Project Marinus PADR economic modelling report

Tasmanian Networks Pty Ltd

27 November 2019

Building a better working world

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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 27 November 2019 ("**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.

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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.

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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 analyse different investment options in electricity transmission assets.

This Report forms a supplementary report to the broader Project Assessment Draft Report (PADR) published by TasNetworks.[1] It describes the key assumptions, input data sources and methodologies that have been applied in the gross market benefits modelling (the modelling) as well as outcomes of our analysis and key insights. It expands on and updates the modelling performed for the Project Marinus Initial Feasibility Report published in February 2019.[2]

EY applied a RIT-T cost-benefit analysis to compute the gross market benefits based on the change in the least-cost generation dispatch and capacity development plan due to Marinus Link.

EY used linear programming techniques to compute a least-cost, whole-of-NEM, hourly time-sequential dispatch and development plan spanning 30 years from 2020-21 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 of a range of scenarios and sensitivities. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator.[3]

To determine the least-cost solution, the model makes decisions for each hourly[4] 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 short-run marginal cost (SRMC), which is primarily related to their variable operation and maintenance (VOM) costs 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[5] for wind, solar PV SAT, CCGT, OCGT, large-scale battery storage and pumped storage hydro (PSH).
- Retiring capacity from a selection of allowable existing generators to reduce the fixed operation and maintenance (FOM) component of the total system cost.[6]

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

[2] TasNetworks, February 2019, *Initial Feasibility Report* and *Appendix 1: Economic Modelling Report*. Available at: https://www.marinuslink.com.au/initial-feasibility-report/. Accessed 11 November 2019.

[3] 14 December 2018, *RIT-T and RIT-D application guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

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

[5] PV = photovoltaic, SAT = Single Axis Tracking, CCGT = Closed-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine

[6] 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 unserved energy (USE) costed at the value of customer reliability (VCR)[7],
- 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 renewable energy zone (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).[8]

From the hourly time-sequential modelling we computed the following costs:

- 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,
- Capital costs of new generation and storage capacity installed,
- Transmission expansion costs associated with REZ development,
- Retirement and rehabilitation costs,
- Synchronous condenser costs in Tasmania to meet inertia requirements,
- Transmission and storage losses which form part of the demand to be supplied but are calculated within the model.

For each case with Marinus Link and in a matched Basslink-only counterfactual[9], we computed the difference between the sum of these components. The changes in costs are the forecast gross market benefits of Marinus Link (not accounting for Marinus Link costs), as defined in the RIT-T.

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[7] Set to $33,460/MWh based on AEMO, September 2014, *Value of Customer Reliability Review: Final Report*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review. Accessed 24 September 2019.

[8] It does however include an additional cost for transmission upgrades to facilitate REZ development where this forms part of the input data set as outlined in Section 6.2.

[9] The without augmentation counterfactual is typically referred to as the Base case in a RIT-T. In this Report we use the term 'Basslink-only 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.

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

- 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 Basslink-only counterfactual.

The forecast gross market benefits of Marinus Link vary across options and scenarios and must be compared to augmentation costs to determine whether any option has net positive market benefits and, subject to that, the preferred option (i.e. the option with the highest net market benefits).

We have conducted market modelling across several scenarios and sensitivities and combinations of Marinus Link scale and timing:

- Four scenarios, namely Status Quo, Global Slowdown, Sustained Renewables Uptake and Accelerated Transition to a Low Emissions Future,
- No Marinus Link and various scales 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 2026-27 for the first stage and two-year deferment or four-year deferment for the second stage,
- Different timings of KerangLink[10], relative to the timing of Marinus Link,
- Various other sensitivities including committed PSH in Tasmania, committed wind in Tasmania, reduced demand in Tasmania.

Table 1 shows the forecast gross market benefits associated with the change in the least-cost development plan under different sizes and timings of Marinus Link over the modelled 30-year horizon.

Table 1: Forecast gross market benefits of Marinus Link for different size and timing options, millions real June 2019 dollars discounted to 1 July 2025

Option	Marinus Link timing	Scenario			
		Global Slowdown	Status Quo	Sustained Renewables	Accelerated Transition
1,500 MW	2026 & 2028	2,901	3,398	3,997	6,551
	2027 & 2028	2,869	3,330	3,894	6,452
	2028 & 2030	2,833	3,290	3,795	6,300
	2028 & 2032	2,814	3,231	3,661	6,194
	2030 & 2032	2,728	3,125	3,470	5,980
	2030 & 2034	-	3,054	3,339	-
1,200 MW	2026 & 2028	2,717	3,016	3,528	5,665

[10] KerangLink is a potential expanded interconnection between New South Wales and Victoria for which a RIT-T is foreshadowed but not yet commenced.

Option	Marinus Link timing	Scenario			
		Global Slowdown	Status Quo	Sustained Renewables	Accelerated Transition
	2028 & 2032	2,615	2,844	3,204	5,316
750 MW	2026	2,212	2,237	2,616	4,010
	2028	2,157	2,147	2,467	3,801
600 MW	2026	1,997	1,952	2,271	3,418
	2028	1,940	1,868	2,136	3,240

The computation of net market benefits has been conducted by TasNetworks outside of this Report[11] as it is dependent on option costs which were developed independently by TasNetworks.

The gross market benefits of Marinus Link forecast in each scenario need to be compared to the relevant Marinus Link costs to determine whether there is a positive net benefit and if so, which is the preferred option. If values of other benefits which are not captured by the least-cost planning model can be computed, such as ancillary services cost reduction, these should also be added. 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 added to the costs.

All references to the preferred option in this Report 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." [12]

The gross market benefits of Marinus Link were forecast across four scenarios covering a broad range of reasonable possible futures for the NEM.

The four scenarios modelled cover a broad range of reasonable possible futures for the NEM:

- The Status Quo scenario was selected by TasNetworks to represent a central view of the market. It used a national emission reduction target of 28 % below 2005 levels by 2030[13] and a combination of input data mostly sourced from the Australian Energy Market Operator (AEMO) including 'Neutral' demand forecasts from the *2018 Electricity Statement of Opportunities*[14], coal retirements as per AEMO's February 2019 planning and forecasting assumptions workbook[15] with updates from AEMO published 25 June 2019[16]

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

[12] 14 December 2018, *RIT-T and RIT-D Application Guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

[13] Trajectory from 17 July 2018. *2018 Integrated System Plan Modelling Assumptions, v2.3*. No longer available online. Available on request from TasNetworks.

[14] AEMO, August 2018, *2018 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 11 November 2019.

[15] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

[16] AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.

and generator/storage capital and fuel costs from the AEMO February 2019 planning and forecasting assumptions workbook[17].

- The Global Slowdown scenario applies a set of assumptions reflecting a future world of lower demand forecasts[18], no emissions reduction target, 'Slow Change' gas fuel cost projections[17], a delay in KerangLink and Snowy 2.0, and a coal capacity constraint that results in earlier coal plant retirements relative to the Status Quo scenario[19].

- The Sustained Renewables Uptake scenario applies all the same assumptions as the Status Quo scenario, except it is intended that renewable capacity build rates are assumed to be maintained at current levels, reflecting current developer interest. To achieve this outcome, the planned retirement date of coal-fired generators are typically three to five years earlier than the dates modelled in the Status Quo scenario. KerangLink is also assumed to be commissioned earlier.

- Accelerated Transition to a Low Emissions Future scenario applies a set of assumptions reflecting a future world of higher electricity demand forecasts[18], a more stringent national emission reduction target of around 52 % below 2005 levels by 2030, 'Fast Change' gas fuel cost projections[17], AEMO's '2 degree' capex scenario[17] and earlier commissioning of KerangLink.

Modelling forecasts a transformation of the NEM in all scenarios modelled. Retirement of coal-fired plant in the NEM (assumed or due to binding model constraints) is the dominant driver of the generation development in all scenarios, with replacement by a combination of:

- Renewable wind and solar PV forecast to meet the energy gap caused by retirements of base load coal-fired energy producing plant at least cost,

- Ongoing development of behind the meter rooftop PV and battery storage (assumed as inputs to model) reducing the growth of NEM schedulable energy demand,

- PSH, batteries and gas-fired generation forecast to close the generation capacity gap caused by thermal retirements, to maintain reliability (by the most economic, least-cost sources of dispatchable capacity).

Without Marinus Link, the Basslink interconnector is forecast to become increasingly constrained at the limit in the northerly direction in all 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 early 2030s or earlier in all scenarios. This is because expected growth in wind generation in Tasmania exceeds the assumed growth in demand, and therefore net energy transfers to the mainland are forecast to increase over time, within the capacity limitations of Basslink. This foreshadows the potential for Marinus Link to generate market benefits.

In all cases, Marinus Link is forecast to have positive gross market benefits in all years from commissioning of the first stage, through to the last year of the modelling. In all scenarios, power flows in the NEM are generally from south to north to deliver low-cost energy from Tasmania to Victoria and other mainland regions. New South Wales, being the largest single region for energy

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[17] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook*, *v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.
[18] AEMO, August 2018, *2018 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 11 November 2019.
[19] Thermal coal retirement commences from 2025 and is accelerated by 3-5 GW from Status Quo scenario. Aurora Energy Research, May 2019, *Aurora Energy Research Analysis of AEMO's ISP Part 2: Economics of Coal Closures*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan. Accessed 18 October 2019.

and demand, is forecast to be increasingly reliant on imports from Victoria, Queensland and South Australia. Marinus Link is forecast to deliver capacity to Victoria and New South Wales by making use of the diversity in peak demand periods between the summer peaking demands in mainland regions and the winter peaking demands in Tasmania.

Marinus Link is forecast to have high utilisation. The benefits of Marinus Link flow from two modes of operation:

- Importing[20] variable renewable energy (solar PV and wind) from Victoria and other mainland regions to Tasmania at times of surplus generation and withholding Tasmanian hydro generation for use at times of higher value and/or pumping. Flow reverses daily to return that energy (plus hydro and wind) in the mornings, evenings and overnight. In this operating mode, Marinus Link is acting to firm mainland states' variable renewable energy sources.

- Exporting Tasmanian generation (wind and hydro) to support mainland regions (principally Victoria and New South Wales) during supply shortfalls. In this operating mode, Marinus Link is acting to provide a supply of low-cost energy to the mainland, displacing relatively high cost existing and new gas-fired generation capacity.

In model outcomes of all scenarios, Marinus Link seamlessly switches from one mode to the other depending on the variability of solar resources on the mainland and wind resources in Tasmania.

Marinus Link enables more efficient use of existing generation and investment in new capacity. The drivers of benefits are several:

- Marinus Link makes better use of existing highly reliable, firm dispatchable Tasmanian hydro generators that are not presently fully used primarily due to the limited capacity of Basslink and secondarily due to the need for reserve if Basslink fails.

- The annual capacity factor of Tasmanian hydro generation is about 45 % and much of this capacity is linked to long-term flexible storage, with a total of 1.4 years of storage at average inflows, and thus can accommodate a substantial increase in variable wind and solar energy without spilling and wasting water.

- Existing conventional Tasmanian hydro generation and new Tasmanian PSH generation (collectively the Battery of the Nation concept) is highly efficient in modulating and storing excess wind in Tasmania.

- The Battery of the Nation concept is also more efficient in modulating and storing energy from mainland solar PV and wind than storing in mainland batteries or PSH, since the transmission losses in shifting power across Bass Strait are small relative to PSH and battery losses.

- While the use of existing and new Tasmanian storages is the primary driver of benefits of Marinus Link, significant wind capacity in Tasmania unlocked by Marinus Link provides additional value to the NEM. Firstly, it increases the diversity of wind resource. Secondly, in assumed capacity factor terms, it is at least as good, or better than, the best mainland wind resources. Thirdly, locating the generators near the deeper storage sources (existing conventional hydro and new PSH) reduces losses and cost compared to importing surplus wind energy generated on the mainland, storing it in Tasmania and then exporting back to the mainland.

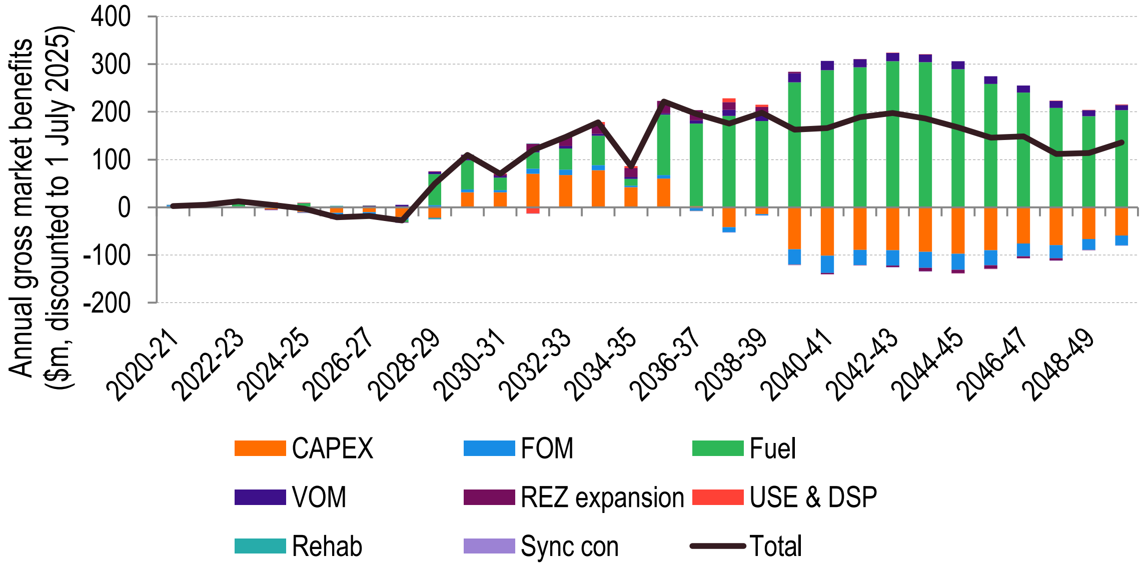
[20] This Report uses NEM sign conventions regarding the direction of flow on interconnectors. Export flows are northward and westward and are positive. For example, flows from Tasmania to Victoria and New South Wales to South Australia are export flows and are positive. Import flow are southward and eastward and are negative. For example, flow from Victoria to Tasmania is import flow and is negative.

The modelling uses measured weather patterns over the last eight-year period at hourly intervals to capture variability in wind and solar resources across the NEM. Such levels of variability are forecast to continue into the long-term future. The ability of the NEM to efficiently absorb such a high level of variability is governed by the scale of interconnections, including Marinus Link.

Avoided fuel costs are the main source of market benefits in all scenarios.

The dominant source of forecast market benefits associated with Marinus Link are fuel cost savings. This is illustrated in Figure 1 which shows forecast annual gross market benefits associated with Marinus Link, stage 1 2028 and stage 2 2032 in the Status Quo scenario. Significant fuel cost savings begin to accrue from 2028-29 when the first stage of Marinus Link enters. From 2028-29, annual benefits fluctuate with the changing supply-demand balance in Victoria, New South Wales and Queensland with forecast demand growth and progressive thermal retirements.

Figure 1: Forecast annual gross market benefit[21] of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario; millions real June 2019 dollars discounted to 1 July 2025



Other salient features of the forecast annual gross market benefits are:

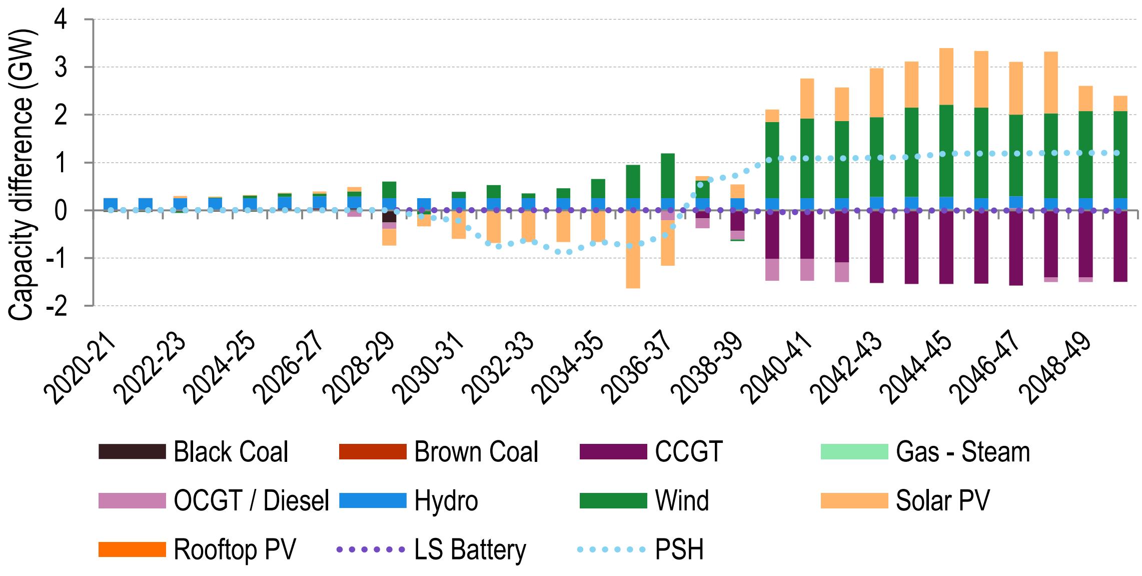
- There are small forecast costs and benefits prior to the entry of the first stage of Marinus Link due to differences in water usage in Tasmania in anticipation of the entry of Marinus Link.
- In the late 2020s to mid-2030s there are forecast capex benefits associated with reduced New South Wales solar PV and PSH build. This switches to anticipated capex costs from 2037-38 after growth in demand and several New South Wales and Queensland coal-fired generator retirements. After this time, the forecast fuel cost savings of avoiding running gas-fired generators, mainly in Victoria, outweighs the forecast higher capex costs of increased wind, solar PV and PSH capacity.
- Other categories of market benefits are comparatively small.

The forecast gross market benefits illustrated in Figure 1 flow from the changes in the NEM capacity mix outlook due to Marinus Link illustrated in Figure 2. In overall terms, Marinus Link accrues benefits through a reduced need to operate existing and develop new high fuel cost

[21] The sum of all annual benefits in present value terms is equal to the total gross benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032 in Table 15.

gas-fired generation on the mainland. This energy is forecast to be replaced by firm hydro capacity from existing conventional hydro and new PSH in Tasmania. This is the primary driver of benefits in the forecast.

Figure 2: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario (difference relative to Figure 10; positive values = higher capacity with Marinus Link)



Development of Marinus Link is also associated with a redistribution of the location and balance of new wind and solar PV capacity; overall more wind capacity is forecast to be built and operated in Tasmania, while solar PV capacity is deferred then ultimately increased on the mainland, mainly in New South Wales and Victoria. The development of wind capacity in Tasmania is favoured with Marinus Link because wind resource in Tasmania has higher forecast capacity factors and benefits from development closer to deeper storage sources (existing conventional hydro and new PSH).

Fuel cost savings associated with a reduced need to develop and operate high fuel cost gas-fired generators on the mainland are also the dominant source of market benefits in the other three scenarios.

- In the Global Slowdown scenario capex savings are forecast to persist for longer than they do in the Status Quo scenario. Assumed lower demand in the Global Slowdown scenario means the need for new capacity is delayed relative to the Status Quo scenario. The inflection point where additional capex is incurred to generate larger fuel cost savings doesn't occur until 2043-44 (delayed from 2037-38 in the Status Quo scenario).

- In the Sustained Renewables Uptake scenario, overall forecast gross market benefits are estimated to be higher than the Status Quo scenario, with the increases mostly contained to the period between commissioning the first stage of Marinus Link in 2028-29 and the late 2030s. The assumed maximum retirement of coal-fired generators, typically three to five years earlier than the timing in the Status Quo scenario, results in an increase to the forecast capex benefits in the late 2020s. The earlier coal retirements are also forecast to increase the potential fuel cost savings throughout the 2030s.

- In the Accelerated Transition to a Low Emissions Future scenario, the more stringent emissions reduction trajectory reduces the combined amount of generation forecast from coal- and gas-fired generators in this scenario compared to the Status Quo scenario. This results in lower forecast fuel cost savings despite a higher assumed gas fuel cost. Forecast capex benefits however are greater and more sustained than in the Status Quo scenario.

Gross market benefits of Marinus Link were forecast across thirteen sensitivities.

Table 2 summarises the sensitivities modelled, their gross market benefit, and the difference in gross market benefits compared to the Status Quo scenario. The sensitivities have been conducted for Marinus Link, stage 1 2028 and stage 2 2032.

Table 2: Forecast gross market benefits of Marinus Link for all sensitivities, real June 2019 dollars discounted to 1 July 2025

Sensitivity	Variation from Status Quo scenario	Gross market benefits ($m)	Difference in gross market benefits compared to Status Quo scenario ($m)
Battery Life Doubles	Large-scale battery storage options have storage increased from 2 hours to 4 hours. Capex, FOM and VOM are kept the same.	3,109	-122
Climate Change	For every 8-year cycle of reference years after the first from 2019-20 to 2026-27, Tasmanian and mainland hydro inflows reduce by 4 %.	3,131	-100
Tasmanian Hydrogen	Tasmanian demand increased by 100 MW from 2023-24 onward to represent a hydrogen load.	3,157	-74
Prudent Storage Level does not Change	For the case that Marinus Link is assumed to be commissioned, Tasmanian PSL profile does not reduce by 10 percentage points.	3,181	-50
Repurposing of Hydro Tasmanian Assets does not Proceed	For the case that Marinus Link is assumed to be commissioned, the 100 MW West Coast expansion and 150 MW Tarraleah upgrade are not included.	2,937	-295
Other Expected Projects do not Proceed	The following projects are not assumed to be commissioned during the study period: VNI Option 1, QNI Option 3A, Project EnergyConnect, KerangLink and Snowy 2.0.[22]	3,503	272
SA Gas Generators Retire with Project EnergyConnect	Pelican Point retires at the start of 2024-25, when Project EnergyConnect is assumed to be commissioned. Torrens Island A, Torrens Island B and Osborne are already assumed to retire by 2024-25 in the Status Quo scenario.	3,304	73
Deferred Coal Retirement	All coal-fired power station fixed maximum retirement dates are deferred three years later than the Status Quo scenario. Coal-fired power stations are still allowed to retire earlier if it is least-cost to do so.	2,861	-370
Rate of Reduction in Battery Costs Doubles	The learning rate for large-scale battery storage is doubled from 2020-21 onward, compared to the assumed Capex trajectory for the Feb AEMO Integrated System Plan (ISP).	3,155	-76
500 MW Additional On-Island Wind	500 MW of wind capacity is assumed to be commissioned in the Tasmanian midland REZ by 2020-21.	3,307	76

[22] This includes removal of any associated step increases in assumed REZ capacity limits before REZ transmission expansion costs are applied.

Sensitivity	Variation from Status Quo scenario	Gross market benefits ($m)	Difference in gross market benefits compared to Status Quo scenario ($m)
600 MW of PSH in Tasmania by 2027-28	The underlying assumptions for this sensitivity come from the Sustained Renewables Uptake scenario. However, for the case that Marinus Link it assumed to be commissioned, it is further assumed that 600 MW of Tasmanian PSH will be commissioned in 2027-28. As such, the capex and FOM cost of this 600 MW of PSH is excluded when calculating the gross market benefits of Marinus Link.	4,351	691[23]
Yallourn Retirement 2027-28	All four of Yallourn power stations units are assumed to have a fixed retirement date at the start of 2027-28. The units are still allowed to retire, or partially retire, sooner if it is least-cost.	3,352	121
Partial September ISP Update	Assumptions for the four scenarios were locked down in late July. Since that time, AEMO has published several updates to the ISP assumptions workbook. The intention of this sensitivity is to provide an indication of the potential changes that could occur when updating to the latest AEMO ISP draft assumptions as of September. This sensitivity varies from the Status Quo scenario by: ▶ using the AEMO 2019 ESOO Central scenario demand forecast ▶ doubling all REZ wind and solar PV build limits[24] ▶ regional PSH build limit increases: QLD limit of 4.9 GW NSW limit of 7 GW VIC limit of 3.6 GW SA limit of 2.034 GW	2,230	-1,002

Based on these sensitivities, some of the factors that may reduce the potential gross market benefits of Marinus Link are: lower mainland demand, increased wind, solar PV and PSH resources on the mainland, delayed coal retirements, lower Tasmanian capacity and reductions in Tasmanian hydro energy. The Partial September ISP Update sensitivity has the largest negative impact on gross market benefits of Marinus Link; we anticipate the impact of these assumptions will be assessed more thoroughly in future modelling work. Alternatively, additional Tasmanian capacity (either generation or storage), early thermal retirements and the delay or withdrawal of proposed transmission projects is expected to increase or bring forward the potential benefits of Marinus Link.

Gross market benefits of Marinus Link are forecast to be positive from the time Marinus Link is commissioned for all size and timing combinations investigated.

To assist in determining the optimal timing and sizing of Marinus Link, we performed simulations of different option-timing combinations and computed gross market benefits. Ultimately, the optimal

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[23] The underlying assumptions for the 600 MW of PSH in Tasmania by 2027-28 sensitivity are from the Sustained Renewables Uptake scenario. This difference in gross market benefits is relative to the aforementioned scenario, not the Status Quo scenario.

[24] The wind and solar PV build limits have not exactly doubled for all REZ in the Sept AEMO ISP compared to the Feb AEMO ISP; however, many have increased by a factor close to two.

timing and sizing were determined independently by TasNetworks after considering relevant costs; however, there are several observations concerning gross market benefits of note:

- Marinus Link is forecast to provide potential gross market benefits in every simulation from the time it is developed for all size options considered.
- Generally, gross market benefits increase in real terms over time in the forecast.
- The modelling shows that as the size of Marinus Link increases, the utilisation of further increments of Marinus Link capacity reduces. However, the modelling shows that in all cases with a second stage, forecast gross market benefits increase with the second stage relative to the first stage.
- For cases where the timing of Marinus Link is deferred, it is forecast to provide the same level of gross market benefits from the time of installation as for the case if it is not deferred. However, it foregoes the potential market benefits associated with the years of deferment, and hence the overall gross market benefits reduce in real terms[25] and present value terms if Marinus Link is delayed.

Market benefits of Marinus Link and KerangLink are largely independent.

Table 3 summarises the forecast total cumulative gross market benefits of Marinus Link 1,500 MW, with different commissioning dates for itself and KerangLink. The outcomes forecast that if KerangLink is commissioned in the 2020s or early 2030s, it has a minor negative impact on Marinus Link's NEM-wide gross market benefits. If KerangLink is commissioned in the mid-2030s, it is not forecast to materially impact the overall benefits of Marinus Link. However, without KerangLink it is forecast that Marinus Link's gross market benefits are almost entirely contained within Victoria. KerangLink enables Marinus Link's gross market benefits to be spread between both Victoria and New South Wales.

Table 3: Summary of forecast gross market benefits of Marinus Link 1,500 MW for different commissioning dates of Marinus Link and KerangLink, Status Quo scenario; millions real June 2019 dollars discounted to 1 July 2025

		Marinus Link timing		
		Stage 1 2026 & stage 2 2028	Stage 1 2028 & stage 2 2030	Stage 1 2030 & stage 2 2032
KerangLink timing	Not commissioned	3,506	3,402	3,239
	2026	3,346	3,296	3,144
	2030[26]	3,398	3,290	3,125
	2034	3,511	3,405	3,238

The gross market benefits of Marinus Link accrue to mainland regions.

The market benefits assessment stipulated in the RIT-T tests which (if any) credible options create the largest NEM-wide system cost savings and does not directly consider regional impacts.

[25] Using a real, pre-tax discount rate of 5.9 % sourced from the *RIT-T Economic Assessment Handbook* published by Energy Networks Australia (15 March 2019. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 24 September 2019) and consistent with the value to be applied by AEMO in most scenarios in the 2019-20 ISP (13 September 2019, *2019 Input and Assumptions Workbook*, v1.2. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 24 September 2019.

[26] KerangLink commissioned 2030-31 reflects the assumptions of the Status Quo scenario.

However, the regional division of impacts are of interest to energy consumers, the energy industry and governments.

As demand and generators are allocated to regions in the model, the model outcomes include the regional marginal cost of supply and gross market benefits can also be assessed regionally. Both these measures indicate that the benefits of Marinus Link accrue to mainland regions.

The marginal cost of supply is an output of the least-cost model in each hour for each region. These costs are generally indicative of wholesale market prices in a highly competitive market where bidding always reflects the cost of generation (which has not been true historically in the NEM), but can assume other values due to model constraints. The cost of supply is forecast to reduce in all mainland regions in all scenarios in most years. Generally, the largest reductions are forecast to occur in Victoria due to hydro and wind generation exported from Tasmania via Marinus Link (and Basslink) displacing dispatch of higher cost generation in Victoria and deferring or avoiding investment in capacity in Victoria.

Analysis of the regional allocation of gross market benefits tells a similar story about the regional impacts of Marinus Link. In all scenarios, an overall increase in estimated cost of supply (i.e. negative benefit) with Marinus Link is forecast in Tasmania. Meanwhile, a decrease in estimated regional cost of supply with Marinus Link is forecast all mainland regions.

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.[27] The RIT-T is a cost-benefit analysis used to assess the viability of investment options in electricity transmission assets. 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 PADR published by TasNetworks.[27] It describes the key assumptions, input data sources and methodologies that have been applied in the gross market benefits 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 PADR.[27] The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator.[28]

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of gross market benefits across scenarios and sensitivities. The categories of gross 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 REZ development,
- Retirement and rehabilitation costs,
- Synchronous condenser costs in Tasmania to meet inertia requirements,
- 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 across a 30-year study period from 2020-21 to 2049-50. Benefits are presented in real June 2019 dollars discounted to 1 July 2025[29]

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

[28] 14 December 2018, *RIT-T and RIT-D Application Guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 23 October 2019.

[29] Discounting benefits to 1 July 2025 continued 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. Given the costs and benefits would accrue from the commissioning year onwards, 2025 was considered an appropriate base year for discounting in the Initial Feasibility Report. At the time PADR modelling commenced, it was not clear which year would be the optimal commissioning year for Marinus Link, other than it could be no earlier than 2025. With no obvious alternative commissioning year, the practise of discounting to 2025 was continued. Given the results can be easily discounted to an alternative year by multiplying by an appropriate factor, the choice of base year for discounting purposes is somewhat arbitrary.

using a 5.9 % real, pre-tax discount rate as selected by TasNetworks based on the commercial discount rate computed in the *RIT-T Economic Assessment Handbook* published by Energy Networks Australia[30] and consistent with the discount rate to be applied by the AEMO in most scenarios in the 2019-20 ISP[31].

The forecast gross market benefits of Marinus Link forecast in each scenario need to be compared to the relevant Marinus Link costs to determine whether there is a forecast positive net benefit. If values of other RIT-T market benefits which are not captured by the least-cost planning model can be computed, such as ancillary services cost reduction, these should also be added. 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 added to the costs.

The computation of net market benefits and determination of the preferred option has been conducted by TasNetworks outside of this Report[32] as it is dependent on option costs which were developed independently by TasNetworks. All references to the preferred option in this Report 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." [33]

As requested by TasNetworks, we also provide additional commentary on other modelled outcomes not applicable in the RIT-T assessment, namely, the regional allocation of benefits of Marinus Link and changes in carbon emissions due to Marinus Link.

The Report is structured as follows:

- Section 3 provides an overview of the methodology applied in the modelling and computation of gross market benefits.
- Section 4 provides an overview of input assumptions for scenarios and sensitivities.
- Section 5 outlines model aspects and input data related to the representation of the transmission networks, transmission losses and demand.
- Section 6 provides an overview of model inputs and methodologies related to the supply of energy and capacity.
- Section 7 describes the forecast generation and capacity outlooks in each of the scenarios without Marinus Link.
- Section 8 provides an overview of gross market benefits forecast for each Marinus Link option across scenarios and sensitivities. It focusses on identifying and explaining the key sources of market benefits of a 1,500 MW Marinus Link, stage 1 operational from 2028 and stage 2 operational from 2032. This is the preferred option based on TasNetworks' analysis of net market benefits.
- Section 9 analyses and allocation of the benefits of Marinus Link to the regions of the NEM.
- Section 10 presents differences in carbon emissions due to Marinus Link.

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[30] 15 March 2019. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 23 October 2019.

[31] AEMO, 13 September 2019, *2019 Input and Assumptions Workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 23 October 2019.

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

[33] 14 December 2018, *RIT-T and RIT-D Application Guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

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 export flows and are positive.
- Import flows are southward and eastward and are negative. For example, flow from Victoria to Tasmania is import flow and is negative.

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 2026 means fully operational from 1 July 2026.

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

3. Methodology and input assumptions

Section 3.1 gives an overview of the model used to compute long term least-cost generation development plan while Section 3.2 which gives an overview of the method for computing gross market benefits. This approach is similar to that applied for the Project Marinus Initial Feasibility Report.[34] Section 3.3 gives an overview of marginal cost of supply outcomes from the least-cost planning model and their use in this Report. Section 3.4 provides an overview of the modelling improvements and data updates since the Initial Feasibility Report is provided.

3.1 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 30 years from 2020-21 to 2049-50. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator.[35]

Based on the full set of input assumptions outlined in sections 4, 5 and 6, 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 grid connected batteries,
- Demand-side participation (DSP) and USE,
- Capex of new generation and storage capacity installed,
- Transmission expansion costs associated with REZ development,
- Retirement and rehabilitation costs,
- Synchronous condenser costs in Tasmania 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[36] 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).

[34] TasNetworks, February 2019, *Initial Feasibility Report* and *Appendix 1: Economic Modelling Report*. Available at: https://www.marinuslink.com.au/initial-feasibility-report/. Accessed 11 November 2019.

[35] 14 December 2018, *RIT-T and RIT-D Application Guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

[36] 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.

- 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[37].

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[38],

- 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).[39]

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.

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[37] 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.

[38] Set to $33,460/MWh based on AEMO, September 2014, *Value of Customer Reliability Review: Final Report*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review. Accessed 24 September 2019.

[39] It does however include an additional cost for transmission upgrades to facilitate REZ development where this forms part of the input data set as outlined in Section 6.2.

- 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 generation development plan.

3.2 RIT-T cost-benefit analysis

For each case with Marinus Link and in a matched Basslink-only counterfactual[40] we computed the difference between the sum of the cost components listed in Section 3.1. The changes in costs are the forecast gross market benefits of Marinus Link (not accounting for Marinus Link costs), as defined in the RIT-T.

The forecast gross 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 Basslink-only counterfactual.

Each component of forecast gross market benefits is computed annually for each year of the 30-year study period. In this Report, we have summarised the benefit and cost streams using a single value computed as the present value of each stream, discounted to 1 July 2025 at a 5.9 % real pre-tax discount rate. This discount rate is sourced from the commercial discount rate calculated in the *RIT-T Economic Assessment Handbook* published by Energy Networks Australia[41] and is consistent with the value to be applied by AEMO in most scenarios in the 2019-20 ISP[42]. The gross market benefits of both additional interregional transmission and new generation are therefore estimated on the same basis under the cost-benefit analysis framework applied under the RIT-T.

The gross market benefits of Marinus Link forecast in each scenario need to be compared to the relevant Marinus Link costs to determine whether there is a forecast positive net benefit. If values of other benefits which are not captured by the least-cost planning model can be computed, such as ancillary services cost reduction, these should also be added. 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 added to the costs.

The computation of net market benefits and determination of the preferred option has been conducted by TasNetworks outside of this Report[43] as it is dependent on option costs which were

[40] The without augmentation counterfactual is typically referred to as the Base case in a RIT-T. In this Report we use the term 'Basslink-only 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.

[41] 15 March 2019. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 24 September 2019.

[42] AEMO, 13 September 2019, *2019 Input and Assumptions Workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 24 September 2019.

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

developed independently by TasNetworks. All references to the preferred option in this Report 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." [44]

3.3 Marginal cost of supply outcomes

The TSIRP model produces hourly marginal cost of supply outcomes in each hourly trading interval. Mathematically, the TSIRP model finds the minimum of a cost function. The marginal cost of supply output by the model is the partial derivative of this objective function with respect to demand in each region. That is, it represents that change in the cost function if the constant right-hand-side of the demand constraint in each hour in each region is altered marginally.[45]

In practice, this marginal cost of supply at different times reflects:

- The SRMC (fuel cost + VOM) of the marginal generator,
- The shadow cost of operating generators (and pumps where applicable) with energy-limited storages (see Section 6.7.4),
- Capex and FOM cost components.

There are several features of the hourly marginal cost of supply outcomes which are worth elaborating on to aid in interpreting outcomes:

- Hourly costs can go up to the VCR as USE is valued at the VCR.
- Hourly cost will often be high if a new OCGT is the marginal generator. These are low-utilisation plant and so the fixed costs are spread over only a few hours. They are also high-cost plant towards the top of the cost stack. Overall, this means that the marginal cost of supply in intervals where an OCGT is the marginal generator often incorporate a component of long run costs.
- When the marginal generator is frequently low-SRMC wind and solar PV, some of the long-run costs of these technologies may be incorporated into the marginal cost of supply.
- Cost can be negative in intervals when renewable energy target constraints are binding. These constraints are implemented as

  $$\text{annual regional renewable energy} \geq \text{constant.}$$

  In some intervals, renewable generation is high relative to demand, there is undispatched renewable energy, and more renewables are being built to meet the renewable energy constraint. In these intervals, *increasing* demand means less capacity needs to be built to meet the constraint and hence the marginal cost of supply is negative.

The prices output generally provide sufficient revenue within the model for new generators within the model to recover their long-run costs. This does not necessarily hold when the renewable energy target constraints are binding as described above. In these cases, marginal costs of supply output by the model may not provide sufficient revenue for plant to recover long-run costs. This corresponds to the situation when a subsidy would be required to build this capacity.

Binding constraints can affect the hourly marginal costs of supply through their penalty cost, or by influencing the generation development plan. Synchronous condensers to meet minimum inertia

[44] 14 December 2018, *RIT-T and RIT-D Application Guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.

[45] Lenzen V, Lienert M, Müsgens F, 2012, 'Political Shocks and Efficient Investment in Electricity Markets', *2012 9th International Conference on the European Energy Market* [IEEE conference proceedings].

requirements in Tasmania are costed through a penalty (see Section 6.3 for more detail). On the other hand, there is no penalty cost associated with the emissions reduction constraint. Instead it is an enforced constraint which limits the amount of thermal generation dispatched and built and increases the amount of wind, solar PV, PSH and large-scale battery storage installed. This means the marginal generator is more frequently low-SRMC wind and solar PV, and the marginal cost of meeting additional demand is more frequently influenced by the long-run costs of building new renewable and storage capacity.

The hourly regional costs of supply are generally indicative of wholesale market prices in a perfectly competitive market where bidding always reflects the costs of generation, but can assume other values due to model constraints. This has not been true historically in the NEM.

3.4 Model improvements and data updates since the Initial Feasibility Report

Several changes to the TSIRP model and input data have been made since publication of the Initial Feasibility Report published in February 2019.[46] Model enhancements were made to increase realism by inclusion of additional detail and input data changes were to apply more recent assumptions where they were available. Except where noted below, the market modelling methodology is consistent with that applied in modelling for the Initial Feasibility Report. All inputs were selected by TasNetworks. The model and data changes are summarised in Table 4.

Table 4: Model and data changes compared to Initial Feasibility Report

Assumption	Initial Feasibility Report[46]	This Report
Hydro Tasmania hydro scheme representation	▶ 6 pond scheme ▶ 7 reference years ▶ Spill benefits estimated outside of market modelling ▶ Two season minimums imposed on large storages only ▶ Small non-scheduled generators assumed to match historical operation. ▶ No change in modelling in Basslink-only counterfactual and with Marinus Link	▶ 10 pond scheme ▶ 8 reference years ▶ Spill benefits estimated within market model ▶ Monthly minimums imposed on whole system ▶ Small non-scheduled generators modelled explicitly. ▶ Capacity changes with Marinus Link See Section 6.1 (especially Table 10) and Section 4.2 for detail.
Operational reserve constraint	Not applied	Applied (see Section 5.3 for detail)
Inertia constraint	Not applied	Applied (see Section 6.3 for detail)
Demand outlook	AEMO ISP 2018[47]	AEMO *2018 Electricity Statement of Opportunities*[48]
Number of historical reference years	7 years	8 years

[46] TasNetworks, February 2019, *Initial Feasibility Report* and *Appendix 1: Economic Modelling Report*. Available at: https://www.marinuslink.com.au/initial-feasibility-report/. Accessed 11 November 2019.
[47] 21 August 2018. *2018 Integrated System Plan Modelling Assumptions, v2.4*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan/ISP-database. Accessed 2 October 2019.
[48] Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 11 September 2019.

Assumption	Initial Feasibility Report[46]	This Report
REZ representation	No representation	Representation aligned with AEMO's February 2019 planning and forecasting assumptions workbook.[49] This includes associated transmission expansion costs for mainland REZs. Tasmanian transmission expansion costs advised by TasNetworks: ▶ North West Tasmania transmission expansion cost of $0.15m/MW ▶ Tasmania Midlands transmission expansion cost of $0.225m/MW ▶ North East Tasmania transmission expansion cost of $0.23m/MW See Section 6.2 for detail.
Wind and solar PV build limits	No limit	Mainland REZ build limits as per AEMO's February 2019 planning and forecasting assumptions workbook.[50] Tasmanian REZ build limits advised by TasNetworks: ▶ North West Tasmania high quality wind limit of 388.4 MW ▶ Tasmania Midlands high quality wind limit of 286 MW ▶ North East Tasmania high quality wind limit of 300 MW ▶ North West Tasmania medium quality wind limit of 1,500 MW ▶ Tasmania Midlands medium quality wind limit of 1,300 MW ▶ North East Tasmania medium quality wind limit of 900 MW ▶ North West Tasmania solar PV limit of 150 MW ▶ Tasmania Midlands solar PV limit of 150 MW ▶ North East Tasmania solar PV limit of 50 MW ▶ North West Tasmania transmission expansion limit of 200 MW ▶ Tasmania Midlands transmission expansion limit of 220 MW ▶ North East Tasmania transmission expansion limit of 1,250 MW
DSP	Not modelled	Aligned with AEMO's February 2019 planning and forecasting assumptions workbook[50]

[49] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook*, *v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.
[50] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook*, *v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

Assumption	Initial Feasibility Report[46]	This Report
PSH regional capacity limit	1 GW per region	**Mainland** Based on December 2018 Entura report[51] to AEMO for 6 hours of storage. ▶ QLD limit of 1.8 GW ▶ NSW limit of 3.4 GW ▶ VIC limit of 1.2 GW ▶ SA limit of 0.5 GW See Section 6.3 for more detail.
		Tasmania Limit of 1.6 GW based on December 2018 Entura report to AEMO[51] for 24 hours of storage. See Section 6.3 for detail.
Committed projects (included in all scenarios, Basslink-only counterfactual and with Marinus Link)	**Mainland regions** AEMO ISP 2018 committed and advanced projects[52]	**Mainland regions** Based on AEMO's February 2019 planning and forecasting assumptions workbook Committed Projects and Advanced VRET Projects.[53] Updated to include Committed and Com* status projects from AEMO Generation Information May 2019.[54]
	Tasmania Musselroe, Woolnorth, Granville Harbour, Wild Cattle Hill Wind Farms + 500 MW additional based on connection applications to TasNetworks	**Tasmania** Based on same data source as mainland regions: Musselroe, Woolnorth, Granville Harbour, Wild Cattle Hill Wind Farms
Tamar Valley CCGT	In standby state (only operates in event of Basslink failure), then forced to retire 2025-26.	No special conditional on operation. Not allowed to retire.
Tamar Valley OCGT	In standby state (only operates in event of Basslink failure). Not forced to retire.	No special conditional on operation. Not forced to retire, but allowed to retire if economic
Thermal retirements	AEMO ISP 2018[52]	Based on end of technical life as per AEMO's February 2019 planning and forecasting assumptions workbook.[53] Where station specific information was available, retirement dates were updated as per the AEMO Project Expected Retirement Date workbook published 25 June 2019.[55]

[51] Entura, 7 December 2018, *Pumped Hydro Cost Modelling*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 2 October 2019.
[52] 21 August 2018. *2018 Integrated System Plan Modelling Assumptions, v2.4*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan/ISP-database. Accessed 2 October 2019.
[53] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.
[54] AEMO, *Generation Information Page*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Accessed 24 September 2019
[55] AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.

Assumption	Initial Feasibility Report[46]	This Report
Non-thermal retirements	Not applied	End of technical life as per AEMO Project Expected Retirement Date workbook published 25 June 2019.[56]
South Australian gas-fired generators	▶ Torrens Island A is assumed to retire 2019-20. ▶ Torrens Island B is not assumed to retire, but can economically retire from 2024-25 onward. ▶ Osborne and Pelican Point not allowed to retire.	▶ Torrens Island A and Torrens Island B are assumed to retire in the year that Project EnergyConnect is commissioned, as per the ElectraNet Project Assessment Conclusions Report (PACR).[57] ▶ Osborne and Pelican Point are assumed to retire in 2023-24 and 2037-38, respectively, as per the AEMO Project Expected Retirement Dates from 25 June 2019.[56] ▶ Pelican Point is not allowed to retire economically prior to Project EnergyConnect to maintain system strength in South Australia.[58]
Coal energy limits	Limit equal to maximum of annual energy from five years 2013-14 to 2017-18 to reflect limitations on annual coal deliveries.	Limit equal to the average of annual energy from five years 2013-14 to 2017-18 to reflect limitations on annual coal deliveries. 50 % capacity factor limit on Liddell as listed in the AEMO February 2019 planning and forecasting assumptions workbook.[59] See Section 6.7.1 for detail.
Forced outage rates	AEMO ISP 2018[60]	AEMO's February 2019 planning and forecasting assumptions workbook.[59] These are higher values based on survey data.[61]
Discount rate	AEMO ISP 2018[60] pre-tax, real rate of 6 %	AEMO Sept 2019 planning and forecasting assumptions workbook[62] pre-tax, real rate of 5.9 %

56 AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.
57 ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report*. Available at: https://www.electranet.com.au/projects/south-australian-energy-transformation/. Accessed 24 September 2019.
58 AEMO, October 2019, *Transfer Limit Advice -System Strength*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Limits-advice. Accessed 12 November 2019.
59 AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.
60 21 August 2018. *2018 Integrated System Plan Modelling Assumptions, v2.4*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan/ISP-database. Accessed 2 October 2019.
61 AEMO, August 2018, *2018 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 11 November 2019.
62 AEMO, 13 September 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

Assumption	Initial Feasibility Report[46]	This Report
Capex for technologies other than PSH	AEMO ISP 2018[63]	AEMO's February 2019 planning and forecasting assumptions workbook[64] uplifted for interest during construction using the construction times in the same data set
Capex for PSH	Mainland PSH values aligned with AEMO ISP 2018[63] Tasmanian PSH reflect Battery of the Nation project data[65]	AEMO's February 2019 planning and forecasting assumptions workbook[64] uplifted for interest during construction using the construction times in the same data set
VOM, FOM, lifetime for technologies other than wind, PSH and large-scale batteries	AEMO ISP 2018[63]	AEMO's February 2019 planning and forecasting assumptions workbook[64]
VOM, FOM, lifetime for wind	▶ VOM = $6/MWh ▶ FOM = $25/kW/year ▶ Lifetime = 25 years Reflecting recent data sets and industry consensus for existing wind farms.	▶ VOM = $2.69/MWh to $3.52/MWh depending on REZ ▶ FOM = $36.38/kW/year to $47.55 depending on REZ. ▶ Lifetime = 30 years AEMO's February 2019 planning and forecasting assumptions workbook[64]
Operational parameters for large-scale batteries	▶ VOM = $0/MWh (AEMO ISP 2018[63]) ▶ FOM = $10/kW/year ▶ Lifetime = 15 years[63] ▶ Cyclic efficiency = 80 %[63]	▶ VOM = $0/MWh ▶ FOM = 8/kW/year to $9.04/kW/year depending on location ▶ Lifetime = 15 years ▶ Cyclic efficiency = 81 % AEMO's February 2019 planning and forecasting assumptions workbook[64]
Operational parameters for PSH	▶ VOM = $0.15/MWh (Battery of the Nation project data[65]) ▶ FOM = $28/kW/year[65] ▶ Lifetime = 50 years[65] ▶ Cyclic efficiency = 80 % (AEMO ISP 2018[65])	▶ VOM = $0/MWh ▶ FOM = 16/kW/year to $18.24/kW/year depending on location. ▶ Lifetime = 50 years ▶ Cyclic efficiency = 77.5 % AEMO's February 2019 planning and forecasting assumptions workbook[64]
Gas fuel costs	AEMO ISP 2018[63]	Aligned with AEMO's February 2019 planning and forecasting assumptions workbook for 2020-21 to 2040-41.[64] Gas fuel costs were assumed to be unchanged post 2040-41, since the AEMO forecast did not cover this period.

[63] 21 August 2018. *2018 Integrated System Plan Modelling Assumptions, v2.4*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan/ISP-database. Accessed 2 October 2019.

[64] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

[65] Hydro Tasmania, April 2018, Battery of the Nation: Analysis of the future National Electricity Market. Available at: https://www.hydro.com.au/docs/default-source/clean-energy/battery-of-the-nation/future-state-nem-analysis-fullreport.pdf. Accessed 18 November 2019.

Assumption	Initial Feasibility Report[46]	This Report
Coal fuel costs	AEMO ISP 2018[66]	Aligned with AEMO's February 2019 planning and forecasting assumptions workbook for 2020-21 to 2040-41.[67] Coal fuel costs were assumed to be unchanged post 2040-41, since the AEMO forecast did not cover this period.
Basslink and Marinus Link losses	Dynamic losses proportioned equally between Tasmania and Victoria for Basslink and Marinus Link aligned with AEMO ISP 2018.[66]	Dynamic losses allocated to sending end. See Section 5.2 for more detail
Other input data	Aligned with AEMO ISP 2018[66]	Aligned with AEMO's February 2019 planning and forecasting assumptions workbook which formed the initial consultation for the ISP 2019-20.[67]

[66] 21 August 2018. *2018 Integrated System Plan Modelling Assumptions, v2.4*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan/ISP-database. Accessed 2 October 2019.

[67] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook*, *v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

4. Scenarios and sensitivity assumptions

4.1 Scenarios

The credible Marinus Link options have been assessed in four scenarios selected by TasNetworks. The scenarios cover a broad range of reasonable possible futures for the NEM:

- The Status Quo scenario was selected by TasNetworks to represent a central view of the market. It used a national emission reduction target of 28 % below 2005 levels by 2030[68] and a combination of input data mostly sourced from the Australian Energy Market Operator (AEMO) including 'Neutral' demand forecasts from the *2018 Electricity Statement of Opportunities*[69], coal retirements as per AEMO's February 2019 planning and forecasting assumptions workbook[70] with updates from AEMO published 25 June 2019[71]and generator/storage capital and fuel costs from the AEMO February 2019 planning and forecasting assumptions workbook.[70]

- The Global Slowdown scenario applies a set of assumptions reflecting a future world of lower demand forecasts[69], no emissions reduction target, 'Slow Change' gas fuel cost projections[70], a delay in KerangLink and Snowy 2.0, and a coal capacity constraint that results in earlier coal plant retirements relative to the Status Quo scenario[72].

- The Sustained Renewables Uptake scenario applies all the same assumptions as the Status Quo scenario, except it is intended that renewable capacity build rates are maintained at current levels, reflecting current developer interest. To achieve this outcome, the planned retirement date of coal-fired generators to typically three to five years earlier than the dates modelled in the Status Quo scenario. KerangLink is also commissioned earlier.

- Accelerated Transition to a Low Emissions Future scenario applies a set of assumptions reflecting a future world of higher electricity demand forecasts[69], a more stringent national emission reduction target of around 52 % below 2005 levels by 2030, 'Fast Change' gas fuel cost projections[70], AEMO's '2 degree' capex scenario[70] and earlier commissioning of KerangLink.

The key underlying assumptions for these scenarios are summarised in Table 5. As noted in Table 5, most input data were sourced from AEMO's February 2019 planning and forecasting assumptions workbook which formed the initial consultation for the ISP 2019-20.[70] This was the most up-to-date data source available at the time of modelling for this assessment.

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[68] Trajectory from 17 July 2018. *2018 Integrated System Plan Modelling Assumptions, v2.3*. No longer available online. Available on request from TasNetworks.

[69] AEMO, August 2018, *2018 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 11 November 2019.

[70] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

[71] AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.

[72]Thermal coal retirement commences from 2025 and is accelerated by 3-5 GW from Status Quo scenario. Aurora Energy Research, May 2019, *Aurora Energy Research Analysis of AEMO's ISP Part 2: Economics of Coal Closures*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan. Accessed 18 October 2019.

Table 5: Overview of key input parameters that vary across scenarios

Key drivers input parameter	Scenario			
	Global Slowdown	Status Quo	Sustained Renewables Uptake	Accelerated Transition
Underlying consumption	AEMO 2018 ESOO Weak[73], with Tasmanian load reduced by 240 MW in 2025-26, rather than 78 MW.	AEMO 2018 ESOO Neutral		AEMO 2018 ESOO Strong
Rooftop PV	AEMO 2018 ESOO Weak	AEMO 2018 ESOO Neutral		AEMO 2018 ESOO Strong
Small non-scheduled PV (100 kW - 30 MW)	AEMO 2018 ESOO Weak	AEMO 2018 ESOO Neutral		AEMO 2018 ESOO Strong
Domestic storage MW and MWh	AEMO 2018 ESOO Weak	AEMO 2018 ESOO Neutral		AEMO 2018 ESOO Strong
DSP	AEMO 2018 ESOO Weak	AEMO 2018 ESOO Neutral		AEMO 2018 ESOO Strong
VCR	Aggregate NEM wide value of $33,460/MWh[74]			
Emission reduction policy	Not explicitly modelled.	The electricity sector has been modelled to achieve at least a 28 % reduction in emissions compared to 2005 levels by 2030. Post 2030, a linear reduction of emissions to 70 % reduction compared to 2016 levels by 2050.[75]		The electricity sector has been modelled to achieve at least a 52 % reduction in emissions compared to 2005 levels by 2030. Post 2030, a linear reduction of emissions to 90 % reduction compared to 2016 levels by 2050.[75]
Victorian Renewable Energy Target (VRET) 2020	Target of 25 % of Victorian demand from renewables by calendar year 2020.[76]			
VRET 2025	Not explicitly modelled	Target of 40 % of Victorian demand from renewables by calendar year 2025.[77]		

[73] AEMO, August 2018, *2018 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 11 November 2019.
[74] AEMO, September 2014, *Value of Customer Reliability Review: Final Report*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review. Accessed 24 September 2019.
[75] Trajectory from 17 July 2018. *2018 Integrated System Plan Modelling Assumptions, v2.3*. No longer available online. Available on request from TasNetworks.
[76] Victoria State Government Department of Environment, Land, Water and Planning, 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.
[77] 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.

Key drivers input parameter	Scenario			
	Global Slowdown	Status Quo	Sustained Renewables Uptake	Accelerated Transition
VRET 2030	Not explicitly modelled	Target of 50 % of Victorian demand from renewables by calendar year 2030.[78]		
Queensland Renewable Energy Target (QRET) 2030	Not explicitly modelled	Target of 50 % of Queensland demand from renewables by calendar year 2030.[79]		
Economic retirement	Allowed for thermal generators if it is least-cost to do so.			
Fixed date thermal retirements (excluding South Australian gas-fired generators - listed separately)	Based on end of technical life as per AEMO's February 2019 planning and forecasting assumptions workbook[80]. Where station specific information was available, retirement dates were updated as per the AEMO Project Expected Retirement Date workbook published 25 June 2019[81]. See Section 6.8		Based on end of technical life as per AEMO's February 2019 planning and forecasting assumptions workbook. Where station specific information was available, retirement dates were updated as per the AEMO Project Expected Retirement Date workbook published 25 June 2019 *except coal-fired units are generally assumed to retire three to five years earlier.*[82] See Section 6.8	Based on end of technical life as per AEMO's February 2019 planning and forecasting assumptions workbook. Where station specific information was available, retirement dates were updated as per the AEMO Project Expected Retirement Date workbook published 25 June 2019. See Section 6.8

[78] 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.

[79] 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.

[80] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

[81] AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.

[82] As requested by TasNetworks, coal-fired generating units with an Expected Retirement Date from 2029-30 to 2034-35 are assumed to retire three years earlier. Coal-fired units with an Expected Retirement Date from 2035-36 onward are assumed to retire five years earlier. Exceptions include Yallourn Unit 4, which is assumed to retire 2028-29 (four years earlier than its Expected Retirement Date) and Stanwell Units 2-4, which are assumed to retire with Stanwell Unit 1 at the start of 2038-39 (rather than staggered one year apart).

Key drivers input parameter	Scenario			
	Global Slowdown	Status Quo	Sustained Renewables Uptake	Accelerated Transition
NEM-wide coal capacity restriction	In line with the lower NEM-wide demand scenario from Aurora Energy Research's revenue adequacy report to AEMO[83], thermal coal retirement commences from 2025 and is accelerated by 3-5 GW from Status Quo scenario.	Not explicitly modelled.		
South Australian gas retirements	Torrens Island A and Torrens Island B are assumed to retire in the year that Project EnergyConnect is commissioned, as per the ElectraNet PACR[84]. Osborne power station and Pelican Point power station are assumed to retire in 2023-24 and 2037-38, respectively, as per the AEMO Project Expected Retirement Dates from 25 June 2019. Pelican Point power station is not allowed to retire economically prior to Project EnergyConnect to maintain system strength in South Australia.[85]			
Fixed date non-thermal retirements	End of technical life as per the AEMO Project Expected Retirement Date workbook published 25 June 2019.			
Coal fuel cost	AEMO Feb 2019 Neutral forecast[86]			
Gas fuel cost	AEMO Feb 2019 Slow Change forecast[86]	AEMO Feb 2019 Neutral forecast		AEMO Feb 2019 Fast Change forecast
New entrant generation technology cost projections for wind, solar PV SAT, OCGT, CCGT, PSH and large-scale battery storage	AEMO Feb 2019 '4 degree' scenario[86]			AEMO Feb 2019 '2 degree' scenario. '4 degree' scenario for PSH[87].
Snowy 2.0	Commissioned 2029-30	Commissioned 2026-27		
VNI Option 1 (Dederang-Lower Tumut path)	Commissioned 2029-30	Commissioned 2022-23[86] See Section 5.1		
Western Victoria RIT-T augmentation	The ISP 2018 preferred option is assumed commissioned by 2023-24			

[83] Aurora Energy Research, May 2019, *Aurora Energy Research Analysis of AEMO's ISP Part 2: Economics of Coal Closures*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan. Accessed 18 October 2019.
[84] ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report*. Available at: https://www.electranet.com.au/projects/south-australian-energy-transformation/. Accessed 24 September 2019.
[85] AEMO, October 2019, *Transfer Limit Advice -System Strength*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Limits-advice. Accessed 12 November 2019.
[86] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.
[87] No '2 degree' scenario was provided for PSH in the AEMO *2019 Input and Assumptions Workbook, v1.0* (5 February 2019).

Key drivers input parameter	Scenario			
	Global Slowdown	Status Quo	Sustained Renewables Uptake	Accelerated Transition
QNI-Option 3A	Commissioned 2023-24[88] See Section 5.1			
Project EnergyConnect	Commissioned 2024-25[89] See Section 5.1			
KerangLink (see Section 5.1.1 for detail on how timing was chosen)	The preferred KerangLink ISP 2018 option is assumed to be commissioned in 2032-33, aligning with the assumed end of technical life for the fourth unit of Yallourn.	The preferred KerangLink ISP 2018 option is assumed to be commissioned in 2030-31 aligning with the assumed end of technical life for the second unit of Yallourn.	The preferred KerangLink ISP 2018 option is assumed to be commissioned in 2027-28 aligning with the assumed end of technical life for the second unit of Yallourn	The preferred KerangLink ISP 2018 option is assumed to be commissioned in 2029-30, aligning with the assumed end of technical life for the first unit of Yallourn.

4.2 Differences in assumptions with and without Marinus Link

Across all scenarios and sensitivities, development of Marinus Link is associated with the following five factors selected by TasNetworks:

- A 10 percentage point decrease in monthly minimum whole of system reservoir volumes in Tasmania (Prudent Storage Levels, PSLs),[90]
- A 100 MW expansion of West Coast power scheme's capacities,[91]
- A 150 MW upgrade of Tarraleah,
- An increase in capacity limits before REZ transmission expansion costs are applied, after Marinus Link stage 1 is commissioned. The capacity limit for North West Tasmania REZ is increased from 200 MW to 1,000 MW. The capacity limit before the REZ transmission expansion cost is applied for Tasmania Midlands REZ is increased from 220 MW to 760 MW.[92]
- An increase in capacity limits before REZ transmission expansion costs are applied for North West Tasmania REZ, after Marinus Link stage 2 is commissioned. The capacity limit is increased from 1,000 MW to 1,888 MW.[93]

[88] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

[89] ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report*. Available at: https://www.electranet.com.au/projects/south-australian-energy-transformation/. Accessed 24 September 2019. There are options for commissioning between 2022 and 2024.

[90] 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 6.1. The decrease in PSL profile with Marinus Link is a modelling assumption selected by TasNetworks and, we understand, does not represent Tasmanian Government policy.

[91] 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.

[92] It is assumed that transmission augmentations associated with Marinus Link stage 1 will pass through these REZs.

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

The cost differential between the with and without Marinus Link simulations are factored in externally by TasNetworks in the main PADR. Any cost differential associated with these five factors are also dealt with by TasNetworks.

4.3 Sensitivities

Several sensitivities to the market modelling were selected by TasNetworks to test the robustness of the magnitude and timing of gross market benefits. An overview of the sensitivities is given in Table 6. All sensitivity simulations were performed for the 1,500 MW Marinus Link, Stage 1 2028, Stage 2 2030, and in most cases were variants to the Status Quo scenario (exceptions noted below).

Table 6: Overview of sensitivities

Sensitivity	Variation from Status Quo scenario
Battery Life Doubles	Large-scale battery storage options have storage increased from 2 hours to 4 hours. Capex, FOM and VOM are kept the same.
Climate Change	For every 8-year cycle of reference years after the first from 2019-20 to 2026-27, Tasmanian and mainland hydro inflows reduce by 4 %.
Tasmanian Hydrogen	Tasmanian demand increased by 100 MW from 2023-24 onward to represent a hydrogen load.
Prudent Storage Level does not Change	For the case that Marinus Link is assumed to be commissioned, Tasmanian PSL profile does not reduce by 10 percentage points.
Repurposing of Hydro Tasmanian Assets does not Proceed	For the case that Marinus Link is assumed to be commissioned, the 100 MW West Coast expansion and 150 MW Tarraleah upgrade are not included.
Other Expected Projects do not Proceed	The following projects are not assumed to be commissioned during the study period: VNI Option 1, QNI Option 3A, Project EnergyConnect, KerangLink and Snowy 2.0.[94]
SA Gas Generators Retire with Project EnergyConnect	Pelican Point retires at the start of 2024-25, when Project EnergyConnect is assumed to be commissioned. Torrens Island A, Torrens Island B and Osborne are already assumed to retire by 2024-25 in the Status Quo scenario.
Deferred Coal Retirement	All coal-fired power station fixed maximum retirement dates are deferred three years later than the Status Quo scenario. Coal-fired power stations are still allowed to retire earlier if it is least-cost to do so.
Rate of Reduction in Battery Costs Doubles	The learning rate for large-scale battery storage is doubled from 2020-21 onward, compared to the assumed Capex trajectory for the Feb AEMO ISP.
500 MW Additional On-Island Wind	500 MW of wind capacity is assumed to be commissioned in the Tasmanian midland REZ by 2020-21.
600 MW of PSH in Tasmania by 2027-28	The underlying assumptions for this sensitivity come from the Sustained Renewables Uptake scenario. However, for the case that Marinus Link it assumed to be commissioned, it is further assumed that 600 MW of Tasmanian PSH will be commissioned in 2027-28. As such, the capex and FOM cost of this 600 MW of PSH is excluded when calculating the gross market benefits of Marinus Link.
Yallourn Retirement 2027-28	All four of Yallourn power stations units are assumed to have a fixed retirement date at the start of 2027-28. The units are still allowed to retire, or partially retire, sooner if it is least-cost.
Partial September ISP Update	Assumptions for the four scenarios were locked down in late July. Since that time, AEMO has published several updates to the ISP assumptions workbook. The intention of this sensitivity is to provide an indication of the potential changes that

[94] This includes removal of any associated step increases in assumed REZ capacity limits before REZ transmission expansion costs are applied.

Sensitivity	Variation from Status Quo scenario
	could occur when updating to the latest AEMO ISP draft assumptions as of September. This sensitivity varies from the Status Quo scenario by: ▶ using the AEMO 2019 ESOO Central scenario demand forecast ▶ doubling all REZ wind and solar PV build limits[95] ▶ regional PSH build limit increases: QLD limit of 4.9 GW NSW limit of 7 GW VIC limit of 3.6 GW SA limit of 2.034 GW
Low Discount Rate	Discount rate is reduced to 3.54 % (real, pre-tax) This is the regulated WACC determined by the AER in the most recent Final Decision for a TNSP as recommended in ENA's RIT-T Handbook.[96] The most recent AER decision is for TasNetworks on 30 April 2019.[97]
High Discount Rate	Discount rate is increased to 8.26 % (real, pre-tax) This is equal to the central rate plus the difference between the central and lower rates as recommended in ENA's RIT-T Handbook.[96]

4.4 Unplanned Basslink Outage

In addition to the sensitivities, the impact on system cost of an unplanned Basslink outage with and without Marinus Link was also assessed.

4.4.1 Methodology

The TSIRP model uses linear programming techniques to compute a least-cost, whole-of-NEM, hourly time-sequential dispatch and development plan spanning 30 years from 2020-21 to 2049-50. That is, the least-cost solution over the full 30 years is found in a single pass of the model with perfect foresight. As such, the model is able to plan for outages in advance, since these are allocated to a pre-defined time-period (regardless of whether the outage is explicitly or randomly allocated). To account for this, a two-step approach was modelled to better assess the cost of an unplanned Basslink outage. The first step is identical to the typical modelling approach described in Section 3, without any Basslink outage.

The second step involves re-running the model from 2027-28 to 2049-50 using the output from the first iteration to define:

- The amount of new entrant capacity that is built by 2027-28,
- The reservoir levels for all conventional and pump hydro units as of 12.00am 1 July 2027,
- The amount of retired capacity from all existing thermal units by 2027-28.

In addition, it is assumed that:

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[95] The wind and solar PV build limits have not exactly doubled for all REZ in the Sept AEMO ISP compared to the Feb AEMO ISP; however, many have increased by a factor close to two.

[96] Energy Networks Australia, 15 March 2019, *RIT-T Economic Assessment Handbook*. Available at: https://www.energynetworks.com.au/rit-t-economic-assessment-handbook. Accessed 8 October 2019.

[97] Australian energy Regulator, 30 April 2019, *TasNetworks Transmission and Distribution Determination 2019 to 2024: Final decision*. Available at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24. Accessed 8 October 2019.

- No new entrant capacity, other than that which is forecast to be installed in the first iteration, can be installed prior to 2028-29,
- No existing capacity, other than that which is forecast to be retired in the first iteration, can be retired prior to 2028-29,
- The Basslink outage occurs from 1 July 2027 to 1 January 2028,
- The monthly minimum PSL requirements must still be met throughout the six-month outage, as it is for all other months in the study period.

The least-cost solution for a case with an unplanned Basslink outage is therefore computed by summating the cost components (listed in Section 3.1) of the first iteration from the start of the study to 30 June 027 and the costs of the second iteration from 1 July 2027 to the end of the study.

For each case with the Basslink outage and in the corresponding no-outage counterfactual we compute the difference between the sum of the cost components to determine the forecast gross market cost of the Basslink outage.

4.4.2 Input assumptions

The cost assessment of a six-month unplanned outage was completed in June 2019, prior to finalising assumptions for the Status Quo scenario. Due to time constraints, this assessment was not repeated using the final assumptions described in Section 4. Table 7 presents the differences in assumptions compared to the Status Quo scenario. Furthermore, this sensitivity was conducted for Marinus Link 1,200 MW, with stage 1 2026 and stage 2 2028. As such, for the case with Marinus Link, the Basslink outage is assumed to occur while Marinus Link has a capacity of 600 MW.

Table 7: Overview of key input parameters that were updated since the system cost was assessed for the unplanned Basslink outage

Key drivers input parameter	Unplanned Basslink Outage sensitivity	Status Quo scenario
Economic retirement	Allowed for thermal generators if it is least-cost to do so.	
Fixed date thermal retirements (excluding South Australian gas-fired generators - listed separately)	Based on end of technical life as per AEMO's February 2019 planning and forecasting assumptions workbook.[98] Where station specific information was available, retirement dates were updated as per the AEMO Project Expected Retirement Date workbook published 12 April 2019.[99]	Based on end of technical life as per AEMO's February 2019 planning and forecasting assumptions workbook. Where station specific information was available, retirement dates were updated as per the AEMO Project Expected Retirement Date workbook published 25 June 2019.[100]

[98] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook*, *v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.
[99] AEMO, 12 April 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.
[100] AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.

Key drivers input parameter	Unplanned Basslink Outage sensitivity	Status Quo scenario
South Australian gas retirements	Torrens Island A and Torrens Island B are assumed to retire in the year that Project EnergyConnect is commissioned, as per the ElectraNet PACR.[101] Osborne power station has no fixed retirement date and Pelican Point power station is assumed to retire in 2037-38, as per the AEMO Project Expected Retirement Dates from 12 April 2019. Osborne power station and Pelican Point power station are not allowed to retire economically prior to Project EnergyConnect to maintain system strength in South Australia.[102]	Torrens Island A and Torrens Island B are assumed to retire in the year that Project EnergyConnect is commissioned, as per the ElectraNet PACR. Osborne power station and Pelican Point power station are assumed to retire in 2023-24 and 2037-38 respectively, as per the AEMO Project Expected Retirement Dates from 25 June 2019. Pelican Point power station is not allowed to retire economically prior to Project EnergyConnect to maintain system strength in South Australia.
Fixed date non-thermal retirements	End of technical life as per the AEMO Project Expected Retirement Date workbook published 12 April 2019.	End of technical life as per the AEMO Project Expected Retirement Date workbook published 25 June 2019.
PSL	Monthly minimums PSL profile that is imposed as part of Tasmania's energy security plan mandated by the Tasmanian Government to manage the consequences of an extended Basslink outage.[103] No changes with and without Marinus Link.	Without Marinus Link: ▶ Monthly minimums PSL profile that is imposed as part of Tasmania's energy security plan mandated by the Tasmanian Government to manage the consequences of an extended Basslink outage. With Marinus Link: ▶ 10 percentage point decrease in monthly minimum whole of system reservoir volumes in Tasmania.
West Coast expansion	A 100 MW expansion of West Coast power scheme's capacities,[104] with and without Marinus Link.	Without Marinus Link: ▶ West Coast power scheme's capacities are unchanged from current levels. With Marinus Link: ▶ A 100 MW expansion of West Coast power scheme's capacities.
Tarraleah upgrade	Tarraleah capacity is unchanged from current level. No changes with and without Marinus Link	Without Marinus Link: ▶ Tarraleah capacity is unchanged from current level. With Marinus Link: ▶ A 150 MW upgrade of Tarraleah
KerangLink	The preferred KerangLink ISP 2018 option is assumed to be commissioned in 2029-30.	The preferred KerangLink ISP 2018 option is assumed to be commissioned in 2030-31 aligning with the assumed end of technical life for the second unit of Yallourn.

Due to these changes in input assumptions, the outcomes of the Unplanned Basslink Outage sensitivity are not directly comparable to other system cost outcomes in this Report; however, they

[101] ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report.* Available at: https://www.electranet.com.au/projects/south-australian-energy-transformation/. Accessed 24 September 2019.

[102] AEMO, October 2019, *Transfer Limit Advice -System Strength*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Limits-advice. Accessed 12 November 2019.

[103] Hydro Tasmania, *Secure Energy*, Available at: https://www.hydro.com.au/clean-energy/secure-energy. Accessed: 15 July 2019.

[104] 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.

are indicative of the impact of an unplanned Basslink outage on system cost with and without Marinus Link.

5. Transmission and demand

5.1 Size and timing of other interconnector developments

In all scenarios, expanded interconnections are assumed to be developed between all mainland regions as summarised in Table 8.

Table 8: Overview of other interconnector developments

Project	Total capacity after development	Timing
VNI upgrade corresponding to AEMO ISP 2018 Group 1 development[105,106]	870 MW north 400 MW south	Status Quo, Sustained Renewables Uptake and Accelerated Transition: 2022-23[107] Global Slowdown: 2029-30
QNI upgrade[108]	580 MW north 1,355 MW south	2023-24
Project EnergyConnect[109]	SA-NSW 800 MW bi-directional Heywood 750 MW bi-directional Combined SA-NSW + Heywood 1,300 MW bi-directional[110]	2024-25
KerangLink[111]	2,800 MW north 2,200 MW south	Global Slowdown: 2032-33 Status Quo: 2030-31 Sustained Renewables Uptake: 2027-28 Accelerated Transition: 2029-30 See Section 5.1.1 for how timing was chosen across scenarios.

These proposed interconnector projects and HumeLink[112] are presently the subject of individual RIT-T assessments, which are in various stages, except KerangLink, for which a RIT-T is foreshadowed but not yet commenced. All the new or expanded interconnections incorporated in

105 Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan. Accessed 10th September 2019.

106 This corresponds to VNI Option 1 in AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

107 AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

108 This corresponds to QNI Option 3A in AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019. Option 1A was listed with a limit of 580 MW North and 1,230 MW South with a delivery date of 2022-23. Since the two upgrades are only one year apart, we did not implement Option 1A. Option 3A was implemented as only a thermal limit increase with no corresponding change in the QNI loss equation.

109 ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report*. Available at: https://www.electranet.com.au/projects/south-australian-energy-transformation/. Accessed 24 September 2019. There are options for commissioning between 2022 and 2024.

110 ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report*. Available at: https://www.electranet.com.au/projects/south-australian-energy-transformation/. Accessed 24 September 2019.

111 This corresponds to VNI Option 7 in AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

112 HumeLink is another transmission development associated with Snowy 2.0; however, it is an intra-regional development in New South Wales. As inter-regional transmission networks are not represented in the modelling and this project does not affect any assumed REZ expansion costs in the AEMO *2019 Input and Assumptions Workbook, v1.0* (5 February 2019), this project does not affect the modelling assumptions.

these studies are assumed to pass the RIT-T by delivering savings in excess of their development costs, and thus delivering net savings to consumers in the NEM.

5.1.1 Determining timing of KerangLink

Owing to the scale of KerangLink and the uncertainty as to timing of construction, a more thorough assessment of the timing of KerangLink in each scenario with and without Marinus Link was conducted.

For an initial indication of the optimal size and timing of KerangLink we performed a simulation where KerangLink is installed by the model on a least-cost basis. As this is a linear optimisation, the cost was linearised to a $/MW value, and the optimal installation schedule determined by the model is incremental. The KerangLink build schedule output may have successive increments in successive years which are not typically of equal capacity. This approach does not optimise the timing for large discrete amounts of capacity as would be determined through a RIT-T for KerangLink.

Following this process, we conducted an iterative assessment of optimum timing of the full Kerang Link interconnector by testing the gross market benefits of the KerangLink at various entry dates, which were selected based on the linearised development plan for KerangLink. The different KerangLink timings were conducted for the Status Quo scenario, across a selection of cases with and without Marinus Link. TasNetworks provided cost estimates for the different KerangLink timings, based on AEMO's February 2019 planning and forecasting assumptions workbook.[113] From those costs, it was concluded that the optimal timing of KerangLink is linked to the timing of Yallourn's retirement, as described in Table 5.

5.2 Interconnector loss assumptions

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 are calculated as shown below, using the 600 MW option as an example:

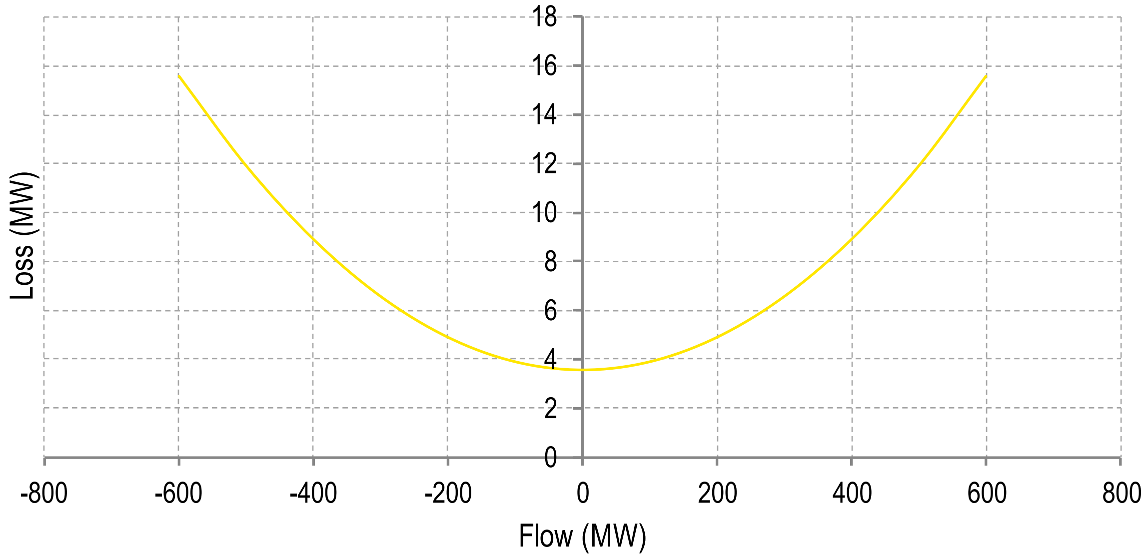
- There is a bi-directional flow limit of 600 MW, measured at the receiving end,[114] as requested by TasNetworks,
- Dynamic losses are allocated to the sending end,
- Dynamic losses along the cable are described by the loss equation shown in Figure 3 provided by TasNetworks. This is determined by the type of conductor, voltage of the cable and length of the cable. TasNetworks advises this loss equation corresponds to a 1,100 mm^2 cable, ±320 kV symmetrical monopole with 320 km overall length. The equation also incorporates converter station losses. This is the same equation used in the market modelling for the Initial Feasibility Report.[115]

[113] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

[114] This differs from the Initial Feasibility Report which proportioned losses equally between Tasmania and Victoria.

[115] TasNetworks, February 2019, *Initial Feasibility Report* and *Appendix 1: Economic Modelling Report*. Available at: https://www.marinuslink.com.au/initial-feasibility-report/. Accessed 11 November 2019.

Figure 3: Dynamic loss equation for Marinus Link



For the 1,200 MW Marinus Link option we have modelled two 600 MW capacity interconnectors in parallel using the same assumptions described above. This gives a total of 1,200 MW of additional interconnector capacity relative to the Basslink-only counterfactual.

For the 750 MW Marinus Link option we have used the same loss equation shown in Figure 3, while the 1,500 MW option uses two 750 MW capacity interconnectors in parallel. The use of the same loss equation implies the use of the same conductor for these options as the 600 MW and 1,200 MW options. TasNetworks has indicated that a larger conductor may be used; this would reduce losses and therefore potentially increase the utilisation of Marinus Link.

The existing Basslink cable was modelled with a bi-directional flow limit of 478 MW, measured at the receiving end with dynamic losses allocated to the sending end.[116] Dynamic losses were modelled using the loss equation in the AEMO report *Updated Regions and Marginal Loss Factors: FY 2019-20*[117]. This is the same equation used in the market modelling for the Initial Feasibility Report.[118]

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.

5.3 Demand

The TSIRP model captures peak period diversity across regions by basing the overall shape of hourly demand on eight historical years ranging from 2010-11 to 2017-18. Specifically, the key steps in creating the hourly demand forecast are as follows:

- The historical underlying demand has been calculated as the sum of historical metered demand and the estimated rooftop PV generation based on historical rooftop PV capacity and solar insolation,

[116] This differs from the Initial Feasibility Report which proportioned losses equally between Tasmania and Victoria.

[117] AEMO, June 2019. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries. Accessed 2 September 2019.

[118] TasNetworks, February 2019, *Initial Feasibility Report* and *Appendix 1: Economic Modelling Report*. Available at: https://www.marinuslink.com.au/initial-feasibility-report/. Accessed 11 November 2019.

- The eight-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region (scenario-dependent, see Table 5 for sources),
- The eight reference years are repeated sequentially throughout the modelling horizon as shown in Figure 4,
- The future expected hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity(scenario-dependent, see Table 5 for sources), which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

Figure 4: Sequence of reference years applied to forecast

Modelled year	Reference year
2020-21	2011-12
2021-22	2012-13
2022-23	2013-14
2023-24	2014-15
2024-25	2015-16
2025-26	2016-17
2026-27	2017-18
2027-28	2010-11
2028-29	2011-12
2029-30	2012-13
2030-31	2013-14
2031-32	2014-15
2032-33	2015-16
2033-34	2016-17
2034-35	2017-18
…	…
2045-46	2012-13
2046-47	2013-14
2047-48	2014-15
2048-49	2015-16
2049-50	2016-17

This method ensures the timing of peak demand across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and diversity of timing of peaks across regions.

Embedded renewables, particularly rooftop solar, reduce the growth in demand seen by the grid-connected generators. AEMO forecasts that embedded generation in the NEM will exceed 10.7 GW capacity by 2020-21 and exert a strong downward influence on daytime grid demand in the NEM, creating a middle-of-the-day trough in demand. Due to rooftop PV uptake, we generally see the peak operational demand intervals shifting later in the day throughout the forecast.

The reference year pattern is also consistent with hydro inflows (see Section 6.1) and site-specific hourly wind and solar availability (see Section 6.2). This maintains correlations between weather patterns, demand, wind, large-scale solar and rooftop PV availability.

TasNetworks selected demand forecasts from the AEMO 2018 ESOO[119] in all scenarios (see Section 4.1). The 2018 ESOO provides a forecast for all demand components from 2018-19 to 2037-38. To modelling a 30-year time horizon, EY has extrapolated this forecast to 2049-50.

[119] AEMO, August 2018, *2018 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 24 September 2019.

6. Supply

6.1 Treatment of Tasmanian hydroelectric generators

Hydro power stations are the main electricity generators in Tasmania. The operational profile of Hydro Tasmania's hydro generators is a key driver of the utilisation of Basslink and Marinus Link. Hydro Tasmania operates 30 hydro power stations with combined capacity of 2.3 GW[120]. Long-term storages on several of the schemes enable Hydro Tasmania to store inflows over months or years and choose when to use the water. Most generators have some storage, enabling flexibility in use of water over at least a day and the ability to respond to short-term price signals. Hydro Tasmania aims to use their limited water resource in the most profitable way, generating when Tasmanian demand is high or when Victorian wholesale prices are high and they can export power across Bass Strait interconnector(s).

Most of Hydro Tasmania's generators are part of connected systems or cascades of multiple generators and variously-sized storages along various Tasmanian river systems. As requested by TasNetworks, we used a ten-pond model of the schemes which aggregated some generators within schemes, as summarised in Table 9. Figure 5 shows the structure of the cascades modelled. Data for modelling of the Hydro Tasmania generators was provided to TasNetworks by Hydro Tasmania.

Table 9: Details of the ten-pond model requested by TasNetworks[121]

Scheme	Generators	Cascade	Total generating capacity (MW)	Total max energy in storage (GWh)	Average annual inflows (GWh)[122]
Gordon	Gordon	Gordon-Peddar	370 (at typical head - lake 40 % full	4,699.0	1,142
Poatina	Poatina	yingina/Great Lake	342	6,867.4	1,298
Trevallyn	Trevallyn	yingina/Great Lake	103	2.3	476
John Butters	John Butters Upper Lake Margaret Lower Lake Margaret	King-Yolande	155.4	250.4	617
Tarraleah	Butlers Gorge Tarraleah	Derwent	87.5 (Tarraleah restricted to 75 MW at present due to canal constraints)	380.6	719
Tungatinah	Lake Echo Tungatinah	Derwent	142 Winter 174 Summer (Lake Echo allowed to run in Summer only to reflect typical running)	44.7	711
Lower Derwent	Liapootah Wayatinah Catagunya Repulse Cluny Meadowbank	Derwent	278	3.6	302

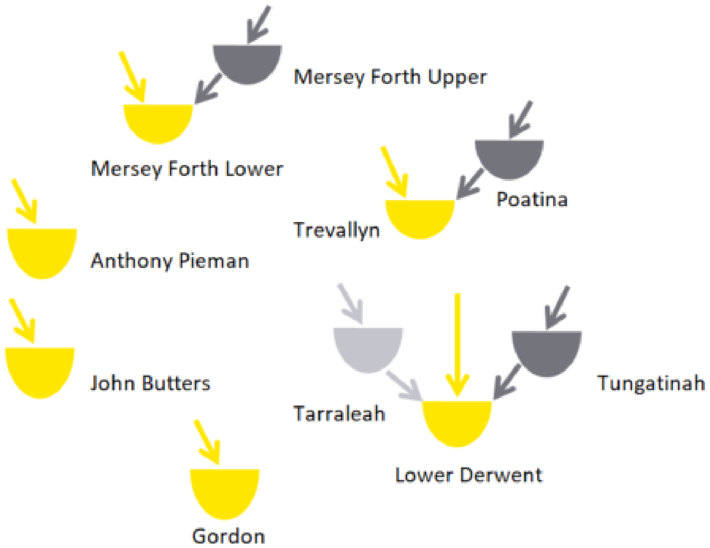
[120] Hydro Tasmania, Our Power Stations, Available at: https://www.hydro.com.au/clean-energy/our-power-stations. Accessed 15 July 2019.

[121] Max capacity, storage size and inflow data provided to TasNetworks by Hydro Tasmania.

[122] Average across eight historical years 2010-11 to 2017-18, inclusive of historical energy spilled. These reference years were selected to align with wind, solar and demand modelling. We could not use earlier data because Bureau of Meteorology weather data (used for wind and solar modelling) prior to 2010-11 is from a different source and is inferior in quality.

Scheme	Generators	Cascade	Total generating capacity (MW)	Total max energy in storage (GWh)	Average annual inflows (GWh)[122]
Anthony Pieman	Tribute Mackintosh Bastyan Reece	Pieman	500	101.6	1,868
Mersey Forth Upper	Rowallan Fisher Lemonthyme	Mersey Forth	110.5	92.0	557
Mersey Forth Lower	Wilmot Cethana Devils Gate Paloona	Mersey Forth	226.5	15.3	547

Figure 5: Cascades modelled



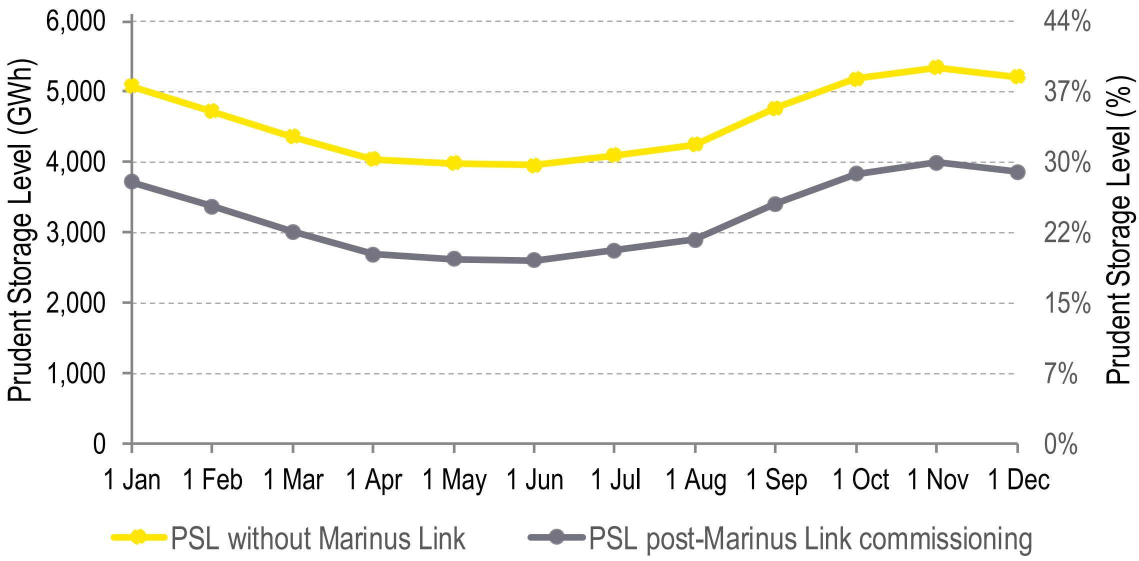
The generation profile of each scheme is determined by the model, which maximises the value of energy available. Water use in each scheme over the study period (i.e. 30 years) is optimised subject to reservoir levels at the start of the study, hourly inflows and minimum monthly whole-of-system reservoir levels.

The whole-of-system reservoir volume is known as Total Energy in Storage and the monthly minimums are the PSL profile that is imposed as part of Tasmania's energy security plan mandated by the Tasmanian Government to manage the consequences of an extended Basslink outage.[123] These levels vary throughout the year to match long-term seasonal rainfall patterns as shown in Figure 6. In the model, these minimums advised by TasNetworks were imposed on the first of each month. Upon entry of Marinus Link, TasNetworks has assumed there is a 10 percentage point decrease in the PSL profile, which represents a reversion to values that were applied prior to energy security review that followed the extended outage of Basslink in 2016 as advised by TasNetworks.

[123] Hydro Tasmania, *Secure Energy*, Available at: https://www.hydro.com.au/clean-energy/secure-energy. Accessed: 15 July 2019.

The decrease in PSL profile with Marinus Link was selected by TasNetworks on the basis that the assumptions detailed in the Tasmanian Energy Security Taskforce Final Report[124], upon which the PSL is based, would no longer be valid with the introduction of Marinus Link, and a revision to the former PSL profile which affords more operating flexibility for Tasmanian hydro resources could be justified. This PSH reduction is an assumption by TasNetworks and, we understand, does not represent Tasmanian Government policy. This decrease delivers a one-off quantity of additional water for generation and ongoing greater flexibility in use of Hydro Tasmania's storages.

Figure 6: PSL profile for Hydro Tasmania's reservoirs



Hourly inflows for each scheme from 2010-11 to 2017-18 were derived from the daily inflow data provided to TasNetworks by Hydro Tasmania. In the model, all schemes can spill water if it is economic to do so and consequently inflow data were inclusive of historical energy spilled. The historical average inflow across the eight reference years is shown in Table 9.

The least-cost planning model determines generation profiles that use water in the optimal way by generating in the highest priced trading intervals such that shifting a megawatt hour (MWh) of generation from one trading interval to another within the optimisation window would increase the cumulative price across all trading intervals in the window by replacing the marginal (most expensive) NEM generation in that interval.

Although optimisation windows are not enforced for any scheme, in the schemes with high inflows relative to storage size, the generation profiles are primarily driven by inflows otherwise water is spilled and energy wasted. In contrast, in larger storages, water can be stored over months and years to use it at its highest value.

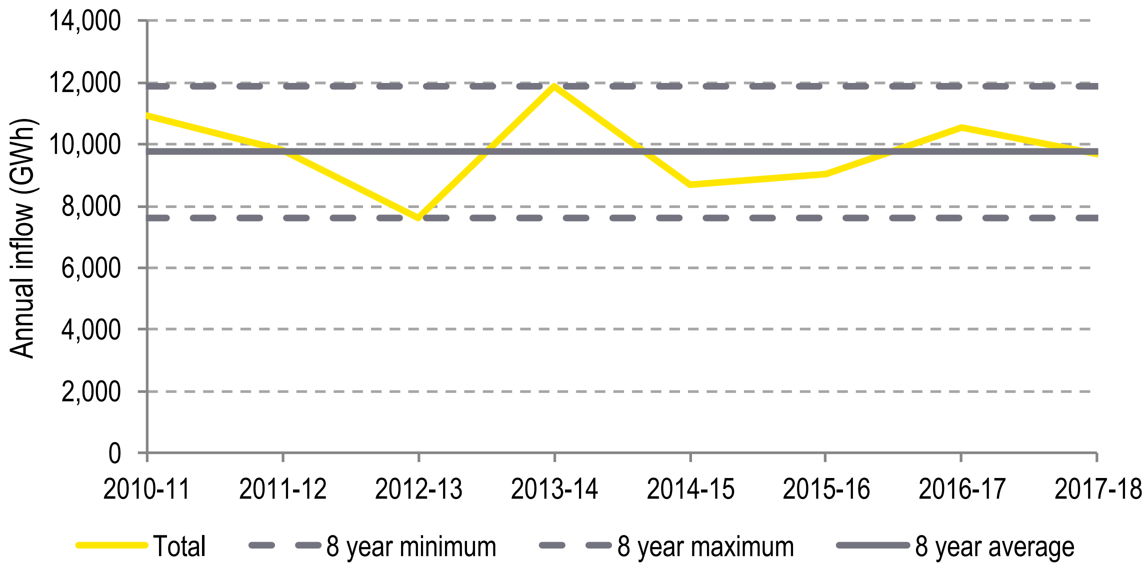
Small and non-scheduled hydro generators are excluded from the AEMO operational demand peak demand and annual energy forecasts applied in this model. However, these generators are dispatchable. Hence, we have adjusted the demand forecasts appropriately, used inflow data inclusive of small non-scheduled generators (provided by Hydro Tasmania to TasNetworks) and allowed the small non-scheduled hydro generators to be dispatched in the forecast to minimise system cost. The daily inflow data provided to TasNetworks by Hydro Tasmania included the small non-scheduled generators.

[124] June 2017, *Tasmanian Energy Security Taskforce Final Report*. Available at https://www.stategrowth.tas.gov.au/energy_and_resources/tasmanian_energy_security_taskforce/final_report. Accessed: 25 November 2019.

In the modelling, a sequence of eight historical hydrological years was used. For the storages with low volume relative to inflow (Trevallyn, Tarraleah, Tungatinah, Lower Derwent, Anthony Pieman, Mersey Forth Upper, Mersey Forth Lower), the inflow trace was day-shifted to correctly align the day-of-the-week and public holidays in the historical data and forecast year. This wasn't necessary for the larger storages (Gordon, Poatina, John Butters) due to their greater generation profile flexibility. The inflow data covers the period between 1 July 2010 and 30 June 2018, i.e., eight financial years from 2010-11 to 2017-18. [125] These eight years are repeated in the modelling as presented in Figure 4.

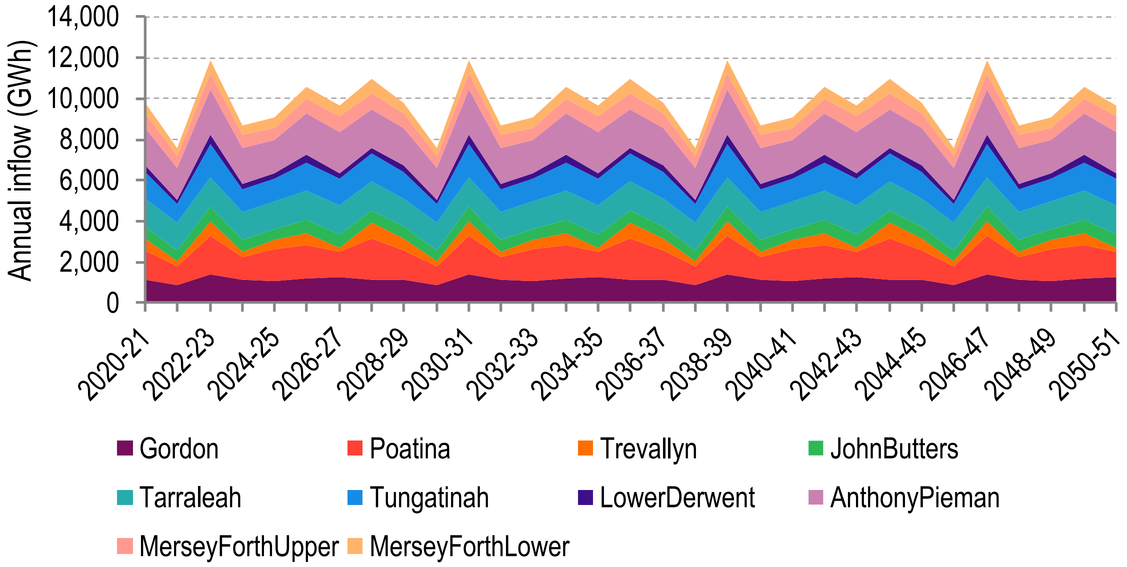
The sequence of eight hydrological years captures a range of conditions observed between 2010-11 and 2017-18 including wet, average and dry years, ranging in total inflows between 7.6 and 11.9 TWh. Figure 7 presents historical inflows to hydro schemes in Tasmania in the last eight years while Figure 8 presents assumed inflows to the ten schemes over the study period.

Figure 7: Historical energy inflows to hydro schemes in Tasmania



[125] These reference years were selected to align with wind, solar and demand modelling. We could not use earlier data because Bureau of Meteorology weather data (used for wind and solar modelling) prior to 2010-11 is from a different source and is inferior in quality.

Figure 8: Assumed future inflow sequence for Hydro Tasmania catchments, inclusive of inflows from upstream reservoirs



As noted in Section 3.4 above, several changes were made to modelling of Tasmanian hydroelectric generators since the Initial Feasibility Report[126] to improve realism of the representation of the system, as requested by TasNetworks. These changes are listed in Table 10.

Table 10: Changes in hydro modelling since the Initial Feasibility Report

Model detail	Initial Feasibility Report[126]	This Report
Representation of system	6 ponds	10 ponds with cascades
Number of reference years	7	8
Treatment of spill	Spill not allowed in model. Benefit or cost of change in spill computed outside of least-cost planning model.	Spill allowed from all ponds in model. Benefit or cost of change in spill computed endogenously in least-cost TSIRP model.
Minimum storage levels	Two season minimums imposed on large storages only.	Enforce a monthly PSL profile over whole system.
Treatment of small non-scheduled hydro generators	Historical small non-scheduled hydro generators were netted off demand so that their future dispatch was assumed to match reference year dispatch.	Explicit modelling of small non-scheduled hydro generators by adding their historical generation onto demand and allowing least-cost planning model to schedule their dispatch.
Changes to the system with Marinus Link commissioning	No changes	► 10 percentage point decrease in PSL profile ► 100 MW expansion of West Coast power scheme's capacities ► 150 MW upgrade of Tarraleah

6.2 Wind and solar PV energy projects

Several wind and solar PV generators (and large-scale battery storage projects) not yet built were committed in all simulations, both in the Basslink-only counterfactual and with Marinus Link. These

126 TasNetworks, February 2019, *Initial Feasibility Report* and *Appendix 1: Economic Modelling Report*. Available at: https://www.marinuslink.com.au/initial-feasibility-report/. Accessed 11 November 2019.

were sourced from AEMO Generation Information May 2019[127], Committed and Com*[128] status. In Victoria, the successful projects for the Victorian Renewable Energy Auction Scheme were modelled as listed in the AEMO February 2019 planning and forecasting assumptions workbook.[129]

Existing and new wind and solar PV projects are modelled based on eight years of historical weather data, as described below. The methodology for each category of wind and solar PV project is summarised in Table 11 and explained further in this section of the Report.

Table 11: Summary of wind and solar PV availability methodology

<table>
<tr><th>Technology</th><th>Category</th><th>Capacity factor methodology</th><th>Reference year treatment</th></tr>
<tr><td rowspan="3">Wind</td><td>Existing</td><td>Specify long-term target based on eight-year average in AEMO ESOO 2018 traces[130] where available, otherwise past meteorological performance</td><td rowspan="3">Capacity factor varied with reference year based on site-specific, historical, near-term wind speed forecasts.</td></tr>
<tr><td>Committed new entrant</td><td>Specify long-term target based on seven-year average of AEMO ESOO 2018 traces of nearest REZ, medium quality tranche.</td></tr>
<tr><td>Generic REZ new entrants</td><td>Specify long-term target based on seven-year average of AEMO ESOO 2018 traces. One high quality option and one medium quality trace per REZ.</td></tr>
<tr><td>Solar PV FFP</td><td>Existing</td><td rowspan="4">Annual capacity factor based on technology and site-specific solar insolation measurements.</td><td rowspan="4">Capacity factor varied with reference year based on historical, site-specific insolation measurements.</td></tr>
<tr><td rowspan="3">Solar PV SAT</td><td>Existing</td></tr>
<tr><td>Committed new entrant</td></tr>
<tr><td>Generic REZ new entrant</td></tr>
<tr><td>Rooftop PV and small non-scheduled solar PV</td><td>Existing and new entrant</td><td>Long-term average capacity factor based on past meteorological performance.</td><td>Capacity factor varied with reference year based on historical insolation measurements.</td></tr>
</table>

All existing and committed large scale wind and solar farms in the NEM were modelled on an individual basis i.e. each project has a location-specific availability trace based on historical resource availability. The availability traces are derived using eight years of historical weather data covering financial years between 2010-11 and 2017-18 (inclusive), consistent with the hydro inflow data discussed in Section 6.1 and the hourly shape of demand.[131] Wind and solar availability traces used in the modelling reflect generation patterns occurring in the eight historical years, and these generation patterns are repeated throughout the study period as shown in Figure 4.

[127] AEMO, *Generation Information Page*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Accessed 24 September 2019

[128] Com* identifies projects that were under construction as of May 2019, but AEMO had not been informed that the project meet all commitment criteria.

[129] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

[130] AEMO, 2018, *2018 Electricity Statement of Opportunities: 2018 REZ Wind Traces* and *2018 REZ Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 23 September 2019.

[131] Bureau of Meteorology weather data prior to 2010-11 is from a different source and is inferior in quality.

The availability traces for wind are derived using the methodology of EY's electricity market modelling team, which uses simulated wind speeds and directions from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[132] at a representative hub height. Wind speeds are converted into power using a generic wind farm power curve. The traces are scaled to achieve average target capacity factor across the eight historical years. The traces reflect inter-annual variations, but at the same time achieve long-term capacity factors in line with historical performance (existing wind farms) or the values for each REZ used in the AEMO 2018 ESOO and 2018 ISP[133] for each REZ (new entrant wind farms, as listed in Table 12).

Table 12: REZ wind and solar PV average capacity factors over 8 reference years

Region	REZ	Wind		Solar PV SAT
		High quality	Medium quality	
Queensland	North Queensland Clean Energy Hub	48 %	38 %	31 %
	Northern Queensland	Tech not available	Tech not available	29 %
	Isaac	46 %	34 %	30 %
	Barcaldine	42 %	35 %	32 %
	Fitzroy	45 %	35 %	30 %
	Darling Downs	45 %	38 %	30 %
NSW	North West New South Wales	27 %	25 %	30 %
	New England	38 %	38 %	29 %
	Central West New South Wales	33 %	30 %	30 %
	Southern New South Wales Tablelands	42 %	41 %	26 %
	Broken Hill	36 %	32 %	31 %
	Murray River (NSW)	31 %	30 %	29 %
	Riverland (NSW)	30 %	30 %	29 %
Victoria	Murray River (VIC)	31%	30 %	29 %
	Western Victoria	Tech not available	34 %	Tech not available
	Moyne	Tech not available	37 %	Tech not available
	Gippsland	30 %	31 %	Tech not available
South Australia	South East South Australia	38 %	36 %	Tech not available
	Riverland (SA)	30 %	30 %	28 %
	Mid-North South Australia	37 %	37 %	Tech not available
	Yorke Peninsula	37 %	34 %	Tech not available
	Northern South Australia	Tech not available	Tech not available	30 %

132 As described by Australian Government Bureau of Meteorology, *ACCESS NSP Data Information*. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 23 September 2018.

133 AEMO, 2018, *2018 Electricity Statement of Opportunities: 2018 REZ Wind Traces* and *2018 REZ Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 23 September 2019.

Region	REZ	Wind		Solar PV SAT
		High quality	Medium quality	
	Leigh Creek	41 %	40 %	32 %
	Roxby Downs	Tech not available	Tech not available	31 %
	Eastern Eyre Peninsula	37 %	36 %	28 %
	Western Eyre Peninsula	36 %	32 %	29 %
Tasmania	North West Tasmania	48 %	43 %	23 %
	Tasmania Midlands	51 %	44 %	24 %
	North East Tasmania	44 %	43 %	25 %

The availability traces for solar PV are derived using solar irradiation data derived from satellite imagery processed by the Australian Bureau of Meteorology. Similarly to wind traces, the solar traces reflect inter-annual variations over eight historical years, but at the same time achieve long-term capacity factors in line with historical performance (existing solar farms) or close to[134] AEMO expectations for each REZ (generic new entrant solar farms [135], as listed in Table 12).

Wind and solar PV capacity expansion in each REZ was limited by three parameters based on AEMO Planning and Forecasting assumptions consultation, February 2019[136]:

- Transmission-limited total build limit (MW) representing the amount of capacity supported by current intraregional transmission infrastructure,
- A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre,
- Resource limits (MW) representing the maximum amount of capacity available in a REZ based on topography, land use etc.

The TSIRP model will incur the additional transmission expansion cost to build more capacity up to the resource limit if it is part of the least-cost development plan.

6.3 PSH assumptions

PSH could be installed by the model in each region on a least system cost basis. To manage the optimisation problem size new PSH installed by the TSIRP model was limited to one storage size per region.

Mainland regions had a six-hour PSH option. The six-hour storage size was chosen as it had the lowest cost and the highest available capacity and so would be most competitive with large-scale

[134] For solar farms, we could not efficiently produce availability traces that achieved exactly AEMO's long-term capacity factor. The traces derived by EY are up to 3 % higher than the AEMO ESOO 2018 solar traces, depending on REZ.

[135] AEMO, 2018, *2018 Electricity Statement of Opportunities: 2018 REZ Wind Traces* and *2018 REZ Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2018-NEM-ESOO. Accessed 23 September 2019.

[136] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

battery storage. Mainland regional capacity limits were based on Entura's December 2018 report to AEMO[137] as follows:

- Queensland 1.8 GW,
- New South Wales 3.4 GW (excluding Snowy 2.0),
- Victoria 1.2 GW,
- South Australia 0.5 GW.

For Queensland, Victoria and South Australia, these totals are the same as the sum of all size options in the AEMO February 2019 planning and forecasting assumptions workbook.[138] For New South Wales, the AEMO assumptions workbook lists 7 GW of PSH capacity available (in addition to Snowy 2.0) across various storage sizes (6 hour, 12 hour, 24 hour and 48 hour) based on 24 energy projects shortlisted for potential development as part of the New South Wales Government's *Pumped Hydro Roadmap*[139,140]. TasNetworks elected to use the Entura values for all regions since they were associated with capital cost estimates, while New South Wales Government report did not have associated capex values.

In Tasmania, the PSH option was 24-hours storage. The capacity limit of 1.6 GW was based on Entura's December 2018 report to AEMO[137]. AEMO's February 2019 planning and forecasting assumptions workbook lists 1.2 GW of at least 24-hour storage[138]. However, as AEMO's methodology for re-aligning capacities of various storage volumes was not known, TasNetworks elected to use a consistent data source for capex and available storage volumes across regions. A storage volume of 24 hours was selected by TasNetworks for Tasmania based on advanced knowledge of a now-published prefeasibility study of potential Tasmanian PSH projects.[141] This study identified over 1.6 GW of capacity occurring at sites with at least 24-hour storages.

6.4 Inertia constraint

An inertia constraint was included in the generation development plan to ensure the aggregate total of inertia in each region in each trading interval is sufficient to meet minimum requirements. These minimum levels ensure each region can be operated in a satisfactory operating state when the region is islanded as defined in the National Electricity Rules.[142]

The minimum inertia required in mainland regions is summarised in Table 13. For Victoria, Queensland and New South Wales, the minimum inertia levels were sourced from AEMO's calculated requirements in 2018.[143] For South Australia, the minimum inertia level was sourced from ElectraNet's calculation of requirements published as part of the *South Australian Energy*

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[137] Entura, 7 December 2018, *Pumped Hydro Cost Modelling*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 2 October 2019.

[138] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

[139] December 2018. Available at: https://energy.nsw.gov.au/renewables/clean-energy-initiatives/hydro-energy-and-storage. Accessed 17 November 2019.

[140] WaterNSW, 12 December 2018, *NSW Govt Unveils WaterNSW Landmark Pumped Hydro Clean Energy Project* [press release]. Available at: https://www.waternsw.com.au/about/newsroom/2018/nsw-govt-unveils-waternsw-landmark-pumped-hydro-clean-energy-project. Accessed 17 November 2019.

[141] Hydro Tasmania, August 2019, *Battery of the Nation – Pumped Hydro Energy Storage Projects: Prefeasibility Studies Summary Report*. Available at: https://www.hydro.com.au/clean-energy/battery-of-the-nation/pumped-hydro. Accessed 19 November 2019.

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

[143] AEMO, 1 July 2018, *Inertia requirements methodology: Inertia requirements and shortfalls*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 September 2019.

Transformation RIT-T[144] and ElectraNet's preferred option from their report into *Addressing the System Strength Gap in SA*.[145,146] The report *Addressing the System Strength Gap in SA* states that the preferred option will provide sufficient inertia capacity to meet the minimum inertia threshold for SA.

Table 13: Minimum inertia levels for islanded mainland regions

Region	Minimum inertia level (MW.s)
Queensland	12,800
New South Wales	10,000
Victoria	12,600
South Australia	0

The inertia contribution of various generators was sourced from AEMO pre-dispatch constraint equations.[147] In reality, a dispatched generator contributes a fixed amount of inertia regardless of its dispatch level. As step functions cannot be accommodated in a linear optimisation model, we instead approximate that inertial generators without minimum loads contribute an amount pro-rated with dispatch; these are CCGTs without minimum loads, OCGTs, diesel generators, conventional hydro, PSH generators and pumps. Stations with minimum loads contribute the full value of inertia when they are available; this applies to coal-fired generators and some CCGT generators with minimum loads applied.

In Tasmania, a customised linear inertia requirement provided by TasNetworks was imposed which accounts for the effect of Tasmanian demand, interconnector flows, seasonal differences in hydro minimum loads and the effect of variable wind production and PSH development. The following equations are enforced as a hard constraint in the model to ensure there is enough inertia in Tasmania in each hour of the forecast.

On export, sum of terms in Table 14, hard-export column ≥ 390 - 0.5*Tasmanian demand
On import, sum of terms in Table 14, hard-import column ≥ 390 - 0.77*Tasmanian demand

Table 14: Tasmania minimum inertia left-hand side constraint terms

Term in inertia constraint equation left-hand side	Hard constraint		Constraint for synchronous condenser costing	
	Inertia contribution on export (MW.s)	Inertia contribution on import (MW.s)	Inertia contribution on export (MW.s)	Inertia contribution on import (MW.s)
TAS-Vic flow	-1.7*export flow (MW)	5.3*import flow (MW)	-1.7*export flow (MW)	5.3*import flow (MW)
Tasmanian wind	-2.8*dispatch (MW)	-4.2*dispatch (MW)	-2.8*dispatch (MW)	-4.2*dispatch (MW)
Tasmanian PSH	2*dispatch gen or load (MW)	6.5*dispatch gen or load (MW)	5*dispatch gen or load (MW)	9*dispatch gen or load (MW)
Tasmanian PSH	3*capacity (MW)		0	

144 ElectraNet, 13 February 2019, *SA Energy Transformation RIT-T: Network technical assumptions report*. Available at: https://www.electranet.com.au/projects/south-australian-energy-transformation/. Accessed 18 September 2019.

145 ElectraNet, 18 February 2019, *Addressing the System Strength Gap in SA*. Available at: https://www.electranet.com.au/wp-content/uploads/2019/02/2019-02-18-System-Strength-Economic-Evaluation-Report-FINAL.pdf. Accessed 18 September 2019.

146 On 20 August 2019, AER approved ElectraNet's proposal to install four synchronous condensers. Available at: https://www.aer.gov.au/news-release/aer-approves-electranet-spending-on-south-australia-system-strength. Accessed 19 November 2019.

147 AEMO market data from MarketNet MMS Data Model, GENERICEQUATIONRHS table. Not publicly available.

Term in inertia constraint equation left-hand side	Hard constraint		Constraint for synchronous condenser costing	
	Inertia contribution on export (MW.s)	Inertia contribution on import (MW.s)	Inertia contribution on export (MW.s)	Inertia contribution on import (MW.s)
Gordon	Dec-May: 3*dispatch (MW) + 626 Jun-Nov: 3.1*dispatch (MW) + 626			
Poatina	600		5*dispatch (MW)	
Trevallyn	4.3*dispatch (MW)			
John Butters	1,713		3.9*dispatch (MW)	
Tarraleah	4*dispatch (MW)			
Tungatinah	May-Oct: 3.1*dispatch (MW) Nov-Apr: 3.2*dispatch (MW)			
Lower Derwent	2*dispatch (MW) + 500			
Anthony Pieman	4*dispatch (MW)			
Mersey Forth Upper	2.8*dispatch (MW)			
Mersey Forth Lower	3.4*dispatch (MW)			
Bell Bay	8.56*dispatch (MW)			
Tamar Valley CCGT	7.72*dispatch (MW)			
Tamar Valley OCGT	7.72*dispatch (MW)			

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

The cost of operation as a synchronous condenser, when required, is computed through an additional constraint with terms using the right two columns of Table 14. This constraint can violate at a cost of 17 cents/MW.s. The total violation cost is an estimate of the cost of running Poatina, John Butters and PSH as synchronous condensers to meet the minimum inertia requirement.

6.5 Reserve constraint

The TSIRP model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, allowing for generation contingences which can occur at any time, by enforcing a regional minimum reserve requirement.

All dispatchable generators in each region are eligible to contribute to reserve (except new PSH and large-scale batteries installed by the model as part of least-cost plan[148]) and headroom that is available on interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the amount of reserve carried, and provides reserve from the lowest cost providers, including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

[148] PSH and large-scale batteries are usually fully dispatched during the peaks and thus will be unable to contribute to reserve. In the event that they are not dispatched fully, it is likely due to insufficient energy in storage.

In the modelling, a single contingency reserve requirement[149] was applied in each region with a high penalty cost.

This constraint was applied to only a subset of simulation hours (highest 1 % of demand hours) to reduce the optimisation problem size. We do not expect this to affect outcomes as a reserve constraint is unlikely to bind in lower demand intervals.

6.6 Forced outage rates and maintenance

Forced full and partial outage rates and maintenance rates were based on the AEMO February 2019 planning and forecasting assumptions workbook. [149]

For each existing generator, all unplanned forced outage patterns are set by a random number generator. The seed for the random number generator is set such that the same forced outage pattern exists between the Basslink-only counterfactual and the various Marinus Link options. New entrant generators are de-rated by their equivalent forced outage rate.

Planned maintenance events for existing generators are scheduled during low demand periods.

6.7 Generator technical parameters

In general, all technical parameters are as detailed in the AEMO February 2019 planning and forecasting assumptions workbook[149], except where noted in this section.

6.7.1 Coal-fired generators

Coal-fired generation is treated as dispatchable between its minimum load and its maximum load. Must run generation is dispatched whenever available at least at its minimum load. In line with the AEMO February 2019 assumptions workbook[149], maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

An assumed energy limit was placed on coal-fired power stations approximately equal to the average annual energy generated between 2013-14 and 2017-18 to reflect limitations on annual coal deliveries. Prior to its retirement the Liddell power station annual capacity factor was limited to 50 % in accordance with the AEMO February 2019 assumptions workbook.[149]

6.7.2 Gas-fired generators

Gas-fired CCGT plant also typically have a must-run component and so are dispatched at or above their minimum load. Minimum loads were applied to several gas generators as listed in the AEMO February 2019 planning and forecasting assumptions workbook.[149]

A minimum load of 50 % for all new CCGTs was assumed to reflect minimum load conditions for efficient use of gas and steam turbines in CCGT operating mode.

OCGTs operate with no minimum load level and so start and are dispatched for a minimum of one hour when the cost of supply is at or above their SRMC.

6.7.3 Wind, solar PV and run-of-river hydro generators

Intermittent renewables, in particular solar PV, wind and run-of-river hydro are dispatched according to their resource availability as they cannot store energy. Intermittent renewable production levels are based on eight years of hourly measurements and weather observations across the NEM including all REZ zones. Using historical reference years preserved correlations in

[149] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook*, *v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

weather patterns, resource availability and demand. Modelling of wind and large-scale solar PV is covered in more detail in Section 6.2.

Solar PV and wind generators are dispatched at their available resource limit unless curtailed economically, when the cost of supply falls to less than their VOM, or by other constraints such as transmission limits.

6.7.4 Energy-limited generators

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

For existing conventional Tasmanian hydro generators, the model and inflows were provided to TasNetworks by Hydro Tasmania. More detail on this is provided in Section 6.1.

For existing hydro generators on the mainland, hourly hydro inflows to the reservoirs and ponds were computed from monthly values sourced from the AEMO ISP assumptions workbook[150] due to this information to being included in the more recent February 2019 planning and forecasting assumptions workbook.[151]

6.8 Retirements

6.8.1 Coal-fired generators

According to the scenario settings selected by TasNetworks, modelled coal-fired generators had fixed, scenario-dependent maximum lifetimes, but could be retired earlier by the model based on economics or to meet the emission reduction constraint or in the case of the Global Slowdown scenario, the coal capacity constraint.

Maximum coal lifetimes across scenarios are illustrated in Figure 9. They vary between scenarios as follows:

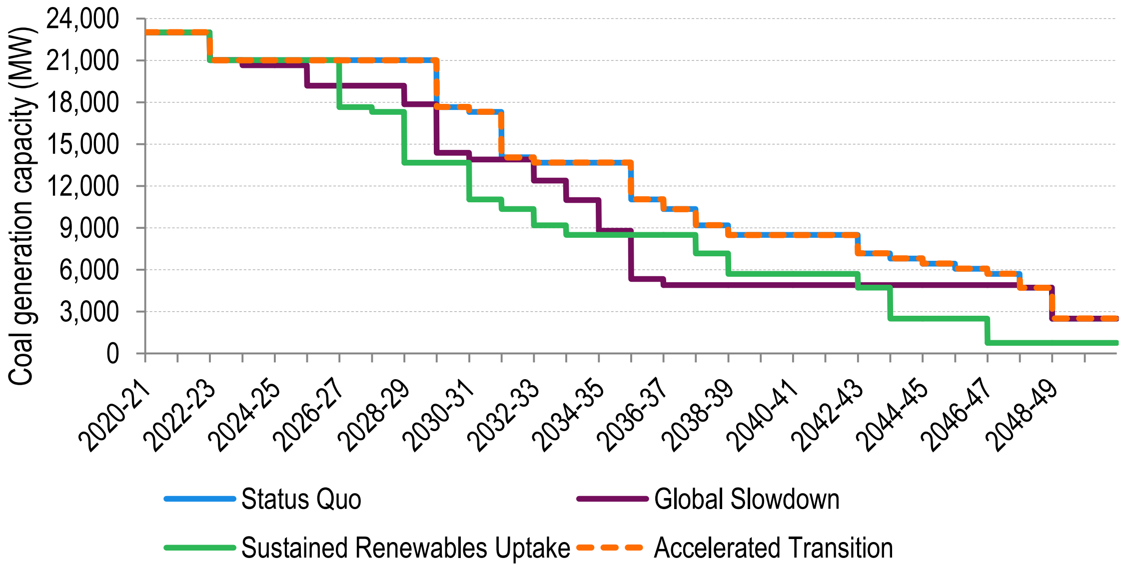
- ► In the Status Quo, maximum retirement dates for coal-fired generators were sourced from AEMO's February 2019 planning and forecasting assumptions workbook[151], with updates from AEMO published 25 June 2019[152], based on announced retirements and end-of-technical life information at that time.

- ► In the Global Slowdown scenario, maximum lifetimes are unchanged, but a coal capacity constraint accelerates some retirements (model output). The constraint limits the combined amount of black and brown coal-fired generating capacity to the lower NEM-wide demand trajectory from Aurora Energy Research's revenue adequacy report to AEMO[153]. Fixed thermal coal retirements commence in 2025 and are accelerated by 3-5 GW relative to the Status Quo scenario. The model selected which coal-fired power stations are retired to meet the constraint at least-cost.

[150] AEMO, 21 August 2018, *2018 Integrated System Plan Modelling Assumptions, v2.4*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan. Accessed 30 September 2019.
[151] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook, v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.
[152] AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.
[153] Aurora Energy Research, May 2019, *Aurora Energy Research Analysis of AEMO's ISP Part 2: Economics of Coal Closures*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan. Accessed 18 October 2019.

- In the Accelerated Transition scenario, assumed maximum lifetimes were unchanged, but an assumed more stringent emission reduction constraint accelerates some retirements (model output).
- In the Sustained Renewables Uptake scenario, coal-fired generating units are generally assumed to retire three to five years earlier than the dates assumed in the Status Quo scenario. This was selected by TasNetworks as a means to force the model to maintain renewables capacity installation rates at approximately current levels, which is the key characteristic intended to be represented in this scenario. Specifically, coal-fired generating units with an Expected Retirement Date from 2029-30 to 2034-35 are assumed to retire three years earlier. Coal-fired units with an Expected Retirement Date from 2035-36 onward are assumed to retire five years earlier. Exceptions include Yallourn Unit 4, which is assumed to retire 2028-29 (four years earlier than its Expected Retirement Date) and Stanwell Units 2-4, which are assumed to retire with Stanwell Unit 1 at the start of 2038-39 (rather than staggered one year apart).

Figure 9: Maximum retirement dates of coal capacity across the NEM by year in all scenarios[154]



6.8.2 Gas-fired generators

With regard to gas-fired generators in South Australia, Torrens Island A and Torrens Island B are assumed to retire in the year that Project EnergyConnect is commissioned, as per the ElectraNet PACR.[155] Osborne power station and Pelican Point power station are assumed to retire in 2023-24 and 2037-38, respectively, as per the AEMO Project Expected Retirement Date workbook published 25 June 2019.[156] Pelican Point power station is not allowed to retire economically prior to Project EnergyConnect to maintain system strength in South Australia.[157]

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[154] This reflects the maximum lifetimes which are model inputs. Capacity was allowed to retire earlier based on economics or to meet the emission reduction constraint. For the Global Slowdown scenario, this trajectory reflects the assumed maximum coal capacity constraint. The stations retired to meet this constraint are selected by the model on a least-cost basis.

[155] ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report.* Available at: https://www.electranet.com.au/projects/south-australian-energy-transformation/. Accessed 24 September 2019.

[156] AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.

[157] AEMO, October 2019, *Transfer Limit Advice -System Strength*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Limits-advice. Accessed 12 November 2019.

Other gas-fired generators are assumed to have maximum retirement dates as per the AEMO Project Expected Retirement Date workbook published 25 June 2019, [158] but could be retired earlier by the model based on economics or to meet the emission reduction constraint.

6.8.3 Other generators

All other generators had retirement dates applied as listed in the AEMO Project Expected Retirement Date workbook published 25 June 2019. [158]Technologies other than coal- and gas-fired generators were not allowed to be retired earlier than these dates by the model based on economics.

[158] AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available on request from TasNetworks.

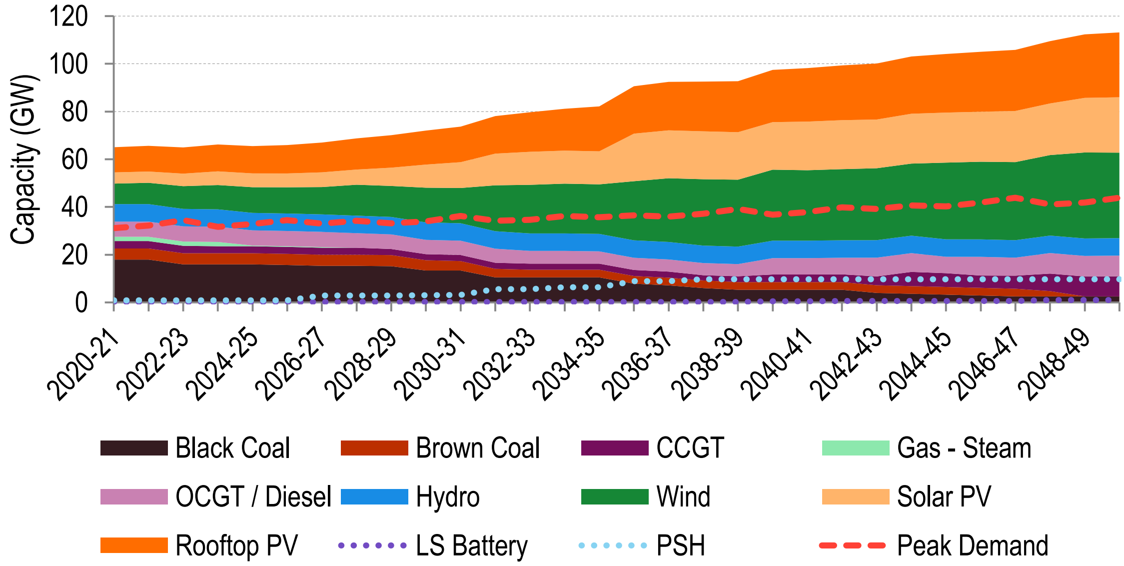
7. NEM outlook across scenarios without Marinus Link

Before considering the gross 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 the modelled scenarios.

7.1 Status Quo scenario without Marinus Link

The forecast NEM-wide capacity mix without Marinus Link in the Status Quo scenario is shown in Figure 10. The capacity in the NEM is forecast to gradually shift away from a predominantly black and brown coal and hydro grid, with wind and solar PV developed to meet the large-scale renewable energy target (LRET), towards increasing capacity of wind, solar PV, gas generation and storage, both PSH and large-scale battery storage.

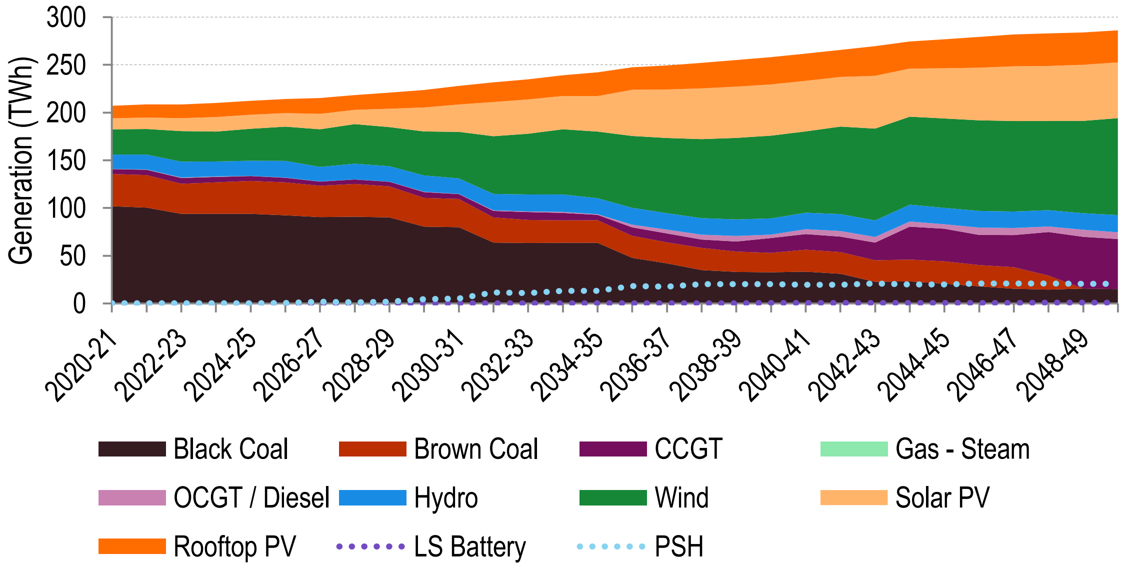
Figure 10: NEM capacity mix forecast[159] without Marinus Link, Status Quo scenario



The energy supplied to the grid, as shown in Figure 11, is forecast by AEMO to grow relatively slowly. The concurrent growth in installed capacity shown in Figure 10 is much faster, due to the relatively lower annual capacity factor of 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 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 peaking generation when solar and wind are not available. The balance of OCGT and CCGT capacity is influenced by the imposition of a 50 % minimum load on new CCGTs and no minimum load requirement on new OCGTs. Overall, the capacity mix in the NEM is based on providing sufficient dispatchable generation, mainly gas and storage, to balance the increasing volume of intermittent renewables entering the market.

159 NEM peak 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.

Figure 11: NEM generation mix forecast without Marinus Link, Status Quo scenario



Without Marinus Link, the forecast overall energy production in the NEM in the Status Quo scenario, as shown in Figure 11, 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, with no early coal retirements forecast to be driven by emissions constraints, but a small amount of economic retirement of coal and gas capacity before age-based retirements,
- The steeply declining cost of renewable generation relative to the stable costs of fossil generation.

In this scenario, there is an emission reduction constraint to meet a 28 % reduction in emissions compared to 2005 levels by 2030 and then a linear reduction of emissions to 70 % reduction compared to 2016 levels by 2050; however, it is always met through age-based and economic retirements and so does not drive outcomes.

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

- From 2020, when the LRET target are expected to be met or exceeded due to the committed generation in all scenarios (see Section 6.2) to 2030, when the 2030 emissions reduction target, 50 % VRET and 50 % QRET targets are expected to be met, black and brown coal generation is forecast to still dominate the energy mix.
- Conventional hydro is forecast to continue at the present levels indefinitely as the annual energy available from existing hydro is relatively static.
- 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 expected ongoing focus on exporting gas at the present forecast international price levels, rather than consuming the gas locally.
- Wind and, to a lesser extent, solar PV generation is forecast to continue to meet or exceed the LRET target of 33,000 GWh per annum in Australia, with the NEM making up around

85 % of the total for Australia. Large-scale wind and solar PV supply approximately 18 % of NEM energy consumption of about 200 TWh/year in the early 2020s. Wind and solar PV capacity and generation is forecast to substantially increase through to 2030, due to the VRET and QRET targets and demand growth in New South Wales in particular, together with improving economic competitiveness of renewables. By 2029-30, large-scale wind and solar PV is forecast to supply almost 32 % of NEM energy consumption.

- 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. New storage technologies such as PSH and batteries may also become economical as the daytime grid demand trough becomes more pronounced. Thus, both conventional hydro and PSH are forecast to contribute to meeting peaks using either stored river inflows or pumped water.

- From the mid-2030s the generation contribution by coal is forecast to fall markedly, mainly driven by coal-fired generators reaching their projected end of life of 50 years operation.

- From the late 2030s there is forecast to be significant growth in gas-fired generation from existing and new CCGT capacity. Significantly expanded wind production from existing and new wind generation throughout the NEM is also forecast from the mid-2030s as shown in Figure 10 and Figure 11. 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 rooftop PV generation, which has a similar operating profile and erodes the benefits of additional solar PV. Particularly from the mid-2030s storage, initially PSH and later grid-connected 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 10 and Figure 11 to reflect that storage is a load as well as a generator.

Renewable generation is forecast to develop in all regions alongside PSH generation in all mainland regions. The economic driver for development in each region is to meet the load growth by region using the best resources available within the region. Most regions have REZ zones with either high wind resources or high solar resources, so are projected to have a combination of solar PV and wind developments. Interconnector losses tend to limit the growth of particular technologies in a region for export to other regions, even if abundant, high-quality resources are available, because transmission losses grow non-linearly with interconnector flows.

However, even though interconnector losses tend to constrain generation development to within each region, the diversity of resources between distant regions of the NEM may outweigh the impact of transmission losses and could lead to high utilisation of interconnectors and expanded growth of renewables in some cases. This is because weather conditions cause 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.[160] It is also because losses over interconnectors are generally less than losses for storage technologies.

For the Status Quo scenario, Figure 12 shows the forecast net energy transfers by year across all existing interconnectors in average MW flow. This shows that some interconnectors are forecast to transfer more energy between regions than others.

- Basslink flows are consistently northward reflecting the forecast level of existing and new wind in Tasmania.

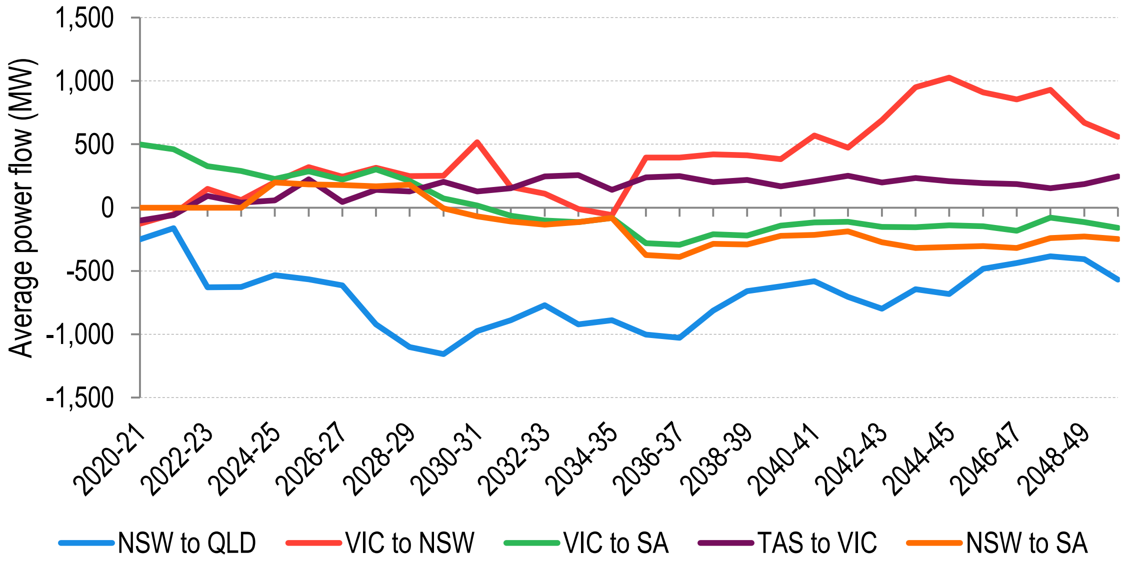
- Victoria to New South Wales interconnector flows are generally northward, although there is substantial variation as retirements in large coal-fired stations in both states cause temporary shifts in flows. KerangLink is assumed to be built in 2030-31, greatly expanding

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

the firm transfer limits between New South Wales and Victoria and contributing to higher exports from Victoria to New South Wales in later years.

- South Australia shifts towards eastward flow owing to favourable renewable generation developments, firstly into Victoria via Heywood and Murraylink and later into New South Wales over the Project EnergyConnect interconnector, which is assumed to be built by 1 July 2024.
- Owing to strong solar resources in Queensland and later retirement of the Queensland coal portfolio, transfers over the Queensland to New South Wales interconnectors are strongly in favour of imports to New South Wales from Queensland.

Figure 12: Average annual interconnector power flow forecast for Status Quo scenario without Marinus Link[161]

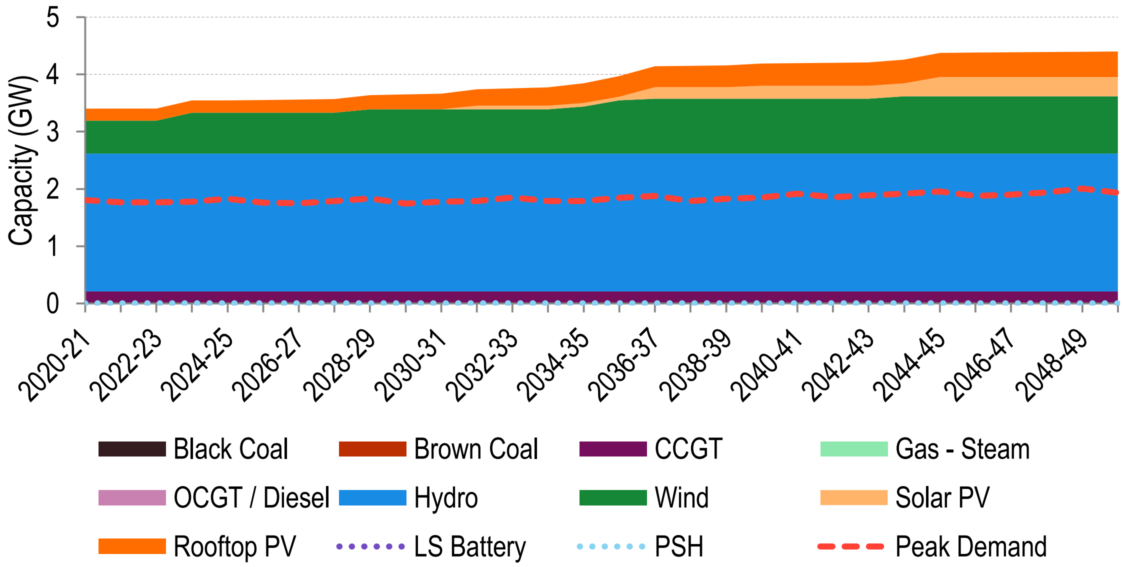


The forecast capacity development plan in Tasmania without Marinus Link is shown in Figure 13. We have already shown in Figure 10 that across the NEM, there is forecast to be a significant increase in solar PV capacity from the mid-2030s because the expected decrease in cost of large-scale solar PV favours its development to replace retiring coal. This development is spread by the least-cost modelling methodology across in all regions, including Tasmania, to take advantage of diversity in weather conditions and seasonal patterns. In Tasmania, the new solar PV generation would be used locally allowing Tasmanian hydro generation to be better utilised at higher value at times of high Victorian demand. In considering the relative cost of technologies, spill of some wind energy without additional interconnection raises the effective cost per MWh of wind, decreasing its competitiveness with lower capacity factor large-scale solar PV[162].

[161] Positive flow directions are East to West and South to North. Positive flow for Directlink and QNI is New South Wales to Queensland; for Basslink is Tasmania to Victoria; for Murraylink and Heywood is Victoria to South Australia; for VIC-NSW and KerangLink is Victoria to New South Wales; for NSW-SA is New South Wales to South Australia.

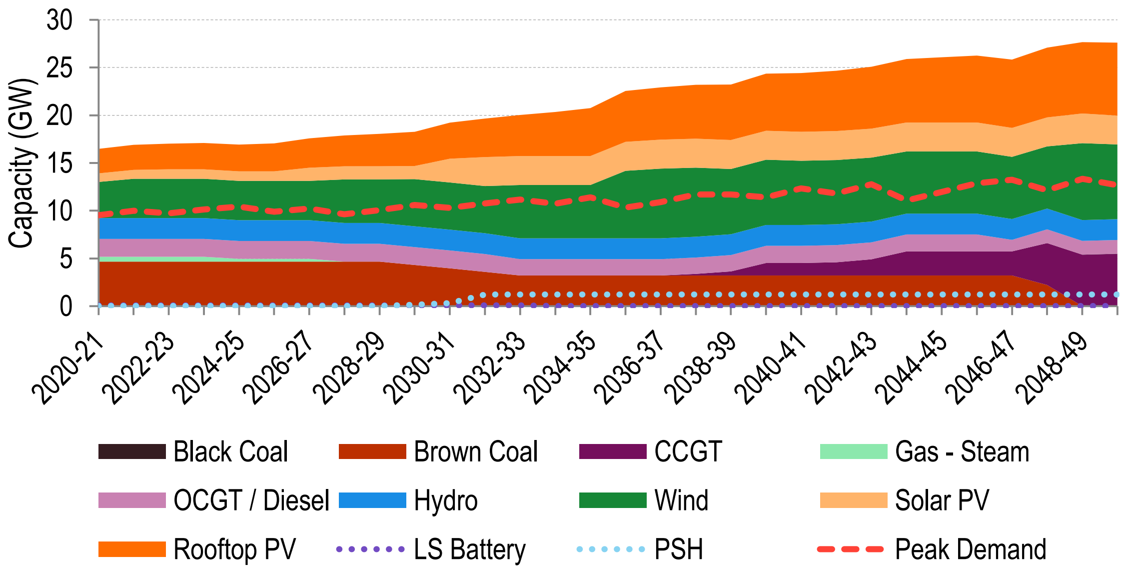
[162] Wind spills before solar PV is curtailed in the dispatch because solar PV has zero VOM and wind has non-zero VOM. However, that is factored into the long-run marginal cost of each technology when making the decision as to the installed capacity of each.

Figure 13: Tasmanian capacity mix forecast without Marinus Link, Status Quo scenario



The forecast capacity mix in Victoria without Marinus Link is shown in Figure 14. In the 2020s, there growth of large-scale wind and solar PV in Victoria is expected due to the assumed VRET 2025 and 2030 targets. All coal-fired generators in Victoria retire at their assumed maximum lifetimes, commencing with one unit of Yallourn in 2029-30. There is a coincident installation of a combination of wind and PSH capacity and increased imports from Tasmania in this year (Figure 12). KerangLink is assumed to be commissioned in 2030-31 coinciding with the assumed retirement of the second unit of Yallourn. In this year, solar PV and PSH capacity increase. A step increase in wind capacity is forecast in 2035-36 when Baywater retires in New South Wales. Exports from Victoria to New South Wales increase markedly at this time (Figure 12). CCGT capacity is installed from 2037-38 as part of least-cost solution to meet demand after further assumed coal and gas retirements in South Australia and Queensland. In general, assumed growth of peak demand and annual energy is strongest in Victoria and New South Wales which influences the least-cost development plan.

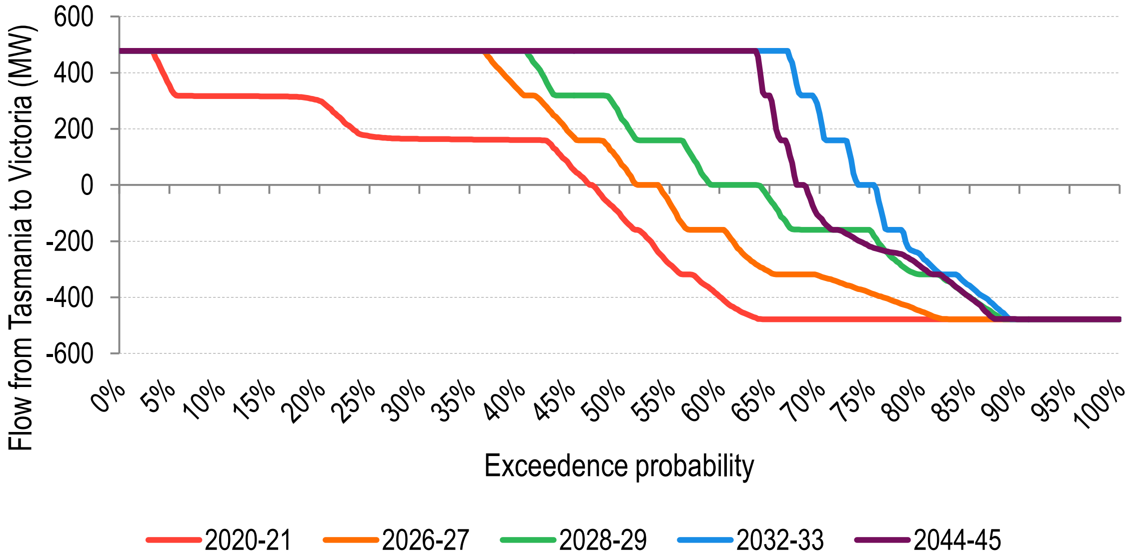
Figure 14: Victorian capacity mix forecast without Marinus Link, Status Quo scenario



The opportunity for Marinus Link can be assessed in a visual way by examining load duration curves for Basslink. These show the proportion of time in each period, typically a year at a time, when interconnection flows are limited in one or other direction, and thus creating a constraint on the ability for energy to be interchanged across the NEM.

Figure 15 shows the forecast flow duration chart for Basslink at sample years throughout the study period. At the start of the study period, Basslink is at its northward limit only about 5 % of the time, and is at its southward limit about 66 % of time. Over the course of the study, Basslink is forecast to become more heavily utilised and more constrained northward. From the early 2030s when Victorian coal-fired generators start to retire, Basslink is at its northward limit around 70 % of the time. This foreshadows the potential for Marinus Link to generate gross market benefits.

Figure 15: Forecast Tasmania-Victoria flow duration[163] with Basslink only, Status Quo scenario



7.2 Global Slowdown scenario without Marinus Link

In the Global Slowdown scenario, the key drivers of a different generation development plan relative to the Status Quo scenario are:

- Assumed low annual energy and peak demand growth,
- An assumed coal capacity constraint that drives earlier retirements of coal-fired generators. This constraint is in line with the Low NEM-wide demand scenario of the Aurora Energy Research's revenue adequacy report to AEMO[164], thermal coal retirement commences from 2025 and is accelerated by 3-5 GW from Status Quo scenario.

The earlier coal retirements and low demand growth are evident in the capacity and generation outlooks, both illustrated as a difference from the Status Quo scenario (Figure 16 and Figure 17). Significantly less capacity is installed in this scenario relative to the Status Quo scenario. However, there is still 45.5 GW of non-storage capacity and 7.2 GW of storage capacity installed on an economic basis over the study period on the mainland. Almost no new capacity is installed in Tasmania on an economic basis.

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

[164] Aurora Energy Research, May 2019, *Aurora Energy Research Analysis of AEMO's ISP Part 2: Economics of Coal Closures*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan. Accessed 18 October 2019.

Figure 16: Difference in NEM capacity mix forecast without Marinus Link between Global Slowdown scenario and Status Quo scenario (difference relative to Figure 10; positive values = higher capacity in Global Slowdown scenario).

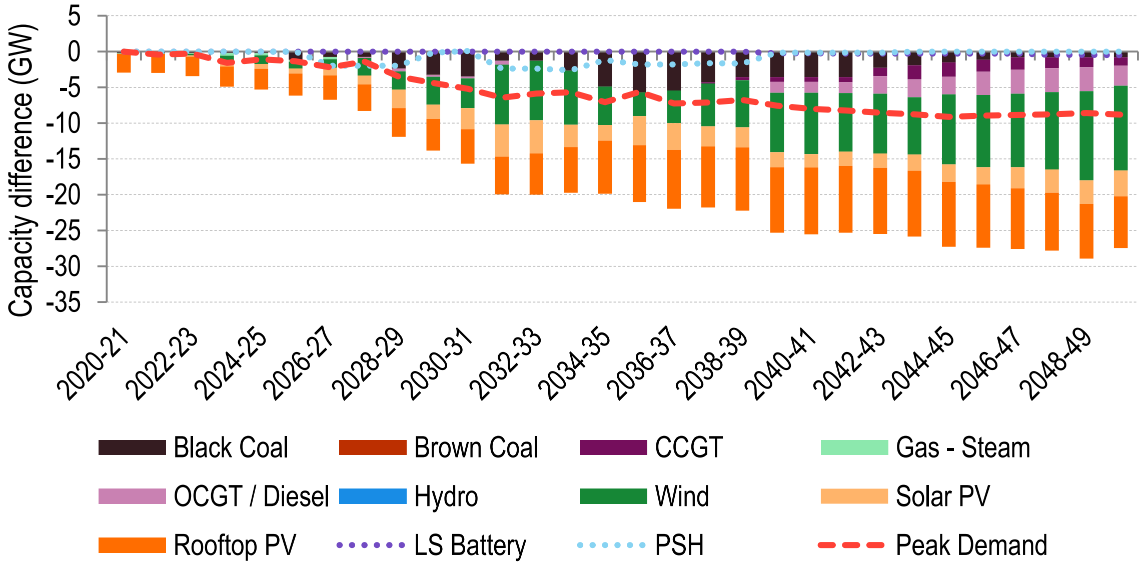


Figure 17: Difference in NEM generation mix forecast without Marinus Link between Global Slowdown scenario and Status Quo scenario (difference relative to Figure 11; positive values = higher energy in Global Slowdown scenario).

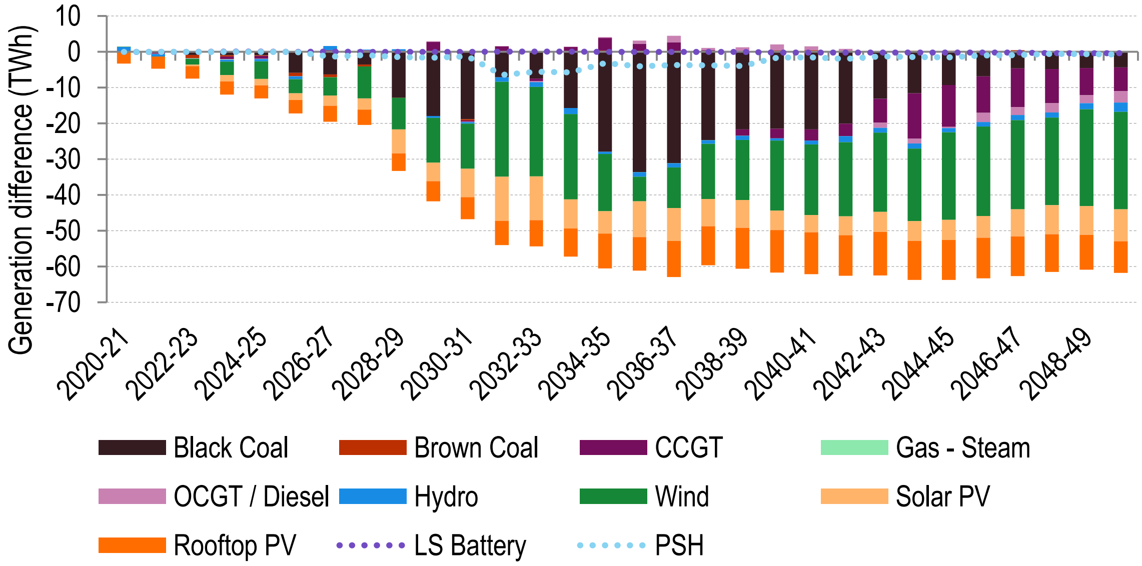
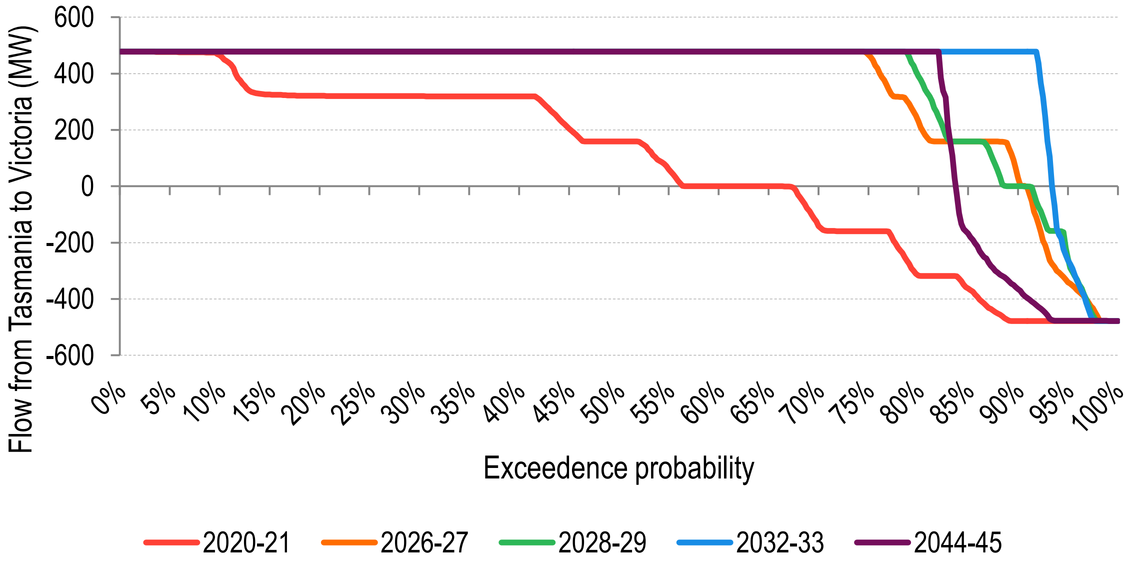


Figure 18 illustrates that Basslink is heavily constrained in the northward direction after the retirement of 240 MW of baseload demand in 2025-26. As in the Status Quo scenario, this foreshadows the potential for Marinus Link to generate gross market benefits.

Figure 18: Forecast Tasmania-Victoria flow duration with Basslink only, Global Slowdown scenario



7.3 Sustained Renewables Uptake scenario without Marinus Link

In the Sustained Renewables Uptake scenario, the assumed latest retirement date of coal-fired generators is typically three to five years earlier than the currently nominated dates modelling in the Status Quo scenario. This is apparent in both the capacity and generation outlooks, both illustrated as a difference from Status Quo scenario (Figure 19 and Figure 20).

Figure 19: Difference in NEM capacity mix forecast without Marinus Link between Sustained Renewables Uptake scenario and Status Quo scenario (difference relative to Figure 10; positive values = higher capacity in Sustained Renewables Uptake scenario).

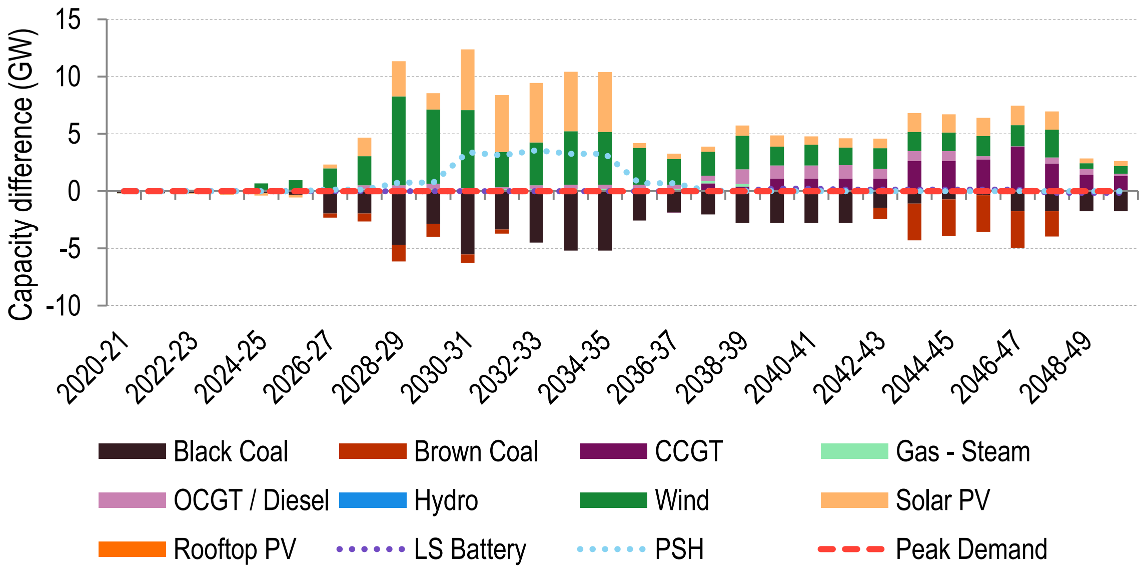
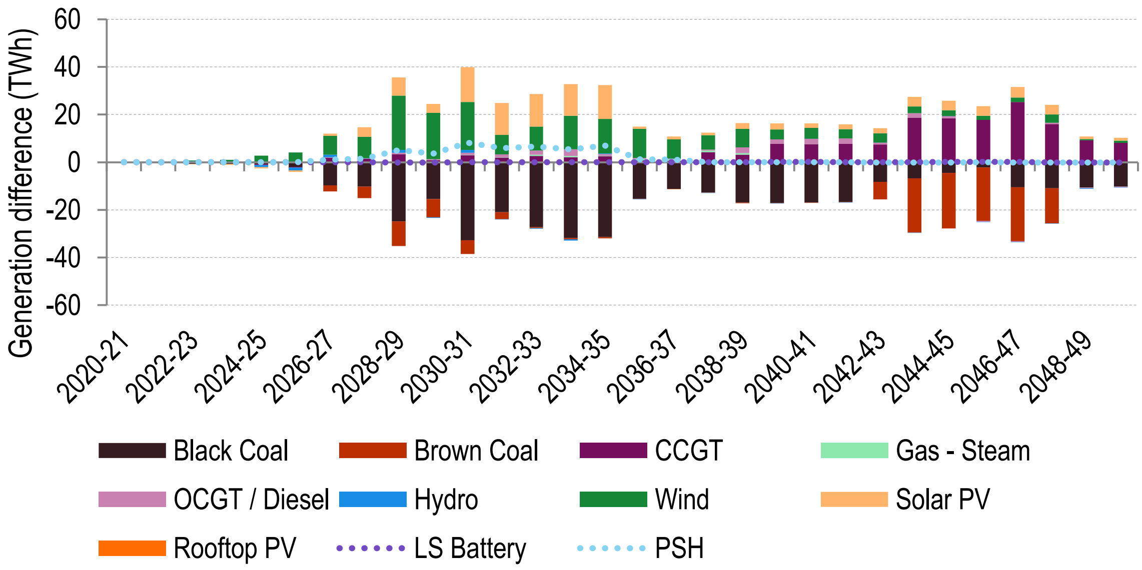


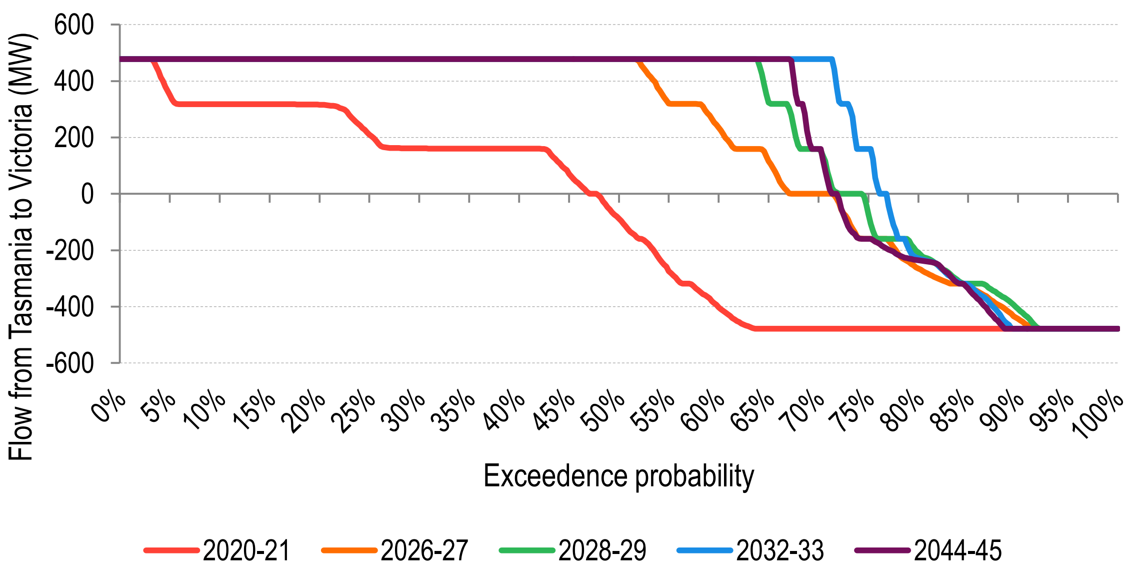
Figure 20: Difference in NEM generation mix forecast without Marinus Link between Sustained Renewables Uptake scenario and Status Quo scenario (difference relative to Figure 11; positive values = higher energy in Sustained Renewables Uptake scenario).



In this scenario, the coal-fired generation is forecast to be replaced with predominantly wind and solar PV from the mid-2020s to mid-2030s, then also gas-fired generation from the mid-2030s. It is forecast that there is an overall increase in the amount of capacity in the NEM relative to the Status Quo scenario from the mid-2020s reflecting the fact that the replacement wind and solar PV capacity has a lower capacity factor than the coal-fired generation it is replacing. By the end of the study period there is only 800 MW of additional capacity relative to the Status Quo scenario.

Figure 21 illustrates that Basslink is heavily constrained in the northward direction from the mid-2020s. Comparison to the equivalent data for the Status Quo scenario (Figure 15) shows Basslink is more heavily constrained in the Sustained Renewables Uptake scenario. The assumed earlier coal retirements in this scenario create an earlier opportunity for Tasmania to build additional capacity and export more energy, but this is limited by the capacity of Basslink.

Figure 21: Forecast Tasmania-Victoria flow duration with Basslink only, Sustained Renewables Uptake scenario



7.4 Accelerated Transition to a Low Emissions Future scenario without Marinus Link

Under this Accelerated Transition scenario, the assumed NEM emissions reduction target of 90 % reduction on 2016 levels by 2050 is forecast to drive earlier retirement of coal-fired generation than the Status Quo scenario (Figure 22 and Figure 23). Replacement capacity is forecast to initially be predominantly wind and large-scale solar PV, with additional peaking thermal capacity from 2037-38. There is a large forecast increase in large-scale storage in this scenario relative to the Status Quo scenario as PSH build limits bind in all mainland regions; in all regions, significant large-scale battery storage is only built after PSH limits bind. 3 GW of large-scale battery storage is forecast to be built in the mainland by the early 2040s and approximately 30 GW by 2050.

Figure 22: Difference in NEM capacity mix forecast without Marinus Link between Accelerated Transition scenario and Status Quo scenario (difference relative to Figure 10; positive values = higher capacity in Accelerated Transition scenario).

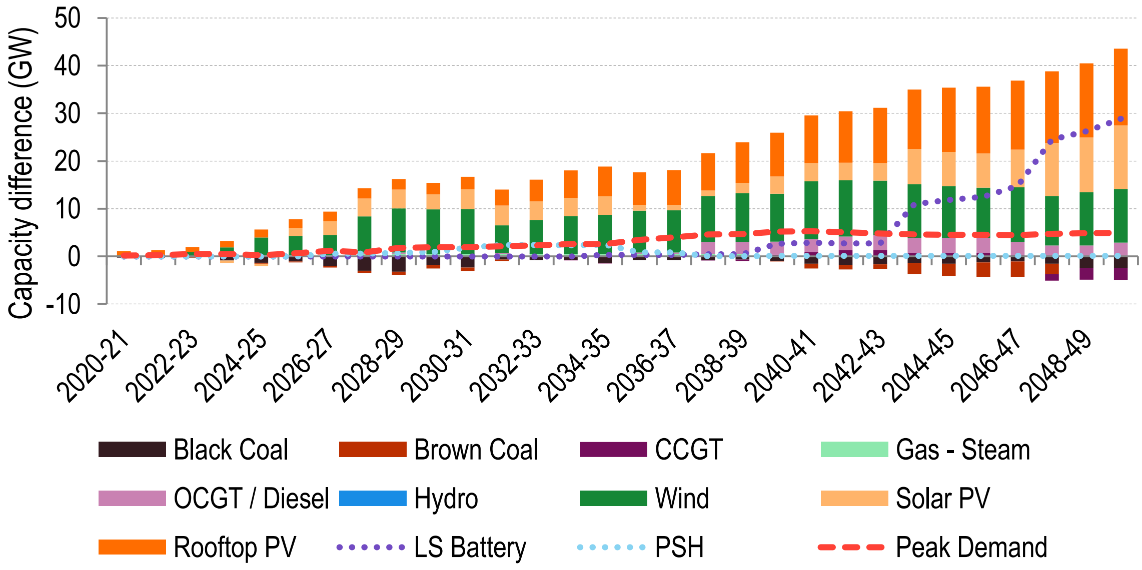
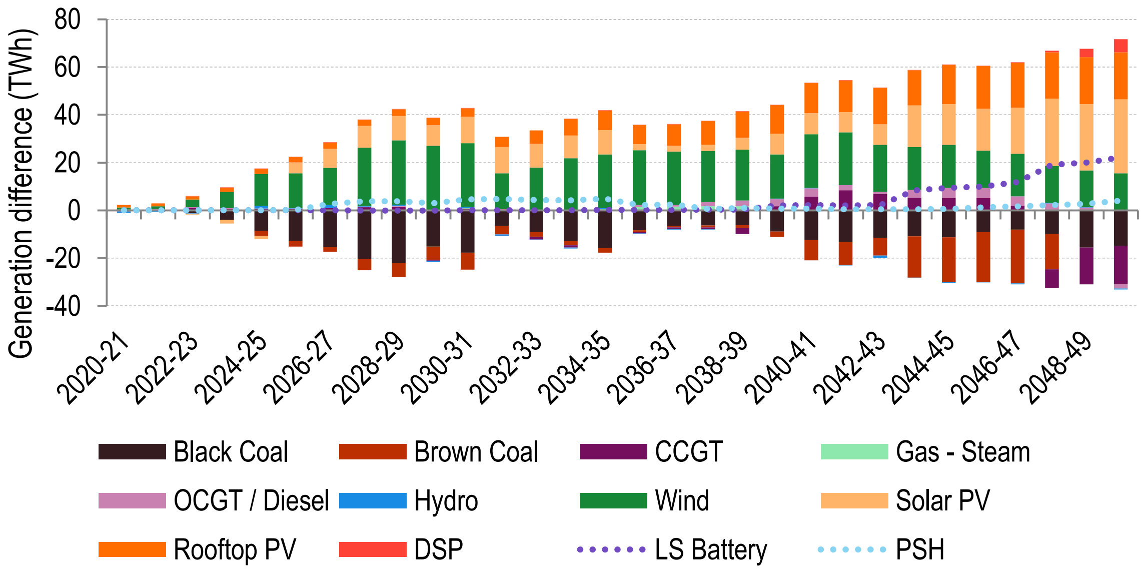


Figure 23: Difference in NEM generation mix forecast without Marinus Link between Accelerated Transition scenario and Status Quo scenario (difference relative to Figure 11; positive values = higher energy in Accelerated Transition scenario).



The differences in the forecast capacity mix relative to the Status Quo scenario are driven by key scenario assumptions such as the more stringent emission reduction target and the accelerated price reductions for renewable generation technology. Overall, assumed higher demand, coupled with the lower capacity factors of the wind, solar PV and peaking capacity replacing the forecast earlier coal retirements means that there is significantly more new capacity forecast in this scenario compared to the Status Quo scenario. An additional 25 GW of non-storage capacity and 28.9 GW of large-scale storage is built on economics (in addition to an assumed 16.1 GW more rooftop PV capacity) to meet an additional 12.3 TWh of sent-out operational energy demand by 2049-50.

Over 2039-40 and 2040-41, the combination of assumed rising demand across the mainland and the emission reduction constraint result in the staggered retirement of approximately 1 GW of brown coal-fired generation in Victoria earlier than the Status Quo scenario and the replacement by a combination of approximately 1,600 MW of new CCGT capacity, 400 MW additional OCGT capacity and 1,300 MW additional large-scale battery storage capacity (only some of this is in excess to that required in the Status Quo scenario as illustrated in Figure 24).

By 2039-40 additional dispatchable capacity is forecast to be needed in Victoria to meet assumed rising demand across the mainland (Figure 24). To keep within the emissions reduction constraint this is forecast to come from a combination of approximately 2,100 MW of new CCGT capacity, 400 MW additional OCGT capacity and 1,300 MW additional large-scale battery storage capacity (only some of this is in excess to that required in the Status Quo scenario as illustrate in Figure 24).

Figure 24: Difference in Victoria capacity mix forecast without Marinus Link between Accelerated Transition scenario and Status Quo scenario (positive values = higher capacity in Accelerated Transition scenario).

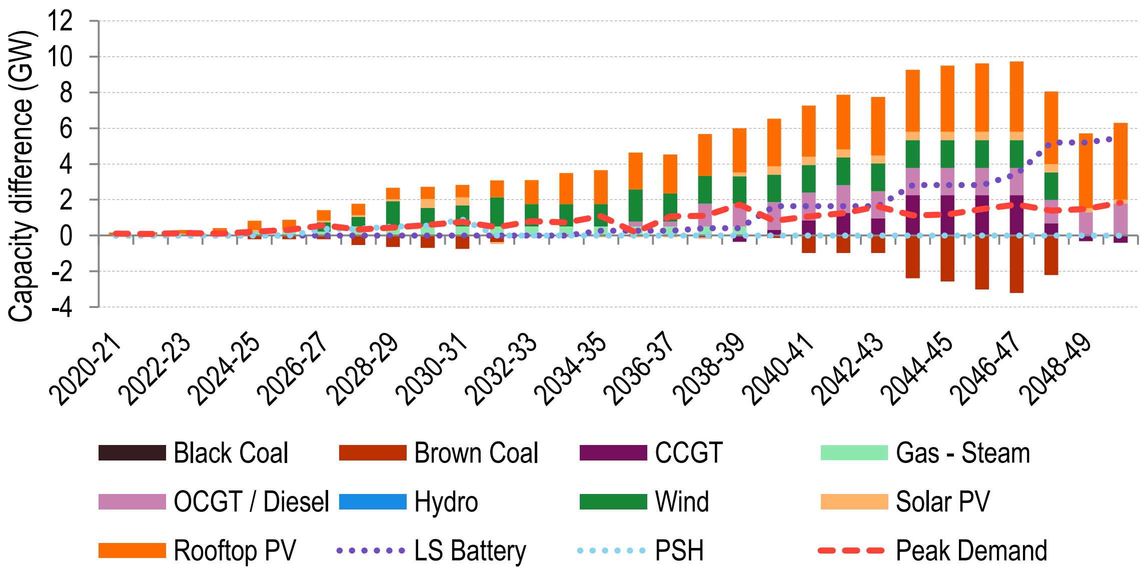
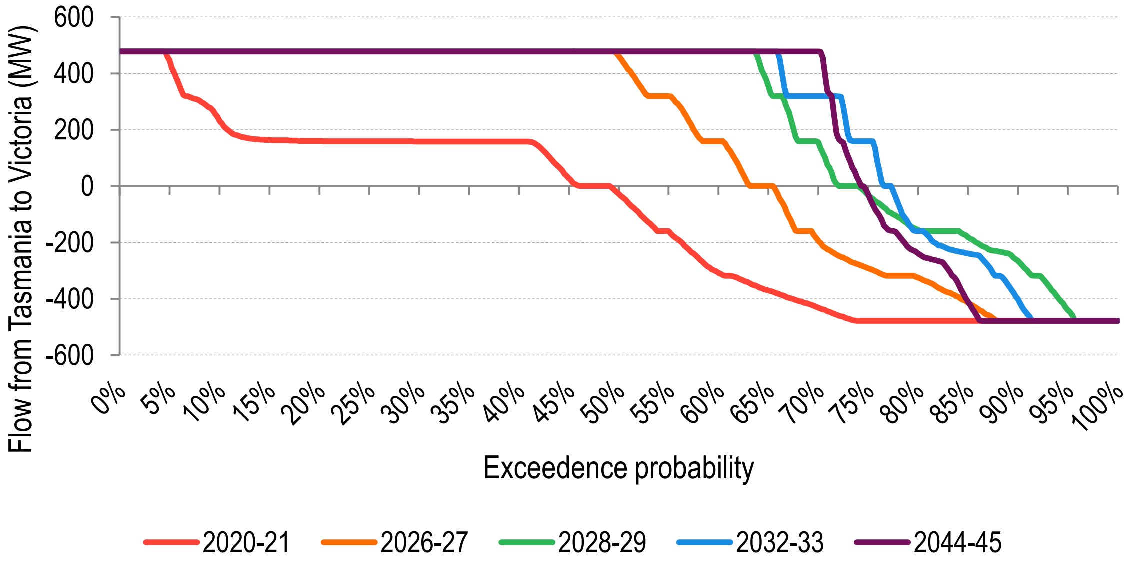


Figure 25 illustrates that Basslink is again heavily constrained in the northward direction from the mid-2020s. Comparison to the equivalent data for the Status Quo scenario (Figure 15) shows Basslink is more heavily constrained in the Accelerated Transition scenario. Although the drivers for earlier coal retirements are different between this scenario and the Sustained Renewables Uptake scenario, the earlier opportunity for greater export of energy from Tasmania is the same. Flow at maximum export for significant amount of time demonstrates that this opportunity is limited by the capacity of Basslink.

Figure 25: Forecast Tasmania-Victoria flow duration with Basslink only, Accelerated Transition scenario



7.5 Opportunity for Marinus Link and other interconnectors

In all scenarios, retirements of coal-fired plant in the NEM (due to assumed maximum lifetimes or earlier economic retirements by the model due to other constraints) are the dominant factor driving change in the capacity mix, with replacement by a combination of:

- ► Renewable wind and solar PV are forecast to meet, at least cost, the energy gap caused by retirements of base load coal-fired energy producing plant,
- ► Ongoing development of behind the meter rooftop PV and battery storage reducing the growth of NEM schedulable energy demand,
- ► PSH, batteries and gas 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.

The expanded mainland interconnectors in all scenarios reduce the overall need for capacity across all regions due to diversity in demand and supply. Specifically, they facilitate efficient operation of existing and new capacity by providing:

- ► Ability to take advantage of peak load diversity between regions by using generation capacity that is spare in one region to deliver capacity to adjacent regions that would otherwise be short or needing to build more,
- ► Ability to share fossil fuel and hydro resources between regions such that the lowest fuel cost generation is used all the time,
- ► Ability for forced outages to be covered by transferring energy and capacity between regions.

The assumed expansions on the mainland are mostly bi-directional and have the effect of reducing the amount of time that flows are forecast to be at their limits.

For this study, without Marinus Link, the Basslink interconnector is forecast to become increasingly constrained at the limit in the northerly direction in all scenarios (Figure 15, Figure 18, Figure 21 and Figure 25). For all four 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 early

2030s or earlier in all scenarios. This is because expected growth in wind generation in Tasmania exceeds the assumed growth in demand, and therefore net energy transfers to the mainland are forecast to increase over time, within the capacity limitations of Basslink.

The level of constraining of Basslink in each scenario is related to the available wind resource in Tasmania that is economically able to be developed. Even with favourable wind resources in Tasmania, the model trades off the amount of development that is economic against the risk that either wind or hydro generation will be curtailed if it cannot be stored at times when demand and Basslink export capacity are less than can be accommodated by backing off hydro generation to allow for wind production.

In the Global Slowdown scenario, Tasmanian demand is assumed to be lower, but this results in more hydro and wind being available to export to the mainland, so the outcome in terms of flows to the north across Basslink is similar to that of other cases.

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

8. Marinus Link forecast gross market benefits

8.1 Summary of forecast gross market benefits

Table 15 shows the forecast gross market benefits outcomes over the modelled 30-year horizon, across all scenarios and Marinus Link options (including association AC transmission augmentations), at different modelled timings. The values are discounted to 1 July 2025[165] and can be multiplied by 0.709 to be translated to values discounted to 1 July 2019 as used by TasNetworks in the PADR.[166]

Table 15: Forecast gross market benefits of Marinus Link for different size and timing options, millions real June 2019 dollars discounted to 1 July 2025

Option	Marinus Link timing	Scenario			
		Global Slowdown	Status Quo	Sustained Renewables	Accelerated Transition
1,500 MW	2026 & 2028	2,901	3,398	3,997	6,551
	2027 & 2028	2,869	3,330	3,894	6,452
	2028 & 2030	2,833	3,290	3,795	6,300
	2028 & 2032	2,814	3,231	3,661	6,194
	2030 & 2032	2,728	3,125	3,470	5,980
	2030 & 2034	-	3,054	3,339	-
1,200 MW	2026 & 2028	2,717	3,016	3,528	5,665
	2028 & 2032	2,615	2,844	3,204	5,316
750 MW	2026	2,212	2,237	2,616	4,010
	2028	2,157	2,147	2,467	3,801
600 MW	2026	1,997	1,952	2,271	3,418
	2028	1,940	1,868	2,136	3,240

The computation of net market benefits and determination of the preferred option has been conducted by TasNetworks outside of this Report[166] as it is dependent on option costs which were developed independently by TasNetworks.

The forecast gross market benefits of Marinus Link in each scenario need to be compared to the relevant Marinus Link costs to determine whether there is a positive net benefit. If values of other benefits which are not captured by the least-cost planning model can be computed, such as ancillary services cost reduction, these should also be added. The costs (if any) associated with the

[165] Discounting benefits to 1 July 2025 continued 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. Given the costs and benefits would accrue from the commissioning year onwards, 2025 was considered an appropriate base year for discounting in the Initial Feasibility Report. At the time PADR modelling commenced, it was not clear which year would be the optimal commissioning year for Marinus Link, other than it could be no earlier than 2025. With no obvious alternative commissioning year, the practise of discounting to 2025 was continued. Given the results can be easily discounted to an alternative year by multiplying by an appropriate factor, the choice of base year for discounting purposes is somewhat arbitrary.
[166] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

changes in Tasmanian hydro capacity that are applied in the model in only the simulations including Marinus Link must also be added to the costs.

All references to the preferred option in this Report 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." [167]

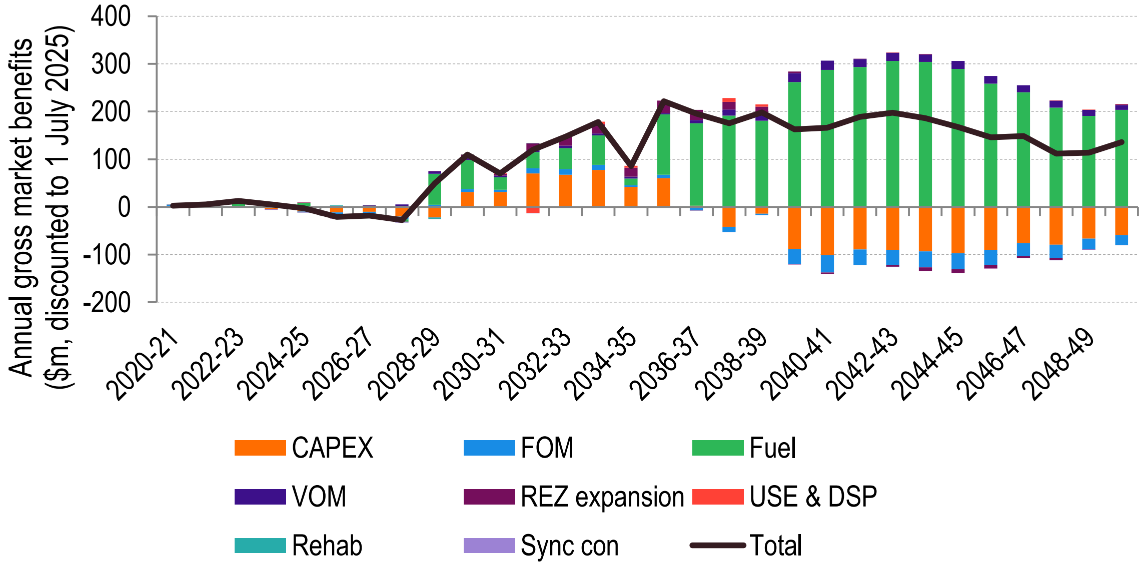
The remainder of Section 8 explores the timing and sources of these benefits, with a focus on the preferred option and timing in the Status Quo scenario: 1,500 MW, stage 1 2028, stage 2 in 2032.

8.2 Status Quo scenario with Marinus Link

8.2.1 Forecast gross market benefits of Marinus Link, Status Quo scenario

It is forecast that the dominant source of market benefits associated with Marinus Link in the Status Quo scenario are fuel cost savings. This is illustrated in Figure 26 which shows the forecast annual gross market benefits associated with Marinus Link, stage 1 2028 and stage 2 2032. Significant fuel cost savings are forecast to begin to accrue from 2028-29 when the first stage of Marinus Link becomes operational. From this time, the forecast annual benefits fluctuate with the changing supply-demand balance in Victoria, New South Wales and Queensland with demand growth and progressive thermal retirements. Negative values in Figure 26 occur when there are expected costs to the NEM associated with the development of Marinus Link (excluding the costs of Marinus Link itself).

Figure 26: Forecast annual gross market benefits[168] of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario; millions real June 2019 dollars discounted to 1 July 2025



Other salient features of the annual gross market benefits are:

- There are small costs and 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.

[167] 14 December 2018, *RIT-T and RIT-D Application Guidelines 2018*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018. Accessed 26 September 2019.
[168] The sum of all annual benefits in present value terms is equal to the total gross benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032 in Table 15.

- In the late 2020s to mid-2030s there are forecast capex benefits associated with reduced New South Wales solar PV and PSH build. This switches to capex costs from 2037-38 after growth in demand and several New South Wales and Queensland coal retirements. From 2037-38, the forecast fuel cost savings of avoiding running gas-fired generators in Victoria outweigh the higher capex costs of increased wind, solar PV and PSH capacity. This is explored further in Section 8.2.2.
- The dip in gross market benefits in 2034-35 is associated with reduced water use in Tasmania with Marinus Link. Water is withheld in 2034-35 and benefits foregone to generate larger fuel savings after Bayswater is assumed to retire in 2035-36.
- Other categories of gross market benefits are comparatively small.

Table 16 shows the forecast total cumulative gross market benefits by category and region. The largest category of forecast benefits is fuel cost savings at $3,827m. There is a forecast cumulative capex cost of $674m to achieve these fuel cost savings. This data reinforces the picture illustrated in Figure 26.

Table 16: Summary of forecast gross market benefits by category and region of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario; millions real June 2019 dollars discounted to 1 July 2025

Region	Capex	FOM	Fuel	VOM	REZ expansion	USE / DSP	Rehab	Sync cons	Total
NSW	1,000	204	359	99	101	-17	0	0	1,746
QLD	38	23	124	15	9	-2	-2	0	205
VIC	699	100	3,269	280	-26	16	-1	0	4,337
SA	375	82	256	36	25	17	-1	0	790
TAS	-2,786	-708	-180	-181	16	0	0	-6	-3,846
Total	-674	-300	3,827	249	124	14	-4	-6	3,231

Table 16 also contains additional detail on the region where benefits accrue. Victoria is forecast to be the main beneficiary of Marinus Link, with large fuel cost savings, but also some capex savings forecast. New South Wales is also forecast to be a net beneficiary with most of the capex savings accruing there. Tasmania is forecast to incur a cost (also excluding the cost of Marinus Link which is not considered in this Report), mostly due to large additional capital investment, but also forecast additional FOM, fuel and VOM costs. The next section (Section 8.2.2) will drill down into more detail on the categories, location and timing of benefits.

8.2.2 Generation development plan with Marinus Link, Status Quo scenario

Figure 27 shows the change in NEM capacity with Marinus Link 1,500 MW, commissioned in two 750 MW stages in 2028 and 2032, relative to the without Marinus Link case shown in Figure 10. Meanwhile, Figure 28 shows a similar change in NEM generation. Both charts mostly illustrate the same broad trends, while Figure 29 and Figure 30 illustrate the forecast differences in capacity due to Marinus Link in Tasmania and Victoria in isolation.

Figure 27: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario (difference relative to Figure 10; positive values = higher capacity with Marinus Link)

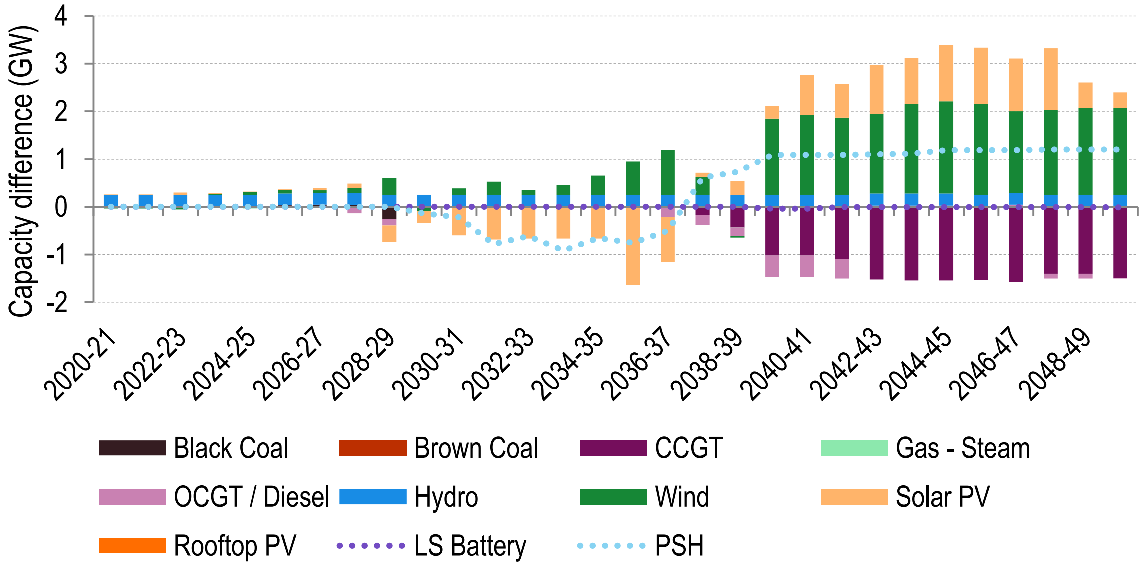


Figure 28: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario (difference relative to Figure 11; positive values = higher energy with Marinus Link)

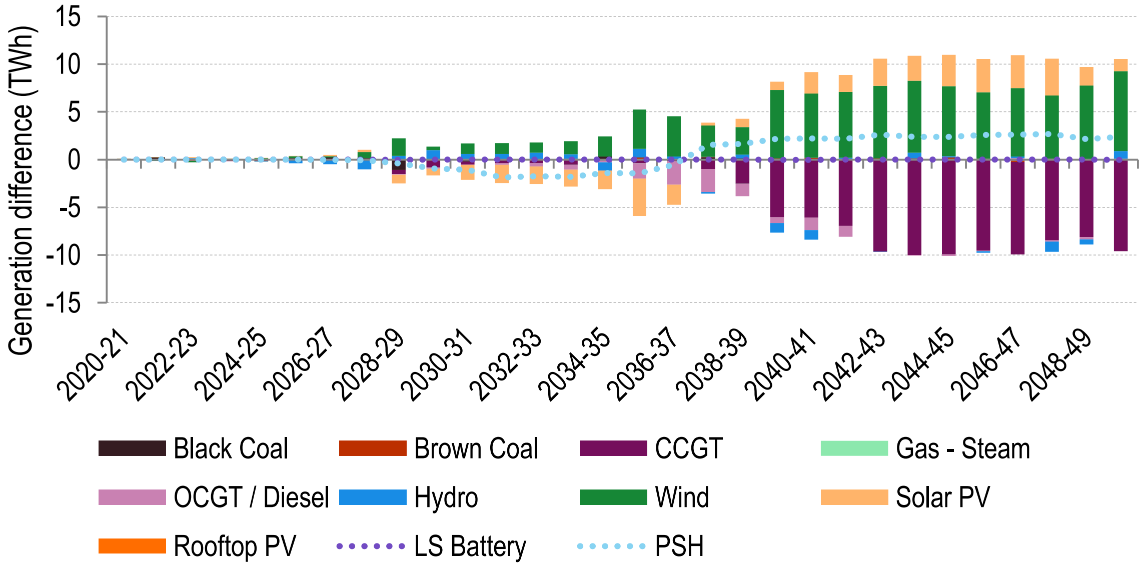


Figure 29: Difference in Tasmanian capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario (difference relative to Figure 13; positive values = higher capacity with Marinus Link)

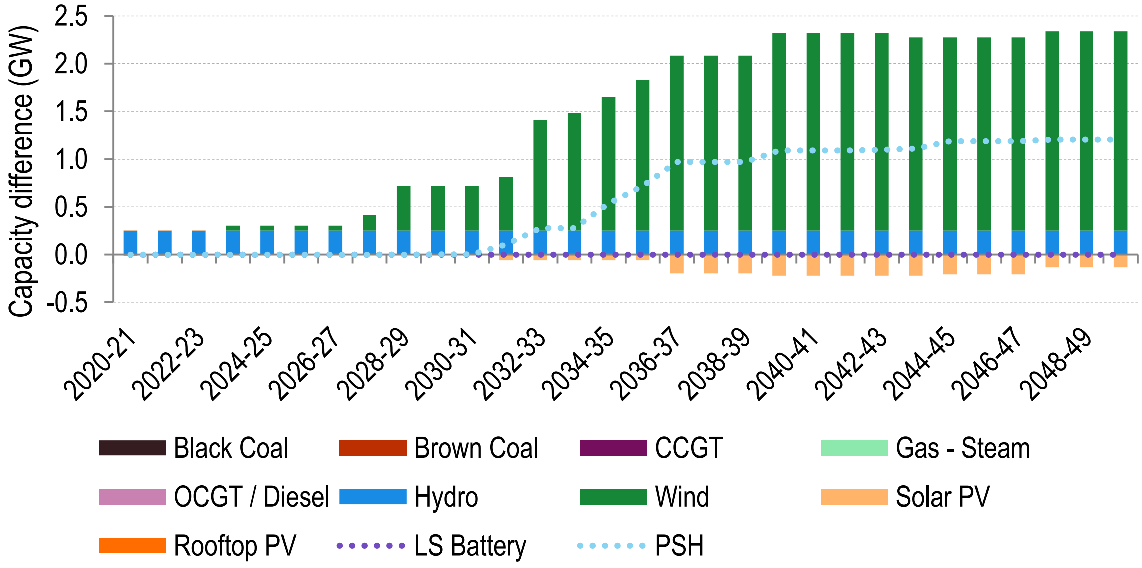
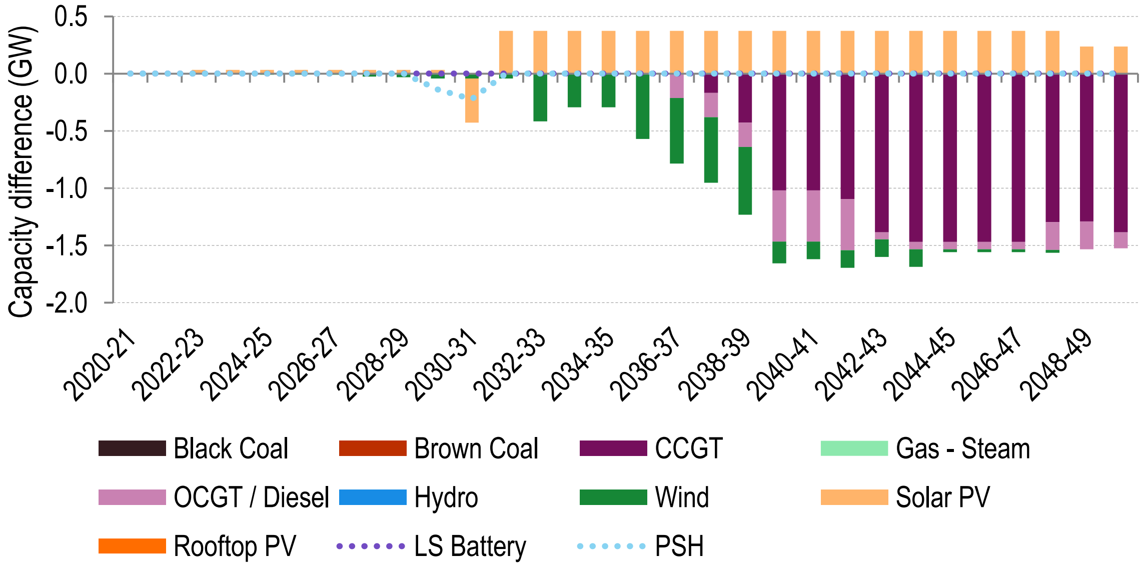


Figure 30: Difference in Victorian capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario (difference relative to Figure 14; positive values = higher capacity with Marinus Link)



The key forecast trends can be broken into two time-periods where different trends are observed. The boundary at around 2037-38 does not correspond to any major retirements but is a critical point in the supply-demand balance after the retirement of Bayswater in 2035-36 and due to ongoing load growth in New South Wales.

From the study start until 2036-37:

- For the NEM overall, from when the first stage is commissioned in 2028, Marinus Link is forecast to facilitate increased development of wind and deferral of solar PV relative to the Basslink-only counterfactual (Figure 27).
- From 2029-30 to 2036-37, mainland PSH development is forecast to be avoided with Marinus Link as Marinus Link enables better utilisation of existing conventional hydro storages in Tasmania (Figure 27). There is also a forecast increase in new Tasmanian PSH during this time (Figure 29).

- The additional Tasmanian export capacity results in a forecast increase in wind capacity built in Tasmania, starting at an additional 50 MW in 2023-24[169] and increasing to an additional 1,800 MW by 2036-37 (Figure 29).
- Up to 900 MW of solar PV capacity is avoided from 2028-29 until 2036-37 (Figure 27), concentrated in New South Wales.

From 2037-38 until study end:

- By the end of the study, up to 1,800 MW more wind capacity and 300 MW of solar PV capacity is forecast with Marinus Link in the NEM overall.
- By 2037-28 and through the 2040s, PSH development on the mainland is forecast to be similar with and without Marinus Link; however, additional PSH capacity is forecast to be built in Tasmania with Marinus Link (Figure 29). There is 1,200 MW more PSH capacity forecast in the NEM overall by 2049-50 with Marinus Link, all located in Tasmania.
- From 2038-39 to the end of the study, Marinus Link is forecast to replace significant volumes of high variable cost energy from existing and new CCGTs in Victoria (Figure 30) with lower variable cost wind and PSH generation, much of which comes from Tasmania (Figure 29). This is associated with higher overall capex costs that are outweighed by fuel benefits (Figure 26). There is up to 1,500 MW less CCGT capacity forecast to be developed by 2049-50 (Figure 27), concentrated in Victoria (Figure 30).
- The additional Tasmanian export capacity results in a forecast increase in wind capacity built in Tasmania, starting at an additional 50 MW in 2023-24[169] and increasing to an additional 2,100 MW by the end of the study (Figure 29). The total new wind capacity in Tasmania reaches 3,100 MW in the Status Quo scenario with Marinus Link.
- From 2038-39 to the end of the study, Marinus Link also facilitates the economic development of additional solar PV on the mainland. It enables energy to be stored in Tasmania in the daytime and returned to the mainland at morning and evening peak demand periods.

Throughout the study period, the analysis shows an increase in hydro capacity in Tasmania with Marinus Link (Figure 27 and Figure 29). This is the assumed increase in West Coast and Tarraleah capacity with Marinus Link discussed in Section 4.2.

In overall terms, Marinus Link is forecast to accrue benefits through a reduced need to operate existing and develop new high fuel cost gas-fired generation on the mainland. This is replaced by hydro capacity from existing conventional hydro and new PSH in Tasmania. This is the primary driver of benefits in the forecast.

Development of Marinus Link is also associated with a redistribution of the location and balance of new wind and solar PV capacity; overall more wind capacity is forecast to be built and operated in Tasmania, while solar PV capacity is deferred then ultimately increased on the mainland, mainly in New South Wales and Victoria. The development of wind capacity in Tasmania is favoured with Marinus Link because wind resource in Tasmania has a higher assumed capacity factor and benefits from development closer to assumed deeper storage sources (existing conventional hydro and new PSH).

[169] Marinus Link is able to effect a change in Tasmanian generation before the first stage is built as water is managed with advanced knowledge of Marinus Link's entry. The model builds some additional wind capacity and withholds hydro in order to use that hydro generation at higher value after entry of Marinus Link.

8.2.3 Interconnector utilisation with Marinus Link, Status Quo 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 31, while Figure 32 shows the difference in transfers relative to the without Marinus Link case (shown in Figure 12). With Marinus Link, more energy flows out of Victoria into South Australia and New South Wales until 2040. After this time, average flow from Victoria to New South Wales is forecast to remain northward, but Marinus Link decreases the average northward flow due to the forecast reduction in CCGT capacity in Victoria.

Figure 31: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario

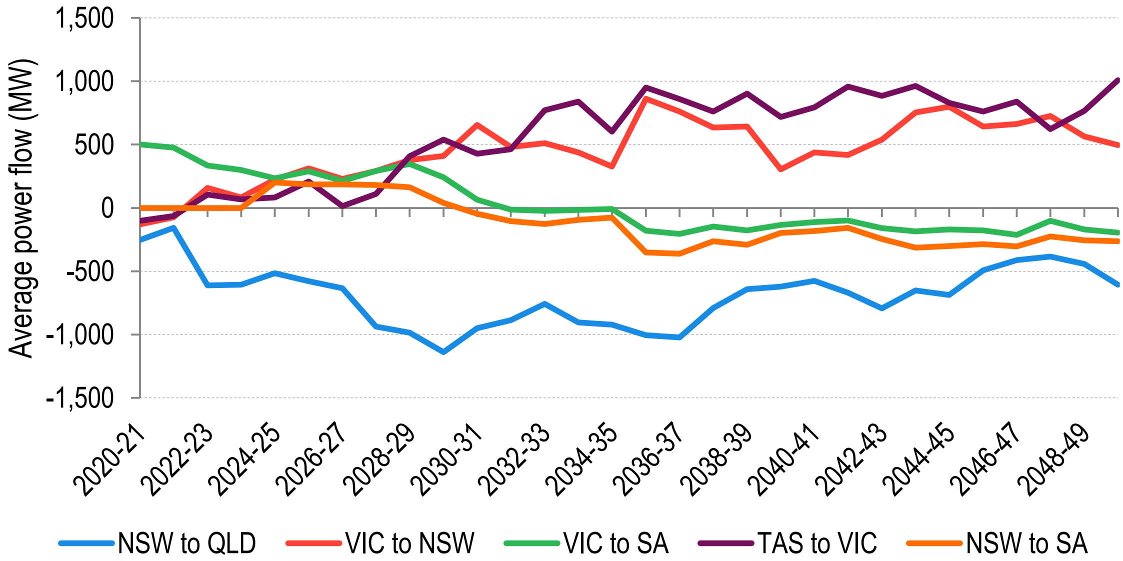


Figure 32: Difference in forecast average annual interconnector power flow due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario (difference relative to Figure 12; positive values = higher flow with Marinus Link)

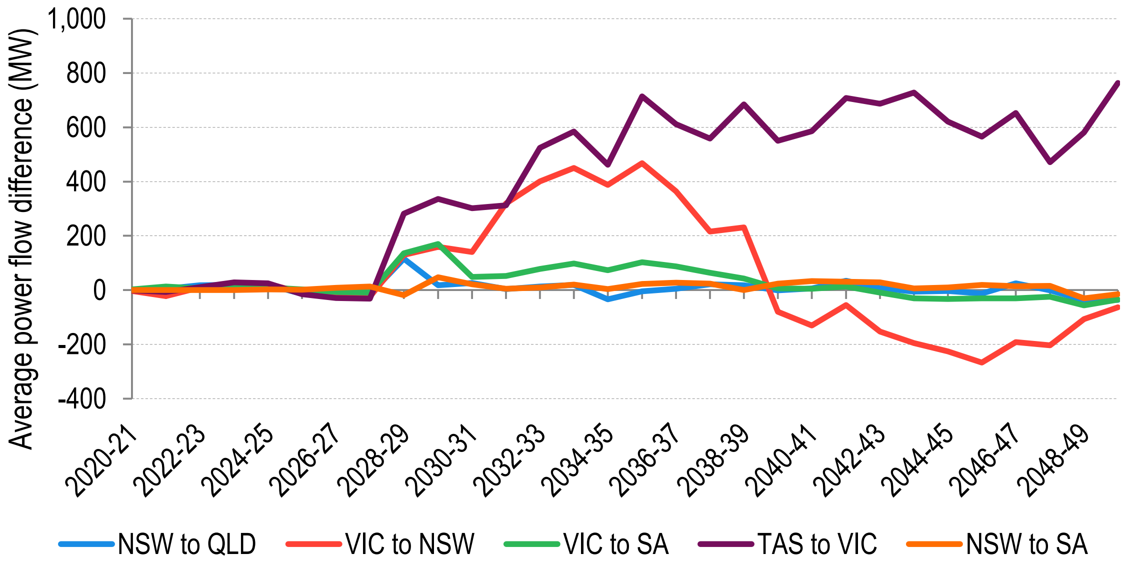
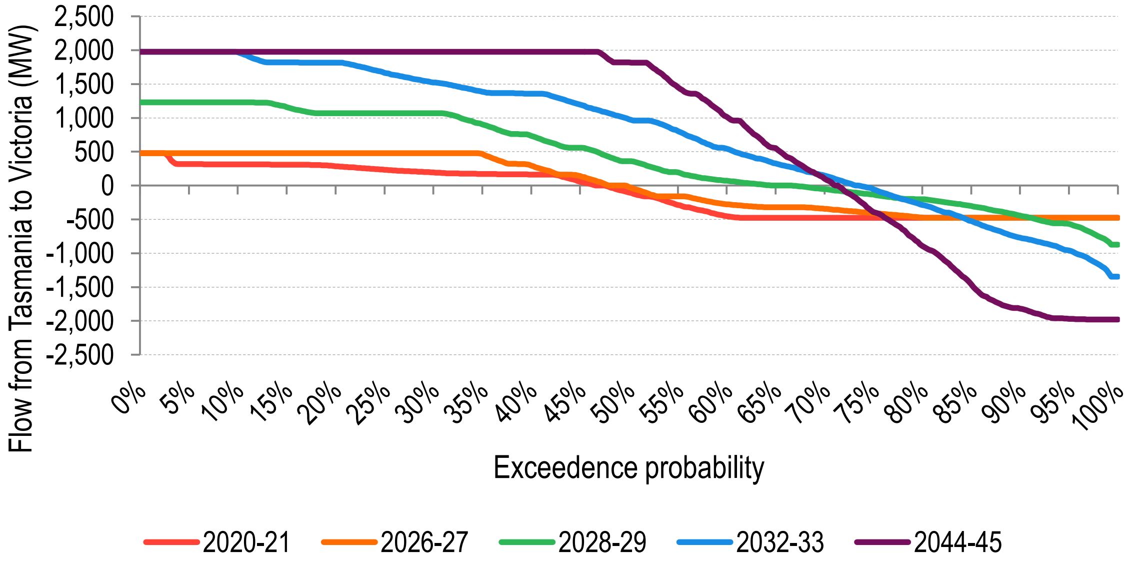


Figure 33 shows the forecast flow duration for all combined links between Tasmania and Victoria at sample study years. For the first two years illustrated (2020-21 and 2026-27), Basslink is the only interconnector. Flows are forecast to shift northerly over these study years so that Basslink forecast flow is at its northward limit around 35 % of the time by 2026-27. When the first stage of Marinus Link enters in 2028-29, it is forecast to be immediately well-utilised. In the year of entry, Basslink and Marinus Link stage 1 forecast flow is at their combined northward limit around 15 % of the time. After the second stage of Marinus Link enters in 2032-33, the forecast flow of the three links is at the combined northward limit around 10 % of the time. Utilisation is forecast to steadily increase over the rest of the study period so that the forecast flow of the three links is at their combined northward limit around 45 % of the time in the final study year.

Figure 33: Forecast Tasmania-Victoria flow duration with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario



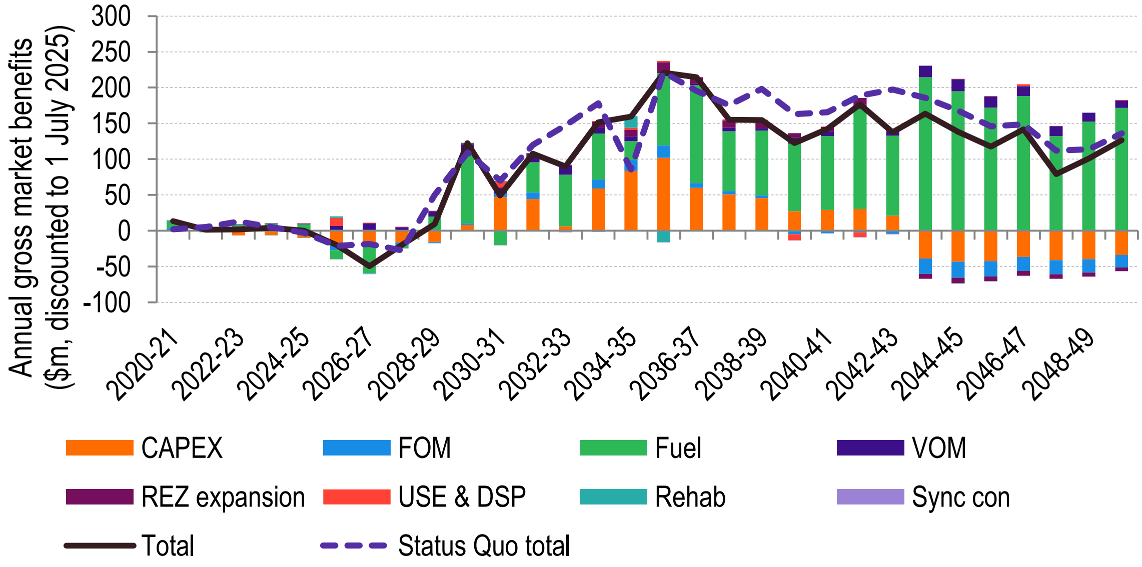
8.3 Global Slowdown scenario with Marinus Link

8.3.1 Forecast gross market benefits of Marinus Link, Global Slowdown scenario

In the Global Slowdown scenario, it is forecast that the dominant source of market benefits is fuel cost savings, as it was in the Status Quo scenario. This is illustrated in Figure 34 which shows the forecast annual gross market benefits associated with Marinus Link, stage 1 2028 and stage 2 2032. Again, fuel cost savings accrue from the time Marinus Link enters in 2028-29. From the late-2030s, the fuel cost benefits are lower in part due to the lower gas fuel cost assumed in this scenario.

In this scenario, capex savings persist for longer than they did in the Status Quo scenario. Lower assumed demand means the need for new capacity is delayed relative to the Status Quo scenario. The inflection point where additional capex is forecast to generate larger fuel cost savings doesn't occur until 2043-44 (delayed from 2037-38 in the Status Quo scenario).

Figure 34: Forecast annual gross market benefits[170] of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Global Slowdown scenario; millions real June 2019 dollars discounted to 1 July 2025



The overall trends in the category and region of gross market benefits are similar in the Global Slowdown and Status Quo scenarios (Table 17 compared to Table 16). As in the Status Quo scenario, Victoria is still the main beneficiary (primarily through fuel cost savings and some capex savings), then New South Wales (through capex and fuel cost savings). All mainland regions are forecast to accrue benefits overall, while Tasmania incurs cost (also excluding the cost of Marinus Link which is not considered in this Report) mostly associated with increased capital investment.

Table 17: Summary of forecast gross market benefits by category and region of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Global Slowdown scenario; millions real June 2019 dollars discounted to 1 July 2025

Region	Capex	FOM	Fuel	VOM	REZ expansion	USE / DSP	Rehab	Sync cons	Total
NSW	626	122	480	132	28	11	-4	0	1,394
QLD	109	24	70	14	24	3	0	0	244
VIC	545	64	1,837	203	1	9	0	0	2,658
SA	92	22	225	37	-2	-5	0	0	368
TAS	-1,124	-318	-243	-163	0	0	5	-7	-1,851
Total	248	-86	2,368	222	51	17	2	-7	2,814

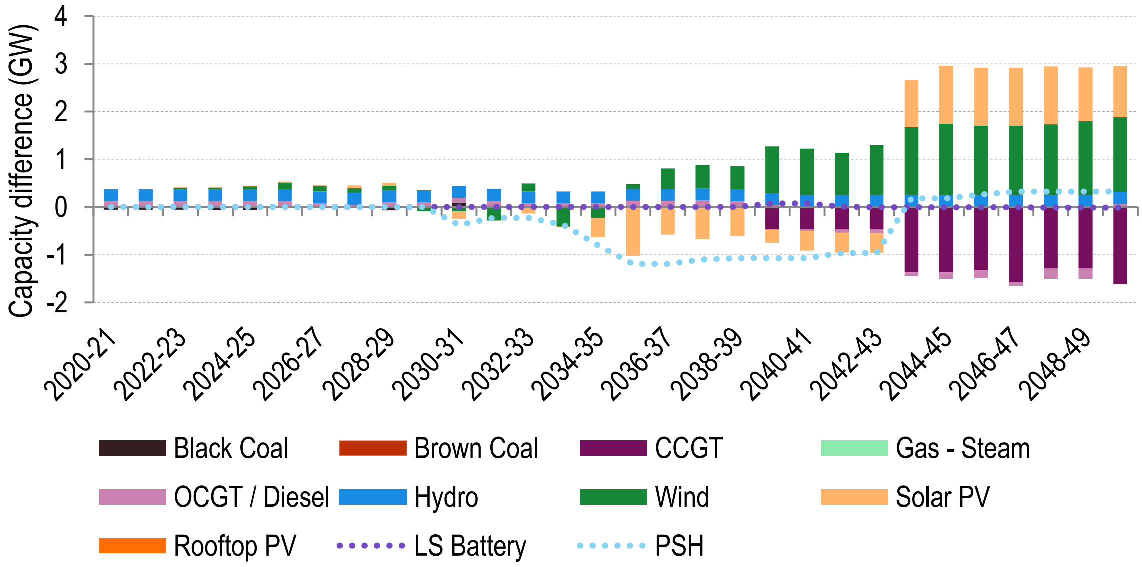
The delay in the inflection point where additional capex is forecast to generate larger fuel cost savings means that there is an overall capex benefit in the Global Slowdown scenario, whereas the Status Quo had an overall capex cost.

[170] The sum of all annual benefits in present value terms is equal to the total gross benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032 in Table 15.

8.3.2 Generation development plan with Marinus Link, Global Slowdown scenario

Figure 35 displays the difference in capacity across the NEM between the case with Marinus Link 1,500 MW, commissioned in two 750 MW stages in 2028 and 2032, relative to the without Marinus Link case for the Global Slowdown scenario.

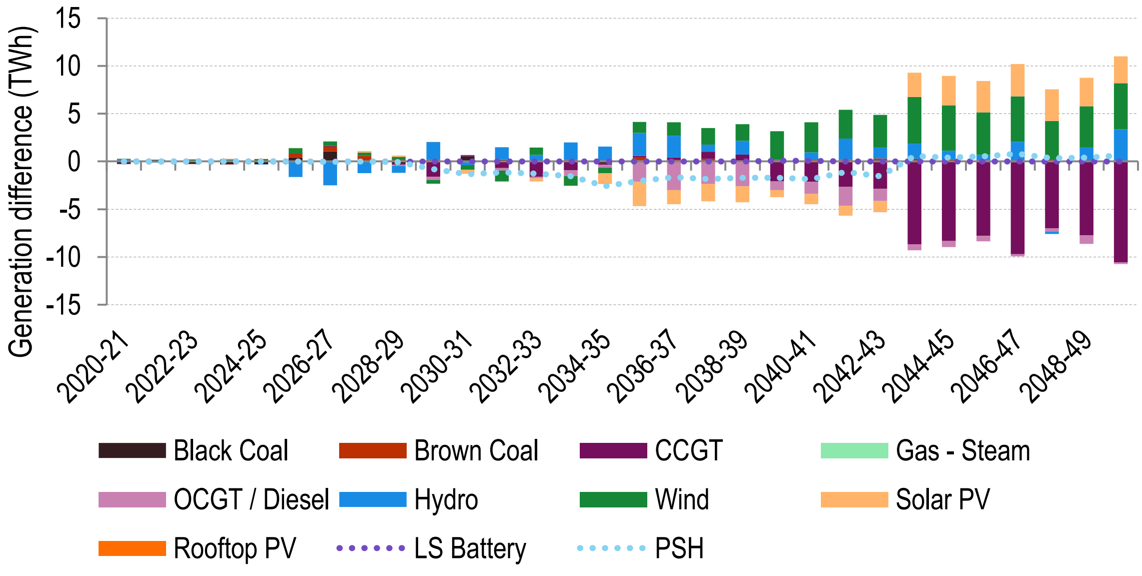
Figure 35: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Global Slowdown scenario (positive values = higher capacity with Marinus Link)



The primary difference in the forecast capacity outlook relative to the Status Quo scenario (Figure 27), is a shift in the timing of the capacity differences. Due to the lower demand forecast that has been assumed for this scenario, there is less incentive for new entrant capacity to be installed within the NEM. Consequently, the deferral of new entrant solar PV and PSH is forecast to occur from the mid-2030s to the early 2040s. From 2043-44 onward, it is forecast that there will be approximately 1,500 MW less OCGT and CCGT capacity with Marinus Link, concentrated in Victoria.

The difference in forecast generation due to Marinus Link (Figure 36) shows similar trends to the difference in forecast capacity mix. The only notable feature that differs is the forecast decrease in hydro generation with Marinus Link in the mid-2020s. This difference occurred in the Status Quo scenario (Figure 28) but is more exaggerated in the Global Slowdown scenario. This forecast decrease occurs in Tasmania. The least-cost use of Tasmanian hydro is to conserve water in these years so that more is available, at higher value, in the late 2020s when coal is assumed to retire. Conserving water in these years drives fuel cost increases in the mainland in these years (Figure 34) and notable features in Tasmania-Victoria interconnector flows as discussed in Section 8.3.3.

Figure 36: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Global Slowdown scenario (positive values = higher energy with Marinus Link)



8.3.3 Interconnector utilisation with Marinus Link, Global Slowdown scenario

Average interconnector flows between regions for the Global Slowdown scenario with Marinus Link are shown in Figure 37. As forecast in the Status Quo scenario (Figure 31), flows are generally forecast to be towards New South Wales, although trends are not as strong. In particular, northward flow from Victoria to New South Wales is reduced relative to the Status Quo scenario.

Figure 37: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Global Slowdown scenario

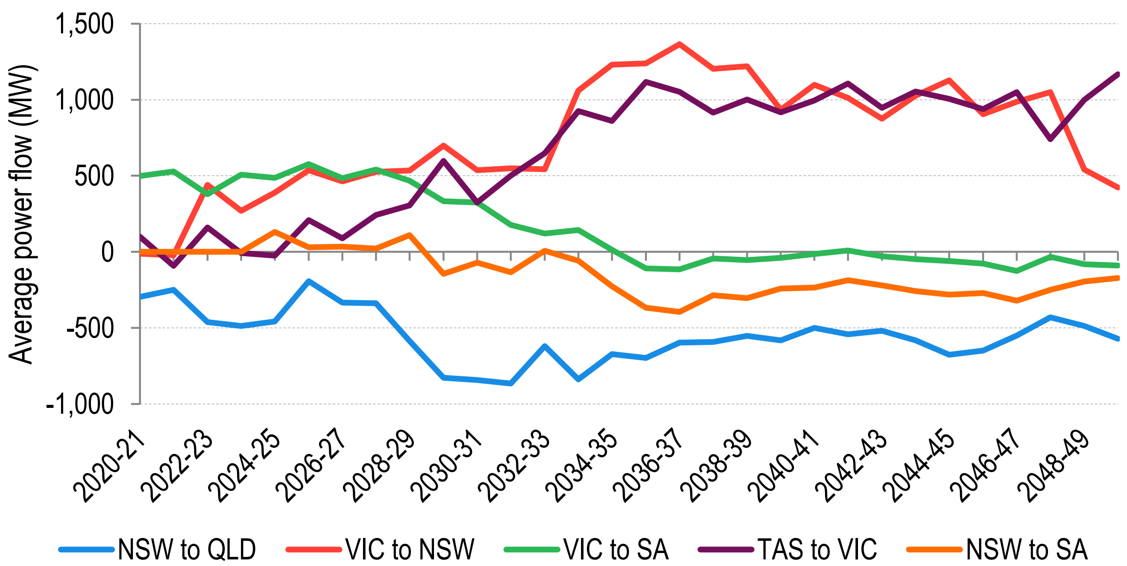
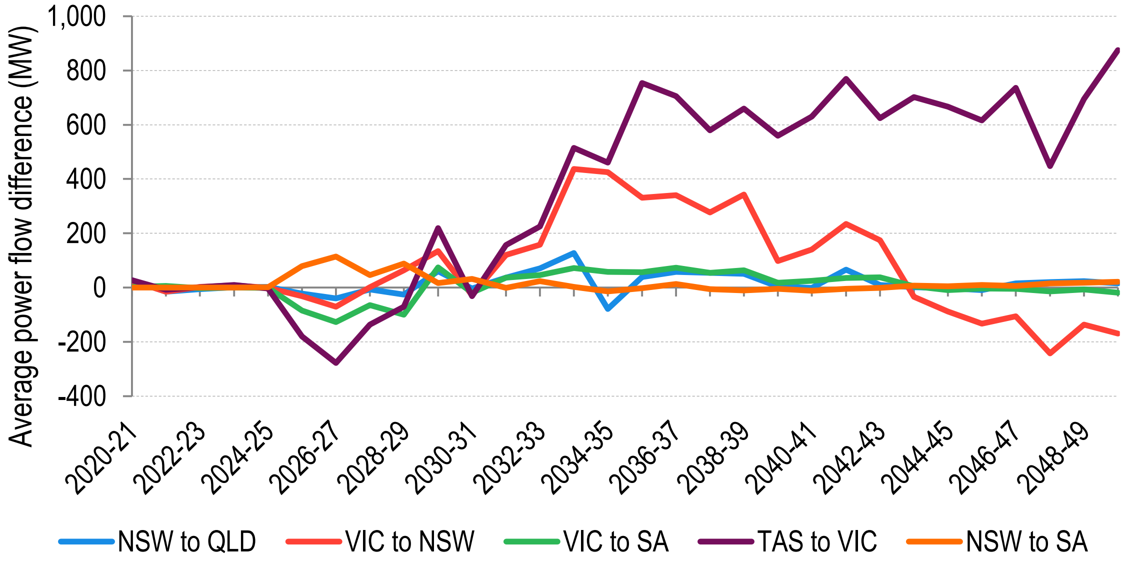


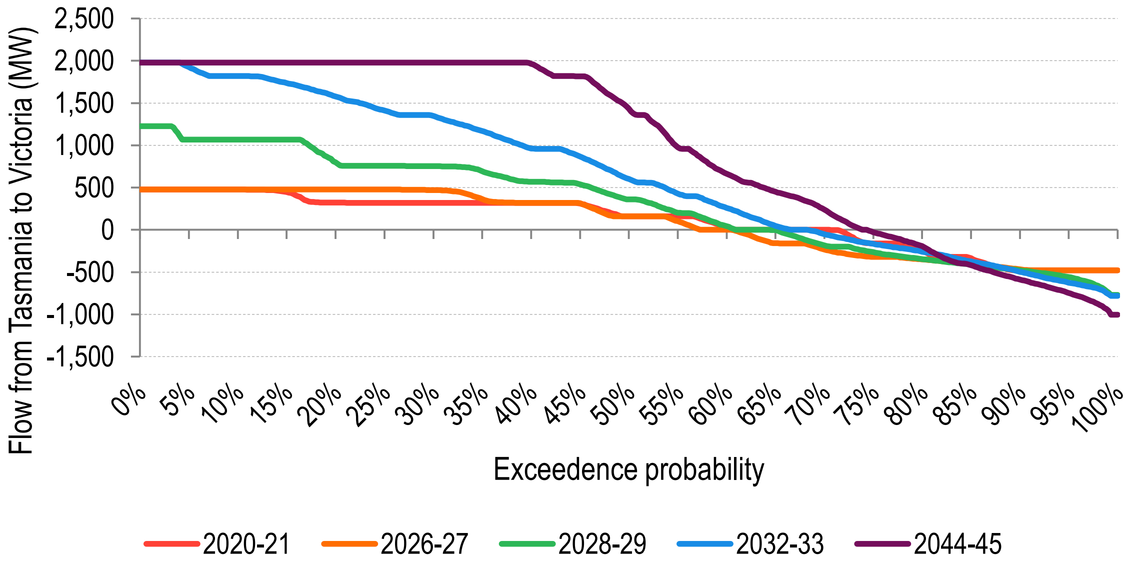
Figure 38 shows the change in average flow due to Marinus Link in the Global Slowdown scenario. As occurred in the Status Quo scenario, Marinus Link increases average export flow from Victoria to New South Wales and South Australia until 2043-44. A key difference to the Status Quo scenario is the notable decrease in forecast export flow from Tasmania to Victoria due to Marinus Link in the mid to late 2020s immediately prior to the entry of the first stage of Marinus Link. This is due to the reduction in hydro generation in Tasmania to conserve limited water inflows for later use after coal retirements when the impact on system cost is greater.

Figure 38: Difference in forecast average annual interconnector power flow due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Global Slowdown scenario (positive values = higher flow with Marinus Link)



The forecast flow duration of the combined links between Tasmania and Victoria is shown in Figure 39. The links are generally less constrained in the Global Slowdown scenario compared to matched years in the Status Quo scenario. However, in the year each stage of Marinus Link enters, the link is forecast to still be well utilised, as they were in the Status Quo scenario (Figure 33). In 2028-29 when the first stage of Marinus Link enters, the combined links are at their northward limit around 5 % of the time (15 % in Status Quo scenario). In 2032-33 when the second stage of Marinus Link enters, the combined links are again at their northward limit about 5 % of the time (10 % in Status Quo scenario).

Figure 39: Forecast Tasmania-Victoria flow duration with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Global Slowdown scenario

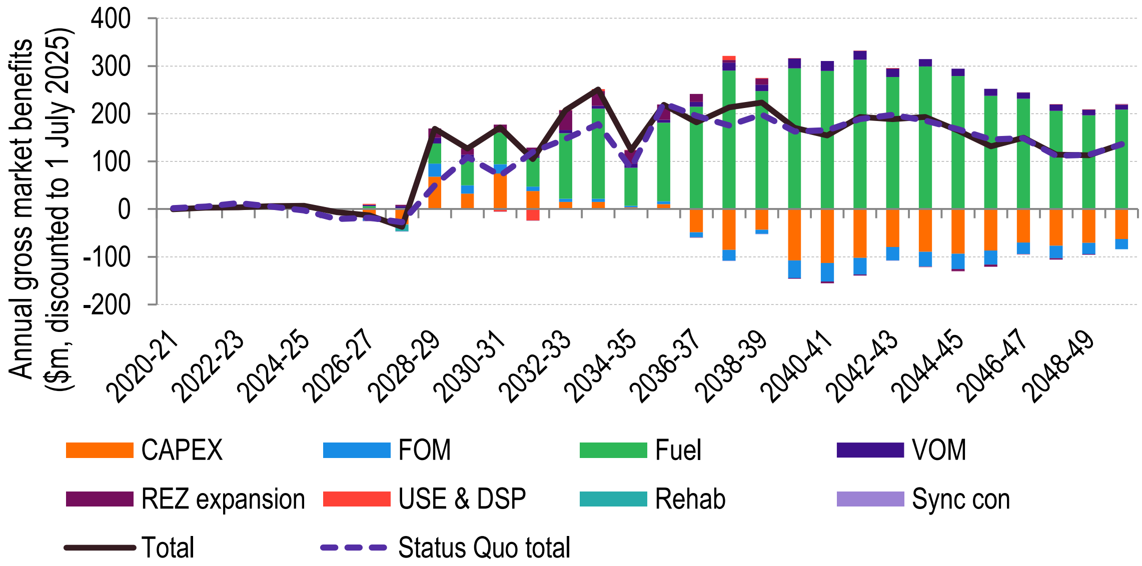


8.4 Sustained Renewables Uptake scenario with Marinus Link

8.4.1 Forecast gross market benefits of Marinus Link, Sustained Renewables Uptake scenario

The annual gross market benefits associated with Marinus Link, stage 1 2028 and stage 2 2032 in the Sustained Renewables Uptake scenario are shown in Figure 40. As occurred in the Status Quo scenario, fuel cost savings accrue from the time Marinus Link enters in 2028-29 and are the dominant source of the forecast gross market benefits.

Figure 40: Forecast annual gross market benefits[171] of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Sustained Renewables Uptake scenario; millions real June 2019 dollars discounted to 1 July 2025



Overall forecast gross market benefits are higher in this scenario than the Status Quo scenario, with the increases mostly contained to the period between commissioning the first stage of Marinus Link in 2028-29 and the late 2030s (Figure 40). The assumed retirement of coal-fired generators, typically three to five years earlier than the timing in the Status Quo scenario results in an increase to the forecast capex benefits in the late 2020s. The earlier coal retirements are also forecast to increase the fuel saving benefits throughout the 2030s.

The overall trends in the category and region of gross market benefits are similar in the Global Slowdown and Status Quo scenarios (Table 18 compared to Table 16). As in the Status Quo scenario, Victoria is still the main beneficiary (primarily through fuel cost savings and some capex savings), then New South Wales (through capex and fuel cost savings). All mainland regions accrue benefits overall, while Tasmania incurs cost (also excluding the cost of Marinus Link which is not considered in this Report) mostly associated with increased capital investment.

Table 18: Summary of forecast gross market benefits by category and region of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Sustained Renewables Uptake scenario; millions real June 2019 dollars discounted to 1 July 2025

Region	Capex	FOM	Fuel	VOM	REZ expansion	USE / DSP	Rehab	Sync cons	Total
NSW	1,114	255	483	122	152	-20	0	0	2,106
QLD	28	10	110	13	26	-2	0	0	185

[171] The sum of all annual benefits in present value terms is equal to the total gross benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032 in Table 15.

Region	Capex	FOM	Fuel	VOM	REZ expansion	USE / DSP	Rehab	Sync cons	Total
VIC	760	177	3,805	297	10	6	-12	0	5,042
SA	293	69	227	31	10	6	-2	0	634
TAS	-3,112	-785	-230	-195	22	0	0	-6	-4,306
Total	-918	-274	4,394	267	221	-9	-14	-6	3,661

The time at which additional capex is forecast to generate larger fuel cost savings is similar to the Status Quo scenario so that overall the least-cost development plan with Marinus Link has higher capex costs, outweighed by fuel cost benefits.

8.4.2 Generation development plan with Marinus Link, Sustained Renewables Uptake scenario

Trends in the forecast capacity development plan and generation mix due to Marinus Link in the Sustained Renewables Uptake scenario are very similar to those in the Status Quo scenario (Figure 41 compared to Figure 27, and Figure 42 compared to Figure 28). Differences between the two scenarios lie in the timing and magnitude of capacity and generation differences, rather than the technology or location of differences.

- In the 2030s it is forecast that there is less avoided PSH build in New South Wales and assumed earlier replacement of New South Wales wind and solar PV with Tasmanian wind. These factors drive forecast higher capex savings and fuel cost benefits during this time in this scenario relative to the Status Quo scenario.
- The forecast avoidance in CCGT capacity and generation in Victoria are larger in magnitude from 2037-38 generating larger fuel cost savings, but similar by 2041-42.

Figure 41: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Sustained Renewables Uptake scenario (positive values = higher capacity with Marinus Link)

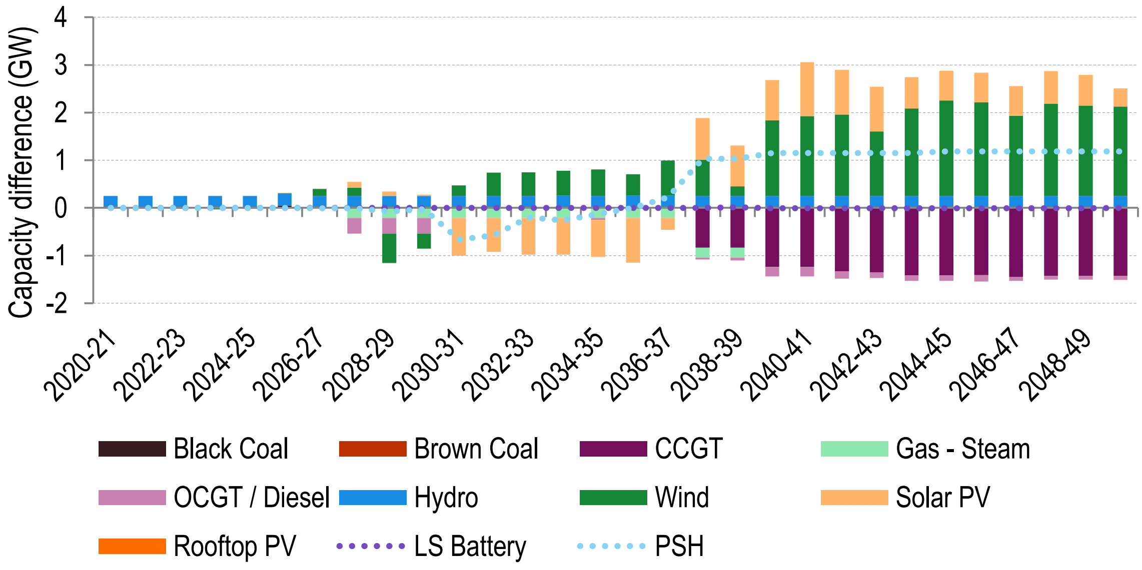
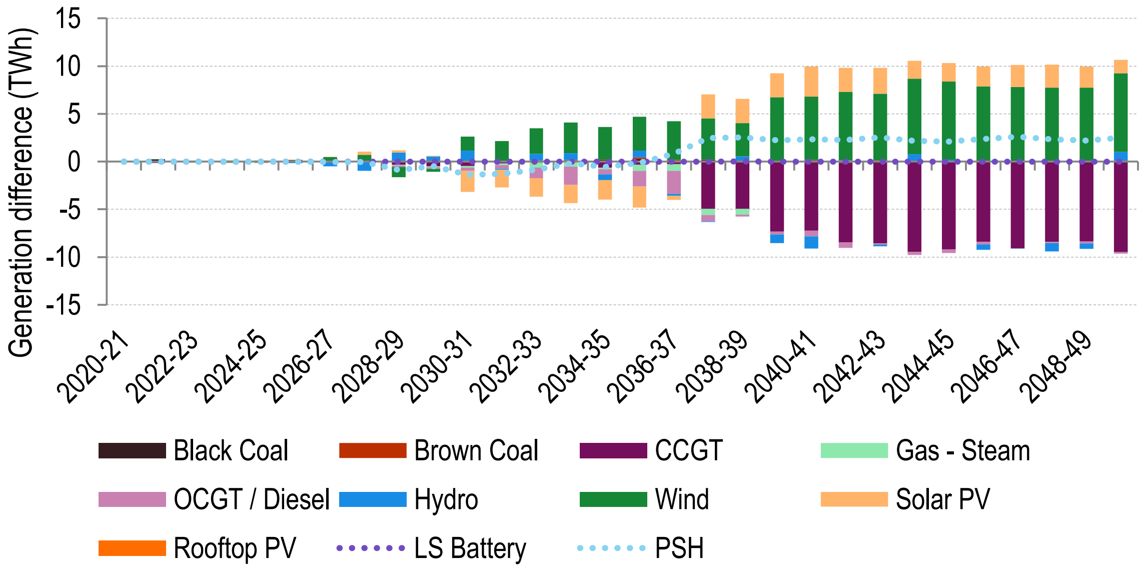


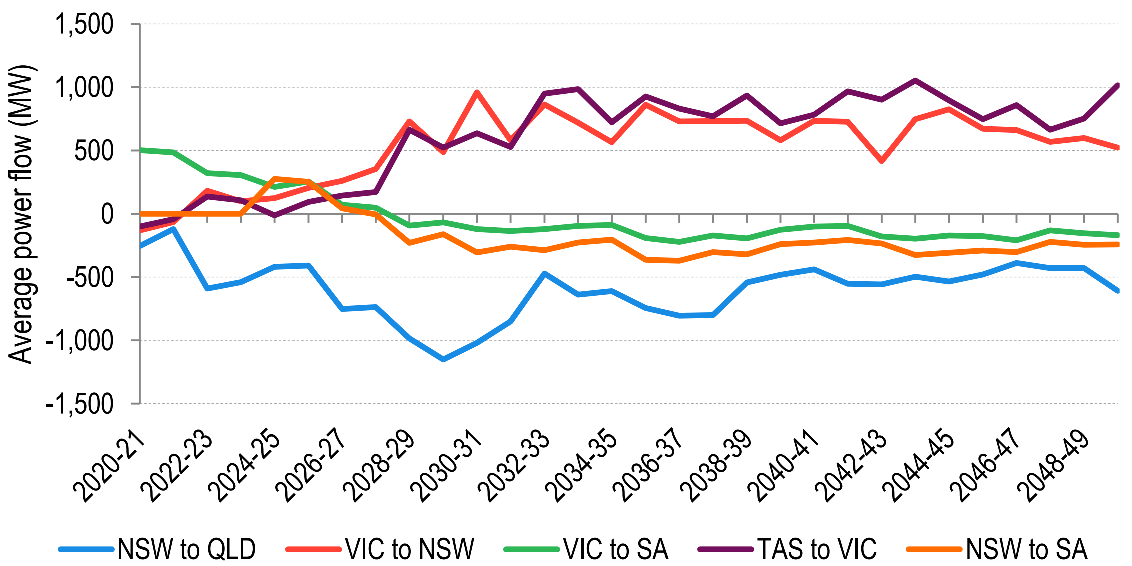
Figure 42: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Sustained Renewables Uptake scenario (positive values = higher energy with Marinus Link)



8.4.3 Interconnector utilisation with Marinus Link, Sustained Renewables Uptake scenario

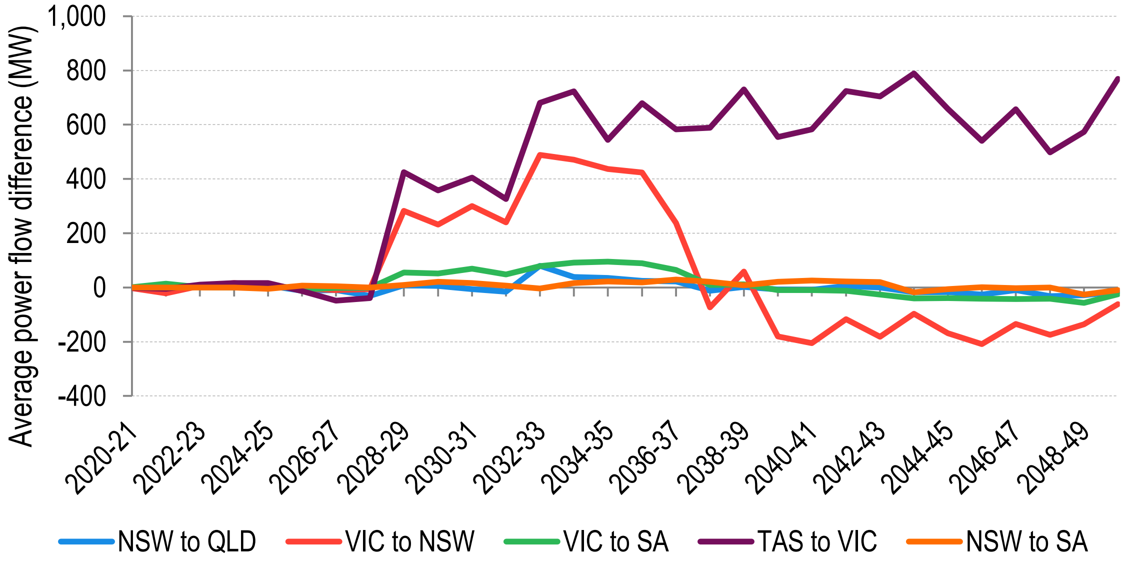
Average interconnector flows between regions for the Sustained Renewables Uptake scenario with Marinus Link are shown in Figure 43. As forecast in the Status Quo scenario (Figure 31), flows are generally forecast to be towards New South Wales. The earlier coal maximum lifetimes mean average flows are forecast to generally be slightly larger in magnitude.

Figure 43: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Sustained Renewables Uptake scenario



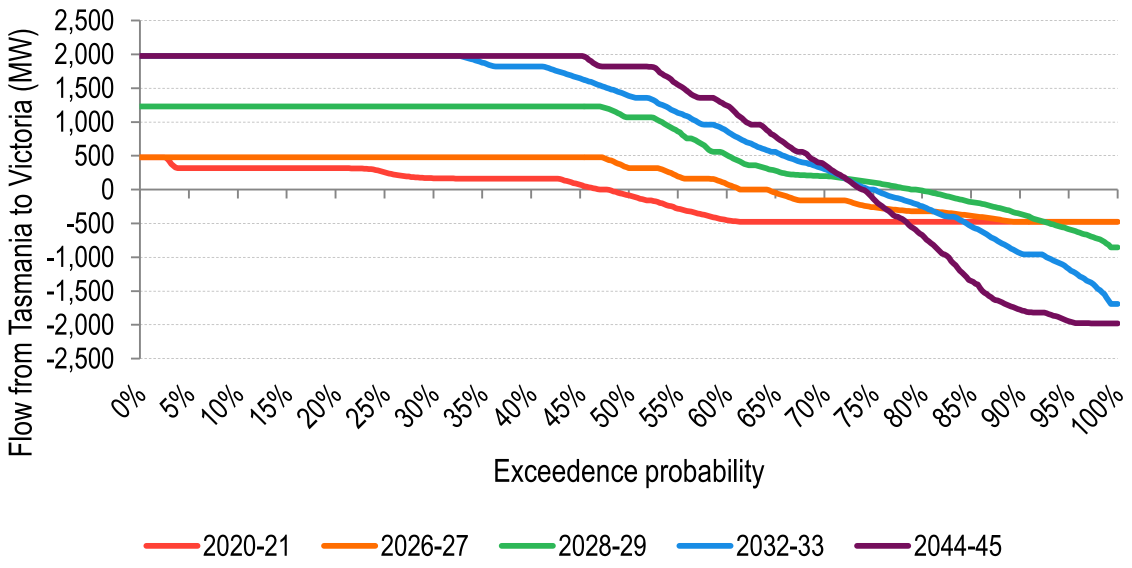
This also true of the difference in annual average flows due to Marinus Link (Figure 44 compared to Figure 32); Marinus Link gives a slightly larger increase in Tasmania to Victoria forecast export flows throughout the study and Victoria to New South Wales forecast export flows from Marinus Link's entry to the mid-2030s.

Figure 44: Difference in forecast average annual interconnector power flow due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Sustained Renewables Uptake scenario (positive values = higher flow with Marinus Link)



The forecast flow duration of the combined links between Tasmania and Victoria is shown in Figure 45. The links are generally more constrained in the Sustained Renewables Uptake scenario compared to the same years in the Status Quo scenario (Figure 33). In the year each stage of Marinus Link enters, the links are forecast to be heavily utilised. In 2028-29 when the first stage of Marinus Link enters, the combined links are forecast to be at their northward limit around 50 % of the time (15 % in Status Quo scenario). In 2032-33 when the second stage of Marinus Link enters, the combined links are again forecast to be at their northward limit about 35 % of the time (10 % in Status Quo scenario).

Figure 45: Forecast Tasmania-Victoria flow duration with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Sustained Renewables Uptake scenario



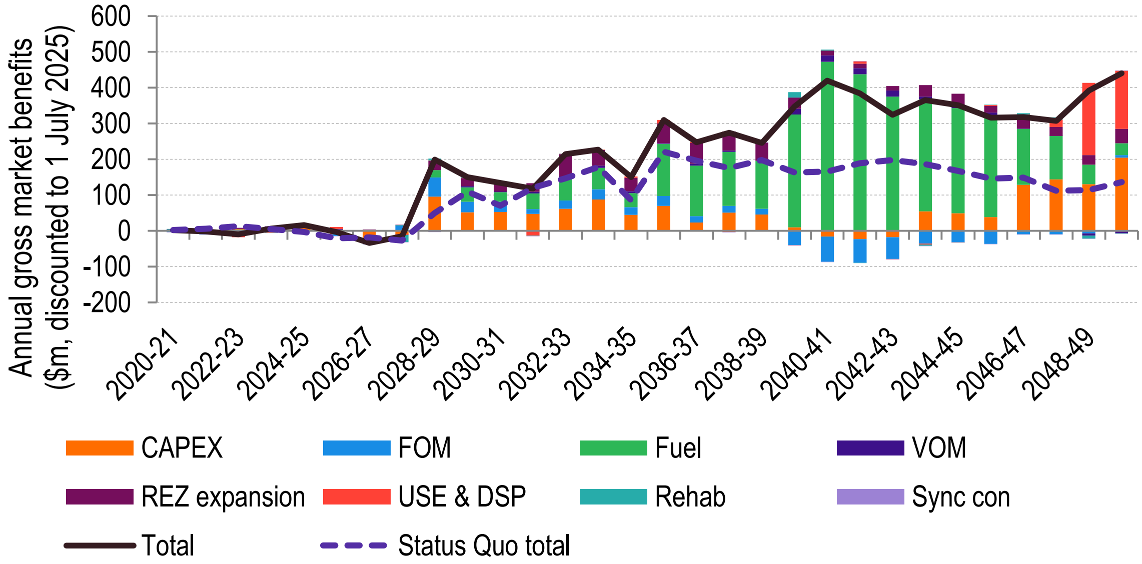
8.5 Accelerated Transition to a Low Emissions Future scenario with Marinus Link

8.5.1 Forecast gross market benefits of Marinus Link, Accelerated Transition to a Low Emissions Future scenario

The forecast annual gross market benefits associated with Marinus Link, stage 1 2028 and stage 2 2032 in the Sustained Renewables Uptake scenario are shown in Figure 46. Key similarities and differences with the Status Quo scenario are listed below.

- As occurred in the Status Quo scenario, the forecast fuel cost savings accrue from the time Marinus Link enters in 2028-29 and are the dominant source of market benefits forecast.
- Forecast fuel savings are lower than in the Status Quo scenario. This is driven by the more stringent emissions reduction trajectory which reduces the combined amount of generation from coal- and gas-fired generators in this scenario compared to the Status Quo scenario. The 'Fast Change' fuel projection is also lower than the 'Neutral' projection applied in the Status Quo scenario.[172]
- From 2028-29, there are capex benefits that are generally forecast to be greater than that observed in Status Quo scenario. From 2043-44, the Accelerated Transition to a Low Emissions Future is forecast to maintain capex benefits of Marinus Link while in the Status Quo scenario, Marinus Link incurs capex costs.
- Forecast REZ expansion cost benefits are forecast to accrue from the time Marinus Link enters in 2028-29 at a higher rate than in the Status Quo scenario.
- In the final two study years there are significant DSP benefits due to Marinus Link in Victoria, New South Wales and to a lesser extent Queensland.

Figure 46: Forecast annual gross market benefits[173] of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Accelerated Transition to a Low Emissions Future scenario; millions real June 2019 dollars discounted to 1 July 2025



[172] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook*, *v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

[173] The sum of all annual benefits in present value terms is equal to the total gross benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032 in Table 15.

The overall trends in the category and region of forecast gross market benefits are similar in the Accelerated Transition and Status Quo scenarios (Table 19 compared to Table 16). As in the Status Quo scenario, Victoria is still the main beneficiary (primarily through fuel cost savings and capex savings), then New South Wales (through capex benefits offset by fuel costs increases). All mainland regions accrue benefits overall, while Tasmania incurs cost (also excluding the cost of Marinus Link which is not considered in this Report) mostly associated with increased capital investment.

Table 19: Summary of forecast gross market benefits by category and region of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Accelerated Transition to a Low Emissions Future scenario; millions real June 2019 dollars discounted to 1 July 2025

Region	Capex	FOM	Fuel	VOM	REZ expansion	USE / DSP	Rehab	Sync cons	Total
NSW	1,678	417	-286	36	276	238	-8	0	2,350
QLD	1,002	55	-443	-40	317	26	26	0	943
VIC	2,050	318	4,441	308	61	117	-19	0	7,276
SA	290	72	153	17	47	-1	0	0	579
TAS	-3,716	-942	-136	-198	43	0	0	-5	-4,955
Total	1,304	-80	3,730	123	743	380	-1	-5	6,194

The overall categories of benefits in Table 19 reinforce the impression created in the annual gross market benefits chart in Figure 46. Fuel cost savings remain the largest source of market benefits, as forecast in the Status Quo scenario. However, in the Accelerated Transition scenario there is also a significant overall capex benefit.

8.5.2 Generation development plan with Marinus Link, Accelerated Transition to a Low Emissions Future scenario

Figure 47 and Figure 48 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 2028 and 2032, relative to the without Marinus Link case for the Acceleration Transition to a Low Emissions Future scenario.

These figures illustrate the drivers of gross market benefits in Figure 46. Key features of note are:

- The capex benefits that accrue from 2028-29 when Marinus Link enters are due to avoiding build of approximately 1,050 MW of wind and 300 MW of solar PV on the mainland by better unlocking existing Tasmanian hydro and building an additional 500 MW of wind capacity in Tasmania.
- Marinus Link's commissioning is also forecast to allow Newport to retire in Victoria (approximately 500 MW of gas-fired steam generator), which results in additional FOM savings in the late 2020s and the 2030s.
- Improved access to low-cost, zero-emissions energy from Tasmania with Marinus Link means that the retirement of brown coal-fired generation in Victoria can be delayed with Marinus Link in the late 2030s and early 2040s while still meeting the emission reduction constraint (Figure 49). The combined effect is that Marinus Link is forecast to generate significant capex and fuel cost savings in Victoria through a reduction in build of CCGT in Victoria. The delay in coal retirements contributes to the FOM cost of Marinus Link during the mid-2040s.

- With Marinus Link, approximately 1.5 GW of additional 24-hour PSH is forecast to be installed in Tasmania by 2039-40 along with over 2 GW more wind capacity (Figure 50). This allows for approximately 10 GW less large-scale 2-hour battery storage and 3.5 GW less solar PV to be installed by the end of the study period. Because of this there are progressive capex benefits throughout the mid to late 2040s, along with large USE/DSP benefits in the final two years of the study period.

- High assumed demand, along with the requirement to achieve a 90 % reduction in emissions, results in the majority of available mainland wind and solar PV locations reaching their assumed build limit by the late 2040s in the forecast. The stringent emissions constraint applied in this scenario also heavily restricts the annual amount of generation from coal-fired and gas-fired generators toward the end of the study. Consequently, in the final two years, the least-cost outcome forecast for the market is to utilise significant DSP generation so as to reduce the need for new entrant generation for the remaining years during the study. In these final years, Marinus Link is forecast to significantly reduce the amount of mainland DSP, especially in New South Wales and Victoria, by enabling transfer of excess energy from zero-emission Tasmanian sources.

Figure 47: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Accelerated Transition scenario (positive values = higher capacity with Marinus Link)

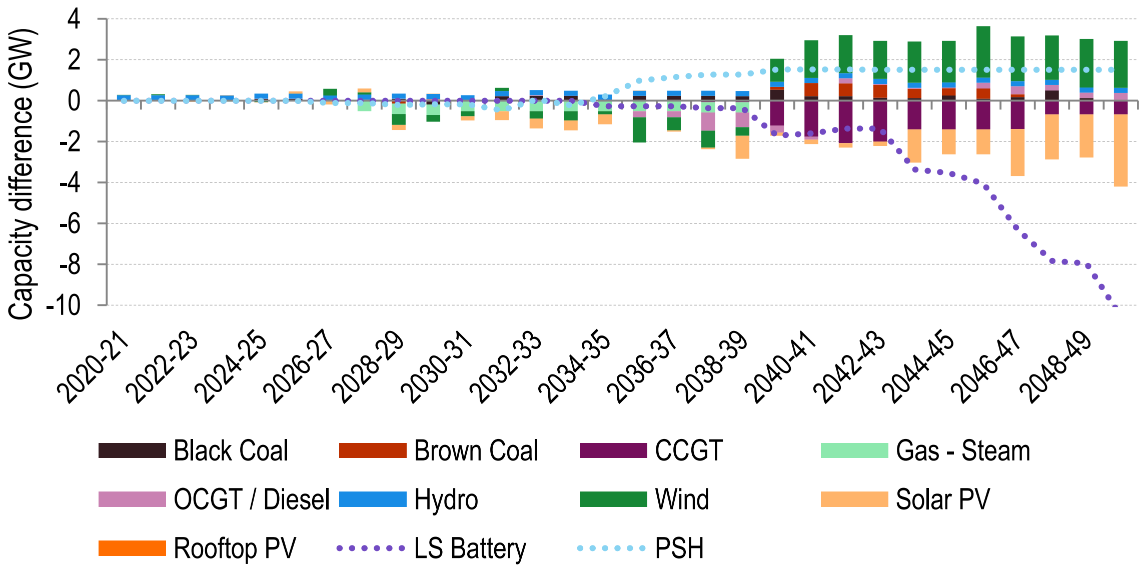


Figure 48: Difference in NEM generation mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Accelerated Transition scenario (positive values = higher capacity with Marinus Link)

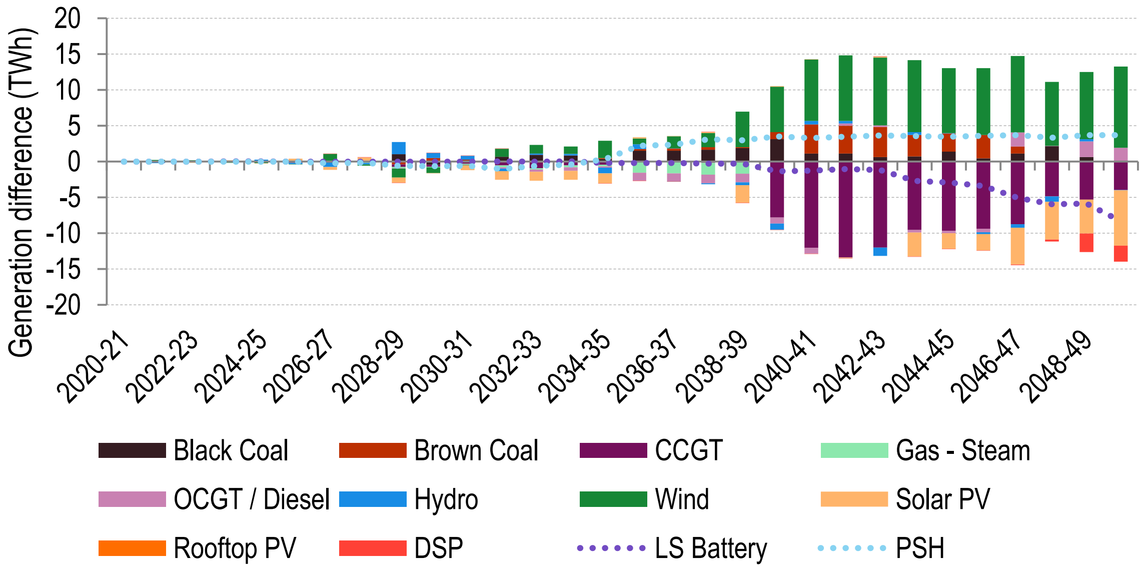


Figure 49: Difference in Victorian capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Accelerated Transition scenario (positive values = higher capacity with Marinus Link)

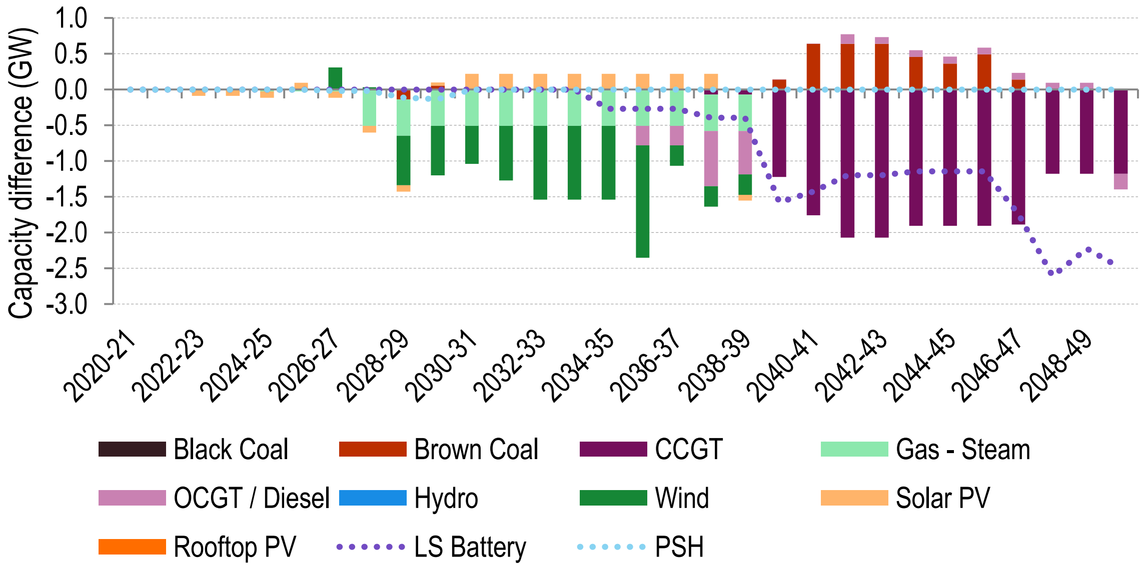
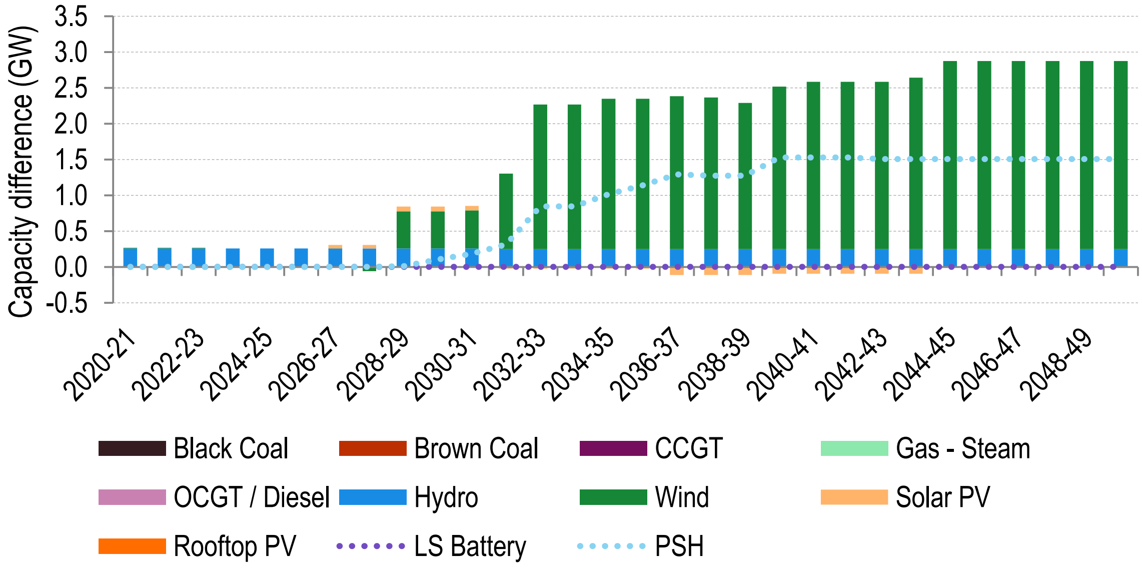


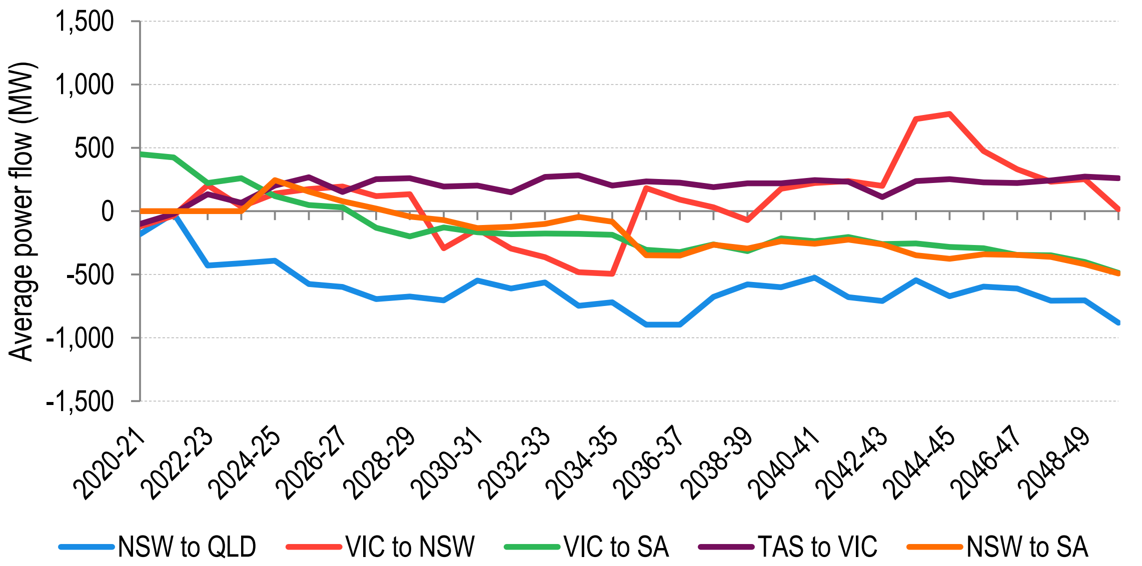
Figure 50: Difference in Tasmanian capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Accelerated Transition scenario (positive values = higher capacity with Marinus Link)



8.5.3 Interconnector utilisation with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032

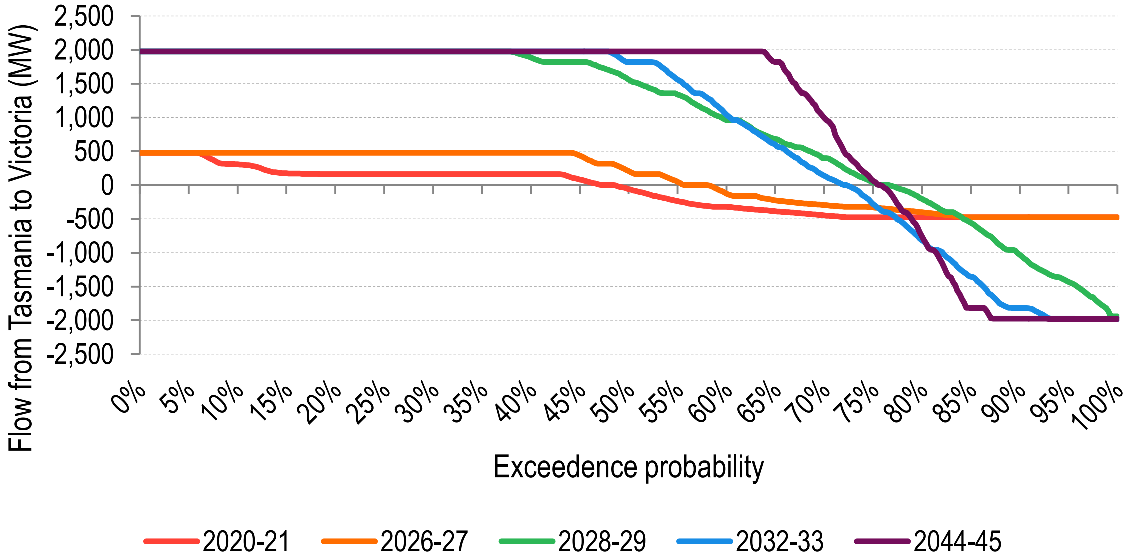
Average interconnector flows between regions for the Accelerated Transition to a Low Emissions Future scenario with Marinus Link are shown in Figure 51. Flows are directed less towards New South Wales than in the Status Quo scenario (Figure 31).

Figure 51: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Accelerated Transition 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 Accelerated Transition scenario compared to matched years in the Status Quo scenario (Figure 33). As occurred in other scenarios, in the year each stage of Marinus Link enters, the links are forecast to be heavily utilised. In 2028-29 when the first stage of Marinus Link enters, the combined links are at their northward limit around 45 % of the time (15 % in Status Quo scenario). In 2032-33 when the second stage of Marinus Link enters, the combined links are again at their northward limit about 40 % of the time (10 % in Status Quo scenario).

Figure 52: Forecast Tasmania-Victoria flow duration with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Accelerated Transition scenario



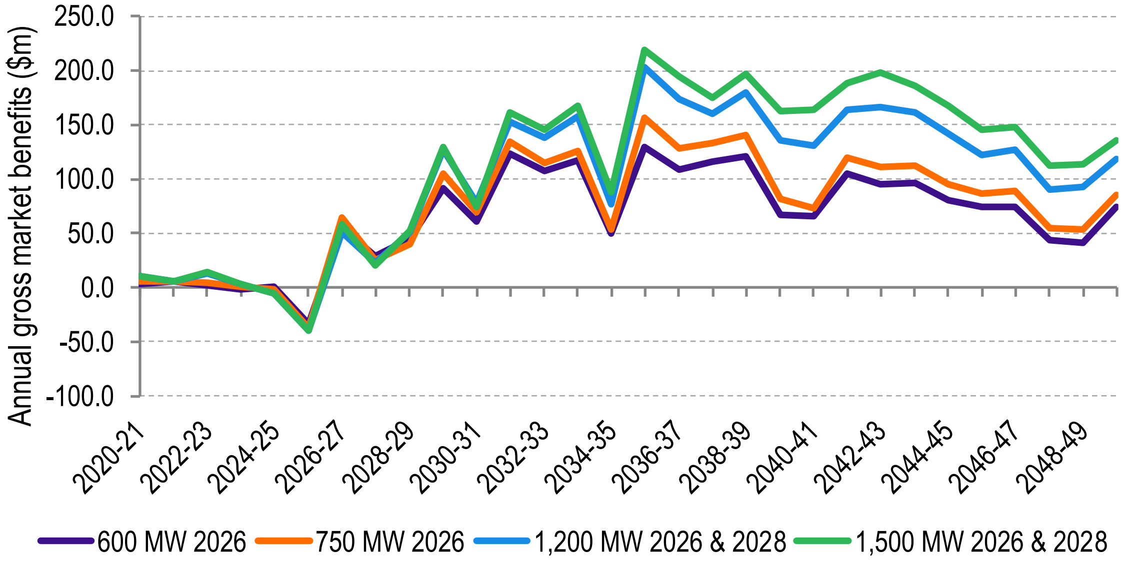
8.6 Effect of size and timing of Marinus Link on forecast gross market benefits

To assist in determining to optimal timing and sizing of Marinus Link, we performed simulations of different option-timing combinations and computed the forecast gross 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[174] as option costs were developed independently by TasNetworks. This section provides several observations about how the size and timing of benefits changes 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 gross 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 gross market benefits of different size options for Marinus Link installed in 2026 (all for single stage options, first stage for two stage options), which was the earliest development year considered. Generally, benefits in real terms increase over time (Figure 53 shows real June 2019 dollars discounted to 1 July 2025).

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

Figure 53: Forecast annual gross market benefits of Marinus Link options of different size, Status Quo scenario; millions real June 2019 dollars discounted to 1 July 2025



The modelling shows that as the size of Marinus Link increases, the utilisation of further increments of Marinus Link capacity reduces. However, the modelling shows that in all cases with a second stage, forecast gross market benefits still increase with the second stage relative to the first stage. A 25 % increase in Marinus Link capacity (an increase from 600 MW to 750 MW or 1,200 MW to 1,500 MW) delivers around a 10 % to 15 % increase in forecast gross market benefits for the timing shown in Figure 53 for all scenarios. This demonstrates that the scale of potential market benefits from larger capacity is still not expected to be reached with almost 2,000 MW of bi-directional connection between Tasmania and the mainland, including Basslink's existing 478 MW capacity.

For cases where the timing of Marinus Link is deferred, it is forecast to provide the same level of gross 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 gross market benefits reduce in real terms and present value terms if Marinus Link is delayed.

8.7 Interaction of Marinus Link and KerangLink

The value proposition of Marinus Link is it provides both low-cost renewable energy to mainland NEM regions (via Victoria) and firming capability for renewables, to help make up the deficit as coal-fired generating units retire. Similarly, the value proposition of KerangLink is that it will:

- Increase Victoria's capacity to export surplus generation, thereby saving fuel costs in other regions,
- Connect Victorian load to the Snowy and Snowy 2.0 schemes, enabling Snowy 2.0 to provide energy to Victoria during high demand periods,
- Reduce intra-regional transmission expenditure, since the route passes through Victorian REZs.

The question which therefore arises is, if both Marinus Link and KerangLink provide similar services, does the NEM require both? This section examines this issue.

Table 20 summarises the forecast total cumulative gross market benefits of Marinus Link 1,500 MW, with different commissioning dates for itself and KerangLink.

Table 20: Summary of forecast gross market benefits of Marinus Link 1,500 MW for different commissioning dates of Marinus Link and KerangLink, Status Quo scenario; millions real June 2019 dollars discounted to 1 July 2025

		Marinus Link timing		
		Stage 1 2026 & stage 2 2028	Stage 1 2028 & stage 2 2030	Stage 1 2030 & stage 2 2032
KerangLink timing	Not commissioned	3,506	3,402	3,239
	2026	3,346	3,296	3,144
	2030[175]	3,398	3,290	3,125
	2034	3,511	3,405	3,238

The outcomes indicate that if KerangLink is commissioned in the 2020s or early 2030s, it has a minor negative impact on Marinus Link's NEM-wide forecast gross market benefits. If KerangLink is commissioned in the mid-2030s, it is forecast to have no material impact on the NEM-wide benefits of Marinus Link. However, without KerangLink, it is forecast that Marinus Link's gross market benefits are almost entirely contained within Victoria. This is illustrated in Table 21 which presents the forecast total cumulative gross market benefits by category and region of Marinus Link 1,500 MW, stage 1 2028, stage 2 2030, in the sensitivity without KerangLink. All other assumptions are as per the Status Quo scenario. Without KerangLink, the forecast gross market benefits of Marinus Link principally accrue in Victoria. With both interconnectors, the forecast gross market benefits of Marinus Link are further unlocked for New South Wales.

Table 21: Summary of forecast gross market benefits by category and region of Marinus Link 1,500 MW, stage 1 2028, stage 2 2030, without KerangLink. All other assumptions as per the Status Quo scenario; millions real June 2019 dollars discounted to 1 July 2025

Region	Capex	FOM	Fuel	VOM	REZ expansion	USE / DSP	Rehab	Sync cons	Total	Total for Status Quo scenario[176]
NSW	493	127	188	76	59	-8	0	0	**935**	1,869
QLD	24	13	55	8	-1	-1	-1	0	**98**	214
VIC	1,056	348	3,958	307	-60	40	-31	0	**5,618**	4,367
SA	445	80	293	33	23	0	0	0	**874**	838
TAS	-2,985	-750	-221	-180	15	0	2	-4	**-4,123**	-3,997
Total	**-968**	**-181**	**4,274**	**244**	**36**	**31**	**-31**	**-4**	**3,402**	3,290
Total for Status Quo scenario	-663	-312	3,862	253	131	23	2	-6	3,290	

The reason that the forecast gross market benefits of two interconnectors are independent of each other relates to the combined potential of Marinus Link and KerangLink to take advantage of northward flow from Tasmania to Victoria to New South Wales. Figure 54 displays the forecast average interconnector flows between regions for the sensitivity with Marinus Link, but without KerangLink. All other assumptions are from the Status Quo scenario. The figure shows that after the assumed retirement of Liddell power station in 2022-23, which occurs prior to the development of KerangLink and Marinus Link, the annual net energy transfer between Tasmania and Victoria to

175 KerangLink commissioned 2030-31 reflects the assumptions of the Status Quo scenario

176 Note that these gross market benefits are for Marinus Link stage 1 2028 and stage 2 2030. As such, these values do not match those presented in Table 16.

New South Wales is forecast to predominantly flow in the northward direction. This is consistent with the RIT-T PADR for the VNI upgrade project[177], which is justified based on additional low-cost energy being able to be exported to New South Wales from Victoria.

Figure 54: Average annual interconnector power flow forecast with Marinus Link 1,500 MW, stage 1 2028, stage 2 2030, without KerangLink, all other assumptions as per Status Quo scenario

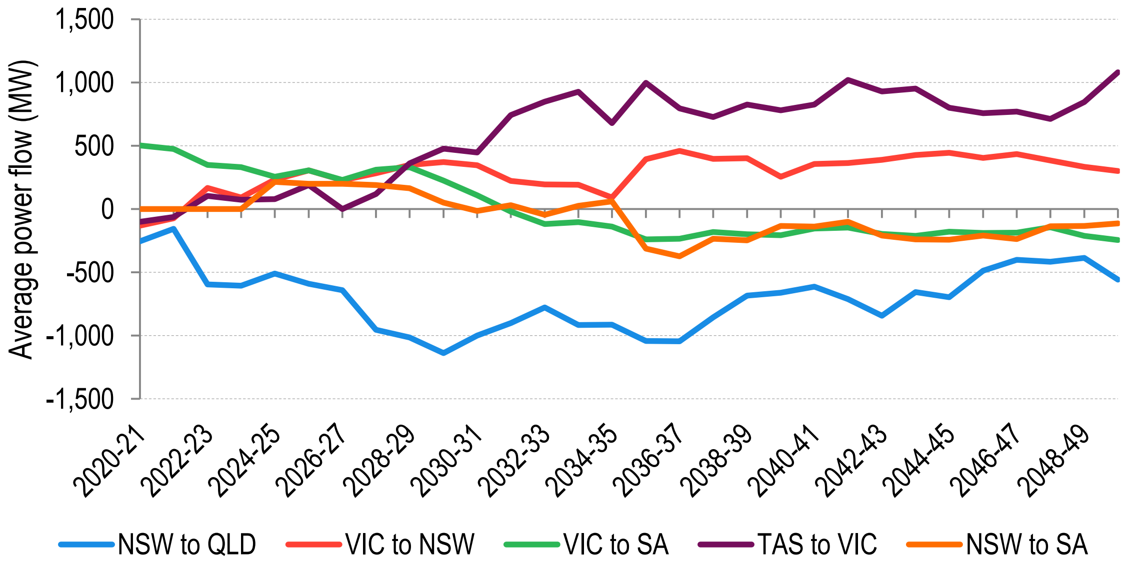
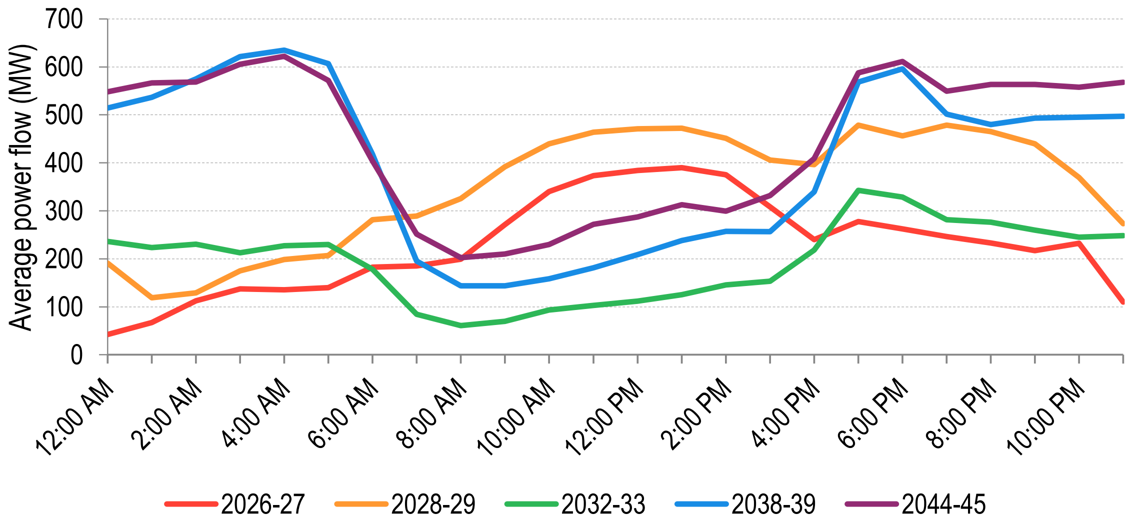


Figure 55 displays the average time-of-day power flow from Victoria to New South Wales with Marinus Link, but without KerangLink. After the assumed retirement of the largest coal-fired generators in New South Wales in the early to mid-2030s (Eraring power station in 2031-32 and Bayswater power station in 2035-36), VNI is heavily utilised in the northward direction during the peak operation demand periods of the early morning and evening. Without KerangLink, it is forecast that the northerly limit of VNI will be constraining flow for up to 50 % of periods. Consequently, the NEM-wide benefits of Marinus Link are, at times, being constrained within Victoria.

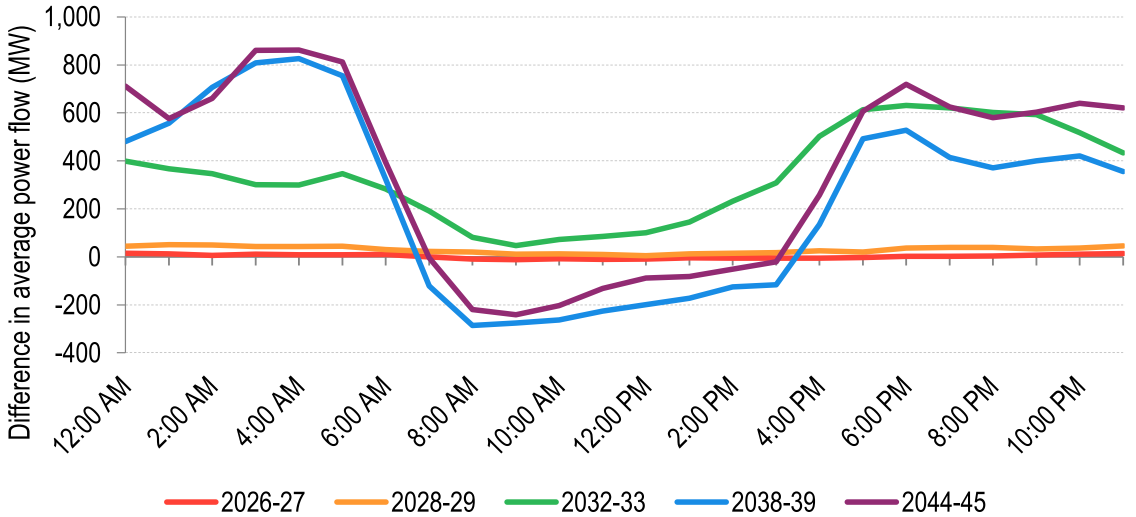
[177] AEMO, August 2019, *Victoria to New South Wales Interconnector Upgrade – Project Assessment Draft Report*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission. Accessed 6 November 2019.

Figure 55: Average time-of-day power flow from Victoria to New South Wales with Marinus Link 1,500 MW, stage 1 2028, stage 2 2030, without KerangLink, all other assumptions as per Status Quo scenario



With KerangLink, the system cost benefits of Marinus Link are forecast to be further unlocked for New South Wales. Figure 56 displays the difference in average time-of-day power flow from Victoria to New South Wales due to KerangLink (with Marinus Link). It shows that throughout the late 2020s and early to mid-2030s, it is forecast that the majority of KerangLink's utilisation will be in the northerly direction. Therefore, with both Marinus Link and KerangLink, it is forecast that the existing Tasmanian hydro capacity and Tasmania's high-quality wind resource is better able to defer new entrant New South Wales capacity throughout the 2030s, resulting in capex benefits for New South Wales.

Figure 56: Difference in forecast average time-of-day power flow from Victoria to New South Wales due to KerangLink, Status Quo scenario (difference relative to Figure 55; positive values = higher flow with KerangLink). Marinus Link 1,500 MW, stage 1 2028, stage 2 2030 is assumed to be committed in both cases.



Throughout late 2030s and 2040s, the two interconnectors allow for New South Wales and Victorian solar PV to better operate alongside new entrant Tasmanian 24-hour PSH to supply peak periods across Victoria and New South Wales. This tends to result in the forecast flow across VNI to be more southerly during the day and more northerly during the mornings and evenings, as was presented in Figure 56. Consequently, if KerangLink and Marinus Link are both commissioned, it is forecast that there is a reduction in the need for New South Wales gas-fired generation to supply demand.

KerangLink therefore enables the benefits of Marinus Link to be distributed throughout the NEM, rather than being confined to Victoria.

8.8 Sensitivities

Table 22 displays the sensitivities, their forecast gross market benefits, and the gross difference compared to the Status Quo scenario. The drivers for these changes compared to the Status Quo scenario are presented in the following subsections. The sensitivities have been conducted for Marinus Link, stage 1 2028 and stage 2 2032.

Table 22: Forecast gross market benefits of Marinus Link for all sensitivities, real June 2019 dollars discounted to 1 July 2025

Sensitivity	Gross market benefits ($m)	Difference in gross market benefits compared to Status Quo scenario ($m)
Battery Life Doubles	3,109	-122
Climate Change	3,131	-100
Tasmanian Hydrogen	3,157	-74
Prudent Storage Level does not Change	3,181	-50
Repurposing of Hydro Tasmanian Assets does not Proceed	2,937	-295
Other Expected Projects do not Proceed	3,503	272
SA Gas Generators Retire with Project EnergyConnect	3,304	73
Deferred Coal Retirement	2,861	-370
Rate of Reduction in Battery Costs Doubles	3,155	-76
500 MW Additional On-Island Wind	3,307	76
600 MW of PSH in Tasmania by 2027-28	4,351	691[178]
Yallourn Retirement 2027-28	3,352	121
Partial September ISP Update	2,230	-1,002

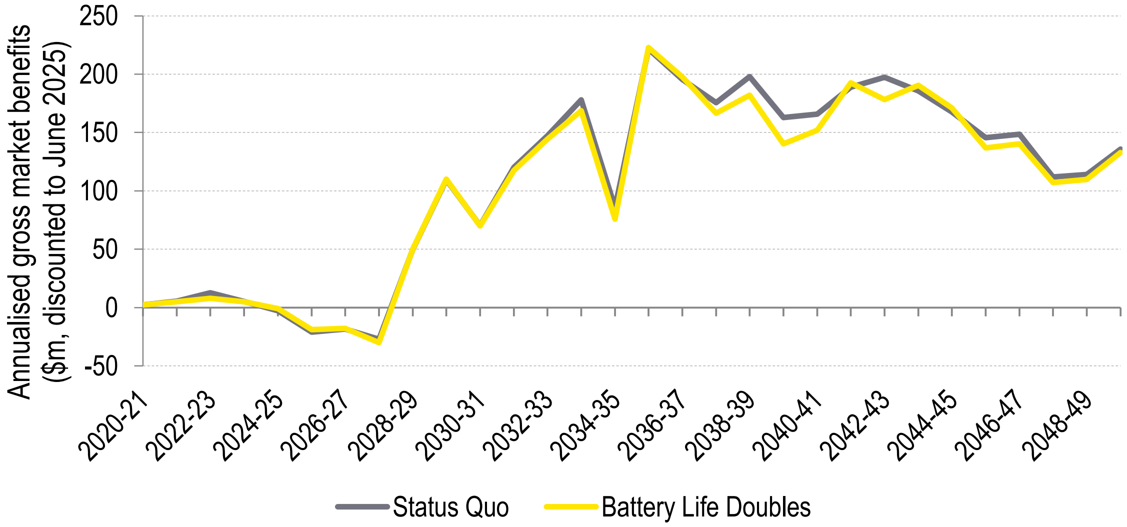
Based on these sensitivities, some of the factors that may reduce the potential gross market benefits of Marinus Link are: lower mainland demand, increased wind, solar PV and PSH resources on the mainland, delayed coal retirements, lower Tasmanian capacity and reductions in Tasmanian hydro energy. The Partial September ISP Update sensitivity has the largest negative impact on gross market benefits of Marinus Link; we anticipate the impact of these assumptions will be assessed more thoroughly in future modelling work. Alternatively, additional Tasmanian capacity (either generation or storage), early thermal retirements and the delay or withdrawal of proposed transmission projects is expected to increase or bring forward the potential benefits of Marinus Link.

[178] The underlying assumptions for the 600 MW of PSH in Tasmania by 2027-28 sensitivity are from the Sustained Renewables Uptake Scenario. This difference in gross market benefits is relative to the aforementioned scenario, not the Status Quo scenario

8.8.1 Battery Life Doubles sensitivity

In this sensitivity, it is assumed that new entrant large-scale battery options have storage increased from two hours to four hours, with no change to the assumed capex, FOM or VOM trajectory. It is forecast that this reduces the gross market benefits of Marinus Link to $3,109m, which is $122m lower than the Status Quo scenario. Figure 57 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

Figure 57: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Battery Life Doubles sensitivity; millions real June 2019 dollars discounted to 1 July 2025

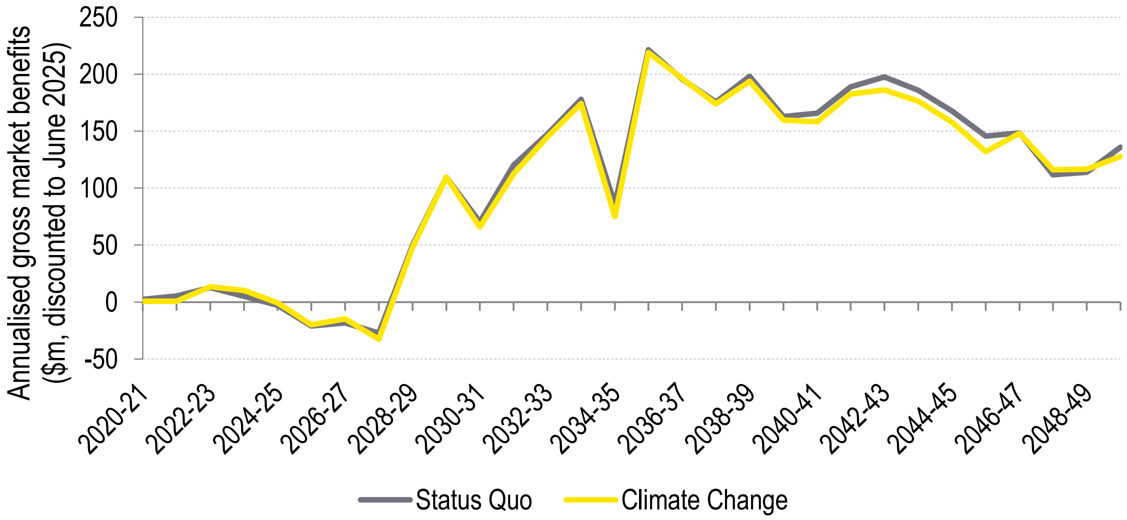


It is forecast that there will be more large-scale battery storage installed in the NEM throughout the 2030s and 2040s compared to the Status Quo scenario, with an additional 10 GW forecast to be commissioned by 2049-50. The combination of solar PV and large-scale battery storage is forecast to reduce the need for gas, which decreases the forecast fuel savings benefits of Marinus Link. However, Marinus Link's ability to unlock existing Tasmanian hydro and new entrant 24-hour Tasmanian PSH is forecast to result in additional capex benefits, associated with deferring mainland large-scale battery storage capacity. Because of these two factors, there is only a small reduction in Marinus Link's forecast gross market benefits from 2030 onward, compared to the Status Quo scenario.

8.8.2 Climate Change sensitivity

For this sensitivity, it is assumed that in each reference year cycle of eight years after the first (i.e. from 2027-28 onwards), hydro inflows in Tasmania and on the mainland reduce by 4 % compared to the previous 8-year cycle. This is intended to investigate the potential reduction in annual rainfall due to climate change. It is forecast that this reduces the gross market benefits of Marinus Link to $3,131m, which is $100m lower than the Status Quo scenario. Figure 58 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

Figure 58: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Climate Change sensitivity; millions real June 2019 dollars discounted to 1 July 2025

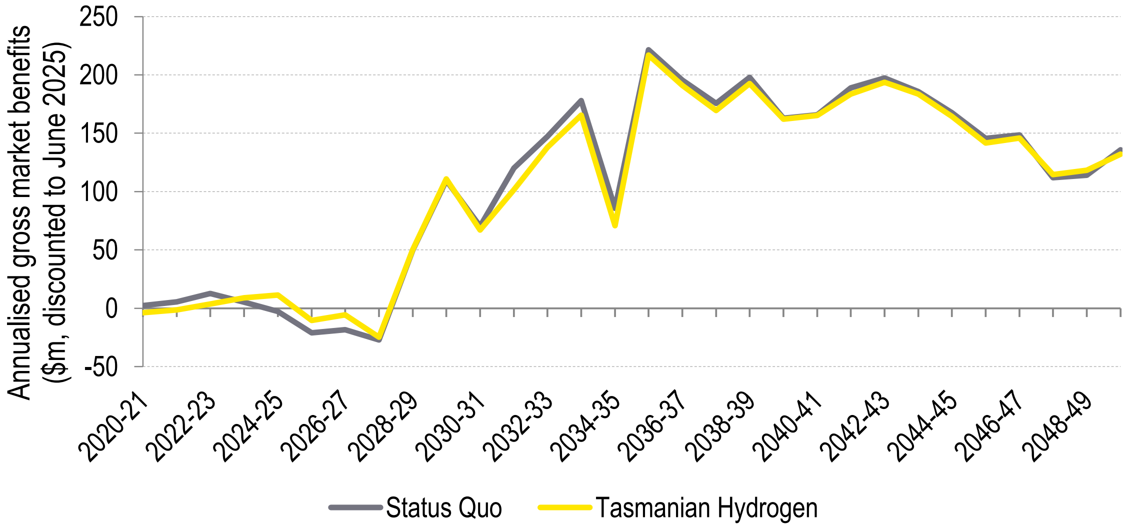


The assumed decrease in annual inflow for all conventional hydro is forecast to result in a minor reduction in the benefits of Marinus Link in the back end of the study period, since there is less annual generation that can come from existing Tasmanian hydro assets.

8.8.3 Tasmanian Hydrogen sensitivity

For this sensitivity, it is assumed that Tasmanian demand increased by 100 MW from 2023-24 onward to represent a hydrogen load. It is forecast that this reduces the gross market benefits of Marinus Link to $3,157m, which is $74m lower than the Status Quo scenario. Figure 59 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

Figure 59: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Tasmanian Hydrogen sensitivity; millions real June 2019 dollars discounted to 1 July 2025

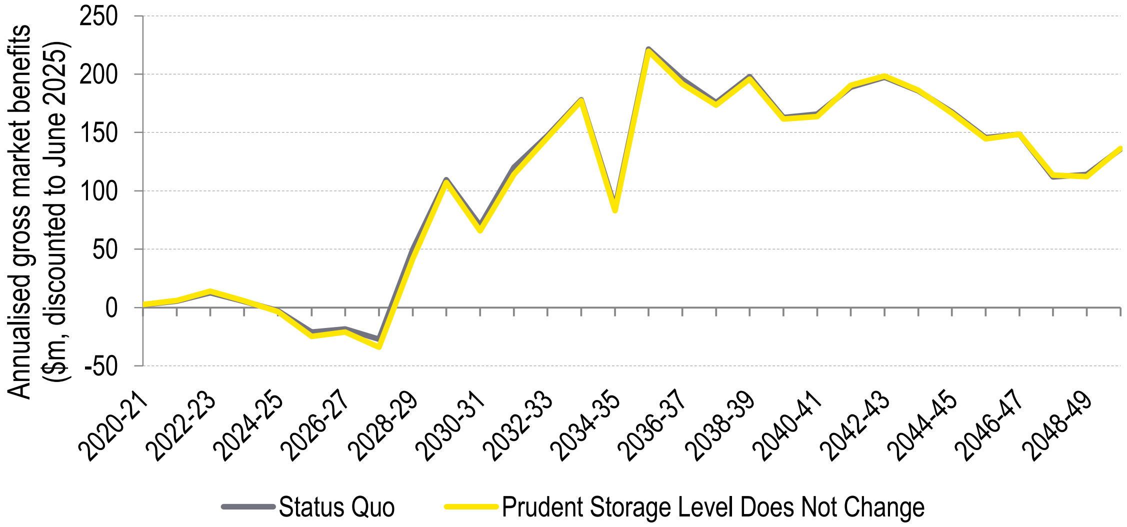


The reduction in the gross market benefits of Marinus Link is predominantly forecast to be contained within the 2030s, since the 100 MW of hydrogen load is reducing the amount of existing Tasmanian generation that can be exported to the mainland. The annual forecast benefits are essentially unchanged throughout the 2040s. In those years, the increased load is forecast to result in approximately 200 MW of new entrant wind capacity to have been installed in Tasmania, which is then able to provide generation to the mainland.

8.8.4 Prudent Storage Level Does Not Change sensitivity

In this sensitivity, the Tasmanian hydro PSL profile is not assumed to reduce by 10 percentage points if Marinus Link is commissioned. This reduces the forecast gross market benefits of Marinus Link to $3,181m, which is $50m lower than the Status Quo scenario. Figure 60 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

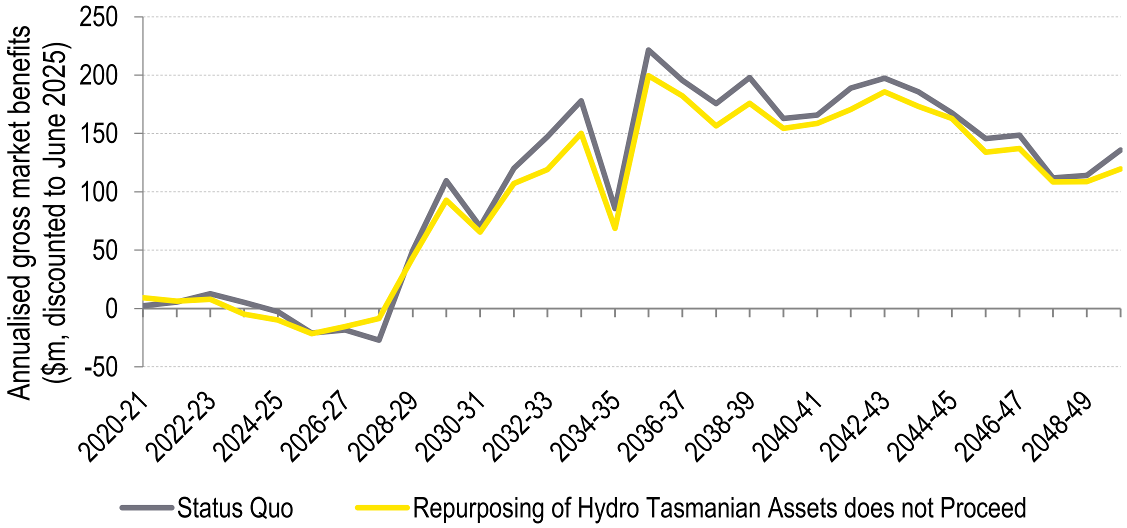
Figure 60: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Prudent Storage Level does not Change sensitivity; millions real June 2019 dollars discounted to 1 July 2025



8.8.5 Repurposing of Hydro Tasmanian Assets Does Not Proceed sensitivity

In this sensitivity, the 100 MW West Coast expansion and 150 MW Tarraleah upgrade assumed in all scenarios are not included if Marinus Link is commissioned. This reduces the forecast gross market benefits of Marinus Link to $2,937m, which is $295m lower than the Status Quo scenario. Figure 61 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

Figure 61: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Repurposing of Hydro Tasmanian Assets does not Proceed sensitivity; millions real June 2019 dollars discounted to 1 July 2025

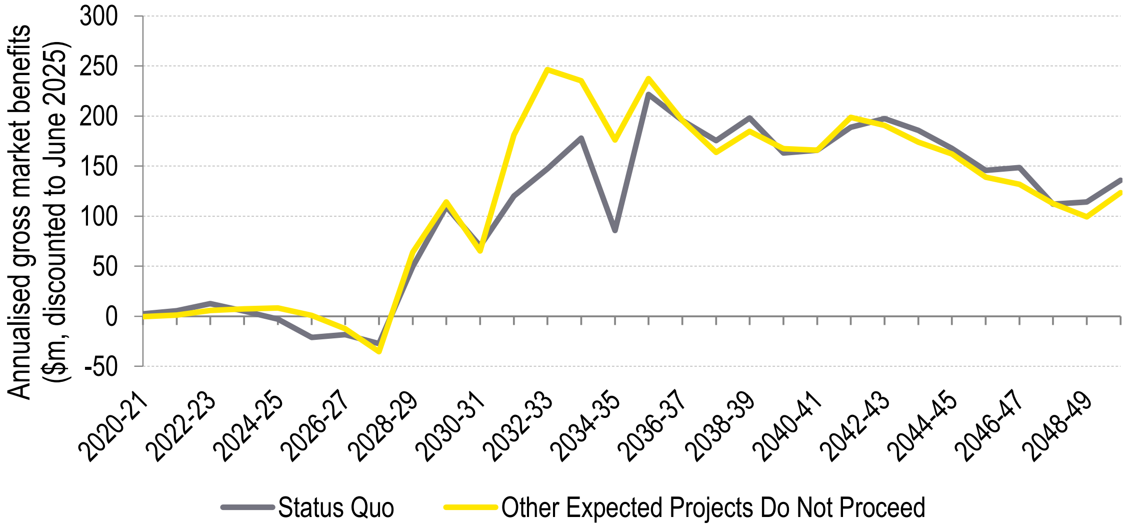


The reduction in existing Tasmanian hydro capacity does not materially influence their overall generation, since this is predominantly determined by the annual inflow. However, the lowered capacity compared to the Status Quo scenario limits Tasmania's capability to supply peak demand periods on the mainland. Consequently, the forecast annual gross market benefits of Marinus Link are lower each year from the assumed commissioning of Marinus Link.

8.8.6 Other Expected Projects Do Not Proceed sensitivity

For this sensitivity, the following projects are assumed not to be commissioned during the study period: VNI Option 1, QNI Option 3A, Project EnergyConnect, KerangLink and Snowy 2.0.[179] It is forecast that this increases the gross market benefits of Marinus Link to $3,503m, which is $272m higher than the Status Quo scenario. Figure 62 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

Figure 62: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Other Expected Projects do not Proceed sensitivity; millions real June 2019 dollars discounted to 1 July 2025



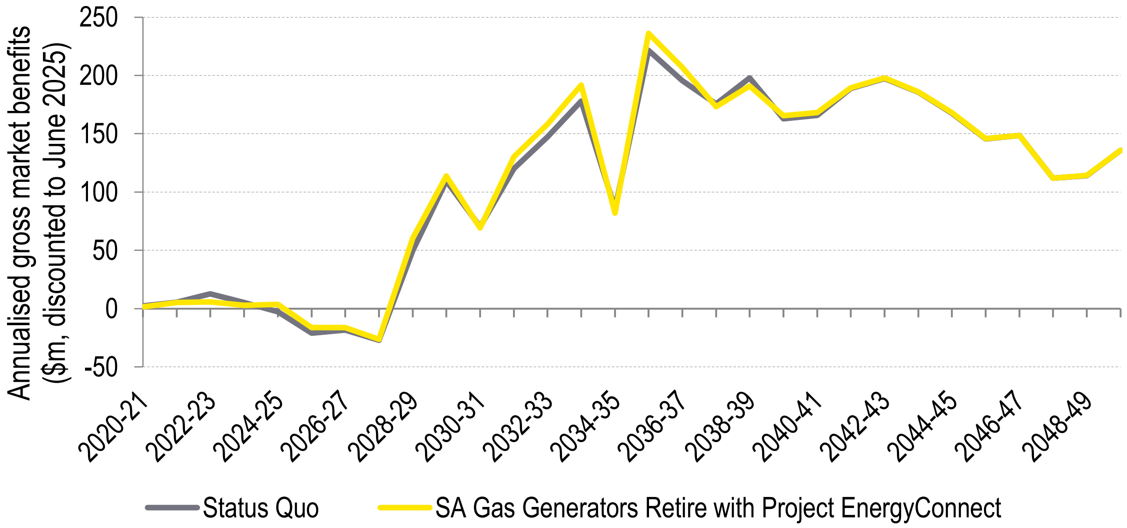
Reducing the transfer between Victoria and New South Wales decreases the potential for either region to support each other during the early 2030s, when Yallourn power station in Victoria and Eraring power station in New South Wales are assumed to retire. This increases the forecast annual benefits of Marinus Link from 2031-32 until Bayswater is assumed to retire in 2035-36. Since KerangLink is assumed not to be commissioned, these benefits are predominantly contained within Victoria.

8.8.7 SA Gas Generators Retire with Project EnergyConnect sensitivity

In this sensitivity, Pelican Point in South Australia is assumed to retire at the start of 2024-25, when Project EnergyConnect is assumed to be commissioned. Torrens Island A, Torrens Island B and Osborne are already assumed to retire by 2024-25 in the Status Quo scenario. The change in Pelican Point retirement date is forecast to increase the gross market benefits of Marinus Link to $3,307m, which is $74m higher than the Status Quo scenario. Figure 63 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

[179] Any associated step increases in assumed REZ capacity limits before REZ transmission expansion costs are applied are also not modelled in this sensitivity.

Figure 63: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, SA Gas Generators Retire with Project EnergyConnect; millions real June 2019 dollars discounted to 1 July 2025

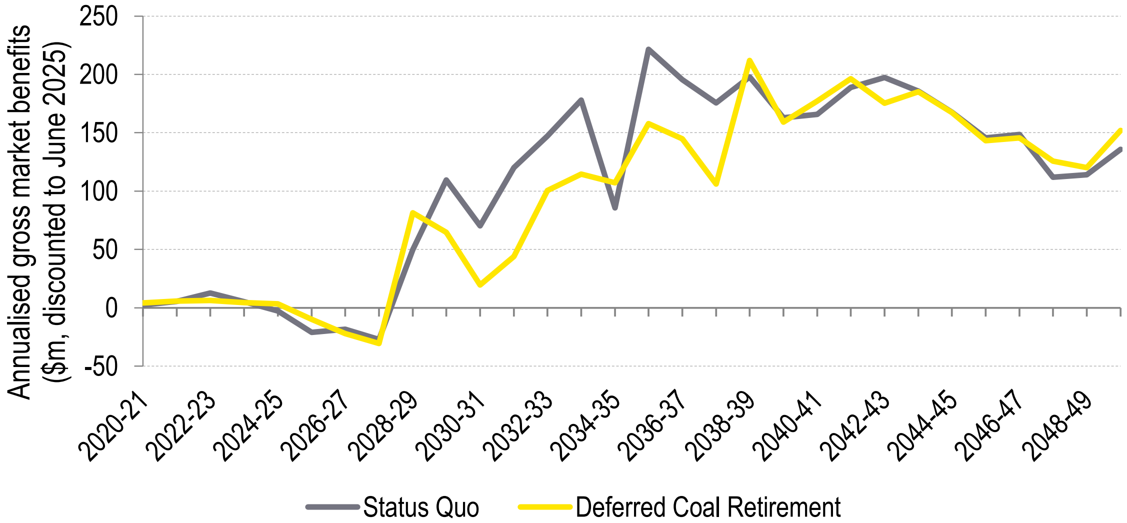


The assumed retirement of Pelican Point power station reduces the amount of CCGT capacity on the mainland by 529 MW. Consequently other, more expensive technologies, such as existing diesel or gas steam generators must occasionally be used during peak demand. Marinus Link is forecast to reduce the need to use these generators. This is particularly true during the 2030s when coal-fired power stations are assumed to retire, which further reduces the amount of dispatchable capacity in the mainland.

8.8.8 Deferred Coal Retirement sensitivity

In this sensitivity, the assumed maximum retirement dates of all coal-fired power station fixed are deferred three years later than the Status Quo scenario. This reduces the forecast gross market benefits of Marinus Link to $2,861m, which is $370m lower than the Status Quo scenario. Figure 64 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

Figure 64: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Deferred Coal Retirement sensitivity; millions real June 2019 dollars discounted to 1 July 2025

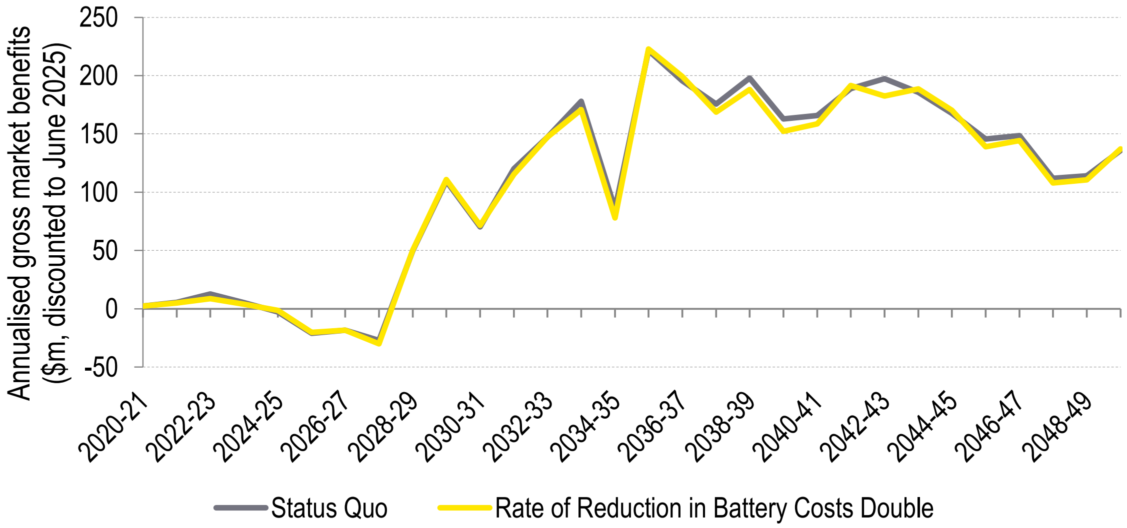


The additional baseload coal capacity that is assumed to be operational from the late 2020s onward is forecast to reduce the annual gross market benefits of Marinus Link by approximately $50m, until the assumed retirement of Bayswater power station in 2038-39.

8.8.9 Rate of Reduction in Battery Costs Doubles sensitivity

For this sensitivity, it is assumed that the learning rate for large-scale battery storage is doubled from 2020-21 onward, compared to the assumed capex trajectory from AEMO's '4 degree' scenario in the February 2019 planning and forecasting assumptions workbook (this is the learning rate applied in the Status Quo scenario).[180] Gross market benefits of Marinus Link are forecast to reduce to $3,155m, which is $76m lower than the Status Quo scenario. Figure 65 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

Figure 65: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Rate of Reduction in Battery Costs Doubles sensitivity; millions real June 2019 dollars discounted to 1 July 2025



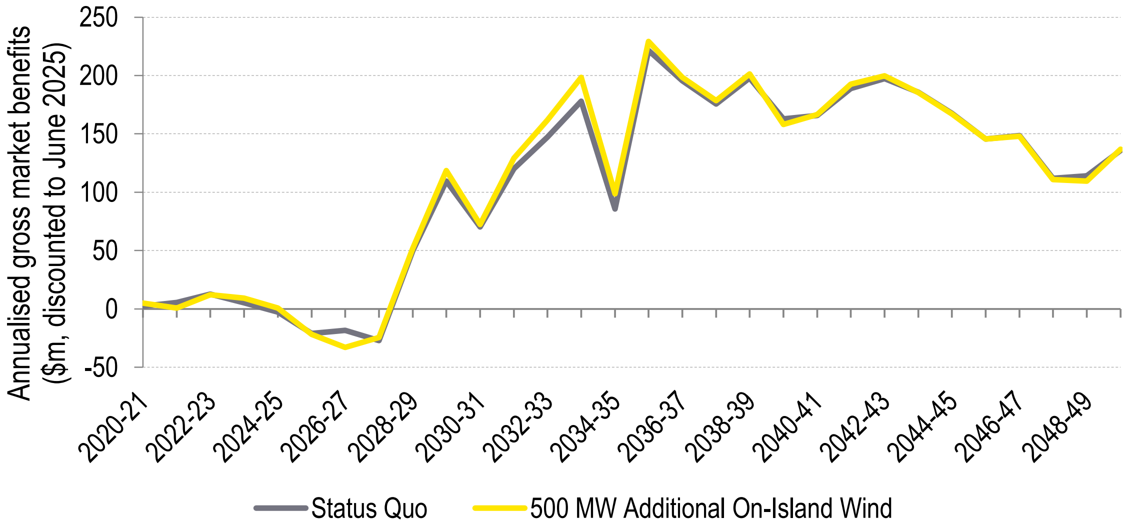
Similar to the Battery Life Doubles sensitivity, more large-scale battery storage is forecast to be installed in the NEM throughout the 2040s. The combination of solar PV and large-scale battery storage is forecast to reduce the need for gas, which decreases the potential fuel savings benefits of Marinus Link. However, Marinus Link's ability to unlock existing Tasmanian hydro and new entrant 24-hour Tasmanian PSH is forecast to result in additional capex benefits, associated with deferring mainland large-scale battery storage capacity. Because of these two counterbalancing factors, there is only a small reduction in Marinus Link's forecast gross market benefits from 2040 onward, compared to the Status Quo scenario.

8.8.10 500 MW Additional On-Island Wind sensitivity

In this sensitivity, 500 MW of wind capacity is assumed to be commissioned in the Tasmanian Midland REZ by 2020-21. This increases the forecast gross market benefits of Marinus Link to $3,307m, which is $76m higher than the Status Quo scenario. Figure 66 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

[180] AEMO, 5 February 2019, *2019 Input and Assumptions Workbook*, *v1.0*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies. Accessed 18 October 2019.

Figure 66: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, 500 MW Additional On-Island Wind sensitivity; millions real June 2019 dollars discounted to 1 July 2025



In the Status Quo scenario with Marinus Link, it is forecast that approximately 700 MW of new entrant wind capacity is installed in Tasmania by 2028-29. Without Marinus Link, it is forecast that 200 MW of new entrant Tasmanian wind capacity is installed by 2028-29 and approximately 400 MW of new entrant Tasmanian wind in total by 2035-36. Consequently, this sensitivity essentially brings forward the installation of new entrant Tasmanian wind capacity and only results in a small amount of additional benefits of Marinus Link from 2028-29 until 2035-36.

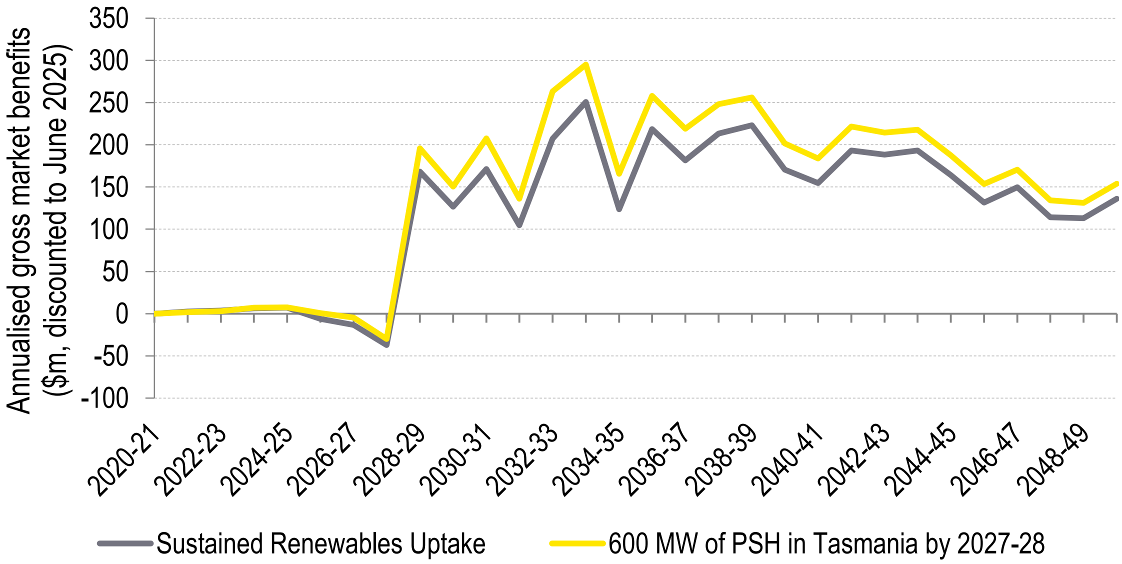
8.8.11 600 MW of PSH in Tasmania by 2027-28

The Australian government's Underwriting New Generation Investments (UNGI) program is intended to support projects that will lower prices, increase competition and increase reliability in the energy system. One of the twelve shortlisted projects is new renewable Tasmanian PSH, which was proposed by Hydro Tasmania.[181]

The underlying assumptions for this sensitivity come from the Sustained Renewables Uptake scenario. However, for the case that Marinus Link is assumed to be commissioned, it is further assumed that 600 MW of Tasmanian PSH is underwritten through the UNGI program and is operational by 2027-28. This increases the forecast gross market benefits of Marinus Link to $4,351m, which is $691m higher than the Sustained Renewables Uptake scenario. Figure 67 displays the forecast annual gross market benefits in this sensitivity alongside the Sustained Renewables Uptake scenario.

[181] Australian Government Department of the Environment and Energy, *Underwriting New Generation Investments Program*. Available at: https://www.energy.gov.au/government-priorities/energy-programs/underwriting-new-generation-investments-program. Accessed 18 November 2019

Figure 67: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, 600 MW of PSH in Tasmania by 2027-28 sensitivity; millions real June 2019 dollars discounted to 1 July 2025



In the Sustained Renewables Uptake scenario with Marinus Link, PSH is forecast to be installed in Tasmania throughout the 2030s, with approximately 500 MW installed by 2032-33 when Bayswater is assumed to retire, and over 600 MW of PSH commissioned by 2034-35. This incurs a capex and FOM cost. The 600 MW of PSH in Tasmania sensitivity assumes that this 600 MW of PSH capacity is committed and so the forecast $4,351m in gross market benefits do not include associated capex and FOM costs associated with this PSH capacity. This results in an increase in capex and FOM savings of approximately $20m to $40m each year from 2032-33 to 2049-50 compared to the Sustained Renewables Uptake scenario.

The earlier forecast annual gross market benefits of approximately $30m from 2028-29 to 2031-32 are predominantly driven by fuel saving and capex deferral of other technologies, due to the additional PSH capacity that is assumed to be available in Tasmania by this time.

Table 23 displays the forecast gross market benefits in the Status Quo scenario and this sensitivity, for two Marinus Link timings: stage 1 commissioned 2027 and stage 2 2028; and stage 1 2028 and stage 2 2032. The increase in gross market benefits compared to the Status Quo scenario is forecast to be higher for the earlier timing of Marinus Link suggesting that the additional PSH in Tasmania and the earlier entry of Marinus Link are complementary. These outcomes indicate that there may be a case for the timing of Marinus Link to be advanced in this sensitivity. This is dependent on option costs and is evaluated by TasNetworks outside of this Report.[182]

Table 23: Summary of forecast gross market benefits of Marinus Link 1,500 MW, Sustained Renewables Uptake scenario and 600 MW of PSH in Tasmania by 2027-28 sensitivity; millions real June 2019 dollars discounted to 1 July 2025

	Marinus Link 1,500 MW stage 1 2027, stage 2 2028	Marinus Link 1,500 MW stage 1 2028, stage 2 2032
Sustained Renewables Uptake scenario	3,894	3,661
600 MW of PSH in Tasmania by 2027-28 sensitivity	4,652	4,351
Difference in gross market benefits	758	691

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

8.8.12 Yallourn Retirement 2027-28 sensitivity

For this sensitivity, it is assumed that all four of Yallourn power stations units have a fixed retirement date at the start of 2027-28. The units are still allowed to retire, or partially retire, sooner if it is least-cost. It is forecast that this increases the gross market benefits of Marinus Link to $3,352m, which is $121m higher than the Status Quo scenario. Figure 68 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario. The assumed early retirement of Yallourn power station is forecast to increase the market benefits of Marinus Link in the late 2020s and early 2030s.

Figure 68: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Yallourn Retirement 2027-28 sensitivity; millions real June 2019 dollars discounted to 1 July 2025

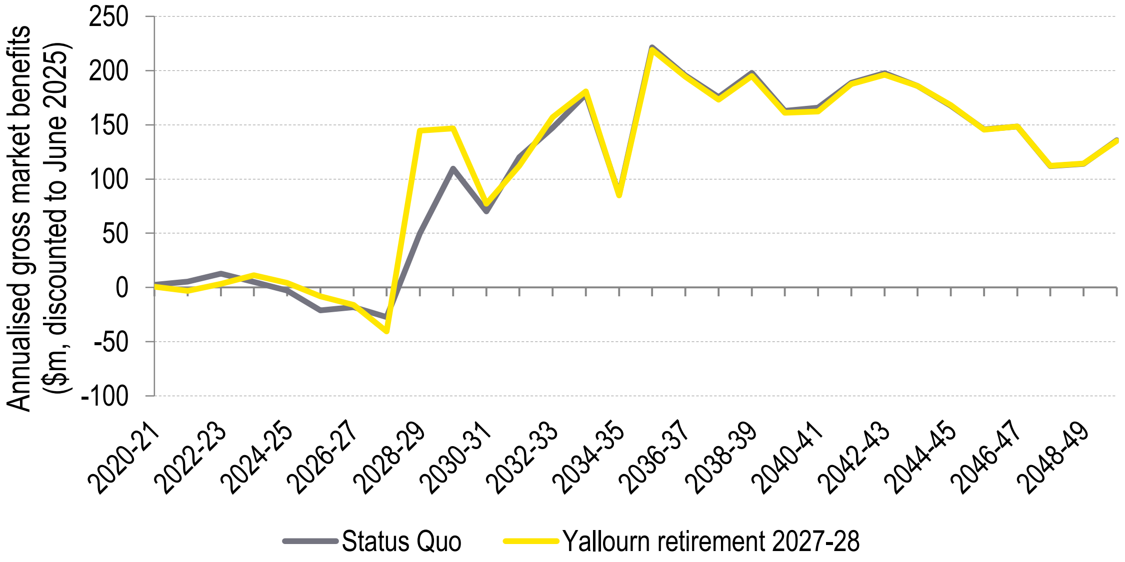


Table 24 displays the forecast gross market benefits in the Status Quo scenario and this sensitivity, for two Marinus Link timings: stage 1 and stage 2 commissioned 2027 (the year that Yallourn power station is assumed to retire in this sensitivity); and stage 1 2028 and stage 2 2032. The increase in gross market benefits compared to the Status Quo scenario is forecast to be higher if Marinus Link is operational by the time Yallourn retires. In addition, gross benefits are realised earlier in this sensitivity than the Status Quo scenario and therefore there may be a case for the timing of Marinus Link to be advanced in this sensitivity. This is dependent on option costs and is evaluated by TasNetworks outside of this Report.[183]

Table 24: Summary of forecast gross market benefits of Marinus Link 1,500 MW, Status Quo scenario and Yallourn Retirement 2027-28 sensitivity; millions real June 2019 dollars discounted to 1 July 2025

	Marinus Link 1,500 MW stage 1 2027, stage 2 2027	Marinus Link 1,500 MW stage 1 2028, stage 2 2032
Status Quo scenario	3,332	3,231
Yallourn Retirement 2027-28 sensitivity	3,561	3,352
Difference in gross market benefits	229	121

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

8.8.13 Partial September ISP Update sensitivity

The assumptions for all four scenarios were selected by TasNetworks in late July. Since that time, AEMO has published several updates to the planning and forecasting assumptions workbook. The intention of this sensitivity is to provide an indication of the changes to outcomes that could occur if the modelling exercise was to be repeated with the latest AEMO assumptions as of September.[184] This sensitivity varies from the Status Quo scenario by:

- Using the AEMO 2019 ESOO Central scenario demand forecast,[185]
- Doubling all REZ wind and solar PV build limits,
- Regional PSH build limit increases.

Figure 69 displays the assumed regional demand for the study period in the Status Quo scenario and this sensitivity. In New South Wales and Victoria, the ESOO 2019 demand forecasts are much lower.

Figure 69: Annual regional sent-out demand forecast in the Status Quo scenario and Partial September ISP Update sensitivity

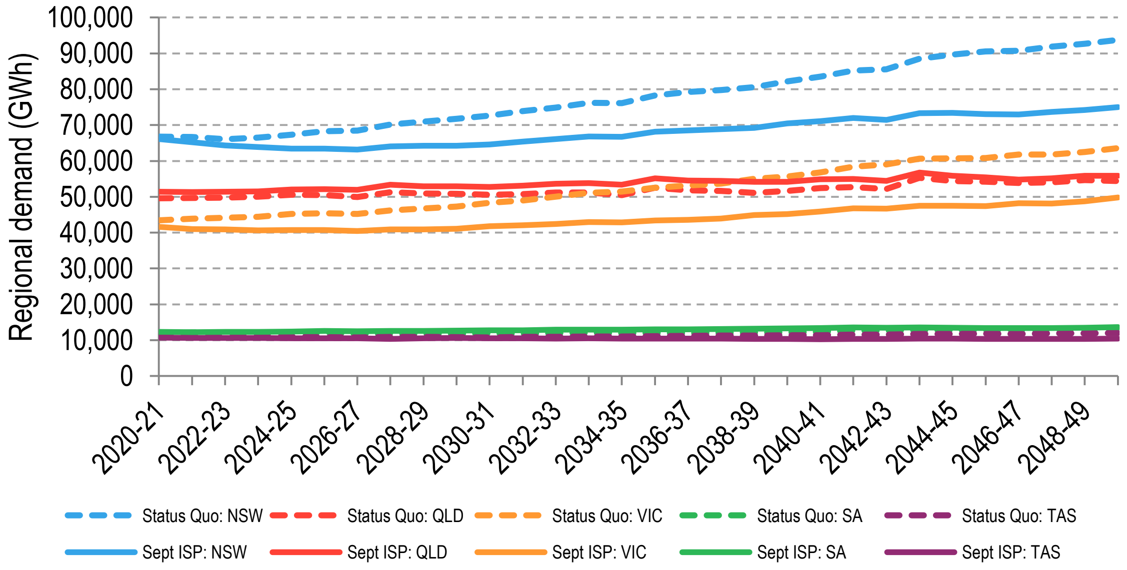
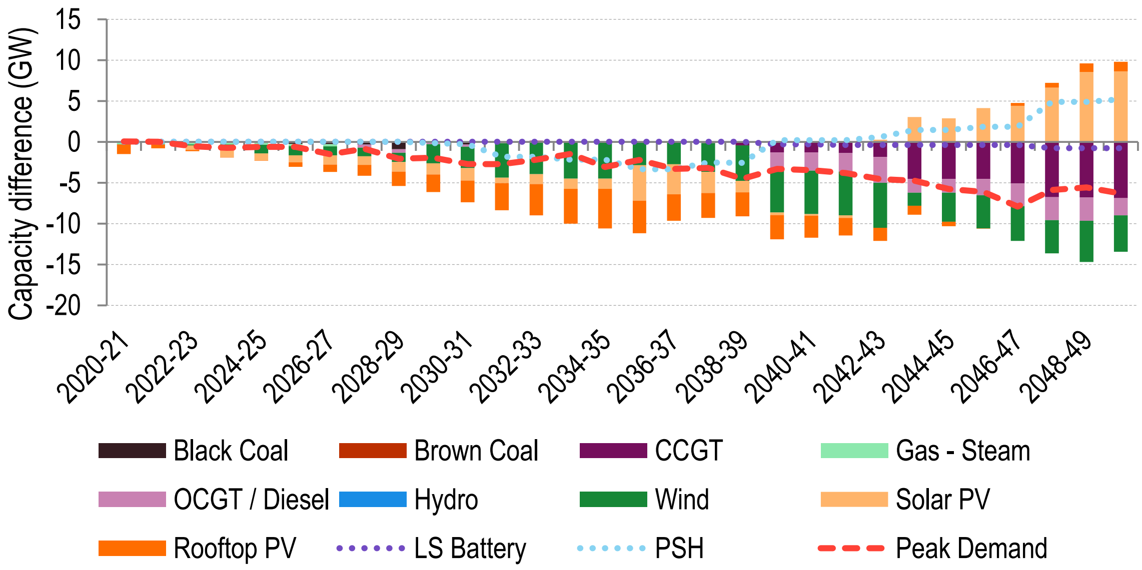


Figure 70 displays the difference in capacity across the NEM for this sensitivity compared to the Status Quo scenario, both without Marinus Link. Throughout the 2030s the lower assumed demand is forecast to result in approximately 4-7 GW less new entrant wind and solar PV capacity, along with 2-4 GW less PSH capacity in the early to mid-2030s. Increasing the assumed build limits is forecast to result in 5.2 GW more PSH and 8.6 GW more solar PV capacity by 2049-50. The combination of solar PV and storage, as well as the lower annual and peak demand in New South Wales and Victoria, is forecast to reduce the amount of CCGT capacity by 6.9 GW by the end of the study period.

[184] AEMO, 13 September 2019, *2019 Input and Assumptions Workbook, v1.2*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan. Accessed 23 October 2019.

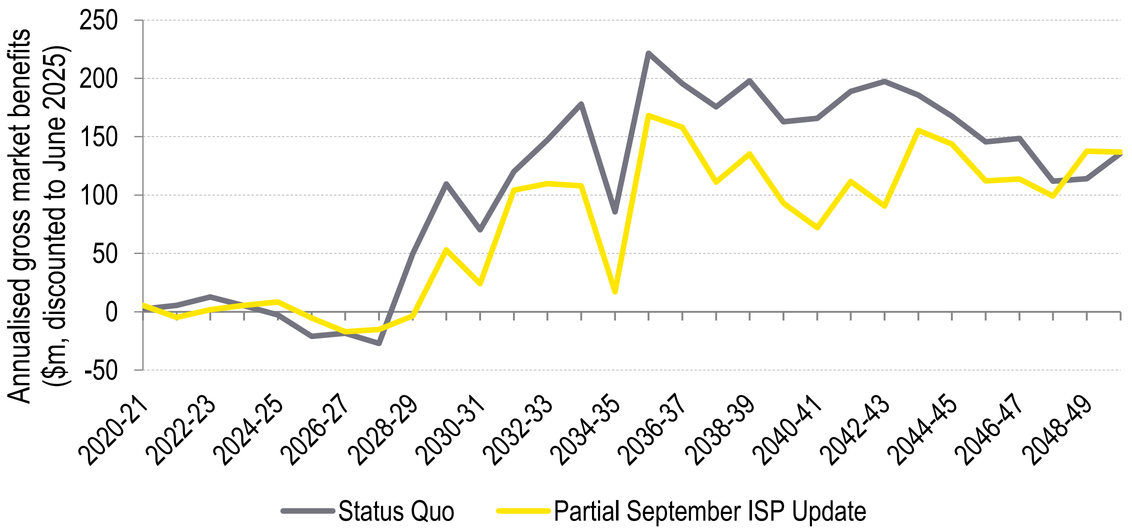
[185] AEMO, August 2019, *2019 Electricity Statement of Opportunities*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities. Accessed 18 November 2019.

Figure 70: Difference in NEM capacity mix forecast without Marinus Link between Partial September ISP Update sensitivity and Status Quo scenario (difference relative to Figure 10; positive values = higher capacity in Partial September ISP Update sensitivity)



The lower assumed demand and subsequent reduction in need for peaking capacity on the mainland, along with the greater availability of mainland PSH and solar PV is forecast to reduce the gross market benefits of Marinus Link to $2,230m, which is $1,002m lower than the Status Quo scenario. Figure 71 displays the forecast annual gross market benefits in this sensitivity alongside the Status Quo scenario.

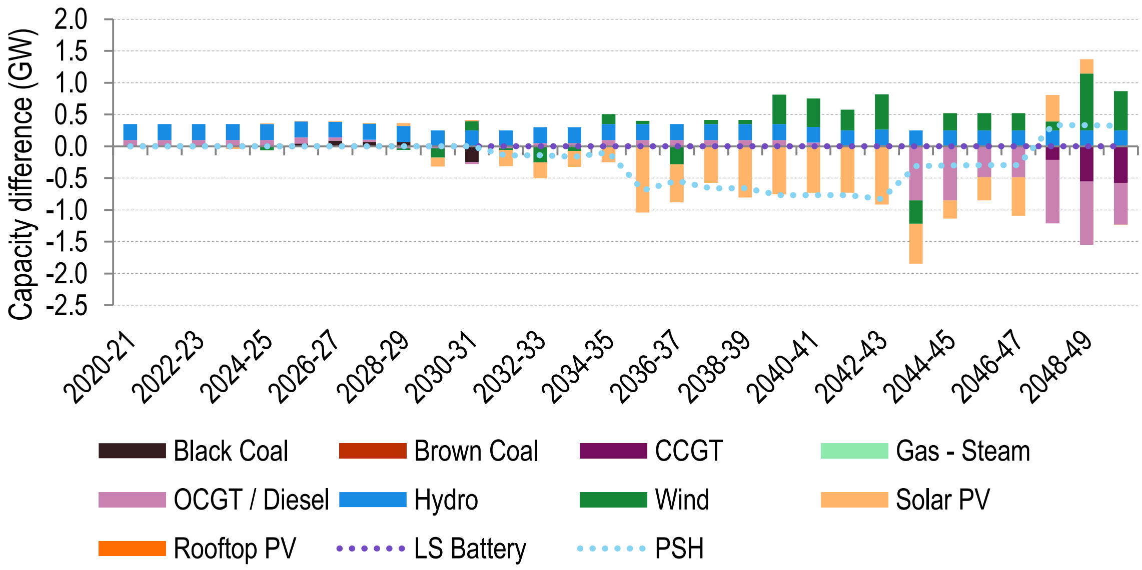
Figure 71: Forecast annual gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Partial September ISP Update sensitivity; millions real June 2019 dollars discounted to 1 July 2025



For this sensitivity, the timing of Marinus Link's benefits is shifted backward. In the Status Quo scenario, the interconnector is forecast to allow for a deferral of new entrant solar PV and mainland PSH capacity from 2029-30 to 2036-37, leading to capex benefits in those years. From 2037-38 onward, the largest category of market benefits is fuel savings, since the combination of PSH and renewables offsets CCGT generation. In this sensitivity, deferral of solar PV and PSH capacity is predominantly forecast to occur later, from 2035-36 to 2046-47. The subsequent inflection point, when new entrant storage and renewables provide more gross market benefits than CCGTs, does not occur until 2047-48.

Figure 72 displays the difference in capacity across the NEM between the case with Marinus Link 1,500 MW, commissioned in two 750 MW stages in 2028 and 2032, relative to the without Marinus Link case for the Partial September ISP Update sensitivity.

Figure 72: Difference in NEM capacity mix forecast due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Partial September ISP Update sensitivity (positive values = higher capacity with Marinus Link)



For this sensitivity, delaying the first stage of Marinus Link to 2031 and second stage to 2035 is forecast to reduce the gross market benefits by $103m, to $2,127m.

8.9 Discount Rate Changes

The TSIRP model makes decisions that minimise the overall cost to supply electricity demand in the NEM over the entire study period based on a pre-defined discount rate. To calculate the gross market benefits of Marinus Link under different discount rates, the model was re-run with the alternate rate (rather than simply discounting the annual benefits from Status Quo scenario with a different discount rate). As such, the forecast generation and capacity mix for the Low Discount and High Discount sensitivities differ to the Status Quo scenario. Table 25 displays the forecast gross market benefits of Marinus Link under different discount rates, as required by the RIT-T methodology. Note that these forecast gross market benefits are not directly comparable, since the annual benefits are also being discounted by their respective rates.

Table 25: Summary of forecast gross market benefits by component for Marinus Link 1,500 MW stage 1 2028 stage 2 2032, Low Discount Rate sensitivity, Status Quo scenario and High Discount Rate sensitivity; millions real June 2019 dollars discounted to 1 July 2025 (at discount rates of 3.54 %, 5.9 % and 8.26 %, respectively)

	Low Discount Rate	Status Quo	High Discount Rate
Discount rate	3.54 %	5.9 %	8.26 %
Gross market benefits ($m)	4,664	3,231	2,251

8.10 System Cost of Unplanned Basslink Outage

This section presents the forecast cost of an unplanned outage of Basslink occurring from 1 July 2027 to 1 January 2028, for a world where Marinus Link does not exist and a world where Marinus Link does exist. This assessment was completed in June 2019, prior to finalising assumptions for the Status Quo scenario. Due to time constraints, this assessment was not repeated using the final assumptions. Changes in assumptions relative to the Status Quo scenario are described in Section 4.4.2. Furthermore, this sensitivity was conducted for Marinus Link 1,200 MW, with stage 1 2026 and stage 2 2028. As such, for the case with Marinus Link, the Basslink outage is assumed to occur while Marinus Link has a capacity of 600 MW.

Due to these changes in input assumptions, the outcomes of the Unplanned Basslink Outage sensitivity are not directly comparable to other system cost outcomes in this Report; however, they are indicative of the impact of an unplanned Basslink outage on system cost with and without Marinus Link.

Table 26 displays the forecast gross system cost, within the 2027-28 financial year, that is associated with a six-month unplanned outage of Basslink for two cases: without Marinus Link; and with Marinus Link 1,200 MW stage 1 2026, stage 2 2028. Without Marinus Link, the forecast impact on gross system cost associated with a six-month unplanned outage of Basslink in 2027-28 is $30m. If Marinus Link is commissioned, even with only one link operational at the time of the Basslink outage, this cost is forecast to be reduced to $3m, since energy can still be transferred between the mainland and Tasmania.

Table 26: Summary of forecast gross market cost associated with an unplanned Basslink outage from 1 July 2027 to 1 January 2028. Marinus Link 1,200 MW stage 1 2026, stage 2 2028; millions real June 2019 dollars discounted to 1 July 2025

	Without Marinus Link	With Marinus Link
Gross market cost in financial year 2027-28	30	3

The impact of the Basslink outage with Marinus Link is minimal because this outage occurs only a year after when Marinus Link stage 1 is commissioned at a time when the differences in NEM development with and without Marinus Link are minimal. In this sensitivity the capacities of Marinus Link stage 1 and Basslink are similar and so at the time of the unplanned outage, the new Marinus Link stage 1 can in effect substitute for Basslink.

During the 2015-16 financial year there was an approximately six month long outage of Basslink from 20 December 2015 to 14 June 2016.[186] At this time there was 308 MW of existing wind capacity in Tasmania.[187] By 2020-21 it is assumed that a further 256 MW of wind capacity will be operational in Tasmania.[188] Due to this additional Tasmanian capacity along with new security measures, such as the whole-of-system PSL for Tasmanian hydro, the historical cost of a six month outage of Basslink may not be representative of a future outage.

The future impacts of the unplanned Basslink outage are dependent on the timing and duration of the outage. The forecast impacts would likely be greater if the outage was to span the Victorian summer peak period, extend for longer, or occur later when the NEM has developed in such a way that Marinus Link is more heavily utilised.

[186] Tasmanian Energy Security Taskforce, June 2017, *Tasmanian Energy Security Taskforce: Final Report*. Available at https://www.stategrowth.tas.gov.au/energy_and_resources/tasmanian_energy_security_taskforce/final_report. Accessed: 25 November 2019

[187] Woolnorth Wind Fam has a capacity of 140 MW. Musselroe Wind Farm has a capacity of 168 MW.

[188] Granville Harbour Wind Farm has an assumed capacity of 112 MW. Cattle Hill Wind Farm has an assumed capacity of 144 MW.

9. Regional impacts of interconnectors

9.1 Who benefits from Marinus Link?

The market benefits assessment stipulated in the RIT-T tests which (if any) credible options create the largest NEM-wide system cost savings. The regional impacts of Marinus Link are not directly considered in assessing the RIT-T, but are of interest to energy consumers, the energy industry and governments.

This section considers the regional impacts of Marinus Link in modelling outcomes from the perspectives of (1) the impact on regional marginal cost of supply, and (2) regional allocation of gross market benefits.

9.1.1 Impact on consumers

With Basslink only, Tasmania has a surplus of energy in all scenarios (owing to the development of additional wind generation in the Status Quo scenario, Sustained Renewables Uptake scenario and Accelerated Transition to a Low Emissions Future scenario, and reduced Tasmanian demand in the Global Slowdown scenario). This is evident in the increasing amount of time that Basslink is at its northward limit in all scenarios (Figure 15, Figure 18, Figure 21, Figure 25). With a surplus of energy, the water value[189] of Hydro Tasmania's generators would be very low, and the wholesale prices in Tasmania would also be low.[190] Mainland regions cannot greatly benefit from Tasmania's surplus capacity and energy when Basslink flows are constrained.

With additional interconnection provided by Marinus Link, it is expected that Tasmanian wholesale prices can better shadow Victorian wholesale prices as northward flows at times of high Victorian price are less constrained. At these times, the wholesale price in Tasmania is expected to be marginally lower than the wholesale price in Victoria. Hydro Tasmania can extract greater value out of their limited water supplies (an increase in water value). The increase in water value of Hydro Tasmania's generators translates into Hydro Tasmania selling energy at higher wholesale prices both on the mainland and in Tasmania which would increase revenue for Hydro Tasmania and costs to Tasmanian energy consumers.[190] However, given the government ownership of Hydro Tasmania, the gross market impact of Marinus Link can be shared between Hydro Tasmania and Tasmanian consumers.

Meanwhile, the mainland regions likely to benefit from Tasmania's surplus capacity with Marinus Link. The additional interconnection displaces higher cost mainland generators, which we expect would lower wholesale prices in mainland regions.

Generally, regulated interconnectors act to bring wholesale prices in the two interconnected regions together, to the extent that is possible.[191] When there is abundant interconnection (i.e. the interconnector is not constrained), the wholesale price in the exporting region is the same as the wholesale price in the importing region, adjusted for interconnector losses.

These theoretical impacts of a regulated interconnector are reflected in the hourly marginal costs of supply output from the TSIRP model. While the model computes the development plan for the NEM based on lowest NEM-wide system cost, demand is met on a regional basis and this hourly marginal cost of supply is an output for each hourly trading interval in each region. These costs are generally indicative of wholesale market prices in a highly competitive market where bidding always reflects the cost of generation (which has not been true historically in the NEM), but can assume other values due to model constraints. Details on the marginal costs of supply outputs from the model were provided in Section 3.3.

[189] In energy-limited hydro systems with storages the "water value" represents the opportunity cost of using a unit of water.
[190] This discussion assumes that Hydro Tasmania bids in a cost-reflective manner i.e. bidding at water value.
[191] Turvey R, 2006, 'Interconnector economics', *Energy Policy* 34: 1457-1472.

Figure 73 to Figure 76 show the change in marginal cost of supply to mainland regions with Marinus Link in the four modelled scenarios. The charts omit the impact on cost of supply to Tasmanian consumers as the Tasmanian Government can share impacts of Marinus Link between Hydro Tasmania and Tasmanian consumers. In all scenarios, the marginal cost of supply generally decreases in all mainland regions. In general, the largest reductions occur in Victoria. Reductions also occur in many years in New South Wales, Queensland and South Australia, but the magnitude of impacts varies between years and scenarios, due to the many changes in demand growth, new generating capacity and retirements in successive years. However, Marinus Link almost always exerts downward pressure on prices as it is another competing source of generation on the mainland, driven by the imperative to bid Tasmanian generation to achieve the most efficient use of water storages.

Figure 73: Forecast change in marginal cost of supply with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Status Quo scenario[192]

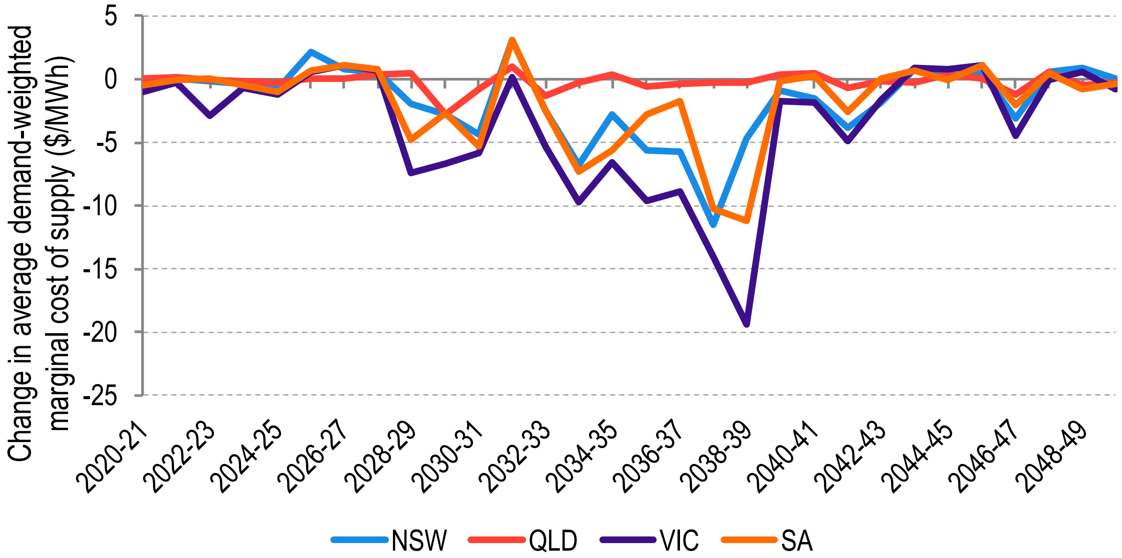
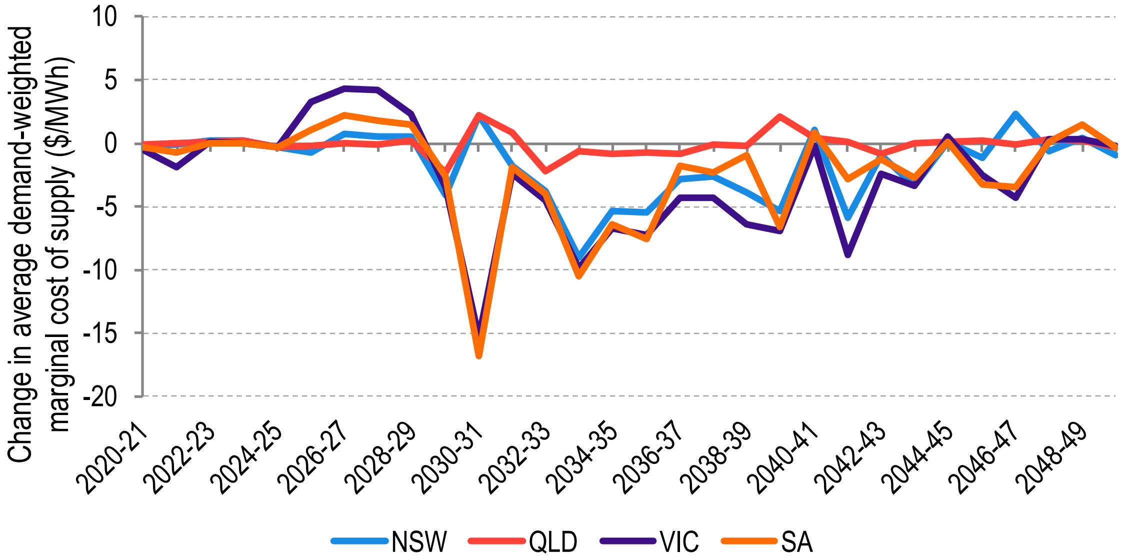


Figure 74: Forecast change in marginal cost of supply with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Global Slowdown scenario



[192] Cost omits the cost of Marinus Link.

Figure 75: Forecast change in marginal cost of supply with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Sustained Renewables Uptake scenario

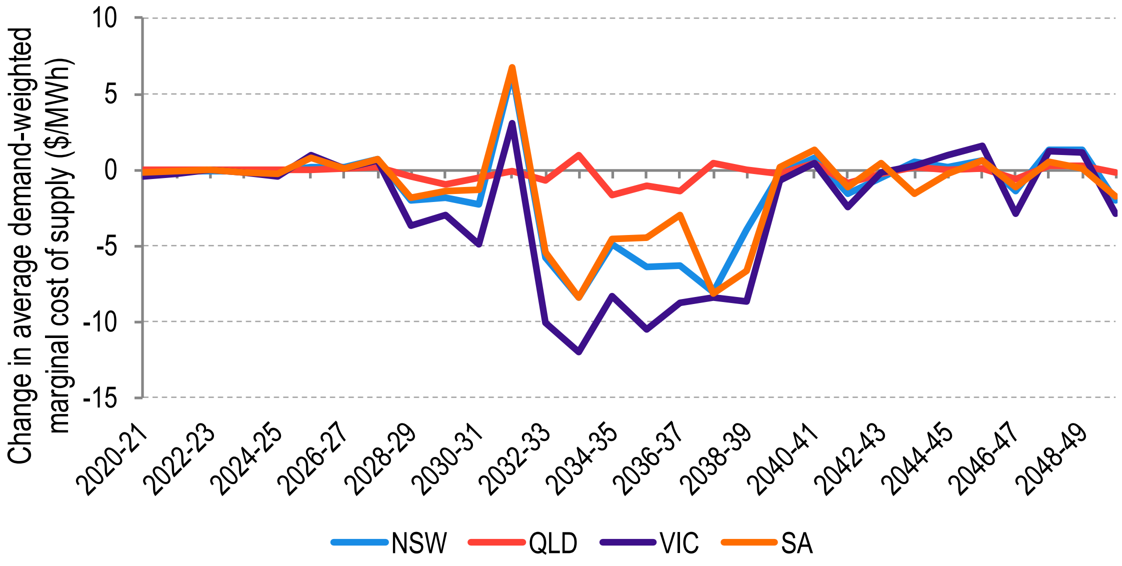
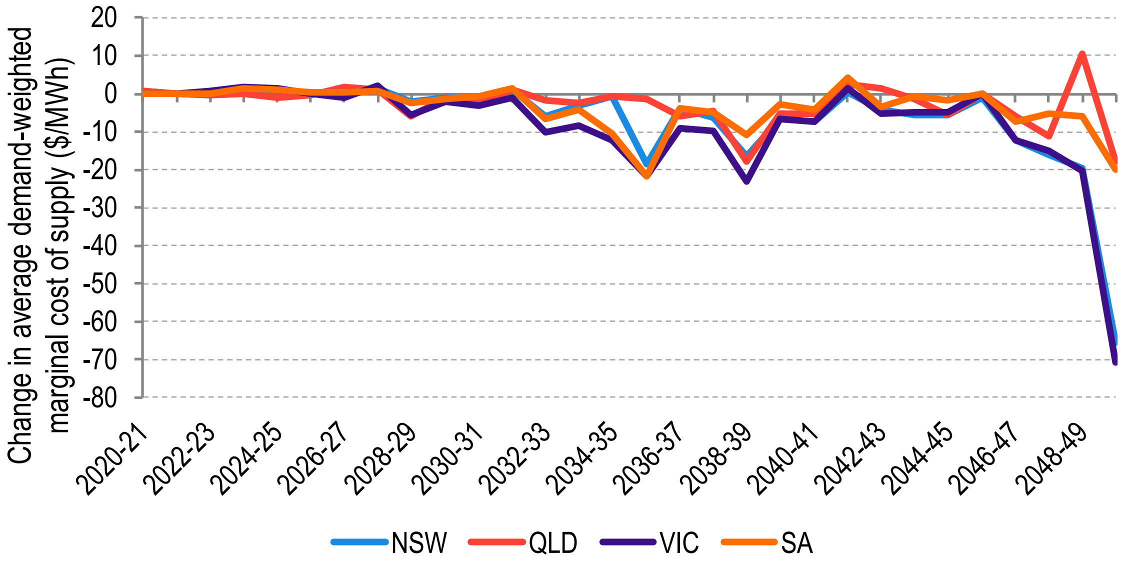


Figure 76: Forecast change in marginal cost of supply with Marinus Link 1,500 MW, stage 1 2028, stage 2 2032, Accelerated Transition to a Low Emissions Future scenario



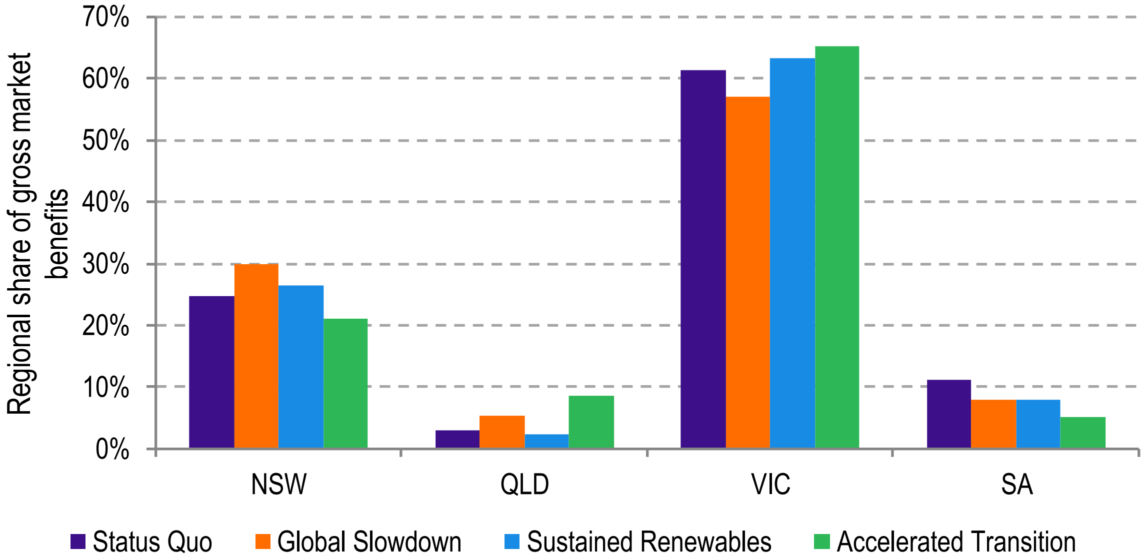
Price impacts are largest in the Accelerated Transition to a Low Emissions Future scenario (Figure 76). This is because the combination of high demand and a stringent emissions reduction constraint means substantial quantities of high-cost capacity are required. When there is a binding emissions reduction constraint, as occurs in this scenario, the marginal cost of supply frequently incorporates a proportion of long-run costs of building new renewable and storage capacity. There is a large decrease in marginal cost of supply in Victoria and New South Wales due to Marinus Link in this scenario in the final year. This is essentially driven by the very high marginal cost of supply without Marinus Link in the final two years in Victoria and New South Wales owing to dispatch of high-cost DSP.

9.1.2 Regional gross market benefits

While the development plan for the NEM computed by the TSIRP model is that which lowers total NEM system cost, all categories of gross market benefits can also be allocated to a NEM region based on where capacity is built or avoided, and where energy is generated or avoided as a result of

Marinus Link. Analysis of these data tells a similar story to the impact of Marinus Link on marginal cost of supply. In all scenarios, there is an overall increase in cost of supply (i.e. negative benefit) with Marinus Link in Tasmania. Meanwhile, all Mainland regions see a decrease in regional cost of supply due to Marinus Link. A summary of the share of forecast gross market benefits in mainland regions is shown in Figure 77.[193] The largest share of forecast gross market benefits accrues to Victoria, then New South Wales, South Australia and finally Queensland.

Figure 77: Mainland regions' share of forecast gross market benefits of Marinus Link 1,500 MW, stage 1 2028, stage 2 2032



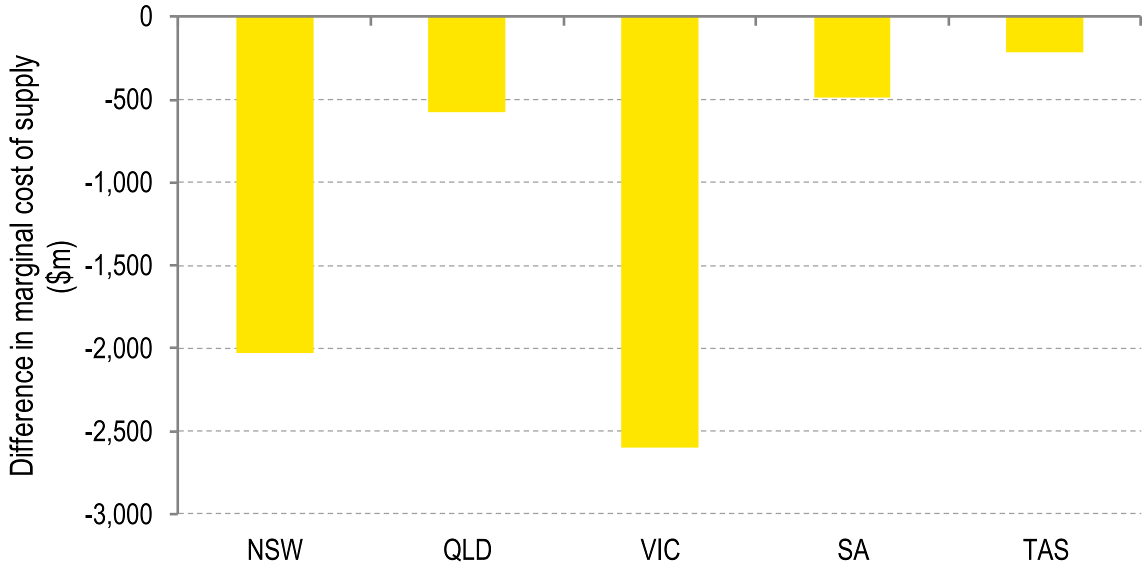
9.2 Who benefits from KerangLink?

The simulations exploring the interaction between Marinus Link and KerangLink (see Section 8.7) allow us to perform similar analysis of the regional impacts of KerangLink on total cost of supply and marginal cost of supply.

The marginal cost of supply reduces due to KerangLink in all regions, with New South Wales and Victoria the largest beneficiaries (Figure 78). These outcomes are heavily influenced by differences in USE outcomes due to KerangLink as USE is valued at the VCR. When computing the *marginal* cost of supply the VCR is applied to all regional demand in intervals with USE.

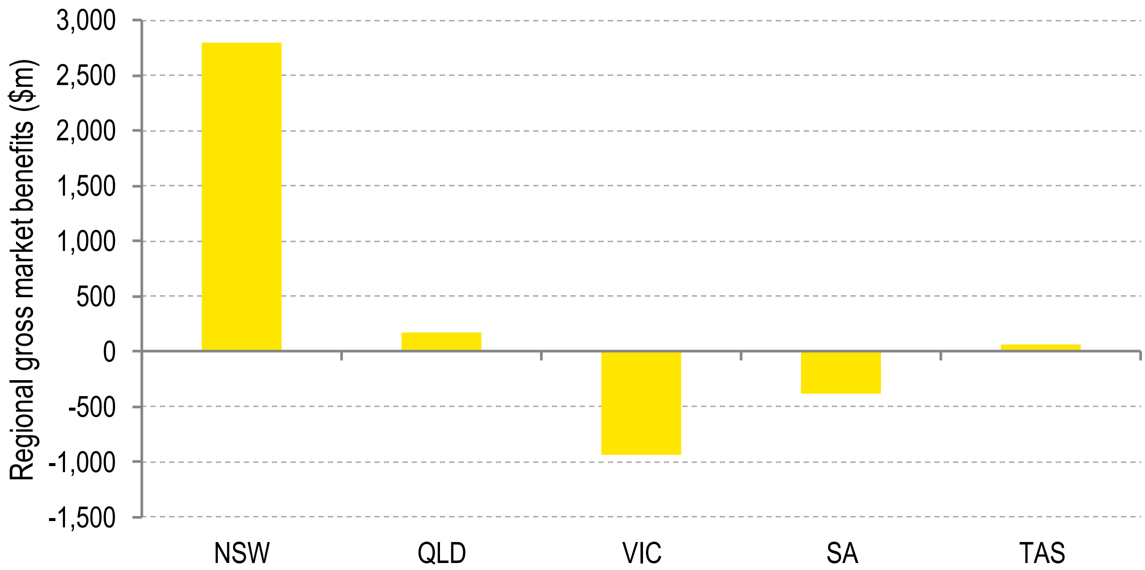
[193] Full detail on the regional split of benefits by category in each scenario was presented in Section 8 (Table 16, Table 17, Table 18, Table 19).

Figure 78: Forecast change in regional marginal cost of supply to due KerangLink, Status Quo scenario



These changes are not consistent with the regional allocation of gross market benefits (change in regional system cost) as they were for Marinus Link (Section 9.1). Most forecast gross market benefits accrue to New South Wales while cost of supply in Victoria increases (Figure 79). The forecast shift in capital investment from New South Wales to Victoria due to KerangLink generates capex and fuel cost savings in New South Wales, while Victoria experiences a net fuel and capex cost. Overall Victoria is forecast to be a clear beneficiary of KerangLink in terms of decreased marginal cost of supply but incurs an increase in gross cost of supply due to higher investment costs. Meanwhile, New South Wales is a clear beneficiary from both perspectives.

Figure 79: Forecast regional gross market benefits of KerangLink, Status Quo scenario



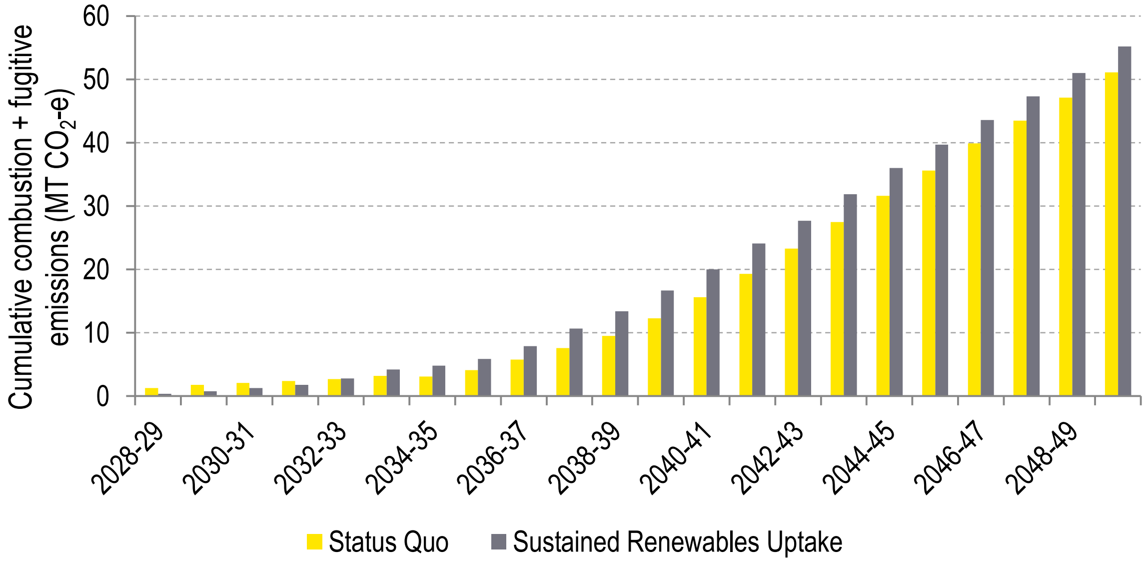
10. Carbon emissions

Differences in carbon emissions with Marinus Link were not valued as a component of the forecast market benefits as part of this RIT-T but are noted here as an additional analysis.

The Status Quo and Sustained Renewables Uptake scenarios assume that the electricity sector is required to achieve at least a 28 % reduction in emissions compared to 2005 levels by 2030 and a 70 % reduction compared to 2016 levels by 2050. In these scenarios, this constraint does not bind. In other words, due to other assumptions in these scenarios, including maximum age-based thermal retirement dates, VRET and QRET, the least-cost long-term NEM development is forecast to meet (actually overachieve) the 28 % and 70 % emissions reduction targets without any generation output being curtailed based on this constraint alone.

The NEM is forecast to exceed the emissions constraint targets in these scenarios with Basslink only and with Marinus Link. However, with Marinus Link it is forecast that the amount of emissions produced in the NEM can be reduced through the better utilisation of existing Tasmanian hydro and by unlocking the benefit of Tasmanian wind and PSH to offset new entrant Victorian CCGT capacity and generation. Figure 80 displays the forecast difference in emissions reduction in the Status Quo and Sustained Renewables Uptake scenarios due to Marinus Link.

Figure 80: Forecast cumulative reduction in combustion and fugitive emissions due to Marinus Link 1,500 MW, stage 1 2028, stage 2 2032



The Accelerated Transition to a Low Emissions Future scenario assumes the electricity sector is required to achieve at least a 52 % reduction in emissions compared to 2005 levels by 2030 and a 90 % reduction compared to 2016 levels by 2050. This emissions constraint binds in this scenario. As a result, the least-cost development plan reduces generation from thermal generators and installs new low- or zero-emissions generators to exactly track the emissions reduction target each year. This occurs in Basslink-only simulations and those with Marinus Link. As such Marinus Link is not forecast to lead to an additional reduction in emissions, but rather, it allows for a more cost-effective method of achieving this target, which is captured in the market benefit outcomes.

For the Global Slowdown scenario, no emission reduction target for the electricity sector was assumed. As such, Marinus Link's impact on emissions has not been assessed in the modelling process.

Appendix A List of abbreviations

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
CCGT	Closed-Cycle Gas Turbine
DSP	Demand-Side Participation
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
LRET	Large-scale Renewable Energy Target
LS battery	Large-Scale battery storage
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
UNGI	Underwriting New Generation Investments

Abbreviation	Meaning
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRET	Victoria Renewable Energy Target

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