An analysis of the economics and greenhouse gas impact of Marinus Link and Battery of the Nation

Prepared for the Bob Brown Foundation

Associate Professor Bruce Mountain and Dr Steven Percy

Victoria Energy Policy Centre

VICTORIA UNIVERSITY
MELBOURNE AUSTRALIA

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Authors' affiliation: Associate Professor Bruce Mountain is the Director of the Victoria Energy Policy Centre and Dr Steven Percy is a Senior Research Fellow at the Victoria Energy Policy Centre.

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Executive Summary

Tasmanian network service provider, Tasnetworks, is proposing to build new interconnectors between Tasmania and Victoria, and Hydro Tasmania is proposing to build the "Battery of the Nation" (BoTN) by repurposing existing capacity and building additional pumped hydro storage. Together these projects are claimed to be able to provide 1,500 MW of dispatchable generation to Victoria. The Australian Energy Market Operator (AEMO) has concluded that more dispatchable generation will be needed to replace coal-fired generators in Victoria when they retire. The Marinus Link and BoTN proposals have so far been funded by the Australian Government (through the Australian Renewable Energy Agency) and also by the Tasmanian Government.

The Bob Brown Foundation has asked us to examine the economics and greenhouse gas implications of Marinus Link and Battery of the Nation. This report sets out our findings.

The full cost of the Marinus Link and BoTN proposal has not been established. While cost estimates of Marinus Link seem to be quite far advanced, the BoTN proposal is not yet well developed. In our analysis we have accepted, for the purposes of this assessment, that 1,500 MW of dispatchable generation is required in Victoria. We then establish the cost of possible alternatives and compare this to the cost of Marinus.

The two obvious alternatives to Marius Link and BoTN are gas turbines/engines or batteries, located in Victoria. AEMO estimates that the build cost of gas turbines is currently around 40% higher, per MW, than batteries. AEMO estimates that a decade from now gas turbines the build cost of gas turbines will be 240% higher than batteries. The variable cost of gas turbines/engines is already at least three times that of batteries. This gap is also like to get wider in future. For these reasons we do not believe that gas turbines/engines are realistic competitors to batteries. We therefore focus on costing a battery comparator to Marinus Link/BoTN.

An important consideration in developing a comparator is to decide on the duration of storage. Tasnetworks and Hydro Tasmania suggest that BoTN will provide "deep storage", in other words sustained production for long periods before storages are depleted. It might be expected that deep storage is preferable to shallow storage particularly if deep storage is not much more expensive. However, deep storage capability may not be valuable if there is no need for it. To assess the value of deep storage we examined prices in Victoria's wholesale electricity market. This found that the incremental gains from buying electricity when it is cheap and selling it when it is experience taper off quickly when storage duration exceeds four hours.

It might be suggested that longer duration storage will become more valuable in future when more coal generators close. We tested this using information from AEMO on the expected half-hourly production from variable renewable sources, and the expected half-hourly demand. The difference between these two – the "Residual Demand" – is the production that needs to be sourced from dispatchable generation sources. Even two decade from now (the end of the period that AEMO produces the forecasts for) when variable renewable penetration will be much higher than now, we find that there are only a small number of intervals that the four hour rolling average Residual Demand is greater than the projected dispatchable generation in Victoria. In other words, consistent with the analysis of market prices, this suggests that storage duration longer than four hours is rarely needed.

Having specified the battery storage volume, it is then an uncontroversial calculation to calculate the discounted present cost of providing batteries over the useful life of Marinus Link and to compare that to the cost of Marinus Link. This calculation reveals that 1,500 MW of four-hour battery can be provided for less than half the cost of Marinus Link. The same capacity of six-hour battery can be provided for 79% of the cost of Marinus Link and 1,500 MW of eight-hour battery storage is still cheaper than Marinus Link. In other words, even if Hydro Tasmania could provide 1,500 MW of hydro and pumped storage without incurring any additional cost, it still be cheaper to build 1,500 MW of batteries in Victoria.

Our analysis is directionally consistent with the previous studies by EY of the economics of additional interconnection undertaken for the Tamblyn Review and then for Tasnetworks. Specifically, EY's study for the Tamblyn Review found that the expected costs of interconnection exceeded benefits in all modelled case. EY's analysis for Tasnetworks found benefits close to or less than Tasnetwork's cost estimate for almost all cases except those that assumed unrealistic emission reduction trajectories. EY's study for the Tamblyn Review did not contemplate that batteries could be an alternative to interconnection. EY's study for Tasnetwork's allowed for batteries but assumed that the relative cost differences between batteries and pumped hydro was four times more favourable to pumped hydro than is consistent with the build cost assumptions that AEMO currently uses (and which we use in this study).

The implication of this analysis is that Victoria cannot reasonably be expected to contribute to the cost of Marinus Link. Though the main purpose of Marinus Link is to provide dispatchable capacity to Victoria, batteries would be much cheaper and would be provided in the contestable wholesale market and so would not require mandated charges on consumers, as Marinus Link will.

One consequence of not building additional interconnection to Victoria is likely to be less additional wind generation capacity in Tasmania. This means foregoing the opportunity to develop relatively more productive wind resources. However, since transmission capacity to strengthen transfers from western Victoria to Melbourne can be built for around one-eighth of the cost per MW-kilometre of the cost of Marinus, the cost advantages of the superior wind resources in Tasmania do not come close to recovering the much higher cost of transmission from Tasmania to Victoria.

With respect to greenhouse gas emissions, storing electricity through pumped hydro or batteries means, generally, switching on electricity generators that would not otherwise be generating. Such generation is likely to be a coal-fired generation (variable renewable generators will produce electricity when the renewable resources are available, not because a battery or pumped hydro generator wishes to store energy). Batteries are however less greenhouse gas intensive than pumped hydro since they lose less energy in the process of charge and discharge. Furthermore, batteries located in Victoria will avoid the transmission losses that pumped hydro generators in Tasmania will cause in getting their production to Victoria.

Finally, though the focus of this analysis has been on a comparison of the quantifiable costs of batteries and pumped hydro, other commercial factors are likely to affect technology selection. Specifically, batteries present low delivery and financing risks, they can be located within distribution networks and provide value to network service providers, they can be relocated and resold, they present negligible local environmental impacts and they are highly competitive in the provision of frequency control ancillary services.

1 Introduction

Hydro Tasmania is proposing to develop the "Battery of The Nation" (BoTN) by developing hydro storage and pumped hydro capacity in Tasmania. Making this storage available to Victoria will require the development of new sub-sea interconnectors. These additional interconnectors, known as Marinus Link, have been proposed by Tasnetworks as regulated assets whose costs are to be recovered from electricity consumers. The combination of BoTN and Marinus Link will involve substantial re-engineering of the Tasmanian electricity system.

We have been asked to assess the economics and greenhouse impacts of Marinus Link and BoTN.

This report is set out as follows:

- Section 2 provides background by describing the Marinus Link and BoTN proposals and then setting out relevant facts on the Tasmanian and Victorian electricity markets;
- Section 3 presents the economic and greenhouse gas analysis of Marinus Link and BoTN;
- Section 4 discusses relevant findings and issues; and
- Section 5 presents a summary of the main conclusions.

There are five appendices that provide details on battery and pumped hydro ancillary services and energy arbitrage revenues; the relationship between arbitrage margin and storage duration; data on Residual Demand; analysis of the Pumped hydro and battery storage Arbitrage Revenue as a function of Storage Duration; and hour of day wind resource analysis.

2 Background

This section presents relevant background. It describes firstly the Marinus and BoTN proposals and their histories and then presents relevant information on demand, supply, prices, interconnection and wind generation correlation / capacity factors.

2.1 Description of the Marinus and BoTN proposal

2.1.1 Marinus

A starting point in the development of proposals for further interconnection between Tasmania is a study[1] of the feasibility of a second interconnector by Dr John Tamblyn (the "Tamblyn Review" commissioned in April 2016 by the Tasmanian and Australian governments in response to Basslink outages and low hydro storage levels, and published in April 2017.

On the basis of the Tasmanian Government's second interconnector specification, the Tamblyn Review suggested a second 600 MW interconnector would cost between \$0.8bn and \$1.1bn. The Review concluded that the economic feasibility of a second interconnector was uncertain. The economic modelling undertaken for the Tamblyn Review by consultants, EY, found the found benefits falling well short of costs for the Base Case. Modelling undertaken by AEMO for the Review suggested a second interconnector would deliver benefits slightly above costs in the case of its neutral economic growth scenario. In other scenarios it suggested benefits would not exceed costs.

Tasnetworks then established "Project Marinus" at the end of 2017 with \$20m funding support from the Australian Government via the Australian Renewable Energy Agency (ARENA) and the Tasmanian Government. In 2018, in the context of its quinquennial regulatory review, TasNetwork applied to the Australian Energy Regulator to propose a "contingent project" in respect of the expansion of transmission capacity in the Palmerston to Sheffield 220 kV corridor "*to facilitate significant generation developments in the*

[1] See https://www.energy.gov.au/sites/default/files/feasibility-second-tas-interconnector-final-report-2017.pdf

North West and/or West Coast of Tasmania, or to facilitate a connection of a second Bass Strait interconnector in North West Tasmania"[2].

At the time of its contingent project application, Tasnetworks provided additional information to substantiate its proposal for the recognition of Marinus Link as a contingent project in its revised regulatory proposal for regulated revenues from 2019 to 2024. In this document, Tasnetworks revised the Tamblyn Report's earlier estimate of the cost of a 600 MW DC interconnector (of between $0.8bn and $1.1bn) to $1.62bn[3]. Tasnetworks also suggested that Tasmanian electricity consumers would only obtain a small portion of the benefits of Marinus Link (presumably the large portion of the benefits therefore accruing to Victorian electricity consumers).

In February 2019, Tasnetworks released its Initial Feasibility Report which coincided with a further $56m of funding from the Australian Government to "*fast track the development of Marinus Link*". In the Initial Feasibility Report, cost estimates had risen to $1.4bn for each of the two 600 MW interconnectors, the first to be commissioned in 2028 and the other in 2032.

In late 2019, Tasnetworks released its "Project Assessment Draft Report" (PADR) a major document in the process of the Regulatory Investment Test administrated by the AER. The PADR now proposed two 750 MW DC cables to be commissioned in 2028 and 2032. The cost estimates had now risen to $1.64bn (one cable) or $2.76bn (two cables) excluding an "accuracy allowance" and a "contingency allowance" and excluding land acquisition costs. The latest cost estimate that Tasnetworks now uses for Marinus Link are $3.5bn for two 750 MW DC links to be commissioned in 2028 and 2032 respectively[4].

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[2] See page 5 in https://www.aer.gov.au/system/files/TasNetworks%20-%20Project%20Needs%20Analysis%20Palmerston%20to%20Sheffield%20220%20kV%20Augmentation%20-%2029%20November%202018.pdf
[3] See page 8 in https://www.aer.gov.au/system/files/TN-Marinus%20Link%20Contingent%20Project%20Explanatory%20Paper.pdf
[4] See for example: https://www.marinuslink.com.au/wp-content/uploads/2019/12/project-marinus-business-case-assessment-report.pdf

2.1.2 Battery of the Nation (BoTN)

In April 2018, Hydro Tasmania released a "Concept Study and knowledge sharing report"[5] supported by the Australian Renewable Energy Agency (ARENA) that identified 14 possible pumped hydro options in Tasmania that "*represent up to about 4800 MW of cumulative installed capacity, with up to 140,000 MWh of energy in storage and high level capital cost estimates in the range of $1.1m/MW to $2.3m/MW of installed capacity*".

Hydro Tasmania then released further reports[6], also funded by ARENA, that have produced interesting analytical insights. However, these reports have not provided much further detail of the projects to be developed as part of the BoTN proposal. Hydro Tasmania has, however, said[7] that it has 500 MW of additional storage capacity than can be extracted by repurposing its existing storages and generators, at little or no additional expense. In the most recent information that we are aware of, Hydro Tasmania has said[8] it expects to be able to develop pumped hydro generation for outlays of $1.5m to $1.8m per MW. This is higher than the estimates used in EY's studies but still well below (30%) AEMO's estimate of the cost of pumped hydro capacity or of the claimed costs of the proposed Snowy 2.0[9] and Kidston Pumped Hydro projects.

2.2 Relevant facts on the TAS and VIC power systems

This sub-section presents relevant facts on the TAS and VIC power systems in order to provide context to the consideration of the merits of Marinus Link and BoTN. It examines demand, supply, prices, interconnector flows and presents analysis of correlation and capacity factors of wind generators in TAS compared with wind generators and demand in mainland energy markets.

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[5] See https://arena.gov.au/assets/2018/06/battery-of-the-nation%E2%80%93-tasmanian-pumped-hydro-in-australias-future-electricity-market.pdf

[6] Hydro Tasmania, April 2019: Battery of the Nation: "Operation of storages without perfect foresight". Hydro Tasmania, September 2019: Battery of the Nation: "Challenges in modelling the transforming NEM". Hydro Tasmania, November 2019: Battery of the Nation: "Unlocking investment in storage for a reliable future NEM". Hydro Tasmania, April 2020: Battery of the Nation: "The case for deep storage".

[7] See https://www.hydro.com.au/docs/default-source/clean-energy/battery-of-the-nation/how-botn-can-contribute-to-victoria-august-2019.pdf?sfvrsn=de409a28_4

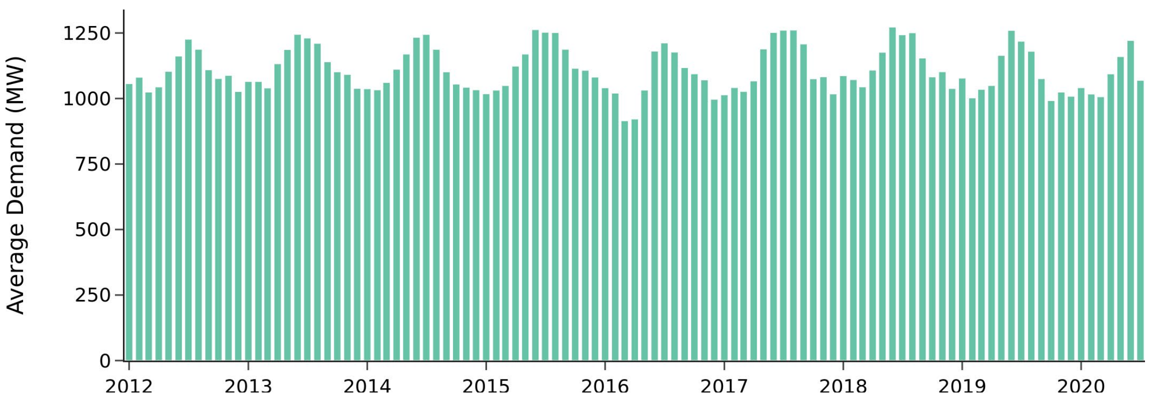
[8] See https://www.marinuslink.com.au/wp-content/uploads/2020/04/FINAL-Hydro-Tasmania-Submission-to-MarinusLink-PADR-6-April-2020.pdf

[9] Though we note that Snowy Hydro's claimed build cost for Snowy 2.0 excludes contingency, financing costs, project management, transmission connection and other items.

2.2.1 Grid demand

In the year to 30 June 2020, grid-supplied electricity in Tasmania was 9.8 TWh. Figure 1 shows the monthly average grid demand (MW)[10] in Tasmania. It shows strong seasonality (higher in winter). Distributed (behind the meter) supply is growing gradually and is estimated to be currently equal to around 2% of Tasmanian grid-based electricity supply.

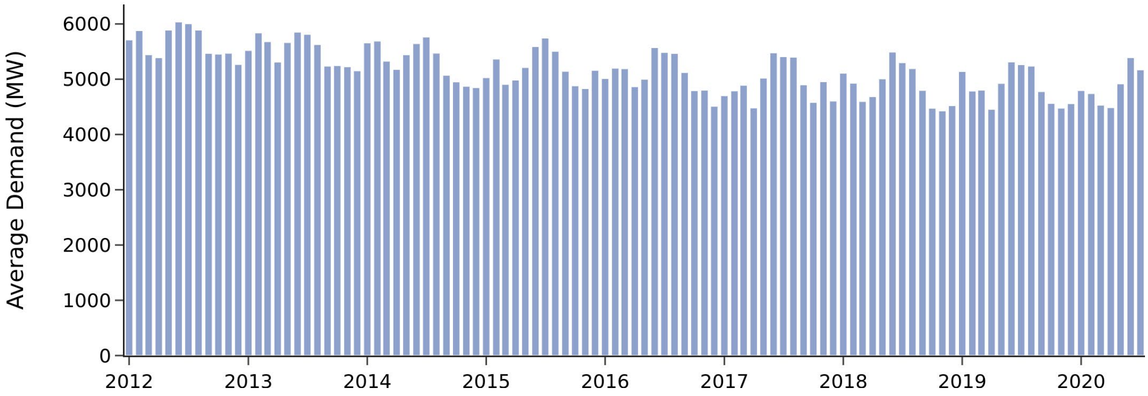
Figure 1. Tasmania monthly average grid demand (MW) 2012 to 2020



In the year to 30 June 2020, annual grid supplied electricity in Victoria was 45.1 TWh. Figure 2 shows the monthly average grid demand (MW)[11] in Victoria. At monthly resolution, the data does not show strong seasonality, although short (hourly) demand peaks occur most often in summer months. Compared with TAS there is a clearly declining trend in both the highest and lowest average monthly demand. This reflects increasing consumption efficiency and greater uptake of distributed (behind the meter) rooftop solar, of which 2.3 GW was installed at the end of June 2020, producing an estimated 2.4 GWh (5.7 % of VIC demand) in the year to 30 June 2020.

[10] Formally, Operating Demand and so net of electricity produced and consumed behind the meter.
[11] Formally, Operating Demand and so net of electricity produced and consumed behind the meter.

Figure 2. Victorian monthly average grid consumption 2012 to 2020



VIC grid-based electrical demand is roughly 5 times that of TAS although per capita electrical demand is twice as high in TAS as VIC reflecting proportionately higher residential consumption and higher heavy industrial demand in TAS.

2.2.2 Grid-based supply

Figure 3 shows grid-scale electricity production in Tasmania. Strong seasonality in production is evident from mid 2014, the two years before this being affected by emission taxes (and consequent higher production from Hydro Tasmania's gas generator at Bell Bay). The gradually growing contribution of wind is evident (1.2 TWh, a little over 10% of TAS demand was sourced from wind farms in the year to 30 June 2020).

Figure 3. Tasmania monthly average grid-based supply 2012 to 2020

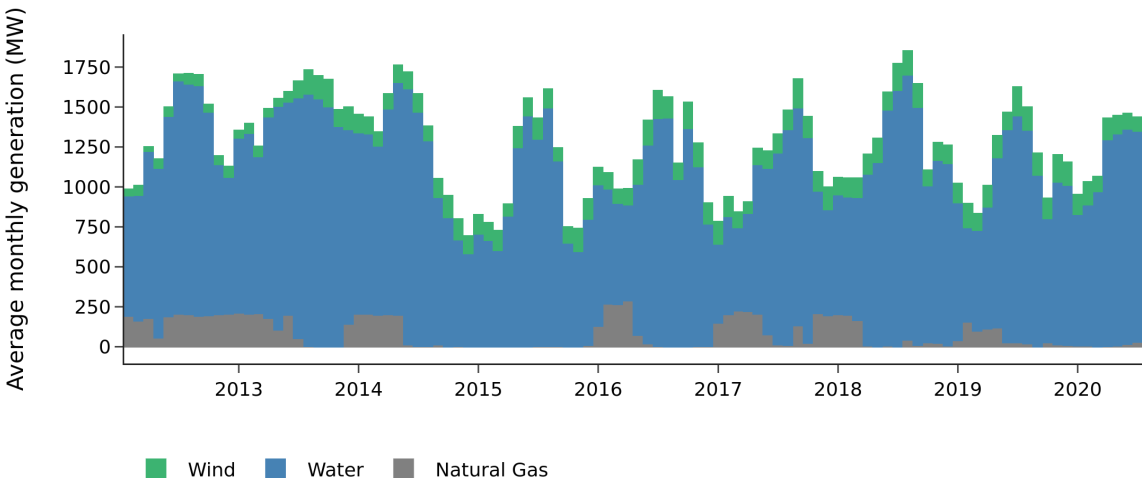
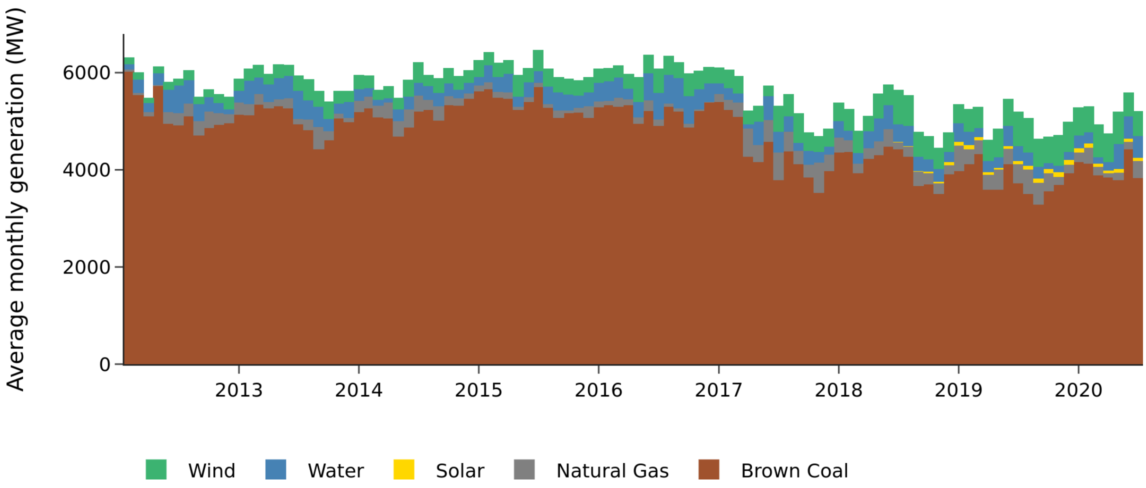


Figure 4 shows the weekly average grid-based supply in VIC. It shows a step change reduction after the closure of Hazelwood Power Station in April 2017. Slightly higher gas generation is evident from that time, although now exceeded by wind generation. A small amount of grid-scale solar production is evident from the end of 2018.

Figure 4. Victoria monthly average grid-based supply 2012 to 2020



2.2.3 Wholesale market spot prices

Figure 5 shows the weekly average spot price in Tasmania from 2012 to 2020. After a long period of stable prices, weekly average prices increased significantly from mid 2015 and then further after the failure of Basslink from late 2015 to mid 2016. Higher prices from 2017 reflect the effect of much higher mainland prices following the closure of Hazelwood. It is notable that monthly average spot prices in TAS have typically tracked slightly below the VIC levels suggesting that even though it is frequently congested, Basslink has had the effect of bringing the TAS price close to the VIC price.

Figure 5. Tasmanian and Victorian monthly average spot price 2012 to 2020

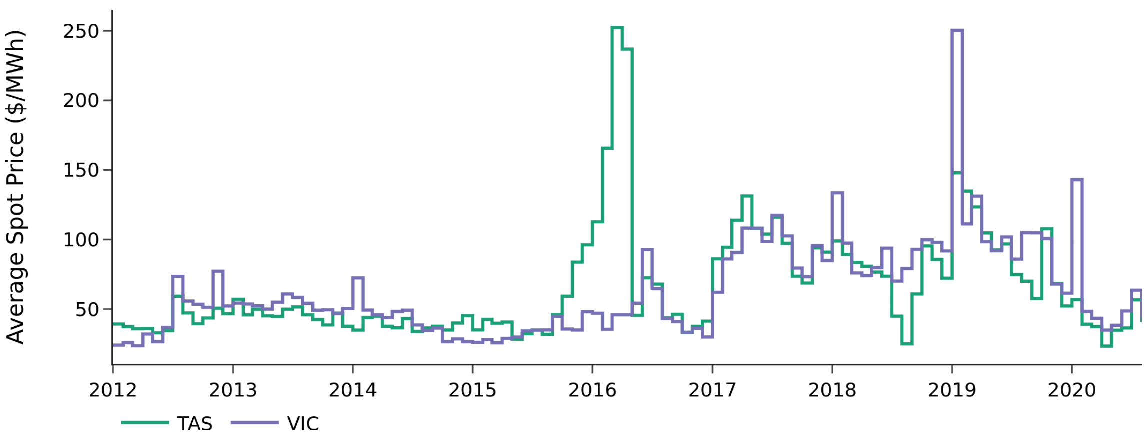


Figure 6 and Figure 7 show the median spot in VIC and TAS respectively and the band bounded by at the lower limit by the 10th percentile price and at the upper limit by the 90th percentile price. Prices for both regions peak in the morning and evening. VIC prices are clearly more volatile than those in TAS, explained by the dominance of hydro capacity in TAS, allowing easy arbitrage of peak and-peak prices and hence narrower differences than in VIC.

Figure 6. Eight-year average Victorian Price throughout the day

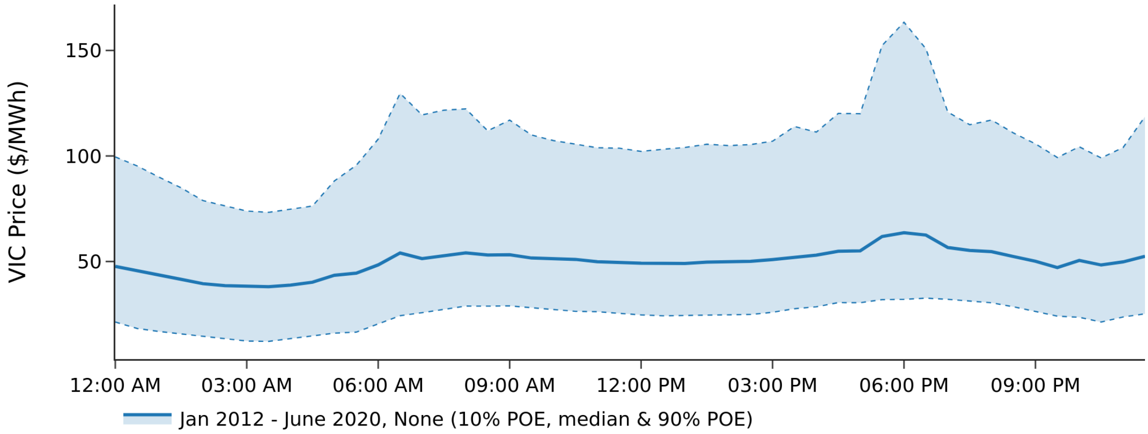
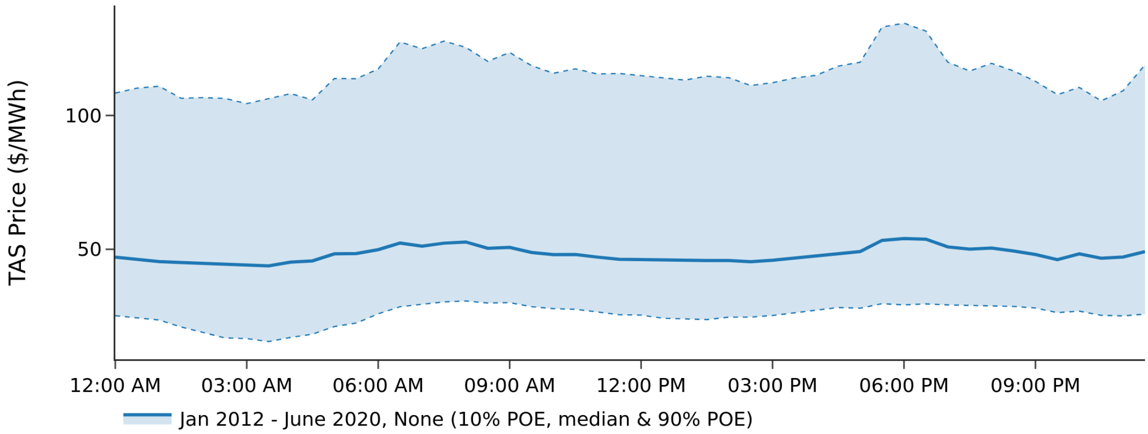


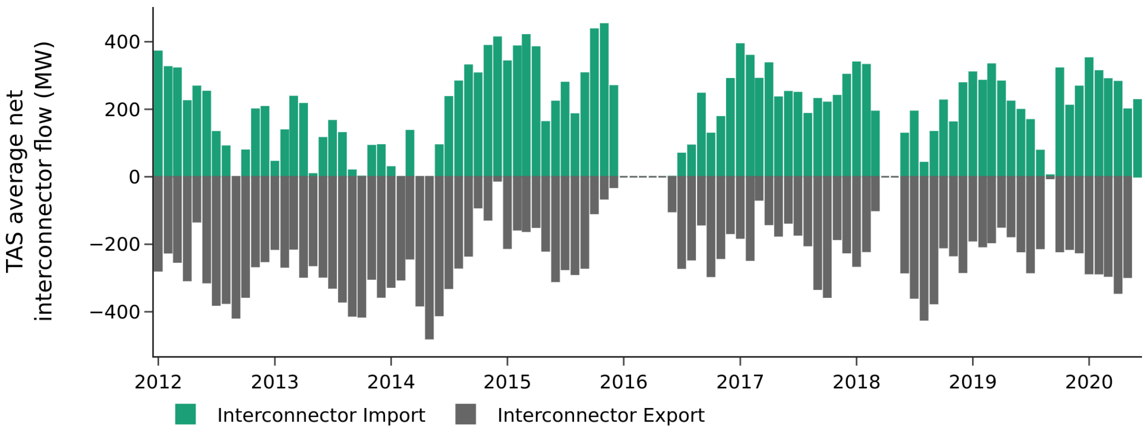
Figure 7. Eight-year average Tasmanian Price throughout the day



2.2.4 Interconnection

Figure 8 shows the monthly average interconnector flows on Basslink from 2012 to the 2020.

Figure 8. Tasmania monthly average interconnector flows 2012 to 2020 (negative is export from TAS)



The clear seasonality (higher exports in winter and higher imports in summer) is evident from 1 July 2014. The information in this chart, along with the information on gas generation dispatch in Tasmania in Figure 3 suggest that hydro storages in TAS are too small to compensate for seasonal TAS demand variation.

Figure 9 shows the spare Tasmanian hydro capacity, calculated as the difference between the 5-minute available hydro capacity offered to the market by Hydro Tasmania and the actual aggregate hydro dispatch. This shows that during summer, when Tasmanian demand is low, there is plenty of spare Tasmanian hydro capacity. However, much higher demand in winter reduces the available spare capacity in winter especially during peak hours where the median spare available capacity value falls to 274 MW at the evening peak and a little more at the morning peak.

Figure 9. Spare Tasmanian hydro capacity for summer and winter in 2019 calendar year.

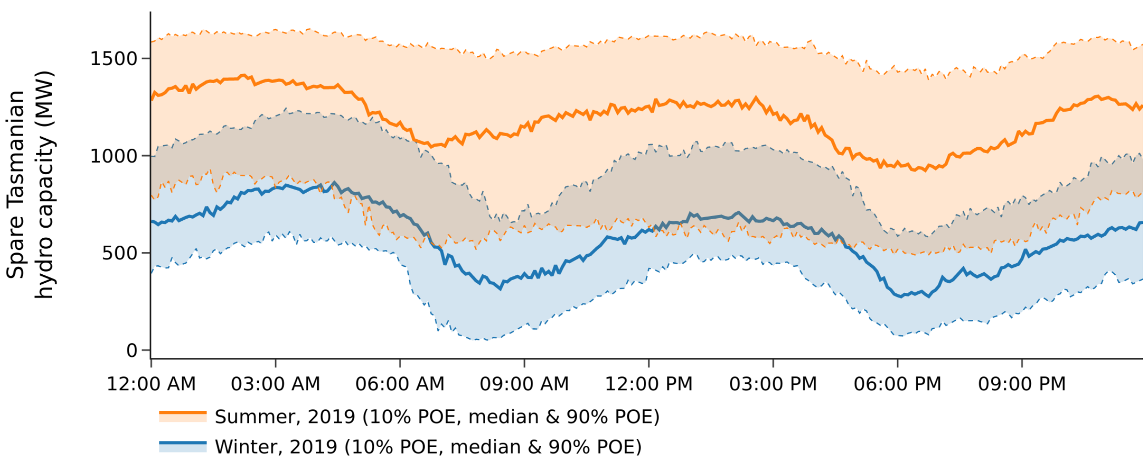


Figure 10 shows the monthly average aggregate flows across VIC's interconnectors with TAS, SA and NSW. From being a substantial net exporter before Hazelwood closed, VIC is now roughly in aggregate trade balance on an annual measurement.

Figure 10. Victoria monthly average net interconnector flows 2012 to 2020 (negative is export)

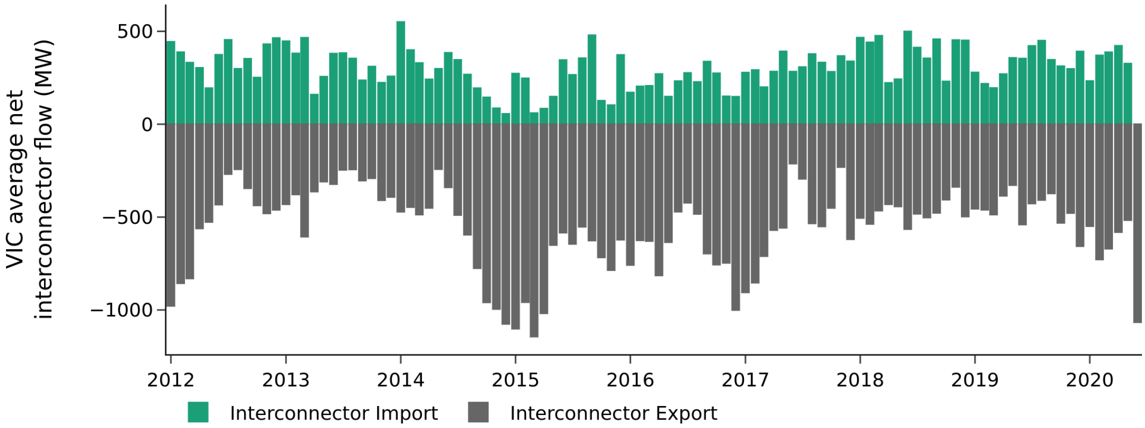


Figure 11 shows the average daily Basslink interconnector flow for the last four financial years, where a positive value is a flow from TAS to VIC. This shows TAS normally exports to VIC during the day and particularly in the evening and imports from VIC in the early morning.

Figure 11. Basslink interconnector flow, (positive value is export from TAS)

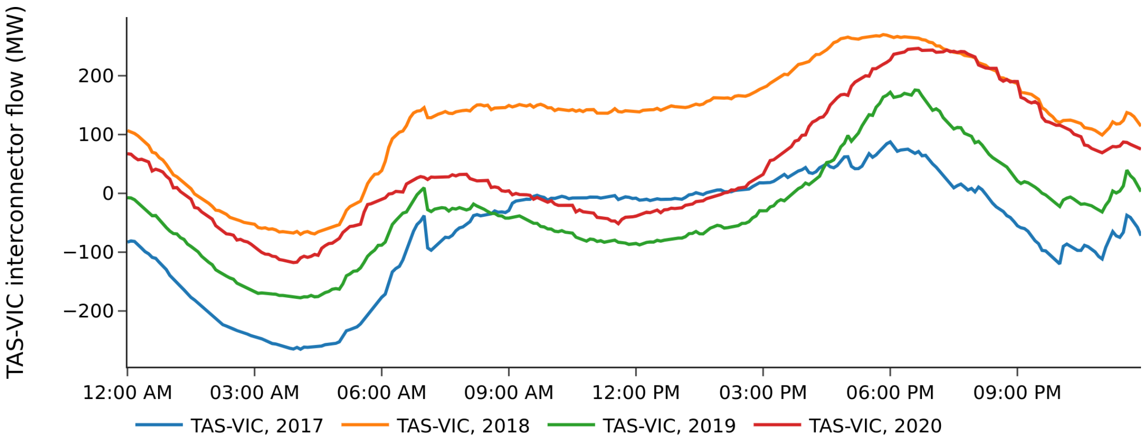
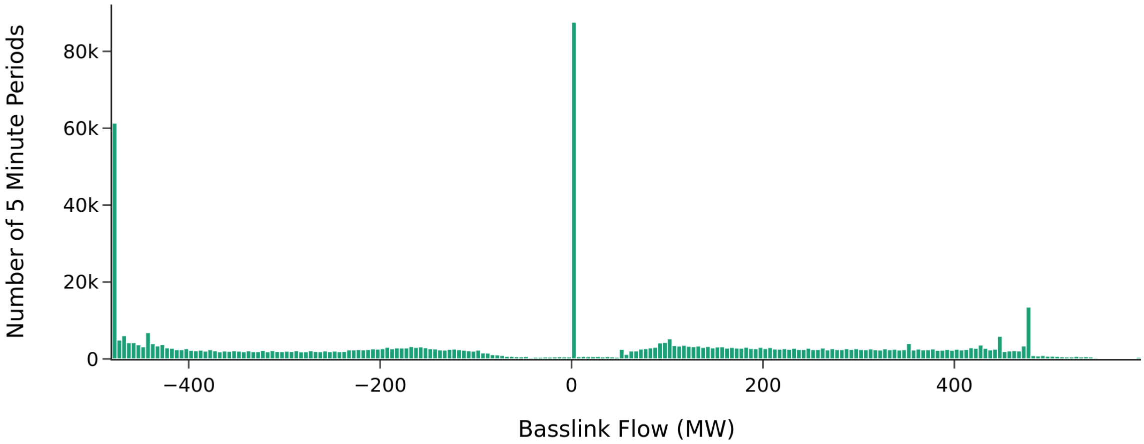


Figure 12 shows a histogram of Basslink power flow from 1 July 2014 to 30 June 2020. This shows that by far the most frequent transfer on Basslink was 0 MW. Basslink has not provided reliable service. It has suffered from three long duration outages, so that the average annual outage rate has been for 13.2% per annum over this period. This is far higher than the outage rate on terrestrial AC transmission. The European Network of Transmission Operators for Electricity reports[12] that while HVDC faults are infrequent, they may be difficult to locate and require considerable resources and time to repair (submarine cable fault average repair duration was 60 days) and so faults on HVDC submarine cables and systems result in significant costs that may lead to higher insurance costs.

Figure 12. Basslink power flow histogram (July 2014 to June 2020)



2.2.5 TAS/VIC wind generation correlation

Figure 13 shows the Pearson correlation coefficient matrix for all combinations of NEM regional wind production and demand from Jan 2018 to July 2020[13] using 5-minute data. Values range between +1 and -1 where a value of +1 represents a perfect positive linear correlation, 0 is no linear correlation, and -1 is perfect negative linear correlation.

Looking first at the correlation between regional wind production (the first six rows and columns), the results show the highest correlation for VIC-NSW and SA-VIC wind (0.63 and 0.52 respectively). Existing TAS wind generation has a 0.39 coefficient with VIC wind, but the proposed Robbins Island and Jim's Plain wind is more strongly correlated with VIC wind.

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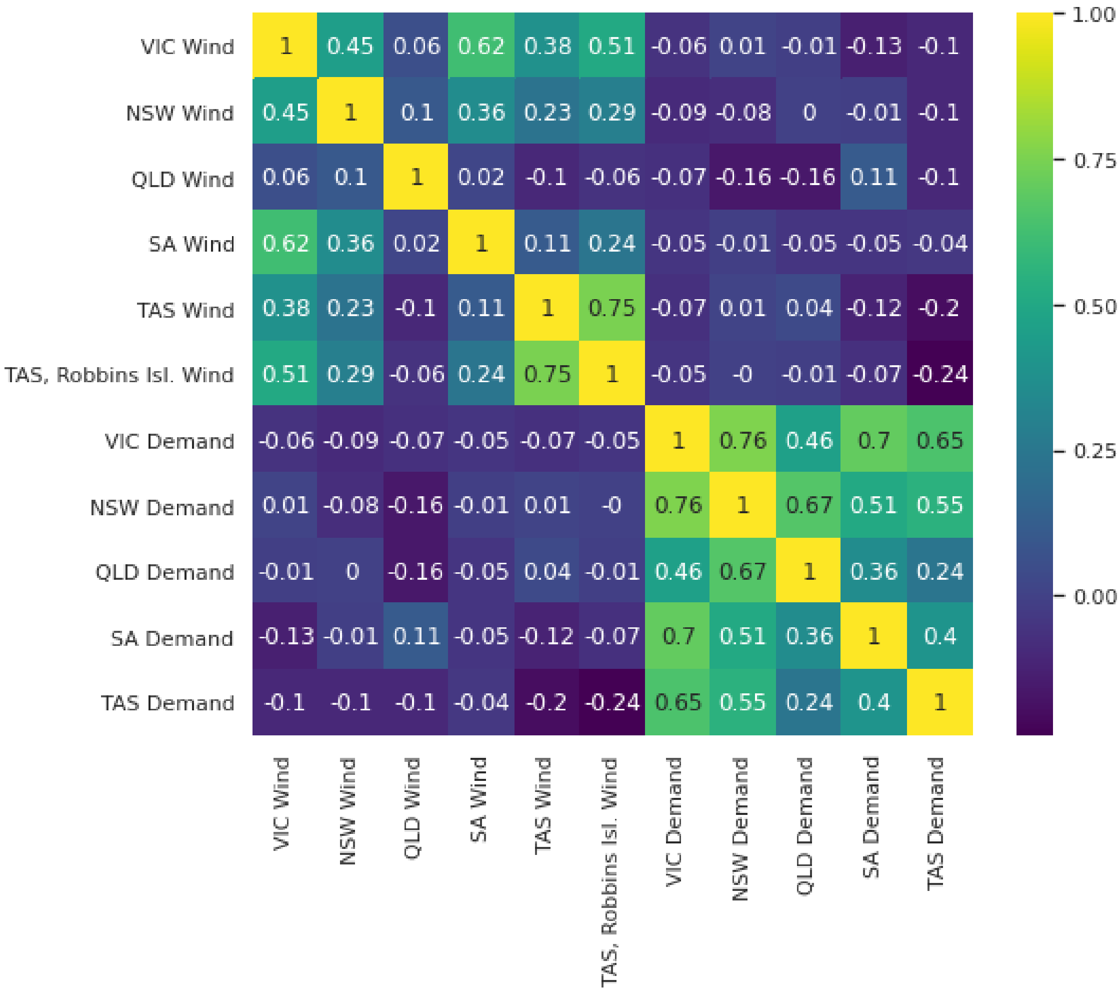
[12] See https://www.europacable.eu/wp-content/uploads/2019/06/Joint-paper-HVDC-Cable-Reliability-ENTSO-E-Europacable_FINAL_13.06.2019.pdf

[13] This date range was determined by the data on Robbins Island and Jim's Plain wind farm data supplied by UPC.

Further analysis of the correlation between TAS wind and wind in mainland markets (see Figure 39 to Figure 42 in Appendix D) shows that over the hours of the day and seasons, TAS wind has a very similar pattern of production as VIC wind.

Figure 13. All regional wind and demand correlation matrix



High demand correlation occurs between regions due to similar patterns of residential and industrial consumption. However, differences will occur due to different temperature patterns and, as expected, Tasmania with colder temperatures sees the lowest correlations with Queensland, New South Wales and South Australia demand; which is most notable in warmer months. Finally, the top right of Figure 13 shows that wind production is uncorrelated with demand for all regions.

2.2.6 Wind generation capacity factors

Table 1 shows the capacity factors for regional wind production for the year to 30 June 2020. Over this period, TAS wind achieved an average annual capacity factor of 46.6%.

Wind farms in mainland markets all achieved similar capacity factors of approximately 35%. Using forecasts for Jim's Plain and Robbins Island wind generation provided to us by UPC renewables, we found that these wind farms would achieve slightly higher capacity factors than existing TAS wind farms.

Table 1. Regional Wind Capacity Factor over the June 2019 to July 2020

	Capacity factor (%)
TAS Wind	46.6
TAS, JP+RI Wind (forecast)	47.4
VIC Wind	35.9
SA Wind	34.2
NSW Wind	35.4
QLD Wind	36.3

Figure 14 and Figure 15 shows the average wind capacity factors through the day and in summer and winter (see Appendix D for other seasons). They show that in summer wind generation in TAS is correlated with solar generation (unlike in other regions).

Figure 14. Average summer regional wind capacity factors measured through the day

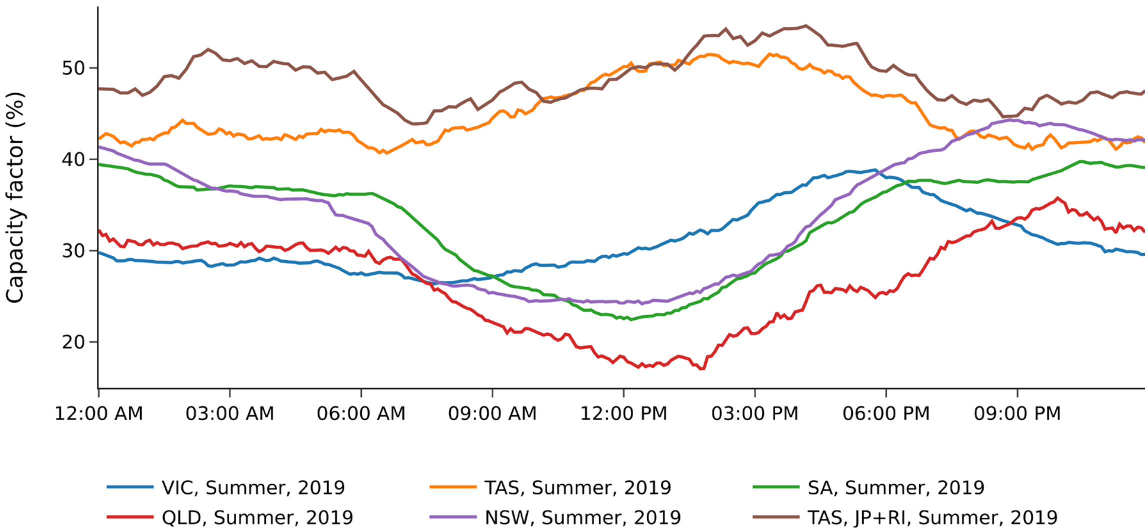
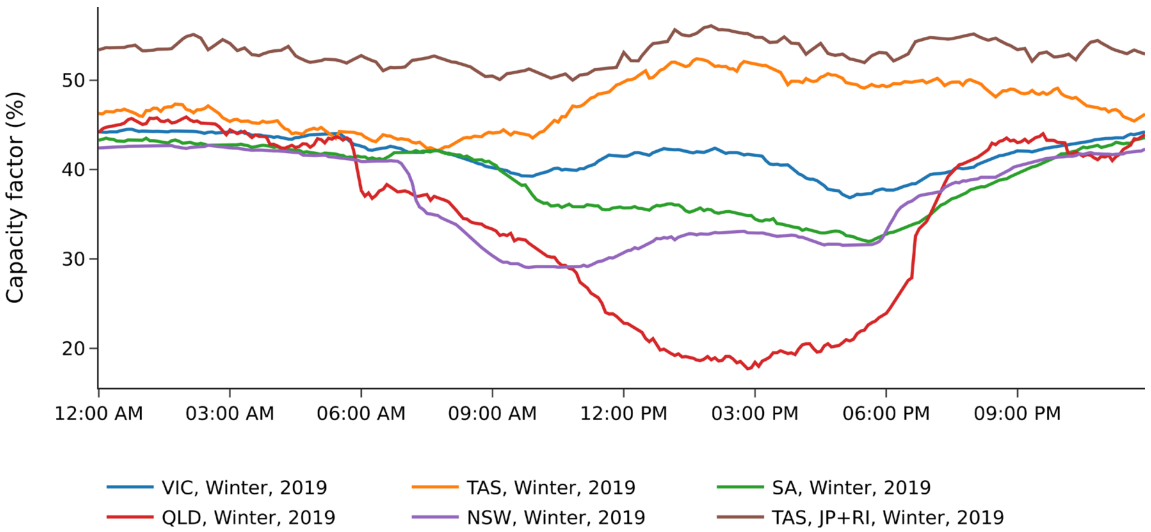


Figure 15. Average winter regional wind capacity factors measured through the day



3 Analysis

In this study, we are asked to advise on the merits in economics and of greenhouse gas emission reduction, of Marinus Link and BoTN. This section presents our economic and then greenhouse gas evaluation.

3.1 Economic evaluation

Detailed cost estimates have been established for Marinus Link. By comparison Hydro Tasmania's BoTN proposal is not defined in detail. Publicly available documents to define the capability, capital costs, location, operational constraints and operating costs of the BoTN developments are not available. A specification of BoTN was included in the estimation of market benefits in a report[14] by EY produced for Tasnetworks. But this specification of BoTN has not been publicly stated by Hydro Tasmania. In fact, there is no publicly available specification of just what BoTN means. Therefore, in order to compare the package of Marinus Link plus BoTN to alternatives, we have no choice other than to assume what BoTN means. On this we err in favour of the proponents and assume that BoTN means the provision of 1,500 MW (to match the capacity of Marinus) of storage capacity to Victoria.

Implicit in this assumption, we do not question whether 1,500 MW will in fact be needed in Victoria when Marinus Link is commissioned. Instead, for the purpose of this analysis, we take as given that any alternative to Marinus and BoTN must be able to provide 1,500 MW of storage, in line with the network capacity that Tasnetworks claims Marinus Link will provide to Victoria.

Specifying the comparator also requires specification of storage duration, i.e. how many continuous hours is 1,500 MW of additional dispatchable capacity likely to be valuable for? BoTN is often described as a source of deep (i.e. long duration) storage although

[14] See https://www.marinuslink.com.au/wp-content/uploads/2019/12/attachment-1-ernst-and-young-marketing-modelling-report.pdf

Hydro Tasmania has not publicly stated the duration of the storage that BoTN will be capable of providing.

To the determine storage duration (the number of continuous hours of production) that is likely to be valuable in Victoria, we used historic spot prices in the NEM, and ran an optimisation model to determine how arbitrage revenues (i.e. the revenue that arises from the difference between the price paid and the paid received) varied with different hours of storage capacity. In this optimisation, we assumed an 85% round trip efficiency to account for losses in charging and then discharging the storage. When we did this in the calculation for batteries, we assumed no ramp rate constraint as is typical for batteries that can change from charging to producing in milli-seconds. We undertook the same analysis for pumped hydro but in this case assumed that pumped hydro could ramp 40% of its capacity in 5 minutes. Appendix B provides more detail of this calculation. The optimisation algorithm assumes perfect foresight and finds the optimum combination of charging and discharging that maximises the profit that the operator of the battery can obtain from the market (assuming its demand and supply does not affect prices).

The relationship between arbitrage revenues and storage duration using historic five-minute spot prices in Victoria for the last five financial years is shown in Figure 16.

Figure 16. Arbitrage revenue as a function of storage duration in Victoria from 2015/16 to 2019/20

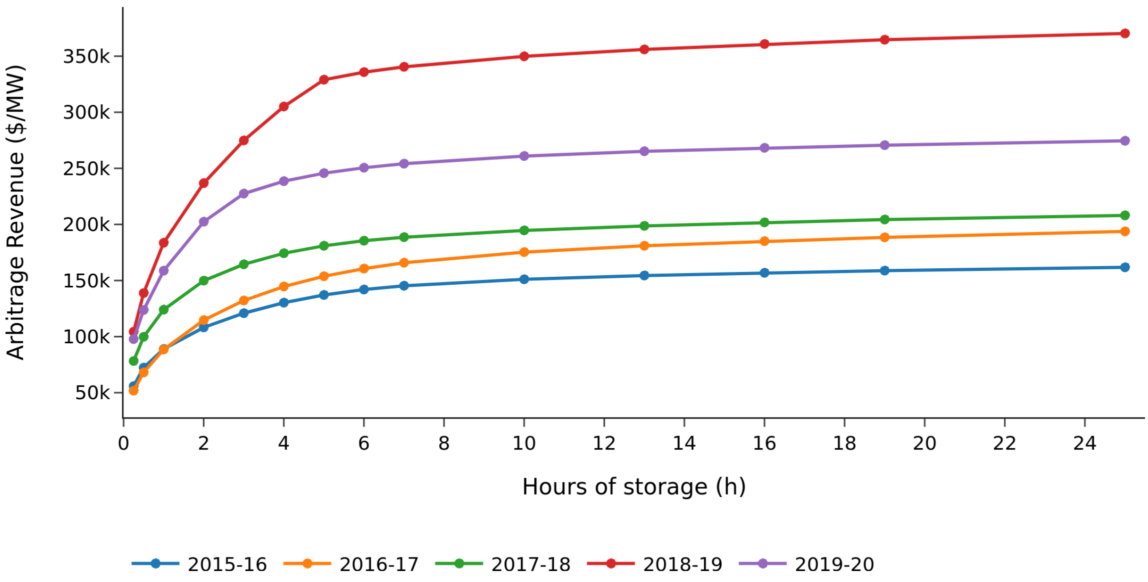


Figure 16 shows that for storage duration beyond four hours, arbitrage revenues only rise slightly. In other words, in Victoria the marginal value of longer storage is small once storage duration exceeds four hours and negligible once storage duration exceeds six hours. Appendix C shows the results in the other NEM regions. The curves in all cases have a similar shape but reflect differing levels of arbitrage revenues reflecting the differences in the prices when buying and selling that can be achieved in each market.

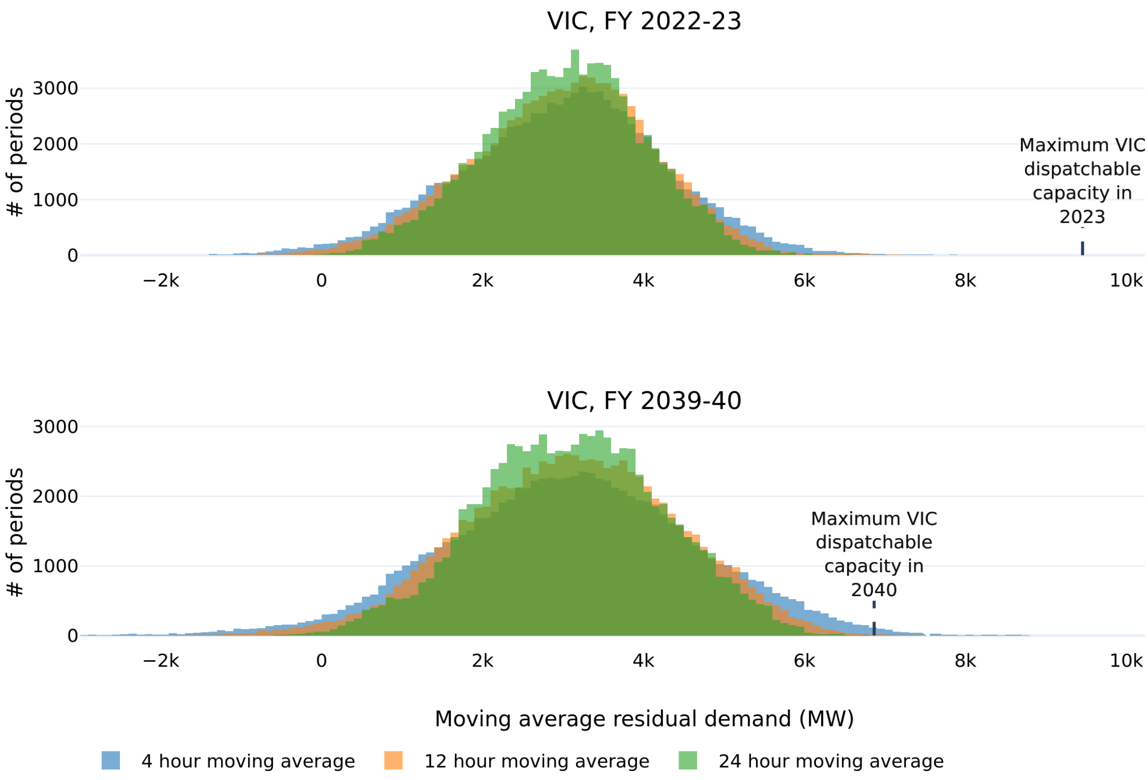
In response to this analysis of historic prices, some might suggest that the future will be different to the past, in particular that as dispatchable (fossil-fuel) generators close, so prices will become volatile and long duration storage to cater for sustained solar and wind droughts will become more valuable. A counter to this, in the logic of markets, is that if investors expect sustained wind and solar droughts and hence sustained high prices it is likely to be profitable to arbitrage those prices (or to provide production that can be profitably operated for short periods). In this case, high prices at the time of solar and wind droughts depend only on the cost of providing surge generation capacity or its substitutes such as storage or demand reduction. Projections of continued rapid decline in battery storage costs suggest ever cheaper arbitrage and hence make expectations of high prices or supply shortfalls at the times of solar and wind droughts unlikely.

We also sought to assess the risk of supply shortfalls at the times of wind and solar droughts by examining the frequency of the rolling average measure of possible future Residual Demand from AEMO forecasts, i.e. the simultaneous demand measured on the high voltage transmission system less the production from variable renewables (wind and solar). The Residual Demand is the demand that needs to be met from a dispatchable (on demand) source (or from demand reduction). This analysis used the 2020 ISP[15] 10% POE Central scenario demand forecasts, renewable profiles and renewable capacity expansion. Different durations of rolling average (4, 12 and 24 hours were used). Histograms show the frequency that differing levels of the rolling average level of Residual Demand occurs So, for example, a 4-hour rolling average Residual Demand shows the number of times that rolling 4-hour Residual Demand occurs. By comparing the frequency distribution of 4-, 12- and 24-hour measures of rolling Residual Demand, it is possible to determine the

[15] See https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2019-isp-database

value of longer duration storage (or its substitutes). Figure 17 below presents the outcome of this analysis.

Figure 17. Histogram of rolling average Residual Demand in Victoria in 2022/23 and 2039/40



The charts show histograms of 4-, 12- and 24-hour moving averages of the residual demand in Victoria in 2022-23 and again in 2039-40 calculated using the production data. The X-axis on the charts are Residual Demand and the Y-axis measures the number of periods that that level of Residual Demand occurs. The right-hand tail of the distribution shows that only a small handful of periods that the rolling average of the 4-hour Residual Demand exceeds the maximum dispatchable capacity in Victoria. There are no times when the 12 or 24-hour moving average Residual Demand exceeds the maximum dispatchable capacity in Victoria in 2040. Furthermore, the distribution of 4 hour rolling averages is only slightly different than the 12- or 24-hour rolling averages. This analysis, consistent with the analysis of historic prices, suggests storage duration longer than four hours has little value in Victoria.

On the basis of these analyses, we have used as the alternative for Marinus, 1,500 MW of four-hour battery. With such capacity, conceivably 1500 MW could be provided for a little under than 12 hours out of every 24-hour period (3 non-contiguous blocks of 4 hours generation, allowing for a little longer than 4 hours to recharge between each block). As a sensitivity, we double the amount of storage to 3,000 MW of four hour (or equivalently 1,500 MW of eight hour) to compare to Marinus Link.

Having specified the comparator, the evaluation involves establishing the present value, over the economic life of Marinus Link, of the expenditure needed to build and maintain Marinus Link + BoTN in comparison to the expenditure needed to build and maintain batteries that provide, at the least, the functionality that Marinus + BoTN are intended to provide to Victoria. Since data on BoTN expenditure does not exist, in this comparison we only include Tasnetwork's claimed MarinusLink expenditure. It might be noted that, conceptually at least, this is the same as the approach that Tasnetworks adopted in its response to a report prepared for TSBC[16] on the merits of Marinus Link[17], to demonstrate what it considered to be the favourable economics of Marinus Link compared to batteries.

The analysis that we do can provide the basis for a conclusion on the merits of Marinus Link and BoTN if it finds that an alternative exists that can provide the same capacity as Marinus + BoTN, but more cheaply.

Before presenting the assumptions used in the comparison, we explain why we have not included open cycle gas turbines (OCGT) in our comparison. AEMO assumes that OCGT have an economic life of 25 years. This compares to the 15-year battery life we have used (as discussed in greater detail below). However, AEMO also assumes that capital outlays in OCGT are around than 40% higher than in batteries, per kW today, and about 240% higher per kWh by 2030 (when the capacity will actually be built). For this reason and since the fuel cost of OCGT production will almost certainly be much higher than the cost of charging batteries or BoTN, OCGT may be cheaper than Marinus+BoTN but much more expensive than batteries.

[16] See https://www.marinuslink.com.au/wp-content/uploads/2020/04/TSBC-Submission-Combined-documents.pdf

[17] However, Tasnetwork's approach differs from ours in important respects. First, they assume 8 hours of battery storage, though they do not justify this assumption. They also do not take the present value of expenditure but, it seems, simply add the undiscounted total expenditure on batteries and compare that to Marinus Link.

Having established the rationale for the comparisons, the assumptions and data sources for this calculation are summarised in Table 2 below:

Table 2. Present value assumptions

	Marinus	Battery	Source
Discount rate	5.9%	5.9%	Tasnetworks (used in Regulatory Investment Test).
Economic life	45 years for M1 and 41 years for M2.	15 years.	AEMO assume 40 years for Marinus Link and 10 year (economic life) and 20 years (technical life) for batteries. NREL assume 15 years. We have chosen 15 years to account for the fact that we have chosen zero residual value and we use NREL's assumption of fixed O&M to maintain capacity for a 15-year economic life. Our calculation ensures 3 full lives for batteries to provide matching service for Marinus 1 and leaves a few years residual life for the last batteries to cover the capacity of M2.
Operations and maintenance spend	\$16m p.a. for Marinus 1, \$8m p.a. for Marinus 2.	2.5% of capital outlay, per year.	Marinus – Transend; NREL for battery
Build cost	\$2,270m for Marinus 1, \$1,405m for Marinus 2. Six-year build time (expenditure spread equally over all 6 years).	AEMO Input and Assumptions Workbook, Version 1.5. Two-year lead time but outlay incurred in second year.	Marinus – Transend; Batteries – AEMO

This analysis concludes that the present cost of Marinus Link is \$3,027bn, while the present cost of the battery alternative is \$1,462bn, a little under half that of Marinus Link. In other words, even assuming that Hydro Tasmania is able to build 1,500 MW of pumped hydro capacity without incurring any cost, it will still be cheaper to install 1,500 MW of battery in Victoria than to build Marinus Link plus BoTN. If we assumed battery capacity sufficient to provide 1,500 MW of six-hour storage, this would cost 79% of the cost of Marinus Link. Even if we assumed 1,500 MW of eight hour storage, batteries would still be cheaper than Marinus Link alone.

3.2 Greenhouse gas evaluation

Storage, or its substitutes such as gas generation, demand reduction/time shifting or connection of temporally diversified renewable generation, will facilitate greater renewable generation entry, and so is essential for the decarbonisation of electricity production. In this sense, storage can play a role in reducing emissions over time. In addition, it is tempting to imagine that since storage will be charged when renewable generation is plentiful, it will mostly be renewable electricity that is stored. However, wind and solar farms produce electricity when the wind or sun are available. Charging a battery or pumping water will not provoke the dispatch of electricity from wind or solar farms. Instead, the energy that is used to pump or charge a battery will come from generators that would not otherwise be generating.

This means that as long as coal-fired generators are the marginal producers (i.e. the generators that meet marginal changes in demand) when market prices are low, storage devices which seek to buy electricity when it is cheap will be storing coal-fired generation with emission intensities of 900 to 1400 kilograms of $CO_{2\text{-equivalent}}$ per MWh. As long as gas generators/engines are the marginal producers when prices are high (when storage devices are most likely to sell electricity), they will be displacing gas turbine/engine generators with emission intensities of around 450 kg per $CO_{2\text{-equivalent}}$ per MWh. The difference in the emissions incurred from the electricity that is bought and the emissions displaced when electricity is sold gives rise to a net increase in emissions of between 450 and 900 kg $CO_{2\text{-equivalent}}$ per MWh for the electricity stored and re-produced. In addition, electricity is lost in the process of charging and re-producing stored energy and in shipping electricity from production to storage and again from storage to load. The emissions associated with this will have the emission intensity of the generators whose electricity is stored.

For these reasons as long as coal generators continue to provide the electricity that batteries/BoTN store (which is likely to be the case for at least the next decade) both batteries and BoTN are likely to be more emission-intensive sources of dispatchable capacity than gas turbines/engines.

However, comparing PHS in TAS and batteries in VIC, batteries can be expected to have round-trip losses that are 5 to 10 percentage points lower than PHS in TAS (noting however that water that is stored in upper reservoirs rather than pumped from lower reservoirs does not incur round trip losses). Furthermore, since batteries will be located in VIC not TAS, they will not incur the additional circa 6% losses in getting electricity from VIC to TAS (when charging) and from TAS to VIC (when generating). For these reasons, we conclude that batteries located in VIC will increase emissions (as long as coal generators are still at the margin), but not as much as BoTN can be expected to.

4 Discussion

Our analysis has found that batteries in Victoria will be able to deliver the same service that Marinus Link and BoTN can deliver, for around half the cost of Marinus Link alone. We do not need to know what pumped hydro capacity in Tasmania will cost: even if all 1,500 of pumped hydro capacity could be delivered without expenditure, the package of Marinus Link and BoTN can still not compete with 1,500 MW of batteries in Victoria.

Are our conclusions in line with those in other studies of Marinus Link and BoTN?

As far as we are aware there have not been any economic studies of the package of Marinus Link and BoTN. There has been a study of the economics of a second interconnector undertaken by consultants EY in 2017 for the Tamblyn Review and a second study of Marinus Link options also undertaken by EY for Tasnetworks, in 2019.

The study undertaken in 2017 by consultants EY for the Tamblyn Review concluded that a second interconnector would not deliver benefits that exceeded its costs and hence that satisfying the Regulatory Investment Test would be difficult unless Tasmanian electricity demand decreased significantly. It should be remembered that the focus of interconnection at this time was not the provision of services offered by additional Hydro Tasmania pumped hydro capacity, but mainly improving the reliability of supply in Tasmania following the sustained Basslink failure and low Tasmania reserves after low inflows and also depleted storages following much higher production during the period of emission prices.

EY's 2019 study for Tasnetworks of market benefits of Marinus Link options concluded that Marinus Link proposals (most options much bigger than in its study for the Tamblyn Review) found higher market benefits in certain cases. Specifically, the study determined market benefits that do not exceed Tasnetwork's stated costs for Marinus Link for any of the "Global Slowdown" or "Status Quo" cases. For the "Sustained Renewables" case, EY estimate the market benefits to be slightly above Tansnetwork's cost estimate for some of the scenarios. For the "Accelerated Transition" scenario, market benefits substantially exceed costs, but none of the "Accelerated Transition" assumptions are plausible and so this scenario can be dismissed. Broadly, it would seem that EY's second assessment of interconnection is roughly consistent with its conclusion from its first assessment: satisfying the Regulatory Investment Test will be difficult.

It should be noted that in this study, EY's estimates of the cost (and specification) of pumped hydro in Tasmania (which it was instructed by Tasnetworks to adopt and which were in turn provided by Entura, a consultancy operated by Hydro Tasmania) were consistent with the estimates that AEMO adopted in its first Integrated System Plan (ISP). However, AEMO has since increased its estimate of (24 hour) pumped hydro build cost by a factor of 2.5 (from $1.37m/MW in the first ISP to $3.42m/MW in the latest, second, ISP). In addition, EY's battery cost estimates were based on AEMO's estimates from February 2019. Since that time AEMO roughly halved its estimate of battery costs in 2029/2030 (when the alternative to Marinus Link would be developed). Comparing the relative cost of pumped hydro in Tasmania to battery in Victoria, the figures used in the EY report are 4 times higher than in AEMO's latest ISP assumptions. Taking account of the latest cost estimates, it is surely the case that EY would have to conclude substantially lower market benefits from Marinus Link than it concluded using cost estimates that are long since superseded.

Have we ignored the benefits offered by superior wind generation in Tasmania?

Part of the rationale for the construction of Marinus Link is to facilitate the exploitation of Tasmanian wind. As discussed in Section 2.2.6, in the year to 30 June 2020, Tasmania's wind farms achieved an average annual capacity factor of 46%, compared to typical capacity factors for existing windfarms on the mainland of around 36%. Assuming all other factors are the same, a wind farm on the mainland that had an average cost of production of $50/MWh, could produce the same amount of electricity for an average cost of $39/MWh in Tasmania. UPC Renewables has said that Phase 2 of its Jim's Plain and Robbins Island wind farms will not proceed unless Marinus Link is built, and that the expected annual production from the Phase 2 wind farms will average 3,400 GWh per year. The present value (discounted at 5.9%) of the cost differences over 25 years, if those wind farms were replaced with wind generation on the mainland is $483m.

Not developing Marinus Link, therefore foregoes this benefit. However, while Tasmanian wind may be more productive than mainland wind, developing transmission capacity to get Victorian wind to Melbourne is very much cheaper than from Tasmania to Melbourne. For example, the Western Victoria 500 kV upgrade from Sydenham to Ballarat and 220 kV extensions from Ballarat to Ararat will allow more than 2,000 MW of production to be transferred from wind and solar resources in west and central Victoria. to Melbourne for an outlay of $350m. By comparison, Marinus Link offers lower transfer capacity (1,500 MW) for 10 times greater outlay. In other words, the benefit of more productive wind in Tasmania is more than swamped by the cost of getting it to the market, Melbourne, where it would be valuable.

It might be the case that the $483m present value difference associated with the superior wind resource in Tasmania might be sufficient, if it was captured by UPC, to fund a much smaller merchant transmission connection to Victoria. This would be a matter for UPC to consider.

Will Marinus Link or batteries reduce greenhouse gas emissions?

It is commonly considered that storage is necessary to facilitate the expansion of renewable generation to replace dispatchable fossil fuel generation. In this sense, storage is essential in the transition from fossil-based to variable renewable electricity production and so the argument follows that increasing storage reduces emissions. It is also often suggested that storage will be charged when renewables are plentiful and so considering the average emission intensity of electricity production at such times it would be fair to say that (mostly) renewable energy is being stored.

On the first argument, it is helpful to distinguish long term effects from short term effects. While storage (or substitutes such as gas generation, demand reduction/shifting or transmission interconnection) will facilitate renewable entry, this does not mean that renewable electricity is being stored when a pumped hydro plant pumps water to its upper reservoir or a battery is being charged.

On the second argument (the average emission intensity when electricity is being stored), this does not correctly reflect how generators are dispatched in the market and hence the relationship between electricity demand for storage, and the generators that are dispatched to meet that storage. Unless the renewable resource is stranded from the market, it will produce when the underlying renewable energy resource (the wind or sun) are available. Charging a battery or pumping water does not create a demand for the renewable resource that does not already exists. Therefore, the energy for charging or pumping will come from the marginal resources that otherwise would not be producing. It is essential to distinguish the marginal resource to identify the source of the electricity that is being stored. In the NEM, this means that as long as coal-fired generators are the marginal producers when prices are low, and open cycle gas generators are the marginal producers when prices are high, storage devices will be storing coal-fired generation with emission intensities of between 900 and 1400 kilograms of CO_2-e per MWh, and selling it back to the market to displace OCGT gas generators with emission intensities of around 450 kg per CO_2-3 per MWh. The difference gives rise to a net increase in emissions of between 450 and 900 kg CO_2-e per MWh for the electricity produced plus emissions (calculated at the emission intensity of the electricity that is stored) to account for the electricity lost in the process of charging and re-producing and for the losses involved in shipping electricity from production to storage and again from storage to load.

For these reasons, as long as coal generators continue to provide the electricity that batteries/PHS store (which is likely to be the case for at least the next decade), both batteries and PHS are likely to be more emission intensive than OCGT. However, as outlined in Chapter 3, OCGT will almost certainly be more expensive than batteries.

Comparing PHS in TAS and batteries in Victoria, batteries can be expected to have round-trip efficiencies around 5 to 10 percentage points higher than PHS in TAS and because the batteries will be located in VIC, they will not incur the additional circa 3% losses in getting electricity from TAS to VIC on the DC cables and in converting AC to DC in TAS and back again from DC to AC in Victoria. For these reasons, we concluded that batteries located in VIC will increase emissions (as long as coal generators still exist) but less so than PHS in TAS.

Who would pay for Marinus Link or batteries?

The source and allocation of funds is an important but complex part of the economics of batteries versus Marinus Link and BoTN. As a regulated asset, the costs of Marinus Link would be imposed on consumers, split between those in Victoria and Tasmania based on whatever agreement or regulation was imposed, and regulated through regulated network access charges. By comparison, to the extent that batteries are provided in the contestable market, investors or consumers would bear the cost of this, with the relative split between investors and consumers depending on the competitiveness of wholesale electricity market in Victoria. If battery development receives policy support, the recovery of this support might be allocated to taxpayers or electricity consumers.

Having regard to the assessment that batteries would cost half as much as Marinus Link, if the allocation of the cost of Marinus Link was freely negotiated between Victoria and Tasmania, how much should Victoria be willing to pay in order to be indifferent between batteries or Marinus Link? Specifically, if batteries have a present cost that is half that of Marinus, would it be in Victoria's interest to pay half the cost of Marinus? We suggest not: it is likely that little or no policy support would be needed to encourage the development of batteries in Victoria – it is almost certainly not the case that Victoria would need to resort to a regulated monopoly to ensure the provision of battery storage in Victoria. Leaving other considerations aside, one possible estimate of the Victorian contribution to Marinus Link at which Victoria would be invariant between Marinus Link and batteries might be the cost of the policy support that Victoria might expect to pay to ensure adequate battery capacity in Victoria. Our analysis suggests this is likely to be somewhere between nothing and a small amount.

Can AEMO's PHS and battery build cost estimates be relied upon?

AEMO's PHS capital cost estimates in Tasmania, as in the rest of Australia increased significantly following consultation with industry in the course of the development of the latest version of the ISP. AEMO assume PHS costs in Tasmania that are 40% higher than those estimated by Hydro Tasmania and used in the Regulatory Investment Test for Marinus Link. AEMO's estimates are consistent with claimed build costs for Snowy 2.0

(even though Snowy has claimed build cost excludes contingency, interest during construction, network connection, project management and other costs). AEMO's estimates are also consistent with the stated costs of the proposed Kidston depleted gold mine pumped hydro plant, whose cost estimates might be considered the most reliable available considering Kidston's ASX reporting requirements.

Hydro Tasmania has not produced any detailed evidence to substantiate its claims and in the absence of this, reliance on AEMO's estimates is appropriate. It should be noted that our conclusions do not rely on Hydro Tasmania's pumped hydro cost estimates since we conclude batteries would be cheaper than Marinus Link alone and so even if pumped hydro could be provided without any cost in Tasmania it would still not change the preference for batteries. However, using reliable hydro build cost estimates will matter in other studies, such as the regulatory investment test.

With regards to AEMO's battery cost estimates, we are not experts in this field, but note that their estimates are consistent with other survey's and authoritative research[18]. For example, Imperial College researchers recently concluded "lithium ion likely to become most cost efficient for nearly all stationary applications from 2030. Investments in alternative technologies may prove futile unless significant performance improvements can retain competitiveness with lithium ion".

Financing and delivery risk?

The focus of this report has been to assess whether lower cost alternatives to Marinus plus BoTN exist. While such assessment is likely to be weigh heavily in choosing between alternatives, the financing and development risks of alternatives are at least as important: a cheaper alternative that presents higher risks may not be cheaper after all. We are not expert in assessing either financing or development risks but many of the issues are obvious and we can point to these and suggest further examination if needed.

First battery development and financing seem straight-forward as the development of the Hornsdale Power Reserve, then the world's largest battery, demonstrated. Developers

[18] See for example, NREL, Imperial College.

guarantee capacity, there is a competing market of battery suppliers, and investors and lenders seem to be quite familiar with the technology. The five grid scale projects developed in the NEM since late 2017 have joined the market with little fanfare. Elsewhere the electricity market in California added more than 1000 MW of grid-scale battery in the last year and the system operator expects to add more than 10,000 MW of battery capacity by 2030.

On the other hand, Marinus Link and BoTN presents substantial development and financing risk. Tasnetworks has no prior expertise in DC cable development (Basslink was developed by the National Grid Company). If all of the cost of Marinus Link is allocated to Tasmania (as we suggest is likely to be appropriate) this will nearly triple Tasnet's Regulatory Asset Base from the current $1.5bn to $5bn.

With respect to BoTN, building 1,000 MW of pumped hydro, even at Hydro Tasmania's estimate build cost will triple the value of Hydro Tasmania's liability to Tascorp (if financed entirely through debt) or it will absorb more than all the retained equity that the Government of Tasmania has in Hydro Tasmania. With regard to delivery risk, Hydro Tasmania has no prior experience in pumped hydro development and its last hydro station (Tribute) was commissioned in 1994. BoTN delivery risk is likely to be substantial.

Other considerations

Various important technical and commercial considerations can't be captured by a present value (or a "market benefits") analysis. For example, the scalability, re-locatability, locational flexibility, the absence of local environmental detriments, the diversification of failure risk and competitiveness in the supply of ancillary services will be valuable. Specifically:

1. Batteries can easily be scaled: Relative to PHS or transmission a much smaller proportion of their cost structure is fixed. And unlike transmission they do not exhibit huge the scale economy that arises since power transfer capability rises as the square of voltage. The attributes mean batteries attract a wider set of potential

owners and do not require regulation that in the same way inevitably arises in transmission.

2. Batteries can easily be relocated: This means that a secondary market is possible. This substantially reduces investors' demand risk.
3. Batteries can be located flexibly within transmission and distribution networks (or behind the meter). This allows batteries to be sited in ways that improve network capacity. This is likely to be a source of value in many cases.
4. Batteries typically do not present local environmental detriments: They are not land intensive, have inconsequential remediation costs, and their construction and installation do not cause large amounts of greenhouse gas emission.
5. Batteries can diversity supply risk: Batteries have established a track record of reliable performance. Failure risk is diversified through multiple small installations rather than the high degree of concentration in transmission and generation that is inevitable with PHS. On the basis of Basslink performance in particular and DC cables in general, as discussed earlier, it would be appropriate to anticipate high forced outage rates with Marinus Link.
6. Batteries are competitive in the supply of ancillary services: As shown in Appendix A, the vast bulk of contingency and regulation ancillary services are provided by coal generators. Hydro and pumped hydro only provide inconsequentially small amounts in these markets. The five batteries that have developed in the NEM currently all focus on the provision of lucrative ancillary services. Their role in this market is likely to expand significantly as coal generators retire.

5 Conclusions

This report presents an analysis of the economics and greenhouse gas implications of the Marinus Link DC project proposed by Tasnetworks and of the Battery of the Nation (BoTN) project proposed by Hydro Tasmania. The focus of the analysis is to compare the projects to alternatives and thereby to establish their economic viability and relative greenhouse gas impact.

Economic evaluation

Batteries located in Victoria can provide a comparable service to that provided by Marinus Link and BoTN. Our comparison of the present value of the cost of batteries compared to Marinus Link finds that batteries will cost less than half as much as Marinus Link alone. Gas turbines or engines are also an alternative to Marinus and BOTN, but they are already much more expensive than batteries to build (about 40% more) and even more so to operate (at least 200% more). Furthermore, the gap between the build cost of gas engines / turbines and batteries and is expected to double over the next decade as the build cost of batteries declines.

In our analysis, we have assumed that an alternative to BoTN will be expected to provide 1,500 MW to Victoria for at least four hours continuously from the time that the second link of Marinus is expected to be commissioned (and 750 MW from the time that the first link is expected to be commissioned). Our analysis of the value of longer duration storage in Victoria suggests that there are very few occasions that storage duration longer than four hours will be needed, and that the arbitrage revenues from longer term storage will not be sufficient to compensate the additional cost. Even if we had assumed 1,500 MW of 8-hour storage (and to be clear we do not think such long duration storage would be valuable), it would still be cheaper than Marinus Link alone.

Expanding generation and storage capacity in Tasmania to achieve the 1,500 MW storage capacity, we have assumed will be a big undertaking, and is likely to mean a substantial re-engineering of the Tasmanian power system. It is not clear that this is what Hydro

Tasmania is envisaging. In this sense, the battery comparator to Marinus Link/BoTN that is likely to provide higher capacity than is envisaged by BoTN and Marinus Link.

It should be recognised that without additional interconnection to Victoria, the second phase of the proposed Jim's Plain and Robbins Island wind farms are unlikely to proceed. Wind farms in Tasmania is generally more productive than on the mainland. Not expanding interconnection to Victoria will therefore forego the development of more productive wind resources. However since Marinus Link is around 8 times more expensive per megawatt-kilometre than contemporary Victorian transmission augmentation, the gain from more productive wind farms in Tasmania is lost many times over in getting that generation to the market where it is valued (Victoria). It may be the case that cheaper alternatives to Marinus Link are available. Wind farm developers in Tasmania are free to explore such merchant interconnection opportunities.

Batteries are also preferable to Marinus Link/BoTN for other reasons, that we have not attempted to quantify in this analysis. Such factors include scalability; the ability to easily relocate; the ability to install batteries at various points in transmission and distribution networks (and so improve network capacity); the ability to diversify outage risk; the absence of local environmental detriments; much lower greenhouse gas emissions in construction and installation, and competitiveness in ancillary services markets.

Considering their competitiveness and having regard to these other factors, it is likely that private investors can be attracted to develop whatever battery storage capacity is likely to be needed to meet Victoria's needs. The Victorian Government will have a role in supplying stable policy, but we think it is unlikely that much, if any, public subsidy will be needed to ensure battery development in Victoria. The implication of this and that Marinus Link cannot compete with batteries in Victoria is that it is implausible to expect that Victoria's electricity consumers should be asked to contribute to any part of the cost of Marinus Link.

If the Tasmanian Government proceeds with Marinus Link and Victoria does not contribute to its expense, the regulatory asset value of transmission in Tasmania will roughly triple from its current level. Unless the cost is borne by taxpayers in Tasmania or, through the Australian Government by taxpayers throughout Australia, significantly higher electricity prices will be needed to fund the development of Marinus Link.

It might be argued that enhanced profits from energy market arbitrage from BoTN could offset the cost of Marinus Link. We doubt that such profits will come anywhere close to offsetting the circa $270m annual cost of Marinus Link. In fact, even if Marinus Link and BoTN are developed, we think there is reason to doubt that this will necessarily deter private battery developers from entering the market in Victoria. Batteries' greater competitiveness in wholesale market arbritrage and particularly in ancillary markets (where pumped hydro and hydro are weak competitors) and batteries' prospects in attracting revenues from network service providers may mean that battery developers will dismiss BoTN as a serious competitor. If this is the case then BoTN may deliver little gain to set against its own costs, let alone to set against the cost of Marinus Link.

Finally, on the economic evaluation, the conclusions of our analysis might be compared to the previous studies undertaken by EY for the Tamblyn Review and subsequently for Tasnetworks. In their report for the Tamblyn Review, EY concluded that the economic benefits of a second interconnector did not exceeds the estimated costs for any of the scenarios modelled. In their second study, EY found benefits only decisively exceeded costs in a scenario that reflected unrealistic assumptions of Australia's emission reduction policy.

It is also valuable to bear in mind just how rapidly battery technology (and market acceptance) has occurred. In their 2017 study, EY did not even contemplate battery as an alternative to a second interconnector, and in their 2019 study EY used assumptions of the build costs of battery in Victoria and pumped hydro in Tasmania that are, relatively, four times higher than the relative costs used in our study (and which are based on the assumptions that AEMO has used in its latest ISP).

Greenhouse gas evaluation

Storage or its substitutes such as gas generation, demand reduction/time shifting, or connection of temporally diversified renewable generation will facilitate greater renewable generation entry and so is essential for the decarbonisation of electricity production. In this sense, storage can play a role in reducing emissions over time. In addition, it is tempting to imagine that since storage will be charged when renewable generation is plentiful, it will mostly be renewable electricity that is stored. However, wind and solar farms produce electricity when the wind or sun are available. Charging a battery or pumping water will not provoke the dispatch of electricity from wind or solar farms. Instead, the energy that is used to pump or charge a battery will come from generators that would not otherwise be generating.

This means that as long as coal-fired generators are the marginal producers (i.e. the generators that meet marginal changes in demand) when market prices are low, storage devices which seek to buy electricity when it is cheap will be storing coal-fired generation with emission intensities of 900 to 1400 kilograms of $CO_{2\text{-equivalent}}$ per MWh. As long as gas generators/engines are the marginal producers when prices are high (when storage devices are most likely to sell electricity), they will be displacing gas turbine/engine generators with emission intensities of around 450 kg per $CO_{2\text{-equivalent}}$ per MWh. The difference in the emissions incurred from the electricity that is bought and the emissions displaced when electricity is sold gives rise to a net increase in emissions of between 450 and 900 kg $CO_{2\text{-equivalent}}$ per MWh for the electricity stored and re-produced. In addition, electricity is lost in the process of charging and re-producing stored energy and in shipping electricity from production to storage and again from storage to load. The emissions associated with this will have the emission intensity of the generators whose electricity is stored.

For these reasons, as long as coal generators continue to provide the electricity that batteries/BoTN store (which is likely to be the case for at least the next decade), both batteries and BoTN are likely to be more emission-intensive sources of dispatchable capacity than gas turbines/engines.

However, comparing PHS in TAS and batteries in VIC, batteries can be expected to have round-trip losses that are 5 to 10 percentage points lower than PHS in TAS (noting however that water that is stored in upper reservoirs rather than pumped from lower reservoirs does not incur round trip losses). Furthermore, since batteries will be located in

VIC not TAS, they will not incur the additional circa 6% losses in getting electricity from VIC to TAS (when charging) and from TAS to VIC (when generating). For these reasons, we conclude that batteries located in VIC will increase emissions (as long as coal generators are still at the margin), but not as much as BoTN can be expected to.

Appendix A. Battery and pumped hydro FCAS and energy arbitrage revenues

Table 3. Battery and PHS revenue

		Regulation revenue ($)	Contingency revenue ($)	Arbitrage revenue ($)	Total revenue ($)
Ballarat Battery Energy Storage System	**2019-20 total**	2,351,000	5,470,000	461,000	8,282,000
	Median month	43,000	589,000	-3,000	629,000
	Minimum month	38,000	174,000	29,000	240,000
	Maximum month	200,000	1,572,000	267,000	2,038,000
Dalrymple North Battery Energy Storage System	**2019-20 total**	0	19,443,000	53,000	19,497,000
	Median month	0	535,000	5,000	540,000
	Minimum month	0	161,000	-8,000	152,000
	Maximum month	0	10,320,000	-12,000	10,308,000
Gannawarra Energy Storage System	**2019-20 total**	4,894,000	0	1,079,000	5,973,000
	Median month	322,000	0	46,000	369,000
	Minimum month	209,000	0	23,000	232,000
	Maximum month	654,000	0	488,000	1,142,000
Hornsdale Power Reserve	**2019-20 total**	11,172,000	44,729,000	1,900,000	57,801,000
	Median month	1,241,000	1,465,000	186,000	2,892,000
	Minimum month	298,000	619,000	102,000	1,019,000
	Maximum month	786,000	22,972,000	60,000	23,818,000
Lake Bonney BESS1	**2019-20 total**	2,587,000	7,886,000	783,000	11,255,000
	Median month	311,000	125,000	1,000	438,000
	Minimum month	24,000	0	4,000	28,000
	Maximum month	714,000	5,361,000	38,000	6,113,000
Wivenhoe Power Station U1	**2019-20 total**	0	53,000	11,865,000	11,919,000
	Median month	0	1,000	893,000	894,000
	Minimum month	0	5,000	507,000	512,000
	Maximum month	0	18,000	2,254,000	2,272,000
Wivenhoe Power Station U2	**2019-20 total**	0	678,000	119,000	797,000
	Median month	0	477,000	-221,000	256,000
	Minimum month	0	45,000	34,000	79,000
	Maximum month	0	72,000	272,000	345,000
Tumut 3 Power Station	**2019-20 total**	595,000	769,000	101,425,000	102,789,000
	Median month	20,000	21,000	4,186,000	4,227,000
	Minimum month	15,000	33,000	-31,000	17,000
	Maximum month	159,000	342,000	61,056,000	61,557,000

Table 4. Battery and PHS revenue per MW

		Regulation revenue ($/MW)	Contingency revenue ($/MW)	Arbitrage revenue ($/MW)	Total revenue ($/MW)
Ballarat Battery Energy Storage System	**2019-20 total**	78,379	182,333	15,360	276,072
	Median month	1,422	19,635	-86	20,971
	Minimum month	1,257	5,789	950	7,996
	Maximum month	6,662	52,389	8,898	67,950
Dalrymple North Battery Energy Storage System	**2019-20 total**	0	648,116	1,772	649,889
	Median month	0	17,834	166	18,000
	Minimum month	0	5,355	-272	5,083
	Maximum month	0	344,002	-389	343,613
Gannawarra Energy Storage System	**2019-20 total**	163,140	0	35,959	199,098
	Median month	10,750	0	1,541	12,291
	Minimum month	6,966	0	778	7,743
	Maximum month	21,811	0	16,261	38,072
Hornsdale Power Reserve	**2019-20 total**	74,480	298,191	12,669	385,339
	Median month	8,273	9,768	1,241	19,281
	Minimum month	1,985	4,124	682	6,791
	Maximum month	5,241	153,144	401	158,787
Lake Bonney BESS1	**2019-20 total**	103,470	315,428	31,302	450,200
	Median month	12,453	5,010	45	17,507
	Minimum month	944	0	178	1,122
	Maximum month	28,556	214,449	1,518	244,523

Figure 18. SA Brown Coal FCAS revenue

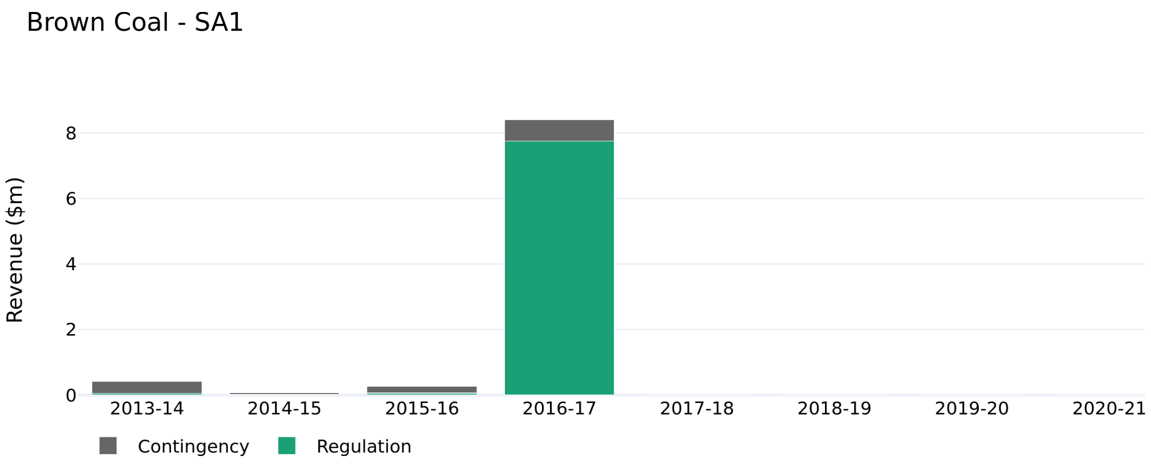


Figure 19. VIC Brown coal FCAS revenue

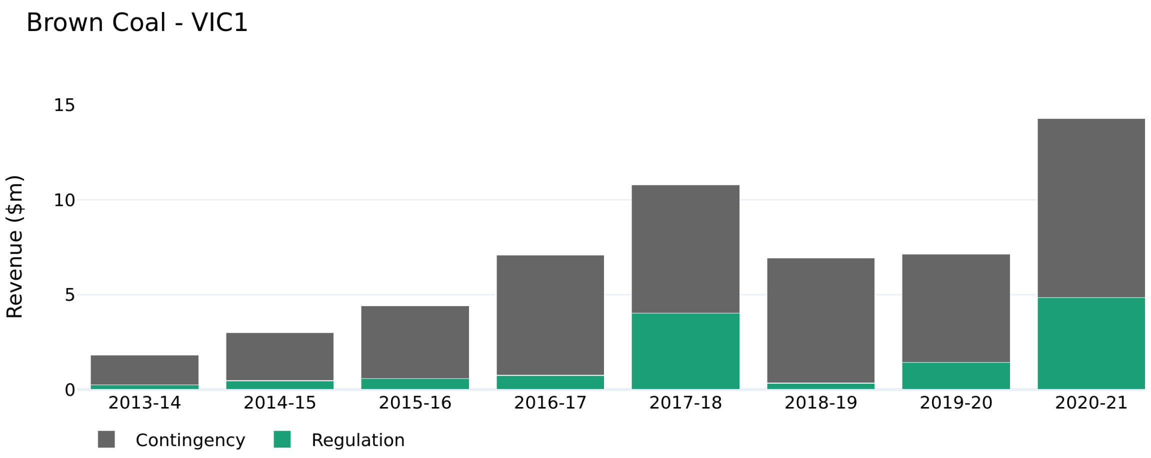


Figure 20. QLD Black Coal FCAS revenue

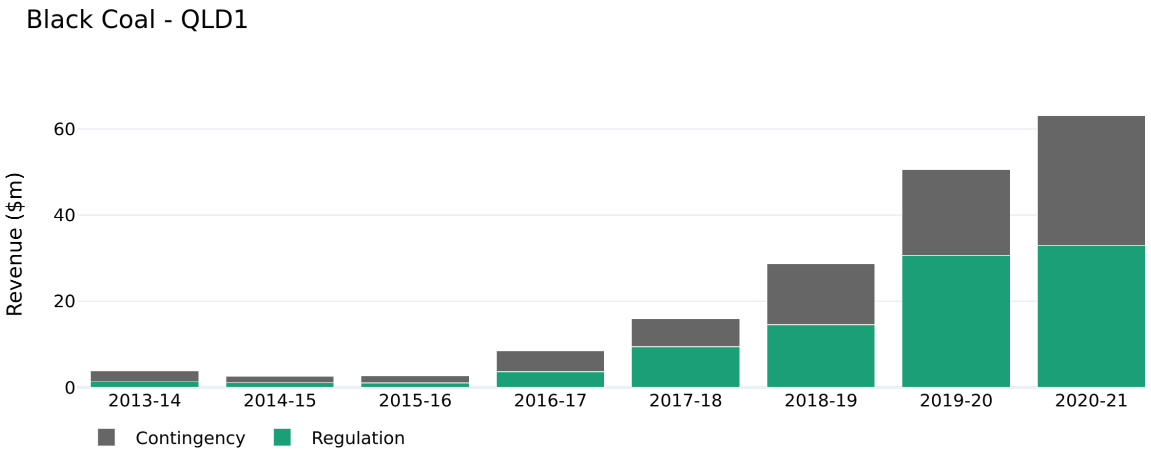


Figure 21. NSW Black Coal FCAS revenue

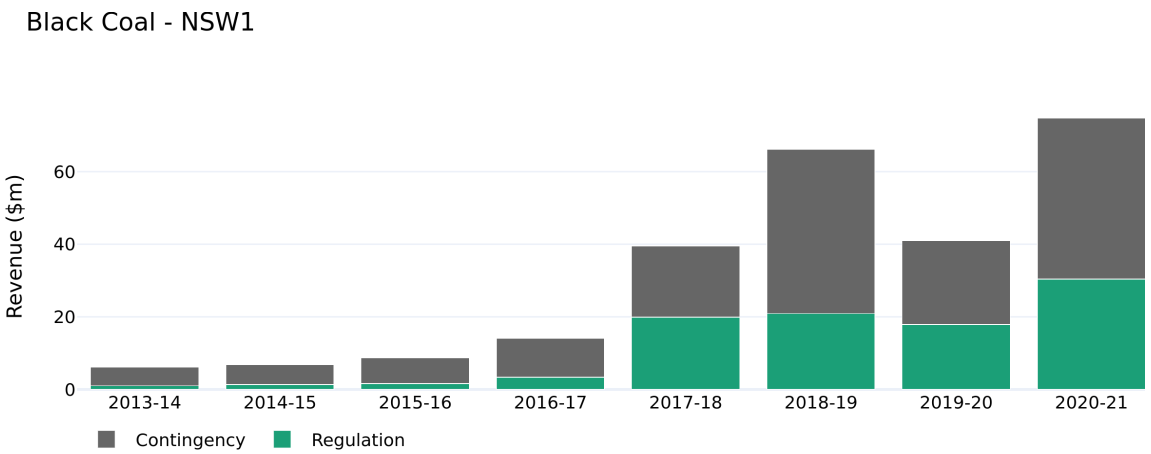


Figure 22. Wivenhoe Power Station U1 FCAS revenue

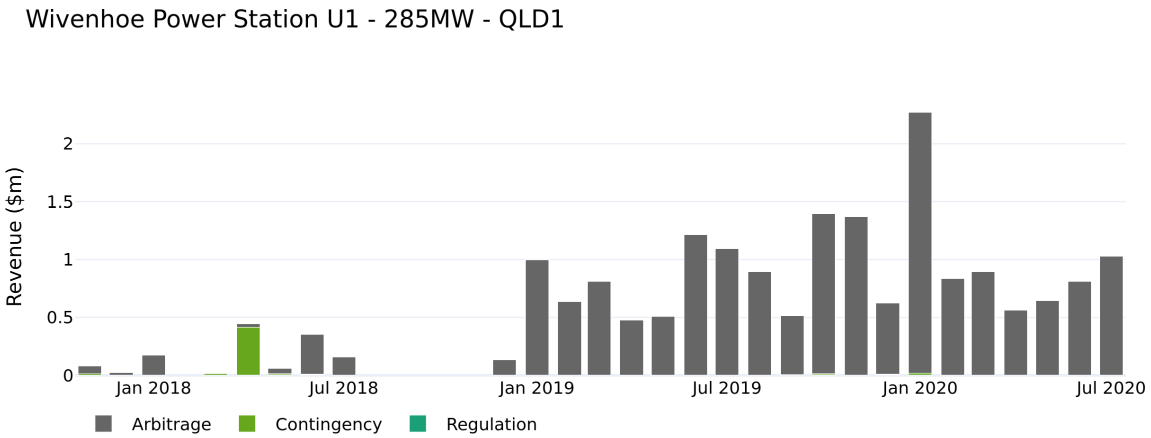


Figure 23. Wivenhoe Power Station U2

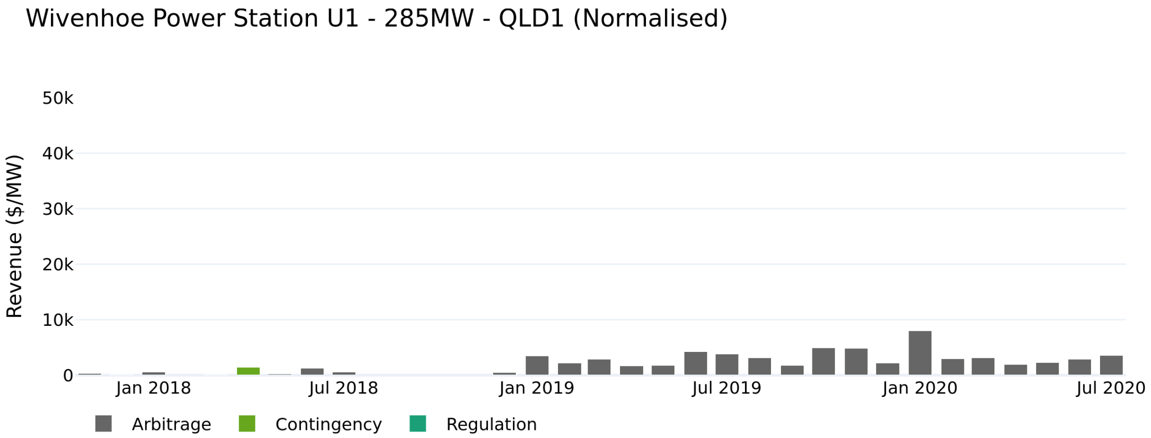


Figure 24. Tumut 3 Power Station

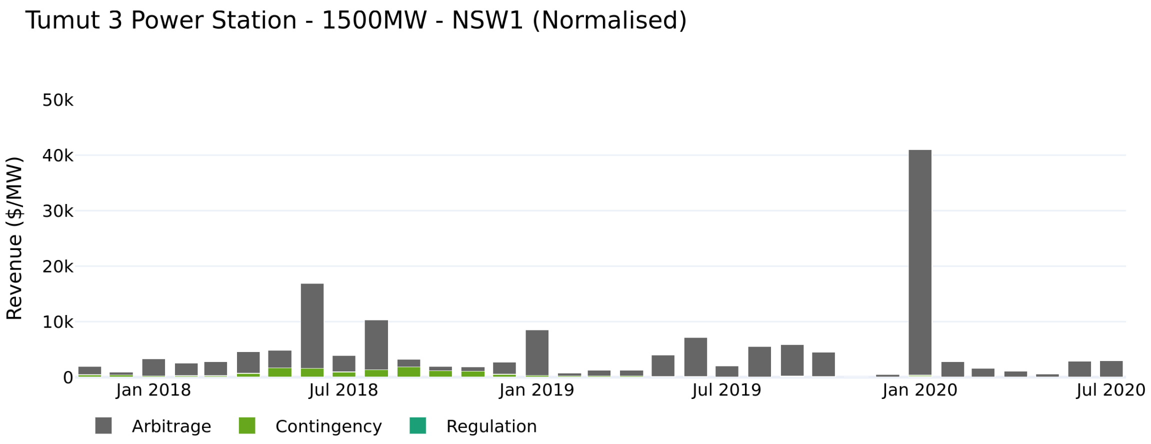


Figure 25. Ballarat Battery Energy Storage System FCAS revenue

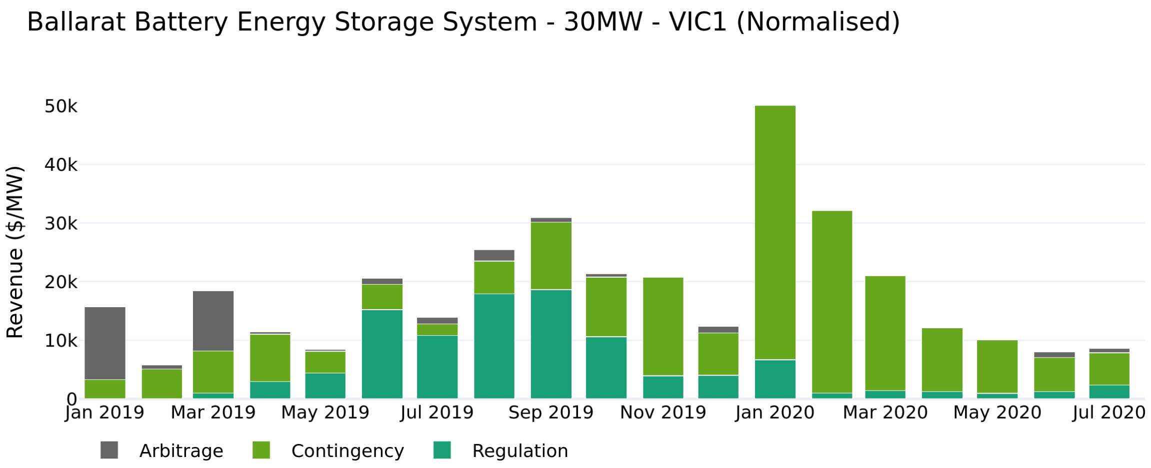


Figure 26. Dalrymple North Battery Energy Storage System FCAS revenue

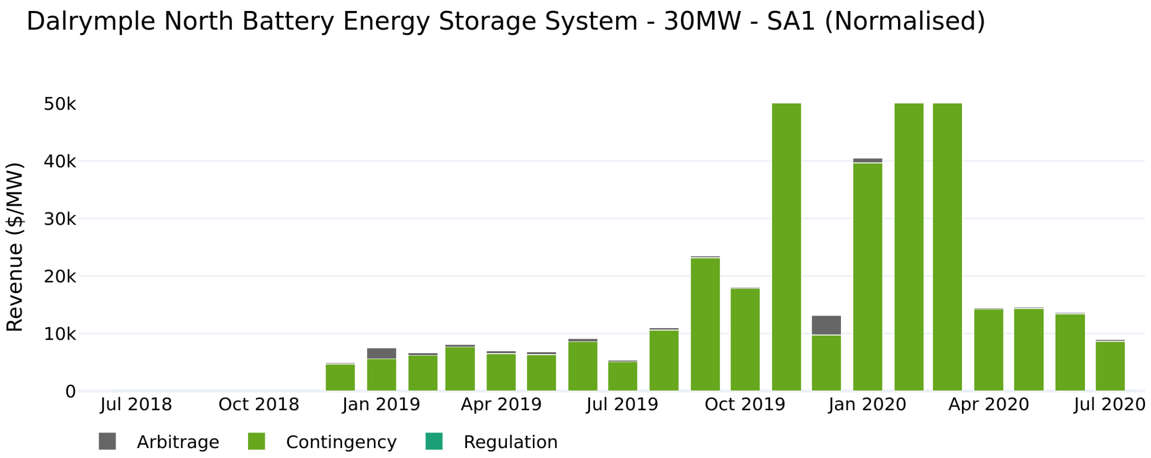


Figure 27. Gannawarra Energy Storage System FCAS revenue

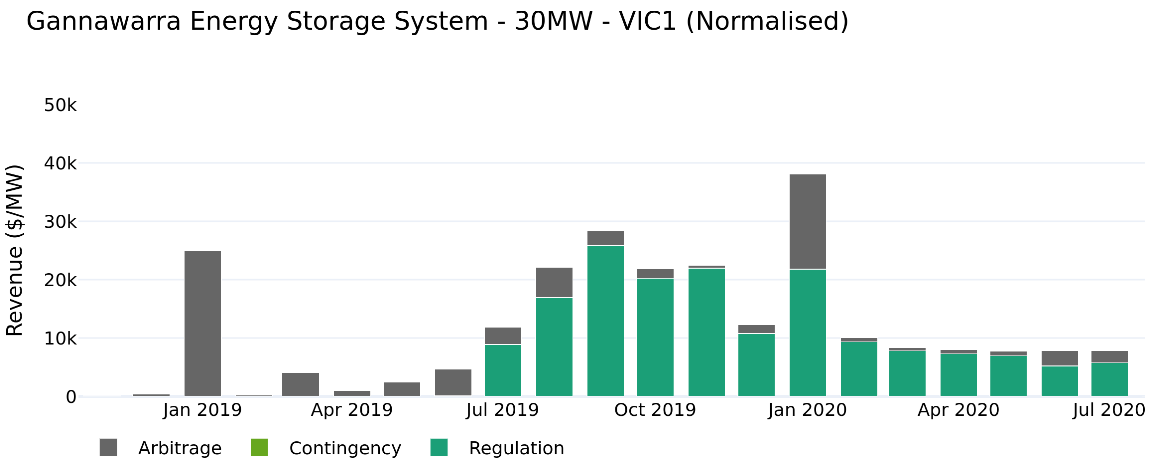


Figure 28. Hornsdale Power Reserve FCAS revenue

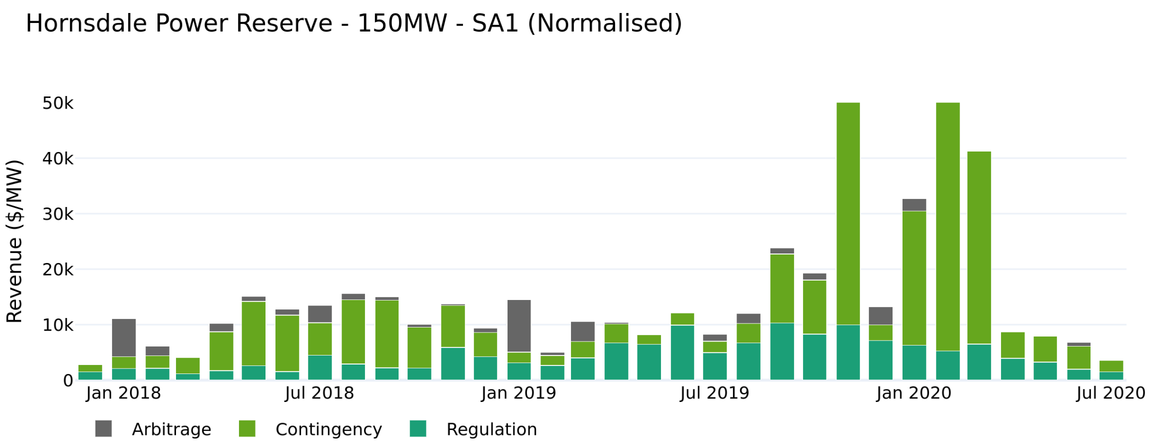
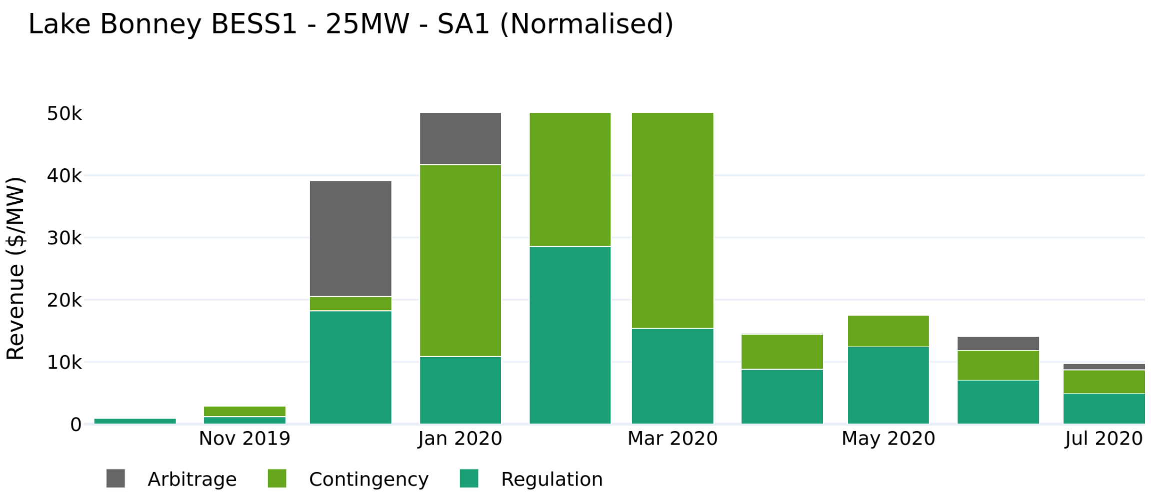


Figure 29. Lake Bonney BESS1 FCAS revenue



Appendix B. Modelling the relationship between arbitrage margin and storage duration

This appendix describes the formulation of a linear-program optimisation model used to estimate the arbitrage revenue from different hours of storage. We model the differences between PHES or BES by configuring different round trip efficiencies and ramping capacities. The analysis in this report solved the model for one year of 5-minute data for the 2019-20 financial year.

Equation (1) is the objective function that defines the maximisation of revenue from charging or discharging the storage system, where $\mathrm{Discharge_t}$ is the discharge power at time t, $\mathrm{Charge_t}$ is the recharge power, and $\mathrm{Price_t}$ is the regional price. Equations (2) to (6) limit the charging and discharging of the storage system to be less than the power and ramping capacity of the storage system where $IntervalChangeFactor$ represents the percentage change in storage output power in one five-minute period. Simulations for PHES used an $IntervalChangeFactor$ of 0.4, determined from the historical operation of the Tumut 3 PHES in NSW, and BES used a value of one due to high ramping capabilities. Equation (7) to (9) defines the energy stored in the battery at t based on the energy in the battery at t-1 plus the energy in and out of the battery, and h represents the number of intervals in one hour; converting power to energy. The charge efficiency and the discharge efficiency, η, are both equal to the square root of the round-trip efficiency.

Maximise:

$$\sum_{t=0}^{n}(Discharge_t \cdot Price_t - Charge_t \cdot Price_t - Discharge_t \cdot Cycle\_Cost) \tag{1}$$

S.T.

$$Charge_t = Charge_{t-1} + PowerChange_t \tag{2}$$

$$Discharge_t = Discharge_{t-1} + PowerChange_t \tag{3}$$

$$PowerChange_t < IntervalChangeFactor \cdot \mathrm{PowerCapacity} \tag{4}$$

$$Charge_t \leq \mathrm{PowerCapacity} \tag{5}$$

$$Discharge_t \leq \mathrm{PowerCapacity} \tag{6}$$

$$Level_t = Level_{t-1} + \frac{\eta Charge_t}{h} - \frac{\eta Discharge_t}{h} \tag{7}$$

$$\eta = \sqrt{RTE} \tag{8}$$

$$Level_t \leq \text{Energy capacity} \tag{9}$$

$$\forall t \; in \; \{0,1,\ldots,n\}$$

Appendix C. Moving average Residual Demand

Figure 30. Histograms of New South Wales Residual Demand

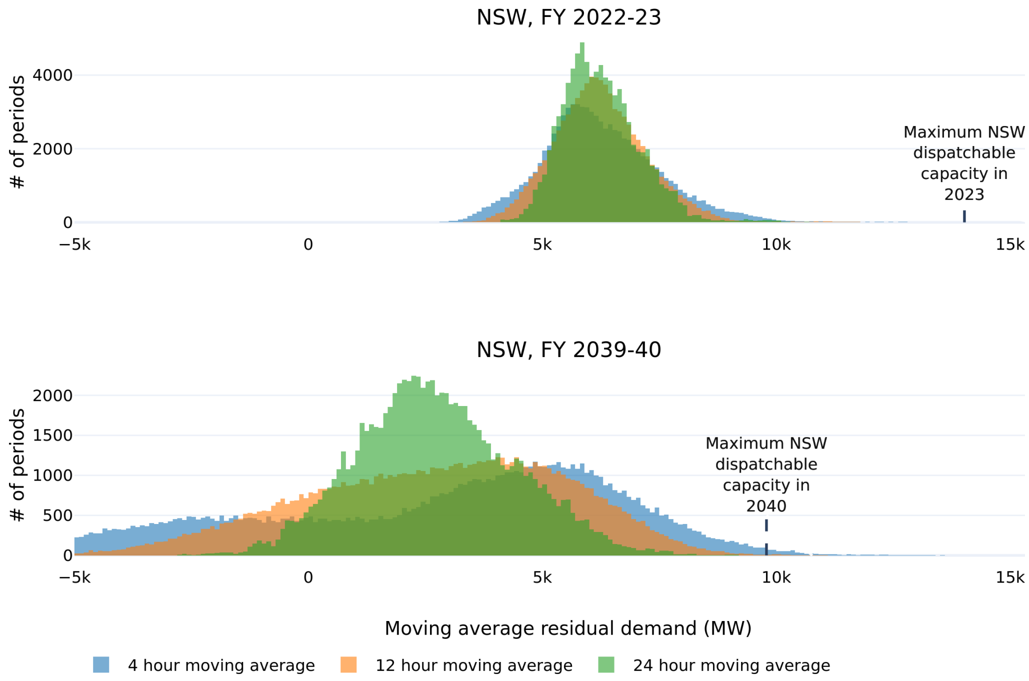


Figure 31. Histograms of Queensland Residual Demand

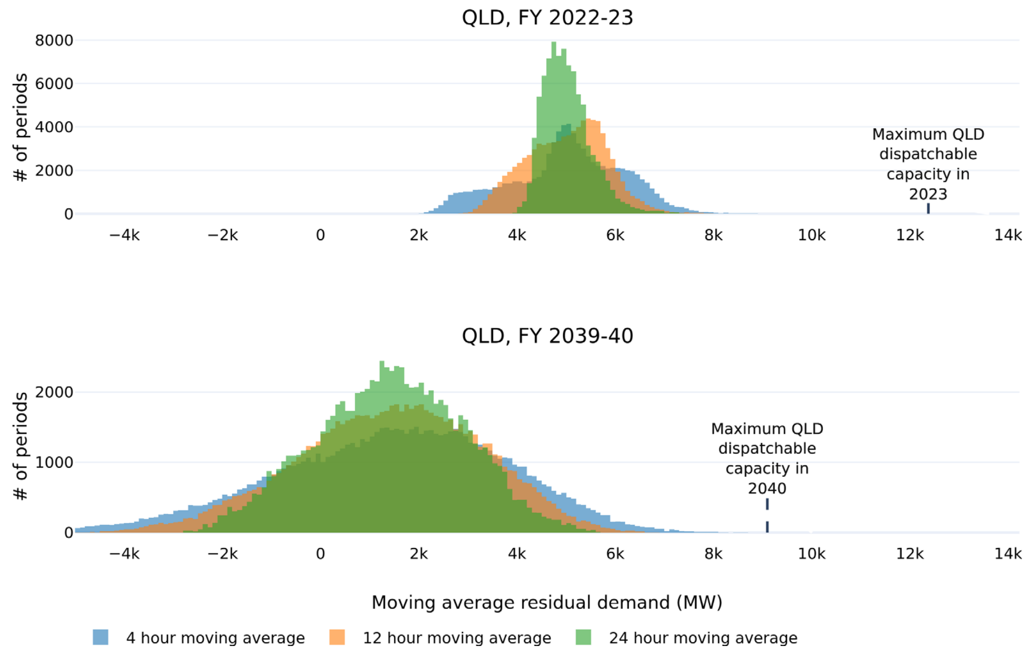


Figure 32. Histograms of South Australian Residual Demand

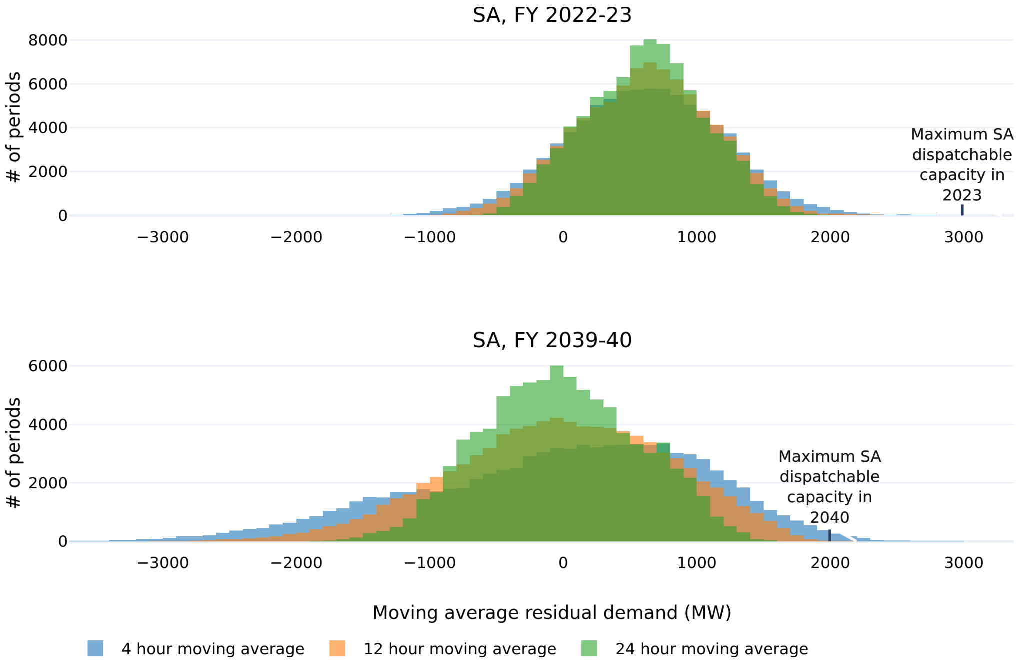
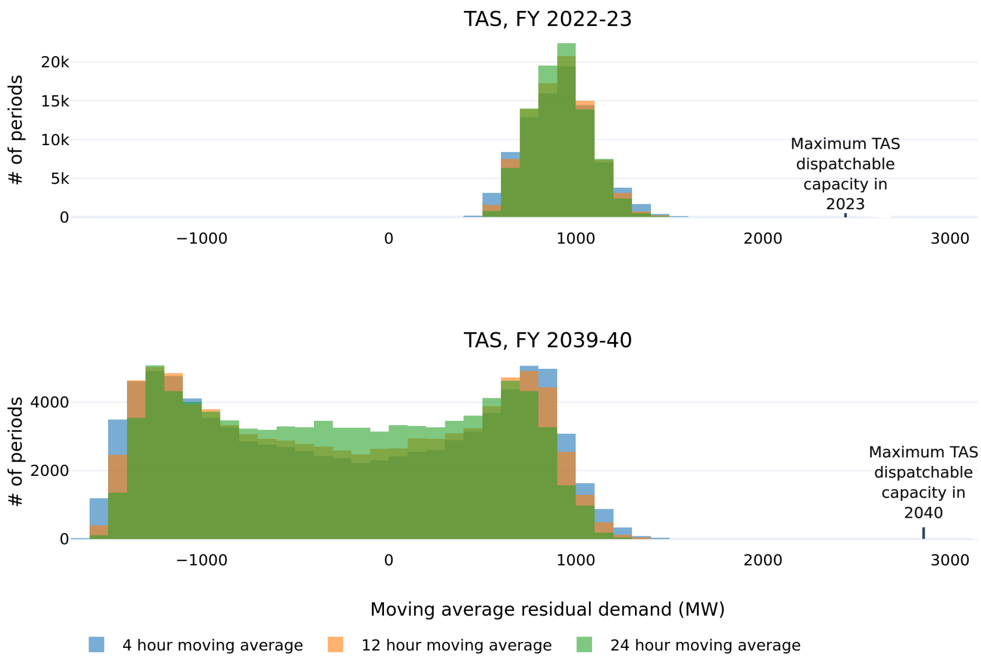


Figure 33. Histograms of Tasmanian Residual Demand



Appendix D. Pumped hydro and battery storage Arbitrage Revenue versus Storage Duration

Figure 34. Pumped hydro Arbitrage Revenue

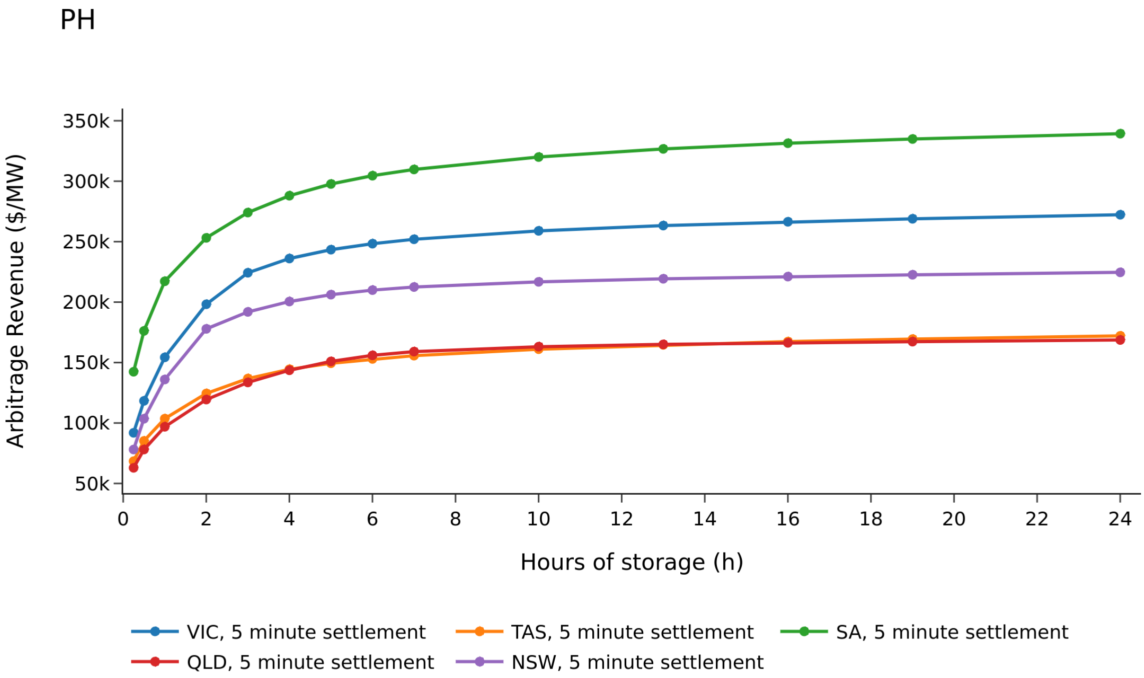


Figure 35. Battery Arbitrage Revenue

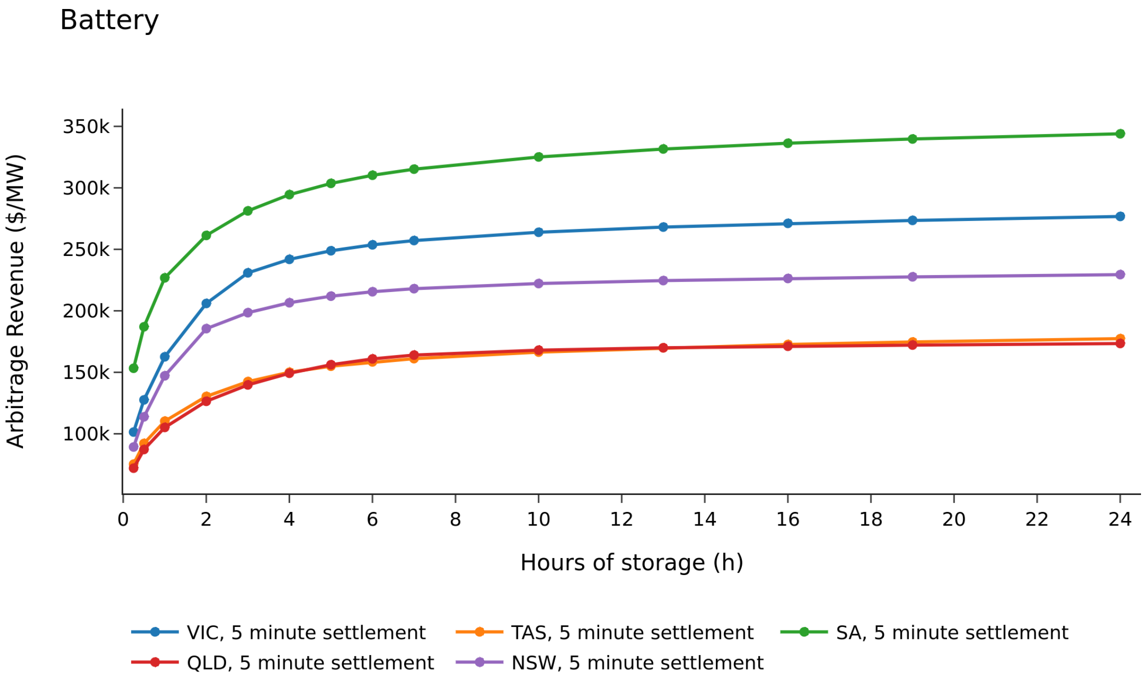
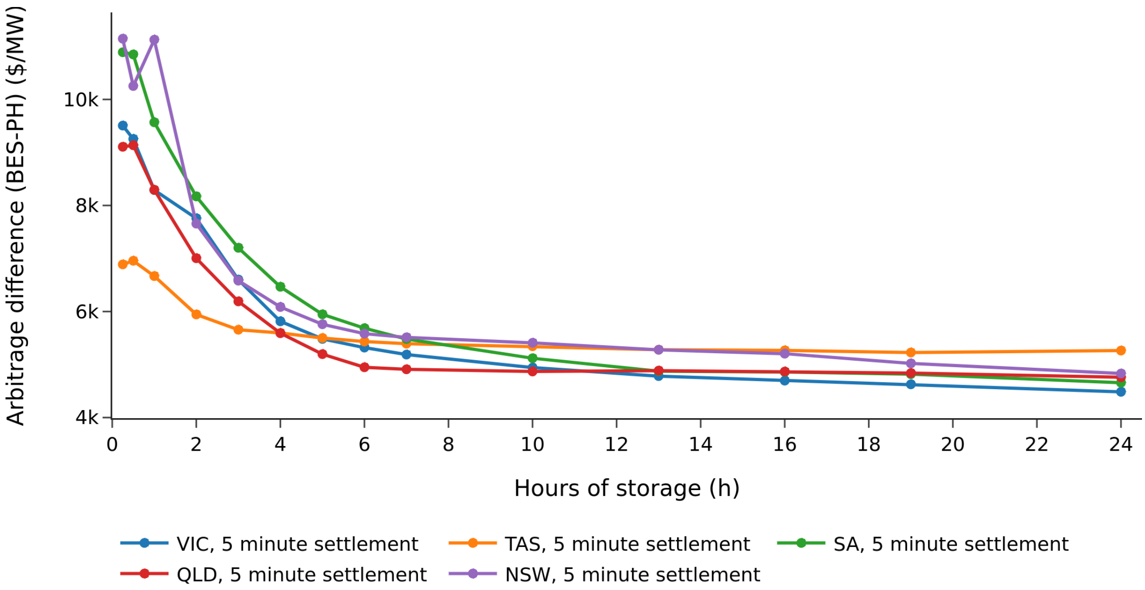


Figure 36. Difference between battery storage and PH Arbitrage Revenue



Appendix E. Hour of day wind resource analysis

Figure 37. Autumn capacity factor

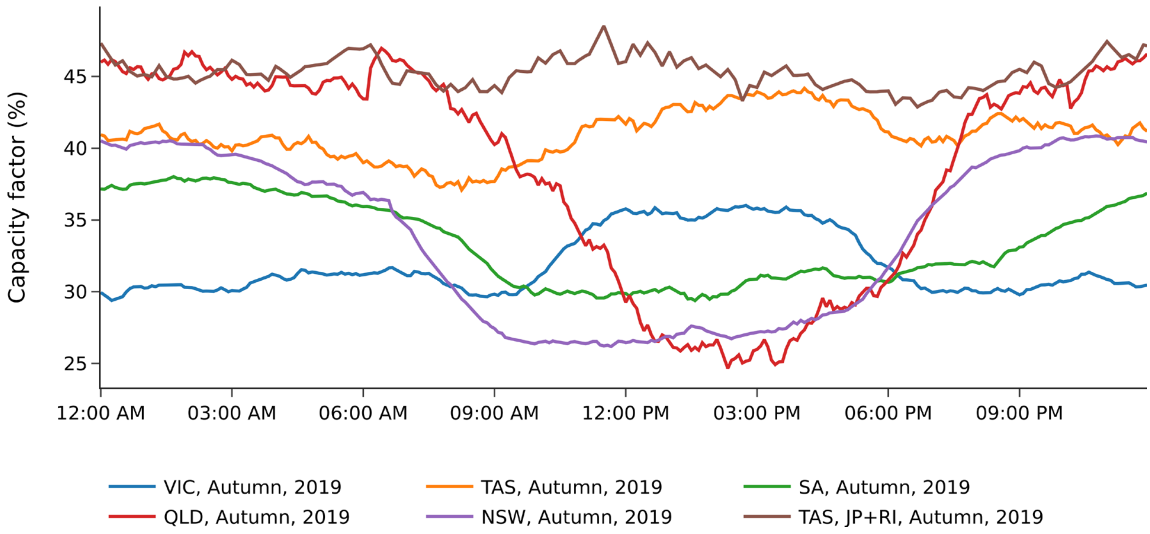


Figure 38. Spring capacity factor

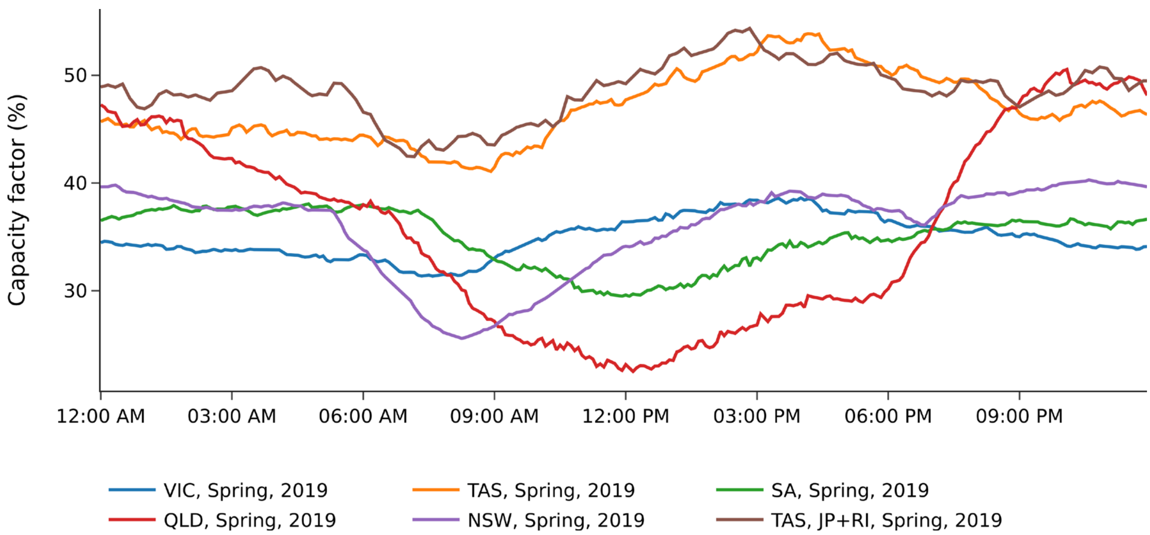


Figure 39. Summer Pearson R correlation coefficient

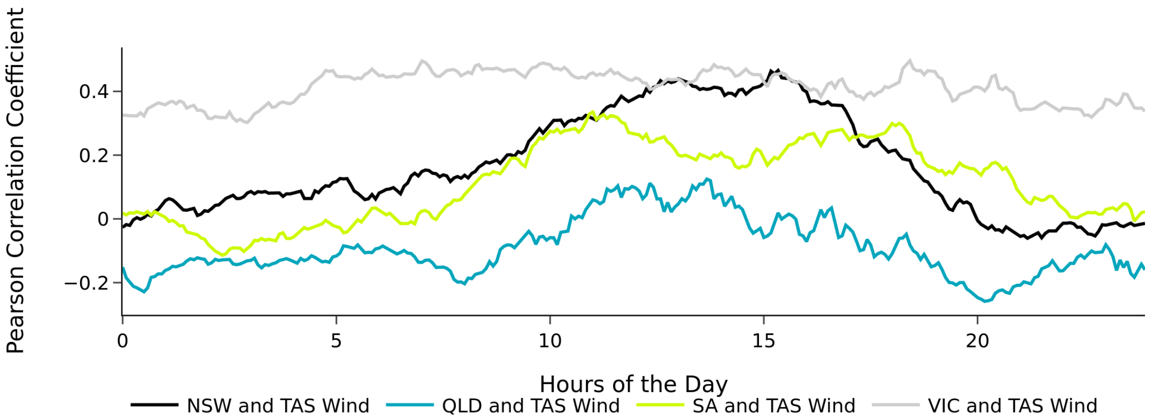


Figure 40. Autumn Pearson R correlation coefficient

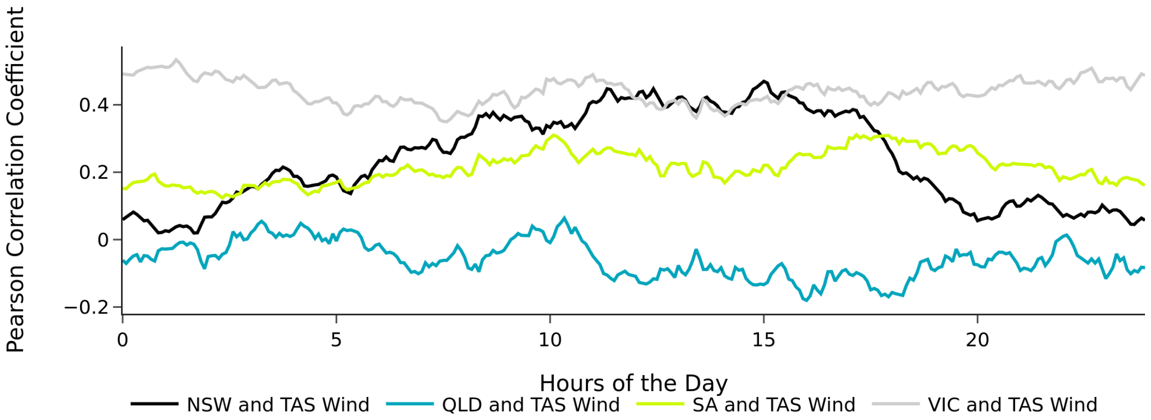


Figure 41. Winter Pearson R correlation coefficient

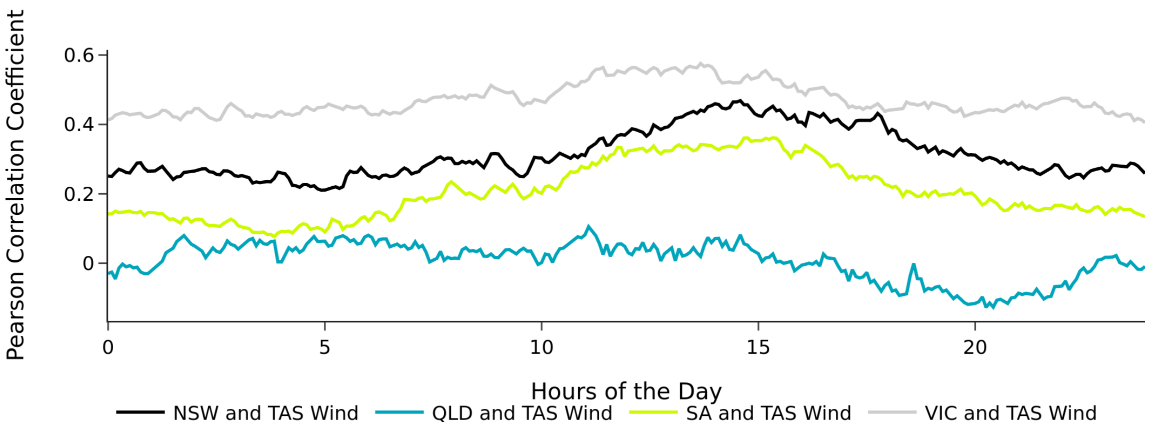


Figure 42. Spring Pearson R correlation coefficient