Transgrid

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Increasing Capacity for Generation in the Wagga North Area

Market Modelling Report

18 December 2025

Contents

1. Executive Summary

Transgrid has initiated a Regulatory Investment Test for Transmission (RIT-T) to assess credible options for increasing generation capacity in the Wagga North area. The region currently hosts approximately 409 MW of renewable generation, with three Battery Energy Storage Systems (BESS) totalling 240 MW proposed for development. An additional option involving a 120 MW / 480 MWh BESS was included following stakeholder feedback. The analysis spans a 20-year horizon (2024/25–2043/44), with benefits discounted to June 2025 at a 7% real pre-tax rate, consistent with AEMO's 2024 Integrated System Plan (ISP) assumptions.

Methodology

The market modelling was based on AEMO's 2024 ISP Detailed Long-Term (DLT) model and applied across three scenarios: Step Change, Progressive Change, and Green Energy Exports. Each scenario reflects different trajectories for renewable uptake, coal retirements, and policy settings. Costs were calculated for a Base Case (with no augmentation) and for each credible option under all scenarios.

At the time of preparing this report, AEMO's updated 2026 ISP Detailed Long-Term (DLT) model has not yet been released. Once the 2026 ISP model becomes available, the market modelling will be revisited and updated as part of the PACR stage to ensure alignment with the latest assumptions and scenarios.

Market benefits were derived as avoided costs relative to the Base Case, including categories such as capital expenditure (CAPEX), fixed and variable operations and maintenance (O&M), fuel costs, curtailment costs, Renewable Energy Zone (REZ) expansion costs, and value of emissions.[1] These costs were computed at half-hourly intervals over the modelling horizon, and the resulting benefits were discounted to present value using a 7% real pre-tax rate. This approach ensures consistency with AEMO's ISP methodology and provides a robust framework for comparing the economic impact of each option.

Options Assessed

Option	Description	Expected Delivery Time
Option 1	Restring Lines 9R5 and 9R6 with a "Mango" ACSR/GZ conductor (or equivalent) operating at 85°C, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2027/28
Option 2	Restring Lines 9R5 and 9R6 with a high-temperature, low-sag conductor (HTLS), and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2027/28
Option 3	Construct a new double circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2030/31
Option 4	Construct a new single circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2029/30
Option 5	Develop a 120 MW / 480 MWh BESS in Wagga North area.	2027/28

Network Assumptions

The Wagga North area is connected to surrounding load centres through transmission lines 9R5, 9R6, and 991, which currently experience thermal overloads during peak demand and high renewable dispatch.

[1] Carbon emissions in tonnes for each option has been presented in this report. The value of emissions will be quantified in the Project Assessment Draft Report (PADR).

These overloads are managed through AEMO constraint equations. For the Base Case, these constraints were modelled to reflect existing operational limits, including seasonal and time-of-day ratings. For each augmentation option, the relevant constraint equations were modified to reflect changes in network and thermal capacity, incorporating updated contingency ratings and design specifications. Additionally, a busbar upgrade at the Wagga 132/66 kV substation was assumed for all network augmentation options except the standalone BESS option, ensuring that busbar constraints do not limit outcomes. This assumption reflects the need to maintain system reliability while enabling increased transfer capacity from Wagga North.

Forecasted Gross Market Benefits

Option	Description	Expected Delivery	Forecast Gross Market Benefits ($m discounted to FY 2024/25)		
			Step Change	Progressive Change	Green Energy Exports
Option 1	Restring Lines 9R5 and 9R6 with a "Mango" ACSR/GZ conductor (or equivalent) operating at 85°C, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2027/28	28.26	20.32	30.44
Option 2	Restring Lines 9R5 and 9R6 with a high-temperature, low-sag conductor (HTLS), and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2027/28	39.97	26.95	43.94
Option 3	Construct a new double circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2030/31	11.14	15.73	6.47
Option 4	Construct a new single circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2029/30	14.25	19.26	7.09
Option 5	Develop a 120 MW / 480 MWh BESS in Wagga North area.	2027/28	80.57	78.65	99.95

Options 1 and 2 significantly increase thermal ratings, with Option 2 fully resolving Wagga North constraints. Options 3 and 4 provide partial relief but introduce constraint shifting. Option 5 alleviates curtailment by absorbing surplus generation and deferring new builds. Timing plays a critical role, as earlier delivery (Options 1, 2, and 5) allows benefits to accrue sooner, increasing discounted values. Across scenarios, CAPEX savings from deferred generation builds, reduced curtailment, and fuel cost changes are the key drivers of market benefits.

2. Introduction

Transgrid has initiated the Regulatory Investment Test for Transmission (RIT-T) to evaluate options for increasing generation capacity in the Wagga North area. This region has experienced substantial growth in renewable energy connections, with approximately 409 MW of generation currently in service. Additionally, three new Battery Energy Storage Systems (BESS) with a combined capacity of 240 MW are proposed for development in the Wagga North Area.

This supplementary report, intended to be read in conjunction with the Project Assessment Draft Report (PADR), presents market modelling outcomes, including system costs and gross network benefits, for the proposed options to enhance generation capacity in the region. The selection of input assumptions and modelling methodology follows the RIT-T guidelines published by the AER.[2]

The RIT-T options were incorporated into AEMO's 2024 ISP Detailed Long-Term (DLT) Model, and the cost-benefit analysis was carried out using the market modelling outcomes for the three ISP scenarios. Gross market benefits for each option are computed by estimating the following key categories of avoided costs for each Option relative to the Base Case:

- **Annualised build cost of new generation capacity installed (CAPEX)**:
  Annualised costs of new generation capacity installed in the model

- **Total FO&M costs**:
  The fixed cost component for operations and maintenance of generator units

- **Total VO&M costs**:
  The variable cost component for operations and maintenance of generator units

- **Total fuel costs**:
  Costs associated with generator fuel consumption

- **Total cost of voluntary load curtailment**:
  Payments made to demand-side participants who voluntarily curtail their load.

- **Total cost of involuntary load curtailment**:
  Costs associated with unserved energy, which is defined as the load that cannot be met due to shortage of generation/transmission capacity.

- **REZ Transmission expansion costs**:
  Costs related to transmission augmentations supporting the Renewable Energy Zones in the model.

- **Value of emissions produced:**
  The estimated value of emissions produced by all sources in the model.

2 AER, Regulatory investment test for transmission (RIT-T) Application guidelines, November 2024

These costs are calculated for half-hourly intervals spanning across a 20-year modelling horizon from 2024/25 to 2043/44. The annualised benefits are discounted to June 2025 using a 7% real, pre-tax discount rate which is consistent with the value applied by AEMO in the 2024 ISP.

For the Base Case, costs were computed assuming no network augmentation (i.e., using the 2024 ISP models and generation constraint assumptions) across all three ISP scenarios. The modelled system costs for each of the five credible network options (Table 1) are then compared against the Base Case to estimate gross market benefits associated with each network option.

At the time of preparing this report, AEMO's updated 2026 ISP Detailed Long-Term (DLT) model has not yet been released. Once the 2026 ISP model becomes available, the market modelling will be revisited and updated as part of the PACR stage to ensure alignment with the latest assumptions and scenarios.

In response to the PSCR, one submission raised the prospect that a BESS may help to address the identified need in the long run. As a result of this submission, we have included an additional network option (from our PSCR) which involves the development of a 120 MW/480 MWh battery energy storage system (BESS) in the Wagga North Area. This option was included in our range of modelled options to allow us to evaluate the potential for BESS in alleviating network constraints and supporting renewable integration, particularly during periods of high electricity generation.

According to AEMO's NEM generation information, there are other BESS projects proposed in the region. They have been excluded from the modelling as they are not classified as anticipated or committed under AEMO's project status definitions.[3]

Table 1: Options Summary

Option	Description	Expected Delivery Time
Option 1	Restring Lines 9R5 and 9R6 with a "Mango" ACSR/GZ conductor (or equivalent) operating at 85°C, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2027/28
Option 2	Restring Lines 9R5 and 9R6 with a high-temperature, low-sag conductor (HTLS), and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2027/28
Option 3	Construct a new double circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2030/31
Option 4	Construct a new single circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2029/30
Option 5	Develop a 120 MW / 480 MWh BESS in Wagga North area.	2027/28

The net economic benefit of each option is determined by comparing its gross market benefits against its capital and implementation costs. These results are presented in the Project Assessment Draft Report

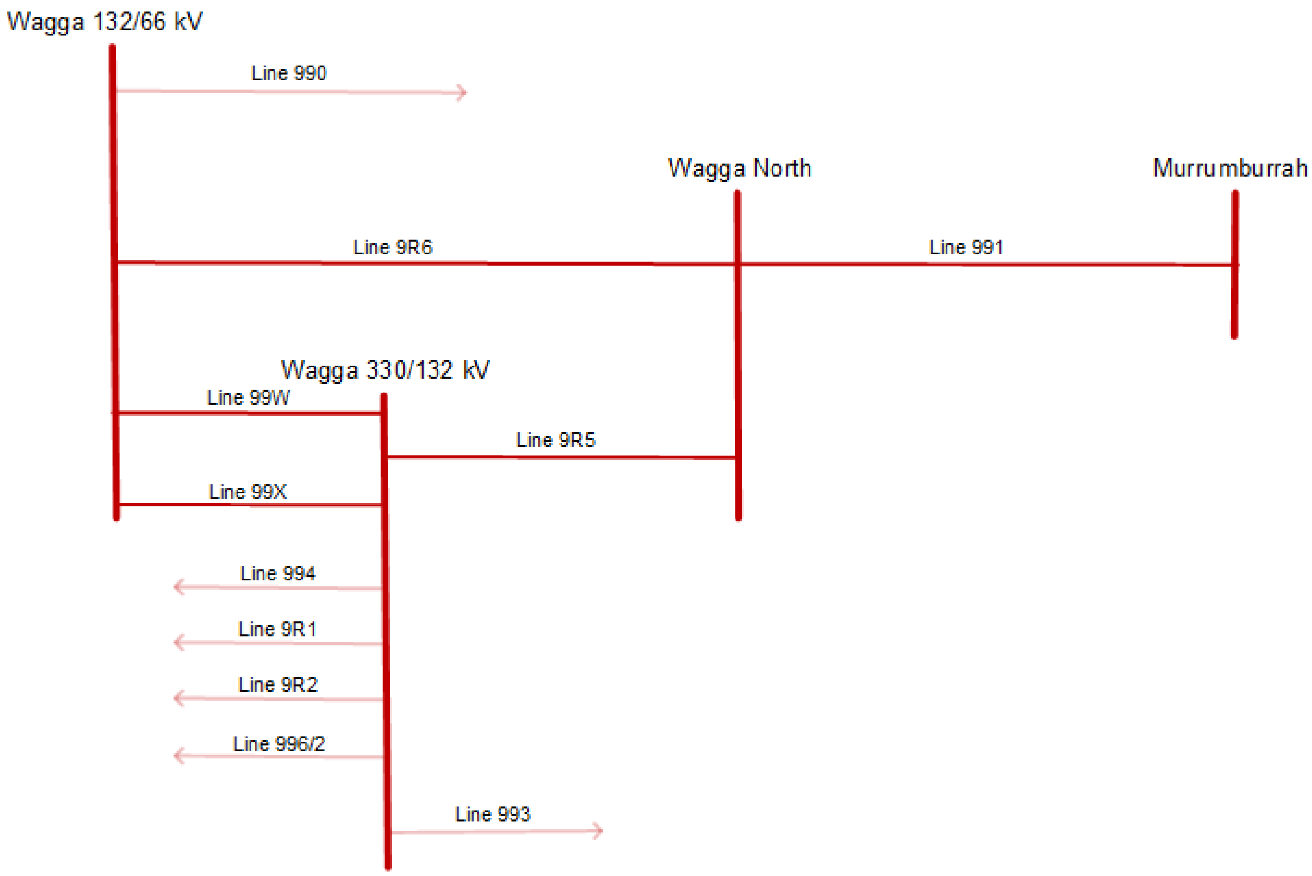
3 This is consistent with the latest RIT-T Guidelines, which indicates that the RIT-T proponent should include 'committed', 'actionable ISP', 'anticipated' and 'modelled' projects to form all relevant states of the world. Source: AER, RIT-T Guidelines, November 2024 p33-34.

(PADR), with this report providing the details of the market modelling that underpin the market benefit estimates.

3. Network Assumptions

With 409 MW of active generation capacity, transmission lines 9R5, 9R6, and 991 (Figure 1) serve a critical role in transporting electricity from the Wagga North and the other Wagga substations to surrounding load centres. Ensuring the reliability and capacity of these lines is essential to maintaining system stability and supporting further renewable integration in the region.

Figure 1: Wagga North Connectivity



3.1. Thermal Constraint Assumptions and Line Ratings

During periods of peak demand, when renewable generation in the Wagga North area is dispatched, thermal overloads are observed on transmission lines 9R5 and 9R6 in the event of an outage on either line. These overloads are currently managed through constraint equations implemented by AEMO's National Electricity Market Dispatch Engine (NEMDE), which curtail local generation to relieve network congestion:

Table 2: Constraint Equations – Wagga North

Constraint ID	Description
N>NIL_9R6_991	Out= Nil, avoid O/L Wagga North to Wagga (9R6) 132kV line on trip of Wagga North to Murrumburrah (991) 132kV line
N>NIL_9R6_9R5	Out= Nil, avoid O/L Wagga North to Wagga132 (9R6) on trip of Wagga North to Wagga330 (9R5) line

N>NIL_9R5_9R6	Out= Nil, avoid O/L Wagga North to Wagga330 (9R5) on trip of Wagga North to Wagga 132 (9R6) line

In the base case, these network constraints are modelled to reflect existing system conditions, incorporating seasonal and time-of-day thermal ratings. These constraints are derived from AEMO's published constraint libraries and reflect the operational limits.

For each augmentation option, the relevant constraint equations are modified to reflect the proposed changes in network topology and thermal capacity. This includes updates to:

- Continuous and short-term emergency ratings for lines 9R5, 9R6, and 991, based on design specifications and thermal performance under various ambient conditions.
- Constraint right-hand side (RHS) limits, adjusted to reflect increased thermal headroom or parallel path support.

The contingency ratings for lines 9R5, 9R6 and 991 are shown in Table 3, Table 4 and Table 5 under each option.

Table 3: Contingency Rating for Line 9R5 Under Different Options

Season	Time of day	Base (MVA)	Option 1 (MVA)	Option 2 (MVA)	Option 3 (MVA)	Option 4 (MVA)
Summer	Day	137	169	223	2 x 137	2 x 137
	Night	138	178	224	2 x 138	2 x 138
Autumn & Spring	Day	143	172	222	2 x 143	2 x 143
	Night	141	187	228	2 x 141	2 x 141
Winter	Day	150	206	239	2 x 150	2 x 150
	Night	154	210	210	2 x 154	2 x 154

Table 4: Contingency Rating for Line 9R6 Under Different Options

Season	Time of day	Base (MVA)	Option 1 (MVA)	Option 2 (MVA)	Option 3 (MVA)	Option 4 (MVA)
Summer	Day	137	169	223	137	137
	Night	138	178	224	138	138
Autumn & Spring	Day	143	172	222	143	143
	Night	141	187	228	141	141
Winter	Day	150	206	239	150	150
	Night	154	210	210	154	154

Table 5: Contingency Rating for Line 991 Under Different Options

Season	Time of day	Base (MVA)	Option 1 (MVA)	Option 2 (MVA)	Option 3 (MVA)	Option 4 (MVA)
Summer	Day	137	137	137	137	137
	Night	138	138	138	138	138
Autumn & Spring	Day	143	143	143	143	143
	Night	141	141	141	141	141
Winter	Day	150	150	150	150	150
	Night	154	154	154	154	154

Additionally, there are system normal constraint equations resulting in generation curtailment in the Wagga North region that are not related to the thermal limits of lines 9R5 and 9R6. These constraints have been excluded from this market modelling assessment, as they are being addressed through a separate project aimed at increasing transmission capacity between Yass and Wagga Wagga (refer to TAPR Section 2.3.5)[4].

3.2. Wagga 132/66 kV busbar Upgrade

Since publishing the Project Specification Consultation Report (PSCR), Transgrid has identified that there will be times when renewable generation will be curtailed to ensure the 132 kV busbar at Wagga 132/66 kV substation does not exceed its current ratings. To address this emerging constraint, a busbar upgrade at the Wagga 132/66 kV substation has been incorporated into the scope of all network augmentation options considered in this assessment, with the exception of the standalone BESS option. The rationale for this exclusion is that a BESS, by design, absorbs surplus generation during periods of high electricity generation, thereby alleviating pressure on the busbar rather than exacerbating it.

The market simulations assume that the busbar will not be constrained, and that the upgrade at the Wagga 132/66 kV substation will be implemented under the network options. Therefore, this update does not change any of the market modelling assumptions. While the cost of the busbar upgrade is not explicitly captured in the market modelling, it will be accounted for in the net cost-benefit analysis (CBA) presented in the Project Assessment Draft Report (PADR).

4. Methodology and key inputs and assumptions

4.1. Key Inputs and Assumptions

The market modelling presented in this report is based on AEMO's 2024 Integrated System Plan (ISP) Detailed Long-Term (DLT) model, which provides a nationally consistent framework for evaluating long-term electricity system development. The modelling approach and input assumptions are aligned with AEMO's 2023-24 Inputs, Assumptions and Scenarios Report (IASR)[5], ensuring consistency with the latest planning and policy settings across the National Electricity Market (NEM).

[4] https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report.pdf
[5] https://www.aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?rev=f6c9a6c48a9946208ab6e1cf7ef32c7f&sc_lang=en

At the time of preparing this report, AEMO's updated 2026 ISP Detailed Long-Term (DLT) model has not yet been released. Once the 2026 ISP model becomes available, the market modelling will be revisited and updated as part of the PACR stage to ensure alignment with the latest assumptions and scenarios.

4.1.1. Modelling Framework

The DLT model is a least-cost capacity expansion and dispatch model that optimises the development and operation of generation, storage, and transmission assets over a 20-year planning horizon (2024/25 to 2043/44). The model's objective function is to minimise the net present value (NPV) of total system costs, including build costs + production costs and fixed operations and maintenance costs

The model ensures energy balance, operational feasibility, and compliance with technical and policy constraints, including reliability standards, emissions targets, and renewable energy integration requirements.

4.1.2. Scenarios Considered

The network options were assessed under three core ISP development scenarios, each representing a distinct trajectory for Australia's energy transition specified in AEMO's ISP[6]:

> **Green Energy Exports:** "reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane. The NEM electricity sector plays a very significant role in decarbonisation."
>
> **Progressive Change:** "meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher relative technology costs and more supply chain challenges relative to other scenarios."
>
> **Step Change:** "achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. The NEM electricity sector plays a significant role in decarbonisation and the scenario assumes the broader economy takes advantage of this, aligning broader decarbonisation outcomes in other sectors to a pace aligned with beating the 2°C abatement target of the Paris Agreement. The NEM's contribution may be compatible with a 1.5°C abatement level, if stronger actions are taken by other sectors of Australia's economy simultaneous with the NEM's decarbonisation. Consumers provide a strong foundation for the transformation, with rapid and significant continued investments in highly orchestrated CER, including electrification of the transportation sector".

4.1.3. Cost Categories Assessed

In accordance with the AER's RIT-T Guidelines, the following categories of system costs were calculated at half-hourly resolution across the modelling horizon:

- Annualised build cost of new generation capacity installed (CAPEX)
- Total FO&M costs

[6] https://www.aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?rev=b811f5d66df24e0a980ce0df8eaa5687&sc_lang=en

- Total VO&M costs
- Total fuel costs
- Total cost of voluntary load curtailment
- Total cost of involuntary load curtailment
- REZ Transmission expansion costs
- Value of emissions produced

4.1.4. Calculation of Gross Benefits

For each scenario, the gross market benefits of each network option are calculated as the difference in total system costs between the option and the Base Case (which assumes no additional network augmentation beyond committed projects). These benefits are aggregated over the 20-year modelling horizon and discounted to June 2025 using a 7% real, pre-tax discount rate, consistent with AEMO's ISP methodology.

The resulting gross benefits are then compared against the capital costs of each option to determine the net economic benefit and, subsequently, the preferred option. This cost-benefit analysis will be conducted as part of the Project Assessment Draft Report (PADR) using the inputs provided from this report.

4.2. Overview of forecasted gross market benefits

The table below presents a summary of the forecasted gross market benefits for each network option and augmentation, outlining key drivers under the different ISP scenarios.

Table 6: Gross Benefit Breakdown

Option	Description	Expected Delivery	Forecast Gross Market Benefits ($m discounted to FY 2024/25)		
			Step Change	Progressive Change	Green Energy Exports
Option 1	Restring Lines 9R5 and 9R6 with a "Mango" ACSR/GZ conductor (or equivalent) operating at 85°C, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2027/28	28.26	20.32	30.44
Option 2	Restring Lines 9R5 and 9R6 with a high-temperature, low-sag conductor (HTLS), and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2027/28	39.97	26.95	43.94
Option 3	Construct a new double circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2030/31	11.14	15.73	6.47
Option 4	Construct a new single circuit transmission line, and upgrade busbar at 132/66 kV Wagga substation to aluminium tube design.	2029/30	14.25	19.26	7.09
Option 5	Develop a 120 MW / 480 MWh BESS in Wagga North area.	2027/28	80.57	78.65	99.95

Options 1 and 2 (uprating lines 9R5 and 9R6 to higher contingency ratings) deliver significantly higher gross market benefits compared to Options 3 and 4. This is primarily due to their earlier commissioning timeline (FY28), allowing benefits to accrue earlier in the modelling horizon and increasing their net present value (NPV).

Option 2 provides the highest market benefit among all transmission augmentations. Its enhanced thermal rating fully alleviates all three Wagga constraint equations, resulting in zero binding across scenarios.

Option 1, while similar in scope, still experiences residual constraint binding, resulting in lower benefits than Option 2.

Option 3 scope includes a new double circuit transmission line, where one circuit is a new line from Wagga 330/132 to Wagga North and the second circuit is the existing line 991 rerouted from Wagga 330/132 to Murrumburrah through structure 613. This configuration increases the transfer capacity from Wagga North to the broader Wagga area, partially alleviating the constraints.

However, this also results in a redistribution of power flows with more power flowing towards the Wagga substations which causes other constraints to bind more frequently. While the augmentation provides some relief, the net benefit is limited due to constraint shifting rather than full resolution. This option is also estimated to commission in FY31 causing it to have the lowest benefits among all assessed options.

Option 4, a new single circuit between Wagga North and Wagga 330/132. The additional circuit increases transfer capacity from Wagga North, but the constraints remain binding as the existing line 9R6 still remains as the limiting factor. Both Options 3 and 4 result in lower benefits in the green energy exports scenario, where constraint binding is less prevalent in later years due to accelerated coal retirements, transmission development and renewable integration.

Option 5 is projected to deliver the highest gross market benefits among all assessed options. This is largely due to the BESS being dispatched as a generator rather than being reserved solely for alleviating network constraints in the Wagga region. Consequently, the model assumes fewer future generator builds, which amplifies the calculated benefits from CAPEX savings.

4.3. Base Case

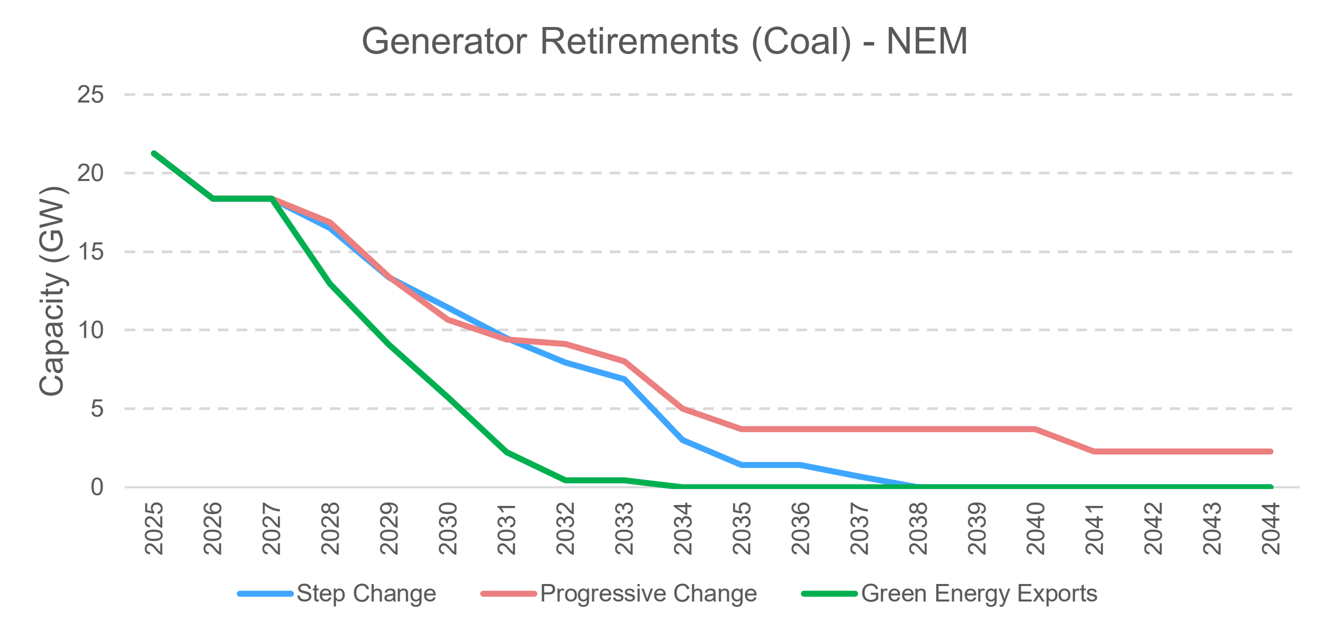
This section outlines the generation and capacity outlooks of the NEM (as part of the Base Case) under three ISP scenarios, assuming no network augmentations at Wagga North. It highlights how thermal constraints at Wagga North influence future generation dispatch and investment decisions across the ISP scenarios.

The ISP model methodology only considers anticipated and committed generators. According to AEMO's latest NEM generation information, all three batteries in the Wagga North Region are "proposed" but not yet anticipated. Hence, these batteries have been excluded from the modelled base cases.

4.3.1. Coal Generator Retirements

Coal retirements are determined through long term modelling in AEMO's 2024 ISP. The ISP methodology explores and validates potential early retirements for each scenario driven by decarbonisation targets, policy constraints, and system cost optimisation. Figure 2 shows the coal generator retirement schedule for all three scenarios.

Figure 2: Coal Generator Retirements – NEM – ISP 2024



4.3.2. Generation

Figure 3 and Figure 4 present the installed capacity and generation forecasts for the base case under the Step Change scenario. the capacity mix progressively shifts toward large-scale renewables (wind and solar), storage technologies, and gas-powered generation.

Figure 3: Installed Capacity - Base Case - Step Change

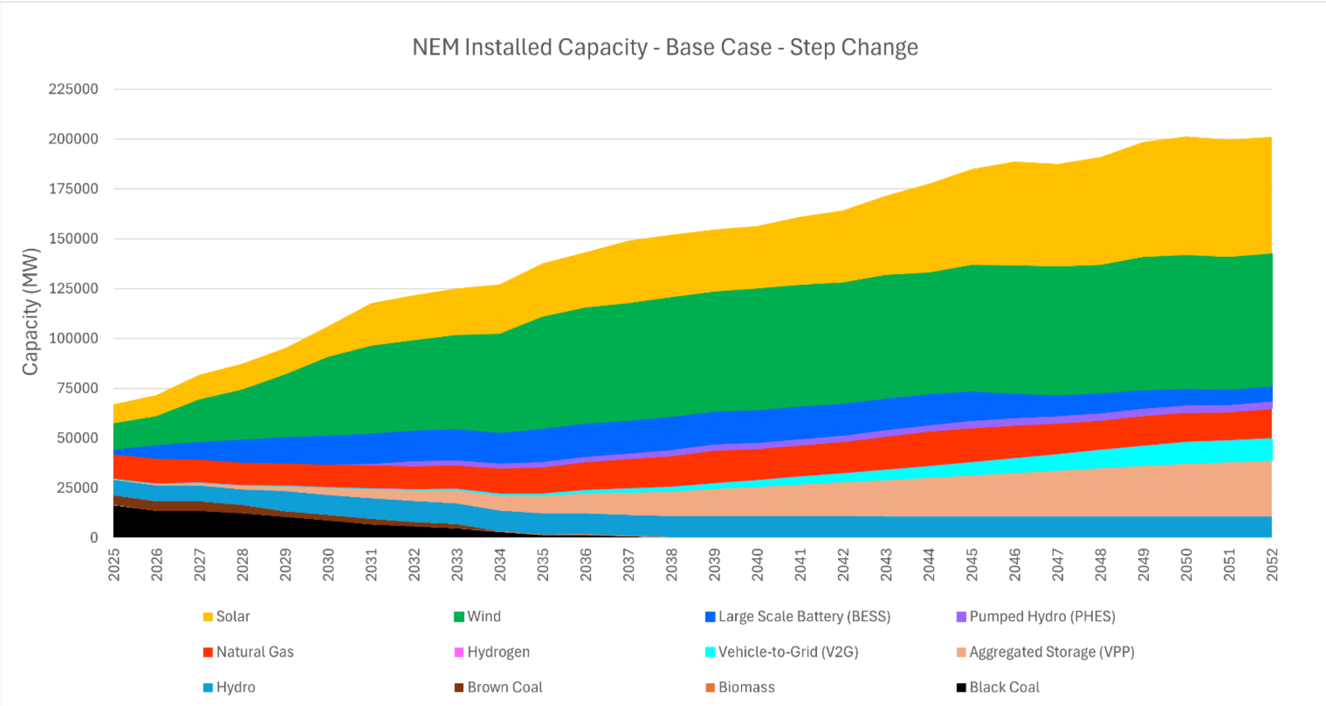
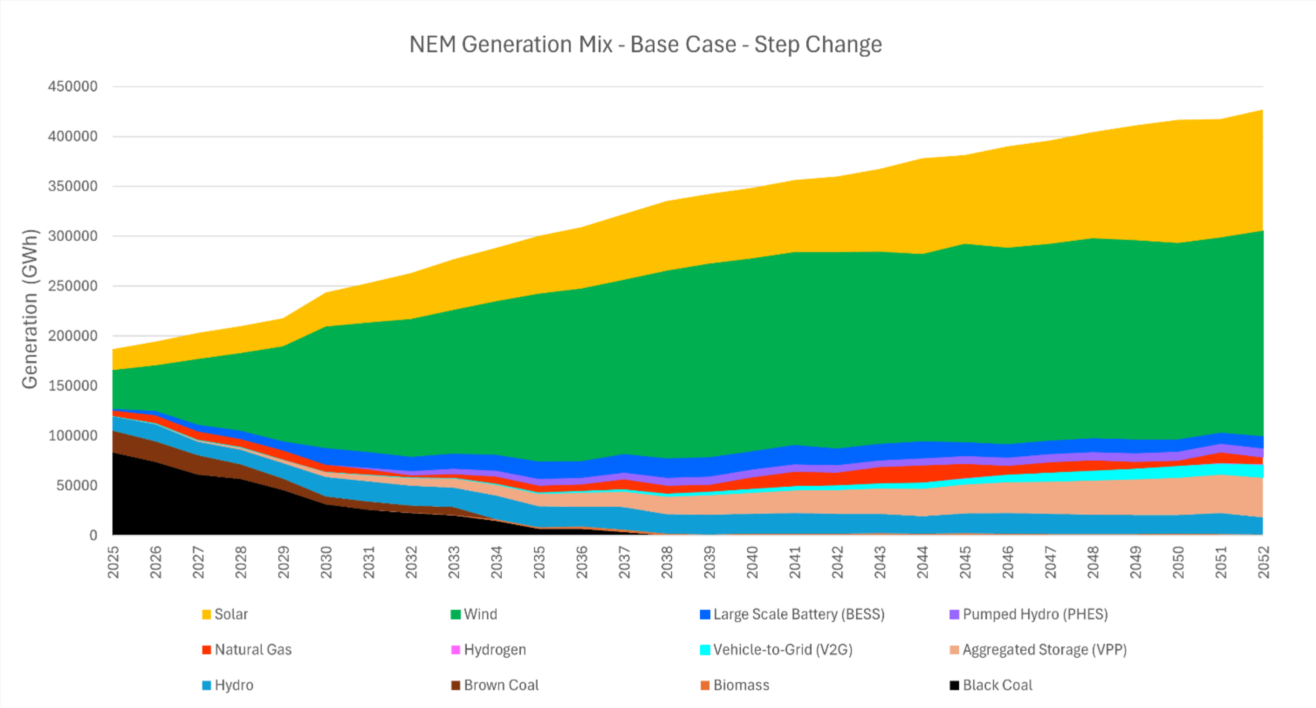


Figure 4: Generation Mix - Base Case - Step Change



The phased retirement of coal-fired generation is being substantially offset by rapid deployment of committed and anticipated wind and solar projects. This acceleration is driven by significant investment in utility-scale renewables across the NEM. The DLT model also forecasts significant growth in new wind and solar capacity builds, especially in renewable energy zones, in line with the decarbonisation targets under the step change scenario. This is also complemented by the build-up of storage technologies and consumer energy resources (CERs), such as aggregated storages, vehicle-to-grid, distributed PV[7] etc.) beginning in the early 2030s.

Under the Progressive Change scenario, there is a significantly lower build-up of renewable generation and a greater reliance on coal-fired generation. This is due to relaxed decarbonisation targets, which reflect slower economic and policy-driven growth. Additionally, the capacity for virtual power plants (VPPs) remains much lower throughout the outlook period, consistent with reduced uptake of consumer energy resources (CER) in this scenario. The difference in capacity and generation between step and progressive change scenarios for the base case are shown in Figure 5 and Figure 6.

The green energy exports scenario outlines an accelerated decarbonisation pathway, driven by aggressive emission targets and policy interventions. This leads to a significantly higher uptake of wind and solar generation supported by large-scale battery storages. The difference in capacity and generation between step and green energy exports scenarios for the base case are shown in Figure 7 and Figure 8.

[7] Distributed PV is not explicitly modelled in the ISP DLT model. Hence, not shown in the capacity and generation mix.

Figure 5: Difference in Installed Capacity – Progressive Change minus Step Change

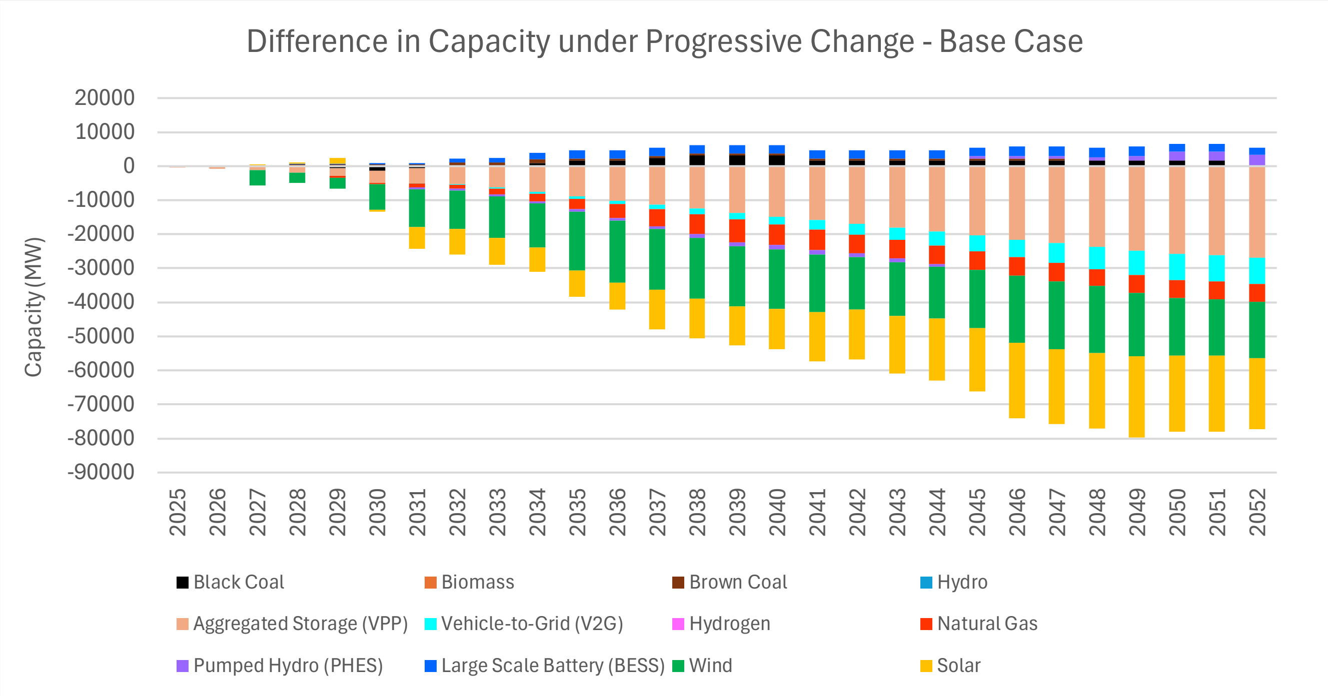


Figure 6: Difference in Generation - Progressive Change minus Step Change

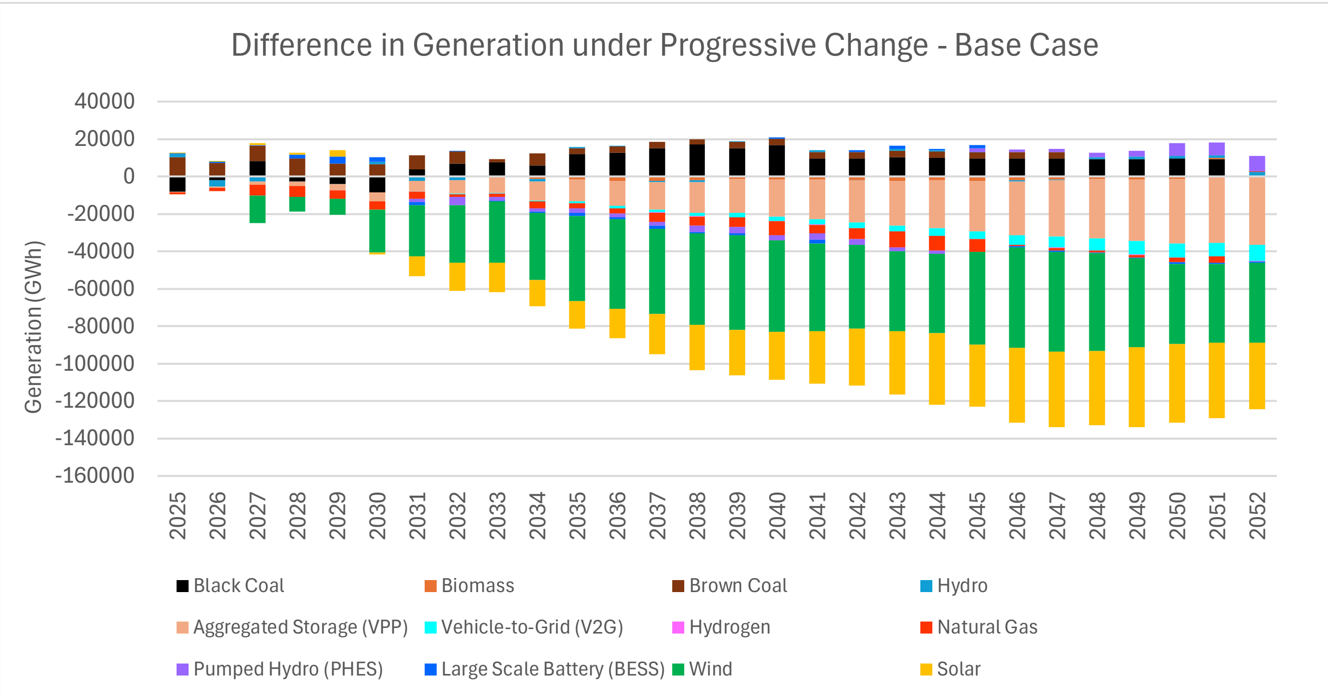


Figure 7: Difference in Installed Capacity – Green Energy Exports minus Step Change

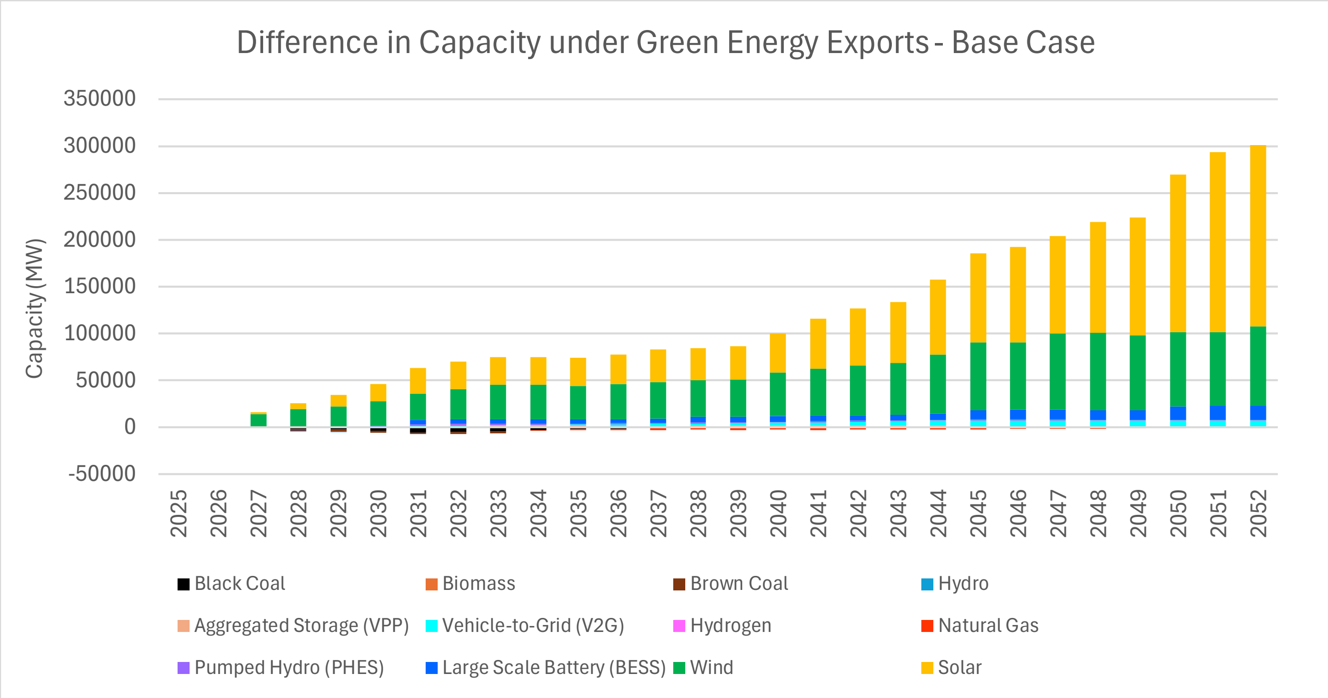
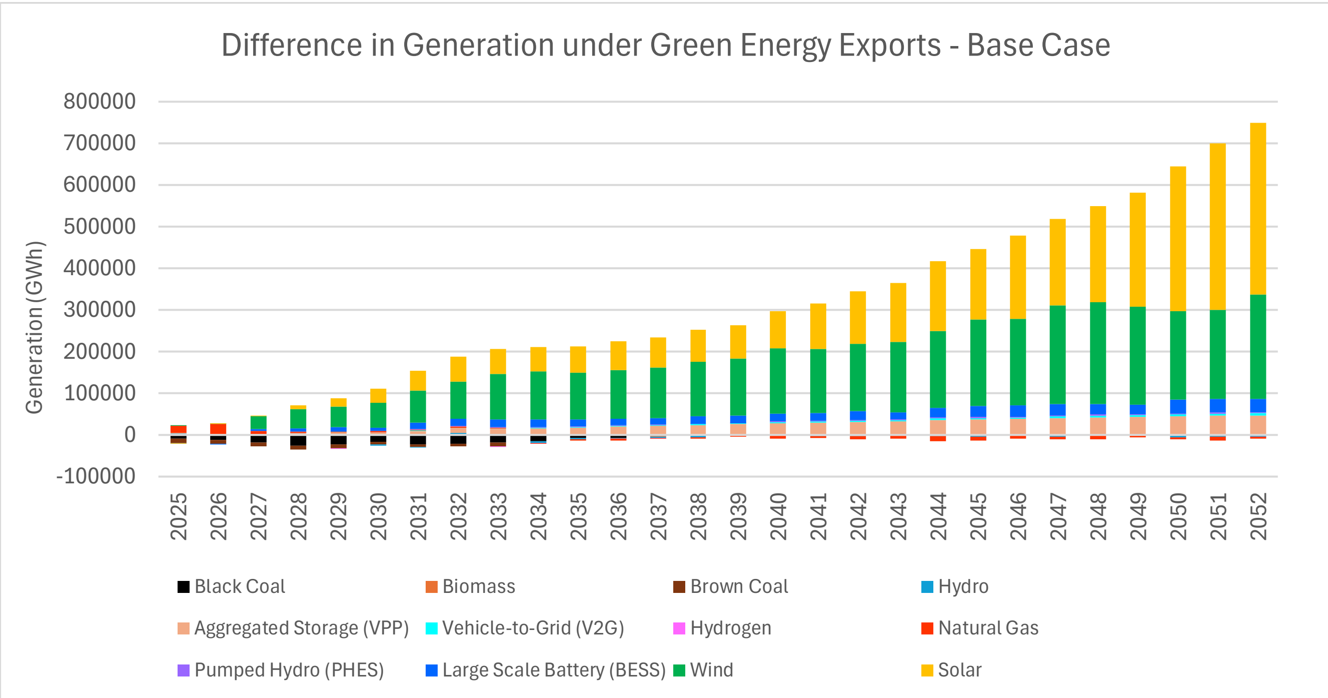


Figure 8: Difference in Generation - Green Energy Exports minus Step Change



4.4. Option 1

Option 1 involves re-conductoring of lines 9R5 and 9R6 with a conventional larger diameter higher capacity conductor such as Mango ACSR/GZ. In comparison to the existing ratings of 125MVA/137MVA, re-stringing the lines should achieve minimum rating of 169 MVA. The total transfer capacity can be increased by at least 95 MW.

This is achieved by:

- Restringing 14.6km of Mango ACSR/GZ (or equivalent) conductor on Line 9R5 and 10.5km of Mango ACSR/GZ (or equivalent) conductor on Line 9R6 (including insulators and fitting replacements);
- Replacement of structures as required to meet structural and ground clearance requirements (approximately 60 structure replacements required);
- Performing associated structure strengthening on Line 9R5 and Line 9R6.

Option 1 also involves uprating the 132 kV busbars at the Wagga 132/66 kV substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design).

The following section provides a more detailed breakdown of the market modelling outcomes for this option and presents the total gross benefits for the option.

4.4.1. Step Change Scenario

Under the Step Change scenario, the cumulative gross market benefits for Option 1 are illustrated in Figure 9. The differences in installed capacity and generation across the NEM between option 1 and the base case under step change is shown in Figure 10 and Figure 11 respectively. Positive values indicate increased capacity or generation under Option 1, while negative values reflect reductions.

Key drivers of market benefits/costs include:

- Deferred or avoided generation builds resulting in significant CAPEX and fixed operating & maintenance (FO&M) savings.
- Reduction in generator curtailment in the Wagga North region, enabling increased dispatch from existing solar farms and reducing the need for new solar capacity being built, particularly in Southwest NSW.
- Fuel cost savings in FY28 driven by reduced gas generation. Although coal generation increases comparatively, its lower fuel cost compared to gas contributes positively to total fuel benefits.
- Minor increase in REZ expansion costs due to additional builds in REZs in Queensland and Victoria compared to the base case.

Figure 9: Discounted, Cumulative Gross Market Benefits for Option 1 – Step Change Scenario

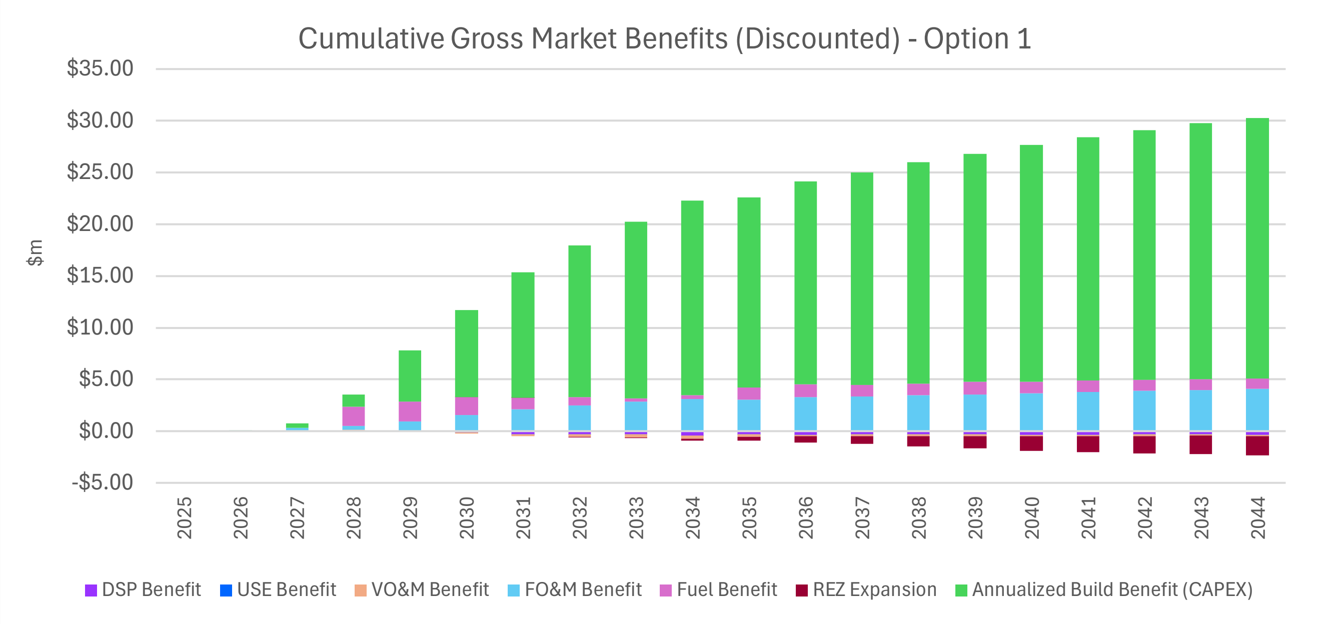


Figure 10: Difference in Installed Capacity (Option 1 - Base Case) – Step Change Scenario

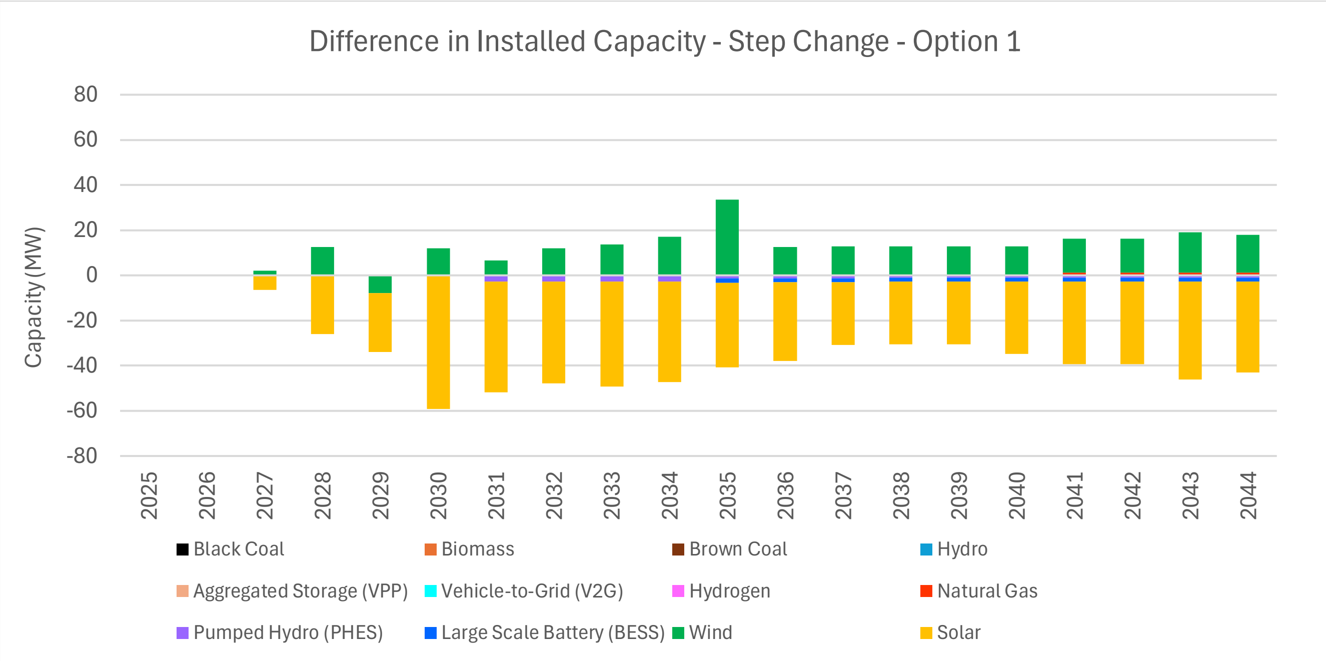
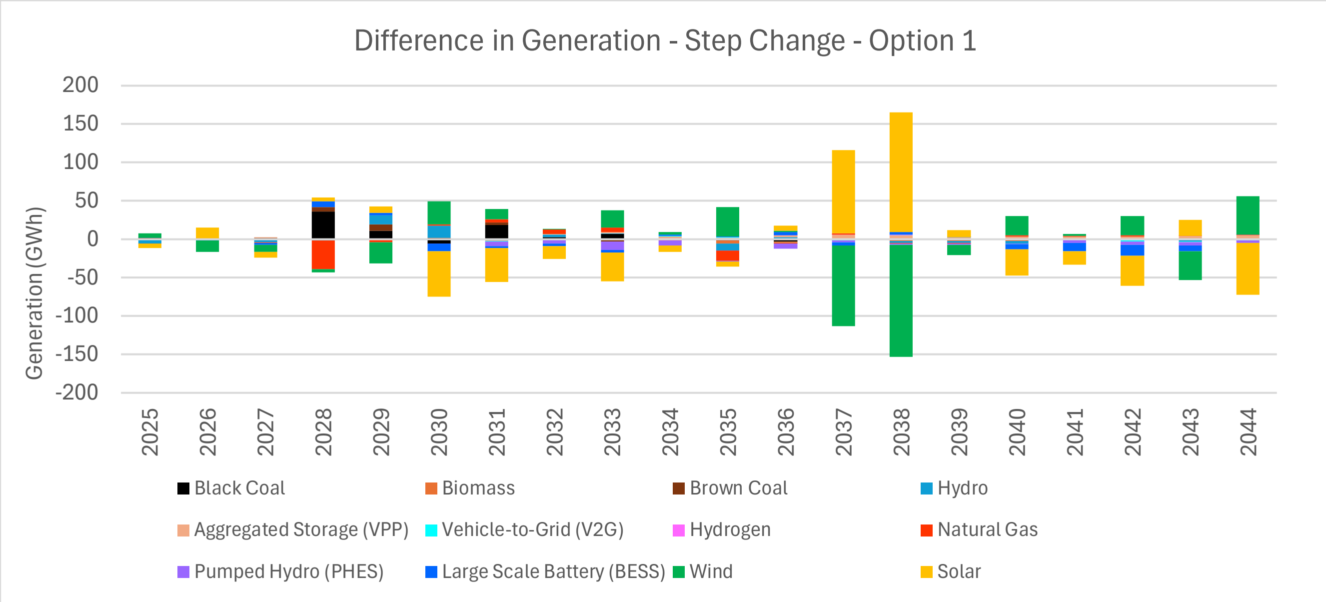


Figure 11: Difference in Generation (Option 1 - Base Case) – Step Change Scenario



From a constraint perspective:

- The 9R6/991 constraint binds earlier and more frequently in the base case, but its impact diminishes over time as new capacity and transmission augmentations come online.
- Option 1 partially alleviates the 9R6/991 constraint but does not fully eliminate it.
- The 9R5/9R6 constraint starts to bind more frequently with option 1 in place, compared to the base case.
- Despite this, Option 1 delivers substantial gross market benefits but potential for further benefits remain.

Figure 12: 9R6/991 Constraint Binding, Base Case vs. Option 1 – Step Change

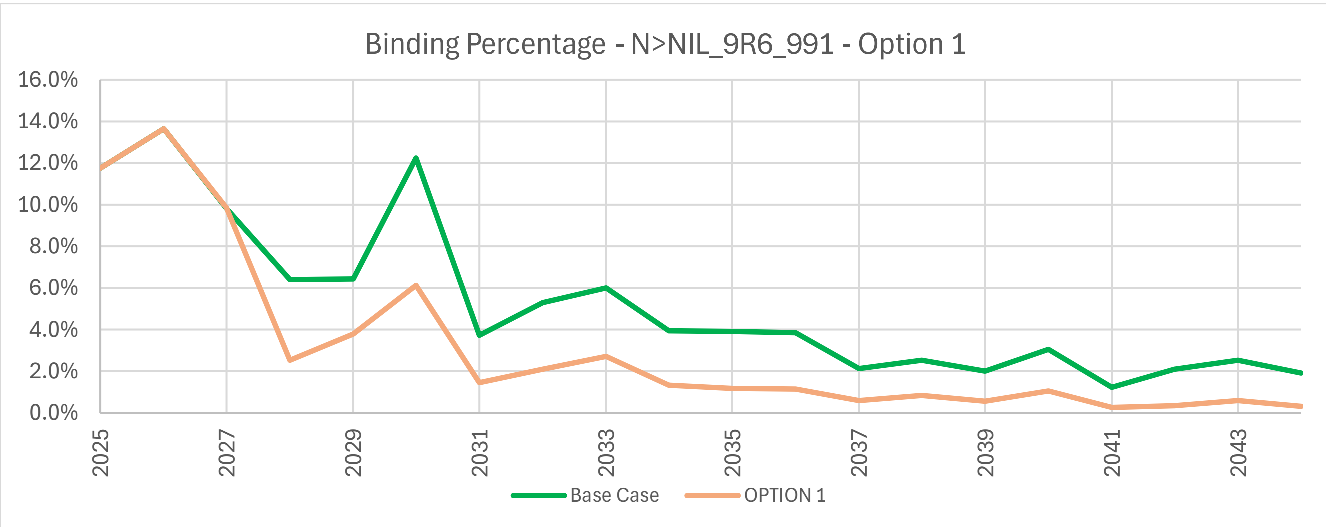


Figure 13: 9R5/9R6 Constraint Binding, Base Case vs. Option 1 – Step Change

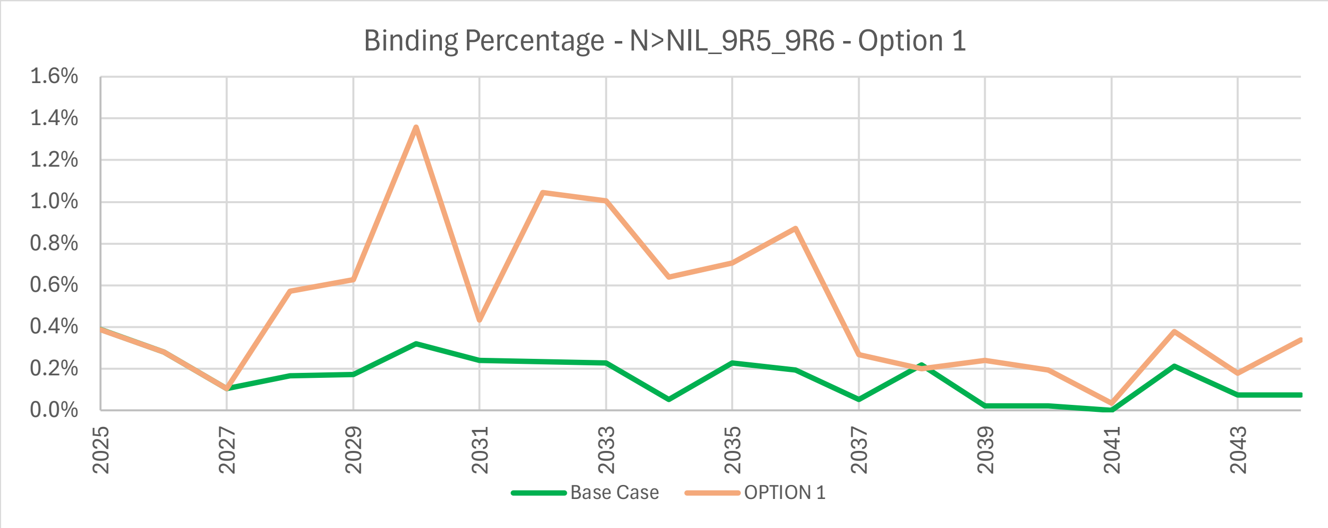
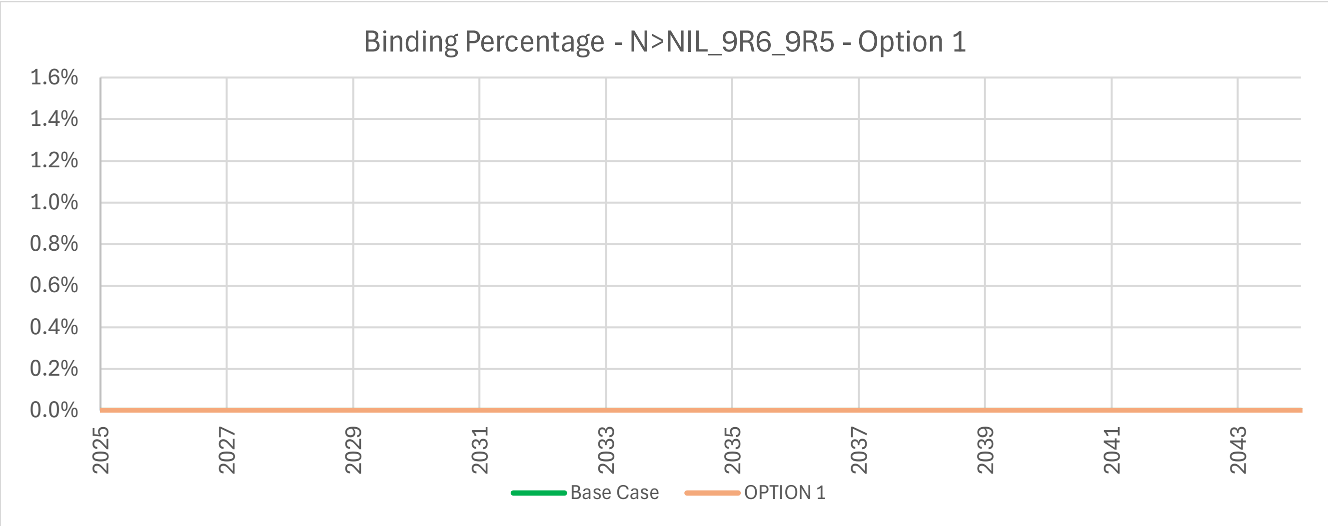


Figure 14: 9R6/9R5 Constraint Binding, Base Case vs. Option 1 – Step Change



4.4.2. Progressive Change Scenario

Under the Progressive Change scenario, the cumulative gross market benefits for Option 1 are illustrated in Figure 15. The differences in installed capacity and generation across the NEM between option 1 and the base case under step change is shown in Figure 16 and Figure 17 respectively.

Similar to the step change scenario, most of the benefit for this scenario is derived from avoided or deferred generation builds, leading to CAPEX and FO&M savings.

However, total gross benefits are lower compared to Step Change due to:

- Reduction in avoided capacity between option 1 and base case, reflecting slower renewable uptake.
- Increased dispatch from gas units in the latter half (post FY33) causing an increase in fuel costs.

Similar to step change, Option 1 provides partial constraint relief, but does not fully mitigate them.

Figure 15: Discounted, Cumulative Gross Market Benefits for Option 1 – Progressive Change Scenario

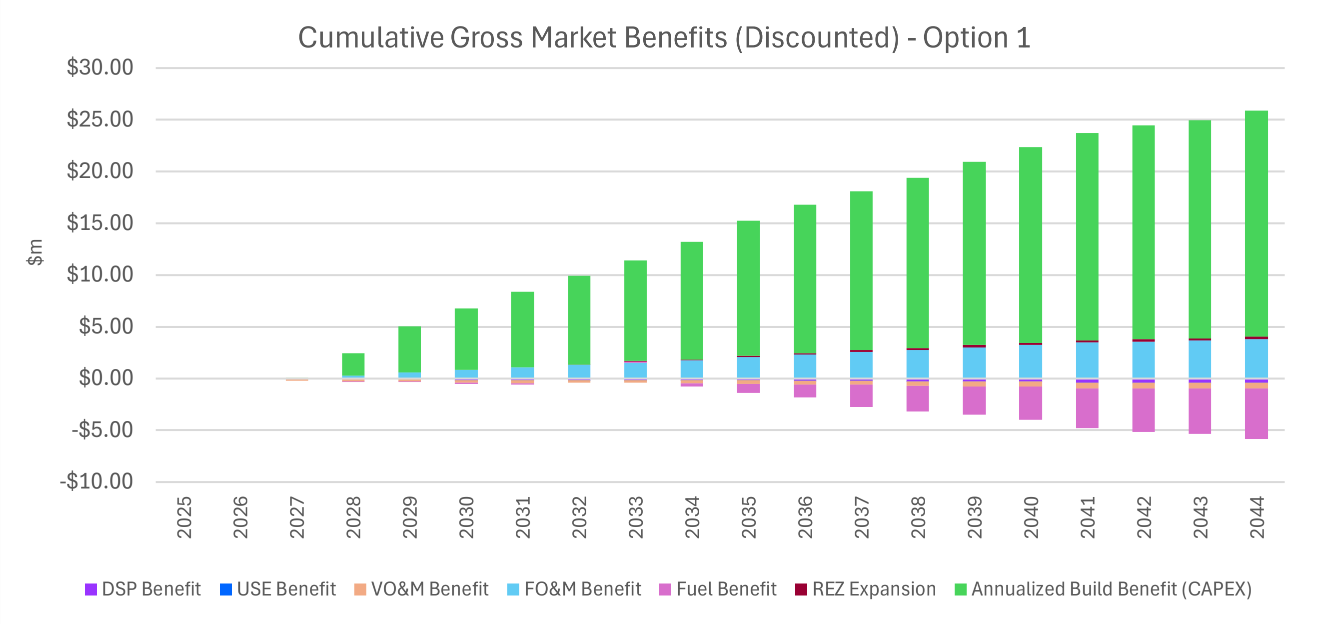


Figure 16: Difference in Installed Capacity (Option 1 - Base Case) – Progressive Change Scenario

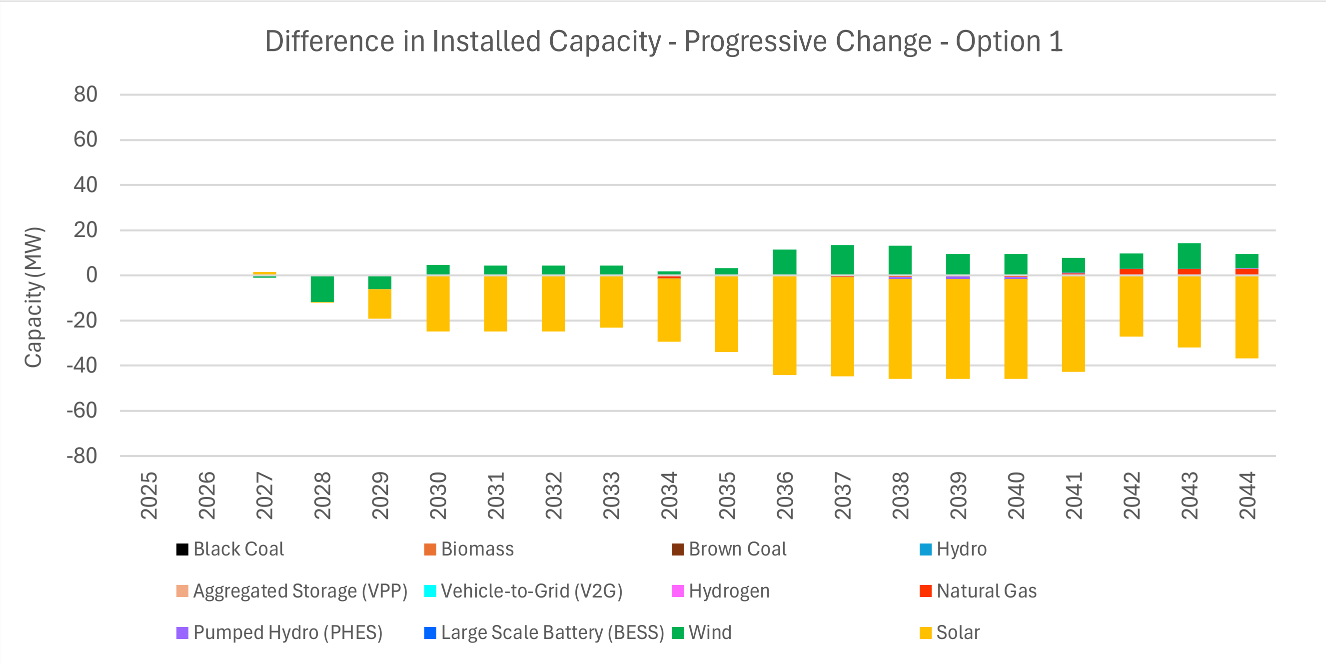


Figure 17: Difference in Generation (Option 1 - Base Case) –Progressive Scenario

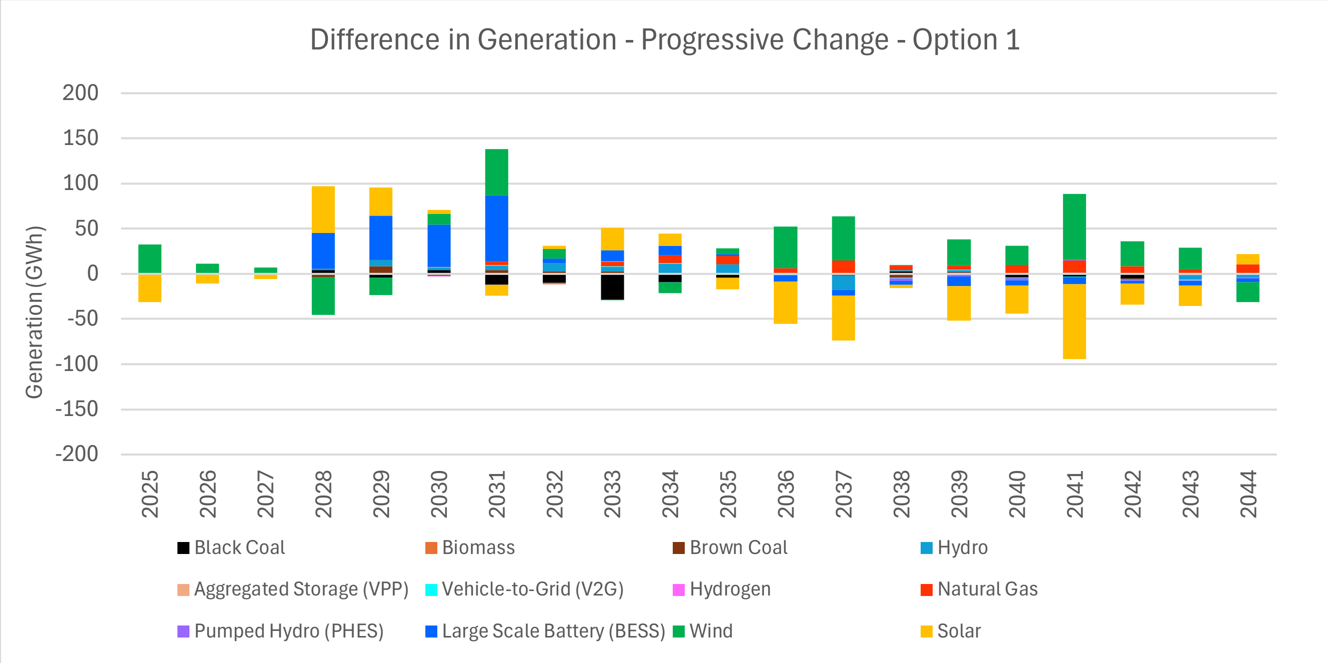


Figure 18: 9R6/991 Constraint Binding, Base Case vs. Option 1 – Progressive Change

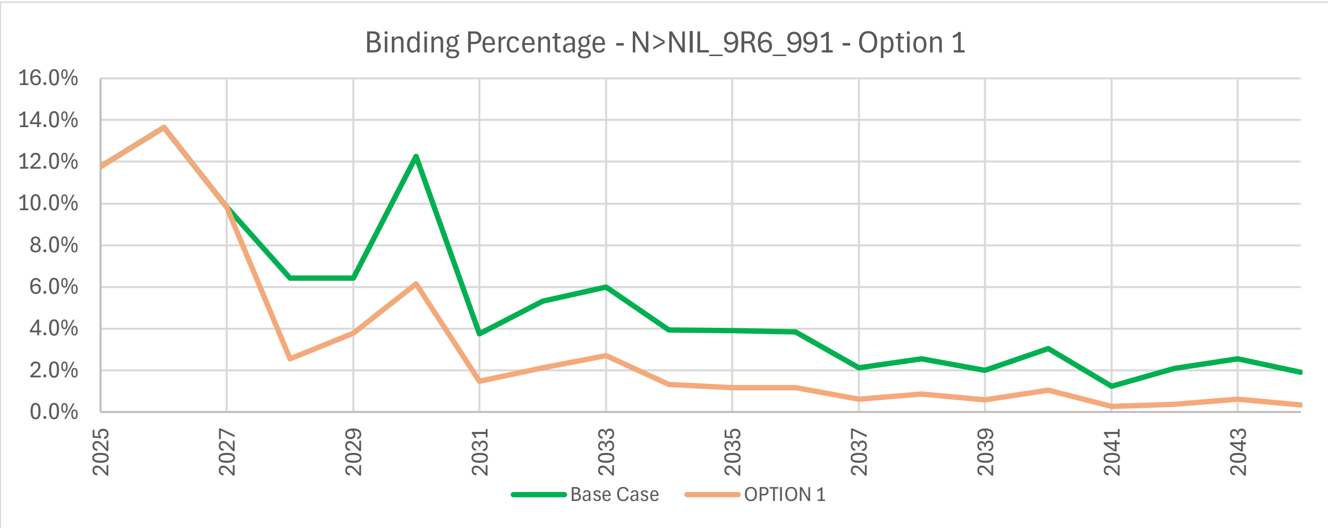


Figure 19: 9R5/9R6 Constraint Binding, Base Case vs. Option 1 – Progressive Change

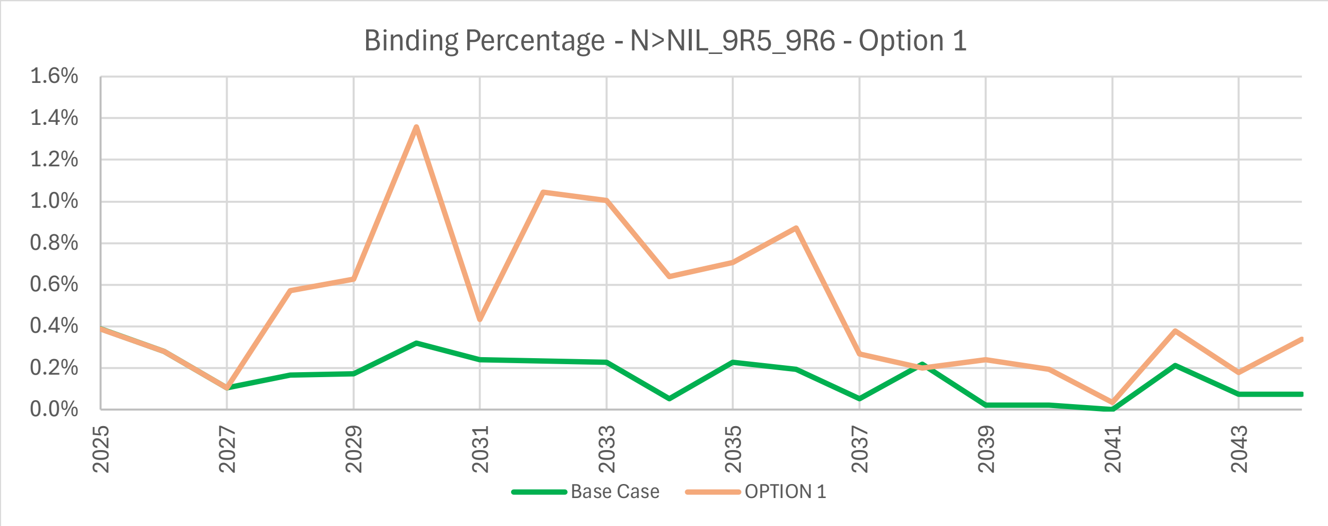
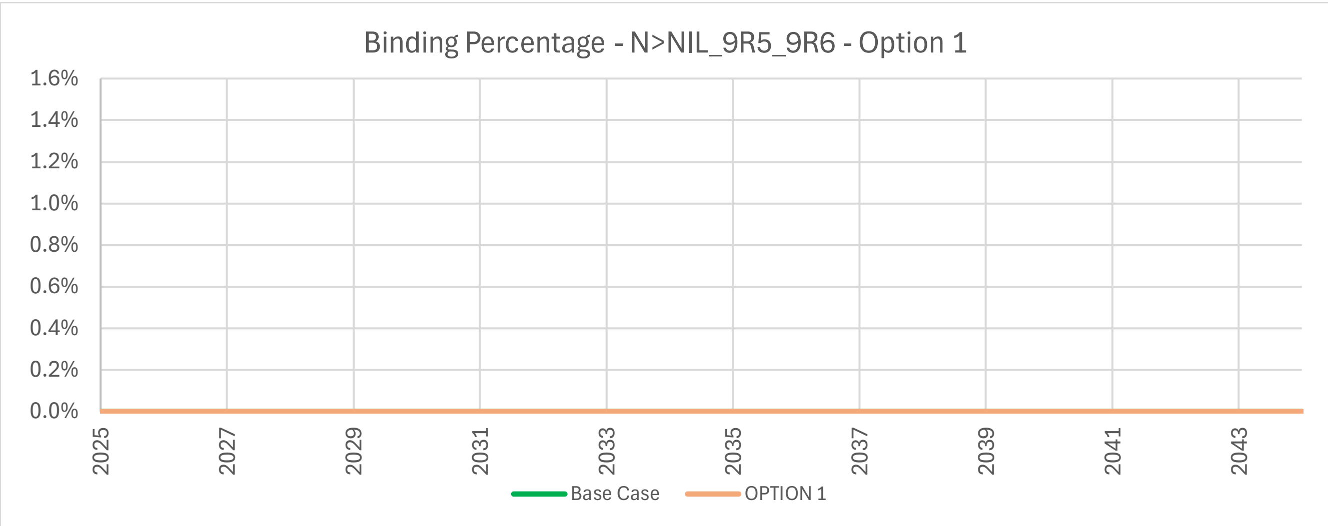


Figure 20: 9R6/9R5 Constraint Binding, Base Case vs. Option 1 – Progressive Change



4.4.3. Green Energy Exports Scenario

Under green energy exports, the cumulative gross market benefits for Option 1 are illustrated in Figure 21. The differences in installed capacity and generation across the NEM between option 1 and the base case under green energy exports is shown in Figure 22 and Figure 23 respectively.

Option 1 delivers its highest market benefits under the Green Energy Exports scenario. The benefits and costs are driven by:

- A larger share of avoided/deferred capacity occurring in the first half of the horizon, which contributes to higher discounted CAPEX savings.
- Most of the avoided capacity is from wind, which is more expensive per kilowatt than large-scale solar (as per AEMO's IASR), further amplifying total benefits.
- Increase in gas units being dispatched in FY28 contributing to higher fuel costs.

Option 1 helps alleviate this constraint, though some binding shifts to the 9R5/9R6 constraint, consistent with outcomes in other scenarios.

Figure 21: Discounted, Cumulative Gross Market Benefits for Option 1 – Green Energy Exports Scenario

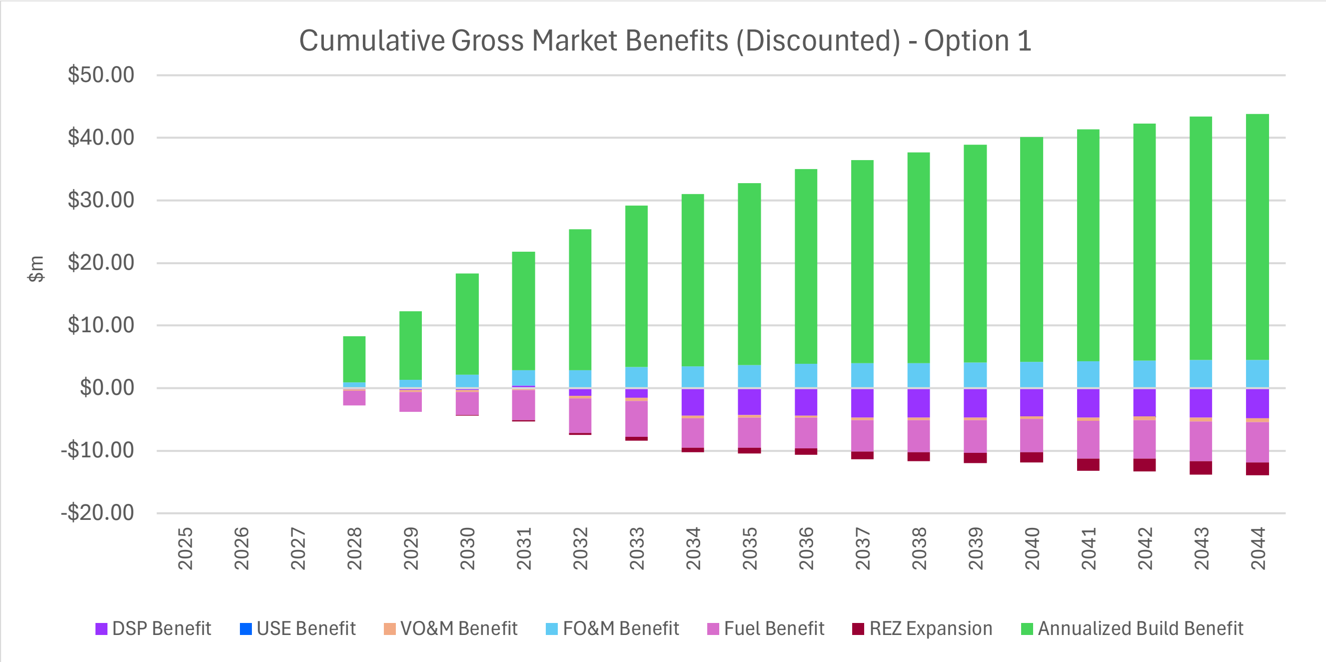


Figure 22:Difference in Installed Capacity (Option 1 - Base Case) – Green Energy Exports Scenario

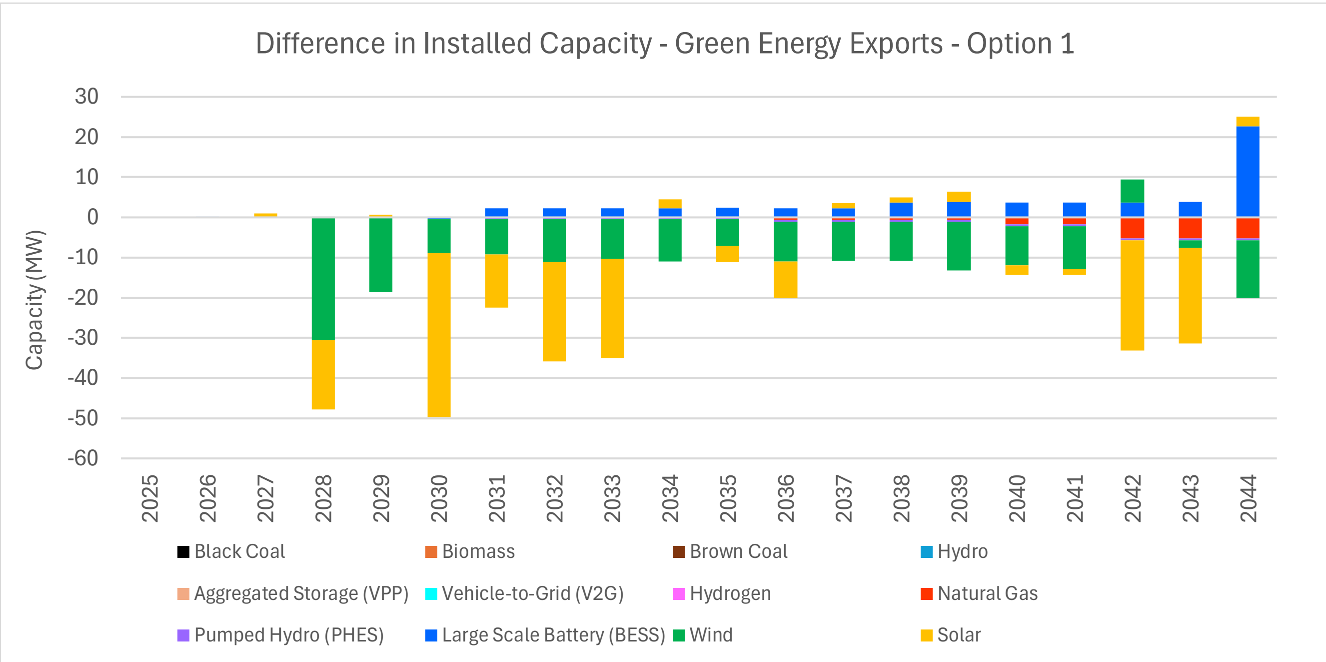


Figure 23: Difference in Generation (Option 1 - Base Case) – Green Energy Exports Scenario

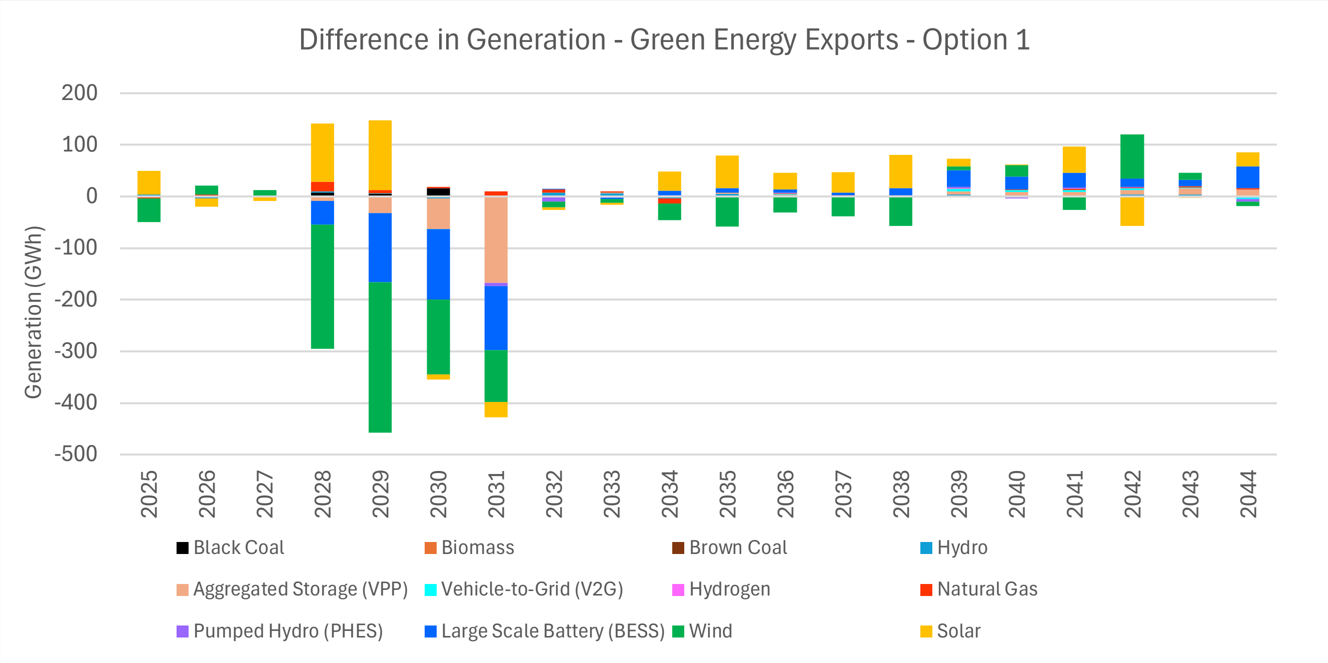


Figure 24: 9R6/991 Constraint Binding, Base Case vs. Option 1 – Green Energy Exports

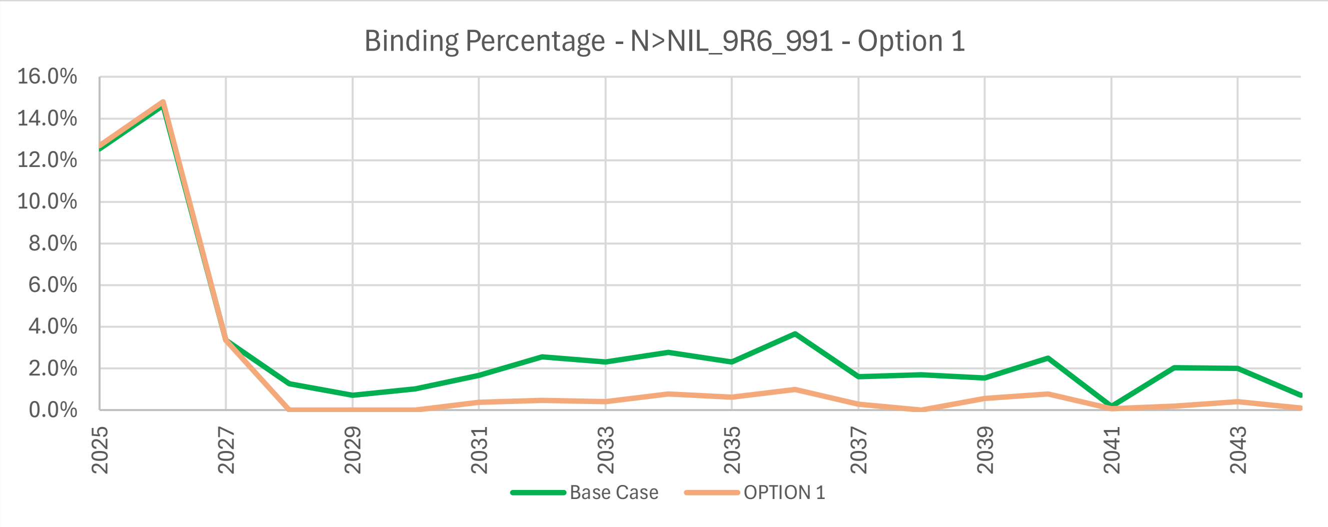


Figure 25: 9R5/9R6 Constraint Binding, Base Case vs. Option 1 – Green Energy Exports

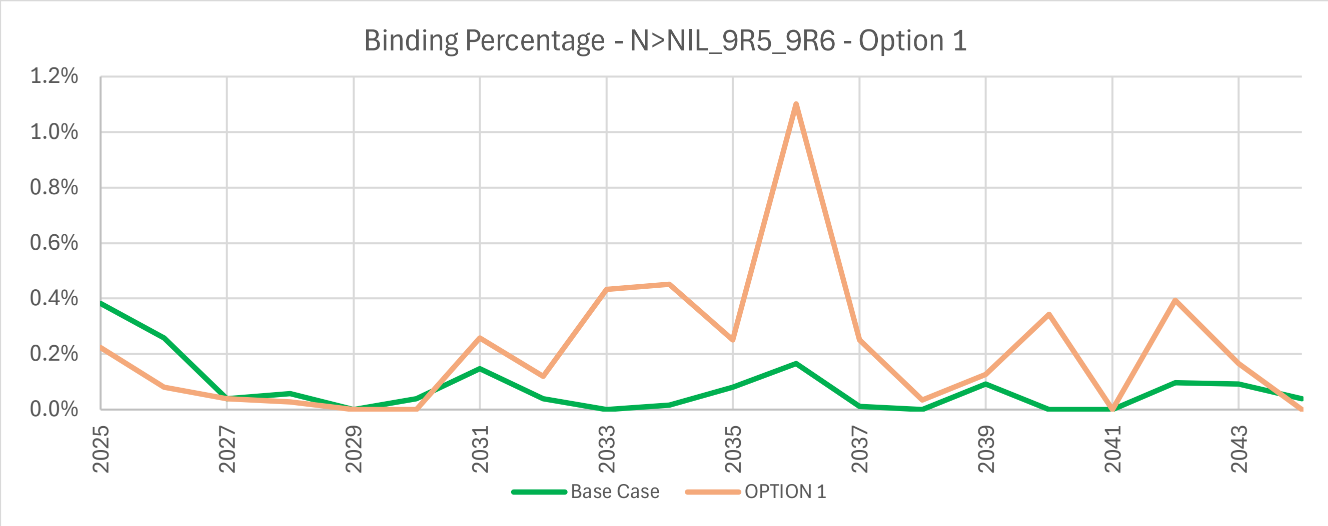
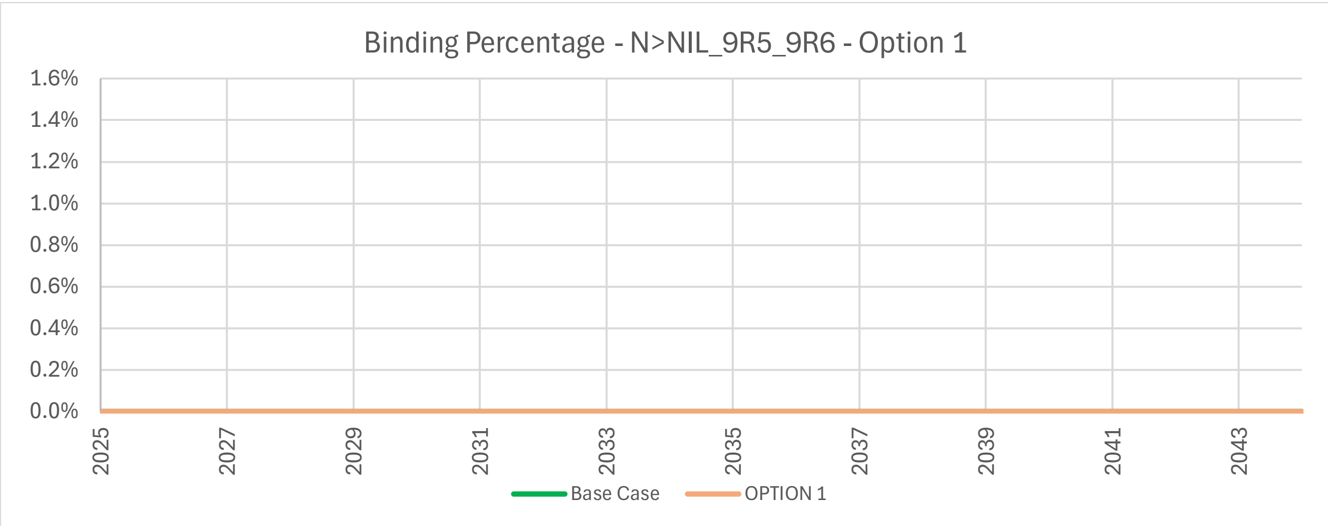


Figure 26: 9R6/9R5 Constraint Binding, Base Case vs. Option 1 – Green Energy Exports



4.5. Option 2

Option 2 involves increasing Lines 9R5 and 9R6 normal ratings to a minimum of 223 MVA by restringing Lines 9R5 and 9R6 with a high-temperature, low-sag (HTLS) conductor of similar diameter, weight and tension capacity to the existing conductor. The use of a HTLS conductor of similar dimensions minimises the number of structure upgrades or replacements for structural reasons.

This is achieved by:

- Restringing 14.6km of Line 9R5 and 10.5km of Line 9R6 with a high-temperature, low-sag (HTLS) conductor, including insulators and fitting replacements;
- Replacement of structures as required for structural and ground clearance (estimated to be less than 10 structures in total for both lines 9R5 and 9R6).
- Performing associated structure strengthening on Line 9R5 and Line 9R6 as required.

Option 2 also involves uprating the 132 kV busbars at the Wagga 132/66 kV substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design).

The following section provides a more detailed breakdown of the market modelling outcomes for this option and presents the total gross benefits for the option.

4.5.1. Step Change Scenario

Under the Step Change scenario, the cumulative gross market benefits for Option 2 are illustrated in Figure 27. The differences in installed capacity and generation across the NEM between option 2 and the base case under step change is shown in Figure 28 and Figure 29: Difference in Generation (Option 2 - Base Case) – Step Change Scenario respectively. Positive values indicate increased capacity or generation under Option 2, while negative values reflect reductions.

Option 2 shares a similar delivery timeline and scope with Option 1 but delivers higher market benefits due to its greater thermal rating, which fully resolves all constraints at Wagga North.

Key benefit/cost drivers include:

- Deferred or avoided generation builds resulting in significant CAPEX and FO&M savings.
- Reduction in generator curtailment in the Wagga North region, enabling increased dispatch from existing solar farms and reducing the need for new solar capacity being built, particularly in Southwest NSW.
- Fuel cost savings in FY28 driven by reduced gas generation. Although coal generation increases comparatively, its lower fuel cost compared to gas contributes positively to total fuel benefits.
- Minor increase in REZ expansion costs due to additional builds in REZs in Queensland and Victoria compared to the base case.

Option 2 completely mitigates all the Wagga North constraints (Figure 30 and Figure 31), reducing curtailment from existing generators in the region. This results in higher gross market benefits than any other transmission augmentation option assessed.

These outcomes suggest that Option 2 offers a superior balance of technical performance and economic value, although the preferred option will be determined through the cost-benefit analysis (CBA) in the Project Assessment Draft Report (PADR).

Figure 27: Discounted, Cumulative Gross Market Benefits for Option 2 – Step Change Scenario

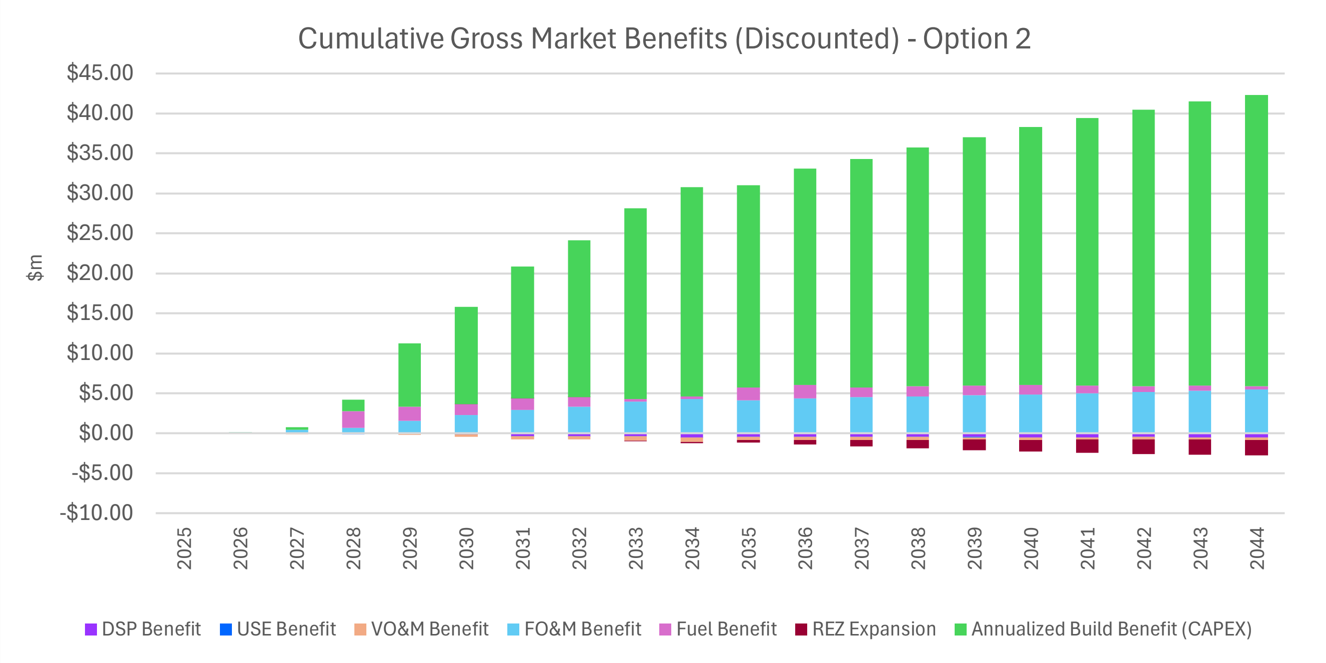


Figure 28: Difference in Installed Capacity (Option 2 - Base Case) – Step Change Scenario

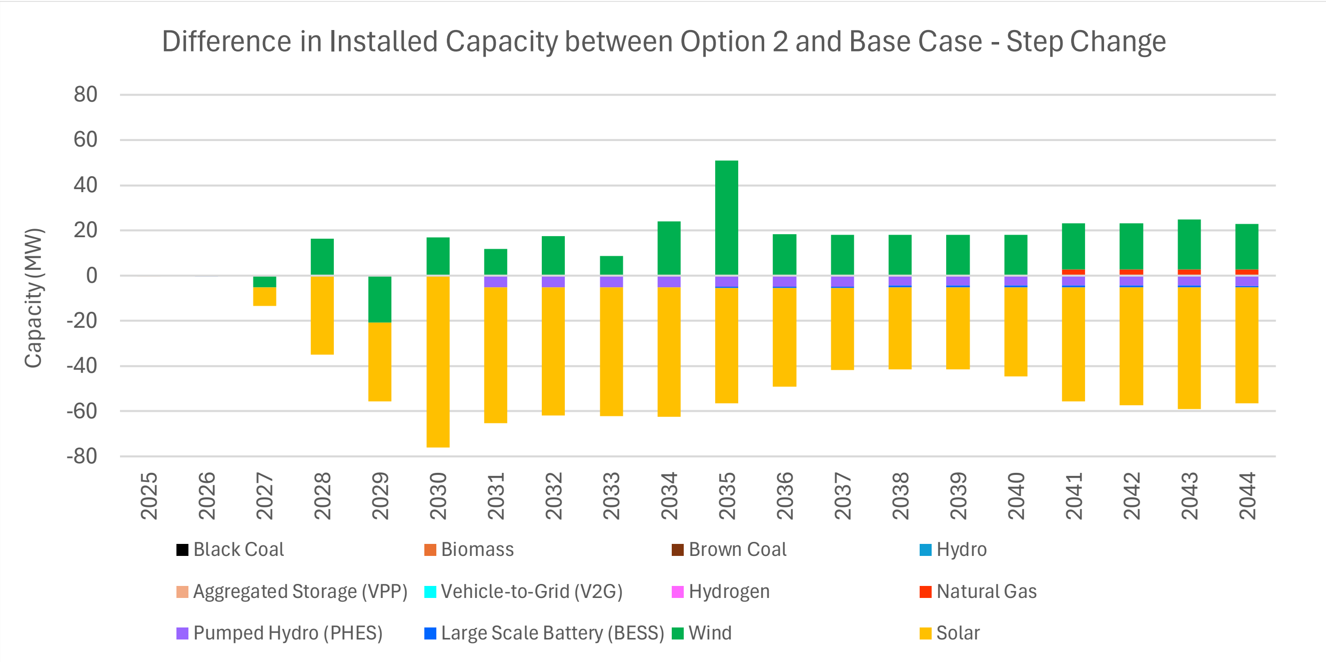


Figure 29: Difference in Generation (Option 2 - Base Case) – Step Change Scenario

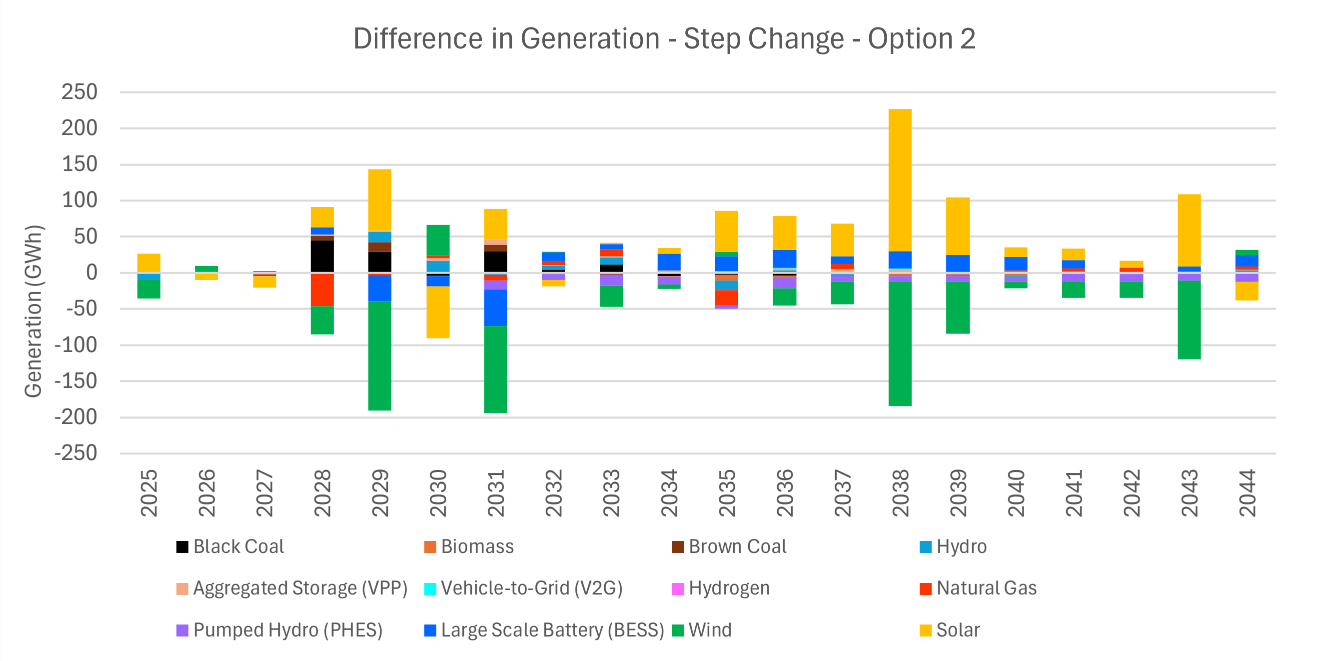


Figure 30: 9R6/991 Constraint Binding, Base Case vs. Option 2 – Step Change

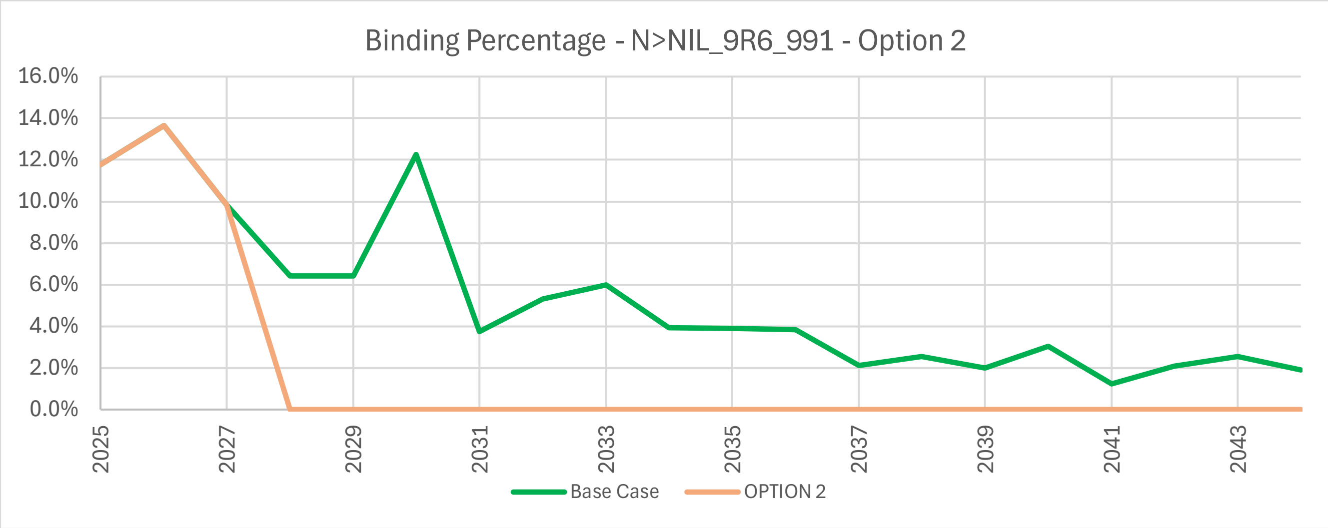


Figure 31: 9R5/9R6 Constraint Binding, Base Case vs. Option 2 – Step Change

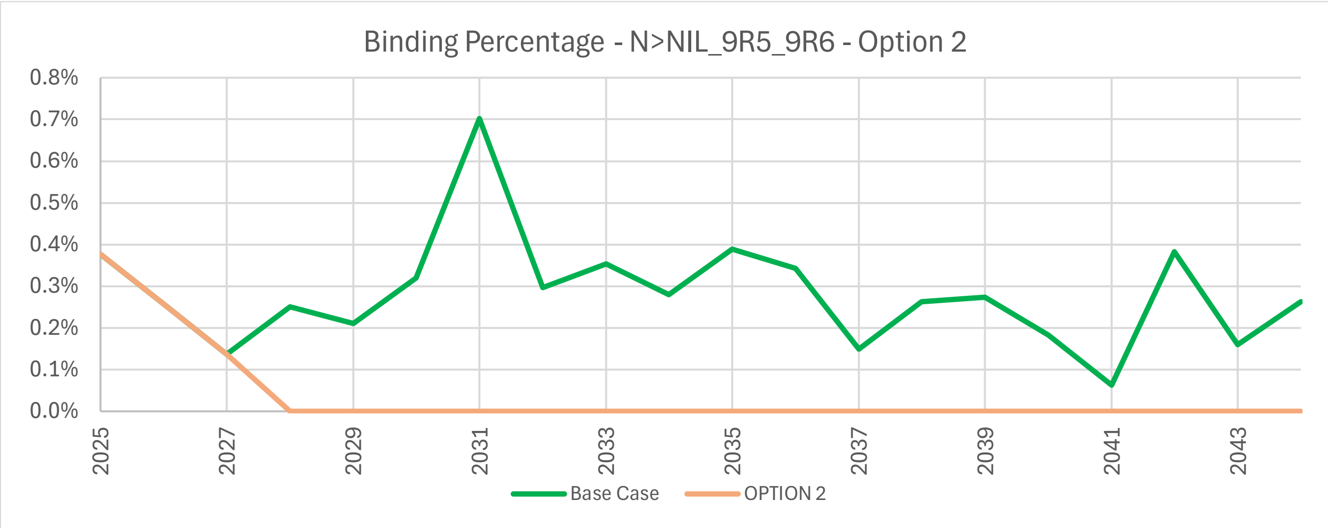
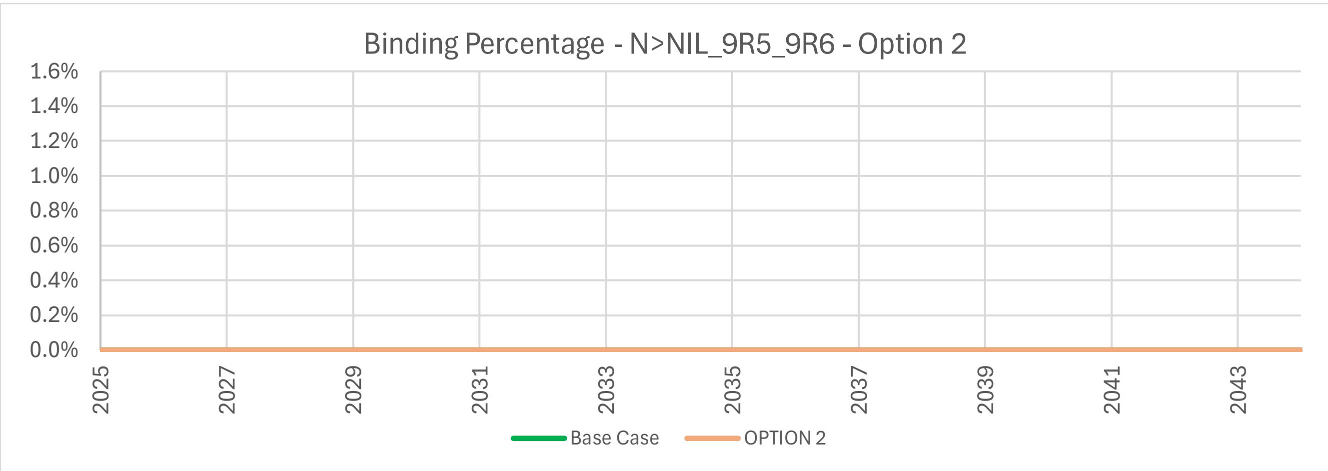


Figure 32: 9R6/9R5 Constraint Binding, Base Case vs. Option 2 – Step Change



4.5.2. Progressive Change Scenario

Under the progressive change scenario, the cumulative gross market benefits for Option 2 are illustrated in Figure 33. The differences in installed capacity and generation across the NEM between option 2 and the base case under progressive change is shown in Figure 34 and Figure 35 respectively.

Benefit trends are consistent with those observed under step change:

- Most benefits stem from avoided and deferred generation builds, leading to CAPEX and FO&M savings.
- Total gross benefits are lower than under Step Change, due to a smaller difference in new builds between Option 2 and the base case. This reflects slower renewable uptake and more conservative policy settings.
- Increased dispatch from gas units from FY31 contributing to an increase in fuel costs.

Similar to step change, all constraints are mitigated with option 2 in place (Figure 36 and Figure 37).

Figure 33: Discounted, Cumulative Gross Market Benefits for Option 2 – Progressive Change Scenario

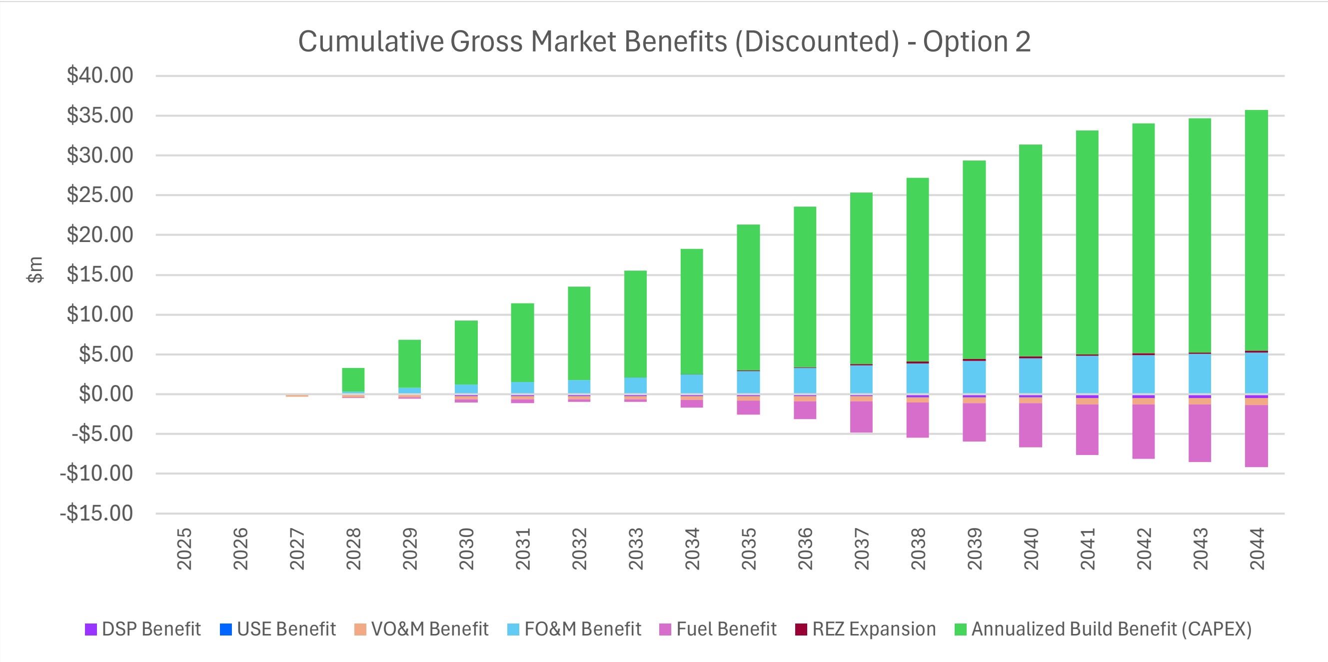


Figure 34: Difference in Installed Capacity (Option 2 - Base Case) – Progressive Change Scenario

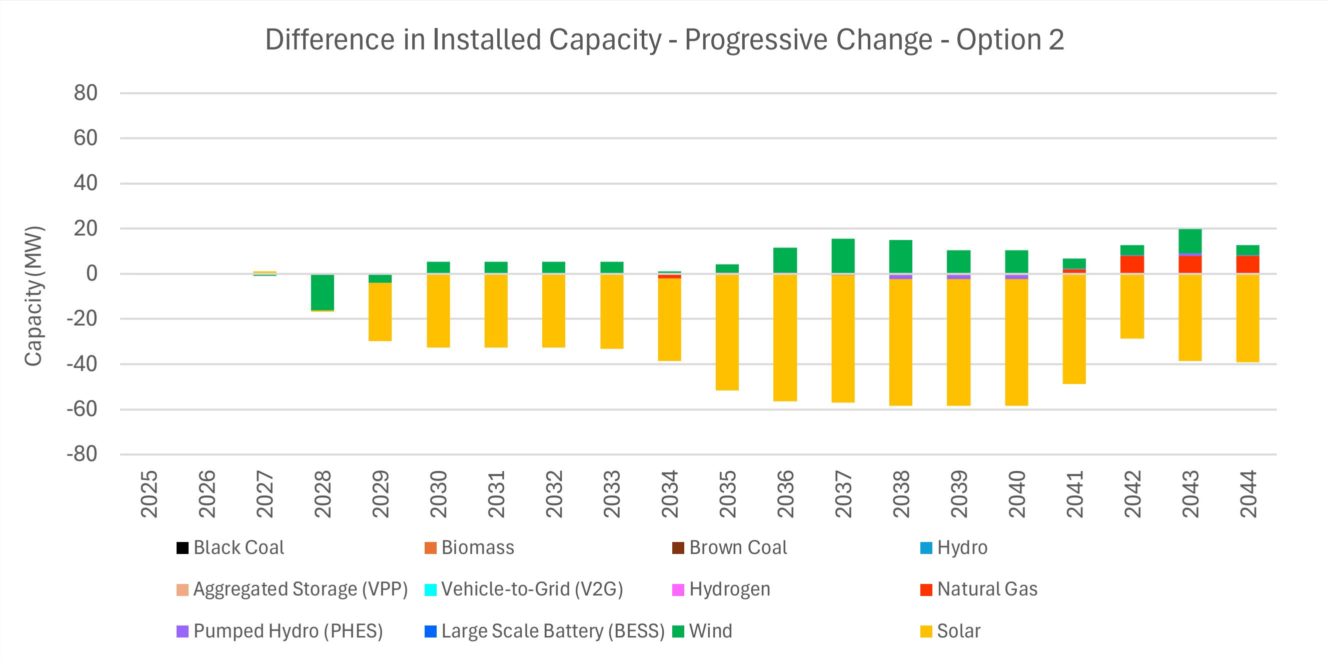


Figure 35: Difference in Generation (Option 2 - Base Case) – Progressive Change Scenario

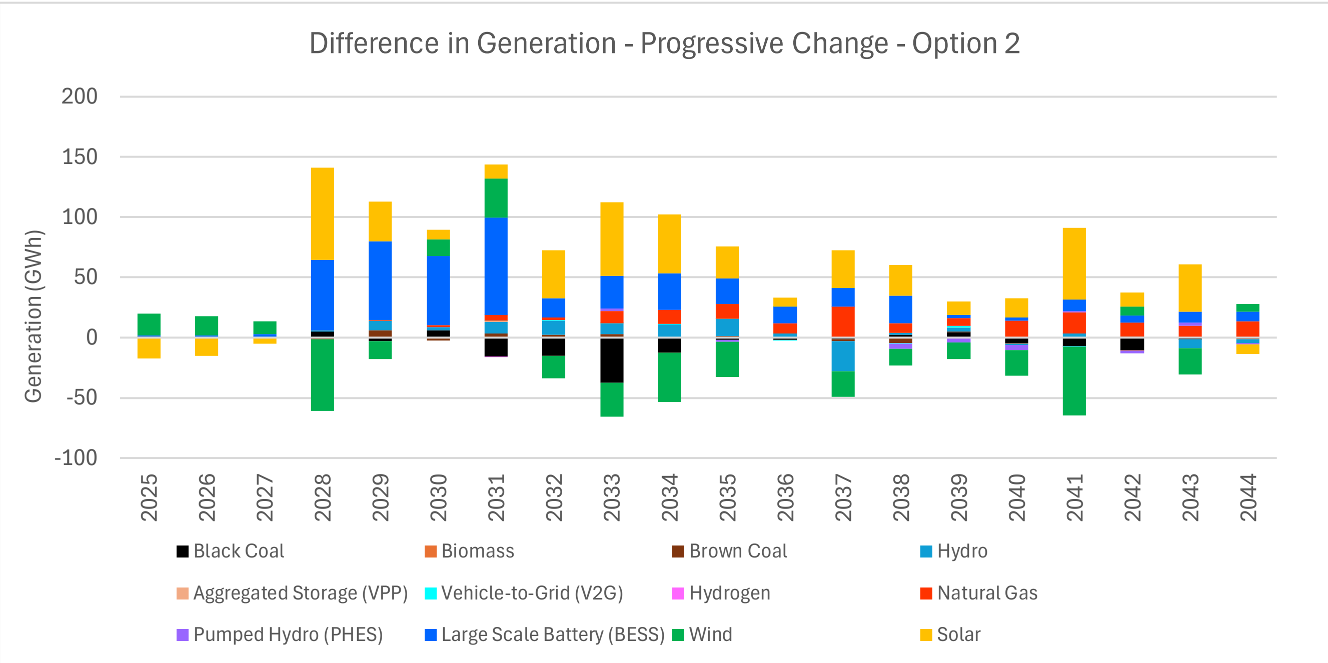


Figure 36: 9R6/991 Constraint Binding, Base Case vs. Option 2 – Progressive Change

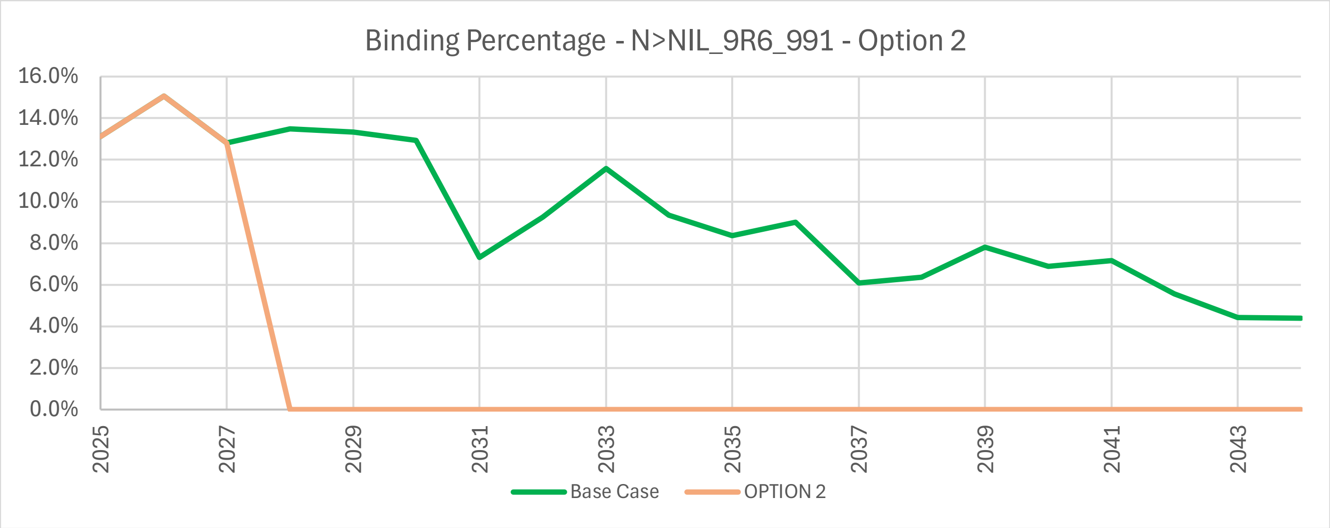


Figure 37: 9R5/9R6 Constraint Binding, Base Case vs. Option 2 – Progressive Change

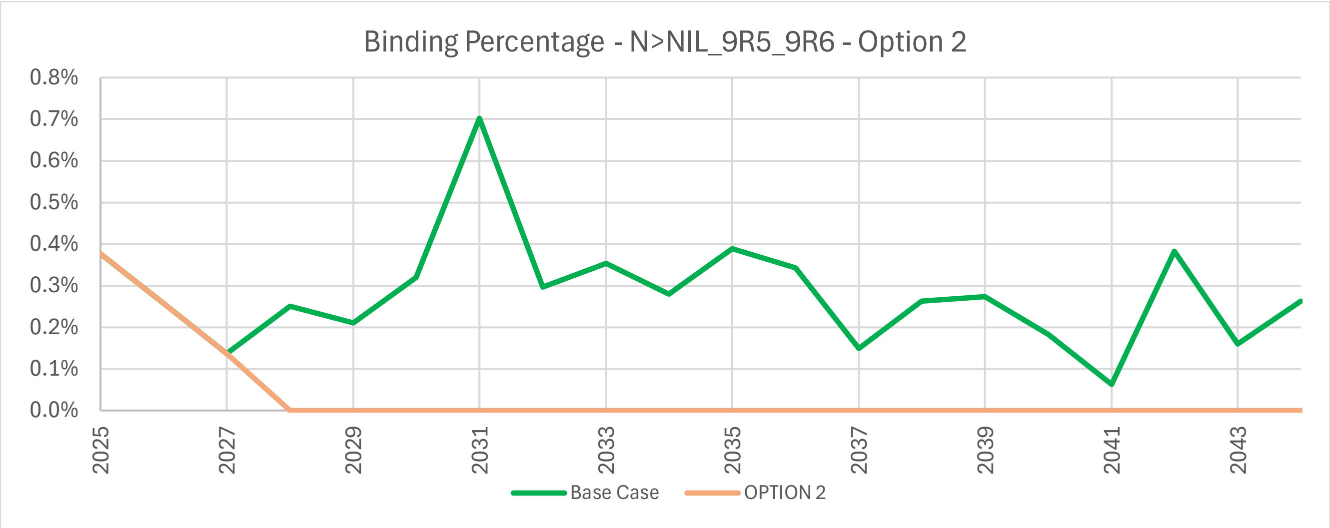
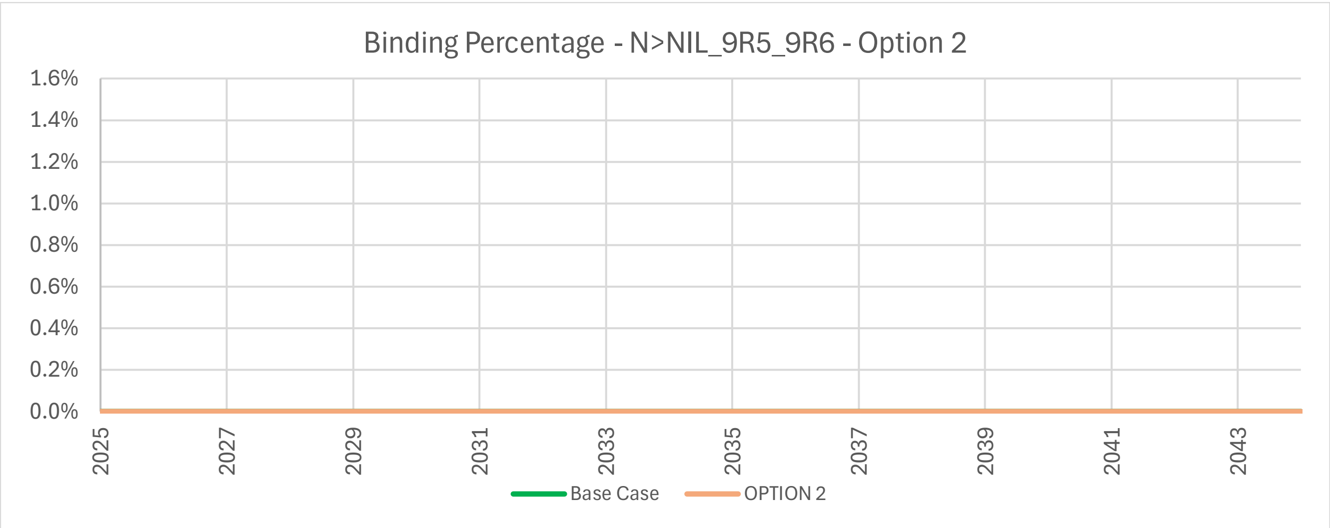


Figure 38: 9R5/9R6 Constraint Binding, Base Case vs. Option 2 – Progressive Change



4.5.3. Green Energy Exports Scenario

Under the green energy exports scenario, the cumulative gross market benefits for Option 2 are illustrated in Figure 39. The differences in installed capacity and generation across the NEM between option 2 and the base case under green energy exports is shown in Figure 40 and Figure 41 respectively.

Key drivers include:

- A larger share of deferred capacity occurring in the first half of the horizon, resulting in higher discounted CAPEX savings.
- Most of the avoided capacity is from wind, which is more expensive per kilowatt than large-scale solar (as per AEMO's IASR), further amplifying total benefits.
- Increase in gas units being dispatched in FY28 contributing to higher fuel costs.

Similar to the other scenarios, all constraints are mitigated with option 2 (Figure 42 and Figure 43).

Figure 39: Discounted, Cumulative Gross Market Benefits for Option 2 – Green Energy Export Scenario

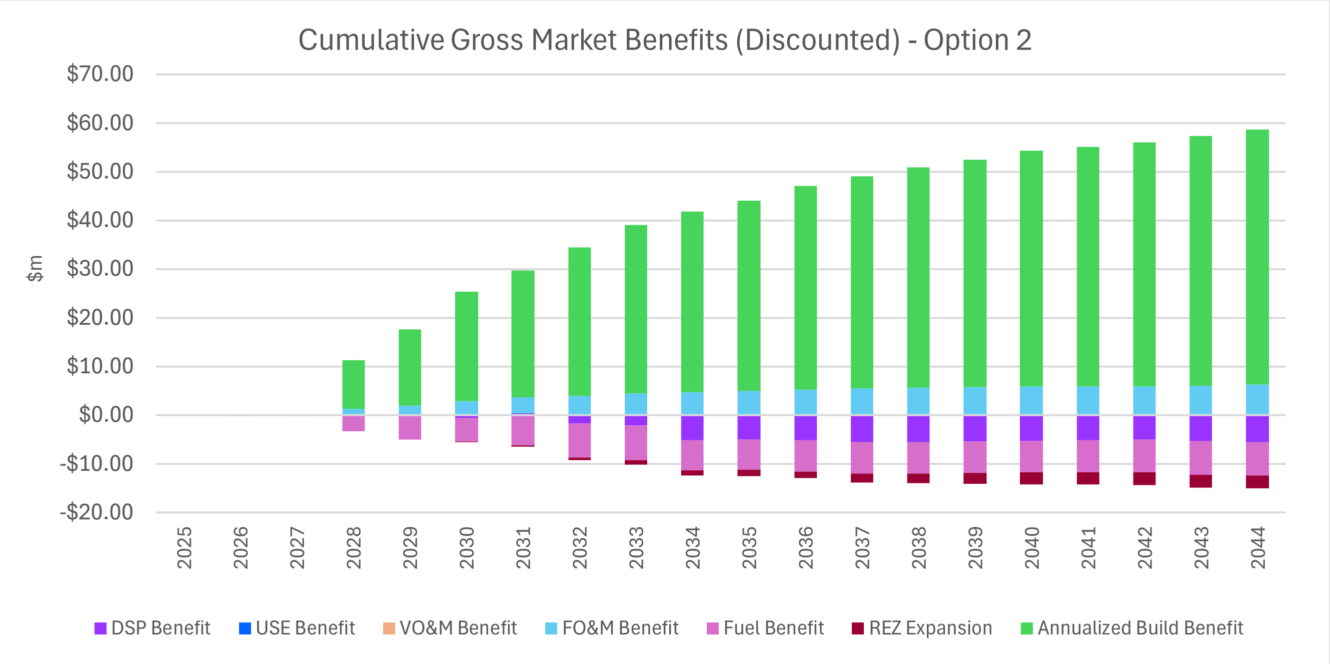


Figure 40: Difference in Installed Capacity (Option 2 - Base Case) – Green Energy Export Scenario

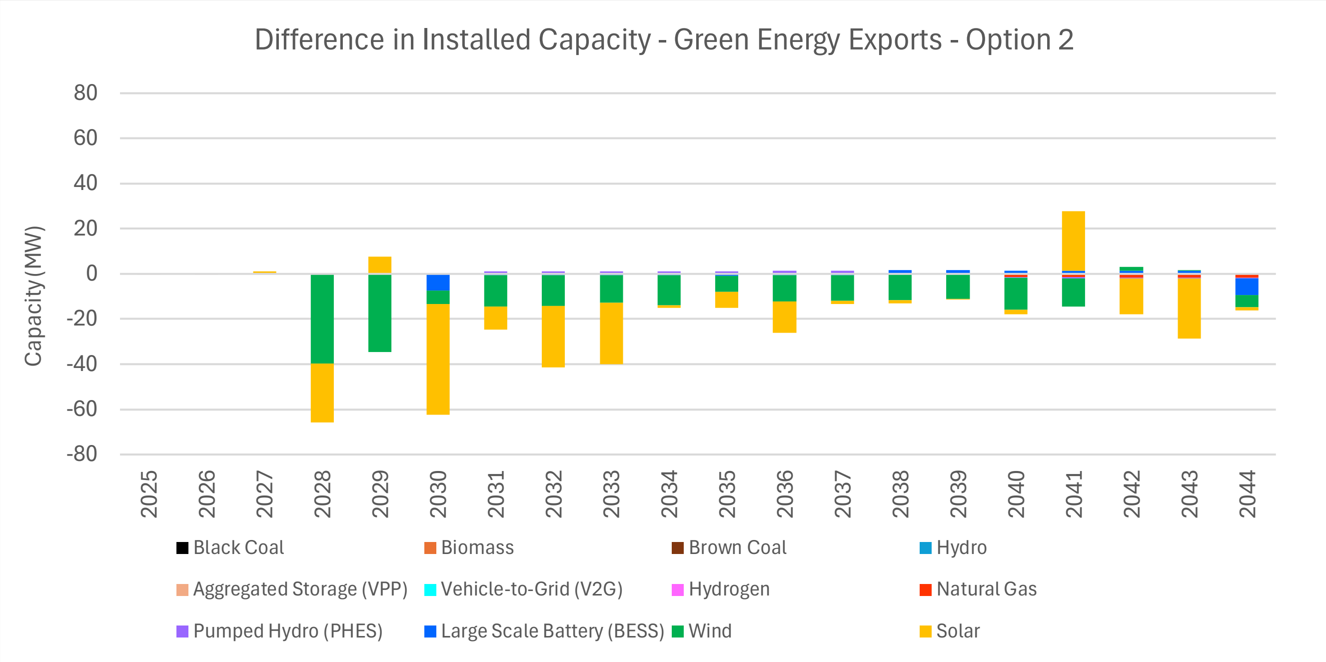


Figure 41: Difference in Generation (Option 2 - Base Case) – Green Energy Export Scenario

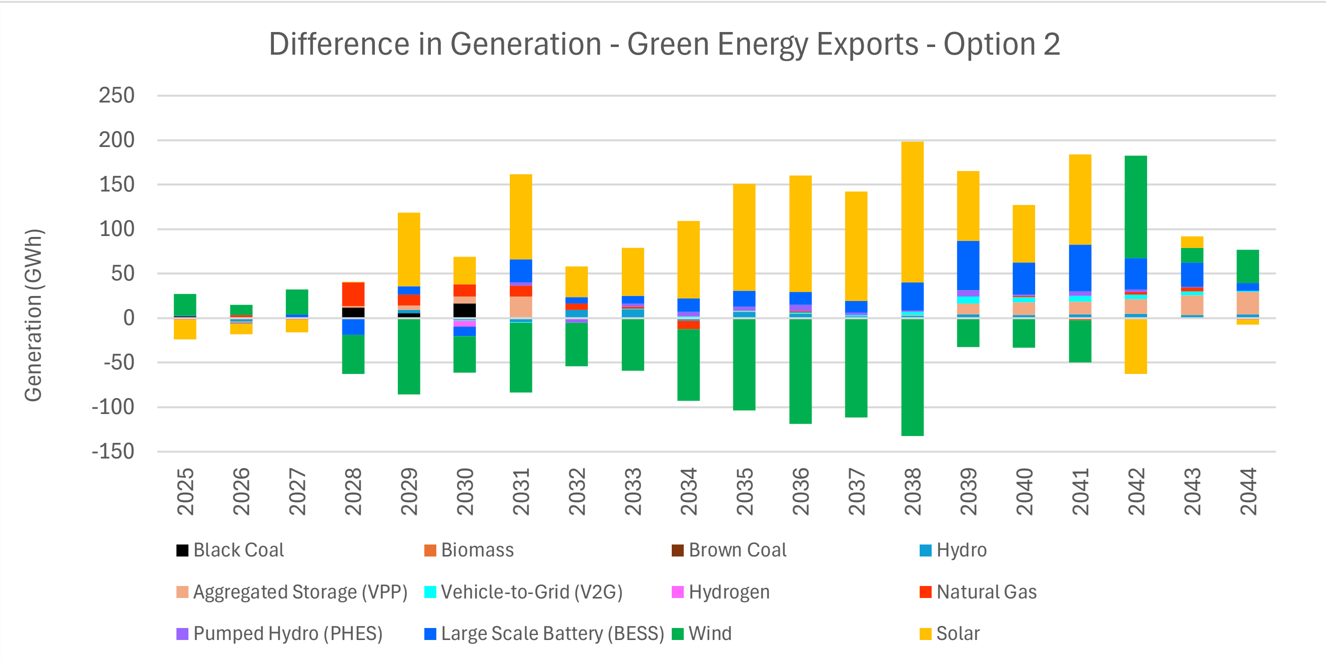


Figure 42: 9R6/991 Constraint Binding, Base Case vs. Option 2 – Green Energy Exports

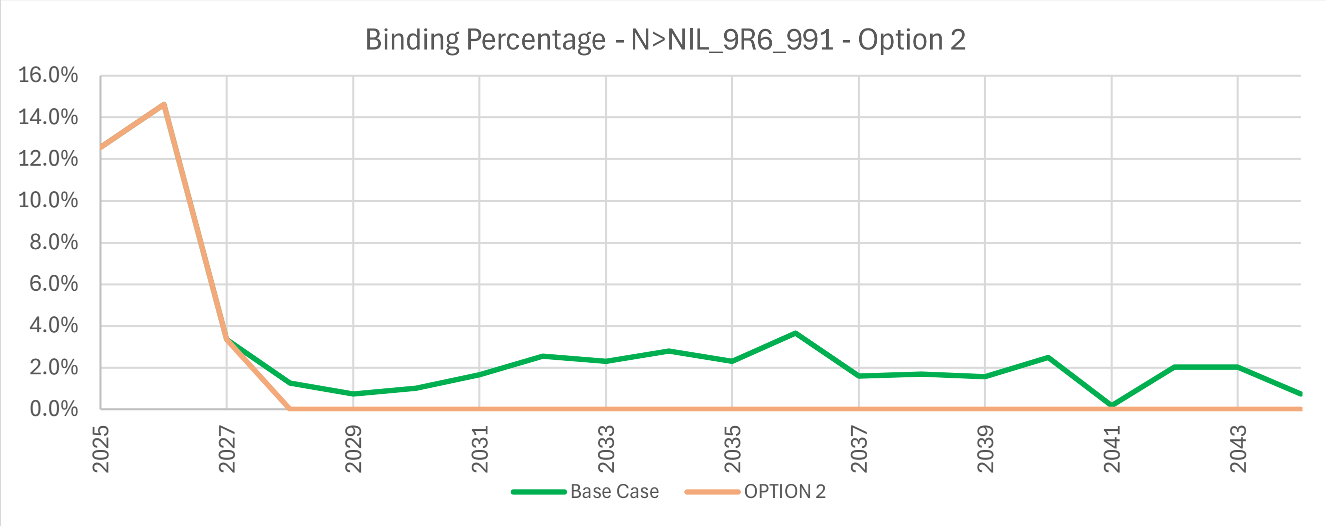


Figure 43: 9R5/9R6 Constraint Binding, Base Case vs. Option 2 – Green Energy Exports

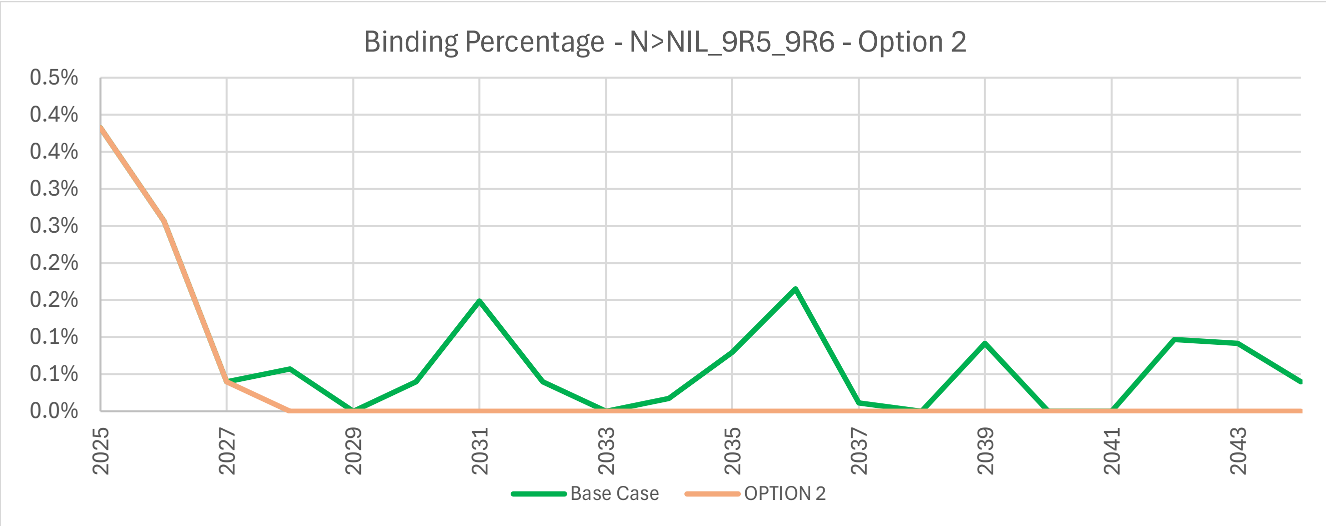
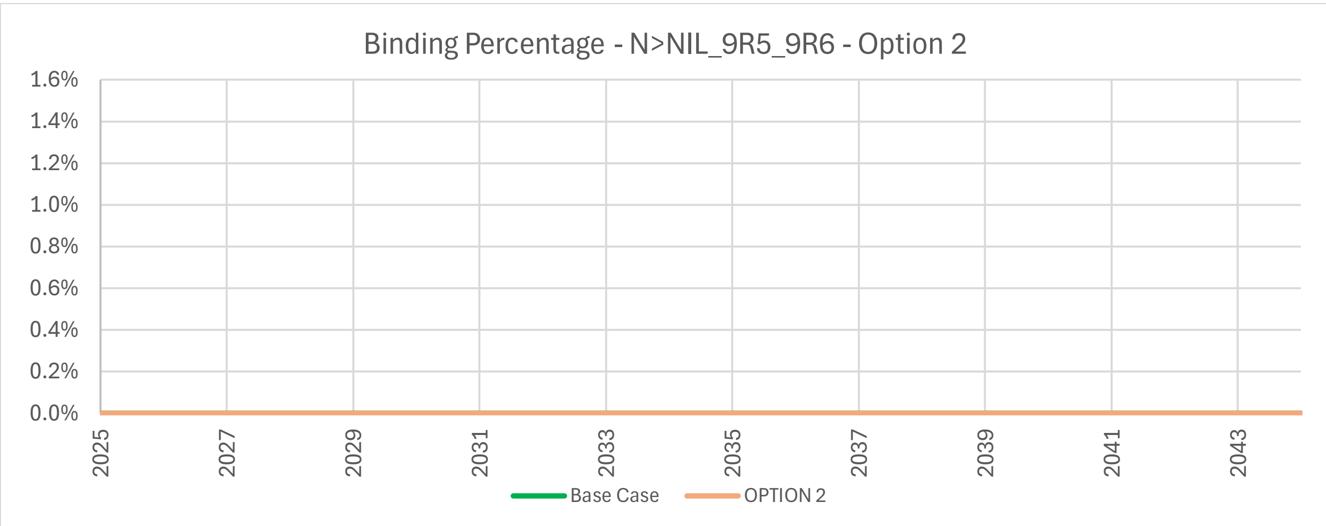


Figure 44: 9R6/9R5 Constraint Binding, Base Case vs. Option 2 – Green Energy Exports



4.6. Option 3

Option 3 involves building a new double-circuit 132 kV transmission line from Wagga 330/132 kV substation to near Wagga North 132/66 kV substation.

This is achieved by:

- constructing approximately 14.6km of new double circuit 132kV transmission line from Wagga 330/132 substation to existing Line 991 Structure 613;
- Diverting Line 991 to Wagga 330/132 substation on one side of the new double circuit transmission line;
- Reusing the existing Line 991 from Structure 613 to Wagga North (WGN) to form the new feeder from Wagga 330/132 to Wagga North, utilizing the opposite side of the new double-circuit transmission line; and
- installing two new 132kV switch bays at the Wagga 330/132 substation.

Option 3 also involves uprating the 132 kV busbars at the Wagga 132/66 kV substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design).

The following section provides a more detailed breakdown of the market modelling outcomes and presents the total gross benefits for the option.

4.6.1. Step Change Scenario

Under the step change scenario, the cumulative gross market benefits for Option 3 are illustrated in Figure 45. The differences in installed capacity and generation across the NEM between option 3 and the base case under step change is shown in Figure 46 and Figure 47 respectively. Positive values indicate increased capacity or generation under Option 3, while negative values reflect reductions.

Key drivers of benefits/costs include:

- The primary benefit driver is avoided solar capacity builds, particularly in Southwest NSW, once the option is commissioned in FY31.
- There is a modest fuel cost increase between FY30 and FY33, driven by increased dispatch from gas units.
- The additional circuit improves transfer capacity from Wagga North to Wagga 330/132, resulting in full mitigation of the 9R5/9R6 and 9R6/991 constraints.
- Rerouting Line 991 resolves 9R6/991 binding as power will flow to Murrumurrah on line 991 from Wagga 330/132 instead of Wagga North. However, loading of Line 9R6 is increased, causing the 9R6/9R5 constraint to bind more frequently once this option comes online.

While Option 3 provides partial constraint relief and improves transfer capability, its effectiveness is limited. It does not fully address all constraint binding in the Wagga North area, leaving residual congestion and risk of curtailment.

Additionally, due to its delayed delivery timeline and limited constraint relief, Option 3 is forecast to deliver the lowest gross market benefits among all transmission augmentation options.

Figure 45: Discounted, Cumulative Gross Market Benefits for Option 3 – Step Change Scenario

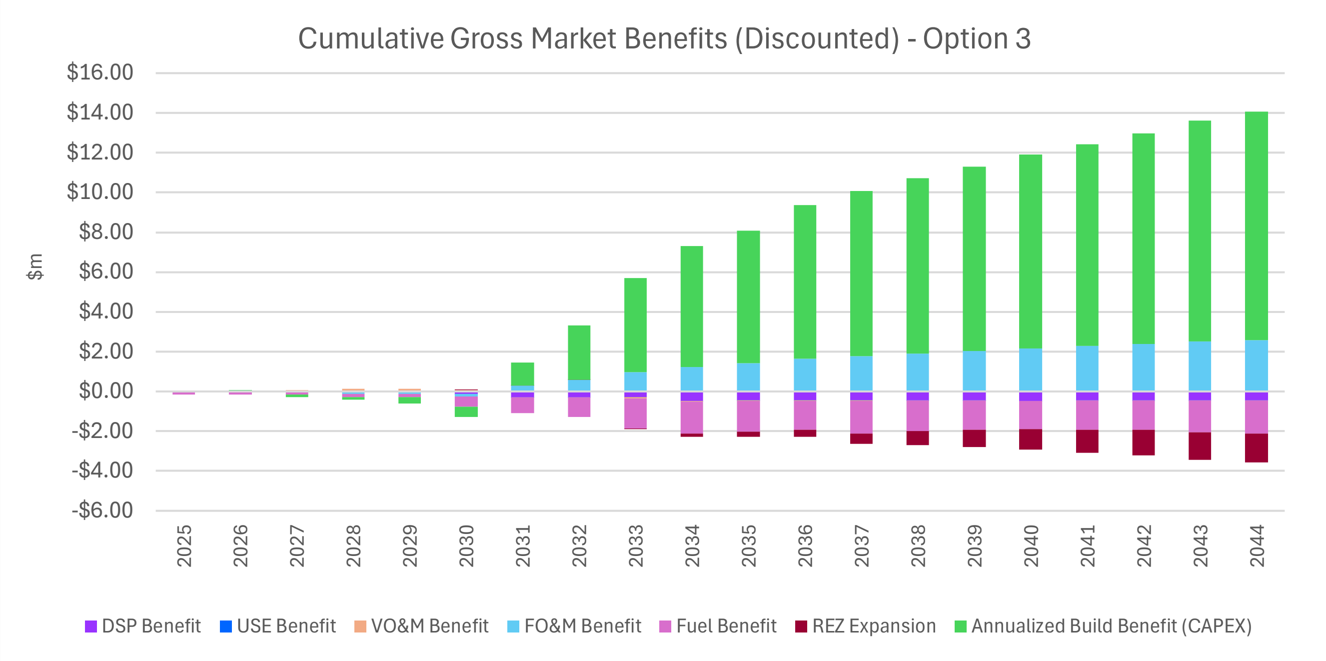


Figure 46: Difference in Installed Capacity (Option 3 - Base Case) – Step Change Scenario

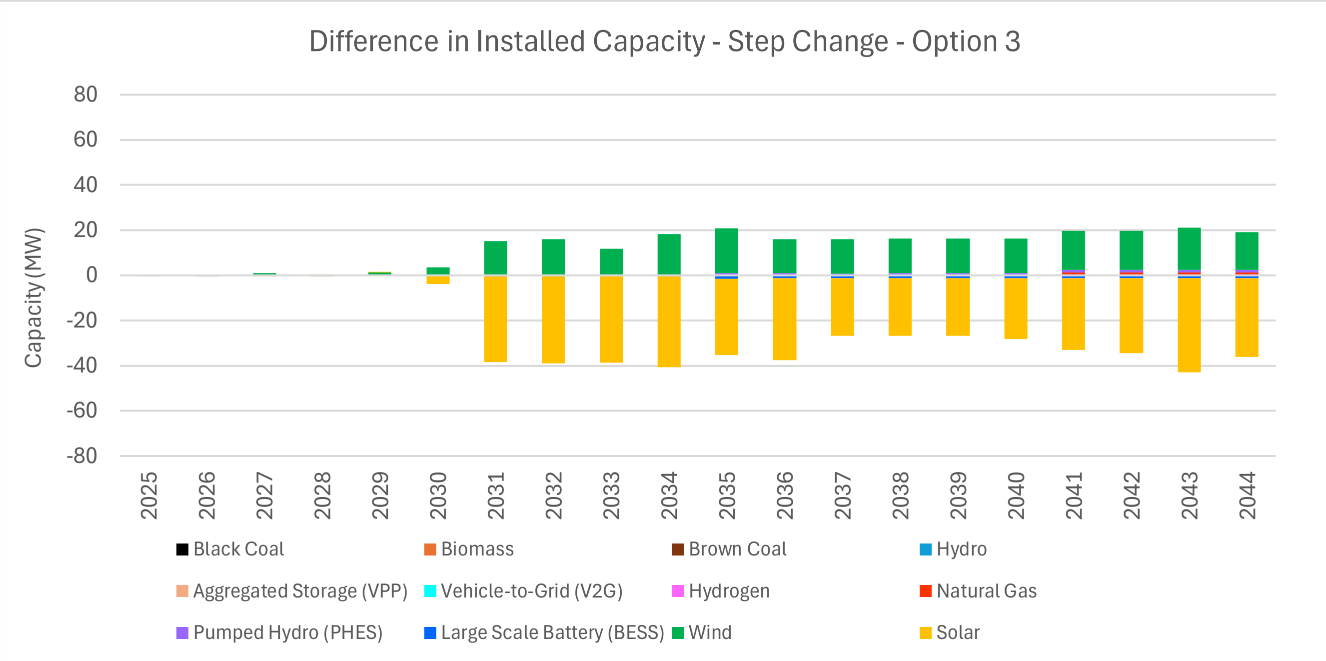


Figure 47: Difference in Generation (Option 3 - Base Case) – Step Change Scenario

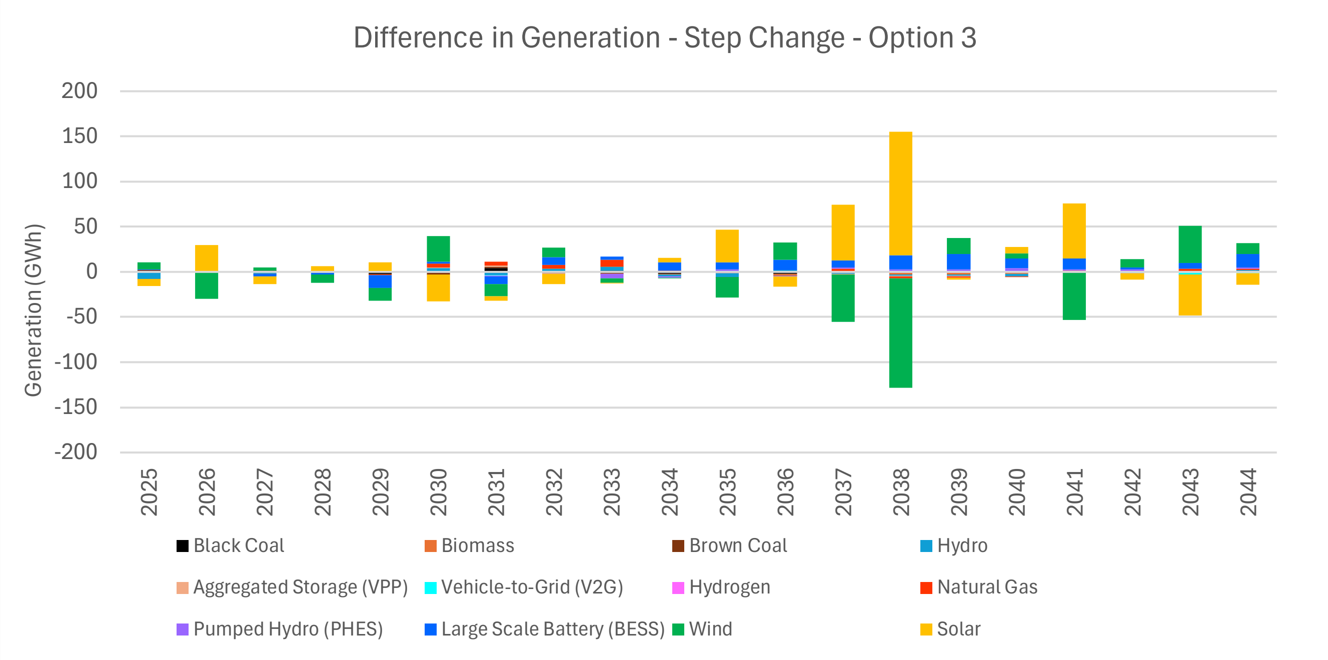


Figure 48: 9R6/991 Constraint Binding, Base Case vs. Option 3 – Step Change

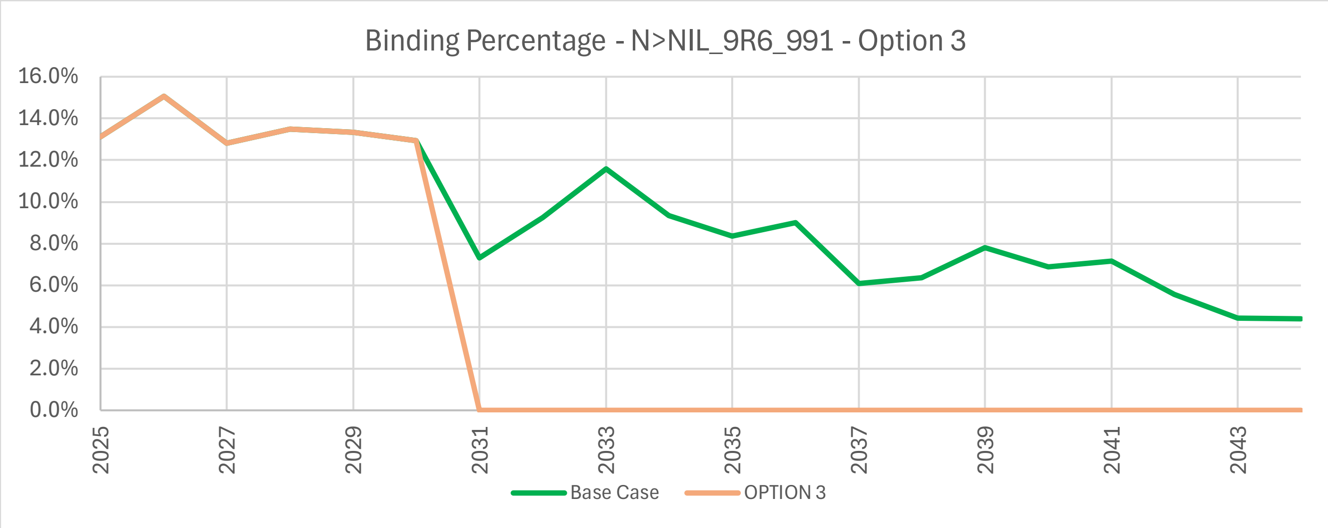


Figure 49: 9R5/9R6 Constraint Binding, Base Case vs. Option 3 – Step Change

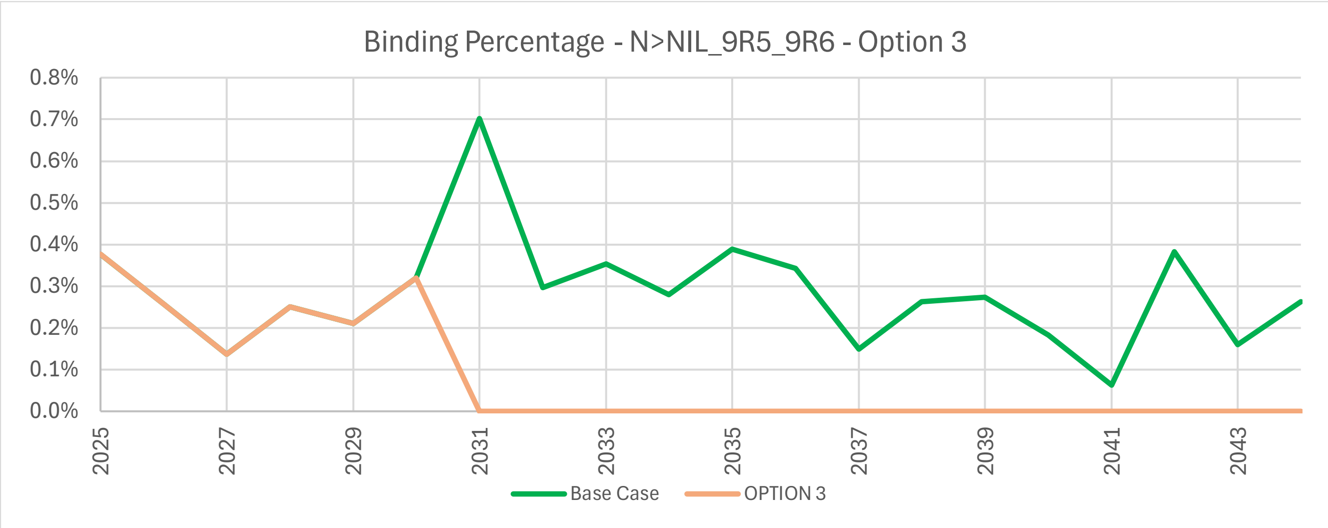
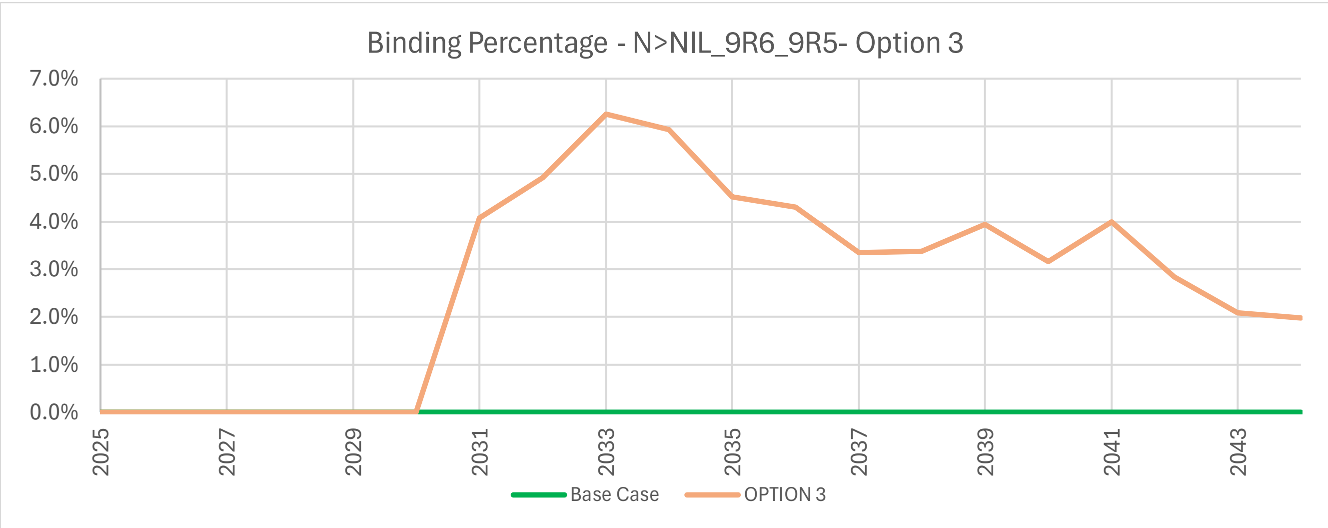


Figure 50: 9R6/9R5 Constraint Binding, Base Case vs. Option 3 – Step Change



4.6.2. Progressive Change Scenario

Under the progressive change scenario, the cumulative gross market benefits for Option 3 are illustrated in Figure 51. The differences in installed capacity and generation across the NEM between option 3 and the base case under progressive change is shown in Figure 52 and Figure 53 respectively.

Key drivers of benefits/costs include:

- Consistent with step change, Option 3 derives most of its benefit through CAPEX savings from avoided solar capacity in the NEM.
- Concurrently, there is also less wind capacity being built which inflates the benefits for this option. Hence, option 3 is forecast to have the highest benefits under this scenario.
- Increased generation from gas units contribute to more fuel costs in the latter half of the horizon.

From a constraint binding perspective, the constraints 9R6/991 and 9R5/9R6 are fully mitigated, while the 9R6/9R5 constraint begins to bind more frequently starting in FY31, when the option is forecast to be delivered.

Figure 51: Discounted, Cumulative Gross Market Benefits for Option 3 – Progressive Change Scenario

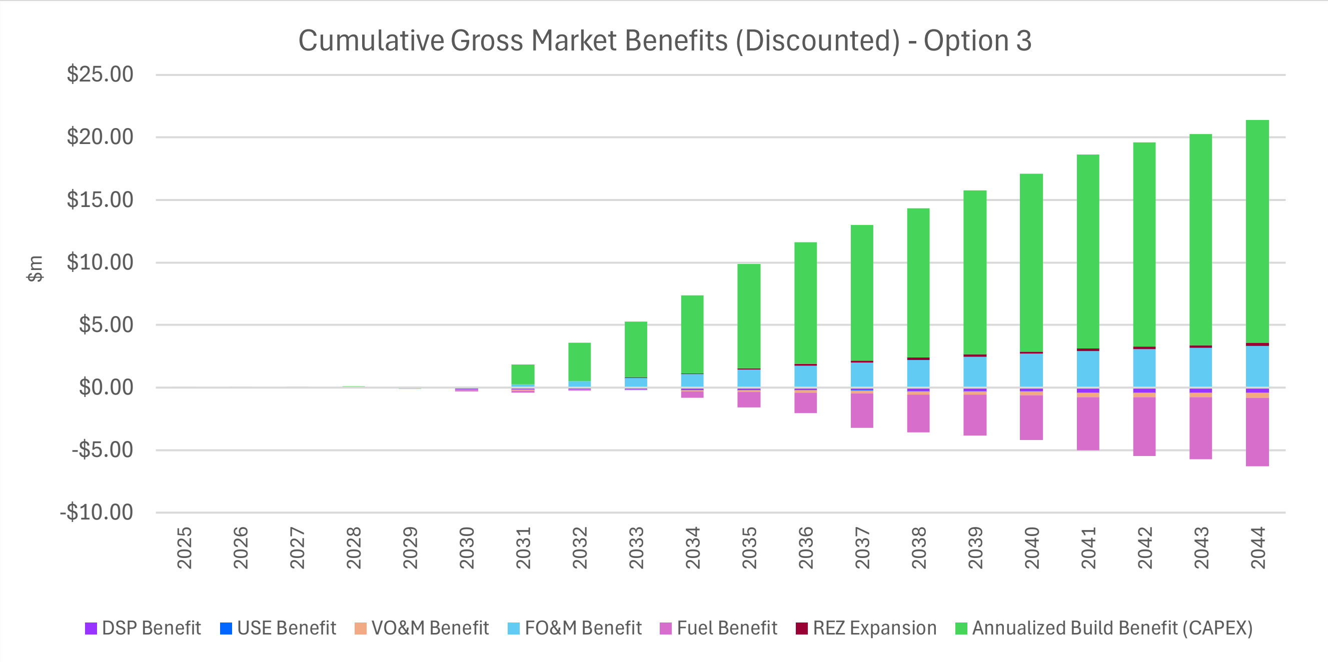


Figure 52: Difference in Installed Capacity (Option 3 - Base Case) – Progressive Change Scenario

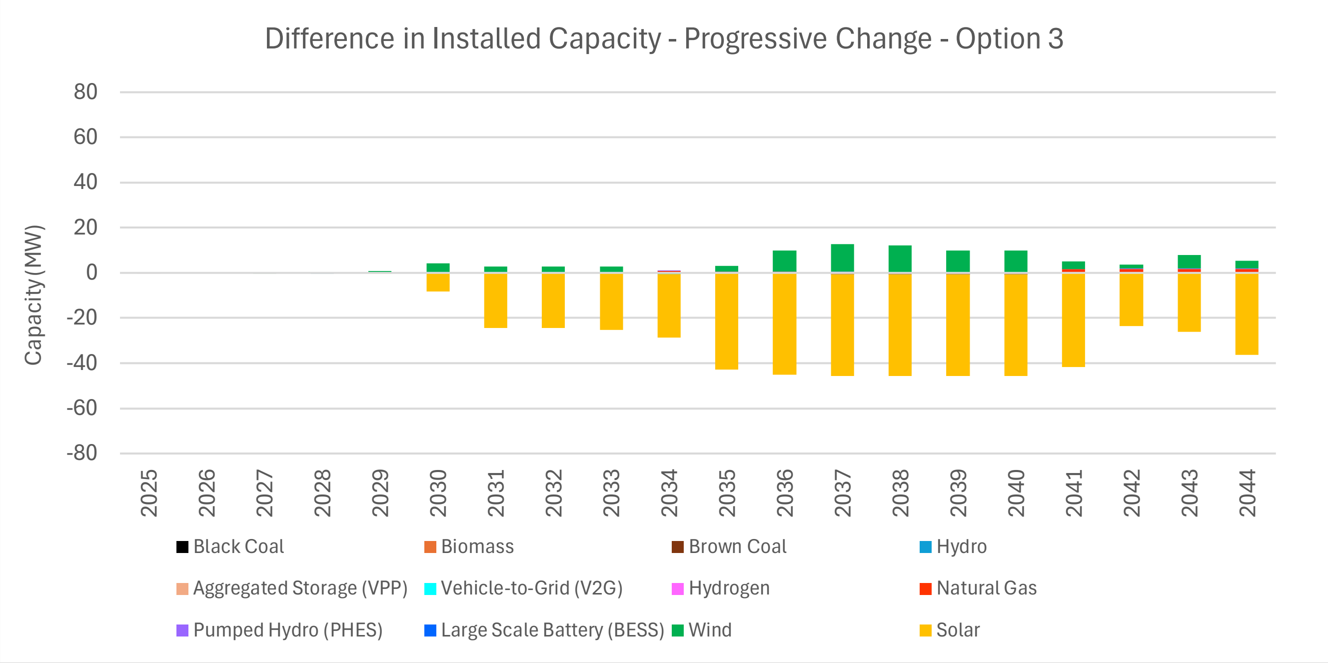


Figure 53: Difference in Generation (Option 3 - Base Case) –Progressive Scenario

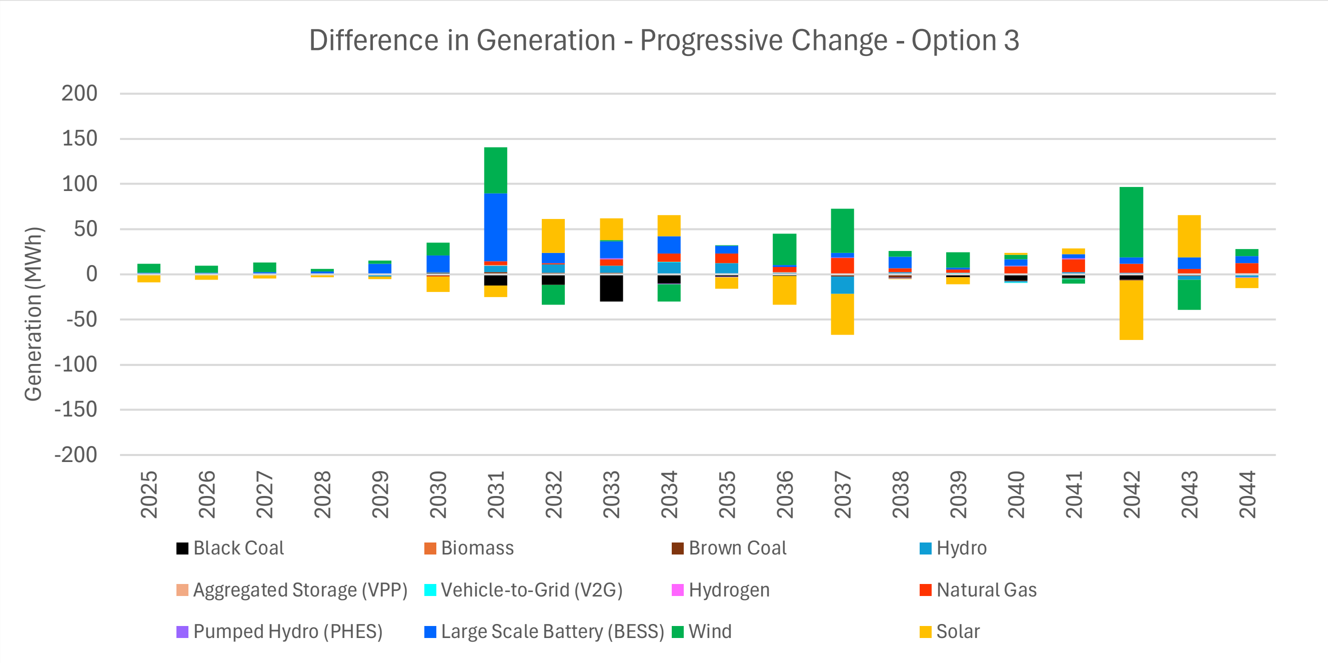


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Figure 54: 9R6/991 Constraint Binding, Base Case vs. Option 3 – Progressive Change

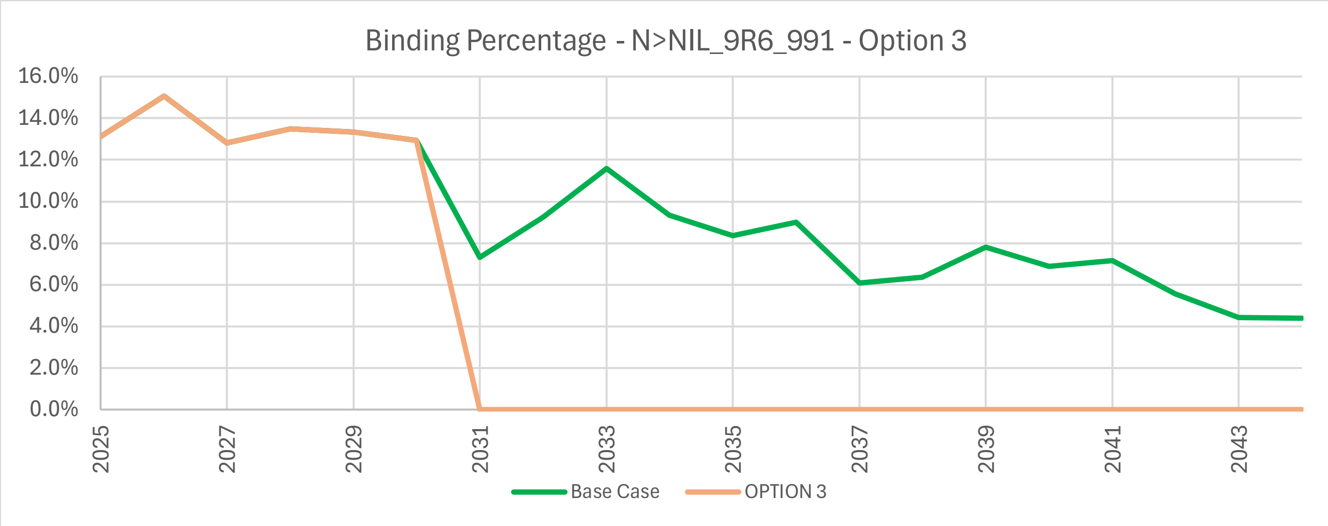


Figure 55: 9R5/9R6 Constraint Binding, Base Case vs. Option 3 – Progressive Change

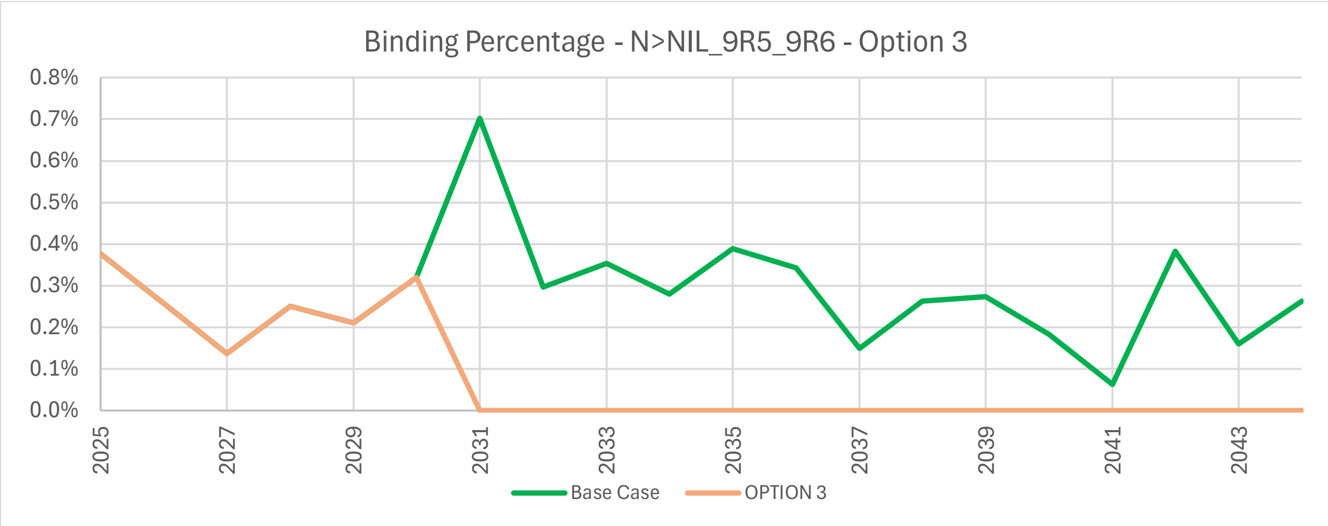
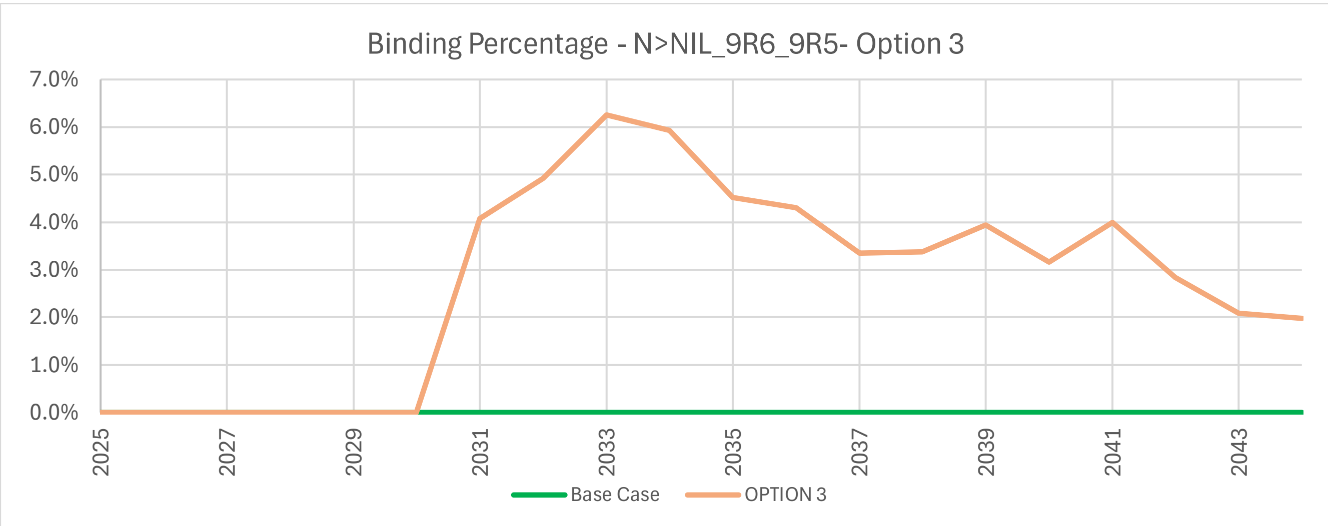


Figure 56: 9R6/9R5 Constraint Binding, Base Case vs. Option 3 – Progressive Change



4.6.3. Green Energy Exports Scenario

The forecasted cumulative gross benefits for option 3 under the green energy exports scenario are shown in Figure 57. Additionally, the difference in forecasted capacity and generation across the NEM between option 2 and the base case under green energy exports is shown in Figure 58 and Figure 59 respectively.

Under the Green Energy Exports scenario, Option 3 delivers moderate market benefits.

- Under this scenario, coal retirements, transmission development, and renewable integration occur at an accelerated pace. Most of the required capacity is delivered early in the planning horizon, prior to the option being implemented in FY31. Consequently, this option is projected to deliver the lowest gross benefits for this scenario, as there is limited opportunity to defer new investments.
- Under this scenario, constraint binding in the base case is low due to high renewable uptake, which further deflates benefits.
- While the option alleviates some constraints, the 9R6/9R5 constraint becomes more prominent post-FY31.

Figure 57: Discounted, Cumulative Gross Market Benefits for Option 3 – Green Energy Exports

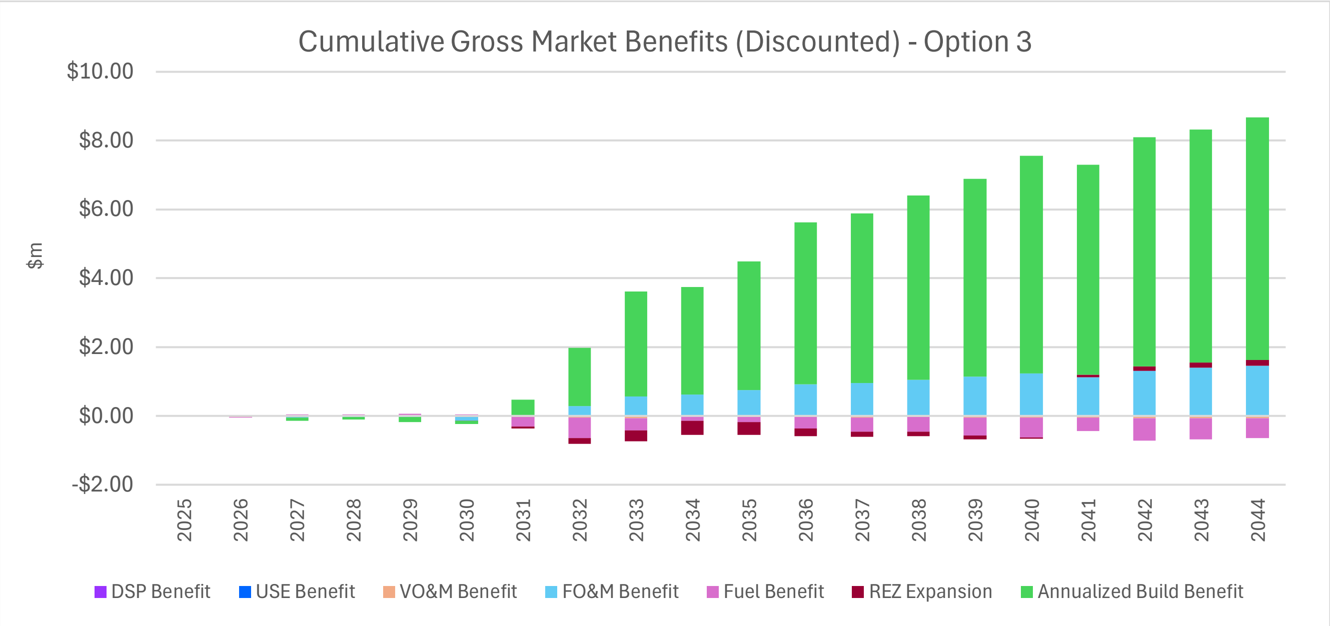


Figure 58: Difference in Installed Capacity (Option 3 - Base Case) – Green Energy Exports

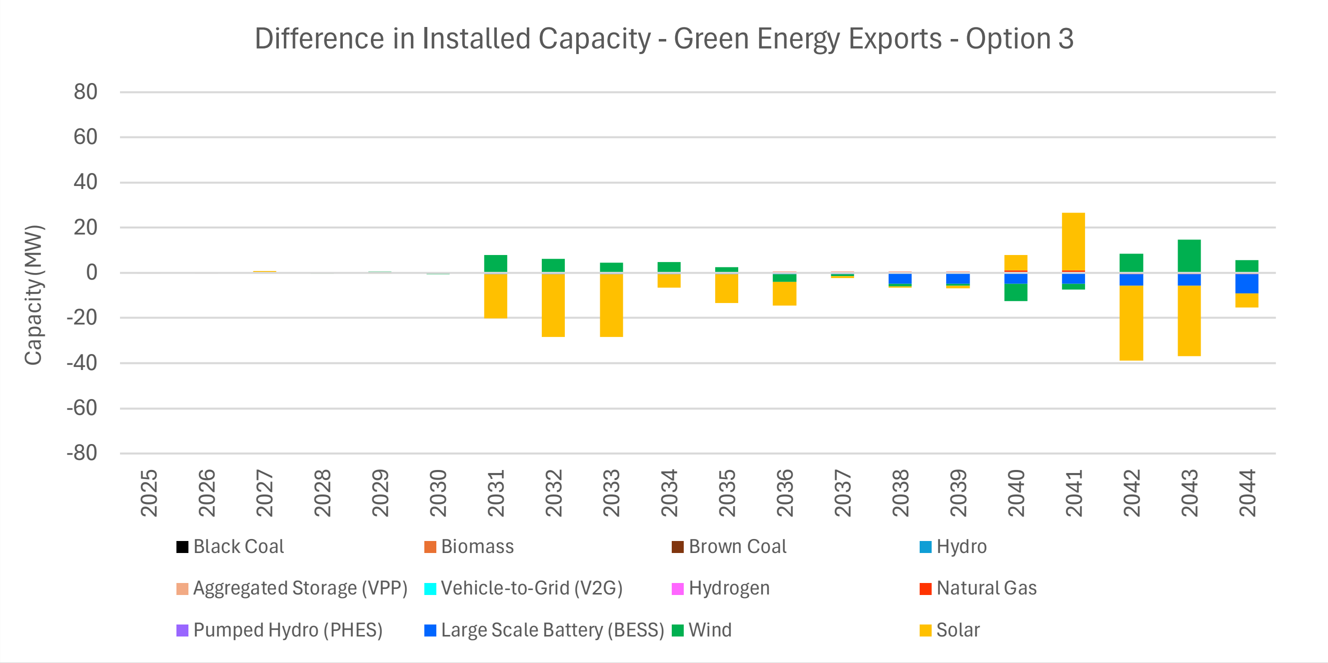


Figure 59: Difference in Generation (Option 3 - Base Case) – Green Energy Exports

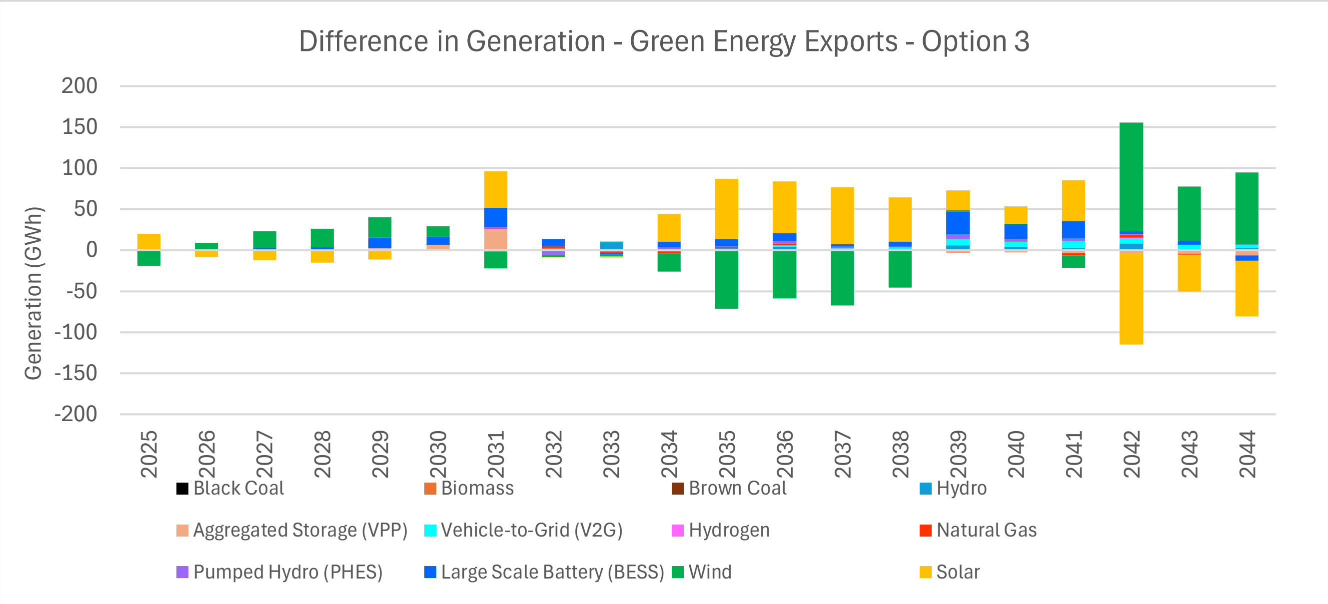


Figure 60: 9R6/991 Constraint Binding, Base Case vs. Option 3 – Green Energy Exports

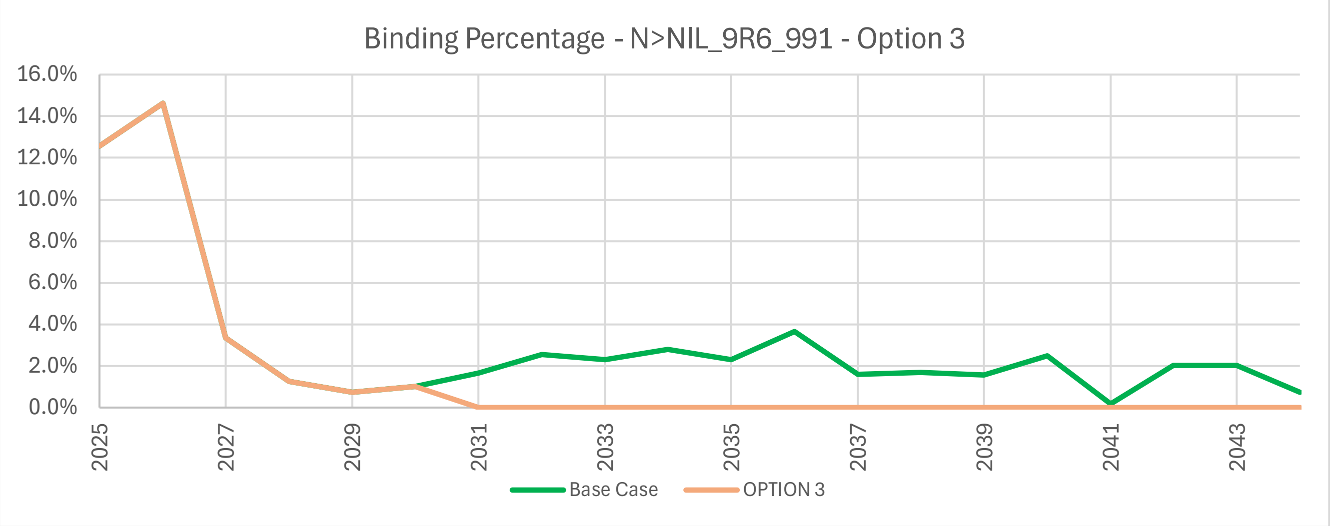


Figure 61: 9R5/9R6 Constraint Binding, Base Case vs. Option 3 – Green Energy Exports

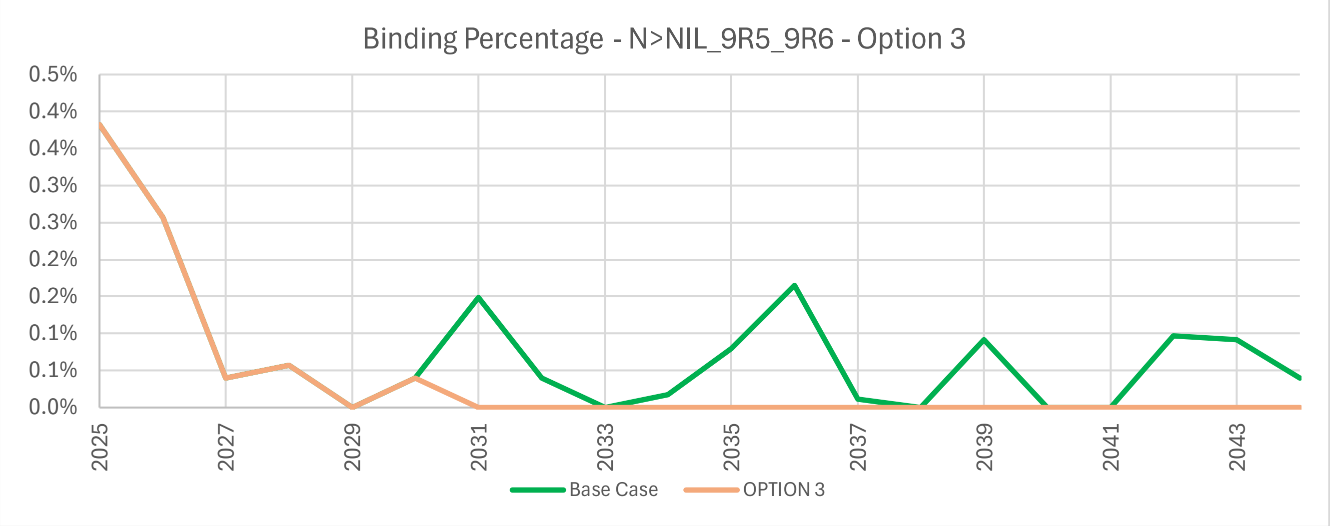
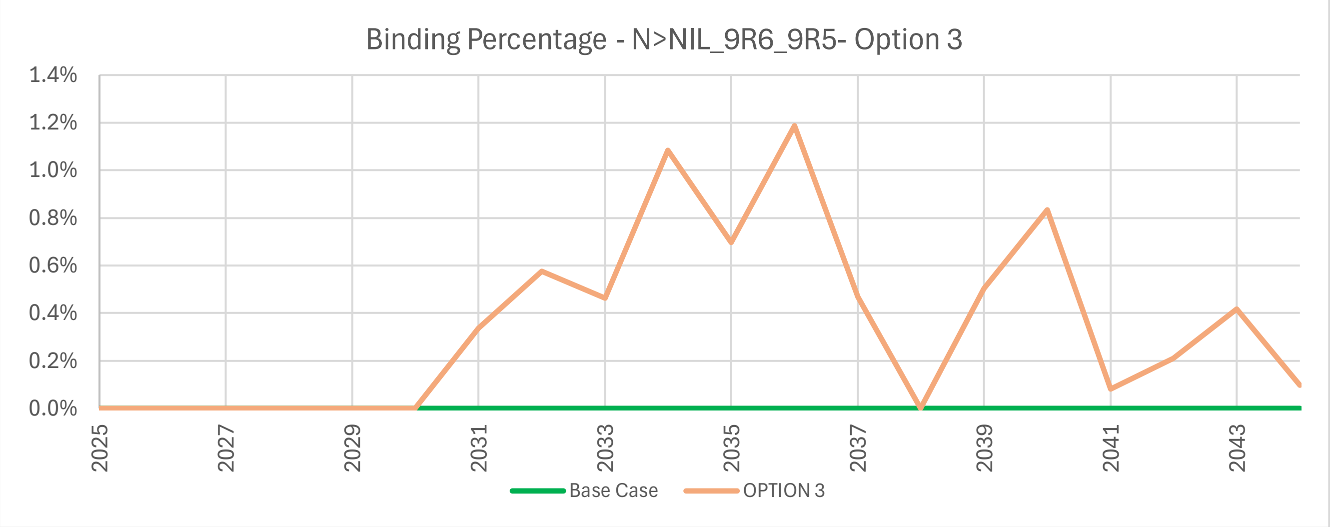


Figure 62: 9R5/9R6 Constraint Binding, Base Case vs. Option 3 – Green Energy Exports



4.7. Option 4

Option 4 involves building a new single circuit 132kV transmission line between Wagga North 132/66 kV substation and Wagga 330/132 kV substation.

This is achieved by:

- constructing approximately 14.9km of new single-circuit 132kV transmission line from Wagga 330/132 substation (WG1) to Wagga North substation (WGN), using 1 x Mango ACSR conductors supported by concrete poles;
- constructing one new 132kV switchbay at Wagga 330/132 substation; and
- constructing one new 132kV switchbay at Wagga North substation.

Option 4 also involves uprating the 132 kV busbars at the Wagga 132/66 kV substation. This will involve renewing, in-situ and on a piece-meal basis, the 132 kV busbar sections, associated busbar connections and circuit termination equipment at the substation in accordance with current Transgrid minimum standards (modern standard aluminium tube design).

The following section provides a more detailed breakdown of the market modelling outcomes and presents the total gross benefits for the option.

4.7.1. Step Change Scenario

Under the Step Change scenario, the cumulative gross market benefits for Option 4 are illustrated in Figure 63. The differences in installed capacity and generation across the NEM between option 4 and the base case under step change is shown in Figure 64 and Figure 65 respectively. Positive values indicate increased capacity or generation under Option 4, while negative values reflect reductions.

Key drivers of benefits/costs under this option include:

- Most of the CAPEX savings for this option, under step change, is from avoided solar capacity once the option is implemented in FY30.
- There is a minor increase in fuel cost from FY31-33 due to increased generation from gas and coal units.
- The additional circuit from Wagga North to Wagga 330/132 increases transfer capacity which mitigates binding on the 9R5/9R6 and 9R6/9R5 constraints. However, the 9R6/991 constraint keeps binding.

Figure 63: Discounted, Cumulative Gross Market Benefits for Option 4 – Step Change Scenario

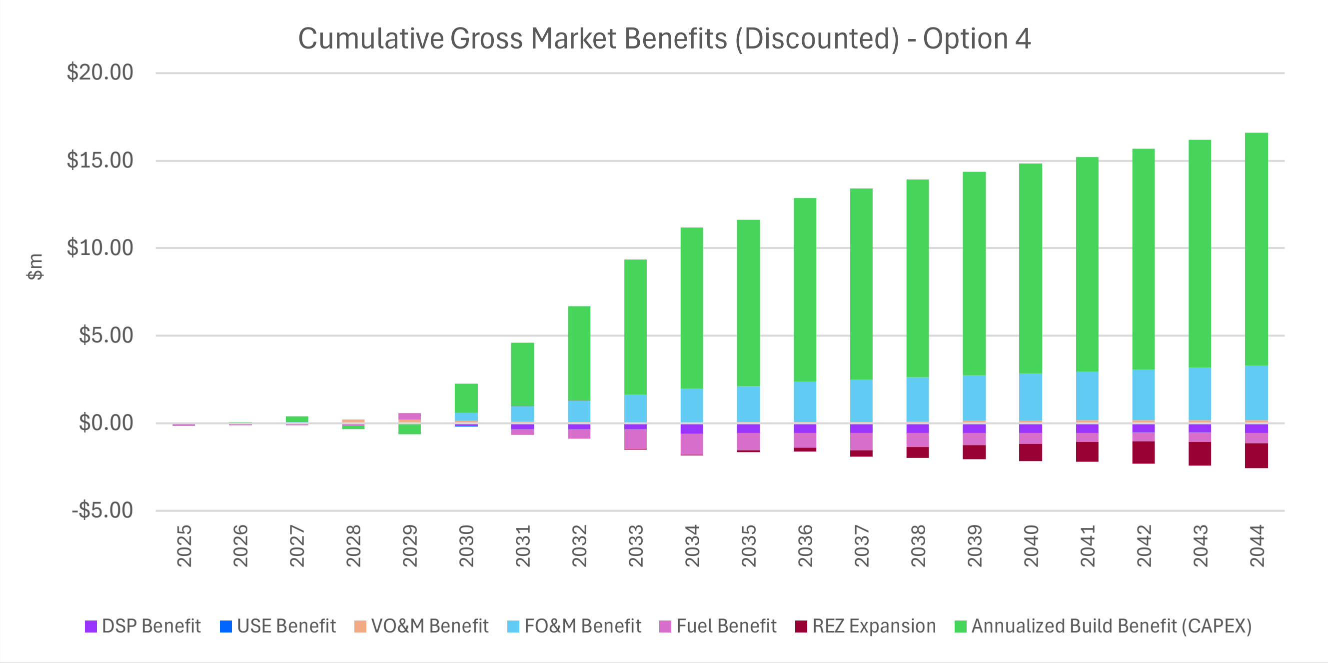


Figure 64: Difference in Installed Capacity (Option 4 - Base Case) – Step Change Scenario

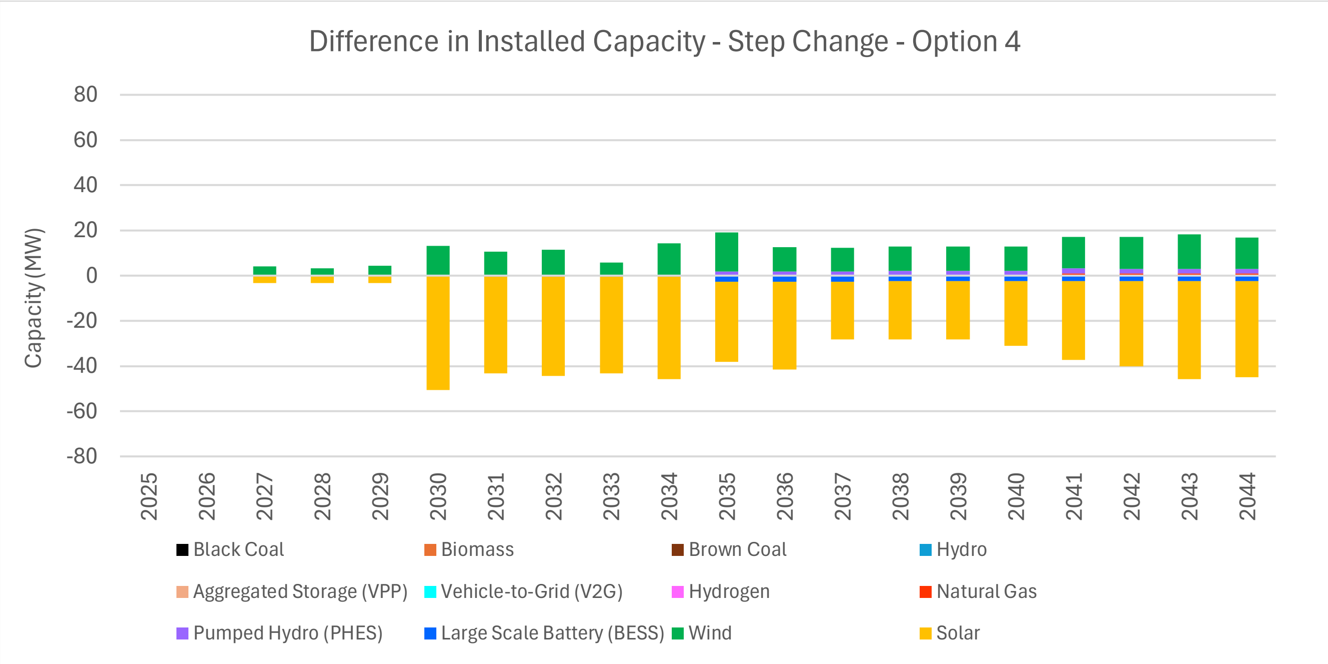


Figure 65: Difference in Generation (Option 4 - Base Case) – Step Change Scenario

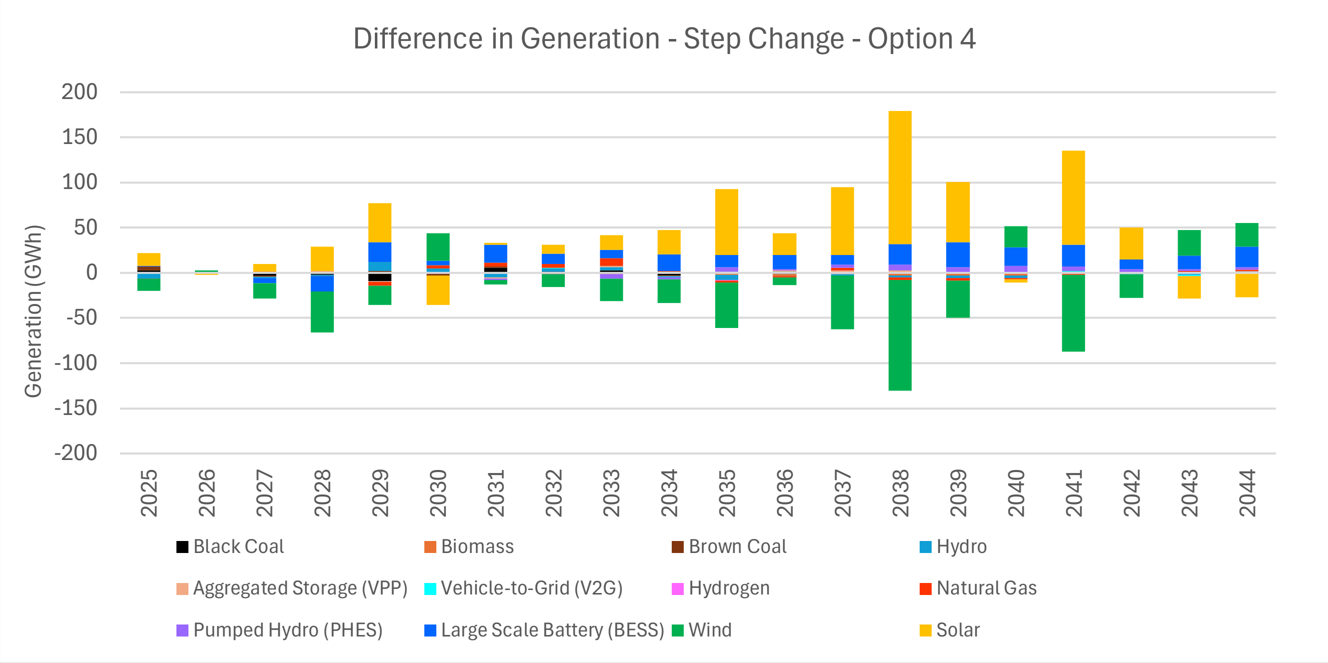


Figure 66: 9R6/991 Constraint Binding, Base Case vs. Option 4 – Step Change

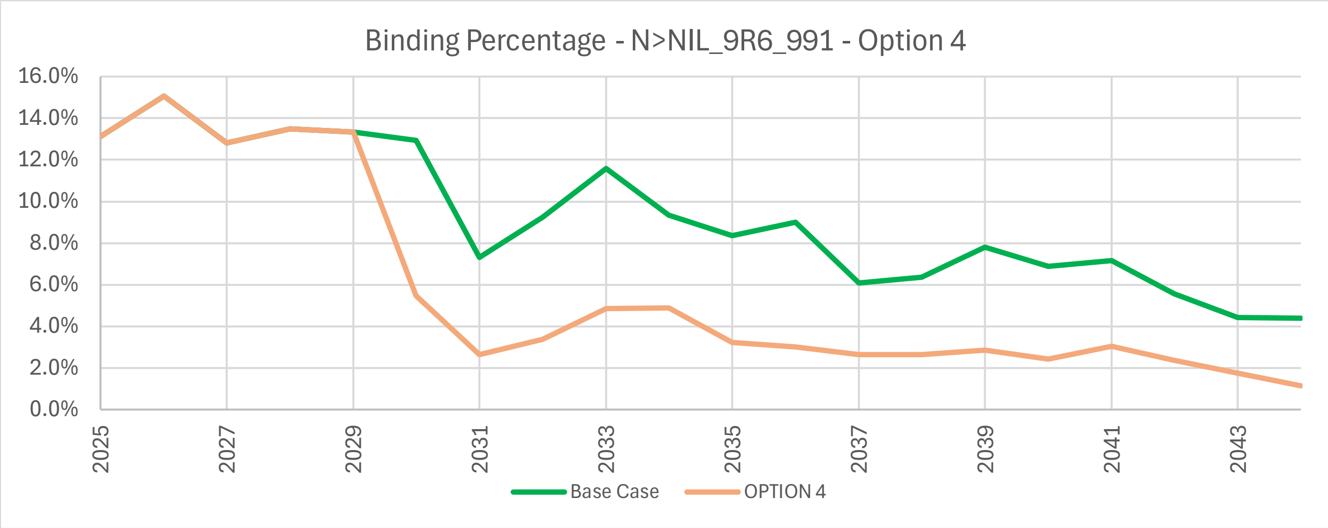


Figure 67: 9R5/9R6 Constraint Binding, Base Case vs. Option 4 – Step Change

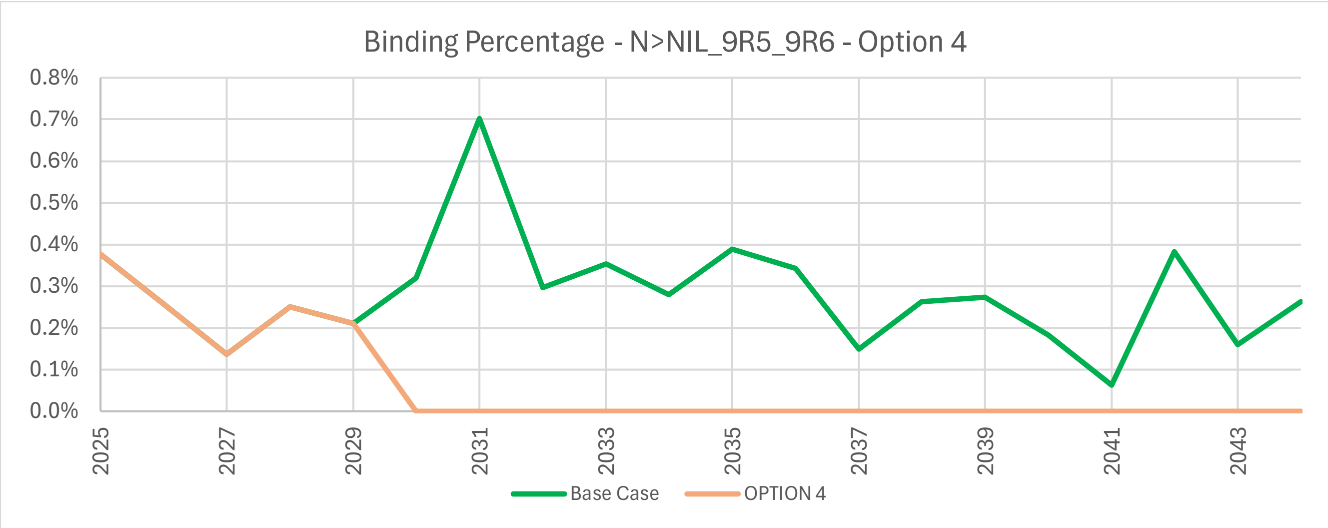
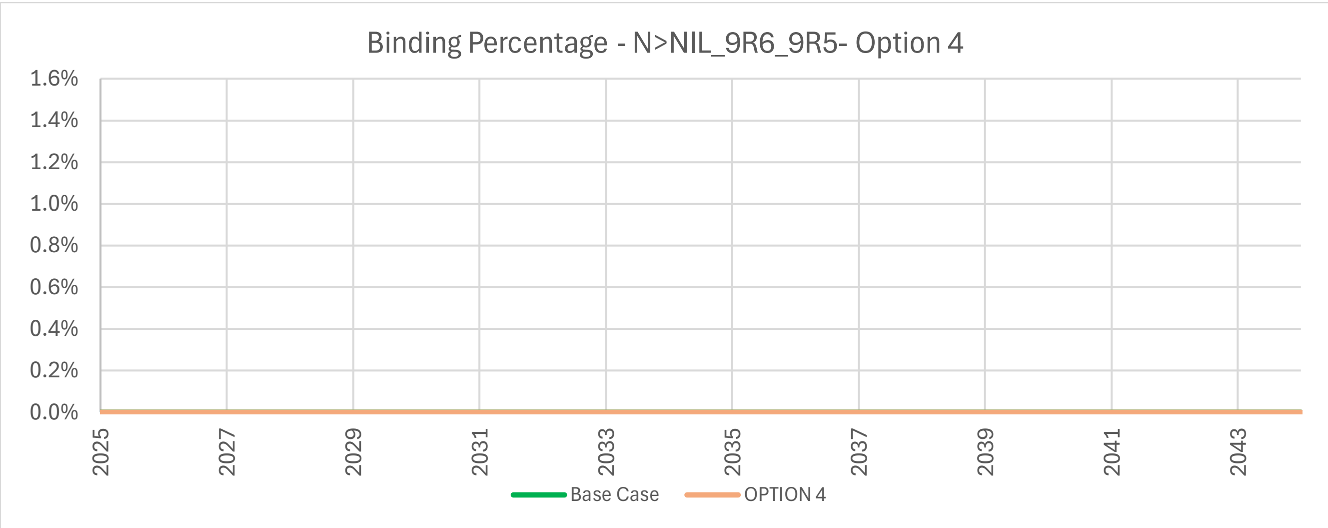


Figure 68: 9R6/9R5 Constraint Binding, Base Case vs. Option 4 – Step Change



4.7.2. Progressive Change Scenario

Under the Progressive Change scenario, the cumulative gross market benefits for Option 4 are illustrated in Figure 69. The differences in installed capacity and generation across the NEM between option 4 and the base case under progressive change is shown in Figure 70 and Figure 71 respectively.

Key drivers for benefits/costs include:

- Consistent with step change, the CAPEX and FO&M savings for this option are primarily from avoided solar capacity.
- There is also a reduction in new wind capacity builds compared to step change which inflates the CAPEX savings under this scenario. Hence, Option 4 has the highest benefits under this
- scenario.

Figure 69: Discounted, Cumulative Gross Market Benefits for Option 4 – Progressive Change Scenario

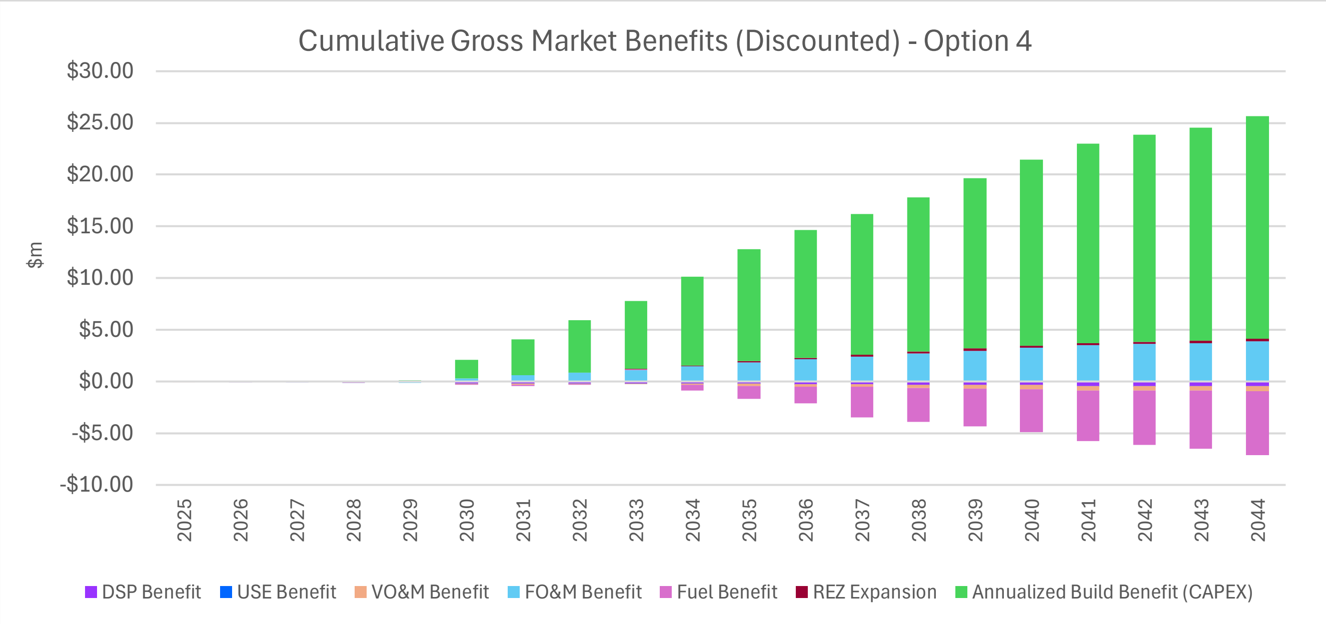


Figure 70: Difference in Installed Capacity (Option 4 - Base Case) – Progressive Change Scenario

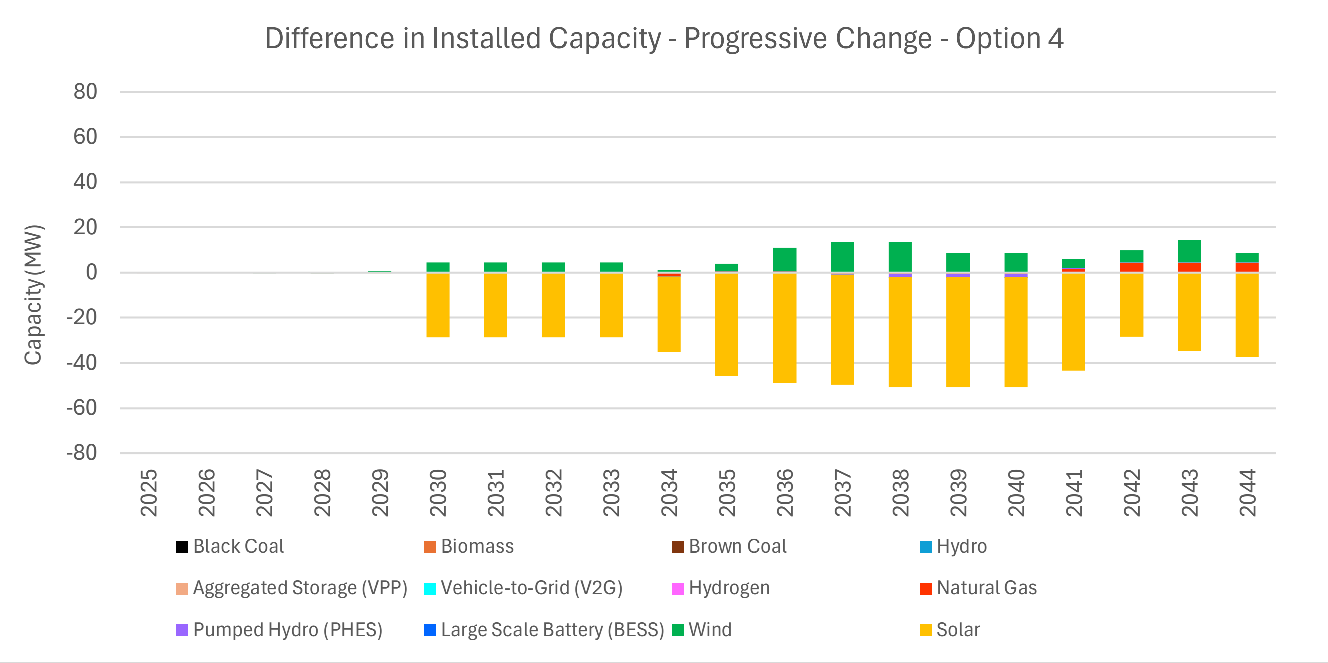


Figure 71: Difference in Generation (Option 4 - Base Case) – Progressive Change Scenario

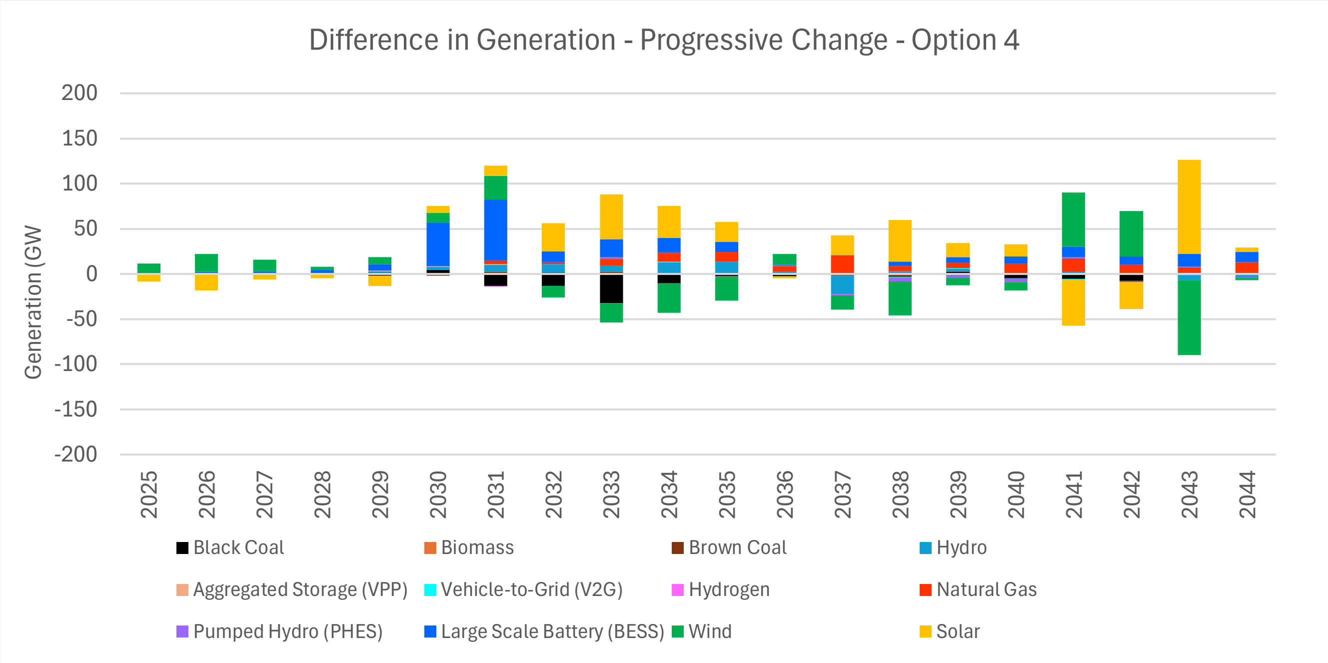


Figure 72: 9R6/991 Constraint Binding, Base Case vs. Option 4 – Progressive Change

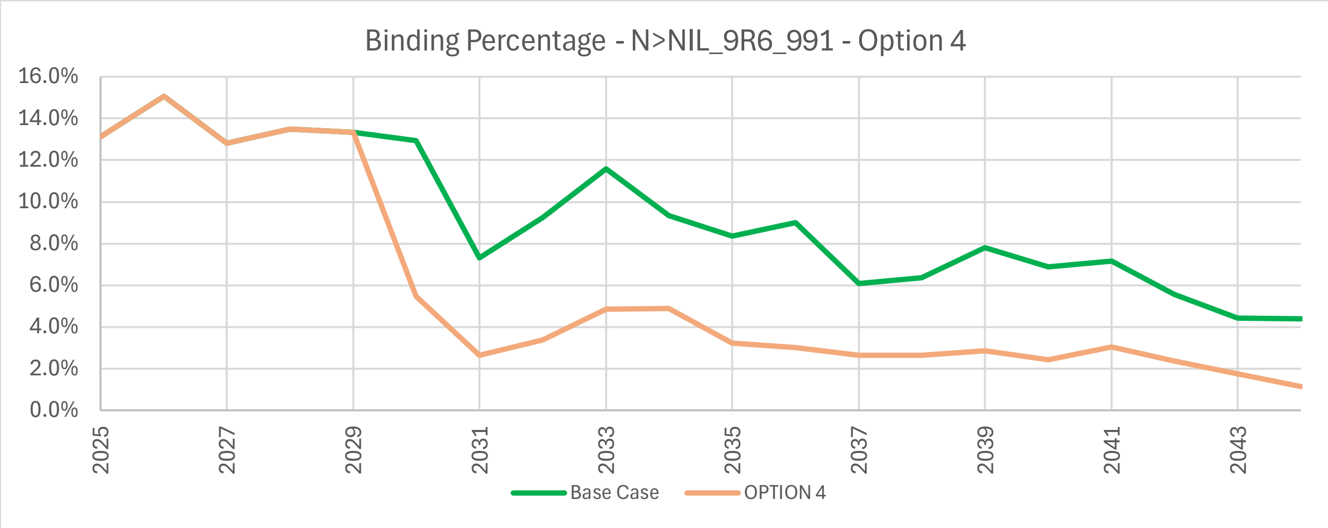


Figure 73: 9R6/991 Constraint Binding, Base Case vs. Option 4 – Progressive Change

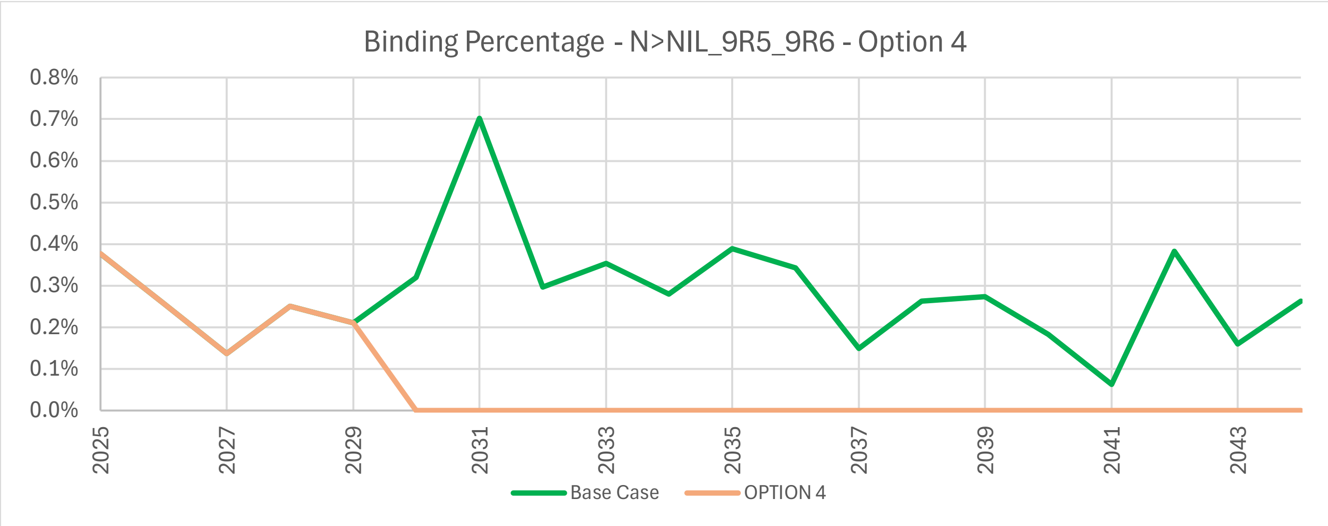
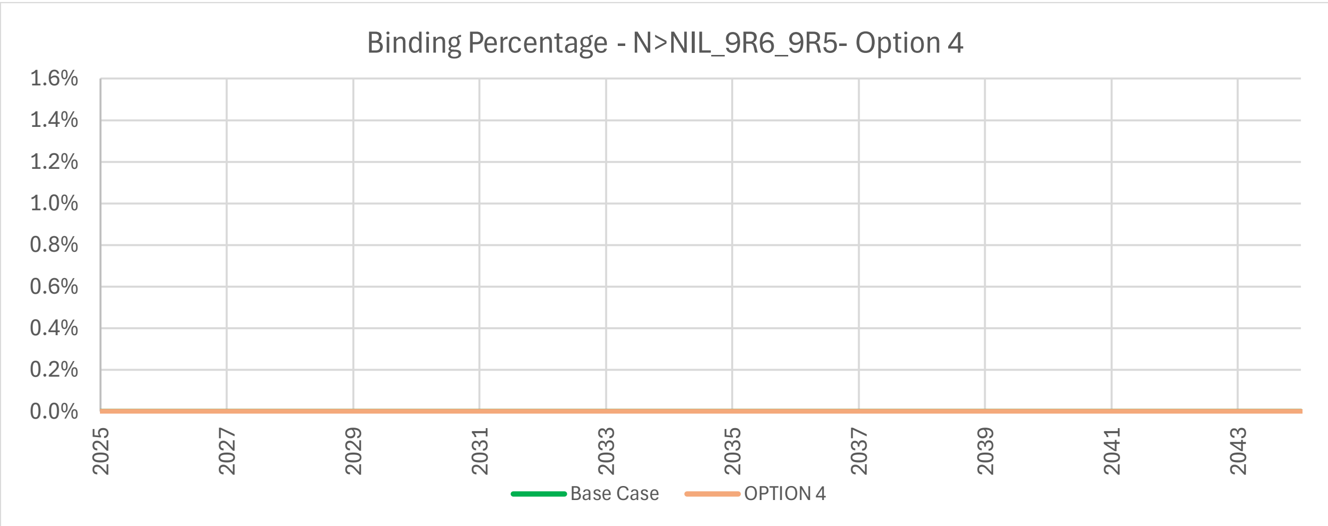


Figure 74: 9R6/991 Constraint Binding, Base Case vs. Option 4 – Progressive Change



4.7.3. Green Energy Exports Scenario

Under the Green Energy Exports scenario, the cumulative gross market benefits for Option 4 are illustrated in Figure 75. The differences in installed capacity and generation across the NEM between option 4 and the base case under green energy exports is shown in Figure 76 and Figure 77 respectively.

- Under this scenario, coal retirements, transmission development, and renewable integration occur at an accelerated pace. Most of the required capacity is delivered early in the planning horizon, prior to the option being implemented in FY30. Consequently, this option is projected to deliver the lowest gross benefits for this scenario, as there is limited opportunity to defer new investments.
- Under this scenario, constraint binding in the base case is low due to high renewable uptake, which further deflates benefits.
- Consistent with the other scenarios, the 9R5/9R6 and 9R6/9R5 constraints are relieved but 9R6/991 keeps binding.

Figure 75: Discounted, Cumulative Gross Market Benefits for Option 4 – Progressive Change Scenario

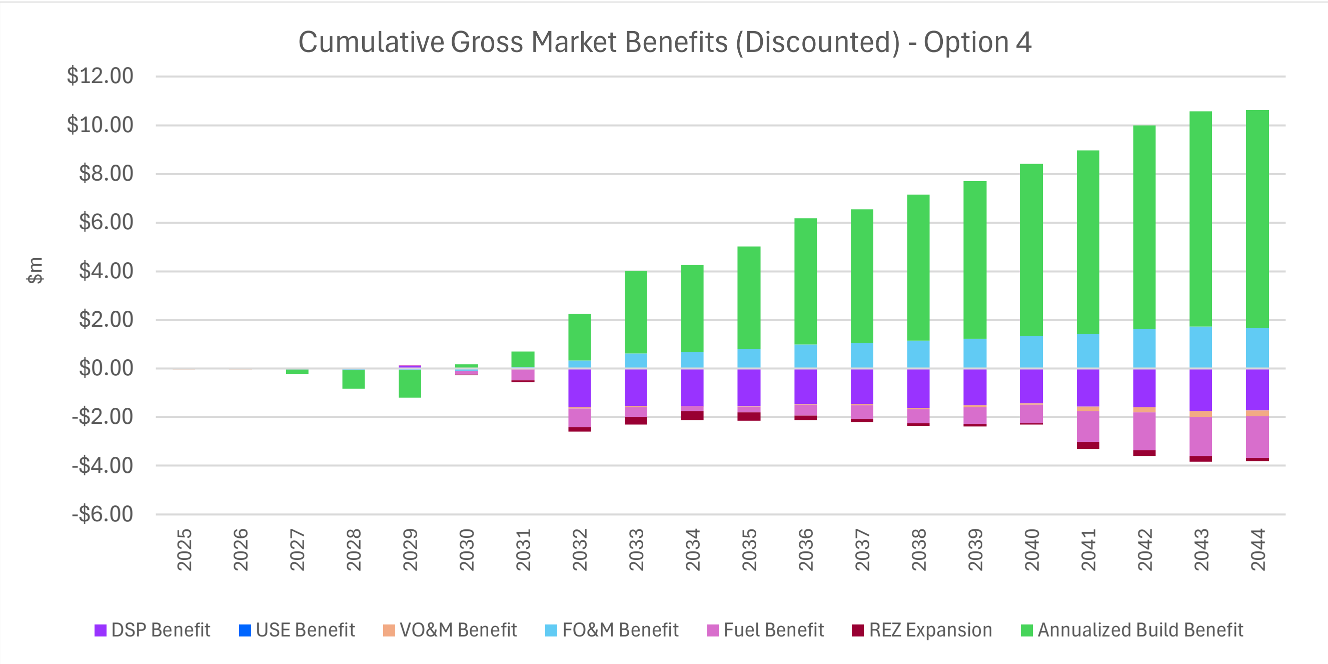


Figure 76: Difference in Installed Capacity (Option 4 - Base Case) – Green Energy Exports

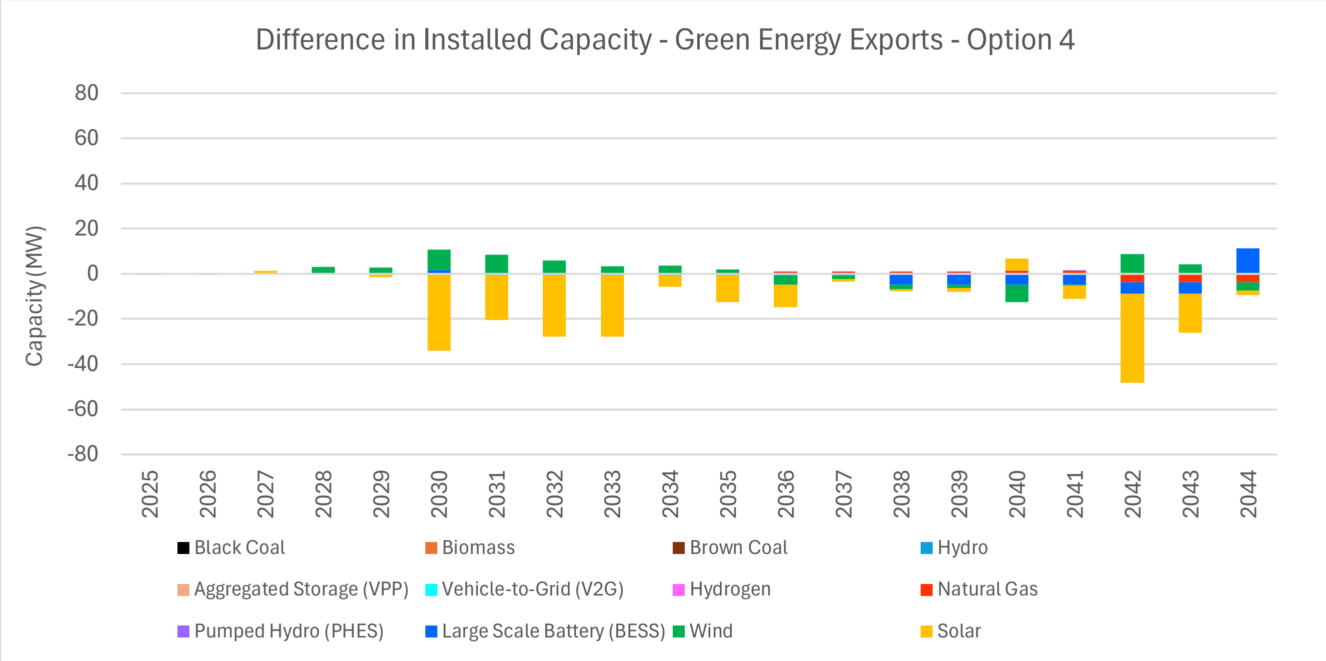


Figure 77: Difference in Generation (Option 4 - Base Case) – Green Energy Exports

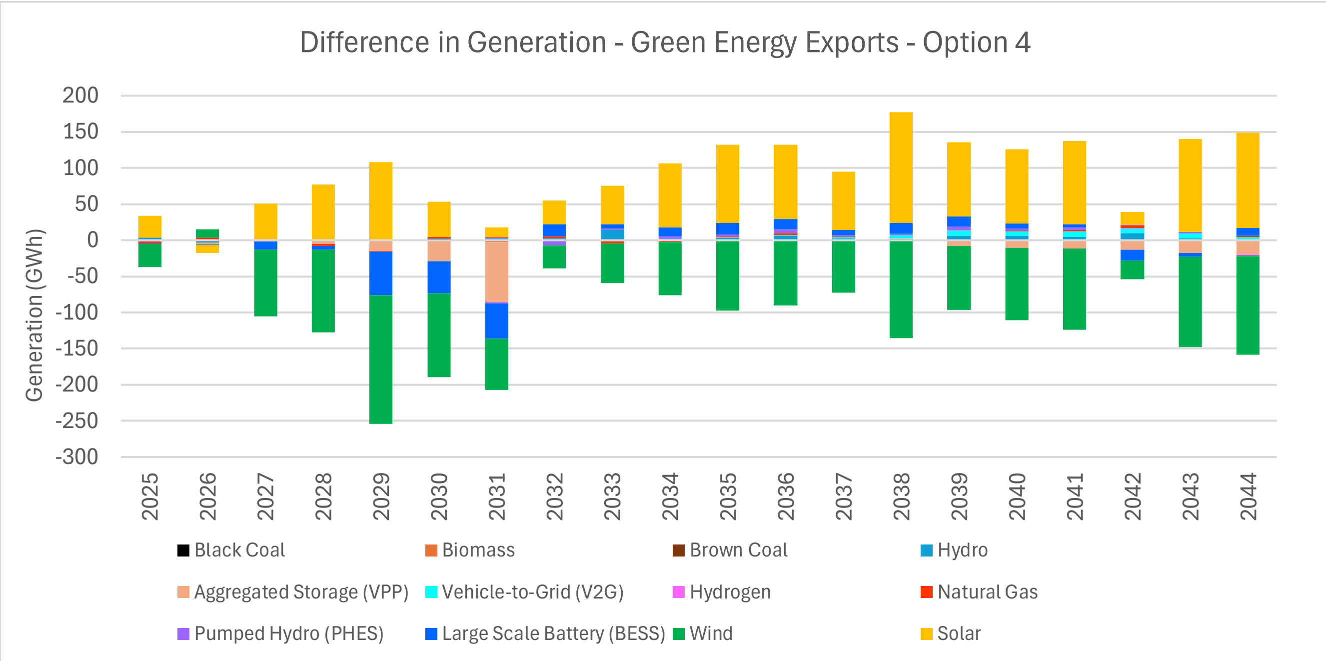


Figure 78: 9R6/991 Constraint Binding, Base Case vs. Option 4 – Green Energy Exports

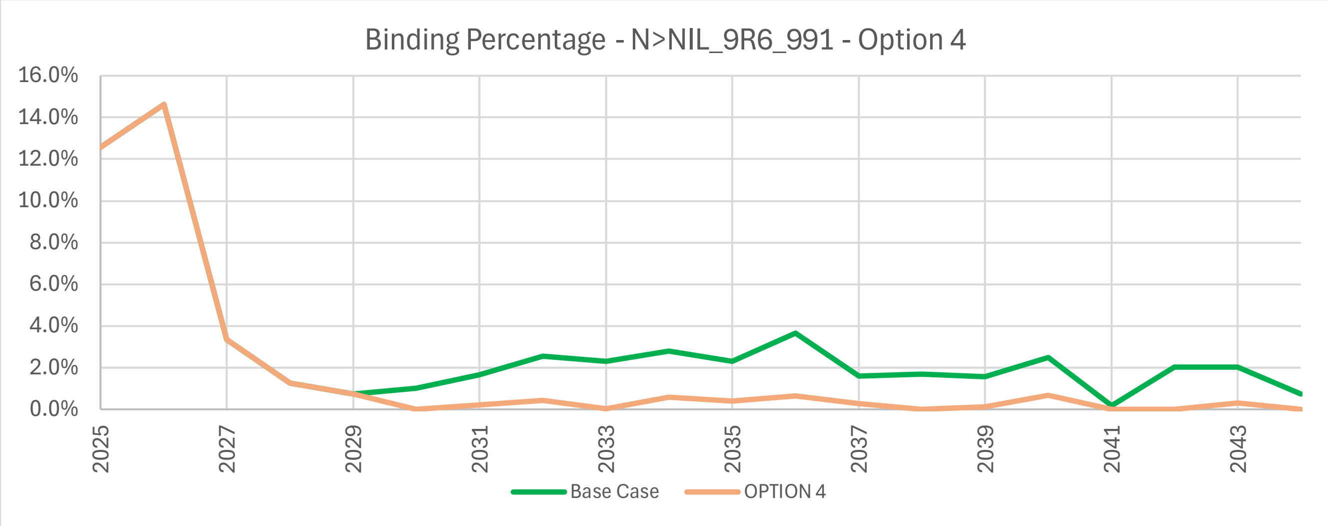


Figure 79: 9R5/9R6 Constraint Binding, Base Case vs. Option 4 – Green Energy Exports

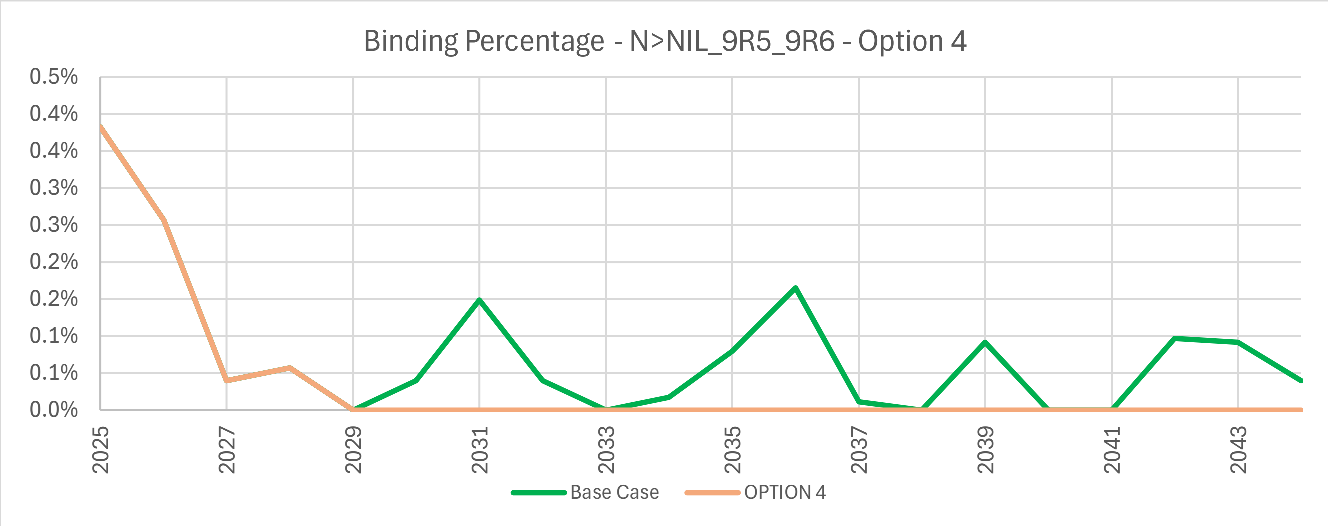
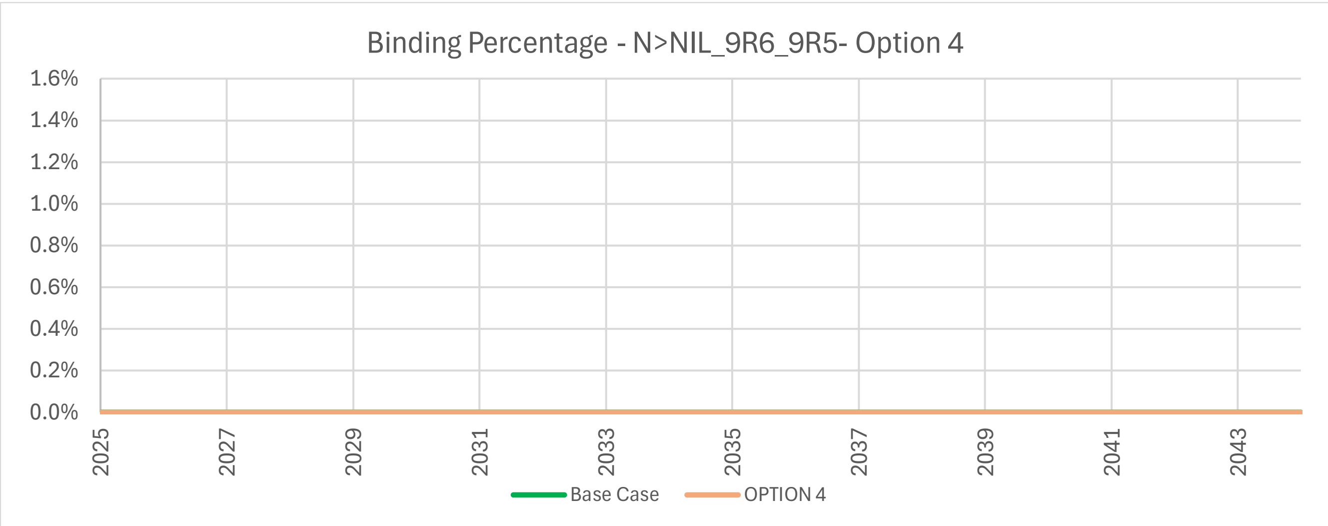


Figure 80: 9R6/9R5 Constraint Binding, Base Case vs. Option 4 – Green Energy Exports



4.8. Option 5

Following the submission to PSCR from one BESS project proposed in Wagga North region, we have included an additional network option which involves the development of a 120 MW / 480 MWh BESS in the Wagga North area.

The busbar upgrade included in Options 1–4 is not included in Option 5. The busbar upgrade is driven by increased line flows arising from higher line ratings under other network options. The BESS option does not increase flows to the Wagga 132 kV busbar because surplus generation in the Wagga North area will be used to charge the BESS. Therefore, the technically the busbar upgrade is not considered necessary for this BESS option.

For the purposes of this assessment, we have assumed that the BESS will be developed or commissioned by Transgrid.

The following section provides a more detailed breakdown of the market modelling outcomes and presents the total gross benefits for the option.

4.8.1. Step Change Scenario

Under the Step Change scenario, the cumulative gross market benefits for Option 5 are illustrated in Figure 81. The differences in installed capacity and generation across the NEM between option 5 and the base case under step change is shown in Figure 82 and Figure 83 respectively. Positive values indicate increased capacity or generation under Option 5, while negative values reflect reductions.

Key drivers of benefits and costs for option 5 under this scenario include:

- The development of a BESS in Wagga North is forecast to have the highest gross benefits among all options. This is because the BESS is dispatched as an additional generator in the NEM which results in a significant increase in avoided capacity, especially wind, which contributes to elevated savings in CAPEX.
- The generation outlook shows a reduction in gas units dispatched, mainly in FY28, which contributes to a small benefit in fuel costs.
- When dispatched, the BESS typically discharges during the evening and charges during the day, sometimes helping to relieve congestion in the Wagga North area (Figure 84). However, this is not always the case as the BESS is not reserved solely for network support and will be dispatched economically to minimise system costs.
- As a result, there is some constraint alleviation, but the constraints keep binding even after the BESS is operational (Figure 85 and Figure 86).

Figure 81: Discounted, Cumulative Gross Market Benefits for Option 5 – Step Change Scenario

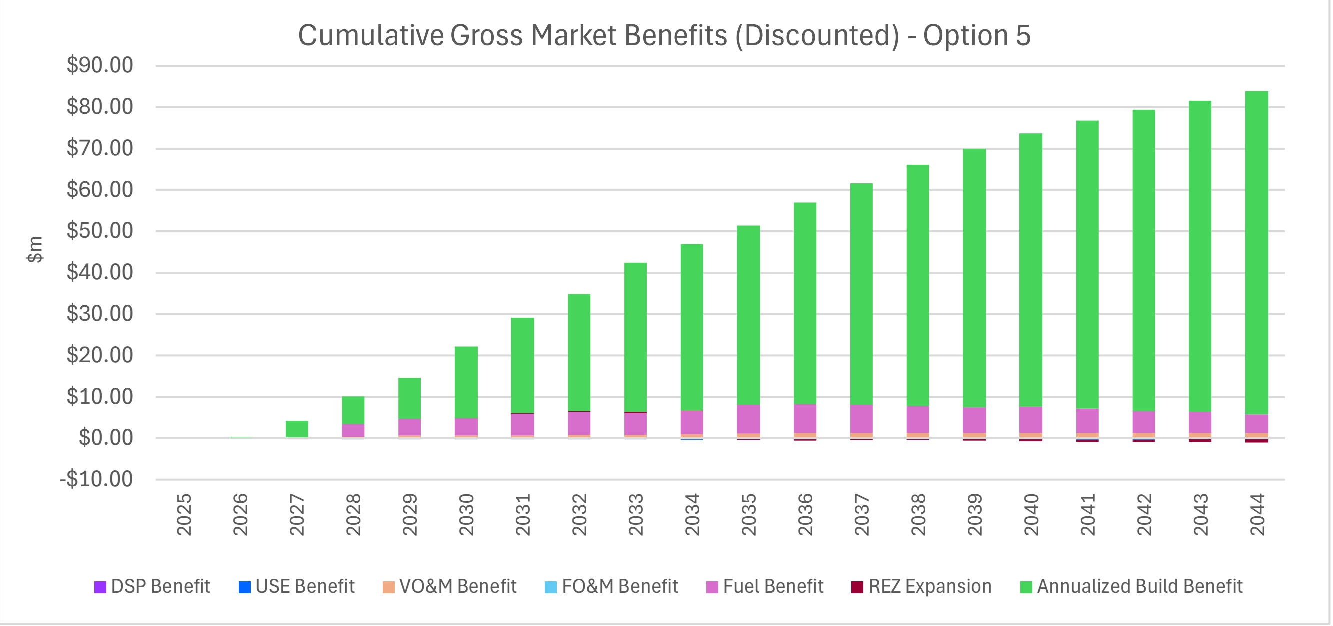


Figure 82: Difference in Installed Capacity (Option 5 - Base Case) – Step Change Scenario

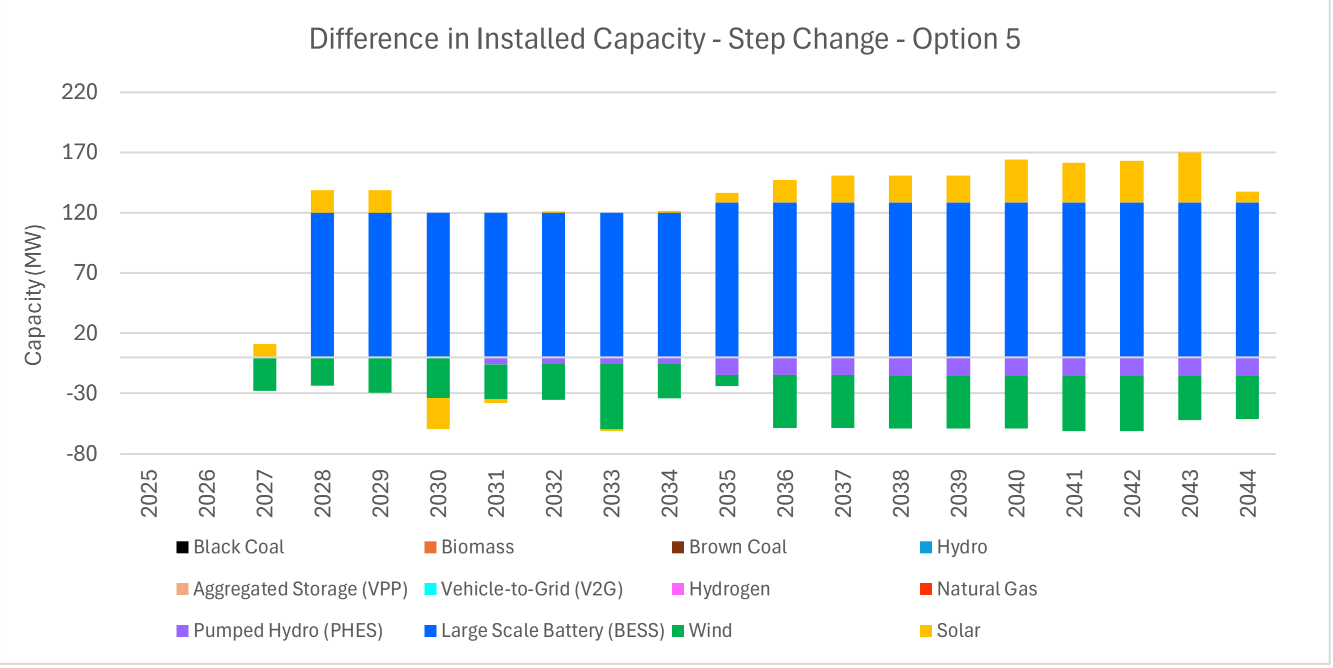


Figure 83: Difference in Generation (Option 5 - Base Case) – Step Change Scenario

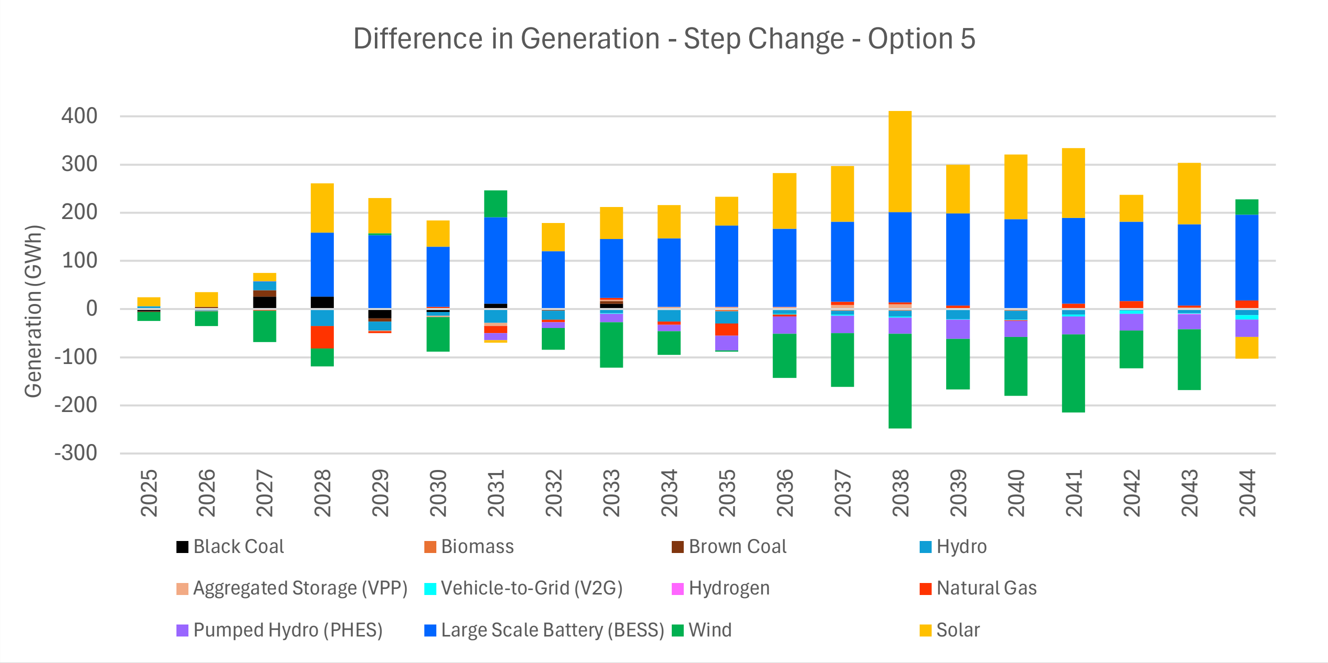


Figure 84: Average BESS Dispatch – Charging and Discharging Times

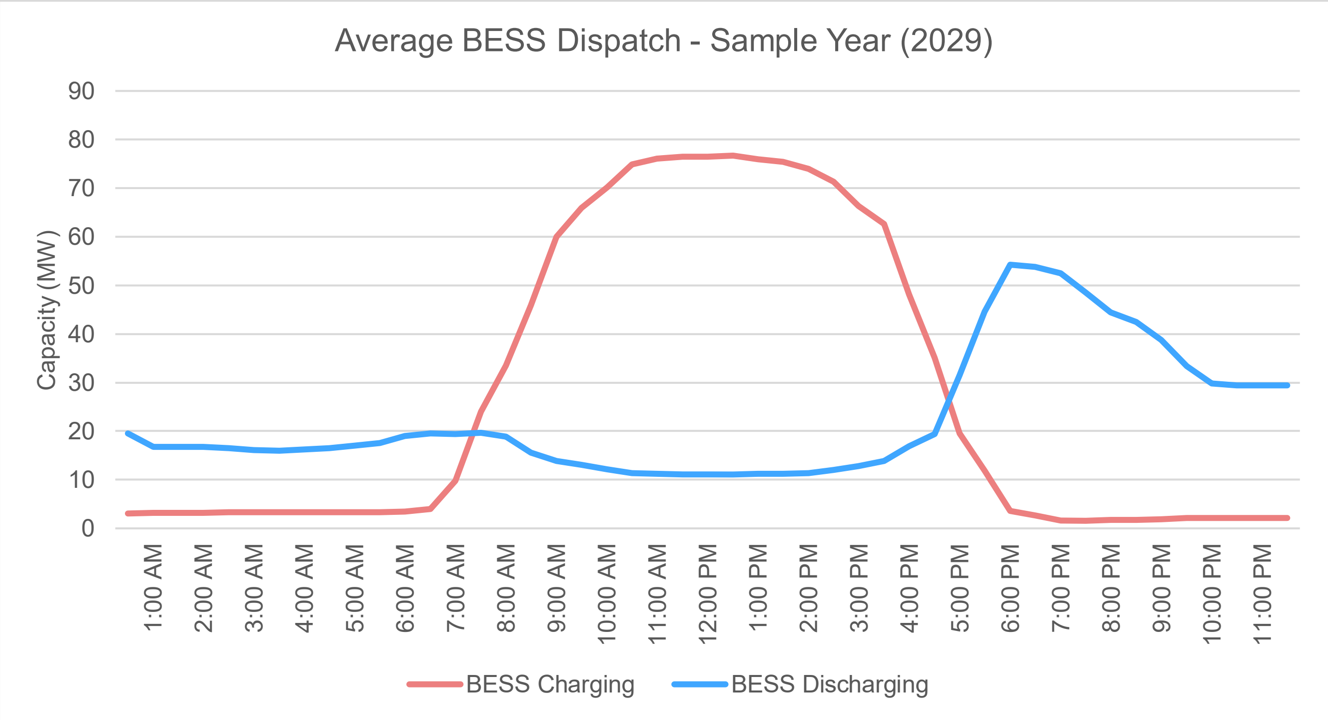


Figure 85: 9R6/991 Constraint Binding, Base Case vs. Option 5 – Step Change

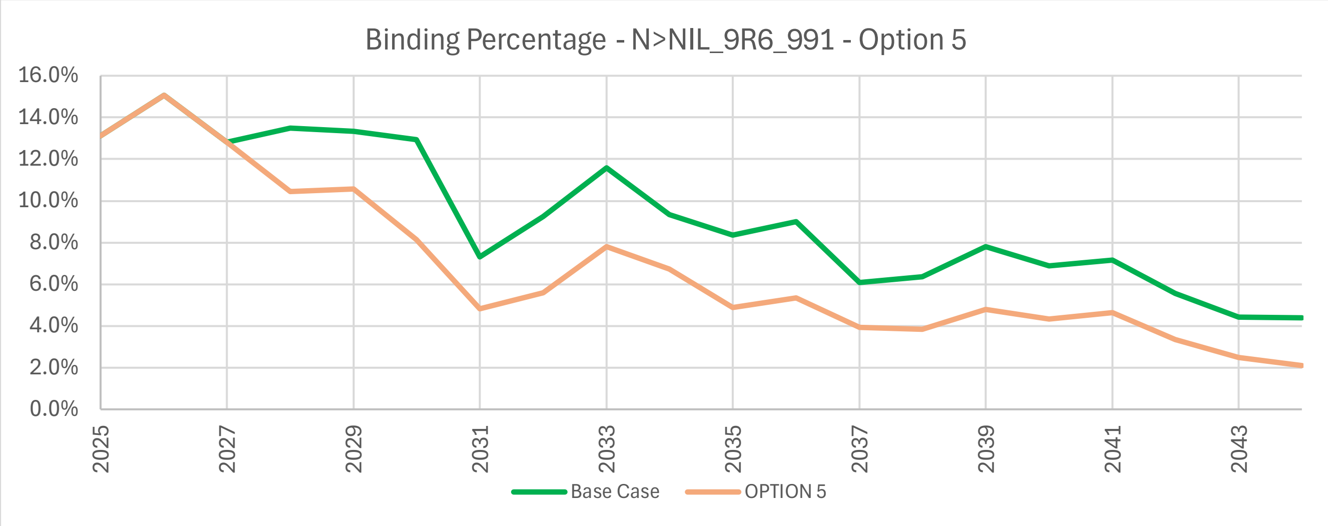


Figure 86: 9R5/9R6 Constraint Binding, Base Case vs. Option 5 – Step Change

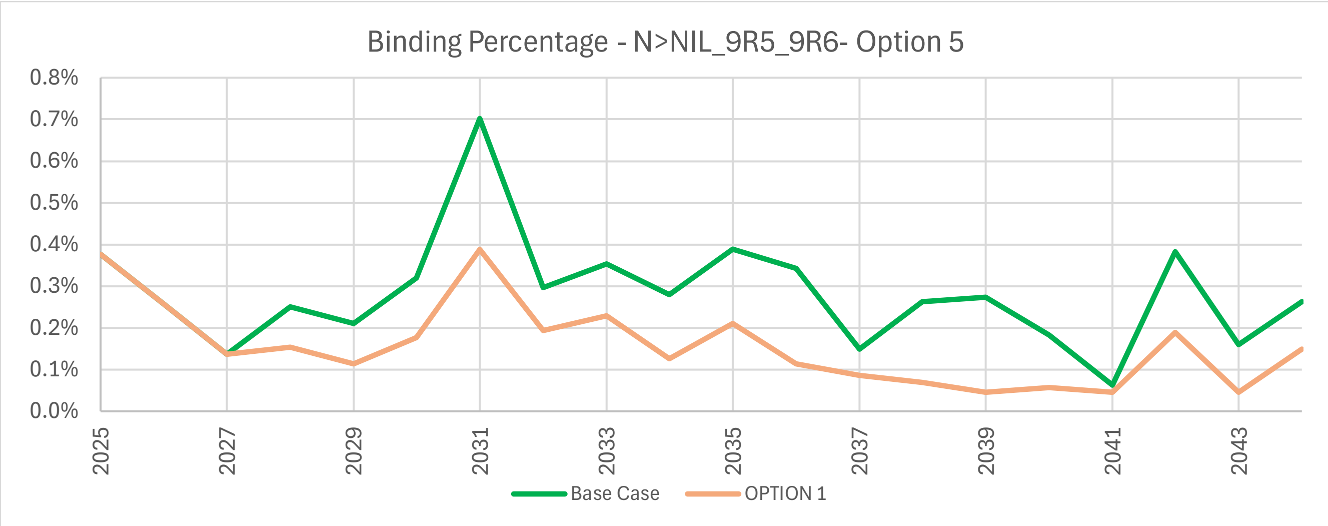
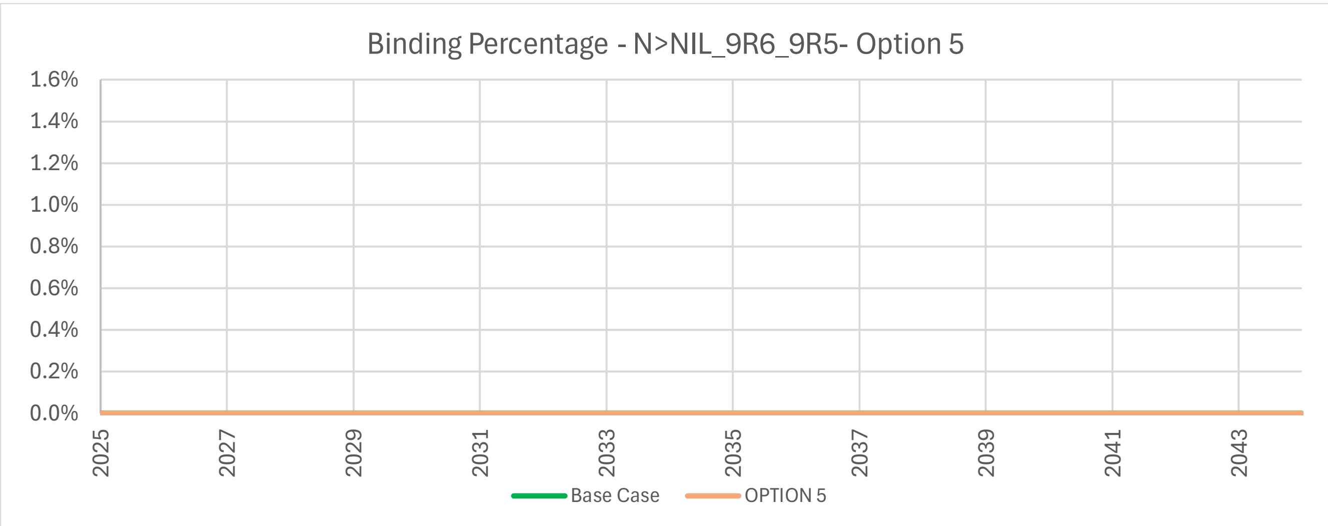


Figure 87: 9R6/9R5 Constraint Binding, Base Case vs. Option 5 – Step Change



4.8.2. Progressive Change Scenario

Under the progressive change scenario, the cumulative gross market benefits for Option 5 are illustrated in Figure 88. The differences in installed capacity and generation across the NEM between option 5 and the base case under progressive change is shown in Figure 89 and Figure 90 respectively.

Consistent with the step change scenario:

- Most of the benefit for this option is derived from avoided wind capacity builds after the BESS is commissioned.
- The constraints are alleviated but not completely mitigated showing that the benefit of implementing the BESS is not homogenously from solving the Wagga North constraints and curtailment will remain even after the BESS is dispatched economically.

Figure 88: Discounted, Cumulative Gross Market Benefits for Option 5 – Progressive Change Scenario

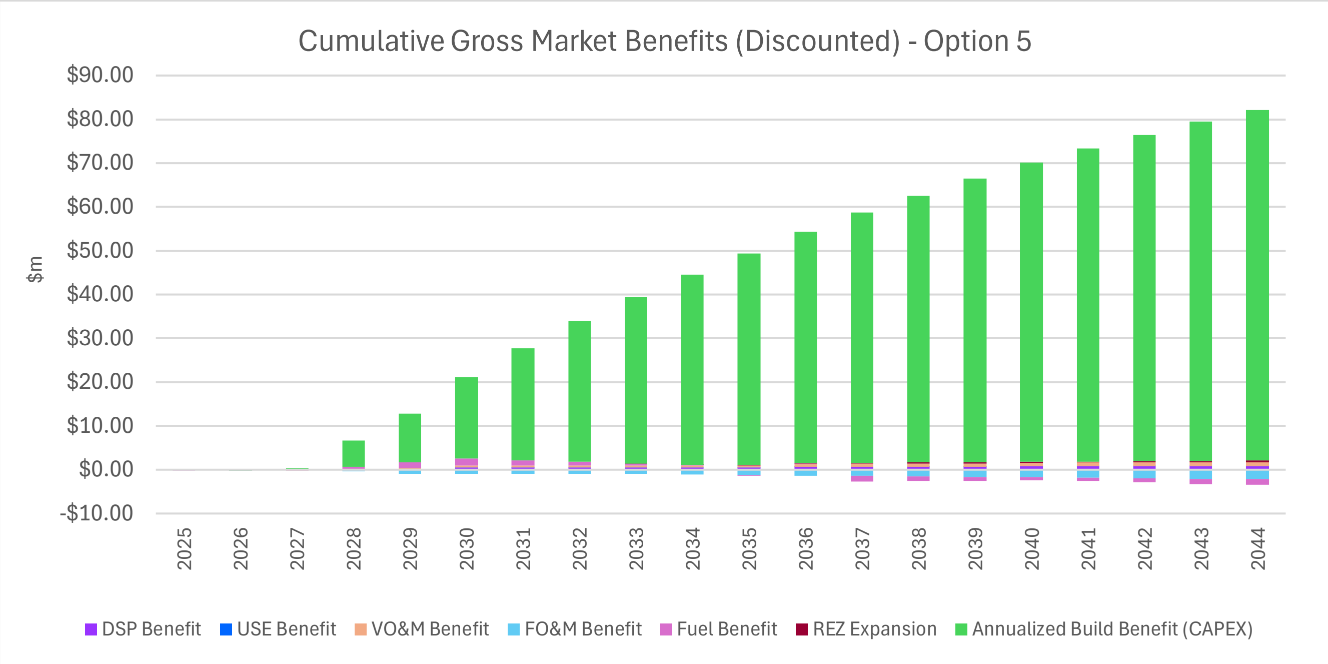


Figure 89: Difference in Installed Capacity (Option 5 - Base Case) – Progressive Change Scenario

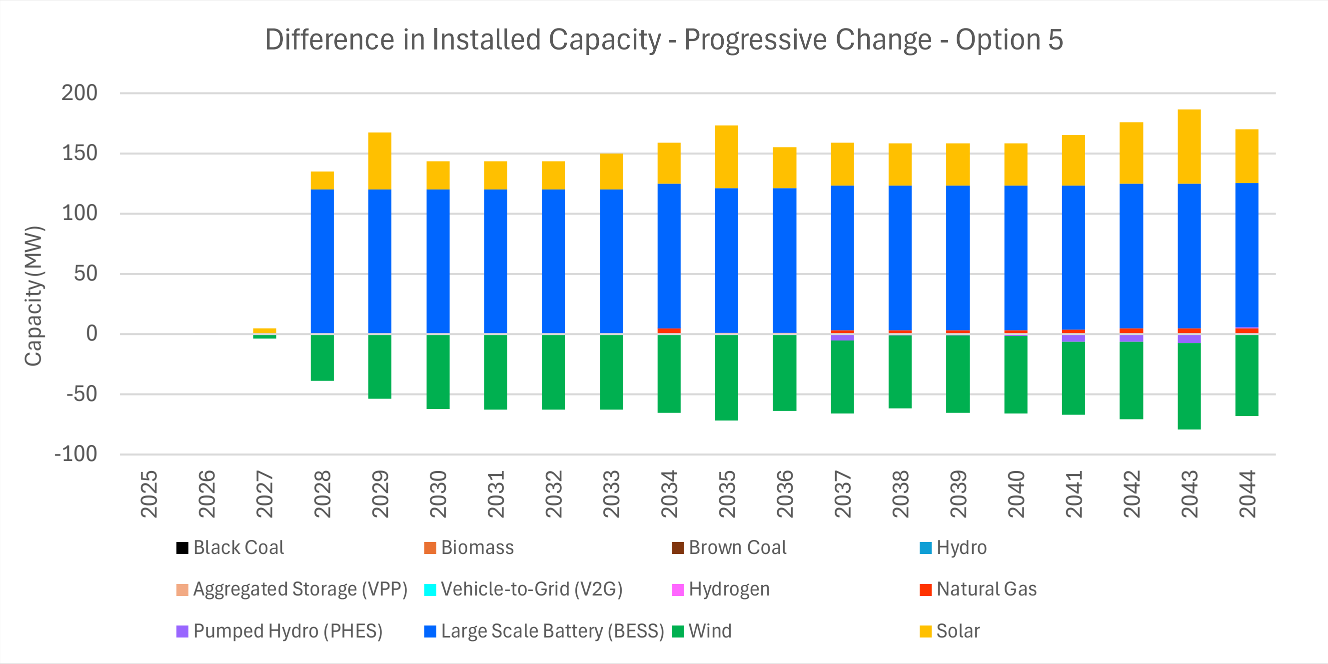


Figure 90: Difference in Generation (Option 5 - Base Case) – Progressive Change Scenario

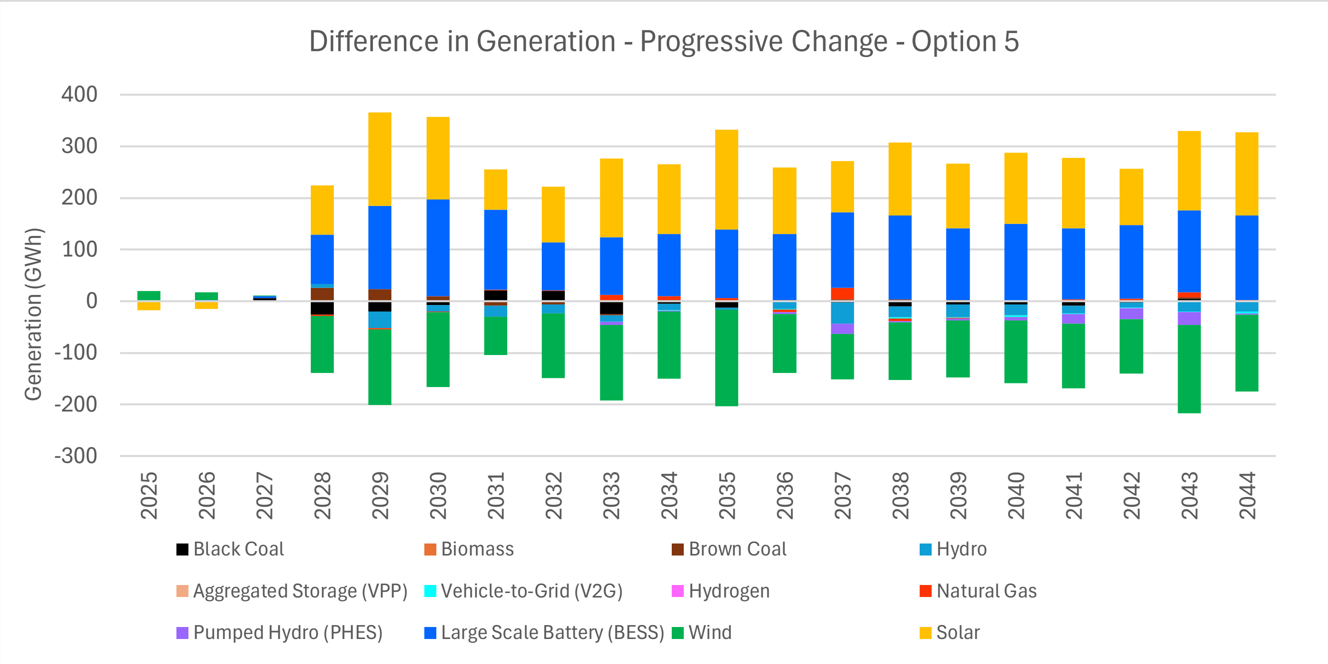


Figure 91: 9R6/991 Constraint Binding, Base Case vs. Option 5 – Progressive Change

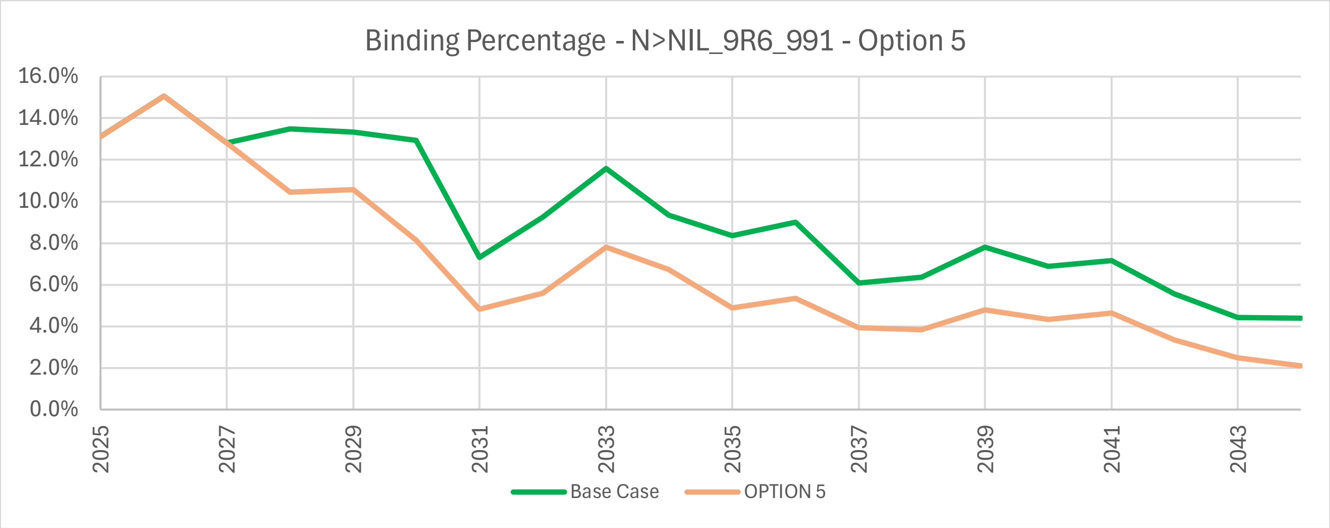


Figure 92: 9R5/9R6 Constraint Binding, Base Case vs. Option 5 – Progressive Change

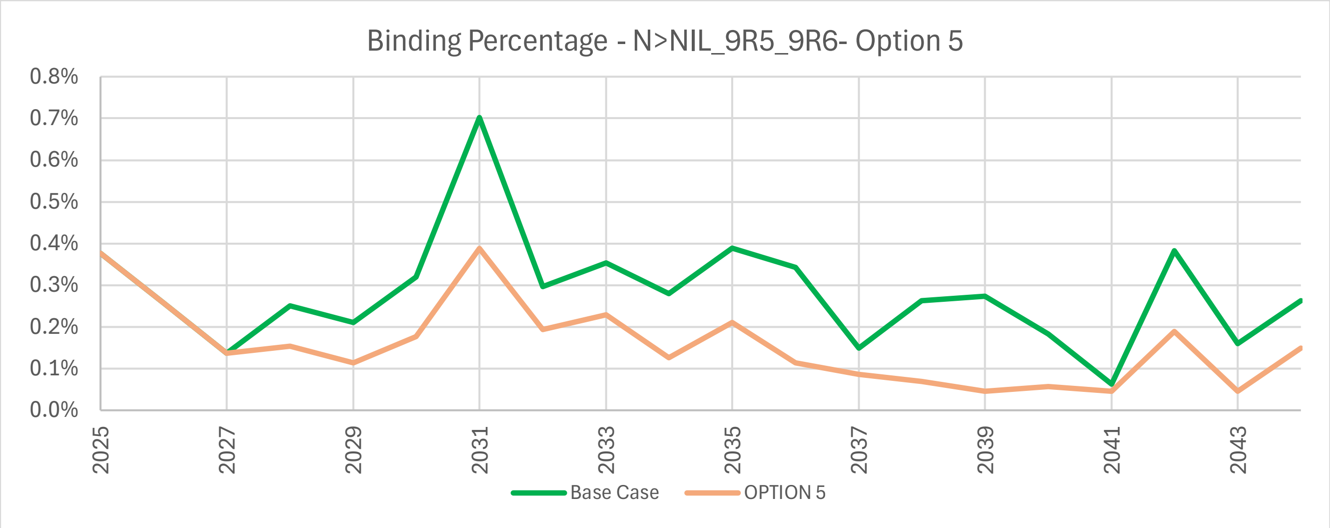
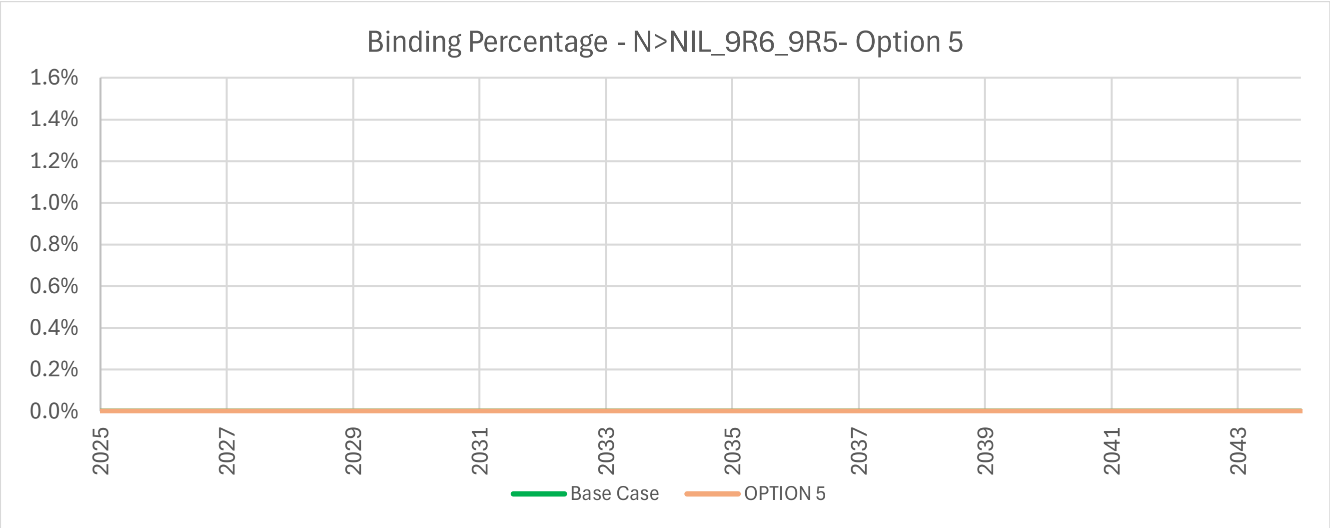


Figure 93: 9R6/9R5 Constraint Binding, Base Case vs. Option 5 – Progressive Change



4.8.3. Green Energy Exports Scenario

Under the Green Energy scenario, the cumulative gross market benefits for Option 4 are illustrated in Figure 94. The differences in installed capacity and generation across the NEM between option 4 and the base case under green energy exports is shown in Figure 95 and Figure 96 respectively.

Key drivers of benefits and costs include:

- Option 5 has the highest gross market benefits under this scenario. Green energy exports has high renewable uptake, so there is more opportunity for capacity deferral when the new BESS is dispatched.
- There is also less dispatch in gas units contributing to an increase in fuel benefits.
- Consistent with other scenarios, constraints are not completely mitigated as the BESS is not reserved for network support.

Figure 94: Discounted, Cumulative Gross Market Benefits for Option 5 – Green Energy Exports

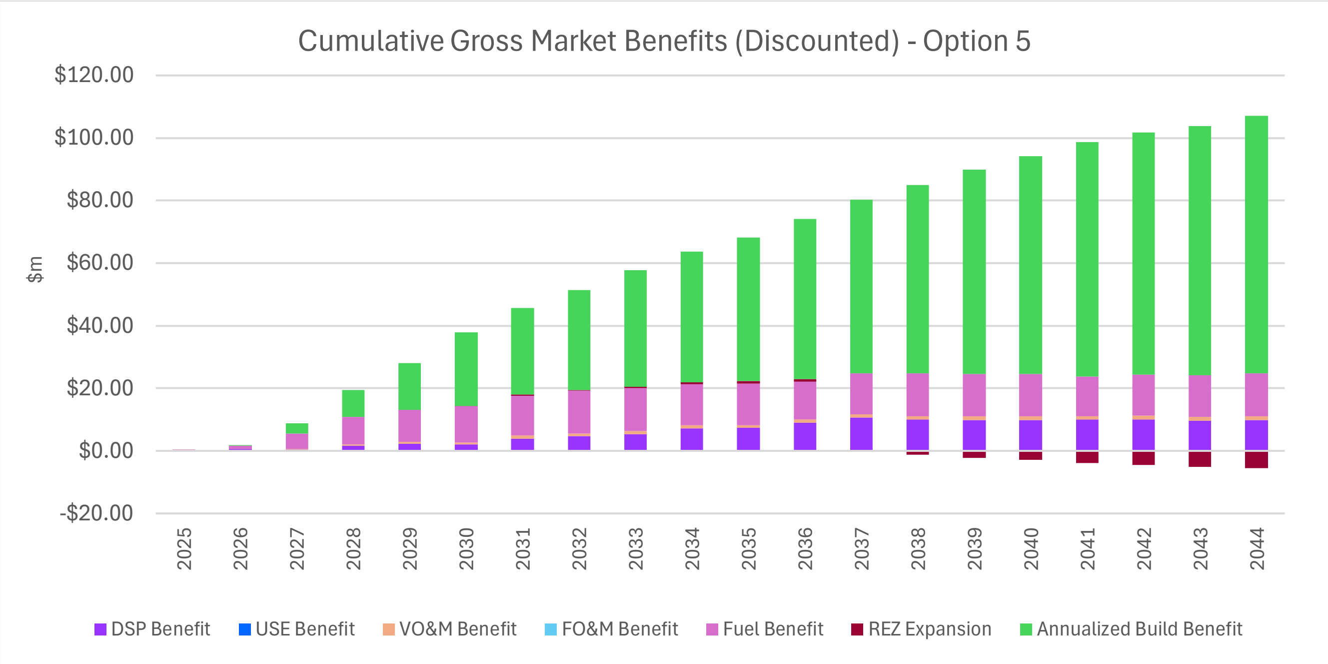


Figure 95: Difference in Installed Capacity (Option 5 - Base Case) – Green Energy Exports

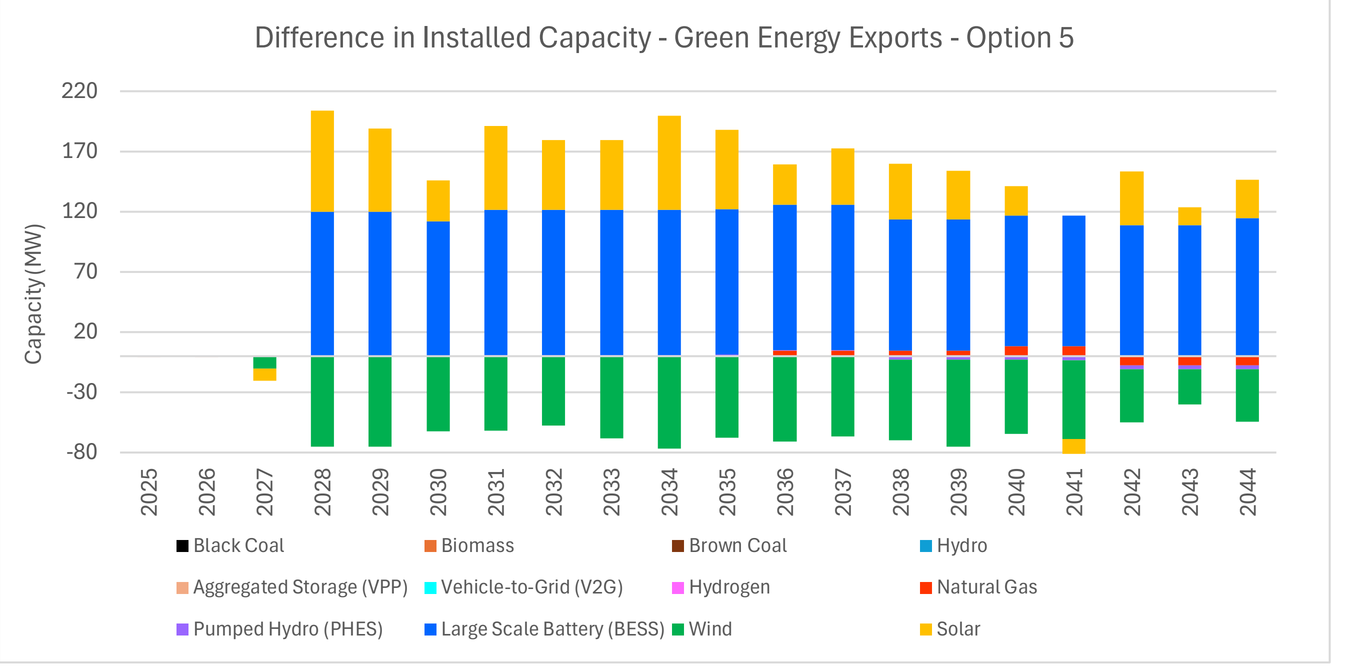


Figure 96: Difference in Generation (Option 5 - Base Case) – Green Energy Exports

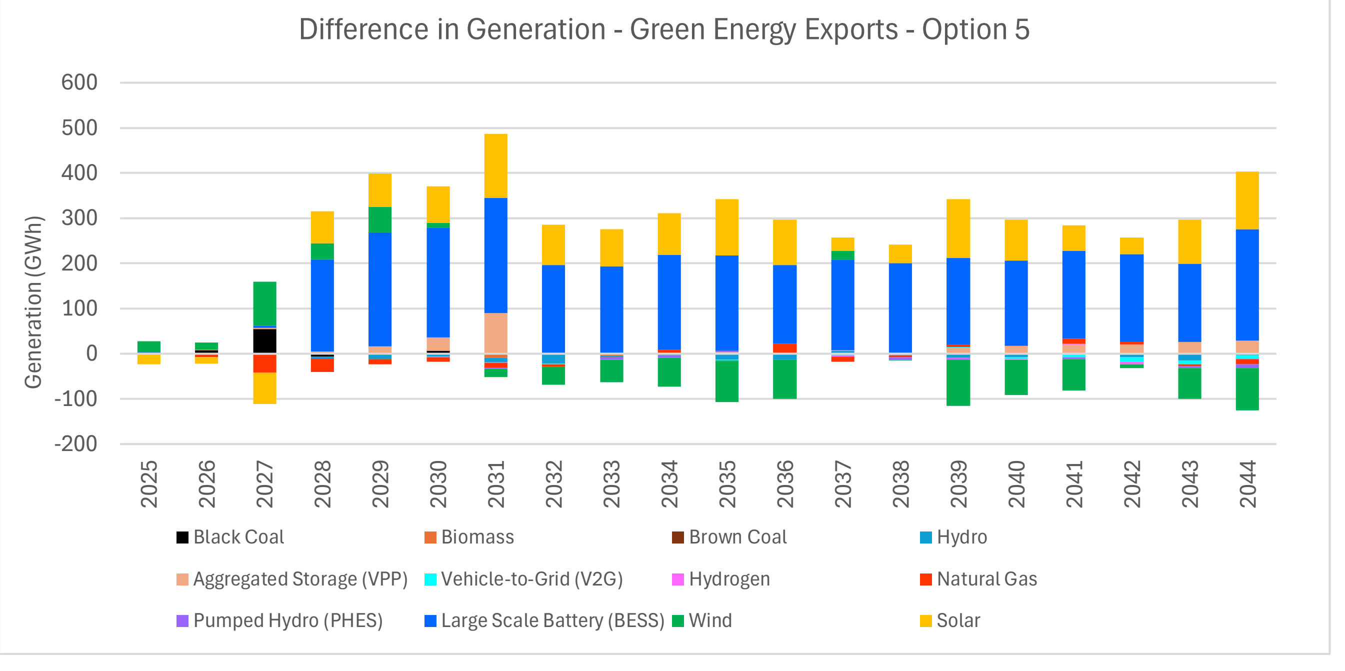


Figure 97: 9R6/991 Constraint Binding, Base Case vs. Option 5 – Green Energy Exports

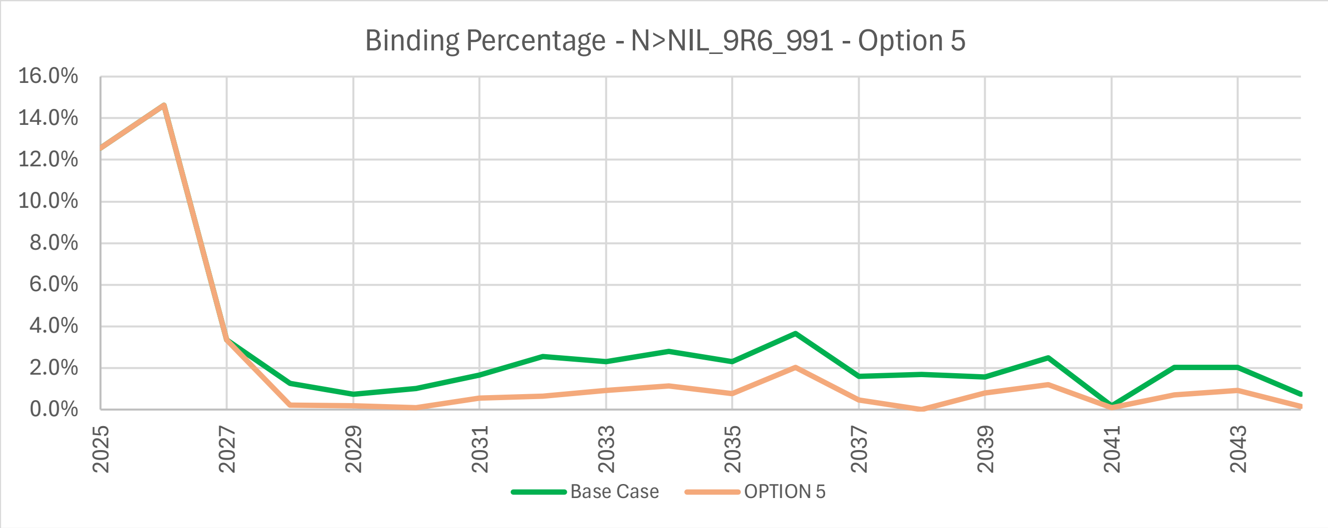


Figure 98: 9R5/9R6 Constraint Binding, Base Case vs. Option 5 – Green Energy Exports

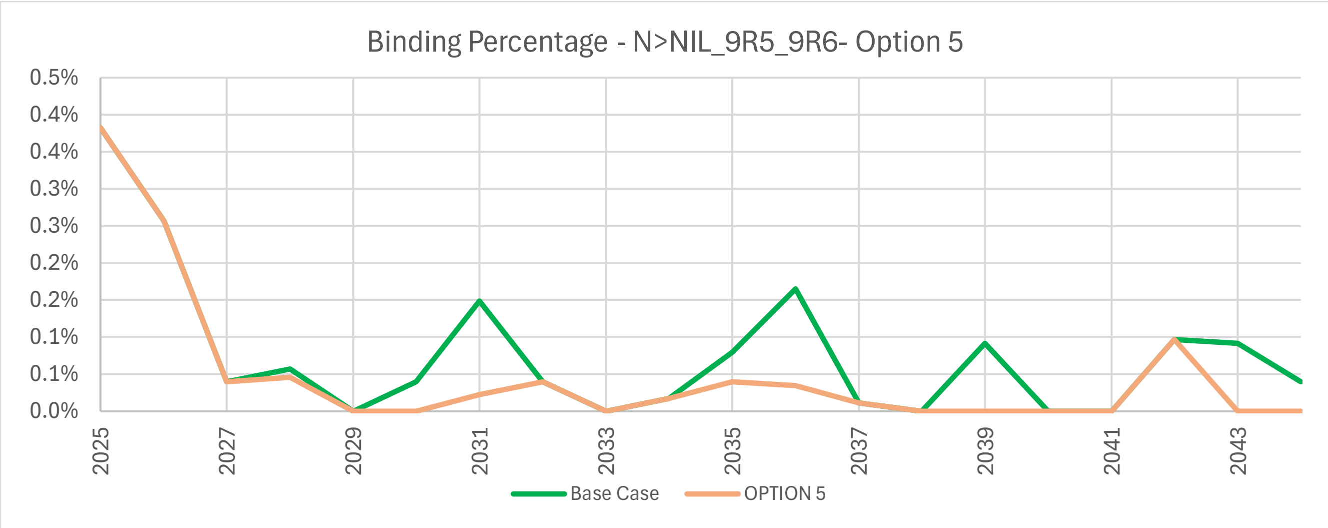
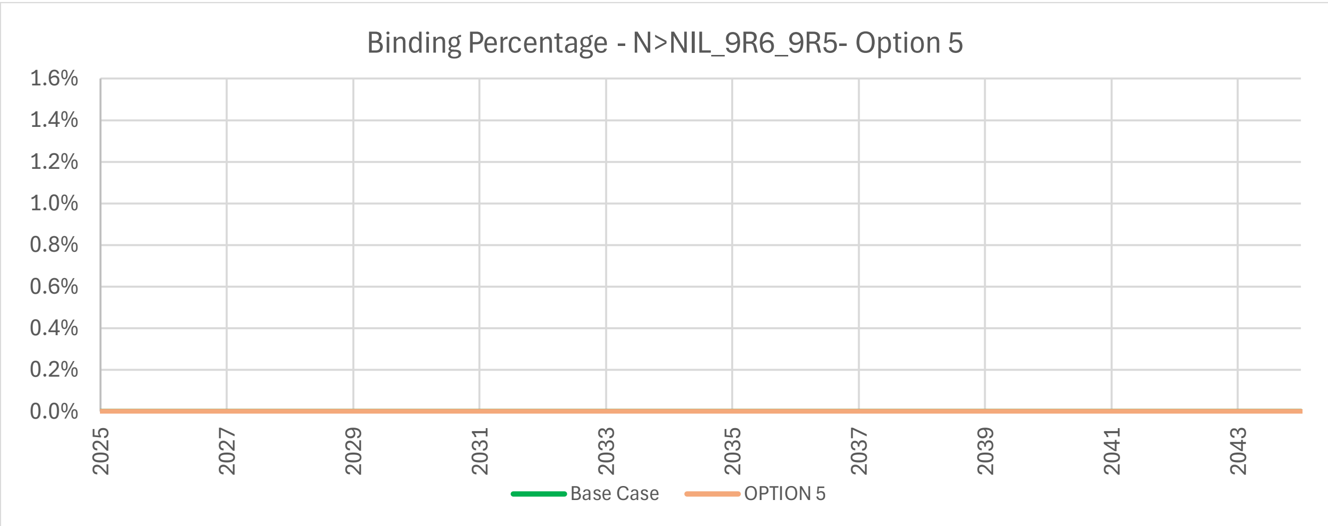


Figure 99: 9R6/9R5 Constraint Binding, Base Case vs. Option 5 – Green Energy Exports



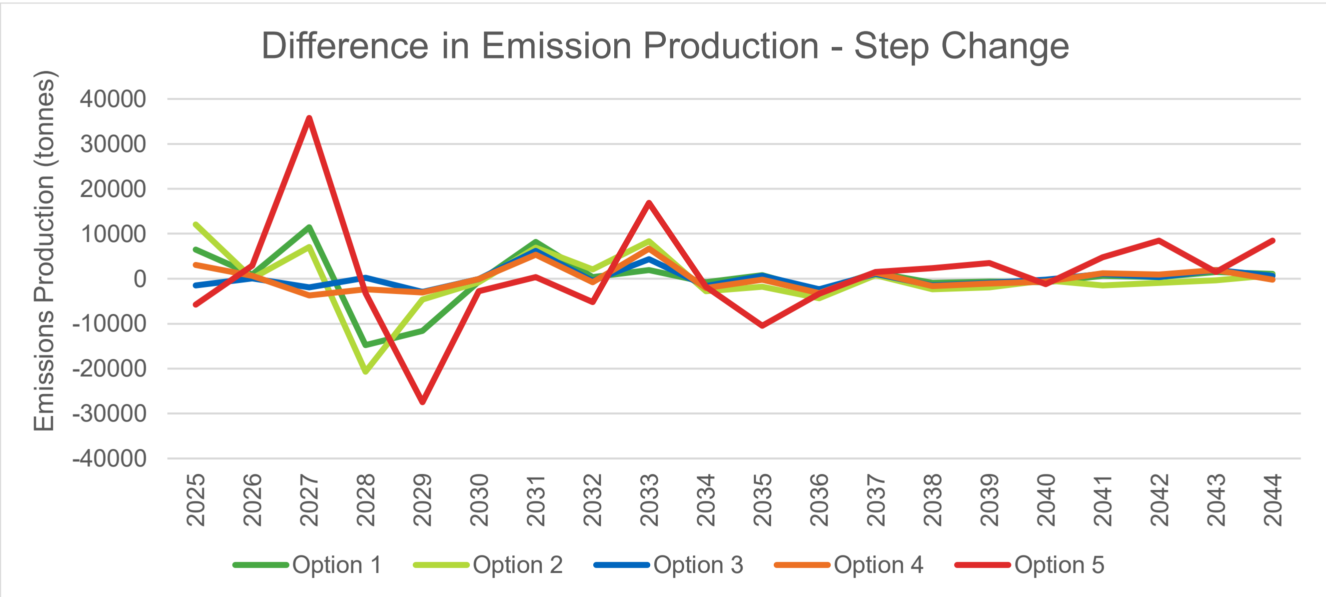
4.9. Changes in Australia's greenhouse gas emissions

On 21 September 2023, the National Energy Laws were amended to reflect the incorporation of emissions reductions within the National Energy Objectives (NEO). Prior to the commencement of the amended Act, the NEO referred to the long-term interests of energy consumers with respect to price, quality, safety, reliability and security of supply of energy. The emissions reduction objective introduced by the Act adds reference to the long-term interests of energy consumers with respect to the achievement of targets set by a participating jurisdiction for reducing Australia's greenhouse gas emissions, or that are likely to contribute to reducing Australia's greenhouse gas emissions.

Following this, the AEMC made harmonising changes to the National Electricity Rules, prompted by a rule change request from energy ministers, to ensure that network investment and planning frameworks are consistent with the new emissions reduction objective. The AEMC's Final Determination, published on 1 February 2024, included introducing a 'changes in Australia's greenhouse gas emissions' as a new class of market benefit to be considered within the RIT-T process[8].

The AER has updated the RIT application guidelines to provide guidance on how valuing emissions reduction is implemented. The AER has also published an interim value of greenhouse gas emissions reduction (VER) which will apply to 30 June 2026 or until it is suspected, whichever is earlier. Figure 100, Figure 101 and Figure 102 show the difference in emissions produced for each option compared to the base case for the three scenarios. The value of emissions will be quantified in the Project Assessment Draft Report (PADR).

Figure 100: Difference in Emission Production - Step Change



[8] https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024

Figure 101: Difference in Emission Production - Progressive Change

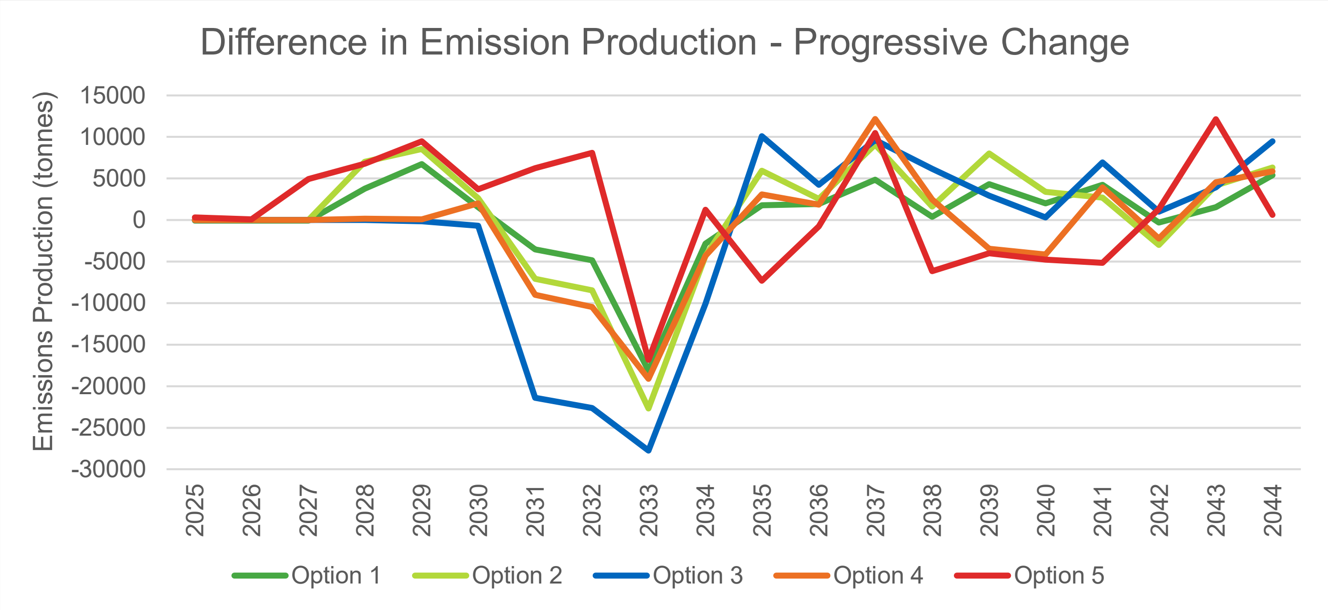


Figure 102: Difference in Emission Production - Green Energy Exports