, instead of a fourth synchronous condenser, is modelled to reduce the portfolio option cost by $124 million under the accelerated synchronous condenser timing, and $467 million under the assumed timing of synchronous condensers. This portfolio option has sufficient fall-back solutions, in the form of further hydro and gas re-dispatch to manage grid-forming BESS uncertainty.

Portfolio option 3b is the preferred option under both coal unit retirement scenarios, both synchronous condenser delivery timings, the New England REZ Stage 2 sensitivity and the synchronous condenser cost sensitivity. This highlights the robustness of the portfolio option to future MCCs, within the bounds of the assumptions tested in this MCC assessment.

Details of the preferred portfolio option 3b are listed below, relative to the PACR preferred option.

Table 19. Details of the preferred portfolio option in this MCC assessment

Technology	Number	Timing	Location
Phase 2 synchronous condensers	Three. Reduction from five in the PACR, to three.	To be delivered by FY31, if feasible, or otherwise as early as feasible.	Sites of the three Phase 2 synchronous condensers are Dinawan, Munmorah and Newcastle[104].
Grid-forming BESS	900 MW for the minimum level of system strength (once credibility is confirmed). An increase from 0 MW for the minimum level, in	Modelled from FY33 based on independent advice from Aurecon, but if credibility can be proven earlier, this will	Sydney West region – connected to the transmission network is considered most beneficial.

[104] Consistent with the PACR, the locations of synchronous condensers in the Sydney/Newcastle region may change as detailed site feasibility studies continue to ensure the optimal locations are progressed.

Technology	Number	Timing	Location
	addition to 5 GW for the efficient level that was identified in the PACR.	increase benefits further. [105]	
Modifications to synchronous machines to enable synchronous condenser mode	650 MW, as identified in the PACR.	From FY29	Projects located close to the Sydney West node are considered most beneficial.

Consistent with the PACR, hydro and gas re-dispatch remains part of the preferred portfolio option in the early 2030s. The need for coal re-dispatch in the same period will be re-evaluated in the contracting timeframe. Transgrid will procure system security services from synchronous machines in the contracting timeframe based on latest information and unit availability from all technologies.

The results of this draft MCC assessment are a revision to the PACR preferred option, rather than a fundamental change. The technologies remain unchanged, but the composition and proportions of each technology have been refined. This refinement is summarised as a reduction in synchronous condensers, substituted by an increased role for grid-forming BESS. The need for hydro, gas and potentially coal re-dispatch is consistent with the PACR, with the actual levels to be defined in the contracting timeframe.

The draft preferred portfolio option is robust to changes to various assumptions tested in this MCC assessment. This includes coal unit retirement dates between the two scenarios, the delivery timing of synchronous condensers between FY31–34, additional system strength solutions in New England REZ and tested for further cost synchronous condenser cost increases of up to 40%.

[105] If the timing to demonstrate credibility of grid-forming BESS contributing to the minimum level is materially delayed, this may constitute a further material change in circumstances which may require an additional synchronous condenser or alternative solutions to be procured.

11. Additional non-network options could further change the optimal portfolio

This draft MCC assessment has re-assessed the preferred portfolio based on updating cost and timing assumptions for synchronous condensers, as well as the revised coal unit retirement schedule under the Draft 2026 ISP Step Change scenario. Based on these changes, the number of Phase 2 synchronous condensers has reduced from five to four based on the revised coal unit retirement schedule and from four to three through additional grid-forming BESS for the minimum level. Non-network solutions included within the revised preferred portfolio include:

- 650 MW of synchronous machine modifications to enable synchronous condenser mode;
- 5 GW of grid-forming BESS for the efficient level;
- 900 MW of grid-forming BESS for the minimum level; and
- Contracts with existing and committed synchronous machines for re-dispatch.

Transgrid has identified three potential future changes which could lead to a reduction in the number of Phase 2 synchronous condensers within the preferred portfolio and lead to a higher market benefit outcome.

- If at least 500 MW of synchronous machines with synchronous condenser capability emerges in the Sydney / Newcastle region (or larger capacity but outside of the region). This is in addition to the 650 MW of synchronous machines with synchronous condenser capability across southern NSW that were identified in the PACR.
- If an additional 950 MW of grid-forming BESS for the minimum level (in addition to the 900MW already included in the preferred portfolio of this draft MCC assessment) emerges in the Sydney / Newcastle region and there is additional evidence to confirm their credibility such that fall-back solutions are not required.
- If sufficient coal generator units extend their Proponent Advised retirement dates beyond 2033 and this is expected to be included in the Step Change scenario in via a subsequent AEMO IASR or ISP update.

Note that this list is not exhaustive. The exact amount required of a future solution will be dependent on its size, location on the grid, critical contingency and electrical characteristics.

For a change in the preferred portfolio to occur, credible non-network options would need to be assessed and then selected within the preferred portfolio prior to Transgrid's lodgement of a contingent project application for Phase 2 synchronous condensers. To reasonably be expected to affect the preferred portfolio, an emerging solution(s) would need to demonstrate it is a credible solution and can meet the following criteria:

- Be assessed as technically feasible;
- Have a proponent;
- Have a sufficient system strength contribution to displace one or more synchronous condensers either individually or as a portfolio with other solutions;

- Be highly likely to be available at or before the date of the Phase 2 synchronous condensers; and
- Be cost-competitive with Phase 2 synchronous condensers.

The following sections explore three potential future changes which could lead to a revision of the preferred portfolio.

11.1. Synchronous machines with synchronous condenser mode enablement

Synchronous machines may install a clutch to enable operation in synchronous condenser mode, where the turbine spins to support system security without generating electricity. This functionality already exists for some hydro units in NSW. Synchronous condenser mode modifications are bespoke and are not always technically feasible based on the design or age of the plant. It is therefore essential that the technical credibility can be demonstrated during a MCC re-assessment process.

The PACR identified within the preferred portfolio the modification of 650 MW of plant in southern NSW to enable synchronous condenser mode, based on non-network expressions of interest throughout the RIT-T process. If additional solutions materialise and can meet the criteria identified, this may constitute a material change in circumstances.

Fault level analysis has been conducted to identify the indicative number of synchronous machines to provide the equivalent fault current to the two minimum level Phase 2 synchronous condensers, based on where the synchronous machines are located in NSW. This number is in addition to the 650 MW already identified in the PACR.

Table 20. Approximate capacity of synchronous machines that can operate in synchronous condenser mode to provide equivalent system strength contribution to the Sydney West node as the Phase 2 synchronous condensers

Location of potential synchronous machines	Capacity required to be equivalent to one Phase 2 synchronous condenser (MW)	Capacity required to be equivalent to two Phase 2 synchronous condensers (MW)
Kemps Creek	450	900
Armidale	950	1,900
Darlington Point	1,700	3,400
Newcastle	500	1,000
Wellington	700	1,400

The exact amount will depend on the specific location, the critical contingency and the electrical characteristics of the project(s).

11.2. Grid-forming BESS for the minimum level

This draft MCC assessment has included 900 MW of grid-forming BESS for the minimum level. This is the maximum amount for which there are fall-back system strength solutions in the event the technology is not demonstrated as credible in-time. If sufficient evidence emerges during an MCC reassessment process and projects materialise which provide enough certainty that fall-back solutions are not required, then additional grid-forming BESS may be relied upon to displace synchronous condensers.

Following the assumptions used in this draft MCC assessment, approximately 950 MW of grid-forming BESS provides the equivalent fault current to one minimum level Phase 2 synchronous condensers (or

1,900 MW for two synchronous condensers). This grid-forming BESS would be in addition to the 900 MW already identified in this assessment.

11.3. Coal generator units

This draft MCC assessment has included two coal generator unit retirement scenarios. Under both scenarios, Bayswater and Vales Point coal units are retired by FY34. If both Bayswater and Vales Point units were to delay their retirement dates beyond FY34, and it is likely AEMO would include it in the Step Change scenario via a subsequent Inputs, Assumptions and Scenarios Report (IASR) or ISP update[106], then we expect this would commensurately defer the need for additional system strength solutions.

Extended coal retirement dates are not expected to change the preferred portfolio composition in isolation, only the timing of the Phase 2 synchronous condensers and level of hydro and gas re-dispatch. However, deferred investment does provide additional time for alternative solutions, including grid-forming BESS or emerging synchronous machines with synchronous condenser capability, to demonstrate credibility.

Importantly, this assessment assumes a similar level of coal unit reliability and operational output could be maintained if coal retirements extend. As noted in Section 2.2.2, AEMO has identified that ageing coal generators present an increasing risk of unavailability and that more flexible operating practices of coal units (expected as the penetration of renewables increase) can accelerate equipment degradation.

The lead-time for synchronous condensers to be fully commissioned and in-service is significant, driven from the high international demand for this equipment. Given this, the decision to procure must be made well-ahead of the three-and-a-half-year notice period required by coal generator unit proponents before their retirement. To impact the preferred portfolio, coal units must provide notice of changing their planned retirement date and be expected to be included in AEMO's next Step Change scenario update before Transgrid's lodges a contingent project application.

[106] Regulatory investment test for transmission application guidelines, AER, November 2024, Section 3.4

12. Next steps for managing system strength requirements

12.1. Consultation

Noting the complexity of system strength planning and the revision of the preferred portfolio option in this assessment, it was determined appropriate to provide stakeholders an opportunity to provide submissions to this MCC assessment. As such, this draft MCC assessment will undergo a 1-month consultation period. Transgrid invites stakeholder submissions; submissions are due on 1 August 2026.

We welcome submissions from non-network proponents and interested parties on all aspects of this MCC assessment, including but limited to feedback on our key assumptions and outcomes of the analysis. We also welcome submissions from non-network parties, offering new, credible non-network options that could replace Phase 2 synchronous condensers in the Sydney / Newcastle region.

Submissions should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au[107]. In the subject field, please reference 'Meeting system strength requirements in NSW MCC assessment'.

Submissions will be used to inform the final MCC assessment, which is expected to be published by 24 August 2026, as stipulated by the AER.

The Final 2026 ISP was released on 25 June 2026. Transgrid will incorporate outcomes of the Final 2026 ISP in its final MCC assessment.

12.2. Proposed next steps for system strength solutions

12.2.1. Network solutions

Synchronous condensers for the first five sites have already been awarded (Phase 1), which is outside the scope of this MCC. Transgrid is currently engaging with suppliers and collaborating with relevant stakeholders to enable the regulatory and procurement process to progress for Phase 2 synchronous condensers identified in this draft MCC.

12.2.2. Non-network solutions

Transgrid will continue to procure non-network system strength solutions as part of a prudent and efficient portfolio, based on the latest information available at the time of procurement.

Notices for future tranches of synchronous machine and grid-forming BESS contracts will be communicated by email to all eligible parties who have previously submitted an expression of interest (EOI).

If you have not previously submitted an EOI for your project(s), or there have been material changes to your project since your EOI, you may submit a new or updated EOI at any time using the documentation on Transgrid's website. Please also advise Transgrid if the contact person named on your most recent EOI submission has changed.

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

Prior to contracting, Transgrid will undertake a detailed technical and commercial assessment. This assessment will include (where required) detailed power system analysis to select and validate additional non-network solutions required to meet minimum fault level requirements and/or achieve stable voltage waveforms, and an assessment of prudency and efficiency against the AER's System Security Network Support Payments Guideline. Transgrid expects contracts would only be offered where the project can meet the relevant technical performance requirements.

Transgrid's proposed non-network contracts are reviewed by the AER, where eligible, for prudency and efficiency before contracts are signed to ensure sufficient oversight on costs that will be passed through to consumers.

12.2.3. Grid-forming BESS

For the efficient level, Transgrid is currently evaluating responses to its initial tender for up to 2 GW of grid-forming BESS to support stable voltage waveform needs. Future tenders will occur as Transgrid progresses towards the PACR-identified portfolio of 5 GW; subject to holistic assessments in the contracting timeframe.

For the minimum level, Transgrid is engaging with industry, AEMO and other TNSPs to progress the assessment and validation of the credibility of grid-forming BESS to provide protection quality fault current.

Minimum level system strength requirements are most critical at the Sydney West node. The minimum level contribution of projects, if proven to be credible, is significantly higher if the project is located on the transmission network within the Sydney West (and Newcastle) region, due to the avoidance of impedance on the distribution network and from transformers at bulk supply points. Transgrid invites proponents of grid-forming BESS located in the Sydney West region interested in supporting the credibility assessment of this technology for minimum level services to get in touch via email at systemstrength@transgrid.com.au with a completed EOI form (from Transgrid's website).

12.2.4. Re-dispatch of synchronous generators

Transgrid has completed its initial tranche of contracts for synchronous system security services for FY26–FY28. The timing for a second tranche of contracts will be informed by additional market modelling based on a holistic assessment in the contracting timeframe. Transgrid invites proponents to maintain an up-to-date EOI with Transgrid for system strength services.

Transgrid welcomes EOIs from parties with solutions that include fitting clutches to existing or new synchronous machines, including hydro, coal and gas units, to enable their operation in synchronous condenser mode for the purposes of re-dispatch. Upgrades to 650 MW of synchronous machines to allow synchronous condenser mode was identified in the preferred portfolio at the PACR stage and will be assessed in the contracting timeframe.

Appendix A. MCC assessment modelled scenario and input parameters

The table below lists key assumptions and input parameters used in this assessment.

Table 21. Key assumptions and input parameters used in this assessment

Assumption	Source for each scenario for MCC assessment	Source for PACR
Transmission development pathway	Optimal development path from AEMO's Draft 2026 ISP	Optimal development path from AEMO’s Final 2024 ISP
Grid-forming BESS contribution to the minimum level	Available from FY33	Available from FY33
Coal generator retirement date	Two scenarios modelled: • Draft 2026 ISP Step Change • Proponent Advised coal unit retirement dates	2024 ISP Step Change
Storage capacity outlook	Draft 2026 ISP Step Change	2024 Final ISP with revisions for New England REZ as discussed in the PACR.
Gas fuel cost	Draft 2026 ISP inputs and assumptions workbook	2024 Final ISP inputs and assumptions workbook
Gas variable operating maintenance cost	Draft 2026 ISP inputs and assumptions workbook	2024 Final ISP inputs and assumptions workbook
Gas emissions intensity	Draft 2026 ISP inputs and assumptions workbook	2024 Final ISP inputs and assumptions workbook
Hydro variable operating maintenance cost	Draft 2026 ISP inputs and assumptions workbook	2024 Final ISP inputs and assumptions workbook
Value of emissions	Draft 2026 ISP inputs and assumptions workbook	AER Final Guidance Note May 2024
Value of customer reliability	AER Values of Customer Reliability 2025 Annual Adjustment	AER Values of Customer Reliability report 2024
Maintenance rate of synchronous condensers	Based on Phase 1 synchronous condenser award	Based on market sounding
Life of synchronous condenser	40 years	40 years
Capital cost of battery	Draft 2026 Draft ISP inputs and assumptions workbook, Step Change scenario	2024 ISP inputs and assumptions workbook
Life of BESS	20 years	20 years

Assumption	Source for each scenario for MCC assessment	Source for PACR
Commercial discount rate	7%, Draft 2026 ISP inputs and assumptions workbook	7%, 2024 Final ISP inputs and assumptions workbook
Technology-specific real-pre-tax weighted average cost of capital (WACC) estimate for regulated transmission	Transmission regulated assets: 3% Battery projects: 8% Draft 2026 Draft ISP inputs and assumptions workbook, Step Change scenario	Not included, as the capitalised cost methodology for cost benefit analysis followed AEMO's approach in the 2024 Final ISP

Appendix B. Assessment of gas availability for system strength re-dispatch

Gas generators contribute to system strength when they are synchronised to the grid, which requires a minimum generation level to operate stably. Operating additional hours for system strength provision (termed 're-dispatch') is dependent on the availability of gas supply to each power station. Gas availability is influenced by pipeline capacity, gas supply and competing demand for gas (e.g., industrial and residential consumption). This appendix summarises the desktop assessment used to develop gas constraints which were applied in the MCC modelling (see Section 3.2.2), reflecting practical limitations in gas availability.

The PACR included a pipeline constraint on the Sydney-Newcastle pipeline, which limited coincident gas re-dispatch for units served by this pipeline. The PACR did not implement any other constraints as it was not expected to affect the ranking of portfolio options. This was because only the worst-ranking option had a material amount of gas re-dispatch, and including the constraint would have made its ranking even worse. For this MCC assessment, the gas constraints are expected to affect the ranking of portfolio options, which is why they have now been included.

Gas generators in NSW

A generator's contribution to the minimum level of system strength depends on its electrical location relative to the system strength nodes, with the need being highest surrounding Sydney West. Due to their electrical-distance, some NSW gas generators provide only a small fault level contribution to these nodes, making them very high-cost on a 'cost per unit of system strength' basis. This assessment focuses on eight NSW gas units which exhibit a material system strength contribution to the Sydney West and Newcastle nodes.

NSW gas units are either open-cycle gas turbines (OCGT) or combined-cycle gas turbines (CCGT). OCGTs are typically more flexible (e.g., faster start and ramp) and are designed for peaking operation, which means they typically operate at low annual capacity factors (around 5%). CCGTs are designed to operate at higher capacity factors. Most of the NSW gas units that have a high system strength contribution to Sydney West and Newcastle nodes are OCGTs (88%), which are ill-suited to sustained operation for system strength (but are well-suited to operation during short periods of low system strength).

Limitations on gas availability for system strength

Transgrid's development of gas constraints for this analysis was based on AEMO's assessment of gas supply via its annual Gas Statement of Opportunities (GSOO)[108], as well as from advice by GHD during the PACR. AEMO was consulted during Transgrid's development of the gas constraints used in this assessment.

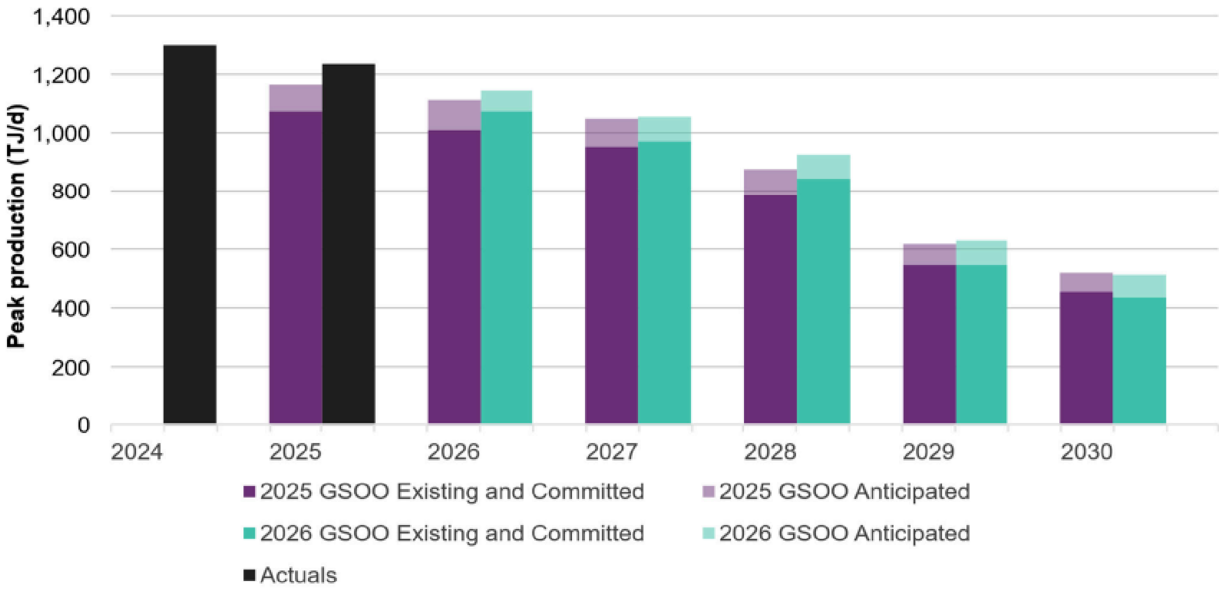
Two constraints were developed, to reflect the expected availability of gas for re-dispatch to meet system strength needs, driven by:

1) Pipeline constraints: the maximum gas that can be delivered to a power station, determined by the capacity of the supplying pipeline.
2) Gas supply constraints: the total gas available to the system, based on total production, imports, and storage less demand from other users (e.g. industrial and residential) and gas required for electricity generation for normal energy market purposes.

[108] Gas Statement of Opportunities 2026, AEMO, April 2026

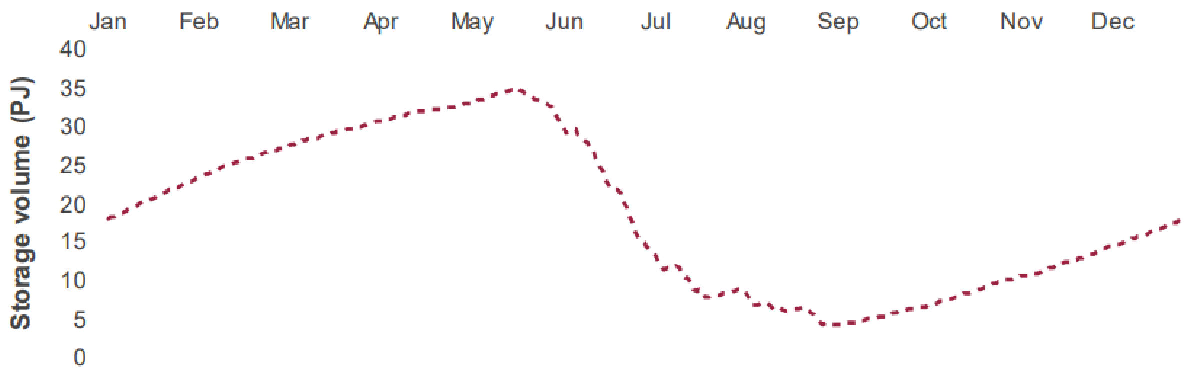
The GSOO indicates declining production in southern Australia (SA, VIC, TAS and NSW), which means there is an increased reliance from southern states on supply from Queensland via the South West Queensland pipeline and seasonal storage. This is illustrated in the graph below from the GSOO.

Figure 28. Figure taken from AEMO's 2026 Gas Statement of Opportunities. Page 53. Actual and forecast maximum daily production capacity from southern gas fields in June, 2024-30 (TJ / d)



As gas usage in the southern states is highest in winter, this can leave storages empty during spring, which is typically a time of low system strength. This makes it more likely has re-dispatch will not be available when it is most needed for system strength. This is shown on the figure below from AEMO's Draft 2026 ISP for the Step Change scenario for 2031 based on the 2015 weather reference year.

Figure 29. Figure taken from Appendix 10 Gas Development Projects for AEMO's Draft 2026 ISP, page 31. Forecast gas storage profile for gas development project Option 3, Step Change, reference year 2015, calendar year 2031 (PJ)



Gas availability is dependent upon the level of line-pack or on-site storage. If periods of low system strength occur after a renewable lull (low coincident wind and solar event), which increases demand for gas, then this will materially affect the availability of gas supply and therefore the ability for gas generators to increase their operation for system strength. Conversely, if gas is used excessively for system strength re-dispatch, then this may jeopardise the availability of gas for energy reliability during a subsequent renewable lull.

Some NSW gas generators have secondary fuels on-site and can operate with diesel. This may increase the availability of some gas units for system strength, but is very costly, highly pollutant and subject to similar availability concerns if secondary fuels are required to meet energy reliability requirements as forecast by AEMO[109].

Forming gas constraints

To reflect the limitations above, Transgrid applied the following two constraints in the modelling:

- Limit coincident gas re-dispatch for system strength at any point in time, to reflect pipeline limitations on the Sydney–Newcastle line. This pipeline supplies gas to the bulk of the gas units in NSW which provide a material system strength contribution to the Sydney West and Newcastle regions.
- Limit total annual gas re-dispatch based on a percentage of annual typical energy market dispatch, to reflect gas supply limitations. This constraint becomes more stringent from FY33 as southern production declines.

Gas re-dispatch is the most expensive system strength option and is not expected to be relied on once alternative solutions are available (synchronous condensers and grid-forming BESS for the minimum level). On that basis, this analysis does not consider longer-term measures to expand gas supply or pipeline capacity. When gas re-dispatch limits are breached in the MCC analysis, periods of additional gas re-dispatch requirements are modelled as risks of gaps, leading to involuntary load curtailment (unserved energy).

Ranking of portfolio options without gas constraints

For transparency, the net market benefits without the gas constraints have been shown below for the Draft 2026 ISP Step Change scenario.

The magnitude of net market benefits is significantly reduced, given the lower cost of gas re-dispatch relative to unserved energy. However, the ranking of portfolio options does not change either with or without grid-forming BESS. A similar decrease in net present value is observed when comparing portfolio option 3a to portfolio option 3b, justifying the decision to only treat portfolio options 3, 4 and 5 as credible.

[109] Draft 2026 ISP Appendix A.10. Gas Development Projects, AEMO, December 2025, Page 33

Figure 30. Draft 2026 ISP Step Change scenario. Net present value assessment without gas constraints, excluding grid-forming BESS

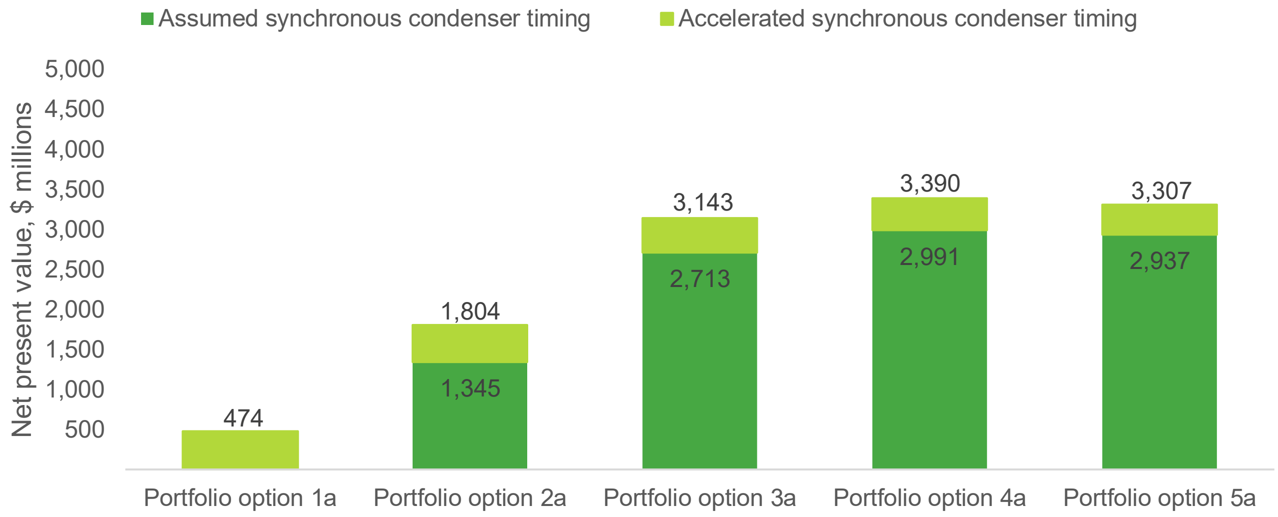
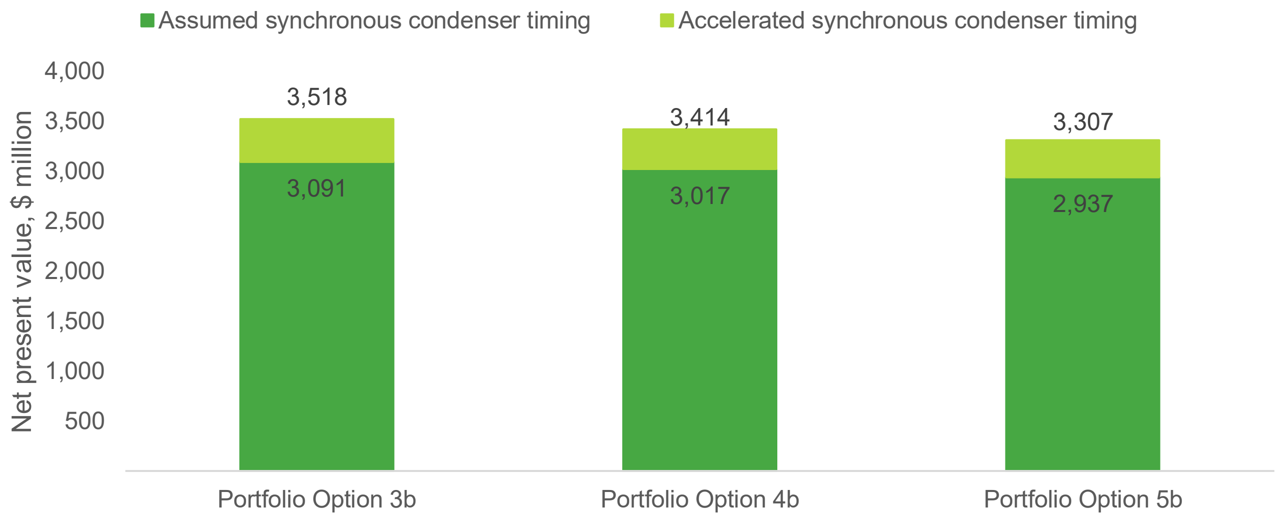


Figure 31. Draft 2026 ISP Step Change scenario. Net present value assessment without gas constraints, including grid-forming BESS



The gas constraints do not influence the ranking of portfolio options in this MCC assessment, this further justifies the simplistic approach to setting the gas constraints to be commensurate with the analysis. However, the gas constraints do affect the magnitude of the net market benefits, indicating the sensitivity of involuntary load curtailment to gas availability.

Appendix C. Comparison of Net Present Value methodology

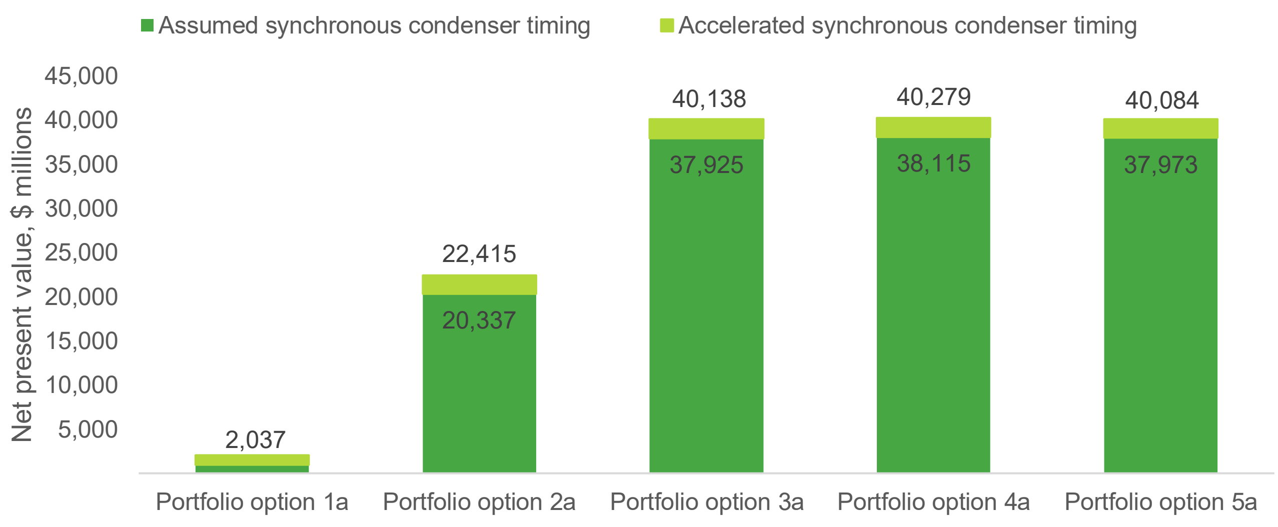
Since the system strength PACR, Transgrid has aligned its approach to annualising and discounting costs with AEMO's ISP methodology[110]. Under this methodology, the capital investment is converted into an equivalent annual annuity to allow like-for-like comparison on assets with different economic lives and different commissioning dates. Transgrid is required to follow the assumptions used by AEMO[111] and has incorporated this methodology into this assessment.

This approach changes the capital cost profile of solutions assessed under this Draft MCC assessment compared to the PACR. In the PACR, the capital cost was modelled based on when it would be incurred by Transgrid; we refer to this as the capitalised cost methodology.

For this draft MCC assessment, using AEMO's cost-benefit assessment methodology, the capital cost is spread over the economic life of the asset to reflect to how the costs would be recovered, this is referred to as the annualised cost methodology. The weighted average cost of capital (WACC) is also included into the annual cost of the capital investment to reflect a regulated return on transmission assets or the techno-specific return identified by AEMO for unregulated assets. This is compared to the capitalised cost methodology (used in the PACR) which did not include a return on investment (for either regulated or unregulated).

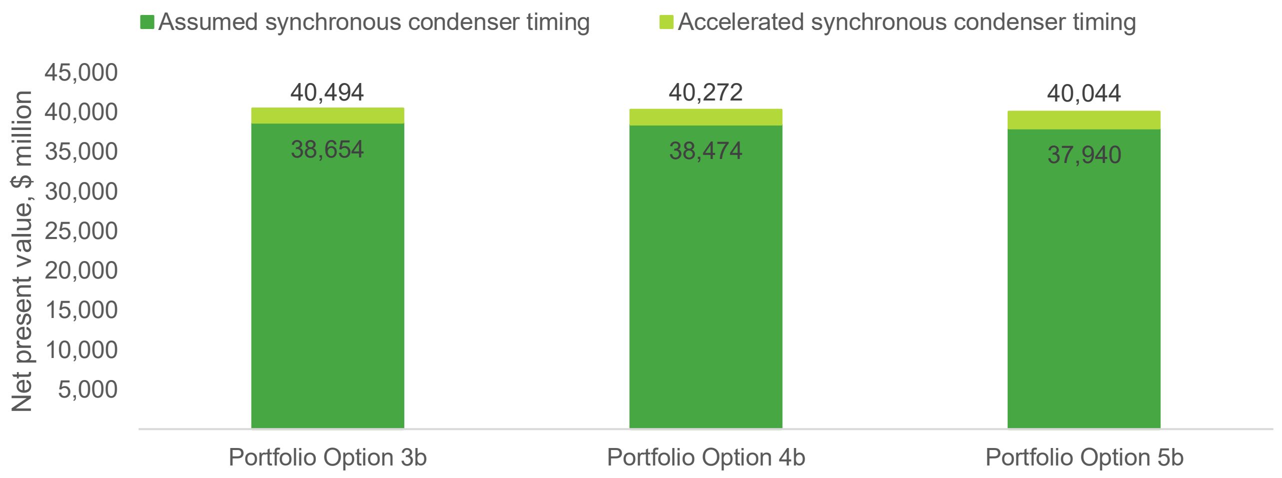
This appendix presents the results of a net present value assessment using the capitalised cost methodology, consistent with the assessment in the PACR. The results are shown below for the Draft 2026 ISP Step Change scenario, both excluding and including grid-forming BESS for the minimum level.

Figure 32. Draft 2026 ISP Step Change scenario. Net present value assessment with capitalised cost methodology, excluding grid-forming BESS



[110] ISP methodology June 2025, AEMO, June 2025, Page 94
[111] Regulatory investment test for transmission application guidelines, AER, December 2024, Section 3.4

Figure 33. Draft 2026 ISP Step Change scenario. Net present value assessment without capitalised cost methodology, including grid-forming BESS



Portfolio option 4a is the preferred option when excluding grid-forming BESS for the minimum level and Portfolio option 3b is the preferred option when including grid-forming BESS. This is consistent with the results of this draft MCC assessment, showing that the ranking of portfolio options is the same across both the capitalised cost and the annualised cost methodologies.

The net present value is slightly lower under the capitalised cost methodology, as the capital cost is incurred earlier. However, the reduction in net present value is relatively small (<1%) compared to the magnitude of the benefits.

Appendix D. Compliance checklist

The table below highlights which how each requirement determined by the AER in its response to Transgrid's notification of a system strength material change in circumstances[112] has been addressed.

Table 22. Compliance checklist of each AER requirement in its determination

Requirement	Relevant section in this report
Undertake a streamlined cost benefit analysis, drawing on: • the existing PACR analysis • updated cost and timing information, and • the most recent AEMO ISP-related inputs and outputs and AEMO's 2025 Transition Plan for System Security, where relevant.	Streamlined cost benefit analysis has been undertaken. The methodology is described in Section 0. The most recent AEMO ISP-related inputs are currently the Draft 2026 ISP. The Final 2026 ISP was released on 25 June 2026 and will be considered within the final MCC assessment.
Transgrid must publish a draft statement on its website by 24 June 2026 which sets out: • a statement that the preferred option identified remains the preferred option, as well as any supporting information necessary to demonstrate that the preferred option identified remains the preferred option; or • a statement that the preferred option is no longer the preferred option and identifying the new preferred option, as well as any supporting information necessary to demonstrate that the preferred option is no longer the preferred option and the reasons the new preferred option is the preferred option.	The refined preferred portfolio option is described in Section 10 including the reasons the new preferred portfolio option is the preferred portfolio option.
Transgrid must publish a draft statement on its website by 24 June 2026 which sets out: • provides supporting information setting out the range of all potential solutions which could reasonably be expected to provide system strength, as well as reasons why any potential options were not considered credible or are considered to not form part of the preferred portfolio option.	The solutions considered in this MCC analysis are described in Section 3.
Transgrid must publish a draft statement on its website by 24 June 2026 which sets out: • provides a description of each of the changes in circumstances, including the changed operation of synchronous generation, and its materiality to the analysis, and	The nature of each material change in circumstance addressed in this assessment is described in Section 2.
Transgrid must publish a draft statement on its website by 24 June 2026 which sets out: • presents the updated cost benefit analysis developed under paragraph	The updated cost benefit analysis results are described in Section 7 and the attached NPV workbooks.

[112] Material change in circumstances – Meeting system strength requirements in NSW – Determination, AER, June 2026

Requirement	Relevant section in this report
Transgrid must seek submissions from registered participants, AEMO and interested parties on the preferred option presented and the issues addressed in the draft statement. The period for submissions must be 1 month from the date Transgrid publishes the draft statement on its website.	Transgrid will conduct a one-month consultation period from the 1 July 2026 to 1 August 2026. Guidance on how to make a submission is provided in Section 12.
Transgrid must publish a final statement which sets out the matters required under paragraph (2), incorporates feedback from submissions and provides a summary of, and response to, submissions received during the consultation period. The final statement must be published on Transgrid's website within 1 month of the closing date for submissions, at the latest by 24 August 2026.	This requirement will be addressed in the final MCC report.