Appendix to the TasNetworks Supplementary Analysis Report

Addendum to Project Marinus PADR economic modelling report

Tasmanian Networks Pty Ltd
9 November 2020

Building a better working world

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Notice

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

The results of EY's work, including the assumptions and qualifications made in preparing the report, are set out in EY's report dated 27 November 2019 ("**Report**") and this report dated 9 November 2020 ("**Addendum**") which is an addendum to the Report and has been prepared at the specific request of the Client to update the scenarios and various input assumptions to align with more recent data. This Addendum must be read in conjunction with the Report[1] to understand the full context and details of the model used to compute the long-term least-cost generation development plan and gross market benefits of Marinus Link. The Report and Addendum should be read in their entirety including this notice, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report and Addendum. No further work has been undertaken by EY since the date of the Report or the Addendum to update them. Except as described in this Addendum, no further work has been undertaken by EY since the date of the Report to update its contents.

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

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Our work commenced on 6 January 2020 and was completed on 21 October 2020. Therefore, our Report and Addendum does not take account of events or circumstances arising after 21 October 2020 and we have no responsibility to update the Report or Addendum for such events or circumstances.

[1] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

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

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

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

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

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1. Executive summary

TasNetworks has engaged EY to evaluate the potential gross 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 has been done in addition to 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 Addendum forms an accompanying report to the broader TasNetworks' Supplementary Analysis Report published by TasNetworks.[2] It is not intended as a stand-alone report, but is rather an Addendum to EY's economic modelling report[3], published on 27 November 2019, which was one of the supporting material's requested by TasNetworks for use in their Project Assessment Draft Report (PADR). It contains additional analysis based on newer input assumptions. This Addendum must be read in conjunction with the PADR economic modelling report[3] to understand the full context and details of the model used to compute the long-term least-cost generation development plan and gross market benefits of Marinus Link. The Addendum primarily describes the key changes in scenario assumptions, input data sources and methodologies that have been applied in the gross market benefits modelling (the modelling) relative to the Project Marinus RIT-T PADR.[4] It also provides a summary of the gross market benefit outcomes of our modelling, excluding the cost of Marinus Link, for all scenarios and sensitivities advised by TasNetworks.

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 21 years from 2021-22 to 2041-42. For each case with Marinus Link and in a matched Basslink-only counterfactual, we computed the difference between total system costs (excluding the cost of Marinus Link). The change in system costs are the forecast gross market benefits of Marinus Link (not accounting for Marinus Link costs), as defined in the RIT-T. The computation of net market benefits has been conducted by TasNetworks outside of this Addendum[2] as it is dependent on option costs, which were developed independently by TasNetworks.

TasNetworks advised the use of the 21 year study period so as to incorporate the half-hourly demand forecast from Australian Energy Market Operator's (AEMO's) 2020 Electricity Statement of Opportunities (ESOO), released in August 2020.[5] This half-hourly data is only forecast to 2041-42. As such, the end date for the modelling period is 8 years prior to that of the study period used for the Project Marinus RIT-T PADR, which finished in 2049-50.[4] The model was used to compute a plan without Marinus Link and several timings of a 1,500 MW-sized Marinus Link across of a range of scenarios and sensitivities advised by TasNetworks.

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[2] TasNetworks, *Marinus Link Regulatory Investment Test for Transmission: Supplementary Analysis Report*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

[3] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

[4] TasNetworks, 4 December 2019, *Project Marinus: RIT-T Project Assessment Draft Report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/rit-t-project-assessment-draft-report.pdf. Accessed 4 October 2020.

[5] AEMO, 27 August 2020, *2020 Electrical Statement of Opportunities*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en. Accessed 24 September 2020.

The modelling methodology follows the applicable RIT-T guidelines published by the Australian Energy Regulator.[6] The modelling presented in this Addendum is not formally part of the RIT-T process and was undertaken in response to requests from stakeholders to closer align input assumptions of scenarios with AEMO's 2020 Integrated System Plan (ISP), released in July 2020, [7] which had not been finalised when the Marinus Link PADR was released.

As advised by TasNetworks, we have conducted market modelling for four timings of the 1,500 MW Marinus Link across five scenarios which are predominantly aligned with the AEMO 2020 ISP.[7] Four key inputs assumptions where TasNetworks have elected to diverge from the ISP scenarios are:

- The ISP scenarios use the AEMO 2019-20 ISP demand forecast whereas TasNetworks elected to apply the AEMO 2020 ESOO demand forecast[8] in this Addendum as it is a more recent forecast which includes the projected impacts of COVID-19.

- The ISP scenarios assume committed projects based on AEMO's February 2020 Generation Information data whereas TasNetworks elected to apply AEMO's 29 July 2020 Generation Information data[9] in this Addendum as it captures recent NEM existing, committed and anticipated generator changes.

- AEMO's scenarios were forecasting VNI West to either not be commissioned or to be installed in 2035-36 across all scenarios. For this Addendum, TasNetworks assume that VNI West is commissioned 2027-28 in all scenarios except the Slow Change scenario, consistent with the accelerated timing in the ISP's optimal development path.[7] TasNetworks chose to assume VNI West is not installed in the Slow Change scenario for this Addendum, which is consistent with the outcome of AEMO's 2020 ISP Slow Change scenario.

- AEMO's scenarios only include the Tasmanian Renewable Energy Target of 200 % renewable generation in Tasmania relative to current demand by 2040 (TRET 2040) in two of their scenarios: the High DER and Step Change scenarios. Alternatively, the modelling for this Addendum assumes TRET 2040 is committed in all five scenarios: The Central, Slow Change, High DER, Fast Change and Step Change scenarios as advised by TasNetworks.

Table 1 displays the forecast gross market benefits associated with the change in the least-cost development plan under different timings of Marinus Link over the modelled 21-year horizon. These gross benefits should not be directly compared to the gross benefits from EY's PADR economic modelling report published,[10] which were discounted to 1 July 2025.[11] Even when adjusting for the discount time, these gross benefits are not directly comparable to the previous modelling which used a 30-year study period.

[6] 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.

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

[8] AEMO, 27 August 2020, *2020 Electrical Statement of Opportunities*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en. Accessed 24 September 2020.

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

[10] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

[11] 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.

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

Option	Marinus Link timing	Scenario				
		Slow Change	Central	High DER	Fast Change	Step Change
1,500 MW	2027 & 2030	843	1,759	1,733	1,910	2,719
	2028 & 2031	827	1,735	1,705	1,842	2,619
	2031 & 2034	731	1,563	1,549	1,598	2,274
	2034 & 2037	580	1,206	1,188	1,258	1,739

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

As discussed above, there are several differences in assumptions between AEMO's 2020 ISP[12] and the modelling done for this Addendum. As part of the modelling process for the Addendum, TasNetworks requested EY to benchmark our modelling to AEMO's by aligning the four aforementioned assumptions with the ISP 2020 and removing the regional minimum inertia requirements, which AEMO does not model. This was intended to assess the alignment of the optimal timing of Marinus Link between EY's hourly time-sequential modelling and AEMO's ISP models in all five scenarios. The gross benefit outcomes of that modelling were provided to TasNetworks to compute the relevant net market benefits. EY has been advised by TasNetworks that under these conditions our model outcomes for Marinus Link were broadly aligned with AEMO's optimal size and timing for all scenarios. This suggests AEMO may forecast a similar optimal timing of Marinus Link to that provided in the accompanying Supplementary Analysis Report by TasNetworks[13] if AEMO was to conduct updated modelling using the AEMO 2020 ESOO demand forecast, committed projects based on the more recent 29 July 2020 Generation Information data and were to assume TRET progresses in all scenarios.

Six sensitivities were performed to test the robustness of gross market benefits on the Central and Step Change scenarios. All sensitivities to the Central scenario were tested with Marinus Link stage 1 commissioned on 1 July 2031 and stage 2 installed on 1 July 2034. All Step Change sensitivities assume stage 1 is commissioned on 1 July 2027 and stage 2 on 1 July 2030. The outcomes are summarised in Table 2 and Table 3, respectively.

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

Sensitivity	Gross market benefits ($m)	Difference in gross market benefits ($m)
Economic Retirements Not Permitted	1,504	-59
Sustained Low Gas Price	1,401	-163
High Battery Cost	1,614	51
Low Battery Cost	1,523	-40

[12] AEMO, 30 July 2020, *2020 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 24 September 2020.
[13] TasNetworks, *Marinus Link Regulatory Investment Test for Transmission: Supplementary Analysis Report*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

Table 3: Forecast gross market benefits of Marinus Link for Step Change scenario related sensitivities, real June 2019 dollars discounted to 1 July 2019

Sensitivity	Gross market benefits ($m)	Difference in gross market benefits ($m)
Hydrogen Load Growth	2,166	-554
Committed PSH	3,292	573

2. Introduction

TasNetworks has engaged EY to evaluate the potential gross market benefits of a second interconnector between Tasmania and Victoria. The forecast gross market benefits from this Addendum are intended to be used within TasNetworks' Supplementary Analysis Report[14] that provides updated analysis to their Project Marinus RIT-T PADR, released in December 2019.[15] This Addendum is not intended as a stand-alone report, but is rather an Addendum to EY's PADR economic modelling report [16], published on 27 November 2019. The Addendum contains additional analysis based on newer input assumptions, which were advised by TasNetworks and are identified in Section 3.3 of this Addendum. It should be read in conjunction with the November 2019 Report, to provide a full understanding of all other assumptions and the full modelling process.

This Addendum describes the key changes in assumptions, input data sources and methodologies that have been applied in the gross market benefits modelling (the modelling) relative to the Project Marinus RIT-T PADR.[15] It also provides a summary of the gross market benefit outcomes of our modelling, excluding project costs, for all scenarios and sensitivities advised by TasNetworks.

Based on the key assumptions and input data, EY has computed the least-cost generation dispatch and development plan for the NEM associated with the 1,500 MW Marinus Link across a range of scenarios, sensitivities and Marinus Link timings advised by TasNetworks. These Marinus Link options are described in detail in the TasNetworks' Supplementary Analysis Report.[14]

The modelling methodology follows the applicable RIT-T guidelines published by the Australian Energy Regulator.[17] The modelling presented in this Addendum is not formally part of the RIT-T process and was undertaken in response to requests from stakeholders to better align input assumptions of scenarios with AEMO's 2020 ISP, which had not been finalised when the Marinus Link PADR was released.

A description of the categories of market benefits captured in the modelling can be found in the PADR economic modelling report.[16] Each component of forecast gross market benefits is computed annually for each year from 2021-22 to 2041-42. Gross benefits are presented in real June 2019 dollars discounted to 1 July 2019. For the Central, High DER, Fast Change and Step Change scenarios a real pre-tax discount rate of 5.9 % is applied. The Slow Change scenario is discounted to 1 July 2019 at a 7.9 % real pre-tax discount rate, consistent with the approach used in AEMO's 2020 ISP.[18]

As with the PADR, 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 forecast positive net benefit. If values of other costs or benefits that are not captured by the least-cost planning model can be computed, such as ancillary services cost reduction, these should also be considered.

The Addendum is structured as follows:

- Section 3 provides a brief overview of the methodology applied in the modelling and computation of gross market benefits. This section focuses on the changes in modelling relative to the PADR.

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[14] TasNetworks, *Marinus Link Regulatory Investment Test for Transmission: Supplementary Analysis Report*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

[15] TasNetworks, *Project Marinus: RIT-T Project Assessment Draft Report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/rit-t-project-assessment-draft-report.pdf. Accessed 4 October 2020.

[16] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

[17] 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.

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

- 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, with a focus on changes relative to the PADR modelling.
- Section 6 provides an overview of model inputs and methodologies related to the supply of energy and capacity, with a focus on methods that have changed since the PADR modelling.
- Section 7 provides an overview of gross market benefits forecast for Marinus Link across scenarios and sensitivities.

2.1 Conventions used in this document

Unless stated otherwise, any reference to Marinus Link implicitly includes the AC transmission augmentations that would be required to support flows across Marinus Link.

Where a stage of Marinus Link is notated as occurring in a particular year, this means that stage is fully operational in the modelling from 1 July of that year e.g. Marinus Link stage 1 2027 means fully operational from 1 July 2027.

Decisions such as commissioning new entrant capacity and retiring capacity for allowable generators are made at the beginning of each financial year, on 1 July.

All dollars in this Report refer to real June 2019 dollars unless otherwise stated.

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

3. Methodology and input assumptions

Section 3.1 provides a brief overview of the model used to compute long term least-cost generation development plan while Section 3.2 supplies a short description of the method for computing gross market benefits. The model is described in detail in Section 3 of EY's PADR economic modelling report,[19] which should be read in conjunction with this Addendum.

Section 3.3 includes an overview of the modelling improvements and data updates since the PADR and economic modelling report.

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 21 years from 2021-22 to 2041-42. The modelling methodology follows the 2018 RIT-T guidelines published by the Australian Energy Regulator.[20]

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:

- Fixed Operation and Maintenance (FOM) costs of all generation capacity,
- Variable Operation and Maintenance (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 pumped storage hydro (PSH) and grid connected batteries,
- Demand-side participation (DSP) and unserved energy (USE),
- Capex of new generation and storage capacity installed,
- Transmission expansion costs associated with Renewable Energy Zone (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 trading interval regarding the generation dispatch level of all existing and new entrant power plants 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. Decisions such as commissioning new entrant capacity and retiring capacity for allowable generators are made at the beginning of each financial year, on 1 July.

[19] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.
[20] 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.

Further explanation on how the TSIRP determines the least-cost solution is available in Section 3 of EY's PADR economic modelling report.[21]

3.2 Cost-benefit analysis

For each case with Marinus Link and in a matched Basslink-only counterfactual[22] 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.

Each component of forecast gross market benefits is computed annually for each year of the 21-year study period. In this Addendum, we have summarised the benefit and cost streams using a single value computed as the present value of each stream, discounted to 1 July 2019 at a 5.9 % real pre-tax discount rate for the Central, High DER, Fast Change and Step Change scenarios, as advised by TasNetworks so as to be consistent with AEMO's 2020 ISP.[23] As per the ISP, the Slow Change scenario is discounted to 1 July 2019 at a 7.9 % real pre-tax discount rate.

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

The computation of net market benefits has been conducted by TasNetworks outside of this Addendum[24] and are not presented within this report as it is dependent on option costs that were developed independently by TasNetworks.

3.3 Model improvements and data updates since the Project Assessment Draft Report

Several changes to the TSIRP model and input data have been made since publication of EY's PADR economic modelling report.[21] Where more recent assumptions were available input data updates were made, while model enhancements were to increase realism by inclusion of additional detail. Except where noted below, the market modelling methodology is consistent with that applied in modelling for the PADR. All inputs were advised by TasNetworks. The model and data changes are summarised in Table 4.

Table 4: Model and data changes compared to the Project Assessment Draft Report

Assumption	Project Assessment Draft Report[21]	This Addendum
Study period	30-year study from 2020-21 to 2049-50.	21-year study from 2021-22 to 2041-42, aligned with AEMO's 2020 ISP[23] and the published half-hourly demand timeseries accompanying AEMO's 2020 ESOO.[25]

[21] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.
[22] The without augmentation counterfactual is typically referred to as the Base case in a RIT-T.
[23] AEMO, 30 July 2020, *2020 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 24 September 2020.
[24] TasNetworks, *Project Marinus: RIT-T Process*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.
[25] AEMO, 27 August 2020, *2020 Electrical Statement of Opportunities*. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en. Accessed 24 September 2020.

Assumption	Project Assessment Draft Report[21]	This Addendum
Hydro Tasmania hydro scheme representation	▶ 10 pond scheme ▶ 8 reference years ▶ No hydro climate factors	▶ 10 pond scheme ▶ 9 reference years ▶ Hydro climate factors applied to reduce annual inflow throughout the modelling period, aligned with AEMO's July 2020 Input and Assumptions workbook.[26]
Operational reserve constraint	Regional reserve constraint.	Regional reserve constraint and a combined mainland reserve constraint. See Section 6.2.
Inertia constraint	Applied.	Updated for Tasmania. See Section 6.1.
QNI Sapphire constraint	Not applied.	Applied. See Section 5.1.
Snowy to Sydney power flow constraint	Not applied.	Applied. See Section 5.1.
Demand outlook	AEMO *2018 Electricity Statement of Opportunities*,[27] 10 % probability of exceedance peak demand forecasts.	AEMO *2020 Electricity Statement of Opportunities*,[28] 10 % probability of exceedance peak demand forecasts.
Number of historical reference years	8 years.	9 years.
REZ representation	Representation aligned with AEMO's February 2019 planning and forecasting assumptions workbook.[29] 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	Representation aligned with AEMO's July 2020 Input and Assumptions workbook.[26] This includes associated transmission expansion costs for mainland REZs.

[26] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

[27] 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.

[28] AEMO, 27 August 2020, 2020 Electrical Statement of Opportunities. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en. Accessed 24 September 2020.

[29] 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	Project Assessment Draft Report[21]	This Addendum
Wind and solar PV build limits	Mainland REZ build limits as per AEMO's February 2019 planning and forecasting assumptions workbook.[30] 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	Mainland REZ build limits as per AEMO's July 2020 Input and Assumptions workbook.[31]
DSP	Aligned with AEMO's February 2019 planning and forecasting assumptions workbook.[30]	Aligned with AEMO's July 2020 Input and Assumptions workbook.[31]
Aggregated energy storages	Modelled on a fixed input profile as a component of demand, like the non-aggregated component of domestic storage.	Explicitly modelled like Virtual Power Plant (VPP), as per AEMO's July 2020 Input and Assumptions workbook.[31]
Hydro inflow reductions due to climate change	Not applied.	Scenario dependant reduction in annual inflow, as per AEMO's July 2020 Input and Assumptions workbook.[31]
Tamar Valley CCGT	No special conditions on operation. Not allowed to retire.	No special conditions on operation. Scenario specific assumptions regarding optional retirements. See Section 4.1.
Tamar Valley OCGT	No special conditions on operation. Not forced to retire but allowed to if economic.	No special conditions on operation. Scenario specific assumptions regarding optional retirements. See Section 4.1.

[30] 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.
[31] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

Assumption	Project Assessment Draft Report[21]	This Addendum
PSH regional capacity limit	**Mainland** 6 hours of storage based on December 2018 Entura report[32] 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	**Mainland** 12 hours of storage based on AEMO's July 2020 Input and Assumptions workbook[33] for locations that allow PSH with 12 hours of storage or longer. ▶ QLD limit of 3.1 GW ▶ NSW limit of 2.6 GW ▶ VIC limit of 2.4 GW ▶ SA limit of 0.904 GW NSW is allowed the option to build an additional 4.4 GW of PSH with 6 hours of storage, totaling 7 GW of PSH available for this region.
	Tasmania 24 hours of storage based on limit of 1.6 GW based on December 2018 Entura report to AEMO.[32]	**Tasmania** 24 hours of storage with limit of 1.571 GW based on AEMO's July 2020 Input and Assumptions workbook[33] for locations with 24 hours of storage or longer.
Committed projects (included in all scenarios, Basslink-only counterfactual and with Marinus Link)	**Mainland regions** Based on AEMO's February 2019 planning and forecasting assumptions workbook Committed Projects and Advanced VRET Projects.[34] Updated to include Committed and Com* status projects from AEMO Generation Information May 2019.[35]	Aligned with AEMO's July 2020 Input and Assumptions workbook **Committed** Projects and Anticipated Projects.[33] Updated to include Committed, Com* and maturing status projects from AEMO Generation Information 29 July 2020.[36]
	Tasmania Based on same data source as mainland regions: Musselroe, Woolnorth, Granville Harbour, Wild Cattle Hill Wind Farms.	Unchanged.
Heat rates	Based on AEMO's February 2019 planning and forecasting assumptions workbook,[34] using only static heat rates (GJ/MWh).	Based on AEMO's July 2020 Input and Assumptions workbook,[33] including complex heat rates (GJ/MWh and GJ/h) for existing units with minimum loads. Other thermal unit use static heat rates from same source.

[32] 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.
[33] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.
[34] 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.
[35] AEMO, *Generation Information*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Accessed 24 September 2019.
[36] AEMO, *Generation Information*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Accessed 24 September 2020.

Assumption	Project Assessment Draft Report[21]	This Addendum
Thermal retirements	Based on end of technical life as per AEMO's February 2019 planning and forecasting assumptions workbook.[34] Where station specific information was available, retirement dates were updated as per the AEMO Project Expected Retirement Date workbook published 25 June 2019.[37]	Where station-specific information was available, retirement dates were updated as per AEMO's Generation Information 29 July 2020.[38] Retirement of other units based on end of technical life as AEMO's July 2020 Input and Assumptions workbook.[39]
Non-thermal retirements	End of technical life as per AEMO Project Expected Retirement Date workbook published 25 June 2019.[37]	End of technical life as per AEMO's July 2020 Input and Assumptions workbook.[39] Where station specific information was available, retirement dates were updated as per AEMO's Generation Information 29 July 2020.[38]
South Australian gas-fired generators	► 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).[40] ► 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.[37] ► Pelican Point is not allowed to retire economically prior to Project EnergyConnect to maintain system strength in SA.[41] No minimum generation requirements.	End of technical life as per AEMO's July 2020 Input and Assumptions workbook.[39] ► Torrens Island A (2023-24) ► Torrens Island B (2035-36) ► Osbourne (2023-24) ► Pelican Point (2037-38) Minimum generation requirements as per AEMO's July 2020 Input and Assumptions workbook.[39]
Optional retirements	Scenario specific assumptions regarding optional retirements. Refer to Section 4.1 of EY's PADR economic modelling report.[42]	Scenario specific assumptions regarding optional retirements. See Section 4.1.

[37] AEMO, 25 June 2019, *Project Expected Retirement Date* [workbook]. No longer available online. Available by request from TasNetworks.
[38] AEMO, *Generation Information*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information#:~:text=This%20generation%20information%20page%20has,National%20Electricity%20Market%20(NEM). Accessed 24 September 2020.
[39] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.
[40] 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.
[41] 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.
[42] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

Assumption	Project Assessment Draft Report[21]	This Addendum
Gas-fired generator minimum loads	As per AEMO's February 2019 planning and forecasting assumptions workbook.[43] Minimum loads on only: ▶ Condamine: 60 MW ▶ Darling Downs: 109 MW ▶ Tallawarra: 190 MW ▶ Yarwun: 120 MW	As per AEMO's July 2020 Input and Assumptions workbook.[44] Minimum loads on only: ▶ Torrens Island B: 40 MW on at least two units until Project EnergyConnect is commissioned ▶ Torrens Island A: 30 MW on final unit until retirement on 30/9/2022
New entrant CCGT limits	▶ Minimum load of 50 %.	▶ Minimum load of 40 %.
Coal energy limits	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.[43]	75 % capacity factor limit on NSW coal generators only, as listed in the AEMO July 2020 Input and Assumptions workbook.[44]
Forced outage rates	AEMO's February 2019 planning and forecasting assumptions workbook.[43]	AEMO's July 2020 Input and Assumptions workbook.[44]
Discount rate	AEMO Sept 2019 planning and forecasting assumptions workbook[45] pre-tax, real rate of 5.9 %.	AEMO's July 2020 Input and Assumptions workbook[44] pre-tax, real rate dependant on scenario: ▶ Slow Change scenario: 7.9 % ▶ All other scenarios: 5.9 %
Discount date	All gross benefits discounted to 1/7/2025. Aligned with the Initial Feasibility Report.[46]	All gross benefits discounted to 1/7/2019, aligned with the TasNetworks Project Marinus RIT-T PADR published December 2019.[47]
Capex for new entrant technologies	AEMO's February 2019 planning and forecasting assumptions workbook[43] uplifted for interest during construction using the construction times in the same data set.	AEMO's July 2020 Input and Assumptions workbook[44] uplifted for interest during construction using the construction times in the same data set.
VOM, FOM, lifetime and operational parameters for technologies	AEMO's February 2019 planning and forecasting assumptions workbook.[43]	AEMO's July 2020 Input and Assumptions workbook.[44]

[43] 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.
[44] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.
[45] 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.
[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] TasNetworks, December 2019, *Project Marinus RIT-T Project Assessment Draft Report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/rit-t-project-assessment-draft-report.pdf. Accessed 24 September 2020.

Assumption	Project Assessment Draft Report[21]	This Addendum
Gas fuel costs	Aligned with AEMO's February 2019 planning and forecasting assumptions workbook for 2020-21 to 2040-41.[48] Gas fuel costs were assumed to be unchanged post 2040-41, since the AEMO forecast did not cover this period.	Aligned with AEMO's July 2020 Input and Assumptions workbook,[49] which covers the full modelling period.
Coal fuel costs	Aligned with AEMO's February 2019 planning and forecasting assumptions workbook for 2020-21 to 2040-41.[48] Coal fuel costs were assumed to be unchanged post 2040-41, since the AEMO forecast did not cover this period.	Aligned with AEMO's July 2020 Input and Assumptions workbook,[49] which covers the full modelling period.
Basslink and Marinus Link losses	Dynamic losses allocated to sending end.	Dynamic losses allocated to sending end. Loss equation for Marinus Link has been updated since the PADR. See Section 5.2.
Proportioning factors for interconnectors except for Basslink and Marinus Link	Aligned with AEMO's February 2019 planning and forecasting assumptions workbook.[48]	Aligned with AEMO's July 2020 Input and Assumptions workbook.[49]
Interconnector upgrades	Scenario-specific assumptions regarding interconnector upgrades. Refer to Section 4.1 of EY's PADR economic modelling report.[50]	Scenario-specific assumptions regarding interconnector upgrades. See Section 4.1.
TRET	No specific constraint.	Implemented as a target of 10.5 TWh of expected generation (inclusive of curtailment) from new renewable capacity in Tasmania. See Section 6.4.
New Tasmanian renewable capacity	No specific constraint.	TasNetworks have advised that at most 40 % of new Tasmanian wind capacity is to be installed in the Tasmanian Midlands REZ for this modelling. This reflects current investment interest.
VCR	$33,460/MWh[51]	$40,990/MWh[52]
Other input data	Aligned with AEMO's February 2019 planning and forecasting assumptions workbook which formed the initial consultation for the ISP 2019-20.[48]	Aligned with AEMO's July 2020 Input and Assumptions workbook which formed the final assumptions for the 2020 ISP.[49]

[48] 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.
[49] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.
[50] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.
[51] AEMO, September 2014, *Value of customer reliability review: Final report*. Available at: https://aemo.com.au/-/media/files/pdf/vcr-final-report--pdf-update-27-nov-14.pdf. Accessed 24 September 2020.
[52] AEMO, December 2019, *Value of customer Reliability: Final report on VCR values*. Available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed 24 September 2020.

4. Scenarios and sensitivity assumptions

4.1 Scenarios

The 1,500 MW Marinus Link option has been assessed in five scenarios advised by TasNetworks, which reflect the five scenarios modelled in AEMO's 2020 ISP and described in detail in the ISP.[53] The scenarios cover a broad range of reasonable possible futures for the NEM:

- The Central scenario represents a central view of the NEM's development reflecting current government policy. It combines a national emissions reduction target of 26 % below 2005 levels by 2030 with the Central demand forecasts found in the 2020 Electricity Statement of Opportunities. Thermal generators retire on their expected closure year.

- The Slow Change scenario applies a set of assumptions reflecting a future world with lower demand forecasts and slower reductions in technology costs. Thermal generators are maintained to at least until their expected closure years, with a possible 10-year life extension if economic to do so.

- The Fast Change scenario applies most of the same assumptions as the Central scenario but with greater investment in grid-scale technology. This includes more stringent emission reduction schemes and earlier adoption of energy storage and electric vehicles. Unlike the Central scenario, this scenario includes a NEM-wide cumulative carbon budget of 2,208 Mt CO2-e by 2050, which is representative of a 2.5˚C to 2.7˚C global mean temperature increase.

- The High DER scenario also applies most of the same assumptions as the Central scenario but with a focus on decentralisation through rapid consumer adoption of DER. This scenario includes higher uptakes of rooftop PV, large-scale batteries, VPPs and electric vehicles. As a result, it also includes lower operational demand forecasts.

- The Step Change scenario applies a set of assumptions reflecting a future world with higher decarbonisation and decentralisation targets. This includes higher electricity demand forecasts, a more stringent NEM-wide cumulative carbon budget of 1,465 Mt CO_2-e, which is representative of a 1.4˚C to 1.8˚C global mean temperature increase, and faster renewable build cost reductions than found in the CSIRO GenCosts 2019-20.[54] Thermal generators are required to retire by their expected closure year but can do so earlier if economic.

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 July 2020 ISP Input and Assumptions workbook,[55] which are the assumptions used in AEMO's 2020 ISP.[53] One key deviation from the 2020 ISP assumptions is that the modelling has used AEMO's 2020 ESOO demand forecast, which was published on 27 August 2020 and includes the projected impacts of COVID-19.[56] Further differences between these assumptions chosen by TasNetworks for modelling for this Addendum and AEMO's 2020 ISP can be found in Section 4.2 and Table 6.

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[53] AEMO, 30 July 2020, *2020 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 28 September 2020.

[54] 6 May 2020, *GenCost 2019-20 report and project data*. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines. Accessed 5 October 2020.

[55] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

[56] AEMO, 27 August 2020, 2020 Electrical Statement of Opportunities. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en. Accessed 24 September 2020.

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

Key drivers input parameter	Scenario				
	Slow change	Central	High DER	Fast Change	Step change
Underlying consumption	AEMO 2020 ESOO Slow Change	AEMO 2020 ESOO Central	AEMO 2020 ESOO High DER	AEMO 2020 ESOO Fast Change	AEMO 2020 ESOO Step Change
Rooftop PV	AEMO 2020 ESOO Slow Change	AEMO 2020 ESOO Central	AEMO 2020 ESOO High DER	AEMO 2020 ESOO Fast Change	AEMO 2020 ESOO Step Change
Battery storage installed capacity	AEMO 2020 ESOO Slow Change	AEMO 2020 ESOO Central	AEMO 2020 ESOO High DER	AEMO 2020 ESOO Fast Change	AEMO 2020 ESOO Step Change
Electric vehicle update	AEMO 2020 ESOO Slow Change	AEMO 2020 ESOO Central	AEMO 2020 ESOO High DER	AEMO 2020 ESOO Fast Change	AEMO 2020 ESOO Step Change
Small non-scheduled PV (100 kW - 30 MW)	AEMO 2020 ESOO Slow Change	AEMO 2020 ESOO Central	AEMO 2020 ESOO High DER	AEMO 2020 ESOO Fast Change	AEMO 2020 ESOO Step Change
Domestic storage MW and MWh	AEMO 2020 ESOO Slow Change	AEMO 2020 ESOO Central	AEMO 2020 ESOO High DER	AEMO 2020 ESOO Fast Change	AEMO 2020 ESOO Step Change
DSP	AEMO 2020 ISP Slow Change	AEMO 2020 ISP Central	AEMO 2020 ISP High DER	AEMO 2020 ISP Fast Change	AEMO 2020 ISP Step Change
VCR	Aggregate NEM wide value of $40,990/MWh.[57]				
Emission reduction policy	The electricity sector has been modelled to achieve at least a 26 % reduction in emissions compared to 2005 levels by 2030.				
NEM cumulative carbon budget by 2050	Not explicitly modelled			2,208 Mt CO2-e	1,465 Mt CO2-e
Victorian Renewable Energy Target (VRET) 2020	Target of 25 % of Victorian generation from renewables by calendar year 2020.[58]				
VRET 2025	Target of 40 % of Victorian generation from renewables by calendar year 2025.[59]				
VRET 2030	Target of 50 % of Victorian generation from renewables by calendar year 2030.[59]				
TRET 2022	100% renewable energy generation as a percentage of total Tasmanian generation.				
TRET 2040	200% renewable energy generation as a percentage of total Tasmanian generation. Modelled as 10.5 TWh of expected generation (inclusive of curtailment) from new renewable capacity in Tasmania by 2040.				

[57] AEMO, December 2019, *Value of Customer Reliability: Final report on VCR values*. Available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed 24 September 2020.

[58] 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.

[59] 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				
	Slow change	Central	High DER	Fast Change	Step change
QRET 2030	Q400 policy only (400MW build by 2021-22).	Target of 50 % of Queensland demand from renewable generation by calendar year 2030.[60]		Q400 policy only (400MW build by 2021-22).	Target of 50 % of Queensland demand from renewable generation by calendar year 2030.[60]
Fixed date retirements	Based on AEMO's 2020 ISP assumptions. Where station specific information was available, retirement dates were updated as per the AEMO July 2020 Input and Assumptions workbook.[61]				
Economic retirement for thermal generators	Maintained at least until expected closure year. Retirement dates for coal generators can potentially be extended by up to 10 years if economic to do so.	From 2024-25, coal and gas generators can retire earlier than their announced retirement date if it is least-cost to do so. This timing complies with the requirement for generators to provide at least three years notice prior to their retirement.[62]		From 2024-25, coal generators can retire earlier than their announced retirement date if it is least-cost to do so. This timing complies with the requirement for generators to provide at least three years notice prior to their retirement.[62] Gas generators are maintained until their expected closure year.	
Gas requirements	As per AEMO 2020 ISP assumptions, at least two units from Torrens Island B (40 MW min load each) are required to be online until Project EnergyConnect is commissioned. Minimum capacity factor constraints for other gas generators aligned with AEMO 2020 ISP assumptions.				
Coal fuel cost	AEMO 2020 ISP Slow Change	AEMO 2020 ISP Central	AEMO 2020 ISP High DER	AEMO 2020 ISP Fast Change	AEMO 2020 ISP Step Change
Gas fuel cost	AEMO 2020 ISP Slow Change	AEMO 2020 ISP Central	AEMO 2020 ISP High DER	AEMO 2020 ISP Fast Change	AEMO 2020 ISP Step Change
Snowy 2.0	Commissioned 1/3/2025				
New entrant generation technology cost projections for wind, solar PV SAT, OCGT, CCGT, large-scale battery storage and PSH	AEMO 2020 ISP Slow Change	AEMO 2020 ISP Central	AEMO 2020 ISP High DER	AEMO 2020 ISP Fast Change	AEMO 2020 ISP Step Change
QNI-Option 1A (QNI Minor)	Commissioned Sept 2022, as per the committed ISP projects from AEMO's 2020 ISP report.[63] See Section 5.1.				
Western Victoria RIT-T augmentation	Commissioned by 2024-25, as per the committed ISP projects from AEMO's 2020 ISP report.[63]				

[60] 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.
[61] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.
[62] AEMC, 8 November 2018, National Electricity Amendment (Generator Three Year Notice of Closure) Rule 2019. Available at: https://www.aemc.gov.au/sites/default/files/2018-11/Final%20Determination.pdf. Accessed 24 September 2020.
[63] AEMO, 30 July 2020, *2020 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 28 September 2020.

Key drivers input parameter	Scenario				
	Slow change	Central	High DER	Fast Change	Step change
VNI Option 1 (Dederang-Lower Tumut path)	Commissioned Sept 2022, as per the actionable ISP projects from AEMO's 2020 ISP report.[64] See Section 5.1.				
Project EnergyConnect	Commissioned July 2024, as per the actionable ISP projects from AEMO's 2020 ISP report.[64] See Section 5.1.				
HumeLink	Commissioned July 2025, as per the actionable ISP projects from AEMO's 2020 ISP report.[64] Intraregional transmission upgrade captured via REZ transmission limits.				
Central-West Orana REZ Transmission Link	Commissioned July 2024, as per the actionable ISP projects from AEMO's 2020 ISP report.[64] Intraregional transmission upgrade captured via REZ transmission limits.				
VNI West (KerangLink)	Not installed.	Commissioned July 2027, as per the accelerated timing in the optimal development path in AEMO's 2020 ISP report.[64] See Section 5.1.			
QNI-Option 2E (QNI Medium)	Not installed.	Commissioned July 2032, as per the least cost development plan for all but the Slow Change scenario in AEMO's 2020 ISP report.[64] See Section 5.1.			
QNI-Option 3E (QNI Large)	Not installed.	Commissioned July 2035, as per the least cost development plan for all but the Slow Change scenario in AEMO's 2020 ISP report.[64] See Section 5.1.			

4.2 Differences in modelling and assumption relative to AEMO's 2020 Integrated System Plan

Table 6 provides a comprehensive list of differences between the assumptions underlying AEMO's 2020 ISP modelling[64] and the assumptions that were advised by TasNetworks for modelling for this Addendum.

Table 6: Assumption differences between AEMO 2020 ISP Input and assumptions workbook and modelling for this Addendum

Key drivers input parameter	Scenarios	Differences	
		AEMO 2020 ISP Input and Assumptions workbook	Assumptions adopted for this modelling
Demand components	All	AEMO 2019-20 ISP demand forecast.[65]	AEMO 2020 ESOO demand forecast.[66] Tasmanian NS generators allowed to be optimised by the LP.
New CCGT operating behaviours	All	No minimum load or capacity factors specified for new entrant CCGT.	Minimum load of 40 % max load of new entrant CCGT.
Committed generation projects	All	Based on AEMO February 2020 Generation Information.	Based on based on AEMO 29 July 2020 Generation Information.

[64] AEMO, 30 July 2020, *2020 Integrated System Plan*. Available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en. Accessed 28 September 2020.
[65] *2020 ISP Demand Traces* [zip file], Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp. Accessed 6 October 2020.
[66] AEMO, 27 August 2020, *2020 Electrical Statement of Opportunities*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo. Accessed 1 October 2020.

Key drivers input parameter	Scenarios	Differences	
		AEMO 2020 ISP Input and Assumptions workbook	Assumptions adopted for this modelling
Coal upgrades and seasonal ratings	All	Based on AEMO February 2020 Generation Information.	Based on based on AEMO 29 July 2020 Generation Information.
Fixed date retirements	All	Based on AEMO February 2020 Generation Information.	Based on based on AEMO 29 July 2020 Generation Information.
VNI Minor upgrade	All	Commissioned 2022-23 as an output of modelling.	Commissioned 2022-23 as an input to the modelling, based on AEMO ISP.
Project EnergyConnect	All	Commissioned 2024-25 as an output of modelling.	Commissioned 2024-25 as an input to the modelling, based on AEMO ISP's classification as an Actionable ISP project.
HumeLink	All	Commissioned 2025-26 as an output of modelling.	Commissioned 2025-26 as an input to the modelling, based on AEMO ISP's classification as an Actionable ISP project.
VNI West	Slow Change	Not commissioned as an output of modelling.	Not commissioned as an input to the modelling, based on AEMO ISP outcome for this scenario.
	All other scenarios	Either not commissioned or commissioned in 2035-36 depending on the scenario as an output of modelling.	Commissioned 2027-28 as an input to the modelling, based on AEMO ISP's classification as an Actionable ISP project with decision rules with accelerated timing reflecting optimal development path.
QNI Medium and QNI Large	Slow Change	Not commissioned as an output of modelling.	Not commissioned as an input of modelling, based on AEMO ISP's classification as an Actionable ISP project.
	All other scenarios	Commissioned 2032-33 and 2035-36, respectively, as an output of modelling.	Commissioned 2032-33 and 2035-36, respectively, as an input to the modelling, based on AEMO ISP's classification as an Actionable ISP project.
Economic retirement for coal generators	Slow Change	Maintained at least until expected closure year, and potentially extended if economic.	Consistent with AEMO's 2020 ISP Slow Change scenario assumptions.
	All other scenarios	Allowed to retire prior to excepted retirement date if economic.	Consistent with AEMO's 2020 ISP scenario assumptions.
Economic retirement for gas generators	Slow Change scenarios	Maintained at least until expected closure year.	Consistent with AEMO's 2020 ISP Slow Change scenario assumptions.
	Central and High DER scenarios	Allowed to retire prior to excepted retirement date if economic.	Consistent with AEMO's 2020 ISP Central and High DER scenario assumptions.
	Fast Change and Step Change scenarios	Allowed to retire if economic however this is not forecast to occur.	Not allowed to retire prior to excepted retirement date, based on modelling outcomes of AEMO's ISP.

Key drivers input parameter	Scenarios	Differences	
		AEMO 2020 ISP Input and Assumptions workbook	Assumptions adopted for this modelling
Heat rate	All	Static heat rate.	Variable heat rate from AEMO's July 2020 Input and Assumptions workbook.[67] See Section 6.3.
Pump hydro storage options for the mainland	All	6 hours, 12 hours, 24 hours and 48 hours of storage available for all regions (except SA, which does not allow 48 hours of storage).	6 hours and 12 hours of storage available for NSW. All other mainland regions allow 12 hours of storage.
Pump hydro storage options for Tasmania	All	6 hours, 12 hours, 24 hours and 48 hours of storage available.	12 and 24 hours of storage available.
Battery storage options	All	2 hours and 4 hours of storage available for each region.	4 hours of storage available for each region.
TRET 2040	Central, Fast Change and Slow Change	Not included.	200 % renewable energy generation as a percentage of total Tasmanian generation. Modelled as a target of 10.5 TWh of expected generation (inclusive of curtailment) from new renewable capacity in Tasmania by 2040-41. See Section 6.4.
	High DER and Step Change	New entry renewable capacity required to meet a target of 200 % renewable energy generation as a percentage of total Tasmania generation by 2040.	
New Tasmanian renewable capacity	All	No specific constraint.	TasNetworks have advised that at most 40 % of new Tasmanian wind capacity is to be installed in the Tasmanian Midlands REZ for this modelling. This is to reflect current investment interest.
Hydro inflow	All	Inclusive of additional 'Dry' year.	Consistent with historical 9-year reference cycle from 2010-11 to 2018-19. As such, not inclusive of additional 'Dry' year.
Tasmanian hydro	All	► 7 pond scheme. ► Inflow from AEMO internal study and hydro operators. ► Historical small and non-scheduled hydro generation included on demand side. ► Details not provide regarding spill.	► 10 pond scheme. ► Hourly inflow from Hydro Tasmania. ► Small non-scheduled generators modelled explicitly. ► Spill allowed for all ponds except Gordon and Poatina.
Prudent Storage Level (PSL)	All	Not included.	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.

[67] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

Key drivers input parameter	Scenarios	Differences	
		AEMO 2020 ISP Input and Assumptions workbook	Assumptions adopted for this modelling
Differences to modelling with and without first stage of Marinus	All	▶ 978 MW flow limit from VIC to TAS without Tasmanian PSH. 1,228 MW flow limit from VIC to TAS if PSH capacity exceeds 250 MW. ▶ Tasmania Midlands REZ free transmission limit is increased from 480 MW to 1,020 MW. ▶ PSL not included. ▶ 100 MW West Coast hydro upgrade. ▶ 130 MW Tarraleah upgrade. ▶ 90 MW Gordon upgrade.	▶ Flow limit from VIC to TAS is limited via hourly inertia constraints. See Section 6.1. ▶ Tasmania Midlands REZ free transmission limit is increased from 480 MW to 1,020 MW (aligned with AEMO). ▶ 10 percentage point decrease in monthly minimum whole of system reservoir PSL requirement in Tasmania. ▶ 100 MW West Coast hydro upgrade (80 MW Anthony Pieman + 20 MW John Butters) (aligned with AEMO). ▶ 150 MW Tarraleah upgrade. ▶ 0 MW Gordon upgrade.
Inertia minimums enforced	All	Not included.	Included. See Section 6.1.
Reserve constraints	All	Minimum regional reserve constraint applied.	Regional reserve constraint and a combined mainland reserve constraint. See Section 6.2.
Tamar Valley CCGT	All	Generator is mothballed.	Dispatched by model on least-cost basis between 0 MW and maximum load of 208 MW.
Forced outage rates	All	As per AEMO's 2020 ISP.	As per AEMO's 2020 ISP, however a more conservative approach is adopted wherein we: ▶ Apply pre-Liddell rates to Liddell only. ▶ For other NSW coal units, apply post-Liddell rates.
Wind and solar traces	All	Developed by AEMO.	Developed by EY. Refer to Section 6.2 of EY's PADR economic modelling report.[68] Potentially different day shifting methodology for public holidays and the first/final week of financial year compared to the hourly demand traces, sourced directly from the AEMO 2020 ESOO. [69]
Marinus Link and Basslink losses	All	Losses proportioned 50/50 to sending/receiving end.	Losses allocated to sending end.
Marinus Link transfer limits	All	Marinus Link transfer limits are dependent on PSH load.	Marinus Link transfer limits are not dependent on PSH load. Instead custom Tasmanian inertia constraints have been applied.
Gordon capacity head-dependence	All	Not mentioned.	▶ 370 MW at 40 % storage volume. ▶ 432 MW at 60 % storage volume.

[68] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.
[69] AEMO, 27 August 2020, *2020 Electrical Statement of Opportunities*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo. Accessed 1 October 2020.

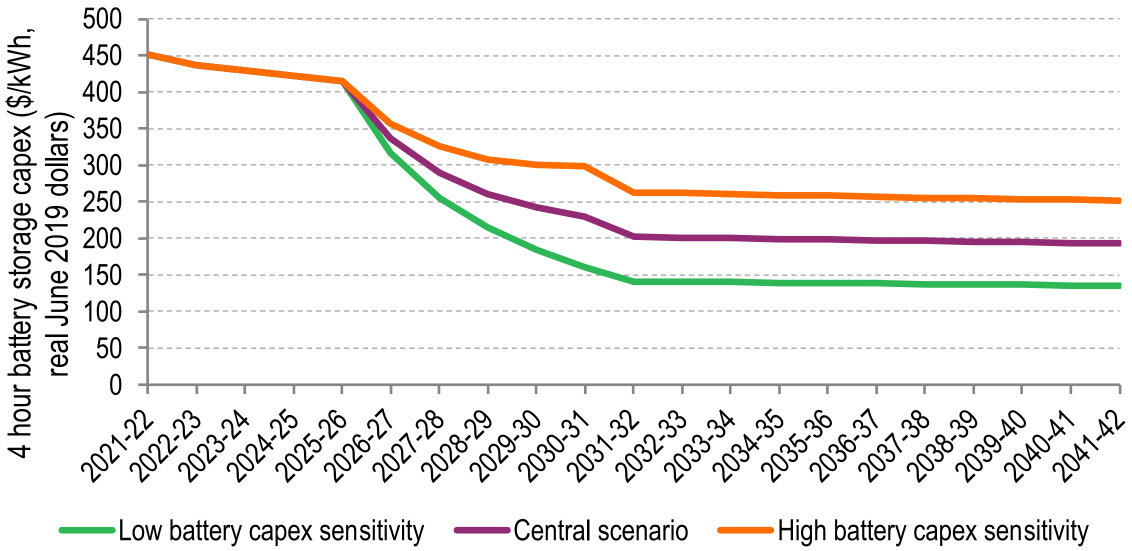
4.3 Sensitivities

Six sensitivities to the market modelling were advised by TasNetworks to test the robustness of the magnitude of gross market benefits. An overview of these sensitivities is given in Table 7. All sensitivity simulations were performed on the 1,500 MW Marinus Link, with scenarios and Marinus Link timings stated below.

Table 7: Overview of sensitivities

Sensitivity	Variation from Status Quo scenario	Scenario and timing
Economic Retirements Not Permitted	All generators are maintained until the expected closure year. Where station-specific information was available, retirement dates were updated as per AEMO's Generation Information 29 July 2020. Retirement of other units are based on the end of technical life as per AEMO's July 2020 Input and Assumptions workbook.	Central scenario Marinus Link timing: Stage 1 on 1/7/2031 Stage 2 on 1/7/2034
Sustained Low Gas Price	All existing and new entrant gas prices reduced to $8/GJ in real June 2019 dollars.	
High Battery Cost	Deviation in AEMO 2020 ISP battery capex from 2025-26 onward, such that capex is 30 % higher than AEMO's trajectory by 2029-30. An example is provided in Figure 1 using the assumed VIC Medium regional cost factors.	
Low Battery Cost	Deviation in AEMO 2020 ISP battery capex from 2025-26 onward, such that capex is 30 % lower than AEMO's trajectory by 2029-30. An example is provided in Figure 1 using the assumed VIC Medium regional cost factors.	
Hydrogen Load Growth	Increased Tasmanian load by 500 MW from 1/7/2035 and 1,000 MW by 1/7/2040. This additional load has been switched off daily between 5pm and 9pm to give an overall capacity factor of roughly 80%.	Step change scenario Marinus Link timing: Stage 1 on 1/7/2027 Stage 2 on 1/7/2030
Committed PSH	750 MW of committed TAS PSH capacity on 1/7/2030.	

Figure 1: Example of the assumed battery storage (4 hours storage) capex trajectory sensitivities advised by TasNetworks as applied to the assumed trajectory using the VIC Medium regional cost factors



5. Transmission and demand

5.1 Size and timing of other interconnector developments

Expanded interconnections assumed by TasNetworks to be developed between all mainland regions in all scenarios are summarised in Table 8. Limits were sourced from AEMO's Input and Assumptions workbook for the 2020 ISP,[70] and timings for each scenario are defined in Section 4.1.

Table 8: Overview of other interconnector developments

Project	Transfer limit after development	Additional generation capacity available in REZs due to the development of interconnectors
QNI minor	715 MW north *with Sapphire generation at 0 MW* 1,310 MW south *with Sapphire generation at 0 MW* 605 MW north *with Sapphire generation at 270 MW* 1,060 MW south *with Sapphire generation at 270 MW*	N/A
VNI minor	870 MW north 400 MW south *Prior to HumeLink: Snowy to Sydney Power flow*[71] *limited to 2,870 MW* *Post HumeLink: Snowy to Sydney Power flow*[71] *limited to 5,000 MW*	N/A
Project EnergyConnect[72]	SA-NSW 800 MW bi-directional Heywood 750 MW bi-directional *Combined SA-NSW + Heywood 1,300 MW forward* *Combined SA-NSW + Heywood 1,450 MW reverse*	South West NSW (NSW): 600 MW Murray River (VIC): 380 MW Riverland (SA): 800 MW
VNI West[73]	2,800 MW north 2,200 MW south *Snowy to Sydney Power flow*[71] *limited to 5,000 MW*	South West NSW (NSW): 1,000 MW Murray River (VIC): 2,000 MW Western Victoria: 1,000 MW
QNI-Medium[74]	1,230 MW north 2,070 MW south	Darling Downs (QLD): 1,000 MW North West NSW (NSW): 1,000 MW

[70] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

[71] VIC to NSW forward direction transfer is influenced by generation in Snowy region and transfer from SA to NSW. To maintain the transfer within the network capability a cut-set limit of Snowy to Sydney flow is defined as:
VIC to NSW forward direction flow + NSW to SA reverse direction flow + Upper/Lower Tumut generation + Snowy 2.0 generation
To reduce the optimisation problem size, this constraint is applied on the peak 5 % of hourly demand in NSW, when it is believed this constraint is most likely to be of importance.

[72] This corresponds to SA-NSW South Australia Energy Transformation RIT-T preferred option in AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

[73] This corresponds to VIC-NSW Option 7 in AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

[74] This corresponds to QNI Option 2E in AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

Project	Transfer limit after development	Additional generation capacity available in REZs due to the development of interconnectors
QNI-Large[75]	2,770 MW north 3,344 MW south	Darling Downs (QLD): 1,000 MW North West NSW (NSW): 1,000 MW *These uplifts are in addition to the QNI-Medium upgrade.*

5.2 Interconnector loss assumptions

5.2.1 Marinus Link

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

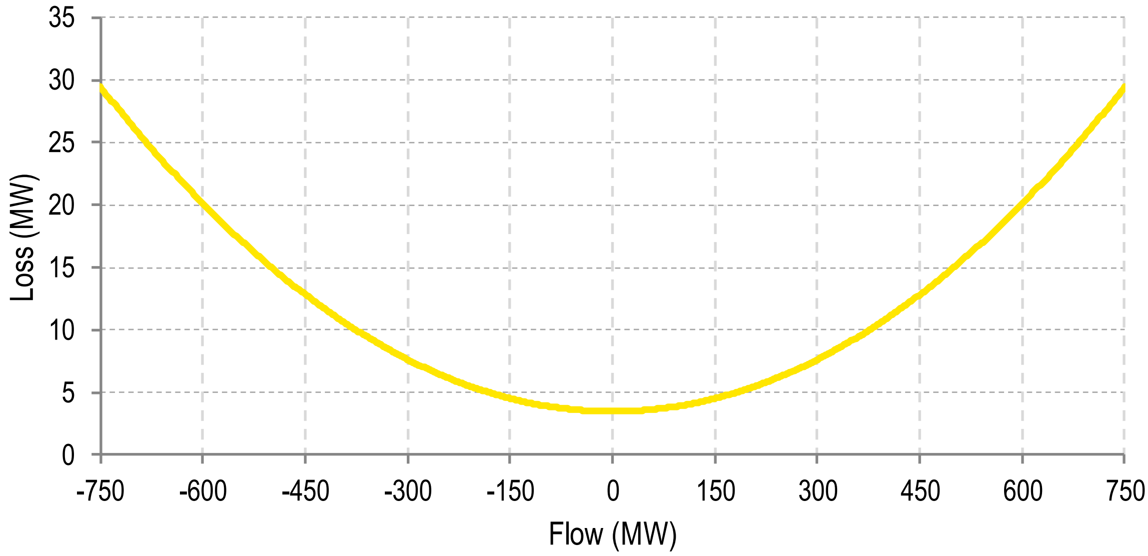
The main assumptions for Marinus Link as advised by TasNetworks are listed below for a 750 MW limit (a 1,500 MW option comprises two 750 MW cables in parallel):

- There is a bi-directional flow limit of 750 MW, measured at the receiving end,
- Dynamic losses are allocated to the sending end,
- Dynamic losses along the cable are described by the loss equation shown in Figure 2 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 1,200 mm^2 submarine cable and 1,400 mm^2 land cable, ±320 kV symmetrical monopole with 340 km overall length. The equation also incorporates converter station losses. This equation has been updated since the market modelling for EY's PADR economic modelling report.[76]

[75] This corresponds to QNI Option 3E in AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

[76] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

Figure 2: Dynamic loss equation for 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. Dynamic losses were modelled using the loss equation in the AEMO report *Updated Regions and Marginal Loss Factors: FY 2019-20*.[77] This is the same equation used in the market modelling for EY's PADR economic modelling report.[78]

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

5.2.2 Mainland interconnector upgrades

Updated network snapshots were used to compute new dynamic loss equations for mainland interconnectors after future upgrades, such as VNI West, were assumed to occur.

5.3 Demand

The TSIRP model captures peak period diversity across regions by basing the overall shape of hourly demand on nine historical years ranging from 2010-11 to 2018-19. This is one additional reference year (2018-19) than the PADR modelling.[78] The modelling for this Addendum directly uses the hourly AEMO 2020 ESOO demand traces for the relevant scenario and reference year sequence.[79] The 2020 ESOO demand dataset provides half-hourly trace data to 2041-42. As such, the study period for the modelling in this Addendum is from 2021-22 to 2041-42, which is also aligned with AEMO's 2020 ISP.[80]

[77] 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.

[78] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

[79] AEMO, 27 August 2020, 2020 Electrical Statement of Opportunities. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo. Accessed 1 October 2020.

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

6. Supply

6.1 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 in the event the region is islanded as defined in the National Electricity Rules.[81]

The assumed minimum inertia required in mainland regions as advised by TasNetworks is unchanged from the PADR modelling and can be found in Section 6.4 of EY's PADR economic modelling report.[82]

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. 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 Tasmanian inertia using following equations. These are enforced as a hard constraint in the model to ensure there is enough inertia in Tasmania in each hour of the forecast.

The following requirements and inertia coefficients were provided by TasNetworks. These constraints were updated since the PADR modelling to improve realism.

On export, sum of terms in Table 9, hard-export column ≥ 810
On import, sum of terms in Table 9, hard-import column ≥ 450 - 0.07*Tasmanian demand
At all times, sum of terms in Table 9, hard-minimum column ≥ 3,800

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

Term in inertia constraint equation left-hand side	Hard constraint			Constraint for synchronous condenser costing		
	Contribution on export (MW.s)	Contribution on import (MW.s)	Contribution to minimum (MW.s)	Contribution on export (MW.s)	Contribution on import (MW.s)	Contribution to minimum (MW.s)
TAS-Vic flow	-5.04*export flow (MW)	5.95*import flow (MW)	0	-5.04*export flow (MW)	5.95*import flow (MW)	0
Tasmanian wind	0	-1.17*dispatch (MW)	0	0	-1.17*dispatch (MW)	0
Tasmanian PSH	3.33*capacity (MW)			3.33*dispatch (MW)		
John Butters	600			3.9*dispatch (MW)		
Poatina	1,713			5.0*dispatch (MW)		
Anthony Pieman	4*dispatch_no-sync (MW)* + 1,652			4*dispatch (MW)		
Gordon	4.3*dispatch_no-sync (MW)* + 626			4.3*dispatch (MW)		
Mersey Forth Lower	3.4*dispatch_no-sync (MW)* + 565			3.4*dispatch (MW)		

[81] Australian Energy Market Commission, 12 August 2019, *National Electricity Rules, version 124*, 5.20B.2
[82] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

Term in inertia constraint equation left-hand side	Hard constraint			Constraint for synchronous condenser costing		
	Contribution on export (MW.s)	Contribution on import (MW.s)	Contribution to minimum (MW.s)	Contribution on export (MW.s)	Contribution on import (MW.s)	Contribution to minimum (MW.s)
Mersey Forth Upper	2.8*dispatch_no-sync (MW)* + 149			2.8*dispatch (MW)		
Lower Derwent	3.7*dispatch (MW)					
Tarraleah	4.0*dispatch (MW)					
Trevallyn	4.3*dispatch (MW)					
Tungatinah	3.2*dispatch (MW)					
Bell Bay	8.6*dispatch (MW)					
Tamar Valley CCGT	7.7*dispatch (MW)					
Tamar Valley OCGT	7.7*dispatch (MW)					

Since John Butters and Poatina can operate as a generator or synchronous condenser, they are assumed to contribute at full value to the hard constraint. 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 three columns of Table 9. These constraints can violate at a cost of 17 cents/MWs. The total violation cost is an estimate of the cost of running Poatina, John Butters and PSH as synchronous condensers to meet the minimum inertia requirement.

6.2 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 (this includes the committed Snowy 2.0 project but does not include other existing or new entrant PSH or large-scale batteries[83]) 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.

In the modelling presented in this Addendum, TasNetworks advised us to apply a single contingency reserve requirement[84] in each region, which must be met at all times.

[83] 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.
[84] AEMO, 30 July 2020, *2019 Input and Assumptions Workbook, v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

This constraint is applied in each region for 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.

There are two geographical levels of reserve constraints applied:

- Reserve constraints applied to each region.
- The model checks that interconnector headroom is backed by spare capacity in the neighbouring region through an additional reserve constraint covering New South Wales, Victoria and South Australia. For each hour that this constraint is applied, the contribution of import from either Tasmania and Queensland is limited by the minimum of headroom across the interconnectors linking these regions to the rest of the mainland and the amount of available dispatchable capacity within Tasmania and Queensland. This constraint to ensure availability in neighbouring regions is new since the PADR modelling[85] and was refined to improve realism.

6.3 Complex heat rates

Since the PADR modelling was completed, AEMO modified their modelling for the 2020 ISP to incorporate complex heat into their time-sequential modelling, which was used to inform their cost benefit analysis and gain operational insights.[86] Consequently, TasNetworks requested EY to incorporate complex heat rates into all market modelling forecasts. These complex heat rates have two components:

- A marginal heat rate – measured in GJ/MWh.
- A base heat rate – measured in GJ/h.

Due to the inherent limitation of linear programming complex heat rates were only applied to existing thermal units with minimum loads. Linear programs can only accommodate complex heat rates in these conditions because the fuel cost savings associated with retiring units with minimum loads can be predetermined by computing the amount of base fuel use saved through retirement. For all other units, this calculation is not possible in a linear program and therefore these units have been assigned non-complex heat rates measured in GJ/MWh.[87]

6.4 Tasmanian Renewable Energy Target

On 3 March 2020, the Tasmanian government announced a new state-based renewable energy target of 200 % generation by 2040, relative to Tasmania's current demand.[88] The AEMO 2020 ESOO demand forecast indicates that Tasmanian operational demand is expected to be roughly 10.5 TWh in 2020-21.[89] Therefore, TasNetworks advised that TRET be modelled such that the expected generation (inclusive of curtailment) from new renewable capacity would be at least

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[85] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

[86] AEMO, 30 July 2020, *Market Modelling Methodologies*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 6 October 2020.

[87] Note: this non-complex heat rate (GJ/MWh) is not the marginal heat rate (GJ/MWh) part of the complex heat rate, but rather those shown on tab "heat rates" of AEMO, 30 July 2020, *2019 ISP Input and Assumptions* workbook, *v1.5*. Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions. Accessed 24 September 2020.

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

[89] AEMO, 27 August 2020, 2020 Electrical Statement of Opportunities. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en. Accessed 24 September 2020.

10.5 TWh by 2040.[90] A linear trajectory is applied from 2022-23 (starting at 0 TWh) to achieve this 10.5 TWh target by 2040-41.

To reflect current investment interest, TasNetworks advised that the amount of new entrant wind capacity built in the Tasmanian Midland REZ should be limited to 40 % of the total amount of wind capacity built in Tasmania.

[90] New renewable capacity refers to capacity built be the model within the least-cost development plan, not committed or recently built Tasmanian renewable projects, such as the 112 MW Granville Harbour Wind Farm. Expected generation for new entrant wind or solar capacity is based on the average capacity factor over the 9-year reference cycle for the particular technology and REZ.

7. Marinus Link forecast gross market benefits

7.1 Summary of forecast gross market benefits

Table 10 shows the forecast gross market benefits outcomes over the modelled 21-year horizon, across all scenarios for the 1,500 MW Marinus Link (including association AC transmission augmentations), at different modelled timings. The values are discounted to 1 July 2019. As such, they should not be directly compared to gross benefits from EY's PADR economic modelling report published on 27 November 2019,[91] which were discounted to 1 July 2025.[92] Even when adjusting for the discount time, these gross benefits are not directly comparable to the previous modelling which used a 30-year study period.

Table 10: Forecast gross market benefits of Marinus Link for different timing options, millions real June 2019 dollars discounted to 1 July 2019

Option	Marinus Link timing	Scenario				
		Slow Change	Central	High DER	Fast Change	Step Change
1,500 MW	2027 & 2030	843	1,759	1,733	1,910	2,719
	2028 & 2031	827	1,735	1,705	1,842	2,619
	2031 & 2034	731	1,563	1,549	1,598	2,274
	2034 & 2037	580	1,206	1,188	1,258	1,739

The computation of net market benefits has been conducted by TasNetworks outside of this Addendum[93] as it is dependent on option costs which were developed independently by TasNetworks.

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

As discussed in Section 4.2, there are several differences in assumptions between AEMO's 2020 ISP[94] and the modelling done for this Addendum. As part of the modelling process for the Addendum, TasNetworks requested that EY benchmark our modelling to AEMO's by aligning five key assumptions, namely:

- Reverting to the AEMO 2019-20 ISP demand forecast, which does not account for the impacts of COVID-19.

[91] 27 November 2019, *Project Marinus PADR economic modelling report*. Available at: https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf. Accessed 24 September 2020.

[92] 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.

[93] TasNetworks, *Marinus Link Regulatory Investment Test for Transmission: Supplementary Analysis Report*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

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

- Assuming committed projects based on AEMO's February 2020 Generation Information data.
- Assuming VNI West is commissioned at the time specified in AEMO's optimal development plan for the applicable scenario. As such VNI West is commissioned 2035-36 in the Central, Fast Change and Step Change scenarios but not commissioned in the Slow Change or High DER scenario.
- Removing the TRET in the Central, Slow Change and Fast Change scenarios. The TRET is still included in the High DER and Step Change scenarios, as per the AEMO 2020 ISP assumptions.
- Removing regional inertia constraints, as these are not included in AEMO's ISP modelling.

Changing the five assumptions listed above was intended to assess the alignment of the optimal timing of Marinus Link between EY's hourly time-sequential modelling and AEMO's ISP model in all five scenarios. The gross benefit outcomes of that modelling were provided to TasNetworks to compute the relevant net market benefits. EY has been advised by TasNetworks that under these conditions our outcomes for Marinus Link were broadly aligned with AEMO's optimal timing for all scenarios. This suggests AEMO may forecast a similar optimal timing of Marinus Link to that provided in the accompanying Supplementary Analysis Report by TasNetworks[95] if AEMO was to conduct updated modelling using the AEMO 2020 ESOO demand forecast, committed projects based on the more recent 29 July 2020 Generation Information data and were to assume TRET progresses in all scenarios.

7.2 Sensitivities

Table 11 and Table 12 display the forecast gross market benefits and changes to forecast gross benefits for each sensitivity relative to the applicable scenario. All sensitivities to the Central scenario were tested with Marinus Link stage 1 commissioned on 1 July 2031 and stage 2 installed on 1 July 2034. All Step Change sensitivities assume stage 1 is commissioned on 1 July 2027 and stage 2 on 1 July 2030. Drivers for these changes are discussed below. Further details of the changes in input assumptions for each sensitivity, as advised by TasNetworks, can be found in Section 4.3 in Table 7.

Table 11: Forecast gross market benefits of Marinus Link for sensitivities to the Central scenario, real June 2019 dollars discounted to 1 July 2019

Sensitivity	Gross market benefits ($m)	Difference in gross market benefits ($m)
Economic Retirements Not Permitted	1,504	-59
Sustained Low Gas Price	1,401	-163
High Battery Cost	1,614	51
Low Battery Cost	1,523	-40

Table 12: Forecast gross market benefits of Marinus Link for sensitivities to the Step Change scenario, real June 2019 dollars discounted to 1 July 2019

Sensitivity	Gross market benefits ($m)	Difference in gross market benefits ($m)
Hydrogen Load Growth	2,166	-554
Committed PSH	3,292	573

[95] TasNetworks, *Marinus Link Regulatory Investment Test for Transmission: Supplementary Analysis Report*. Available at: https://projectmarinus.tasnetworks.com.au/rit-t-process/.

As seen in Table 11 and Table 12, the two primary drivers for reducing the gross market benefits of Marinus Link are an increase in Tasmanian demand and reducing the cost of generation in the mainland. The reduction in benefit due to higher Tasmanian demand is apparent in the Hydrogen Load Growth sensitivity, which increases the annual load in Tasmania by approximately 3.5 TWh annually from the mid-2030s and 7 TWh throughout the 2040s. The Sustained Low Gas Price sensitivity, which assumes a gas price of $8/GJ for all existing and new entrant gas projects, and Low Battery Cost sensitivity result in a lower cost for the mainland to meet its own demand, thus reducing the benefit of Marinus Link.

An increase in gross market benefits of Marinus Link is forecast to occur in sensitivities that increase the cost of mainland supply or commit capacity in Tasmania. This is observed in the High Battery Cost sensitivity and the Committed PSH sensitivity, which assumes 750 MW of PSH capacity in built in Tasmania in 2030-31 regardless of Marinus Link.

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
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSH	Pumped Storage Hydro
PSL	Prudent Storage Level
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test-Transmission
SA	South Australia
SAT	Single Axis Tracking
SRMC	Short-Run Marginal Cost
TAS	Tasmania
TW	Terawatt
TWh	Terawatt-hour
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria

Abbreviation	Meaning
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRET	Victoria Renewable Energy Target

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