Project Marinus PACR economic modelling report

Tasmanian Networks Pty Ltd

22 June 2021

Building a better working world

Building a better
working world

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

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

Notice

Ernst & Young was engaged on the instructions of Tasmanian Networks Pty Ltd ("**TasNetworks**" or the "**Client**") to provide market modelling in relation to the proposed Marinus Link interconnector (the "**Project**"), in accordance with the contract dated 14 June 2018.

The results of Ernst & Young's work, including the assumptions and qualifications made in preparing the report, are set out in Ernst & Young's report dated 22 June 2021 (the "**Report**"). The Report should be read in its entirety including this notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. No further work has been undertaken by Ernst & Young since the date of the Report to update it.

Ernst & Young has prepared the Report under the directions of the Client and as per the guidance included in the RIT-T and followed the process outlined therein. Ernst & Young has not been engaged to act, and has not acted, as advisor to any other party. Accordingly, Ernst & Young makes no representations as to the appropriateness, accuracy or completeness of the Report for any other party's purposes.

No reliance may be placed upon the Report or any of its contents by any party other than the Client ("Third Parties"). Any Third Party receiving a copy of the Report must make and rely on their own enquiries in relation to the issues to which the Report relates, the contents of the Report and all matters arising from or relating to or in any way connected with the Report or its contents.

Ernst & Young disclaims all responsibility to any Third Parties for any loss or liability that the Third Parties may suffer or incur arising from or relating to or in any way connected with the contents of the Report, the provision of the Report to the Third Parties or the reliance upon the Report by the Third Parties.

No claim or demand or any actions or proceedings may be brought against Ernst & Young arising from or connected with the contents of the Report or the provision of the Report to the Third Parties. Ernst & Young will be released and forever discharged from any such claims, demands, actions or proceedings.

Our work for this Report commenced on 12 January 2021 and was completed on 19 May 2021. Therefore, our Report does not take account of events or circumstances arising after 19 May 2021 and we have no responsibility to update the Report for such events or circumstances.

In preparing this Report we have considered and relied upon information from a range of sources believed to be reliable and accurate. We do not imply, and it should not be construed, that we have verified any of the information provided to us, or that our enquiries could have identified any matter that a more extensive examination might disclose.

The work performed as part of our scope considers information provided to us and a number of combinations of input assumptions relating to future conditions, which may not necessarily represent actual or most likely future conditions. Additionally, modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved, if any.

We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on a future course of action. We provide no assurance that the scenarios we have modelled will be accepted by any relevant authority or third party.

Our conclusions are based, in part, on the assumptions stated and on information provided by the Client and other information sources used during the course of the engagement. The modelled outcomes are contingent on the collection of assumptions as agreed with the Client and no consideration of other market events, announcements or other changing circumstances are reflected in this Report. Neither Ernst & Young nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided by the Client or other information sources used.

This letter should be read in conjunction with our Report, which is attached.

Ernst & Young has consented to the Report being published electronically on the Client's website for informational purposes only. Ernst & Young has not consented to distribution or disclosure beyond this. The material contained in the Report, including the Ernst & Young logo, is copyright. The copyright in the material contained in the Report itself, excluding the Ernst & Young logo, vests in the Client. The Report, including the Ernst & Young logo, cannot be altered without prior written permission from Ernst & Young.

Ernst & Young's liability is limited by a scheme approved under Professional Standards Legislation.

Table of contents

1. Executive summary 1

2. Introduction 8
   2.1 Conventions used in this document 9

3. Scenario assumptions 10
   3.1 Overview of input assumptions 10
   3.2 Differences in assumptions with and without Marinus Link 12
   3.3 Marinus Link loss model 13

4. NEM outlook across scenarios without Marinus Link 15
   4.1 Overview of scenario outcomes without Marinus Link 15
   4.2 Central scenario without Marinus Link 17
   4.3 Slow Change scenario without Marinus Link 22
   4.4 High DER scenario without Marinus Link 24
   4.5 Fast Change scenario without Marinus Link 26
   4.6 Step Change scenario without Marinus Link 28
   4.7 Opportunity for Marinus Link 30

5. Marinus Link forecast market benefits 31
   5.1 Summary of forecast market benefits 31
   5.2 Overview of effects of Marinus Link 32
   5.3 Central scenario with Marinus Link 33
   5.4 Slow Change scenario with Marinus Link 38
   5.5 High DER scenario with Marinus Link 42
   5.6 Fast Change scenario with Marinus Link 45
   5.7 Step Change scenario with Marinus Link 47
   5.8 Effect of size and timing of Marinus Link on forecast market benefits 51
   5.9 Modelled outcomes for the future of the NEM: Example week in 2032-33 52

6. Sensitivities 60
   6.1 Overview of input assumptions 60
   6.2 Marinus Link forecast market benefits 61
   6.3 Outcomes of discount rate sensitivities to all scenarios 62
   6.4 Outcomes of Central scenario sensitivities 64
   6.5 Outcomes of Step Change scenario sensitivities 67
   6.6 Outcomes of No TRET sensitivities 70

7. Methodology 76
   7.1 Long-term investment planning model overview 76
   7.2 RIT-T cost-benefit analysis 78

Appendix A List of abbreviations 79

1. Executive summary

TasNetworks has engaged EY to evaluate the potential market benefits to the National Electricity Market (NEM) of additional interconnection between Tasmania and Victoria in the form of a new interconnector known as Marinus Link. This work supports the Regulatory Investment Test for Transmission (RIT-T) currently in progress for Marinus Link.

The RIT-T is a cost-benefit analysis used to identify investment options in electricity transmission assets that maximise net economic benefits. EY's work pertains to the second part of that cost-benefit analysis: the potential market benefits Marinus Link is forecast to provide.

This Report forms a supplementary report to the broader Project Assessment Conclusions Report (PACR) published by TasNetworks.[1] It describes the key assumptions, input data sources and methodologies that have been applied in the market benefit modelling (the modelling) as well as outcomes of our analysis and key insights. It expands on and updates the modelling performed for Project Marinus' Project Assessment Draft Report (PADR)[2] and the Supplementary Analysis Report.[3] The modelling methodology follows the RIT-T guidelines for actionable ISP projects published by the Australian Energy Regulator.[4]

EY used linear programming techniques to compute a least-cost, whole-of-NEM, hourly time-sequential dispatch and development plan spanning from 2021-22 to 2049-50. The model was used to compute a plan without Marinus Link and with several different Marinus Link size and timing options across a range of scenarios and sensitivities:

- Five scenarios, namely Central, Slow Change, High DER, Fast Change and Step Change,
- Without-Marinus Link and various sizes of Marinus Link, either one 600 MW or 750 MW link or two 600 MW or 750 MW links to give a total of 1,200 MW or 1,500 MW transfer capacity,
- Different timings of Marinus Link, from the earliest date of 2027-28 for the first stage and a two- or three-year deferment for the second stage to 2034-35 for the first stage and a three-year deferment for the second stage,
- Various sensitivities across selected scenarios including different discount rates, sustained low gas price, hydrogen load growth in Tasmania, committed pumped storage hydro (PSH) in Tasmania, removal of the Tasmanian Renewable Energy Target[5] (TRET), removal of all state-based schemes and several others.

The five scenarios are predominantly based on those defined in the Australian Energy Market Operator's (AEMO's) 2020 Integrated System Plan (ISP), released in July 2020,[6] with assumptions updated to reflect more recent information provided in AEMO's Draft 2021 Input and Assumptions Workbook, released in December 2020[7] and a more detailed representation of Tasmanian

---

[1] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

[2] EY, 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/padr/. Accessed 18 May 2021.

[3] EY, 9 November 2020. *Appendix to the TasNetworks Supplementary Analysis Report*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

[4] 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 4 May 2021.

[5] Tasmanian Government, 19 November 2020. *Renewable Energy Target passes Parliament*. Available at: http://www.premier.tas.gov.au/site_resources_2015/additional_releases/improving_the_playing_field_across_tasmania/forging_a_manufacturing_future/renewable_energy_target_passes_parliament. Accessed 21 March 2021.

[6] AEMO, 30 July 2020, *2020 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 24 September 2020.

[7] AEMO, 12 December 2020, *2021 Input and Assumptions Workbook, v3.0*. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 12 January 2021.

generators and inertia constraints. Key assumption updates from AEMO's Draft 2021 Input and Assumptions Workbook include:

- Inclusion of the Electricity Statement of Opportunities (ESOO) 2020 Demand forecast to 2049-50.
- Discount rate for all scenarios, except the Slow Change, changed from 5.9 % to 4.8 %. Slow Change scenario updated from 7.9 % to 3.8 %, as per AEMO's change in assumptions from the 2020 ISP to the Draft 2021 Input and Assumptions Workbook.[8]
- Revision of projections of capital costs, fixed operation and maintenance (FOM) costs, variable operation and maintenance (VOM) costs, fuel costs and heat rates.
- Existing and committed projects from the January 2021 release of AEMO's Generation Information.[9]
- New entrant technical parameters based on Aurecon 2020 AEMO costs and technical parameter review.
- Update of state legislated renewable energy policies, including the New South Wales Electricity Infrastructure Roadmap[10] and the TRET[11] for all scenarios.
- Inclusion of system strength cost for new entrant renewable capacity.

A full summary of assumptions is available in the TasNetworks Inputs, Assumptions and Scenario workbook for Project Marinus PACR.[12]

On the following page, Table 1 shows the forecast market benefits associated with the change in the least-cost development plan under different sizes and timings of Marinus Link from 2021-22 to 2049-50. The forecast market benefits of Marinus Link in each scenario should be compared to the relevant Marinus Link costs to determine whether there is a positive net economic benefit and if so, which is the preferred option.[13]

[8] As per AEMO's Draft 2021 Input and Assumptions Workbook, a discounted rate of 3.8 % is applied for the Slow Change scenario. All other scenarios apply a discount rate of 4.8 %. The difference in discount rates must be taken into consideration when comparing market benefits across scenarios.

[9] AEMO, January 2021 Generation Information Page. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 26 May 2021.

[10] New South Wales Government, 10 December 2020. *Electricity Infrastructure Roadmap*. Available at: https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap. Accessed 21 March 2021.

[11] Tasmanian Government, 19 November 2020. *Renewable Energy Target passes Parliament*. Available at: http://www.premier.tas.gov.au/site_resources_2015/additional_releases/improving_the_playing_field_across_tasmania/forging_a_manufacturing_future/renewable_energy_target_passes_parliament. Accessed 21 March 2021.

[12] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

[13] In this Report we use the term *market benefit* and *net economic benefit* as defined in the RIT-T guidelines. All references to the *preferred option* are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options".

Table 1: Forecast market benefits of Marinus Link for different size and timing options, millions real June 2020 dollars discounted to 1 July 2020

		Scenario				
		Slow Change	Central	High DER	Fast Change	Step Change
30-year carbon budget:		No explicit carbon budget			2,068 Mt CO_2-e	1,325 Mt CO_2-e
Option	Marinus Link timing	Discount rate: 3.8 %	Discount rate: 4.8 %			
1,500 MW	2027 & 2029	4,405	3,420	3,425	3,679	5,655
	2027 & 2030	4,384	3,416	3,421	3,673	5,627
	2028 & 2031	4,270	3,385	3,388	3,630	5,490
	2031 & 2034	3,876	3,241	3,237	3,432	5,014
	2034 & 2037	3,414	2,903	2,875	3,040	4,336
1,200 MW	2027 & 2029	3,986	3,250	3,262	3,481	5,195
	2027 & 2030	3,952	3,244	3,256	3,473	5,159
750 MW	2027	2,802	2,676	2,676	2,839	4,179
600 MW	2027	2,283	2,281	2,277	2,425	3,557

The computation of net economic benefits (market benefits less costs) has been conducted by TasNetworks outside of this Report[14] as option costs were developed independently by TasNetworks. The market benefits estimated in this Report exclude other benefits that could potentially be computed, such as ancillary services cost reduction.

In all scenarios, power flows on Marinus Link are generally from south to north to deliver low-cost energy from Tasmania to Victoria and other mainland regions. Despite the large uptake of renewable generation and storage as a result of various assumed state-based schemes, even the combined New South Wales Electricity Infrastructure Roadmap, the Queensland Renewable Energy Target (QRET), the Victorian Renewable Energy Target (VRET) and the TRET are not forecast to be sufficient to supply the NEM by the end of the 2030s in any of the modelled scenarios. Based on the maximum exit dates assumed in the coal retirement schedule,[15] over 4,000 MW of coal capacity is expected to retire by 2029-30, 8,300 MW by 2032-33 and more than 12,000 MW by 2035-36. Moreover, in all scenarios, state-based schemes and carbon budgets are forecast to trigger economic coal-fired generator retirements ahead of these maximum retirement dates.

Across all scenarios, this modelling shows that the least-cost method to replace retiring generation and to meet changes in demand is through a combination of wind, solar PV, battery storage, PSH, gas and interconnection to increase resource diversification. As with the previous phases of modelling for the Marinus Link RIT-T, the first stage of Marinus Link is forecast to unlock the benefit of the conventional hydro generators that are already operational within Tasmania, while also allowing additional high capacity factor Tasmanian wind generation to be exported to the mainland. The second stage of Marinus Link further allows Tasmanian wind generation to be utilised by the mainland and provides a signal for potential new entrant PSH projects to be built in Tasmania.

The commissioning of Marinus Link is forecast to reduce system cost through two mechanisms:

---

[14] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

[15] Maximum retirement dates from AEMO, January 2021 Generation Information Page. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 26 May 2021.

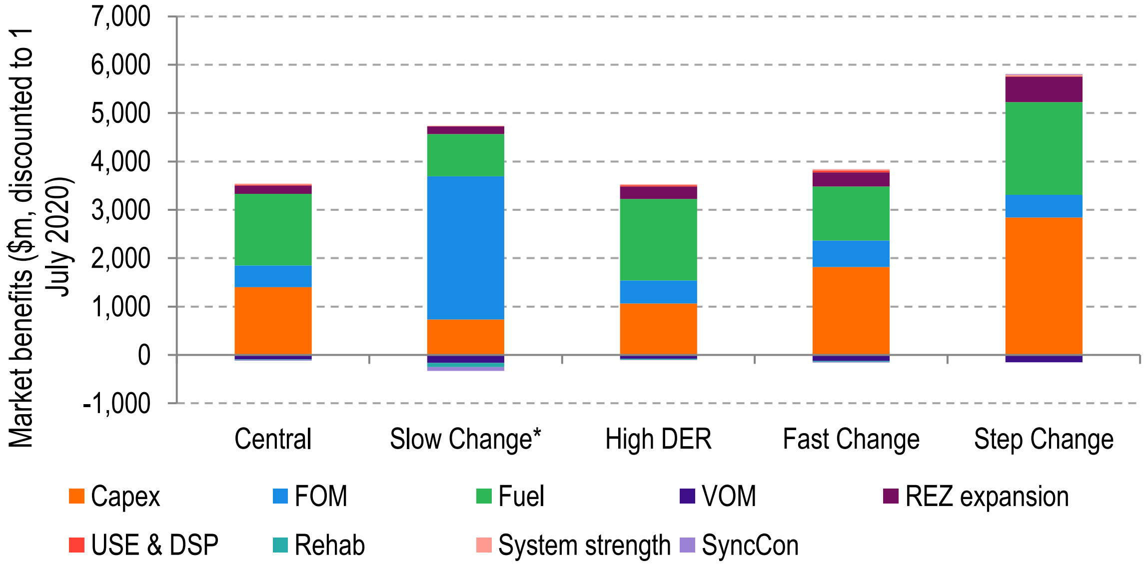
- **Lowering the cost of energy supply to the mainland**: Marinus Link is forecast to achieve this in two ways. When surplus low-cost, high-capacity factor Tasmanian wind is available, the interconnector can export this energy to the mainland, which offsets higher-cost coal-fired and gas-fired generation. Additionally, Marinus Link can import variable renewable energy (predominantly solar PV and wind) from the mainland to Tasmania at times of surplus generation on the mainland. This is forecast to enable existing Tasmanian hydro generation to reduce output during times of low-cost renewable generation so that energy from its stored water can be exported to the mainland in the evenings and overnight, when more expensive coal- or gas-fired generation would otherwise be required.

- **Lowering the cost of capacity supply to the mainland**: Export from Tasmanian generation can be relied on to support mainland regions during supply shortfalls, which is forecast to displace some of the need for relatively high-cost existing and new entrant gas-fired generation capacity. The average Tasmanian demand is approximately 1,200 MW and peaks at roughly 1,800 MW during winter months. Based on existing conventional hydro projects and the assumed upgrades of these generators there is expected to be approximately 2,700 MW of dispatchable hydro capacity online once the first stage of Marinus Link is commissioned. As such, under average conditions and even without contribution from Tasmanian wind generation, there is enough dispatchable capacity available on Tasmania to supply its own demand and export over Basslink and the first stage of Marinus Link at their respective limits. Across all five scenarios, the second stage of Marinus Link is forecast to unlock the potential for new entrant pumped storage hydro capacity to be built in Tasmania, which allows the full 1,500 MW Marinus Link to be relied on.

In principle, mainland battery storage or PSH could be used instead of Marinus Link to shift low-cost energy from variable renewables to times of supply shortfall and provide additional dispatchable capacity. The model forecasts use of existing Tasmanian hydro capacity and Marinus Link instead because it is a lower cost option. Existing Tasmanian hydro (1) does not incur capital costs within the model whereas new entrant batteries and PSH do, (2) can provide longer-duration storage to support periods where 8- and 12-hour batteries and PSH cannot (without building multiple units). Additionally, cyclic losses of battery and PSH technologies are greater than the transmission losses associated with importing excess mainland generation into Tasmania during the day and exporting excess generation from conventional Tasmanian hydro during the evenings and overnight.

The forecast market benefits of Marinus Link (750 MW stage 1 operational in 2027 and 750 MW stage 2 operational in 2029) across scenarios are displayed in Figure 1. It is apparent that the primary sources of market benefits of Marinus Link in most scenarios are forecast capex and fuel cost savings.

Figure 1: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029; millions real June 2020 dollars discounted to 1 July 2020. (*Slow Change uses a discount rate of 3.8 % while other scenarios use 4.8 %.)



In the Central scenario from entry of Marinus Link to the early 2030s the fuel cost savings predominantly relate to a reduction in coal use. From the early- to mid-2030s, the main source of forecast fuel cost savings is reduced use of existing Closed-Cycle Gas Turbines (CCGTs). From the late-2030s, these forecast fuel cost savings are from reduced use of higher-cost Open-Cycle Gas Turbines (OCGTs). OCGTs are forecast to be installed in slightly higher volume in the without-Marinus Link counterfactual[16] to provide dispatchable capacity to meet evening peaks in demand and longer periods where alternative capacity is unavailable (e.g. a wind drought or unit outages).[17]

From the mid-2030s the installation of Marinus Link is forecast to result in $50m to $100m of capex saving annually across the NEM in the Central scenario. This is due to Marinus Link's ability to unlock the benefit of conventional Tasmanian hydro, wind and the potential for Tasmanian pumped storage hydro, which is forecast to be economically installed in the 2030s.

Consistent with the application of all federal and state based renewable energy schemes, TRET is assumed to be committed, since it is a legislated target.[18] Therefore, capex and operating costs are incurred in achieving the scheme in both with and without Marinus Link cases. However, under the current set of assumptions, the full benefit of the TRET is only enabled if Marinus Link is installed.

In the other four scenarios, the sources of forecast market benefits of Marinus Link are somewhat similar to the Central scenario:

- In the Slow Change scenario, Marinus Link is forecast to provide fuel cost and capex cost benefits; however, most of the forecast market benefit comes from FOM savings. While FOM savings are forecast to occur in the other scenarios, they are more significant in the Slow Change scenario due to the lower Tasmanian and mainland demand that is assumed for this scenario. Relative to the Central scenario, lower Victorian demand causes earlier coal closures while lower Tasmanian demand frees up conventional Tasmanian hydro

[16] The without augmentation counterfactual is typically referred to as the Base case in a RIT-T. In this Report we use the term 'without-Marinus Link counterfactual' to avoid confusion with the term 'Base case' used in the Initial Feasibility Report to refer to a particular set of input assumptions which were varied in sensitivities.

[17] OCGTs form part of the least-cost development plan because they are cheaper than building sufficient deeper storage at low utilisation to cover longer, but less frequent periods of high demand net of low-SRMC wind and solar generation.

[18] Tasmanian Government, 19 December 2020. *Renewable Energy Target passes Parliament*. Available at: http://www.premier.tas.gov.au/site_resources_2015/additional_releases/continuing_our_plan_to_be_a_renewable_energy_powerhouse/continuing_our_plan_to_be_a_renewable_energy_powerhouse. Accessed 28 May 2021.

generation. Marinus Link allows Tasmanian energy to be dispatched more frequently to Victoria which is forecast to cause additional early brown coal closures and associated FOM savings. Due to the different discount rate for this scenario, 3.8 % compared to 4.8 % in all other scenarios, the market benefits are not directly comparable to the other scenarios. Since Marinus Link is forecast to have positive market benefits from the year it is assumed to be commissioned, the lower discount rate results in higher market benefits.

- In the High DER scenario, the forecast market benefits are similar to the Central scenario in category, quantity and timing.
- In the Fast Change scenario, it is assumed that the NEM must abide by a 30-year carbon budget of 2,068 Mt CO_2-e from 2020-21 to 2049-50. Although the Central scenario does not include a carbon budget, due to the assumed state-based RET policies, such as the New South Wales Electricity Infrastructure Roadmap, VRET, QRET and TRET, the Fast Change carbon budget of 2,068 Mt CO_2-e is almost forecast to be achieved. Consequently, the forecast market benefits of Marinus Link in the Fast Change scenario are only slightly higher than that of the Central scenario.
- In the Step Change scenario, Marinus Link's market benefits are further increased, and the timing of these market benefits are forecast to occur sooner, due to the higher emission reduction target for this scenario (a 30-year carbon budget of 1,325 Mt CO_2-e).

To assess the robustness of the market benefit of Marinus Link, 26 sensitivities were modelled. TasNetworks selected the majority of these sensitivities to assess downside risks associated with changes in assumptions. Based on these sensitivities, some of the factors that may reduce the potential market benefits of Marinus Link are:

- Higher discount rate,
- Hydrogen load growth in Tasmania,
- Sustained low gas price,
- Removal of economic retirements,
- Removal of Tarraleah and West coast generator upgrades,
- Additional generation capacity in Victoria.

Alternatively, the following factors are forecast to increase or bring forward potential market benefits of Marinus Link:

- Lower discount rate,
- Committed Tasmanian PSH.

Several sensitivities were forecast to have minimal impact on potential market benefits of Marinus Link:

- Optional gas retirements,
- A 30 % higher or lower battery capex,
- A smaller cable and enforced special protection scheme on Marinus Link and Basslink that constrains import flow.

Several sensitivities to the Central and Step Change scenarios explore the impact of the TRET and other state-based schemes on the market benefits of Marinus Link. Without Marinus Link, there is roughly 400 MW to 600 MW of new entrant wind capacity forecast to be installed in Tasmania throughout the study period if the TRET is not enforced. However, if Marinus Link is assumed to be commissioned, the least-cost expansion of the NEM involves achieving the TRET in the Step Change scenario and near-achievement of the TRET in the Central Scenario.[19] Since it is only the without-Marinus Link counterfactual that is materially different, the sensitivities where the TRET is removed results in a lower market benefit than their respective scenarios where the TRET is included.

[19] In the least-cost expansion of the NEM Tasmania achieves the 150 % renewable generation by 2032-33. By 2040, the least-cost expansion plan is only several hundred megawatts shy of the capacity required to achieve the full 200 % renewable target for the TRET.

2. Introduction

TasNetworks has engaged EY to evaluate the potential market benefits of a second interconnector between Tasmania and Victoria. This work supports the RIT-T currently in progress.[20] The RIT-T is a cost-benefit analysis used to identify investment options in electricity transmission assets that maximise net economic benefits. EY's work pertains to the second part of that cost-benefit analysis: the market benefits Marinus Link is forecast to provide.

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 forms a supplementary report to the broader PACR published by TasNetworks.[20] It describes the key assumptions, input data sources and methodologies that have been applied in the market benefit modelling (the modelling) as well as outcomes of our analysis and key insights.

Based on the key assumptions and input data, EY has computed the least-cost generation dispatch and development plan for the NEM associated with four options for Marinus Link across a range of scenarios, sensitivities and Marinus Link timings. The Marinus Link options were defined by TasNetworks and are described in detail in the PACR.[20]

The modelling methodology follows the RIT-T guidelines for actionable ISP projects published by the Australian Energy Regulator.[21]

TasNetworks selected input assumptions predominantly based on those defined in AEMO's 2020 ISP, released in July 2020[22] with some updates to reflect more recent information provided in AEMO's Draft 2021 Input and Assumptions Workbook, released in December 2020[23] and a more detailed representation of Tasmanian generators and inertia constraints.

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

- Capital expenditure (capex) of new generation and storage capacity installed,
- FOM costs of all generation capacity,
- VOM costs of all generation capacity,
- Fuel costs of all generation capacity,
- Cost of voluntary and involuntary load curtailment,
- Transmission expansion costs associated with Renewable Energy Zone (REZ) development,
- System strength costs,
- Retirement and rehabilitation costs,
- Synchronous condenser costs to meet inertia requirements,

---

[20] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

[21] 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 4 May 2021.

[22] AEMO, 30 July 2020, *2020 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 24 September 2020.

[23] AEMO, 12 December 2020, *2021 Input and Assumptions Workbook, v3.0*. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 12 January 2021.

- Transmission and storage losses which form part of the demand to be supplied but are calculated within the model.

Each category of market benefits is computed annually throughout the study period from 2021-22 to 2049-50. Market benefits are presented in real June 2020 dollars discounted to 1 July 2020[24] using a 4.8 % real, pre-tax discount rate (Central, Step Change, High DER and Fast Change scenarios) or 3.8 % (Slow Change scenario) based on AEMO's Draft 2021 Input and Assumptions Workbook.[25] The TSIRP model makes decisions that minimise the overall cost to supply electricity demand in the NEM over the entire study period based on the assumed discount rate. The discount rate applied is the same for all technology types.

Forecast market benefits of Marinus Link in each scenario should be compared to the relevant Marinus Link costs to determine whether there is a positive net economic benefit and if so, which is the preferred option. The computation of net economic benefits (market benefits less costs) has been conducted by TasNetworks outside of this Report[26] as option costs were developed independently by TasNetworks. The market benefits estimated in this report exclude other benefits that could potentially be computed, such as ancillary services cost reduction.

The Report is structured as follows:

- Section 3 provides an overview of key input assumptions for the scenarios.
- Section 4 describes the forecast generation and capacity outlooks in each of the scenarios without Marinus Link.
- Section 5 provides an overview of market benefits forecast for each Marinus Link option across scenarios. It focusses on identifying and explaining the key sources of market benefits of a 1,500 MW Marinus Link, stage 1 operational from 2027 and stage 2 operational from 2029.
- Section 6 summarises the forecast market benefits for all sensitivities.
- Section 7 provides an overview of the methodology applied in the modelling and computation of market benefits.

2.1 Conventions used in this document

This Report uses NEM sign conventions regarding the direction of flow on interconnectors:

- Export flows are northward and westward and are positive. For example, flows from Tasmania to Victoria and New South Wales to South Australia are positive export flows.
- Import flows are southward and eastward and are negative. For example, flow from Victoria to Tasmania is negative import flow.

Unless stated otherwise, any reference to Marinus Link implicitly includes the AC transmission augmentations that would be required to support flows across Marinus Link. Where a stage of Marinus Link is notated as occurring in a particular year, this means that stage is fully operational in the modelling from 1 July of that year e.g. Marinus Link stage 1 2027 means fully operational from 1 July 2027.

A list of abbreviations used in this Report can be found in Appendix A.

---

[24] This differs to EY's appendix to the Marinus Link PADR where market benefits were discounted to 1 July 2025 which coincided with the approach taken for the Initial Feasibility Report. The year 2025 was chosen for the Initial Feasibility Report because that was the year in which it was assumed Marinus Link would be commissioned.

[25] AEMO, 12 December 2020, *2021 Input and Assumptions Workbook*, *v3.0*. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 12 January 2021.

[26] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

3. Scenario assumptions

3.1 Overview of input assumptions

The credible Marinus Link options have been assessed in five scenarios selected by TasNetworks. The scenarios cover a broad range of reasonable possible futures for the NEM and are predominantly based on those defined in AEMO's 2020 Integrated System Plan (ISP), released in July 2020.[27] Assumptions have been updated in some cases to reflect more recent information provided in AEMO's Draft 2021 Input and Assumptions Workbook, released in December 2020[28] and a more detailed representation of Tasmanian generators and inertia constraints. The five scenarios are:

- The Central scenario: The pace of transition from thermal generation to renewables is determined by current federal and state-based renewable energy policies followed by installation on an economic basis.
- The Slow Change: Reflective of a future with lower demand due to the retirement of large industrial loads across Australia and therefore residential PV representing a larger proportion of meeting underlying demand. Slower reduction in capital cost for wind, solar PV and large-scale grid-connected battery storage.
- The High DER scenario: A faster uptake of customer-led transition of the NEM in the form of more rooftop PV, behind-the-meter batteries and electric vehicles (EVs).
- The Fast Change scenario: Coordinated national action to reduce emissions leading to an acceleration in the reduction of cost for wind, solar PV and large-scale batteries.
- The Step Change scenario: Accelerated coordination of national action to reduce emissions. Rapid uptake of customer-led transition of the NEM in the form of rooftop PV, behind-the-meter batteries and EVs.

The key underlying assumptions for these scenarios as selected by TasNetworks are summarised in Table 2. A full summary of assumptions is available in the TasNetworks Inputs, Assumptions and Scenario workbook for Project Marinus PACR.[29]

Table 2: Overview of key input parameters that vary across scenarios

Key drivers input parameter	Scenario				
	Slow change	Central	High DER	Fast Change	Step change
Demand	AEMO 2020 ESOO[30] Slow Change	AEMO 2020 ESOO Central	AEMO 2020 ESOO High DER	AEMO 2020 ESOO Fast Change	AEMO 2020 ESOO Step Change
2030 emissions reduction policy	The electricity sector has been modelled to achieve at least a 26 % reduction in emissions compared to 2005 levels by 2030.[28]				

[27] AEMO, 30 July 2020, *2020 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 24 September 2020.

[28] AEMO, 12 December 2020, *2021 Input and Assumptions Workbook, v3.0*. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 12 January 2021.

[29] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

[30] AEMO, August 2020, 2020 Electricity Statement of Opportunities. 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 23 March 2021.

Key drivers input parameter	Scenario				
	Slow change	Central	High DER	Fast Change	Step change
NEM cumulative carbon budget from 2020-21 to 2049-50	Not explicitly modelled			2,068 Mt CO_2-e[31]	1,325 Mt CO_2-e[31]
New South Wales Electricity Infrastructure Roadmap	Included as a 2031-32 target.[32]	Included as a 2029-30 target.[32]			
VRET	Target of 40 % of Victorian generation from renewables by calendar year 2025.[33] Target of 50 % of Victorian generation from renewables by calendar year 2030.[33]				
TRET 2040	200 % renewable energy generation as a percentage of total Tasmanian generation.[34] Modelled as 10.5 TWh of expected generation (inclusive of curtailment) from new renewable capacity in Tasmania by 2040.				
QRET 2030	Target of 50 % of Queensland demand from renewable generation by calendar year 2030.[35]				
Generator retirements	Based on AEMO's 2020 ISP assumptions. Where station specific information was available, retirement dates were updated as per AEMO's Draft 2021 Input and Assumptions workbook.[36,37,38] A full list of operational and announced retirement dates can be found on the 'Nameplate Capacity' tab of the TasNetworks Inputs, Assumptions and Scenario workbook for Project Marinus PACR.[39] From 2024-25, coal generators can retire earlier than their announced retirement date if it is least-cost to do so. This timing complies with the requirement for generators to provide at least three years notice prior to their retirement.[40]				

[31] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 23 March 2021.

[32] AEMO, December 2020, *DRAFT 2021 Inputs Assumptions and Scenarios Report*. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 23 March 2021.

[33] Victoria State Government, 31 October 2019. *Victoria's Renewable Energy Targets*. Available at: https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets. Accessed 11 November 2019.

[34] Peter Gutwein, Premier and Minister for Climate Change. *Acting on Climate Change*. Available at: http://www.premier.tas.gov.au/releases/acting_on_climate_change. Accessed 4 October 2020.

[35] Queensland Government Department of Natural Resources, Mines and Energy, 23 October 2019. *Powering Queensland Plan: An Integrated Energy Strategy for the State*. Available at: https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland. Accessed 11 November 2019.

[36] AEMO, 12 December 2020, *2021 Input and Assumptions Workbook, v3.0*. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 12 January 2021.

[37] The assumed retirement schedule for Yallourn power station (a staggered retirement of one unit each year from 2029-30 to 2032-33) was selected prior to the announcement by EnergyAustralia that specified Yallourn power station's retirement date would be brought forward to mid-2028. Full details are available at: https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition.

[38] The assumed retirement date for Eraring power station (2032-33) was selected prior to the reporting that Origin Energy has informed AEMO that unit 4 of Eraring will close in 2030 and unit 1 in 2031. The remaining two units will remain online until the previously announced retirement date of 2032-33. Details are available at: https://reneweconomy.com.au/origin-to-close-first-unit-of-australias-biggest-coal-generator-in-2030/.

[39] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/

[40] AEMC, 8 November 2018, National Electricity Amendment (Generator Three Year Notice of Closure) Rule 2019. Available at: https://www.aemc.gov.au/sites/default/files/2018-11/Final%20Determination.pdf. Accessed 24 September 2020.

Key drivers input parameter	Scenario				
	Slow change	Central	High DER	Fast Change	Step change
Coal fuel cost	Wood Mackenzie 2020,[41] Slow Change	Wood Mackenzie 2020, Central			Wood Mackenzie 2020, Step Change
Gas fuel cost	Lewis Grey Advisory 2020,[41] Slow Change	Lewis Grey Advisory 2020, Central			Lewis Grey Advisory 2020, Step Change
New entrant generation technology cost projections for wind, solar PV SAT, OCGT, CCGT, large-scale battery storage	CSIRO Draft GenCost 2021[41] Central			CSIRO Draft GenCost 2021 High VRE	
Discount rate and WACC (pre-tax, real)	3.8 %[41]	4.8 %[41]			
QNI-Option 1A (QNI Minor)	Commissioned Sept 2022, as per the committed ISP projects from AEMO's 2020 ISP report.[42]				
Western Victoria RIT-T augmentation	Commissioned by 2024-25, as per the committed ISP projects from AEMO's 2020 ISP report.[42]				
VNI Option 1 (Dederang-Lower Tumut path)	Commissioned Sept 2022, as per the actionable ISP projects from AEMO's 2020 ISP report.[42]				
Project EnergyConnect	Commissioned July 2024, as per the actionable ISP projects from AEMO's 2020 ISP report.[42]				
HumeLink	Commissioned July 2025, as per the actionable ISP projects from AEMO's 2020 ISP report.[42] Intraregional transmission upgrade captured via REZ transmission limits.				
Central-West Orana REZ Transmission Link	Commissioned July 2024, as per the actionable ISP projects from AEMO's 2020 ISP report.[42] Intraregional transmission upgrade captured via REZ transmission limits.				
VNI West (KerangLink)	Not installed.	Commissioned July 2027, as per the accelerated timing in the optimal development path in AEMO's 2020 ISP report.[42]			

3.2 Differences in assumptions with and without Marinus Link

Across all scenarios and sensitivities, development of Marinus Link is associated with the following five additional changes assumed by TasNetworks:

- A 10-percentage point decrease in monthly minimum whole of system reservoir volumes in Tasmania (Prudent Storage Levels, PSLs).[43]

---

[41] AEMO, 12 December 2020, *2021 Input and Assumptions Workbook, v3.0*. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 12 January 2021.
[42] AEMO, 30 July 2020, *2020 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 28 September 2020.
[43] 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 **Error! Reference source not found.**. The decrease in PSL profile with Marinus Link is a modelling assumption selected by TasNetworks and does not represent Tasmanian Government policy.

- A 100 MW expansion of West Coast power scheme's capacities.[44]
- A 150 MW upgrade of Tarraleah's capacity.
- An increase in capacity limits before REZ transmission expansion costs are applied for Central Highlands REZ, after Marinus Link stage 1 is commissioned. The capacity limit is increased from 480 MW to 1,200 MW.[45]
- An increase in capacity limits before REZ transmission expansion costs are applied, after Marinus Link stage 2 is commissioned. The capacity limit for North West Tasmania REZ is increased from 340 MW to 940 MW.

The cost differential between the with and without Marinus Link simulations is factored in externally by TasNetworks in their PACR report. Any cost differential associated with these five factors are also dealt with by TasNetworks. EY's work captures any additional market benefits facilitated by these changes.

3.3 Marinus Link loss model

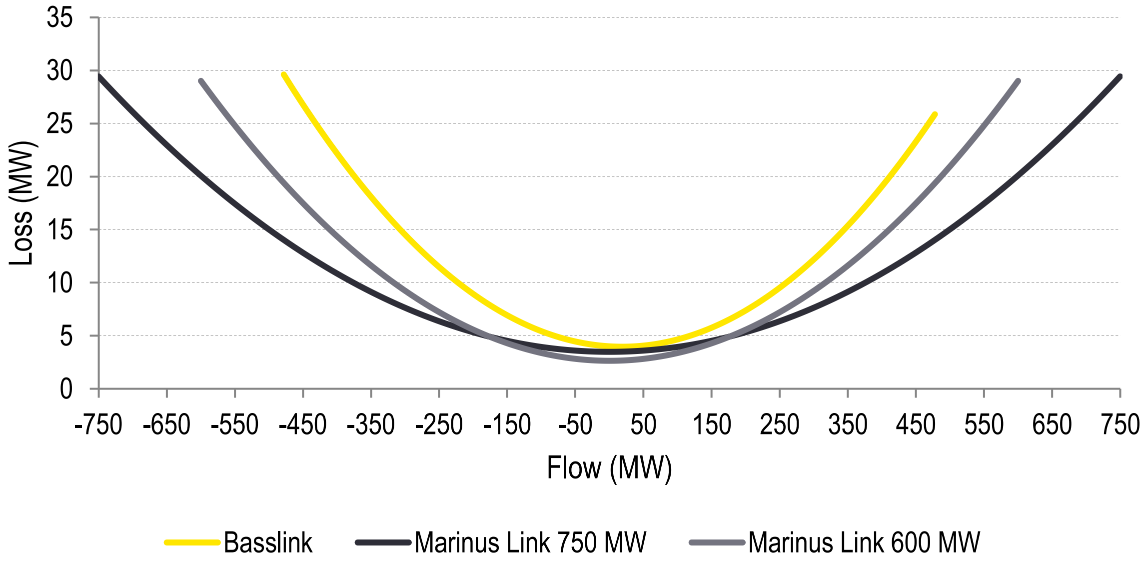
Losses on interconnectors between Tasmania and Victoria (on the cable and at converter stations) are calculated dynamically in each dispatch interval using a loss equation. The loss is apportioned to the two regions using a proportioning factor.

The main assumptions for Marinus Link as selected by TasNetworks are:

- Four Marinus Link size options made of two cable options, a 600 MW and a 750 MW cable. The 1,200 MW size option is modelled as two 600 MW interconnectors in parallel. Similarly, the 1,500 MW option is modelled as two 750 MW cables.
- There is a bi-directional flow limit of 600 MW/750 MW, measured at the receiving end.
- Dynamic losses are allocated to the sending end.
- Dynamic losses along the cable are described by the 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.

[44] 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.
[45] It is assumed that transmission augmentations associated with Marinus Link stage 2 will pass through this REZ.

Figure 2: Dynamic loss equation for Marinus Link and Basslink



Basslink and Marinus Link are modelled so as to share flows to minimise aggregate losses between Tasmania and Victoria, subject to flow limits on each interconnector.

4. NEM outlook across scenarios without Marinus Link

Before considering the market benefits of Marinus Link, the differences between the generation and capacity outlooks in each of the scenarios are presented to illustrate the breadth of possible futures captured across the five modelled scenarios.

4.1 Overview of scenario outcomes without Marinus Link

In all scenarios, retirements of coal-fired plant are the dominant factor driving change in the capacity in the NEM. These retirements occur due to their assumed maximum lifetimes or earlier economic retirements by the model due to state-based renewable energy policies and emission reduction targets. The existing coal-fired power stations are replaced by a combination of:

- Renewable wind and solar PV. These technologies are forecast to meet, at least cost, the energy gap caused by retirements of coal-fired generators,
- Ongoing development of behind-the-meter rooftop PV and battery storage. These reduce the growth of NEM schedulable energy demand,
- PSH, batteries and gas-fired generation. These are forecast to close the generation capacity gap caused by retirements, to ensure that reliability is maintained at or above present levels by the most economic, least-cost sources of dispatchable capacity.

Figure 3 shows the energy sources in the Central scenario in 2021-22 (other scenarios are similar) and all scenarios in 2040-41. It illustrates the scale of the transition from coal-fired generation as the dominant source of energy to variable renewables in all scenarios. In 2040-41, variable renewable generators (wind, large-scale solar PV and distributed PV) generate between 70 % (Slow Change) and 86 % (Step Change) of the energy. The main difference between scenarios is the pace of the transition.

Figure 3: NEM generation mix forecast without Marinus Link (storage not shown)

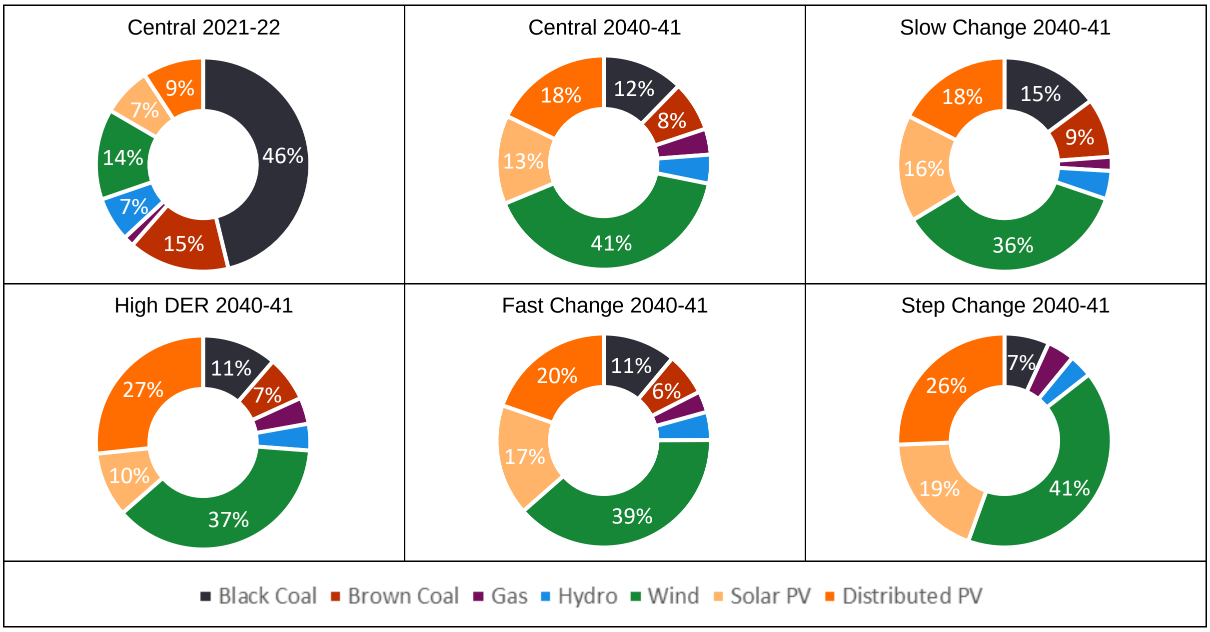
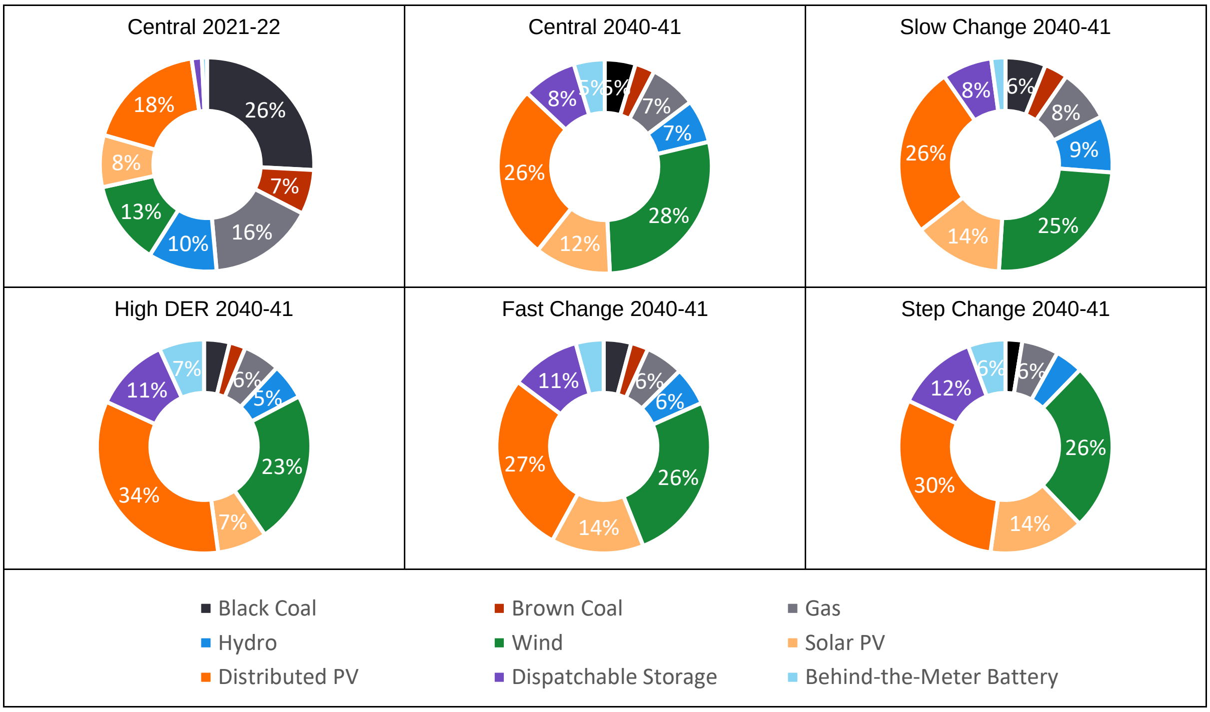


Figure 3 does not show the forecast development and use of storage (PSH, dispatchable batteries and behind-the-meter batteries). In addition to the assumed uptake of behind-the-meter batteries (fixed profile and virtual power plant VPP, 1.6-2.4 hours storage), the least-cost capacity mix is forecast to include both shorter-duration batteries (≤8 hours storage) and longer-duration PSH (≥12 hours storage) in all scenarios. Between 6 % and 9 % of energy in 2040-41 is shifted from weather-dependent time-of-generation to time-of-use using dispatchable storage. The model is capable of 'daisy-chaining' multiple shorter-duration batteries to achieve the same operational profile as a deeper storage; however, the forecast capacity mix includes deeper PSH instead as this is lower-cost.

As coal-fired generators retire, storage technologies are also forecast to fill an important role as new sources of dispatchable capacity alongside new OCGTs. Existing gas-fired generators and hydro generators also contribute. Figure 4 shows the capacity mix in the Central scenario in 2021-22 (other scenarios are similar) and all scenarios in 2040-41. Between 2021-22 and 2040-41 the percentage of variable renewable capacity is forecast to increase from 35-45 % to 60-70 % of total installed capacity across scenarios. Over the same period, the percentage of dispatchable capacity is forecast to fall from 55-65 % to 25-35 % of total capacity. However, in all scenarios the amount of dispatchable capacity is forecast to remain near to or in excess of peak demand.

Figure 4: NEM capacity mix forecast without Marinus Link



While batteries and PSH offer both energy-shifting and dispatchability services, new OCGT capacity is also forecast to form part of the least-cost capacity mix in all scenarios because they are cheaper than building sufficient deeper storage at low utilisation to cover longer, but less frequent periods of low supply (wind droughts and longer thermal unit outages).

Mainland interconnectors and their associated upgrades in all scenarios reduce the overall need for capacity across all regions by taking advantage of diversity in generation and load. Through interconnection underutilised generation capacity that is spare in one region can deliver capacity to adjacent regions that would otherwise be short or require additional build. Specifically, interconnectors facilitate more efficient operation of both existing and new capacity by providing:

- Ability to take advantage of diversity in weather patterns that drive wind and solar generation and differing resource quality across regions,
- Ability to share dispatchable capacity (fossil fuel and hydro resources) between regions such that the lowest fuel cost generation is used all the times,
- Ability for forced outages to be accommodated by transferring energy and capacity between regions.

The assumed interconnector expansions on the mainland have the effect of reducing the amount of time that interconnector flows are forecast to be at their limits.

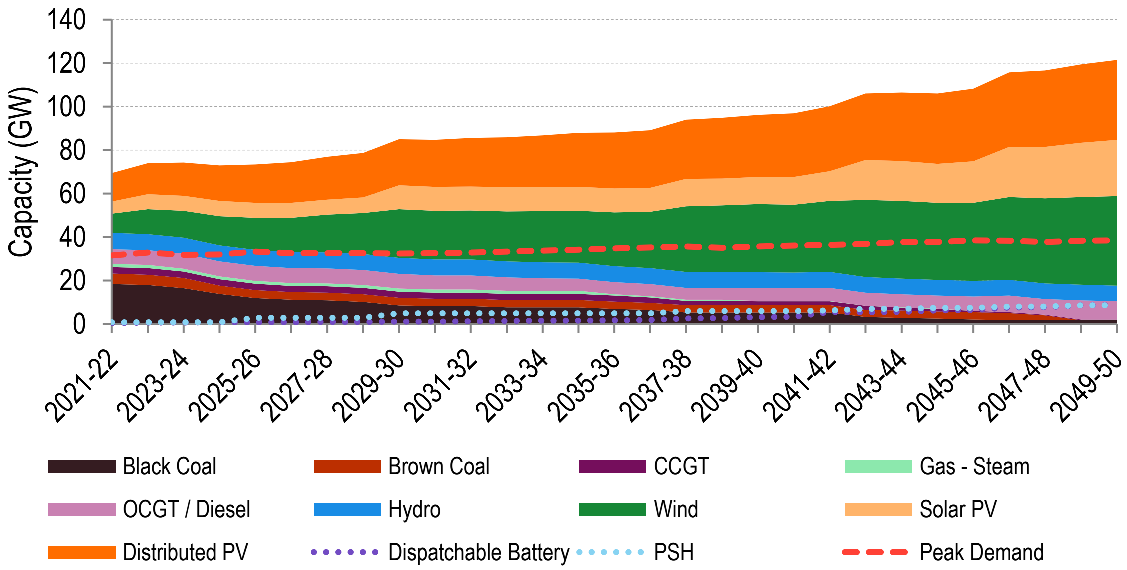
TRET is assumed to be built in all scenarios in the without-Marinus Link counterfactual which causes available Tasmanian generation to exceed Tasmanian demand and export capability in the longer term. Until the early 2030s, the volume of curtailed energy in Tasmania is low and similar in magnitude to the amount curtailed in other regions in all scenarios except Slow Change. In the longer term, without Marinus Link to aid in export of Tasmanian generation to the mainland, Tasmanian generation is forecast to be curtailed. Since the assumed short-run marginal cost (SRMC) for conventional hydro is greater than that of wind and solar PV, hydro generation is curtailed first under this least-cost modelling approach.

The remainder of Section 4 outlines the capacity and generation forecasts in each of the modelled scenarios without Marinus Link in more detail.

4.2 Central scenario without Marinus Link

The forecast NEM-wide capacity mix without Marinus Link in the Central scenario is shown in Figure 5. The capacity in the NEM is forecast to gradually shift away from a predominantly black and brown coal grid with some wind and solar PV developed, towards increasing capacity of wind, solar PV and storage, both PSH and dispatchable battery storage.[46] Some new entrant gas generation (OCGT) is also forecast to be installed from the late 2030s, but in less quantity.

Figure 5: NEM capacity mix forecast[47] without Marinus Link, Central scenario

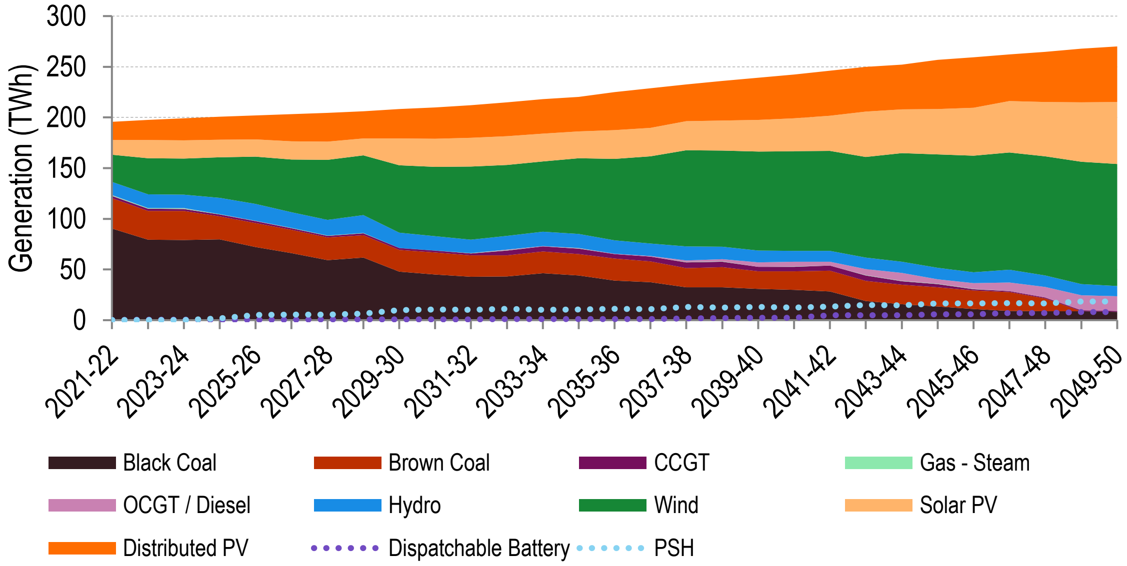


The energy supplied to the grid (an input to the modelling) is forecast by AEMO to grow relatively slowly as shown in Figure 6. The concurrent growth in installed capacity shown in Figure 5 is much faster, due to the relatively lower assumed annual capacity factors of forecast new wind and solar PV generation compared with the coal-fired generation that is retiring. However, the total cost of developing and operating solar PV and wind resources is forecast to be below that of gas-fired plant, so the mix of generation favours solar PV, wind and storage over OCGT and CCGT gas-fired plant, except as needed to meet the need for dispatchable generation when solar and wind are

[46] Dispatchable battery storage includes large-scale grid-connected battery storage and the assumed uptake of the aggregated, or smart, virtual power plant (VPP) component of residential and commercial behind-the-meter storage.
[47] NEM peak operational demand shown in this chart takes into account the diversity in timing of regional peak demands and is not simply the sum of the regional peak demand forecasts as interconnectors allow resource sharing between regions. In each region, there is generally sufficient dispatchable generation (including storage) to meet maximum demand.

not available. Based on inputs from the Draft 2021 Input and Assumptions Workbook[48], new entrant CCGT require a minimum load of 46 % whereas no minimum load requirement is assumed on new entrant OCGTs. Overall, the capacity mix in the NEM is based on providing sufficient dispatchable generation, mainly storage and gas-fired, to firm and time-shift the increasing volume of intermittent renewables entering the market.

Figure 6: NEM generation mix forecast without Marinus Link, Central scenario



Without Marinus Link, the forecast overall energy production in the NEM for the Central scenario, as shown in Figure 6, is an outcome of several factors including:

- Grid energy growth,
- State-based renewable energy targets,
- Retirements of major coal and gas generators due to age and early closures to reduce overall system cost,
- The declining cost of renewable generation relative to the stable costs of fossil-fuelled generation.

The technology mix is forecast to change dramatically in the Central scenario over the study period. Primarily, it is forecast that:

- From 2020 to 2030, the New South Wales Electricity Infrastructure Roadmap is forecast to bring an additional 12 GW of renewable capacity into New South Wales along with 2 GW of 8 or more-hour storage, in addition to the 2 GW Snowy 2.0 project. Across the rest of the NEM, the VRET, QRET and TRET are forecast to bring forward the installation of an additional 4 GW of new entrant renewable capacity, above already committed and advanced projects.
- Due to the uptake of new renewable capacity, it is forecast that renewable generation in the NEM, inclusive of distributed PV and hydro, will approximately double from roughly 70 TWh in 2021-22 to 140 TWh by 2029-30. Due to the lower operating cost of wind and solar, this increase in generation is predominantly forecast to offset black coal-fired generation.

[48] As per AEMO, 12 December 2020, *2021 Input and Assumptions Workbook*, *v3.0*. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 12 January 2021

- The assumed uptake in new renewable capacity is forecast to result in early coal-fired power station retirements during the mid-to-late 2020s. In Victoria, it is forecast that Yallourn power station will undergo a staggered retirement from 2024-25 and be fully retired by 2030-31. This is an accelerated timeline compared to the assumed staggered aged-based retirement schedule of 2029-30 to 2032-33, with one unit retiring each year throughout that period. It should be noted that while the assumed 2029-30 to 2032-33 retirement schedule was consistent with the most recent information at the time assumptions were selected by TasNetworks, this has since been brought forward by EnergyAustralia to an entire station retirement date in mid-2028.[49]
- In New South Wales, it is forecast that there will roughly 50 TWh of as-generated black coal generation at the start of the study in 2021-22. By 2023-24, with the assumed retirement of Liddell power station and entry of additional committed wind, grid-scale solar PV and rooftop PV, this is forecast to reduce to approximately 40 TWh. The large uptake in New South Wales renewable generation due to the New South Wales Electricity Infrastructure Roadmap as well as assumed rooftop PV uptake results in a forecast further reduction of New South Wales black coal generation to between 25 TWh to 30 TWh during the mid-to-late 2020s. Lowered coal generation is associated with a corresponding reduction in capacity, signifying a forecast of early coal closures in New South Wales during the mid-to-late 2020s. The early coal retirement forecast to occur in New South Wales during this time allows the capacity factor for the remaining fleet of coal-fired power stations to remain consistent throughout the study period. It should be noted that the assumed retirement dates for New South Wales coal-fired power stations were selected by TasNetworks based on the January 2021 release of AEMO's Generation Information,[50] which included an assumed retirement year of 2032-33 for Eraring power station. It has since been reported that Origin Energy has informed AEMO that unit 4 (720 MW) of Eraring power station is expected to close in 2030 and unit 1 may retire in 2031.[51] The remaining two units will remain online unit the previously announced retirement date of 2032-33.
- Conventional hydro generation on the mainland is assumed to reduce by approximately 7 % by 2049-50 to reflect reductions in reservoir inflows due to climate factors. The corresponding reduction in Tasmanian inflows is approximately 5 %.
- Gas-powered generation levels are forecast to be very low in the next decade due to the high cost of gas fuel relative to black and brown coal, and the high uptake of wind, solar PV and storage capacity to achieve state-based renewable targets.
- Low demand during the day and overnight enhances opportunities for both conventional hydro and other storage technologies. Conventional hydro such as Tasmanian hydro and Snowy hydro can avoid operating during low demand periods and thus retain stored energy for peak periods. By the start of the 2030s, it's assumed that there will be 4 GW of new entrant long duration storage due to the commissioning of Snowy 2.0 and the additional 2 GW of 8 or longer-hour storage as part of the New South Wales Electricity Infrastructure Roadmap.
- From the mid-2030s the generation contribution by coal is forecast to fall to approximately half of what it is at the beginning of the study. This is partly driven by the uptake of new entrant renewables but is also due to the 12 GW of coal-fired generators reaching their assumed end of life of operation between now and 2035-36.

[49] EnergyAustralia, 10 March 2021, EnergyAustralia powers ahead with energy transition. Available at: https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition. Accessed 21 March 2021.
[50] AEMO, Generation Information Page. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 26 May 2021.
[51] Renew Economy, 18 May 2021, Origin to close first unit of Australia's biggest coal generator in 2030. Available at: https://reneweconomy.com.au/origin-to-close-first-unit-of-australias-biggest-coal-generator-in-2030/. Accessed 18 May 2021.

- From the mid-2030s there is forecast for significant growth in wind production throughout the NEM, above what is forecast to be built to achieve the assumed state-based renewable energy targets, as shown in Figure 5 and Figure 6. Solar PV generation is also forecast to grow strongly but is not expected to produce as much energy as wind, due to lower capacity factors, and competition from distributed PV (rooftop PV and small non-scheduled PV) generation, which has a similar operating profile and erodes the benefits of additional solar PV.
- From the mid-to-late 2030s storage, initially PSH and later dispatchable battery storage, is forecast to become economic to firm up the intermittent renewable production from wind and solar PV. This is shown in the dotted lines Figure 5 and Figure 6. They are not shown stacked with projections of other technologies to reflect that storage is a load as well as a generator.
- By the late-2030s it is forecast that there will be growth in gas-fired generation from existing and new OCGT capacity to provide additional dispatchable capacity on top of the forecast installation of storage. OCGTs form part of the least-cost development plan because they are cheaper than building sufficient deeper storage at low utilisation to cover longer, but less frequent periods of low supply (wind droughts and thermal unit outages). The overall amount of gas-fired capacity remains comparable to current levels through the study (Figure 5) and gas-fired generation lower than observed in throughout the 2010s.

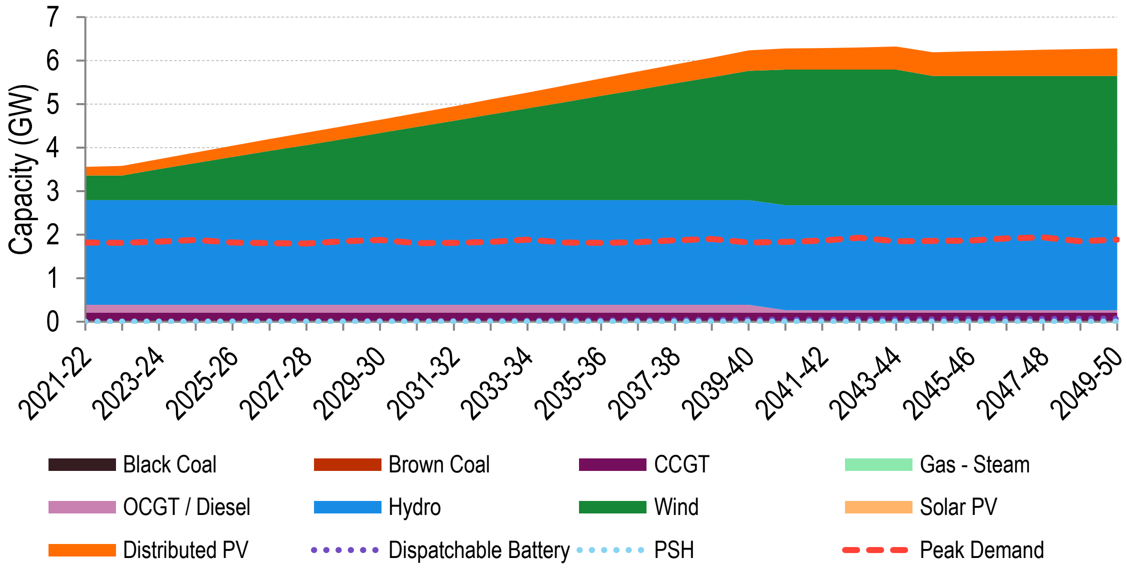
Renewable generation is forecast to develop alongside PSH and dispatchable battery capacity in all mainland regions. The economic driver for development in each region is to meet the load growth and replace retiring capacity using the lowest cost resources available within the region, or through imports from other regions. Most regions have REZ zones with either assumed high capacity factor wind resources or high solar resources, so are projected to have a combination of solar PV and wind developments.

Transmission losses (that grow non-linearly with flows), limits and REZ upgrade costs tend to limit the growth of particular technologies in a region for export to other regions, even if abundant high-quality resources are available. For example, high capacity factor wind in Far North Queensland and Tasmania is not fully developed up to REZ resource limits before lower capacity factor wind is built in New South Wales REZs closer to the supply-demand imbalance associate with New South Wales coal retirements. The least-cost model optimally computes these trade-offs. However, the diversity of resources between distant regions of the NEM can outweigh the impact of transmission losses and leads to high utilisation of interconnectors and expanded growth of renewables. This is because weather conditions create considerable diversity in the production profile of wind and solar PV between regions and thus regions without wind or sun may import from regions experiencing windy and sunny conditions.[52] It is also because losses over interconnectors are generally less than cyclic losses for storage technologies.

The forecast capacity development plan in Tasmania without Marinus Link is shown in Figure 7. Between 2022-23 and 2040-41 it is forecast that approximately 2.5 GW of new capacity will be installed to achieve the TRET. Due to the high capacity factor that is assumed for Tasmanian wind and low correlation with mainland wind availability, it is forecast that the entirety of this 2.5 GW is wind capacity.

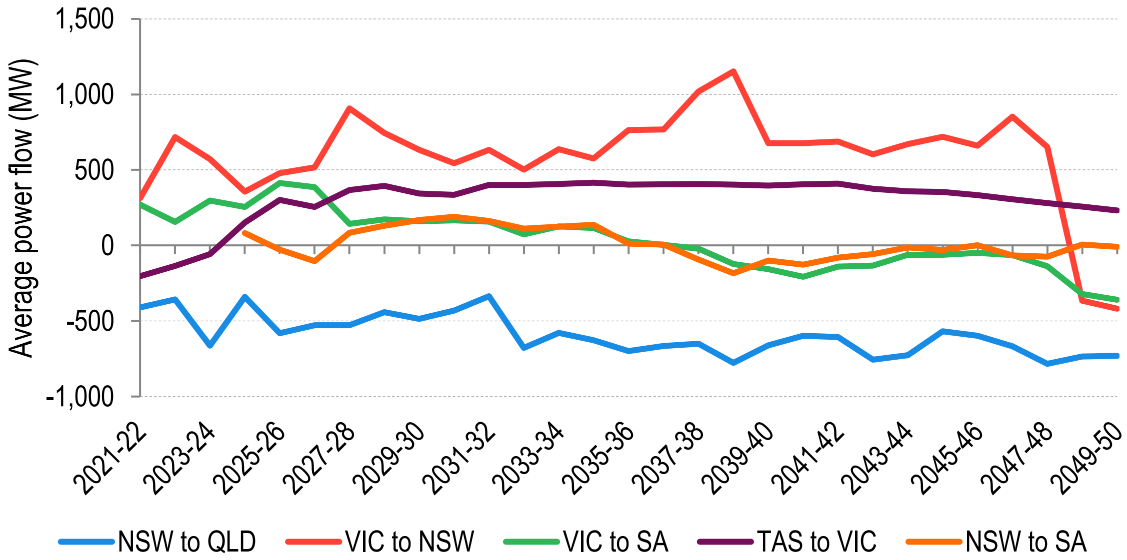
[52] Both wind and solar are modelled using nine years of meteorological patterns at the half hourly level, converted to hourly to accord with the model resolution.

Figure 7: Tasmanian capacity mix forecast without Marinus Link, Central scenario



For the Central scenario, Figure 8 shows the forecast net average energy transfers by year across all existing interconnectors.

Figure 8: Average annual interconnector power flow forecast for Central scenario without Marinus Link



The figure shows that some interconnectors are forecast to transfer more energy between regions than others.

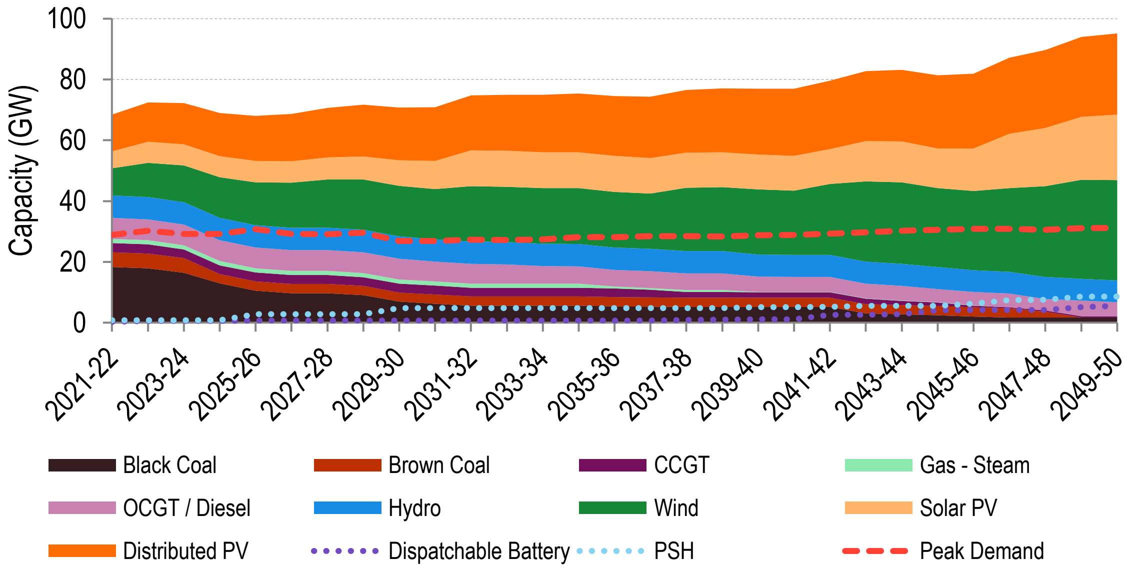
- Basslink flows are consistently northward reflecting the assumed level of existing and new wind in Tasmania. Consequently, the existing transfer limits from Tasmania to Victoria often result in curtailment of Tasmanian generation. This demonstrates the opportunity for Marinus Link.
- Victoria to New South Wales interconnector flows are generally northward, although once all Victorian brown coal-fired capacity has retired by the late-2040s this trend is forecast to reverse. VNI West is assumed to be built in 2027-28, greatly expanding transfer limits between New South Wales and Victoria and contributing to higher exports from Victoria to New South Wales in some later years.

- South Australia shifts towards net neutral flow due to the uptake of renewable developments across New South Wales and Victoria. By the late 2020s, after the assumed installation of Project EnergyConnect in 2024-25, it is able to transfer variable renewable energy throughout the NEM during times when surplus energy is available in one region, but shortfalls occur in another.
- Owing to strong solar resources in Queensland and relatively later retirement of the Queensland coal portfolio as compared to New South Wales, transfers over the Queensland to New South Wales interconnectors are strongly in favour of imports to New South Wales from Queensland, despite the assumed inclusion of the New South Wales Electricity Infrastructure Roadmap.

4.3 Slow Change scenario without Marinus Link

In the Slow Change scenario, the key drivers relative to the Central scenario are lower assumed annual energy and peak demand growth. Significant reductions in demand occur in 2021-22 and 2026-27, with the assumed retirements of large industrial loads in Victoria and Tasmania. Further large industrial load retirements are assumed to occur in New South Wales and Queensland in 2029-30. Figure 9 displays the forecast NEM capacity mix for this scenario.

Figure 9: NEM capacity mix forecast without Marinus Link, Slow Change scenario



The large reduction in load is forecast to result in less coal generation and to bring forward the retirement of 2 GW to 3 GW of coal capacity throughout the mid-2020s and into the 2030s, relative to the Central scenario. This is shown in Figure 10 and Figure 11, which display the difference in forecast capacity and generation respectively between the Central and Slow Change scenarios. The assumption of lower demand also results in roughly 16 GW less non-storage capacity and 3 GW of storage capacity commissioned on an economic basis over the study period across the NEM. For this scenario, although the underlying system demand is lower, the contribution from distributed PV capacity is higher than that of the Central scenario. This continued uptake of distributed PV despite a reduction in energy consumption allows for advancing coal capacity retirements across the NEM.

Figure 10: Difference in NEM capacity mix forecast without Marinus Link between Slow Change scenario and Central scenario (difference relative to Figure 5; positive values equal higher capacity in Slow Change scenario).

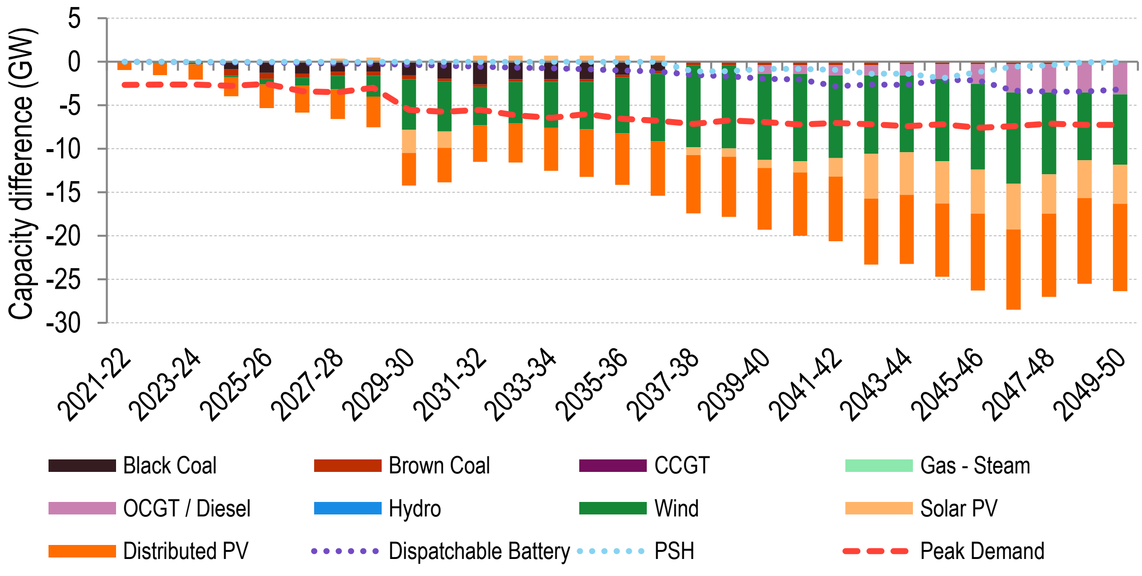


Figure 11: Difference in NEM generation mix forecast without Marinus Link between Slow Change scenario and Central scenario (difference relative to Figure 6; positive values equal higher energy in Slow Change scenario).

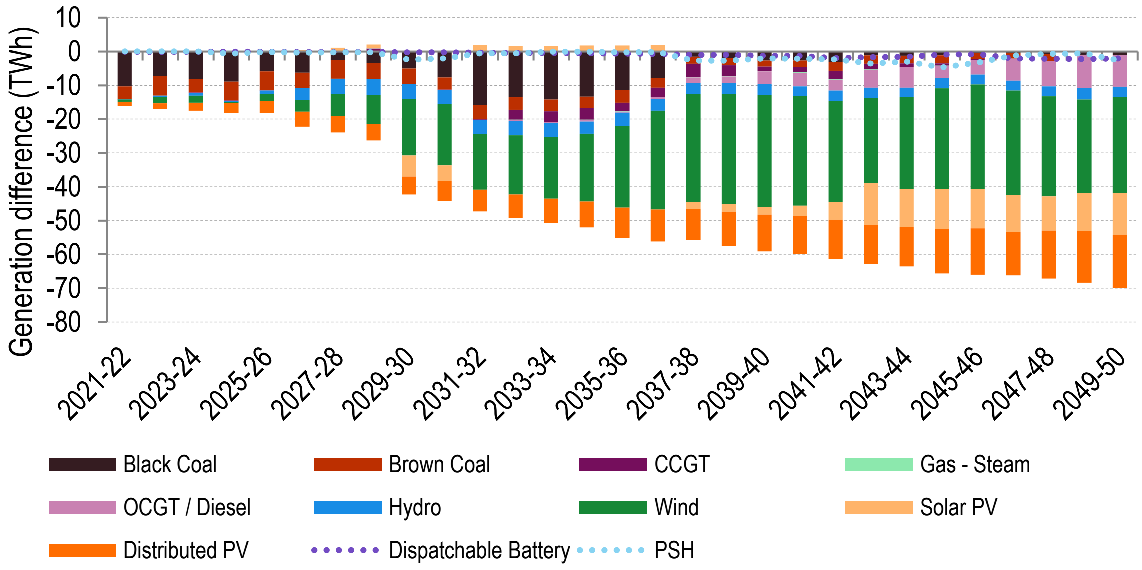
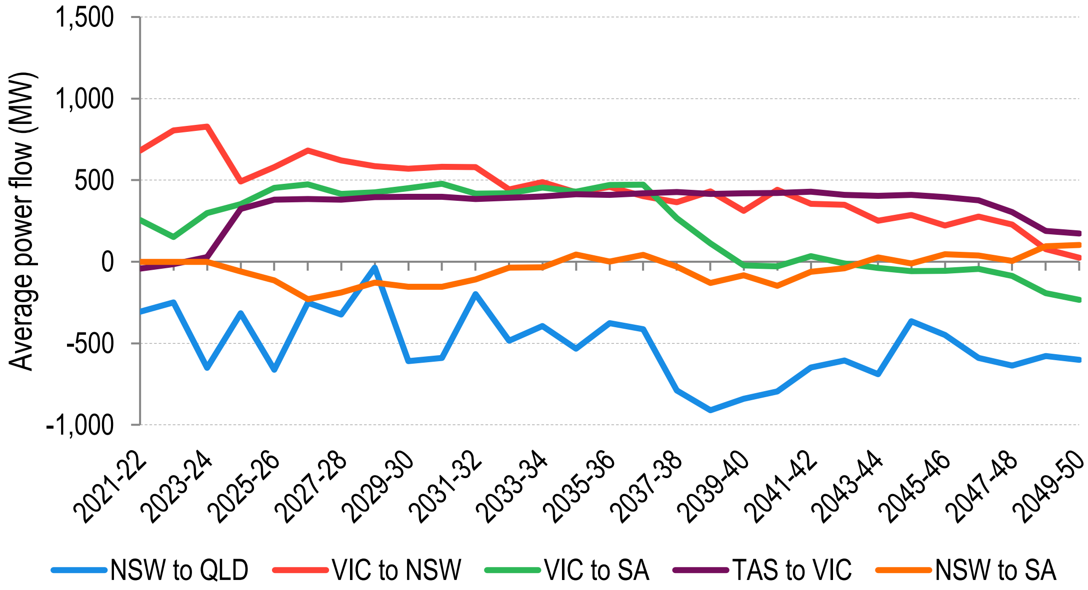


Figure 12 illustrates that Basslink is forecast to be heavily constrained in the northward direction due to the retirement of 320 MW of industrial load in 2025-26 in Tasmania. As with the Central scenario, this foreshadows the potential for Marinus Link to generate market benefits as this retirement creates surplus energy and dispatchable capacity that could be exported to the mainland with additional interconnection. Lower demand than the Central scenario means the Slow Change scenario has additional surplus energy which translates into higher forecast northward flows across Basslink.

Without Marinus Link, Basslink is forecast to become further constrained as the study progresses due to the build-out of the TRET. This highlights the fact that the assumed state-based renewable energy policies have been created in anticipation of a Step Change future with a higher demand future than is assumed in the Slow Change scenario.

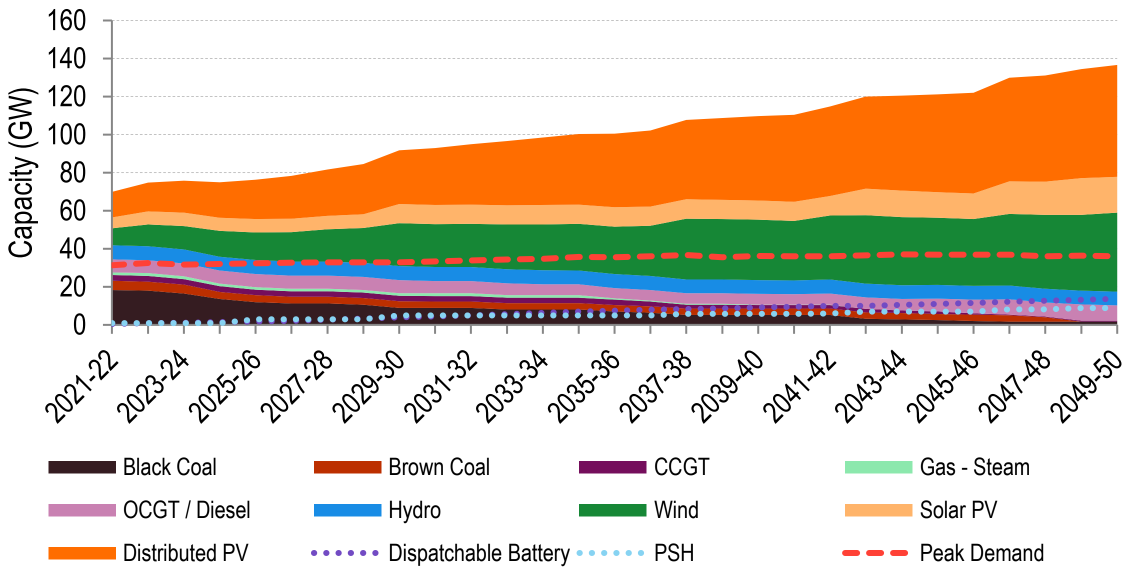
Figure 12: Average annual interconnector power flow forecast for Slow Change scenario without Marinus Link



4.4 High DER scenario without Marinus Link

In the High DER scenario, the anticipated uptake of distributed energy resources is significantly higher than that of the Central scenario. From the perspective of generation, this results in a larger contribution of distributed PV in the form of rooftop PV and small non-scheduled PV installation. The forecast annual capacity is presented in Figure 13.

Figure 13: NEM capacity mix forecast without Marinus Link, High DER scenario



The reduction in operational demand due to the uptake of rooftop PV and small non-scheduled PV generation is partially offset by the anticipated uptake in EV demand across all regions, which increases the underlying demand. By the mid-2030s, dispatchable battery capacity is forecast to be roughly 5 GW more than that of the Central scenario. This is predominantly driven by the assumed uptake of domestic storage. This includes the aggregated VPP component of domestic storage, which has the potential to assist the NEM in meeting periods of high demand. Figure 14 and Figure 15 present the forecast difference in capacity and generation outlooks between the High DER scenario and the Central scenario.

Figure 14: Difference in NEM capacity mix forecast without Marinus Link between High DER scenario and Central scenario (difference relative to Figure 5; positive values equal higher capacity in High DER scenario).

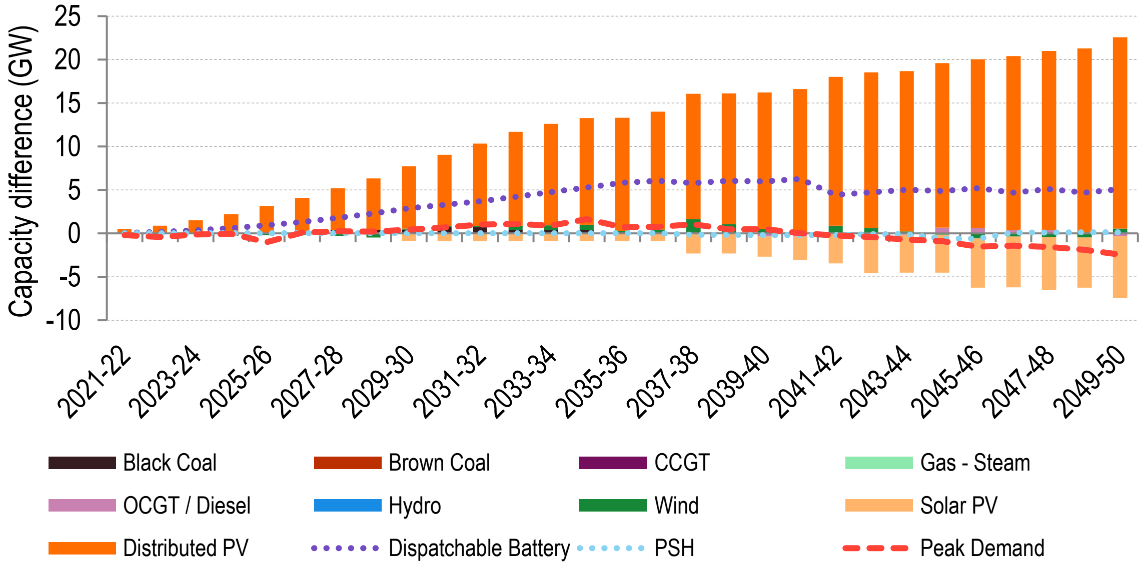
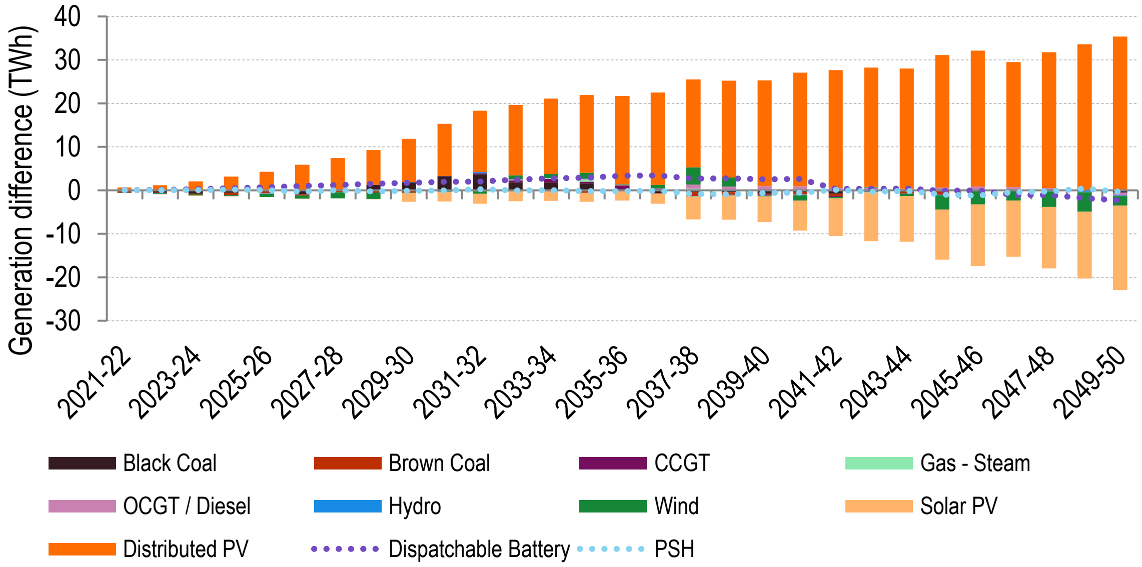


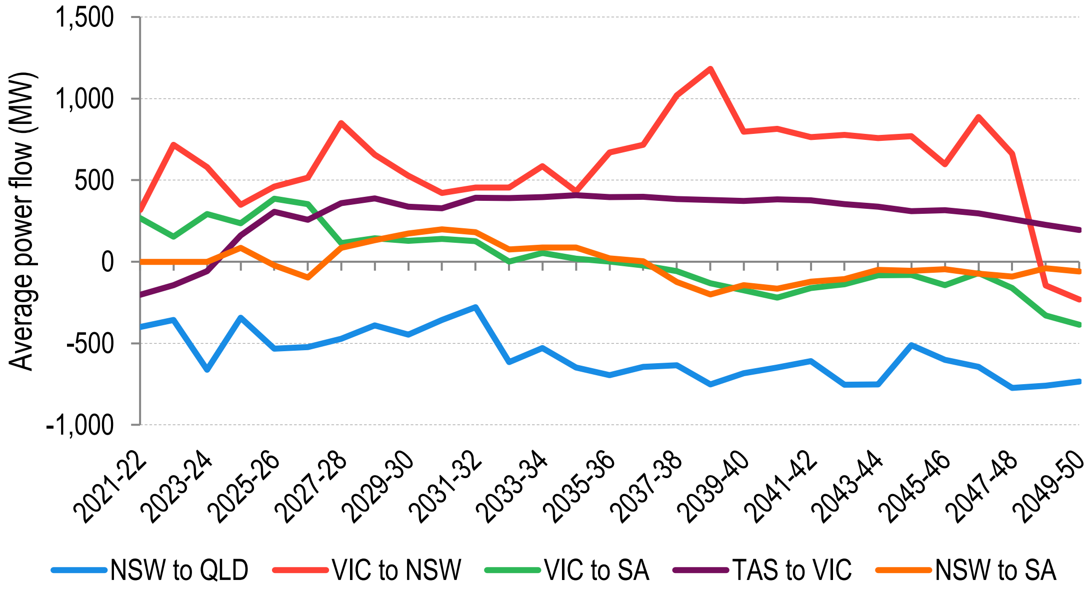
Figure 15: Difference in NEM generation mix forecast without Marinus Link between High DER scenario and Central scenario (difference relative to Figure 6; positive values equal higher energy in High DER scenario)



In this scenario, the anticipated increase in distributed PV capacity is forecast to slightly reduce the forecast economic installation of solar PV towards the end of the study period.

Figure 16 illustrates that Basslink is heavily constrained in the northward direction from the late-2020s due to the high capacity factor wind capacity that is forecast to be installed in Tasmania to achieve the TRET.

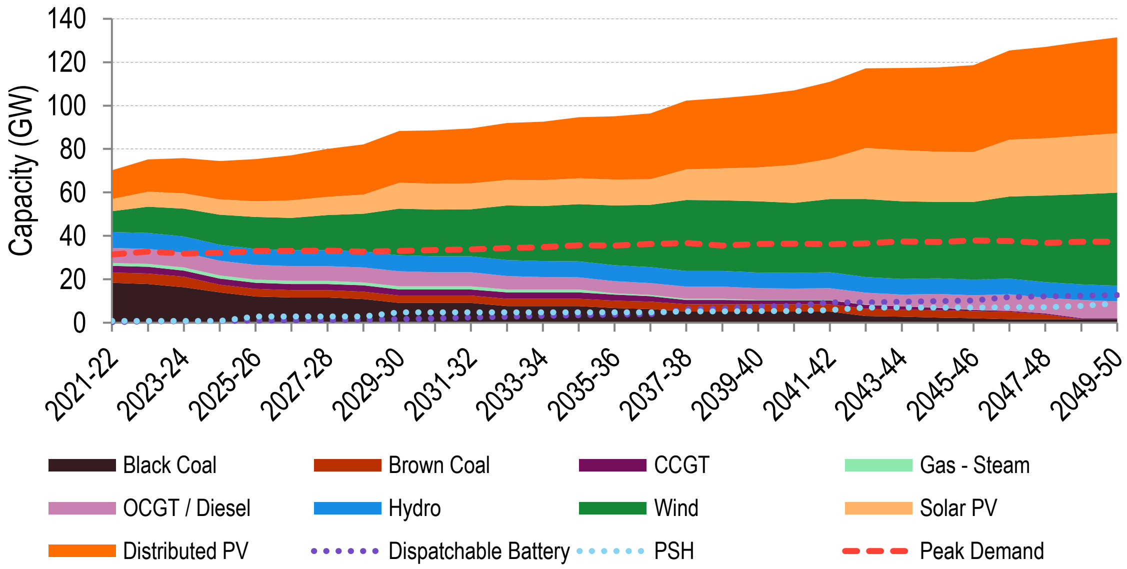
Figure 16: Average annual interconnector power flow forecast for High DER scenario without Marinus Link



4.5 Fast Change scenario without Marinus Link

Under the Fast Change scenario, it is assumed that the NEM will limit its total carbon emission to 2,068 Mt CO_2-e from 2020-21 to 2049-50. Furthermore, it is assumed that this national focus on emission reduction will result in additional DER uptake across the NEM, relative to the Central scenario, in the form of distributed PV, behind-the-meter storage and EVs. Figure 17 displays the capacity forecast for the Fast Change scenario.

Figure 17: NEM capacity mix forecast without Marinus Link, Fast Change scenario



Even without a national incentive scheme to reduce emissions beyond state-based RETs, the current policies such as the New South Wales Electricity Infrastructure Roadmap, VRET, QRET and TRET are almost sufficient to enable the cumulative 2020-21 to 2049-50 emission budget for this scenario to be met. Relative to the Central scenario, approximately 2 GW to 3 GW of additional wind capacity is forecast to be brought forward to be installed in the 2030s and 3 GW to 5 GW of additional solar PV capacity during the 2040s. By 2049-50, the overall capacity mix across the NEM is forecast to be fairly similar to that of the Central scenario, with the exception of the additional 7.5 GW of distributed PV and 4 GW of VPP capacity that has been assumed as part of the input supply. This is shown in Figure 18 and Figure 19, which display the forecast difference in capacity and generation outlooks between the High DER scenario and the Central scenario, respectively.

Figure 18: Difference in NEM capacity mix forecast without Marinus Link between Fast Change scenario and Central scenario (difference relative to Figure 5; positive values equal higher capacity in Fast scenario).

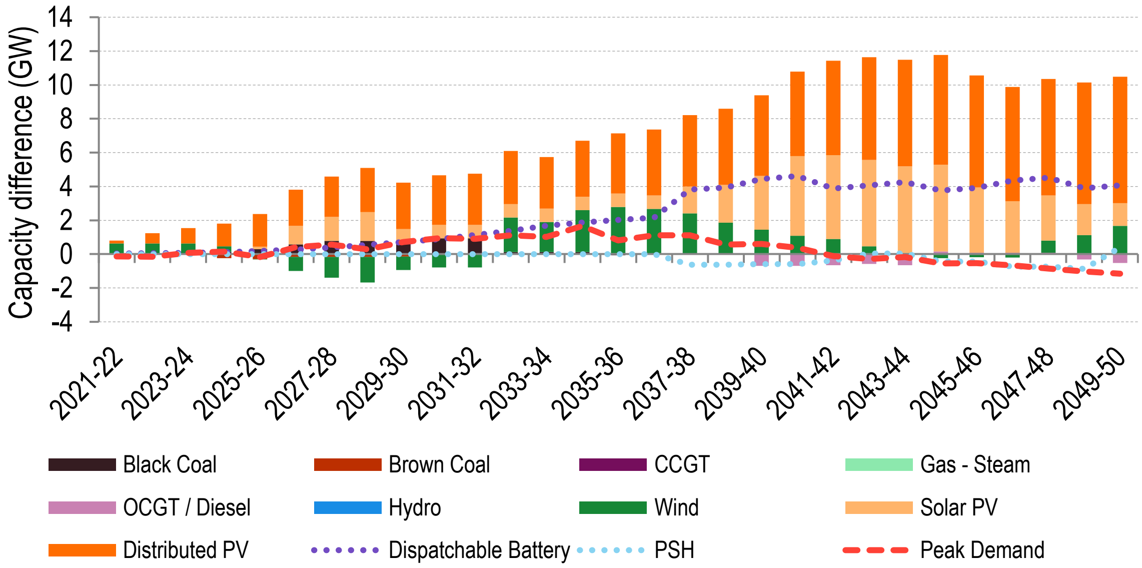


Figure 19: Difference in NEM generation mix forecast without Marinus Link between Fast Change scenario and Central scenario (difference relative to Figure 6; positive values equal higher energy in Fast Change scenario).

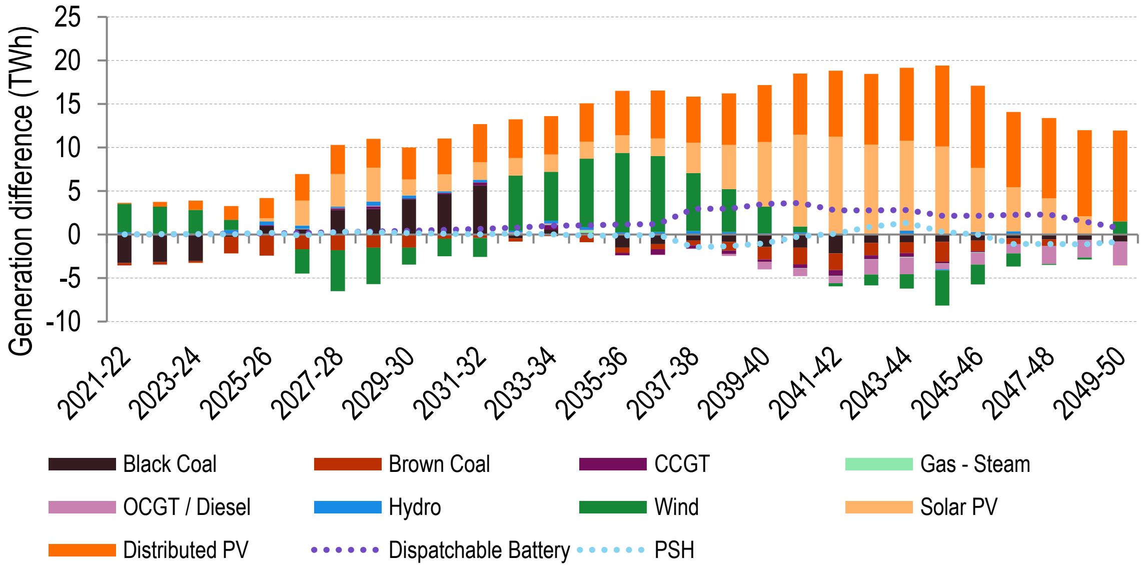
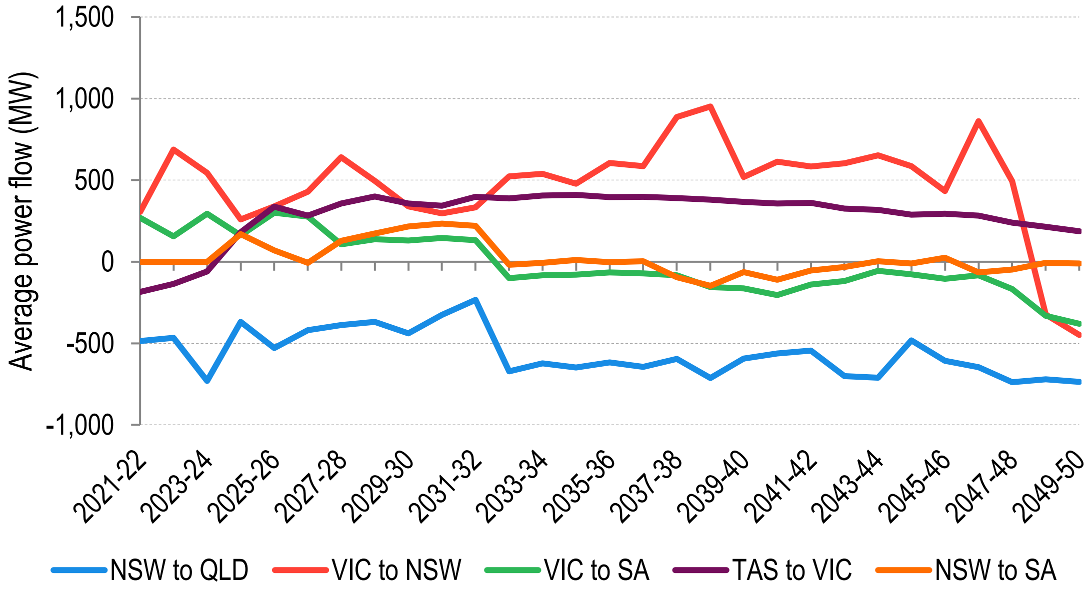


Figure 20 illustrates that Basslink is again forecast to be heavily constrained in the northward direction from the mid-2020s.

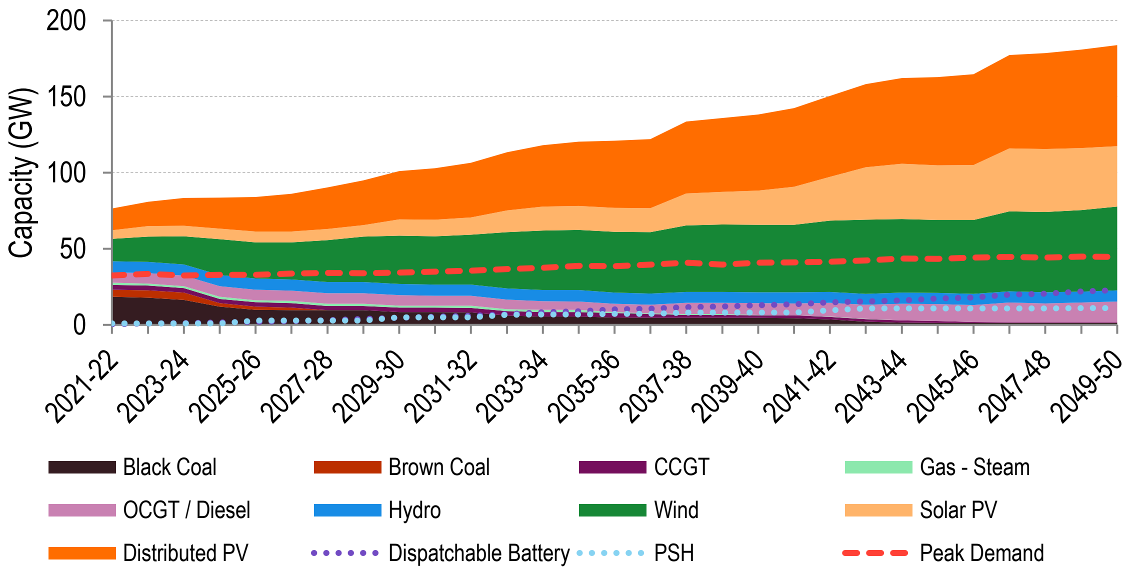
Figure 20: Average annual interconnector power flow forecast for Fast Change scenario without Marinus Link



4.6 Step Change scenario without Marinus Link

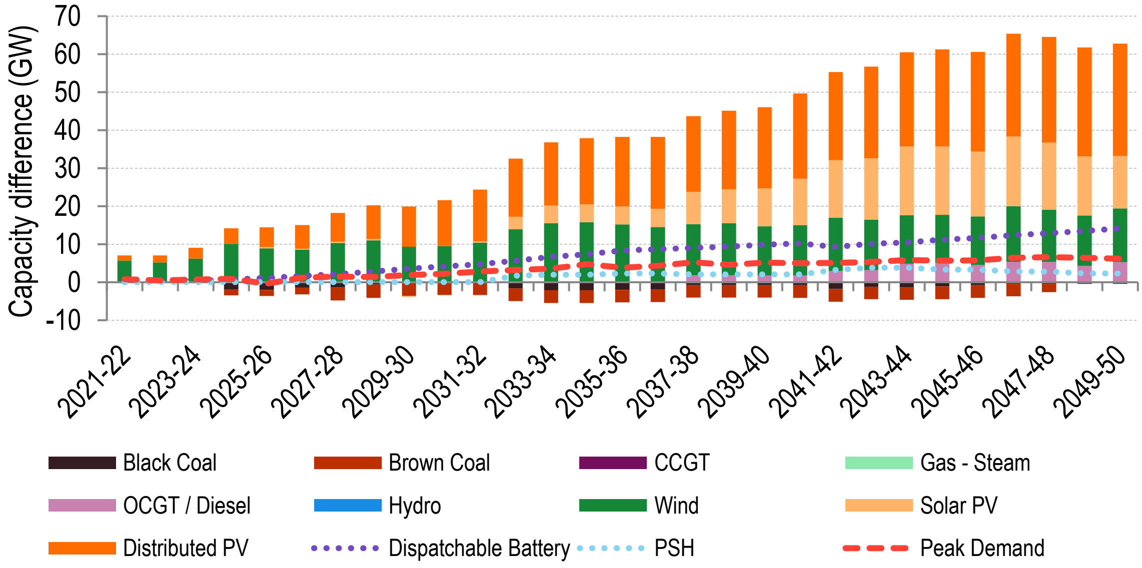
In the Step Change scenario, it is assumed that nation-wide action will result in the NEM emitting no more than 1,325 Mt CO_2-e from 2020-21 to 2049-50. Relative to the Central scenario, it is assumed that there will be a significant uptake in DER across all regions of the NEM. Figure 21 displays the capacity forecast for the Step Change scenario.

Figure 21: NEM capacity mix forecast without Marinus Link, Step Change scenario



The commitment to significant emissions reductions across the NEM is forecast to result in roughly 5.7 GW of additional wind capacity installed in the NEM from the beginning of the study, above what is forecast for the Central scenario. This is shown in Figure 22. Furthermore, 3 GW to 5.5 GW of early coal retirements from the mid-2020s are forecast.

Figure 22: Difference in NEM capacity mix forecast without Marinus Link between Step Change scenario and Central scenario (difference relative to Figure 5; positive values equal higher capacity in Step Change scenario).

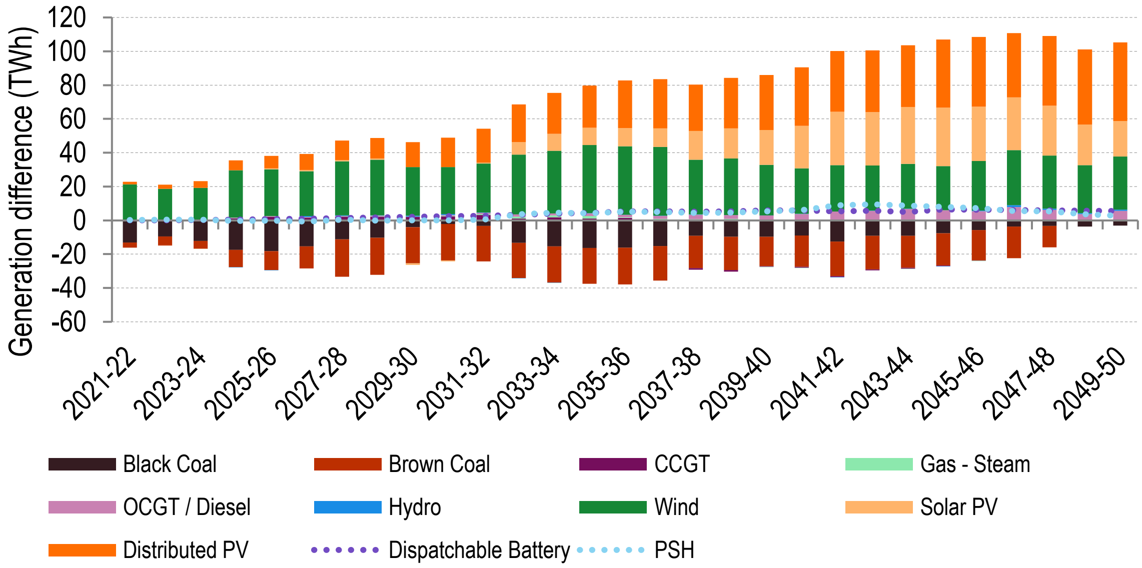


From the 2030s onward, it is assumed that operational demand for the Step Change scenario noticeably increases above that of the Central scenario. This is due to the assumption of higher electrification throughout Australia, partly in the form of a faster uptake of EV load. Despite the higher assumed uptake of distributed PV, which reduces demand, operational demand for the Step Change scenario is 20 TWh to 30 TWh more than that of the Central scenario by the late 2030s and more than 50 TWh higher by the end of the study.

The assumed uptake of behind-the-meter battery storage reduces peak demand periods; however, the overall increase in demand still results in higher peak operational demand for the Step Change scenario, relative to the Central scenario.

Figure 23 presents the forecast difference in generation outlooks between the Step Change scenario and the Central scenario.

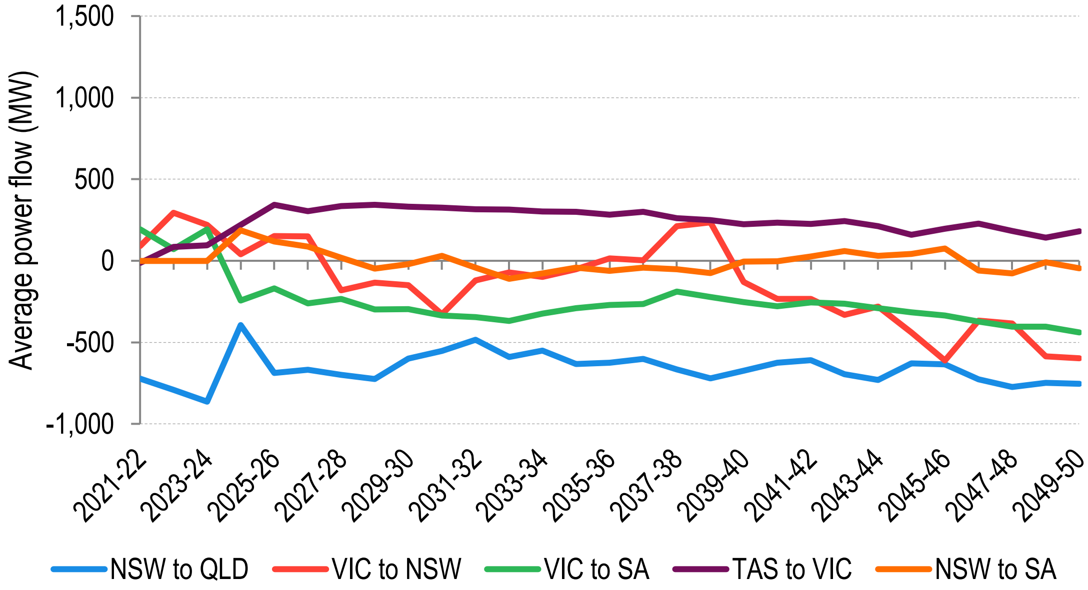
Figure 23: Difference in NEM generation mix forecast without Marinus Link between Step Change scenario and Central scenario (difference relative to Figure 6; positive values equal higher energy in Step Change scenario).



Throughout the 2020s operational demand is assumed to be similar between the Step Change scenario and the Central scenario. The reduction in coal generation is replaced by an increase in new wind capacity. From the 2030s, this increase in demand is forecast to be met by additional wind and solar PV generation. New entrant gas-fired capacity is forecast to be installed from the late-2030s to further assist in supplying the NEM.

Figure 24 illustrates that Basslink is again heavily constrained in the northward direction from the mid-2020s. As the study progresses, Basslink is less utilised as the least-cost generation development forecast includes significant build of mainland renewable capacity. Even though Tasmania has a surplus of clean, low-cost energy from hydro at this time, it is frequently competing with lower cost wind and solar generation on the mainland that would otherwise be curtailed.

Figure 24: Average annual interconnector power flow forecast for Step Change scenario without Marinus Link



4.7 Opportunity for Marinus Link

Without Marinus Link, the Basslink interconnector is forecast to become increasingly constrained at the limit in the northerly direction in all scenarios (Figure 8, Figure 12, Figure 16, Figure 20 and Figure 24). For all five scenarios, the level of constraining of Basslink reaches extreme levels in most future years, with between 50 % and 90 % of the time having flows at the limits from the late 2020s. This is because the expected growth in wind generation in Tasmania (due to the TRET) exceeds that of assumed demand growth, and therefore net energy transfers to the mainland are forecast to increase over time, within the capacity limitations of Basslink.

In all scenarios, the capacity of Basslink is forecast to limit the opportunity for Tasmania to supply energy to mainland regions at lower cost.

The limited transfer capacity of Basslink on its own means spare Tasmanian capacity cannot offset the need to build new capacity on the mainland and, in scenarios with a carbon budget, clean Tasmanian renewable energy cannot effectively assist in meeting that budget. The development of Marinus Link is forecast to allow this to occur, as will be illustrated in the Section 5.

5. Marinus Link forecast market benefits

5.1 Summary of forecast market benefits

Table 3 shows the forecast market benefits outcomes over the modelled horizon of 2021-22 to 2049-50, across all scenarios and Marinus Link options (including associated AC transmission augmentations), at different modelled timings. The values are discounted to 1 July 2020.[53]

Table 3: Forecast market benefits of Marinus Link for different size and timing options, millions real June 2020 dollars discounted to 1 July 2020

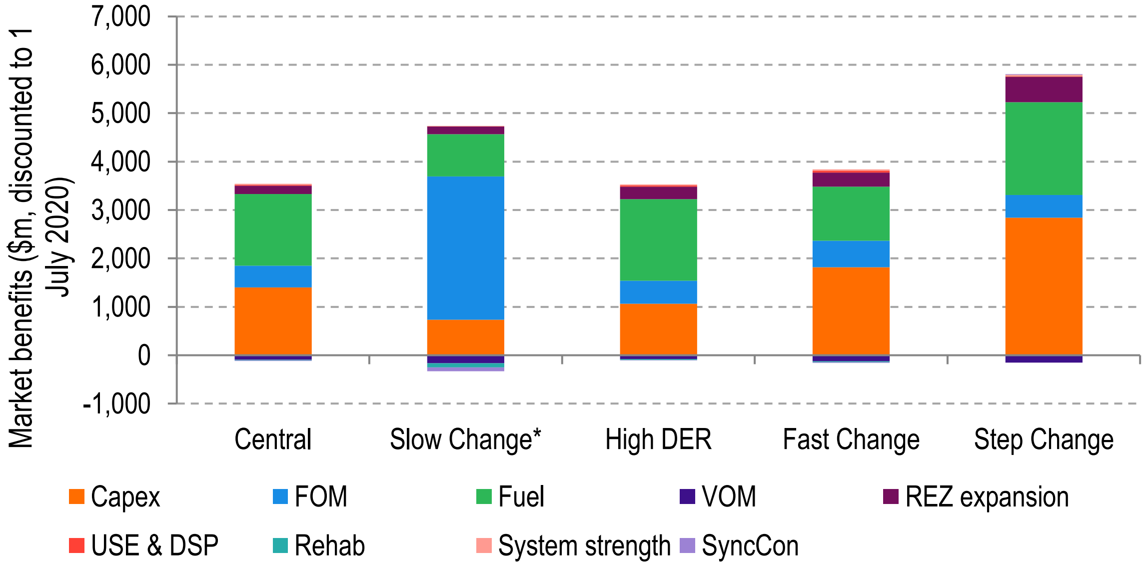
		Scenario				
		Slow Change	Central	High DER	Fast Change	Step Change
30-year carbon budget:		No explicit carbon budget			2,068 Mt CO_2-e	1,325 Mt CO_2-e
Option	Marinus Link timing	Discount rate: 3.8 %[54]	Discount rate: 4.8 %			
1,500 MW	2027 & 2029	4,405	3,420	3,425	3,679	5,655
	2027 & 2030	4,384	3,416	3,421	3,673	5,627
	2028 & 2031	4,270	3,385	3,388	3,630	5,490
	2031 & 2034	3,876	3,241	3,237	3,432	5,014
	2034 & 2037	3,414	2,903	2,875	3,040	4,336
1,200 MW	2027 & 2029	3,986	3,250	3,262	3,481	5,195
	2027 & 2030	3,952	3,244	3,256	3,473	5,159
750 MW	2027	2,802	2,676	2,676	2,839	4,179
600 MW	2027	2,283	2,281	2,277	2,425	3,557

Forecast market benefits of Marinus Link in each scenario should be compared to the relevant Marinus Link costs to determine whether there is a positive net economic benefit. The computation of net economic benefits (market benefits less costs) and determination of the preferred option has been conducted by TasNetworks outside of this Report[55] as option costs were developed independently by TasNetworks. The market benefits estimated in this report exclude other benefits that could potentially be computed, such as ancillary services cost reduction.

Fuel cost, capex and FOM savings are forecast to be the main sources of market benefits in all scenarios as shown in Figure 25 for Marinus Link 1,500 MW, stage 1 2027, stage 2 2029. In the Slow Change scenario FOM savings dominate while in the other four scenarios capex and fuel savings dominate.

[53] This differs to EY's appendix to the Marinus Link PADR where market benefits were discounted to 1 July 2025 which coincided with the approach taken for the Initial Feasibility Report. The year 2025 was chosen for the Initial Feasibility Report because that was the year in which it was assumed Marinus Link would be commissioned.
[54] As per AEMO's Draft 2021 Input and Assumptions Workbook, a discounted rate of 3.8 % is applied for the Slow Change scenario. All other scenarios apply a discount rate of 4.8 %. Apply caution when comparing market benefits across scenarios.
[55] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

Figure 25: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029; millions real June 2020 dollars discounted to 1 July 2020. (*Slow Change uses a discount rate of 3.8 % while other scenarios use 4.8 %.)



5.2 Overview of effects of Marinus Link

Building Marinus Link is forecast to provide the following market benefits:

- Enables existing conventional Tasmanian hydro to save water for dispatch at times of lower supply such as in the periods of peak demand, during wind droughts and thermal unit outages.
- Provides greater mainland access to high-quality, diverse Tasmanian wind generation.
- Reduces spill of Tasmanian renewable energy available in excess of what can be stored or exported across Basslink.
- Improves mainland access to the combination of Tasmanian conventional hydro and wind generation:
    - offsetting the use of thermal generation on the mainland (creating fuel cost and FOM savings),
    - deferring the need to build new capacity on the mainland (creating capex and FOM savings),
    - allowing additional new mainland solar PV capacity to be built in place of more expensive mainland wind.
- In scenarios with a binding emissions reduction constraint, Marinus Link provides access to cheaper zero-emissions generation for lower cost supply.

These market benefits are apparent with even a single stage of Marinus Link. Building a second stage is forecast to provide the following additional market benefits:

- Enabling the build of long-duration PSH to be built in Tasmania. This provides the additional ability to store excess production from variable renewable generators in Tasmania and on the mainland for dispatch at times of low supply. This reduces the need to use or build gas-fired generation or multiple shorter-duration batteries at higher cost on the mainland.

Consistent with the application of all federal and state based renewable energy schemes, TRET is assumed to be a committed policy since it is a legislated target.[56] Therefore, capex and operating costs are incurred in achieving the scheme in both with and without Marinus Link cases. However, under the current set of assumptions, the full benefit of the TRET is only enabled if Marinus Link is installed.

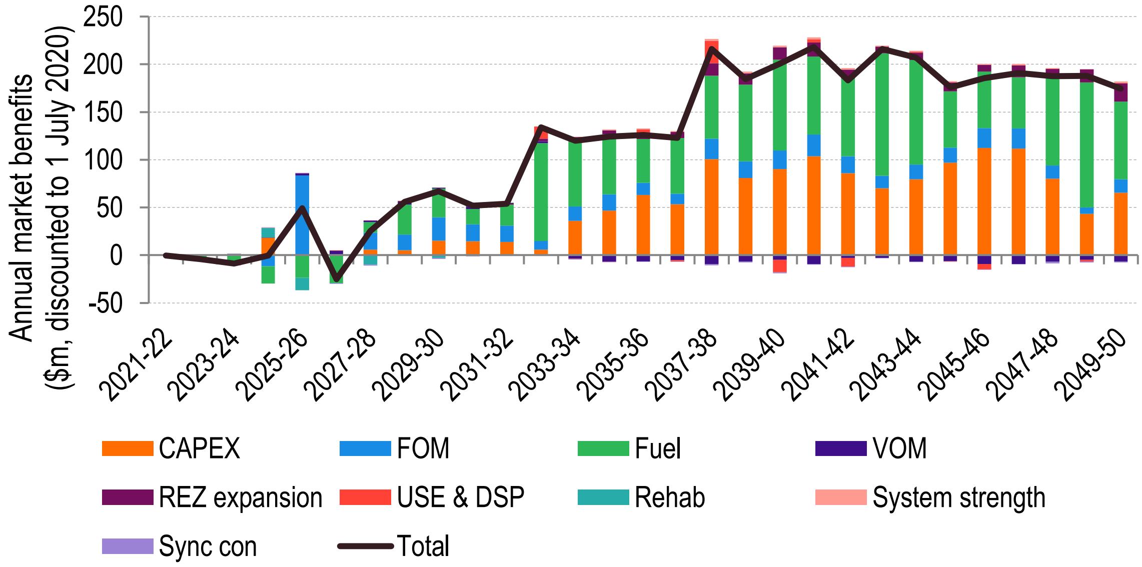
The remainder of Section 5 explores the timing and sources of these market benefits in each scenario, with a focus on the 1,500 MW sized Marinus Link with stage 1 installed 2027 and stage 2 in 2029.

5.3 Central scenario with Marinus Link

5.3.1 Forecast market benefits of Marinus Link, Central scenario

In the Central scenario the dominant sources of market benefits associated with Marinus Link are forecast to be fuel cost and capex savings. This was illustrated in Figure 25 which shows the forecast market benefits associated with Marinus Link, stage 1 2027 and stage 2 2029. The annual breakdown of forecast market benefits is shown in Figure 26 which can be understood in association with the generation and capacity differences discussed in Section 5.3.2.

Figure 26: Forecast annual market benefits[57] of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Central scenario; millions real June 2020 dollars discounted to 1 July 2020



Fuel cost savings are forecast to begin to accrue from 2027-28 when the first stage of Marinus Link becomes operational. Once Eraring power station in New South Wales is assumed to be fully retired in 2032-33, the market benefits of Marinus Link increases significantly due to the offsetting reduction in dispatchable capacity needed to meet demand across the mainland NEM. The forecast annual market benefits increase again from 2037-38, after the assumed retirements of Bayswater power station in New South Wales (2035-36), Tarong power station in Queensland (two units in 2036-37 and the remaining two units in 2037-38) and Tarong North power station in Queensland (2037-38), which further alter the supply-demand balance across the NEM.

Other salient features of the annual market benefits forecast are:

---

[56] Tasmanian Government, 19 December 2020. *Renewable Energy Target passes Parliament*. Available at: http://www.premier.tas.gov.au/site_resources_2015/additional_releases/continuing_our_plan_to_be_a_renewable_energy_powerhouse/continuing_our_plan_to_be_a_renewable_energy_powerhouse. Accessed 28 May 2021.

[57] The sum of all annual market benefits in present value terms is equal to the total market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029 in Table 3.

- Negative values such as the higher fuel costs in 2024-25 to 2026-27 occur when there are expected costs to the NEM as a result of the development of Marinus Link (in addition to the costs of Marinus Link itself).
- The small costs and market benefits prior to the entry of the first stage of Marinus Link due to differences in water usage in Tasmania in anticipation of the entry of Marinus Link. In particular there are higher fuel costs in the years until Marinus Link stage 1 is installed because Hydro Tasmania is incentivised to store water in order to gain an increase in its value following commissioning of Marinus Link.[58]
- The noticeable FOM saving in 2025-26 is due to the assumed refurbishment cost that coal units need to undertake every 10 years to continue operating in accordance with their technical specifications. With the first stage of Marinus Link being commissioned in 2027-28, a relatively small amount of additional New South Wales coal capacity is economically retired (relative to the without-Marinus Link counterfactual) to avoid incurring a relatively large cost to remain online for an additional 10 years.
- In total, the cost differences prior to the installation of Marinus Link are only $11m; however, the least-cost modelling approach captures these changes as part of the optimal solution.
- Marinus Link provides positive market benefits from the first year of commissioning in 2027-28.
- From 2027-28 to 2031-32, the fuel cost savings are predominantly related to Marinus Link's ability to allow a combination of lower-cost Tasmanian conventional hydro generation and high capacity factor wind to displace mainland coal-fired generation. From 2032-33 to 2036-37, the main source of fuel cost savings is forecast to be from reduced use of existing CCGTs. After 2037-38, this fuel cost saving is forecast to be from reduced use of higher cost OCGTs, which are forecast to be installed in slightly higher volume in the without-Marinus Link counterfactual to provide dispatchable capacity.
- By 2029-30, there is roughly 16 GW of new renewable capacity forecast to be built above already committed projects, and 2 GW of 8-or-more hour storage, plus the committed Snowy 2.0 PSH project in New South Wales. This capacity is built to achieve the New South Wales Electricity Infrastructure Roadmap, VRET, QRET and TRET. As this capacity is assumed to come online regardless of the commissioning of Marinus Link, capex benefits are limited until the early-to-mid-2030s when additional new entrant capacity can be avoided or deferred.
- From the mid-2030s it is forecast that the installation of Marinus Link will result in $50m to $100m of capex saving annually net across the NEM, with all the savings occurring on the mainland. This is due to Marinus Link's ability to unlock additional energy and different time of use of energy from Tasmania from existing conventional Tasmanian hydro, existing and new wind and PSH, which is forecast to be economically installed from the mid-to-late 2030s onward. Throughout the 2030s, Marinus Link is forecast to result in 2 GW less wind capacity installed on the mainland. By the early 2040s, Marinus Link is forecast to offset the need for this 2 GW of mainland wind and 500 MW of mainland OCGT capacity.[59]
- Net FOM savings are forecast from 2027-28 when the first stage of Marinus Link is commissioned. These average $17m per year and are associated with earlier thermal retirements and the deferral or avoidance of new capacity.
- Other categories of market benefits are comparatively small.

[58] This has occurred in past years at times when a change in the value of the stored water can be predicted, such as prior to the introduction of a price on carbon.

[59] Since all state-based renewable policies are assumed to be committed regardless of Marinus Link, the forecast costs to achieve these policies are incurred in both the case with Marinus Link and the without-Marinus Link counterfactual. This leads to a negligible difference in the cost to achieve these targets when comparing the two cases.

5.3.2 Generation development plan with Marinus Link, Central scenario

Figure 27 shows the change in NEM capacity with Marinus Link 1,500 MW, commissioned in two 750 MW stages in 2027 and 2029, relative to the without-Marinus Link counterfactual shown in Figure 5. Figure 28 shows the change in forecast NEM generation.

Figure 27: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Central scenario (difference relative to Figure 5; positive values equal higher capacity with Marinus Link)

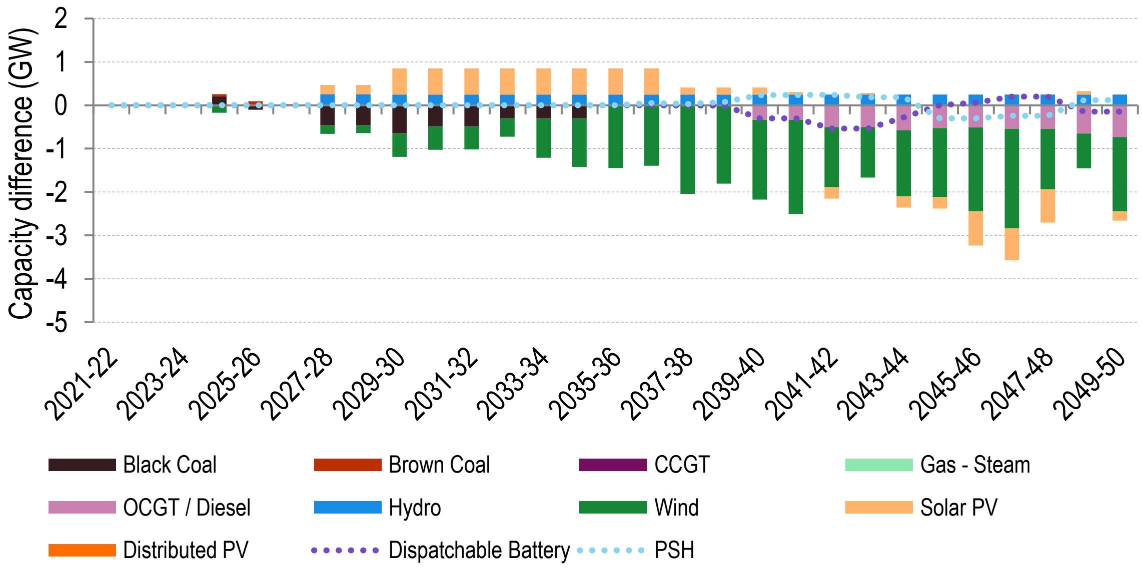
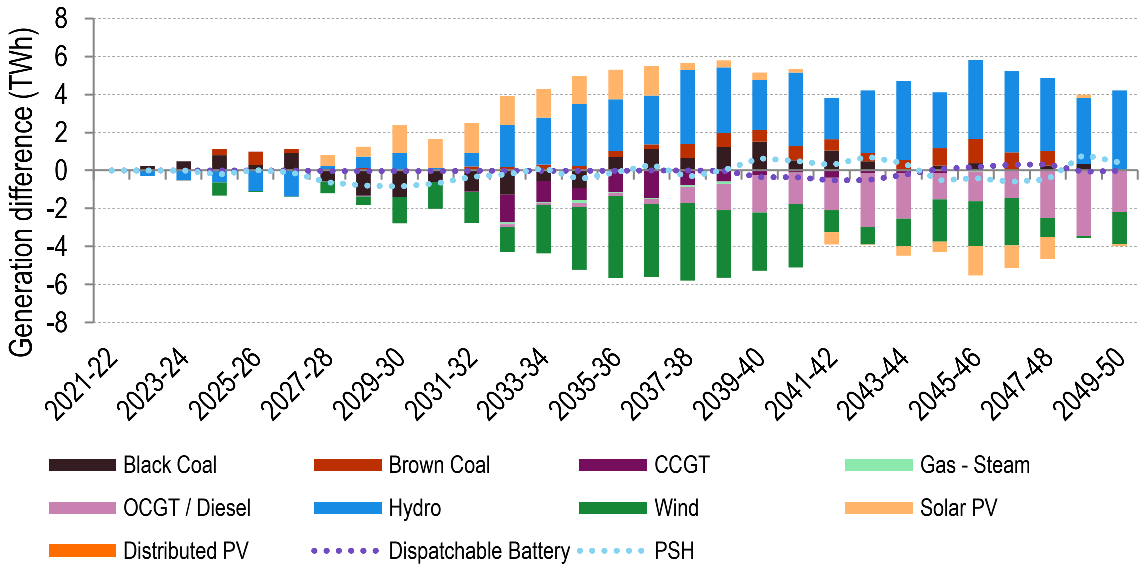


Figure 28: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Central scenario (difference relative to Figure 6; positive values equal higher energy with Marinus Link)



The key forecast trends can be broken into two time-periods where different trends are observed. The boundary at around 2037-38 is a critical point in the supply-demand balance after the retirement of Bayswater in 2035-36 and due to ongoing load growth across the NEM.

From the study start until 2036-37:

- For the NEM overall, from when the first stage of Marinus Link is assumed to be commissioned in 2027, Marinus Link is forecast to facilitate increased development of New South Wales solar PV development in preference to new entrant wind capacity, relative to the without-Marinus Link counterfactual (Figure 27). State-based renewable energy targets do not assume a particular technology (wind or solar PV) is installed to meet the targets. The installation of Marinus Link better enables New South Wales solar PV generation to be exported across Victoria and into Tasmania during the day. This in turn allows Tasmanian conventional hydro generators to store water to assist in supplying the NEM when renewable generation has less availability.

- The additional Tasmanian export capacity, which allows TRET capacity to be dispatched, is forecast to result in roughly 2 GW less mainland wind capacity installed by the mid-2030s. (Figure 27).

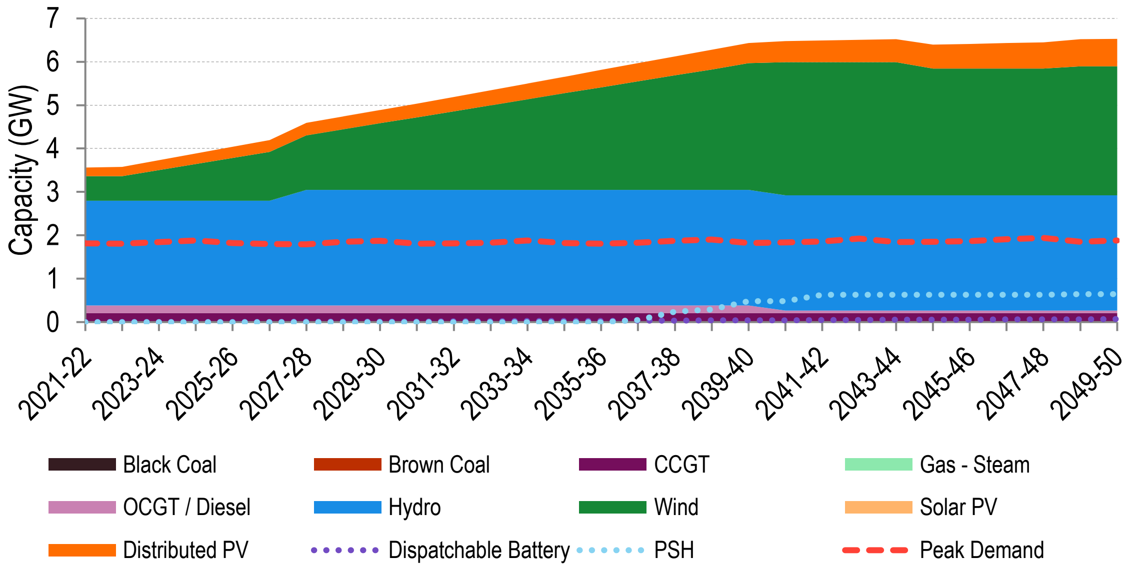
From 2037-38 until the end of the period covered for this study:

- By the end of the study period, the diversity of Tasmanian wind generation, coupled with existing conventional hydro and the potential for new entrant PSH projects is forecast to offset the need for 700 MW of new entrant OCGT capacity on the mainland and 500 MW of mainland PSH. There are both capex and fuel cost benefits associated with the reductions.
- The additional Tasmanian export capability enabled by Marinus Link is forecast to result in roughly 600 MW of new entrant PSH capacity in Tasmania from the late-2030s to the early 2040s.
- Upon the retirement of both Loy Yang A and Loy Yang B in Victoria in the late 2040s, it is forecast that new wind capacity will be installed in Tasmania, to the point that it exceeds the 2.5 GW of new renewable capacity to achieve the TRET.

Overall, Marinus Link is forecast to accrue market benefits through a reduced need to operate existing and to develop new high fuel cost gas-fired generation on the mainland and by offsetting new renewable capacity on the mainland, in favour of the high capacity factor and less correlated Tasmanian wind generation that is unlocked by Marinus Link. These are the primary drivers of market benefits in the forecast.

Figure 29 displays the forecast capacity installed in Tasmania with Marinus Link. As observed in the capacity difference chart (Figure 27), conventional Tasmanian hydro capacity increases with Marinus Link. This is the assumed increase in West Coast and Tarraleah capacity with Marinus Link discussed in Section 3.2. With Marinus Link, the assumed uptake of wind capacity in Tasmania by 2040-41 associated with the TRET is forecast to be dispatched alongside conventional hydro and PSH without significant curtailment.

Figure 29: Tasmanian capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Central scenario



5.3.3 Interconnector utilisation with Marinus Link, Central scenario

In association with changes in regional capacity development and generation mix, Marinus Link is also forecast to change the usage patterns of interconnectors. The average net energy transfer by year across all interconnectors in the NEM is shown in Figure 30 (for comparison to the without-Marinus Link counterfactual shown in Figure 8).

With Marinus Link and VNI West in service, Victoria retains its position as a net exporter of energy to New South Wales and South Australia for most of the study period until the assumed retirement of Victorian brown coal generators Loy Yang A and Loy Yang B in the late 2040s.

Figure 30: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Central scenario

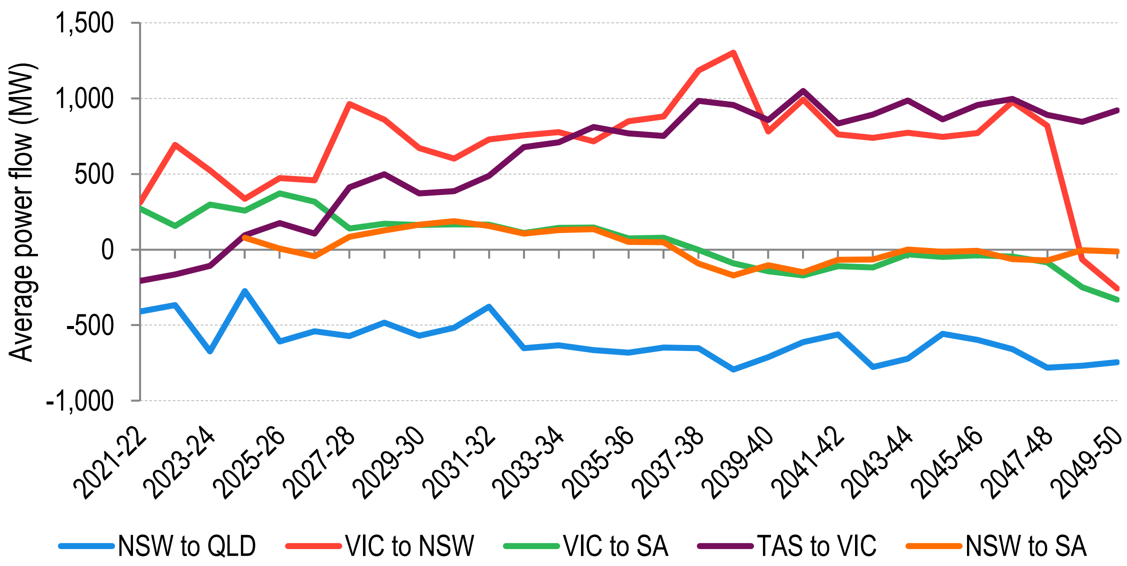
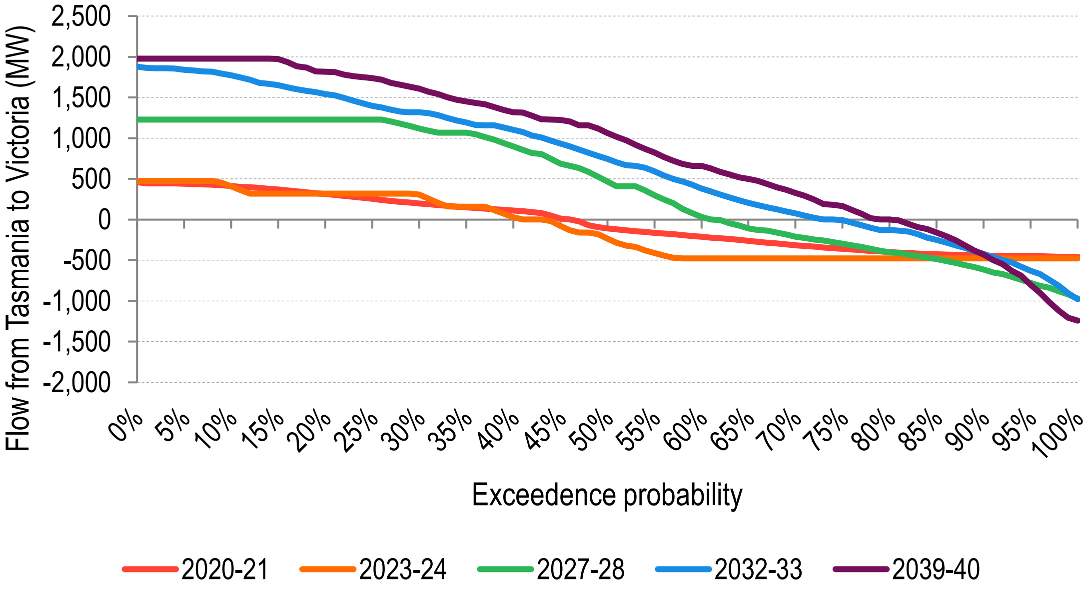


Figure 31 shows the forecast flow duration for all combined links between Tasmania and Victoria at sample study years alongside historical flow from 1 May 2020 to 30 April 2021 (referred to as

2020-21).[60] For the first two years illustrated (2020-21 and 2023-24), Basslink is the only interconnector. During early 2020s, Basslink is forecast to flow similar to its historical behaviours, with the interconnector exporting energy to the mainland for roughly half of the hours within the year. Flows are forecast to shift northward over the study so that once the first stage of Marinus Link is commissioned (2027-28), the forecast combined Basslink and Marinus Link flow is at its northward limit around 30 % of the time. By 2032-33, after the second stage of Marinus Link enters, the forecast flow of the three links does not reach the combined northward limit; however, flow is forecast to be northward for roughly 70 % of periods. Utilisation is forecast to steadily increase over the study period so that the forecast flow of the three links is at their combined northward limit around 20 % of the time by the late-2030s.

Figure 31: Forecast Tasmania-Victoria flow duration[61] with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Central scenario



5.4 Slow Change scenario with Marinus Link

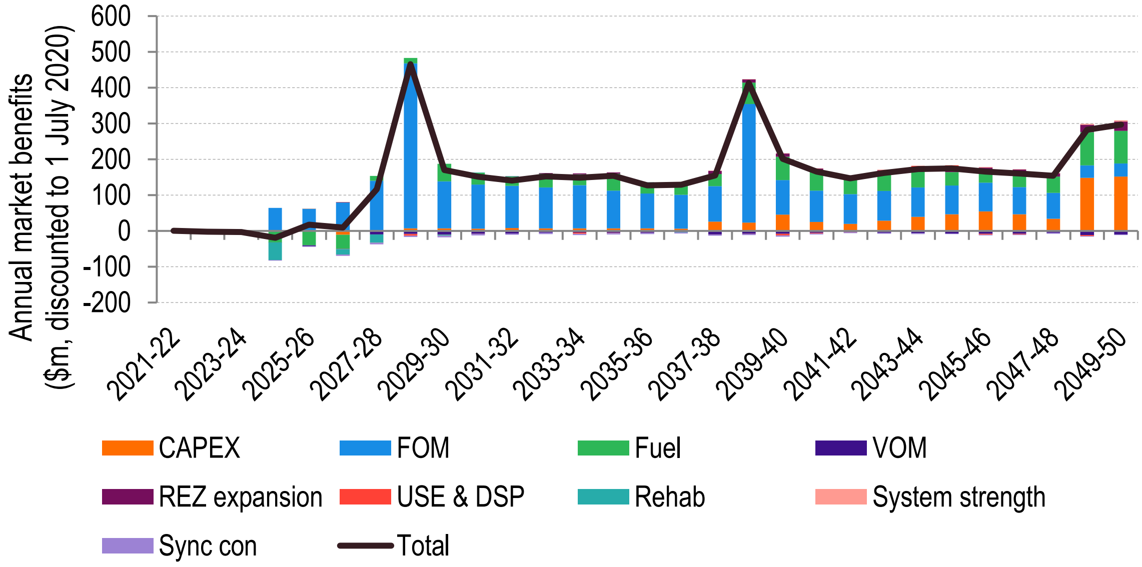
5.4.1 Forecast market benefits of Marinus Link, Slow Change scenario

In the Slow Change scenario, the dominant source of market benefits are forecast to be FOM savings as illustrated in Figure 25 and in a more detailed annual breakdown in Figure 32 for a 1,500 MW Marinus Link, stage 1 2027 and stage 2 2029. Due to the different discount rate for this scenario (3.8 % compared to 4.8 % in all other scenarios) the market benefits are not directly comparable to the other scenarios. Since Marinus Link is forecast to have positive market benefits from the year it is assumed to be commissioned, the lower discount rate results in higher market benefits.

[60] This report was completed prior to the completion of 2020-21.

[61] Positive flow represents flow from Tasmania to Victoria; negative flow indicates flow from Victoria to Tasmania

Figure 32: Forecast annual market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Central scenario; millions real June 2020 dollars discounted[62] to 1 July 2020



As mentioned in Section 4.3, the Slow Change scenario assumes significant load reduction across all regions, including Tasmania, due to the reduction of large industrial loads. This results in a surplus of generation and dispatchable capacity across the NEM. By unlocking this excess of low-cost dispatchable generation in Tasmania, Marinus Link enables earlier retirement of Victorian brown coal capacity, leading to the forecast FOM saving compared with keeping this capacity online in the without-Marinus Link counterfactual. The larger forecast FOM saving benefits in 2028-29 and 2039-40 are due to the avoided 10-year refurbishment cost that Victorian brown coal units are assumed to undertake to allow them to reach their age-based retirement dates.

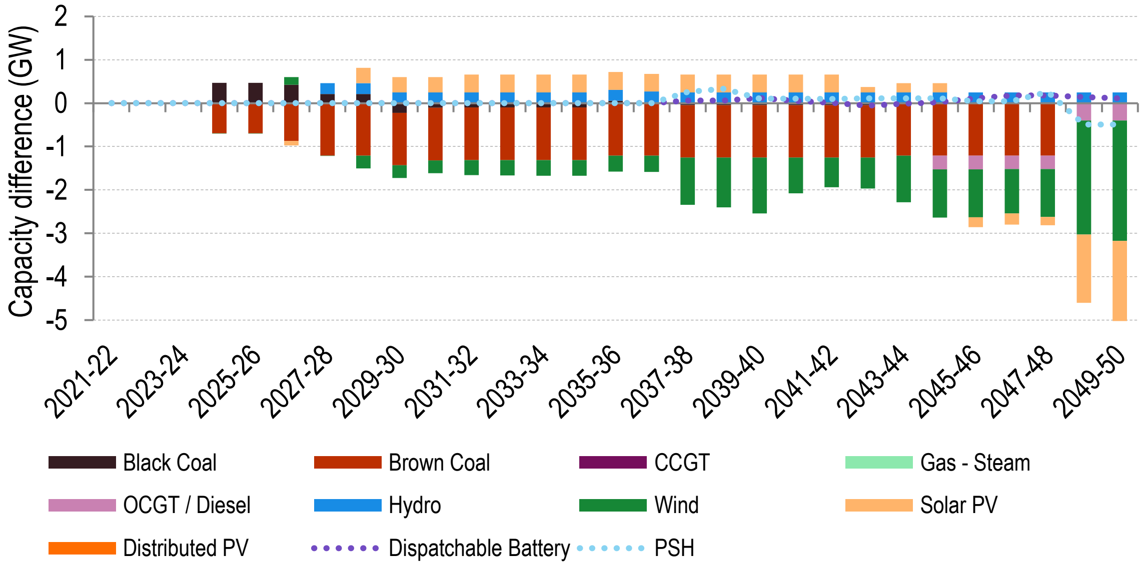
As with the Central scenario, capex and fuel cost savings are also forecast to occur on the mainland, but are smaller in magnitude than in the Central scenario.

5.4.2 Generation development plan with Marinus Link, Slow Change scenario

Figure 33 displays the difference in capacity across the NEM between the case with Marinus Link 1,500 MW, commissioned in two 750 MW stages in 2027 and 2029, relative to the without-Marinus Link counterfactual for the Slow Change scenario.

[62] As per AEMO's Draft 2021 Input and Assumptions Workbook, a discount rate of 3.8 % is applied for the Slow Change scenario. All other scenarios apply a discount rate of 4.8 %.

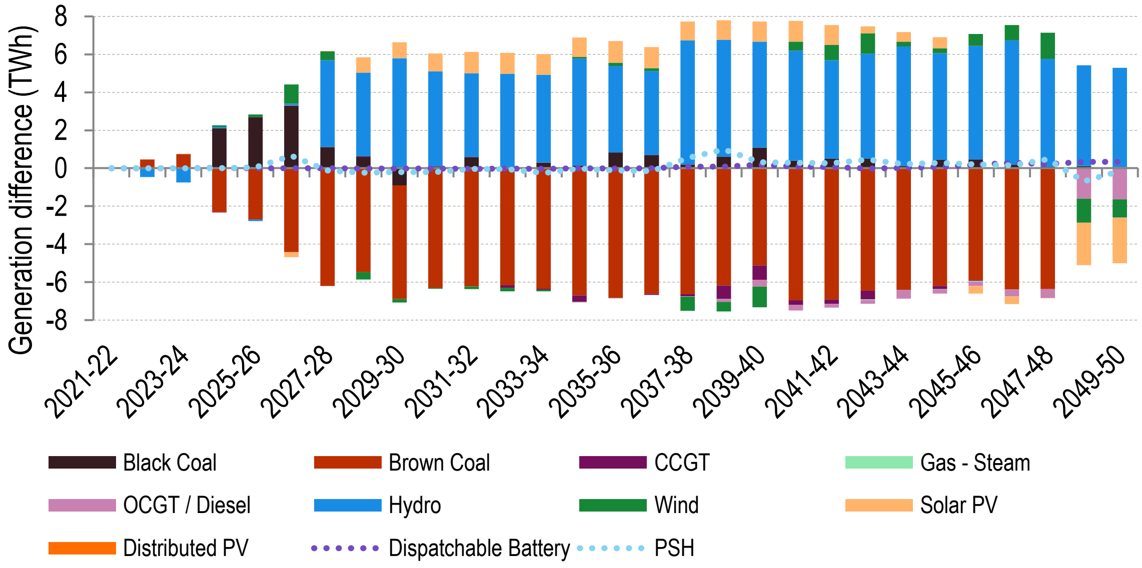
Figure 33: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Slow Change scenario (positive values equal higher capacity with Marinus Link)



As discussed in Section 4.3, for the Slow Change scenario without Marinus Link it is forecast that an additional 2 GW to 3 GW of early coal retirements will occur above that of the Central scenario. This is due to having lower demand associated with assumed industrial load closures and a higher relative proportion of distributed PV than that of the Central scenario. By 2029-30 with Marinus Link, when both stages are commissioned, Marinus Link is forecast to offset an additional 1.5 GW of Victorian brown coal capacity. From the late 2030s additional new entrant capacity is forecast to be built above the existing New South Wales Electricity Infrastructure Roadmap, VRET, QRET and TRET goals. By unlocking the wind and conventional hydro generation in Tasmania, Marinus Link is forecast to offset the need for up to 4.6 GW of Victorian renewable capacity by 2049-50.

The difference in forecast generation due to Marinus Link (Figure 34) shows similar trends to the difference in forecast capacity mix. Without Marinus Link the assumed large reduction in Tasmanian load coupled with TRET is forecast to result in significant spill for conventional hydro. With Marinus Link this Tasmanian hydro generation, that would otherwise be curtailed, is able to offset Victorian brown coal generation.

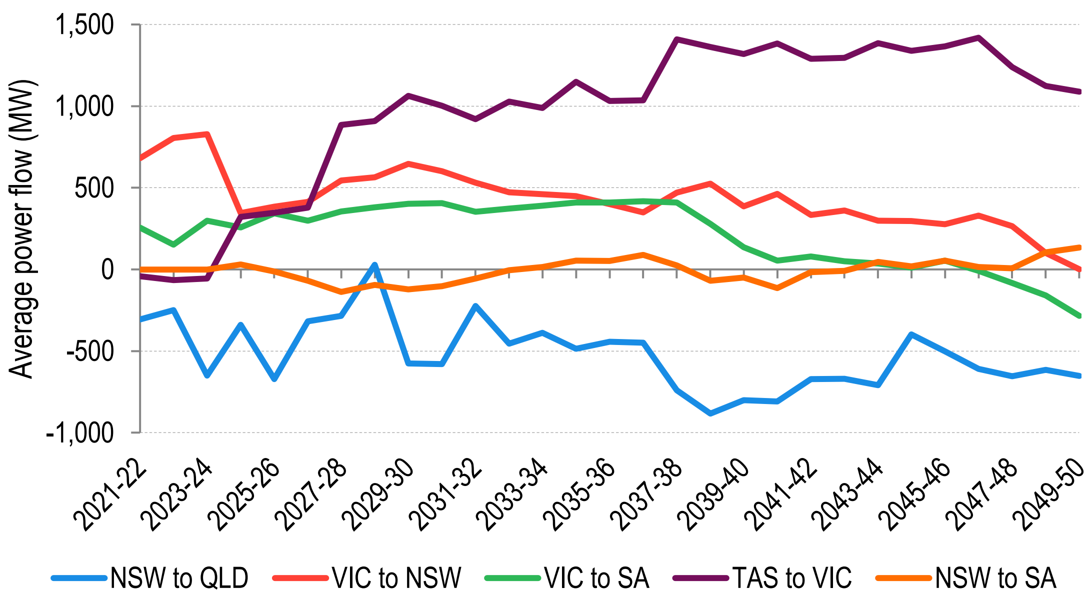
Figure 34: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Slow Change scenario (positive values equal higher energy with Marinus Link)



5.4.3 Interconnector utilisation with Marinus Link, Slow Change scenario

Figure 35 displays the average net energy transfer by year across all interconnectors in the NEM (for comparison to the without-Marinus Link counterfactual shown in Figure 12). The assumed retirement of roughly 320 MW of industrial load in Tasmania during the mid-2020s is forecast to result in a higher average energy transfer from Tasmania to Victoria throughout the majority of the study period, compared to the Central scenario. For the Slow Change scenario, it is not assumed that the VNI West upgrade will proceed. Consequently, less of this import from Victoria can be exported to New South Wales.

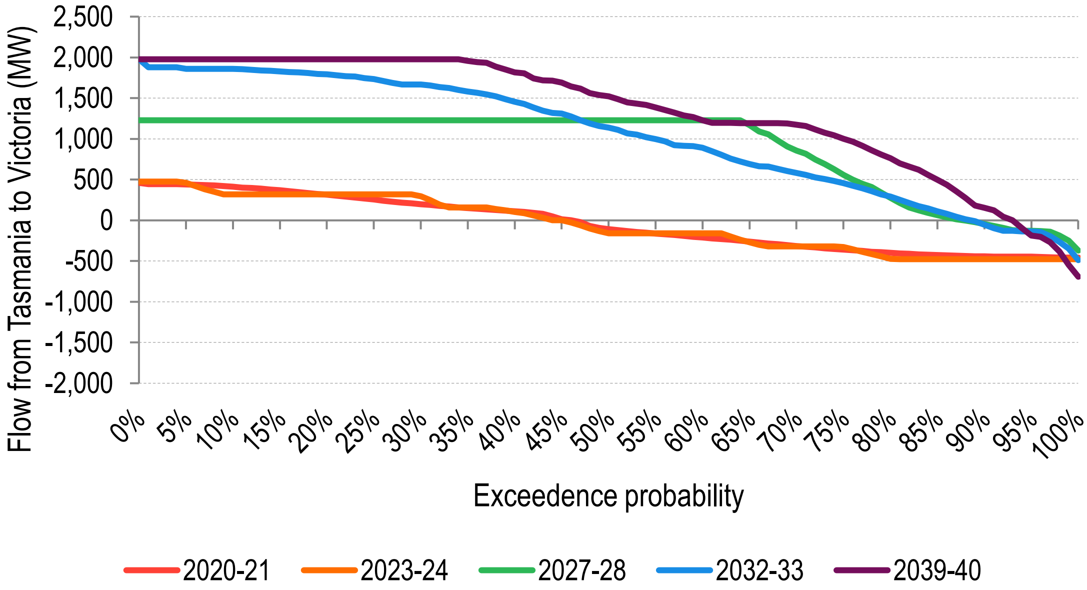
Figure 35: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Slow Change



The forecast flow duration of the combined links between Tasmania and Victoria is shown in Figure 36. In the first year that Marinus Link stage 1 is installed, 2027-28, it is forecast that the combined flow across Basslink and Marinus Link will be constrained in the northward direction for roughly 65 % of hours. From this time onward, it is forecast that Tasmania will export to Victoria for

90 % or more of periods, due to the low Tasmanian demand and excess renewable generation from conventional hydro and new entrant wind capacity.

Figure 36: Forecast Tasmania-Victoria flow duration with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Slow Change scenario

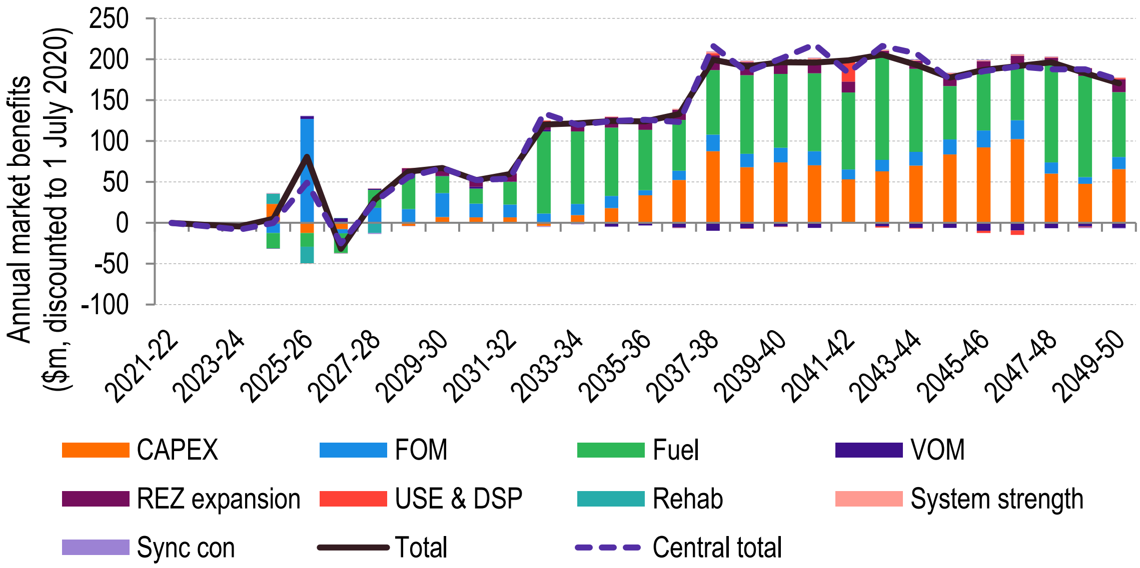


5.5 High DER scenario with Marinus Link

5.5.1 Forecast market benefits of Marinus Link, High DER scenario

The forecast market benefits associated with 1,500 MW Marinus Link, stage 1 2027 and stage 2 2029 in the High DER scenario are shown in Figure 25 and on an annual basis in Figure 37. As with the Central scenario, fuel cost savings accrue from the time Marinus Link enters in 2027-28 and are the dominant source of the forecast market benefits along with capex savings from the mid-2030s.

Figure 37: Forecast annual market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, High DER scenario; millions real June 2020 dollars discounted to 1 July 2020



5.5.2 Generation development plan with Marinus Link, High DER scenario

Trends in the forecast capacity development plan and generation mix due to Marinus Link for the High DER scenario are very similar to those in the Central scenario (Figure 38 compared to Figure 27, and Figure 39 compared to Figure 28). The higher assumed uptake of distributed storage and domestic storage slightly shifts the technologies that Marinus Link is forecast to offset, with a greater reduction in mainland wind and gas capacity in the High DER scenario, rather than solar PV and dispatchable battery storage in the Central scenario. Despite the large assumed uptake of domestic storage for the High DER scenario, new entrant gas-fired generation is still forecast to be installed during the 2040s. Marinus Link is forecast to offset the need for approximately 500 MW to 1,000 MW of this gas-fired capacity throughout the 2040s.

Figure 38: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, High DER scenario (positive values equal higher capacity with Marinus Link)

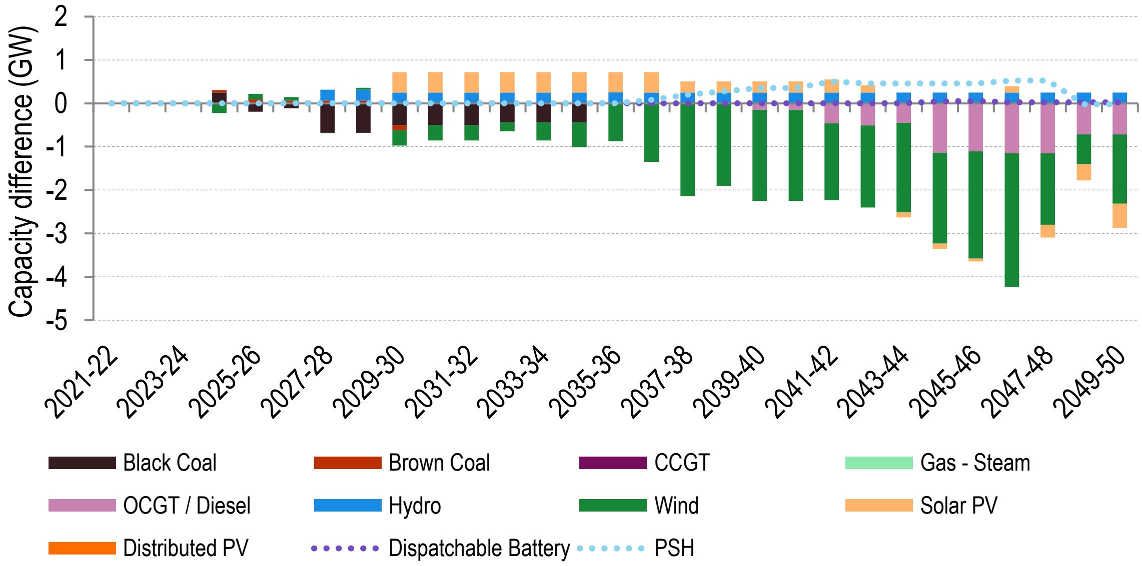
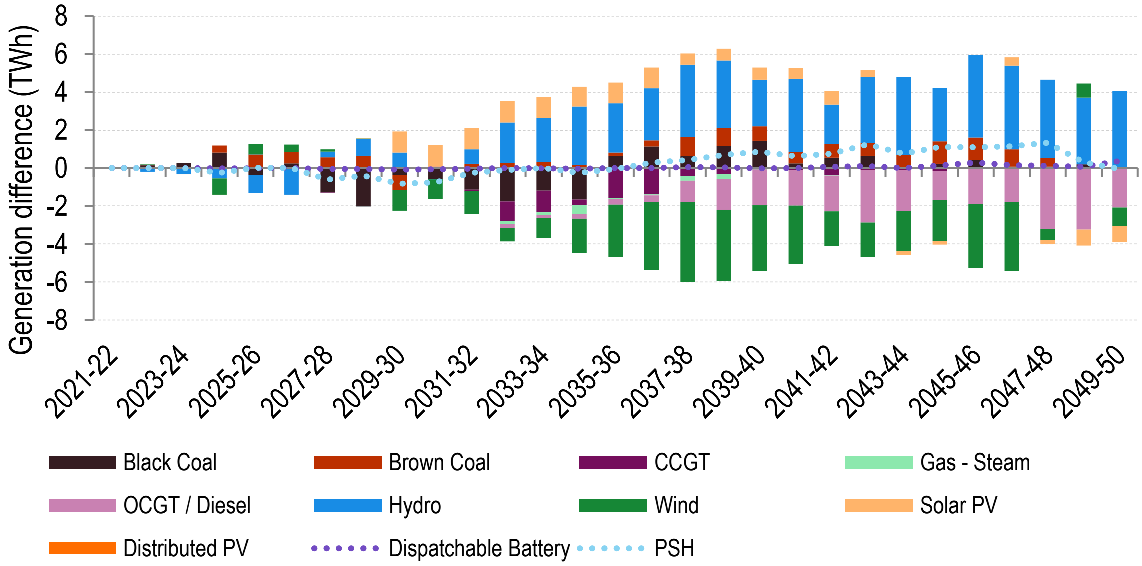


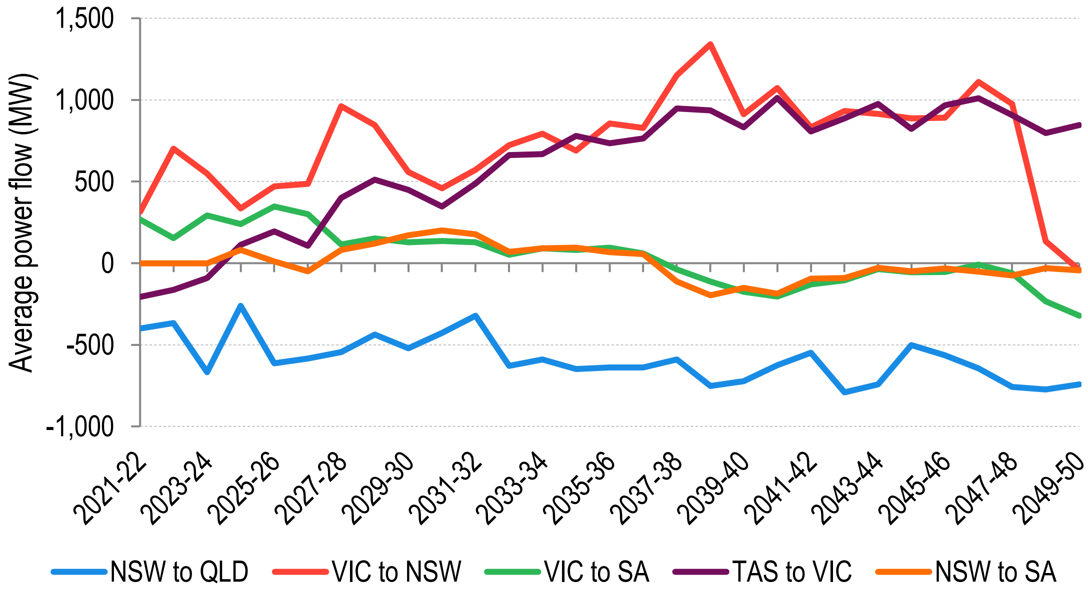
Figure 39: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, High DER scenario (positive values equal higher energy with Marinus Link)



5.5.3 Interconnector utilisation with Marinus Link, High DER scenario

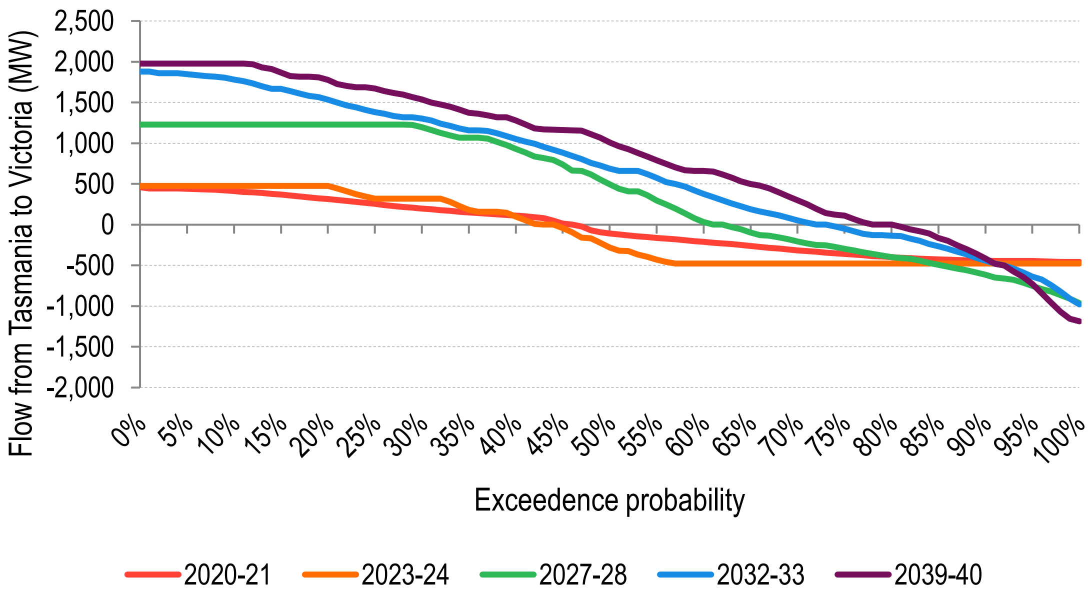
Figure 40 displays the average net energy transfer by year across all interconnectors in the NEM (for comparison to the without-Marinus Link counterfactual shown in Figure 16). The forecast link flow is generally consistent with that of the Central scenario.

Figure 40: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Higher DER scenario



The forecast flow duration of the combined links between Tasmania and Victoria is shown in Figure 41. In each year after the first stage of Marinus Link enters, the links are forecast to be heavily utilised. In 2027-28 when the first stage of Marinus Link enters, the combined links are forecast to be at their northward limit around 30 % of the time.

Figure 41: Forecast Tasmania-Victoria flow duration with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, High DER scenario

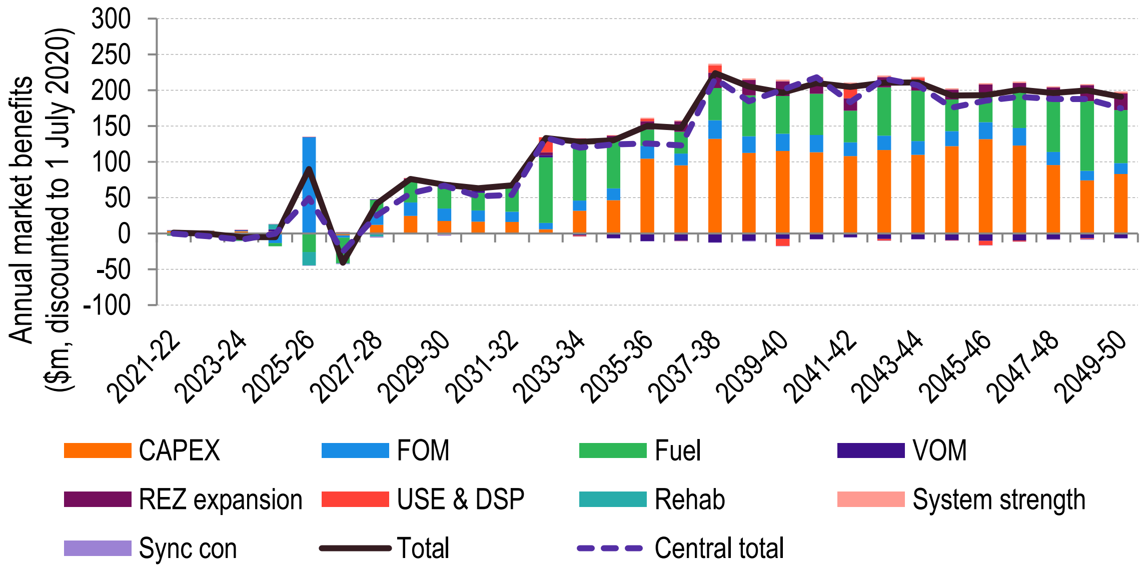


5.6 Fast Change scenario with Marinus Link

5.6.1 Forecast market benefits of Marinus Link, Fast Change scenario

The forecast market benefits associated with Marinus Link, stage 1 2027 and stage 2 2029 in the Fast Change scenario are shown in Figure 25 and on an annual basis in Figure 42. As with the Central and High DER scenarios, the primary sources of market benefits are forecast to come from fuel and capex cost savings.

Figure 42: Forecast annual market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Fast Change scenario; millions real June 2020 dollars discounted to 1 July 2020



As with the Central scenario, Marinus Link is forecast to have a market benefit of roughly $50m annually from 2027-28 until the assumed retirement date of Eraring power station in 2032-33. At that time market benefits increase to $100m to $150m annually. From the late 2030s, the discounted annual market benefit of Marinus Link is forecast to be approximately $200m each year.

5.6.2 Generation development plan with Marinus Link, Fast Change scenario

Figure 43 and Figure 44 display the difference in capacity and generation respectively across the NEM between the case with Marinus Link 1,500 MW, commissioned in two 750 MW stages in 2027 and 2029, relative to the without-Marinus Link counterfactual for the Fast Change scenario. As previously observed in Figure 17 from Section 4.5, the assumption of a NEM-wide carbon emission target of 2,068 Mt CO_2-e, is forecast to result in more renewable capacity built across the NEM throughout the 2030s and into the 2040s, relative to the Central scenario. The high-quality wind resource in Tasmania corresponds with Tasmanian wind capacity achieving higher capacity factor than most mainland locations. As such, from the early-to-mid 2030s the high-capacity factor Tasmanian wind generation that is unlocked by Marinus Link is forecast to offset the need for larger amounts of mainland renewable capacity. From the mid-2040s, it is forecast that Marinus Link will result in less gas-fired capacity across the mainland.

Figure 43: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Fast Change scenario (positive values equal higher capacity with Marinus Link)

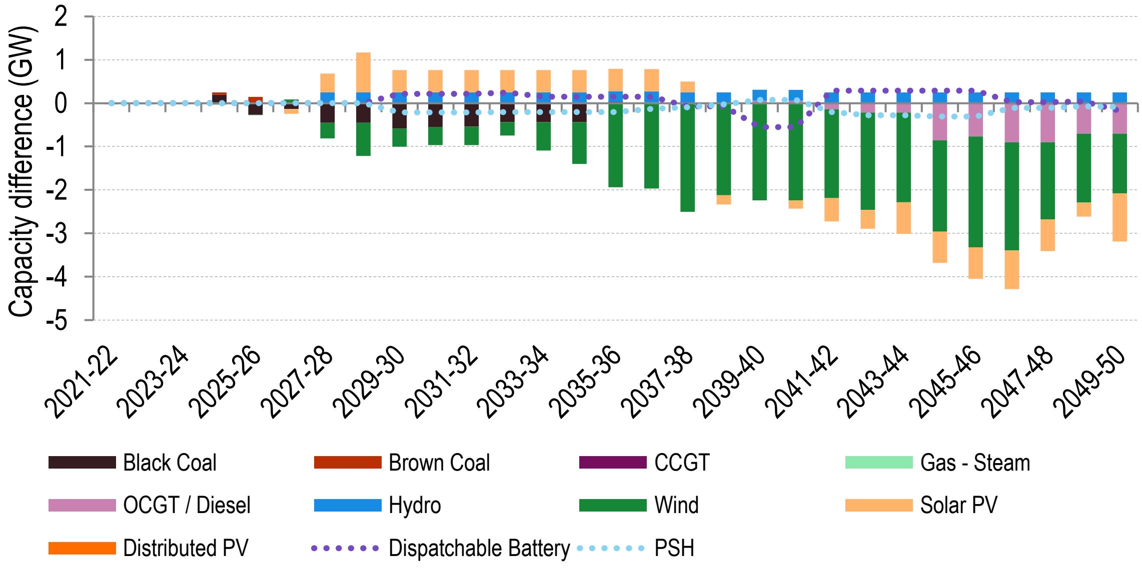
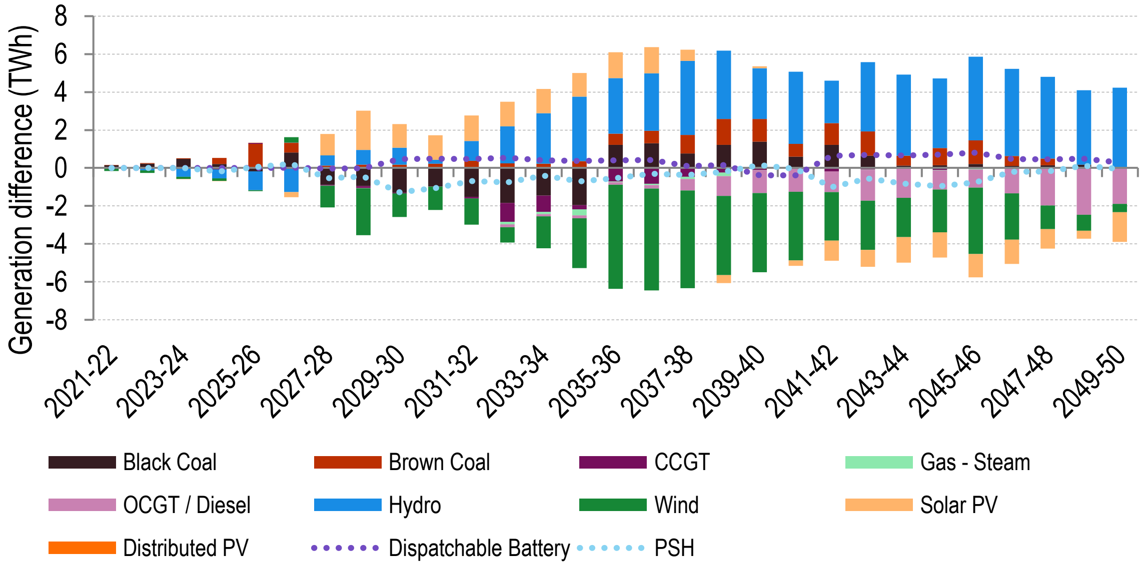


Figure 44: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Fast Change scenario (positive values equal higher energy with Marinus Link)



In the Fast Change scenario, regardless of the assumed inclusion of Marinus Link, the least-cost development path is targeted towards achieving the 30-year 2,068 Mt CO_2-e target. Although Marinus Link is not forecast to result in emissions reductions beyond this target, Marinus Link does allow this objective to be met at a lower market cost to the system (excluding the cost of Marinus Link itself).

5.6.3 Interconnector utilisation with Marinus Link, Fast Change scenario

Figure 45 displays the average net energy transfer by year across all interconnectors in the NEM (for comparison to the without-Marinus Link counterfactual shown in Figure 20). The forecast flow duration of the combined links between Tasmania and Victoria is shown in Figure 46. The forecast link flow is generally consistent with that of the Central scenario.

Figure 45: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Fast Change scenario

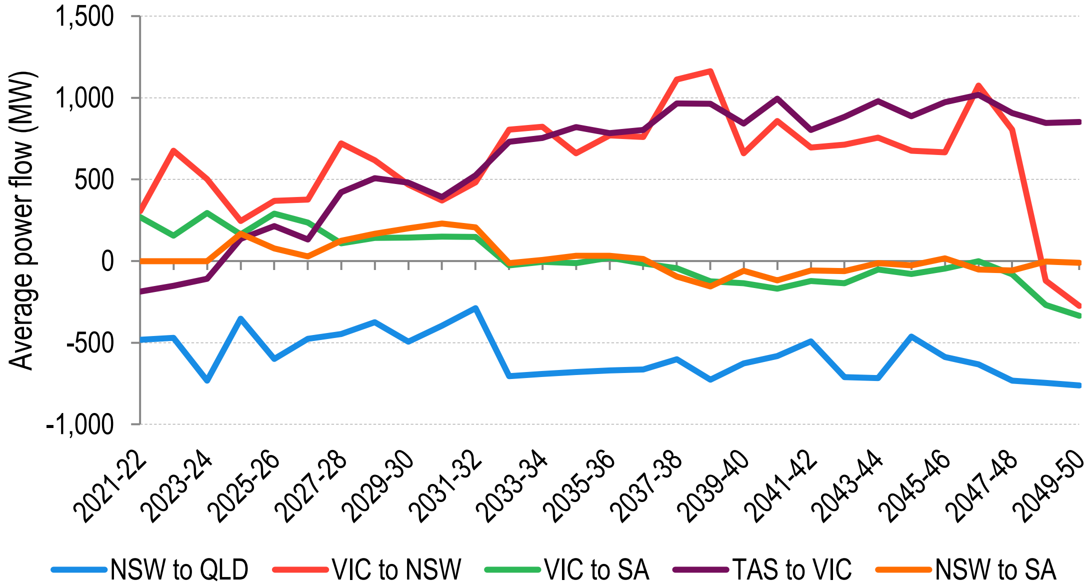
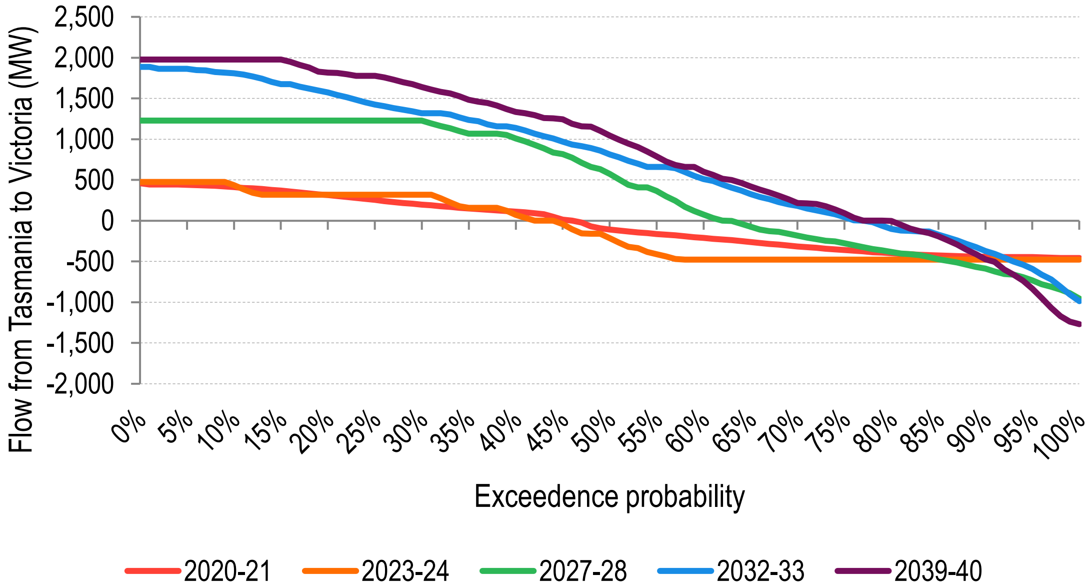


Figure 46: Forecast Tasmania-Victoria flow duration with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Fast Change scenario



5.7 Step Change scenario with Marinus Link

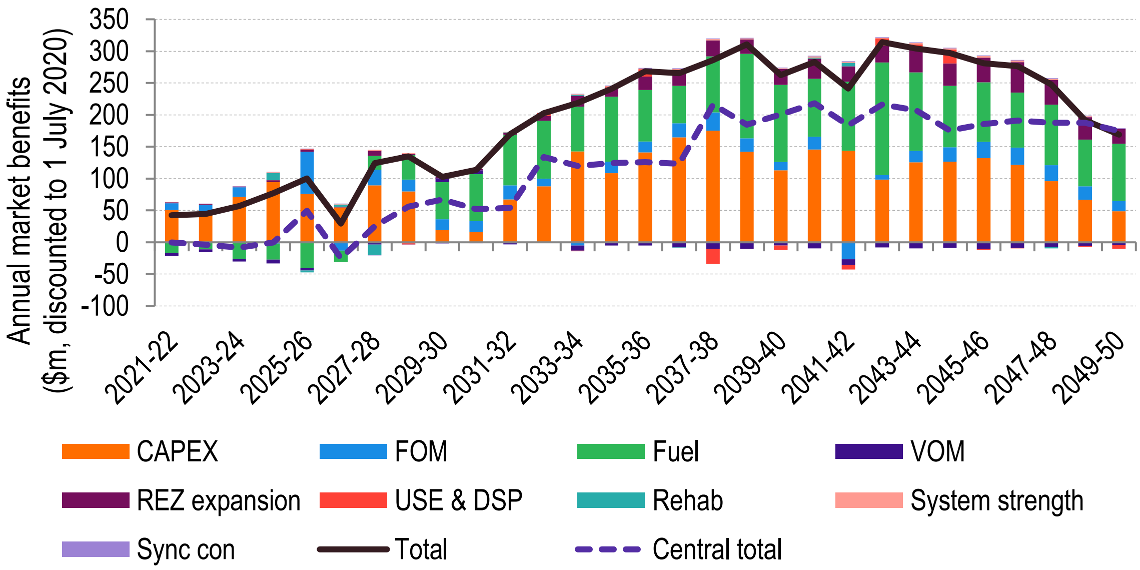
5.7.1 Forecast market benefits of Marinus Link, Step Change scenario

The forecast market benefits associated with 1,500 MW Marinus Link, stage 1 2027 and stage 2 2029 in the Step Change scenario are shown in Figure 25 and on an annual basis in Figure 47. Key similarities and differences with the Central scenario are listed below.

- As with the Central scenario, the forecast fuel cost savings accrue from the time Marinus Link enters in 2027-28 and are a large source of the forecast market benefits.

- Forecast fuel savings are higher than in the Central scenario. This is because Marinus Link provides additional dispatchable capacity to the mainland which is forecast to reduce the need for gas-fired generation from the late-2030s onward.
- Inherent in the modelling is the implicit assumption that the decision to construct Marinus Link is known from the beginning of the period covered by the study. The knowledge that Marinus Link can more efficiently reduce emissions throughout the 2030s and 2040s allows for less action towards this emission reduction target to take place throughout the 2020s. As discussed in Section 4.6, for the Step Change scenarios without Marinus Link, it is forecast that the least-cost approach to achieve this cumulative 1,325 Mt CO_2-e budget is to install 5,700 MW of new wind capacity from the beginning of the study period. Due to the higher emission reduction in the back end of the study, it is forecast that slightly less (300 MW) wind capacity is required to be installed at this time with Marinus Link. This results in the forecast capex saving from the first year of the study.

Figure 47: Forecast annual market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Step Change scenario; millions real June 2020 dollars discounted to 1 July 2020



5.7.2 Generation development plan with Marinus Link, Step Change scenario

Figure 43 and Figure 44 displays the difference in capacity and generation respectively across the NEM between the case with Marinus Link 1,500 MW, commissioned in two 750 MW stages in 2027 and 2029, relative to the without-Marinus Link counterfactual for the Step Change scenario. General trends in the forecast capacity development plan and generation mix due to Marinus Link for the Step Change scenario are similar to those in the Central scenario (Figure 43 compared to Figure 27, and Figure 44 compared to Figure 28); however, the differences are slightly larger.

Figure 48: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Step Change scenario (positive values equal higher capacity with Marinus Link)

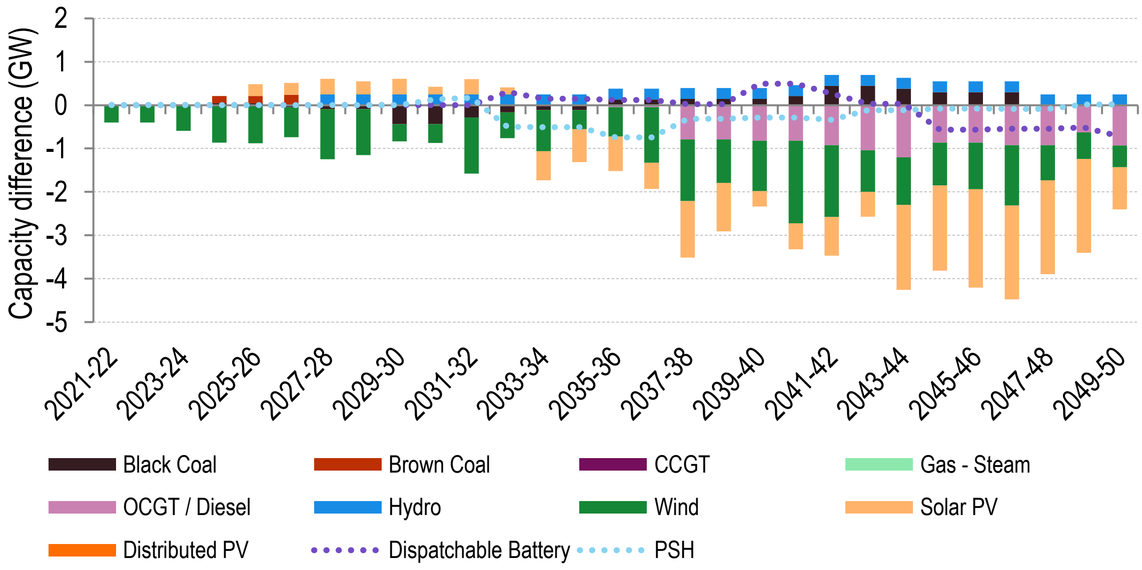
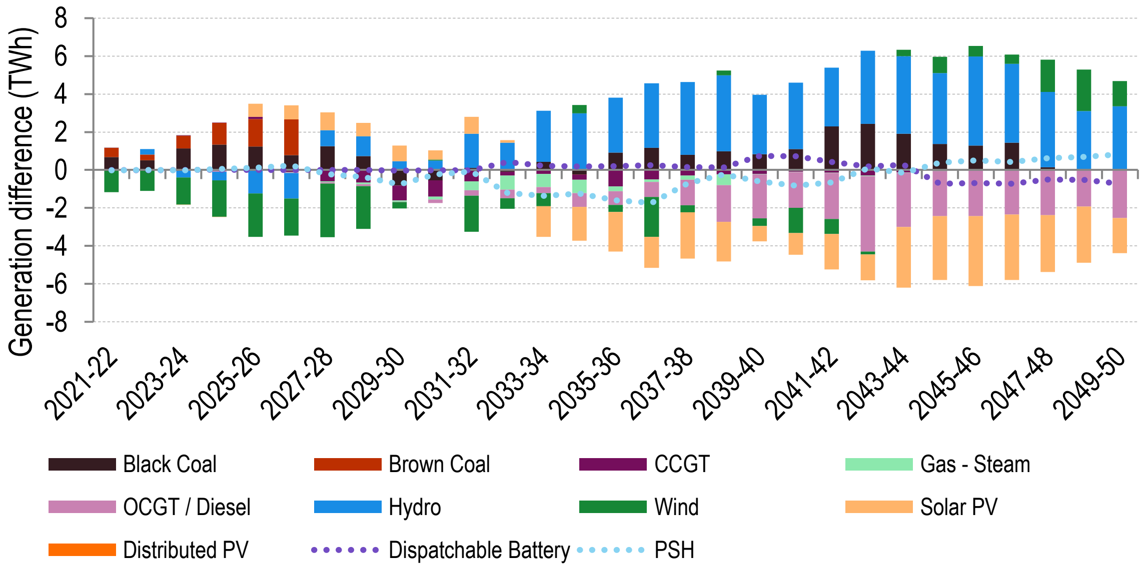


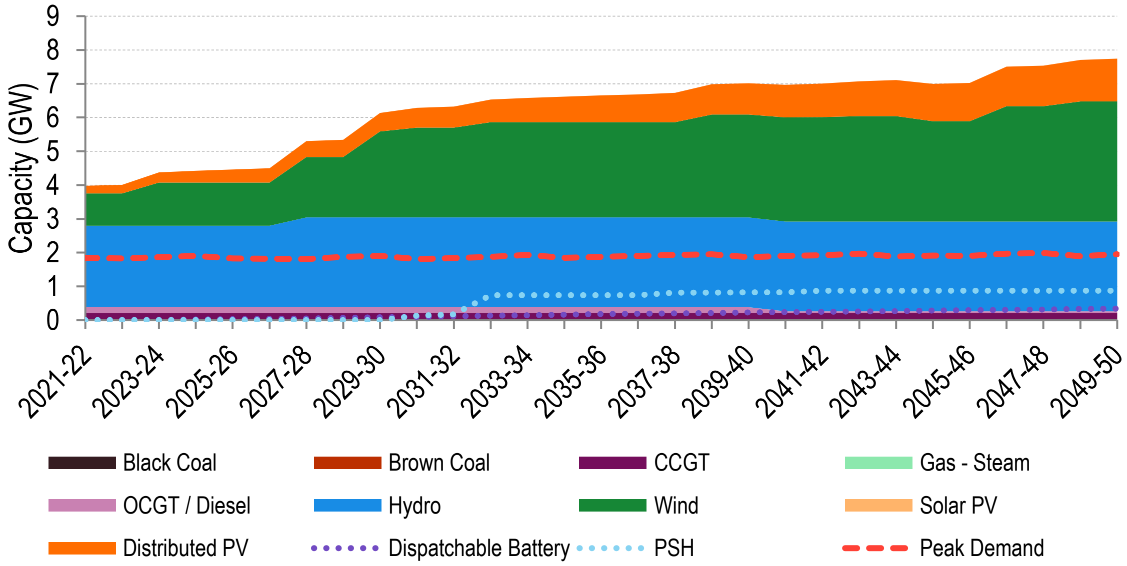
Figure 49: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Step Change scenario (positive values equal higher energy with Marinus Link)



One salient feature of the Step Change scenario is the forecast increase in coal-fired generation with Marinus Link throughout the study period. This occurs because dispatchable Tasmanian capacity made accessible through Marinus Link reduces the need to use existing and new gas-fired dispatchable capacity on the mainland from the mid-2030s. The avoided emissions from reduced use of gas means the scenario (with a 30-year carbon budget and foreknowledge) can afford to use coal-fired generators more throughout the study and still get to the same cumulative emissions at lower cost.

Figure 50 displays the forecast capacity installed in Tasmania with Marinus Link. In this scenario when Marinus Link is installed the least-cost generation development plan forecast includes Tasmanian renewable capacity to exceed the TRET. Furthermore, it is forecast that roughly 750 MW of PSH will be installed in Tasmania in 2032-33, when Eraring reaches its assumed retirement date.

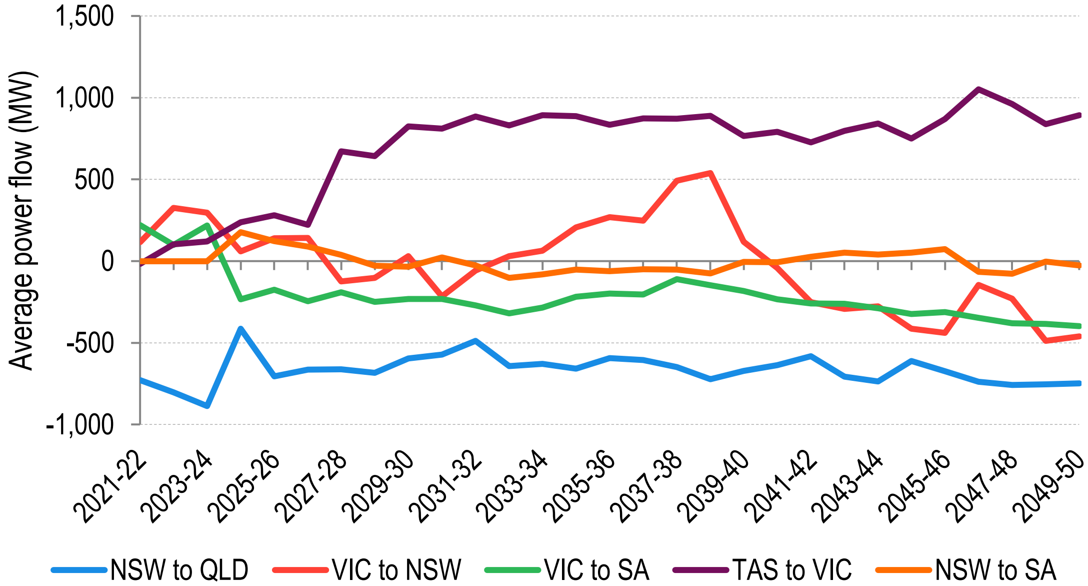
Figure 50: Tasmanian capacity mix forecast with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Step Change scenario



5.7.3 Interconnector utilisation with Marinus Link, Step Change scenario

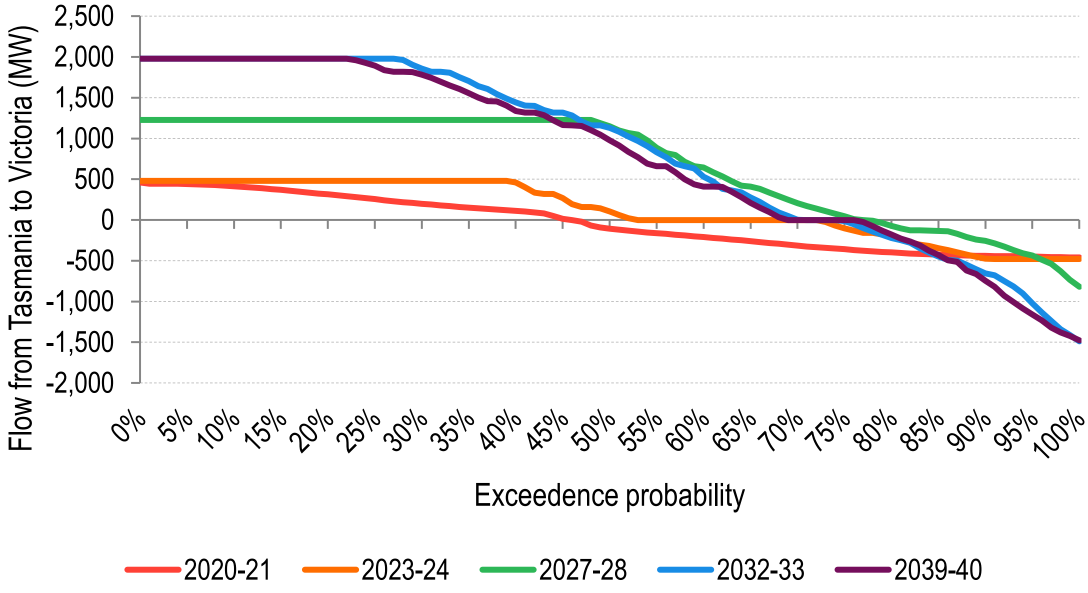
Figure 51 displays the average net energy transfer by year across all interconnectors in the NEM (for comparison to the without-Marinus Link counterfactual shown in Figure 24).

Figure 51: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Step Change scenario



The forecast flow duration of the combined links between Tasmania and Victoria is shown in Figure 52. The links are generally more constrained in the Step Change scenario compared to matched years in the Central scenario (Figure 31). This is due to the additional renewable capacity that is forecast to be installed in Tasmania in this scenario. In 2027-28 when the first stage of Marinus Link enters, the combined links are at their northward limit around 50 % of the time (30 % in Central scenario). In 2032-33 when Eraring is assumed to retire, the combined links are forecast to be at their northward limit about 30 % of the time.

Figure 52: Forecast Tasmania-Victoria flow duration with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Step Change scenario



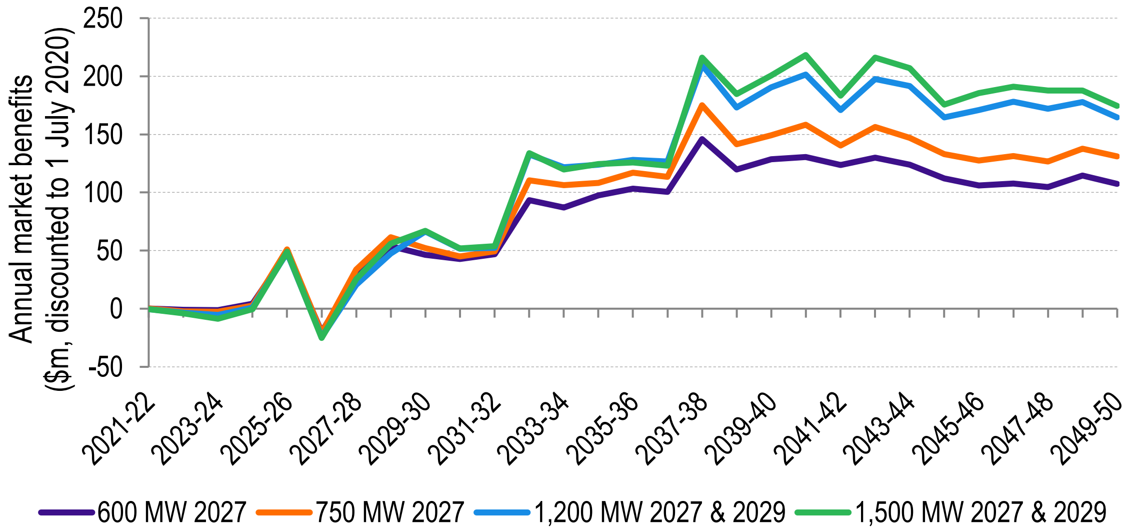
5.8 Effect of size and timing of Marinus Link on forecast market benefits

We performed simulations of different option-timing combinations and computed the forecast market benefits. Ultimately, the determination of the optimal timing and sizing is dependent on the relativity of each option-timing combination to the relevant Marinus Link costs. This assessment was conducted by TasNetworks outside of this Report[63] as option costs were developed independently by TasNetworks. This section provides several observations about how the size and timing of market benefits may change with the size and timing of Marinus Link but does not draw any conclusions regarding *optimal* size or timing.

Marinus Link is forecast to provide market benefits in every simulation from the time it is developed for all size options considered. This is evident in Figure 53 which shows forecast annual market benefits of different size options for Marinus Link installed in 2027 (all for single stage options, first stage for two stage options, with the second stage installed 2029), which was the earliest development year considered. Generally, forecast annual market benefits in real terms increase until 2037-38, at which point they approximately stabilise until the end of the study period (Figure 53 shows real June 2020 dollars discounted to 1 July 2020).

[63] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

Figure 53: Forecast annual market benefits of Marinus Link options of different size, Central scenario; millions real June 2020 dollars discounted to 1 July 2020



The modelling shows that as the size of Marinus Link increases, the utilisation of further increments of Marinus Link capacity reduces. However, it is forecast that in all cases with a second stage, forecast market benefits still increase relative to a single stage. A 25 % increase in Marinus Link capacity from 600 MW to 750 MW delivers around a 15 % to 25 % increase in forecast market benefits for the timing shown in Figure 53 for all scenarios. Increasing the capacity of Marinus Link by 25 % from 1,200 MW to 1,500 MW is forecast to result in market benefits being 5 % to 10 % higher across all scenarios for the earliest timing of Marinus Link. This demonstrates that the scale of potential market benefits from larger capacity is not directly proportional to an increase in transfer capacity.

For cases where the timing of Marinus Link is deferred, it is forecast to provide the same level of market benefits from the time of installation as for the case if it is not deferred. However, it foregoes the market benefits associated with the years of deferment, and hence the overall market benefits reduce in real terms and present value terms if Marinus Link is delayed.

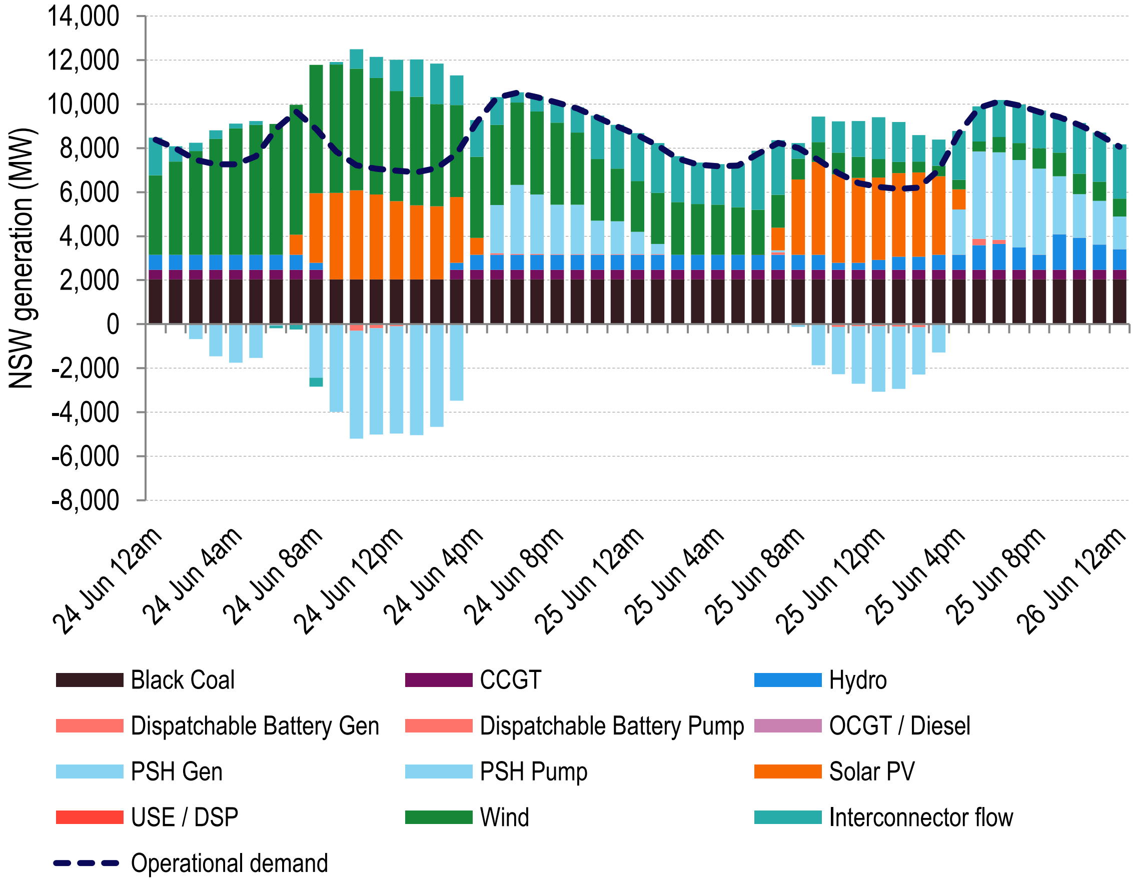
5.9 Modelled outcomes for the future of the NEM: Example week in 2032-33

5.9.1 Central scenario: Without Marinus Link

By 2032-33 in New South Wales, it is assumed that Liddell power station, Vales Point power station and Eraring power station will have fully retired. The 2,640 MW Bayswater power station, comprised of four individual units, and the 1,400 MW Mount Piper power station, with two individual units, are expected to be the only stations remaining online in New South Wales. With an assumed 6.5 % outage rate for each unit, it becomes reasonably likely that at least one coal unit will be on outage at a given time. This section focuses on a particular week in June 2033, when two coal units are forecast to be offline based on the randomly selected outage schedule. In New South Wales (and Victoria and Tasmania), average demand tends to be higher in winter than other seasons, and solar output (both large-scale solar PV and distributed PV) tends to be lower. Consequently, after significant amounts of thermal power stations retire and renewable generation increases, winter months are forecast to present a difficulty in regard to the reliability and affordability of suppling the NEM. The Grattan Institute refer to this phenomenon as "the winter problem".[64] Figure 54 presents the forecast hourly dispatch for 24 and 25 June 2033.

[64] Grattan Institute, April 2021, *Go for net zero: A practical plan for reliable, affordable, low-emissions electricity*. Available at: https://grattan.edu.au/wp-content/uploads/2021/04/Go-for-net-zero-Grattan-Report.pdf. Accessed 31 May 2021.

Figure 54: Hourly (interval starting) New South Wales generation mix[65] forecast for 24 and 25 June 2033, Central scenario without Marinus Link



During the two days presented in Figure 54, available black coal-fired generation is forecast to operate at full output as baseload generation for New South Wales. For most of this period, CCGT capacity and hydro generators are also forecast to consistently dispatch. The surplus of wind and solar availability on 24 June allows PSH projects to pump both throughout the early-morning and during the middle of the day. By importing generation from adjacent regions via interconnectors, New South Wales PSH projects can store additional energy during the day at time when other regions also have an abundance of low-cost renewable generation. At this time, existing CCGT and hydro projects are not required to generate. During the evening and night of 24 June, a combination of coal, CCGT, hydro, PSH, wind and import from nearby regions is forecast to meet New South Wales demand, without need to utilise higher-cost OCGT generation.

Based on the forecast reference year profile, a wind drought is forecast to occur on 25 June. Despite the 10,200 MW of wind capacity online, on average there is only 800 MW available from 8am to midnight. During the daytime, when solar availability is high, demand is easily met; however, PSH projects are forecast to pump while existing CCGT dispatch occurs. This operation is forecast to occur as part of the least-cost solution to offset higher cost OCGT generation and USE in the days to follow.

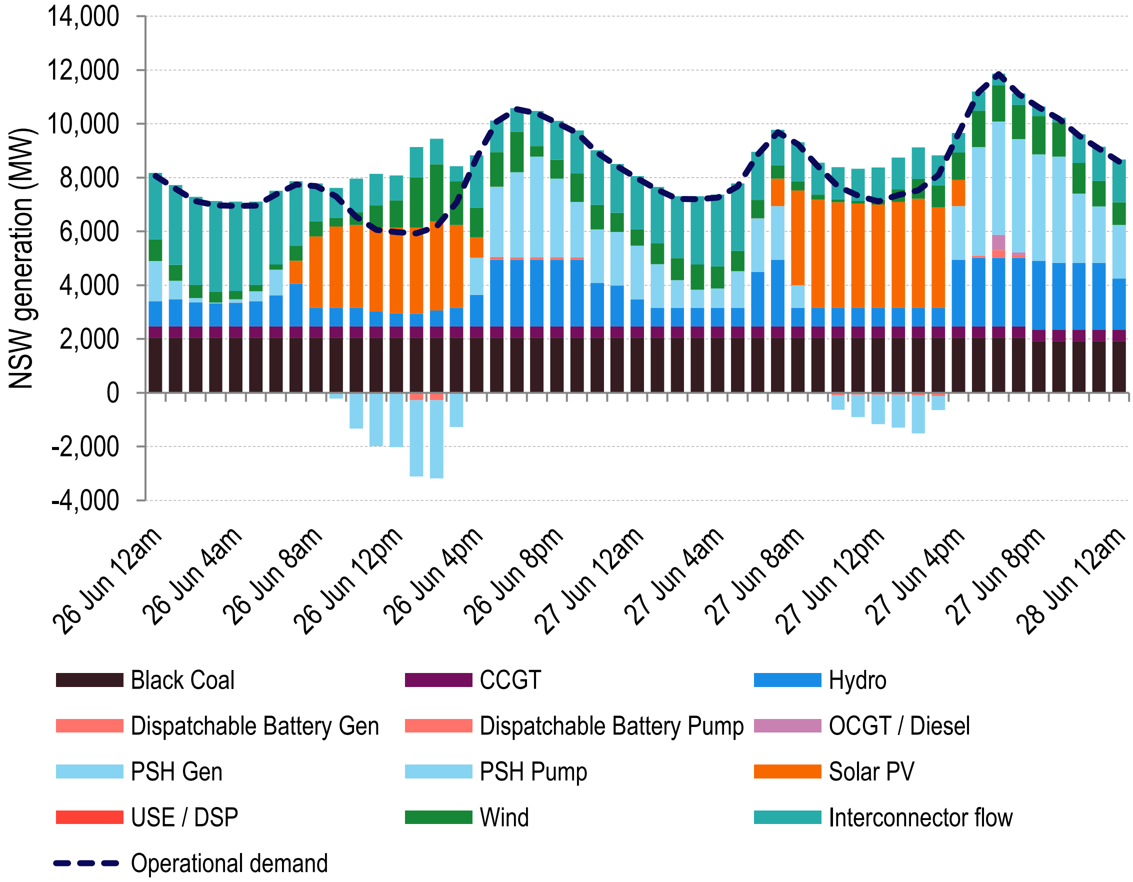
In the evening and throughout the night of 25 June, PSH projects are forecast to generate continuously for up to 12 hours, albeit not always at full dispatch. Some dispatchable battery

[65] Pumping and charging from storage is displayed as a negative contribution since it is a net load. Positive interconnector flow represents net import into New South Wales as this contributes to meeting New South Wales demand. Negative interconnector flow represents net export from New South Wales.

storage contribution is forecast to dispatch at the start of the evening peak, but the requirement for continuous dispatch means longer-term storage is required.

Figure 55 presents the following two days of 26 and 27 June 2033.

Figure 55: Hourly (interval starting) New South Wales generation mix forecast for 26 and 27 June 2033, Central scenario without Marinus Link



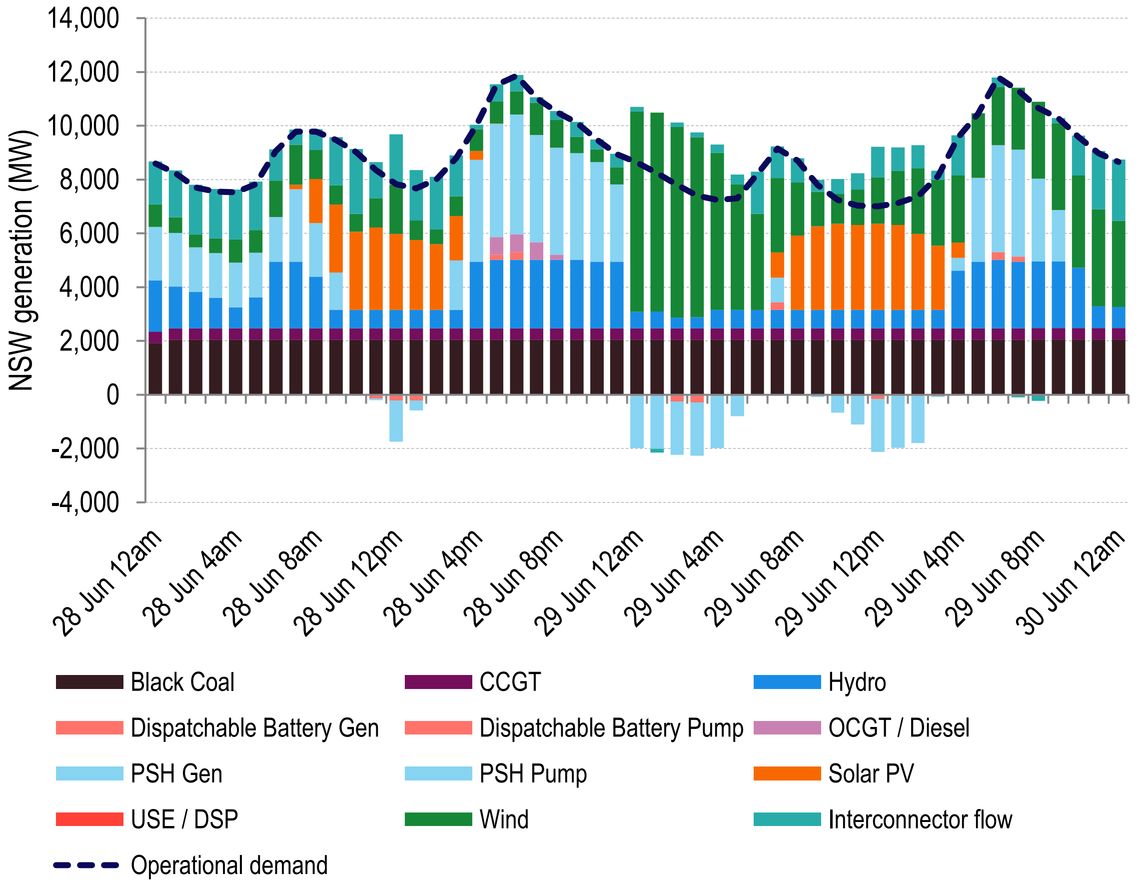
During the night of 25 June and into the early morning of 26 June, New South Wales is forecast to import up to 3,400 MW from its adjacent regions. This allows New South Wales to meet the 7,000 MW to 8,000 MW of operational demand between midnight and 8am after most coal-fired power stations are assumed to have retired with minimal contribution from wind and nothing from solar PV. Once again, in the middle of the day PSH is forecast to pump, despite the need for existing CCGTs to contribute to demand. Although conventional hydros are available to dispatch during the middle of the day, which would offset CCGT generation, this is not forecast to occur. This is due to the energy limitations on conventional hydro stations, in that there is a limited amount of water that can be stored within their reservoirs to be utilised.

During the night of 26 June and into 27 June, PSH is forecast to generate from 5pm to 8am along with up to 2,700 MW of import to meet the 7,000 MW to 11,000 MW of operational demand during this period. Most of this time there is no solar availability and an average of 8 % wind availability.

In the evening of 27 June, conventional hydro is fully dispatched along with a high contribution from PSH and generation from dispatchable battery storage, minimal wind dispatch and high-cost OCGT generation. Once again, long-duration PSH generation is forecast to generate continuously throughout the evening and into the morning alongside imported generation from other regions and the dispatchable capacity that is available throughout this period.

The forecast hourly generation of the next two days, 28 and 29 June is presented in Figure 56.

Figure 56: Hourly (interval starting) New South Wales generation mix forecast for 28 and 29 June 2033, Central scenario without Marinus Link



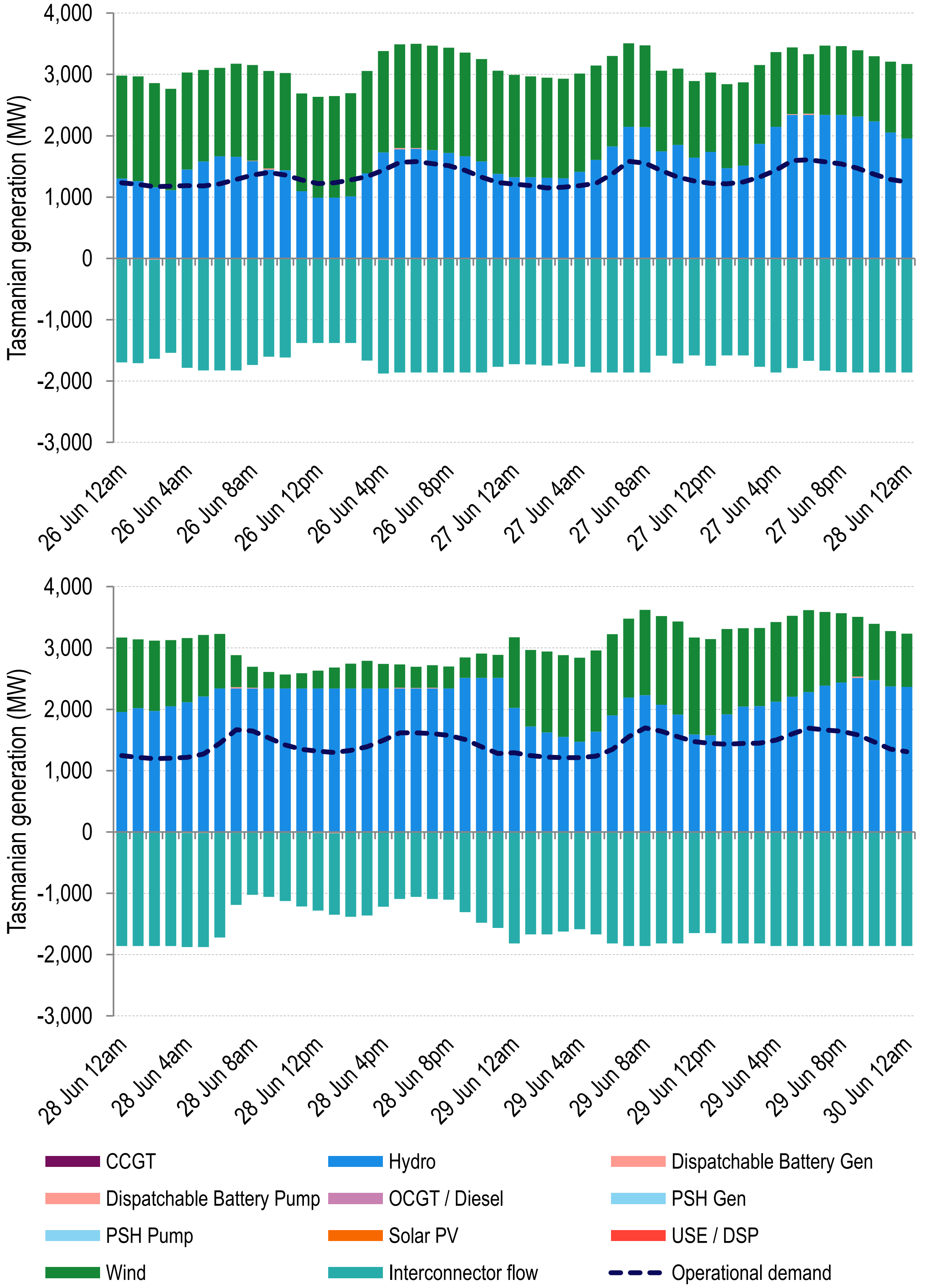
Once again, for these two days it is forecast that existing CCGTs are being dispatched continuously to meet demand. Consequently, even 12-hour PSH projects are required to pump during the middle of the day after having been depleted over extended use so that they can be dispatched during the evening peak and overnight.

By 29 June, the extended wind drought in the input meteorological patterns subsides, with up to 7,700 MW of wind capacity available to generate. This allows hydro generators to reduce their output to retain water to be used during times of peak demand. With wind once again becoming available to generate throughout the evening peak, the combination of black coal, existing CCGTs, conventional hydro, dispatchable battery storage, PSH and wind is able to meet New South Wales demand without the need for higher cost OCGT generation on 29 June.

5.9.2 Central scenario: With Marinus Link

The commissioning of Marinus Link unlocks the ability of Tasmanian wind and hydro to assist in supplying the rest of the NEM. Figure 57 shows an illustrative example in the hourly generation for Tasmania on 26 and 27 June followed by the generation on 28 and 29 June. This is the same four-day low wind period illustrated without Marinus Link in Figure 55 and Figure 56.

Figure 57: Top: Hourly (interval starting) Tasmanian generation mix forecast for 26 and 27 June 2033. Bottom: 28 and 29 June 2033. Central scenario with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029.



The diversity of renewable availability across the NEM means that Tasmania has ample wind generation at this time when New South Wales is forecast to undergo a wind drought. For most of these four days, the forecast lowest cost dispatch to meet NEM-wide demand is for Tasmania to generate in excess of its own demand and export 1,500 MW to 2,000 MW of low-cost generation to

Victoria, which can then flow to New South Wales and offset higher-cost coal and gas. Even when wind availability in Tasmania is also low, such as on 28 June, conventional hydro capacity still allows Tasmania to export more than 1,000 MW of generation in most intervals.

The forecast hourly generation in New South Wales on the first two days of this illustrative period, 26 and 27 June 2033 with Marinus Link is presented in Figure 58. Figure 59 presents the following two days of 28 and 29 June 2033.

Figure 58: Hourly New South Wales generation mix forecast for 26 and 27 June 2033, Central scenario with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029

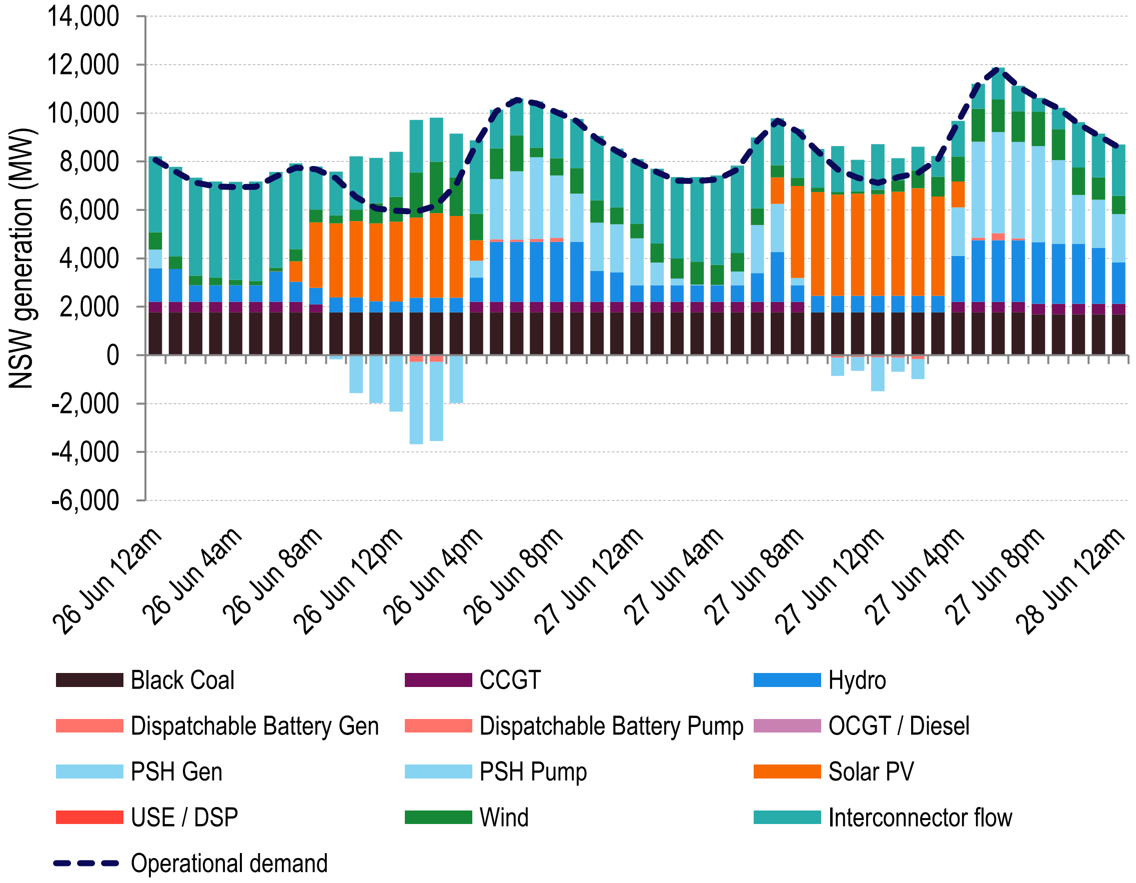
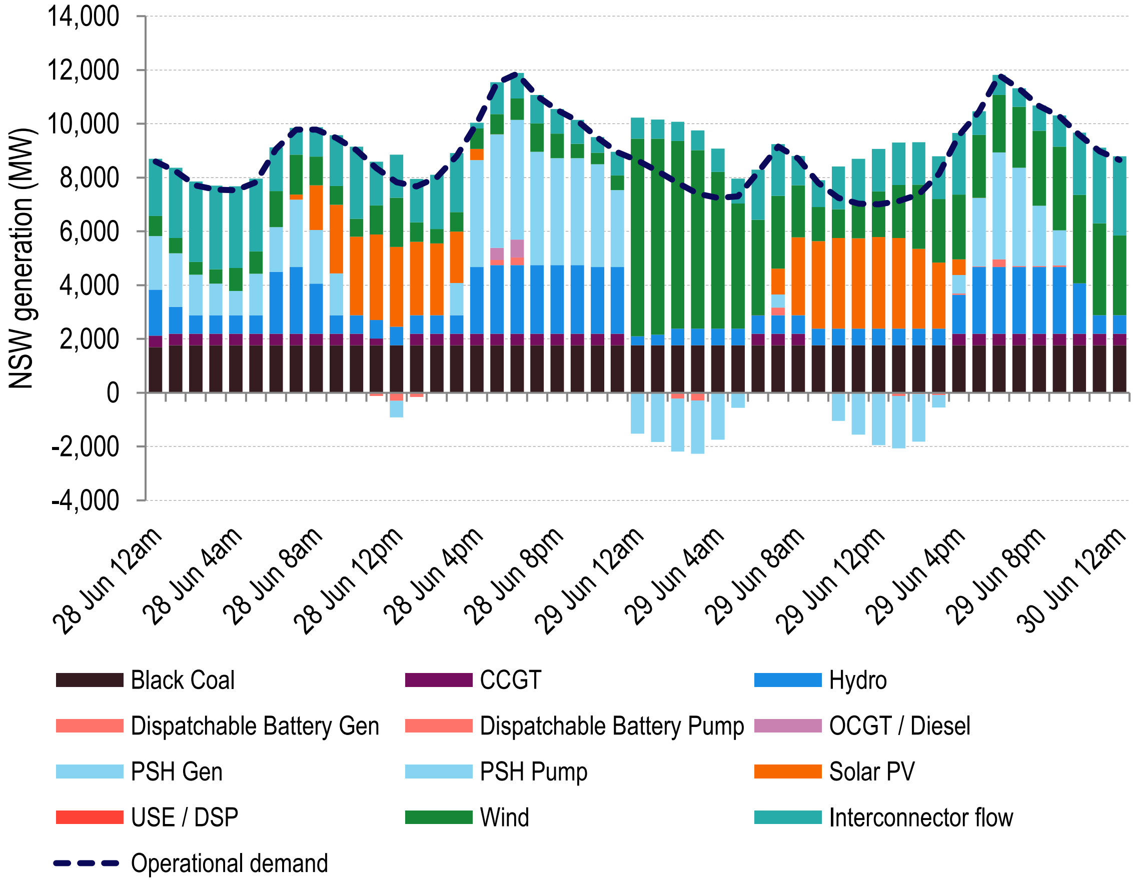


Figure 59: Hourly New South Wales generation mix forecast for 28 and 29 June 2033, Central scenario with Marinus Link 1,500 MW, stage 1 2027, stage 2 2029



Unlike the without-Marinus Link counterfactual discussed in Section 5.9.1, existing New South Wales CCGTs are not forecast to generate continuously throughout this four-day period, due to the additional importing of low-cost renewable generation from Tasmania through Victoria. Consequently, New South Wales PSH projects are not forecast to pump at high cost during times when CCGT generation occurs during this period. Furthermore, Marinus Link is forecast to avoid the need for high-SRMC OCGT capacity to generate for three of the four days. In the forecast with Marinus Link the evening peaks are instead met by coal, existing CCGTs, hydro, dispatchable battery storage, PSH, wind and import.

5.9.3 Central scenario: Forecast market benefits

In both the with and without Marinus Link case, no DSP dispatch or USE is forecast during the six forecast days presented in this example. Both cases are optimised to determine the lowest cost capacity and generation expansion plan under their respective conditions: with or without the commissioning of Marinus Link. That is to say, over the week presented above, including 30 June 2032, without Marinus Link it is forecast that 1,530 GWh of coal-fired generation and 355 GWh of gas-fired generation will be dispatched across the NEM. In this same period with Marinus Link, the Tasmanian wind and hydro generation that is unlocked by Marinus Link is forecast to offset the need for 49 GWh of generation from coal-fired power stations and 82 GWh from gas-fired turbines. In fuel and VOM costs alone, this is equivalent to a forecast undiscounted saving of $2m from avoided coal use and $9m from avoided gas use over the forecast week.

Events like this, albeit generally less extreme, are forecast to occur throughout the study due to the variable nature of the renewable generation which is forecast to replace retiring coal-fired generators. It is this variable nature and the requirement for a combination of storage, dispatchable capacity and interconnection to allow diversity of renewable availability that results in a forecast

NEM-wide discounted market benefit of roughly $100m in 2032-33 and a total of approximately $1.5b in forecast fuel cost savings for Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, as shown previously in Section 5.3.1.

6. Sensitivities

6.1 Overview of input assumptions

Several sensitivities to assumptions in the market modelling were selected by TasNetworks to test the robustness of the magnitude and timing of market benefits. An overview of the sensitivities is given in Table 4. All sensitivities were performed for the 1,500 MW Marinus Link.

Table 4: Overview of sensitivities, Marinus Link 1,500 MW

Sensitivity	Scenario	Variation to scenarios
3.80 % WACC	All scenarios Stage 1: 2027 Stage 2: 2030	A reduced discount rate and weighted-average-cost-of-capital (WACC) of 3.80 % has been applied across all scenarios.[66] In the TasNetworks' PACR, this sensitivity is referred to as '3.8 % Weighted Average Cost of Capital (WACC)'.
6.80 % WACC		An increased discount rate and WACC of 6.80 % has been applied across all scenarios. In the TasNetworks' PACR, this sensitivity is referred to as '6.8 % Weighted Average Cost of Capital (WACC)'.
No economic retirements	Central Stage 1: 2027 Stage 2: 2030	All generators are maintained until the expected closure year. Where station-specific information was available, retirement dates were updated as per AEMO's Generation Information 29 January 2021.[67] Retirements of other units are based on the end of technical life as per AEMO's July 2020 Input and Assumptions workbook.
Optional gas retirements		All existing gas generators allowed to retire from 1/7/2024.
Sustained low gas price		All new entrant and existing gas prices reduced to $8/GJ in real June 2020 dollars.
High and low battery costs		Deviation in AEMO 2020 ISP battery capex from 2025-26 onward, such that capex is +/-30 % higher than AEMO's trajectory by 2029-30. In the TasNetworks' PACR, this sensitivity is referred to as 'Variation in battery costs (+/- 30 %)'.
No Tasmanian hydro upgrades		None of Tarraleah (150 MW), John Butters (20 MW) or Anthony Pieman (80 MW) upgrades proceed with the installation of Marinus Link stage 1 (or stage 2). In the TasNetworks' PACR, this sensitivity is referred to as 'Hydro Tasmania generation capacity remains unchanged'.
Hydrogen load growth	Step Change Stage 1: 2027 Stage 2: 2030	Increased Tasmanian load by 500 MW from 1/7/2035 and 1,000 MW by 1/7/2040. This additional load has been switched off daily between 5pm and 9pm to give an overall capacity factor of roughly 80 %.
Committed PSH		750 MW of 24-hour Tasmanian PSH capacity is installed with the second stage of Marinus Link (1/7/2030). The additional cost of this new capacity is included in both with and without Marinus Link simulations. In the TasNetworks' PACR, this sensitivity is referred to as '750 MW of committed PSH in Tasmania'.
Victorian 10 GW		Minimum of 10 GW Victorian new entrant wind and solar PV capacity installed by 1/7/2032. This capacity constraint has been enforced linearly from 0 MW on 1/7/2021 to 10 GW on 1/7/2032. In the TasNetworks' PACR, this sensitivity is referred to as 'Development of Victorian REZs'.
No procured SPS		Tasmanian import flow across both Marinus Link and Basslink is constrained on the basis of enforcing a Special Protection Scheme (SPS). In the TasNetworks' PACR, this sensitivity is referred to as 'Testing import

66 As the Slow Change scenario has a default discount (WACC) of 3.8 %, no additional results for this scenario are displayed.
67 AEMO, Generation Information Page. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Accessed 26 May 2021.

Sensitivity	Scenario	Variation to scenarios
		capacity on marinus Link for procurement of System protection Scheme (SPS)'.
Smaller cable size		Marinus Link losses are increased due to choosing to build a smaller cable. In the TasNetworks' PACR, this sensitivity is referred to as 'Optimising the conductor size of HVDC cable'.
Removal of TRET	Central and Step Change Stage 1: 2027 Stage 2: 2029	All TRET constraints have been removed across all scenarios. Refer to the TasNetworks Inputs, Assumptions and Scenario workbook for Project Marinus PACR[68]for the way TRET has been implemented.
No state-based schemes		Removal of all state-based energy targets. For the Central scenario, a Step Change carbon budget (of 1,325 Mt CO_2-e by 2050) is also enforced.
High Electrification		Increased demand to signify more national electrification. For the Central scenario, a Step Change carbon budget (of 1,325 Mt CO_2-e by 2050) is also enforced. All state-based energy targets have also been removed.

6.2 Marinus Link forecast market benefits

Table 5 to Table 9 display the forecast market benefits in each sensitivity and the difference (exclusive of costs) compared to their respective scenario. The drivers for these changes, compared to the relevant scenario, are presented in the remainder of Section 6. Workbooks containing a more detailed annual breakdown of market benefits, capacity and generation outcomes for each sensitivity can be supplied by TasNetworks upon request.

Table 5: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, discount rate sensitivities; millions real June 2020 dollars discounted to 1 July 2020

Sensitivity	Slow Change	Central	Fast Change	High DER	Step Change
3.80 % WACC	NA[69]	3,940	4,193	3,981	6,258
6.80 % WACC	2,711	2,512	2,895	2,510	4,553

Table 6: Differences in forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, discount rate sensitivities; millions real June 2020 dollars discounted to 1 July 2020

Sensitivity	Slow Change	Central	Fast Change	High DER	Step Change
3.80 % WACC	NA[69]	524	520	560	631
6.80 % WACC	-1,673	-904	-778	-910	-1,074

Table 7: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, Central sensitivities; millions real June 2020 dollars discounted to 1 July 2020

Sensitivity	Scenario and timing	Market benefits ($m)	Difference in market benefits compared to Central scenario ($m)
No economic retirements	Central Stage 1: 2027 Stage 2: 2030	3,077	-339
Optional gas retirements		3,478	62
Sustained low gas price		2,695	-721
High battery costs		3,417	1

[68] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.
[69] Since the Slow Change scenario already assumes a WACC of 3.8 %, there is no corresponding 3.8 % WACC sensitivity.

Sensitivity	Scenario and timing	Market benefits ($m)	Difference in market benefits compared to Central scenario ($m)
Low battery costs		3,427	11
No Tasmanian hydro upgrades		3,133	-283

Table 8: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, Step Change sensitivities; millions real June 2020 dollars discounted to 1 July 2020

Sensitivity	Scenario and timing	Market benefits ($m)	Difference in market benefits compared to Step Change scenario ($m)
Hydrogen load growth	Step Change Stage 1: 2027 Stage 2: 2030	3,883	-1,744
Committed PSH		6,513	887
Victorian 10 GW		5,493	-134
No procured SPS		5,621	-6
Smaller cable size		5,608	-19

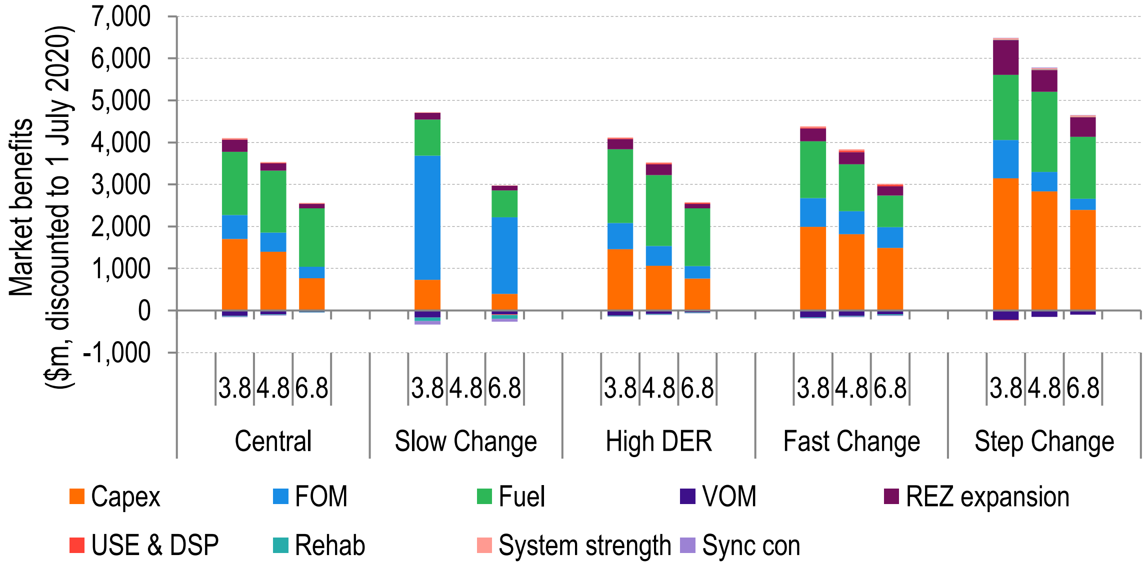
Table 9: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Central and Step Change sensitivities; millions real June 2020 dollars discounted to 1 July 2020

Sensitivity	Scenario and timing	Market benefits ($m)	Difference in market benefits compared to Central scenario ($m)
Removal of TRET	Central Stage 1: 2027 Stage 2: 2029	1,868	-1,552
No state-based schemes		3,490	70
High Electrification		3,938	518
Removal of TRET	Step Change Stage 1: 2027 Stage 2: 2029	4,103	-1,552
No state-based schemes		4,197	-1,458
High Electrification		5,335	-320

6.3 Outcomes of discount rate sensitivities to all scenarios

Figure 60 compares the categories of forecast Marinus Link market benefits across the discount rate sensitivities. Since the annual market benefit outcomes are discounted by their respective rates the total forecast market benefits shown in Figure 60 cannot be compared with one another meaningfully.

Figure 60: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, discount rate sensitivities; millions real June 2020 dollars discounted to 1 July 2020



The TSIRP model makes decisions that minimise the overall cost to supply electricity demand in the NEM over the entire study period based on an assumed discount rate. The discount rate applied is the same for all technology types.

To calculate the market benefits of Marinus Link under different discount rates and WACCs, the model was run with both a low (3.8 %) and high (6.8 %) discount rate and WACC. These alternate rates were applied when annualising costs to compute the least-cost solution and to the annual market benefit outcomes (rather than just discounting the annual market benefits outcomes with a different discount rate).

In all five scenarios, Marinus Link has positive market benefits from the time it is assumed to be commissioned. Therefore, increasing the discount rate and WACC decreases the total discounted market benefits.

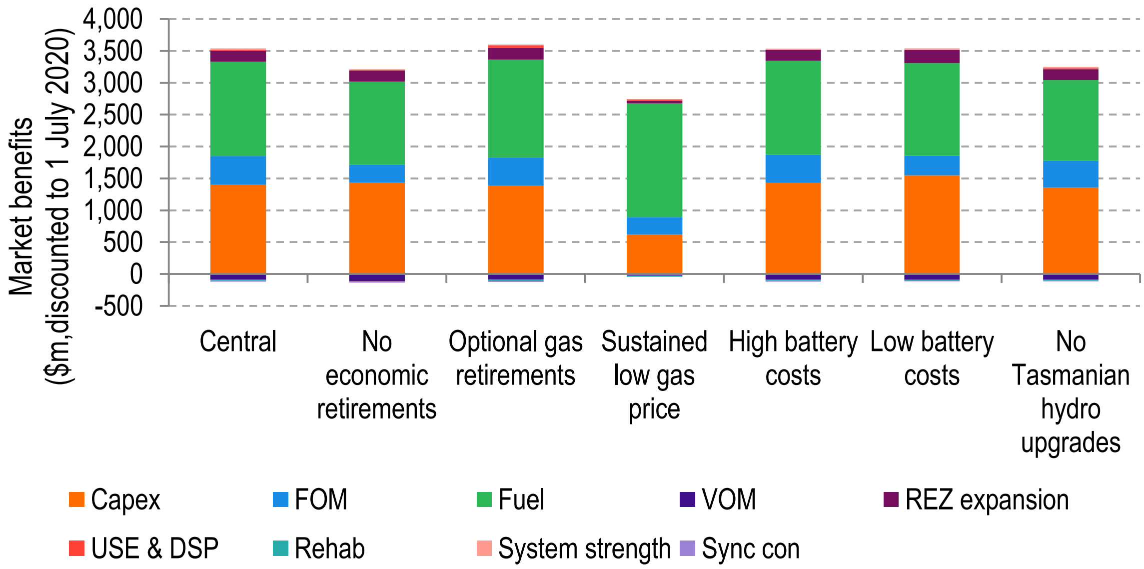
The application of these alternate rate adds an additional layer of complexity because this can lead to different least-cost capacity mix outcomes. By decreasing the discount rate and WACC from 4.8 % to 3.8 %, technologies with longer repayment periods become more competitive to build and weighting of later decisions increases. As such, the amount of PSH capacity forecast increased with lower discount rate whereas the amount of distributed battery capacity decreased. With a lower discount rate and WACC a larger quantity of new entrant wind is forecast to be built from the first year of the study. 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 and therefore market benefits increase with a lower WACC.

The opposite is also true when discount rate and WACC increase. By increasing the discount rate and WACC from 4.8 % to 6.8 %, technologies with shorter repayment periods become more competitive to build and the weighting of later decisions decreases. The total amount of dispatchable battery capacity built is forecast to increase and the amount of PSH decrease. Higher amounts 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 therefore market benefits decrease with a higher discount rate and WACC.

6.4 Outcomes of Central scenario sensitivities

Figure 61 compares the forecast Marinus Link market benefits across each Central scenario sensitivity with the Central scenario.

Figure 61: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, Central scenario sensitivities; millions real June 2020 dollars discounted to 1 July 2020



6.4.1 No economic retirements

In this sensitivity, the option to economically retire existing coal capacity is removed and therefore all generators are maintained until their expected closure dates.[70,71] This change in assumption reduces the forecast market benefits of Marinus Link to $3,077m, which is $339m lower than the Central Scenario.

As presented in Section 5.3.2, for the Central scenario, Marinus Link is forecast to result in 300 MW to 500 MW of additional retirement of coal-fired power stations in New South Wales from 2027-28 to 2034-35. These retirements result in high FOM, fuel and capex savings during these years. When the option for economic retirements is removed, these savings are reduced and therefore the overall market benefit of Marinus Link decreases. This can be seen in Figure 61.

6.4.2 Optional gas retirements

For this sensitivity, it is assumed all existing gas generators have the option to economically retire from 1/7/2024. As economic coal retirements are enabled in the Central scenario, this means that all thermal generators have the option to economically retire from 1/7/2024. This change in assumption increases the forecast market benefits of Marinus Link to $3,478m, which is $62m higher than that of the Central scenario.

[70] The assumed retirement schedule for Yallourn power station (a staggered retirement of one unit each year from 2029-30 to 2032-33) was selected prior to the announcement by EnergyAustralia that specified Yallourn power station's retirement date would be brought forward to mid-2028. Full details are available at: https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition.

[71] The assumed retirement date for Eraring power station (2032-33) was selected prior to the reporting that Origin Energy has informed AEMO that unit 4 of Eraring will close in 2030 and unit 1 in 2031. The remaining two units will remain online until the previously announced retirement date of 2032-33. Details are available at: https://reneweconomy.com.au/origin-to-close-first-unit-of-australias-biggest-coal-generator-in-2030/

6.4.3 Sustained low gas price

For this sensitivity, it is assumed that the gas price for all existing and new entrant gas generators remains at $8/GJ (real June 2020 dollars) for the entire modelling period. This change in assumption reduces the forecast market benefits of Marinus Link to $2,695m, which is $721m lower than that of the Central scenario.

By reducing the price of gas, existing gas units are forecast to be more heavily utilised and therefore less new entrant wind capacity is forecast to be built. Instead, when new entrant capacity is needed, higher levels of gas-fired generation and lower levels of other technologies are forecast. Overall, less new entrant capacity is forecast relative to the Central scenario, due to the higher capacity factor of gas-fired generation, when compared to renewable wind or solar PV technologies. Therefore, the predominant reason why Marinus Link market benefits decrease is because less forecast new entrant capacity can be avoided. Lower forecast capex savings due to Marinus Link are somewhat counterbalanced by greater fuel cost savings from avoided gas generation with Marinus Link. This is due to the low-cost combination of Tasmanian wind alongside dispatchable Tasmanian conventional hydro capacity and new entrant PSH, which offsets the need for mainland gas-fired capacity as a form of dispatchable generation.

More specifically, without Marinus Link and by the end of the study period, reducing gas prices to $8/GJ increases total forecast gas capacity (CCGT and OCGT, existing and new entrant) from 8.8 GW to 10.6 GW. With Marinus Link, reducing gas prices increases total gas capacity from 8.1 GW to 10 GW. Furthermore, more coal is economically retired due to these higher amounts of gas (a more economic dispatchable form of generation). Figure 62 displays the difference in capacity across the NEM between the case with Marinus Link, relative to the without-Marinus Link counterfactual for this sensitivity, alongside the generation differences in Figure 63.

Figure 62: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, Sustained low gas price sensitivity (positive values equal higher capacity with Marinus Link)

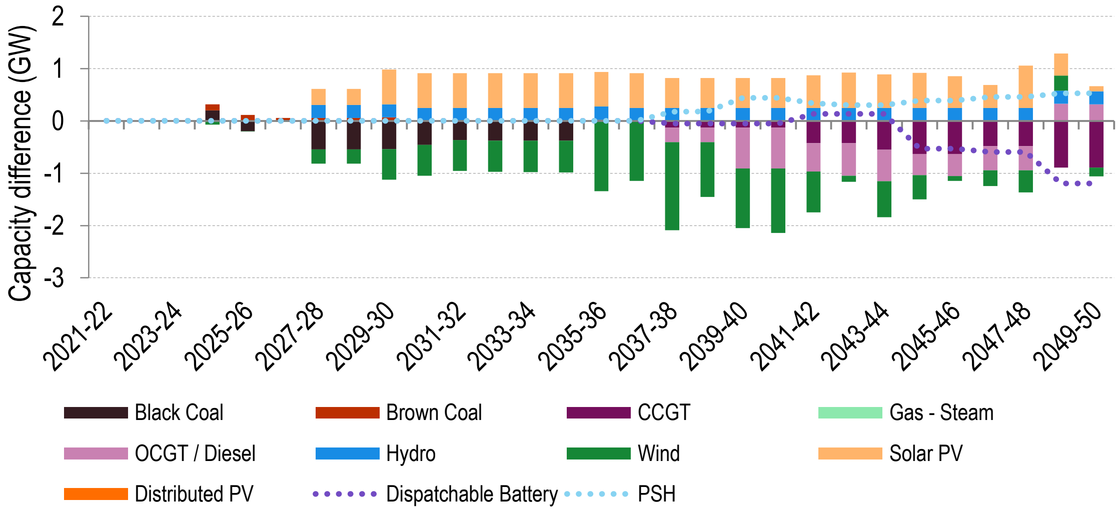
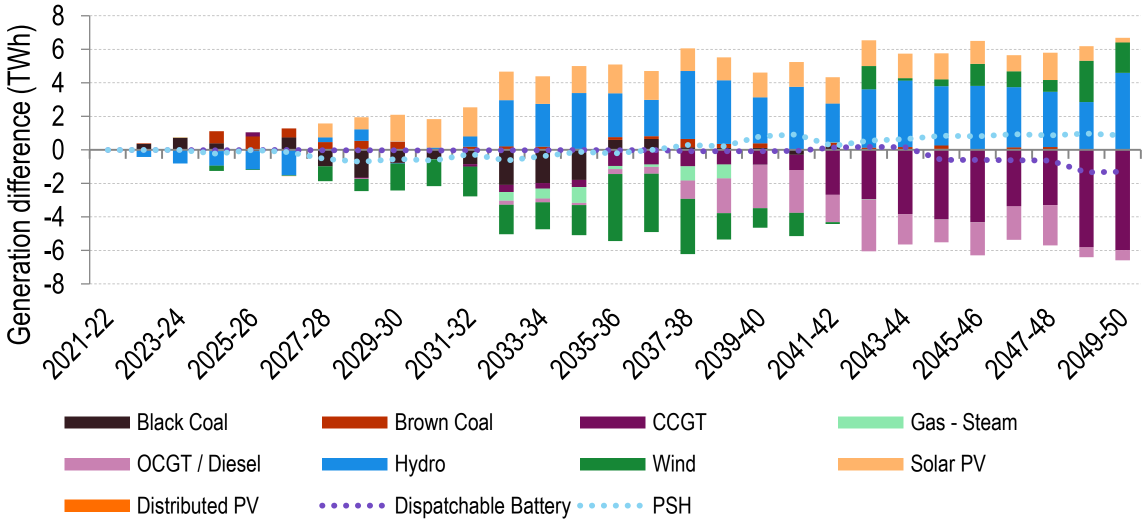


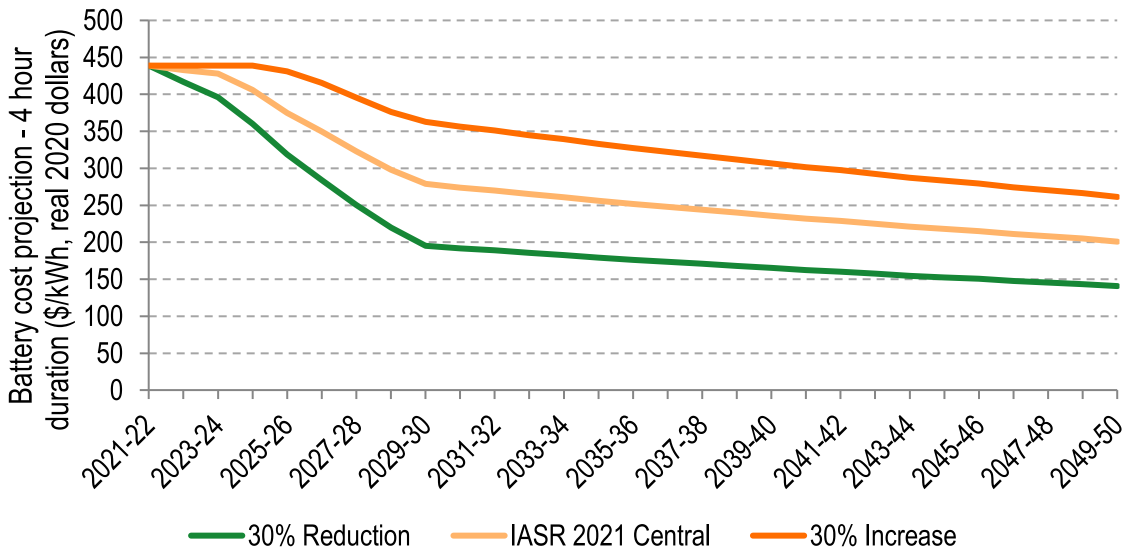
Figure 63: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, Sustained low gas price sensitivity (positive values equal higher energy with Marinus Link)



6.4.4 High and low battery costs

For these sensitivities, it is assumed that battery costs (across all new entrant grid battery storage sizes) are either increased or decreased by 30 % from 2025 onwards as seen in Figure 64. These changes in battery costs result in forecast Marinus Link market benefits of $3,417m and $3,427m for the high and low battery cost sensitivities, respectively. This is a $1m and $11m respective increase in forecast market benefits when compared with the Central scenario.

Figure 64: Example of the assumed battery storage (4-hour storage) capex trajectory sensitivities advised by TasNetworks as applied to the assumed trajectory using the VIC Medium regional cost factors, excluding 10-year battery replacement costs.



For the high battery cost sensitivity, roughly 3 GW less battery capacity is installed, regardless of Marinus Link. For the low battery cost sensitivity, approximately 5 GW more battery capacity is installed, regardless of Marinus Link. This is because increasing the cost of technologies decreases their economic viability and vice versa.

When lowering battery capex and not including Marinus Link, 1.2 GW of 8-hour batteries is forecast to be installed in 2029-30 rather than 12-hour PSH in New South Wales to meet the 2 GW storage component of the New South Wales Electricity Infrastructure Roadmap (the remaining 0.8 GW remaining as 12-hour PSH). However, in this sensitivity without Marinus Link, it is still forecast that some deeper storage (12-hour PSH) and dispatchable capacity (OCGTs) will be economically installed on the mainland. When including Marinus Link however, the entire 2 GW storage component of the New South Wales Electricity Infrastructure Roadmap storage constraint is forecast to be fulfilled by 8-hour batteries. This is because existing conventional hydro capacity and the potential for low-cost new entrant Tasmanian deep storage is unlocked with Marinus Link, which reduces the need for longer-term New South Wales PSH, in favour of lower-capex 8-hour batteries.

6.4.5 No Tasmanian hydro upgrades

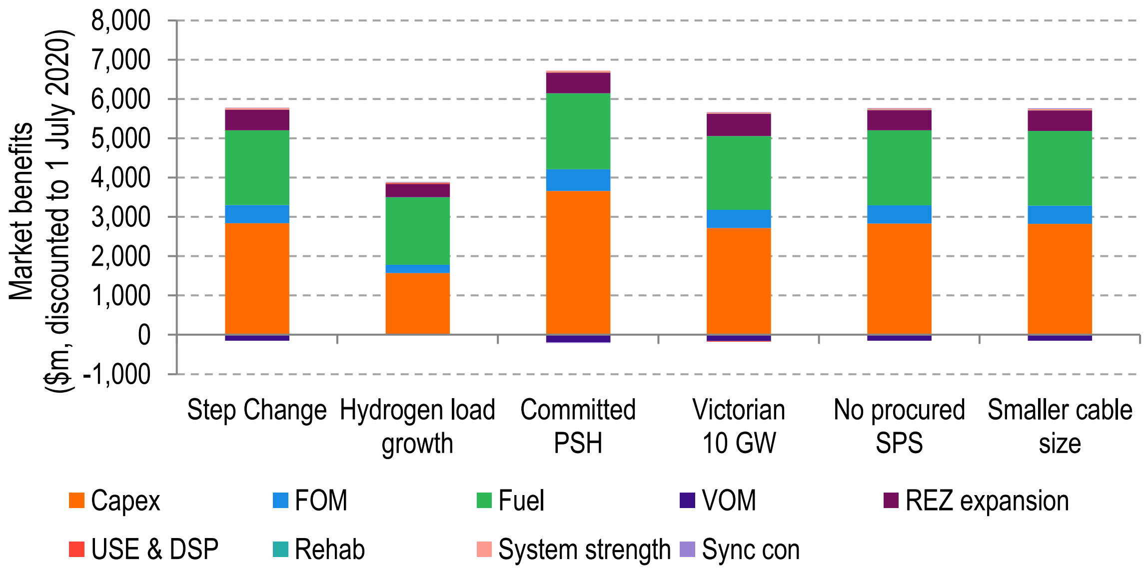
In this sensitivity, it was assumed that all Tasmanian hydro scheme upgrades, Tarraleah (150 MW), John Butters (20 MW) and Anthony Pieman (80 MW), do not proceed with the installation of Marinus Link stage 1. By removing these upgrades, the forecast market benefits of Marinus Link are reduced to $3,133m, which is $283m lower than the Central scenario.

The main reason why market benefits are forecast to reduce when lowering Tasmanian hydro capacity is because this limits Tasmania's ability to supply peak demand periods on the mainland. This increases existing and new entrant thermal generation and therefore results in higher fuel costs. Market benefits are forecast to diverge from 2032-33, once all units from the Eraring coal-fired power station have reached their assumed retirement date. In the late 2030s to early 2040s, varying levels of new OCGT, PSH and battery capacity are built on the mainland, slightly reducing annual market benefits relative to the Central scenario.

6.5 Outcomes of Step Change scenario sensitivities

Figure 65 compares the forecast annual Marinus Link market benefits across all Step Change scenario sensitivities and the Step Change scenario.

Figure 65: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, Step Change scenario sensitivities; millions real June 2020 dollars discounted to 1 July 2020



6.5.1 Hydrogen load growth

For this sensitivity, it is assumed that Tasmanian demand increases by 300 MW, 500 MW and 1,000 MW from 1/7/2030, 1/7/2035 and 1/7/2040. This was selected by TasNetworks to represent a series of additional Tasmanian hydrogen loads. Each load is switched off daily between 5pm and 9pm to give an overall capacity factor of roughly 80 %. This change in assumption reduces forecast market benefits of Marinus Link to $3,883, which is $1,744m lower than in the Step Change scenario.

Forecast annual market benefits begin to diverge between the two forecasts (with and without an additional hydrogen load) from 2030-31 when the first load is assumed to increase. This is because increasing Tasmanian demand decreases the ability for Marinus Link to export low-cost renewable generation to the mainland. This reduces the ability of Marinus Link to offset mainland capacity. Increasing Tasmanian demand also allows new entrant Tasmanian wind to be built, in addition to that required to meet TRET.

6.5.2 Committed PSH

For this sensitivity, it is assumed that 750 MW of 24-hour Tasmanian PSH capacity is installed with the second stage of Marinus Link on 1/7/2030. The additional cost of this new capacity is included in both the with Marinus Link simulation and the without-Marinus Link counterfactual. This change in assumptions increases forecast market benefits of Marinus Link to $6,513m, which is $886m higher than the Step Change scenario.

Without Marinus Link, no new entrant Tasmanian PSH is forecast in the Step Change scenario. With Marinus Link, approximately 750 MW of new entrant PSH is forecast to be built in 2032-33. This means that forecast market benefits from the Step Change Marinus Link include the cost associated with building 750 MW of PSH. Therefore, choosing to commit this capacity across both with and without Marinus Link cases, essentially neutralises the cost of the 750 MW of PSH capacity. As such, Marinus Link's forecast market benefits increase by the cost of building 750 MW of PSH. Minor changes in market benefits also arise from differences in capacity build, mainly in the without-Marinus Link counterfactual, because of this additional committed storage capacity.

Figure 66 displays the difference in capacity across the NEM between the case with Marinus Link, relative to the without-Marinus Link counterfactual for this sensitivity, alongside the generation differences in Figure 67.

Figure 66: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, Committed PSH sensitivity (positive values equal higher capacity with Marinus Link)

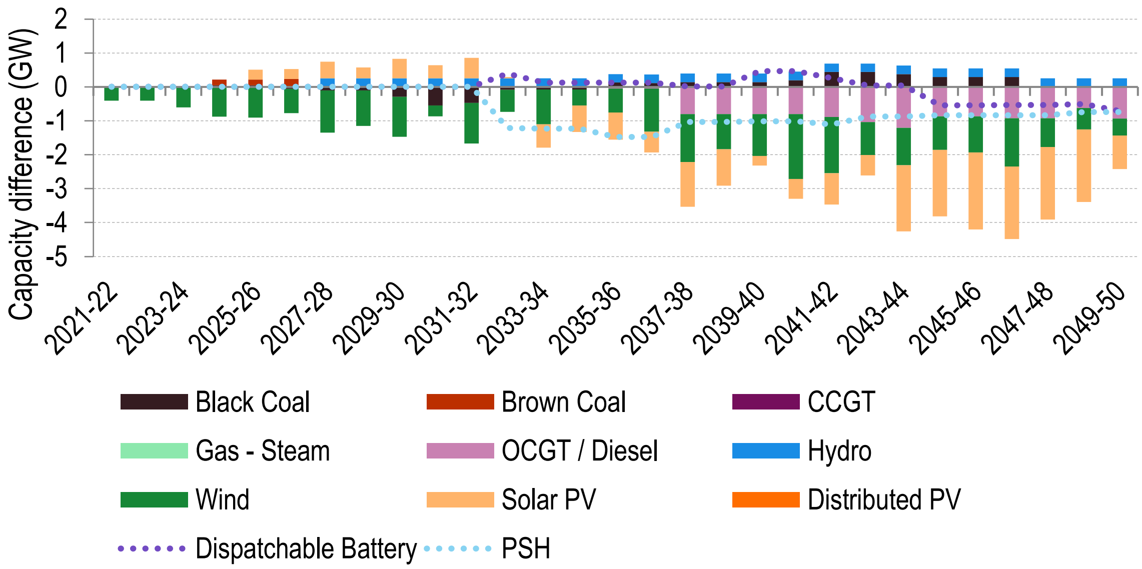
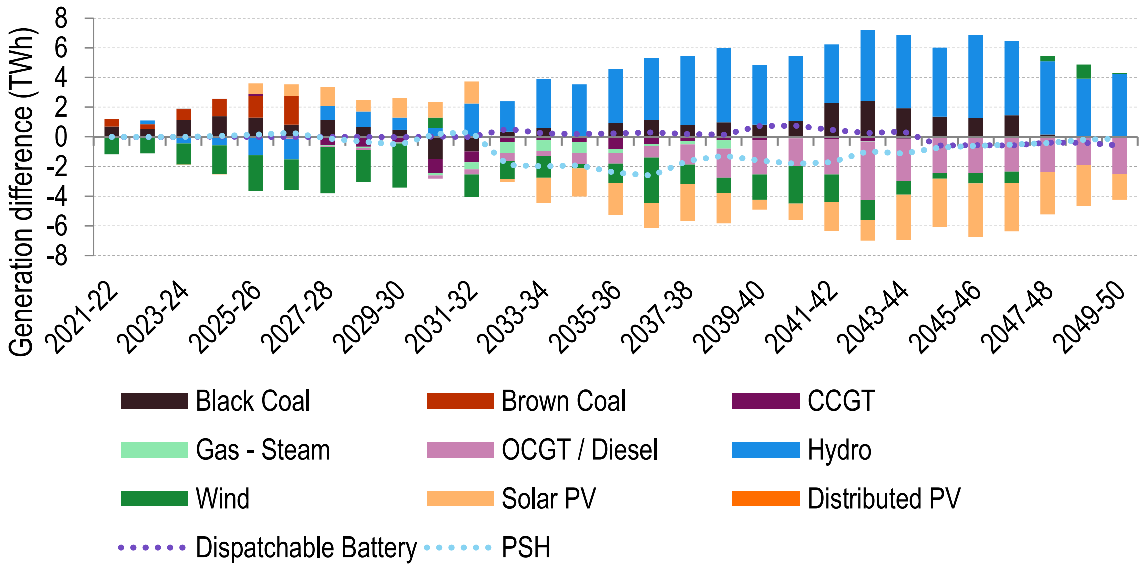


Figure 67: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2030, Committed PSH sensitivity (positive values equal higher energy with Marinus Link)



6.5.3 Victorian 10 GW

In this sensitivity, a minimum of 10 GW of new entrant wind and solar PV capacity is enforced to be installed in Victoria by 1/7/2032. This capacity constraint has been implemented as a linear constraint, ramping from 0 MW on 1/7/2021 to 10 GW on 1/7/2032. This change reduces forecast Marinus Link market benefits to $5,493m, which is $134m lower than the Step Change scenario.

Applying this 10 GW capacity target for Victoria increases the amount of new entrant solar PV and wind forecast to be built in Victoria, both with and without Marinus Link. By doing so, market benefits decrease marginally as Marinus Link is unable to avoid building this new capacity by supplying the mainland with additional generation.

Regardless of Marinus Link's installation, the increased amounts of Victorian new entrant solar PV and wind are forecast to result in the early economic retirements of additional thermal generation, relative to that of the Central scenario.

6.5.4 No procured SPS

For this sensitivity, it is assumed that no SPS is procured for Marinus Link stage 1. As such, constraints found in Table 10 have been applied in this sensitivity. This change in assumptions reduces the forecast market benefits of Marinus Link to $5,621m, which is $6m lower than the Step Change scenario. This change to import limits is shown to not significantly change market benefits. The effect is small because:

- Tasmania is predominantly exporting,
- 1,228 MW is larger than the typical system load in Tasmania and so import limits are in practice only restrictive for three years from 2027-28 to 2029-30 inclusive.

Table 10: No procured SPS modelling constraints

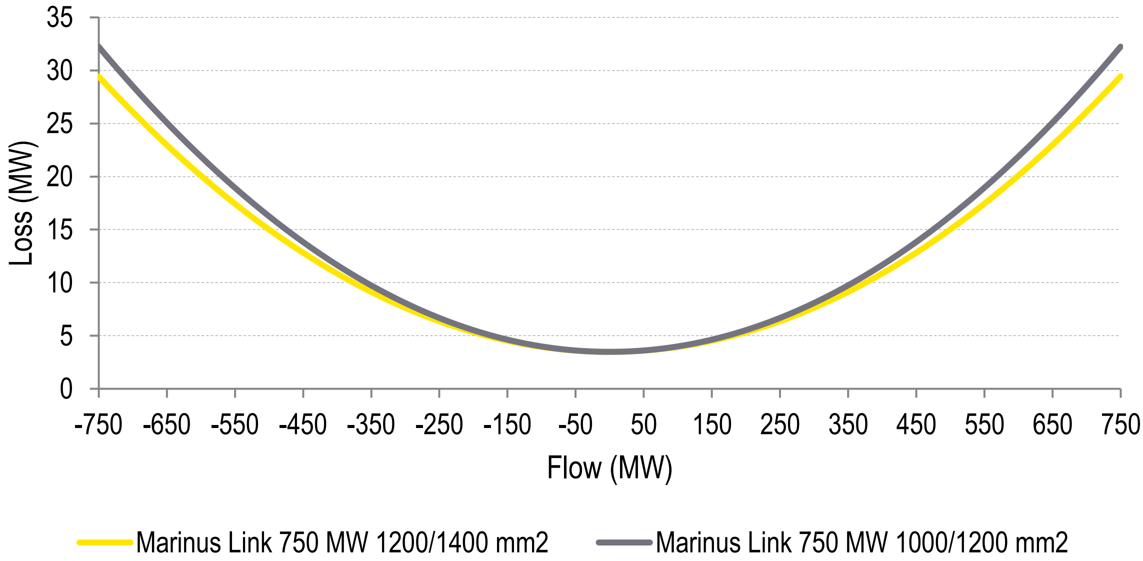
Timing	TAS import limit	TAS export limit	Justification (Import limit)
Study period start to 30/6/2027	478 MW	478 MW	Until entry of Marinus Link, maintain current limits.

Timing	TAS import limit	TAS export limit	Justification (Import limit)
1/7/2027 to 30/6/2030	478 MW	1,228 MW	Until entry of second stage of Marinus Link, assume that trip of the largest link is the credible contingency (single stage of Marinus Link). Therefore, combined Tasmanian import limit equal to current limits 478 MW.
1/7/2030 to 30/6/2032	1,228 MW	1,978 MW	After entry of second stage of Marinus Link (but before significant PSH is built in Tasmania), assume that trip of the largest link is the credible contingency (single stage of Marinus Link). Therefore, combined Tasmanian import limit equal to 478 MW + 750 MW.
1/7/2032 - end of study period	1,978 MW	1,978 MW	After entry of significant PSH in Tasmania, assume that dispatchable capacity in Tasmania is sufficient to survive trip of a single interconnector.

6.5.5 Smaller cable size

For this sensitivity, the cable size of Marinus Link is reduced from a 1,200/1,400 mm^2 submarine/land cable size (which is assumed for the five scenarios) to 1,000/1,200 mm^2 submarine/land cable size (sensitivity). This results in higher cable losses as described below in Figure 68. This change reduces the forecast market benefits of Marinus Link to $5,608m, which is $19m lower than the Step Change scenario.

Figure 68: Smaller cable size sensitivity, comparison of Marinus Link loss curves



6.6 Outcomes of No TRET sensitivities

Figure 69 and Figure 70 compare the forecast Marinus Link market benefits across the Central and Step Change scenario for all no TRET sensitivities.

Figure 69: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Central scenario sensitivities; millions real June 2020 dollars discounted to 1 July 2020

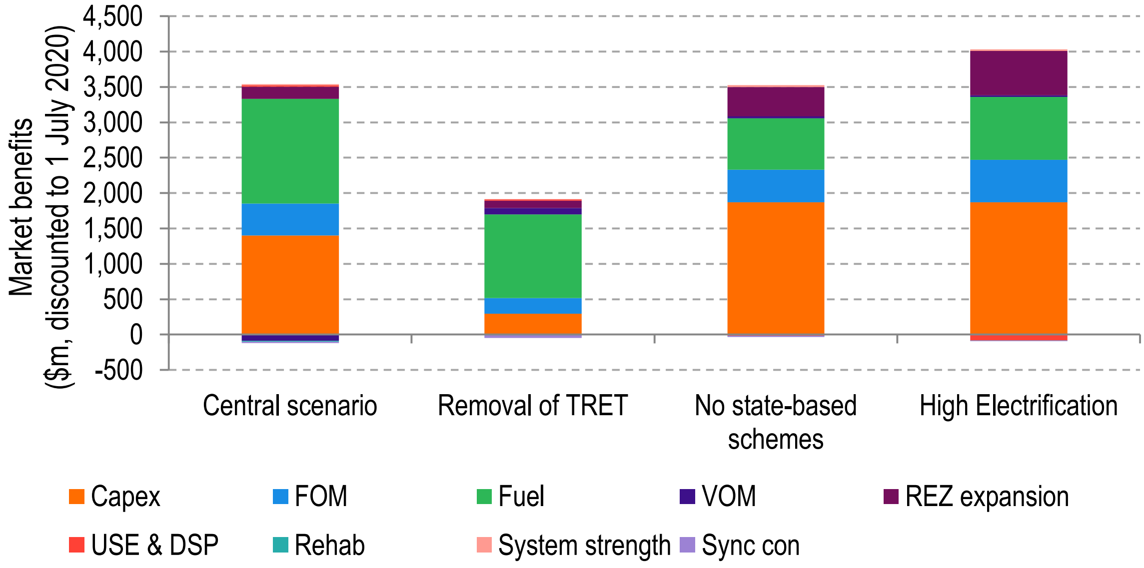
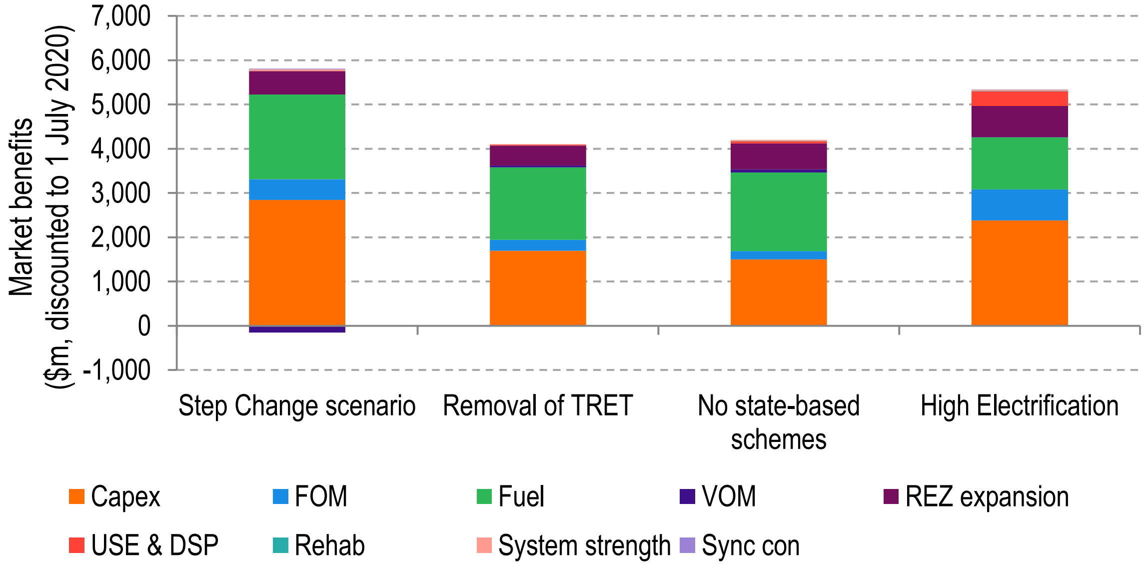


Figure 70: Forecast market benefits of Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Step Change scenario sensitivities; millions real June 2020 dollars discounted to 1 July 2020



6.6.1 Removal of TRET

In this sensitivity, the TRET is assumed not to be legislated and therefore has been removed from both with and without Marinus Link simulations. This lowers the forecast market benefits of Marinus Link to $1,868m and $4,103m for the Central and Step Change scenarios, respectively. This translates to a reduction in Marinus Link market benefits of $1,552m in both scenarios.

When including TRET, a large amount of new entrant Tasmanian wind capacity is forecast to be installed in both the with and without Marinus Link cases. This is because Tasmanian wind has a relatively low LCOE when compared to Tasmanian solar PV.

Without Marinus Link, there is only a small amount of new entrant wind capacity forecast to be economically installed in Tasmania when TRET is removed for both the Central and Step Change sensitivities. However, with Marinus Link, meeting TRET is still a part of the least-cost solution for expanding the NEM in the Step Change scenario. This is shown in Figure 71 which displays the forecast installation of new entrant wind and solar PV capacity in Tasmania throughout the study period in the Step Change scenario and sensitivity. Even in the Central No TRET sensitivity, also shown in Figure 71, the least-cost expansion of the NEM involves Tasmania achieving approximately the 150 % renewable generation by 2032-33. By 2040, the least-cost expansion plan is only several hundred megawatts shy of the capacity required to achieve the full 200 % renewable target for the TRET. The timing of this new entrant Tasmanian wind capacity is however delayed and coincides with the closer of various mainland coal retirements.

Figure 71: Forecast installation of new entrant wind and solar PV capacity in Tasmania with Marinus Link

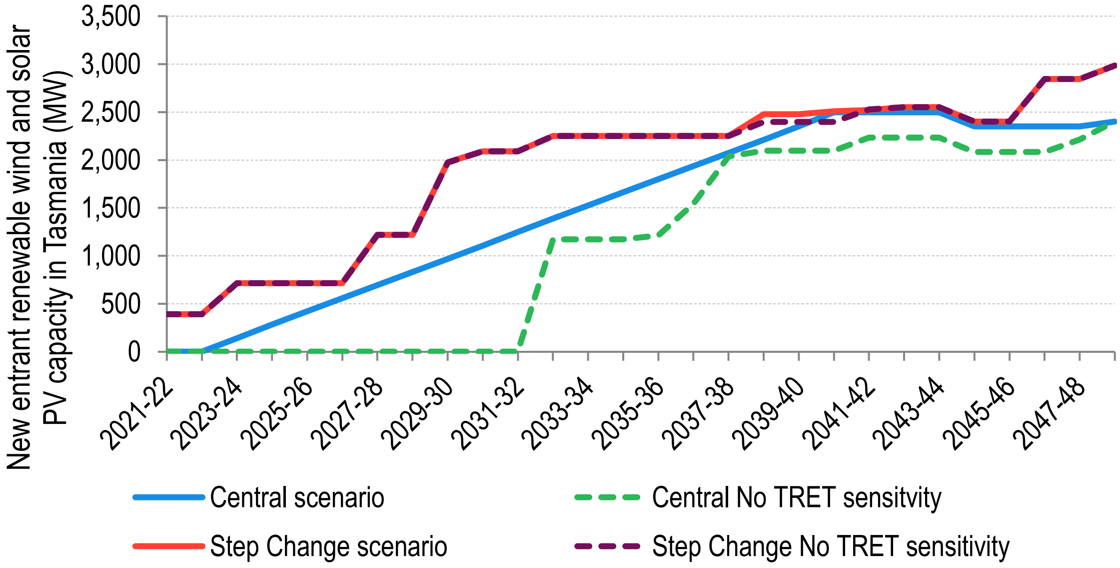


Figure 72 and Figure 73 display the difference in capacity and generation, respectively, across the NEM between the case with Marinus Link, relative to the without-Marinus Link counterfactual for the Step Change sensitivity, with the removal of TRET. As previously shown in Figure 71, regardless of an explicit renewable energy target for Tasmania, new entrant wind capacity is forecast to be installed in Tasmania with the commitment of Marinus Link. Similar to the original Step Change scenario, presented in Section 5.7, this uptake of Tasmanian capacity and generation with Marinus Link is forecast to provide a lower cost alternative to mainland wind, solar PV, storage and gas capacity and generation across the study period.

Figure 72: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Removal of TRET sensitivity (Step Change - positive values equal higher capacity with Marinus Link)

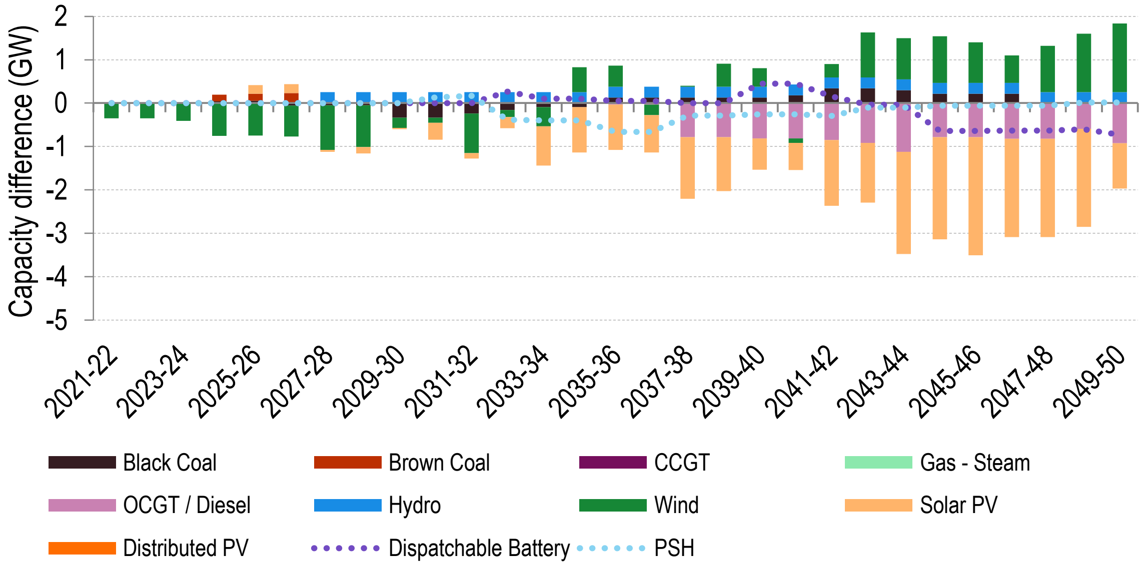
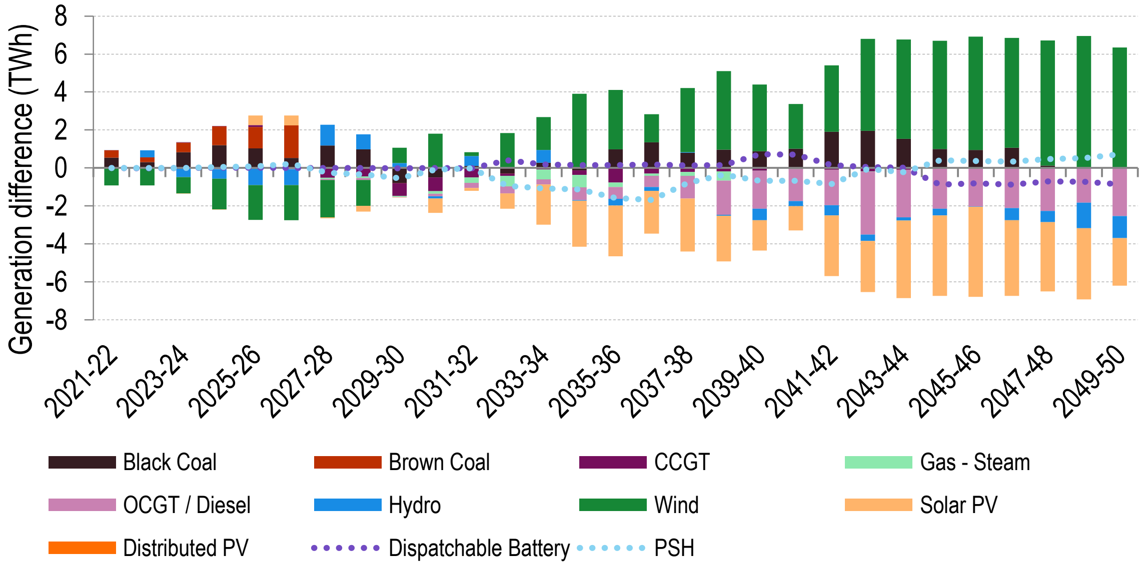


Figure 73: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2027, stage 2 2029, Removal of TRET sensitivity (Step Change - positive values equal higher energy with Marinus Link)



6.6.2 No state-based schemes

In this sensitivity, all state-based renewable schemes are removed from modelling (VRET, QRET, TRET and the New South Wales Electricity Infrastructure Roadmap), but a national Step Change carbon budget of 1,325 Mt CO_2-e by 2050 is assumed. As such, the Central scenario now also includes a national carbon budget (with the Step Change scenario continuing to have this budget). These changes in assumptions result in forecast market benefits of Marinus Link of $3,490m in the Central scenario (a $70m increase) and $4,197m in the Step Change scenario (a $1,458m decrease).

In the Central sensitivity, a national carbon budget is newly introduced relative to the Removal of TRET sensitivity. By limiting total emissions across the NEM, low emission intensity new entrant capacity is built to replace the existing and retiring high emission intensity thermal capacity. By 2040, dispatchable capacity is forecast to be needed to help meet mainland demand. Without Marinus Link, large amounts of new OCGT capacity is forecast to be built and dispatched on the mainland in the later years of the study; because of the carbon budget this means less emissions can be permitted in the early years. With Marinus Link, greater access to Tasmanian hydro, PSH and wind is forecast to reduce such OCGT build, and therefore more emissions can be permitted in the early years of the study. The overall result is that with Marinus Link, less capacity is needed to be built, especially in the earlier years of the study. Consequently, market benefits 'shift' to earlier years relative to the Central scenario; market benefits increase in earlier years (to 2036-37) and decrease in later years (from 2038-39 to the end of the study period).

As the Step Change sensitivity without TRET already includes a carbon budget and excludes TRET, the further removal of all mainland state-based schemes is only forecast to result in a minor delay in the installation of mainland renewables by several years to the previous sensitivity. Consequently, market benefits are similar to the Removal of TRET sensitivity.

6.6.3 High electrification

For this sensitivity, demand is assumed to increase in all NEM regions to signify a national effort to decarbonise and a further electrification of other industries. These assumed changes in demand can be seen in Figure 74 and Figure 75.

Figure 74: High electrification sensitivity, assumed changes in regional demand (Central scenario)

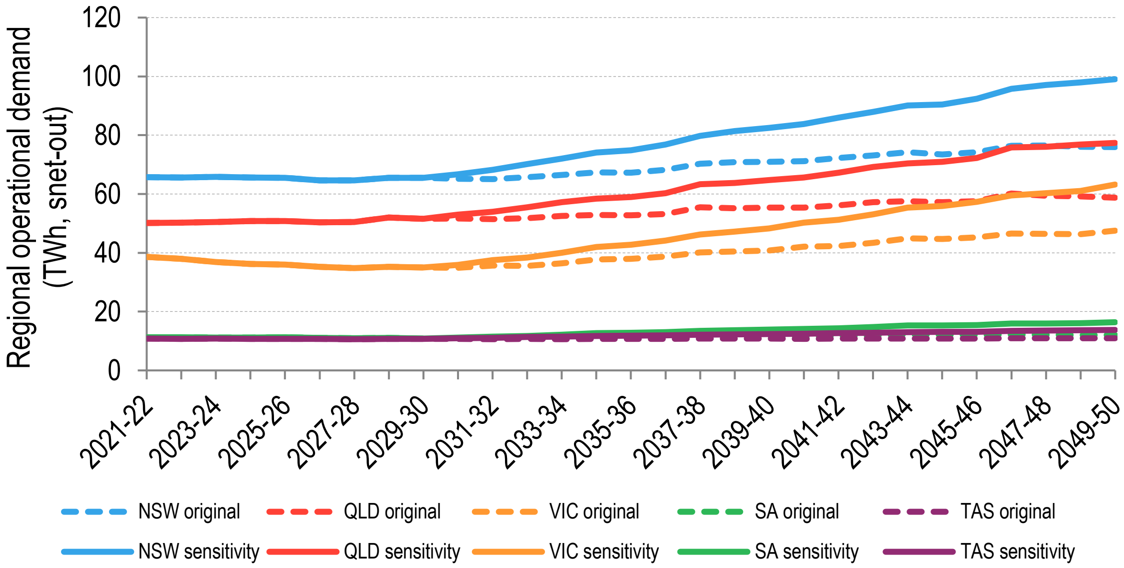
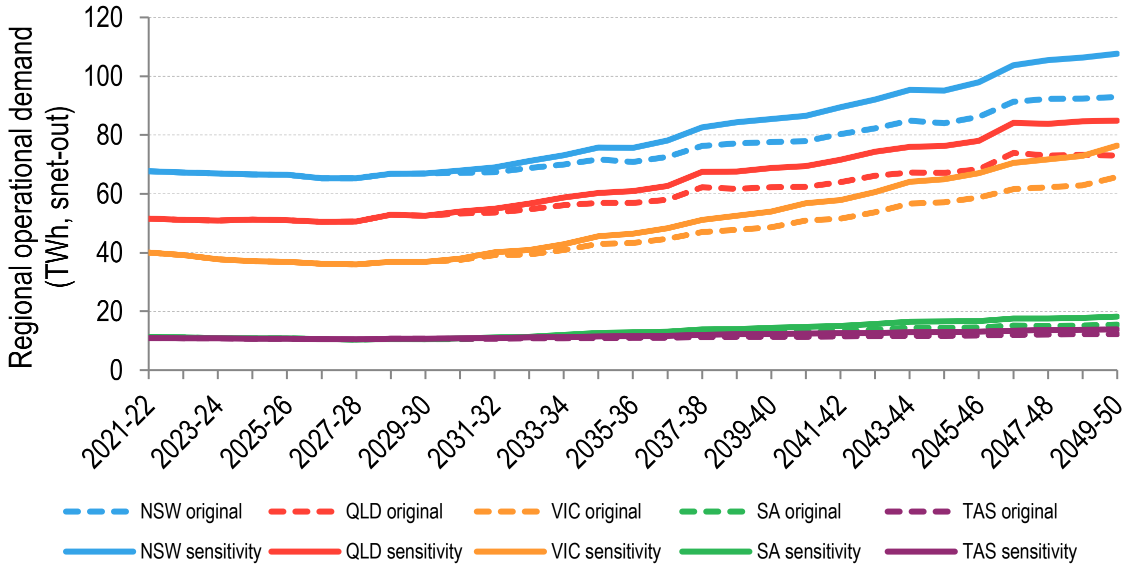


Figure 75: High electrification sensitivity, assumed changes in regional demand (Step Change scenario)



For both the Central and Step Change scenarios, a Step Change carbon budget (of 1,325 Mt CO_2-e by 2050) is enforced (i.e. the Central scenario also includes a national carbon budget). All state-based schemes are also removed. These changes in assumptions increase the forecast market benefits of Marinus Link to $3,938m for the Central scenario (an increase of $518m) and $4,103m for the Step Change scenario (a decrease of $320m).

With similar reasoning to that of the no state-based schemes simulations (found in Section 6.6.2), market benefits are forecast to occur earlier in the Central sensitivity (higher market benefits earlier in the study period and lower market benefits later in the study period). However, by also assuming an increase in NEM demand, greater amounts of new entrant capacity and total amounts of dispatchable generation are forecast on the mainland. As such, forecast market benefits increase further as Marinus Link can further avoid more capacity and further dispatch cheap Tasmanian resources instead.

The Step Change high electrification sensitivity follows a similar narrative to that of the no state-based schemes sensitivity, in that Marinus Link avoids mainland new entrant capacity (especially dispatchable OCGTs and batteries) by increasing access to Tasmanian resources (hydro, PSH and wind). Without Marinus Link, the combination of a low carbon future and high demand is forecast to result in DSP being utilised as one of the methods to keep down emissions toward the end of the study period. At times Marinus Link's ability to unlock these Tasmanian resources are forecast to provide a lower cost alternative to DSP, resulting in DSP and USE benefits from the mid-to-late 2040s.

7. Methodology

Section 7.1 gives an overview of the model used to compute long term least-cost generation development plan while Section 7.2 gives an overview of the method for computing market benefits.

7.1 Long-term investment planning model overview

EY used linear programming techniques to compute a least-cost, whole-of-NEM, hourly time-sequential dispatch and development plan spanning from 2021-22 to 2049-50. The modelling methodology follows the RIT-T guidelines for actionable ISP projects published by the Australian Energy Regulator.[72]

Based on the full set of input assumptions, the Time-Sequential Integrated Resource Planning (TSIRP) model makes decisions that minimise the overall cost to supply electricity demand in the NEM over the entire study period, with respect to:

- FOM costs of all generation capacity,
- VOM costs of all generation capacity,
- Fuel costs of all generation capacity, including the fuel costs of changes in interconnector transmission losses and storage losses for PSH and dispatchable batteries,
- Demand-side participation (DSP) and USE,
- Capex of new generation and storage capacity installed,
- Transmission expansion costs associated with REZ development,
- System strength costs,
- Retirement and rehabilitation costs,
- Synchronous condenser costs to meet inertia requirements,
- Transmission and storage losses which form part of the demand to be supplied but are calculated within the model.

To determine the mathematical least-cost solution, the model makes decisions for each hourly[73] trading interval regarding:

- The generation dispatch level for each power plant along with the charging and discharging of storage. Stations are dispatched according to their SRMC, which is primarily related to their VOM and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or un-planned outages), network limitations and energy limits (e.g., storage levels).
- Commissioning new entrant capacity for wind, solar PV SAT, CCGT, OCGT, large-scale battery storage and PSH.
- Retiring capacity from a selection of allowable existing generators to reduce the FOM component of the total system cost.[74]

---

[72] 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 4 May 2021.

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

[74] In the event of a binding emissions constraint, high emissions plant are dispatched less in order to meet the emissions target. Capacity may then be retired if it is uneconomic to keep incurring FOM costs for capacity that is not running.

These hourly decisions also consider constraints that include:

- Supply must equal demand in each region for all trading intervals, while maintaining a reserve margin, with USE costed at the VCR,[75]
- Minimum load for some generators,
- Transmission interconnector flow limits (between regions),
- Maximum and minimum storage reservoir limits (for conventional hydro, PSH and battery storage),
- New entrant capacity build limits for wind and solar PV for each REZ where applicable, and PSH in each region,
- Regional minimum inertia requirements,
- Renewable energy targets by region or NEM-wide in applicable scenarios,
- Emission constraints in applicable scenarios.

The model does not include intra-regional constraints, i.e., it does not contain the detail of the transmission network within a region, only inter-regional transfer limits (between regions).[76]

The model incorporates assumed fixed retirement dates for existing generation, if not economically retired earlier. It also factors in the annual costs, including annualised capital and FOM costs for all new generator capacity. The model decides how much new capacity to build in each region to deliver the least-cost market outcome. The model retires generator capacity and replaces it with new capacity if the combined capital, fuel, and operation and maintenance cost is lower than the total costs of keeping that capacity.

The model meets the specified emissions trajectory in applicable scenarios, at least cost, which may be by 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 generation, typically coal, gas and liquid fuel which is assumed to have unlimited energy in general. The running costs for these generators is the sum of the VOM and fuel costs. 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 NEM rules. On the other hand, peaking generators have no minimum operating level and start whenever their variable costs will be recovered.
- Semi-scheduled and non-scheduled wind and solar PV generators are fully dispatched according to their available resource in each hour, unless constrained by oversupply, when they may be curtailed or spilt (in the case of hydro with inflows in excess of storage).
- Storage plant of all types (conventional hydro generators with storages, PSH and large-scale battery storages) are operated to minimise the overall system costs. This means they tend to generate at times when the demand for power is high, and so dispatching energy-limited generation will lower system costs. Conversely, at times when there is a surplus of capacity, storage hydro withdraws capacity and PSH and battery storage operate in charging mode.
- The model incorporates the time value of money through use of a discount rate when evaluating near-term and more distant costs and benefits in computing the least-cost

[75] Regional VCR costs as per AEMO, 12 December 2020, *2021 Input and Assumptions Workbook, v3.0*. Available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 12 January 2021.

[76] It does however include an additional cost for transmission upgrades to facilitate REZ development where this forms part of the input data.

generation development plan. The discount rate applied is the same for all technology types.

7.2 RIT-T cost-benefit analysis

For each case with Marinus Link and in a matched without-Marinus Link counterfactual[77] we computed the difference between the sum of the cost components listed in Section 7.1. The changes in costs are the forecast market benefits of Marinus Link (not accounting for Marinus Link costs), as defined in the RIT-T.

The forecast market benefits also capture the impact of Marinus Link on:

- Estimated transmission losses to the extent that losses across interconnectors affect the generation that is needed to be dispatched in each trading interval,
- Differences in losses in storages, including PSH and battery storage between the with Marinus Link simulations and without-Marinus Link counterfactual.

Each component of forecast market benefits is computed annually for each year from 2021-22 to 2049-50. In this Report, we have summarised the market benefit and cost streams using a single value computed as the present value of each stream, discounted to 1 July 2020 at a scenario-specific real pre-tax discount rate. The market benefits of both additional interregional transmission and new generation are therefore estimated on the same basis in each scenario under the cost-benefit analysis framework applied under the RIT-T. The use of a different discount rate in the Slow Change scenario means market benefits in this scenario cannot easily be compared to the other four scenarios.

The market benefits of Marinus Link forecast in each scenario should be compared to the relevant Marinus Link costs to determine whether there is a forecast positive net economic benefit.[78] The market benefits estimated in this report exclude other benefits that could potentially be computed, such as ancillary services cost reduction. The costs (if any) associated with the changes in Tasmanian hydro capacity that are applied in the model in only the simulations including Marinus Link must also be considered.

The computation of net market benefits and determination of the preferred option has been conducted by TasNetworks outside of this Report[79] as it is dependent on option costs which were developed independently by TasNetworks.

[77] The without augmentation counterfactual is typically referred to as the Base case in a RIT-T. In this Report we use the term 'without-Marinus Link counterfactual' to avoid confusion with the term 'Base case' used in the Initial Feasibility Report to refer to a particular set of input assumptions which were varied in sensitivities.

[78] In this Report we use the term *market benefit* and *net economic benefit* as defined in the RIT-T guidelines.

[79] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

Appendix A List of abbreviations

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
CCGT	Closed-Cycle Gas Turbine
DSP	Demand-Side Participation
EV	Electric Vehicle
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSH	Pumped Storage Hydro
PSL	Prudent Storage Level
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test-Transmission
SA	South Australia
SAT	Single Axis Tracking
SRMC	Short-Run Marginal Cost
TAS	Tasmania
TW	Terawatt
TWh	Terawatt-hour
USE	Unserved Energy
VCR	Value of Customer Reliability

Abbreviation	Meaning
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VPP	Virtual Power Plant
VRET	Victoria Renewable Energy Target

EY | Building a better working world

EY exists to build a better working world, helping to create long-term value for clients, people and society and build trust in the capital markets.

Enabled by data and technology, diverse EY teams in over 150 countries provide trust through assurance and help clients grow, transform and operate.

Working across assurance, consulting, law, strategy, tax and transactions, EY teams ask better questions to find new answers for the complex issues facing our world today.

EY refers to the global organization, and may refer to one or more, of the member firms of Ernst & Young Global Limited, each of which is a separate legal entity. Ernst & Young Global Limited, a UK company limited by guarantee, does not provide services to clients. Information about how EY collects and uses personal data and a description of the rights individuals have under data protection legislation are available via ey.com/privacy. EY member firms do not practice law where prohibited by local laws. For more information about our organization, please visit ey.com.

Liability limited by a scheme approved under Professional Standards Legislation.

In line with EY's commitment to minimize its impact on the environment, this document has been printed on paper with a high recycled content.

ey.com