PROJECT MARINUS

RIT-T Project Assessment Draft Report

ARENA
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This document has been produced by Tasmanian Networks Pty Ltd, ABN 24 167 357 299 (hereafter referred to as "TasNetworks").

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Foreword

Electricity markets around the world are changing rapidly as economies decarbonise in response to global warming. In Australia, the rapid growth in renewable generation, the growth in distributed energy resources (**DER**) and the closure of coal plant are creating significant challenges for market participants, network companies, and customers.

In its role as the national transmission planner, the Australian Energy Market Operator (**AEMO**) published its inaugural Integrated System Plan (**ISP**) for the National Electricity Market (**NEM**) in July 2018. In that landmark planning document, AEMO highlighted that a significant number of coal-fired generators have either advised that they are closing or will reach the expected end of technical life during the next 20 years.

According to AEMO's analysis, the retiring coal plants can be most economically replaced with a portfolio of utility-scale renewable generation, storage, DER, flexible thermal capacity, and transmission.[1] The projected portfolio of new resources involves substantial amounts of geographically dispersed variable renewable generation, placing a greater reliance on the role of the transmission network.

In its 2018 ISP, AEMO highlighted the significant value that transmission investment can provide to the NEM, including through the provision of increased interconnector capacity, by enabling the demand for electricity to be met at a lower total cost.[2]

Testing Marinus Link against competing alternatives

Against the backdrop of unprecedented and rapid transformation across the electricity sector, Project Marinus was established by TasNetworks in December 2017. With funding support from the Australian Government via the Australian Renewable Energy Agency (**ARENA**) and the Tasmanian Government, Project Marinus was asked to undertake a detailed Feasibility and Business Case Assessment of a second Bass Strait electricity interconnector, known as Marinus Link. As part of its work program, TasNetworks commenced the Regulatory Investment Test for Transmission (**RIT-T**), which is the regulatory process governing the appraisal of large transmission projects.

TasNetworks is pleased to publish this Project Assessment Draft Report (***PADR***), which is the next stage of the RIT-T process and follows the publication of a Project Specification Consultation Report (***PSCR***) in July 2018. At the core of the *PADR* is a comprehensive cost-benefit analysis that examines whether and when

1 AEMO, *Integrated System Plan 2018*, July 2018, p. 4.

2 AEMO, *Integrated System Plan 2018*, July 2018, p. 5.

Marinus Link and supporting transmission should proceed, having regard to all other alternative investment and expenditure options for meeting customers' demand for electricity over the next 30 years.

As part of the cost-benefit analysis, we engaged Ernst & Young to undertake extensive market modelling to identify the lowest cost combination of generation, demand side response, and transmission developments, including options for expanding interconnector capacities between different NEM regions. Our modelling treats all transmission, generation, and storage options on an equal basis, without any pre-conceived preference for particular investment types or technologies.

Customer and stakeholder engagement

Customer and stakeholder engagement is an important part of our process and we welcome the feedback we have received so far. We extended the consultation process beyond the requirements of the RIT-T to include engagement on our *Initial Feasibility Report*, which we published in February 2019. The *Initial Feasibility Report* provided indicative information on the likely costs and benefits of Marinus Link. The feedback we have received has helped guide our modelling approach and input assumptions, which underpin the conclusions in this *PADR*.

AEMO has also provided invaluable assistance, particularly in relation to the market modelling outcomes. To ensure that this *PADR* is as transparent and robust as possible, we have highlighted and explained any differences between our approach and AEMO's in relation to the model inputs, scenarios, methodology, and outcomes.

Marinus Link provides a cheaper supply option for mainland NEM regions

Tasmania's existing hydro capacity is a significant source of value to electricity customers on the mainland of Australia, given the forecast coal plant closures and the projected growth in renewable generation. In particular, the existing hydro capacity in Tasmania is able to provide benefits to Australian mainland NEM regions by:

- Displacing expensive gas-fired peaking generation that would otherwise be required to meet electricity demand; and
- Providing lower cost, higher capacity, energy storage to provide 'firm' capacity from variable renewable generation.[3]

[3] Due to the topography in Tasmania and the presence of existing hydro storages, 1 megawatt (**MW**) of pumped storage capacity can typically be provided for 24 hours, compared to six hours on the mainland.

Whilst these benefits can be provided by the existing hydro capacity in Tasmania, they can only be unlocked by investing in additional network capacity to transfer energy across Bass Strait. This is why Marinus Link and supporting transmission are required; so that the NEM is able to make best use of Tasmania's existing resources.

Our modelling also shows that significantly more dispatchable generation and storage will be required to support the mainland NEM than could be provided by Tasmania's existing hydro capacity. Therefore, an important second role for Marinus Link and supporting transmission is to enable Tasmania to exploit its natural advantages in topography and weather to provide lower cost storage capacity and wind generation to mainland Australia.

Marinus Link should proceed in two stages

The economic cost-benefit analysis in this *PADR* demonstrates that Marinus Link and supporting transmission should proceed because it delivers a net market benefit. This conclusion remains the same for the full range of capacities and timings examined in this *PADR* and for any of the four scenarios modelled. Having established that Marinus Link and supporting transmission should proceed, the challenge is to determine its optimal timing and capacity.

Our detailed analysis indicates that the optimal capacity and timing for Marinus Link and supporting transmission under the RIT-T framework is:

- **Stage 1**: An initial 750 megawatt (**MW**) high voltage direct current (**HVDC**) link between Burnie in Tasmania and Hazelwood in Victoria with supporting network augmentations in Tasmania, should be commissioned in 2028; and
- **Stage 2**: The commissioning of a further 750 MW HVDC link in 2032.

In broad terms, Stage 1 enables customers in NEM regions on the mainland of Australia to benefit from the spare capacity that already exists in Tasmania's hydro system. Stage 2 is delayed until 2032, at which time our modelling shows Australian mainland NEM regions would require additional peaking gas-fired generation and storage. By staging additional interconnector capacity in 2032, investment in lower cost storage capacity and wind generation in Tasmania will provide further savings to the NEM on the mainland of Australia by displacing more expensive alternatives.

Whilst the RIT-T concludes that Marinus Link and supporting transmission should proceed in stages, the project cost estimates assume that it is managed as a single project, which will provide significant cost savings principally in relation to environmental planning, tendering, and project management.

In aggregate, this combination of Stage 1 and Stage 2 investments in Marinus Link and supporting transmission maximises the net market benefit across a range of scenarios. The total expected net market benefit is $1,674 million, expressed in net present value terms.[4]

The net market benefit of Marinus Link and supporting transmission is compared to the 'base case', which is the most economic combination of generation, storage, and transmission investment in the absence of Marinus Link and supporting transmission. Our cost-benefit analysis therefore shows that Marinus Link and supporting transmission delivers very significant net benefits – i.e. after accounting for its capital and operating costs – to the electricity market. Ultimately, Marinus Link and supporting transmission will deliver a lower cost electricity supply for electricity consumers across the NEM on the mainland of Australia than would occur if Marinus Link and supporting transmission do not proceed.

The central estimate of the capital costs for the preferred option as identified by the RIT-T, including transmission network augmentations, is $2.76 billion.[5] The estimated costs include supporting network augmentation in Tasmania to ensure that the planned transfer capacity can be delivered. The required augmentations are:

- Construction of a 220 kilovolt (**kV**) switching stations in the Burnie area adjacent to the converter stations;
- Construction of a new double-circuit 220 kV transmission line from Burnie to Sheffield, and decommissioning of the existing 220 kV single-circuit transmission line in this corridor;
- Establishment of a new 220 kV switching station at Staverton;
- Construction of a new double-circuit 220 kV transmission line from Staverton to Burnie via Hampshire; and
- Construction of a new double-circuit 220 kV transmission line from Palmerston to Sheffield.

No transmission augmentations would be required in Victoria because the HVDC converter station would be located adjacent to the existing Hazelwood substation, using its spare capacity.

Early project delivery

Whilst our economic cost-benefit analysis has identified that Marinus Link should proceed in two 750 MW increments commissioned in 2028 and 2032, a case can be made for delivering Marinus Link and supporting

4 Unless otherwise stated, market benefits are expressed in present value terms discounted to 1 July 2019. All values are expressed in 2019 dollars.

5 $2.76 billion is the expected capital expenditure excluding allowances for accuracy and contingencies. This cost estimate is in 2019 dollars and is also subject to change as better information becomes available through the tender process.

transmission earlier. For example, delivering the first stage in 2027 and the second stage in 2028 would have the following advantages compared to the optimal timing identified in this report:

1. Marinus Link and supporting transmission would provide additional protection against unexpected events, such as: earlier than expected coal project plant closures; significant generator outages; a prolonged Basslink outage; or extreme heatwaves; and
2. Earlier construction will bring forward the jobs and investment stimulus that are expected to be provided to the Victorian and Tasmanian economies.[6]

Our economic cost-benefit analysis indicates that a later, staged, timing delivers a higher net market benefit as defined by the RIT-T. However, Marinus Link and supporting transmission could proceed earlier if it is supported by an external source of funding (e.g. government grant funding).

TasNetworks continues to work with AEMO as it prepares its draft and final 2019-20 ISP, which considers future transmission investment needs for the NEM. Recognising that differences in modelling assumptions may result in different timings between TasNetworks and AEMO analysis, it is nevertheless clear that Marinus Link and supporting transmission will play a role in the future NEM, and that the project should proceed through the Design and Approvals phase.

Pricing impact

TasNetworks has received extensive feedback from customers regarding the transmission network pricing impact of Marinus Link and supporting transmission, particularly in Tasmania.

In response to this feedback, TasNetworks has expressed the view that all customers in the NEM should pay for interconnector augmentations in proportion to the benefits they receive. We consider this principle should apply to all new interconnectors, not just Marinus Link.

We note also that in its November 2019 meeting, the Council of Australian Governments (**COAG**) Energy Council requested the Energy Security Board (**ESB**) to provide advice on a fair cost allocation methodology for interconnectors. This further demonstrates the NEM-wide significance of interconnector pricing.

To formalise our views, we have consulted with the Tasmanian Government and other stakeholders to prepare a discussion paper about possible changes to the National Electricity Rules (**NER**) to deliver network pricing outcomes for interconnectors that reflect the benefits that those interconnectors provide across the NEM. This discussion paper is available on our web site alongside this *PADR*. We welcome stakeholders' views on the

6 It is important to note that the benefit of the project in terms of jobs is not included in the RIT-T analysis, which is only concerned with costs and benefits to the electricity sector.

discussion paper, which will inform our submission to the ESB's anticipated consultation on this important issue.

Further engagement

This *PADR* commences the next phase of our engagement process. We welcome input and feedback from our customers and stakeholders. Further information on our engagement program is provided in this *PADR* and on our website.

1 Introduction and Overview

1.1 Purpose of this document

A second interconnector between Tasmania and Victoria and supporting alternating current (**AC**) network augmentations would be a major investment in long-lived transmission assets. In accordance with the NER, Marinus Link and supporting transmission would need to satisfy the RIT-T (which is a comprehensive economic cost-benefit analysis) if the costs of Marinus Link and supporting transmission are to be recovered from electricity customers via regulated transmission charges.

The first stage of the RIT-T commences with a *Project Specification Consultation Report*, which we published in July 2018. The *PSCR* described the 'identified need' that further interconnection between Tasmania and Victoria would address. It also provided details of:

- The assumptions underpinning this need;
- The credible options that would address this need;
- How we intend to evaluate the benefits of these options;
- The likely implementation timetable; and
- The indicative costs.

We received fifteen submissions in response to the *PSCR*.

In February 2019, TasNetworks also published an *Initial Feasibility Report*, which discussed the technical, environmental, planning, and economic aspects of Marinus Link. Although the *Initial Feasibility Report* is not part of the formal RIT-T process, it provided stakeholders with a further opportunity to comment on the project and to guide our future work. We received ten submissions in response to the *Initial Feasibility Report*.

This document is the *Project Assessment Draft Report*, which is the next step in the RIT-T process. In addition to responding to the submissions received thus far, the *PADR* presents the market modelling of the costs and benefits of a wide range of credible options. The RIT-T concludes by identifying the 'preferred option' as the credible option that maximises the net economic benefit to all those who produce, consume, and transport electricity in the market compared to all other credible options.[7]

[7] In accordance with clause 5.16.1(b) of the NER.

1.2 RIT-T analysis supports Marinus Link

The analysis presented in this *PADR* shows that a staged 1500 MW Marinus Link, constructed in 750 MW increments in 2028 and 2032, with the supporting AC network upgrades, satisfies the RIT-T. Our analysis shows that the Marinus Link and supporting transmission constructed in two stages produces expected net benefits of $1,674 million in present value terms compared to the base case, in which Marinus Link and supporting transmission does not proceed.

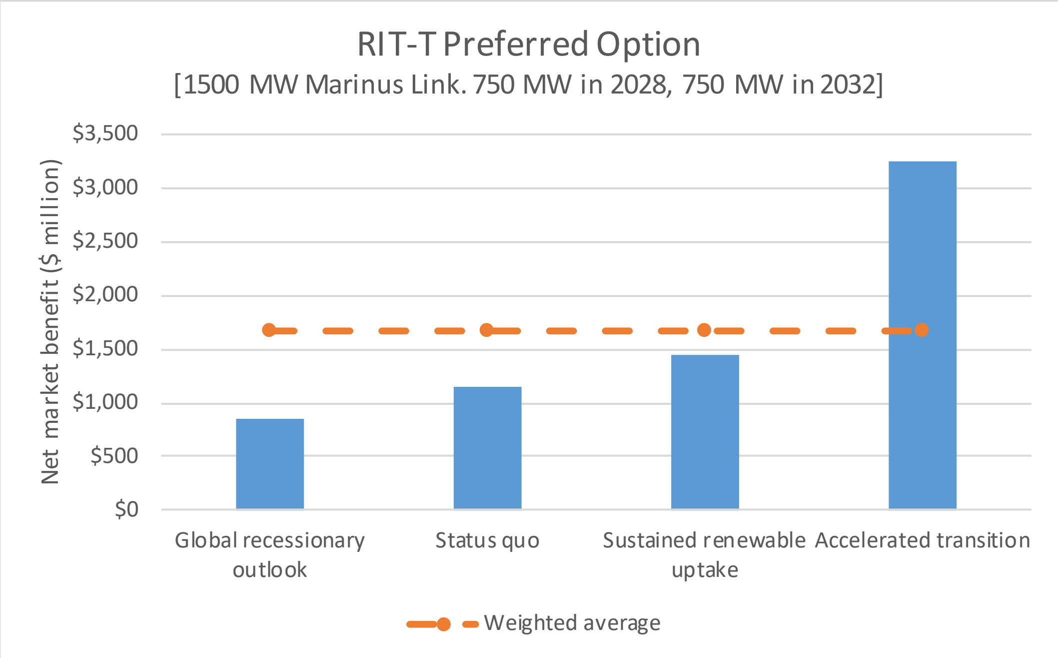
Our modelling approach ensures that Marinus Link and supporting transmission are tested against a wide range of alternatives, including generation, storage, demand-side response, and transmission interconnectors. It is a comprehensive approach that treats all options and technologies on an equal basis.

Key findings

Our RIT-T analysis shows that:

- Marinus Link and supporting transmission provide value to NEM customers on the mainland of Australia by providing access to the existing hydro capacity in Tasmania. As more solar and wind resources replace coal-fired generation, energy storage will be required to firm the output from these resources. Marinus Link and supporting transmission enable the use of existing Tasmanian hydro generation and lower cost pumped hydro to provide energy storage more efficiently than the alternative of gas-fired generation and new storage options on mainland Australia.
- Over the planning horizon, our modelling identifies the need for additional gas-fired generation and storage capacity on mainland Australia, in response to coal closures and the projected growth in renewable energy resources. Marinus Link and supporting transmission provide a cost-effective alternative by providing greater access to Tasmania's natural resources and topography, which enable Tasmania to provide wind generation and storage capacity to the mainland at a lower total cost.
- The most significant factors influencing the economic feasibility and timing of Marinus Link and supporting transmission are: the timing of coal-fired generation retirement in the NEM; load forecasts; and gas prices.
- In accordance with the RIT-T, we have tested alternative timings and capacities for Marinus Link and supporting transmission compared to the base case, across a range of different scenarios. The base case examines the costs of meeting customers' demand for electricity if Marinus Link and supporting transmission do not proceed. As such, it considers alternatives to Marinus Link including interconnector, storage, and generation investments on mainland Australia, as well as demand management measures.

- Our analysis shows that Marinus Link and supporting transmission would deliver a net market benefit for all feasible options and timings, across all scenarios. On this basis, Marinus Link and supporting transmission should proceed. Our detailed examination of the capacity options and timings indicate that the optimal Marinus Link is a staged 1500 MW Marinus Link, constructed in 750 MW increments in 2028 and 2032. This option is expected to deliver an average net market benefit across the four scenarios of $1,674 million compared to the base case.



- Each stage of the project would comprise:
    - A HVDC undersea cable crossing Bass Strait, continuing to an underground HVDC cable to cross land in Tasmania and Victoria;
    - A HVDC converter station at each of the Tasmanian and Victorian ends of the cable; and
    - AC transmission network upgrades to allow power delivery to the HVDC link.

1.3 Marinus Link and other NEM investments

Our RIT-T analysis is underpinned by Ernst & Young's market expansion model, which determines the least cost evolution of the NEM to 2050. The model allows us to test the implications of different options for Marinus Link and supporting transmission against a base case under which Marinus Link and supporting transmission do not proceed.

An important aspect of Ernst & Young’s market modelling is that it examines the total integrated system costs of meeting customers’ future electricity needs. The model selects the lowest cost combination of generation, storage, and demand-side response and we have also looked at the optimal timing and capacity of other interconnector options. Each option for Marinus Link and supporting transmission is therefore accompanied by different investments across the NEM to meet customers’ electricity needs.

Ernst & Young’s analysis shows that Marinus Link and supporting transmission delivers genuine savings for customers through a reduced cost to supply electricity compared to the base case. The modelling has identified the following investments across the NEM that would accompany Marinus Link and supporting transmission, in addition to the existing committed and anticipated transmission and generation projects:

- KerangLink interconnector, raising the total Victoria to New South Wales interconnector transfer limit to 2800 MW (northwards) and 2200 MW (southwards);
- Utility and small-scale photovoltaic (**PV**) of 35 gigawatts (**GW**) by 2050;
- Wind generation of 29 GW, including 2.5 GW in Tasmania by 2050;
- New gas generation of 6.1 GW;
- Battery storage capacity of 700 MW (1.4 gigawatt hours (**GWh**)); and
- Additional pumped storage capacity of 10.1 GW (82.2 GWh), including 1.2 GW (28.8 GWh) in Tasmania.

This new capacity will replace 20 GW of coal generation, as well as a smaller quantity of ageing gas generation, which is expected to retire by 2050, based on our ‘Status quo/current policy’ scenario. Alternative scenarios with more aggressive emissions reduction targets indicate an even greater amount of renewable generation development will occur in the NEM.

Our modelling has identified that Marinus Link and supporting transmission would play an important role in a major transformation of the NEM. Marinus Link and supporting transmission enables Tasmania to contribute to approximately 10 per cent of this transformation capacity, whilst Tasmania accounts for around 5 per cent of total NEM energy consumption. Therefore, Marinus Link and supporting transmission makes a significant contribution to delivering the lowest cost integrated solution to meet customers’ electricity needs.

1.4 The case for advanced project delivery

Marinus Link and supporting transmission satisfies the RIT-T by maximising the net economic benefit to all those who produce, consume, and transport electricity in the market compared to all other credible options. The optimal capacity and timing is:

- An initial 750 MW HVDC link between Tasmania and Victoria, with supporting network augmentations in Tasmania, to be commissioned in 2028; and
- A further 750 MW HVDC link to be commissioned in 2032.

Whilst commissioning Marinus Link in 750 MW increments in 2028 and 2032 is the optimal capacity and timing for Marinus Link as defined by the RIT-T, there are arguments for advancing the timing of Marinus Link and supporting transmission. For example, building the project earlier would assist in mitigating the risks of earlier coal plant closures, customer power loss during heatwaves, and extended outages of Basslink.

Whilst arguments can be presented for a different timing of Marinus Link and supporting transmission, the RIT-T is clear that we must consider the ‘average’ or expected outcomes in the electricity sector, rather than focus our attention on the mitigation of downside risks or the prospect of accelerating jobs growth in Tasmania. In particular:

- Under the RIT-T, it is not permissible to select the preferred option on the basis of its performance under a particular scenario or sensitivity, such as early coal plant closure or prolonged Basslink outage. Instead, the net market benefit must reflect the expected performance across all reasonable scenarios, weighted by their respective probabilities of occurrence.
- The RIT-T only includes costs and benefits in the electricity sector and therefore does not consider economy-wide costs and benefits. As such, whilst investment and jobs growth in Tasmania and Victoria are important, they do not have any standing in the RIT-T analysis unless they are explicitly valued by governments in the form of a funding contribution which can be included in the RIT-T analysis.

From a regulatory perspective, customers should not be disadvantaged by a decision to deliver Marinus Link and supporting transmission earlier than indicated by the RIT-T. It is therefore up to State and Federal Governments to determine whether Marinus Link and supporting transmission should be delivered earlier.

1.5 Structure of this PADR

The remainder of this *PADR* is structured as follows:

- Chapter 2 highlights the market and policy changes that have occurred since our *PSCR* was published in July 2018.
- Chapter 3 summarises the feedback we received on our *PSCR* and explains how we have taken this feedback into account in preparing this *PADR*.
- Chapter 4 describes the credible options that have been examined in this *PADR*.
- Chapter 5 discusses our modelling approach in detail, including the key input assumptions, scenarios and sensitivity analysis, the discount rate applied and the planning horizon. It also explains that our modelling approach implicitly considers a wide range of competing alternatives to Marinus Link and supporting transmission beyond the specific projects described in this report.
- Chapter 6 reports the results of the net market benefit analysis and the preferred option for Marinus Link and supporting transmission. This section also sets out the development phases and timeframes for the preferred option.
- Chapter 7 discusses the question of 'who pays' for Marinus Link and supporting transmission, and the steps we are taking to ensure that the interconnector pricing arrangements deliver a fair and efficient outcome for customers.

1.6 Consultation and next steps

TasNetworks welcomes submissions from stakeholders on this *PADR* by 2 March 2020. Submissions should be made to:

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All enquiries relating to this document or requests for information should also be directed to the person named above.

The next formal stage of this RIT-T involves publication of the Project Assessment Conclusions Report (***PACR***). We anticipate that the *PACR* will be published in mid-2020.

2 Key recent developments

This chapter highlights the regulatory and market changes that have occurred in the NEM since the publication of the *PSCR* in July 2018. We explain how we have taken account of these developments in this *PADR* and how they may influence our future analysis in the *PACR*, which is the final stage of the RIT-T.

Key Messages

- TasNetworks has considered the developments following the publication of AEMO's 2018 ISP, including the steps taken by the ESB to implement an 'Actionable ISP'. Our approach in this *PADR* is to assume that the ESB's 'Group 1' and 'Group 2' projects will proceed. Where specific projects have progressed, such as Western Victoria RIT-T and project EnergyConnect, the proposed projects have also been included in our market modelling.
- Since the publication of the *PSCR*, a commitment has been made to progress Snowy 2.0. For the purpose of this *PADR*, it is assumed that Snowy 2.0 will proceed.
- AEMO has updated its input assumptions and scenarios since the publication of the 2018 ISP and our *PSCR*. Our modelling approach relies on AEMO's 2019 Planning and Forecasting Consultation Paper assumptions published in February 2019 (at the time of commencing our RIT-T assessment) as a starting point, recognising we must explain any deviation from AEMO's approach. We expect AEMO's position to continue to evolve in response to stakeholder feedback and new information.
- Our market modelling assumes that new renewable generation capacity is located in Renewable Energy Zone (**REZ**s). Consistent with other modelling inputs, we have adopted AEMO's REZ definitions as published in February 2019 in our market modelling.
- We have carefully considered AEMO's Insights Papers, which provide helpful analysis on key developments in the electricity market, including the economic implications of coal closures and the role of pumped storage in providing network resilience. In addition to these considerations, we have also had regard to the Annual Planning Reports of Transmission Network Service Providers (**TNSP**) and any recent RIT-T publications.
- The Australian Energy Market Commission (**AEMC**) and the ESB are considering reforms that could have significant impacts on the market arrangements, including firm transmission rights for generators and changes to the transmission pricing arrangements. In terms of our market modelling, we do not expect these reforms to have a material impact. The transmission pricing issues are relevant to the 'who pays' question, which we address in Chapter 7 of this *PADR*.

Key Messages (continued)

- Subsequent to the publication of the PSCR, the Australian Energy Regulator (AER) amended its RIT-T Guidelines. We have adopted these updated guidelines in this PADR.
- AEMO continues to progress its analysis to support draft and final 2019-20 ISPs, presently expected to be released in December 2019 and March 2020. AEMO's draft ISP may suggest some differences in timing for Marinus Link and supporting transmission – potentially both earlier and later timings under different scenarios and with some different modelling inputs. TasNetworks will continue to work with AEMO as the ISP and RIT-T processes continue.

2.1 Actionable ISP

At the time of publishing the *PSCR* in July 2018, TasNetworks had not had an opportunity to fully consider the information contained in AEMO's 2018 ISP and the supporting market modelling. Therefore, we undertook to engage further with AEMO to gain a better understanding of its modelling and conclusions. In addition, we also recognised that our own scenarios and market modelling may need to be updated in light of this further work.

Given this background, it is useful to recap on the transmission network developments that were identified in AEMO's 2018 ISP and the subsequent initiatives to convert the ISP into an 'actionable plan'.

AEMO's 2018 ISP identified transmission investments that are needed to accommodate the changes in the power system that are both underway and expected. These investments were categorised into three groups: near term (Group 1), medium term (Group 2) and longer term (Group 3). The Group 1 projects are focused on delivering the following outcomes:

- Increase capacity between New South Wales and Queensland and Victoria by 170-460 MW;
- Reduce congestion for existing and committed renewable energy developments in both Western and North Western Victoria; and
- Remedy system strength deficits in South Australia.

Group 1 projects were found to be necessary under all scenarios and should be completed as soon as practicable.

In September 2018, the COAG Energy Council asked the ESB to identify a work program, including possible changes to the RIT-T, to convert the ISP into an actionable strategic plan. Following a series of industry workshops, the ESB published its 'action plan' which included 12 recommendations on:[8]

- How Group 1 projects in the ISP can be delivered as soon as practicable;
- How Group 2 and 3 projects should be progressed; and
- How the ISP would be converted into an actionable strategic plan.

At the December 2018 COAG Energy Council meeting,[9] the Federal and State Energy Ministers discussed progress on the ISP and agreed on an approach, set out by the ESB, to deliver Group 1 projects as soon as possible, including changes to the NER to streamline the regulatory processes. The Ministers also asked the ESB to consider how these reforms could be applied to other priority projects, such as the South Australia to New South Wales interconnector.

The Ministers noted that a rigorous cost-benefit analysis will be an essential part of the process to ensure costs to consumers are minimised. They also agreed that the ESB should do more work on further measures to operationalise the ISP, including providing regular updates and reassessments of Group 2 and 3 projects.

In preparing this *PADR*, we have treated all Group 1 projects as anticipated transmission projects,[10] which will be completed as soon as practicable in accordance with the ISP. For EnergyConnect, which was identified as a Group 1 project, we have adopted ElectraNet's project specification in its completed *PACR*.[11] The Group 2 projects are also treated as anticipated projects, although the timing of these projects is determined by our market modelling. Our sensitivity analysis examines the impact if these projects do not proceed, which is to increase the net market benefit of Marinus Link and supporting transmission proceeding.

In November 2019, as this *PADR* was nearing publication, both the AER and the ESB released further consultation papers on actioning the ISP. The ESB papers focus on the required legal and regulatory changes, whilst the AER papers were primarily concerned with the development of new and existing guidelines. This consultation is still in progress at time of publication of this *PADR*. The ESB's proposed changes allow RIT-Ts

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[8] Energy Security Board, *Integrated System Plan: Action Plan*, December 2018.

[9] COAG Energy Council Secretariat, *COAG Energy Council Meeting Communique*, Wednesday 19 December 2018.

[10] Clause 19 of the RIT-T defines an anticipated project as a project that is in the process of meeting at least three of the criteria for a committed project, but not all the criteria.

[11] ElectraNet, *South Australia Energy Transformation, Project Assessment Conclusions Report*, February 2019.

on ISP projects that have already commenced to be completed under the Rules that existed at the time of commencement, should the TNSP elect to do so.

Also in November 2019, the COAG Energy Council agreed the ESB will bring its Rules package to action the ISP to the Council in March 2020. Additionally, it requested the ESB to prepare advice on a fair interconnector cost allocation methodology as part of its work to action the ISP.[12] As discussed elsewhere in this *PADR*, the question of who pays for Marinus Link and supporting transmission has been raised by many stakeholders. The ESB's forthcoming work on interconnector cost allocation will be our focus to deliver better pricing outcomes for Marinus Link.

We will maintain a watching brief in relation to the ESB's initiatives to operationalise the ISP. It should be noted that we may update our modelling at the *PACR* stage in response to any further developments.

Full details of our modelling assumptions are provided in Chapter 5 and Attachment 1. An explanation of the issues surrounding interconnector pricing, and our next steps in regards to this issue, may be found in Chapter 7.

2.2 Snowy 2.0

Since the publication of the *PSCR*, Snowy Hydro's Board approved the Snowy 2.0 project. The Snowy 2.0 project will link two existing scheme dams, Tantangara and Talbingo, through 27 km of underground tunnels and an underground power station with pumping capabilities.

Similar to the Battery of the Nation project in Tasmania, Snowy 2.0 is responding to the need for:

- Additional firm, dispatchable, capacity to augment NEM generation; and
- A cost effective, reliable, method of storing large amounts of electricity.

Snowy 2.0 will increase the Snowy Hydro Scheme's existing generation capacity by 2000 MW and large-scale energy storage capacity of 350,000 MWh. It is expected to be able to generate for up to 175 hours at full capacity without refilling. For the purpose of this *PADR*, Snowy 2.0 is treated as an anticipated generation project.[13]

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[12] COAG Energy Council Secretariat, *COAG Energy Council Meeting Communique*, 22 November 2019.

[13] A sensitivity study considers the impact of Snowy 2.0 not proceeding. Results of the sensitivity testing are set out in section 6.2.

2.3 Renewable Energy Zones

An important feature of AEMO's 2018 ISP was the identification 34 REZs, selected on the basis of the available renewable energy resources and transmission capacity to facilitate least cost integration into the transmission system.

For Marinus Link and supporting transmission, the REZs identified in Victoria and Tasmania are relevant to the preferred route selection, which is discussed in section 4.5.2. In addition, assumptions regarding REZ development have implications for the market modelling and the market benefit that Marinus Link and supporting transmission may provide. As explained in Chapter 5, the market modelling assumes that renewable generation capacity is constructed in REZs.

Given these observations, it is important for our modelling to reflect recent changes in the REZs and to explain how any future changes will be addressed in the *PACR*. Figure 1 below shows AEMO's latest views on the REZ candidates for its 2019-20 ISP.[14]

[14] AEMO, *2019 Forecasting and Planning Scenarios, Inputs, and Assumptions*, August 2019, Figure 22, p. 48.

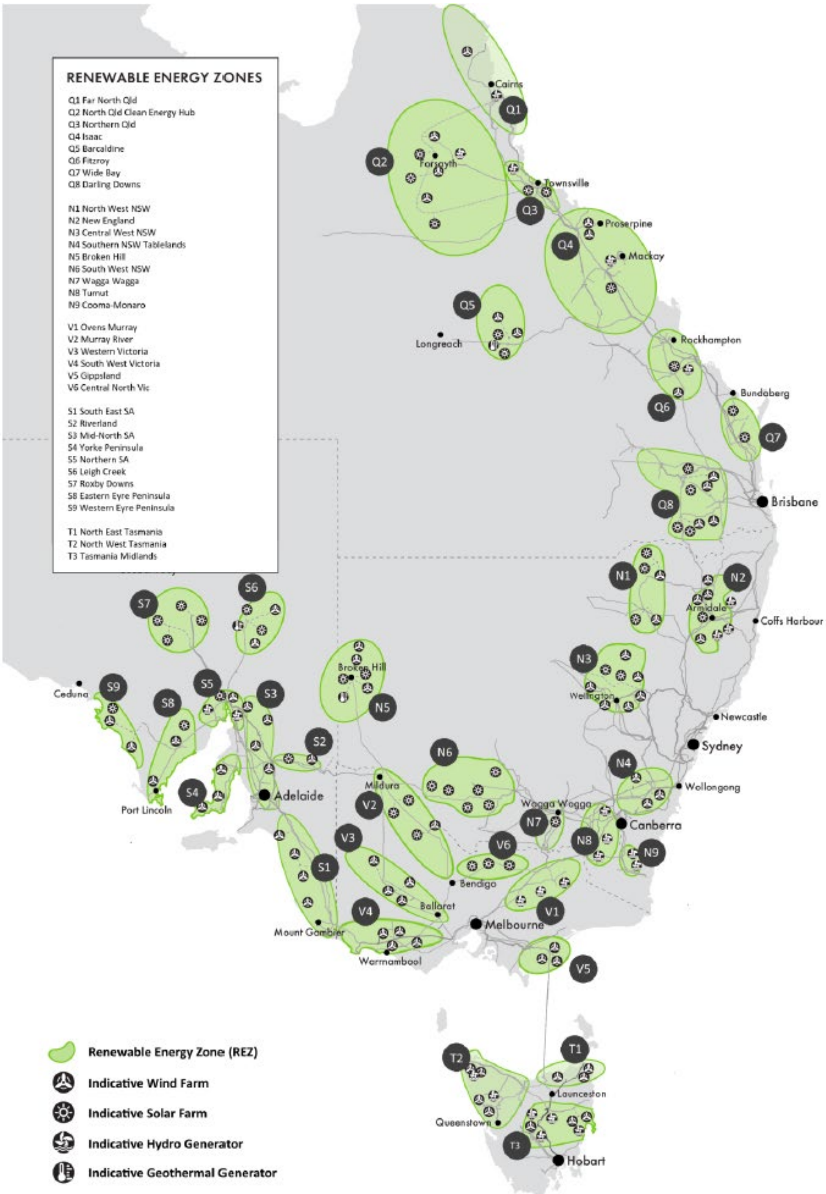

Figure 1 AEMO's Renewable Energy Zones candidates for the 2019-20 ISP

In its ISP Action Plan, the ESB raised the possibility that scale-efficient investment in transmission capacity to support REZ development could be facilitated by the establishment of an Adjustment Fund. Under this approach, the Adjustment Fund would finance a large capacity connection and then sell down the capacity to generators as they develop. The ESB recommended to the COAG Energy Council that this approach should be given further consideration, including the required size of the finance, the source of funds, and how funds should be recovered and managed.

As already noted, future REZ development is important to Marinus Link and supporting transmission in terms of the optimal route selection and the market modelling. TasNetworks notes that whilst the REZ concept has been clearly articulated in the 2018 ISP, it remains unclear how REZs will be developed in practice. At this stage, it is not appropriate to assume that the proposed Adjustment Fund will have a material impact on REZ development from the perspective of Marinus Link and supporting transmission, although we will maintain a watching brief.

In relation to any future changes to the REZs, TasNetworks notes that it may be appropriate to update our market modelling in the *PACR*.

2.4 AEMO's 2019 planning and forecasting assumptions and scenarios

In February 2019, AEMO commenced consultation on its planning and forecasting inputs,[15] scenarios, and assumptions for use in its 2019 publications, including the Electricity Statement of Opportunities and the 2019-20 ISP. Alongside its consultation paper, AEMO also published its workbook which detailed its updated assumptions and scenarios for planning purposes.

The consultation paper provided information and sought stakeholder submissions on a range of matters, including:

- Proposed scenarios, inputs, and assumptions for use in AEMO's 2019 NEM planning and forecasting publications; and
- Material issues and modelling improvements in the preparation of the 2019-20 ISP and preliminary views on how those issues should be resolved.

In relation to the second point, AEMO highlighted the following issues where it sought stakeholder feedback to improve its modelling approach:

- Understanding the reliability of ageing thermal plants, the timing and scale of existing thermal generators retiring and what new energy sources will replace them.
- Enhancing the understanding of pumped storage with specific emphasis on the Snowy 2.0 and Battery of the Nation projects.
- Using improved cost, storage, lead time, and demand management assumptions, based on the GenCost project.

[15] AEMO, *2019 Forecasting and Planning Scenarios, Inputs, and Assumptions*, August 2019, Figure 22, p. 48.

- Taking account of the increasing consumer investment trends towards rooftop PV, battery storage, demand-side participation, energy efficiency and other forms of DER – including the role that Virtual Power Plants could play in future.
- Identifying necessary measures to enhance the resilience of the future power system through network and non-network services, which includes addressing technical issues such as frequency stability, voltage control, and power system strength.
- Developing an approach to value measures that enhance the resilience of the power system to climate change risks.
- Commencing tri-sector integration of electricity, gas, and transport in AEMO's co-optimisation model.
- Developing early insights on the potential impact of a transition to a hydrogen economy (noting AEMO needs to develop and test functional changes in its modelling tools and collect more data before including hydrogen as a full scenario in future ISPs).

AEMO received extensive feedback from stakeholders in response to its consultation paper and workbook. Figure 2 below reproduces AEMO's summary of the top ten themes raised in stakeholder submissions, including the frequency of the issue raised and the degree of consensus.

	Theme	Frequency	Consensus
-	The **consultation process** and the efforts being made to increase engagement with stakeholders are positive	High	High
1	**Emissions reduction modelling** needs to explicitly incorporate policies and account for stricter trajectories	High	High
2	The current **scenarios** do not sufficiently capture the range of possible energy futures	High	Medium
3	The modelling of **generator retirements** needs to account for earlier retirements, and be based on more than technical retirement age	High	Medium
4	Improvements can be made to the **Distributed Energy Resources** modelling approach	High	Low
5	A commercial **discount rate** should be used, as opposed to a social discount rate below the WACC	Medium	High
6	Increase the transparency and dynamism of **Marginal Loss Factor** modelling	Medium	Medium
7	The establishment of more **Renewable Energy Zones** and their modelling	Medium	Low
8	When modelling benefits, incorporate **ancillary benefits and services**, or establish a market for these services	Low	High
9	**System strength** is an important issue and improvements need to keep being made in terms of how to incorporate it effectively into the models	Low	Medium
10	**Resilience modelling** approach: both HILP and mitigation options	Low	Low

Figure 2 Top ten themes in stakeholder submissions to AEMO[16]

The extent of the feedback from stakeholders on AEMO's modelling assumptions and inputs illustrates the inherent uncertainty in forecasting future developments in the energy sector. In light of this uncertainty and the rapid pace of change, our approach is to use AEMO's assumptions and scenarios as a starting point for our

16 AEMO, Planning and Forecasting 2019 Consultation Process Briefing Webinar, Wednesday 3 April 2019, slide 13.

RIT-T assessment. Where we consider it appropriate to vary these assumptions or scenarios, we explain the rationale for our approach and take account of stakeholder feedback.

Details of our model inputs, assumptions, and scenarios are explained in Chapter 5.

2.5 AEMO Insights Papers

In May and June 2019, AEMO published three 'Insights Papers', covering the benefits of interconnection,[17] the economics of coal closure,[18] and building power system resilience with pumped hydro energy storage.[19] In undertaking our economic cost-benefit analysis in this *PADR*, we have had regard to these and AEMO's key findings, which are summarised below.

The pumped hydro storage insights paper released in July 2019 focused on the case for developing Snowy 2.0 and Battery of the Nation pumped hydro schemes to assist the NEM in its transition as baseload thermal generation assets retire. The paper highlights the valuable seasonal storage and insurance against drought risk that deep storages like Snowy 2.0 and Battery of the Nation will provide. The paper also acknowledges the valuable role that shallow storages – being six to eight hours in duration – will play in a transitioning NEM by complementing solar generation and shifting excess energy. The paper goes on to state that Marinus Link or KerangLink would increase system resilience in case of premature retirement of brown coal generation assets in Victoria.

In its conclusion, the paper recognised the long lead time associated with transmission augmentation projects and recommended that Marinus Link, along with other transmission projects identified in the ISP, should be subject to an expedited approval process in accordance with the ESB's change package for the NER. The paper also recommended accelerating environmental and planning approvals, where feasible.

AEMO engaged Aurora Energy Research to understand the economics of coal closure under the four scenarios outlined in the 2018 ISP. This Insights Paper concluded that, under a neutral scenario, the coal generation assets are likely to be profitable and will remain in service as assumed in the ISP modelling estimates. The paper states that certain generation assets are more vulnerable to early closure as compared to others due to increased cost of plant operation arising from routine ramping up and down of the generation assets on account of additional renewables entering the NEM.

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17 Aurora Energy Research, *Analysis of AEMO's ISP Part 1: Benefits of Interconnection*, May 2019.

18 Aurora Energy Research, *Analysis of AEMO's ISP Part 2: Economics of Coal Closure*, May 2019.

19 AEMO, *Building Power System Resilience with Pumped Hydro Energy Storage*, July 2019.

Another key finding of the paper was the early closure of coal generators under the slow demand scenario. Aurora Energy Research estimated that between 3 GW and 5 GW of coal generation is likely to retire prematurely if the NEM demand by 2040 is 35 per cent lower than the neutral ISP forecast. Aurora Energy Research leveraged their global experience, having worked with coal plant owners under similar circumstances, and reached this conclusion based on renewable generation trajectory in the NEM and increased fixed and operating costs associated with ageing coal plants.

2.6 Hydro Tasmania "White Paper"

In December 2018, Hydro Tasmania released a White Paper on the potential value of Tasmania's renewable generation assets with more interconnection.[20] The paper draws attention to the winter peaking nature of the Tasmanian market, and the 400 MW of spare dispatchable hydro capacity that could be utilised during the critical summer months at no additional cost, if increased interconnection capacity is provided.

The paper also highlights that, if a second Bass Strait interconnector was to be commissioned, Hydro Tasmania would proactively invest to repurpose generation assets for capacity increases rather than baseload operations. Hydro Tasmania identified 340 MW of additional capacity that could be added to the Tasmanian system at minimal incremental cost. The stations that would contribute to this capacity increase were:

- 150 MW at Tarraleah, station re-optimised to better manage Derwent scheme operations;
- 100 MW in Western Tasmania, mid-life refurbishment opportunity for the generator runners; and
- 90 MW at Gordon Power Station managed by maintaining the station at higher lake level for better head effect.

The availability of latent and repurposed hydro operations in a scenario with additional interconnection was adopted by AEMO for its pumped storage Insights Paper and for the ongoing 2019-20 ISP modelling. We have taken account of Hydro Tasmania's White Paper in the economic cost-benefit analysis in this *PADR*.

[20] Hydro Tasmania, *Battery of the Nation – Unlocking Tasmania's Energy Capacity – The Potential of Tasmania's Renewable Generation Assets with More Interconnection*, December 2018.

2.7 Related RIT-Ts and Transmission Annual Planning Reports

2.7.1 Western Victoria Renewable Integration RIT-T

In Victoria, an unprecedented level of renewable generation development is already leading to issues such as constraints on generation output (due to both thermal and stability limitations), diminishing system strength, and diminishing marginal loss factors. These factors are most prevalent in the North West of Victoria, with AEMO undertaking a RIT-T, *Western Victoria Renewable Integration*, to progress options to alleviate these issues. AEMO published the Project Assessment Conclusions Report in July 2019, which recommends a combination of minor upgrades and two major new transmission developments, all in the western half of Victoria, by 2025.[21]

Marinus Link proposes to connect into the Latrobe Valley, so the proposed transmission upgrades in Western Victoria will not have a direct impact on Marinus Link and supporting transmission. Our market modelling indicates that these upgrades will relieve constraints on Victorian renewable generation and, therefore, complement the benefits provided by Marinus Link and supporting transmission.

2.7.2 Victoria to New South Wales interconnection

The 2018 ISP identified the need for immediate augmentation of the existing Victoria to New South Wales interconnector to increase its transfer capacity. AEMO and Transgrid have since initiated a RIT-T for a Victoria to New South Wales Interconnector Upgrade Project. The *PADR* for this project was published in August 2019, proposing a suite of relatively low cost augmentations which collectively deliver an increase in northwards flow capacity of 170 MW.[22]

KerangLink is a new proposed high-capacity interconnector between Victoria and New South Wales. It was proposed in the 2018 ISP as a means to provide a high capacity flow path between Melbourne and the New South Wales Snowy Mountains area.[23] The link would have northwards transfer capability of 2100 MW and southwards transfer capability of 1800 MW. A RIT-T for KerangLink is yet to commence.

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21 AEMO, *Western Victoria Renewable Integration Project Assessment Conclusions Report*, July 2019.

22 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade – Project Assessment Draft Report*, August 2019.

23 KerangLink was called Snowy Link South in the 2018 ISP.

In AEMO's Insights Paper,[24] the optimal timing of KerangLink coincides with the retirement of Yallourn Power Station. The paper concludes that earlier construction of KerangLink should be pursued as a 'least regrets' strategy, if Yallourn is expected to have more than a 20 per cent chance of early closure. Section 6.5 of this *PADR* discusses the synergy between KerangLink and Marinus Link. In the 'Status quo/current policy' scenario, it is assumed that KerangLink will be available at the time the second Yallourn generating unit is decommissioned.

2.7.3 Victorian reactive power support

The 2019 Victorian Annual Planning Report notes that voltage control issues are becoming more problematic in Victoria due to the increased prevalence of distributed solar generation leading to daytime low load (and high voltage) conditions combined with renewable generation development occurring in weak parts of the network. A RIT-T is in progress to examine remedial options, with the *PADR* recommending a combination of shunt reactors and a synchronous condenser across three different terminal stations as the preferred option.[25] The proposed project deals predominantly with voltage control West of central Melbourne and Marinus Link will have little bearing on these immediate issues.

The 2019 Victorian Annual Planning Report also noted the likelihood of voltage control issues arising in the future as Latrobe Valley coal power stations retire. It explained that a HVDC converter located in the Latrobe Valley would be unlikely to be capable of providing the same amount of reactive power capability as existing synchronous generators in the area and further network investment may be required to ensure sufficient reactive absorption and injection capabilities are available.

2.7.4 Victorian coal closures

The 2019 Victorian Annual Planning Report examined the impact of retirement of Victorian coal generators on the use and need for augmentation of the transmission network. The results were inconclusive, noting the outcome would differ, depending on whether the Latrobe Valley 500 kV and 220 kV networks are operated in parallel or radially at times of peak demand and the injection point of future generation sources.

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[24] AEMO, *Building Power System Resilience with Pumped Hydro Energy Storage*, July 2019.

[25] AEMO, *Victorian Reactive Power Support Regulatory Investment Test for Transmission Project Assessment Draft Report*, June 2019.

2.8 AEMC's Coordination of Generation and Transmission Investment review

The AEMC published its final report on its Coordination of Generation and Transmission Investment (**CoGaTI**) review in December 2018. The review was initiated in response to a request by the COAG Energy Council. The AEMC's final report has been followed by a further consultation paper which was published on 1 March 2019.

In its consultation paper, the AEMC explains that, under the current access regime, there are limited congestion related locational signals for generators, and increasing congestion in the network is resulting in unpredictable and volatile market outcomes.[26] In addition, there is a significant amount of generation capacity that is seeking to connect to the network in areas where there is limited or no available transmission capacity. The AEMC concludes that this lack of coordination is increasing costs in the sector.

The AEMC's consultation paper proposes the introduction of dynamic regional prices to reduce disorderly bidding and changes to the access arrangements to enable generators to fund transmission infrastructure in exchange for firm transmission rights. These proposed changes are intended to improve the coordination of transmission and generation investment by ensuring that all parties face appropriate price signals and customers obtain the services that they want at minimum efficient cost.

The AEMC also identified inter-regional transmission pricing as an issue that needs to be reviewed, as the current arrangements have been criticised for not giving effect to the 'beneficiary pays' principle. The AEMC's timeline for addressing this issue has since been superseded by the COAG Energy Council's request that the ESB prepare advice on a fair interconnector cost allocation methodology. [27]

As explained in Chapter 5, our modelling approach is to select transmission and generation options that meet customers' energy requirements at minimum cost. As such, the model outcomes are consistent with the objectives of the AEMC's proposed CoGaTI reform. Therefore, for the purpose of this *PADR*, it is not necessary to adopt any particular assumptions or conduct sensitivity analysis to test the implications of the AEMC's reform program.

In relation to inter-regional transmission pricing, the ESB's reform program is of particular interest to Marinus Link and supporting transmission, especially given the potential misalignment between those customers who

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26 AEMC, Consultation Paper, *CoGaTI Implementation – Access and Charging*, 1 March 2019, p. i.

27 CoAG Energy Council Secretariat, *COAG Energy Council Meeting Communique*, 22 November 2019.

would pay for Marinus Link and supporting transmission, and those customers who would benefit. We discuss this issue further in Chapter 7 of this *PADR*.

2.9 Post-2025 market review

The COAG Energy Council has asked the ESB to provide advice on a long-term, fit-for-purpose, market framework to support reliability that could apply from the mid-2020s.

By the end of 2020, the ESB is required to recommend any changes to the existing market design or recommend an alternative market design to enable the provision of the full range of services needed to deliver a secure, reliable, and lower emissions electricity system at least cost. The COAG Energy Council has also noted that:

- Any changes to the existing design or a recommendation to adopt a new market design would need to satisfy the National Electricity Objective; and
- Any significant changes to the electricity market design would need to be well considered and telegraphed well in advance of any change, to ensure there is minimal disruption to the forward contract markets for electricity.

Similar to the AEMC's CoGaTI reform program, we recognise that this reform program may have important implications for the future development of transmission and generation, and therefore, indirectly, the future market benefits provided by Marinus Link and supporting transmission. However, at this stage, it is not possible to assess what the reforms may be or their potential impact.

TasNetworks will therefore maintain a watching brief without making any particular assumptions or undertaking specific sensitivity analysis in relation to this potential reform. Our market modelling seeks to minimise the total system costs of meeting customers' demand for electricity. In this regard, we expect the objective of any market reform to be aligned with our modelling approach.

2.10 AER's RIT-T Guidelines

In December 2018, the AER updated its RIT-T Guidelines to include the following changes:[28]

- Introducing a section that links the purpose of the RIT-T to promoting the National Electricity Objective to help proponents apply the RIT-T more effectively;
- Further guidance on stakeholder consultation, with a stronger emphasis on transparency and engaging with stakeholders consistently throughout and before the RIT-T application process;
- Introducing guidance on how network businesses should apply information in AEMO's ISP in their RIT-Ts. Specifically, the RIT-T Guidelines now explain how the ISP should inform input assumptions used in the RIT-Ts. The RIT-T Guidelines also explain that RIT-T proponents should refer to the ISP to better understand the inter-regional impacts of their proposed investments, including how different investments in the NEM will affect each other;
- Introducing guidance on how to account for external capital contributions. The RIT-T Guidelines now set out how external contributions should be treated in the RIT-T market-wide cost-benefit analysis;
- Expanding the RIT-T Guidance on framing the identified need to emphasise that this should be framed as a proposal to consumers and as an objective rather than as a means to achieve an objective;
- Introducing guidance on how RIT-T proponents can capture the effects of high impact, low probability events in their RIT-T cost-benefit analysis; and
- Clarifying and expanding on the guidance previously provided on option value, scenario analysis, sensitivity analysis, and the treatment of external policies.

TasNetworks has applied the AER's new RIT-T guidelines in this *PADR*.

28 The matters listed here are those that are most relevant to this *PADR*. For full details of the changes, please refer to the AER's website.

3 Submissions and feedback received

As already noted, TasNetworks published the *PSCR* for Marinus Link in July 2018, which is the first step in the RIT-T process. Clause 5.16.4(k) of the NER requires the *PADR* to include a summary of, and commentary on, stakeholder submissions in response to the *PSCR*. In addition to meeting this requirement, this chapter discusses the submissions that we received in response to the *Initial Feasibility Report* and how the matters raised in those submissions have also been addressed in preparing this *PADR*.

Key messages

- Stakeholders have raised a wide range of issues in their submissions to the *PSCR* and the *Initial Feasibility Report*.
- Not surprisingly, stakeholders expressed different views on the likely benefits of Marinus Link and supporting transmission and the extent to which these benefits can or cannot be achieved by competing generation, storage, and transmission investments. Rather than addressing these different views, TasNetworks' approach is to rely on independent market modelling, conducted by Ernst & Young, to determine whether there is an economic case for Marinus Link.
- Stakeholders sought clarification on the costs of Marinus Link and whether it should include supporting network augmentations. TasNetworks can confirm that supporting network augmentation costs are included in the economic cost-benefit analysis presented in this *PADR*.
- A significant number of comments were made regarding our investment appraisal and modelling approach. To address these comments, we have provided extensive detail in this *PADR* on our modelling approach, including our input assumptions and scenarios. This transparent approach should provide stakeholders with confidence in our economic cost-benefit analysis and enables them to raise any specific concerns.
- Stakeholders have expressed concerns regarding 'who pays' for Marinus Link. We agree with stakeholders that the costs of Marinus Link and supporting transmission should be recovered from its beneficiaries. This issue is discussed in further detail in Chapter 7.

3.1 Feedback on PSCR

TasNetworks received 15 submissions on the *PSCR* from the following companies and organisations:

- AusNet Services
- Clean Energy Council
- COTA Tasmania
- Energy Australia
- Energy Consumers Australia
- Energy Users Association of Australia
- Hydro Tasmania
- Meridian Energy Australia
- Northern Tasmanian Development Corporation
- Origin Energy
- Roger Martin
- Snowy Hydro
- Tasmanian Small Business Council
- Tasmanian Renewable Energy Alliance
- UPC Renewables

A full summary of each submission is provided in Appendix 1. A number of submissions commented positively on the consultative and transparent approach that we are adopting in relation to Marinus Link and supporting transmission. We welcome this feedback and reiterate our strong commitment to consult with stakeholders and communities in relation to this project.

Table 1 below provides an overview of the feedback that is most relevant to the completion of the *PADR*. Respondents' comments are grouped together under key theme headings.

Table 1 Overview of feedback on PSCR

Key theme	Comments
Integrated System Plan	• Stakeholders will want to understand the reasons for any differences in the *PADR's* assumptions and conclusions compared to the 2018 ISP. (AusNet Services, Energy Australia, Origin Energy, Tasmanian Small Business Council)
Basslink's Performance	• There should be a full analysis of Basslink's operation to gauge whether a second interconnector is justified. (COTA Tasmania) • A single interconnection between Victoria and Tasmania through Basslink has created energy security issues in peak periods. A mix of new generation technologies and redundancy across the regions is part of the solution for the system of the future. (Meridian)
Potential benefits of Marinus Link	• Marinus Link offers unique interconnection benefits as a result of different demand patterns, generation assets, and potential storage solutions across regions. (Clean Energy Council, Hydro Tasmania, Meridian, UPC Renewables) • The benefits sought for Tasmania (reduced costs and increased energy security) could potentially be met through non-network solutions, or less ambitious augmentations. (Tasmanian Renewable Energy Alliance, Origin Energy, Tasmanian Small Business Council) • The *PSCR* identifies energy security for Victoria as a potential benefit but it is questionable whether a project of this magnitude is the best way of addressing this requirement. (Energy Australia) • Network resilience is a potential benefit from the second interconnector that may be worth considering, although it is difficult to quantify. (AusNet Services). • Tasmania is not unique in being able to provide storage, with Snowy 2.0 and utility scale batteries, for example, also in a position to do so. Moreover, Tasmania's hydro assets and transmission will require significant investment to offer expanded services. (Roger Martin, Tasmanian Small Business Council) • Export of Tasmanian renewable energy to the mainland NEM could contribute to emissions reductions in the NEM. This could be a significant benefit. (Tasmanian Renewable Energy Alliance) • Thermal generation sources are becoming increasingly unreliable. A more interconnected NEM can offer system resilience. (Clean Energy Council) • Increased interconnection would facilitate competition benefits. (Clean Energy Council, Hydro Tasmania) • Marinus Link will address Victoria's forecast supply adequacy concerns and provide fast-ramping capacity in response to the rapid decline in solar output in the evening. (Hydro Tasmania) • HVDC can provide fast frequency response and black start capability, as well as independent active and reactive power control. (Hydro Tasmania)
Project costs	• The *PADR* should clearly outline any expected capital costs across regions and the likely impact and/or benefit to consumers in each region. (Energy Australia) • The new cost estimates are between \$300 million-\$800 million higher than the Tamblyn report. An unrealistically high estimate of cost will undermine the cost-benefit analysis. A more detailed reconciliation of costs compared to the Tamblyn report is required. (UPC Renewables)

Key theme	Comments
Investment assessment and modelling	• TasNetworks should detail the costs and benefits to Tasmanian customers in the short- and long-term, showing the impact on electricity bills. (COTA Tasmania, Energy Consumers Australia, Tasmanian Small Business Council) • The project should not proceed unless it delivers lower electricity prices for consumers. Affordability must be a constraint on investment decisions. (COTA Tasmania, Energy Consumers Australia) • TasNetworks' examination of two options is too narrow for such a large project. There are other options that should be more thoroughly examined, such as a smaller link (perhaps with option value), use of the Basslink corridor, and use of alternative converter technology. (Tasmanian Small Business Council) • The assessment of this RIT-T should explicitly examine the costs and benefits of Marinus Link and the Battery of the Nation project. (Origin Energy, Tasmanian Small Business Council) • The rapid deployment of new technologies such as grid and decentralised battery storage and demand management could meet the need to match energy supply and demand faster than can large-scale projects such as pumped hydro. This undercuts the business case for investments such as Marinus Link. (Tasmanian Renewable Energy Alliance, Roger Martin) • TasNetworks should rely on the central assumptions and scenarios developed by AEMO for the ISP where possible. (Snowy Hydro, Tasmanian Small Business Council) • A "hydrogen scenario" should be modelled to determine whether Tasmania's hydrogen options should be pursued in parallel with the Battery of the Nation project. (Northern Tasmanian Development Corporation) • TasNetworks should provide clear and transparent information around any assumptions of new generation capacity. TasNetworks should also provide sufficient robust, transparent, and realistic modelling of market benefits, capturing all potential sensitivities and future scenarios. (Energy Australia) • Modelling should clearly address assumptions and methodology around how the lifting of water level restrictions is modelled. The treatment of high impact, low probability, events should also be modelled transparently. (Energy Australia) • Modelling should consider the economics of all resources across regions, noting that Victoria has interconnection with South Australia and New South Wales, and the ISP recommends immediate upgrades between Victoria and New South Wales. The estimated length of time to complete this project could potentially see several other ISP projects initiated and completed in that time. (Meridian, Energy Consumers Australia, Tasmanian Small Business Council) • Modelling should test assumptions around coal closure, noting that the United States of America has assumed a much shorter lifespan for coal generation (up to ten years). (UPC Renewables) • 'Round trip' network losses and 'round-trip' efficiency of storage need to be modelled carefully in assessing the potential benefit of energy arbitrage activities where Tasmania stores excess energy from the mainland. (Energy Australia, Roger Martin)

Key theme	Comments
Project funding and cost recovery	• Tasmanian electricity consumers should not carry the cost and risk of a development that benefits a range of parties, including wind farm developers. (EUAA, Tasmanian Renewable Energy Alliance, Energy Consumers Australia, Tasmanian Small Business Council) • There is little comment in the *PSCR* on who would pay the network charges for Marinus Link. In our view, they should be allocated according to who benefits, including renewable energy owners, consumers in Tasmania and consumers in Victoria. (Tasmanian Small Business Council) • The costs of Marinus Link may fall to Tasmanian customers, which would not be fair. (COTA Tasmania, EUAA Tasmanian Renewable Energy Alliance, Energy Consumers Australia) • TasNetworks should consider alternative funding models that reflect the important strategic drivers for this project, including Government funding (Energy Consumers Australia, EUAA) • If additional interconnection was to be funded outside the RIT-T framework we would be concerned that this may have a negative distortionary impact on the market. (Energy Australia) • It is possible that the Battery of the Nation Project could fund the costs of a new interconnector, avoiding cost recovery through a RIT-T process. (Meridian)

3.2 Feedback on the Initial Feasibility Report

Whilst the *Initial Feasibility Report* is not a formal element of the RIT-T process, it is important to recognise the submissions made and explain how we have taken them into account in preparing this *PADR*.

In response to the *Initial Feasibility Report*, TasNetworks received ten submissions from the following companies and organisations:

- Aurora Energy
- Clean Energy Council
- Clean Energy Regulator
- Energy Users Association of Australia
- Epuron
- Hydro Tasmania
- Latrobe City Council
- Meridian Energy Australia
- Origin Energy
- UPC Renewables

Table 2 below provides an overview of the feedback, grouped together under the same themes as the *PSCR* feedback in Table 1, if applicable.

Table 2 Overview of feedback on the Initial Feasibility Report

Key theme	Comments
Potential benefits of Marinus Link	• We can see the potential for Marinus Link to deliver long-term, NEM-wide, benefits. (Clean Energy Council; Energy Users Association of Australia; Epuron; Hydro Tasmania; Meridian Energy Australia; UPC Renewables) • Strengthened interconnection between regions can ensure efficient use and development of diverse regional resources, including Tasmania's storage opportunities and flexible generation (Clean Energy Council; Epuron; Hydro Tasmania) • The potential benefits of a 1200 MW link should be explored in more detail. (Epuron, Hydro Tasmania) • Given the long lead times for significant transmission augmentations, it is important to recognise the benefit of bringing the project forward. (Clean Energy Council, Hydro Tasmania)
Project costs	• The costs of the network upgrades should be included in the costs of Marinus Link. (Aurora Energy, Origin)
Investment assessment and modelling	• It is important to consider the other ISP projects that may proceed and the extent to which they affect the viability of Marinus Link. (Clean Energy Council, Meridian Energy Australia) • Coal plant closure will have a significant impact on the economics of the project and should be subject to more detailed scenario analysis (Clean Energy Council; Hydro Tasmania, Meridian Energy Australia) • It is important to ensure that the modelling assumptions, particularly in relation to wind generation, are up to date and recognise regional differences. (Epuron, Hydro Tasmania, UPC Renewables) • New Tasmanian wind farms benefit from a high capacity factor (~50-55 per cent), low curtailment (up to 5 per cent in mainland states), and strong MLF (likely 5-15 per cent higher than mainland states). (Epuron, UPC Renewables) • The location of the link needs to be carefully considered as it will affect the cost-benefit assessment. (Epuron, Hydro Tasmania)
Project funding and pricing arrangements	• The transmission pricing arrangements should ensure that those who benefit from the project pay for it. (Aurora Energy, Clean Energy Council, Energy Users Association of Australia, Meridian Energy Australia) • The Tasmanian Government's position that the project will not proceed unless costs can be allocated to the beneficiaries is supported. (Aurora Energy, Hydro Tasmania)

3.3 Key messages and our response

We welcome the significant level of engagement from stakeholders and the positive feedback received in relation to the *PSCR* and the *Initial Feasibility Report*. This section draws out the key messages from stakeholders' feedback and provides a high-level summary of how we are responding in this *PADR*:

3.3.1 Integrated System Plan

In response to the *PSCR*, a number of stakeholders commented that the analysis presented in this *PADR* should be consistent with AEMO's 2018 ISP, with any differences explained. In response to stakeholders' feedback, Chapter 5 explains any differences between our modelling input, assumptions, and scenarios, and AEMO's ISP.

As explained in section 2.4, it is important to recognise that AEMO is continuing to refine its ISP analysis in response to new information in a rapidly evolving environment, and we are endeavouring to ensure our modelling assumptions consider AEMO's latest assumptions. Similarly, we must also adopt the best available data and assumptions, especially where stakeholders have asked us to consider a specific issue that is of particular relevance to Marinus Link.

From a pragmatic perspective, the time requirement to undertake complex electricity market expansion modelling (which amounts to many months) means it is possible that AEMO's modelling data could be updated between the commencement of modelling and its completion. Indeed this has happened in this *PADR's* modelling: our modelling was based on AEMO's February 2019 data, but AEMO published updated data in September 2019 as our modelling was approaching completion.

AEMO continues to progress its analysis to support draft and final 2019-20 ISPs, presently expected to be released in December 2019 and March 2020. AEMO's draft ISP may suggest some differences in timing for Marinus Link and supporting transmission – potentially both earlier and later timings under different scenarios and with some different modelling inputs. TasNetworks will continue to work with AEMO as the ISP and RIT-T processes continue.

3.3.2 Basslink performance

In response to the *PSCR*, a number of stakeholders highlighted Basslink's performance as a relevant matter in the modelling analysis. We agree with these submissions and note that Basslink's remaining life is also relevant to market benefit analysis.

3.3.3 Potential benefits of Marinus Link

In response to the *PSCR* and the *Initial Feasibility Report*, stakeholders have made a wide range of comments regarding the potential benefits of Marinus Link and the extent to which these benefits may or may not be delivered through alternative means, such as storage, other interconnectors, or generation. A range of different views have been expressed, with some supporting Marinus Link as being able to provide benefits as a result of its particular circumstances, whilst other stakeholders cast doubt on whether Marinus Link is the most efficient solution. Other submissions have argued that 1200 MW capacity is preferred and that there may be benefits in bringing the project forward.

In response to the observations made by stakeholders, TasNetworks has approached the project assessment without any preconceived view as to whether Marinus Link and supporting transmission are better able or less able to provide benefits than other alternative solutions, or whether a particular interconnector capacity or location should be preferred. Instead, our approach is to rely on transmission network simulations and market modelling to identify the option that maximises net market benefits, in accordance with the NER. By applying an objective approach throughout the RIT-T process, all alternatives will be assessed on equal terms without favouring one solution over another.

3.3.4 Project costs

In response to the *PSCR*, stakeholders emphasised the importance of accurate project costs, including a reconciliation to the cost projections in the Tamblyn report.[29] In addition, two submissions to the *Initial Feasibility Report* commented that the cost of network upgrades should be included in the costs of Marinus Link.

We agree with the submissions made in relation to the importance of properly scoped project costs, which should include the costs of network upgrades that are required to facilitate the proposed transfer capability. Appendix 2 of this *PADR* provides details of the project costs for each credible option, which are inclusive of the required network augmentations to support power flows across Marinus Link.

In relation to the cost reconciliation with the Tamblyn report, it must be recognised that the Tamblyn report only presented indicative cost estimates, which reflected the scope and timing of that report. In contrast, the cost estimates in this *PADR* are more fully developed, including the additional AC transmission network upgrades that would be required to support the increased power flows, a longer direct current (**DC**) cable route than assumed in the Tamblyn report, and financing and project development costs which were excluded from the estimates in the Tamblyn report.

3.3.5 Investment assessment and modelling

In response to the *PSCR* and the *Initial Feasibility Report*, stakeholders provided a wide range of feedback on the modelling approach and input assumptions. The central messages in these submissions is that TasNetworks' modelling should:

[29] Dr John Tamblyn, *Feasibility of a second Tasmanian interconnector*, April 2017

- Be transparent;
- Adopt reasonable input assumptions;
- Recognise regional differences in wind generation performance;
- Avoid an overly narrow approach; and
- Test outcomes through suitably wide sensitivity analysis.

TasNetworks agrees that transparent and robust modelling is central to an appropriate evaluation of Marinus Link and supporting transmission. As already noted, Chapter 5 sets out our modelling approach, inputs, assumptions, scenarios, and sensitivity analysis. In addition, further detailed information on our modelling approach is provided in Attachment 1.

3.3.6 Project funding and cost recovery

The central theme in stakeholder submissions to both the *PSCR* and the *Initial Feasibility Report* is that Tasmanian customers should not bear a disproportionate share of the project costs, and alternative funding models should be considered to avoid this outcome. TasNetworks agrees with these submissions and we provide an explanation of how we are addressing this issue in Chapter 7.

4 Description of the credible options

This chapter explains the 'Identified Need' that Marinus Link and supporting transmission are intended to address, and describes each of the credible options. We also explain the base case against which the credible options are tested. The technical challenges associated with the power system are also discussed.

Key messages

- The 'Identified Need' complies with the AER's RIT-T Guidelines and is unchanged from the description we provided in the *PSCR*.
- In accordance with the RIT-T, the credible options for Marinus Link and supporting transmission are assessed against a base case. Under the base case, the lowest cost combination of generation, demand-side response, and storage options across the NEM is selected, assuming Marinus Link and supporting transmission do not proceed. The base case includes Snowy 2.0 and interconnector options proposed in the 2018 ISP. The base case therefore includes alternative interconnector augmentations and non-network solutions.
- The credible options outlined in the *PSCR* were HVDC links with capacity increments of approximately 600 MW, which meant options comprising either a 600 MW or 1200 MW Marinus Link, with staging options. In this *PADR*, we have extended the analysis to include 750 MW increments of capacity (i.e. a 750 MW or 1500 MW Marinus Link). Capacity increments of less than 600 MW are not economically feasible.
- The route selection has been refined from the options identified in the *PSCR*, with a single preferred route for the HVDC transmission now selected between Burnie in Tasmania and the Latrobe Valley in Victoria.
- Our power system analysis indicates that the credible options are technically feasible.

4.1 Identified need

The RIT-T requires that we should consider all 'credible options' that would meet the 'identified need'. In the *PSCR*, the identified need was described as follows:

> "The characteristics of customer demand, generation, and storage resources vary significantly between Tasmania and the rest of the NEM. Increased interconnection capacity between Tasmania and the other NEM regions has the potential to realise a net economic benefit by capitalising on this diversity."

We did not receive any specific feedback from stakeholders in relation to the proposed wording of the Identified Need in the *PSCR*. However, as noted in section 2.10 of this *PADR*, the AER updated its RIT-T Guidelines to include further clarification on how an 'Identified Need' should be framed. In particular, the AER commented as follows[30]:

> "In all cases, it is essential that RIT–T proponents express identified needs as the achievement of an objective or end, and not simply the means to achieve the objective or end. This objective should be expressed as a proposal to electricity consumers and be clearly stated and defined in RIT–T reports, as opposed to being implicit. Framing the identified need as a proposal to consumers should assist the RIT–T proponent in demonstrating why the benefits to consumers outweigh the costs. That is, the RIT–T proponent should articulate its investment objective to increase consumer and producer surplus in the NEM or undertake reliability corrective action as an objective to deliver a benefit or benefits to electricity consumers.
>
> […]
>
> Framing an identified need as an objective more broadly, rather than a means to achieve an objective, should prevent biasing the development of credible options towards a particular solution."

TasNetworks notes that the 'Identified Need' as outlined in the *PSCR* is appropriately focused on the objective of realising a net economic benefit for consumers, as required by the AER's RIT-T Guidelines. As explained in the 'Identified Need', this may be achieved by increasing interconnector capacity to capitalise on the diversity in customer demand, generation, and storage resources in Tasmania and the rest of the NEM.

Whilst this *PADR* is focused on whether additional interconnector capacity between Tasmania and Victoria is warranted to increase net market benefits, our modelling approach considers alternative solutions. As such, the RIT-T analysis presented in this *PADR* is not biased towards a particular solution, but instead considers all available investment and operating expenditure options. This point is best illustrated by describing the base case against which the credible options must be assessed.

30 AER, *Application Guidelines, Regulatory Investment Test for Transmission*, December 2018, p. 15.

4.2 Base case

The AER's RIT-T Guidelines explains that:[31]

> "The base case is where the RIT–T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. 'BAU activities' are ongoing, economically prudent activities that occur in absence of a credible option being implemented."

Our market modelling examines the total integrated system costs of meeting customers' future electricity needs to 2050. Under the base case, the model selects the lowest cost combination of generation, storage, and demand-side response across the NEM, on the assumption that Marinus Link and supporting transmission do not proceed. Committed and anticipated generation and transmission projects are also included in the base case.

As such, a complete range of investments and operating expenditure options are considered in order to minimise the total costs in present value terms of meeting customers' future electricity requirements. This includes all combinations of generation, storage, and interconnection upgrades across the NEM and non-network solutions. The model also allows for unserved energy, if this results in a lower total cost.

As already noted, in order for Marinus Link and supporting transmission to proceed, it must achieve a lower cost solution in present value terms than the base case.

4.3 Credible options

We described two credible options in the *PSCR*:

- Option 1: A 600 MW monopole HVDC link, including associated AC transmission network augmentation and connection assets.
- Option 2: A 1200 MW bipole HVDC link, including associated AC transmission network augmentation and connection assets.

In our subsequent *Initial Feasibility Report*, we stated that a 1200 MW link would likely be delivered in two 600 MW stages and could comprise of either a single bipole link or two independent symmetrical monopole links. Subsequently, our further analysis found that 750 MW increments of capacity would also be feasible, and would provide higher power transfer capacity at a relatively small incremental cost. The consideration of other

[31] AER, *Application Guidelines, Regulatory Investment Test for Transmission*, December 2018, p. 21.

options also responds to some stakeholder feedback that the credible options should be broader than indicated in the *PSCR*.

Using monopole configuration, the 1200 MW option essentially comprises two independent 600 MW links. Similarly, a 1500 MW capacity Marinus Link could be implemented using two independent 750 MW links. We have therefore adopted four credible options:

A. 600 MW HVDC interconnector and associated AC network upgrades;

B. 750 MW HVDC interconnector and associated AC network upgrades;

C. 1200 MW HVDC interconnector, consisting of two 600 MW interconnectors, plus associated AC network upgrades;

D. 1500 MW HVDC interconnector, consisting of two 750 MW interconnectors, plus associated AC network upgrades.

In options **C** and **D**, further choice can be made in relation to the timing of the second interconnector, with the possibility of a staged construction. It is also equally possible to construct both stages together, although construction practicalities will mean the two links are still constructed independently and one would be available for service some months before the other.[32] Our analysis has considered the possibilities of both staged and simultaneous commissioning of the two links which would comprise options **C** and **D**.

[32] For example, the cable carrying capacity of the cable laying vessel, and the requirement to lay the cables of each link some distance apart (to enable independent cable repair in the event of damage to a cable) will mean the cables would be laid for one link first, then the other. It would not be possible to lay cables for both links simultaneously from one vessel.

Table 3 below provides a high-level description of each credible option. A description of our considerations in determining the required AC network augmentations is provided in Appendix 3.

Table 3 Outline of the credible options

Credible option	Main elements of this option
A. 600 MW interconnector	A 600 MW HVDC interconnector using voltage source converter technology and monopole configuration. Converter stations located in the Burnie area in Tasmania and the Hazelwood area in Victoria. HVDC transmission to use buried cable for the entire route. AC network augmentations in Tasmania comprise: • Construction of a new 220 kV switching station in the Burnie area adjacent to the converter station; • Construction of a new double-circuit 220 kV transmission line from Burnie to Sheffield and the decommissioning of the existing 220 kV single-circuit transmission line in this corridor; and • Construction of a new double-circuit 220 kV transmission line from Palmerston to Sheffield. No AC augmentations are required in Victoria as there is sufficient transmission capacity to accommodate power flows to or from the interconnector. Limited 500 kV connection assets are required to connect the HVDC converter station to Hazelwood Substation.
B. 750 MW interconnector	Like Option **A**, with converter stations and HVDC cable rated to 750 MW. AC network augmentations are identical to Option **A**.
C. 1200 MW interconnector	Like Option **A**, two parallel 600 MW HVDC interconnectors. AC network augmentations in Tasmania comprise: • Construction of new 220 kV switching stations in the Burnie area adjacent to the converter stations; • Construction of a new double-circuit 220 kV transmission line from Burnie to Sheffield and decommissioning of the existing 220 kV single-circuit transmission line in this corridor; • Establishment of a new 220 kV switching station at Staverton; • Construction of a new double-circuit 220 kV transmission lines from Staverton to Burnie via Hampshire; and • Construction of a new double-circuit 220 kV transmission line from Palmerston to Sheffield. As noted for Option **A**, no AC augmentations are required in Victoria.
D. 1500 MW interconnector	Like Option **C**, with converter stations and HVDC cable rated to 750 MW. AC network augmentations are identical to Option **C**.

In the remainder of this chapter, we discuss the capacity size, location, and technology choices. In summary:

- We have identified the additional option of a 750 MW link capacity as being technically viable, with capital costs only marginally higher than a 600 MW link;
- We have not identified any option with a capacity below 600 MW which would offer a material reduction in capital cost from the 600 MW option;
- Monopole configuration is the preferred link configuration;
- Voltage source converter is the preferred converter technology;
- The choice of cable technology will be left open and resolved during the tender process;
- Our preferred route for the DC cable is from Burnie in Tasmania to the Latrobe Valley in Victoria;
- AC network augmentations back to Palmerston in Tasmania will be required to support power flows onto the DC link;
- In Victoria, the DC link will terminate near Hazelwood substation, minimising the AC network augmentations required.

4.4 Technical requirements of the power system

A credible option must be technically feasible, which means that it is capable of providing the services that the proponent intends it to provide and comply with relevant laws, regulations, and administrative requirements. This section therefore considers the technical requirements of the power system that would need to be addressed by each credible option.

4.4.1 Power flows on the AC network

The changing mix of generation in the NEM, driven by the growth in renewables and coal plant closures, will lead to substantial changes in power flows across transmission networks. TNSPs are already responding to these changes, as explained in section 2.7. The connection of Marinus Link must take account of these altered transmission network power flows so that the transfer capability can be delivered at the minimum investment cost.

The following developments are key drivers of the changing power system flows that must be considered in defining the credible options for Marinus Link:

In Victoria:

- The development of the Western Victoria Renewable Energy Zones;
- Snowy 2.0 and KerangLink; and
- The changes in flows on the Latrobe Valley to Greater Melbourne transmission corridor, as the Latrobe Valley generators retire and renewable energy developments in Eastern Victoria develop.

In Tasmania:

- Proposed generation developments in the North West and central highlands of Tasmania, which are being actively progressed;
- The potential for further renewable developments in these areas and the North East of Tasmania; and
- The Battery of the Nation proposal for pumped storage hydro developments in the North West and West Coast areas of Tasmania.

4.4.2 System strength

The displacement of traditional (synchronous) generation sources by inverter-based (non-synchronous) generation reduces power system strength. A lower power system strength has two main impacts. First, power system faults will have a more severe or more widespread impact, ultimately resulting in a higher chance of a blackout following a fault. Second, some types of generator technologies require a minimum system strength to operate. A lower system strength will therefore make it more difficult for such generators to be able to connect to the network.

Recognising the recent reduction in system strength, and the potential for further reductions in the future, the AEMC introduced a new Rule that requires TNSPs to maintain a certain level of system strength at certain nodes in the network.[33] The new Rule also places an obligation on new connecting generators to “do no harm” to the level of system strength required to maintain system security.

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[33] AEMC, *Managing Power System Fault Levels*, September 2017.

Therefore, Marinus Link must be capable of operation with the relevant minimum system strength limits specified for Victoria and Tasmania, and it must not degrade the level of system strength available to maintain system security. As explained in section 4.6, the converter technology chosen for Marinus Link is significantly more robust to low system strength than alternative converter technologies. In addition, if Marinus Link is able to contribute system strength, this will provide a secondary benefit to Victoria and/or Tasmania.

4.4.3 Maximum contingency size

A key factor in the capacity and configuration of the credible options is the size of the contingency presented by Marinus Link. Our *PSCR* and *Initial Feasibility Report* considered a maximum capacity of 600 MW, consistent with the largest contingency sizes in the South East of the NEM. More recent advice from AEMO through the joint planning process, is that a contingency size of up to 750 MW could be accommodated in Victoria, which reflects the maximum contingency on the mainland NEM, being 750 MW at Kogan Creek power station.

Power system studies have been conducted that show that it is feasible to develop a fast-acting system protection scheme that can support a 780 MW maximum contingency size in Tasmania (750 MW plus link losses). In addition, initial analysis suggests that it is also possible to build a backup protection scheme should the primary protection scheme fail.

4.4.4 Inertia

Power system inertia is the power system's innate ability to resist changes in frequency following changes in generation or load. Inertia is inherently provided by synchronous generating units, but the shift to a higher share of inverter-connected generation – which does not inherently provide inertia – has the potential to reduce the power system's inertia and thereby degrade power system security.[34]

[34] System frequency needs to be maintained within a prescribed tolerance level, and only have a certain rate of change, to support a secure power system. If inertia is too low for the change in generation or load, the resulting frequency change may seriously affect power system security.

In 2017, the AEMC introduced a Rule that requires TNSPs to maintain a certain level of inertia within their networks,[35] or to provide equivalent fast frequency response services.[36] Therefore, Marinus Link must be capable of operating with the levels of inertia present in both the Tasmanian and Victorian networks. As Tasmania's power system is small in comparison to the potential size of Marinus Link,[37] the following implications arise:

- Marinus Link must be capable of maintaining stable operation with the faster rates of change of frequency, which can potentially occur in a small power system; and
- Marinus Link's import capability may need to be constrained to ensure that minimum levels of inertia are maintained.

We have conducted power system studies to develop a constraint equation that limits the power transfer into Tasmania if there is insufficient inertia to maintain frequency within prescribed limits following a contingency event. This constraint has been incorporated into our market modelling. The market modelling therefore considers the reduction in Marinus Link's import capability that would be required to maintain sufficient inertia in the Tasmanian system.

4.5 Technical characteristics of credible options

This section discusses the primary technical characteristics of the credible options. It explains how these characteristics meet the technical requirements of the power system.

4.5.1 Link capacity

The interconnector capacity refers to the amount of power that an interconnector can transmit. The rated capacity is the amount of power that can be transmitted continuously. An interconnector may transmit higher power, but for short periods of time only. This capacity is referred to as the short-term rating.

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35 AEMC, *Managing the Rate of Change of Power System Frequency*, 2017.

36 As a HVDC link has no energy storage capability, fast frequency response (i.e. a rapid increase power injection) at one end of the link must be accompanied by an equivalent increase in power flow at the other end. The ability of an HVDC link to provide fast frequency response is therefore determined by both prevailing power system conditions as well as the design characteristics of the link.

37 Tasmanian median demand is approximately 1200 MW. Marinus Link options vary from 600 MW to 1500 MW.

In broad terms, the cost of providing interconnector capacity benefits from economies of scale. This means that additional capacity can be provided at a relatively small incremental cost. However, power system integration of an interconnector becomes more challenging with increasing capacity. As already noted, our view is that the maximum rated capacity of each a HVDC link is 750 MW,[38] reflecting the single largest mainland Australia contingency.

Our discussions with suppliers have not revealed any substantial reduction of costs for a pole size below 600 MW, and on this basis, we consider 600 MW to be the smallest credible option.

4.5.2 Route selection

The *PSCR* set out the short-listed route selection for a second interconnector, as set out in the Figure 3.

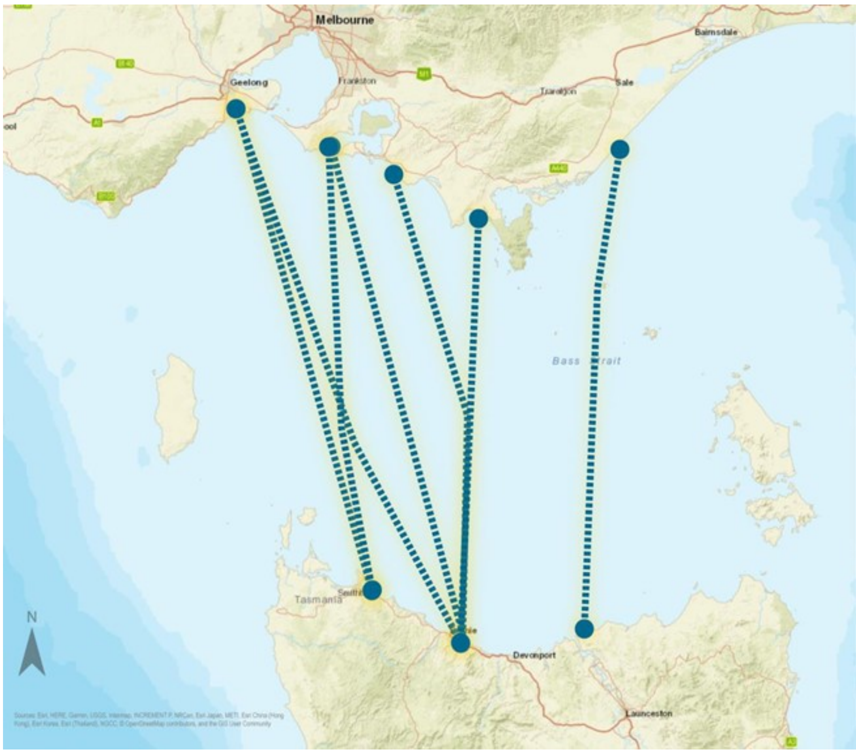

Figure 3 Short-listed route selections in the *PSCR*[39]

[38] For the purposes of this discussion, a 'link' refers to a single independently operable unit of an HVDC interconnector made up of two cables and an independent converter at each end.

[39] TasNetworks, *Project Marinus Project Specification Consultation Report*, July 2018, Figure 7.1, p. 41.

In the *PSCR*, we explained that each of these locations would have different implications for the transmission investment required in Tasmania and Victoria to support the increased transfer capacity. We noted that the choice of location depends on a range of factors, including environmental and land use planning considerations, and the cost and feasibility of each option from a power system integration perspective.

Following the publication of the *PSCR*, we undertook further work on the possible route selections, having particular regard to:

- Environmental, visual impact, and cultural heritage considerations;
- Land access;
- The ability of each transmission system to support energy flows from the new interconnector, as discussed in section 4.4.1; and
- The potential generation developments in Victoria and Tasmania, consistent with AEMO's REZs.

Sites in North West Tasmania, including in the Burnie and Sheffield areas, and in the Latrobe Valley area of Eastern Victoria were identified as favourable locations for new converter stations and connection to the transmission networks. This reflected technical analysis of the transmission network's ability to host an interconnector of 600 MW or 1200 MW and broader network planning and operation considerations.

Following the publication of the *PSCR*, the analysis described above led us to conclude that two HVDC transmission routes were most favourable: from Burnie (Tasmania) to the Latrobe Valley (Victoria), or Sheffield (Tasmania) to the Latrobe Valley.

Figure 4 Indicative routes in our Initial feasibility Report

Of these two options, we have now concluded that the preferred connection site in Tasmania is Burnie, as this option has lower cost than locating the converter station at Sheffield. In particular, locating the converter station at Sheffield would require the construction of overland DC transmission assets in Tasmania between the point of shore crossing and the Sheffield converter station. Such assets could only be used by Marinus Link. Locating the converter station at Burnie requires the augmentation of the AC network between Sheffield and Burnie, at a similar cost to the DC transmission infrastructure. The AC augmentation would become part of the shared network and provide additional benefits, by minimising the cost to connect future wind or solar generation from the North West Tasmanian REZ. We provide a detailed analysis of the AC transmission investment options in Appendix 3.

Within the Latrobe Valley, Hazelwood Substation has been identified as the preferred connection point for the Victorian converter station. This substation, and the transmission corridor to greater Melbourne, has sufficient capacity to host a 1500 MW converter station, following the closure of the 1600 MW Hazelwood power station.

Our preferred HVDC transmission route is therefore from Burnie in Tasmania to Hazelwood in Victoria. We have undertaken both land and marine initial surveys of the proposed route, and we have found no technical, environmental, or cultural heritage issues to indicate the route is not feasible.

4.6 Technology choices

This section explains the preferred technology for the credible options, including the consideration of high voltage alternating current (**HVAC**) versus HVDC technology, converter technology, and cable insulation technology.

4.6.1 HVAC vs HVDC interconnection

There are two ways to transfer electricity in a power system: high voltage alternating current (**HVAC**) or HVDC. Higher voltages reduce system losses, and power systems are generally alternating current due to its relative ease of voltage transformation and lower cost connections compared with DC.

However, over long distances, the efficiency of HVDC systems is higher than that of HVAC systems. This is particularly true where cable is used instead of overhead transmission lines. HVDC cables are lower cost than HVAC cables and do not require complex reactive power compensation. As Marinus Link would include approximately 350 km of subsea cable in crossing Bass Strait, and underground HVDC land-based cable in Tasmania and Victoria, the only feasible option for Marinus Link is a HVDC interconnector.

4.6.2 Converter technology

Converters transform electricity between the HVDC of the interconnector and the HVAC power systems at each end. There are two main HVDC converter technologies available in the market. These are the Line Commutated Converter (**LCC**) and the Voltage Source Converter (**VSC**).

LCC technology, commonly known as HVDC Classic, has been used in subsea interconnectors and long-distance high-power transmission for more than 50 years. It is the technology used on Basslink. VSC is a newer technology and has only been developed for power transfer capacity greater than 500 MW in recent years. VSC technology is becoming more prevalent due to better technical performance and greater operational flexibility than LCC technology, in particular:

- LCC requires a minimum system strength to operate, whereas VSC can be designed to operate with zero system strength; and
- The direction of power flow can be reversed with no interruption in a VSC link, whereas an LCC requires some time at zero power transfer during the reversal process. This has a consequential effect that an LCC link cannot offer frequency control ancillary services which would result in a change of direction of power flow.

Tasmania's current level of system strength makes it not feasible to host a second LCC interconnector of the magnitude proposed for Marinus Link. The system strength for the Latrobe Valley connection is forecast to be high until at least the 2040s. However, once the last of the existing coal-fired generators in the Latrobe Valley retires, it is possible that this area will also have low system strength.

VSC technology is proposed for Marinus Link, due to its ability to:

- Operate with lower system strength in Tasmania and a broader NEM future power system with increased inverter-connected renewable generation and less synchronous generation;
- Support continuous power flow during power flow reversals;
- Support continuous provision of frequency control ancillary services;
- Provide substantial reactive support under alternating current system contingencies; and
- Offer black start capability (the ability to re-start the power system after a blackout event).

4.6.3 Link configuration

There are three possible connection configurations for HVDC links:

- An *asymmetrical monopole* configuration requires one high voltage cable and one low voltage cable. For example, a 600 MW pole would require a voltage of about 500 kV. The two cables can be laid close together, thereby minimising the magnetic field in the vicinity of the cable.
- A *symmetric monopole* configuration requires two high voltage cables, although each cable operates at a lower voltage than in an asymmetrical monopole. For example, a 600 MW pole would require a voltage of about 320 kV. The two cables can be laid close together, thereby minimising the magnetic field in the vicinity of the cable.
- A *bipole* configuration is used for higher power transfer capacities. It utilises two converters at each end (e.g. two 600 MW converters for a 1200 MW link) but requires only three cables: two high voltage and one low voltage. For a 1200 MW link, each high voltage cable would operate at about 500 kV. It is usual practise to lay the high voltage cables with some separation, to avoid the possibility of a single event damaging all cables. This causes a higher magnetic field in the vicinity of the cable.

A bipole configuration is exposed to the possibility of a common mode failure causing the loss of both poles, thereby rendering the entire link inoperable. A fault which impacted upon both poles (improbable but conceivable) would exceed the maximum contingency size. As the maximum contingency size could be exceeded, we have excluded the possibility of a bipole configuration from further analysis.

The converter cost is similar regardless of whether the link is configured as a symmetrical or asymmetric monopole; any cost difference between the two configurations is predominantly a result of the amount of cable required and the cable technology available.

4.6.4 Cable technology

Two cable technologies are commonly used in HVDC applications; being mass-impregnated (i.e. oil impregnated) paper (**MI**) and cross-linked polyethylene (**XLPE**). Compared to MI cables, XLPE offers cost savings due to their higher operating temperature, simpler manufacturing process, and lower weight. Whilst HVDC extruded XLPE cables have been qualified at 500 kV, it is relatively new technology. MI is therefore typically used for higher voltage interconnection. XLPE cables are better suited to land-based applications because of lighter weight and easier handling and jointing.

The first 400 kV XLPE submarine cable entered service in late 2018. There is a large number of projects using 320 kV XLPE cables and operational experience is generally positive. Due to the technical risks involved, TasNetworks would only consider the use of XLPE cable at proven operating voltages, meaning a symmetrical monopole configuration could be used with XLPE cable for Marinus Link.

Although we currently anticipate using XLPE cable in symmetrical monopole configuration, this is on the basis of expected lower cable cost and delivery constraints. There is no technical reason to preclude the use of MI cable and asymmetrical monopole configuration. We are therefore leaving open the choice of cable technology, and by implication, the resulting choice of symmetric or asymmetrical monopole link configuration. At this stage, our project cost estimates are based on XLPE cables in symmetrical monopole configuration, as we expect this solution to be lower cost.

4.7 Costs of each option

Table 4 provides a summary of the estimated capital, operating, and annualised total costs of each credible option. These costs are central estimates for Marinus Link and the required AC network upgrades and exclude accuracy and contingency allowances.[40] Our cost estimates will be subject to change as further information becomes available through the tender process. Appendix 2 provides further detail on our cost estimation methodology, which is regarded as appropriate for this stage of the RIT-T process.

Table 4 Estimated costs of each option (in 2019 dollars) ($ million)

Marinus Link Option	600 MW	750 MW	1200 MW	1500 MW
Capital cost (DC)	1,312	1,403	2,184	2,344
Capital cost (AC)	239	237	419	418
Annual operating cost	15	16	23	24
Annualised total cost	110	116	182	193

In the case of 1200 MW and 1500 MW options, which are built in two stages, the annualised costs show that the additional capacity can be provided at a lower cost per MW. This outcome reflects the economies of scale associated with increased capacity, as explained earlier. Similarly, efficiencies are also achieved in managing Marinus Link as a single project commissioned in two stages, rather than as two separate projects. The cost savings will arise principally in relation to environmental planning, tendering, and project management.

Our market modelling assumes that the annualised costs are incurred from when the option is commissioned through to the end of the modelling period in 2050. Costs beyond 2050 are excluded from the analysis, on the basis that the associated benefits are also excluded.

An alternative modelling approach would be to extrapolate benefits to the end of the asset life. Our modelling indicates that annual benefits of Marinus Link and supporting transmission exceed annual costs during the

40 The estimates are presented on a P50 basis, which means that it is median cost estimate.

final years of the modelling period, hence this benefit extrapolation approach, if employed, would increase the net market benefit of the project.

4.8 Options considered but not assessed further

The *PSCR* raised the possibility of adding a second pole to Basslink, thereby converting it from a monopole to a bipole link. From an engineering perspective this would involve:

- Constructing a second HVDC converter at each end;
- Augmenting the overhead DC transmission sections to carry an additional conductor, adding a second high-voltage DC cable (in both the undersea and underground sections); and
- Augmenting the transmission network into George Town to increase its capacity.

After examining this option more closely, we have found that this option is infeasible on the following technical grounds:

- Due to system strength constraints, the second pole must use VSC technology. The existing Basslink converters use LCC technology. Adding a VSC second pole to an existing LCC link has only been done once (the Skagerrack 3/4 Norway to Denmark interconnector) and proved technically very challenging.
- Engaging HVDC equipment vendors to provide a bespoke solution, at a time when HVDC is in high demand globally, would likely prove very difficult and far more expensive than a greenfield 600 MW link.
- Increasing the capacity of Basslink to 1200 MW does not offer any route diversity. Therefore, a single event could render the entire 1200 MW interconnector inoperable.

In addition to these technical reasons, an agreement would need to be reached with Basslink's owners. Furthermore, regulatory issues, stemming from the fact Basslink Pty Ltd is a Market Network Service provider, would need to be resolved.

For these reasons, the option of adding a second pole to Basslink was not evaluated further.

5 Calculation of market benefits – approach, assumptions, scenarios and sensitivities

Key messages

- We have engaged Ernst & Young to conduct market modelling that captures the majority of the RIT-T benefits. A separate model has been developed by GHD to identify the cost savings in ancillary services.
- Ernst & Young's market expansion model includes a number of recent enhancements, which improve the quality of the analysis. Significant effort has been made to ensure that the data inputs and other model assumptions will provide an objective appraisal of Marinus Link and supporting transmission.
- Our approach is to adopt the best available data and assumptions, whilst recognising that new information continues to become available over time. The same observation applies to AEMO's scenarios, which have changed since our modelling commenced in February 2019. Nevertheless, our scenarios are closely aligned with AEMO's latest position.
- To augment our cost-benefit analysis, we have undertaken a range of sensitivity studies to understand the impact of key variables on market modelling results. This sensitivity analysis essentially provides a 'what if' analysis, which should provide stakeholders with confidence that the modelling results have been stress-tested appropriately.
- By engaging Ernst & Young and GHD to conduct the modelling on our behalf, stakeholders should be confident that the methodology is robust and independent. A key purpose of this chapter and the accompanying appendices is to ensure that our approach is transparent, thereby enabling stakeholders to provide feedback as part of the RIT-T process.

5.1 Overview of market benefits modelling

The RIT-T requires a number of different classes of market benefits to be considered:[41]

(a) Changes in fuel consumption arising through different patterns of generation dispatch;

(b) Changes in voluntary load curtailment;

[41] AER, *Final Regulatory Investment Test for Transmission*, June 2010, Clause (5).

(c) Changes in involuntary load shedding, with the market benefit to be considered using a reasonable forecast of the value of electricity to consumers;

(d) Changes in costs for parties, other than the transmission network service provider, due to:

(i) Differences in the timing of new plant;

(ii) Differences in capital costs; and

(iii) Differences in the operational and maintenance costs;

(e) Differences in the timing of transmission investment;

(f) Changes in network losses;

(g) Changes in ancillary services costs;

(h) Competition benefits being net changes in market benefit arising from the impact of the credible option on participant bidding behaviour;

(i) Any additional option value (meaning any option value that has not already been included in other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the market;

(j) Negative of any penalty paid or payable (meaning the penalty price multiplied by the shortfall) for not meeting the renewable energy target, grossed-up if not tax deductible to its value if it were deductible; and

(k) Other benefits that the TNSP determines to be relevant and are agreed to by the AER in writing before the *PSCR* is made available to other parties.

Our modelling has not assessed two categories of market benefits, competition benefits, and option value. As discussed in Chapter 6, all credible options for Marinus Link and supporting transmission have a positive net market benefit in all scenarios. The modelling of competition benefits would increase the net market benefits of all options and would not materially change the ranking of the credible options. We accept that Marinus Link and supporting transmission may deliver competition benefits, but given the substantial effort required to model competition benefits for no material change in outcome, we have elected not to undertake competition benefits modelling.

We have also elected not to model option value, as the only item in relation to option value we are able to identify relates to the timing of the second stage of Option **C** or Option **D**. Our modelling already considers the optimal timing of both stages of Option **D** (the ultimate preferred option) across all scenarios. We did not consider the effort to model option value associated with the second stage of Option **D**, under variants of these four scenarios, would deliver a materially different outcome.

The remaining benefits have been modelled using the assessment tools set out in Figure 5 below.

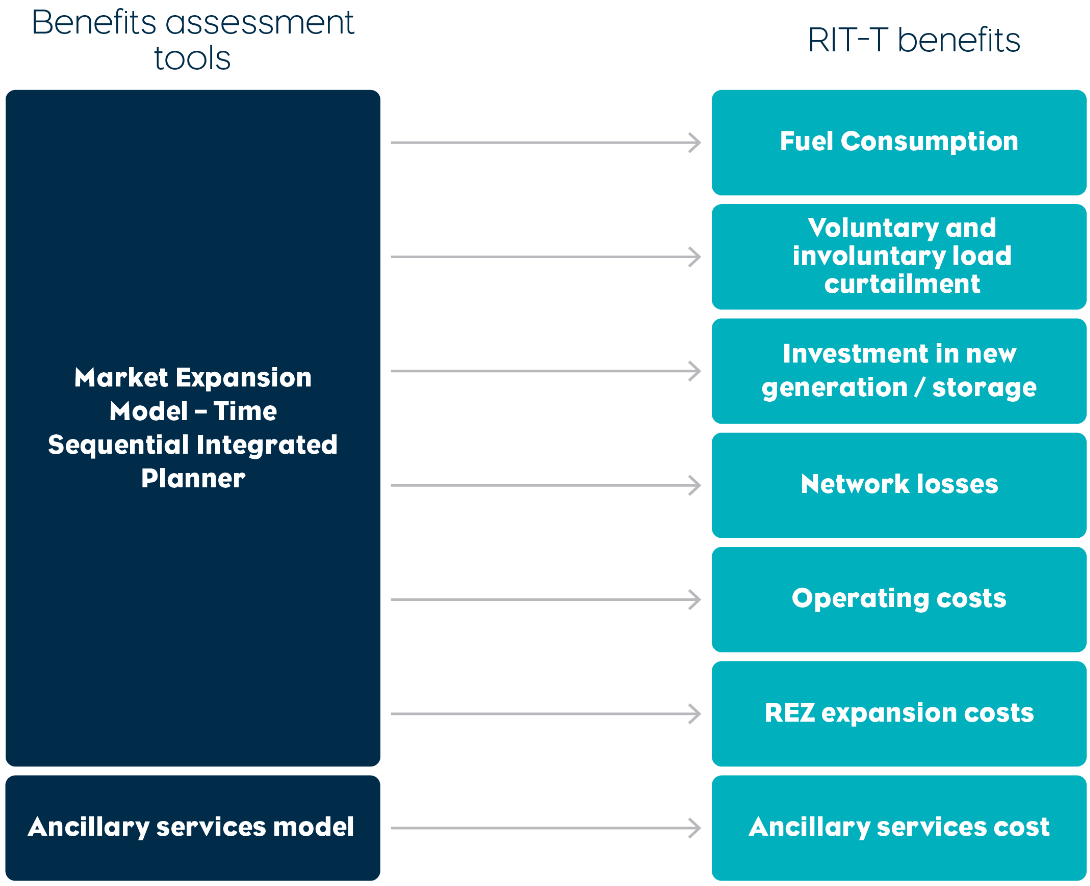

Figure 5 Our assessment tools for estimating the RIT-T benefits

In contrast to typical modelling approaches, which used a combination of wholesale market, long term planning and dispatch models, we engaged Ernst & Young to employ its market expansion model, which is named 'Time Sequential Integrated Resource Planner' (**TSIRP**).

Ernst & Young's market expansion model essentially adopts an integrated approach to capture the majority of the RIT-T benefits. This approach is more efficient and comprehensive from a modelling perspective, as it avoids the need to ensure consistency across three different models. It should also be noted that whilst Ernst & Young's model considers changes in network losses on interconnectors, it does not consider changes in intra-regional network losses.

Given the importance of the market expansion model, we provide a detailed description of the model, its data inputs and assumptions in section 5.2.

In relation to ancillary services modelling, we engaged GHD to undertake an independent assessment of the impact of Marinus Link and supporting transmission. Ancillary services perform an essential role of ensuring stable power system operation on a minute-to-minute basis, especially when subjected to unforeseen contingency events. While generators and other network devices directly provide ancillary services, interconnectors offer the ability to transfer some types of ancillary services between regions, thereby lowering the overall cost of ancillary services within the NEM. GHD's ancillary services benefits modelling methodology and results are presented in Attachment 2.

5.2 Market Expansion Model

5.2.1 Model description

The market expansion model takes the projected NEM demand over the study period as an input to determine the optimal generation and transmission interconnector investments to supply this demand, such that the overall cost of supply to the entire NEM is minimised. The optimal generation mix may consist of both existing generation and assumed new generation.[42]

Voluntary load reduction (i.e. demand-side participation) is also included in the model and will be applied when this results in a lower cost of supply. In addition to ensuring customer load is supplied, the model also applies simplified operational constraints to ensure there are sufficient reserves of dispatchable generation during high demand periods, and to ensure NEM inertia requirements are met.

Taking all these factors into account, the model will determine the most appropriate timing of new generation and energy storage investments, and the retirement of existing generation that reaches end-of-life or is uneconomic, across all NEM regions, to yield the overall least cost outcome over the entire study period. The model expresses the total cost of supply in present value terms.

For a particular scenario (discussed in section 5.3), the model is run multiple times: the first run is to determine the NEM-wide costs which would occur without Marinus Link, and then subsequent model runs are undertaken with alternative credible options in place. Each model run will optimise the generation and storage investments to minimise supply costs, i.e. the different projects will be identified assuming different capacities and timings for Marinus Link and supporting transmission. The difference in NEM-wide resource costs between these two states of the market represents the net market benefits resulting from that Marinus Link and supporting transmission option.

Further detail of the market expansion model can be found in Attachment 1.

42 New generation types include traditional generation technologies, as well as large-scale solar and wind generation, pumped hydro storage, and grid-scale batteries.

5.2.2 Recent model enhancements

In response to stakeholder feedback, the following enhancements have been made to the market expansion model since our *Initial Feasibility Report*:

- **Demand response**. Customer demand reduction during high price periods is now included in the model;
- **Transmission expansion costs**. Transmission costs associated with (i) augmenting a transmission network to form a REZ hub, and (ii) connection of generators to the REZ hub, are included. Different network expansion costs can be specified for simulations with and without proposed interconnectors. This has the practical effect, in relation to REZ-related transmission expansion, that the market benefit category *avoided costs of future network expansion* is largely captured by the market expansion model and does not need to be calculated separately. This revised approach to including such transmission costs aligns with the approach AEMO takes in its ISP modelling.
- **Improved hydro scheme modelling**. Working collaboratively with Hydro Tasmania, the modelling of Hydro Tasmania's power schemes has been modified to further improve the representation of water flow in the various hydro schemes. AEMO has made similar refinements to its ISP model.
- **Inclusion of operational reserves**. Operational reserves have been modelled during high demand periods, to reflect the fact that AEMO must ensure reserve dispatchable generating capacity is available to cover for a contingency event. We understand AEMO also incorporates operational reserve requirements in its ISP modelling.
- **Inclusion of inertia constraints**. Inertia constraints have been included, to ensure dispatch outcomes take account of the operational requirements relating to minimum inertia and rate of change of frequency following a contingency event. The inertia constraint will, in general, act to restrict Marinus Link power flow from Victoria to Tasmania to a lesser value than its maximum capacity.

5.2.3 Model input data

A number of stakeholders commented that our modelling should be consistent with AEMO's ISP, with any differences explained. We support stakeholders' views on this issue.

This *PADR* is based on AEMO's draft 2019 forecasting and planning data, *2019 Input and Assumptions Workbook* version 1.0, released on 5 February 2019.[43] With very few exceptions, these costs and data given in this spreadsheet are used as inputs for Marinus Link and supporting transmission modelling.

The nature of power system planning is that forecast data constantly evolves. In August 2019, with a subsequent update in September, AEMO issued a revised *2019 Input and Assumptions Workbook (version 1.1)* for the 2019-20 ISP. At this time, our modelling was nearing completion, and substantial delays would have been resulted if we had updated all input assumptions to match the latest dataset. We are working with AEMO to understand the impacts of differences between the February 2019 data set and AEMO's latest modelling data.

5.2.4 Hydro Tasmania's expansion projects

As mentioned in section 2.6 we have considered Hydro Tasmania's proposed capacity expansion projects discussed in its 2018 White Paper. Although these capacity expansions are not committed projects, they relate to the need to replace ageing turbine runners; expenditure which Hydro Tasmania will incur regardless of Marinus Link. Hydro Tasmania has advised that if Marinus Link does not proceed, it will undertake like-for-like turbine runner replacements. If Marinus Link does proceed, it will replace the existing turbine runners with runners of higher capacity, at essentially the same cost. This would result in 100 MW of additional generation capacity, at no incremental cost.

Hydro Tasmania presents an argument in the same paper that Tarraleah Power Station requires substantial remedial works and a viable option is to replace the station with one of substantially higher capacity (220 MW versus current 70 MW) at a similar cost to refurbishing the existing station.

Therefore, we have introduced changes to Hydro Tasmania's power schemes in our modelling, for simulations in which Marinus Link is implemented: West Coast power schemes' capacities are increased by a total of 100 MW; and the Upper Derwent scheme's capacity is increased by 150 MW. Simulations of the base case (i.e.

[43] AEMO's inputs, assumptions, and methodologies for planning and forecasting activities are available at: https://www.aemo.com.au/Electricity/National- Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies

Marinus Link does not proceed) assume existing capacities, on the basis that Hydro Tasmania has advised it would not proceed with capacity upgrades in the absence of Marinus Link.

Whilst these changes were not included in AEMO's *draft 2019 Input and Assumptions workbook*, AEMO advised earlier in the year that it intends to implement such changes in its Marinus Link scenarios.

Hydro Tasmania's White Paper also discusses 400 MW of latent existing hydro capacity and additional capacity that could be gained from Gordon Power Station by maintaining Lake Gordon at a higher storage level. These effects, which are simply representative of the existing hydro system, are already included in Ernst & Young's model.

5.2.5 Timing of other interconnector projects

We have assumed that a number of interconnector projects identified in the 2018 ISP will proceed, as set out in Table 5 below.

Table 5 Timing of 2018 ISP interconnector projects

Proposed upgrade	RIT-T status	Our modelling assumption
Vic-NSW	*PADR* published in August 2019	Treated as an anticipated project, assumed to be commissioned in 2022.
EnergyConnect	*PSCR* published in February 2019 indicating positive market benefits	Treated as an anticipated project, assumed to be commissioned in 2024.
HumeLink (formerly SnowyLink North)	*PSCR* in June 2019	Treated as an anticipated project, assumed to be commissioned in 2025.
QNI	*PSCR* published in November 2018	Treated as an anticipated project, assumed to be commissioned in 2024.

In addition to the Group 1 and 2 projects highlighted in the 2018 ISP, AEMO has indicated that the timing of KerangLink,[44] should occur sooner than the mid-2030s as indicated in its 2018 ISP. The cost of this

[44] AEMO, *Building Power System Resilience with Pumped Hydro Energy Storage*, July 2019.

interconnector augmentation option in AEMO's February 2019 assumptions workbook was estimated to be $1.55 billion. Our analysis has been based on this cost estimate, although we note that AEMO increased its cost estimate upwards in August 2019.[45]

AEMO's analysis indicates the optimal timing for KerangLink is 2030-31. However, using option value analysis in case of early Yallourn retirement, AEMO concluded that its timing could be advanced to 2026-27. Similarly, our analysis also indicated that KerangLink provides a positive net market benefit to the NEM in most scenarios, with its optimal commissioning date being 2030-31 under the Status quo/current policy scenario. We have used Ernst & Young's market model to determine the optimal commissioning of KerangLink under each scenario, as outlined in Table 6.

Table 6 Timing of KerangLink across scenarios

Interconnector option	Status quo / current policy	Global slowdown	Sustained renewables uptake	Accelerated transition to a low emissions future
VIC-NSW Option 7a KerangLink	2030-31	2032-33	2027-28	2029-30

5.2.6 Assessment period

The RIT-T analysis has been undertaken over a 30-year period, from financial years 2020-21 to 2049-50. We consider that this assessment period is consistent with the principles set out in section 3.12 of the RIT-T Application Guidelines, which state:

> "The duration of modelling periods should take into account the size, complexity, and expected life of the relevant credible option to provide a reasonable indication of the market benefits and costs of the credible option. This means that by the end of the modelling period, the network is in a 'similar state' in relation to needing to meet a similar identified need to where it is at the time of the investment.
>
> […] In the case of very long-lived and high-cost investments, it may be necessary to adopt a modelling period of 20 years or more."

It is noted that the credible options have asset lives that extend beyond the end of the assessment period. To ensure that the long-lived capital costs of these assets are captured appropriately in the 30-year assessment

45 This is not expected to change the conclusions.

period, the modelling employs annualised capital costs, calculated as annuities over the full expected life of the relevant assets.

5.2.7 Discount rate

In relation to the discount rate or cost of capital, paragraph 14 of the RIT–T specifies that:

> "The discount rate in the RIT–T must be appropriate for the analysis of a private enterprise investment in the electricity sector and must be consistent with the cash flows that the RIT–T proponent is discounting. The lower boundary should be the regulated cost of capital."

For the purpose of the analysis presented in this *PADR*, a central discount rate of 5.9 per cent real pre-tax has been adopted. This rate is consistent with the discount rate in the ENA handbook and was adopted as the commercial discount rate in a recent RIT-T application.[46] We have also applied sensitivity analysis to the discount rate, in accordance with the AER's RIT-T Guidelines.

5.3 Reasonable scenarios

The RIT-T states that the market benefit of a credible option is obtained by:

i. Comparing, for each relevant reasonable scenario, the state of the world with the credible option in place with the state of the world in the base case; and

ii. Weighting any positive or negative benefit derived in (i) by the probability of each relevant reasonable scenario occurring.

The RIT-T Application Guidelines further requires TNSPs to consider AEMO's ISP scenarios as a starting point, allowing deviations from the ISP scenarios with justification. In accordance with these requirements, we have adopted four scenarios, which are aligned closely to the scenarios outlined in the AEMO's ISP 2019:

- Global slowdown;
- Status quo/current policy;
- Sustained renewables uptake; and
- Accelerated Transition to a Low Emissions Future

[46] AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade, PADR*, August 2019.

At the time of finalising our scenario definitions, AEMO was consulting on its 2019 ISP scenarios. It is inevitable that new information will become available during a detailed cost-benefit analysis for a major transmission project, such as Marinus Link. Therefore, from a practical perspective, it is not possible to continually update forecasts and scenarios for the latest available information. However, such differences are unlikely to have material impact on the conclusions of the modelling exercise if the scenarios and sensitivity analysis have been properly designed.

Our approach has been to develop scenarios that capture the key variables that drive the optimal capacity and timing of Marinus Link and supporting transmission, which are:

- Load growth;
- Future gas prices; and
- The timing of coal plant closures.

Our focus on these variables has been informed by provisional modelling designed to identify the key drivers and ensure that the scenarios are appropriately designed. Having established appropriate scenarios, the task of sensitivity analysis is to test the robustness of our findings by examining the impact of particular events or variables. However, appropriately designed scenarios should already capture the principal variables that affect the investment decision.

We explain our scenarios below. Further detailed information in relation to the scenarios, including the treatment of ISP projects, is provided in Attachment 1.[47]

5.3.1 Status quo/current policy

The Status quo/current policy scenario represents the current median-projection NEM demand profile and a continuation of current policy. Under this scenario, the Mandatory Renewable Energy Target is included in its current form and state-based renewable energy targets are implemented.

Existing generators are retired at the current owner-nominated dates, and major energy infrastructure projects such as Snowy 2.0 and interconnector projects from the 2018 ISP are assumed to proceed.

Under this scenario, the NEM average rate of installation of large-scale renewable energy projects is forecast to slow in the early 2020s, as the RET is met by 2020, although Victorian and Queensland renewable energy targets still incentivise renewables development in those states.

[47] As already noted, our modelling treats the ISP interconnector projects and Snowy 2.0 as anticipated projects. The impact of ISP projects not proceeding is tested through sensitivity analysis, which is discussed in Appendix 4.

This scenario is closely aligned to AEMO's 2019 'Central' scenario.

5.3.2 Global slowdown

This scenario essentially represents a future in which there is a sustained global economic slowdown, resulting in reduced demand for both commodities and energy.

Key aspects of this scenario are a reduced national energy demand, including the loss of all mainland aluminium smelters.[48] Gas prices are assumed to fall by 25 per cent (compared to those in Status quo/current policy) due to reduced demand. All emissions reduction schemes are assumed to be terminated in this scenario, in an effort to reduce energy infrastructure expenditure.

With energy consumption reducing by over 36 TWh per annum from 2029-30 in this scenario, this load reduction represents 5.5 GW of excess capacity in the NEM.[49] This excess system capacity, accompanied with existing renewables in the NEM, leads to the earlier retirement of ageing thermal generation fleet. Coal retirement capacity is sourced from AEMO's Insights Paper on coal closure.

This scenario closely aligns with AEMO's 2019 'Slow Change' scenario.

5.3.3 Sustained renewables uptake

The recent momentum in development of renewables was predominantly led by the Large-scale Renewable Energy Target (**LRET**).[50] In early September 2019, the Clean Energy Regulator announced that the LRET would be met by 2020.

The Sustained Renewables Uptake scenario is in many respects similar to the Status quo/current policy scenario but it assumes that the momentum in renewable investment is sustained. Consequently, a number of coal-fired generators retire three to five years earlier than their currently nominated closure dates.

This scenario aligns broadly with AEMO's 2019 'Fast Change' scenario.

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[48] Tasmania's aluminium smelter closure is not specifically modelled. However, we have included a reduction of Tasmania's base load by 240 MW. This could represent a number of large industrial load reductions and/or closures in Tasmania.

[49] Assumed capacity factor of 75 per cent.

[50] Target is 33,000 GWh by 2020. While the Renewable Energy Act is legislated until 2030, the target remains unchanged from 2020 to 2030.

5.3.4 Accelerated transition to a low emissions future

This scenario represents a future in which there is a concerted international effort to meet the objectives of the Paris Climate Accord, and consequently a major change to Australia's emissions reduction policy.

This scenario models a NEM emissions reduction target of 90 per cent emissions reduction on 2016 levels by 2050, along with accelerated price reductions for renewable generation technology due to increases in international production. Load is assumed to increase overall compared with the Status quo/current policy scenario at 1.75 per cent per annum, due predominantly to the accelerated transition to electrification of the transport sector to support a lower emissions trajectory.

This scenario essentially aligns with AEMO's 2019 'Step Change' scenario.

5.3.5 AEMO's High DER scenario

AEMO has developed a fifth scenario, 'High DER', for which we have no direct equivalent. AEMO's description of its High DER Scenario is:

> **The 'High DER**' scenario reflects a more **rapid consumer-led transformation** of the energy sector, relative to the Central scenario. It represents a highly digital world where technology companies increase the pace of innovation in easy-to-use, highly interactive, engaging technologies. This scenario includes reduced costs and increased adoption of DER, with automation becoming commonplace, enabling consumers to actively control and manage their energy costs while existing generators experience an accelerated exit. It is also characterised by widespread electrification of the transport sector.[51]

The essential characteristic of this scenario is that of a more rapid move away from centralised generation and transmission infrastructure to consumer-level generation, energy storage, and demand response. However, even under this scenario, centralised generation and transmission will still exist.

Ernst & Young's market expansion model does not distinguish between transmission and distribution-connected generation or storage, although it does model demand-side participation. Rather than develop an equivalent scenario to High DER, we have chosen to examine the impact of a mass uptake of consumer-level generation and storage solutions through sensitivity studies in which the cost of battery storage is drastically reduced. This is discussed further in section 5.4.

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[51] AEMO, *2019 Forecasting and Planning Scenarios, Inputs, and Assumptions*, August 2019.

5.3.6 Weighting of reasonable scenarios

With no evidence that any one scenario is more likely to occur than any other, we have chosen to weight the four scenarios equally, as recommended by the AER.[52]

5.4 Sensitivity analysis

In addition to modelling scenarios, RIT-T application guidelines require the proponent to undertake sensitivity analysis. Sensitivity analysis entails varying one or multiple inputs to test how the output of a model is affected by changes in its input assumptions. As already noted, the purpose of sensitivity analysis is to test the robustness of the modelling results and conclusions by examining the impact of particular events or variables that have not been captured in the scenarios.

Our sensitivity analysis has been informed by a combination of stakeholder feedback, the RIT-T Application Guidelines and experience gained during the *Initial Feasibility Report* analysis. Our sensitivity analysis has included:

- **Retirement of South Australian gas units**, which is the assumption in the EnergyConnect RIT-T but is not reflected in our scenarios;
- **Earlier or later coal plant closures**, which enhances or weakens the case for storage and dispatchable generation;
- **Hydrogen development in Northern Tasmania**, in response to a request from a stakeholder;
- **Improvements in battery technology or cost reductions**, which potentially changes the value provided by the Tasmanian hydro system;
- **Transmission projects not proceeding**, whilst the modelling assumes major transmission projects proceeding either as complementary or alternative options to Marinus Link and supporting transmission, it is useful to examine the impact if these projects do not proceed; and
- **Changes in cost assumptions**, our sensitivity analysis also examines the impact if the projects costs are higher or lower than our central estimates by +/- 30 per cent.

Full details of our sensitivity analysis are presented in Appendix 4. A summary of the findings from our sensitivity analysis is presented in the next chapter which presents the results from our cost-benefit analysis.

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[52] AER, *Application Guidelines Regulatory Investment Test for Transmission*, 2018, p. 56.

6 Net market benefit results

This chapter presents the results of the cost-benefit analysis for Marinus Link and supporting transmission, in accordance with the RIT-T. As explained in this chapter, our findings reflect the results of Ernst & Young's market expansion model and GHD's modelling of ancillary services costs. To assist stakeholders, we discuss the sources of the benefits provided by Marinus Link and supporting transmission in the context of NEM developments, including future generation and transmission interconnectors.

Key messages

- Our modelling examines the four credible options for Marinus Link, which propose interconnector capacities ranging from 600 MW to 1500 MW plus supporting AC network augmentations. For each option, we have evaluated the net market benefits of Marinus Link and supporting transmission compared to a base case 'without Marinus Link and supporting transmission'.
- All credible Marinus Link and supporting transmission options deliver net market benefits compared to the 'without Marinus Link and supporting transmission' base case under each of the four scenarios. The cost-benefit analysis therefore shows unequivocally that Marinus Link and supporting transmission should proceed. The challenge is to decide on its optimal capacity and timing, including whether Marinus Link should be staged.
- Our analysis has revealed that there are significant economies of scale in constructing 750 MW increments of interconnector capacity compared to 600 MW. Furthermore, the cost-benefit analysis shows that there is significant additional value if Marinus Link is 1500 MW, staged in two 750 MW increments. As a consequence, Option **D** – a staged 1500 MW interconnector – is the preferred RIT-T option.
- In terms of timing, the four scenarios reveal different drivers for earlier or later commissioning. The cost-benefit analysis shows that commissioning 750 MW increments in either (a) 2030 and 2032 or (b) 2028 and 2032, are essentially the same if the scenarios are weighted evenly. However, there are ancillary services cost savings, and benefits in relation to risk mitigation that are not captured in the market modelling, which indicate that the 2028 and 2032 commissioning dates should be preferred. Our sensitivity analysis confirms this finding.
- Our modelling shows that Tasmania's existing hydro capacity is a significant source of value to mainland electricity customers, given the forecast coal plant closures and the projected growth in renewable generation. Marinus Link and supporting transmission unlock this benefit by:
  - Displacing expensive gas-fired peaking generation on the mainland that would otherwise be required to meet electricity demand; and

- Providing the NEM with access to lower cost, higher capacity, energy storage to provide 'firm' capacity from variable renewable generation.

- Marinus Link and supporting transmission also responds to the NEM's increasing need for dispatchable generation and storage. Marinus Link and supporting transmission enable Tasmania to exploit its natural advantages in terms of topography and wind resources to provide further savings for lower cost storage capacity and wind generation compared to the available options on the mainland.
- Our analysis and conclusions are consistent with the emerging themes from AEMO's planning analysis that the NEM will transform from a power system dominated by large thermal plant to a power system with a multitude of generation types over diverse geographical areas. Variable renewable generation, storage and interconnectors will play an increasingly important role. Whilst the exact timing of particular elements of this transformation will vary depending on modelling inputs and scenarios, the overall outcome is consistent between AEMO's and our modelling.
- Marinus Link, with its supporting transmission, is one of a number of interconnector projects that will be required as these significant changes occur. We have paid particular attention to the interaction between Marinus Link and KerangLink. Our analysis shows that Marinus Link and KerangLink are complementary. The construction of both of these interconnectors will benefit the transforming NEM more than the construction of either project alone.
- In accordance with the RIT-T, the preferred option for Marinus Link is a 1500 MW HVDC link with supporting AC network augmentations, with the first 750 MW stage commissioned in 2028 and the second 750 MW stage commissioned in 2032. The expected net market benefit of this option is $1,674 million in present value terms.

6.1 Net market benefit results

As explained in Chapter 5, Ernst & Young's market expansion model captures the majority of the RIT-T benefits from Marinus Link and supporting transmission, with additional modelling undertaken by GHD to evaluate the ancillary services benefits.[53] To simplify the presentation of our results, we focus primarily on the results from

[53] Ernst & Young's market expansion model assumes there are no intra-regional constraints preventing generated power from reaching load centres

or interconnectors. Ernst & Young's model therefore implicitly considers that the supporting transmission augmentations have been commissioned

at the same time Marinus Link is commissioned.

the market expansion model, noting that ancillary services is relatively immaterial in terms of the total net market benefits.

As explained in Chapter 5, the market expansion model selects generation and storage investments so that the projected NEM demand over the study period can be met at the lowest total cost, assuming different options for Marinus Link and supporting transmission (in terms of the size and timing of new investment). The computational requirements of the model are significant.

The net market benefit is calculated in present value terms as the difference in total NEM costs with and without various Marinus Link and supporting transmission options, minus the costs of the relevant option. The credible options for Marinus Link and supporting transmission are summarised in the Table 7 below.

Table 7 Summary of the credible options[54]

Credible option	Main elements of this option
A. 600 MW interconnector	A 600 MW HVDC interconnector using voltage source converter technology and monopole configuration. AC network augmentations in Tasmania. No AC augmentations are required in Victoria.
B. 750 MW interconnector	Like Option A, with converter stations and HVDC cable rated to 750 MW. AC network augmentations like Option **A**.
C. 1200 MW interconnector	Two parallel 600 MW HVDC interconnectors like Option **A**. AC network augmentations in Tasmania, in addition to those identified in Options A and B. As noted for Option **A**, no AC augmentations are required in Victoria.
D. 1500 MW interconnector	Like Option **C**, with converter stations and HVDC cable rated to 750 MW. AC network augmentations are identical to Option **C**.

In assessing the credible options, it is essential to consider the optimal timing for Marinus Link and supporting transmission in addition to the optimal capacity, especially because Options **C** and **D** can be staged. In practice, therefore, each credible option has a range of different timings, which adds significantly to the computational task of assessing whether Marinus Link and supporting transmission should proceed and, if so, its optimal capacity and timing.

54 A more detailed description of the credible options is provided in Table 3 in section 4.3 of this document.

Given this complexity, we have adopted a step-wise approach to evaluating the competing options through a series of questions. Our first step is to focus our modelling effort on addressing the following two questions:

1. Would Marinus Link and supporting transmission provide a net market benefit if it were commissioned at an early date, being 2026?
2. Is the optimal initial capacity for Marinus Link 600 MW or 750 MW?

Our modelling results that address these questions are presented in Table 8. For ease of reference, the highest net market benefit is shaded.

Table 8 Net market benefits of 600 MW versus 750 MW commissioned in 2026[55]

Credible option (MW)	Commission-ing year	Net market benefit by scenario ($ million)				
		Global slowdown	Status quo/ current policy	Sustained renewables uptake	Accelerated transition	Weighted average
750 MW	2026	671	690	958	1,946	1,066
600 MW	2026	574	542	768	1,582	867
Additional value provided by the 750 MW option		97	147	190	364	200

Based on the results presented in Table 8, our findings are as follows:

1. For all four scenarios, Marinus Link and supporting transmission deliver a net market benefit compared to the 'without Marinus Link and supporting transmission' base case. The weighted average net market benefit ranges from $867 million for the 600 MW option to $1,066 million for 750 MW of capacity.
2. For all four scenarios, Marinus Link and supporting transmission deliver a greater net market benefit for a 750 MW capacity compared to a 600 MW capacity. The weighted average shows a 750 MW interconnector delivers $200 million or 23 per cent additional value compared to the 600 MW option.[56]

These findings are important because they demonstrate that Marinus Link and supporting transmission, if commissioned at an early date (being 2026), deliver a significant net market benefit to the NEM under all four scenarios. It is therefore reasonable to conclude that the NEM is better off with Marinus Link and supporting

55 Totals mentioned in this section may not sum precisely due to rounding of the underlying values.

56 The difference between $1,066 million and $867 million.

transmission compared to a base case under which Marinus Link and supporting transmission does not proceed. This is a significant finding.

Furthermore, the net market benefit analysis indicates that there are significant economies of scale in constructing a 750 MW interconnector compared to a 600 MW option, with the larger option consistently outperforming the smaller interconnector across all four scenarios. The magnitude of the outperformance ($200 million or 23 per cent) is highly material. As such, it is reasonable to conclude that the optimal initial interconnector capacity is 750 MW, rather than 600 MW. Therefore, Option **B** is preferred to Option **A**.

We now turn our attention to two further questions:

1. Is the optimal capacity for Marinus Link 750 MW, 1200 MW or 1500 MW?
2. What is the optimal timing for Marinus Link and supporting transmission?

To address the question regarding the optimal capacity (Question 3), we extend the above analysis (which was based on an early commissioning date) to examine the net market benefit if a second increment of capacity is added in 2028. Table 9 resents the net market benefits, which indicate that the staged 1500 MW option (Option **D**) in 2026 and 2028 is preferred to the 1200 MW option (Option **C**) also staged in 2026 and 2028, across all four scenarios.

Table 9 Net market benefits for 1500 MW or 1200 MW Marinus Link options

Credible option (MW)	Commissioning years (first and second stages)	Net market benefit by scenario ($ million)				
		Global slowdown	Status quo/ current policy	Sustained renewables uptake	Accelerated transition	Weighted average
1500 MW	2026 and 2028	595	947	1,372	3,182	1,524
1200 MW	2026 and 2028	555	767	1,130	2,645	1,274
Additional value provided by the 1500 MW option		40	180	242	538	250

Table 10 below compares the net market benefits of the 1500 MW option (Option **D**) in 2026 and 2028 with a 750 MW interconnector in 2026 (Option **B**).

Table 10 Net market benefits for 1500 MW or 750 MW Marinus Link options

Credible option (MW)	Commissioning year	Net market benefit by scenario ($ million)				
		Global slowdown	Status quo/ current policy	Sustained renewables uptake	Accelerated transition	Weighted average
1500 MW	2026 and 2028	595	947	1,372	3,182	1,524
750 MW	2026	671	690	958	1,946	1,066
Additional value provided by the 1500 MW option		-77	258	414	1236	458

Table 10 shows that whilst the 750 MW option (Option **B**) would deliver a higher net market benefit under the 'Global slowdown' scenario, the weighted average across all four scenarios produces a net market benefit that is $458 million or 43 per cent higher for the staged 1500 MW capacity in with the first 750 MW commissioned in 2026 and the second 750 MW in 2028 (Option **D**). On this basis, we conclude that the 1500 MW capacity (Option **D**) is preferred to a single interconnector of 750 MW (Option **B**).

In summary, our modelling results show that a 1500 MW interconnector is the optimal capacity, assuming an early commissioning date (Question 3). This result is not surprising given the very strong economies of scale that would be achieved by installing an initial interconnector capacity of 750 MW compared to the 600 MW option.

We now turn our attention to the optimal timing of this investment (Question 4).

To address this question, Table 11 below shows the net market benefit from different timing options for a 1500 MW option. It includes one option where 1500 MW is commissioned in a single year, being 2027. The highest net market benefit is highlighted in blue for ease of reference.

Table 11 Optimal timing for the 1500 MW option (Option D)

Credible option (MW)	Commissioning year of each 750 MW stage	Net market benefit by scenario ($ million)				
		Global slowdown	Status quo/ current policy	Sustained renewables uptake	Accelerated transition	Weighted average
1500 MW in two 750 MW stages	2026 and 2028	595	947	1,372	3,182	1,524
	2027 and 2028	627	953	1,353	3,166	1,525
	2028 and 2030	764	1,088	1,446	3,221	1,630
	2028 and 2032	851	1,147	1,451	3,246	1,674
	2030 and 2032	884	1,165	1,409	3,188	1,661

Table 11 above shows that the 2028 and 2032 timing has the highest weighted average net market benefit of $1,674 million. This net market benefit is $13 million or 0.8 per cent higher than the later timing of 2030 and 2032, and $44 million or 3 per cent higher than the option with the earlier timing of 2028 and 2030. We also note that the economically optimal timing varies according to scenario:

- Under the Global slowdown scenario, commissioning in 2030 and 2032 provides the highest net market benefit of $884 million;
- Under the Status quo / current policy scenario, 2030 and 2032 commissioning again provides the greatest net market benefit, being $1,165 million;
- In the Sustained Renewables Uptake scenario, two options are very closely aligned as the estimated net market benefit is $1,446 million for the 2028 and 2030 option compared to $1,451 million for 2028 and 2032. We also note that the earlier timing is likely to provide 'insurance benefits' arising from the additional availability of interconnector capacity, which have not been factored into the modelling. In these circumstances, it is reasonable to regard both options as equivalent. Alternatively, it is arguable that the earlier timing may be marginally preferred if the insurance benefits were included.
- In the Accelerated Transition to a Low Emissions Future scenario, the same two options that were closely aligned for the Sustained Renewables Uptake scenario can also be regarded as equivalent, as the difference in the estimated net market benefits is only 0.8 per cent. Alternatively, it may be reasonable to regard the 2028 and 2030 timing as marginally preferred for the reasons already outlined.

A graphical representation of the optimal timing for the 1500 MW option across the four scenarios is shown in Figure 6.

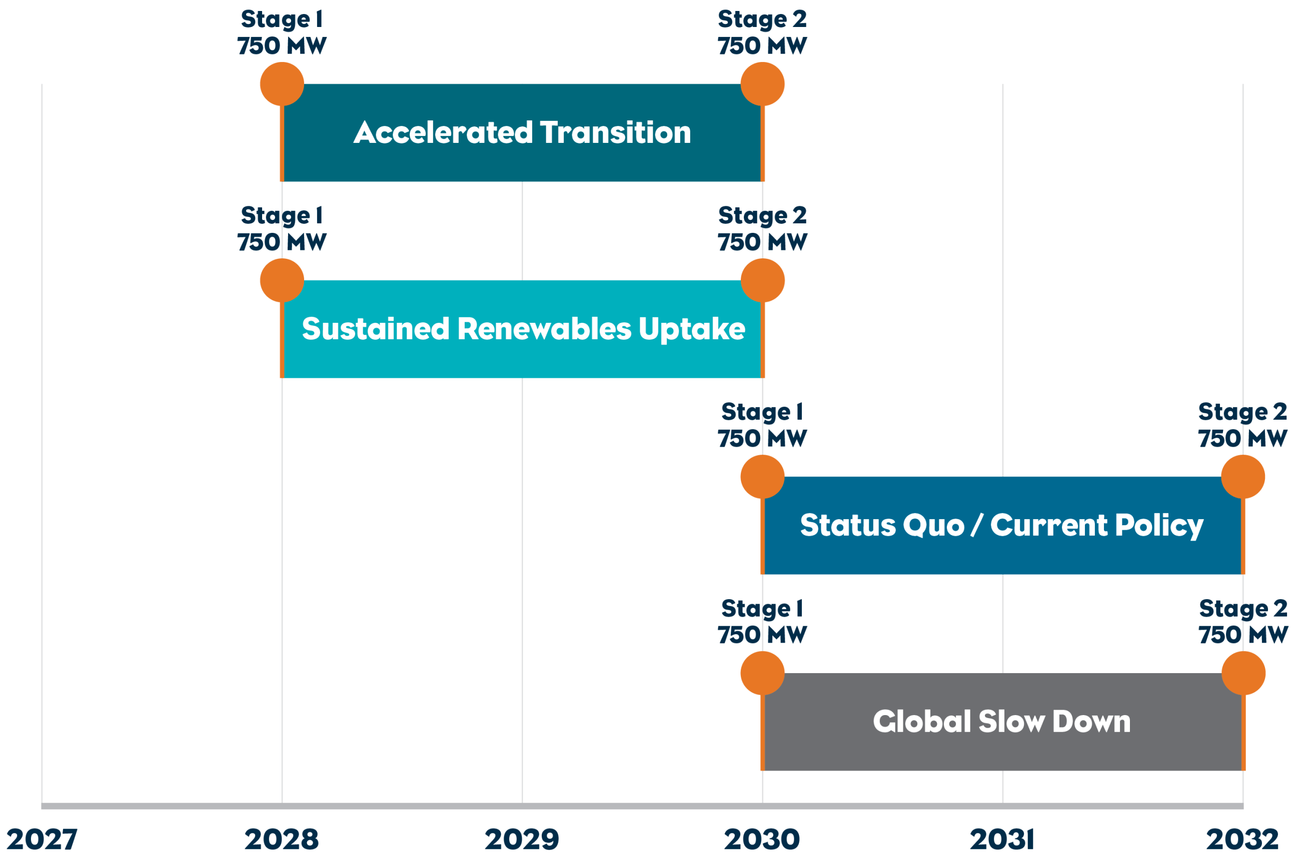

Figure 6 Optimal timing of the 1500 MW option under different scenarios

In accordance with the RIT-T, our task is to select the option that maximises the net market benefit, weighted across the four scenarios. From Table 12, the option with the greatest net market benefit is the 1500 MW Marinus Link option (Option **D**), with the first 750 MW stage and supporting transmission commissioned in 2028 and the second 750 MW stage commissioned in 2032.

Based on the analysis presented in this section, it would be reasonable to conclude that this is the preferred option in accordance with the RIT-T. However, to provide a final cross check, Table 12 below compares the net market benefits of the 1500 MW option in 2028 and 2032 against the other credible options commissioned within the same timeframes.

Table 12 Net market benefits for each credible option in 2028 and 2032

Credible option (MW)	Commissioning year	Net market benefit by scenario ($ million)				
		Global slowdown	Status quo/ current policy	Sustained renewables uptake	Accelerated transition	Weighted average
600 MW	2028	657	606	796	1,578	909
750 MW	2028	764	756	983	1,929	1,108
1200 MW	2028 and 2032	781	943	1,198	2,695	1,405
1500 MW	2028 and 2032	851	1,147	1,451	3,246	1,674

Table 12 confirms that the 1500 MW option commissioned in 2028 and 2032 maximises net market benefits across the four scenarios. Before concluding that this option satisfies the RIT-T; however, it is important to consider the results of our sensitivity analysis, which are set out in section 6.2 below.

6.2 Sensitivity testing

Sensitivity analysis is the process of examining the influence of a particular variable on the market benefit outcomes.[57] As explained in section 5.4, the task of sensitivity analysis is to test the robustness of our findings by examining the impact of particular events or variables. Importantly, however, appropriately designed scenarios should already capture the principal variables that affect the investment decision. The sensitivity analysis therefore provides an important cross-check that our approach and conclusions are valid.

A summary of sensitivity testing results is presented in Table 13 below. Unless noted otherwise, each sensitivity test was undertaken using the Status quo/current policy scenario. Further detailed information on this analysis is provided in Appendix 4.

[57] AER, *Application Guidelines Regulatory Investment Test for Transmission*, 2018.

Table 13 Summary of sensitivity analysis results (1500 MW commissioned in two 750 MW stages in 2028 and 2032, Status quo/current policy scenario)

Sensitivity	Change in market benefit ($ million)[58]	Impact on optimal timing of Marinus Link[59]
500 MW additional on-island wind	53	Timing unchanged
Other expected projects do not proceed (Snowy 2.0, KerangLink etc.)	192	First stage unchanged, likely advances 2nd stage by 1 year
600 MW of Pumped Hydro in Tasmania by 2027 (Underwriting New Generation Investments)	537[60, 61]	Advances 2nd stage to 2028
6-month Basslink outage (1 in 10 years)	N/A See text below	N/A See text below
Rate of reduction in battery costs doubles	-54	Timing unchanged
Early Yallourn Retirement (Complete retirement by mid-2027)	85	Likely advances 1st stage by 1 year and second stage to 2030
100 MW Tasmanian hydrogen processing load from 2023	-53	Timing unchanged
Battery life doubles (4 hour duration) but costs unchanged	-87	Timing unchanged
Prudent Storage Level does not change	-36	Timing unchanged
Assumed repurposing of Hydro Tasmania assets does not proceed	-209	Timing unchanged
Reducing weighting of Global slowdown and Accelerated transition scenarios to 15 per cent	-150[62]	Timing unchanged

58 The net market benefits for Status quo/current policy scenario is $1,147 million. The variation in benefits is reported from this value.

59 The optimal timing of Marinus Link and supporting transmission under Status quo/current policy scenario is 750 MW in 2030 (stage 1) and 750 MW in 2032 (stage 2). The impact of change in timing is assessed from this perspective.

60 This sensitivity is based on the Sustained Renewables Uptake scenario with Marinus Link and supporting transmission commissioned in 2027 (first 750 MW) and 2028 (second 750 MW).

61 In this sensitivity, the costs of the additional 600 MW pumped hydro have been externalised from the model which increases the net market benefit of Marinus Link. Refer to Appendix 4 for details.

62 The net market benefit deviation is based on a weighted average basis of the four scenarios ($1,674 million).

Sensitivity	Change in market benefit ($ million)[58]	Impact on optimal timing of Marinus Link[59]
Climate change sensitivity	-71	Timing unchanged
South Australian gas-powered generators retire with commissioning of Project EnergyConnect	51	No material change to timing
Coal retirement of all generators delayed by 3 years	-263	Both stages delayed by 3 years
Partial 2019-20 ISP assumptions update	-710	Both stages delayed by 2 to 3 years
High discount rate (8.26 per cent)	-735	Timing unchanged
Low discount rate (3.54 per cent)	1353	Advances 2nd stage by 1 year
Capital costs (30 per cent higher)	-334	Defers 2nd stage by 1 year
Capital costs (30 per cent lower)	334	Advances both stages by 1 year

The sensitivity analysis identifies a number of instances where the preferred timing as identified by the RIT-T would be brought forward. In relation to many of the other sensitivities, the timing of the preferred option remains unchanged. For the capital cost sensitivity, a 30 per cent downside risk leads to the longest deferral of three years. The magnitude of this cost overrun is considered unlikely and should not affect the investment decision at this stage. Nevertheless, it highlights the importance of keeping the project costs under close review.

The Basslink outage sensitivity did not attempt to quantify impact of a Basslink outage on the net market benefit of Marinus Link. This sensitivity instead provides an indication of the costs to the market that would be avoided if Marinus Link was present and an extended Basslink outage was to occur. This avoided cost is approximately $19 million, and is discussed further in Appendix 4.

As discussed previously, our modelling was based predominantly on the latest AEMO data available at the time this *PADR* modelling commenced, being in February 2019. Since then, AEMO has released two data updates, in August 2019 and in September 2019. Due to the time requirements to enter updated data and run the model, it was not possible to re-run our scenario modelling using AEMO's September data. The "Partial 2019-20 ISP assumptions sensitivity" in Table 13 examined the impact of changing the most significant model input variables to AEMO's September 2019 values, in the Status quo / current policy scenario only. Although the result was a reduction in the net market benefit of Marinus Link and supporting transmission by $710 million compared with the Status quo / current policy scenario result, the net market benefit in this sensitivity is (positive) $437 million, indicating that the benefits of Marinus Link and supporting transmission would still outweigh their estimated costs. This sensitivity also resulted in a change of the optimal timing, with the first stage delayed by one year and the second stage delayed by three years.

We are continuing to work with AEMO as it progresses its 2019-20 ISP, to more fully understand the changes in modelling assumptions. Although differing modelling assumptions may result in differing timings between TasNetworks' and AEMO's analysis, it is clear that Marinus Link and supporting transmission will play a role in the future NEM and, as discussed in the next section, the project should proceed to the Design and Approvals phase.

On the basis of the above information and the analysis presented in section 6.1, the application of the RIT-T has identified the commissioning of Marinus Link and supporting transmission in two 750 MW stages in 2028 and 2032 (Option **D**) as the preferred option.

6.3 Preferred option and timeframes

Clause (1) of the RIT-T states:

> The *preferred option* is the *credible option* that maximises the *net economic benefit* to all those who produce, consume, and transport electricity in the *market* compared to all other *credible options*.

This RIT-T has considered four credible options:

A. 600 MW monopole HVDC link with supporting AC transmission network augmentations;

B. 750 MW monopole HVDC link with supporting AC transmission network augmentations;

C. 1200 MW monopole HVDC link, comprising two independent 600 MW monopoles, with supporting AC transmission network augmentations; and

D. 1500 MW HVDC link, comprising two independent 750 MW monopoles, with supporting AC transmission network augmentations.

Based on the information presented in sections 6.1 and 6.2, the preferred RIT-T option is to commission two 750 MW capacity increments in 2028 and 2032, with the required supporting transmission network augmentations (Option **D**). The scope of work for the preferred option in accordance with the RIT-T is summarised below. In particular, Figure 7 shows the indicative development phases and timeframes for the preferred option, while Table 14 provides an overview of the required scope of work.

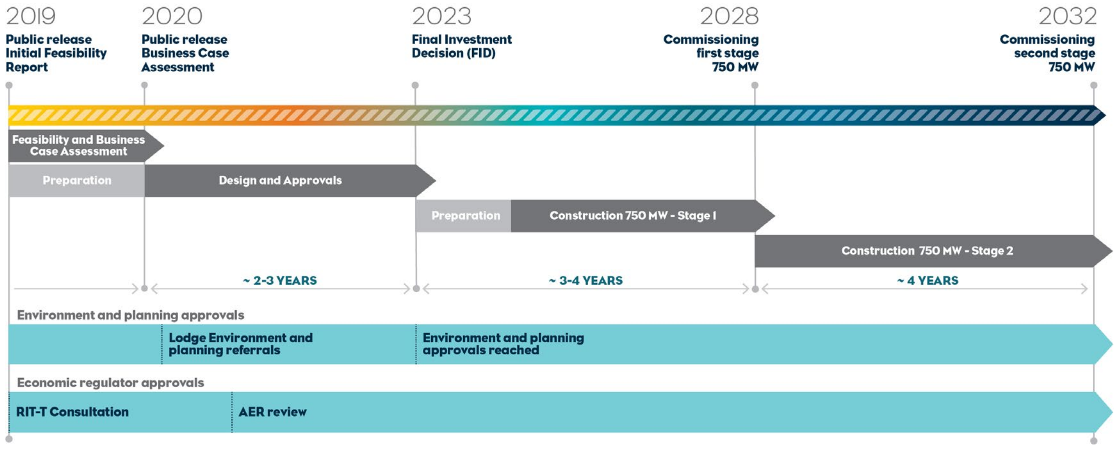

Figure 7 Development phases and timeframes for the preferred RIT-T option

Table 14 Scope of work for the preferred RIT-T option

Investment type	Development
DC assets	Two parallel 750 MW HVDC interconnectors using voltage source converter technology and monopole configuration. The first 750 MW interconnector is commissioned in 2028 and the second in 2032. Converter stations located in the Burnie area in Tasmania and the Hazelwood area in Victoria. HVDC transmission to use buried cable for the entire route.
AC assets	AC network augmentations in Tasmania: • Construction of new 220 kV switching stations in the Burnie area adjacent to the converter stations; • Construction of a new double-circuit 220 kV transmission line from Burnie to Sheffield and decommissioning of the existing 220 kV single-circuit transmission line in this corridor; • Establishment of a new 220 kV switching station at Staverton; • Construction of a new double-circuit 220 kV transmission lines from Staverton to Burnie via Hampshire; and • Construction of a new double-circuit 220 kV transmission line from Palmerston to Sheffield. No AC augmentations are required in Victoria, as there is sufficient transmission capacity to accommodate power flows to or from the interconnector. Limited 500 kV connection assets are required to connect the HVDC converter station to Hazelwood Substation.

6.3.1 An option for earlier delivery

Whilst this *PADR* indicates timing of stage 1 in 2028 and the second stage in 2032 is economically optimal, the discussion in section 6.1 demonstrated that the net market benefits of this timing are only marginally better than alternative timing options, and furthermore the optimal timing differs between scenarios. The evolution of the NEM during forthcoming years may suggest an earlier (or later) timing is preferable to 2028 and 2032. We are therefore adopting the prudent approach of progressing the project towards a final investment decision which allows for the possibility of delivery earlier than 2028.

Should a government wish to ensure Marinus Link and supporting transmission are commissioned earlier than the economically optimal timing measured under the RIT-T, a financial contribution, equal to the difference in net market benefits between the economically optimal timing and the desired earlier timing, would allow the earlier timing to pass the RIT-T. Table 15 below summarises the data from two timing options previously presented in Table 11. The weighted average net market benefit for commissioning in 2027 and 2028 is $1,525 million, which is $149 million less than the net market benefit with the economically optimal commissioning timing of 2028 and 2032. A government grant contribution of $149 million would allow the earlier timing of the first stage in 2027 and the second stage in 2028 to be the preferred option under the RIT-T.

Table 15 Net market benefits with alternative commissioning timing for the 1500 MW option (Option D)

Credible option (MW)	Commissioning year of each stage	Weighted average net market benefit ($million)
1500 MW in two 750 MW stages	2027 and 2028	1,525
	2028 and 2032	1,674

6.3.2 Material inter-network impacts

If the preferred option is likely to have a material inter-network impact, clause 5.16.4(k)(9)(iii) of the NER requires the RIT-T proponent to provide an augmentation technical report to the affected Transmission

Network Service Provider. In these circumstances, the augmentation technical report would be prepared by AEMO in accordance with clause 5.21. A material inter-network impact is defined as:

> "A material impact on another *Transmission Network Service Provider's network*, which impact may include (without limitation):
>
> (a) the imposition of *power transfer constraints* within another *Transmission Network Service Provider's network*; or
>
> (b) an adverse impact on the quality of *supply* in another *Transmission Network Service Provider's network*."

In section 7.5 of our *PSCR* we commented that the credible options were likely to have a material inter-network impact. Since that time, however, we have refined the location in which Marinus Link would connect within the Victorian network, and commenced further technical studies which currently indicate that the preferred option is unlikely to have a material network impact. At this stage, therefore, we have not requested that AEMO provides an augmentation technical report.

We are continuing to work with AEMO in relation to these issues. If it becomes apparent that the preferred option would result in a material inter-network impact, we will request AEMO to prepare an augmentation technical report.

6.4 Why does Marinus Link provide a net market benefit?

The results in section 6.1 show that Marinus Link and supporting transmission provide an overall economic benefit to the NEM. The purpose of this section is to provide an explanation of how Marinus Link is able to provide these benefits in the context of the broader developments in the NEM.

We begin by providing a high-level summary of the benefits, followed by a discussion of how the NEM would develop without Marinus Link. The final section discusses how Marinus Link and supporting transmission affect the NEM development in a way that delivers significant a net market benefit.

6.4.1 High-level summary of benefits

Table 16 provides a breakdown of the net market benefit for the preferred 1500 MW option, for each scenario, as calculated by Ernst & Young's market expansion model and GHD's assessment of ancillary service benefits.

Table 16 Details of market benefits of the preferred RIT-T option under each scenario

Market benefit category	Value of benefit for each scenario ($ million)			
	Global slowdown	Status quo / current policy	Sustained renewables uptake	Accelerated transition
NEM Capital Costs	176	-478	-651	924
NEM Fixed Operating Costs	-61	-212	-194	-57
NEM Fuel Costs	1,679	2,713	3,115	2,644
NEM Variable Operating Costs	158	177	190	87
Renewable Expansion Transmission Costs	36	88	157	527
Unserved Energy	12	10	-7	270
Rehabilitation Costs	1	-3	-10	-1
Synchronous Condensers	-5	-4	-4	-4
Ancillary Service Benefits	128	128	128	128
Gross Market Benefits [1]	2,122	2,418	2,722	4,517
Marinus Link Estimated Costs [2]	1,271	1,271	1,271	1,271
Net Market Benefits	851	1,147	1,451	3,246

Notes:

1. Totals may not sum precisely due to rounding of the underlying values in this table.
2. Marinus Link and supporting transmission estimated costs are less than the estimated capital cost of the 1500 MW option presented in section 4.7 because the market benefit calculation considers only the annualised costs which occur during the modelling period (to 2050), whereas Marinus Link has an asset life of 40 years.

The analysis shows that lower fuel costs is the largest source of benefit from Marinus Link and supporting transmission, varying between $1.7 billion in the 'Global slowdown' scenario to $3.1 billion in the 'Sustained renewables uptake' scenario. These savings relate primarily to savings in gas-powered generation, which would be required on the mainland in the absence of Marinus Link and supporting transmission.

Figure 8 provides a time series analysis of the information presented in Table 16. It also shows the gross and net market benefits on an annual basis.

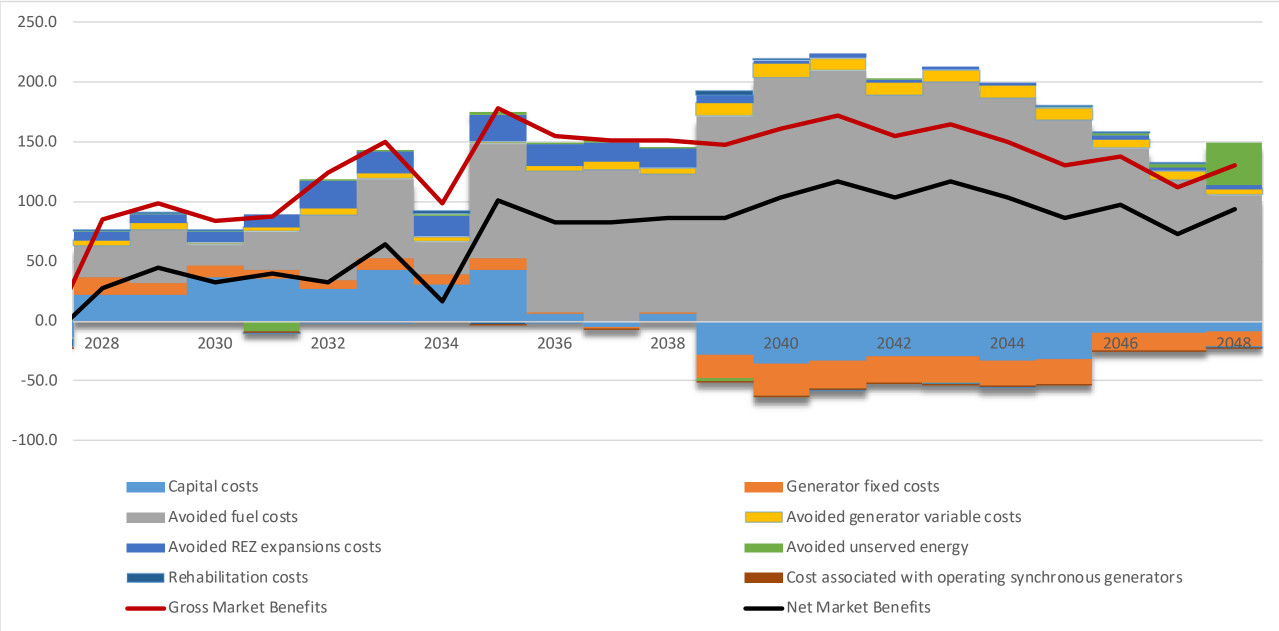

Figure 8 Annual average net market benefits, 1500 MW Marinus Link and supporting transmission with first stage commissioned in 2028 and second stage in 2032

The remainder of this section explains why these benefits can be achieved, commencing with a discussion of how the NEM would develop in the absence of Marinus Link.

6.4.2 The future NEM without Marinus Link

Our market modelling reflects the same overall trend in NEM evolution that has been observed by others, such as in AEMO's ISP. Specifically, traditional base-load coal generation is expected to be retired and replaced by a combination of renewable generation, gas generation, storage technologies, and customer demand response. Figure 9 shows a sample of the forecast change in generation mix to 2050.

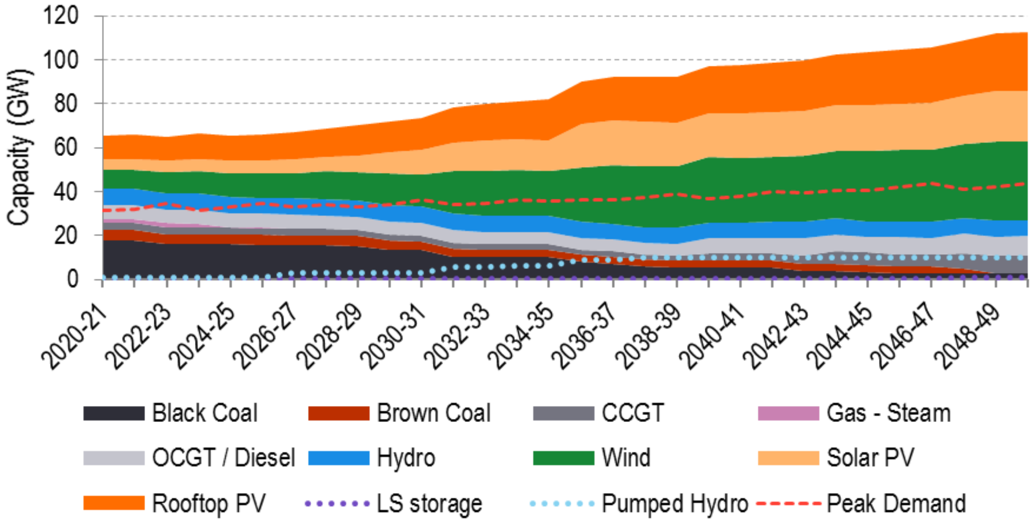

Figure 9 Modelled change in NEM generation capacity in the Status quo / current policy scenario[63]

Coal plant retirement is forecast to be driven by a combination of age-based retirements, economic viability, and emissions reduction requirements.[64] Retiring base-load coal plant is forecast to be replaced by a greater capacity of variable renewable generation (i.e. wind and solar).

Due to its lower capacity factor, substantially more wind and solar generation capacity must be installed than the coal plant it replaces to meet NEM energy demands. Some gas-fired generation, both open cycle and combined cycle gas turbines, and storage (both batteries and pumped hydro) are forecast to be installed, to ensure supply reliability during times of low wind and solar availability.

As can be seen in Figure 9, the retirement of coal-fired generation means that the amount of dispatchable generation (i.e., coal, gas, diesel and hydro) is forecast drop below the NEM maximum demand at some time during the modelling period.[65] This is true for both the NEM overall, and also for all mainland Australian NEM regions individually.

Figure 10 shows the situation for New South Wales under the Status quo/current policy scenario. The retirement of Liddell Power Station will mean dispatchable capacity will fall below maximum demand, during which time New South Wales will be reliant on a combination of renewables, interconnector inflows from adjacent states, and storage capacity to meet its peak demand.

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[63] Legend abbreviations: CCGT = combined cycle gas turbine; OCGT = open cycle gas turbine; PV = photo-voltaic; LS storage = large scale battery storage.

[64] Emissions reductions requirements only contribute to coal retirements in accelerated transition to low emission future scenarios.

[65] This occurs in about 2030 in the Status quo/current policy scenario, but different timing will occur in other scenarios.

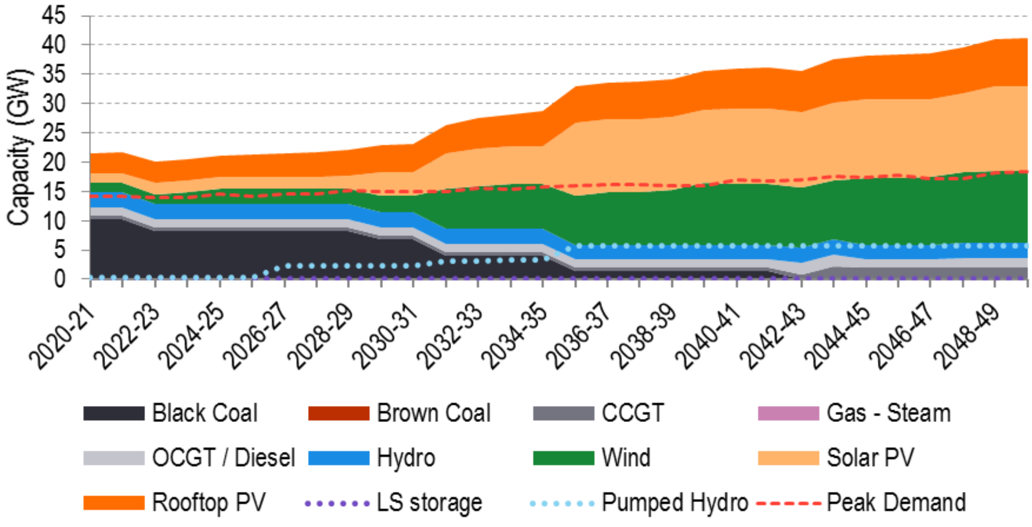

Figure 10 Modelled change in New South Wales generation capacity in the Status quo/current policy scenario

The situation for Tasmania is different, as shown in Figure 11, because Tasmania's dispatchable capacity exceeds its maximum demand for the entire modelling period. This is an important source of potential value for Marinus Link.

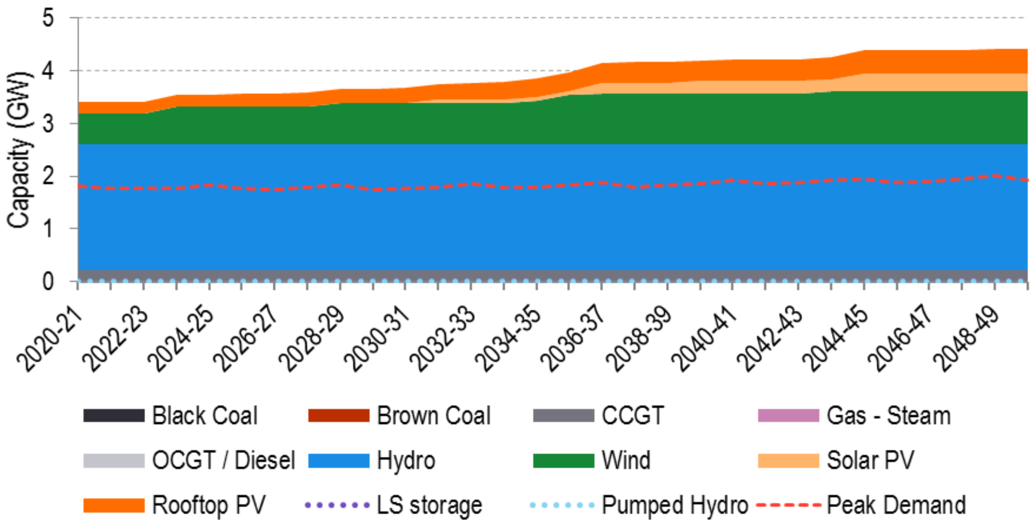

Figure 11 Modelled change in Tasmanian generation capacity in the Status quo/current policy scenario

Under the 'without Marinus Link and supporting transmission' base case, all mainland interconnectors will be highly used, as they allow excess renewable generation to be transferred between regions. The Queensland – New South Wales interconnector (**QNI**) is heavily used with southward flows to support New South Wales' load, because New South Wales black coal generators are expected to retire earlier than Queensland's. QNI flows are at the maximum southwards limit in the order of 25 per cent to 30 per cent of the time during the 2030s and 2040s, a result that is consistent across all scenarios.

Basslink is particularly heavily utilised. Figure 12 shows the flow duration curves on Basslink, in the absence of Marinus Link, for five representative years under the Status quo/current policy scenario. In 2026-27, Basslink is operating at its flow limit for approximately 55 per cent of the time (40 per cent at northwards (positive) limit; 15 per cent at southwards limit). The time at which Basslink is operating at its flow limit is forecast to increase to over 80 per cent of the time from 2032-33. This suggests greater interconnection between Tasmania and Victoria, if provided, would be highly utilised.

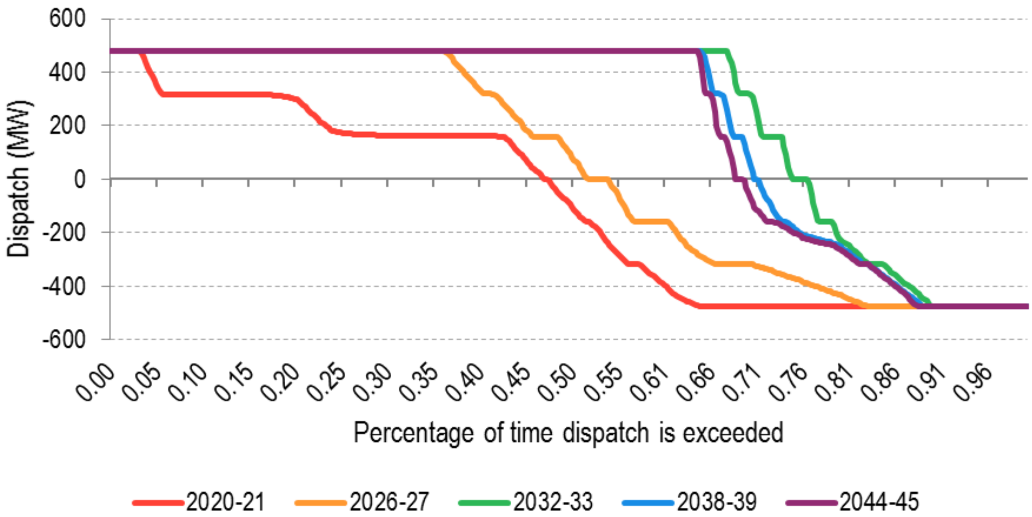

Figure 12 Basslink flow duration curve in the Status quo/current policy scenario in the absence of Marinus Link [66, 67]

Given Basslink's high utilisation, without Marinus Link it is not possible for the mainland to take advantage of Tasmania's existing and potential storage capacity. This is because Basslink's transfer capacity is insufficient to allow the required energy to be sent back and forth between Tasmanian and Victoria when required.

If Marinus Link is not commissioned, additional storage capacity and dispatchable generation would be required in mainland NEM regions to supplement mainland renewables. Existing mainland hydro generation

66 Positive flow is from Tasmania to Victoria.

67 Flow duration curves represent the amount of time power flow exceeds a given value. In the year 2020-21 (red line), the line crosses 200 MW at 23 per cent. This means Basslink flow was greater than +200 MW (positive = sending power from Tasmania to Victoria) for 23 per cent of the time. It reaches the maximum negative value (-478 MW; i.e. maximum Victoria to Tasmania flow) at 66 per cent. This means 66 per cent of the time, the flow is more positive than this value – or alternatively, for 34 per cent of the time (100 per cent – 66 per cent) the flow is at the maximum limit from Victoria to Tasmania.

and pumped storage (i.e. the Snowy Hydro Scheme, Snowy 2.0, and various smaller hydro schemes) will be fully used. Our market model predicts that a combination of gas turbines and storage would be developed to meet energy demand at times when insufficient mainland renewable generation exists.[68]

If the preferred Marinus Link and supporting transmission option were constructed, the average increase in net Tasmania to Victoria energy transfer during the period from 2032 to 2050 is approximately 5400 GWh per annum. Putting this in context, the forecast increase in NEM-wide wind generation in 2050, compared with 2030, is approximately 60,900 GWh. Marinus Link is therefore only a part of the required contribution to the changing NEM. Further analysis of the benefit Marinus Link and supporting transmission deliver is provided in the next section.

6.4.3 How does Marinus Link change things?

In broad terms, Marinus Link and supporting transmission allow the use of Tasmania's excess hydro capacity to provide storage to mainland renewables, displacing the costs of running gas-powered generators and mainland storage capacity. Fuel cost savings is the largest single source of benefit from Marinus Link, although two further benefits are obtained over time:

- First, Tasmanian wind resources have a higher capacity factor than mainland wind resources, with similar build costs. It therefore becomes a lower cost solution to provide additional wind generation capacity in Tasmania, rather than on the mainland.
- Second, as more coal plant retires in the future, even more renewable energy and storage is required. The cost of new Tasmanian pumped hydro schemes is forecast to be lower than mainland alternatives, both in terms of $/MW capacity and $/MWh of storage, making it more economical to build additional storage in Tasmania than on mainland Australia.

In this section, we explore the benefits that the preferred Marinus Link and supporting transmission option, identified in accordance with the RIT-T, would deliver and explain the source of those benefits. The discussion also focuses on the benefits under different scenarios to assist stakeholders in understanding the impact of key variables on the composition of the benefits.

[68] Furthermore, gas generation also acts to inject energy to the NEM, rather than just store energy. The use of gas generation consequently reduces the amount of wind and solar required to be built if only storage was relied upon to meet excess demand periods.

Figure 13 shows the annual market benefits derived by the preferred option in the Status quo/current policy scenario. Positive values are market benefits (i.e. savings), negative values are market net costs.[69] Figure 13 highlights that fuel savings (red) dominate the market benefits.

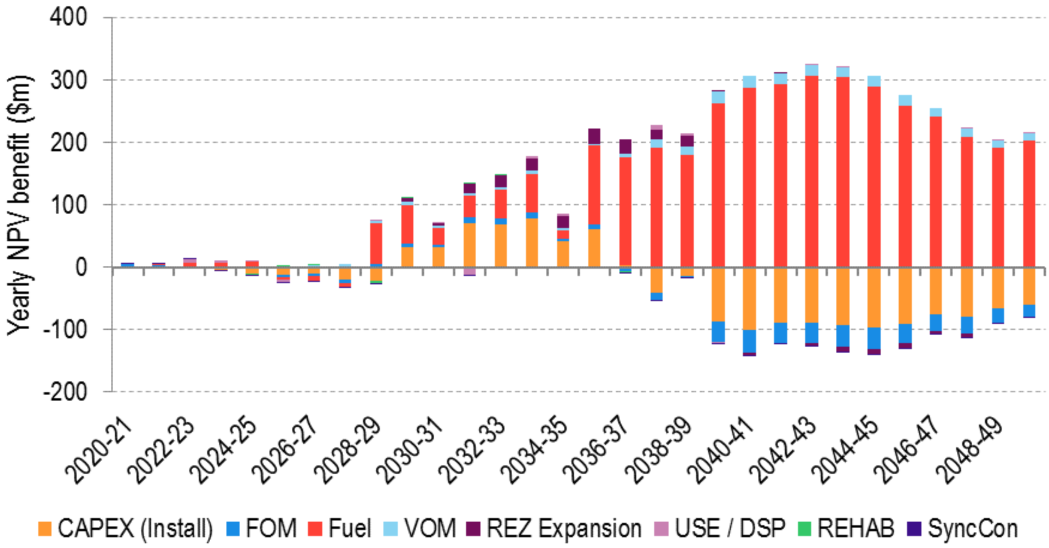

Figure 13 Annual market benefits by category, for the preferred RIT-T option (1500 MW link commissioned in 2028 and 2032) in the Status quo/current policy scenario[70]

The first stage of Marinus Link and supporting transmission is commissioned in 2028. Whilst the fuel saving benefits start from the first year, they increase significantly from 2036 onwards which is the year that Bayswater Power Station is forecast to retire.

The closure of Eraring and Bayswater Power Station have a material impact on the supply of baseload power in New South Wales. In the absence of Marinus Link, a combination of open cycle (in the 2030s) and closed cycle (in the 2040s) gas turbines provide the required energy. Marinus Link and supporting transmission provide firming capacity to the NEM, which allows renewables to be developed and displace gas generation.

Figure 13 also indicates a net saving of capital expenditure from 2029 through to 2036, but then a net increase in the 2040s. Marinus Link and supporting transmission result in less pumped hydro, solar and wind in NSW, Victoria and South Australia until about 2036, with increased wind development in Tasmania. The net impact

69 The fact that there are market benefits and costs prior to 2028 (when Marinus link is commissioned) is due to the model changing the market development slightly, in the years prior to Marinus Link, to minimise the overall cost of supply once Marinus Link is in service.

70 The market benefits in this graph are discounted to 2025 instead of 2019. The relative magnitudes of benefits – and thus the discussion – are unaffected. Legend abbreviations: CAPEX = capital expenditure (for new generation and storage); FOM = fixed operation and maintenance costs; VOM = variable operation and maintenance costs; REZ expansion = transmission expansion to renewable energy zones; USE = unserved energy; DSP = demand side participation; REHAB = rehabilitation costs; SyncCon = cost to operate synchronous condensers.

prior to 2036 is an overall saving in capital costs. In later years, as more energy is required in the NEM (due to load growth and to fill the gap left by remaining coal retirements), Marinus Link and supporting transmission enable renewables to be developed, displacing gas turbines.

Under the Global slowdown scenario, as shown in Figure 14 below, the annual market benefits are lower but more evenly spread out over time. The lower energy demand in this scenario means less generation is required overall, and the impacts of both Marinus Link and coal retirement are not as significant as in the Status quo/current policy scenario. The dominant saving is still fuel costs, predominantly gas cost savings.

Savings in capital expenditure are less significant than in the Status quo/current policy scenario, as less new generation is needed due to the lower demand. Capital expenditure savings occur throughout the 2030s, driven to a large extent by Marinus Link and supporting transmission enabling the deferral of about 1 GW of New South Wales pumped hydro capacity to the 2040s.

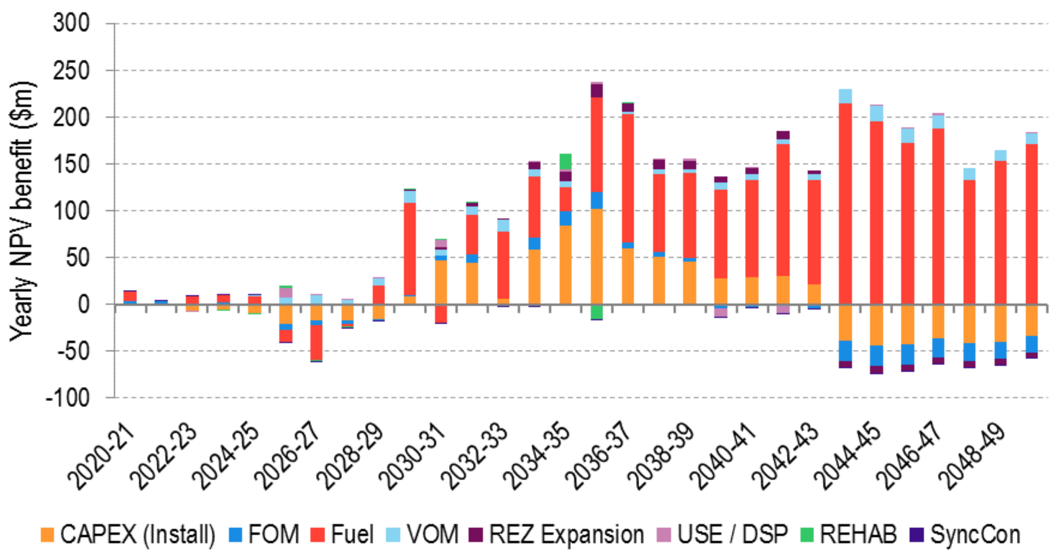

Figure 14 Annual market benefits by category, for the preferred RIT-T option (1500 MW link commissioned in 2028 & 2032) in the Global slowdown scenario[71]

[71] The market benefits in this graph are discounted to 2025 instead of 2019. The relative magnitudes of benefits – and thus the discussion – are unaffected. Legend abbreviations: CAPEX = capital expenditure (for new generation and storage); FOM = fixed operation and maintenance costs; VOM = variable operation and maintenance costs; REZ expansion = transmission expansion to renewable energy zones; USE = unserved energy; DSP = demand side participation; REHAB = rehabilitation costs; SyncCon = cost to operate synchronous condensers.

Figure 15 shows the benefits of Marinus Link and supporting transmission under the Sustained renewables scenario. This scenario assumes that coal plant retires between three and five years earlier than the Status quo/current policy scenario. As a consequence, the benefits from Marinus Link and supporting transmission are brought forward to earlier in the period, dominated by fuel cost savings.

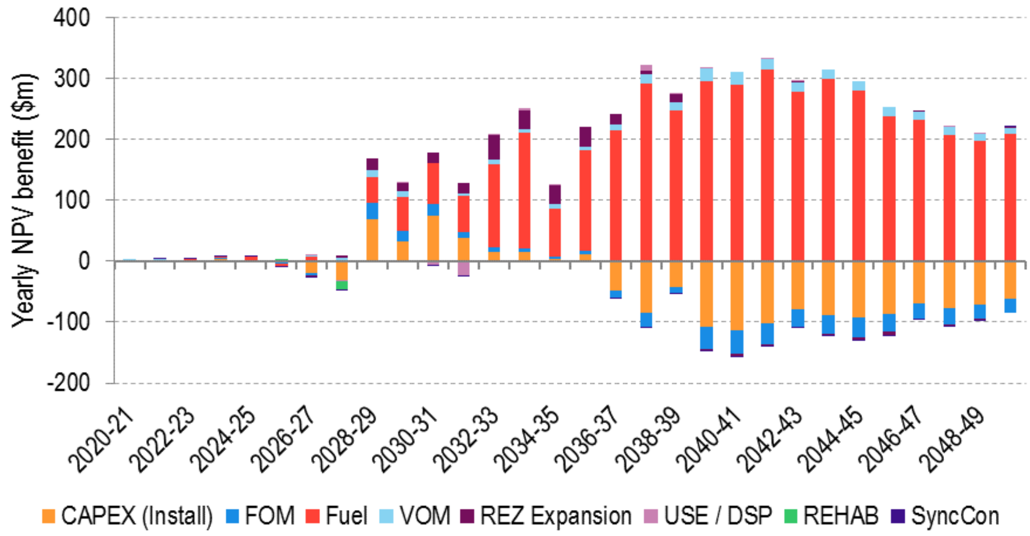

Figure 15 Annual market benefits by category, for the preferred RIT-T option (1500 MW link commissioned in 2028 & 2032) in the Sustained renewables uptake scenario[72]

In the Accelerated transition to a low emissions future scenario in Figure 16 below, the fuel saving benefits diminish significantly towards the end of the period. Under this scenario, the high emissions reduction target restricts the development and use of gas turbines even without Marinus Link, thereby limiting the ability of Marinus Link and supporting transmission to reduce gas usage.

72 The market benefits in this graph are discounted to 2025 instead of 2019. The relative magnitudes of benefits – and thus the discussion – are unaffected. Legend abbreviations: CAPEX = capital expenditure (for new generation and storage); FOM = fixed operation and maintenance costs; VOM = variable operation and maintenance costs; REZ expansion = transmission expansion to renewable energy zones; USE = unserved energy; DSP = demand side participation; REHAB = rehabilitation costs; SyncCon = cost to operate synchronous condensers.

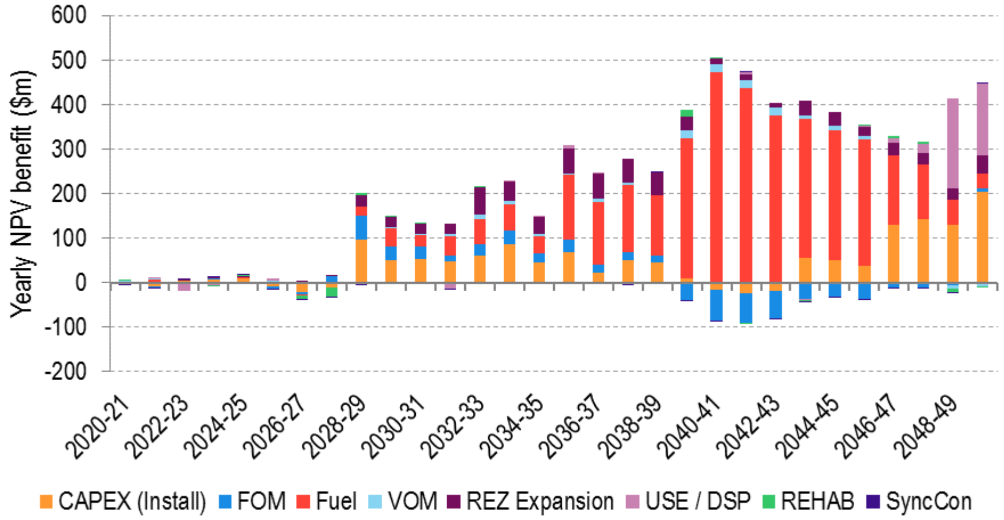

Figure 16 Annual market benefits by category, for the preferred RIT-T option (1500 MW link commissioned in 2028 & 2032) in the Accelerated transition to a low emissions future scenario[73]

Without Marinus Link, the limited use of fossil fuels causes a notable amount of unserved energy cost in the final two years of the study, as there is insufficient dispatchable generation to meet demand and the model's limit of mainland pumped hydro development is reached. This is averted with the presence of Marinus Link and supporting transmission, which allows the economic development of Tasmanian pumped hydro. More Tasmanian pumped hydro development occurs in this scenario than any other.

In summary, the above discussion highlights that the primary benefits from Marinus Link and supporting transmission are fuel costs savings as mainland Australia exploits the natural advantages that Tasmania provides through its existing and potential future hydro systems and wind resources. Marinus Link and supporting transmission unlock this potential by providing the mainland NEM with access to these Tasmanian resources.

As already noted, across the four scenarios and our sensitivity analysis, the net market benefit from Marinus Link and supporting transmission is significant, with the optimal timing and capacity increments being the commissioning of 750 MW in 2028 followed by a further 750 MW in 2032. Our modelling indicates that, in net present value terms, the total expected net benefits from Marinus Link and supporting transmission will be more than $1.6 billion over the study period, averaged across the four scenarios.

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[73] The market benefits in this graph are discounted to 2025 instead of 2019. The relative magnitudes of benefits – and thus the discussion – are unaffected. Legend abbreviations: CAPEX = capital expenditure (for new generation and storage); FOM = fixed operation and maintenance costs; VOM = variable operation and maintenance costs; REZ expansion = transmission expansion to renewable energy zones; USE = unserved energy; DSP = demand side participation; REHAB = rehabilitation costs; SyncCon = cost to operate synchronous condensers.

6.5 Other interconnector options

The previous section provided a detailed examination of the benefits that Marinus Link and supporting transmission are able to provide to the NEM. Essentially, we explained that Marinus Link provides low cost renewable energy to mainland NEM regions (via Victoria) and firming capability for renewables, as coal generating units retire.

Nevertheless, TasNetworks recognises that AEMO has identified KerangLink as a transmission interconnector project that could play a similar role to Marinus Link. In particular, AEMO's 2018 ISP commented that:[74]

> "A large capacity Victoria to New South Wales interconnector upgrade is flagged ahead of, and in preparation for, retirement of existing coal-fired generation in the mid-2030s
>
> […]
>
> …the Snowy Link project (major Victoria to New South Wales upgrade) delivers capital deferral benefits by unlocking access to REZs without the need to build additional intra-regional transmission. It facilitates greater investment in, and sharing of, diverse renewable generation resources and storage across New South Wales and Victoria, and reduces the need for gas-powered generation and energy storage to provide firming services and manage the concentration of renewable generation. Consequently, generation capital deferral benefits are negative (more renewable generation investment required), but annual fuel cost savings increase (less need to burn gas)."

The purpose of this section, therefore, is to explain how Marinus Link and KerangLink are expected to work together to deliver an optimal outcome for the NEM.

Figure 17 shows the net energy flow across all NEM inter-regional boundaries for each year of the study period, in the absence of Marinus Link. It shows that the flows from Victoria to New South Wales are predominantly positive (i.e. northwards) for almost every year of the study. The net flow to New South Wales increases from 2035-36 onwards, coinciding with the retirement of Bayswater Power Station (New South Wales, 2640 MW capacity).[75] This suggests that the primary purpose of the Victoria to New South Wales interconnectors (both existing and KerangLink) is to supply energy to New South Wales.

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74 AEMO, *Integrated System Plan 2018*, July 2018, p 87 and 95.

75 This was also preceded by retirement of Eraring (2880 MW) in 2031-32 and Vales Point (1320 MW) in 2029-30.

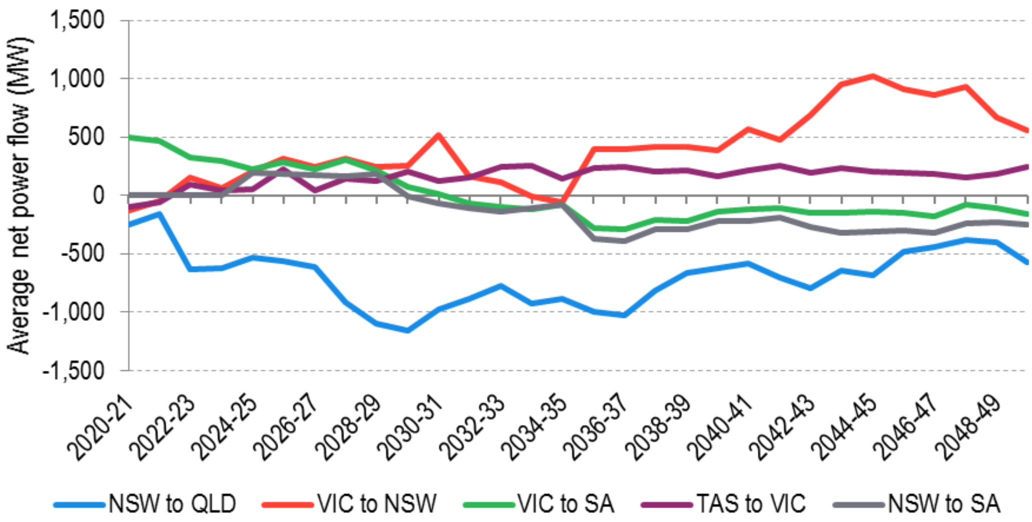

Figure 17 Net energy flow across NEM regional boundaries by year, Status quo/current policy scenario without Marinus Link

Our preliminary modelling suggested that optimal timing of KerangLink was in 2034-35 to coincide with the retirement of Eraring (2880 MW in New South Wales). Once the retirement of Eraring was advanced to 2031, this brought forward the optimal timing of KerangLink to 2030-31. This year also coincides with the retirement of second unit of Yallourn (375 MW retiring in Victoria). This retirement of over 3200 MW of dispatchable capacity is the primary driver for increased resource sharing between the regions. Our analysis further indicated to meet the Victorian Renewable Energy Target requirement, Victoria could incur about $1.3 - $1.7 billion in REZ expansion costs and KerangLink is primarily relieving the congestion constraints in Southern New South Wales and Northern and Western Victoria region.

Besides accessing Victorian REZs, KerangLink provides limited dispatchable capacity to Victoria. This is primarily due to Snowy 2.0 capacity (2000 MW expected in 2026) being fully used to service the void in dispatchable capacity left by retirement of Liddell and Vales Point B (2000 MW in 2022 and 1320 MW in 2029 respectively) in New South Wales. KerangLink flows northwards are about three times greater than its flows southwards, which further validates our analysis.

Our modelling shows that if Marinus Link is commissioned, it services Victoria by firming renewables and subsequently allowing KerangLink to provide a greater role of net energy transfer towards New South Wales. Marinus Link and KerangLink complement each other by efficiently providing dispatchable capacity from Snowy Hydro and Tasmanian hydro schemes to Victoria and New South Wales, while also sharing excess renewable energy generation between regions. Our modelling indicates that excess wind generation from Victoria will be exported to New South Wales and similarly Victoria and Tasmania are likely to be absorbing excess New South Wales solar generation to meet demand and charge pumped hydro schemes.

Most importantly, the combination of Marinus Link and KerangLink together are able to create additional value for the NEM. Table 17 shows the net market benefit that would arise with different commissioning timings of either/both Marinus Link and KerangLink.

Table 17 Net market benefit from various combinations of Marinus Link and KerangLink timing, in the Status quo/current policy scenario (values in $ million)

		No Marinus Link	Marinus Link 1500 MW timing		
			2026 & 2028	2028 & 2030	2030 & 2032
KerangLink	No KerangLink	0	1,025	1,168	1,246
	2026	454	1,366	1,548	1,634
	2030	568	1,516	1,657	1,733
	2034	444	1,472	1,614	1,689

Table 17 also shows that the net market benefit from combinations of Marinus Link and KerangLink are greater than either link in the absence of the other. For example, the net market benefit of KerangLink commissioned in 2030 (but no Marinus Link) is $568 million. The benefit of a 1500 MW Marinus Link commissioned in 2028 and 2030, but with no KerangLink is $1,168 million. However, the net market benefit of both links being commissioned with these timings is $1,657 million, which is substantially greater than the benefit of either link on its own.

We acknowledge that this analysis uses only one scenario and only one of the four Marinus Link and supporting transmission options, but it demonstrates that the two links are complementary. Given this conclusion, stakeholders should be confident that Ernst & Young's market expansion model has appropriately considered the interplay between Marinus Link and other transmission interconnectors.

7 Who pays for the link?

This *PADR* has demonstrated that Marinus Link, with the supporting network augmentations, satisfies the RIT-T. In accordance with the RIT-T, the identified preferred option may proceed as a regulated investment, which would be remunerated through transmission revenues and prices set in accordance with Chapter 6A of the NER.

In addition to demonstrating the case for investment, however, the question of 'who pays' for Marinus Link and supporting transmission must also be considered. In the current economically sensitive climate of high energy prices, it is not sufficient to demonstrate that the project maximises net economic benefits in accordance with the RIT-T provisions. The project must also be supported by those who will ultimately pay for it, namely transmission customers.

This point has been made by several stakeholders in their submissions to our *PSCR* and our *Initial Feasibility Report*.[76]

TasNetworks recognises that the resolution of the 'who pays' issue is beyond the scope of this *PADR*. Nevertheless, it is appropriate to take this opportunity to explain the problems with the current transmission pricing arrangements for interconnectors and the steps we are taking to resolve them.

7.1 Current pricing arrangements

The NER contain detailed provisions that govern the setting of transmission prices for regulated transmission assets. Unfortunately, the pricing provisions relating to new interconnector assets, such as Marinus Link, are not fully defined in the NER. As explained below, historical pricing practices for interconnector assets have developed that are unlikely to produce fair or efficient prices.

The mechanism for recovering the costs of an interconnector has arisen on a number of occasions, most notably for Murraylink, Directlink, QNI, and the Heywood interconnector upgrade.

In each of these cases, the annual revenue requirement for the interconnector and the supporting network augmentations has been allocated between the two connected regions in proportion to the value of the assets geographically located in the relevant regions. To date, this allocation has been agreed informally between the principal TNSPs in each region (and/or the State jurisdictions), noting that the NER do not provide any formal guidance in relation to this process.

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[76] COTA Tasmania, Energy Consumers Australia, Tasmanian Small Business Council.

Following the allocation of the revenue requirement between the two interconnected regions, transmission prices are then set by the coordinating transmission company in each region in accordance with its approved pricing methodology. The pricing methodology must be consistent with the NER for transmission pricing and the AER's Transmission Pricing Methodology Guidelines.

It is a NER requirement that each transmission company's pricing methodology must apply an annual Modified Load Export Charge (**MLEC**). In broad terms, the purpose of the MLEC is to enable each transmission company to levy charges on its neighbouring jurisdiction to reflect the neighbour's use of its network (including interconnector assets and other network assets), and vice versa.[77] To some extent, therefore, the MLEC revisits the initial allocation of the costs between the two interconnected regions.

The current transmission pricing practice for interconnectors therefore involves the following two-step process:

- Step 1: Each transmission company (and its State jurisdiction) agrees the allocation of the revenue requirement for the interconnector and the supporting network augmentations between the two regions; and
- Step 2: The MLEC is applied annually in accordance with each transmission company's approved pricing methodology and the NER.

Our analysis indicates that the first step has the largest effect in allocating costs between regions, with the MLEC only adjusting this initial allocation by a modest amount. As such, it is the agreement between the relevant transmission companies (and State jurisdictions) on how the revenues should be recovered in each region (Step 1) that is the key determinant of 'who pays' for an interconnector and the supporting network augmentations that are required to facilitate the optimal energy transfers.

In summary, therefore, the current transmission pricing practice is to recover the costs of the interconnector between the two connected regions principally according to the geographic location of the assets. This approach does not allocate the interconnector costs to each NEM region according to the benefit each obtains from the investment. As such, the current pricing approach is unfair and inefficient because:

- Some customers who benefit from the investment will pay a lower amount towards to cost of the investment than they should; and

[77] It is questionable whether the MLEC is designed appropriately in relation to interconnector assets, as the use of the asset may not reflect the value that each region obtains from it.

- Other customers will contribute to the costs of the investment, even though they obtain little or no benefit from it.

In its recent report, the AEMC concluded that inter-regional pricing arrangements should, over time, ensure that those who benefit from an interconnector pay for that interconnector.[78] We agree with the AEMC.

In the next section, we explore what this means for Marinus Link and supporting transmission.

7.2 Who benefits from Marinus Link?

The market modelling presented in Chapter 6 estimated the classes of market benefits that Marinus Link and supporting transmission are likely to deliver under different scenarios. In accordance with the RIT-T, the purpose of that analysis is to identify the credible option that maximises expected market benefits across a number of scenarios. The underlying modelling results also indicate how customers are expected to benefit across the NEM regions.

We focus on 'customer benefits' because the NER require the costs of shared transmission investment to be paid for by load customers only. In our view, it is appropriate to consider the question of 'who benefits' from a transmission investment in the context of those market participants who are required to pay for it – namely load customers.

In the case of Marinus Link and supporting transmission, these customer benefits primarily comprise:

- Lower wholesale generation prices;
- Lower ancillary service costs; and
- Reductions in the expected unserved energy.

The primary customer benefit resulting from Marinus Link and supporting transmission is lower cost to supply generation to the NEM than would occur if the link does not proceed. In any competitive market, a reduction in supply costs should be reflected in a reduction of the price for the good or service paid by customers. In the context of the NEM, a reduced cost of supply would be expected to result in reduced wholesale prices, because a fundamental tenet of the NEM's market design is that it endeavours to ensure wholesale prices reflect the marginal cost of supply. Whilst the following analysis is presented in terms of the customer-centric benefit (being reductions in wholesale prices) the underlying modelling and analysis was actually in terms of the marginal cost of supply.

[78] AEMC, Consultation paper, *CoGaTI Implementation – Access and Charging*, 1 March 2019, p. 21.

Ordinarily, if a region increases its exports of any good or service, it will tend to experience an increase in its 'domestic' price for that good or service. In the case of Marinus Link and supporting transmission, however, the Tasmanian Government has stated that Tasmanian customers should not be worse off as a result of Marinus Link, and the Tasmanian Government has regulatory instruments available to ensure Tasmanian end-use customers are effectively shielded from any increases in the wholesale price.[79.]

Figure 18 shows the impact of Marinus Link and supporting transmission on wholesale generation prices across the NEM regions and over time. This graph shows the difference between forecast wholesale prices if Marinus Link and supporting transmission does not proceed, and the forecast prices with Marinus Link and supporting transmission in place. Tasmania is shown to be unaffected, given the Tasmanian Government's position.

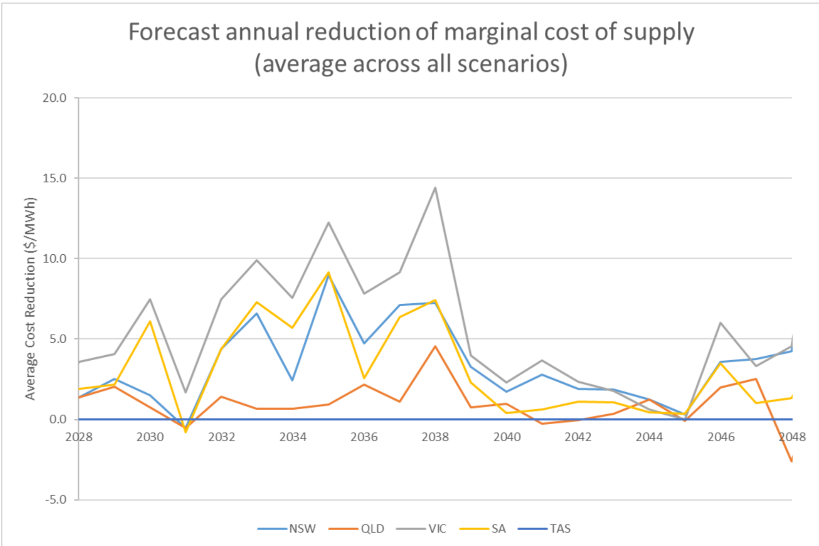

Figure 18 Reductions in forecast regional wholesale generation prices as a result of Marinus Link and supporting transmission

Figure 19 extends the above analysis to show the share of total customer benefits that each NEM region will obtain from Marinus Link and supporting transmission over the 20-year period from 2028 to 2048. It shows that New South Wales and Victoria obtain the majority of the benefits, being 42 per cent and 47 per cent respectively.

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79 http://www.premier.tas.gov.au/releases/electricity_price_cap

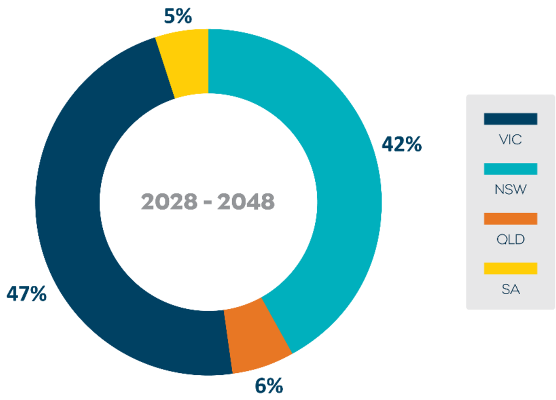

Figure 19 Regional distribution of benefits from Marinus Link and supporting transmission on a weighted average across four scenarios 2028-2048

Our analysis shows that initially, Marinus Link and supporting transmission predominantly benefit Victoria by providing dispatchable capacity during the retirement of brown coal. As the pace of coal retirements accelerate across the NEM, New South Wales' share of benefits from Marinus Link and supporting transmission increases.

It is notable that our analysis does not identify Tasmanian electricity customers as beneficiaries from Marinus Link and supporting transmission. Historically, Basslink has provided reliability benefits to Tasmania during 'dry' years. In future, however, the growth in Tasmania's wind generation, coupled with a more conservative approach to managing hydro storage levels, will reduce reliability risks. On this basis, Marinus Link and supporting transmission are not expected to provide significant reliability benefits to Tasmanian customers. Nevertheless, the additional interconnector capacity provided by Marinus Link and supporting transmission will provide market benefits to the NEM in the event of a Basslink outage, as inter-regional trade will be able to continue albeit at a reduced level.

The share of the benefits from Marinus Link and supporting transmission across the NEM regions contrasts with the pricing outcomes under the current NER. As already noted, the current transmission pricing practice would allocate the costs of Marinus Link and supporting transmission principally on the basis of the geographic location of the assets between Tasmania and Victoria. Whilst this is not a straightforward exercise, as the HVDC cable is mostly located in Bass Strait and is therefore in neither region, it is likely to result in an approximately 50/50 sharing of the costs between Tasmania and Victoria. It is doubtful if New South Wales, Queensland, and South Australia would pay any contribution to the costs of Marinus Link and supporting transmission under the current pricing arrangements, despite collectively receiving over 50 per cent of the customer benefits from it.

Based on similar preliminary analysis for KerangLink, the benefits of this interconnector extend beyond the states of Victoria and New South Wales. In this instance again, the cost contribution would be split equally, based on the geographic location of the assets – again creating a mismatch between those who pay for the investment and those who benefit from it.

A clear message emerges from the above analysis: the current NER pricing will not provide reasonable or fair outcomes for customers in each region. In the next section we explain the steps we are taking to address this issue.

7.3 A way forward

TasNetworks' primary concern is to ensure that the pricing arrangements for new interconnectors deliver fair and reasonable outcomes for customers in each region. In broad terms, this means better matching of the costs borne by each region with the benefits they receive. By delivering this outcome, customers in each region should welcome any interconnector investment that satisfies the RIT-T because those customers will know that:

- The project maximises net market benefits; and
- Customers in each region will pay a contribution to the cost of the investment that is commensurate with the benefits they receive.

TasNetworks acknowledges that it is difficult to estimate the benefits enjoyed by each region from a new interconnector, as these benefits will likely change over the life of the asset in response to future market developments. Nevertheless, whilst estimates cannot be made with a high degree of precision, it should be possible for the RIT-T proponent to produce estimates that significantly improve on the current pricing methodology (which does not consider beneficiaries at all).

Following the publication of the *PSCR*, we have discussed our concerns with a number of stakeholders including the AER, the AEMC, and the ESB. Each of these stakeholders recognises the issues raised and understands that the current NER for transmission pricing are failing to deliver fair and efficient outcomes for new interconnectors, such as Marinus Link (including supporting transmission) and KerangLink. We have also examined arrangements in the United States of America, where the 'beneficiary pays' principle has been successfully applied in a number of jurisdictions.

In November 2019, this issue was brought to the fore by the COAG Energy Council, which requested the ESB to provide advice on a fair cost allocation methodology for interconnectors. We therefore anticipate the ESB will consult on alternative interconnector pricing arrangements in 2020.

To assist in resolving the pricing issues for Marinus Link and other new interconnectors, we have consulted with the Tasmanian Government and other stakeholders to prepare a discussion paper relating to possible changes to the NER concerning interconnector pricing. Our discussion paper proposes a methodology to provide a fair and more efficient pricing outcome for new interconnectors, by building on the current RIT-T analysis and consultation processes. The discussion paper may be found as Attachment 3 to this *PADR* on our website, and we are seeking stakeholders' views on issues raised and our proposed interconnector pricing methodology.

Stakeholders' views will inform our submission to the ESB's consultation on this issue. We request that interested parties provide feedback by 2 March 2020 as part of the consultation process for this *PADR*, as detailed in section 1.6. If the current interconnector pricing framework ultimately remains unchanged, an alternative solution for Marinus Link (including supporting transmission) is to obtain external funding from the Australian and/or State Governments to ensure that Tasmanian electricity customers do not pay more than their fair share. Essentially, obtaining external funding would ensure that efficient projects, such as Marinus Link and supporting transmission, are able to proceed without causing an adverse pricing impact on any group of electricity customers.

Whilst this option provides a pragmatic solution, in our view, it is appropriate for the electricity sector to adopt pricing arrangements for new interconnectors that give effect to the beneficiary pays principle. In this sense, external funding might be considered to be a complementary or 'fall-back' option, if the electricity sector is unable to introduce better pricing arrangements within a reasonable timeframe.

TasNetworks is committed to a fair pricing outcome for Marinus Link. TasNetworks will continue to engage with stakeholders, governments, and regulators to promote a workable solution. However, it remains the case that Marinus Link and supporting transmission will only proceed if acceptable pricing outcomes are achieved.

Appendices and attachments

Appendix 1	Summary of submission to the *PSCR*
Appendix 2	Cost analysis for each credible option
Appendix 3	Analysis of AC transmission augmentations in Tasmania
Appendix 4	Market modelling sensitivity studies
Appendix 5	National Electricity Rule compliance checklist

Attachment 1	Ernst & Young market modelling report
Attachment 2	GHD ancillary services benefits report
Attachment 3	Discussion paper: “Beneficiaries pay” pricing arrangements for new interconnectors

Attachments are located on our website alongside this *PADR.*

Appendix 1 – Summary of submissions to the *PSCR*

Respondent	Key points
AusNet Services	• AusNet Services highlighted the importance of energy security and supports further work to assess the benefits to Tasmania and Victoria. • The potential benefits from a second interconnection may depend on the location and augmentation of connection points in each region. This issue should be addressed in the next stage of the RIT-T. • The Victorian network has the highest capacity in the South East of Victoria. Connection along the East Coast may be efficient as it may avoid the need for deep augmentation. • A full exploration and explanation of the diversity in resources should be undertaken to ensure that the second interconnector does not simply result in a relocation of generation and storage from one jurisdiction to another. • Network resilience will become increasingly important. Greater network resilience may be an additional benefit of increased interconnection, but is difficult to quantify. • Significant changes to the ISP assumptions would be needed to reach a different conclusion on the need for, and timing of, a new interconnector. For example, AusNet Services supports further analysis on the timing of thermal generation closures. Stakeholders will want to understand any differences between TasNetworks' proposal and the conclusions in the ISP. • Each of the connection options identified in the *PSCR* are credible from a technical perspective. AusNet Services offers its support to investigate further options.
Clean Energy Council	• Marinus Link is a welcome addition to the ongoing energy transformation debate. • Further consultation in future ISPs is required to capture the unique jurisdictional opportunities and knowledge relevant to Tasmanian-based ISP projects. • Marinus Link is an important mechanism for capitalising on the diversity between Victoria and Tasmania. • Tasmania has a combination of excellent wind resources and large-scale storage. The flexibility of the Tasmanian hydro generation may support the case for the development of a Renewable Energy Zone in Tasmania and Victoria. • Thermal generation sources are becoming increasingly unreliable. A more interconnected NEM can offer system resilience. • Interconnection will facilitate competition benefits and can help address market concentration issues. • TasNetworks is releasing feasibility studies, which is above and beyond the requirements of the RIT-T and is a very transparent and consultative approach.

Respondent	Key points
COTA Tasmania	• Tasmanian consumers are struggling with cost of living pressures, and so it may not be the right time to invest in a second interconnector. • Basslink's performance should be reviewed (including its cost, annual profit and the amount of time its capacity is used fully) to assess whether a second interconnector is required. • COTA understands that the costs of funding Marinus Link may fall to Tasmanian customers, which would not be fair. • TasNetworks' consultation should explain the short-term and long-term impact on Tasmanian customers by detailing the costs and benefits of Marinus Link. • TasNetworks' modelling must show that Tasmanian consumers will benefit from Marinus Link in terms of lower electricity bills in order for COTA to support the project. Unless the project reduces current electricity prices to consumers, it should not proceed. • The Tasmanian Government intends to leave the NEM. If this were to occur, it is unclear how energy could continue to be sold at a profit to Victoria.
Energy Australia	• Consumers should not be burdened with the risks that benefits promised by large transmission development projects do not eventuate. • It is important to ensure that the benefits to the consumer (and/or taxpayer) justify the project being developed. • The identified need should not exclude a non-network solution. • TasNetworks should provide sufficient robust, transparent, and realistic modelling of market benefits capturing all potential sensitivities and future scenarios. • Modelling should consider any physical dispatch constraint such as minimum on-off times. It should also clearly articulate any assumptions around generation expansion in Tasmania and the remainder of the NEM. • Modelling should clearly address assumptions and methodology around how the lifting of water level restrictions is modelled. • Any benefits from High Impact Low Probability events should be clearly presented separately from other benefit classes. • The *PSCR* identifies energy security for Victoria as a potential benefit, but it is questionable whether a project of this magnitude is the best way of addressing this requirement. • If additional interconnection was to be funded outside the RIT-T framework we would be concerned that this may have a negative distortionary impact on the market. • 'Round trip' network losses and 'round-trip' efficiency of storage need to be modelled carefully in assessing the potential benefit of energy arbitrage activities, where Tasmania stores excess energy from the mainland. • We urge TasNetworks to provide clear and transparent information around any assumptions of new generation capacity.

Respondent	Key points
Energy Consumers Australia	• Consumers need a high level of assurance that the costs and benefits stack up, that it is in their long-term interests, for the project to proceed on a regulated, consumer-funded basis. At present, the proposal is not capable of acceptance by consumers. • Affordability must be constraint on investment and decisions about energy. An overemphasis on reliability and investment at the expense of affordability over the last ten years pushed electricity prices in some parts of the NEM to unsustainable levels. • We are not convinced that the identified need is in the long-term interests of consumers. It appears that the identified need is about providing commercial opportunities for generators – some of which do not yet exist. • The estimated length of time to complete this project could potentially see several other ISP projects initiated and completed in that time. The difficulty for TasNetworks is how it addresses these real risks in its RIT-T assessment. The impact of not adequately assessing this risk could be that consumers are left paying for an expensive, large piece of infrastructure that is significantly under-utilised. • TasNetworks should consider how the planning and delivery of the project could be modularized and sequenced to better align the costs and benefits for consumers over time. • TasNetworks should also consider alternative funding models that reflect the important strategic drivers for this project. The Finkel review recognised that there may remain a need for governments to directly invest in strategic interconnection and transmission capacity. • Energy Consumers Australia would appreciate the opportunity to discuss the best way to continue to work with TasNetworks and other stakeholders on the Marinus Link proposal.
Energy Users Association of Australia	• Our members are highly exposed to movements in both gas and electricity prices and have been under increasing stress due to escalating energy costs. • It is vital to maintain important consumer safeguards such as a robust RIT-T, rational reliability standards and strong, independent oversight by economic regulators. None of these safeguards should be ignored or weakened in the pursuit of loosely defined “strategic” assets that do not deliver lasting and material financial benefits to consumers. • The following parties would benefit from Marinus Link: Hydro Tasmania, TasNetworks, Tasmanian Wind Developers, Tasmanian Government, Victorian Government, Federal Government, and Energy Consumers. • It is unreasonable and unfair to expect that energy consumers carry the entire cost and volume risk of the project. This is not a situation unique to Marinus Link as all new interconnectors and deep connection assets designed to connect Renewable Energy Zones identified in the ISP, all face similar consumer risk issues. • The EUAA are of the view that we must move away from the consumer pays approach to a co-contribution model where those who stand to benefit from assets such as Marinus Link, pay a fair and reasonable amount of the cost. • Exposing more network costs to open markets and competition will drive better outcomes for consumers compared to a regulated environment that, despite good intentions to deliver a result that replicates a competitive market outcome, has not always proven to be so.

Respondent	Key points
Hydro Tasmania	• Hydro Tasmania commends TasNetworks for their consultative and transparent approach in developing this component of the RIT-T for Marinus Link. • A larger interconnector (1200MW) will provide the best opportunities for the NEM to manage the transition of the energy sector and to efficiently utilise the energy resources in both states. • We are confident that Marinus Link can make a strong contribution to meeting the objectives and needs identified in the ISP. • Hydro Tasmania has identified 14 potential locations for the development of pumped hydro energy storage (PHES) and is currently working to refine this list, with the majority costing $1.5 million per MW or less, which is very cost-competitive. • Marinus Link will prove to be a highly cost-efficient option to address Victoria's forecast supply adequacy concerns. • The ability for Tasmanian wind proponents to capitalise on Tasmania's extensive wind resources is, in the most part, reliant on the development of further interconnection. • Tasmania's wind resources have a high capacity factor and a low correlation with other NEM regions. • HVDC can provide fast frequency response and black start capability, as well as independent active & reactive power control. • Hydro Tasmania believes that Marinus Link would bring additional and significant competition benefits to the NEM through facilitating more liquid contract markets. • There will be a heightened need for Victoria to have access to flexible and fast-ramping capacity, which can be provided by Marinus Link as solar output rapidly declines in the evening.
Meridian Energy Australia	• Marinus Link offers unique interconnection benefits as a result of different demand patterns, generation assets and potential storage solutions across the regions. • Modelling should consider the economics of all resources across the regions, noting that Victoria has interconnection with SA and NSW and the ISP recommends immediate upgrades between Victoria and NSW. • Further information should be provided on the viability of the Battery of the Nation Project. It is possible that the Battery of the Nation Project could fund the costs of a new interconnector, avoiding cost recovery through a RIT-T process. • Basslink has created energy security issues in peak periods. A mix of new generation technologies and redundancy across the regions is part of the solution for the system of the future.
Northern Tasmanian Development Corporation	• There is potential for hydrogen production to become a new and substantial export industry for Tasmania. The Bell Bay Industrial Zone is an obvious candidate for the location of hydrogen production and export facilities.

Respondent	Key points
	• Tasmania should produce a Hydrogen Roadmap, similar to the one produced in South Australia. Such a roadmap would enable Tasmania's hydrogen options to be considered in parallel to those offered by the Battery of the Nation project, and with similar levels of evidence-based confidence. • A "hydrogen scenario" should be modelled to determine whether Tasmania's hydrogen options should be pursued in parallel with the Battery of the Nation project.
Origin Energy	• The market benefits of the project can potentially also be met through non-network solutions, or less ambitious augmentations. • We note that in the 2018 Integrated Systems Plan, AEMO's least-cost modelling did not automatically select additional interconnection to the Tasmanian region. • The assessment of this RIT-T should explicitly examine the costs and benefits of Marinus Link if the Battery of the Nation project does not proceed. It is inappropriate for the market benefits of transmission projects to be assessed while assuming a specific new generation and storage layout, where this new generation is not committed.
Roger Martin	• Pumped hydro is unlikely to be viable in Tasmania due to the 20 per cent round trip losses, the Basslink cable losses and the potential for rapid installation of batteries if prices decline further. • The opportunities for price arbitrage may decline as a result of the 5 minute rule, Snowy Hydro and electric vehicles. • Tasmania's existing very large storages (Lake Gordon, Pedder and Great Lake) and medium storages (Lake St Clair, Lake King William, Lake Echo) already have the potential to act as a battery though do not always appear to be have used as such. There are limitations on speed and capacity for future expansion. • Security considerations may justify a 600MW cable. A larger cable may be viable if existing Basslink's life is now expected to be much shorter than original projected 40 years; or if there is significant increase in Government's desire to meet the Paris agreement commitments (much less than 2 degrees, net zero emissions by 2050 etc).
Snowy Hydro	• Strategic transmission projects identified in the 2018 ISP cannot afford further delay and need to become actionable. • Snowy Hydro supports TasNetworks approach of relying on the central assumptions and scenarios developed by AEMO for the ISP, where possible. • TasNetworks notes the possibility that the ISP may "fast track" transmission projects through the RIT-T process if AEMO classifies these projects as "least regret" investments. Snowy Hydro agrees with this approach. • AEMO has done a comprehensive job with the inaugural ISP. Snowy Hydro considers it appropriate that the ISP should focus on identifying transmission projects which are strategic and nationally significant. In our opinion the transmission developments identified in the inaugural ISP has met these criteria.

Respondent	Key points
Tasmanian Renewable Energy Alliance	• The RIT-T assessment process looks only at costs and benefits to the NEM as a whole, but does not address the allocation of costs and benefits between Tasmania and the rest of the NEM. Nor does it address the allocation of costs, risks and benefits between electricity customers and the owners of generation assets. • The investigation does not sufficiently address the possibility that increased wind generation in Tasmania without additional interconnection may meet Tasmanian affordability and energy security requirements with less cost and less risk to Tasmania and to Tasmanian consumers. • Tasmanian pumped hydro and Tasmanian wind generation may in theory be the most cost effective way to provide new dispatchable renewable generation to Victoria, pursuing this involves considerable risk being allocated to consumers. • The rapid deployment of new technologies such as grid and decentralised battery storage and demand management could meet the need to match energy supply and demand faster than can large scale projects such as pumped hydro. This undercuts the business case for investments such as Marinus and may result in the cost to consumers of a regulated asset exceeding the benefits. • Funding options should be identified which create better alignment between who benefits from developments and who bears the cost and risk. Specifically, Tasmanian electricity consumers should not carry the cost and risk of development which benefits mainly developers of wind farms in Tasmania exporting electricity to Victoria. • The 'identified need' in the PSCR is a statement of a business opportunity rather than a statement of a need. • The funding of Tasmanian pumped hydro is not addressed in either the PSCR or Hydro's future state of the NEM analysis but we assume this would be developed as an investment by Hydro Tasmania and would involve additional borrowing by Hydro. • Export of Tasmanian renewable energy into the mainland NEM could contribute to emissions reductions in the NEM. This could be a significant benefit provided that it can be shown that exported Tasmanian energy would displace fossil fuels.
Tasmanian Small Business Council	• This project is important to Tasmania and its small business sector. We strongly support and endorse TasNetworks' application of the RIT-T to the project and intend to engage further with you on it. • TasNetworks' examination of two options is too narrow for such a large project. There are other credible options that should be more thoroughly examined, such as a smaller link (perhaps with option value), use of the Basslink corridor and use of alternative converter technology. • TasNetworks has not gone far enough in identifying non-network options and needs to take a more active role in doing so for the second stage of the RIT-T. TasNetworks has not considered the possibility of a smaller 300 MW link and has dismissed the option of using the existing Basslink corridor without any hard analysis. • The current ISP is not a firm basis for further development of Marinus Link, and additional information is required to overcome this gap. • The RIT-T should also consider the impacts of mainland options on Marinus Link, including those favoured by AEMO, as well as generation and demand side alternatives. In our view, non-network options need to be more actively sought out and seriously considered.

Respondent	Key points
	• In relation to the benefit of reduced ancillary service costs, consideration should be given to the cost of existing or new alternative sources such as hydro, gas generation, Basslink, demand response and batteries. • Tasmania is not unique in being able to provide storage, with Snowy 2.0 and utility scale batteries, for example, also in a position to do so. Moreover, Tasmania's hydro assets and transmission will require significant investment to offer expanded services. • The Battery of the Nation project initiative still needs to be thoroughly tested in regard to the viability of its components, the amount of additional capacity available and their costs per MW. On the surface, the claims made by Hydro Tasmania about pumped hydro capacity and its costs per MW appear to be too optimistic. If pumped hydro capacity has to be scaled back, this would place more emphasis on intermittent wind generation. • Regarding an increased possibility of retail competition emerging in Tasmania, in our view this is likely to be more heavily influenced by the dominance of Hydro Tasmania, the associated difficulties with new retailers managing wholesale price risk and the Government's future appetite for regulating pricing. • The measurement of aggregate market benefits, albeit important from a regulatory standpoint, is not so meaningful to consumers, who wish to understand the impact of major network investments on them, especially their electricity bills, although this is not required under the RIT-T. Other beneficiaries, such as renewable generation developers, should also pay costs in proportion to the benefits they derive from the project. • The small size of the Tasmanian market compared to the rest of the NEM and the absence of any capacity problem also suggests that a second interconnector will be less beneficial to Tasmanian consumers. Charges should reflect the distribution of benefits between the two regions.
UPC Renewables	• UPC is a strong supporter of more interconnection between Tasmania and Victoria. • The combination of low cost wind, low cost pumped hydro and low cost hydro generation will deliver a solution to the trilemma of affordable, renewable and dispatchable electricity for the ultimate benefit of Tasmanian and NEM consumers • UPC has been concerned about the assumptions used in the ISP and the potential for these to distort the value proposition of more interconnection between Tasmania and Victoria. For example, it is incorrect to assume that wind or solar have the same cost and capacity factors across all regions. UPC expects capacity factors close to 50 per cent for its Tasmanian projects (compared to the ISP assumption of 40 per cent across the NEM regions) and capex costs 10-20 per cent lower than indicated in the recent ISP modelling by AEMO. • The ISP incorrectly assumes that the cost of pumped storage is the same across the NEM and understates the cost on the mainland ($1.4 million per MW compared to UPC's estimate of $2.0 million-2.5 million per MW). More recent work by ARENA and Hydro Tasmania has demonstrated that the Tasmanian pumped hydro opportunities have a capex of between $1.1 million-$2.3 million per MW. • Scenarios must be realistic. For example, assuming the low cost wind and pumped hydro developments occur in Tasmania without more interconnection is unrealistic. Pumped hydro and interconnection should be analysed as a combined project in order to estimate the full benefits of these projects. • Correlation between operating Victorian and Tasmanian wind farms is very low. • It would be useful to include the cost of voluntary and involuntary load reductions, although the value is very specific to the region and the type of loads involved.

Respondent	Key points
	• As indicated by the Office of the Tasmanian Economic Regulator, frequency control ancillary services costs have increased nearly 10 fold over the last 5 years to $43 million in 2017 financial year. It is likely that another interconnector will provide access to lower cost ancillary services. A return to 2015-16 levels would see the cost decrease by nearly $25 million per annum and hence a significant value attributable to more interconnection. • Modelling should test assumptions around coal closure, noting that analysis in the US has assumed the lifespan of coal generation has been substantially less (up to 10 years).

Appendix 2 – Cost analysis for each credible option

This appendix provides further detail of the cost estimates summarised in section 4.7.

Methodology

TasNetworks' capital cost estimate for Marinus Link and supporting transmission considers pre-construction costs, construction costs, interest during construction, and project management costs. The sum of these estimated costs represents a base capital cost, which can be annualised over lifetimes of respective assets. To this annual cost estimate we then add estimated annual operating costs. This results in the total estimated annual cost which is used for the purpose of determining the net market benefit under this RIT-T.

Some cost components are excluded from the analysis for the purpose of this RIT-T, as explained below. This will result in the estimated costs which are used for this RIT-T differing from Marinus Link and supporting transmission project cost estimates stated in other documents which TasNetworks may produce.

Pre-construction costs

Our pre-construction cost estimate reflects the costs to ready Marinus Link (including supporting AC transmission augmentations) for a final investment decision. The costs support completion of the activities required to prepare the project to enter the construction phase, including:

- Marine and land surveys (geotechnical);
- Land use planning and environmental approvals;
- Acquiring access to land and easements;
- Developing conceptual technical designs and specifications;
- Developing tender specifications for equipment supply and installation;
- Undertaking the necessary steps to establish revenue certainty;
- Confirming and implementing commercial arrangements;
- Finalising and implementing contracting, procurement and insurance strategies;
- Completing the detailed estimate for project cost and construction schedule;

- Developing the preferred ownership structure for Marinus Link; and
- Finalising financing arrangements.

A detailed estimate has been prepared at an activity level aligned to the schedule for the project. The estimate reflects the required internal resourcing and external service provision required to deliver the underlying tasks of each activity including ensuring appropriate program management and governance for the phase.

As detailed in Table 18 below, externally funded costs already incurred are excluded from the cost estimate for the purpose of this RIT-T.

Supply and installation of DC assets

The current cost estimates for the HVDC component are reflective of the project having no comparable precedent, being greenfield in nature and being a pre-quotation estimate prepared as part of ongoing feasibility work. The costs of HVDC components have been estimated utilising a combination of the following inputs:

- Budget pricing received from HVDC component manufacturers for the manufacture and supply of cable and converter equipment;
- Supplier quotes for equipment installation including both subsea and land cable burial and protection; and
- Estimates of civil construction requirements based upon experience with similar works.

Supply and installation of AC assets

AC assets costs have been estimated using per-unit costs based on TasNetworks' prior experience with AC network upgrades. Unit quantities have been determined using estimated transmission line lengths and initial considerations of switching station configuration.

Interest during construction

Interest during construction has been included, based on an interest rate of 4 per cent during the Construction Phase. Our current estimate assumes equal cash flows during a four year construction period for each of the two stages of the link.

Project management costs

Project management costs for the AC assets are included in TasNetworks' unit costs. Project management costs for the DC assets have been assumed to be 7 per cent of supply and installation cost.

Assumptions for the purpose of annualising costs

The summation of the costs described above results in an estimated base cost. To annualise these costs, we have assumed:

- HVDC assets have an operational life of 40 years;
- AC transmission assets have an operational life of 60 years;
- Interest during construction is capitalised for the relevant asset;
- Pre-construction costs are capitalised to the HVDC or supporting AC transmission in proportion to the construction costs of those assets; and
- The weighted average cost of capital is the same as the discount rate used (5.9 per cent, other than in discount rate sensitivities.)

Operating costs

Operating and maintenance costs have been estimated separately for the HVDC and supporting AC transmission components.

- For the HVDC component, this includes costs of maintenance, insurance, estimated staffing requirements and corporate support costs.
- For the supporting AC transmission, operating and maintenance costs are assumed to be 1 per cent of capital costs, which is consistent with TasNetworks' standard cost estimation methodology for similar AC assets and reflects TasNetworks' typical asset maintenance costs.

Costs excluded from RIT-T assessment

The total estimated cost of Marinus Link and supporting transmission also includes the following items which are excluded from the cost estimate used for this RIT-T.

Table 18 Cost items excluded from RIT-T net market benefit analysis

Cost item	Why excluded from RIT-T analysis
Accuracy allowance Contingency allowance	Base costs are median (P50) expected costs. Addition of these allowances would bias costs to the high end of the possible cost range. Costs including accuracy and contingency allowances are considered in the sensitivity analysis.
Costs of Initial Feasibility Assessment and Business Case Approval work.	This is a sunk cost, funded by the Tasmanian Government and the Australian Government via ARENA. Because these parties are external to the electricity industry, the cost does not represent a wealth transfer within the NEM and should be excluded from RIT-T assessment. These costs will not form part of the regulated asset base.
Strategic land acquisitions.	These are sunk costs that could be used for Marinus Link or an alternative future project.
Costs of assets to provide unregulated communication services.	Optical fibre must be installed with a HVDC link for operational purposes. With the installation of additional terminal equipment, there is an opportunity to utilise excess bandwidth in the optical fibre to provide communication services to external parties. Such services would be unregulated. The costs associated purely with the provision of these services cannot be included in the regulated asset base.

Cost estimates

Table 19 below presents a more detailed breakdown of the estimated costs which were summarised in section 4.7.

Table 19 Cost breakdown for RIT-T net market benefit analysis

Cost item	Cost in $ millions			
	Option A: 600 MW	Option B: 750 MW	Option C: 1200 MW	Option D: 1500 MW
Pre-construction	180	180	180	180
HVDC supply and installation	1,034	1,114	1,813	1,955
Supporting AC supply and installation	201	201	372	372
Interest during construction	64	69	114	121
Project management	71	76	124	134
Total estimated base cost	**1,550**	**1,640**	**2,603**	**2,762**
Annualised capex cost	95	100	159	169
Annual HVDC operating cost	13	14	19	20
Annual AC operating cost	2	2	4	4
Total estimated annual cost	**110**	**116**	**182**	**193**

Appendix 3 – Analysis of AC transmission augmentations in Tasmania

This appendix presents our evaluation of the Tasmanian AC transmission network augmentation configurations required to facilitate the secure and reliable connection of the preferred option for Marinus Link, being 1500 MW, to the Tasmanian transmission network.

The existing network in North West Tasmania has been established to principally service load customers, and is not capable of providing the power transfer capacity required for Marinus Link. The existing transmission network would be capable of transferring only approximately 180 MW to Marinus Link.[80] As a result, it is not feasible to connect a 1500 MW Marinus Link in North West Tasmania without augmenting the transmission network.

Augmentation of the Victorian AC transmission network is not required. We are proposing that Marinus Link will connect to the Victorian 500 kV network at Hazelwood Substation, which has sufficient capacity to accommodate the connection of a 1500 MW HVDC interconnector.

In the Tasmanian network, an additional consideration is the connection of new renewable generation and pumped hydro resources which are expected to be developed in the coming years.

Market modelling undertaken by the Marinus project is indicating that the connection of the Marinus link will stimulate significant new generation in Tasmania. More significantly, current active developer interest in establishing connections for renewable generation in North West Tasmania demonstrates that such renewable generation projects are highly likely to proceed. We are considering both requirements – the need for transmission capacity to supply Marinus Link and the anticipated need to integrate future renewable generation – holistically, in an effort to ensure that the augmentations to support Marinus Link are consistent with longer term network augmentation requirements and thereby result in the least cost in the long term.

As a result, the Tasmanian transmission network augmentations that are proposed for Marinus Link will also provide a collector network for new renewable generation and pumped hydro storage which will be stimulated by the establishment of a second interconnector. A comprehensive, flexible North West plan has been developed.

80 The main constraining factor is the rating of the Sheffield to Burnie 220 kV circuit, being 138 MVA nominally.

Requirements to be satisfied by AC augmentations

Requirements to support Marinus Link

The supporting transmission augmentations must meet minimum technical requirements:

i. Not lead to a reduction in system security;
ii. Adequate transfer capacity to allow maximum Marinus Link import or export;
iii. Ensure network resilience, including route diversity;
iv. Maximise the usage of existing transmission corridors; and
v. Minimise the amount of new transmission infrastructure created.

To assess technical requirements (i) and (iii), power system simulations were undertaken. These simulations assumed that the existing 220 kV transmission voltage will be utilised for all new transmission lines.[81]

Both steady state simulations and dynamic simulations were undertaken to investigate both credible and non-credible contingencies, to ensure the proposed design meets the minimum technical requirements of the NER and does not negatively impact on system security, including for loss of one Marinus Link monopole.[82]

Simulations have demonstrated that at least three new circuits are required for a radial design, and two circuits are required for a ring design to prevent voltage collapse and transient instability for the contingent loss of one of the circuits.

Connection of future REZs

AEMO has identified three REZs in Tasmania, as shown in Figure 20 below:

- North East Tasmania (REZ T1)
- North West Tasmania (REZ T2)
- Tasmania Midlands (REZ T3)

[81] The highest voltage currently used in the Tasmanian transmission network is 220 kV. We considered the possibility of using a higher voltage under a separate scope of work in 2018. The conclusion of that study was to remain with the existing maximum of 220 kV.

[82] Steady state studies examine power sharing, comparison of losses, and post-contingency line loading. Dynamic studies examine stability following contingency events.

Figure 20 Tasmanian renewable energy zones[83]

Strong developer interest for renewable energy sources in Tasmania has been described in the TasNetworks Annual Planning Report 2019.[84] The tables below are an excerpt of that report, showing developer interest. Some of these projects are being actively progressed and are seeking connection to the transmission network.

Wind Development

North West Tasmania proposals		
Guildford	Connection to Sheffield–Farrell 220 kV transmission line https://epuron.com.au/wind/guildford/	300 MW
Hellyer	Connection to Hampshire Switching Station https://epuron.com.au/wind/hellyer-wind-farm/	150 MW
Port Latta	Connection to Port Latta Substation http://portlattawindfarm.com.au/	25 MW
Robbins Island[85]	Combined connection to Sheffield Substation, with project to be staged https://robbinsislandwindfarm.com/	400–1000 MW
Jim's Plain[78]		160 MW
Western Plains	Connection to Port Latta Substation http://epuron.com.au/wind/stanley-wind-farm/	46 MW

[83] AEMO, *2019 Forecasting and Planning Scenarios, Inputs, and Assumptions*, August 2019, Figure 22, p. 48.

[84] TasNetworks, *Annual Planning Report 2019*.

[85] Robbins Island and Jim's Plain are termed renewable energy parks and are proposed to incorporate some solar and the possibility of storage

North West Tasmania proposals		
Other wind farm proposals		
Low Head	Likely connection to George Town Substation http://www.lowheadwindfarm.com.au/	35 MW
Rushy Lagoon and Waterhouse	Connection to George Town Substation http://www.upcrenewables.com/australia	1,100 MW
St Patricks Plains	Connection to Waddamana–Palmerston 220 kV transmission line https://epuron.com.au/wind/st-patricks-plains/	300 MW

Pumped Hydro Energy Storage

Pumped hydro developments		
Lake Cethana	Pumped hydro station in North West area links Lake Cethana to a new upper storage providing 12 hours of storage capacity	600 MW
Lake Rowallan	Pumped hydro station in North West area links Lake Rowallan to a new upper storage providing 24 hours of storage capacity	600 MW
Tribute	Pumped hydro station in West Coast area links two existing storage Lake Plimsoll and Lake Murchison providing 31 hours of storage capacity	500 MW

Ernst & Young's market modelling for a 1500 MW Marinus Link, including required AC transmission augmentations, indicates that new wind and pumped hydro developments will result from the establishment of a second interconnector, across the 30-year study period:[86]

- North East Tasmania – 250 MW (wind);
- North West Tasmania – 1520 MW (wind) and 1200 MW pumped hydro; and
- Tasmania Midlands – 760 MW (wind).

The market modelling, upon which this *PADR* is based, is therefore broadly consistent with actual developer interest. In order for the market benefits of Marinus Link to materialise, future connections of REZs to the Tasmanian transmission network will be required.

[86] The results were from the Status Quo / Current Policy scenario. Some other scenarios indicated greater amounts of renewables would be developed.

The network augmentations proposed under this RIT-T must primarily serve the purpose of supporting Marinus Link. However, judicious selection of such network augmentation options has the potential to facilitate the efficient connection future network augmentations. Our options selection therefore considers both the immediate need of enabling Marinus Link, and the future network capacity requirements needed to expand the network to allow renewable energy and pumped storage hydro developments to efficiently connect to the network.

Augmentation Route Selection Principles

In selecting routes for new or altered transmission corridors, we have considered environmental impacts, land-owner impacts, and the visual impact of the proposed transmission lines. When technically and economically feasible, our first preference is to use existing transmission corridors.

Transmission augmentation options - North West to Midlands transmission network

The transmission augmentations required to support Marinus Link fall into two categories: augmentation to the network in North West Tasmania, and augmentation of the network between North West Tasmania and the Tasmanian Midlands. This section discusses the augmentation of the network between North West Tasmania and the Tasmanian Midlands. The next section deals with augmentation options in the North West of Tasmania.

The existing 220 kV transmission network shown in Figure 21 currently links the Tasmanian Midlands to North West Tasmania using two separate corridors. One corridor is a direct link between Palmerston Substation in the Midlands and Sheffield Substation in the North West. This corridor contains one single-circuit 220 kV transmission line, which has relatively low capacity. The second corridor is from Palmerston Substation to Sheffield Substation via Hadspen and George Town substations. This corridor consists of double-circuit 220 kV lines for its entire length, and has a much higher capacity. Due to load and generation locations along this corridor, plus its lower impedance, power flows in this corridor are much higher than in the direct Palmerston to Sheffield circuit.

The limited capacity of the direct Palmerston to Sheffield corridor determines how much energy can be exchanged between North West Tasmania and the West Coast and the rest of the Tasmanian power system.

Studies have concluded that power flows between the North West (which inherently includes Marinus Link) and the Tasmanian Midlands would be heavily constrained without any augmentation to the Palmerston to Sheffield transmission corridor. The limited capacity of the Palmerston to Sheffield circuit constrains the transfer capacity of the circuits between Hadspen and George Town. Increasing the transfer capacity between the Palmerston and Sheffield Substations would alleviate the constraint on the circuits between Hadspen and George Town and increase power flows between the North West and the Tasmanian Midlands to support Marinus Link.

Palmerston – Sheffield Options Considered

The existing circuit is strung on single-circuit towers and has a relatively high impedance. The addition of a second transmission line containing a single circuit would result in uneven load sharing between the two circuits, and would be technically challenging. Our preferred option is to widen the existing easement to facilitate the construction of a new double circuit transmission line.

The existing single circuit would be repurposed to augment the supply to the Meander Valley region to support proposed new industrial load.

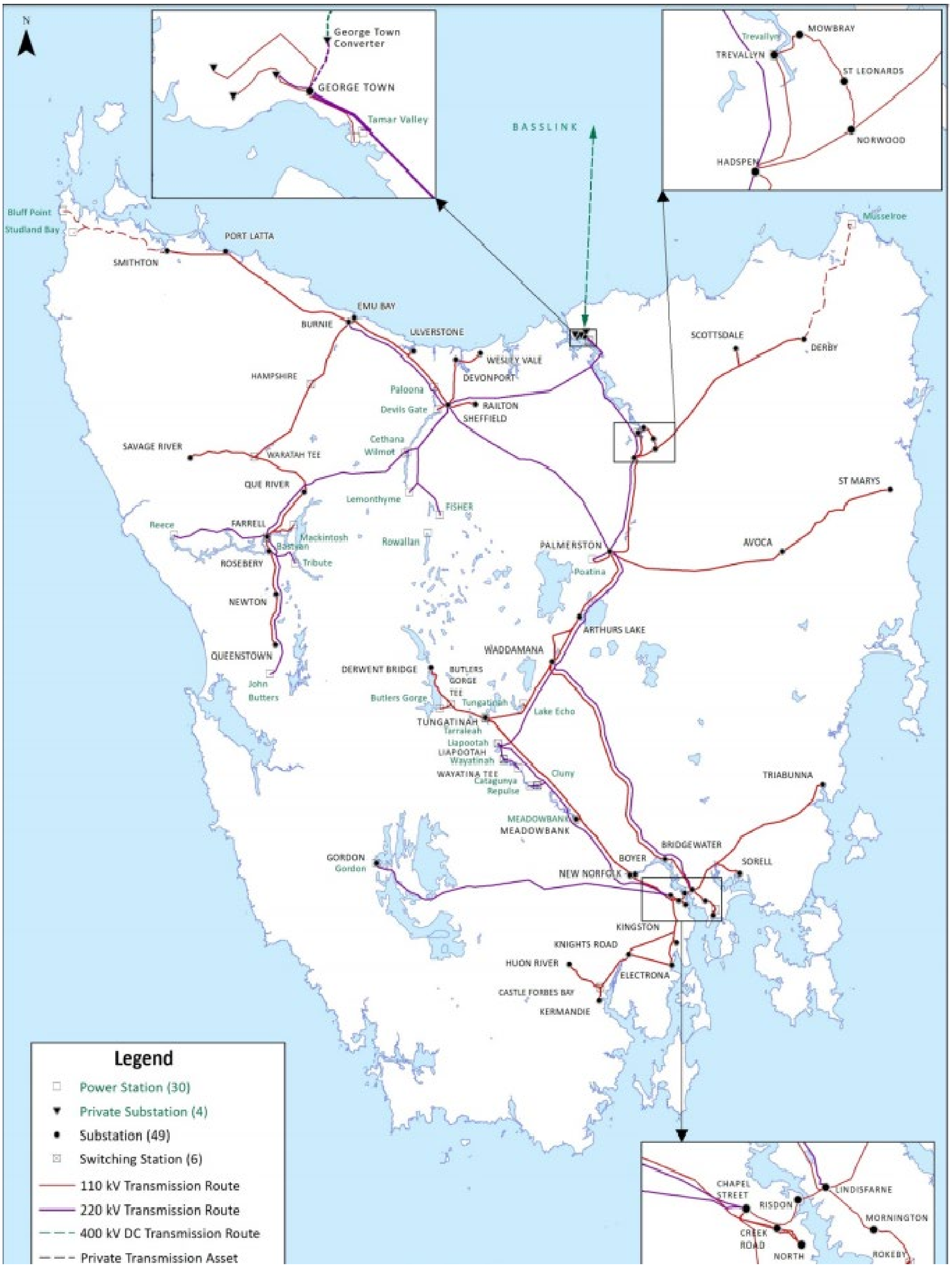

Figure 21 Tasmanian electricity transmission network

Transmission augmentation options – North West transmission network

Overview of the North West Transmission Configurations Considered

When examining the North West transmission network augmentation, we considered routes in the following corridors:

- The existing Northern Corridor between Sheffield and Burnie;
- The existing Western Corridor between Hampshire and Burnie; and
- A proposed new Southern Corridor between Sheffield and Hampshire via Staverton.

Figure 22 below is an indicative map illustrating these corridors.

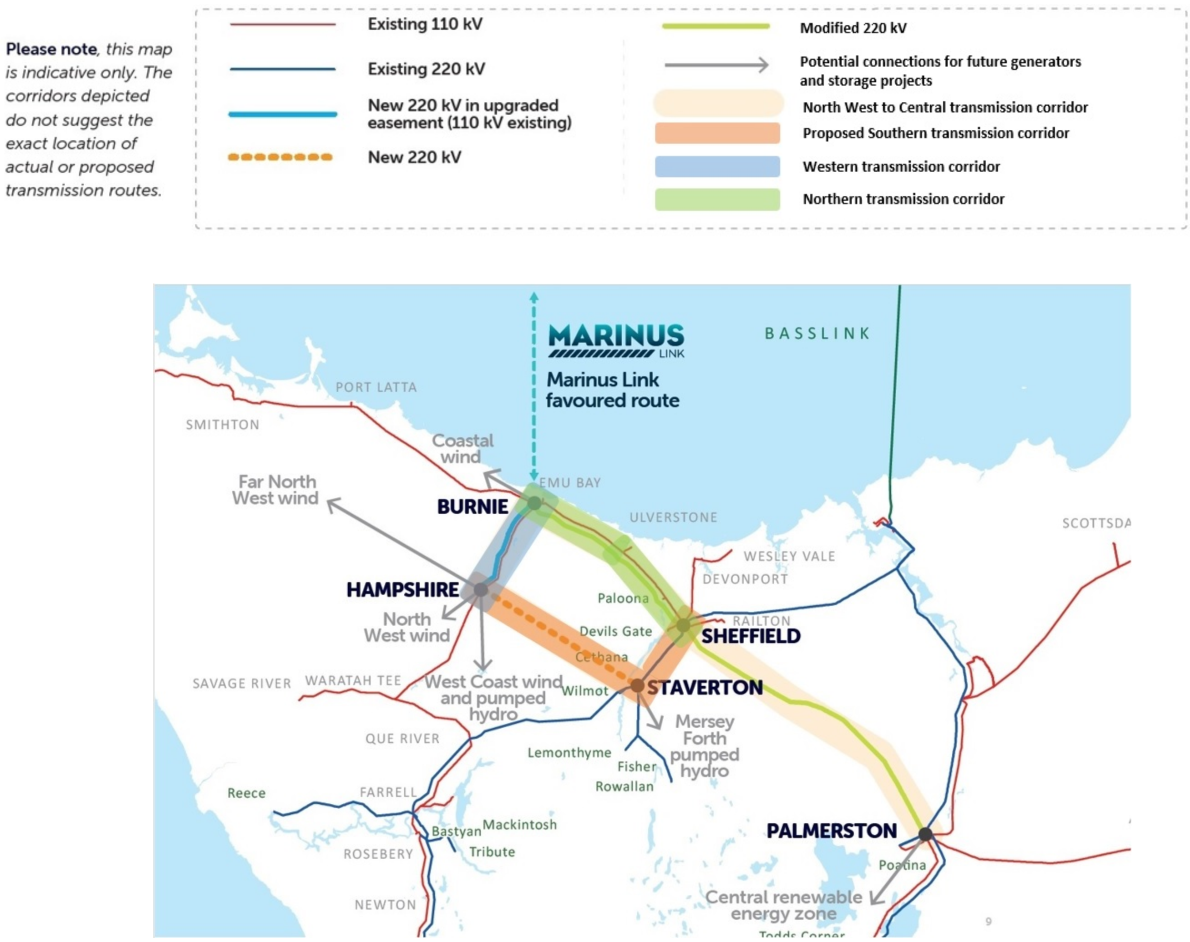

Figure 22 Indicative transmission corridor locations

We have identified three viable network configurations in the North West:

- Configuration 1: Northern and Western routes.
- Configuration 2: A combination of Northern, Western and Southern routes, with the Southern route direct from Hampshire to Sheffield.
- Configuration 3: A combination of Northern, Western and Southern routes, with the Southern route via Staverton.

All of these configurations are technically feasible, but have varying network benefits, landowner impacts and costs.

North West Configuration 1: Northern and Western routes

This configuration, shown schematically in Figure 23, is the conceptually simplest configuration which could support Marinus Link. In this configuration, the existing Burnie to Sheffield transmission corridor would be developed to establish two new double-circuit 220 kV transmission lines. The existing single-circuit Sheffield to Burnie 220 kV transmission line would be decommissioned once the first new transmission line was commissioned.

To facilitate renewable energy developments in the North West, this configuration would require the establishment of a new 220 kV transmission corridor between Burnie and Hampshire and a new 220 kV switching station to be established at Hampshire. Hampshire would then become the connection point for renewable energy developments in the mid North West.

In Figure 23 (and the subsequent diagrams for the remaining configurations) the transmission developments required to support Marinus Link are shown in solid yellow/grey (for new transmission lines) or solid light blue (for new substations or switching stations). The shared network developments which would be required to connect renewable generation in the North West area, are shown with dashed lines of corresponding colours. For completeness, the Palmerston to Sheffield augmentation is shown on all three diagrams.

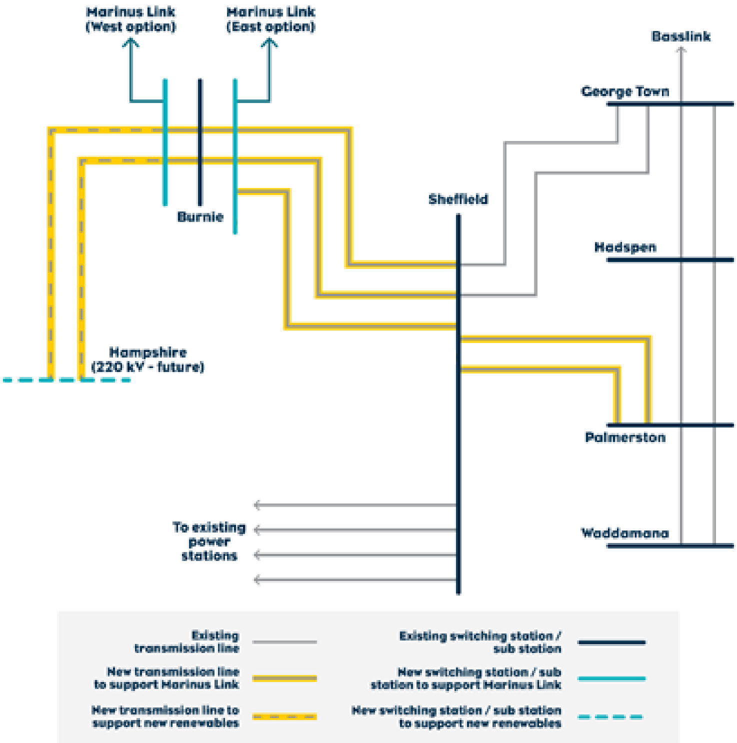

Figure 23 Schematic diagram of Configuration 1

The benefit of this configuration is that the Sheffield to Burnie route follows an existing corridor. However, widening is required to allow the construction of a second transmission line. The construction of two new transmission lines in the existing corridor would impose significant changes to the visual amenity of the existing easement. This configuration would have the greatest impact on land owners of all the configurations considered.

This option also lacks route diversity and has constructability issues due to the close proximity of the existing 220 kV transmission line.

This configuration, shown in Figure 24 involves constructing a 220 kV double-circuit loop taking in Sheffield, Burnie, and a site which could host a future switching station at Hampshire. Compared with Configuration 1, this configuration would provide transmission corridor diversity to improve system resilience, and it would require less future augmentation to support renewable generation connections in North West Tasmania.

As with Configuration 1, a new 220 kV switching station would be established at Hampshire, when required, to provide connections for renewable energy developments in the North West.

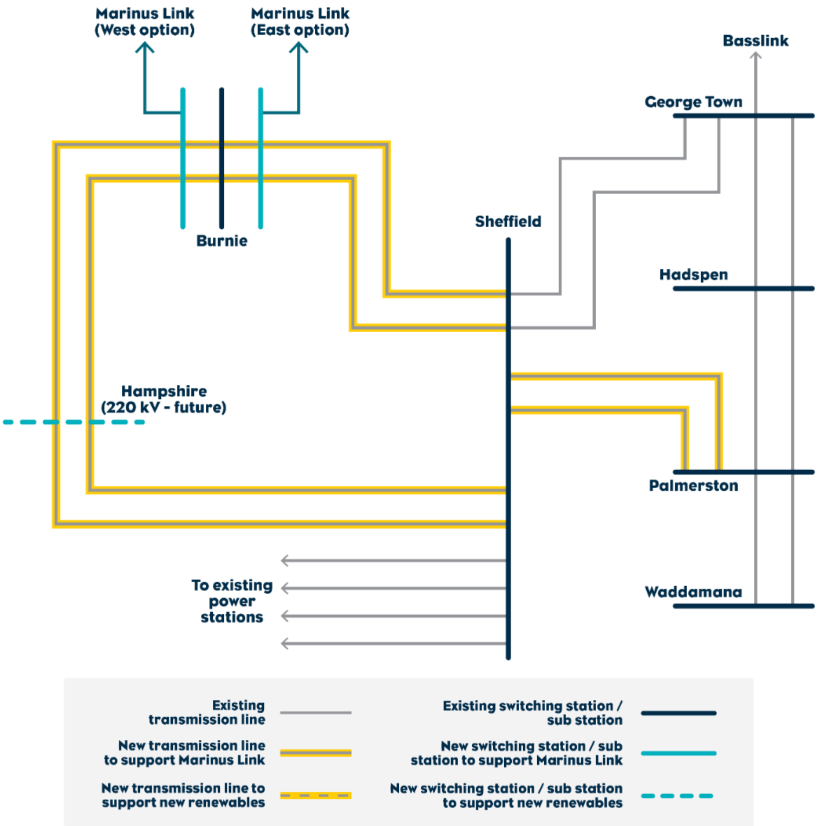

Figure 24 Schematic diagram of Configuration 2

In contrast to Configuration 1, the main advantages of this configuration are the provision of route diversity, and the improved constructability of the Northern route. If the Southern and Western routes between Sheffield and Burnie substations are constructed first, it provides the least risk option to demolish the existing single circuit transmission line between Sheffield and Burnie substations and construct a new double circuit transmission line on the same path as the existing line. This option greatly reduces the impact on landowners and the community compared with Configuration 1, which would require widening of the corridor. Configuration 2 also impacts on a smaller number of individual landowners than Configuration 1.

Disadvantages include the cost requirement for creating a new transmission corridor and transmission line between Hampshire and Sheffield Substation, compared with Configuration 1.

As with Configuration 1, this configuration does not allow for the connection of pumped hydro in the Mersey Forth area without further augmentation.

North West Configuration 3: Combination of Northern, Western and Southern routes, Southern to Sheffield via Staverton

This configuration is similar to Configuration 2, except the Hampshire to Sheffield corridor will make use of the existing transmission lines between Sheffield and a new switching station at Staverton. This configuration proposes to utilise two existing double-circuit 220 kV transmission lines between Sheffield and Staverton for the Mersey Forth hydro power stations. With minor works to increase their capacity, these transmission lines will then have sufficient capacity to support foreseeable future developments in the North West Tasmania REZ. Under this configuration, we propose to uprate and divert these transmission lines into a new switching station at Staverton.

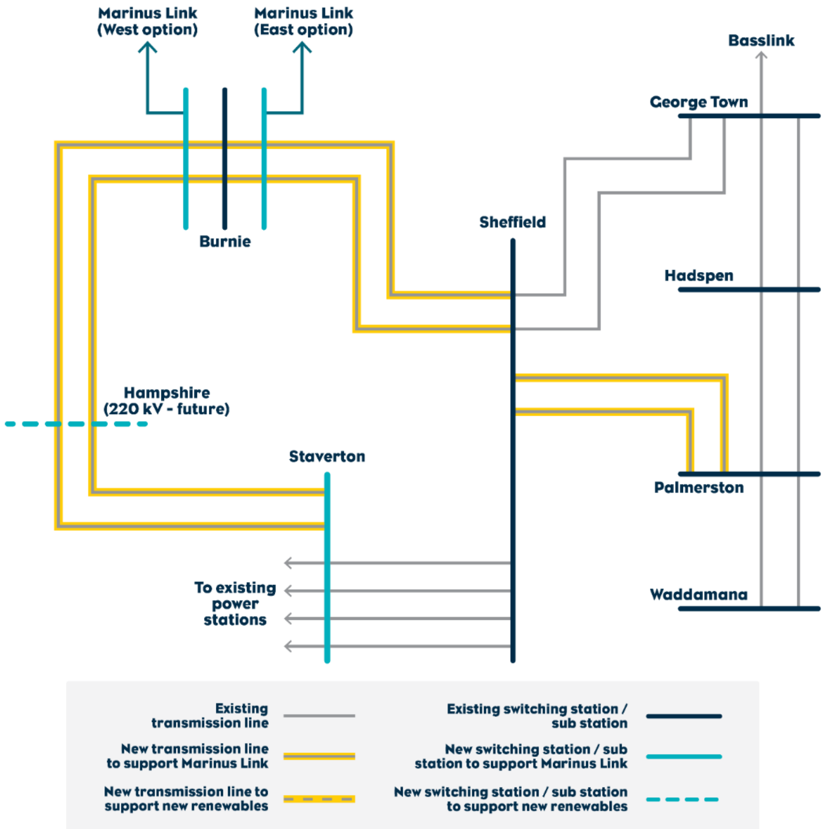

Figure 25 Schematic diagram of Configuration 3

This configuration has all of the benefits of Configuration 2, with the additional benefit of utilising existing transmission lines between Sheffield and Staverton. As no easement widening is required in this corridor, this configuration further reduces the impact on landowners and the community when compared with Configuration 2, and it reduces the cost of constructing a new transmission line in this corridor. This option adds the cost of the proposed Staverton Switching Station and minor transmission line uprating works, however this cost is offset by not needing to build a transmission line between Staverton and Sheffield.

The Staverton Switching Station would also provide a cost effective connection point for the Mersey Forth pumped hydro stations being considered by Hydro Tasmania under the Battery of the Nation project.

In summary this option provides route diversity, support for proposed and future wind farm connections in the North West Tasmania REZ, and a cost effective connection for potential Mersey Forth pumped hydro projects.

Comparison of North West configurations

Network Resilience

In Configuration 1, all four transmission circuits which support Marinus Link pass through a single corridor. An event such as a bushfire in this corridor could require all four circuits to be removed from service, thereby requiring Marinus Link to be removed from service also.

Also the contingent loss of all four transmission circuits in this corridor, if they were heavily loaded, would pose a significant risk of a whole system collapse (potential system black), contravening Tasmania's legislated network planning requirements.[87]

In configurations 2 and 3, the transmission lines which support Marinus Link follow geographically diverse routes. A similar natural event would, in all probability, impact on only one transmission line at one time. Power transfer to/from Marinus Link could still occur – albeit at reduced levels – on the remaining transmission line and the unplanned loss of one corridor would have significantly less impact on the power system.

Support for future REZs

TasNetworks is actively progressing a number of connection applications for renewable developments in the North West, and it is possible that connections for some developments will be required in advance of Marinus Link. If a development occurs in the North West prior to the completion of this RIT-T there may be a requirement to build a new 220 kV Switching Station at Hampshire for all considered configurations.

Configurations 2 and 3 include a double-circuit transmission line between Burnie and Hampshire. This would need to be built in addition to assets required under Configuration 1 to facilitate the connection of future renewable generation in North West Tasmania, hence Configuration 1 offers less benefits in terms of facilitating future network expansion.

[87] Electricity Supply Industry (Network Planning Requirements) Regulations 2018, clauses 5(1)(a)(ii) and (iii).

The establishment of a switching station at Staverton in Configuration 3 will allow reuse of existing assets and will also provide a connection point for potential pumped hydro sites in the Mersey-Forth region. Configurations 1 and 2 would require additional future works (which could be the Staverton Switching Station) to provide connection for pumped hydro in this area. Configuration 3 therefore provides a greater benefit in terms of reuse of existing transmission lines and facilitating the connection of future potential pumped hydro developments.

Cost

Table 20 below summarises the estimated capital costs of the three alternatives we have presented. To provide a valid comparison, two cost estimates are presented:

- The estimated cost to provide only augmentations necessary to support Marinus Link. That is, the costs of the "non-dashed" augmentations in Figure 23 to Figure 25; and
- The estimated cost of augmentation to the configuration to support likely future renewable generation in the North West of Tasmania and pumped hydro connections. This represents the long-term cost which would be required to develop the network so that the full benefits of Marinus Link can be realised and includes the "dashed" items in Figure 22 to Figure 25, notably the new 220 kV Hampshire and Staverton Switching Stations for all configurations. Elements of these incremental augmentations may require subsequent RIT-Ts, however a reduction in these future costs is considered a source of benefit in this RIT-T.

Table 20 Estimated capital cost comparison for the three different network configurations

	Configuration 1	Configuration 2	Configuration 3
Estimated cost to provide only augmentations to support Marinus Link	$300 million	$341 million	$346 million
Estimated cost to provide likely ultimate arrangement	$391 million	$386 million	$361 million

Summary and recommended option

Of the three configurations, Configuration 1 has the lowest estimated up-front cost and Configuration 3 has the lowest estimated cost to provide full future development. These two configurations are therefore preferred from a cost perspective.

Comparing land-owner impact between Configurations 2 and Configuration 3, Configuration 3 is preferable due to the elimination of the need for easement widening between Sheffield and Staverton.

TasNetworks is actively progressing connection applications for renewable developments in the North West, and it is possible that connections for some developments will be required in advance of Marinus Link. On this basis, we consider that the estimated cost to provide full future network development is the better indicator of the least-cost shared network augmentation configuration than the cost to provide augmentations only for Marinus Link. On this basis, Configuration 3 is preferred to Configuration 1.

Configuration 3 has further advantages over Configuration 1 in terms of ease of construction, and the fact that it offers route diversity.

Our conclusion, therefore is that Configuration 3, being

- a 220 kV double-circuit loop from Sheffield to Burnie to Staverton via Hampshire,
- construction of a 220 kV switching station at Staverton,
- uprating of four 220 kV circuits from Sheffield to Staverton,
- the construction of a double-circuit 220 kV transmission line between Palmerston and Sheffield substations, and
- If a renewable connection in the mid North West precedes Marinus link, the construction of a 220 kV switching station at Hampshire.

is the preferred AC augmentation to facilitate the connection of Marinus Link to the Tasmanian power system.

Appendix 4 – Market Modelling Sensitivity Studies

This appendix provides further detail about the sensitivity studies presented in section 6.2.

As outlined in section 6.3.1, Marinus Link provides positive net market benefits with the commissioning timeline of 2027 (stage 1) and 2028 (stage 2) but the benefits of Marinus Link and supporting transmission are maximised for staged commissioning of the link in 2028 and 2032 (i.e., optimal timing). Sensitivity studies were therefore undertaken not just to determine the impact a particular input assumption has on the net market benefits of the project, but also to gain an insight into assessing its impact on the optimal timing of Marinus Link.

Methodology

Scenarios considered

Unless noted otherwise, sensitivity studies were undertaken using the Status quo/current policy scenario only. Sensitivities generally involved two simulation runs of the market model: one simulation with the inputs under consideration changed and Marinus Link and supporting transmission assumed not to be present, and a second simulation with the same inputs but with Marinus Link and supporting transmission present. Unless stated otherwise, Marinus Link was assumed to be commissioned in two stages, the initial 750 MW in 2028 and the second 750 MW in 2032.

Assessing the impact on optimal timing

For sensitivity analysis, the impact on the optimal timing of Marinus Link and supporting transmission was estimated by comparing the gross market benefits[88] of the project in each year with the annualised cost of Marinus Link and supporting transmission. For instance, Figure 26 provides a comparison between the annual gross market benefits from the original Status quo/current policy result (grey line) and the sensitivity study for the entire Yallourn Power Station retirement in 2028 (black line). It also shows the annualised costs of the first 750 MW stage of Marinus Link and supporting transmission (light blue dashed line) and the annualised costs for both stages of Marinus Link and supporting transmission (dark blue dashed line).

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88 Gross market benefit is calculated as the difference in total NEM costs between the “with Marinus Link” and “without Marinus Link” case.

In the sensitivity which considers early Yallourn retirement, the gross market benefit of Marinus Link and supporting transmission is greater than the annualised cost of the first stage (750 MW) from 2028 (gross market benefit of $187 million compared to the annualised cost of first link of $97 million). In the original Status quo/current policy scenario, the gross market benefits of the first stage exceed the annualised costs from 2029 onwards. The year in which the annualised costs exceeds the annualised benefits has thus been brought forward by one year, and on this basis it can be inferred that the optimal year for commissioning the first stage of the interconnector would be advanced by one year if this sensitivity eventuates.

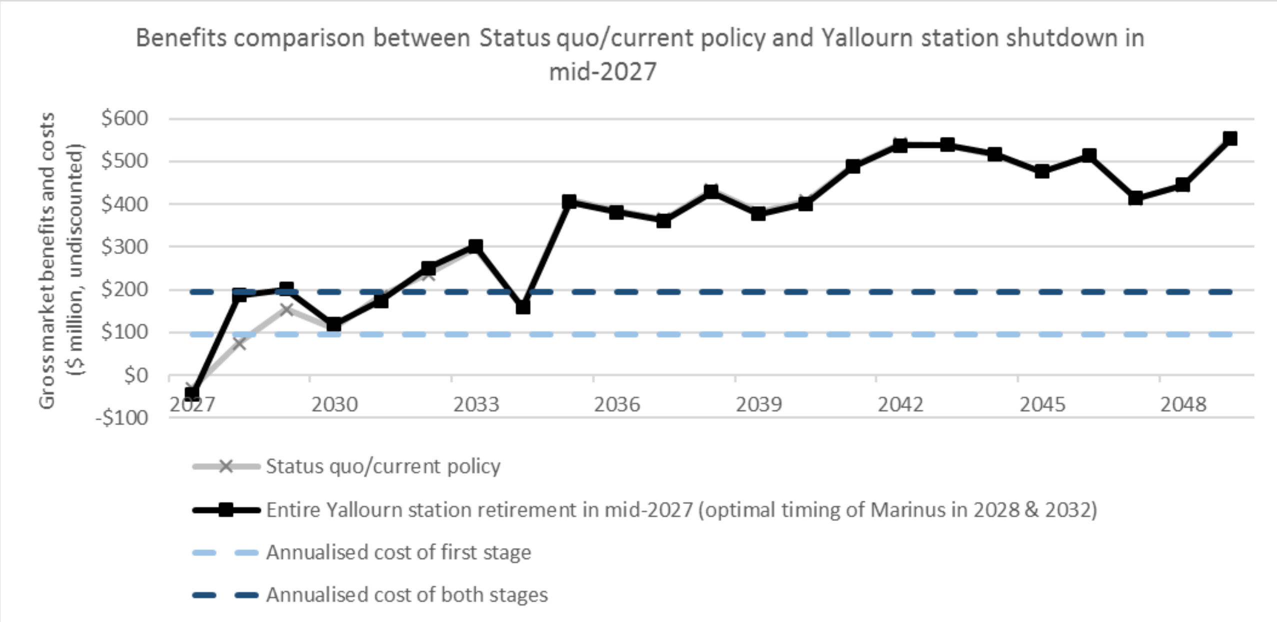

Figure 26 Example of our approach to estimating the optimal timing of Marinus Link in sensitivity studies

Table 12 in section 6.1 presented the net market benefit of Marinus Link and supporting transmission with different commissioning timing options, and from that table the optimal timing in the Status quo/current policy scenario is 2030 for stage 1 and 2032 for stage 2. This differs from what might be inferred from looking at the annualised costs and benefits in Figure 26, which is 2029 for stage 1 and 2032 for stage 2 in the Status quo/current policy scenario.[89]

[89] The difference lies in the fact that the market expansion model calculates the path to a least cost supply for the NEM for the entire modelling period. Changing the year of commissioning Marinus Link and supporting transmission could result in a different optimal generation development outcome in later years, which could have a greater impact on the net market benefit across the whole modelling period than the change in net market benefit in the particular year in which Marinus Link and supporting transmission is commissioned.

It is the change in the year in which annualised gross market benefits exceed costs which we are taking to be the indicator of advancement or deferral of Marinus Link and supporting transmission optimal timing, rather than the absolute year. As previously explained, Figure 26 indicates an advancement of the timing of the first stage by one year is warranted. The key outcome is the timing could be advanced by one year, not that the timing of the first stage should be 2028.[90]

Annualised gross market benefits exceeding costs is a simplistic yet practical approach to estimating the impact on the optimal timing of the project when a number of sensitivity studies are to be undertaken. The alternative approach (which we adopted in section 6.1 Table 11) requires conducting multiple market modelling simulations for each sensitivity, with the commissioning timing of Marinus Link and supporting transmission varied with each simulation. Due to the computation time requirements, this approach would not be practically possible, and even if it was it would most likely provide limited incremental insight.

For similar computational resource reasons, sensitivity studies were conducted on a single scenario. It is possible that the optimal timing of the interconnector could be advanced or delayed beyond timeframes indicated in this analysis once the net market benefits for the remaining three scenarios are calculated.

Discounting

The gross market benefits shown on the graphs in this appendix will differ numerically from the gross market benefits in Ernst & Young's market modelling report (Attachment 1) due to the following:

- Ernst & Young's gross market benefits results are all discounted values, whereas undiscounted values are used in graphs in this appendix.[91] We are using undiscounted market benefits in order to allow a comparison with undiscounted annualised costs, which will have a constant value regardless of the years that the Marinus Link stages are commissioned.
- The undiscounted ancillary services benefits from GHD's analysis have been included.

All tables in this appendix which present net market benefits results use net present values, discounted to 2019, consistent with the results presented in Chapter 6.

The remainder of this appendix discusses the rationale for, and results of, individual sensitivities.

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90 Relating this back to the results in section 6.1, in which we state the optimal year for the commissioning of the first stage of Marinus Link and supporting transmission (in the Status quo/current policy scenario) is 2030, we would conclude the first stage should be advanced to 2029.

91 The values in Ernst & Young's report (Attachment 1) are discounted to 2025 for reasons explained in that report. We firstly convert these values to be discounted to 2019 (by multiplying by 1/(1+discount rate)(2025-2019)), then un-discounting the annual values.

Battery sensitivities

In its forthcoming ISP, AEMO has stated it will include a *High DER* scenario for which we have no direct equivalent in this RIT-T modelling. AEMO's description of this scenario notes

> *… This scenario includes reduced costs and increased adoption of DER, with automation becoming commonplace, enabling consumers to actively control and manage their energy costs while existing generators experience an accelerated exit. It is also characterised by widespread electrification of the transport sector.*[92]

A key factor in such a scenario would be a combination of reduced battery costs and increased battery capacity. Much of the benefit of Marinus Link stems from it enabling the use of existing Tasmanian hydro storages and new pumped hydro storage to firm variable renewable energy sources. It therefore follows that this benefit may be reduced if battery costs reduce substantially, enabling battery devices to provide the firming capability instead.

We have undertaken two sensitivity studies to understand the impact that reduced battery costs or increased battery storage capacity would have on the viability Marinus Link. These sensitivities were:

- The rate of battery cost reduction throughout the study period was doubled. AEMO's battery cost forecast data (which is an input to Ernst & Young's market model) assumes a 34 per cent cost reduction of battery technology will occur over the study period, due to battery technology advances and improved economies of scale as battery production and installation rates increase. Our first sensitivity increased the cost reduction to 68 per cent.
- We undertook a second sensitivity study in which the energy storage capacity of batteries was increased from two hours to four hours, for the entire study period, without any corresponding increase in technology costs.

Results

Table 21 below provides net market benefits for the two battery sensitivity studies. Both of the battery sensitivities had a minimal impact on the net market benefits of Marinus Link and supporting transmission. Figure 27 shows that the years in which the gross market benefits exceed costs (of both the first stage only and both stages) are unchanged, hence the optimal timing of Marinus Link remains unchanged in these sensitivities.

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92 AEMO, 2019 forecasting and planning scenarios, inputs, and assumptions, August 2019

This marginal impact on net market benefits is predominantly due to a couple of factors: the shorter lifespan of batteries and shorter duration of their storage capability compared with pumped hydro. Pumped hydro's service life is over three times greater than batteries (50 years as compared to 15 years) while the capital costs of pumped hydro per MW of capacity is only 40 per cent higher[93]. Thus, the annualised cost of pumped hydro is lower than batteries. In addition, despite doubling the energy capacity of batteries to four hours, additional firming capability must still be built in the power system to cater for times when storage well in excess of four hours is needed. Deeper pumped hydro facilities like Snowy 2.0 and Tasmanian pumped storage provide longer duration firming capability of at least 24 hours, reducing the need for gas powered firming generation in the system.

Our modelling forecasts that in both of these sensitivities, additional battery storage is built in the 2030s and 2040s compared with the Status quo/current policy scenario. Whilst this may impact on the net market benefits of Marinus Link and supporting transmission in these years, in the earlier years the net market benefit is essentially unchanged. As a result, the estimated optimal timing of Marinus Link under these sensitivities is unchanged from the Status quo/current policy scenario.

It should also be noted that in our modelling, degradation in battery life is not considered while one would reasonably expect some reduction in performance over its 15 years of life.

Table 21 Net market benefit results from battery cost sensitivity studies

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
Battery cost reduction rate doubles	1,093	-54
Battery storage capacity increased to 4 hours	1,060	-87

93 Average storage build costs for the period of 2025 to 2050 as outlined in February 2019 assumptions workbook for battery storage under 4 degree cost scenario ($947/kW, $2019) and 24 hour pumped hydro capital costs ($1,353/kW, $2019) in Tasmania.

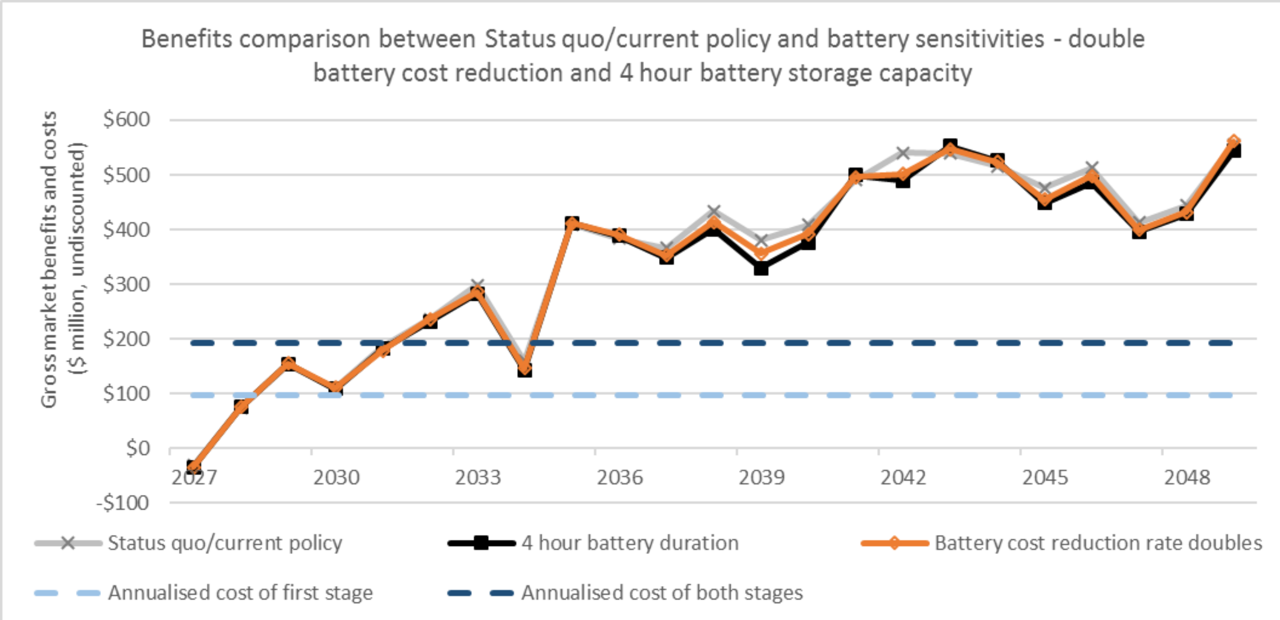

Figure 27 Annual variation of market benefits for the battery sensitivities

Delayed coal retirement

This sensitivity examines the impact if coal generating plant remains in service longer than stated in AEMO's Generation Information web page, which is the retirement timing used in the Status quo/current policy scenario. We have undertaken this sensitivity because in three of the four modelled scenarios coal generators are expected to retire earlier than indicated, due to either inflexibility of ageing power stations to modulate output with variable renewable generation, or constrained output due to adoption of a stricter emissions reduction trajectory. This sensitivity assumes that coal generators will be able to make necessary retrofits, at no incremental cost to the electricity market (i.e. the necessary works are externally grant funded), to extend the life of all coal generation assets by three years beyond the retirement schedule in AEMO's Generation Information web page.

Gas powered generators possess the necessary flexibility to adjust their output with varying renewable generation, and emit comparatively fewer emissions. Our model results indicate gas generation will therefore play a role in the transitioning NEM. For this reason, the retirement schedule for gas powered generators remains unchanged across all modelling scenarios, and in this sensitivity.

Results

Table 22 presents the net market benefits of Marinus Link and supporting transmission, which reduces by $263 million for this sensitivity. The delay in retirement of coal generating assets delays the optimal timing of

Marinus Link and supporting transmission by three years (refer Figure 28). This delay is expected, since existing coal generators have a lower short-run marginal cost than most other fossil fuel based generators and under the least cost modelling approach, existing assets are considered sunk cost investments that only need to recover operational costs and no capital expenditure. The market simulation model indicates that extension of coal generation assets by three years would cause a deferral in the construction of variable renewable generation, storage and gas generation that would be required to replace the retiring coal generation, and a commensurate delay in the need for the firming capacity provided by Marinus Link and supporting transmission.

Table 22 Net market benefit results from delayed coal retirement sensitivity study

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
Coal retirements delayed by 3 years	884	-263

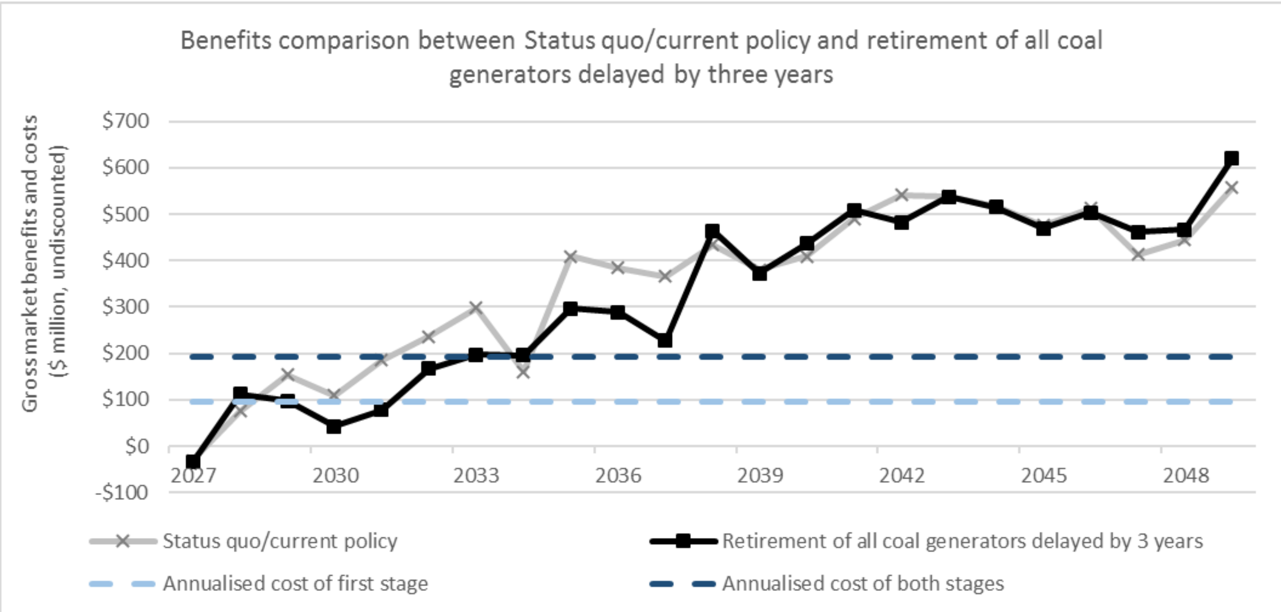

Figure 28 Annual variation of market benefits for the delayed coal retirement sensitivity

Advanced coal retirement

This sensitivity examines the impact if Yallourn Power Station in Victoria was to retire completely by 2028. In its Insights Paper, *Building power system resilience with pumped hydro energy storage*, AEMO recommended that,

> "an early, pre-emptive development of KerangLink and HumeLink would increase the resilience of the power system to coal-fired generation closing earlier than expected."

The same paper noted that Marinus Link would also increase system resilience in the case of early coal plant closure.

This sensitivity considered two cases: Yallourn early retirement with Marinus Link and supporting transmission commissioned at the economically optimal timing; and Yallourn early retirement coupled with Marinus Link and supporting transmission commissioned at the earlier date of 2027 for both 750 MW stages. This latter sensitivity was conducted earlier in the overall modelling process, and it has since become apparent that commissioning both stages of Marinus Link in 2027 would be difficult to achieve. The most practical early commissioning timeline is 2027 (stage 1) and 2028 (stage 2). We still present the result of this sensitivity, because it provides some insight into the impact of early Yallourn retirement on the economics of earlier commissioning of Marinus Link and supporting transmission.

In the Status quo/current policy scenario, the four Yallourn generating units retire in successive years, commencing in mid-2029. This sensitivity retires all of Yallourn's generating units in mid-2027, advancing the retirement of the first unit of the power plant by two years and bringing forward the last unit by five years as compared to Status quo/current policy scenario. All other generators' planned closure dates remained unaltered in this sensitivity. The sensitivity was conducted under the Status quo/current policy scenario.

Results

Table 23 shows the net market benefits of Marinus Link and supporting transmission will increase with the advance of Yallourn power station's retirement to mid-2027. The magnitude of increase in net market benefits depends upon the commissioning timing of Marinus Link and supporting transmission, however this sensitivity conservatively suggests advancing the first stage of Marinus Link by at least a year and consideration should be given to advancing the second stage to 2030. As depicted in Figure 29, the second stage of Marinus Link and supporting transmission in 2032 is commissioned belatedly to assist Victoria in its transition from coal based generation to variable renewable generators firmed with dispatchable capacity from Marinus Link. It is also interesting to note that the increase in net market benefits of commissioning Marinus Link and supporting transmission from 2027, under an environment of early Yallourn retirement, is comparable to the financial contribution of $149 million required from the government (section 6.3.1) to advance the timing of Marinus Link to 2027 (stage 1) and 2028 (stage 2).

The timing of KerangLink was left unchanged at 2030 for both of the sensitivity runs. Additional analysis would need to be undertaken to understand the revised optimal timing of Kerang Link. However, as observed in section 6.5, given the complementary nature of both the projects there may be value in advancing the timing of both interconnectors to mitigate the risk associated with premature closure of coal generators.

Table 23 Net market benefit results from Yallourn power station retirement in 2028

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
Yallourn station retirement in mid-2027 (optimal timing of Marinus Link in 2028 and 2032)	1,232	85
Status quo/current policy scenario with 1500 MW Marinus Link commissioned in 2027	894	-
Yallourn station retirement in mid-2027 (1500 MW Marinus Link in 2027)	1,056	162

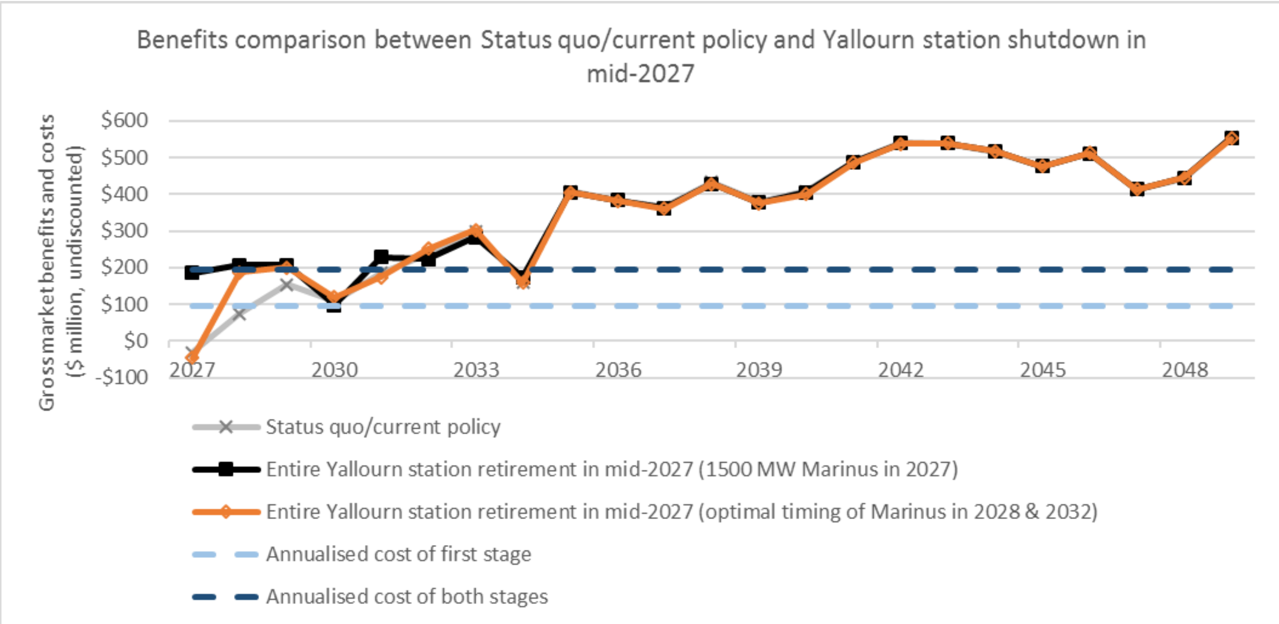

Figure 29 Annual variation of market benefits for Yallourn power station retirement in mid-2027

Tasmanian hydrogen development

In response to the PSCR, Northern Tasmanian Development Corporation requested that a Hydrogen Scenario be modelled. Complete modelling of such a scenario is beyond the scope of this RIT-T, as it would involve modelling of hydrogen fuel substitution within the NEM and consequential changes to both electricity and gas demand.

We have, however, undertaken a more limited study examining the impact on Marinus Link of a hydrogen extraction plant constructed in Northern Tasmania. This assumes:

- The hydrogen produced is all exported, resulting in no change in electricity or gas demand, other than the electrical load requirement of the hydrogen production facility;
- The hydrogen production facility operates as a 24/7 baseload plant. Whilst hydrogen production could theoretically be ramped in response to renewable electricity generation, we understand that hydrogen production facilities must (initially at least) be operated at maximum capacity to yield an adequate return on investment; and
- The hydrogen production facility was assumed to consume 100 MW and commence operation in 2023.

At the time this sensitivity was undertaken there was no information in the public domain about hydrogen development in Tasmania, so the above were TasNetworks assumptions. Only the Status quo/current policy scenario was considered for this sensitivity.

Results

Table 24 presents that the net market benefits of Marinus Link and supporting transmission reduces by $53 million for this sensitivity. Figure 30 demonstrates the optimal timing of the project remains unchanged. The reduction in benefits is driven by the slightly reduced ability of the Tasmanian hydro system to provide firming capacity to the mainland, due to meeting increased load obligations in Tasmania.

It is important to understand this analysis considers only the impacts on the NEM and ignores the economic contribution of the proposed hydrogen plant.

Table 24 Net market benefit results from Tasmanian hydrogen sensitivity study

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
100 MW of additional hydrogen load in Tasmania (2022)	1,094	-53

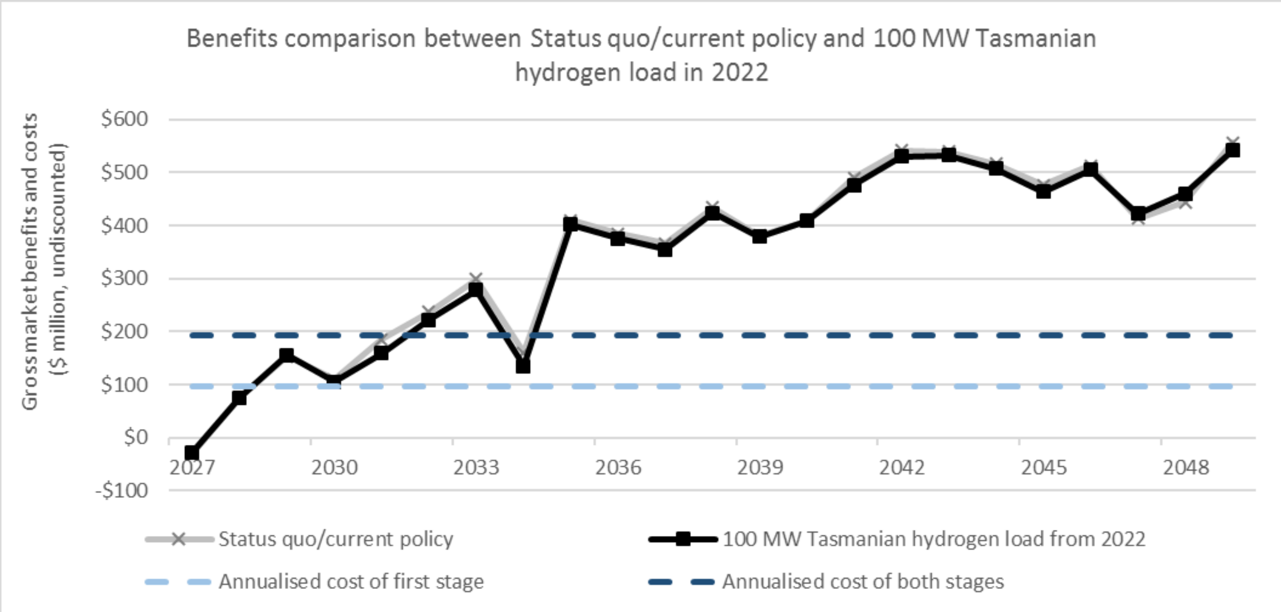

Figure 30 Annual variation of market benefits for the Tasmanian hydrogen sensitivity

Changes to Hydro Tasmania's plant operation

The four scenarios described in Chapter 5 all assumed two changes to Hydro Tasmania's operation would occur with the presence of Marinus Link:

- The "prudent storage levels" – the minimum storage levels which the Tasmanian government requires Hydro Tasmania to maintain for energy security reasons – would be reduced to the prudent storage levels that existed prior to the recommendations of the Tasmanian Energy Security Taskforce[94]. The current prudent water management levels were recommended from a Tasmanian energy supply security

94 Department of State Growth, Tasmanian Energy Task Force, August 2017

perspective in the event of an extended Basslink outage coinciding with a drought. The commissioning of Marinus Link will inherently provide an increased level of energy supply security, hence the prudent storage levels could be reduced without adverse impact. This is TasNetworks' assumption and does not reflect a policy decision by the Tasmanian Government.

- Repurposing of Hydro Tasmania's assets for increased power delivery, at minimal incremental cost, would occur if Marinus Link is commissioned. This is described in more detail section 2.6. These asset refurbishment projects are not committed.

We have undertaken two sensitivity studies in which these changes are assumed not to occur in the event that Marinus Link is constructed. That is, prudent storage levels remain at their current levels, and assumed Tasmanian hydro capacity upgrades do not occur.

Results

Table 25 presents the changes in total net market benefits of Marinus Link and supporting transmission in these sensitivity studies, with annualised market benefits being shown in Figure 31.

Prudent storage levels unchanged

Not reducing the prudent storage levels by 10 per cent has minimal impact on net market benefits, and the optimal timing of the interconnector remains unchanged. The reduced prudent storage levels were introduced to the model because they are likely to provide additional flexibility in operating existing hydro plant by reducing water levels so they are better equipped to capture more of the precipitation during major rain events and correspondingly reduce water spill. Detailed examination of model results revealed that the bulk of the benefit from reduced prudent storage levels derives from the one-off use of the water currently reserved for energy security purposes.

Hydro Tasmania's generation capacity unchanged

The key value proposition of Marinus Link and supporting transmission is to transition Tasmanian hydro operations from being a predominantly around-the-clock provider of energy to Tasmanian load to more variable operation that provides dispatchable capacity to firm variable renewable energy. With this context, it is highly unlikely that Tasmanian hydro would not be retrofitted for capacity upgrades if, as stated by Hydro Tasmania, this can be done at minimal incremental cost to refurbishment works that are required regardless. However, in the case hydro capacity upgrades did not proceed, the net market benefits of Marinus Link and supporting transmission will be lower by $209 million but the optimal timing of the project remains unchanged.

The annualised net market benefit chart (Figure 31) indicates the reduction of market benefits is spread relatively evenly throughout the study period beyond 2032, due to the more limited ability of Tasmanian hydro generation to provide firming services to mainland NEM regions on an hourly basis.

Table 25 Net market benefit results from sensitivity studies without changes to Hydro Tasmania generator operation

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
Prudent water level reductions do not occur	1,111	-36
Tasmanian hydro capacity remains unchanged	938	-209

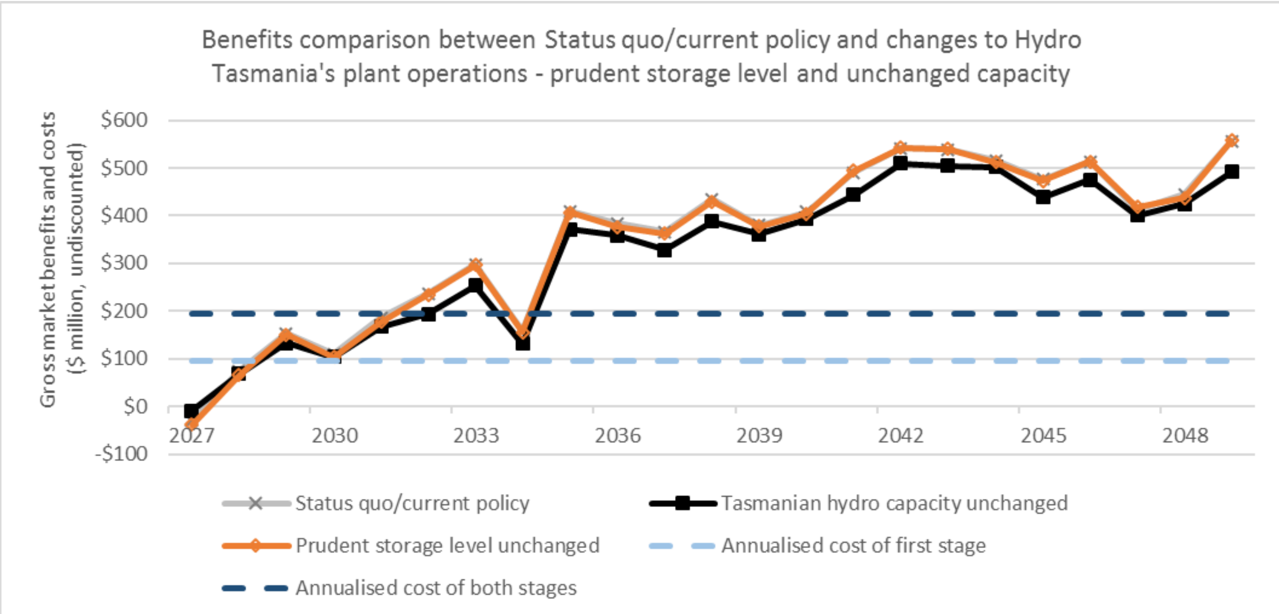

Figure 31 Annual variation of market benefits for sensitivity studies without changes to Hydro Tasmania generator operation

Assumed projects do not proceed

All our scenarios follow AEMO's assumption that Snowy 2.0 is a committed project, and consequently HumeLink and KerangLink will also be required. RIT-Ts for neither HumeLink nor KerangLink have commenced, and therefore neither is actually a committed project.

Similarly, we have included Project EnergyConnect in all our scenarios on the basis that the interconnector was listed as a Group 2 project in the 2018 ISP and its PACR is completed. However the AER has not formally approved the project.

This sensitivity examines the impact on Marinus Link in the event that Snowy 2.0, Project EnergyConnect, HumeLink and KerangLink do not proceed.

Results

Table 26 and Figure 32 provide results for this sensitivity. The overall increase in net market benefit of Marinus Link and supporting transmission is $193 million, which occurs predominantly in 2030 to 2035.

The differences between this sensitivity and the Status quo/current policy scenario are complex and somewhat difficult to unravel, as there are multiple differences: two regional interconnectors and a significant change of storage potential in New South Wales. The impacts can be broadly summarised with respect to Marinus Link as follows:

In years from 2030 to 2035, when Yallourn Power Station is forecast to retire but prior to the forecast retirement of Bayswater Power Station, Victoria would require support from other NEM regions, either as bulk energy transfer or firming of its own renewable generation. If Marinus Link, Kerang Link and Snowy 2.0 were all present, then this support could be provided by both New South Wales and Tasmania. Without Snowy 2.0 and KerangLink, Marinus Link and supporting transmission would play a much greater role in supporting Victoria during this period, hence the increase of market benefits for Marinus Link between 2030 and 2035. Figure 32 indicates that the second stage of Marinus Link would be likely to be advanced by one year.

Following the forecast retirement of Bayswater Power Station in 2036, in the absence of the dispatchable capacity of Snowy 2.0 and the additional transfer capacity between Victoria, South Australia and New South Wales, New South Wales would have much greater reliance on local generation than in the Status quo/current policy scenario. In this sensitivity, New South Wales' local gas generation is forecast to increase notably after 2036, and solar generation is forecast to reduce, compared with the Status quo/current policy scenario. Victorian and Tasmanian generation would also decrease after 2036 compared with the case in which the interconnectors and Snowy 2.0 are present. The benefits of the Marinus Link / KerangLink synergy to support New South Wales would be lost, reducing the share of benefits Marinus Link provides to New South Wales. However Marinus Link would be able to increase its support to Victoria and South Australia, as these states would receive less support from New South Wales. The overall impact is little change in the market benefit of Marinus Link and supporting transmission after 2036.

Table 26 Net market benefit results from the sensitivity study in which Snowy 2.0, Project EnergyConnect, HumeLink and KerangLink do not proceed

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
Assumed projects do not proceed	1,339	192

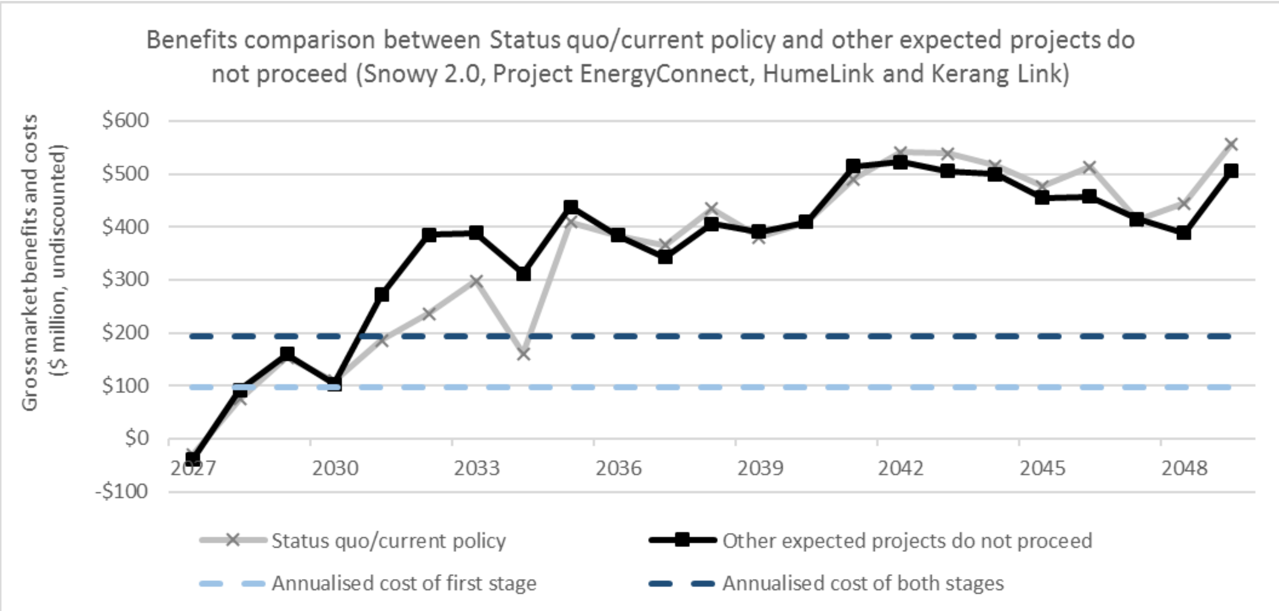

Figure 32 Annual variation of market benefits from the sensitivity study in which Snowy 2.0, Project EnergyConnect, HumeLink and KerangLink do not proceed

South Australian gas plant retirements

All our scenarios include Project EnergyConnect, a 750 MW interconnector between South Australia and New South Wales, coming online in July 2023. This is based on the PACR published earlier this year for the project. The PACR also indicated that Torrens Island B (800 MW), Osborne (180 MW) and Pelican Point (529 MW) gas generators will be retired once the interconnector is commissioned. In our modelling, these units are not forced to retire, and they appear to have an economically sustainable capacity factor once black coal units in New South Wales commence retirement. For this sensitivity, the three gas units are forced to retire with the commissioning of Project EnergyConnect, as per the RIT-T modelling for that project.

Results

Forced retirement of 1,500 MW of South Australian gas fired generators would increase the net market benefits of Marinus Link and supporting transmission, but does not materially change the timing from the Status quo/ current policy scenario. Our modelling in the Status quo/current policy scenario indicates South Australian gas generators would make up some of the energy deficit in the power system when Liddell (2023), Vales Point (2029) and Gladstone (2029) power stations retire. However, with the forced retirement of South Australian gas generators, the value of firming generation provided by Marinus Link would increase and will potentially be needed sooner.

Table 27 Net market benefit results from the South Australian gas plant retirement sensitivity study

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
South Australian gas plant retirements	1,198	51

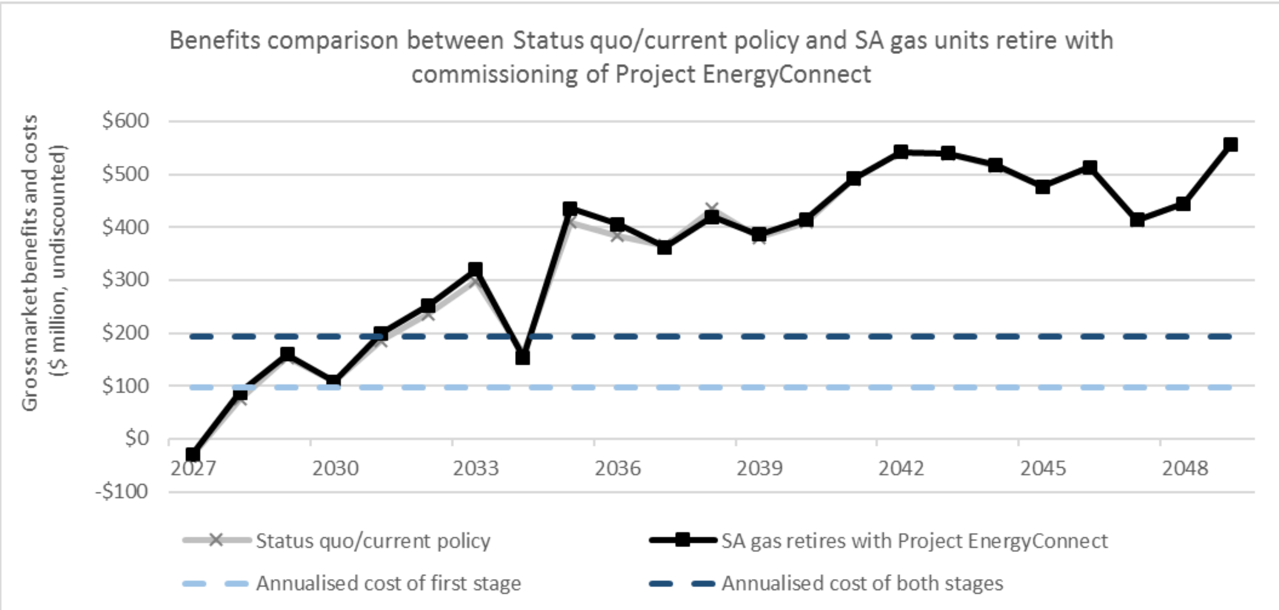

Figure 33 Annual variation of market benefits from the South Australian gas plant retirement sensitivity study

Additional wind generation in Tasmania becomes committed

Tasmania is currently witnessing great interest in further wind farm development in the state due to availability of some of the best wind resources in the country. In addition to the wind farms already under construction in Tasmania, TasNetworks has received over 3,000 MW of proposals for future wind development in the state, a number of which are being progressed with active connection applications. None of these projects have satisfied all five criteria to be considered committed projects for the purposes of this RIT-T, and on this basis they have not been assumed for our core scenarios. This sensitivity assumes a further 500 MW of wind generation becomes committed in Tasmania in the early 2020s, regardless of whether Marinus Link is developed or not, which is reflective of current developer interest.

Results

The net market benefit of Marinus Link improves by $53 million and has a marginal impact on the optimal timing, possibly bringing the second stage forward by one year.

This marginal difference from the Status quo/current policy scenario initially seems counter-intuitive, but can be explained once the wind generation development forecast by the market model is understood. In the Status quo/current policy scenario, the market model forecasts that once Marinus Link and supporting transmission are commissioned, additional wind generation would be developed in Tasmania. Over 500 MW of new wind generation will be developed by 2031 (compared with the case in which Marinus Link does not proceed), with even further development occurring in subsequent years.

If 500 MW of new wind generation is already committed in the market model prior to Marinus Link, then the wind development that is otherwise forecast to occur prior to 2031 is not required. That is, forcing additional wind generation to be committed early simply alleviates the need for that generation to be developed later, with the overall result of little increase in the market benefit of Marinus Link.

From this result we conclude that our decision not to consider some wind development that is currently being actively pursued as committed in our market modelling – on the basis that it does not meet the RIT-T definition of a committed project – has made no material difference to modelling outcomes.

Table 28 Net market benefit results from the sensitivity study into additional wind generation becoming committed in Tasmania

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
Additional 500 MW wind committed in Tasmania	1,200	53

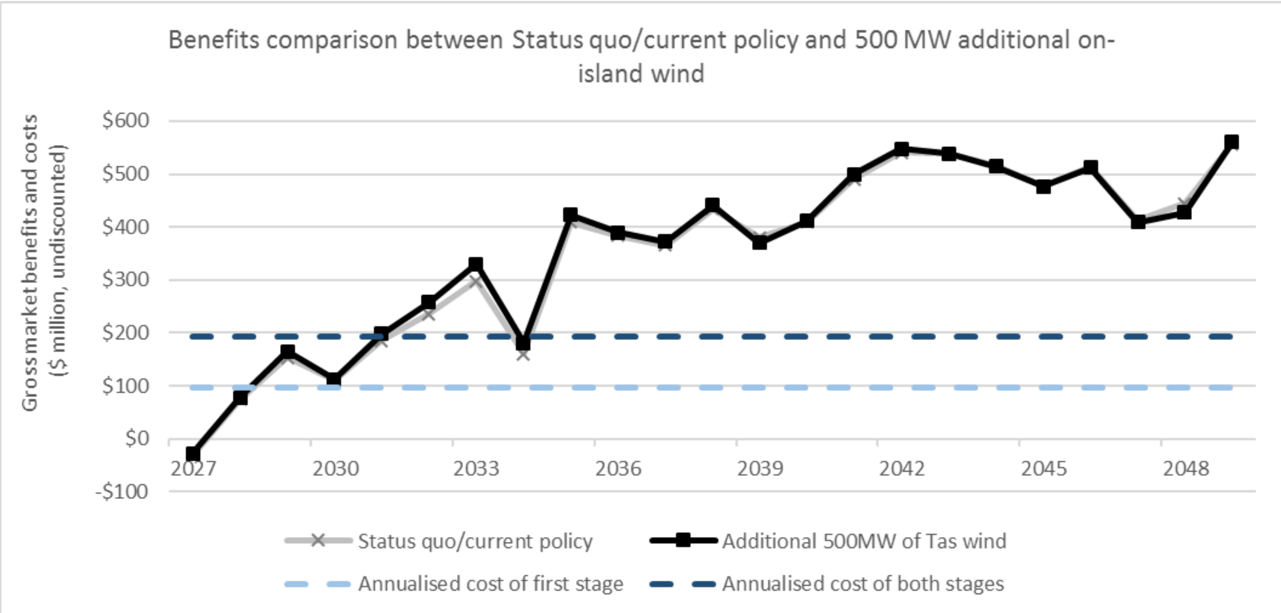

Figure 34 Annual variation of market benefits from the sensitivity study into additional wind generation becoming committed in Tasmania

Tasmanian pumped hydro becomes committed

Hydro Tasmania's Battery of the Nation initiative is currently shortlisted under the Australian government's UNGI program. The objective of the UNGI program is to lower wholesale energy prices, increase competition and increase reliability in the energy market. The program is intended to ensure dispatchable generation is available to meet customer demand and thus prevent reliability degrading as traditional dispatchable generators retire.

This sensitivity examines the likely net market benefits Marinus Link will provide in the event the UNGI program enables 600MW of pumped hydro to be committed in Tasmania by 2027, on the condition that Marinus Link is committed. As discussed in Chapter 6, the first stage of Marinus Link and supporting transmission leverages the existing spare capacity in the Tasmanian hydro system. The market simulation forecasts that Tasmanian pumped hydro is developed at approximately the same time the second stage of Marinus Link is commissioned. Committing additional pumped hydro earlier may therefore warrant earlier construction of the second stage of Marinus Link. For this sensitivity, we have examined two Marinus Link and supporting transmission timing options: the economically optimal timing of 2028 (stage 1) and 2032 (stage 2), and the possible earlier timing outlined in section 6.3.1 of 2027 (stage 1) and 2028 (stage 2).

We have based this sensitivity on the Sustained renewables uptake scenario, as opposed to the Status quo/current policy scenario, on the premise that underwriting of projects is to manage risks that reliability would be compromised under that scenario, without such underwriting. As such, it forms the basis of this sensitivity study.

Results

Table 29 presents the net market benefit results of this sensitivity, and Figure 35 illustrates the impact on timing.

The net market benefit of Marinus Link is shown to increase by $537 million compared with the original Sustained renewables uptake scenario. Such a result is expected, however, because in the original Sustained renewable uptake scenario, the costs of Tasmanian pumped hydro (which was forecast to be developed in the 2030s) were included in the long term supply cost borne by the NEM. In this scenario, the costs of the UNGI-underwritten pumped hydro developed in 2027 are externalised, and this effectively replaces the pumped hydro which was previously forecast to be developed in the 2030s.

The more significant finding is that a commitment to pumped hydro development in Tasmania appears to warrant advancement of the timing of Marinus Link and supporting transmission. This is indicated by both the annualised benefits of the economically optimal timing (stage 1 in 2028 and stage 2 in 2032), and the alternative timing of stage 1 in 2027 and stage 2 in 2028. The grey line in Figure 35 shows the annualised benefits from the 2028 / 2032 timing. The benefits exceed the costs of both link stages from 2028 onwards, indicating that there would be a positive net market benefit if both stages of Marinus Link were commissioned in that year. Similarly, the black line in Figure 35 (2027 / 2028 timing) demonstrates that with this timing, benefits exceed costs from 2028 onwards also.

Table 29 Net market benefit results from the sensitivity study in which a Tasmanian pumped hydro project becomes committed in 2027

Sensitivity	Net market benefit ($ million)	Difference from sustained renewables uptake scenario ($ million)
Original Sustained renewables uptake scenario (with Marinus Link 750 MW in 2027 and 750 MW in 2028)	1,353	-
600 MW of pumped hydro committed in 2027 (UNGI)	1,890	537

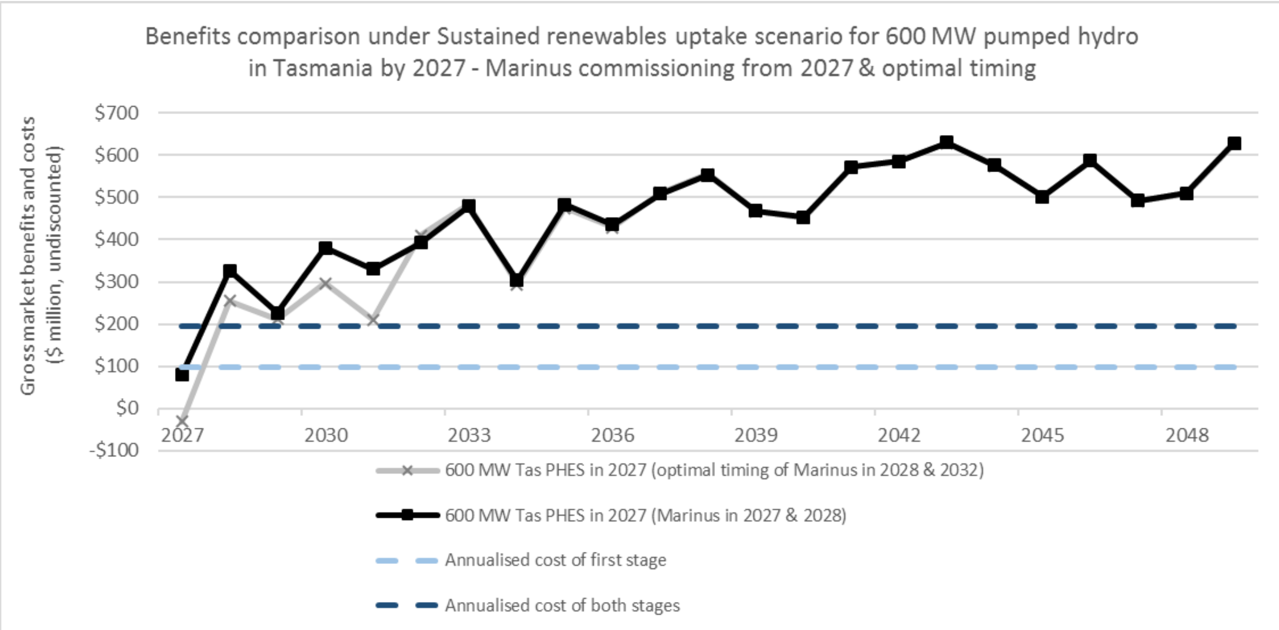

Figure 35 Annual variation of market benefits from the sensitivity study in which a Tasmanian pumped hydro project becomes committed in 2027

Impact of climate change

In a number of stakeholder forums, relating to both Marinus Link and electricity industry planning more generally, the need to consider the impacts of climate change in long-term electricity network planning has been broadly acknowledged by forum participants. At present, load and energy forecasting data published by AEMO does not consider the long term impacts of climate change.

Because much of the benefit of Marinus Link derives from an increased utilisation of hydro capacity (both existing and potential pumped storage) and development of Tasmanian wind potential, it is reasonable to ask whether long term climate change impacts may adversely affect the value of Marinus Link. Some stakeholders have informally expressed the view that TasNetworks should be considering climate change impacts in our economic assessment.

In the absence of detailed publically available data on climate change impacts across the NEM, we have undertaken a sensitivity study in which we assume that inflows to all hydro schemes in the NEM decrease by 4 per cent every 8 years during the study period. We acknowledge this approach is highly simplistic, but it is intended to be indicative of the potential impact of climate change only.

Results

Table 30 presents the impact of lower inflows: the net market benefits of Marinus Link and supporting transmission are reduced by $71 million. Figure 36 demonstrates that the annual benefits are essentially unchanged until the late 2030s, hence the estimated optimal timing of the interconnector remains unchanged.

The salient outcome of this sensitivity is that, even with lower rainfall in forthcoming decades, there is only a small impact on the net market benefit of Marinus Link and supporting transmission.

Table 30 Net market benefit results from the climate change sensitivity study

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
Potential impact of climate change accounted	1,076	-71

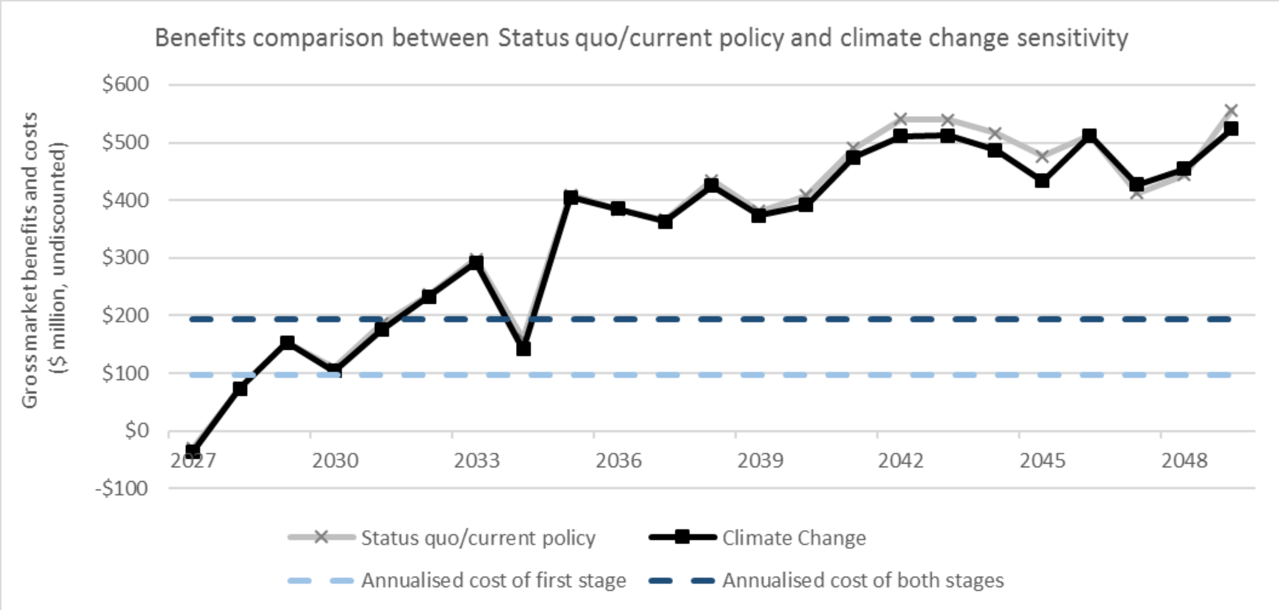

Figure 36 Annual variation of market benefits from the climate change sensitivity study

Basslink outage

Whilst the results in Chapter 6 demonstrate that the primary benefits of Marinus Link and supporting transmission relate to providing firming services and export of renewable energy to mainland NEM regions, an additional benefit the link will provide is a parallel flowpath to Basslink, and hence redundancy in the event Basslink is out of service.

The implementation of the recommendations of the Tasmanian Energy Security Taskforce, following the 2016 Basslink outage event, ensure that Tasmanian energy security would be maintained even in the event of a future Basslink outage.[95] Whilst Tasmanian energy security is therefore no longer at risk from such an event, the occurrence of a Basslink outage would nevertheless incur costs to the NEM. The presence of Marinus Link would be expected to reduce these costs substantially.

Our Basslink outage sensitivity differs from other sensitivity studies presented, in that it does not attempt to quantify the outcomes in terms of a change to the net market benefits or timing of Marinus Link and supporting transmission. Instead, we quantify the costs which would be incurred in the event of a 6-month Basslink outage without Marinus Link, and the amount by which such costs would be reduced if Marinus Link and supporting

95 Department of State Growth, Tasmanian Energy Task Force, August 2017

transmission were present. This will assist in quantifying the value of bringing Marinus Link forward from its economically optimal timing under this RIT-T.

Methodology

In this sensitivity, two pairs of market modelling simulations were conducted. One pair of simulations assumes Marinus Link is not present. A market modelling simulation was conducted using the Status quo/current policy scenario, and the total of supply to the NEM noted. A second simulation was then conducted, in which Basslink's transfer capacity was forced to zero from 1 July 2027 until 31 December 2027, and the total cost of supply to the NEM again noted.[96] The difference in the total cost of supply to the NEM in these two simulations will be the cost of Basslink being out of service.

A second pair of simulations was then conducted, with all variables being the same except the first 600 MW stage of Marinus Link was assumed to be in service from mid-2026.[97] By forcing Basslink's transfer capacity to zero for the same 6-month period in one simulation of the pair, the cost of the Basslink outage can again be calculated. In this instance Marinus Link is in service, and the cost of the Basslink outage should therefore be significantly lower.

Results

Table 31 presents the results of the two pairs of market simulation studies, in net present value terms consistent with all other results. We observe that the present value of the cost of a Basslink outage is reduced from $21 million to $2 million with the presence of Marinus Link and supporting transmission.[98]

In the absence of Marinus Link, the cost of a Basslink outage occurring from July to December 2027 is forecast to be $21 million. This is substantially lower than the costs of the 2016 Basslink outage, because the increased Prudent Storage Levels, plus the installation of additional wind generation in Tasmania since 2016, allow Tasmanian energy security to be maintained using existing Tasmanian generation.[99] The modelled costs of

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96 Additional changes were made for the second simulation to ensure the same generation development had occurred prior to the Basslink outage as occurred in the no-outage simulation. Further details can be found in Ernst & Young's report (Attachment 1) section 4.4

97 We do not consider mid-2026 to be a plausible timing for construction of Marinus Link. It was implemented for the purpose of this study simply to create a situation with Marinus Link in service at the same time as the Basslink outage. Similarly a 600 MW Marinus Link was used because this sensitivity was undertaken before the preferred option was identified. Whether the first stage of Marinus Link is 600 MW or 750 MW is immaterial in this instance, because either option exceeds the unavailable capacity of Basslink.

98 Refer section 8.10 of Attachment 1. Values in Attachment 1 are discounted to 2025, and must be multiplied by 0.71 to convert discounting to 2019.

99 Costs of the 2016 Basslink outage were detailed in https://www.hydro.com.au/docs/default-source/about-us/our-governance/request-to-information-%28rti%29/16-06-23-rti-decision-letter-richard-baines-implementation-of-diesel-generation.pdf?sfvrsn=d0374928_2

the Basslink outage relate not only to increased supply costs in Tasmania, but also to increased supply costs to mainland NEM regions because Basslink's ability to supply some Tasmanian renewable generation to mainland regions is interrupted. As anticipated, the costs of a Basslink outage reduce significantly with the presence of one stage of Marinus Link, to $2 million. From these results, the benefit to the NEM of Marinus Link in reducing the costs of a Basslink outage is in the order of $19 million.

Due to modelling limitations this study considered a Basslink outage from July to December. We would expect the costs of a Basslink outage to increase if the outage was to occur during summer months, when Basslink typically supplies energy to Victoria at near full capacity on peak demand days. Furthermore, the costs may increase in future years, once Tasmania's role in providing firming services and increased renewable energy to mainland NEM regions increases. We therefore consider the result presented here to be conservative.

Table 31 Modelled cost to NEM of a Basslink outage in July to December 2027

Sensitivity	Cost to NEM ($ million)	Saving due to Marinus Link ($ million)
Basslink outage without Marinus Link	21	-
Basslink outage with Marinus Link	2	19

Changes to discount rate

The base discount rate of 5.9 per cent (real, pre-tax) is used in the NPV analysis, which is consistent with the commercial discount rate calculated in the Energy Network Australia RIT-T Economic Assessment Handbook. The handbook recommends calculating the lower discount rate based on the regulated Weighted Average Cost of Capital (WACC) of the most recent transmission determination by the AER, and applying a symmetrically higher discount rate at the upper bound. The lower discount rate is calculated to be 3.54 per cent and a higher discount rate of 8.26 per cent.

Results for high and low discount rate

The higher and lower discount rates do not change the preferred credible option of the project.

Figure 37 and Figure 38 show the annual variation in gross market benefits with differing discount rates. Note that the costs shown in these graphs differ from all previous graphs: the annualised costs of both stages only are shown, based on the discount rate under consideration. It is therefore necessary to compare the gross market benefits with the corresponding cost (i.e. black gross benefits line with black costs dashed line; grey gross benefits line with grey dashed costs line). The high discount rate did not change the optimal timing of the project, but under the low discount rate sensitivity the optimal timing of the second stage of Marinus Link advances by a year.[100]

Table 32 Net market benefit results with alternative discount rates

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
High discount rate result (8.26%)	412	-735
Low discount rate result (3.54%)	2,500	1,353

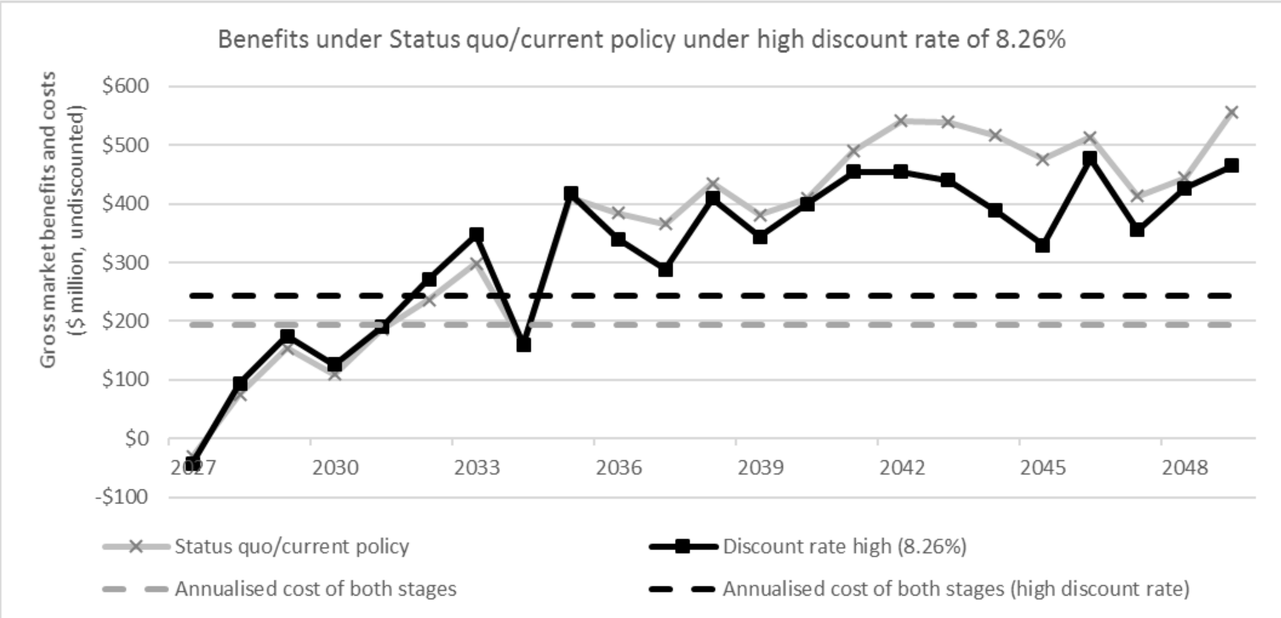

Figure 37 Annual variation of market benefits with a high discount rate

100 To prevent cluttering of the graphs, the costs for the first stage only are not shown in Figure 37 and Figure 38. The relevant annualised costs for the first stage only are: original discount rate (5.9%) - $97.0 million; high discount rate (8.26%) - $121.4 million; low discount rate (3.54%) - $73.5 million.

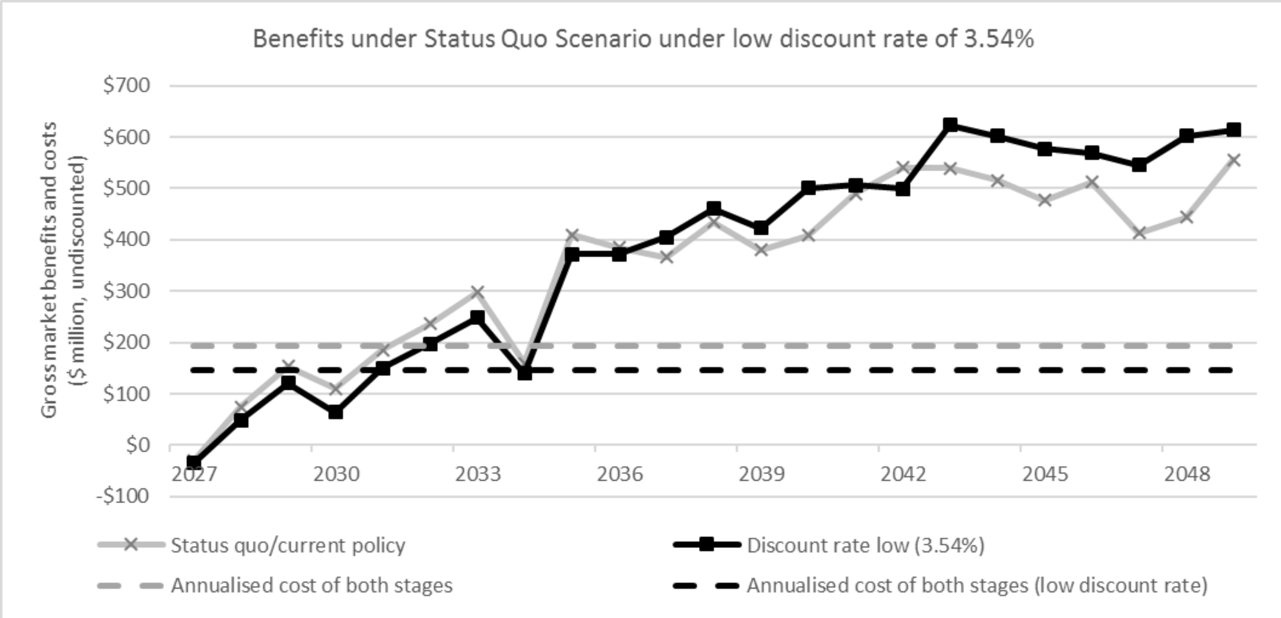

Figure 38 Annual variation of market benefits with a low discount rate

Changes to Marinus Link capital cost

The cost of the preferred option as outlined in section 4.7 excludes allowances for accuracy and contingencies, to give an expected project cost of $2.76 billion.

If accuracy and contingencies are included, the estimated Marinus Link and supporting transmission would have a total project cost in the range of $3.5 billion. This includes an approximate cost of $3 billion for the HVDC link and an approximate cost of $0.5 billion for the required supporting transmission. The total project cost estimates include allowances for accuracy and contingency, reflecting the fact that cost estimates for project elements are subject to a number of factors that may influence project costs.

The net market benefits were tested against increasing and decreasing the costs of the project by +/- 30 per cent from the median expected cost of $2.76 billion, to test the robustness of the preferred credible option.

Results for 30 per cent higher and lower capital cost sensitivities

The net market benefits of Marinus Link and supporting transmission symmetrically increase and decrease by $334 million under lower and higher capital costs sensitivities respectively. If we consider only the Status quo/current policy scenario, the higher capital costs sensitivity defers the second stage of the project by one year (refer Figure 39). Similarly, both stages of the project advance by a year under the lower capital costs sensitivity (refer Figure 40).

Table 33 presents the results if the net market benefit of Marinus Link and supporting transmission is calculated with the contingency and accuracy allowances included. This table shows the results of each scenario individually, and the weighted average of all scenarios. Including contingency and accuracy allowances, Marinus Link and supporting transmission has a positive net market benefit, weighted across all scenarios, of $1,340 million.

Table 33 Net market benefit results with higher and lower capital costs

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
30 per cent higher capital costs	813	-334
30 per cent lower capital costs	1481	334

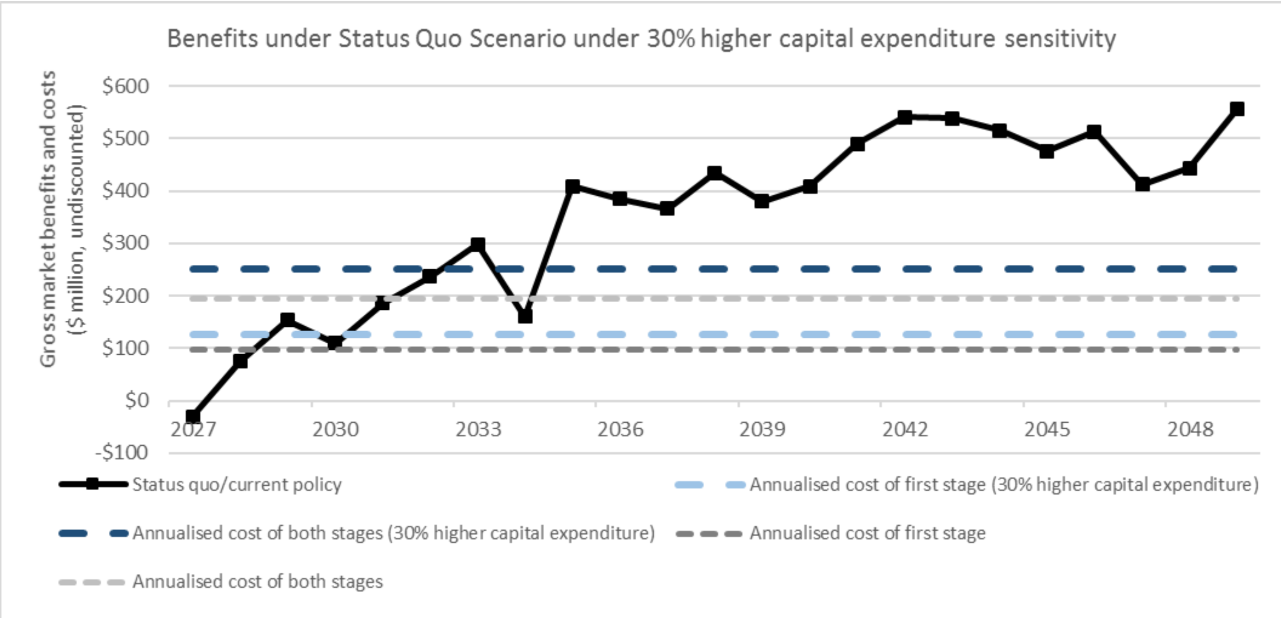

Figure 39 Annual variation of market benefits with 30 per cent higher capital costs

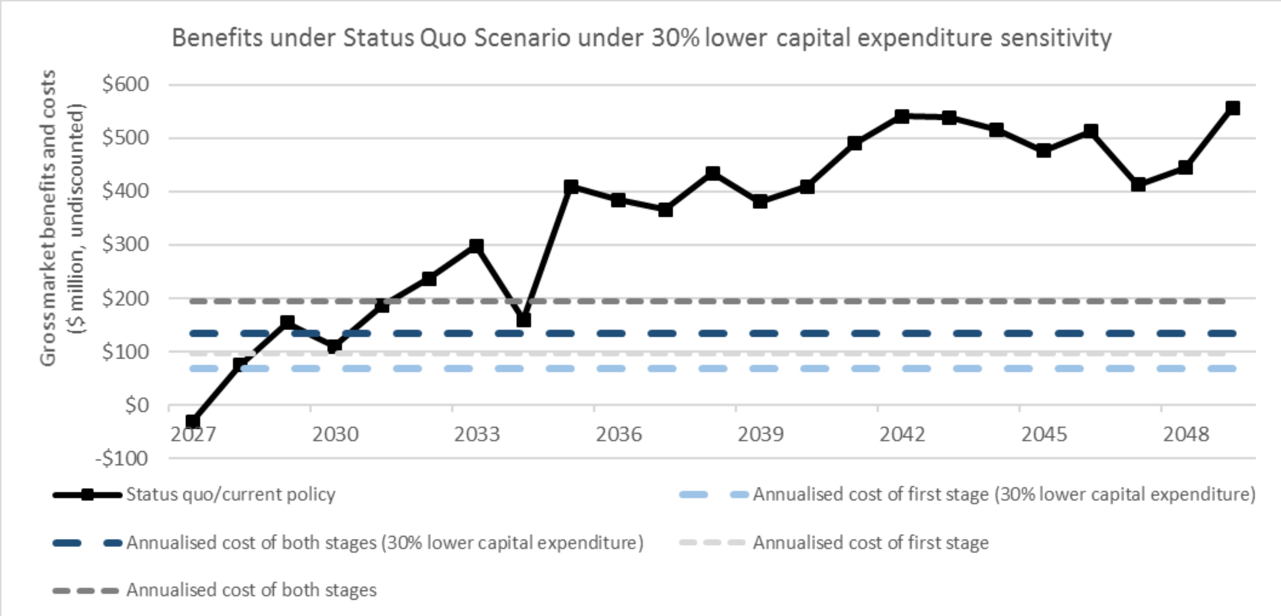

Figure 40 Annual variation of market benefits with 30 per cent lower capital costs

Table 34 Net market benefit results in all scenarios, considering both median and high estimated project costs ($ million)

Scenarios	Gross market benefits	Median expected costs (P50)	High estimate project costs (inc. contingencies and accuracy allowance)	Gross benefits less median costs	Gross benefits less high estimate project costs
	[A]	[B]	[C]	[A-B]	[A-C]
Global Slowdown	2,122	1,271	1,605	851	517
Status quo/current policy	2,418	1,271	1,605	1,147	813
Sustained renewables uptake	2,722	1,271	1,605	1,451	1,117
Accelerated transition to low emissions future	4,517	1,271	1,605	3,246	2,912
Average	2,945	1,271	1,605	1,674	1,340

Change in scenario weightings

As outlined in section 5.3.6, all scenarios were weighted equally due to lack of clear evidence for any particular scenario to occur more likely than another. This sensitivity attempts to test the robustness of the preferred credible option in case scenario weightings are changed as described in Table 35 below.

Table 35 Weighting summary for modelling and sensitivity scenarios

Scenarios	Modeling Weighting	Sensitivity Weighting
Global slowdown	25%	15%
Status quo/Current policy	25%	35%
Sustained renewables uptake	25%	35%
Accelerated transition to a low emissions future	25%	15%

Results for change in scenario weighting

The net market benefits for Marinus Link and supporting transmission reduce by $150 million but the timing of the project remains unchanged.

Table 36 Net market benefit results with change in scenario weighting

Sensitivity	Net market benefit ($ million)	Difference from weighted average basis ($ million)
Original scenario weighted average net market benefit	1,674	-
Changed scenario weightings	1,524	-150

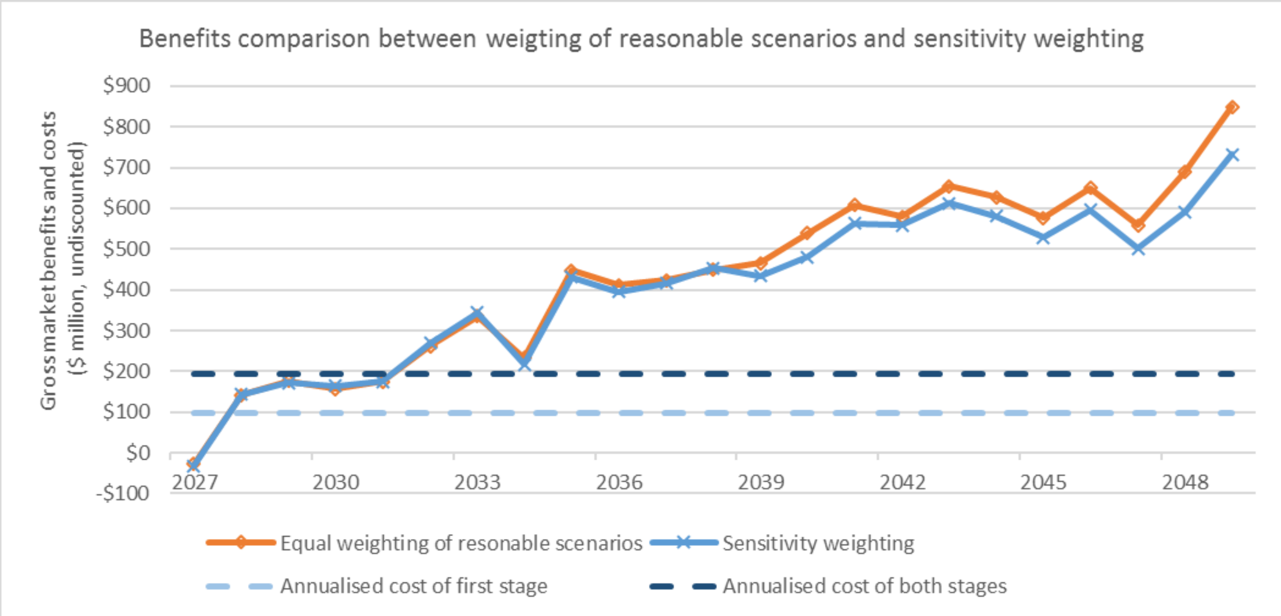

Figure 41 Annual variation of market benefits with change in scenario weighting

Partial 2019-20 ISP assumptions update

As outlined in section 6.2, our *PADR* modelling is based on AEMO's assumptions workbook released for the 2019 Planning and Consultation Paper. The final assumptions workbooks released for 2019-20 ISP in September 2019 include three significant changes, namely:

- Approximately 25 per cent lower electricity consumption is forecast in Victoria and New South Wales by the end of the modelling period;
- Doubling of the total aggregate potential generation capacity of all REZs; and
- Over 60 per cent increase in the pumped hydro potential across the NEM.

The reduction in demand forecast is driven by lowered expectation of uptake in electric vehicles whereas increased capacity of renewables and pumped hydro potential is based on AEMO's consultation with stakeholders. This sensitivity attempts to capture these three critical updates.

The latest demand estimate and pumped hydro potential as outlined in the finalised assumptions workbook were incorporated for this sensitivity. The potential renewable capacity increase within a REZ is more challenging since along with introducing new REZs, revised historical capacity factor traces were provided for wind and solar generation in the latest assumptions workbook. As a means of approximation, REZ capacity as published in February 2019 was doubled. The wind and solar traces were left unchanged.

Results for partial 2019-20 ISP assumptions update

For this sensitivity, the net market benefits of Marinus Link and supporting transmission reduces by $710 million, but still has a positive net market benefit of $437 million. The optimal timing of both stages would be delayed by two to three years. TasNetworks will continue working with AEMO as it progresses its 2019-20 ISP, to more fully understand the changes in modelling assumptions. Although differing modelling assumptions may result in differing timings between TasNetworks' and AEMO's analysis, it is clear that Marinus Link and supporting transmission will play a role in the future NEM and the project should proceed to the Design and Approvals phase.

Table 37 Net market benefit results with partial 2019-20 ISP assumptions update

Sensitivity	Net market benefit ($ million)	Difference from Status quo/current policy scenario ($ million)
Original Status quo/current policy scenario result	1,147	-
Partial 2019-20 ISP assumptions update	437	-710

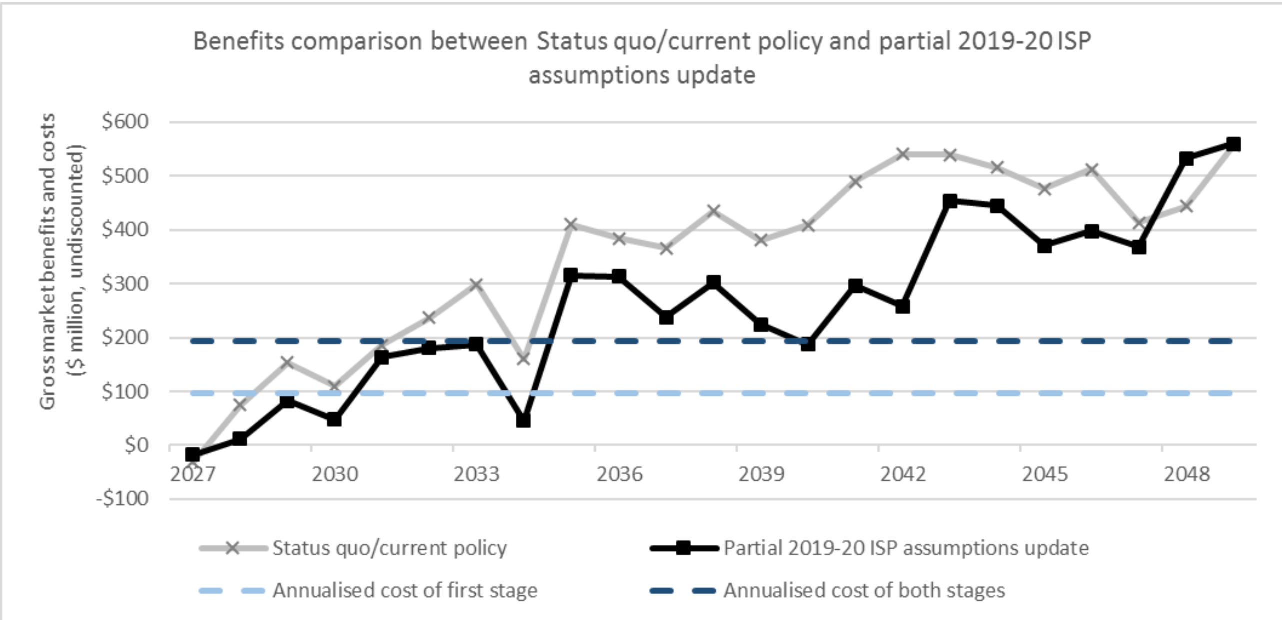

Figure 42 Annual variation of market benefits with partial 2019-20 ISP assumptions update

Appendix 5 – National Electricity Rules Compliance Checklist

This appendix sets out a compliance checklist which demonstrates the compliance of this *PADR* with the requirements of clauses 5.16.4(j) to 5.16.4(s) of the National Electricity Rules version 127.

NER clause	Summary of requirements	Relevant section(s) in *PADR*
5.16.4(j)	Project assessment draft report If one or more Network Service Providers wishes to proceed with a RIT-T project, within 12 months of the end date of the consultation period referred to in paragraph (g), or such longer period as it agreed in writing by the AER, the RIT-T proponent for the relevant RIT-T project must prepare a report (the project assessment draft report), having regard to the submissions received, if any, under paragraph (f) and make that report available to all Registered Participants, AEMO and interested parties.	The *PADR* has been prepared in accordance with this requirement, noting that the AER agreed an extended period.
5.16.4(k)	The project assessment draft report must include:	
	(1) A description of each credible option assessed;	Section 4.3.
	(2) A summary of, and commentary on, the submissions to the project specification consultation report;	Chapter 3 and Appendix 1.
	(3) A quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	Costs: Section 4.7, Appendices 2 and 3. Classes of Material Benefits: Section 6.4, Attachments 1 and 2.
	(4) A detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Sections 5.1 and 5.2; Appendices 2 and 3; and Attachments 1 and 2.
	(5) Reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Section 5.1.
	(6) The identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	Attachment 1, Sections 6.1 and 6.4.
	(7) The results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Section 6.1.
	(8) The identification of the proposed preferred option;	Section 6.3.

NER clause	Summary of requirements	Relevant section(s) in *PADR*
	(9) For the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide:	
	(i) Details of the technical characteristics;	(i) Section 6.3.
	(ii) The estimated construction timetable and commissioning date;	(ii) Section 6.3.
	(iii) If the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and	(iii) Section 6.3 (no augmentation technical report)
	(iv) A statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	(iv) Sections 6.1, 6.2, 6.3.
5.16.4(l)	If a Network Service Provider affected by a RIT-T project elects to proceed with a project which is for reliability corrective action, it can only do so where the proposed preferred option has a proponent. The RIT-T proponent must identify that proponent in the project assessment draft report.	Not applicable.
5.16.4(m)	A RIT-T proponent that is a Transmission Network Service Provider may discharge its obligation under paragraph (j) to make the project assessment draft report available by including the project assessment draft report as part of its Transmission Annual Planning Report provided that report is published within 12 months of the end date of the consultation period required under paragraph (g) or within 12 months of the end of such longer time period as is agreed by the AER in writing under paragraph (j).	Not applicable.
5.16.4(n)	A RIT-T proponent that is a Distribution Network Service Provider may discharge its obligation under paragraph (j) to make the project assessment draft report available by including the project assessment draft report as part of its Distribution Annual Planning Report provided that report is published within 12 months of the end date of the consultation period required under paragraph (g) or within 12 months of the end of such longer time period as is agreed by the AER in writing under paragraph (j).	Not applicable.
5.16.4(o)	The RIT-T proponent must: (1) provide a summary of the project assessment draft report to AEMO within 5 business days of making the project assessment draft report; and (2) upon request by an interested party, provide a copy of the project assessment draft report to that person within 3 business days of the request.	 A summary document has been provided to AEMO. Noted.

NER clause	Summary of requirements	Relevant section(s) in *PADR*
5.16.4(p)	Within 3 business days of receipt of the summary, AEMO must publish the summary of the project assessment draft report on its website.	AEMO obligation.
5.16.4(q)	The RIT-T proponent must seek submissions from Registered Participants, AEMO and interested parties on the preferred option presented, and the issues addressed, in the project assessment draft report.	Section 1.6. The *PADR* will be available on our website.
5.16.4(r)	The period for consultation referred to in paragraph (q) must be not less than 6 weeks from the date that AEMO publishes the summary of the report on its website.	Section 1.6.
5.16.4(s)	Within 4 weeks after the end of the consultation period required under paragraph (r), at the request of an interested party, a Registered Participant or AEMO (each being a relevant party for the purposes of this paragraph), the relevant Network Service Provider must meet with the relevant party if a meeting is requested by two or more relevant parties and may meet with a relevant party if after having considered all submissions, the relevant Network Service Provider, acting reasonably, considers that the meeting is necessary.	Noted.

Acronyms

Acronym	
AC	alternating current
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
capex	capital expenditure
COAG	Council of Australian Governments
CoGaTI	Coordination of Generation and Transmission Investment
DC	direct current
DER	distributed energy resources
ESB	Energy Security Board
GW	giga-Watt
GWh	gigawatt hours
HVAC	high voltage alternating current
HVDC	high voltage direct current
ISP	AEMO's Integrated System Plan
kV	kilo-Volt
LCC	line commutated converter
MI	mass-impregnated (i.e. oil impregnated) paper
MIND	mass impregnated non-draining
MLEC	modified load export charge
MW	mega-Watt
NEM	National Electricity Market
NER	National Electricity Rules
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PACR	Project Assessment Conclusions Report
PV	photovoltaic
QNI	Queensland – New South Wales interconnector
REZs	renewable energy zones
RIT-T	regulatory investment test for transmission
TNSP	transmission network service provider
TSIPR	Time Sequential Integrated Resource Planner
VSC	voltage source converter
XLPE	cross-linked polyethylene