Marinus Link gross market benefit update

Marinus Link Pty Ltd

10 July 2025

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Ernst & Young
111 Eagle Street
Brisbane QLD 4000 Australia
GPO Box 7878 Brisbane QLD 4001

Tel: +61 7 3011 3333
Fax:+61 7 3011 3100
ey.com/au

Release Notice

Ernst & Young ("EY") was engaged on the instructions of Marinus Link Pty Ltd ("**Client**") to undertake market modelling of system costs and benefits to forecast the gross market benefit of the proposed Marinus Link interconnector (the "**Project**"), in accordance with the service order dated 12 May 2025.

The results of EY's work, including the assumptions and qualifications made in preparing the report, are set out in EY's report dated 10 July 2025 ("**Report**"). The Report should be read in its entirety including this release notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report.

EY has prepared the Report for the benefit of the Client and has considered only the interest of the Client. EY has not been engaged to act, and has not acted, as advisor to any other party. Accordingly, EY makes no representations as to the appropriateness, accuracy or completeness of the Report for any other party's purposes.

Our work commenced on 5 May 2025 and was completed on 24 June 2025. No further work has been undertaken by EY since the date of the Report to update it. Therefore, our Report does not take account of events or circumstances arising after 24 June 2025 and we have no responsibility to update the Report for such events or circumstances arising after that date.

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Modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual outcomes, because events and circumstances frequently do not occur as expected, and those differences may be material. EY takes no responsibility that the projected outcomes will be achieved. EY highlights that the analysis included in this Report does not constitute investment advice or a recommendation to you on a future course of action. EY provides no assurance that the scenarios that have been modelled will be accepted by any relevant authority or third party.

The analysis and Report do not constitute a recommendation on a future course of action.

Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenarios, and the key assumptions are described in the Report. These assumptions were selected by the Client. The modelled scenarios represent six possible future options for the development and operation of the National Electricity Market, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

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Table of contents

1. Executive summary

Following the conclusion of the Project Marinus Regulatory Investment Test for Transmission (RIT-T)[1] by TasNetworks in June 2021 and the EY report on gross market benefit assessment of Marinus Link in March 2024[2], the electricity sector in Australia has continued to experience a period of change in policy settings and project cost outlooks. Due to the extent of these changes, Marinus Link Pty Ltd (MLPL), engaged EY to undertake further market modelling of system costs to forecast the gross market benefits to the National Electricity Market (NEM) of an additional interconnector between Tasmania and Victoria. The proposed second interconnector would comprise a high-voltage direct current (HVDC) link between Tasmania and Victoria, known as Marinus Link, plus augmentation to the alternating current (AC) transmission networks to ensure the full capacity of Marinus Link can be supported by each regions' transmission network.

This Report describes the key modelling outcomes and insights as well as the assumptions and input data sources and the modelling methods used. Our work was limited to an evaluation of potential gross market benefits based on inputs and assumptions underlying each scenario selected by MLPL in accordance with the Cost Benefit Analysis (CBA) guidelines. These forecast outcomes must be compared to the cost of Marinus Link to determine the forecast net economic benefit. That evaluation is not part of the scope of this Report. The net economic benefit assessment is performed by MLPL outside of this Report using the forecast gross market benefits from this Report and other inputs and has been prepared and published by MLPL[3].

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the NEM for two scenarios in the Australian Energy Market Operator's (AEMO) Draft 2025 Input, Assumptions and Scenarios Report (IASR)[4], being: the Step Change and Progressive Change scenarios. The modelling for each of two scenarios combined the following input assumptions:

- The Draft 2025 IASR[4] assumptions relating to policies, costs and generator technical parameters.
- AEMO's August 2024 Electricity Statement of Opportunities (ESOO)[5,6] demand projections, excluding hydrogen demand.
- The Draft 2025 IASR[4] hydrogen demand projections.

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[1] TasNetworks, June 2021, *Project Marinus RIT-T Project Assessment Conclusions Report (PACR)*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2021/06/Project-Marinus-RIT-T-PACR.pdf. Accessed 27 June 2025

[2] EY, 28 March 2024, *Gross market benefit assessment of Marinus Link*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2024/04/EY-report-Project-Marinus-Gross-Benefits-28-March-2024.pdf. Accessed 27 June 2025

[3] Marinus Link Pty Ltd, 11 July 2025, *Summary RIT-T update report July 2025*. Available at: https://marinuslink.com.au/wp-content/uploads/2025/07/Summary-RIT-T-update-report-July-2025.pdf. Accessed 3 July 2025

[4] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. Available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

[5] AEMO, *National Electricity and Gas Forecasting*. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal. Accessed 25 June 2025

[6] At the time of modelling this was the most up to date source of demand data.

- The assumed timing for major transmission upgrades based on AEMO's outcomes from the 2024 Integrated System Plan (ISP)[7] or proponent earliest in-service date as per the Transmission Augmentation Information December 2024[8] where these dates were later.

The IASR scenarios adhere to the following philosophies, which were developed by AEMO in consultation with stakeholders[4]:

- Step Change: Decarbonisation efforts that support Australia's share in limiting global temperature rise to below 2˚C compared to pre-industrial levels. This scenario uses significant transport electrification, as well as developing hydrogen production or low emissions alternatives to support domestic industrial loads. This is a refinement of the 2024 AEMO ISP Step Change scenario.
- Progressive Change: Aims to meet Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. However, this scenario is hindered by a reduction in industrial loads, higher technology costs and supply chain challenges. Assumed Tasmanian load is lowest in this scenario. Again, this is a refinement of the 2024 AEMO ISP Progressive Change scenario.

Common policy settings across both scenarios include the Federal Government's 82% renewables target by 2030, New South Wales (NSW) Electricity Infrastructure Roadmap target, Queensland Renewable Energy Target (QRET), Tasmanian Renewable Energy Target (TRET), Victorian Renewable Energy Target (VRET), Victorian Energy Storage Target and the Victorian Offshore Wind Target.[9]

The modelling methodology follows the *CBA guidelines* published by the Australian Energy Regulator (AER)[10], which contain the applicable RIT-T guidelines for Actionable ISP projects including Marinus Link. The model was used to compute a plan without Marinus Link, with Marinus Link stage 1 only (commissioned in 2030) and with both Marinus Link stage 1 and stage 2 (commissioned in 2030 and 2034 respectively) across both scenarios.

To assess the least-cost solution with and without Marinus Link, EY's Time Sequential Integrated Resource Planner (TSIRP) model is used. It makes decisions for each hourly dispatch interval in relation to:

- The generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to be dispatched at their short run marginal cost (SRMC), which is derived from their variable operation and maintenance (VOM) and fuel costs. The generation for each dispatch interval is subject to the modelled availability of power stations in each hour (those that are not on planned or un-planned outages), network limitations and energy limits (e.g., storage levels).
- Commissioning new entrant capacity for wind, solar PV SAT, CCGT, OCGT, large-scale battery and PHES[11].

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[7] AEMO, 26 June 2024, *2024 Integrated System Plan*. Available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 25 June 2025

[8] AEMO, 13 December, *NEM Transmission Augmentation information December 2024.* Available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information. Accessed 25 June 2025

[9] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. Available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

[10] Australian Energy Regulator, 21 November 2024, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/industry/registers/resources/guidelines/cost-benefit-analysis-guidelines. Accessed 1 July 2025

[11] PV=photovoltaics, SAT = Single Axis Tracking, CCGT = Combined-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine, PHES = Pumped Hydro Energy Storage

- The withdrawal/retirement of existing generation on a least-cost basis, often to meet the emissions budgets assumed in the modelled scenario.

The hourly decisions consider certain assumed operational constraints, including:

- Supply must equal demand in each region for all dispatch intervals plus a reserve margin, with unserved energy (USE) costed at the value of customer reliability (VCR).
- Minimum loads for coal generators.
- Interconnector flow limits (between regions).
- Maximum and minimum storage (conventional storage hydro, PHES, virtual power plant (VPP) and large-scale battery) reservoir limits and cyclic efficiency.
- New entrant capacity build limits for wind and solar for each Renewable Energy Zone (REZ) where applicable, and PHES in each region.
- Carbon budget constraints for the modelled scenarios.
- Renewable energy targets where applicable by region or NEM-wide.
- Other constraints such as Tasmanian inertia constraints, as defined in the Report.

From the hourly time-sequential modelling the following costs were computed, as defined in the AER's CBA guidelines[12]:

- Capex costs of new generation and storage capacity installed.
- Total fixed operation and maintenance (FOM) costs of all generation and storage capacity.
- Total VOM costs of all generation and storage capacity.
- Total fuel costs of all generation capacity.
- Total cost of voluntary demand-side participation (DSP) and involuntary USE.
- Transmission expansion costs associated with REZ development.
- Retirement/rehabilitation costs to cover decommissioning, demolition and site rehabilitation.
- Synchronous condenser costs to meet Tasmanian inertia requirements.
- Emissions as a byproduct of thermal generation valued according to AER's Valuing emissions reduction documentation, calculated as a post-process to the optimisation.

The forecast gross market benefits capture the impact of transmission losses to the extent that losses across interconnectors affect the generation that needs to be dispatched in each dispatch interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including PHES and large-scale batteries.

For each simulation, we computed the sum of these cost components and compared the difference between the Marinus Link case and the without Marinus Link Base Case across the 25-year period (the Modelling Period), from 2026-27 to 2050-51. The difference in the calculated present value of costs is the forecast gross market benefits[13] associated with Marinus Link proceeding. The gross market benefits are discounted to 1 July 2025 using a 7% real, pre-tax discount rate, consistent with the central value applied by AEMO in the Draft 2025 IASR[14] as selected by MLPL. A summary of the

[12] Australian Energy Regulator, 21 November 2024, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/industry/registers/resources/guidelines/cost-benefit-analysis-guidelines. Accessed 1 July 2025

[13] In this Report, we use the term *gross market benefit* to mean "market benefits" as defined in the AER's *Cost benefit analysis guidelines*, and "net economic benefits" in the same manner defined in the guidelines.

[14] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

gross market benefits of Marinus Link in the Step Change and Progressive Change scenarios over the Modelling Period in shown in Table 1.

Table 1: Overview of scenarios with associated forecast gross market benefits of Marinus Link over the Modelling Period discounted to 1 July 2025. All dollar values are presented in $million, real June 2024

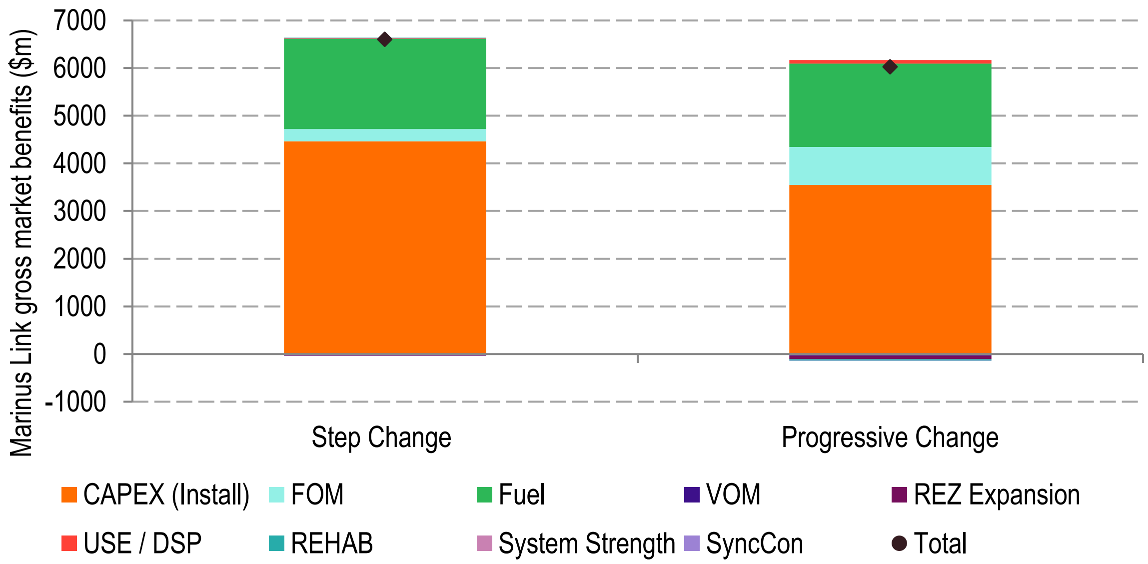
Marinus Link size	Marinus Link timing	Step Change	Progressive Change
1,500 MW	2030 & 2034	6,601	6,026
750 MW	2030	5,591	5,002

Figure 1 shows in the two largest sources of forecast benefits are consistent with the forecast benefits from the March 2024 Marinus Link modelling[15], being:

- The largest driver is capex saving across the NEM associated with the deferral or avoidance of investment in new generation and storage.
- The second largest driver is mainland fuel cost savings associated with reduced coal and gas generation.

This is also consistent with the two largest sources of forecast benefits from the Project Assessment Conclusions report (PACR) for the Marinus Link RIT-T by TasNetworks[16]. Comparison of values between the two reports should be made with caution given they are in different dollars, discounted to different dates and over different modelling periods.

Figure 1:Composition of forecast total gross market benefits of Marinus Link stage 1, in 2030 and stage 2, in 2034 over the modelling Period discounted to July 2025. All dollar values are presented in $million, real June 2024



The forecast capex savings associated with Marinus Link are predominantly driven by the combination of high capacity factor wind resource in Tasmania, coupled with the legislated TRET. By better connecting Tasmania with the mainland Marinus Link is forecast to unlock the potential for

[15] EY, 28 March 2024, *Gross market benefit assessment of Marinus Link*, https://www.marinuslink.com.au/wp-content/uploads/2024/04/EY-report-Project-Marinus-Gross-Benefits-28-March-2024.pdf. Accessed 27 June 2025

[16] TasNetworks, 24 June 2021, *Project Marinus RIT-T Project Assessment Conclusions Report (PACR)*. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 27 June 2025

high quality Tasmanian wind, new entry pumped hydro and existing conventional Tasmanian hydroelectric power stations to offset the need for higher cost mainland renewable capacity and thermal generation as the NEM transitions from existing thermal generation to a higher proportion of renewables.

Marinus Link is forecast to result in fuel cost savings on the mainland by enabling better access to existing Tasmanian hydroelectric generators and wind resource, as a lower cost alternative to the construction and operation of dispatchable gas on the mainland. The extent of these savings varies by scenario.

The Step Change scenario is forecast to have higher benefits for Marinus Link than the Progressive Change scenario. While previously in the March 2024 Marinus Link modelling, Progressive Change was forecast to have higher benefits than Step Change scenario, the relativity of demand between the two scenarios has changed in the Draft 2025 IASR assumptions. In the current Report, the downward impact of the assumed decrease in mainland demand in Step Change is counterbalanced by an assumed decrease in Tasmanian demand. Meanwhile, Tasmanian demand in Progressive Change has not changed significantly, and mainland demand is overall lower.

In the without Marinus Link cases, much of the new renewable generation that is forecast to be installed in Tasmania to achieve the TRET is spilled. With lower Tasmanian demand in Step Change compared to March 2024 modelling assumptions, the volume of spilled renewable generation is higher without Marinus Link, leading to larger savings with Marinus Link. In Progressive Change, Tasmanian demand remains similar to Step Change. However, mainland demand has decreased in Progressive Change, leading to reduced savings as there is less mainland generation to be displaced.

While the Green Energy Industries scenario has not been modelled, the key inputs and assumptions are such that the forecast gross market benefits would likely be greater for Marinus Link than the benefits modelled in the Step Change and Progressive Change scenarios. These include higher overall demand, a high proportion of renewables required to meet this demand, and a more restrictive carbon budget.

Forecast emissions benefits are a byproduct of avoided thermal generation, when Tasmanian capacity is unlocked with Marinus Link. Due to Marinus Link, energy that would have otherwise been spilled can be exported to meet mainland demand, avoiding thermal generation and capacity which leads to emissions savings. Emissions savings are valued according to AER's *Valuing emissions reduction* documentation[17], calculated as a post-process to the optimisation. Emissions benefits are a separate category of market benefits that was previously not assessed in the March 2024 Marinus Link modelling and varies between the scenarios due to differences in carbon budget and demand.

Table 2 shows the gross benefits with associated emissions savings for Marinus Link over the 25-year modelling period from 2026-27 to 2050-51 for the Step Change and Progressive Change scenarios.

Table 2: Overview of scenarios with associated emissions benefits for Marinus link over the Modelling Period discounted to 1 July 2025. All dollars are presented in $million, real June 2024

Marinus Link size	Marinus Link timing	Step Change	Progressive Change
1,500 MW	2030 & 2034	104	3,835
750 MW	2030	71	2,566

[17] AER, May 2024, *Valuing emissions reduction AER guidance and explanatory statement*. Available at: https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf. Accessed 24 June 2025

The Progressive Change scenario is forecast to have much higher emissions benefits compared to Step Change. This is facilitated by a more relaxed carbon budget which does not bind the Progressive Change scenario. Increased headroom for emissions allows greater coal generation and later coal retirements than in the Step Change scenario, aligning more closely with announced retirements by 2040 as seen in Figure 2. In the Progressive Change scenario, the higher levels of emissions-intensive generation in the Base Case, particularly brown coal, is partially avoided with Marinus Link, leading to significant emissions benefits. Moreover, Victorian brown coal generation is more directly impacted by Tasmanian generation from Marinus Link. In contrast, in the Step Change scenario, all brown coal is retired in the Base Case which prevents the opportunity to avoid its emissions intensive generation. Thermal generation displaced by Marinus Link in the Step Change scenario is predominantly gas, which has lower emissions intensity and leads to lower emissions benefit.

2. Introduction

MLPL has engaged EY to undertake market modelling of system costs to forecast the gross market benefits to the NEM of an additional interconnector between Tasmania and Victoria.

The proposed second interconnector would comprise an HVDC link between Tasmania and Victoria, known as Marinus Link, plus augmentation to the AC transmission networks to ensure the full capacity of Marinus Link can be supported by each regions' transmission network.

This Report describes the key modelling outcomes and insights as well as the assumptions and input data sources and the modelling methods used. It forms a supplementary report to MLPL's analysis of net economic benefits of Marinus Link, which has been prepared and published by MLPL.[18]

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the NEM for two scenarios in the Draft 2025 IASR, being the Step Change and Progressive Change scenarios. The Step Change and Progressive Change scenarios collectively represent 85% of the Delphi Weighted Average in the 2024 ISP7. The modelling for each of the scenarios combined the following:

- The Draft 2025 Stage 2 IASR[19] input assumptions relating to policies, costs, generator technical parameters and hydrogen demand.
- AEMO's August 2024 ESOO[20] demand projections.
- The assumed timing for major transmission upgrades based on AEMO's outcomes from the 2024 ISP, published in April 2024 or the earliest commissioning date in Transmission Augmentation Information published December 2024 where this was later than the 2024 ISP outcomes.

The modelling methodology follows the CBA guidelines for actionable ISP projects published by the AER[21]. The model was used to compute a plan without Marinus Link, with Marinus Link stage 1 only (commissioned in 2030) and with both Marinus Link stage 1 and stage 2 (commissioned in 2030 and in 2034) across both scenarios.

The descriptions of outcomes in this Report are focussed on identifying and explaining the sources of forecast gross market benefits. The categories of gross market benefits modelled are changes in:

- Capex costs of new generation and storage capacity installed.
- FOM costs of all generation and storage capacity.
- Total VOM costs of all generation and storage capacity.
- Total fuel costs of all generation capacity.
- Total cost of DSP and USE.

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[18] Marinus Link Pty Ltd, 11 July 2025, *Summary RIT-T update report July 2025*. https://marinuslink.com.au/wp-content/uploads/2025/07/Summary-RIT-T-update-report-July-2025.pdf. Accessed 3 July 2025

[19] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

[20] AEMO, *National Electricity and Gas Forecasting*. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal. Accessed 25 June 2025

[21] Australian Energy Regulator, 21 November 2024, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/industry/registers/resources/guidelines/cost-benefit-analysis-guidelines. Accessed 1 July 2025

- Transmission expansion costs associated with REZ development.
- Transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model.
- Retirement/rehabilitation costs to cover decommissioning, demolition and site rehabilitation.
- Synchronous condenser costs to meet Tasmanian inertia requirements.
- Emissions as a byproduct of thermal generation valued according to AER's *Valuing emissions reduction* documentation[22], calculated as a post-process to the optimisation.

Each category of forecast gross market benefits is computed annually across the 25-year Modelling Period, from 2026-27 to 2050-51. The forecast benefits presented are discounted to 1 July 2025 using a 7% real, pre-tax discount rate, consistent with the central value applied by AEMO in the Draft 2025 Stage 2 IASR.

The forecast gross market benefits of each scenario need to be compared to the ongoing cost of Marinus Link to determine the forecast net economic benefit for that case. That evaluation is not part of the scope of this gross market benefits assessment and hence has not been included in this Report. It is performed by MLPL outside of this Report using the forecast gross market benefits from this Report and other inputs.

The Report is structured as follows:

- Section 3 describes the input assumptions and scenarios modelled in this study.
- Section 4 presents the NEM capacity and generation outlook without Marinus Link for the two scenarios.
- Section 5 presents the forecast gross market benefits associated with Marinus Link.
- Appendix A provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.
- Appendix B outlines model design and input data related to representation of the transmission network and transmission losses.
- Appendix C outlines model design and input data related to demand.
- Appendix D provides an overview of model inputs and methodologies related to supply of energy.

[22] AER, May 2024, *Valuing emissions reduction AER guidance and explanatory statement*. Available at: https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf. Accessed 24 June 2025

3. Scenario assumptions

3.1 Overview of input assumptions for scenarios

Marinus Link gross market benefits have been forecast under the Step Change and Progressive Change scenarios. The modelling combines input assumptions on policies, costs, generator technical parameters and hydrogen demand from the AEMO Draft 2025 Stage 2 IASR[23] with all other demand projections from the 2024 ESOO[24]. A more comprehensive list of assumptions and their sources is summarised in Table 3. All input assumptions were selected by MLPL and in most cases were drawn from the latest data sources in accordance with the CBA guidelines. In some instances, inputs were maintained in alignment with the March 2024 forecast of gross market benefits of Marinus Link[25] to aide comparison and due to time constraints. This includes the five-node network model as described in Appendix B. Deviations from the Draft 2025 Stage 2 IASR[23] are listed in Section 3.2.

Table 3: Overview of key input parameters in the Step Change and Progressive Change scenarios

Input parameter	Scenarios	
	Step Change	**Progressive Change**
Underlying consumption	2024 ESOO - Step Change Hydrogen demand based on Draft 2025 IASR v7.2[23] - Step Change[26]	2024 ESOO - Progressive Change Hydrogen demand based on Draft 2025 IASR v7.2[23] - Progressive Change[26]
Committed and anticipated generation	Committed and anticipated generators from the 2023 IASR Assumptions Workbook[27]	
New entrant capital cost and FOM for wind solar PV, SAT, OCGT, CCGT, PHES large-scale batteries	Draft 2025 IASR assumptions Workbook[23] - Step Change	Draft 2025 IASR assumptions Workbook[23] - Progressive Change
Retirements of coal-fired power stations	April 2025 Generation Information[28] for announced retirements or earlier if economic or driven by decarbonisation objectives. QEJP coal retirements have not been considered in the modelling scenarios	
Gas fuel price	Draft 2025 IASR assumptions Workbook[23] - Step Change	Draft 2025 IASR Assumptions Workbook[23] - Progressive Change
Coal fuel price	Draft 2025 IASR assumptions Workbook[23] - Step Change	Draft 2025 IASR assumptions Workbook[23] - Progressive Change

23 AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

24 AEMO, *National Electricity and Gas Forecasting*. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal. Accessed 25 June 2025

25 EY, 28 March 2024, *Gross market benefit assessment of Marinus Link*, https://www.marinuslink.com.au/wp-content/uploads/2024/04/EY-report-Project-Marinus-Gross-Benefits-28-March-2024.pdf. Accessed 27 June 2025

26 At the time of modelling this was the most up to date source of demand data

27 AEMO, 8 September *2023 IASR Assumptions Workbook v5.2*. Available at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 25 June 2025

28 AEMO, 15 April 2025, *NEM April 2025 Generation Information*. Available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 27 June 2025

Input parameter	Scenarios	
	Step Change	Progressive Change
Emissions factors	Draft 2025 IASR assumptions Workbook[23] – Step Change: includes gas biomethane blending factors	Draft 2025 IASR assumptions Workbook[23] – Progressive Change: includes gas biomethane blending factors
NEM carbon budget to 2030	Draft 2025 IASR Assumptions workbook[23] – Step Change: 418 mega ton (Mt) CO_2-e 2026-27 to 2029-30	Draft 2025 IASR Assumptions workbook[23] – Progressive Change: 418 Mt CO_2-e 2026-27 to 2029-30
NEM long- term temperature-linked carbon budget	Draft 2025 IASR Assumptions Workbook[23] – Step Change 586 Mt CO_2-e from 2026-27 to 2049-50	Draft 2025 IASR Assumptions Workbook[23] – Progressive Change 797 Mt CO_2-e from 2026-27 to 2049-50
Federal renewable energy target	82% share of renewable generation by 2029.30 Consistent with the Draft 2025 IASR Assumptions Workbook v7.2[23]	
Victoria policy	Victoria Renewable Energy Target (VRET) – 40% by 2025, 65% by 2030 and 95% by 2035 Victoria Energy Storage Target – 2.6 GW by 2030 and 6.3 GW by 2035 Victoria Offshore Wind Target – 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040 Consistent with Draft 2025 IASR Assumptions Workbook v7.2[23]	
Queensland Renewable Energy Target (QRET)	50% by 2029-30, 70% by 2031-32 and 80% by 2034-35 Consistent with Draft 2025 IASR Assumptions Workbook v7.2[23]	
Tasmanian Renewable Energy Target (TRET)	100% by 2022, linear trajectory from the mid-2020s to 150% available renewable generation by 2030 and 200% by 2040 as a percentage of 2020 demand in Tasmania. The trajectory can be exceeded if part of the least cost solution. Consistent with Draft 2025 IASR Assumptions Workbook v7.2[23]	
NSW Electricity Infrastructure Roadmap	NSW Roadmap, with at least the same amount of electricity as 8 GW in New England, 3 GW in the Central West Orana (CWO) REZ and 1 GW of additional capacity and 2 GW of long duration storage (8 hrs or more) by 2029-30. Consistent with 2024 ISP[29]	
Victorian SIPS	300 MW/450 megawatt-hour (MWh), 250 MW for SIPS service during summer. In the summer months the remaining 50 MW can be deployed in the market on a commercial basis, in the winter months the full capacity is available. From April 2032 the full capacity is available to the market. Consistent with Draft 2025 IASR Assumptions Workbook v7.2[23]	
EnergyConnect	Draft 2025 IASR Assumptions Workbook v7.2[23]. commissioned by July 2027	
Western Renewables Link	Transmission Augmentation Information December 2024[30]. Commissioned by July 2027	
HumeLink	2024 ISP29 commissioned by July 2030	
New-England REZ Transmission	Transmission Augmentation Information December 2024[30]. Earliest in service date advised by proponent: ▪ New England REZ Transmission Link 1 commissioned by 1 July 2032 ▪ New England REZ Transmission Link 2 commissioned by 1 January 2034	

[29] AEMO, 26 June 2024, *2024 Integrated System Plan*. Available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp. Accessed 25 June 2025

[30] AEMO, 13 December, *NEM Transmission Augmentation information December 2024*. Available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information#:~:text=The%20Transmission%20Augmentation%20Information%20workbook%20contains%20information%20for,%28ESOO%29%20and%20Inputs%2C%20Assumptions%20and%20Scenarios%20Report%20%28IASR%29. Accessed 25 June 2025

Input parameter	Scenarios	
	Step Change	Progressive Change
Marinus Link	As per MLPL assumptions. The first stage of Marinus Link commissioned by 1 January 2030 and the second stage of Marinus Link commissioned by 1 July 2034	
Queensland-New South Wales Interconnector (QNI) Connect	2024 ISP[29] commissioned by July 2034	
Victoria-New South Wales Interconnector (VNI) West	In line with Transmission Augmentation Information December 2024[30] commissioned by December 2029	In line with the 2024 ISP[29] commissioned by July 2034
Discount rate	7% real, pre-tax	

3.2 Differences in assumptions from the Draft 2025 Stage 2 IASR

Several inputs were maintained in alignment with the March 2024 forecast of gross market benefits of Marinus Link[31] to facilitate comparison to previous modelling and due to time constraints. These are listed in Table 4.

Table 4: Differences in assumptions from the Draft 2025 Stage 2 IASR[36]

Input parameter	Scenarios	
	Step Change	Progressive Change
Group Constraints with intraconnectors: NQ1, NQ2, NQ3, MN1 and NSA1	Final ISP 2022 Inputs and assumptions workbook[32]	
Committed and anticipated generators	2023 IASR Assumptions Workbook[2727][27]	
VOM for existing and new entrant generators[33]	2023 IASR Assumptions Workbook[27]	
NSW roadmap trajectory	2023 IASR Assumptions Workbook[27]	
REZ capacity factors	2023 IASR Assumptions Workbook[27]	
Hydrogen load dispatch	2023 IASR Assumptions Workbook[27] - annual utilisation factor of 80%, no optional electrolyser build. Draft 2025 Stage 2 IASR uses annual minimum utilisation factors with optional electrolyser build[34]	

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[31] EY, 28 March 2024, *Gross market benefit assessment of Marinus Link*, https://www.marinuslink.com.au/wp-content/uploads/2024/04/EY-report-Project-Marinus-Gross-Benefits-28-March-2024.pdf. Accessed 27 June 2025

[32] AEMO, 30 June 2022, *2022 ISP Inputs, assumptions and scenarios workbook*, Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed 27 June 2025

[33] VOM values are in 2023 dollars as per the 2023 IASR

[34] AEMO, March 2025, *Draft ISP Methodology*, Available at: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/draft-isp-methodology-march-2025.pdf?la=en. Accessed 25 June 2025.

The five-node NEM model outlined in Appendix B is consistent with that used for previous Marinus Link modelling. It differs from the 15-node model described in the Draft 2025 IASR. Using the five-node model required some simplified group constraint assumptions based on the Final 2022 ISP Inputs and assumptions workbook[35]. For group constraints in the Draft 2025 Stage 2 IASR[36] which contain intraconnector limits, the Final 2022 ISP group constraint formulation have been used instead. Table 4 lists the constraints used from the 2022 ISP.

3.3 Differences in assumptions with and without Marinus Link

Across all scenarios, development of Marinus Link is associated with the following four additional changes assumed by MLPL consistent with the AEMO Draft 2025 IASR[36]:

- A 100 MW expansion of West Coast power scheme's capacities[37].
- A 150 MW upgrade of Tarraleah's capacity and a 90 MW upgrade of Gordon 1 capacity.
- A reduced REZ transmission expansion cost applied for the Central Highlands REZ, after Marinus Link stage 1 is commissioned. The assumed linearised cost decreases from $0.63m/MW to $0.32m/MW.
- A reduced REZ transmission expansion cost applied for the North West Tasmania REZ, after Marinus Link stage 1 is commissioned. The assumed linearised cost decreases from $0.38m/MW to $0.035m/MW.

MLPL also assumed a 10 percentage point decrease in monthly minimum whole-of-system reservoir volumes in Tasmanian (Prudent Storage Levels, PSLs).[38]

The cost differential between the with and without Marinus Link simulations is factored in externally by MLPL. Any cost differential associated with these five factors are also dealt with by MLPL. EY's work captures any gross market benefits resulting from these changes.

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[35] AEMO, 30 June 2022, *2022 ISP Inputs, assumptions and scenarios workbook*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed 27 June 2025

[36] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

[37] Capacity of the Anthony Pieman scheme is assumed to increase from 500 MW to 580 MW. Capacity of the John Butters scheme is assumed to increase from 155.4 MW to 174.4 MW.

[38] The PSL profile is imposed as part of Tasmania's energy security plan mandated by the Tasmanian Government to manage the consequences of an extended Basslink outage. For more detail see Appendix D1. The decrease in PSL profile with Marinus Link is a modelling assumption selected by MLPL and does not represent Tasmanian Government policy.

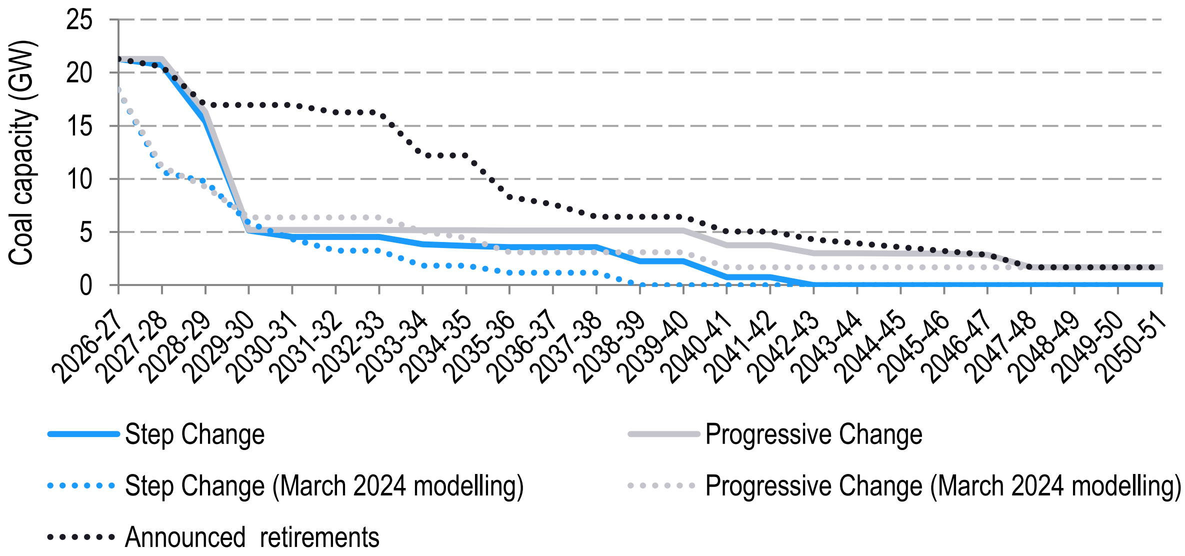
4. Forecast NEM outlook in the without Marinus Link case

Before presenting the forecast benefits of the options, it is useful to understand the expected capacity and generation outlooks in the modelled scenarios, and the underlying input assumptions driving those outlooks in the counterfactual case without Marinus Link.

4.1 Forecast coal power plant withdrawal

Based on the scenario settings described in Section 3 thermal generation retirements are determined on a least-cost basis. Coal generator retirements are assumed to occur at or earlier than their end-of-technical-life or announced retirement year. The announced retirement schedules for coal units are based on the April 2025 Generation Information[39]. Forecast coal capacity in the without Marinus Link case across the two scenarios as an output of the modelling is illustrated in Figure 2. The announced schedule is also shown alongside the outcomes of the March 2024 assessment of gross market benefits of Marins Link.[40]

Figure 2: Forecast coal capacity in the NEM by year in the without Marinus Link case (solid lines and dashed lines demonstrate the coal capacity forecasts in this model and ISP 2024 outcomes, respectively)



The forecast pace of the transition is predominantly determined by a combination of assumed carbon budgets, renewable energy targets (federal, NSW Electricity Infrastructure Roadmap, VRET, QRET and TRET), demand outlook and end-of-life for existing assets in a system developed and dispatched at least cost. The model forecasts the entire coal capacity withdraws by the early 2040s for the Step Change scenario. In the Progressive Change scenario, coal-fired generation is forecast to remain until the end of the Modelling Period.

The National Electricity Rules require generators to provide three years notice of closure, meaning the earliest date for optional retirement in this modelling is 2027-28. As such, a large amount of

[39] AEMO, 15 April 2025, *NEM April 2025 Generation Information*. Available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 25 June 2025

[40] EY, 28 March 2024, *Gross market benefit assessment of Marinus Link*, https://www.marinuslink.com.au/wp-content/uploads/2024/04/EY-report-Project-Marinus-Gross-Benefits-28-March-2024.pdf. Accessed 27 June 2025

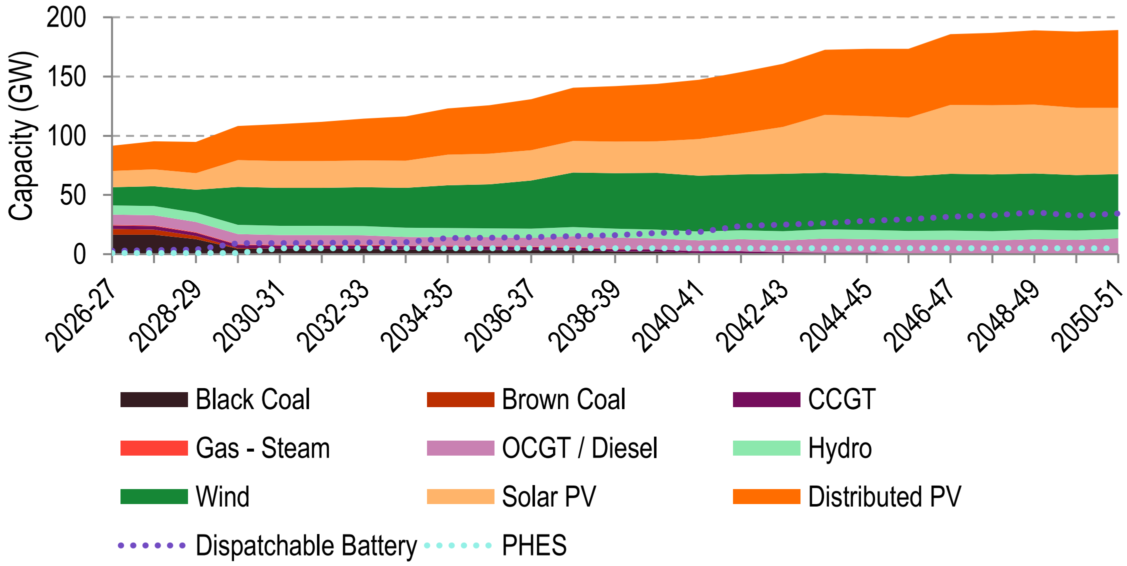
coal retirements occurs in the two years leading up to when the federal 82% renewable generation target is to be achieved in 2029-30, which results in a steeper retirement schedule than in the previous March 2024 Marinus Link modelling. Leading up to 2029-30, the scenarios in this Report are forecast to have more coal capacity than the corresponding scenarios in the March 2024 forecast.

From 2030-31, there is a higher amount of coal capacity remaining in the Step Change scenario compared to the corresponding scenario In the March 2024 modelling. This can be attributed to later maximum retirement dates, reduced assumed emissions factors and increased capex of alternative technologies as per AEMO's Draft 2025 Stage 2 IASR[41]. In the Progressive Change scenario, coal capacity maintains a flat trajectory after 2030-31, aligning with announced retirements until 2046-47. Coal capacity remains for longer in Progressive Change due to the more relaxed assumed carbon budget, despite initially aligning with the trajectory in Step Change to achieve the same renewable energy targets consistent across the scenarios.

4.2 Forecast NEM capacity and generation outlook

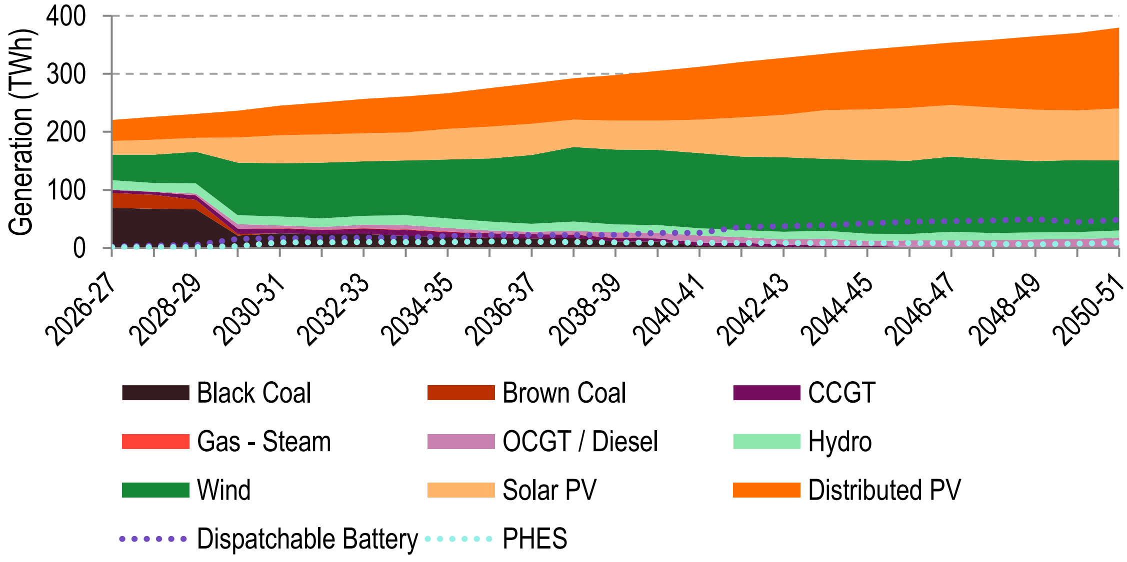
The NEM-wide capacity mix forecast in the Step Change scenario without Marinus Link is shown in Figure 3 and the corresponding generation mix in Figure 4.

Figure 3: NEM capacity mix forecast for the Step Change scenario without Marinus Link



[41] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

Figure 4: NEM generation mix forecast for the Step Change scenario without Marinus Link



Up to 2030, outcomes are largely driven by the assumed federal renewable energy target ahead of state-based renewable energy targets and carbon budgets assumptions. There is a forecast rapid withdrawal of black and brown coal capacity in the period leading up to 2030 to achieve the 82% renewable generation target. To replace the forecast retiring coal capacity, wind capacity is predominantly forecast to be installed, along with dispatchable battery and pumped hydro storage capacity in line with assumed state-based storage targets. Solar PV and OCGT capacity are forecast to increase from the 2030s complementing other technologies. The forecast new gas-fired capacity also supports reserve requirements. Distributed PV is considered as an input assumption. The NEM is forecast to have roughly 189 GW total (generation and storage) capacity by 2050-51. This total is lower than that previously forecasted for Marinus Link in March 2024 due to overall lower assumed demand, especially hydrogen. Demand assumptions are described in Table 3 in Appendix C.

The Progressive Change scenario presents a slower energy transition compared to the Step Change scenario. Figure 5 and Figure 6 show the differences in NEM capacity development and generation in the Progressive Change scenario compared to Step change, presented as Progressive Change minus the Step Change Scenario. Progressive Change is forecast to install less wind and solar than Step Change due to a less restrictive carbon budget, and lower forecast demand. The larger carbon budget leads to delays in coal retirement outcomes and more coal and gas generation in Progressive Change. However, the difference between the two scenarios is now smaller than the previous March 2024 forecast due to reduced demand in Step Change. Additionally, Tasmanian load is assumed to be averaging approximately 2,000 GWh lower in Progressive Change than Step Change seen from comparing Figure 17, which is less than the previous difference of approximately 7,000 GWh.

Figure 5: Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios without Marinus Link

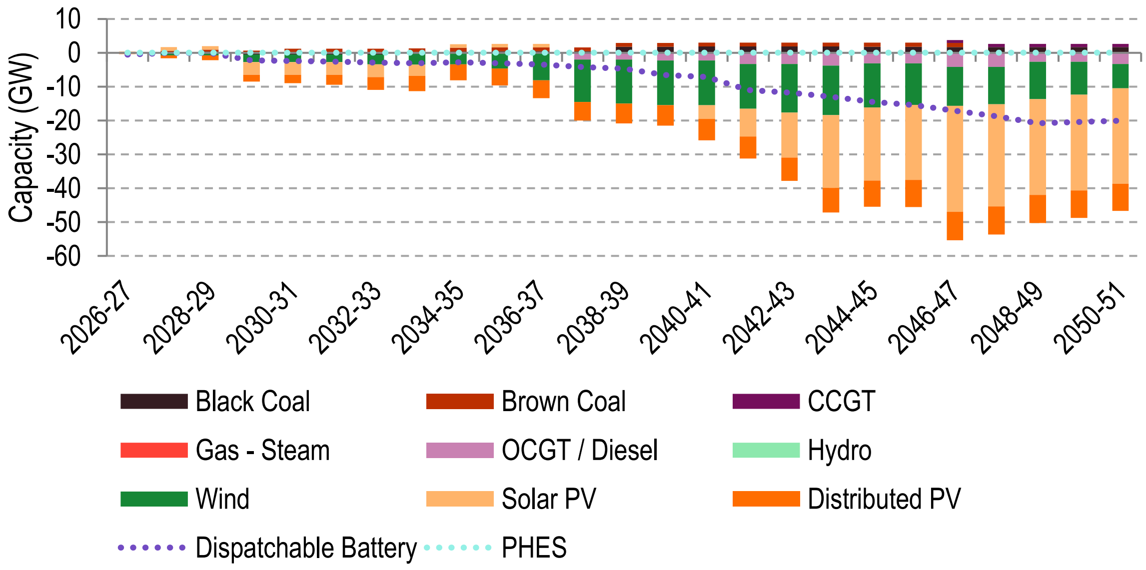
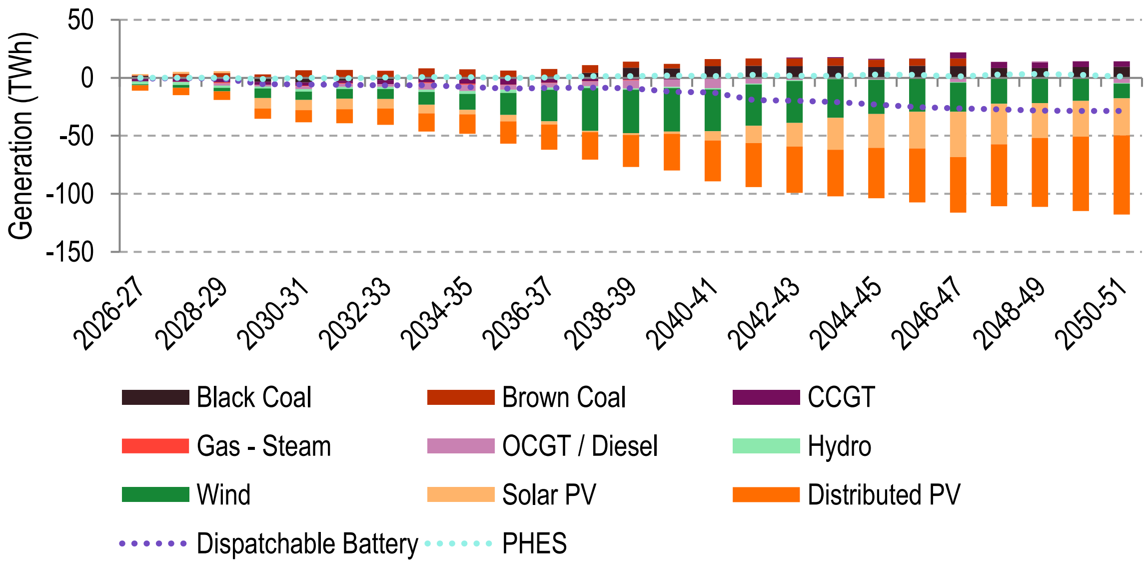


Figure 6: Difference in NEM generation forecast between the Progressive Change and Step Change scenarios without Marinus Link



5. Forecast gross market benefit outcomes

5.1 Summary of forecast gross market benefit outcomes across scenarios

Table 5 shows the gross market benefits of Marinus Link forecast over the 25-year Modelling Period from 2026-27 to 2050-51 for the Step Change and Progressive Change scenarios, excluding the value of emissions savings.

Table 5: Overview of forecast gross market benefits of Marinus link over the Modelling Period discounted to 1 July 2025, excluding the value of emissions savings. All dollars are presented in $million, real June 2024

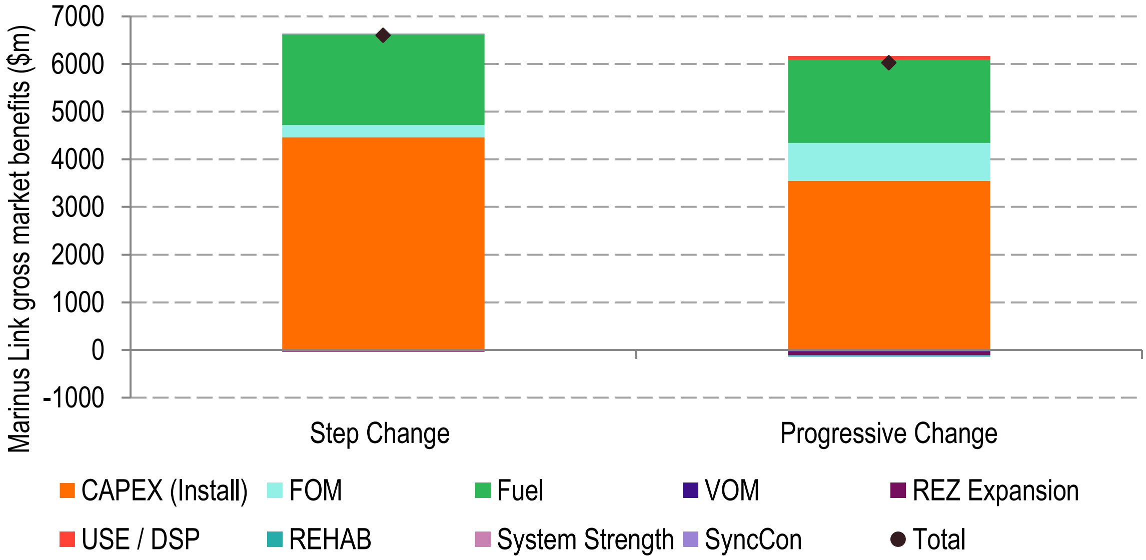
Marinus Link size	Marinus Link timing	Step Change	Progressive Change
1,500 MW	2030 & 2034	6,601	6,026
750 MW	2030	5,591	5,002

The forecast gross market benefits of each scenario must be evaluated by comparing it to the cost of Marinus Link to determine the forecast net economic benefit of each option. This evaluation is not part of our scope and hence has not been included in this Report. It is performed by MLPL outside of this Report using the forecast gross market benefits from this Report and other inputs.

In all scenarios, forecast benefits for Marinus Link are primarily driven by capex savings across the NEM, followed by mainland fuel cost savings as shown in Figure 7. This is consistent with the two largest sources of forecast benefits in the March 2024 Marinus Link modelling[42]. Comparison of values between the two reports should be made with caution given they are in different dollars, discounted to different dates and over different modelling periods.

[42] EY, 28 March 2024, Gross market benefit assessment of Marinus Link, https://www.marinuslink.com.au/wp-content/uploads/2024/04/EY-report-Project-Marinus-Gross-Benefits-28-March-2024.pdf. Accessed 27 June 2025

Figure 7: Composition of forecast total gross market benefits of Marinus Link stage 1, in 2030 and stage 2, in 2034 over the modelling Period discounted to 1 July 2025. All dollar values are presented in $million, real June 2024



The forecast capex savings associated with Marinus Link are predominantly driven by the combination of high capacity factor wind resource in Tasmania, coupled with the legislated TRET. By better connecting Tasmania with the mainland Marinus Link is forecast to unlock the potential for high quality Tasmanian wind, new entry pumped hydro and existing conventional Tasmanian hydroelectric power stations to offset the need for higher cost mainland renewable capacity and thermal generation as the NEM transitions from existing thermal generation to a higher proportion of renewables.

Marinus Link is forecast to result in fuel cost savings on the mainland by enabling better access to existing Tasmanian hydroelectric generators and wind resource, as a lower cost alternative to the construction and operation of dispatchable gas on the mainland. The extent of these savings varies by scenario.

The Step Change scenario is forecast to have higher benefits for Marinus Link than the Progressive Change scenario. While previously in the March 2024 Marinus Link modelling, Progressive Change was forecast to have higher benefits, the relativity of demand between the two scenarios has changed in the Draft 2025 IASR assumptions. All else being equal, Marinus Link benefits increase with higher assumed mainland demand and decrease with higher assumed Tasmanian demand. The balance of changes to both mainland and Tasmanian demand assumptions determines the overall impact of gross benefits. In the current Report, the downward impact of the assumed decrease in mainland demand in Step Change is counterbalanced by an assumed decrease in Tasmanian demand. Meanwhile, Tasmanian demand in Progressive Change has not changed significantly, and mainland demand is overall lower. See Appendix C for a detailed breakdown of changes in demand.

In the without Marinus Link cases, much of the new renewable generation that is forecast to be installed in Tasmania to achieve the TRET is spilled, since local Tasmanian demand is not high enough to fully utilise this generation. With lower Tasmanian demand in Step Change compared to March 2024 modelling assumptions, the volume of spilled renewable generation is higher without Marinus Link, leading to larger savings with Marinus Link when Tasmanian generation can benefit the rest of the NEM. In Progressive Change, Tasmanian demand remains similar to Step Change. However, mainland demand has decreased in Progressive Change, leading to reduced savings as there is less mainland generation to be displaced.

Other major contributors to differences in benefits from the March 2024 modelling include changes in coal retirements, emissions factors, capex costs, imperfect foresight for storage and distributed storage. In more detail:

- Coal retirement schedules have later maximum retirement dates, due to delays in announced retirements. This leads to increased coal in the system, as described in Section 4.1, which can be used to displace other generation in the with Marinus Link case, causing increased benefits.
- Emissions factors for thermal units in the IASR v7.2 have decreased since the previous IASR. Gas generation is also assumed to have biomethane blending which reduces their emissions factors over time. This leads to increased thermal generation and a later coal retirement outcome.
- Capex costs have generally increased, with differing WACC by technology, which creates favourable conditions for more thermal generation and higher avoided costs.
- To model more imperfect foresight for storage as described in Appendix D, the duration for all modelled storage has been slightly decreased. This leads to less efficient operation of storage, and increased benefits when storage build is avoided. Distributed storage from VPPs and electric vehicle to grid batteries (EV V2G) have generally decreased for the Step Change and increased for the Progressive Change scenarios. This would increase storage related benefits for Step Change as the amount of assumed storage as an input has decreased, requiring more optional build, which is avoided with Marinus Link. The Progressive Change scenario would see the opposite effect.

While the Green Energy Industries scenario has not been modelled, the key inputs and assumptions are such that the forecast gross market benefits would likely be greater for Marinus Link than the benefits modelled in the Step Change and Progressive Change scenarios. In the March 2024 Marinus Link modelling, key assumptions which led to higher benefits for the Green Energy Exports scenario included higher overall demand, and a high proportion of renewables required to meet this demand with a more restrictive carbon budget. In the Draft 2025 IASR[43], the expected relativity of these assumptions in Green Energy Industries compared to the other scenarios is similar. The demand for the Green Energy Industries scenario is presented in Figure 16 within Appendix C, which shows that it has higher assumed demand than the Step Change and Progressive Change scenarios. Furthermore, modelling for Green Energy Industries is intended to be included in a future update.

5.1.1 Forecast benefits from emissions

Forecast emissions benefits are a byproduct of avoided thermal generation, when Tasmanian hydro and wind capacity is unlocked with Marinus Link. Due to Marinus Link, energy that would have otherwise been spilled can be exported to meet mainland demand, avoiding thermal generation and capacity which lead to emissions savings. Emissions savings are valued according to AER's *Valuing emissions reduction* documentation[44], calculated as a post-process to the optimisation. Emissions benefits are a separate category of market benefits that was not assessed in the March 2024 Marinus Link modelling and varies between the scenarios due to differences in assumed carbon budget and demand.

Table 6 shows the forecast gross benefits with associated emissions savings for Marinus Link over the 25-year modelling period from 2026-27 to 2050-51 for the Step Change and Progressive Change scenarios.

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[43] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

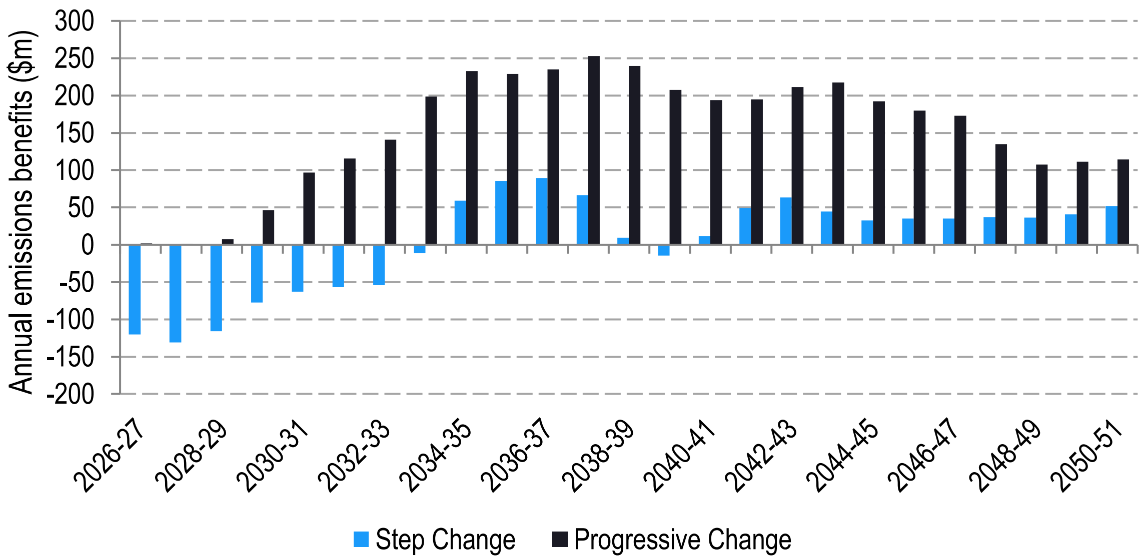
[44] AER, May 2024, *Valuing emissions reduction AER guidance and explanatory statement*. Available at: https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf. Accessed 24 June 2025

Table 6: Overview of scenarios with associated emissions benefits for Marinus link over the Modelling Period discounted to 1 July 2025. All dollars are presented in $million, real June 2024

Marinus Link size	Marinus Link timing	Step Change	Progressive Change
1,500 MW	2030 & 2034	104	3,835
750 MW	2030	71	2,566

In the Step Change scenario, the carbon budget is binding, meaning that both the with and without Marinus Link cases produce the same overall amount of emissions in Mt to 2049-50. As a result, the small benefits are associated with different timing of those emissions, as shown in Figure 8. Marinus Link is associated with an increase in emissions in the near-term, outweighed by decreased emissions and associated benefits from 2034-35.

Figure 8: Forecast annual emissions benefits for the Step Change and Progressive Change scenario, for Marinus Link stages 1 and 2, discounted to 1 July 2025. All dollars are presented in $million, real June 2024



The Progressive Change scenario is forecast to have much higher emissions benefits compared to Step Change. This is mainly due to a more relaxed carbon budget which does not bind in Progressive Change. Increased headroom for emissions allows greater coal generation and later coal retirements than in the Step Change scenario, aligning more closely with announced retirements by 2040 as seen in Figure 2. In the Progressive Change scenario, the higher levels of emissions-intensive generation in the Base Case, particularly brown coal, is partially avoided with Marinus Link, leading to significant emissions benefits. Moreover, Victorian brown coal generation is more directly impacted by Tasmanian generation from Marinus Link. In contrast, in the Step Change scenario, all brown coal is retired in the Base Case which prevents the opportunity to avoid its emissions intensive generation. Thermal generation displaced by Marinus Link in the Step Change scenario is predominantly gas, which has lower emissions intensity and leads to lower emissions benefit.

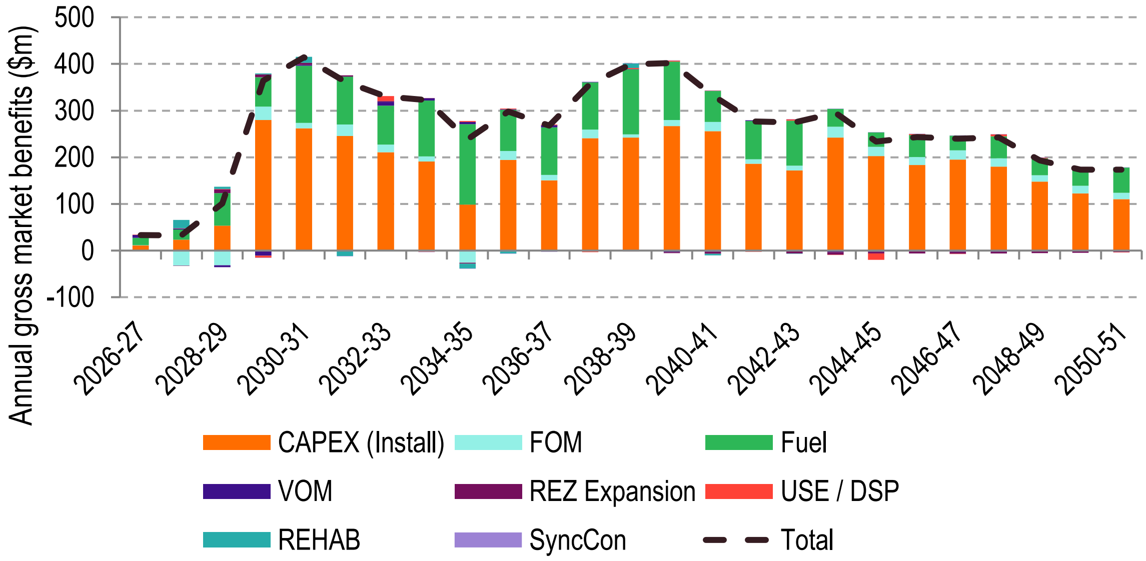
The annual emissions benefits for Marinus Link stage 1 and 2 shown in Figure 8 correspond with the avoided thermal generation seen in Sections 5.2.2 and 5.3.2.

5.2 Market modelling outcomes for the Step Change scenario

5.2.1 Forecast gross market benefits, Step Change scenario

The annual gross market benefits forecast from the inclusion of Marinus Link stage 1 and stage 2 in the Step Change scenario are depicted in Figure 9 on an annual basis. Over the Modelling Period, it is forecast that the inclusion of Marinus Link stages 1 and 2 results in $6,601m in gross market benefits.

Figure 9: Annual Marinus Link market benefit forecast for the Step Change scenario discounted to 1 July 2025, Marinus Link stages 1 and 2. All dollar values are presented in $million, real 2024.



Market benefits due to Marinus are predominantly forecast to occur after the assumed commissioning of its first stage in 2030. However, some of the forecast benefits accrue prior to its installation due to differences in the least-cost development plan in anticipation of commissioning. Most of the potential benefits with Marinus Link are forecast to occur from the reduction in expected capex and fuel costs. In the first few years post Marinus Link commissioning, the bulk of potential market benefits are forecast to come from capex savings, in avoided mainland generation investment. Following this, the proportion of fuel benefits increases in the mid-2030s as Marinus Link enables displacement of mainland thermal generation. Towards the last 10 years of the forecast, forecast market benefits are predominantly capex again as Tasmanian wind generation displaces the need for new mainland renewable capacity.

5.2.2 Forecast NEM generation development plan, Step Change scenario

The differences in the forecast capacity and generation outlooks in Step Change scenario across the NEM with and without Marinus Link are shown in Figure 10 and Figure 11, respectively.

Figure 10: Capacity difference with and without Marinus Link for the Step Change scenario, Marinus Link stages 1 and 2

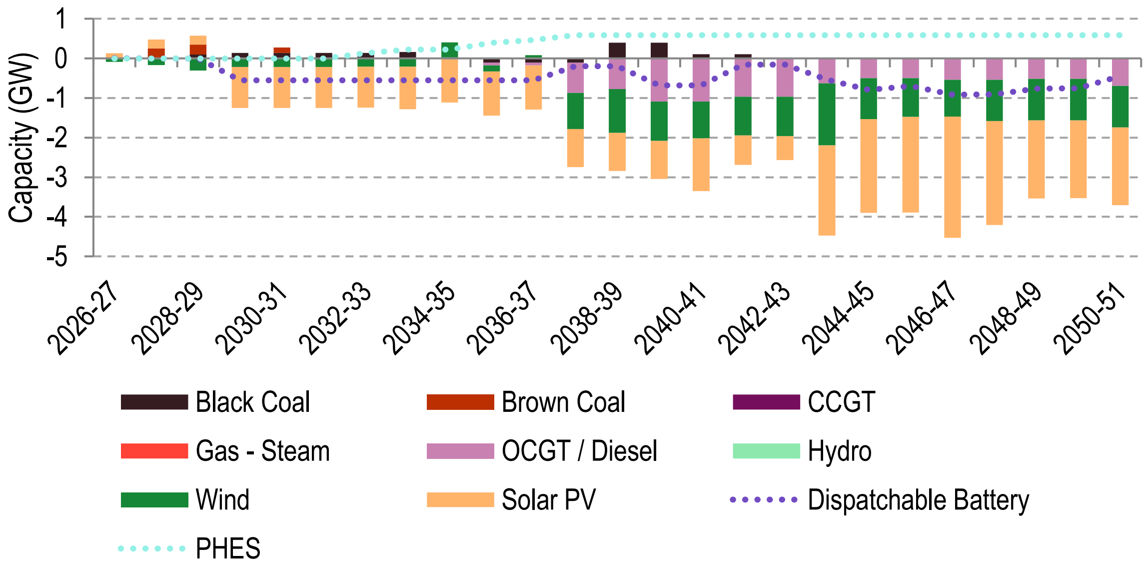


Figure 11: Generation difference with and without Marinus Link for the Step Change scenario, Marinus Link stages 1 and 2

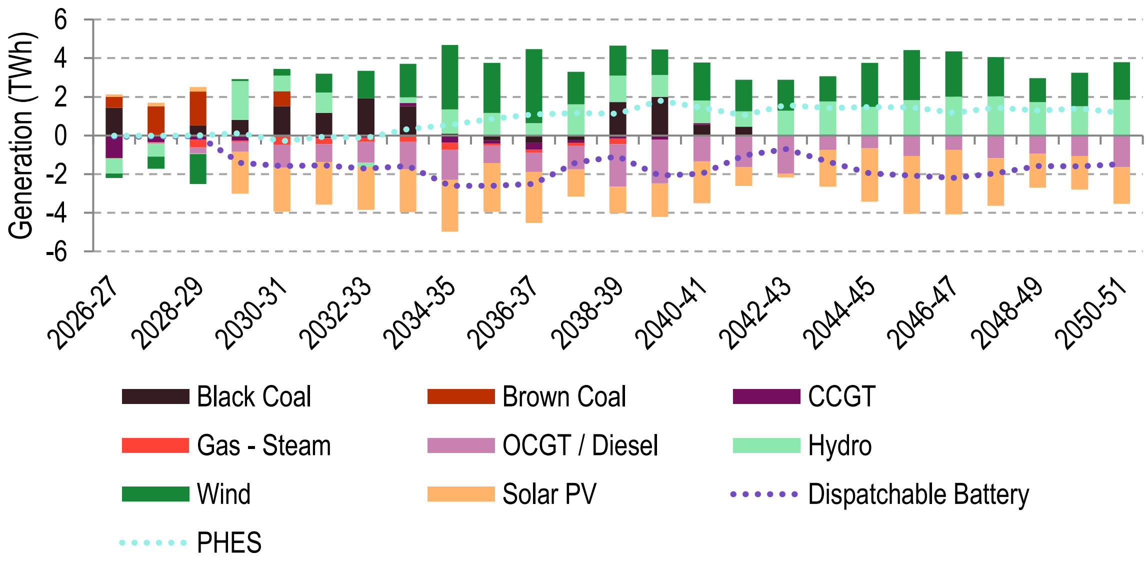


Figure 10 shows that solar PV, wind, dispatchable battery and gas capacity across the NEM are forecast to be avoided with the inclusion of Marinus Link. There are small delays in coal-fired generator retirement. Figure 11 shows that forecast wind generation, hydro and pumped hydro generation increases despite the reduction in overall wind capacity. This is in line with drivers of capex benefits in Section 5.1 as Marinus Link is forecast to better connect Tasmania to the mainland. Tasmanian generation offsets the need for mainland capacity and generation. Coal-fired generation is forecast to increase output with Marinus Link while still meeting the assumed emissions budget over the full 25-year Modelling Period. There is a significant amount of increased coal generation at the beginning of the Modelling Period, prior to the commissioning of Marinus Link. As previously mentioned, the model pre-empts emissions savings with Marinus Link and can generate more coal in the earlier years of the Modelling Period to avoid capex costs, while still meeting the long-term emissions budget. This is achieved because Marinus Link is forecast to decrease reliance on gas generation in later years by improving diversity in generation sources and load. Essentially, Marinus Link is forecast to allow the NEM to achieve the assumed renewable energy and emissions targets at lower cost (excluding consideration of the cost of Marinus Link itself).

Compared to the March 2024 Marinus Link modelling, forecast coal retirement dates have been delayed as presented in Section 4.1. As a result, coal capacity is able to be utilised for longer in the study period, until 2043 as shown in Figure 11. This means with Marinus Link, coal generation can displace more generation from other higher cost technologies, contributing to higher benefits.

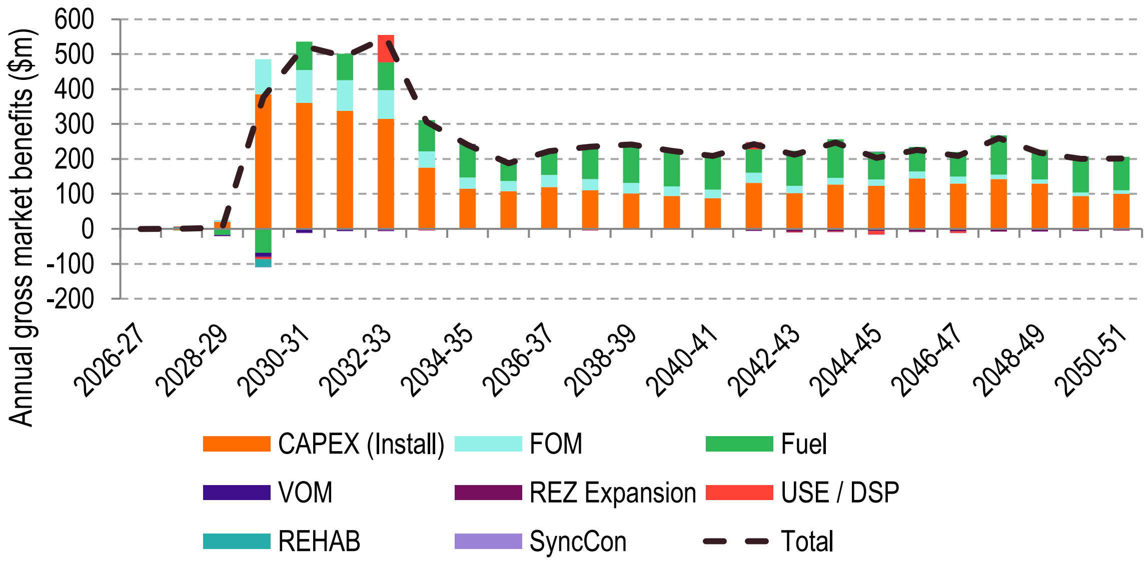
Additionally, dispatchable battery capacity developments are offset, countered with an increase in pumped hydro from Tasmania. This is an indication of the increased storage benefits mentioned in Section 5.1 due to modelling imperfect foresight for storage and less assumed distributed storage.

5.3 Market modelling outcomes for the Progressive Change scenario

5.3.1 Forecast gross market benefits, Progressive Change scenario

The annual gross market benefit forecast for the inclusion of Marinus Link stage 1 and stage 2 in the Progressive Change scenario are depicted in Figure 12 on an annual basis. Over the Modelling Period, it is forecast that the inclusion of marinus Link results in $6,026m in gross market benefits.

Figure 12: Annual Marinus Link benefit forecast for the Progressive Change scenario discounted to 1 July 2025, Marinus Link stages 1 and 2. All dollar values are presented in $million, real June 2024



Similar to the Step Change scenario, the highest annual benefits of Marinus Link are forecast to accrue once Marinus Link is commissioned in 2030. The composition of benefits is also similarly mostly from capex, especially in the initial years until the mid-2030s, where a higher amount of build is driven by renewable targets. However unlike in the Step Change scenario, the proportion of capex benefits remains steady after this as coal retirements stagnate and fuel benefits are more prominent, owing to lower demand and a higher emissions budget making it lower cost to run existing thermal generation over building new renewable capacity, which can be seen in Figure 13 and Figure 14. This is then avoided with Marinus Link which leads to a higher proportion of fuel benefits and lower capex compared to the Step Change scenario.

See Section 5.1 for details on the main drivers of movements in benefits in the Progressive Change scenario and comparisons to Step Change.

5.3.2 Forecast NEM generation development plan, Progressive Change scenario

The differences in the forecast capacity and generation outlooks in the Progressive Change Scenario across the NEM with and without Marinus Link stages 1 2 are shown in Figure 13 and Figure 14 respectively.

Figure 13: Capacity difference with and without Marinus Link for the Progressive Change scenario, Marinus Link stages 1 and 2

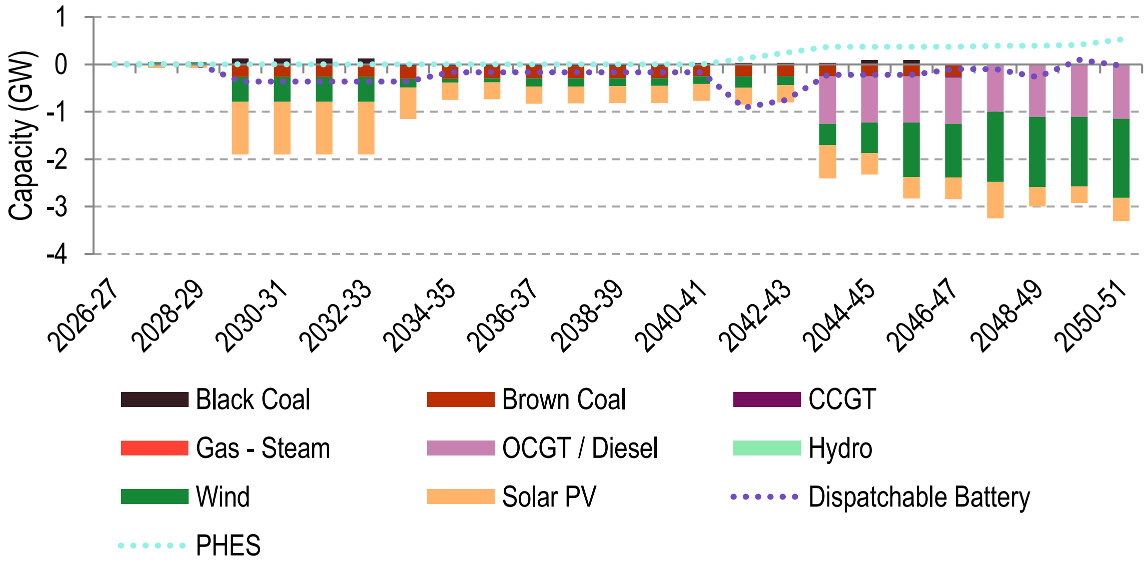


Figure 14: Generation difference with and without Marinus Link for the Progressive Change scenario, Marinus Link stages 1 and 2

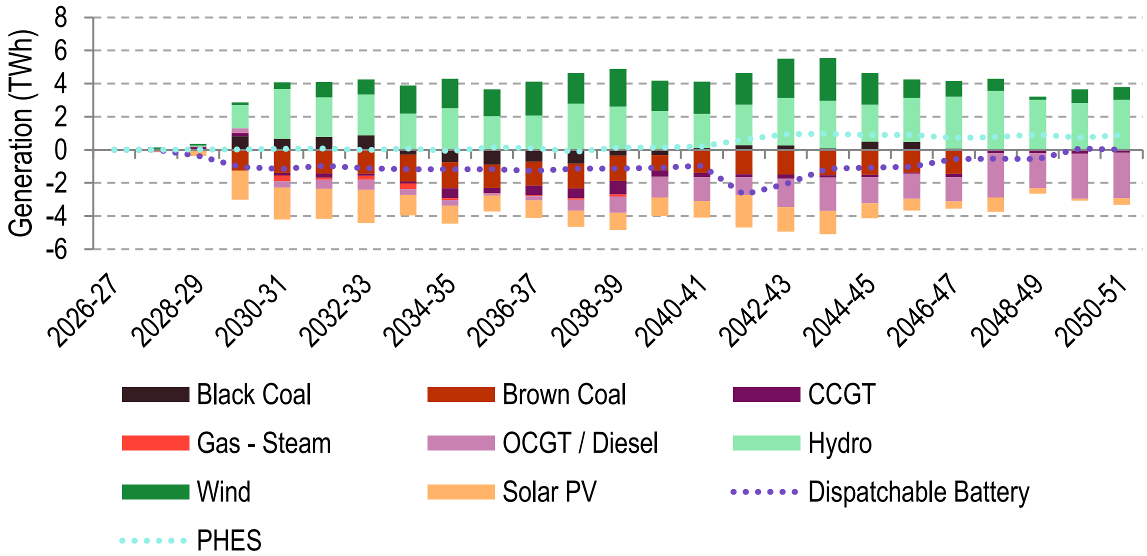


Figure 13 and Figure 14 show that Marinus Link is forecast to reduce investment in new wind and solar PV as well as allow earlier retirement of existing brown coal capacity from 2029-30, when the first stage of Marinus Link is assumed to be commissioned. Marinus Link is forecast to avoid corresponding brown coal generation and mainland dispatchable gas generation by better connecting existing Tasmanian hydroelectric generators and wind to the mainland as a lower cost alternative.

Compared to the March 2024 Marinus Link modelling, there is an increase in avoided brown coal. The increased availability of brown coal capacity is utilised in the Progressive Change scenario without Marinus Link due to a more relaxed carbon budget that is non-binding. This is reduced with Marinus Link, which contributes to emissions benefits described in Section 5.1.1.

Appendix A Methodology

A1. Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 25 years from 2026-27 to 2050-51. The modelling methodology follows the CBA guidelines for actionable ISP projects published by the Australian Energy Regulator[45]. The forecast gross market benefits of Marinus Link are calculated as the difference in the system cost that is forecast with and without Marinus Link.

Based on the full set of input assumptions, the model makes decisions that minimise the overall cost to supply the electricity demand for the NEM over the entire Modelling Period, with respect to:

- Capex of new generation and storage capacity installed,
- FOM costs of all generation and storage capacity,
- VOM costs of all generation and storage capacity,
- Fuel costs of all generation capacity,
- Cost of DSP and USE,
- Transmission expansion costs associated with REZ development,
- Transmission[46] and storage losses which form part of the demand to be supplied and are calculated dynamically within the model,
- Retirement / rehabilitation costs to cover decommissioning, demotion and site rehabilitation.
- Synchronous condenser costs to meet Tasmanian inertia requirements.
- Emissions as a byproduct of thermal generation valued according to AER's *Valuing emissions reduction* documentation[47], calculated as a post-process to the optimisation.

To determine the least-cost solution, the model makes decisions for each hourly[48] dispatch interval in relation to:

- The generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to be dispatched according to their SRMC, which is derived from their VOM and fuel costs, as well as technical parameters. The generation for each dispatch interval is subject to the modelled availability of power stations in each hour (subject to planned or unplanned outages or variable renewable availability), network limitations and energy limits (e.g., storage levels).
- Commissioning new entrant capacity for wind, offshore wind, solar PV SAT, CCGT, OCGT, large-scale battery and PHES.

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[43] Australian Energy Regulator, 21 November 2024, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/industry/registers/resources/guidelines/cost-benefit-analysis-guidelines. Accessed 1 July 2025.

[46] For the transmission elements modelled, described in Appendix B.

[47] AER, May 2024, *Valuing emissions reduction AER guidance and explanatory statement*. Available at: https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf. Accessed 24 June 2025

[48] Whilst the NEM is dispatched on five-minute intervals, the model resolution is hourly as a compromise between managing computation time while still capturing the renewable and storage resources in sufficient detail for the purposes of the modelling.

These hourly decisions consider constraints that include:

- Supply must equal demand in each region for all dispatch intervals, while maintaining a reserve margin, with USE costed at the VCR,
- Minimum loads for some generators,
- Transmission interconnector flow limits (between regions),
- Maximum and minimum storage reservoir limits (for conventional storage hydro, PHES, VPP and large-scale battery),
- New entrant capacity transmission and resource limits for wind and solar in each REZ and costs associated with increasing these limits, and PHES in each region,
- Emission and carbon budget constraints, as defined for each scenario,
- Renewable energy targets where applicable by region or NEM-wide.

The model does not include all intra-regional transmission constraints. It contains only inter-regional transfer limits (between regions) and REZ transmission constraints within each region[49].

The model factors in the annual costs, including annualised capital costs, for all new generator capacity and the model optimises how much new capacity, storage and REZ transmission to build in each region to deliver the least-cost market outcome.

The model meets the specified carbon budget at least cost, which may be by either building new lower emissions plant or reducing operation of higher emissions plant, or both.

There are three main types of generation that are scheduled by the model:

- Dispatchable generators, typically coal, gas and liquid fuel which are assumed to have unlimited energy resource in general. The running cost for these generators is the sum of the VOM and fuel costs. FOM costs are another component of the running cost of generators contributing to expected earlier economic retirements[50]. Coal generators and some CCGTs have minimum loads to reflect operational stability limits and high start-up costs and this ensures they are always online when available. This is consistent with the self-commitment nature of the design of the NEM. On the other hand, peaking generators have no minimum operating level and start whenever the cost of supply is at or above their variable costs and operate for a minimum of one hour.
- Wind and solar generators are fully dispatched according to their available variable resource in each hour, unless constrained by oversupply or network limitations.
- Storage plant of all types (conventional hydro generators with storages, PHES, large-scale battery and VPPs) are operated to minimise the overall system costs. This means they tend to generate at times of high cost of supply, e.g., when the demand for power is high, and so dispatching energy-limited generation will avoid utilisation of high-cost plant such as gas-fired or liquid fuel generators. Conversely, at times of low supply cost, e.g., when there is a prevailing surplus of renewable generation capacity, storage hydro preserves energy and PHES and large-scale batteries operate in pumping or charging mode.

[49] Including additional cost for transmission upgrades to facilitate REZ development where this forms part of the input data.

[50] Note that earlier coal retirements are an outcome of the least cost optimisation rather than revenue assessment.

A2. Reserve constraint in long-term investment planning Cost-benefit analysis

As per the AEMO ISP methodology[51] assumed by the Client, the TSIRP model ensures there is sufficient dispatchable capacity in each region to meet peak demand by enforcing regional minimum reserve levels to allow for generation contingencies, which can occur at any time.
All dispatchable generators in each region are eligible to contribute to reserve (except storage[52]), as is headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the amount of reserve carried, and provides reserve from the lowest cost providers, including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

In the modelling presented in this Report, a single contingency reserve requirement was applied with a high penalty cost. This amount of reserve is intended to allow sufficient capacity for operational reliability in the event that conditions vary from the perfect-foresight optimisation model (e.g., variability in production from variable renewable energy sources, different forced outage patterns, sub-optimal operation of storage)[53].

There are two geographical levels of reserve constraints applied:

- Reserve constraints are applied to each region.
- The model ensures that interconnector headroom is backed by spare capacity in the neighbouring regions through an additional reserve constraint.

A3. Cost-benefit analysis

From the hourly time-sequential modelling, the categories of costs as listed in 0 are computed as defined in the RIT-T for actionable ISP projects.

For each scenario with Marinus Link, a matched without Marinus Link counterfactual (referred to as the Base Case) long-term generation and investment plan is simulated. The changes in each of the cost categories are computed as the forecast gross market benefits due to Marinus Link.

Each component of forecast gross market benefits is computed annually over the 25-year Modelling Period. In this Report, we summarise the forecast benefit and cost streams using a single value computed as the net present value (NPV)[54], discounted to 1 July 2025 at a 7% real, pre-tax discount rate, consistent with the 2025 IASR[55].

The forecast gross market benefits of each scenario must be compared to the cost of the Marinus Link options to determine the forecast net economic benefit for each option. That evaluation is not part of the scope of this gross market benefits assessment and hence has not been included in this

[51] AEMO, June 2023, *ISP Methodology*, available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en. Accessed 26 June 2025.

[52] PHES, VPPs and large-scale battery storages are usually fully dispatched during the peak demand periods and thus will be unable to contribute to reserve. In the event that they are not dispatched fully, it is likely that they will have insufficient energy in storage.

[53] This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size.

[54] We use the term net present value rather than present value as there are positive and negative components of market benefits captured; however, we do not consider augmentation costs.

[55] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

Report. It is performed by the Client outside of this Report using the forecast gross market benefits from this Report and other inputs.

Appendix B Transmission

B1. Regional definitions

A five-node setup was implemented in the modelling presented in this Report to represent the inter-regional network limitations and transmission losses. The regional reference node are listed in Table 7Table 7.

Table 7: Regions, zones and reference nodes

Region	Regional Reference Node (RRN)
Queensland (QLD)	South Pine 275 kV
New South Wales (NSW)	Sydney West 330 kV
Victoria (VIC)	Thomastown 66 kV
South Australia (SA)	Torrens Island 66 kV
Tasmania (TAS)	George Town 220 kV

B2. Interconnector loss models

Dynamic loss equations for the existing network are sourced from the 2023 IASR[56].

B2.1. Marinus Link loss model

Losses on interconnectors between Tasmania and Victoria (on cable and converter stations) are calculated dynamically in each dispatch interval using a loss equation. The loss is apportioned to the two regions using proportioning factor.

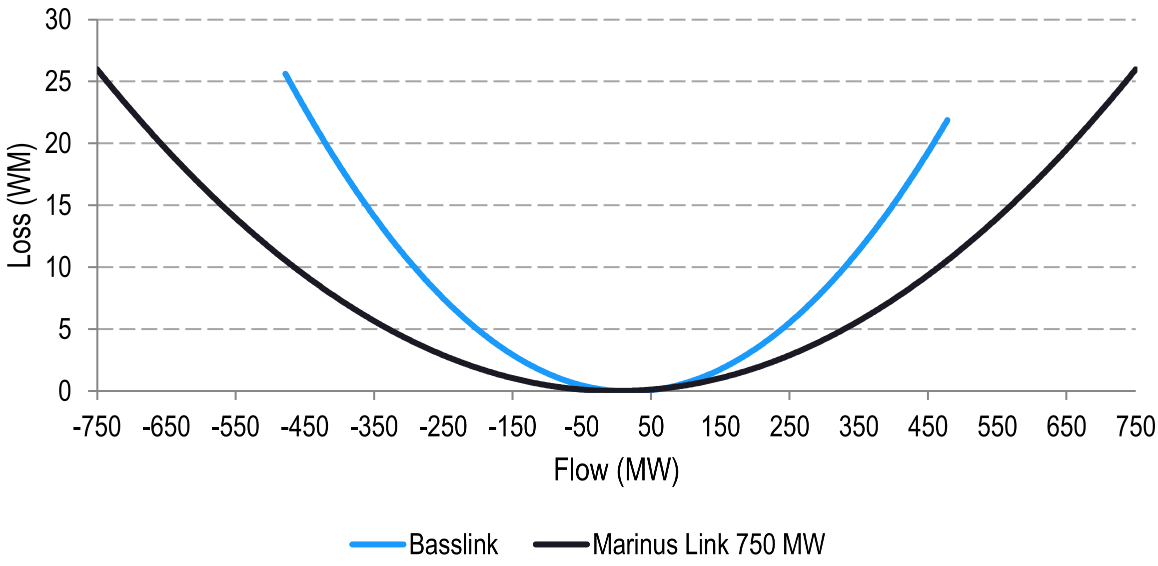
Consistent with the Marinus Link RIT-T by TasNetworks, the main assumptions for Marinus Link are[57]:

- 1,500 MW modelled as two 750 MW cables.
- There is a bi-directional flow limit of 750 MW, measured at the receiving end.
- Dynamic losses are allocated to the sending end.
- Dynamic losses along the cable are described as loss equations shown in Figure--, provided by TasNetworks. This is determined by the type of conductor, voltage of the cable and length of the cable and incorporates converter station losses.

[56] AEMO, 8 September 2023, *2023 Inputs, Assumptions and scenarios Report*, Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 6 June 2026

[57] TasNetworks, 24 June 2021, Input assumptions and scenarios workbook for Project Marinus PACR. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 16 June 2025

Figure 15: Dynamic loss equation for Marinus Link



Basslink and Marinus Link are modelled to share flows to minimize aggregate losses between Tasmania and Victoria

B3. Interconnector capabilities

The notional limits imposed on interconnectors are shown in Table 8.

Table 8: Notional Interconnector capabilities used in the modelling (sourced from the Draft 2025 IASR v7.2[58])

Interconnector (from node - To node)	Import notional limit	Export notional limit
QNI	1450 MW	950 MW
QNI Connect	3150 MW	2210 MW
Terranora	150 MW summer 200 MW winter	50 MW summer/winter
EnergyConnect (NSW-SA)	800 MW	800 MW
VIC-NSW	400 MW 2069 MW (after VNI West)	1000 MW 2935 MW (after VNI West)
Heywood (VIC-SA)	650 MW 750 MW (after EnergyConnect)	650 MW 750 MW (after EnergyConnect)
Murraylink (VIC-SA)	200 MW	220 MW
Basslink (TAS-VIC)	478 MW	478 MW
Marinus Link (TAS-VIC)	750 MW for the first stage and 1500 MW after the second stage	750 MW for the first stage and 1500 MW after the second stage

[58] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

The following interconnectors are included in the left-hand side of constraint equations which may restrict them below the notional limits specified in Table 8:

- Heywood + EnergyConnect has combined transfer export and import limits of 1,300 MW and 1450 M, respectively. The model will dispatch across the two links to minimise cost
- Basslink and Marinus Link are included in the Tasmania inertia constraints as described in the next section.

B4. Tasmania inertia constraints

An inertia constraint was included in the generation development plan to ensure the aggregate level of inertia in Tasmania is each dispatch interval is sufficient to meet minimum requirements. These minimum levels in each region can be operated in a satisfactory operating state in the event the region is islanded as defined in the National Electricity Rules[59]

A linear inertia requirement described in the Marinus Link RIT-T by TasNetworks[60]was imposed, which accounts for the effect of Tasmanian demand, interconnector flows, seasonal differences in hydro minimum loads and the effect of variable wind production and PHES development. The set of inertia constraints account for the contribution of Tasmania generators to inertia with requirements varying with import, export and Tasmania demand conditions. Applicable hydroelectric generators are also able to operate in synchronous condenser mode at a cost of $0.17/MW.s[61], as per the Marinus Link RIT-T[60]. Details of these constraints are included I this document for completeness in the remainder of this section.

The following requirements and inertia coefficients are consistent with the Marinus Link RIT-T[60].

On export, sum of terms in Table 9, hard export column ≥ 810

*On import, sum of terms in table 9, hard-import column ≥ 450 – 0.07*Tasmanian demand*

At all times, sum of terms in Table 9, hard-minimum column ≥ 3,800

Table 9: Tasmania minimum inertia left-hand side constraint terms

Term in inertia constraint equation left-hand side	Hard constraint			Constraint for synchronous condenser costing		
	Contribution on export (MW.s)	Contribution on Import (MW.s)	Contribution to minimum (MW.s)	Contribution of export (MW.s)	Contribution on Import (MW.s)	Contribution to minimum (MW.s)
TAS-VIC flow	-5.04*export flow (MW)	5.95*import flow (MW)	0	-5.04*export flow (MW)	5.95*import flow (MW)	0
Tasmanian wind	0	-1.17*dispatch (MW)	0	0	- 1.17*dispatch (MW)	0
Tasmanian PHES	3.33*capacity (MW)			3.33*dispatch (MW)		
John Butters	600			3.9*dispatch (MW)		
Poatina	1,713			5.0*dispatch (MW)		

[59] Australian Energy Market Commission, 12 August 2019, *National Electricity Rules*, version 124, 5.20B.2

[60] TasNetworks, 24 June 2021, Inputs assumptions and scenario workbook for Project Marinus PACR. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 17 June 2025

[61] In real June 2023 dollars

Term in inertia constraint equation left-hand side	Hard constraint			Constraint for synchronous condenser costing		
	Contribution on export (MW.s)	Contribution on Import (MW.s)	Contribution to minimum (MW.s)	Contribution of export (MW.s)	Contribution on Import (MW.s)	Contribution to minimum (MW.s)
Anthony Pieman	4*dispatch_no-sync (MW)* + 1,652			4*dispatch (MW)		
Gordon	4.3*dispatch_no-sync (MW)* + 626			4.3*dispatch (MW)		
Mersy Forth Lower	3.4*dispatch_no-sync (MW)* + 565			3.4*dispatch (MW)		
Mersy Forth Upper	2.8*dispatch_no-sync (MW)* +149			2.8*dispatch (MW)		
Lower Derwent	3.7*dispatch (MW)					
Tarraleah	4.0*dispatch (MW)					
Trevallyn	4.3*dispatch (MW)					
Tungatinah	3.2*dispatch (MW)					
Bell Bay	8.6*dispatch (MW)					
Tamar Valley CCGT	7.7*dispatch (MW)					
Tamar Valley OCGT	7.7*dispatch (MW)					

Since John Butters and Poatina can operate as a generator or synchronous condenser, they are assumed to contribute at full value to the hard constraint. PHES is assumed to also contribute inertia by operating as a generator, pump or synchronous condenser and so terms for each appear in the hard constraint.

The cost of operation as a synchronous condenser, when required, is computed through an additional constraint with terms using the right three columns of Table 9. These constraints can violate at a cost of 17 cents/MWs. The total violation cost is an estimate of the cost of running Poatina, John Butters and PHES as synchronous condensers to meet the minimum inertia requirement.

Appendix C Demand

The TSIRP model captures forecast demand diversity across regions by basing the overall shape of hourly demand on nine historical financial years ranging from 2010-11 to 2018-19[62]. Demand timeseries were provided to EY by AEMO through MLPL for the purpose of this modelling. The nine reference years are repeated sequentially throughout the Modelling Period as shown in Table 10.

Table 10: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2026-27	2017-18
2027-28	2018-19
2028-29	2010-11
2029-30	2011-12
2030-31	2012-13
2031-32	2013-14
2032-33	2014-15
2033-34	2015-16
2034-35	2016-17
2035-36	**2017-18**
2036-37	**2018-19**
2037-38	**2010-11**
2038-39	**2011-12**
---	**...**
2048-49	**2012-13**
2049-50	**2013-14**
2050-51	**2014-15**

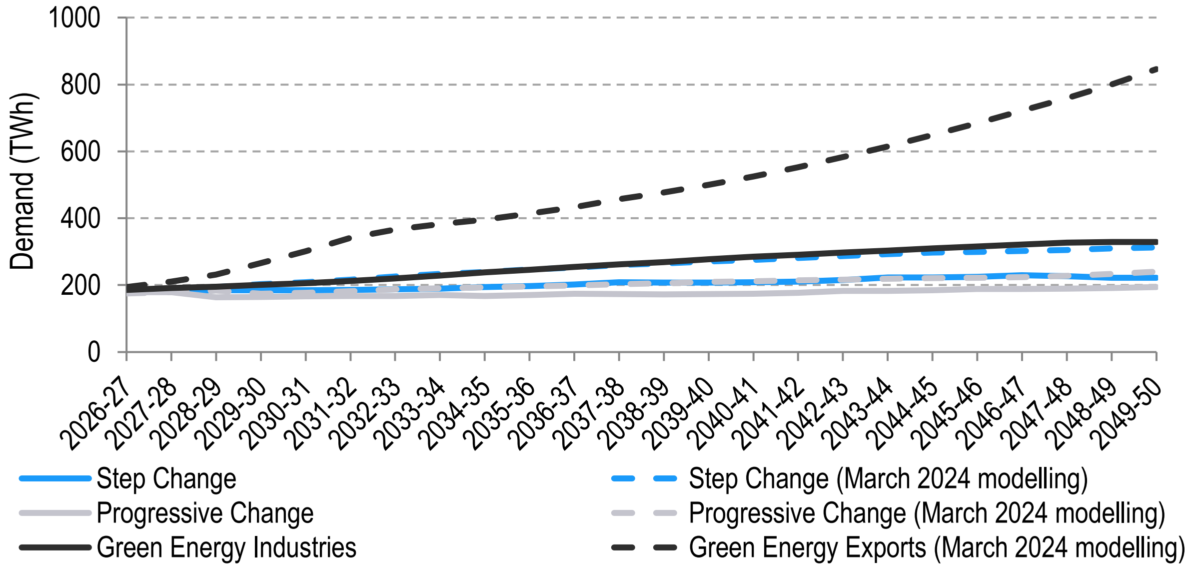
[62] These reference years were chosen due to only having Tasmanian hydro hourly traces for these nine reference years. Having more accurate Tasmanian hydro traces was deemed more material to modelling outcomes than having additional reference years.

This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to distributed PV uptake, we generally see the peak operational demand dispatch intervals shifting later in the day throughout the Modelling Period.

The reference year pattern is also consistent with site-specific hourly large-scale wind and solar availability (see Appendix D) and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and distributed PV availability.

MLPL selected demand forecasts from the ESOO 2024[63,64] consistent with the relevant scenarios in the Draft 2025 IASR[65], with the exception of hydrogen, which are used as inputs to the modelling. Figure 16 **Error! Reference source not found.**shows the assumed NEM operational demand for the modelled scenarios, inclusive of hydrogen demand.

Figure 16: Assumed annual operational demand and hydrogen demand in the modelled scenarios for the NEM[66]



In comparison to the previous modelling in March 2024, operational demand (including hydrogen) has notably decreased. There is a significant decrease in total demand in the Step Change scenario across the modelling horizon, with the total operational demand in 2050 decreasing from 312 TWh to 221 TWh. The demand in the Progressive Change and Green Energy scenarios has also decreased relative to demand in the March 2024 modelling, although the trajectory of demand in the Green Energy scenario is still significantly higher than the other scenarios in this Report.

Error! Reference source not found. Figure 17 show the assumed annual operational plus hydrogen demand for the modelled scenarios in Tasmania.

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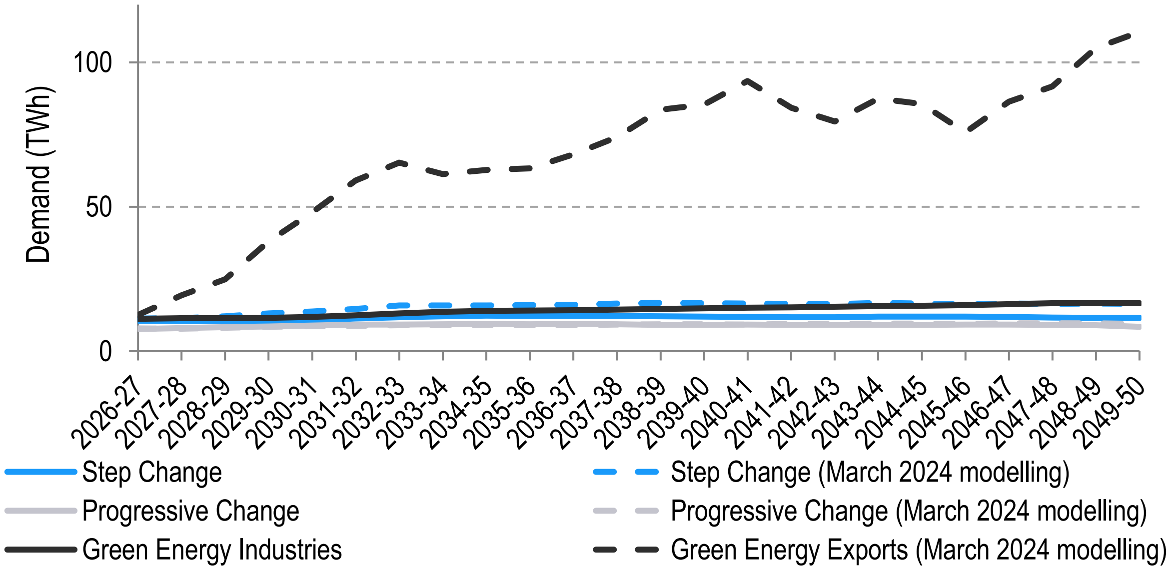
[63] AEMO, *National Electricity and Gas Forecasting*. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal. Accessed 25 June 2025

[64] At the time of modelling this was the most up to date source of demand data

[65] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. Available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

[66] The Green Energy Industries scenario was not modelled in this Report, and is shown here for illustrative purposes to understand the potential outcome if it were modelled

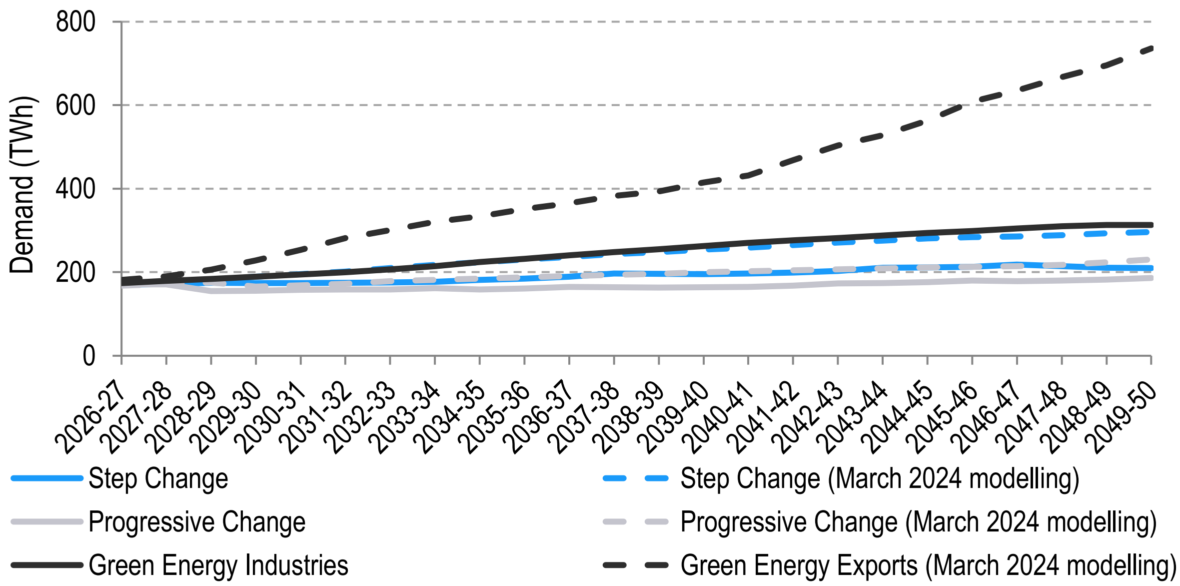
Figure 17: Assumed annual operational and hydrogen demand in the modelled scenarios for Tasmania



In the Step Change scenario, Tasmania demand has decreased significantly compared to the previous March 2024 modelling, remaining relatively flat across the modelling horizon. In the Progressive Change scenario, demand is this Report has a similar trajectory to the March 2024 modelling. Demand in the Green Energy Industries scenario increases at a much higher rate than the other scenarios, although it is significantly lower than the corresponding scenario in the March 2024 modelling.

Figure 18Figure 18 shows the assumed annual operational and hydrogen demand in the modelled scenarios in mainland NEM. The demand in mainland NEM follows a slow upward trajectory relative to Tasmania demand which increases slightly in the early 2030s before plateauing.

Figure 18: Assumed annual operational and hydrogen demand in modelled scenarios for mainland NEM

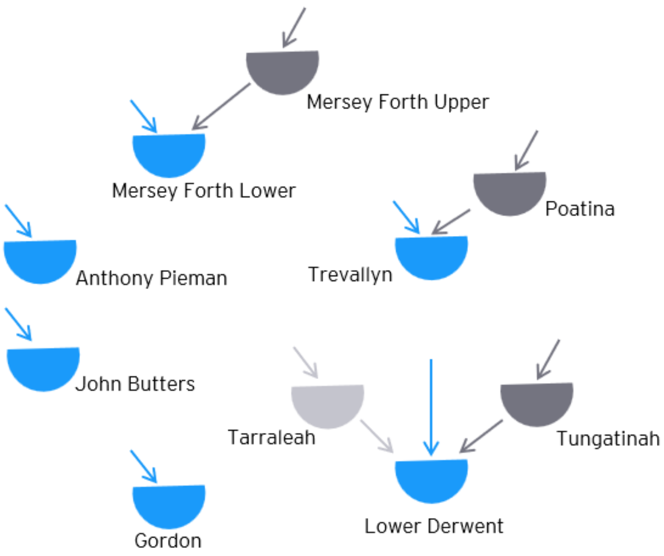


Appendix D Supply

D1. Tasmanian hydroelectric generators

Most of Hydro Tasmania's generators are part of connected systems or cascades of multiple generators and variously sized storages along various Tasmanian river systems. Consistent with the Marinus Link RIT-T by TasNetworks[67], we used a ten-pond model of the schemes which aggregated some generators within schemes. Figure 19 shows the structure of the cascades modelled. Data for modelling of the Hydro Tasmania generators was provided to MLPL by Hydro Tasmania.

Figure 19: Cascades modelled



The hourly generation profile of each scheme is determined by the model, which maximises the value of energy available. Water use in each scheme over the 25-year Modelling Period is optimised subject to reservoir levels at the start of the study, hourly inflows and minimum monthly whole-of-system reservoir levels. Hourly reservoir inflow data was sourced from Hydro Tasmania. Additionally, small non-scheduled generators are modelled explicitly and spill is allowed for all ponds except Gordon and Poatina.

The whole-of-Tasmanian system reservoir volume is known as Total Energy in Storage and the monthly minimums are the prudent storage level (PSL) profile. The PSL is imposed as part of Tasmania's energy security plan mandated by the Tasmanian Government to manage the consequences of an extended Basslink outage[68].These levels vary throughout the year to match long-term seasonal rainfall patterns as shown in Figure 20. In the model, these minimums from the Marinus Link RIT-T by TasNetworks[67] were imposed on the first day of each month.

Upon entry of Marinus Link, there is an assumed ten percentage point decrease in the PSL profile, which represents a reversion to values that were applied prior to the energy security review that followed the extended outage of Basslink in 2016. The decrease in PSL profile with Marinus Link was consistent with the Marinus Link RIT-T undertaken by TasNetworks[67]. This was selected by MLPL

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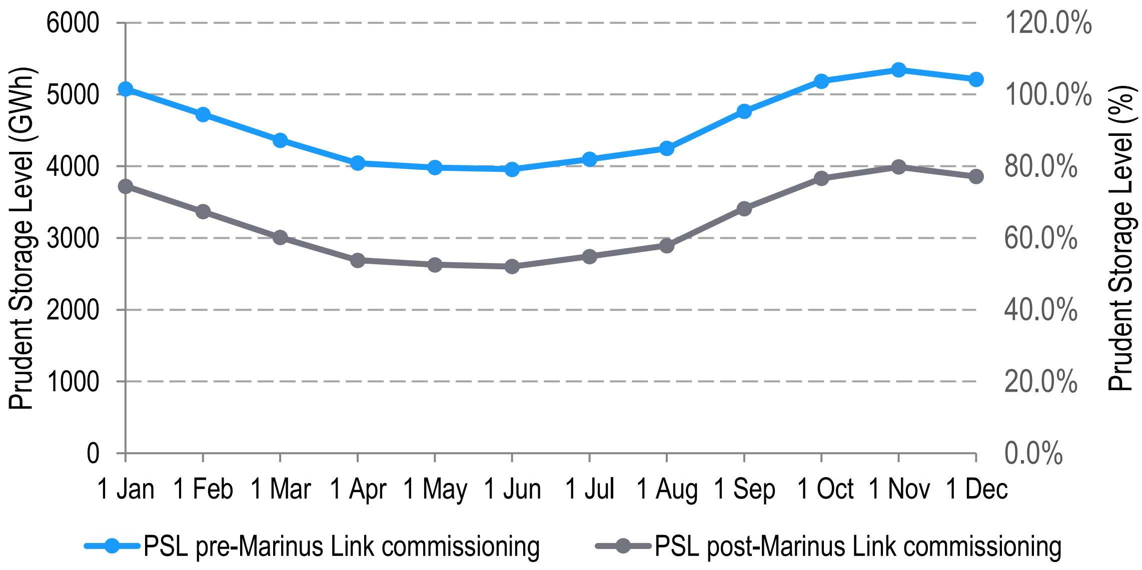
[67] TasNetworks, 24June 2021, *Input assumptions and scenario workbook for Project Marinus PACR.* Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 26 June 2024.

[68] Hydro Tasmania, *Secure Energy*. Available at: https://www.hydro.com.au/clean-energy/secure-energy. Accessed 26 June 2025.

on the basis that the assumptions detailed in the Tasmanian Energy Security Taskforce Final Report[69], upon which the PSL is based, would no longer be valid with the introduction of Marinus Link, and a revision to the former PSL profile could be justified. This PSL reduction does not represent Tasmanian Government policy. This decrease delivers a one-off quantity of additional water for generation and ongoing greater flexibility in use of Hydro Tasmania's storages.

Figure 20: Assumed PSL profile for Hydro Tasmania's reservoirs



D2. Wind and solar energy projects and REZ representation

Several generators not yet built are assumed to progress through to commercial operation in all simulations. The source of this list is AEMO's 2023 IASR Assumptions Workbook[70] for existing, committed and anticipated projects.

Existing and new wind and solar projects are modelled based on nine years of historical weather data[71] and the methodology for each category of wind and solar project is summarised in Table 11. All large-scale wind and solar availability profiles are developed by EY.

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[69] Tasmanian Government, *Tasmanian Energy Security Taskforce Final Report*. Available at: https://www.stategrowth.tas.gov.au/energy_and_resources/tasmanian_energy_security_taskforce/final_report. Accessed 26 June 2025.

[70] AEMO, 8 September 2023, *2023 IASR Assumptions Workbook v5.2*: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 27 March 2024.

[71] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 27 March 2024.

Table 11: Summary of solay and wind methodology

Technology	Category	Capacity factor methodology	Reference year treatment
Wind	Existing	Specify long-term, target based on nine-year average in AEMO ESOO 2019 traces[72], where available, otherwise past meteorological performance	Capacity factor varies with reference year based on site-specific, historical, near-term wind speed forecasts
	Committed new entrant	Reference year specific targets based on capacity factor of nearest REZ, medium quality tranche in AEMO's 2021 ISP Inputs and Assumptions workbook v3.3[73,74]	
	Generic REZ new entrants	Reference year specific targets based on AEMO's 2023 IASR workbook v.5.2[70]. One high quality option and one medium quality option per REZ	
Solar PV Fixed-Flat Plate	Existing	Annual-capacity factor based on technology and site-specific solar insolation measurements	Capacity factor varies with reference year based on site-specific, historical insolation measurements
Solar PV SAT	Existing		
	Committed new entrant	Reference year specific targets based on capacity factor of nearest REZ, medium quality tranche in AEMO's 2021 ISP Inputs and Assumptions workbook v3.373[,74]	
	Generic REZ new entrant	Reference year specific targets based on AEMO's 2023 Draft IASR workbook v5.2[70]	

All existing and committed large-scale wind and solar farms in the NEM are modelled on an individual basis. Each project has a location-specific availability profile based on historical resource availability. The availability profiles are derived using nine years of historical weather data covering financial years between 2010-11 and 2018-19 (inclusive) and synchronised with the hourly demand profile. Wind and solar availability profiles used in the modelling reflect generation patterns

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[72] AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces and 2019 Solar Traces*. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo/2019-nem-electricity-statement-of-opportunities. Accessed 10 July 2025

[73] On the whole, capacity factor estimates for medium quality tranche wind and solar PV within a REZ have not materially changed between the 2021 IASR and the 2023 IASR for the relatively small number of committed generators.

[74] AEMO, 10 December 2021, *Inputs and Assumptions Workbook v3.3*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 10 July 2025

occurring in the nine historical years, and these generation patterns are repeated throughout the Modelling Period as shown in Table 10Table 10.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[75] at a representative hub height. Wind speeds are converted into power using a generic wind farm power curve. The wind speed profiles are scaled to achieve the average target capacity factor across the nine historical years. The profiles reflect inter-annual variations, but at the same time achieve long-term capacity factors in line with historical performance (existing wind farms) or the values used in the AEMO 2019 ESOO and 2023 ISP inputs and assumptions[76] for each REZ.

The availability profiles for solar are derived using solar irradiation data from satellite imagery processed by the Australian Bureau of Meteorology. As for wind profiles, the solar profiles reflect inter-annual variations over nine historical years, but at the same time achieve long-term capacity factors in line with historical performance (existing solar farms) or target AEMO's capacity factor for each REZ.

Wind and solar capacity expansion in each REZ is limited by four parameters based on the AEMO 2023 IASR assumptions workbook[76]:

- Transmission-limited total build limit (MW) representing the amount of dispatch supported by current intra-regional transmission infrastructure.
- A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre.
- Resource limits (MW) representing the maximum amount of capacity expected to be feasibly developed in a REZ based on topography, land use etc at the given capex.
- A resource limit violation penalty factor ($/MW) to build additional capacity beyond the resource limit. This represents additional capex to build on sites with higher land costs.

The TSIRP model incurs the additional transmission expansion cost to build more capacity up to the resource limit, and potentially beyond the limit at cost, if it is part of the least-cost development plan.

AEMO's 2025 Draft IASR Assumptions workbook[77] includes intra-regional flow between nodes within the same region. Due to using a five-node model (i.e. one node per region), it is not possible to model intra-regional flow for REZ transmission limits. As a result, MLPL has agreed to revert to the final 2022 ISP assumptions[78] for REZs which are contained in intra-regional flow constraints[76,79].

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[75] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 27 March 2024.

[76] AEMO, 8 September 2023, *2023 IASR Assumptions Workbook v5.2*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 27 March 2024.

[77] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

[78] AEMO, 30 June 2022, *Input, assumptions and scenarios workbook*. Available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed 25 June 2025

[79] This was applied to several REZs in Queensland and South Australia, including Northern QLD, Isaac, Fitzroy, Wide Bay, Darling Downs, Mid North SA and Yorke Peninsula.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically (when sufficient sources of must-run generation and generation with cost at or below their VOM are available) or by other constraints such as transmission limits.

D3. Generator forced outage rates and maintenance

Full and partial forced outage rates for all generators as well as mean time to repair used in the modelling are based on the AEMO 2023 IASR Assumptions workbook.[76]

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage pattern exists between the Base Case and the with Marinus Link case. New entrant generators are de-rated by their equivalent forced outage rate.

Planned maintenance events for existing generators are scheduled during low demand periods and the number of days required for maintenance is set based on the AEMO 2023 IASR Assumptions workbook.[76]

D4. Generator technical parameters

Technical generator parameters applied are as detailed in the 2025 Draft IASR Assumptions Workbook[80] for AEMO's long-term planning model, except as noted in the Report.

D5. Coal-fired generators

Coal-fired generators are treated as dispatchable between minimum load and maximum load. Must run generation is dispatched whenever available at least at its minimum load. As with the 2025 Draft IASR Assumptions Workbook[80], maximum loads vary seasonally. This reduces the amount of available capacity in the summer periods.

D6. Gas-fired generators

Gas-fired CCGT plant also typically have a must-run component and so are dispatched at or above their minimum load to deliver efficient fuel consumption.

In line with the 2025 Draft IASR Assumptions Workbook[80], a minimum load of 46% of capacity for all new CCGTs has been applied to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

OCGTs are assumed to operate with no minimum load. As a result, they start and are dispatched for a minimum of one hour when the cost of supply is at or above their SRMC.

D7. Storage-limited generators

Conventional hydro with storages, PHES and batteries are dispatched in each interval such that they are most effective in reducing the costs of generation up to the limits of their storage capacity.

To better represent the potential for suboptimal dispatch outcomes of storage devices, AEMO has proposed to incorporate headroom and footroom reservation in storage reservoirs in the time-sequential modelling[81]. This approach is adopted to better align with AEMO's latest modelling.

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[80] AEMO, 28 February 2025, *Draft 2025 Stage 2 Inputs and Assumptions Workbook v7.2*. available at https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr. Accessed 17 June 2025

[81] AEMO, 1 April 2025, *Addressing perfect foresight for storage devices in the time-sequential model* https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/attachment--addressing-perfect-foresight-for-storage-devices-in-the-time-sequential-model.pdf?la=en. Accessed 17 June 2025

However, implementation in this modelling differs by increasing and reducing the minimum and maximum state of charge respectively, effectively limiting accessible storage capacity, rather than reserving them for access in special circumstances.

Hourly hydro inflows to the reservoirs and ponds are computed from monthly values sourced from the AEMO 2023 IASR Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied[82]. The Tasmanian hydro schemes, including run-of-river plants, were modelled using a ten-pond model, with additional information for hourly inflow data sourced from Hydro Tasmania as described in Appendix D1.Appendix D Additionally, small non-scheduled generators are modelled explicitly and spill is allowed for all ponds except Gordon and Poatina.

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[82] AEMO, 30 June 2022, *Input and Assumptions Workbook v3.4*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed 27 March 2024.

Appendix E Glossary of terms

Abbreviation	Meaning
AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australian energy Regulator
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CO_2	Carbon Dioxide
CCGT	Combined-Cycle Gas Turbine
DSP	Demand side participation
ESOO	Electricity Statement of Opportunities
EV V2G	Electric vehicle to grid battery
FOM	Fixed Operation and Maintenance
GW	Gigawatt
HVDC	High-Voltage Direct Current
ISP	Integrated System Plan
IASR	Inputs, Assumptions and Scenarios Report
$m	Million dollars
Mt	Mega Ton
MW	Megawatt
MWh	Megawatt-hour
NEM	National Enlectricity Market
NPV	Net Present Value
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
PACR	Project Assessment Conclusions Report
PHES	Pumped Hydro Energy Storage
PSL	Prudent Storage Level
PV	Photovoltaic
QEJP	Queensland Energy and Jobs Plan
QLD	Queensland
QNI	Queensland-New South Wales Interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SAT	Single Axis Tracking

Abbreviation	Meaning
SRMC	Sort-Run Marginal Cost
TAS	Tasmania
TRET	Tasmania Renewable Energy Target
TSIRP	Time-sequential integrated resource planner
USE	Unserved energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wale Interconnector
VOM	Variable operation and Maintenance
VRET	Victoria Renewable Energy Target
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital

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