Gross market benefit assessment of Marinus Link

Marinus Link Pty Ltd

28 March 2024

Building a better working world

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The results of EY's work are set out in this report ("Report"), including the assumptions and qualifications made in preparing the 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.

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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 three 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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1. Executive summary

Following the conclusion of the Project Marinus Regulatory Investment Test for Transmission (RIT-T)[1] by TasNetworks in June 2021, the electricity sector in Australia has continued to experience a period of change in policy settings and project and 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 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. It 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.[2]

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) for the three scenarios in the Australian Energy Market Operator's (AEMO) Draft 2024 Integrated System Plan (ISP) [3], being: the Step Change, Progressive Change and Green Energy Exports scenarios (the 2023-24 scenarios), as well as several sensitivities. The modelling for each of three scenarios combined the following input assumptions:

- The 2023 Input, Assumptions and Scenarios Report (2023 IASR)[4] relating to policies, costs and generator technical parameters.
- AEMO's August 2023 Electricity Statement of Opportunities[5] demand projections provided by AEMO to Marinus Link Pty Ltd (consistent with AEMO's demand projections in the Draft 2024 ISP[3]).
- The assumed timing for major transmission upgrades based on AEMO's outcomes from the Draft 2024 ISP[3].

The 2023-24 scenarios adhere to the following philosophies, which were developed by AEMO in consultation with stakeholders:[6]

- 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 2021 AEMO IASR

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[1] TasNetworks, 24 June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 27 March 2024.
[2] MLPL, 28 March 2024, *RIT-T Update – Summary Report*, Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 28 March 2024.
[3] AEMO, 15 December 2023, *Draft 2024 ISP*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 27 March 2024.
[4] 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.
[5] AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 27 March 2024.
[6] AEMO, July 2023, *2023 IASR Report*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en. Accessed 27 March 2024.

Step Change scenario. The scenario name 'Step Change' is the same as the name of a scenario in TasNetworks[1] the Project Marinus RIT-T, but the underlying assumptions are different.

- 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.
- Green Energy Exports: Very strong decarbonisation domestically and global, including the strong use of electrification, green hydrogen and biomethane. This is a refinement of the 2021 AEMO IASR Hydrogen Superpower scenario. Assumed Tasmanian load is highest in this scenario.

Common policy settings across the three 2023-24 scenarios include the Federal Government's 82% renewables target by 2030, NSW Electricity Infrastructure Roadmap target, Queensland Renewable Energy Target, Tasmanian Renewable Energy Target, Victorian Renewable Energy Target, Victorian Energy Storage Target and the Victorian Offshore Wind Target.

The modelling methodology follows the *Cost benefit analysis guidelines* (CBA guidelines) published by the Australian Energy Regulator (AER),[7] 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 and with several different Marinus Link size and timing options across the scenarios and sensitivities:

- Without-Marinus Link and two sizes of Marinus Link: one 750 MW link and two 750 MW links to give a total of 1,500 MW transfer capacity.
- The first stage of Marinus Link commissioned during 2029-30 and different timings for the second stage of Marinus Link ranging in two-year increments from 2031-32 to 2035-36.

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[8], large-scale battery, PHES.
- The withdrawal of existing generation on a least-cost basis, often to meet the emissions budgets assumed in the modelled scenario and sensitivities.

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.

[7] Australian Energy Regulator, 25 August 2020, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. Accessed 27 March 2024.

[8] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Combined-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine.

- 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, as defined in the ISP 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[9]:

- 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 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.

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 with Marinus Link case and the without Marinus Link Base Case across the 26-year period (the Modelling Period), from 2024-25 to 2049-50. The difference in the calculated present value of costs is the forecast gross market benefits[10] associated with Marinus Link proceeding. The gross market benefits are discounted to 1 July 2023 using a 7% real, pre-tax discount rate, consistent with the central value applied by AEMO in the 2023 AEMO IASR[11] as selected by Marinus Link Pty Ltd. This discount rate is higher than those applied in previous Marinus Link studies (such as the RIT-T) and as such the outcomes detailed below are not directly comparable. A summary of the gross market benefits of Marinus Link in the three scenarios over the Modelling Period is shown in Table 1.

Table 1: Overview of scenarios with associated forecast gross market benefits for Marinus Link over the Modelling Period discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.

Marinus Link size	Marinus Link timing	Step Change	Progressive Change	Green Energy Exports	Scenario weighted average[12]
1,500 MW	2029-30 & 2033-34	4,035	5,664	6,160	5,038

[9] Australian Energy Regulator, 25 August 2020, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. Accessed 27 March 2024.

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

[11] 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.

[12] AEMO, 15 December 2023, *Draft 2024 ISP*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 27 March 2024.

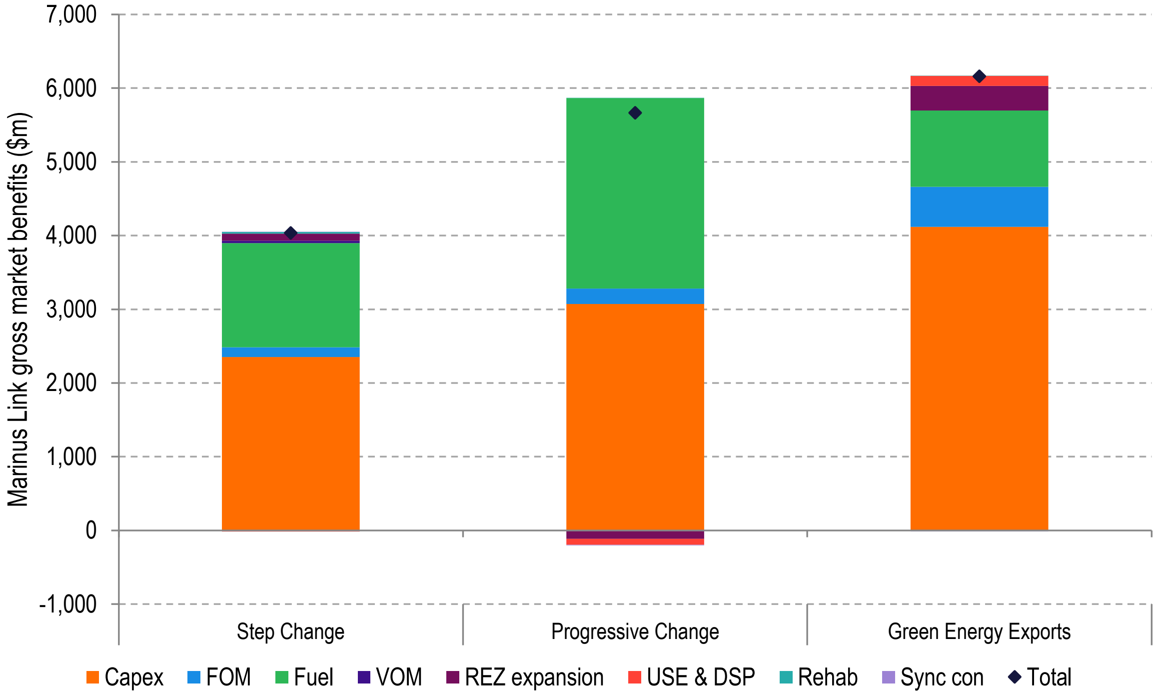
Marinus Link size	Marinus Link timing	Step Change	Progressive Change	Green Energy Exports	Scenario weighted average[12]
750 MW	2029-30	3,283	4,460	4,767	4,000

Figure 1 shows that in all scenarios, there are two key drivers of forecast benefits for Marinus Link:

- The largest driver is capex savings 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 use of coal and gas as fuel.

This is consistent with the two largest sources of forecast benefits from the Project Assessment Conclusions Report (PACR) for the Marinus Link RIT-T by TasNetworks[13].

Figure 1: Composition of forecast total gross market benefits of Marinus Link stage 1 2029-30 and stage 2 2033-34 over the Modelling Period discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.



The forecast capex savings associated with Marinus Link are predominantly driven by the combination of high capacity factor wind resource in Tasmania, as per the 2023 AEMO IASR assumptions, coupled with the legislated Tasmanian Renewable Energy Target (TRET). By better connecting Tasmania with the mainland, Marinus Link is forecast to unlock the potential for high quality Tasmanian wind, new entrant Tasmanian PHES and existing conventional Tasmanian hydroelectric power stations to offset the need for higher cost mainland renewable capacity and gas-fired 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, as a lower cost alternative to the construction and operation of dispatchable gas on the mainland. The extent of these saving varies by scenario, along with the size and timing of Marinus Link. For the Green Energy Exports scenario, fuel cost savings

[13] TasNetworks, 24 June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 27 March 2024.

are also forecast to accrue due to a reduction in generation from hydrogen turbines from the late-2030s with Marinus Link.

The Progressive Change scenario is forecast to have higher potential benefits for Marinus Link compared to the Step Change scenario. This is primarily due to the Progressive Change scenario having less Tasmanian demand than the Step Change scenario, as per the 2023 AEMO IASR assumptions. In the Progressive Change scenario, without Marinus Link, much of the new renewable generation that is forecast to be installed in Tasmania to achieve the TRET is curtailed, or spilled, since local Tasmanian demand is not high enough to fully utilise this generation. While this still occurs in the Step Change scenario, the additional Tasmanian load reduces the volume of spilled renewable generation without Marinus Link. When included, Marinus Link is forecast to better connect Tasmania with the mainland, which allows the rest of the NEM to benefit from Tasmanian renewable capacity.

The Green Energy Exports scenario is forecast to have higher benefits for Marinus Link compared to the Step Change scenario. For this scenario, potential capex benefits are not only forecast to occur in the mainland, but also in Tasmania. As per the 2023 AEMO IASR assumptions, Tasmanian electricity consumption increases significantly over the Modelling Period in the Green Energy Exports scenario due to assumed hydrogen production. By the early 2030s, assumed Tasmanian demand is approximately six-fold higher than current annual consumption. The TSIRP model captures wind and solar diversity across NEM regions by basing their hourly availability profile on multiple historical weather patterns targeting different capacity factors for each weather reference year. Due to the variable nature of renewable energy, some forecast years have lower availability than others. During the forecast years coinciding with lower-than-average capacity factors, Tasmania can import more energy from the mainland with Marinus Link, compared to the without-Marinus Link counterfactual. This is forecast to result in capex savings for Tasmania, since it provides a lower cost alternative than overbuilding capacity to ensure Tasmania can supply hydrogen production targets during years of low variable renewable availability.

Prior to the release of the Draft 2024 ISP, MLPL had also instructed EY to model the Step Change, Progressive Change, Green Energy Exports scenarios and several sensitivities in anticipation of the Draft 2024 ISP publication in December 2023. That modelling had been done based on AEMO's latest information at the time. As a result, those scenarios (referred to in this Report as the Pre-Draft ISP scenarios) and their sensitivities assumed the timing of major transmission upgrades based on the Final 2022 ISP outcomes. There were also several other smaller changes to input assumptions based on interpretation of the 2023 IASR prior to the publication of the Draft 2024 ISP including:

- Queensland coal-fired generator maximum retirement dates extended beyond the expected closure year associated with the Queensland Energy and Jobs Plan (QEJP).
- Virtual power plant (VPP) were not assumed to contribute to meeting the Victoria Energy Storage Target of 2.6 GW by 2030 and 6.3 GW by 2035.

These sensitivities explored the alternative timing of the second stage of Marinus Link.

Other sensitivities in this Report include a hydrogen load adjustment, a change in committed Tasmanian pumped hydro energy storage (PHES) capacity, a delay in the Victorian offshore wind target, different discount rates, different gas prices and different battery capital costs.

Table 2 summarises the forecast gross market benefits associated with the sensitivities for the timing and size of Marinus Link, which were computed in November 2023, prior to the publication of AEMO's Draft 2024 ISP. Table 2 shows that if the assumed Marinus Link timing is unchanged, then there is a relatively small change in forecast gross market benefits – the difference is shown in brackets and reflects the difference in gross market benefits in Table 2 compared to Table 1. By inference the relative magnitude of forecast benefits between different assumed timings for Marinus Link would be similar for the Draft 2024 ISP scenarios.

Table 2: Overview of forecast gross market benefits for Marinus Link in the Pre-Draft ISP scenarios discounted to 1 July 2023 and change relative to core scenarios in brackets. All dollar values are presented in $million, real June 2023.

Marinus Link size	Marinus Link timing	Pre-Draft ISP Step Change-	Pre-Draft ISP Progressive Change	Pre-Draft ISP Green Energy Exports	Scenario weighted average[14]
1,500 MW	2029-30 & 2031-32	4,336	6,038	6,395	5,359
	2029-30 & 2033-34	4,224 (+189)	5,953 (+290)	6,164 (+4)	5,241 (+204)
	2029-30 & 2035-36	4,105	5,812	5,914	5,093
750 MW	2029-30	3,502 (+219)	4,691 (+231)	4,768 (+1)	4,191 (+191)

One of the primary drivers for differences between the core scenarios in this Report compared to the Pre-Draft ISP scenarios is changes in augmentation timings between the Draft 2024 ISP[14] and the Final 2022 ISP[15]. The Pre-Draft ISP scenarios include later timings for augmentations, such as VNI West, and some differences in REZ transmission assumptions associated with interconnector projects, resulting in small increases in forecast benefits of Marinus Link.

Several sensitivities were selected by MLPL to test the robustness of the magnitude of market benefits. All sensitivities were conducted on the Pre-Draft ISP Step Change scenario with Marinus Link stage 1 2029-30 and stage 2 2033-34 which had a forecast gross market benefit of $4,224m. An overview of the sensitivities is given in Table 3.

Table 3: Overview of sensitivities with associated forecast gross market benefits for Marinus Link stage 1 2029-30 and stage 2 2033-34 discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.

Sensitivity	Variation to Pre-Draft ISP scenario	Forecast gross market benefits ($m)	Change in forecast market benefits ($m)
Progressive hydrogen load	The Step Change Tasmanian hydrogen load trajectory is replaced with the Progressive Change hydrogen load trajectory.[16]	5,317	1,093
750 MW committed Tasmanian PHES	A 750 megawatt (MW) Tasmanian Pumped Hydro Energy Storage (PHES) project is committed from 2032-33.	4,904	680
Victoria offshore wind delay	Victorian offshore wind targets delayed by 5 years, with the 9 gigawatt (GW) capacity target now to be met in 2045-46.	4,394	170
High gas price	Gas prices for all existing and new entrant generators increased by 40% from the 2023 AEMO IASR Step Change scenario.[16] e.g. Victorian OCGT gas price ranging between $15/GJ and $20/GJ from the mid-2020s onward.	4,801	576
Low gas price	Gas prices for all existing and new entrant generators decreased by 40% from the 2023 AEMO IASR Step Change scenario. [16] e.g. Victorian OCGT gas price ranging between $6/GJ and $9/GJ from the mid-2020s onward.	3,411	-814

[14] AEMO, 15 December 2023, *Draft 2024 ISP*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 27 March 2024.

[15] AEMO, 30 June 2022, *2022 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed 27 March 2024.

[16] 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.

Sensitivity	Variation to Pre-Draft ISP scenario	Forecast gross market benefits ($m)	Change in forecast market benefits ($m)
High battery capital cost	Apply the 2023 AEMO IASR Progressive Change battery capex scenario (higher than the Step Change trajectories).[16]	4,254	29
Low battery capital cost	Apply the 2023 AEMO IASR Green Energy Exports battery capex scenario (lower than the Step Change trajectories).[16]	3,977	-248

Benefits for Marinus Link are forecast to increase in scenarios with lower Tasmanian demand, increased Tasmanian storage capacity and delayed Victorian offshore wind targets. The forecast increase in capex and fuel cost benefits under these scenarios are predominantly attributed to Marinus Link being able to export relatively higher amounts of renewable energy from Tasmania to the mainland, displacing higher cost gas generation. The high gas price sensitivity is also forecast to lead to greater Marinus Link gross market benefit due to more incentive to build new wind and solar capacity to avoid higher cost gas generation. The opposite true for the low gas price sensitivity. A small additional benefit is forecast for the high battery capital cost sensitivity and vice versa for the low battery capital cost sensitivity.

Further sensitivities adjusting the discount rate were also run on the Pre-Draft ISP Step Change scenario with Marinus Link stage 1 2029-30 and stage 2 2033-34, which are described in Table 4. Note that for the discount rate sensitivities, the alternate rates were applied when annualising costs to compute the least-cost solution and to the annual market benefit outcomes (rather than just discounting annual market benefits outcomes with the alternate discount rate). A different discount rate would also need to be applied to the costs of Marinus Link used in the calculation of net economic benefits.

Table 4: Overview of adjusted discount rate sensitivities with associated forecast gross market benefits for Marinus Link stage 1 2029-30 and stage 2 2033-34 for the Pre-Draft ISP Step Change scenario discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.

Sensitivity	Variation to Pre-Draft ISP scenario	Forecast gross market benefits ($m)
High discount rate	An increased discount rate and weighted-average-cost-of-capital (WACC) of 10.50% has been applied for the selected scenario, in line with the 2023 AEMO IASR upper bound.[17]	3,186
Low discount rate	A reduced discount rate and WACC of 3.00% has been applied for the selected scenario, in line with the 2023 AEMO IASR lower bound.[17]	6,084

Since Marinus Link is forecast to have positive gross market benefits from the time it is assumed to be commissioned, an increase in the discount rate leads to a decrease in the total discounted market benefits. The alternate rates also lead to different least-cost capacity mix outcomes. A lower rate promotes technologies with longer repayment periods to become more competitive and the weighting of later decisions increases. This is observed when the discount rate is reduced as more PHES capacity is forecast instead of large-scale battery storage. Wind capacity is also forecast to be built in marginally higher amounts. As the amount of new entrant capacity increases, Marinus Link therefore has greater ability to defer capital expenditure resulting in higher gross market benefits. The opposite is true for a higher discount rate which is forecast to result in lower discounted gross market benefits for Marinus Link.

[17] 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.

2. Introduction

Marinus Link Pty Ltd has engaged EY to undertake market modelling of system costs to forecast the gross market benefits to the NEM of an addition 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, prepared and published by MLPL.[18]

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the NEM for the three scenarios in the Draft 2024 ISP [19], being: the Step Change, Progressive Change and Green Energy Exports scenarios (the 2023-24 scenarios), as well as several sensitivities. The modelling for each of three scenarios combined the following:

- The 2023 IASR[20] input assumptions relating to policies, costs and generator technical parameters.
- AEMO's August 2023 Electricity Statement of Opportunities[21] demand projections by AEMO provided to Marinus Link Pty Ltd (consistent with AEMO's demand projections in the Draft 2024 ISP).
- The assumed timing for major transmission upgrades based on AEMO's outcomes from the Draft 2024 ISP, published in December 2023.[19]

The modelling methodology follows the CBA guidelines for actionable ISP projects published by the AER[22]. The model was used to compute a plan without Marinus Link and with several different Marinus Link size and timing options across the three scenarios and a range of sensitivities:

- Without-Marinus Link and two sizes of Marinus Link: one 750 MW link and two 750 MW links to give a total of 1,500 MW transfer capacity.
- The first stage of Marinus Link commissioned during 2029-30 and different timings for the second stage of Marinus Link ranging in two-year increments from 2031-32 to 2035-36.
- Various sensitivities to input assumptions across a selected scenario including a hydrogen load adjustment, a change in committed Tasmanian PHES capacity, a delay in the Victorian offshore wind target, different discount rates, different gas prices and different battery costs.

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

- Capital costs of new generation and storage capacity installed.

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[18] MLPL, 28 March 2024, *RIT-T Update – Summary Report*, Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 28 March 2024.

[19] AEMO, 15 December 2023, *Draft 2024 ISP*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 27 March 2024.

[20] 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.

[21] AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 27 March 2024.

[22] Australian Energy Regulator, 25 August 2020, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. Accessed 27 March 2024.

- Total 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 and involuntary load curtailment.
- 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.

Each category of forecast gross market benefits is computed annually across the 26-year Modelling Period, from 2024-25 to 2049-50. The forecast benefits presented are discounted to 1 July 2023 using a 7% real, pre-tax discount rate, consistent with the central value applied by AEMO in the 2023 IASR[23].

The forecast gross market benefits of each scenario and sensitivity 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 provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.
- Section 5 outlines model design and input data related to representation of the transmission network and transmission losses.
- Section 6 outlines model design and input data related to demand.
- Section 7 provides an overview of model inputs and methodologies related to supply of energy.
- Section 8 presents the NEM capacity and generation outlook without Marinus Link for the three scenarios.
- Section 9 presents the forecast gross market benefits associate with Marinus Link. It is focussed on identifying and explaining the key sources of forecast gross market benefits for the Step Change scenario, while providing a summary of other scenarios and sensitivities.

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[23] 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.

3. Scenario assumptions

3.1 Overview of input assumptions for scenarios

Marinus Link gross market benefits have been forecast under the Step Change, Progressive Change and Green Energy Exports scenarios in accordance with CBA guidelines for actionable ISP projects published by the Australian Energy Regulator. The modelling combines input assumptions on policies, costs and generator technical parameters from the AEMO 2023 IASR[24] with demand projections provided by AEMO to MLPL in September 2023 for use in this assessment and assumed timing of major transmission upgrades based on the Draft 2024 Integrated System Plan (ISP) outcomes[25]. A more comprehensive list of assumptions and their sources is summarised in Table 5. All input assumptions were selected by MLPL in accordance with the CBA guidelines.

Table 5: Overview of key input parameters in the Step Change, Progressive Change and Green Energy Exports scenarios

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Green Energy Exports
Underlying consumption	2023 ESOO[26] - Step Change	2023 ESOO[26] - Progressive Change	2023 ESOO[26] - Green Energy Exports
Committed and anticipated generation	Committed and anticipated generators from the 2023 IASR Assumptions Workbook[24]		
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PHES large-scale batteries and hydrogen turbine	2023 IASR Assumptions Workbook[24] - Step Change	2023 IASR Assumptions Workbook[24] - Progressive Change	2023 IASR Assumptions Workbook[24] - Green Energy Exports
Retirements of coal-fired power stations	2023 IASR Assumptions Workbook[24]: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives. Queensland coal retirements no later than the QEJP retirement schedule. Consistent with Draft 2024 Integrated System Plan (ISP) outcomes[25]		
Gas fuel price	2023 IASR Assumptions Workbook[24] - Step Change	2023 IASR Assumptions Workbook[24] - Progressive Change	2023 IASR Assumptions Workbook[24] - Green Energy Exports
Coal fuel price	2023 IASR Assumptions Workbook[24] - Step Change	2023 IASR Assumptions Workbook[24] - Progressive Change	2023 IASR Assumptions Workbook[24] - Green Energy Exports
NEM carbon budget	2023 IASR Assumptions Workbook[24] - Step Change: 681 mega ton (Mt) CO_2-e 2024-25 to 2051-52	2023 IASR Assumptions Workbook[24] - Progressive Change: 1,203 Mt CO_2-e 2024-25 to 2051-52	2023 IASR Assumptions Workbook[24] - Green Energy Exports: 357 Mt CO_2-e 2024-25 to 2051-52
Federal renewable energy target	82% share of renewable generation by 2029-30 Consistent with 2023 IASR Assumptions Workbook[24]		

[24] 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.

[25] AEMO, 15 December 2023, *Draft 2024 ISP*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 27 March 2024.

[26] AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 27 March 2024.

<table>
<tr><th rowspan="2">Key drivers input parameter</th><th colspan="3">Scenario</th></tr>
<tr><th>Step Change</th><th>Progressive Change</th><th>Green Energy Exports</th></tr>
<tr><td>Victoria policy</td><td colspan="3">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 2023 IASR Assumptions Workbook[24]</td></tr>
<tr><td>Queensland Renewable Energy Target (QRET)</td><td colspan="3">50% by 2029-30, 70% by 2031-32 and 80% by 2034-35
Consistent with 2023 IASR Assumptions Workbook[24]</td></tr>
<tr><td>Tasmanian Renewable Energy Target (TRET)</td><td colspan="3">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 2023 IASR Assumptions Workbook[24]</td></tr>
<tr><td>NSW Electricity Infrastructure Roadmap</td><td colspan="3">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 2023 IASR Assumptions Workbook[24]</td></tr>
<tr><td>Victorian SIPS</td><td colspan="3">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 2023 IASR Assumptions Workbook[24]</td></tr>
<tr><td>EnergyConnect</td><td colspan="3">2024 ISP committed project[27]: EnergyConnect commissioned by July 2026</td></tr>
<tr><td>Western Renewables Link</td><td colspan="3">2024 ISP anticipated project[27]. Western Victoria upgrade commissioned by July 2027</td></tr>
<tr><td>HumeLink</td><td>Draft 2024 ISP outcome[27] – Step Change: HumeLink commissioned by July 2029</td><td>Draft 2024 ISP outcome[27] – Progressive Change: HumeLink commissioned by July 2030</td><td>Draft 2024 ISP outcome[27] – Green Energy Exports: HumeLink commissioned by July 2029</td></tr>
<tr><td>New-England REZ Transmission</td><td>Earliest in-service date advised by proponent[27]:
▶ New England REZ Transmission Link 1 commissioned by September 2028,
Draft 2024 ISP outcome[27] – Step Change:
▶ New England REZ Upgrade commissioned by July 2030,
▶ New England REZ Transmission Link 2 commissioned by July 2034</td><td>Draft 2024 ISP outcome[27] – Progressive Change:
▶ New England REZ Transmission Link 1 commissioned by July 2031,
▶ New England REZ Upgrade commissioned by July 2031
▶ New England REZ Extension commissioned by July 2042</td><td>Earliest in-service date advised by proponent[27]:
▶ New England REZ Transmission Link 1 commissioned by September 2028,
Draft 2024 ISP outcome[27] – Green Energy Exports:
▶ New England REZ Upgrade commissioned by July 2030,
▶ New England REZ Transmission Link 2 commissioned by July 2032</td></tr>
<tr><td>Marinus Link</td><td colspan="3">Several different size and timings as per MLPL assumptions: The first stage of Marinus Link commissioned by October 2029 and the second stage of Marinus Link commissioned by July 2033.</td></tr>
</table>

[27] Scenario specific optimal timing updated based on earliest estimated commissioning date from relevant Transmission Network Service Provider. AEMO, *Appendix 5: 2024 Integrated System Plan*, available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/appendices/a5-network-investments.pdf?la=en. Accessed 27 March 2024.

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Green Energy Exports
Queensland-New South Wales interconnector (QNI) Connect	Draft 2024 ISP outcome[27] – Step Change: QNI Connect commissioned by July 2033	Draft 2024 ISP outcome[27] – Progressive Change: QNI Connect commissioned by July 2036	Draft 2024 ISP outcome[27] – Green Energy Exports: QNI Connect commissioned by July 2030
Victoria-New South Wales Interconnector (VNI) West	Earliest in-service date advised by proponent[27]: VNI West commissioned by December 2029	Draft 2024 ISP outcome[27] – Progressive Change: VNI West commissioned by July 2034	Draft 2024 ISP outcome[27] – Green Energy Exports: VNI West commissioned by July 2031
Snowy 2.0	Snowy 2.0 is commissioned by December 2029 Consistent with the 2023 IASR Assumptions Workbook[24].		
Borumba PHES	Borumba PHES is commissioned by July 2030 Consistent with the nearest financial year in the 2023 IASR Assumptions Workbook[24]		
Discount rate	7% real, pre-tax[24]		

3.2 Overview of input assumptions for Pre-Draft ISP scenarios

The sensitivities completed in November 2023, prior to the publication of the Draft 2024 ISP assume the timing of major transmission upgrades and associated increase in REZ transmission limits based on the 2022 ISP outcomes[28] as summarised in Table 6. There were also several other smaller changes to input assumptions based on interpretation of the 2023 IASR prior to the publication of the Draft 2024 ISP including:

- Queensland coal-fired generator maximum retirement dates extended beyond the expected closure year associated with the QEJP.
- Virtual power plant (VPP) were not assumed to contribute to meeting the Victoria Energy Storage Target of 2.6 GW by 2030 and 6.3 GW by 2035.
- Revised Tranche 2 transmission expansion cost for Central West Orana from $0.08m/MW to $0.16m/MW to reflect updated scope and alignment with the New South Wales Network Infrastructure Strategy.

This Report refers to these as the Pre-Draft ISP scenarios.

Table 6: Overview of key input parameters in the Pre-Draft ISP Step Change, Progressive Change and Green Energy Exports scenarios

Key drivers input parameter	Pre-Draft ISP scenario		
	Step Change	Progressive Change	Green Energy Exports
EnergyConnect	2022 ISP anticipated project[29]: EnergyConnect commissioned by July 2026		
Western Renewables Link	2022 ISP anticipated project[27]. Western Victoria upgrade commissioned by July 2026 +1 year		

[28] AEMO, 30 June 2022, *2022 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed 27 March 2024.
[29] AEMO, *Appendix 5: 2022 Integrated System Plan*, available at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a5-network-investments.pdf?la=en. Accessed 27 March 2024.

Key drivers input parameter	Pre-Draft ISP scenario		
	Step Change	Progressive Change	Green Energy Exports
HumeLink	2022 ISP outcome[27] - Step Change: HumeLink commissioned by July 2028 -1 year	2022 ISP outcome[27] - Progressive Change: HumeLink commissioned by July 2035 +5 years	2022 ISP outcome[27] - Hydrogen Superpower: HumeLink commissioned by July 2027 -2 years
New-England REZ Transmission	2022 ISP outcome[27] - Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035 Stage 1: -1 year Stage 2: +1 year	2022 ISP outcome[27] - Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038 Stage 1: -4 year Stage 2: -4 year	2022 ISP outcome[27] - Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031 Stage 1: -1 year Stage 2: -1 year
Marinus Link	Several different size and timings as per MLPL assumptions: The first stage of Marinus Link commissioned by October 2029 and different timings for the second stage of Marinus Link ranging in two-year increments from July 2031 to July 2035.		
Queensland-New South Wales interconnector (QNI) Connect	2022 ISP outcome[27] - Step Change: QNI Connect commissioned by July 2032 -1 year	2022 ISP outcome[27] - Progressive Change: QNI Connect commissioned by July 2036 No change	2022 ISP outcome[27] - Hydrogen Superpower: QNI Connect commissioned by July 2029 -1 year
Victoria-New South Wales Interconnector (VNI) West	2022 ISP outcome[27] - Step Change: VNI West commissioned by July 2031 +2 years	2022 ISP outcome[27] - Progressive Change: VNI West commissioned by July 2038 +4 years	2022 ISP outcome[27] - Hydrogen Superpower: VNI West commissioned by July 2030 +1 year

3.3 Differences in assumptions with and without Marinus Link

Across all scenarios and sensitivities, development of Marinus Link is associated with the following four additional changes assumed by MLPL consistent with the AEMO 2023 IASR[30]:

- A 100 MW expansion of West Coast power scheme's capacities[31].
- A 150 MW upgrade of Tarraleah's capacity and a 90 MW upgrade of Gordon's 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 $0.29m/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.

[30] 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.

[31] 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.

MLPL also assumed a 10 percentage point decrease in monthly minimum whole of system reservoir volumes in Tasmania (Prudent Storage Levels, PSLs).[32]

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 changes in gross market benefits resulting from these changes.

[32] 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 Section 7.1. The decrease in PSL profile with Marinus Link is a modelling assumption selected by TasNetworks for the Marinus Link RIT-T and does not represent Tasmanian Government policy.

4. Methodology

4.1 Long-term investment planning

EY has applied linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 26 years from 2024-25 to 2049-50. The modelling methodology follows the CBA guidelines for actionable ISP projects published by the Australian Energy Regulator[33]. 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 costs 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 for all generation capacity.
- DSP and USE costs.
- 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.

Transmission[34] and storage losses form part of the demand to be supplied and are calculated dynamically within the model within the cost minimisation objective.

To determine the least-cost solution, the model makes decisions for each hourly[35] 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 onshore wind, offshore wind, solar PV SAT, CCGT, OCGT, large-scale battery and PHES.

These hourly decisions take into account 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).

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33 Australian Energy Regulator, 25 August 2020, *Cost benefit analysis guidelines*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. Accessed 27 March 2024.

34 For the transmission elements modelled, described in Section 5.

35 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.

- Transmission access and resource build limits for wind and solar in each REZ and costs associated with increasing these limits.
- 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[36].

The model factors in the annual costs, including annualised capital costs, for all new generator capacity and the model decides 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[37]. 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 spilled due to oversupply or constrained by 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.

4.2 Reserve constraint in long-term investment planning

As per the AEMO ISP methodology[38] assumed by MLPL, 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[39]) and 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,

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

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

[38] 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 27 March 2024.

[39] 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.

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)[40].

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.

4.3 Cost-benefit analysis

From the hourly time-sequential modelling, the cost categories listed in Section 4.1 are computed as defined in the RIT-T for actionable ISP projects.

For each scenario and sensitivity 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 26-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)[41], discounted to 1 July 2023 at a 7% real, pre-tax discount rate, consistent with the 2023 IASR[42].

The forecast gross market benefits of each scenario and sensitivity need to be compared to the cost in the relevant case to determine whether there is a positive forecast net economic benefit. That 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.

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

[41] 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.

[42] 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.

5. Transmission

5.1 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 regions and regional reference nodes are listed in Table 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

5.2 Interconnector loss models

Dynamic loss equations for the existing network are sourced from the 2023 IASR.[43]

5.2.1 Marinus Link loss model

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

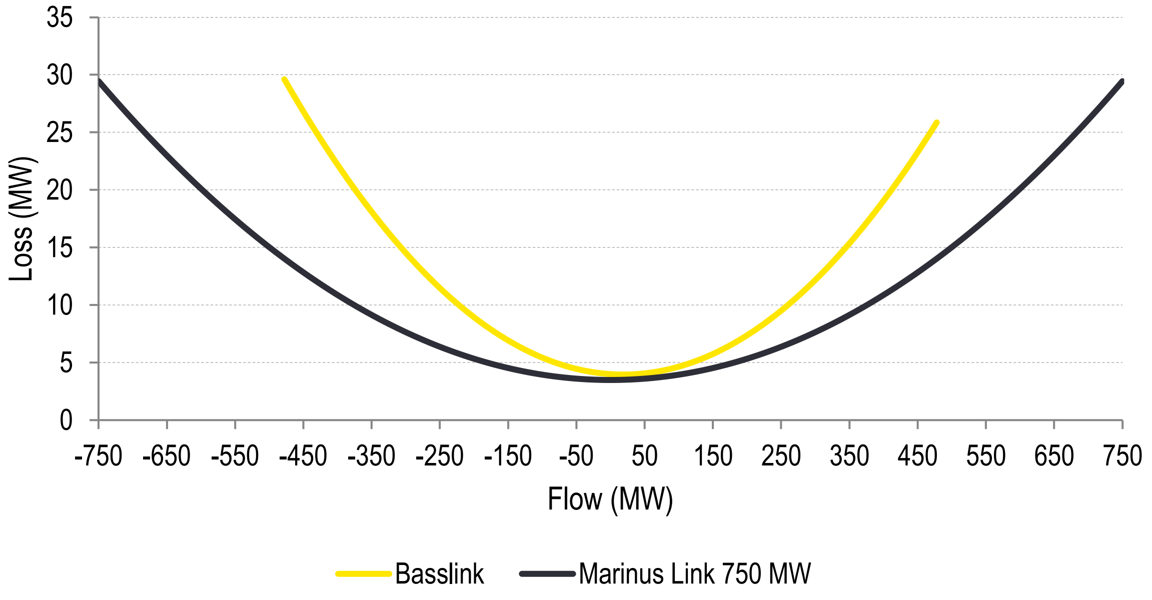
Consistent with the Marinus Link RIT-T by TasNetworks, the main assumptions for Marinus Link are[44]:

- 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 2, 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.

[43] 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.

[44] TasNetworks, 24 June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 27 March 2024.

Figure 2: Dynamic loss equation for Marinus Link



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

5.3 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 2024 ISP[45])

Interconnector (From node – To node)	Import[46] notional limit	Export[47] notional limit
QNI	1,165 MW summer 1,170 MW winter	745 MW summer/winter
QNI Connect	2,865 MW summer 2,870 MW winter	2,205 MW summer/winter
Terranora	150 MW summer 200 MW winter	50 MW summer/winter
EnergyConnect (NSW-SA)	800 MW	800 MW
VIC-NSW	400 MW 2,205 MW (after VNI West)	1,000 MW 3,045 MW (after VNI West)
Heywood (VIC-SA)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)

[45] 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.

[46] Import refers to power being transferred from the 'To node' to the 'From node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. E.g., import on Marinus Link implies southward flow and import on Heywood and EnergyConnect implies eastward flow.

[47] Export refers to power being transferred from the 'From node' to the 'To node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. E.g., export on Marinus Link implies northward flow and export on Heywood and EnergyConnect implies westward flow.

Interconnector (From node – To node)	Import[46] notional limit	Export[47] notional limit
Murraylink (VIC-SA)	200 MW	220 MW
Basslink (TAS-VIC)	478 MW	478 MW
Marinus Link[48] (TAS-VIC)	750 MW for the first stage and 1,500 MW after the second stage (for applicable variants)	750 MW for the first stage and 1,500 MW after the second stage (for applicable variants)

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 1,450 MW, respectively. The model will dispatch across the two links to minimise costs.
- Basslink and Marinus Link are included in the Tasmania inertia constraints described in Section 5.3.1.

5.3.1 Tasmania inertia constraints

An inertia constraint was included in the generation development plan to ensure the aggregate level of inertia in Tasmania in each dispatch interval is sufficient to meet minimum requirements. These minimum levels ensure each region can be operated in a satisfactory operating state in the event the region is islanded as defined in the National Electricity Rules[49].

A linear inertia requirement described in the Marinus Link RIT-T by TasNetworks[50] 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 Tasmanian 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, as per the Marinus Link RIT-T[50]. Details of these constraints are included in this document for completeness in the remainder of this section.

The following requirements and inertia coefficients are consistent with the Marinus Link RIT-T[50].

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*

[48] The 2023 IASR imposes a combined Basslink + Marinus Link constraint on import limits as the ISP model does not consider Tasmanian inertia requirements. As this Report explicitly models inertia constraints the import limit constraints are not imposed.
[49] Australian Energy Market Commission, 12 August 2019, *National Electricity Rules, version 124*, 5.20B.2
[50] TasNetworks, 24 June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 27 March 2024.

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

Term in inertia constraint equation left-hand side	Hard constraint[51]			Constraint for synchronous condenser costing		
	Contribution on export (MW.s)	Contribution on import (MW.s)	Contribution to minimum (MW.s)	Contribution on 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)		
Anthony Pieman	4*dispatch_no-sync (MW)* + 1,652			4*dispatch (MW)		
Gordon	4.3*dispatch_no-sync (MW)* + 626			4.3*dispatch (MW)		
Mersey Forth Lower	3.4*dispatch_no-sync (MW)* + 565			3.4*dispatch (MW)		
Mersey 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.

[51] A hard constraint is one that cannot be violated.

6. 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[52]. 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 Figure 3.

Figure 3: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2024-25	2015-16
2025-26	2016-17
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
...	...
2047-48	2011-12
2048-49	2012-13
2049-50	2013-14

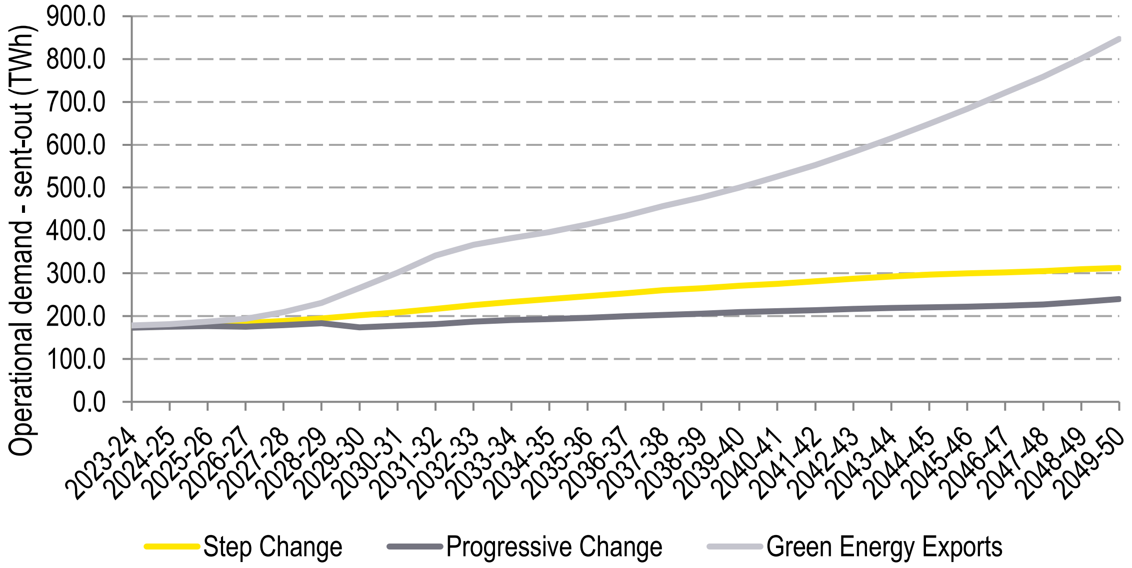
This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to distributed 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 Section 7.1) and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and distributed PV availability.

[52] 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.

MLPL selected demand forecasts from the ESOO 2023[53] consistent with the relevant scenarios in the 2023 IASR[54], which are used as inputs to the modelling. Figure 4 shows the assumed NEM operational demand for the modelled scenarios, inclusive of hydrogen demand.

Figure 4: Assumed annual operational demand in the modelled scenarios for the NEM, inclusive of hydrogen demand



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[53] AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 27 March 2024.

[54] 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.

7. Supply

7.1 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[55], we used a ten-pond model of the schemes which aggregated some generators within schemes. Figure 5 shows the structure of the cascades modelled. Data for modelling of the Hydro Tasmania generators was provided to Marinus Link Pty Ltd by Hydro Tasmania.

Figure 5: 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 26-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[56].These levels vary throughout the year to match long-term seasonal rainfall patterns as shown in Figure 6. In the model, these minimums from the Marinus Link RIT-T by TasNetworks[55] 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[55]. This was selected by MLPL on the basis that the assumptions detailed in the Tasmanian Energy Security Taskforce Final

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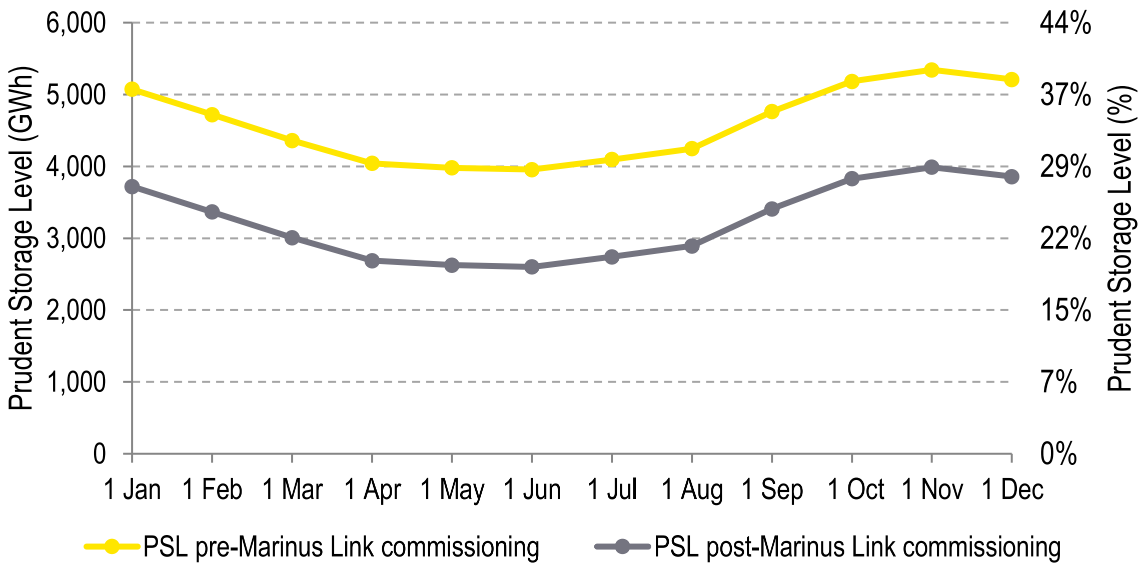
[55] TasNetworks, 24June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 27 March 2024.

[56] Hydro Tasmania, *Secure Energy*. Available at: https://www.hydro.com.au/clean-energy/secure-energy. Accessed 27 March 2024.

Report[57], 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 6: Assumed PSL profile for Hydro Tasmania's reservoirs



7.2 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[58] for existing, committed and anticipated projects.

Existing and new wind and solar projects are modelled based on nine years of historical weather data[59] and the methodology for each category of wind and solar project is summarised in Table 10. All large-scale wind and solar availability profiles are developed by EY.

[57] 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 27 March 2024.

[58] 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.

[59] 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 10: Summary of wind and solar availability 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[60,61] 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[62,63].	
	Generic REZ new entrants	Reference year specific targets based on AEMO's 2023 ISP Inputs and Assumptions workbook[64]. 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 historical, site-specific insolation measurements.
Solar PV SAT	Existing		
	Committed new entrant	Reference year specific targets based on capacity factor of nearest REZ, in AEMO's 2021 ISP Inputs and Assumptions workbook[62,63].	
	Generic REZ new entrant	Reference year specific targets based on AEMO's 2023 ISP Inputs and Assumptions workbook[64].	

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 occurring in the nine historical years, and these generation patterns are repeated throughout the Modelling Period as shown in Figure 3.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[65] 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

[60] 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 Accessed 27 March 2024.

[61] On the whole, capacity factor estimates for existing projects have not materially changed between the Marinus Link RIT-T and this Report.

[62] AEMO, 10 December 2021, *Input 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 27 March 2024.

[63] 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.

[64] 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.

[65] 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.

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[66] 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[66].

- 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 2023 IASR Assumptions workbook also includes intra-regional flow between nodes within the same region[66]. 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 for REZs which are contained in intra-regional flow constraints[66,67].

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.

7.3 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.[66]

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.[66]

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66 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.

67 This was applied to several REZs in Queensland, including Northern QLD, Isaac, Fitzroy, Wide Bay and Darling Downs.

7.4 Generator technical parameters

Technical generator parameters applied are as detailed in the 2023 IASR Assumptions Workbook[68] for AEMO's long-term planning model, except as noted in the Report.

7.5 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 2023 IASR Assumptions Workbook[68], maximum loads vary seasonally. This reduces the amount of available capacity in the summer periods.

7.6 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 2023 IASR Assumptions Workbook[68], 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.

7.7 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.

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[69]. 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 Section 7.1. Additionally, small non-scheduled generators are modelled explicitly and spill is allowed for all ponds except Gordon and Poatina.

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[68] 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.

[69] 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.

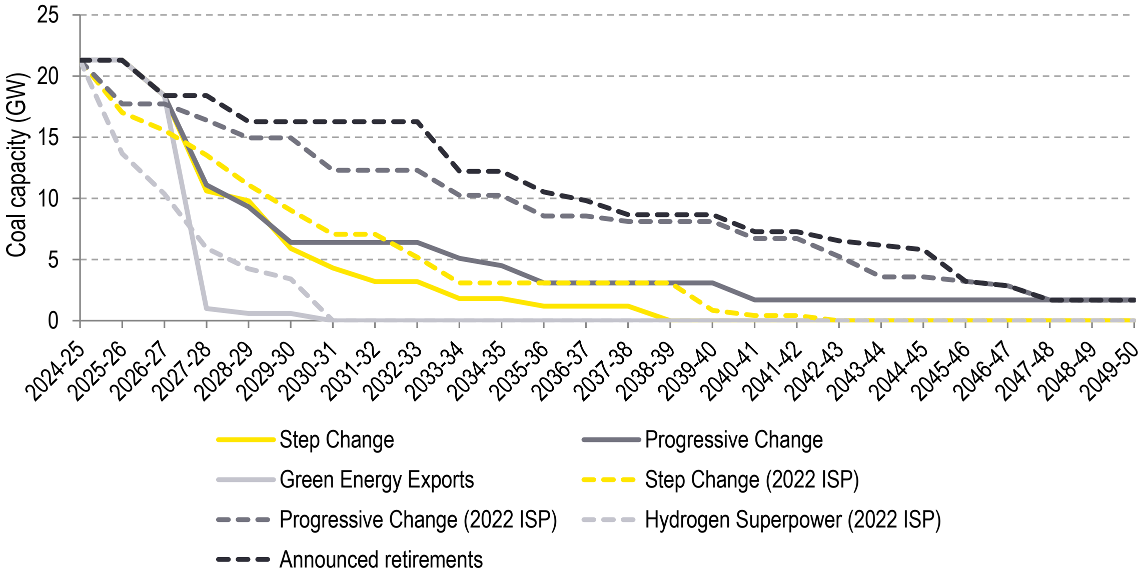
8. Forecast NEM outlook in the without Marinus Link case

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 case without Marinus Link counterfactual.

8.1 Forecast coal power plant withdrawal

Based on the scenario settings described in Section 3, and in line with the 2024 ISP methodology, 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 2023 IASR Assumptions Workbook[70]. Forecast coal capacity in the with Marinus Link case across all scenarios as an output of the modelling is illustrated in Figure 7.

Figure 7: Forecast coal capacity in the NEM by year across all scenarios in the without Marinus Link case[71] (solid lines and dashed lines demonstrate the coal capacity forecasts in this model and ISP 2022 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 2030s in the Green Energy Exports scenario, and around 2040 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. As such, the coal capacity forecast in 2025-26 is higher in this Report compared to the 2022 ISP outcomes, which allowed coal retirements from the beginning of 2025-26. From the late 2020s, the scenarios in this Report are forecast to have less coal capacity than their corresponding 2022 ISP scenario outcomes due to the more ambitious renewable energy target policy assumed in the AEMO 2023

[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] In the model 2,880 MW from the four units of Eraring retires in August 2025 (after the beginning of the 2025-26 financial year).

IASR[72]. This is particularly relevant for the Progressive Change scenario where earlier withdrawals occur due to the assumed 82% federal renewable generation target.

Although some scenario names may overlap with the Marinus Link RIT-T by TasNetworks[73], such as the Step Change scenario, the underlying assumptions are different. Compared to the Marinus Link RIT-T, the three scenarios in this Report are generally forecast to have a faster transition from existing thermal generation towards variable renewable energy resources.

8.2 Forecast NEM capacity and generation outlook

The NEM-wide capacity mix forecast in the Step Change scenario without Marinus Link is shown in Figure 8 and the corresponding generation mix in Figure 9. In this scenario, the forecast generation capacity of the NEM shifts towards increasing capacity of wind and solar, complemented by large-scale battery, PHES, and gas.

Figure 8: NEM capacity mix forecast for the Step Change scenario without Marinus Link[74]

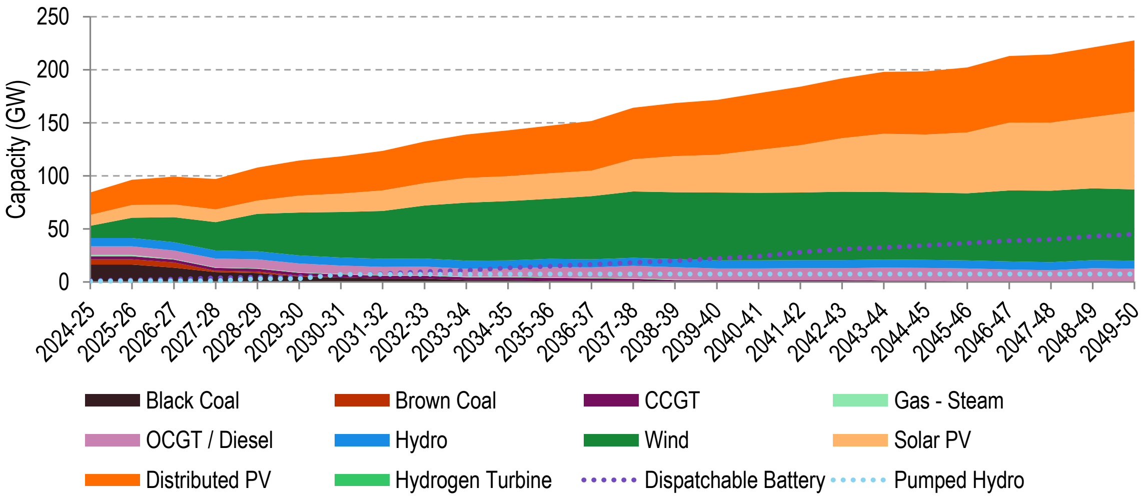
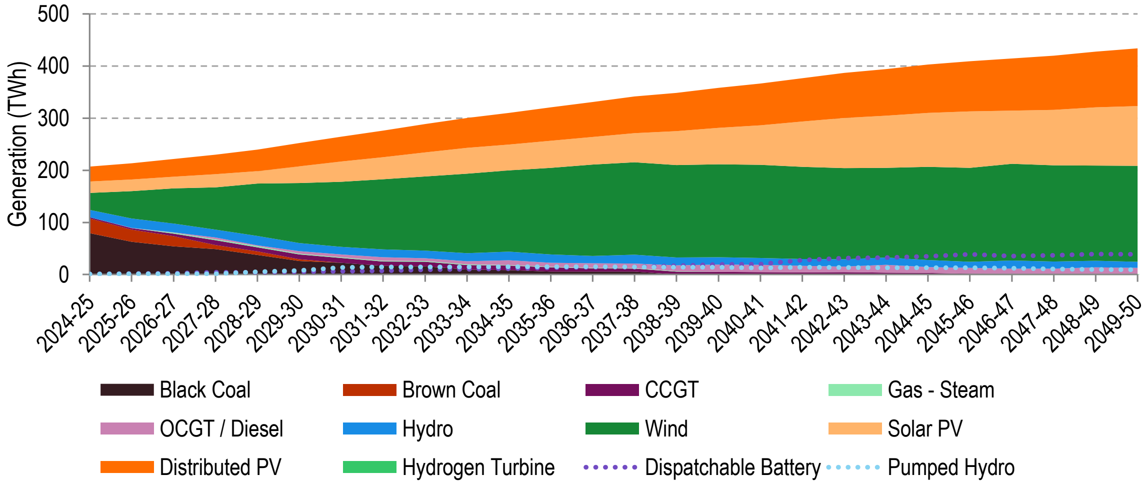


Figure 9: NEM generation mix forecast for the Step Change scenario without Marinus Link



[72] 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.

[73] TasNetworks, 24 June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 27 March 2024.

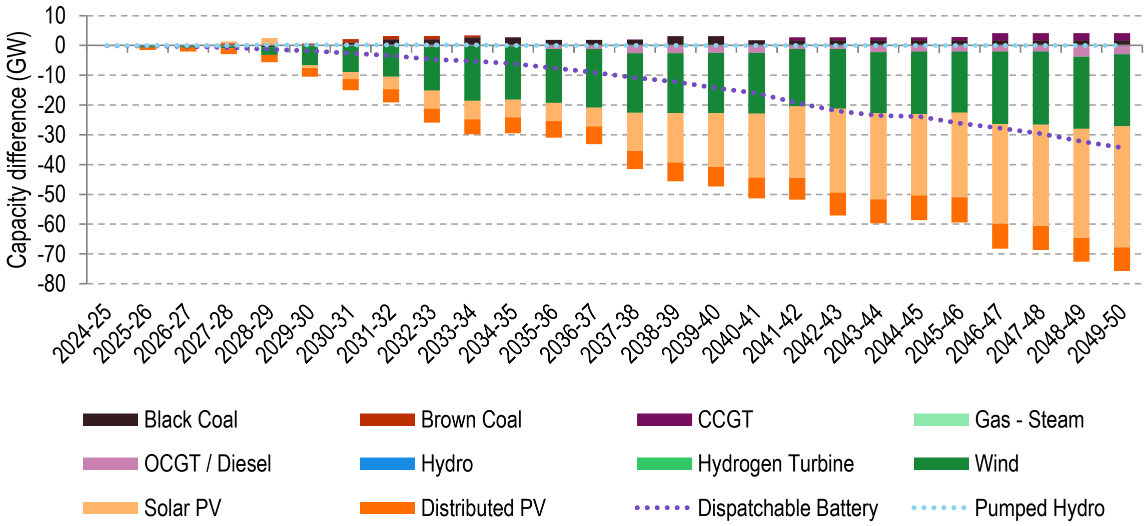
[74] Dispatchable battery includes both large-scale battery and VPP.

Up to 2030, new wind and solar build is largely driven by the assumed federal renewable energy target. During this time period, the federal renewable energy policy drives outcomes ahead of state-based renewable energy targets and entry of renewable capacity to replace coal retirements to achieve the assumed carbon budget. To replace the retiring capacity, wind capacity is predominantly forecast to be installed throughout the mid-to-late 2020s, along with large-scale battery and pumped hydro storage capacity in line with the assumed state-based storage targets. Solar PV and OCGT capacity are forecast to increase from the late 2030s complementing other technologies. The forecast new gas-fired capacity also supports reserve requirements. Overall, the NEM is forecast to have roughly 281 GW total (generation and storage) capacity by 2049-50 (including distributed PV which is an input assumption).

The other selected scenarios vary in the pace of the energy transition from the Step Change scenario. Figure 10 and Figure 12 show the differences in the NEM capacity development of the other two scenarios relative to the Step Change scenario, while Figure 11 and Figure 13 show generation differences. The differences are presented as alternative scenario minus the Step Change scenario[75] and both capacity and generation differences for each scenario show similar trends.

Figure 10 and Figure 11 show that the Progressive Change scenario is forecast to retain coal generation and install less wind and solar generation compared to the Step Change scenario largely due to a less restrictive carbon budget, and lower forecast demand. Additionally, Tasmanian load is assumed to be consistently lower in the Progressive Change scenario compared to Step Change, averaging approximately 7,000 GWh lower from the early 2030's onwards.

Figure 10: Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios without Marinus Link



[75] For example, Figure 10 shows Progressive Change capacity minus Step Change capacity. A net negative position indicates that the Progressive Change scenario has less capacity than the Step Change scenario, and vice versa.

Figure 11: Difference in NEM generation forecast between the Progressive Change and Step Changes scenarios without Marinus Link

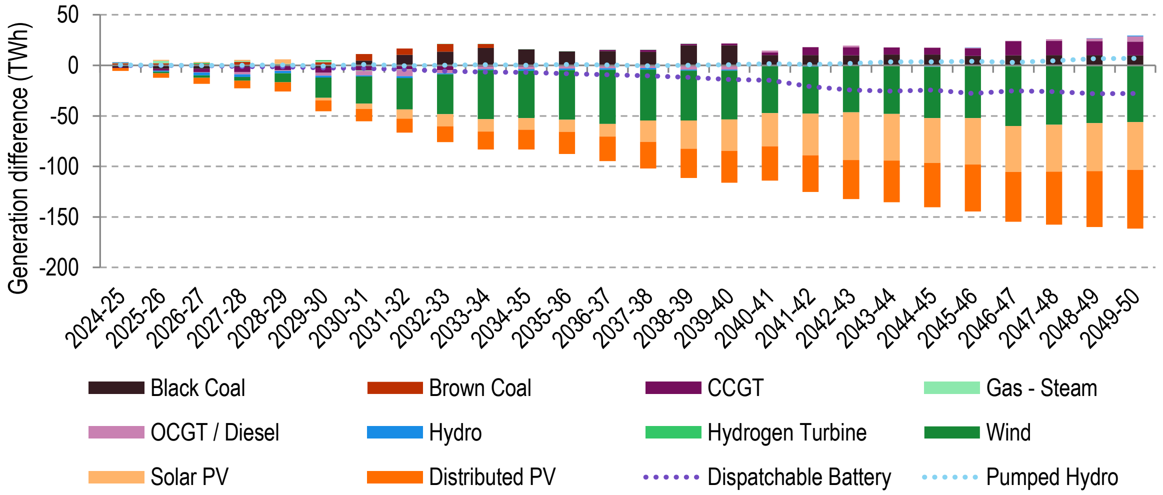


Figure 12 and Figure 13 show that the Green Energy Exports scenario is forecast to withdraw coal generation and install wind and solar generation more rapidly than the Step Change scenario due to a more restrictive carbon budget and higher demand forecast. Additionally, Tasmanian load remains consistently higher in the Green Energy Exports scenario compared to Step Change.

Figure 12: Difference in NEM capacity forecast between the Green Energy Exports and Step Change scenarios without Marinus Link

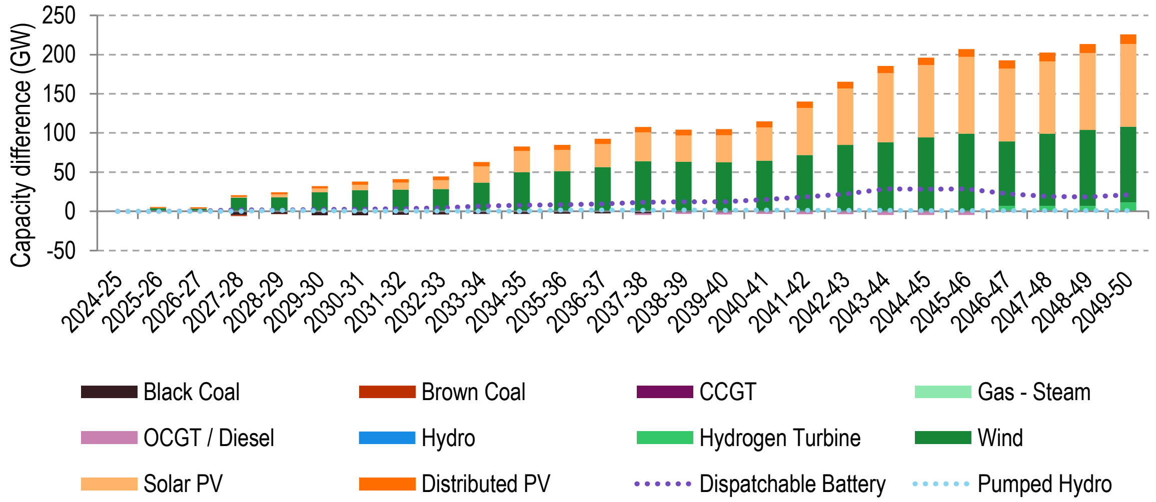
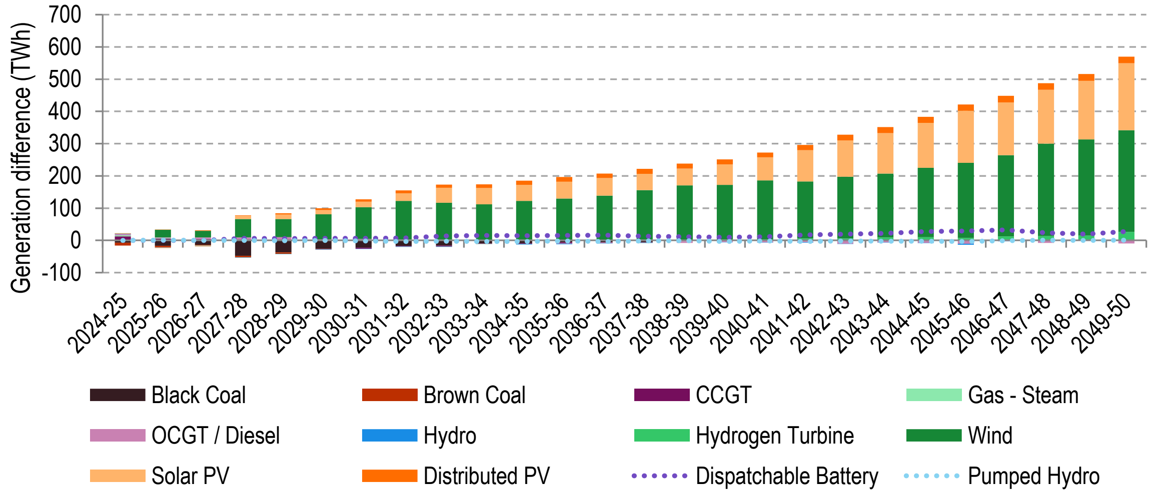


Figure 13: Difference in NEM generation forecast between the Green Energy Exports and Step Change scenarios without Marinus Link



9. Forecast gross market benefit outcomes

9.1 Summary of forecast gross market benefit outcomes across scenarios

Table 11 shows the forecast gross market benefits of Marinus Link over the 26-year Modelling Period from 2024-25 to 2049-50 for the Step Change, Progressive Change and Green Energy Exports scenarios.

Table 11: Overview of scenarios with associated forecast gross market benefits for Marinus Link over the Modelling Period discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.

Marinus Link size	Marinus Link timing	Step Change	Progressive Change	Green Energy Exports	Scenario weighted average[76]
1,500 MW	2029-30 & 2033-34	4,035	5,664	6,160	5,038
750 MW	2029-30	3,283	4,460	4,767	4,000

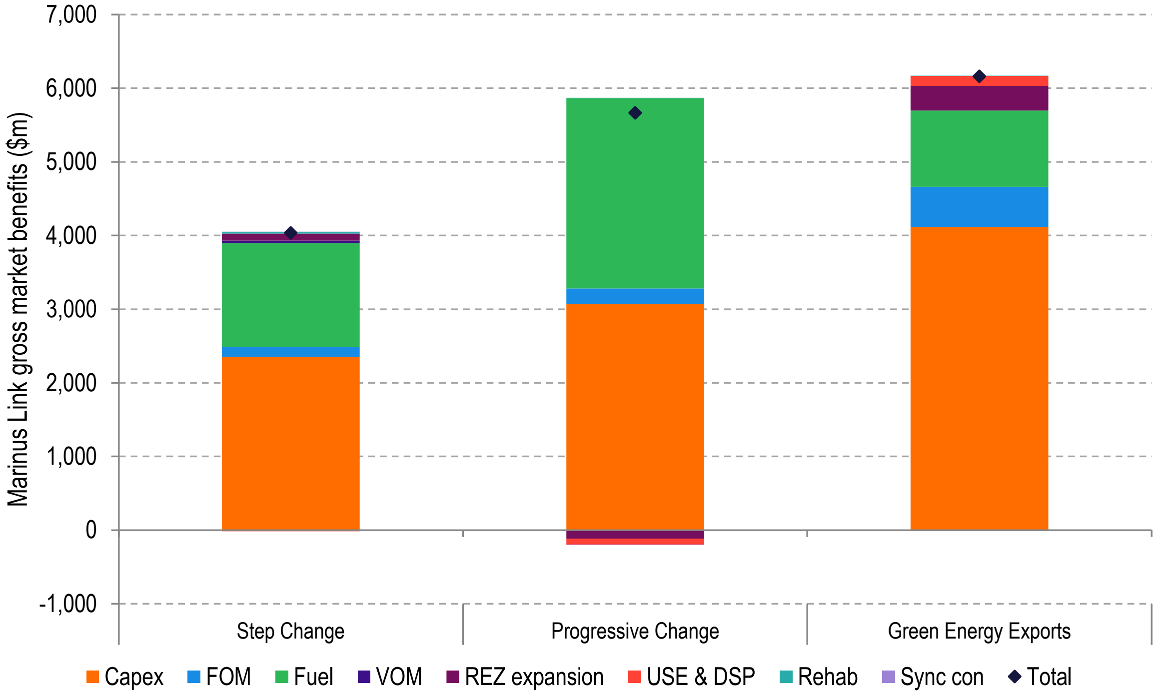
The forecast gross market benefits of each scenario must be compared to the cost of Marinus Link to determine the forecast net economic benefit for each option. That evaluation is not part of our scope and hence has not been included in this Report. It is performed by MLPL outside of this Report using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

In all scenarios, the forecast benefits for Marinus Link are primarily driven by capex saving across the NEM, followed by mainland fuel cost saving as the second highest source of forecast benefit, as displayed in Figure 14. This is consistent with the two largest sources of forecast benefits from the PACR for the Marinus Link RIT-T by TasNetworks[77]. While Figure 14 presents outcomes from the middle timing of 2033-34 for stage 2, other cases considering an earlier or later second stage entry have a similar composition of market benefits.

[76] AEMO, 15 December 2023, *Draft 2024 ISP*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 27 March 2024.

[77] TasNetworks, 24 June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 27 March 2024.

Figure 14: Composition of forecast total gross market benefits of Marinus Link stage 1 2029-30 and stage 2 2033-34 over the Modelling Period discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.



The forecast capex savings associated with Marinus Link are predominantly driven by the combination of high capacity factor wind resource in Tasmania, as per the 2023 AEMO IASR assumptions, 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 gas-fired 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 saving varies by scenario, along with the size and timing of Marinus Link. For the Green Energy Exports scenario, fuel cost savings are also forecast to accrue due to a reduction in generation from hydrogen turbines from the late-2030s with Marinus Link.

The Progressive Change scenario is forecast to have higher benefits for Marinus Link than the Step Change scenario. This is primarily due to the Progressive Change scenario having less Tasmanian demand than the Step Change scenario, as per the 2023 AEMO IASR assumptions. In the Progressive Change scenario, without Marinus Link, much of the new renewable generation that is forecast to be installed in Tasmania to achieve the TRET is curtailed, or spilled, since local Tasmanian demand is not high enough to fully utilise this generation. While this still occurs in the Step Change scenario, the additional Tasmanian load reduces the volume of spilled renewable generation without Marinus Link. When included, Marinus Link is forecast to better connect Tasmania with the mainland, which allows the rest of the NEM to benefit from Tasmanian renewable capacity.

The Green Energy Exports scenario is also forecast to have higher benefits for Marinus Link than the Step Change scenario. For this scenario, capex benefits are not only forecast to occur in the mainland, but also in Tasmania. As per the 2023 AEMO IASR assumptions, Tasmanian electricity consumption increases significantly over the Modelling Period in the Green Energy Exports scenario due to an assumed uptake in demand for hydrogen production. By the early 2030s, Tasmanian demand is approximately six-fold higher than current annual consumption. The TSIRP model captures forecast wind and solar diversity across NEM regions by basing their hourly availability profile on multiple historical weather patterns, targeting different capacity factors for each historical weather reference year, as per the 2023 AEMO IASR assumptions. Due to the variable nature of renewable energy, some forecast years have lower availability than others. During the forecast years coinciding with lower-than-average capacity factors, Tasmania can import more energy from the mainland with Marinus Link, compared to the without-Marinus Link counterfactual. This is forecast to result in capex savings for Tasmania, since it provides a lower cost alternative than overbuilding capacity to ensure Tasmania can supply hydrogen production targets during years of low variable renewable availability.

In the remainder of this section:

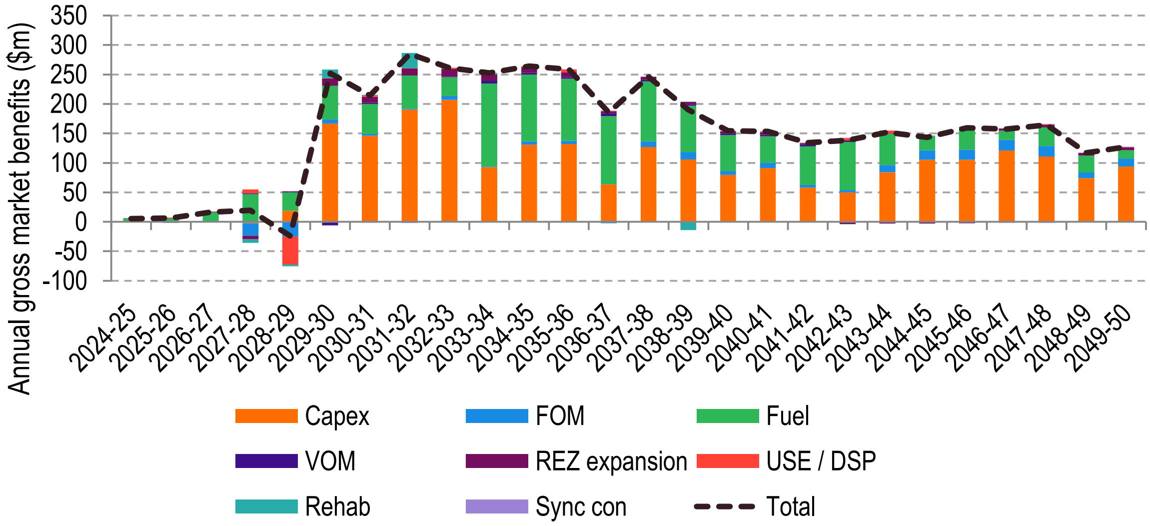
- Sections 9.2 to 9.4 describe the market dynamics for each of the three scenarios with assumed commissioning of two stages of Marinus Link, with the first stage commissioned in 2029-30 and the second stage in 2033-34.
- Section 9.5 outlines differences in forecast outcomes with different assumed timing of Marinus Link.
- Section 9.6 then outlines the Marinus Link sensitivities.
- Section 9.7 briefly compares the assumed scenarios and forecast outcomes to the Marinus Link RIT-T.

9.2 Market modelling outcomes for Step Change scenario

9.2.1 Forecast gross market benefits, Step Change scenario

The annual gross market benefits forecast from the inclusion of Marinus Link stage 1 2029-30 and stage 2 2033-34 in Step Change scenario are depicted in Figure 15 on an annual basis. Over the Modelling Period, it is forecast that the inclusion of Marinus Link results in $4,035m in gross market benefits.

Figure 15: Annual Marinus Link market benefit forecast for Step Change scenario discounted to 1 July 2023, Marinus Link stage 1 2029-30 and stage 2 2033-34. All dollar values are presented in $million, real June 2023.



Market benefits due to Marinus Link are predominantly forecast to occur after the assumed commissioning of its first stage in 2029-30. However, some of the forecast benefits accrue prior to its installation due to differences in the least-cost development plan that are forecast to pre-empt the Project's commissioning. Most of the potential benefit with Marinus Link is forecast to be from the reduction in expected capex and fuel costs. In the first few years post Marinus Link commissioning, the bulk of the potential market benefits are forecast to come from capex savings in avoided mainland generation investment. Following this, the bulk of the potential benefits are forecast to come from fuel savings as Marinus Link enables displacement of mainland gas-fired generation originally used to fill part of the supply gap left by coal retirements. Towards the last six years of the forecast, the largest component of forecast market benefits reverts to capex as Tasmanian wind capacity displaces mainland renewable capacity.

9.2.2 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 16 and Figure 17, respectively.

Figure 16: Capacity difference with and without Marinus Link for Step Change scenario, Marinus Link stage 1 2029-30 and stage 2 2033-34

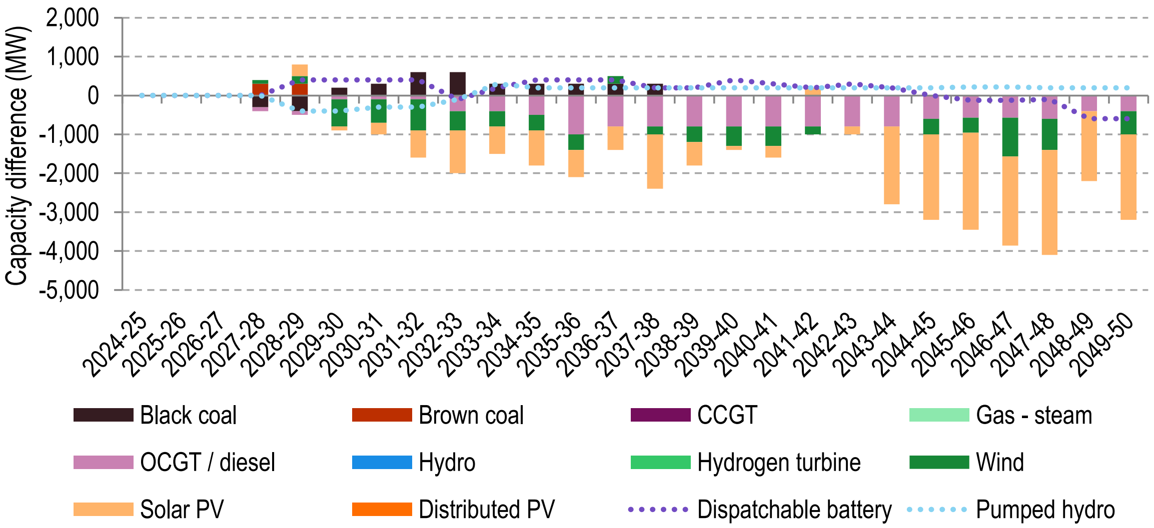


Figure 17: Generation difference with and without Marinus Link for Step Change scenario, Marinus Link stage 1 2029-30 and stage 2 2033-34

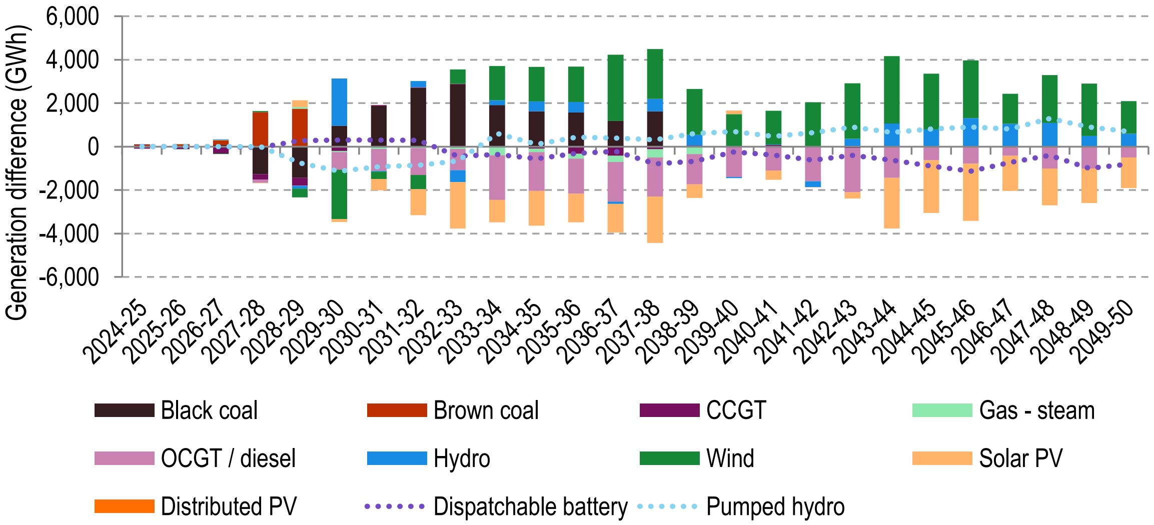


Figure 16 shows that wind, solar PV and gas capacity across the NEM are forecast to be avoided with inclusion of Marinus Link.

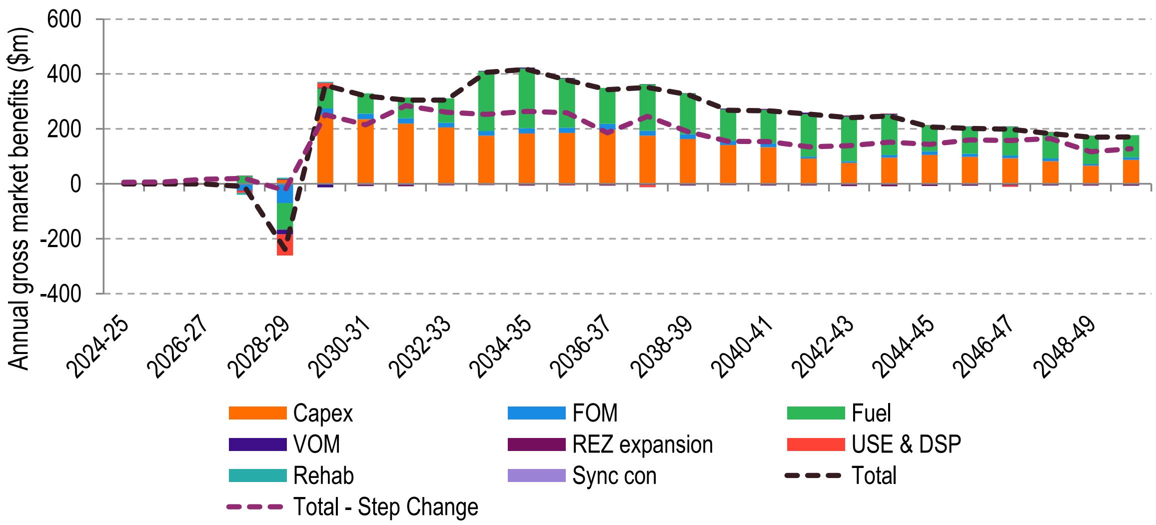
Figure 17 shows that forecast wind generation increases despite a reduction in overall wind capacity. This occurs because Marinus Link provides access to higher capacity factor Tasmanian wind resource, allowing investment in higher quality wind resource in place of mainland wind capacity. Additionally, Marinus Link is forecast to reduce Tasmanian wind curtailment by facilitating increased export to the mainland. Coal-fired generation is forecast to increase output with Marinus Link while still meeting the assumed emissions budget over the full 26-year Modelling Period. 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 assume renewable energy and emissions targets at lower cost (excluding consideration of the cost of Marinus Link itself).

9.3 Market modelling outcomes for Progressive Change scenario

9.3.1 Forecast gross market benefits, Progressive Change scenario

The annual gross market benefit forecast for the inclusion of Marinus Link stage 1 2029-30 and stage 2 2033-34 in Progressive Change scenario are depicted in Figure 18 on an annual basis. Over the Modelling Period, it is forecast that the inclusion of Marinus Link results in $5,664m in gross market benefits.

Figure 18: Annual market benefit forecast for Progressive Change scenario discounted to 1 July 2023, Marinus Link stage 1 2029-30 and stage 2 2033-34. All dollar values are presented in $million, real June 2023.



Similar to the Step Change scenario, the highest annual benefits of Marinus Link are forecast to accrue once Marinus Link is commissioned. Differences in the forecast capacity and generation outlook during the 2020s result in temporary negative benefits in 2028-29 as part of the long-term least cost expansion of the NEM over the full Modelling Period. The Progressive Change scenario is forecast to have higher gross benefits than the Step Change scenario, partly due to the Progressive Change scenario having a lower assumed demand trajectory in Tasmania. In low Tasmanian demand scenarios without Marinus Link, 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. In the with Marinus Link case, this energy can instead be exported to the mainland, displacing gas generation and mainland renewable capacity, which is forecast to result in fuel cost and capex savings. It is noted that the benefit of this scenario isn't solely driven by lower Tasmanian demand, but rather the fact that mainland demand growth outstrips Tasmanian demand growth.

9.3.2 Forecast NEM generation development plan, Progressive Change scenario

The differences in the forecast capacity and generation outlooks in Progressive Change scenario across the NEM with and without Marinus Link stage 1 2029-30 and stage 2 2033-34 are shown in Figure 19 and Figure 20, respectively.

Figure 19: Capacity difference with and without Marinus Link for Progressive Change scenario, Marinus Link stage 1 2029-30 and stage 2 2033-34

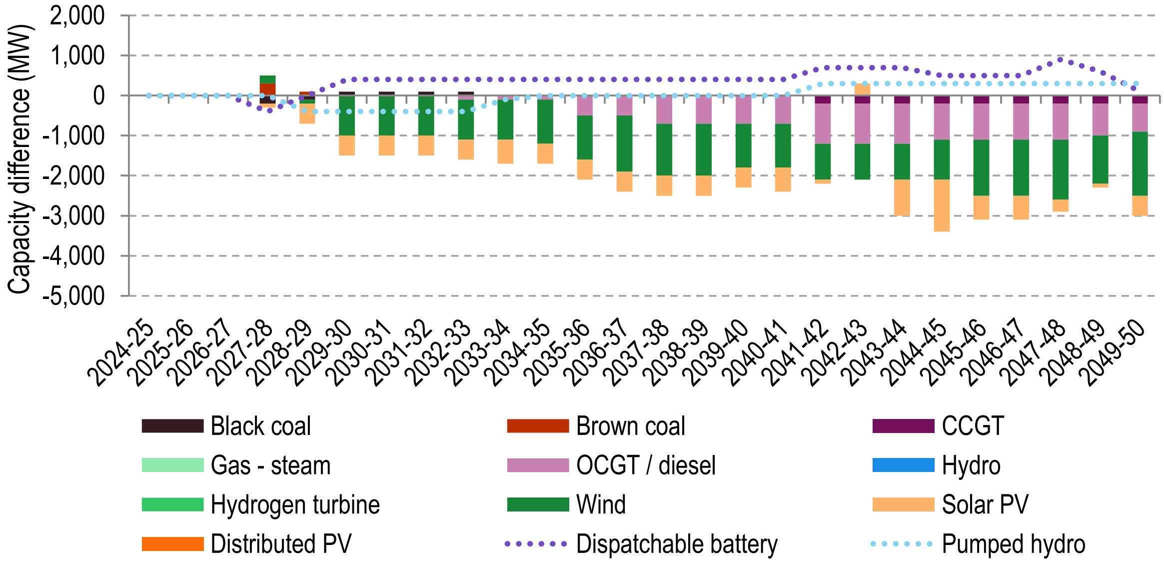


Figure 20: Generation difference with and without Marinus Link for Progressive Change scenario, Marinus Link stage 1 2029-30 and stage 2 2033-34

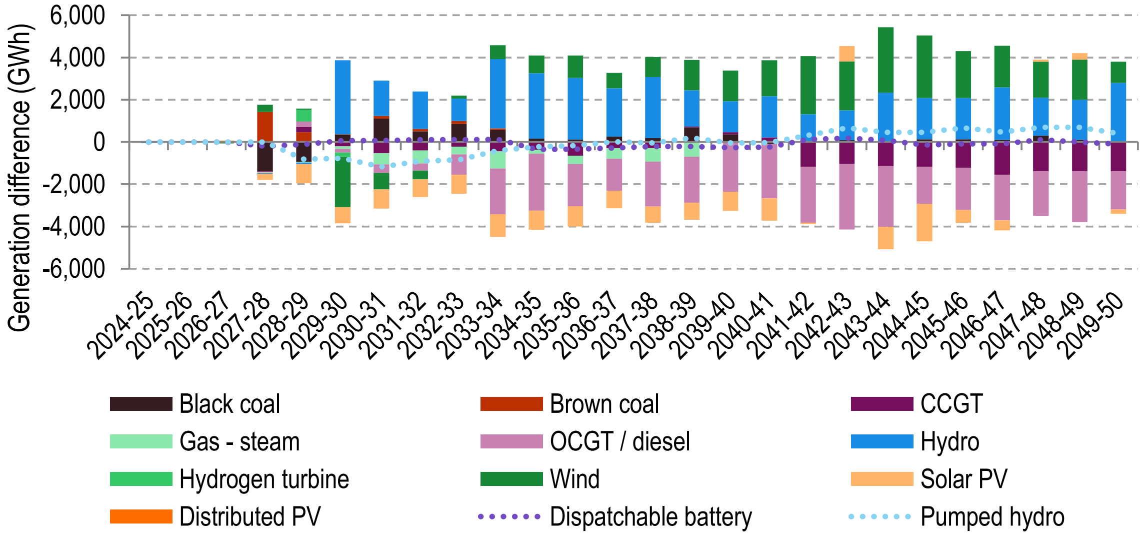


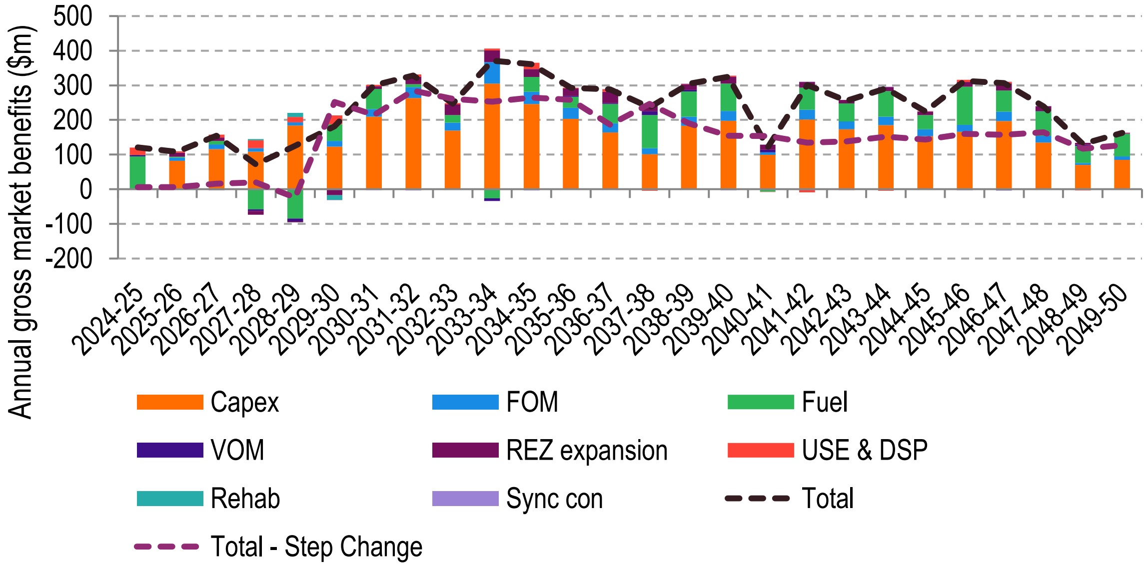
Figure 19 and Figure 20 show that investment in new wind and solar PV is forecast to be avoided from 2029-30, when the first stage of Marinus Link is assumed to be commissioned. From the early-2030s onward, Marinus Link is forecast to avoid mainland dispatchable gas generation by better connecting existing Tasmanian hydroelectric generators and new Tasmanian wind to the mainland as a lower cost alternative.

9.4 Market modelling outcomes for Green Energy Exports scenario

9.4.1 Forecast gross market benefits, Green Energy Exports scenario

The forecast gross market benefits for the inclusion of Marinus Link stage 1 2029-30 and stage 2 2033-34 in the Green Energy Exports scenario are depicted in Figure 21 on an annual basis. Over the Modelling Period, it is forecast that the inclusion of Marinus Link will result in \$6,160m in gross market benefits.

Figure 21: Annual market benefit forecast for Green Energy Exports scenario discounted to 1 July 2023, Marinus Link stage 1 2029-30 and stage 2 2033-34. All dollar values are presented in $million, real June 2023.



Under this scenario, Marinus Link is forecast to accrue more benefit throughout the Modelling Period, than the Step Change scenario. The bulk of the benefit comes from forecast capex savings associated with Marinus Link. Due to having a much higher assumed demand trajectory than other scenarios and a higher proportion of variable renewable energy required to meet this demand, there is greater opportunity for Marinus Link to offset mainland capacity development. The commissioning of Marinus Link allows for capex savings, as a larger portion of demand can be met with higher capacity factor Tasmanian wind and the diverse renewable energy can be better shared bidirectionally between Tasmania and the rest of the NEM. This scenario is forecast to have less fuel cost savings from the mid-2020s to the mid-2030s than the Step Change scenario, since the constraining carbon budget significantly restricts the amount of coal and gas generation that can occur in the Green Energy Exports scenario. Fuel cost saving that are forecast from the mid-2030s onward are inclusive of hydrogen as a fuel source.

Potential gross benefits are also forecast to accrue in the years prior to commissioning Marinus Link stage one. The potential capex savings are driven by a deferral in mainland project expenditure in anticipation of Marinus Link commissioning. Additionally, forecast fuel savings in 2024-25 are driven by foreknowledge that Marinus Link increases renewable support between states once commissioned. This provides additional headroom in the long-term emissions budget, meaning higher emission but lower cost fuels (black and brown coal) can generate in place of lower emission, higher cost fuels (natural gas) in 2024-25 to minimise system cost.

9.4.2 Forecast NEM generation development plan, Green Energy Exports scenario

The differences in the forecast capacity and generation outlooks in the Green Energy Exports scenario across the NEM with and without Marinus Link are shown in Figure 22 and Figure 23, respectively. Throughout the Modelling Period, the primary source of forecast benefits of Marinus Link are driven by the forecast reduction in new entrant installation across NEM (Figure 22). With Marinus Link, Tasmanian renewable generation, including existing hydro, is forecast to be better utilised to help meet the assumed emission target, reducing the requirement for new entrant capacity in the mainland.

Figure 22: Capacity difference with and without Marinus Link for Green Energy Exports scenario, Marinus Link stage 1 2029-30 and stage 2 2033-34

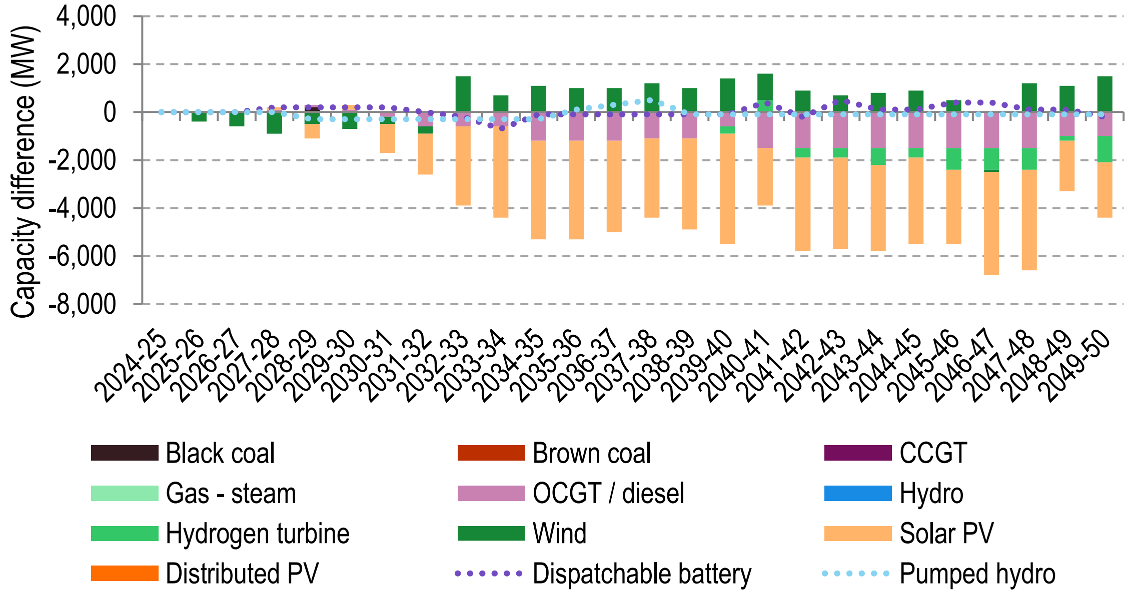


Figure 23: Generation difference with and without Marinus Link for Green Energy Exports scenario, Marinus Link stage 1 2029-30 and stage 2 2033-34

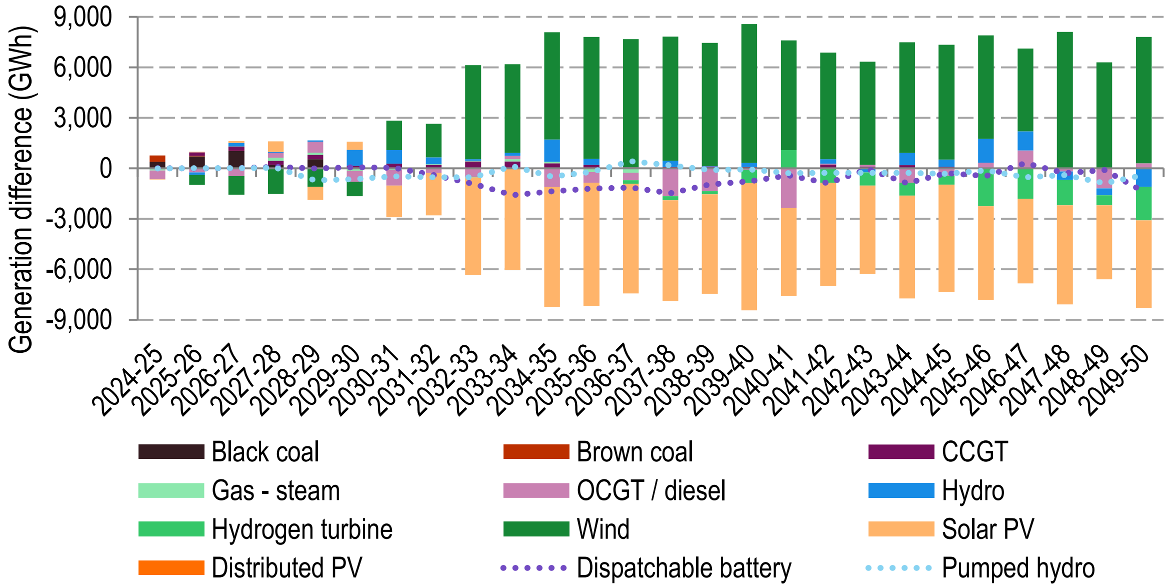


Figure 22 shows the forecast reduction in new entrant capacities; this is primarily a reduction in solar PV and OCGTs. Figure 23 shows that Marinus Link is forecast to reduce solar operation across the NEM as a result of having better access to high capacity factor Tasmanian wind generation instead.

9.5 Market modelling outcomes for the Marinus Link timing sensitivities

This section presents the forecast market benefits for Marinus Link across each Pre-Draft ISP scenario for the timing variants. These variants allow comparison of market benefits to a single stage only, and earlier and later variants of the second stage. The commissioning dates as follows:

- First stage only commissioned in 2029-30.

- First stage in 2029-30 and second stage commissioned by 2031-32.
- First stage in 2029-30 and second stage commissioned by 2035-36.

Prior to the release of the Draft 2024 ISP, MLPL had instructed EY to model the Step Change, Progressive Change, Green Energy Exports scenarios in anticipation of the Draft 2024 ISP publication in December 2023. These sensitivities were completed in November 2023. Because of this, they apply the input assumptions summarised in Section 3.2. The forecast market benefits are summarised in Table 12. When assumed Marinus Link timing is the same, there is a small change in forecast gross market benefits as shown in the values in brackets in Table 12. By inference the relative magnitude of forecast benefits between assumed different timings for Marinus Link is expected to be similar for the Draft 2024 ISP scenarios.

Table 12: Overview of forecast gross market benefits for Marinus Link in the Pre-Draft ISP scenarios over the Modelling Period discounted to 1 July 2023 and change relative to core scenarios in brackets. All dollar values are presented in $million, real June 2023.

Marinus Link size	Marinus Link timing	Pre-Draft ISP Step Change	Pre-Draft ISP Progressive Change	Pre-Draft ISP Green Energy Exports	Scenario weighted average[78]
1,500 MW	2029-30 & 2031-32	4,336	6,038	6,395	5,359
	2029-30 & 2033-34	4,224 (+189)	5,953 (+290)	6,164 (+4)	5,241 (+204)
	2029-30 & 2035-36	4,105	5,812	5,914	5,093
750 MW	2029-30	3,502 (+219)	4,691 (+231)	4,768 (+1)	4,191 (+191)

One of the primary drivers for differences between the core scenarios in this Report compared to the Pre-Draft ISP scenarios is changes in augmentation timings between the Draft 2024 ISP[78] and the Final 2022 ISP[79]. The Pre-Draft ISP scenarios includes later timings for augmentations, such as VNI West, and some differences in REZ transmission assumptions associated with interconnector projects, resulting in small increases in forecast benefits of Marinus Link.

The combination of these factors is forecast to impact the three scenarios to different extents. The forecast gross market benefits change by the largest amount for the Progressive Change scenario, since it has the largest changes in network augmentation timings (up to five years).

Figure 24, Figure 25 and Figure 26 display the forecast gross market benefits across each of the Pre-Draft ISP scenarios, respectively.

[78] AEMO, 15 December 2023, *Draft 2024 ISP*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation. Accessed 27 March 2024.

[79] AEMO, 30 June 2022, *2022 ISP*. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed 27 March 2024.

Figure 24: Annual market benefit forecast for the Pre-Draft ISP Step Change scenario discounted to 1 July 2023, with single and second-stage Marinus Link timing variants. All dollar values are presented in $million, real June 2023.

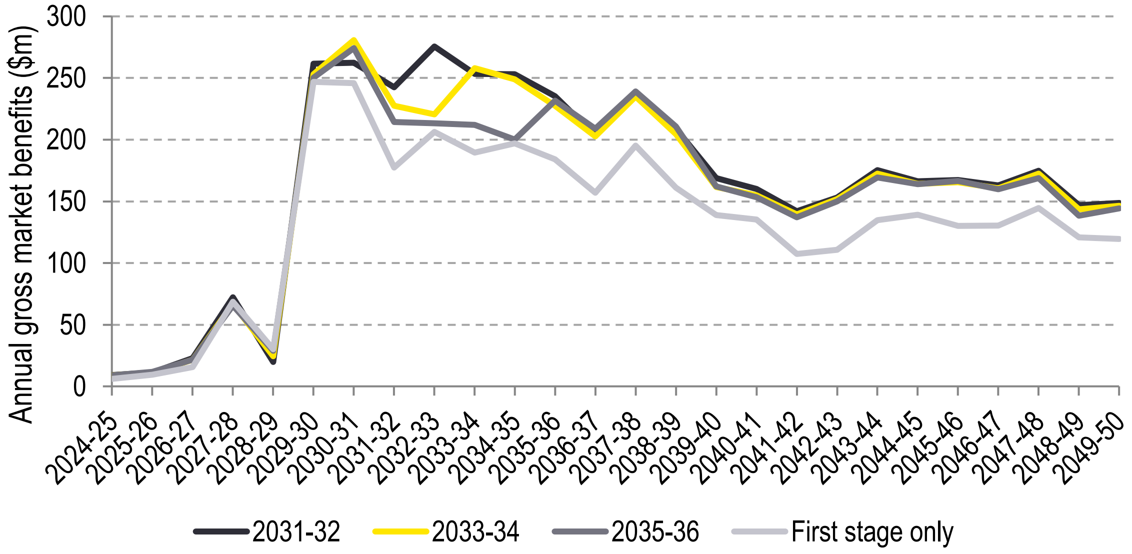


Figure 25: Annual market benefit forecast for Pre-Draft ISP Progressive Change scenario discounted to 1 July 2023, with single and second-stage Marinus Link timing variants. All dollar values are presented in $million, real June 2023.

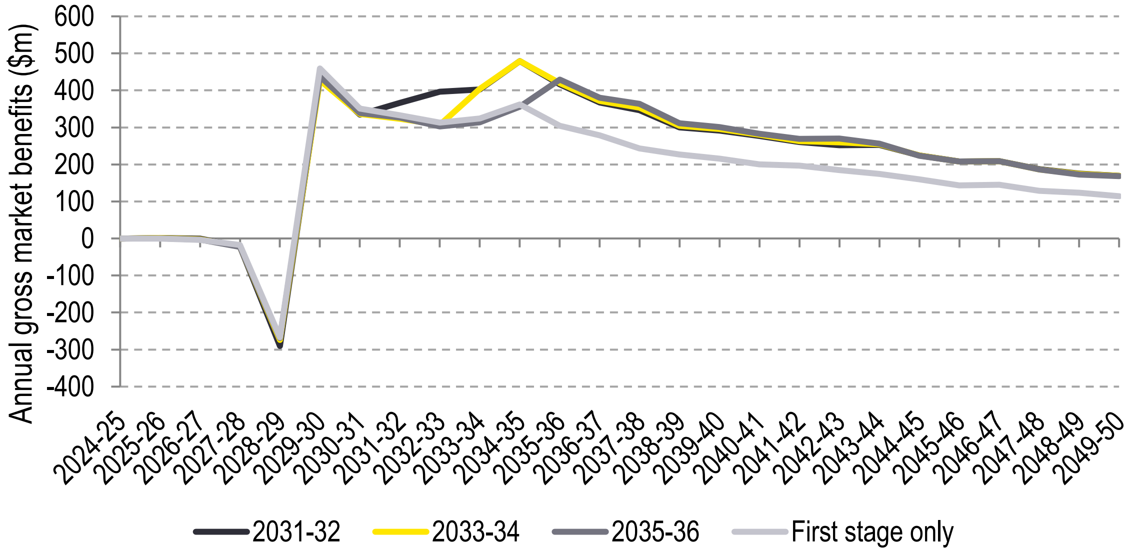
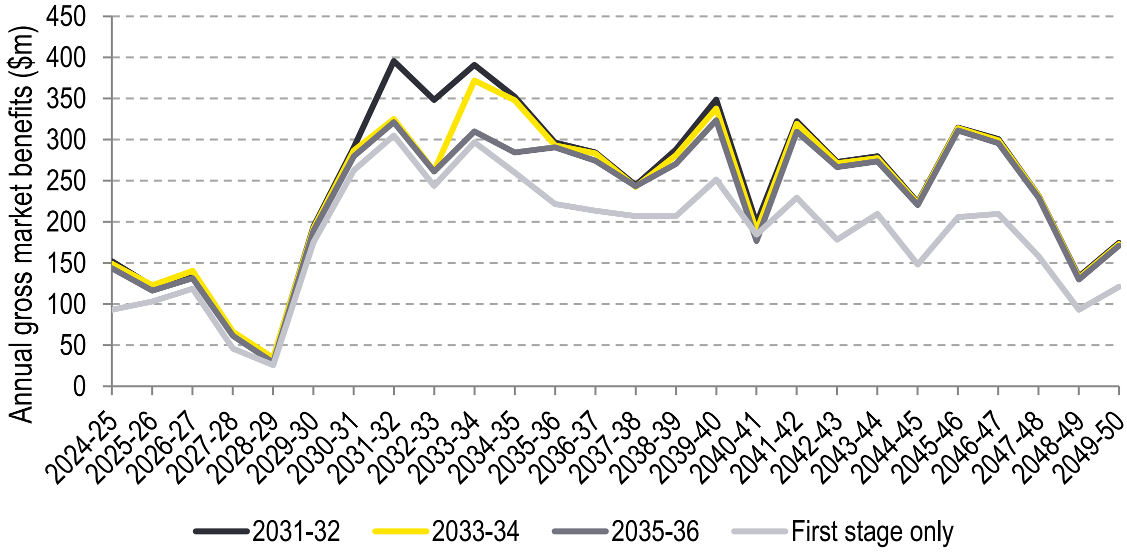


Figure 26: Annual market benefit forecast for Pre-Draft ISP Green Energy Exports scenario discounted to 1 July 2023, with single and second-stage Marinus Link timing variants. All dollar values are presented in $million, real June 2023.



Across each Pre-Draft ISP scenario, the earlier the second stage of Marinus Link is commissioned the greater the forecast annual gross market benefits. As the second-stage timing is delayed, the benefits are reduced until the second stage is commissioned. Once the second stage is online the annual gross market benefits across the three timings converge.

Similarly, a single stage only Marinus Link leads to the lowest gross market benefits due to less transfer capacity between Tasmania and Victoria.

Note, this report comments on the gross market benefits of Marinus Link. Further analysis would have to be conducted against project costs, noting that costs vary with stage timing.

9.6 Other sensitivities

9.6.1 Summary of forecast gross market benefit outcomes across sensitivities

MLPL instructed EY to undertake additional sensitivities to test the robustness of the magnitude and timing of forecast gross market benefits of Marinus Link. All sensitivities were conducted on the Pre-Draft ISP Step Change scenario with Marinus Link stage 1 2029-30 and stage 2 2033-34 which had a forecast gross market benefit of $4,224m. The sensitivities test adjusting a range of input assumptions such as demand, gas prices and battery capex trajectory. The list of sensitivities and their associated forecast gross market benefits are presented in Table 13.

Table 13: Overview of sensitivities with associated forecast gross market benefits for Marinus Link stage 1 2029-30 and stage 2 2033-34 over the Modelling Period discounted to 1 July 2023. All changes are relative to the Pre-Draft ISP Step Change scenario with Marinus Link stage 1 2029 30 and stage 2 2033 34 which had a forecast gross market benefit of $4,224m over the Modelling Period. All dollar values are presented in $million, real June 2023.

Sensitivity	Variation to Pre-Draft ISP scenario	Forecast gross market benefits ($m)	Change in forecast market benefits ($m)
Progressive hydrogen load	The Step Change Tasmanian hydrogen load trajectory is replaced with the Progressive Change hydrogen load trajectory from the 2023 AEMO IASR.[80]	5,317	1,093
750 MW committed Tasmanian PHES	A 750 MW Tasmanian Pumped Hydro Energy Storage (PHES) project is committed from 2032-33.	4,904	680
Victoria offshore wind delay	Victorian offshore wind targets delayed by five years, with the 9 GW capacity target now to be met in 2045-46.	4,394	170
High gas price	Gas prices for all existing and new entrant generators increased by 40% from the 2023 AEMO IASR Step Change scenario.[80] e.g. Victorian OCGT gas price ranging between $15/GJ and $20/GJ from the mid-2020s onward.	4,801	576
Low gas price	Gas prices for all existing and new entrant generators decreased by 40% from the 2023 AEMO IASR Step Change scenario.[80] e.g. Victorian OCGT gas price ranging between $6/GJ and $9/GJ from the mid-2020s onward.	3,411	-814
High battery capital cost	Apply the 2023 AEMO IASR Progressive Change battery capex scenario (higher than the Step Change trajectories).[80]	4,254	29
Low battery capital cost	Apply the 2023 AEMO IASR Green Energy Exports battery capex scenario (lower than the Step Change trajectories).[80]	3,977	-248

Further sensitivities adjusting the discount rate were also conducted on the Pre-Draft ISP Step Change scenario with the outcomes detailed in Table 14. Note that for the discount rate sensitivities, the alternate rates were applied when annualising costs to compute the least-cost solution and to the annual market benefit outcomes (rather than just discounting annual market benefits outcomes with the alternate discount rate). A different discount rate would also need to be applied to the costs of Marinus Link used in the calculation of net economic benefits.

Table 14: Overview of adjusted discount rate sensitivities with associated forecast gross market benefits over the Modelling Period for Marinus Link stage 1 2029-30 and stage 2 2033-34 for the Pre-Draft ISP Step Change scenario discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.

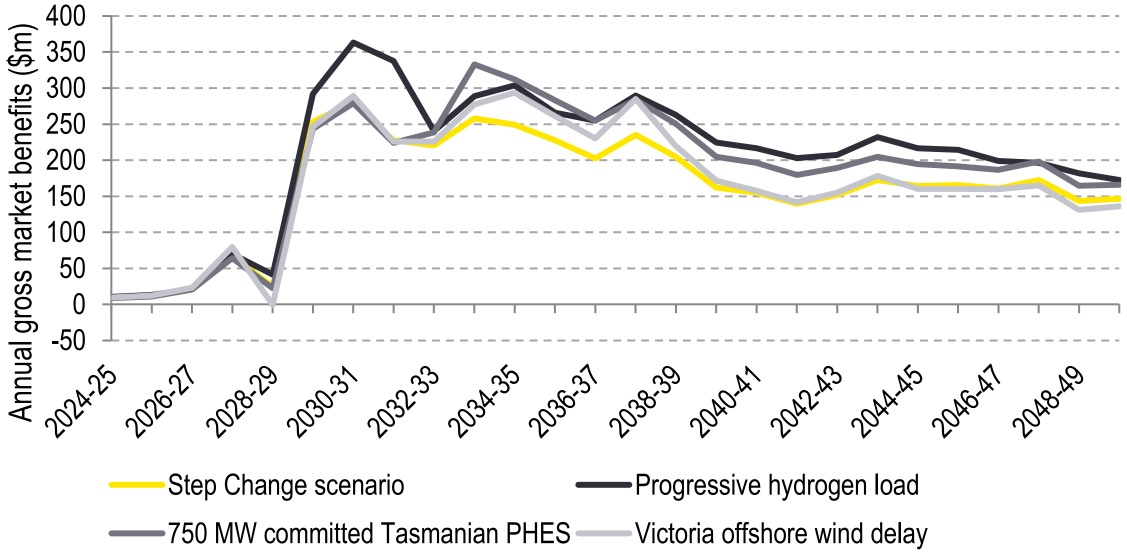
Sensitivity	Variation to Pre-Draft ISP scenario	Forecast gross market benefits ($m)
High discount rate	An increased discount rate and WACC of 10.50% has been applied for the selected scenario, in line with the 2023 AEMO IASR upper bound.[80]	3,186
Low discount rate	A reduced discount rate and WACC of 3.00% has been applied for the selected scenario, in line with the 2023 AEMO IASR lower bound.[80]	6,084

[80] 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.

9.6.2 Hydrogen load, committed Tasmanian PHES and Victoria offshore wind delay sensitivities

Figure 27 presents the forecast benefit of Marinus Link for the 2033-34 second stage timing under the Pre-Draft ISP Step Change scenario, compared to the same scenario but with a Progressive Change hydrogen load, 750 MW committed Tasmanian PHES and Victoria offshore wind delay sensitivities.

Figure 27: Annual market benefit forecast for Marinus Link 2033-34 second stage timing sensitivities discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.



Given significant uncertainty on the scale, timing and location of hydrogen load in the NEM, and the inclusion of a large hydrogen load in Tasmania for the Step Change scenario, MLPL instructed the impact of the large hydrogen load to be analysed through a sensitivity. The Progressive hydrogen load sensitivity assumes a lower Tasmanian hydrogen demand trajectory and forecasts gross market benefits for Marinus Link at $5,317m. This is $1,093m higher than the Pre-Draft ISP Step Change scenario for the corresponding size and timing of Marinus Link. Similar to the reasoning for the higher benefits for the Progressive Change scenario compared to the Step Change scenario, lower Tasmanian demand results in higher spill of Tasmanian generation to meet TRET without Marinus Link. With Marinus Link, the spilt energy can instead be exported to the mainland leading to fuel cost and capex savings from displacing gas and renewable generation.

Given the potential for additional Tasmanian PHES capacity to be committed prior to Marinus Link commissioning, MLPL requested its impact be explored through a sensitivity. Committed Tasmanian PHES (750 MW from 2032-33) also results in a higher forecast benefit of $4,904m, $680m higher than the equivalent Pre-Draft ISP Step Change scenario. The cost of this committed PHES capacity is included in both the Marinus Link and without Marinus Link counterfactual simulations but can be better utilised with Marinus Link which increases forecast gross benefits.

Without Marinus Link, it is forecast that the committed PHES cannot be as effectively utilised, which increases system cost relative to the equivalent simulation without committed Tasmanian PHES.

Given the potential uncertainty associated with the timing of delivery of the Victorian offshore wind target and its close network proximity Marinus Link, MLPL requested the impact of a delay to Victorian offshore wind be to explored through a sensitivity. There is a $170m increase in forecast benefits from the equivalent Step Change scenario when the Victorian offshore wind targets are delayed by five years. This is primarily due to the export from Marinus Link having to compete with less mainland generation when commissioned.

9.6.3 Gas price sensitivities

Figure 28 and Figure 29 present the gas prices and annual forecast benefit for the high and low gas price sensitivities, with a comparison to the equivalent Pre-Draft ISP Step Change scenario.

Figure 28: Victorian new entrant OCGT gas price for core Step Change scenario and accompanying low and high price sensitivities

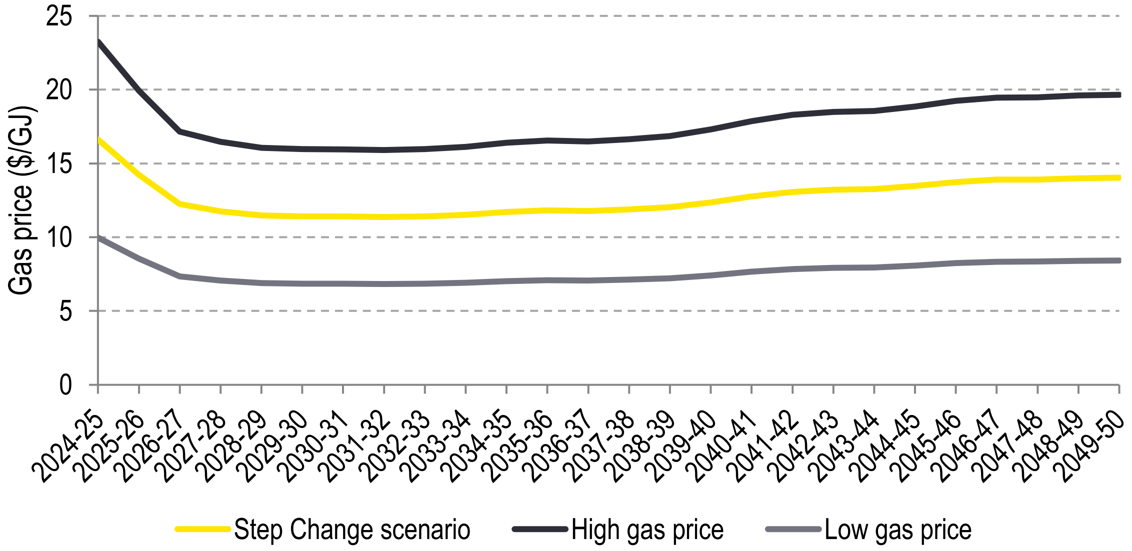
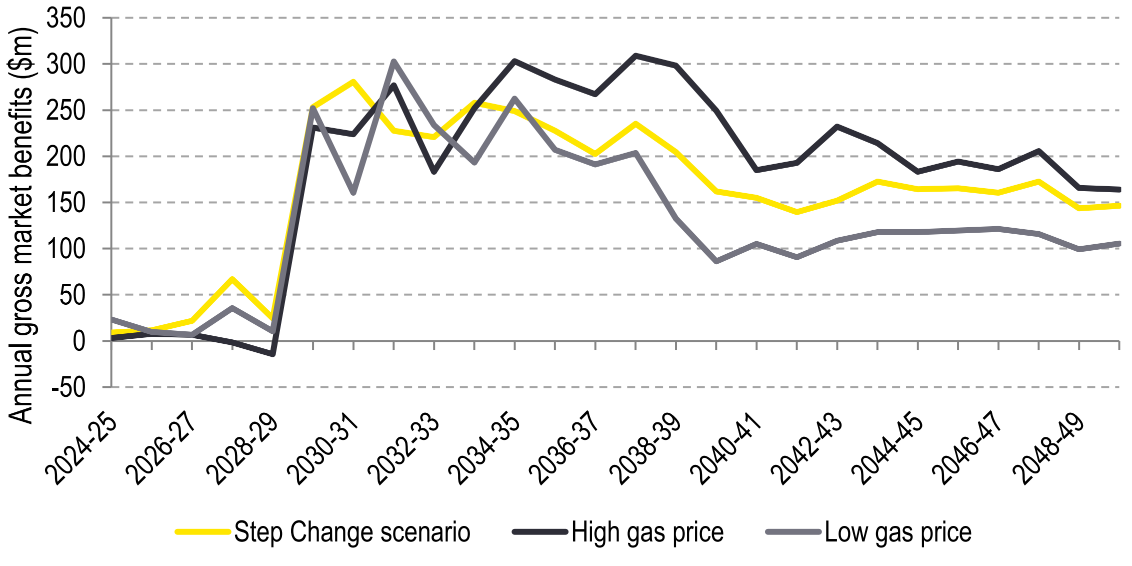


Figure 29: Annual market benefit forecast for gas price sensitivities with Marinus Link 2033-34 second stage timing discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.



Overall, a high gas price results in $4,801m of forecast benefits for Marinus Link, $576m higher than the equivalent Pre-Draft ISP Step Change scenario. A higher gas price leads to a reduction in utilisation of existing gas plant, and also an increase in renewable and storage technologies installed to meet demand in its place. Hence, Marinus Link has greater benefits due to its ability to offset the mainland capacity required to meet demand as well as displacing higher cost gas generation of existing plants.

Conversely, a reduction in the gas price leads to a $814m fall in forecast market benefits of Marinus Link. A lower gas price means existing gas units are forecast to be more heavily utilised and hence, less new entrant wind capacity is forecast to be installed. Instead, when new entrant capacity is needed, higher levels of gas fired generation and lower levels of other technologies are forecast to be commissioned. Marinus Link therefore has reduced opportunity to generate capex savings by reducing investment.

9.6.4 Large-scale battery capital cost sensitivities

Figure 30 and Figure 31 show the sample Victorian four-hour battery capital cost and the annual forecast benefit for the high and low battery capital cost sensitivities, with a comparison to the equivalent Pre-Draft ISP Step Change scenario and Marinus Link timing.

Figure 30: Victorian new entrant battery four-hour capital cost for core Step Change scenario and accompanying low and high capital cost sensitivities

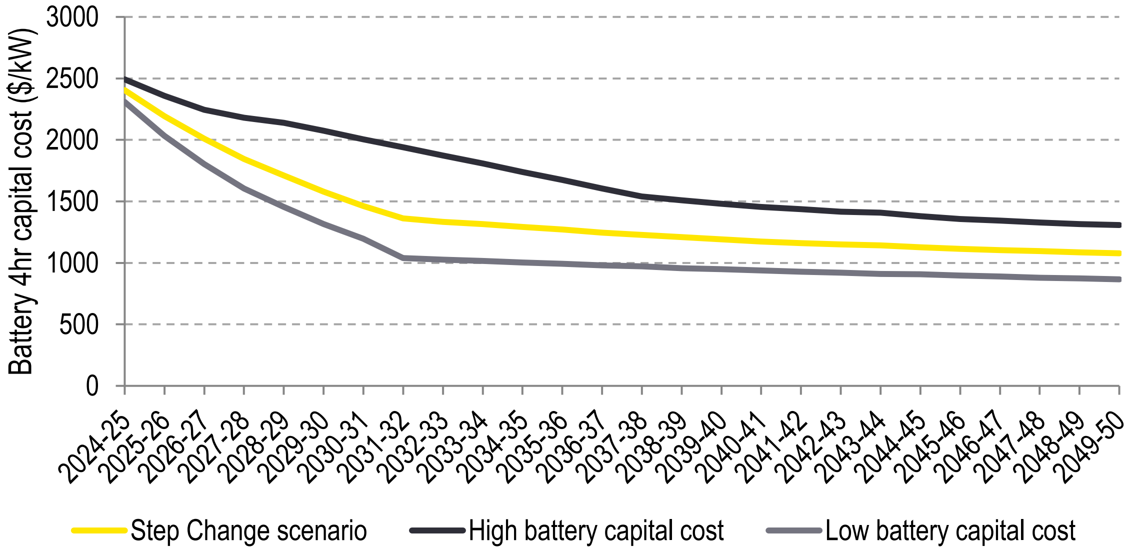
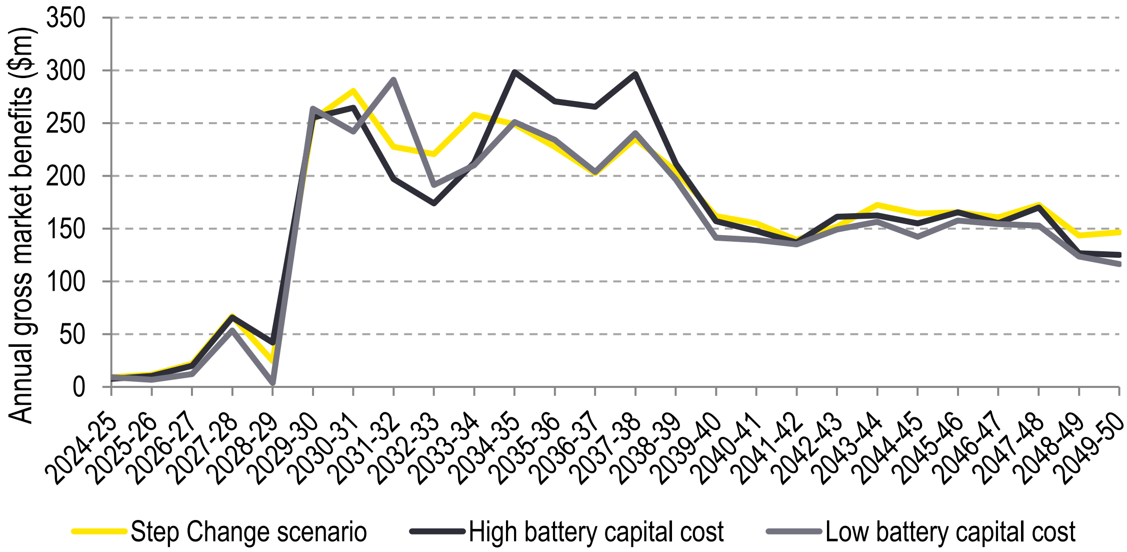


Figure 31: Annual market benefit forecast for capital cost sensitivities with Marinus Link 2033-34 second stage timing discounted to 1 July 2023. All dollar values are presented in $million, real June 2023.



A minor increase in forecast benefits of $29m is estimated for the high battery capital cost sensitivity while benefits are forecast to decrease by $248m when assuming a low battery capital cost. For the high battery capital cost sensitivity, approximately 5 GW less battery capacity is forecast to be installed compared to the Pre-Draft ISP Step Change scenario, regardless of Marinus Link. When battery capital cost is reduced, approximately 5.5 GW of additional batteries are forecast to be installed. The vast majority of expected battery capacity difference are observed on the mainland, whereas the forecast Tasmanian battery capacity remains largely the same regardless of the assumed capital cost trajectory. A lower battery capital cost means that it is more economical to install mainland storage, leading to less need for energy to be imported from Tasmania resulting in reduced forecast benefits for Marinus Link.

The opposite is true for assumed higher battery capex, however the magnitude of the impact on forecast gross benefits of Marinus Link is not as large. This is because the assumed capital cost of PHES is unchanged relative to the Pre-Draft ISP Step Change scenario and provides an alternative to large-scale battery under the higher battery capex sensitivity. Hence, the model forecasts lower battery storage build and in turn, greater build of mainland PHES. This leads to an overall minimal change in the gross benefit between the sensitivity and scenario.

9.6.5 Discount rate sensitivities

The forecast gross market benefits for Marinus Link varied under different assumed discount rates. With input assumptions otherwise the same as the Pre-Draft ISP Step change scenario, they were:

- $3,186m real June 2023 dollars discounted to 1 July 2023 using a discount rate of 10.50%.
- $6,084m real June 2023 dollars discounted to 1 July 2023 using a discount rate of 3.00%.

A different discount rate would also need to be applied to the costs of Marinus Link used in the calculation of net economic benefits.

Since Marinus Link is forecast to have positive gross market benefits from the time it is assumed to be commissioned, an increase in the discount rate and WACC leads to a decrease in the total discounted market benefits. The alternate rates also lead to different least-cost capacity mix outcomes. By increasing the discount rate and WACC, technologies with shorter repayment periods become more competitive to build and the weighting of later decisions decreases. Consequently, the total amount of dispatchable battery capacity built is forecast to increase and the amount of PHES to decrease. A higher amount of new entrant solar PV is forecast to be built and reduced economic thermal retirements are forecast to occur. As the amount of new entrant capacity decreases, Marinus Link has less ability to defer capital expenditure and hence, market benefits decrease with a higher discount rate.

A lower discount rate increases total discounted market benefits in the NPV calculation but also promotes technologies with longer repayment periods to become more competitive and increases the weighting of later decisions. This is observed when the discount rate is reduced as more PHES capacity is forecast instead of large-scale battery storage. Wind capacity is also forecast to be built in marginally higher amounts while thermal retirements are forecast to marginally reduce. As the amount of new entrant capacity increases, Marinus Link therefore has greater ability to defer capital expenditure resulting in higher gross market benefits.

9.7 Comparison to Marinus Link RIT-T scenarios and outcomes

The final stage of the Marinus Link RIT-T, the PACR was published by TasNetworks in June 2021[81]. It modelled five core scenarios named Central, Slow Change, High DER, Fast Change and Step Change. Although the Step Change scenario name remains in use in the Draft 2024 ISP and in this Report, the underlying assumptions are different. Several noticeable changes include:

- Compared to the Marinus Link RIT-T, the three scenarios in this Report are generally forecast to have a faster transition from existing thermal generation towards variable renewables energy due to new state and federal policy commitments including an expanded VRET, QRET and federal net zero emissions by 2050. All scenarios in this Report assume a cumulative emission budget, whereas in the PACR, only the Step Change and Fast Change scenarios did so. However, even then, the assumed NEM-wide cumulative emissions budget to 2050 is

[81] TasNetworks, 24 June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 27 March 2024.

significantly more restrictive in this Report's Step Change scenario than the PACR's Step Change scenario.

- Generator cost assumptions have increased for the 2020s due to lingering global supply chain constraints from the COVID-19 pandemic.

In this Report, benefits are discounted to 1 July 2023 using a 7% real, pre-tax discount rate, consistent with the central value applied by AEMO in the 2023 AEMO IASR[82]. This discount rate is higher than those applied in previous Marinus Link studies (such as the RIT-T). As such, the magnitude of forecast gross market benefit outcomes are not directly comparable.

The two largest sources of forecast benefits in both this Report and the Marinus Link RIT-T are potential capex saving across the NEM, followed by potential mainland fuel cost saving.

[82] 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.

Appendix A 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
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 Electricity 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

Abbreviation	Meaning
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SAT	Single Axis Tracking
SRMC	Short-Run Marginal Cost
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
TSIRP	Time-sequential integrated resource planner
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales 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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