Victoria Energy Policy Centre
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Melbourne
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Inquiry Secretary
Inquiry into Energy Matters in Tasmania
Parliament House Hobart

By email: energymatters@parliament.tas.gov.au

27 November 2024

Dear Sir/Madam,

I am grateful for the opportunity to make a submission to your important inquiry. Please find my submission attached to this covering letter. I would be pleased to answer any questions the Inquiry may have of me.

Yours faithfully,

Professor Bruce Mountain
Director, Victoria Energy Policy Centre
Victoria University

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1 Introduction

This document is my submission to the Joint Select Committee on Energy Matters. The focus here is on item (e) of the Terms of Reference - MarinusLink and Battery of The Nation (BoTN).

The submission examines the extent of the comparative advantage in electricity production and re-production in Tasmania, relative to the mainland, and the implications of this for the merits of the BoTN and MarinusLink.

It seems that in policy and regulatory circles in Tasmania and on the mainland, it has been taken as an article of indisputable truth that Tasmania's hydro resource is valuable for the decarbonisation of electricity supply by providing a "battery of the nation". Hydro Tasmania, possibly the originator of the BoTN term, originally described it as "*our bold vision to maximise Tasmania's hydropower capacity and add pumped hydro*" in their 2018 report.

The BoTN vision is quite understandable, but its merit to consumers and the public depends on the extent of the comparative advantage that Tasmania has in renewable electricity production and storage, and having that delivered to the mainland. Hydro Tasmania's BoTN report was published a few months after the Hornsdale Power Reserve "the world's first big battery" was commissioned in South Australia, with a capacity to produce its peak power output for just over one hour.

Such electro-chemical batteries, particularly lithium-ion chemistries, have quickly become popular in motor cars and for stationary storage. While often dismissed as only capable of cost-effectively storing small amounts of electricity, in fact using the cost assumptions compiled by CSIRO for its Gencost report (which AEMO uses in the development of its Integrated System Plan) it is now evident that "deep" (long duration) storage from lithium-ion batteries will entail comparable capital outlays per MWh of storage capacity by the time that Cethana is expected to be commissioned. Electro-chemical batteries are also much cheaper to operate than pumped hydro on account of much lower round-trip losses, so putting electro-chemical batteries at a considerable advantage relative to pumped hydro storage, once they are operational.

With respect to generation from the wind, average yields are higher in Tasmania than average yields in Victoria. But this is offset to some degree by higher costs in those parts of Tasmania that offer the best wind resource. Furthermore technology change in wind generation (the ability to harvest lower winds more effectively) and the increasing importance of the *value* of production not the *volume* of production means that Tasmania's comparative advantage in wind generation relative to Victoria is small if it exists at all.

It is also now evident that MarinusLink will cost much more to build than first claimed. This should not be a surprise. Cost under-estimation is evident in all major transmission projects proposed by transmission network service providers and promoted by AEMO. Such systematic under-estimation reflects a deliberate strategy to lock-in policy support in the early stages of a project by under-stating the expected costs of the project, and then progressively ratcheting costs up as policy support is ever more locked-in. We expect that such cost underestimation will prove to be the case not just for Cethana and MarinusLink but also for the North West Transmission Development and the expansion of Hydro Tasmania's existing hydro generation capacity.

AEMO has long been an enthusiastic supporter of MarinusLink and has been quite transparent in working with the Tasmanian Government to promote its development. AEMO's analysis of the costs and benefits of MarinusLink is biased for the reasons identified in this submission, and consistent with the observation that AEMO is a formally a company limited by guarantee, answerable to its members which include the State of Tasmania, TasNetworks and Hydro Tasmania.

Since Tasmania does not have a comparative advantage in storage or in wind generation it follows that there is no case to expand interconnection to access a service that has no comparative advantage. Therefore it would not be reasonable for Tasmanian or Victorian electricity consumers to be asked to contribute any part of the cost of MarinusLink, and for the same reason it would unreasonable to impose any part of the cost onto Australian tax-payers.

Finally I consider whether Tasmanian and Victorian electricity consumers might reasonably be expected to pay for the use of Basslink, taking account of the fact that

Basslink's owner, APA, is seeking a regulated income in place of a contract with Hydro Tasmania. The analysis here suggests that it would be reasonable to set regulated charges at a level consistent with an asset valuation about half as high as APA is seeking. Looking back, it is quite clearly the case that the value of Basslink trade has been far lower than the cost of Basslink. The loss – which we estimate at $650m over the last 13 years - has been borne by Tasmanians.

Commensurate with this analysis of the economics of storage, trading over Basslink is unlikely to become more valuable in future than it has been in the past: arbitrage profits can be expected to decline as ever cheaper storage reduces the price differential at which arbitrage becomes profitable.

Finally the reduction in solar costs is enormously advantageous to Tasmania, even moreso than on the mainland. Solar PV is by far the cheapest source of electricity production. When produced on the roofs of Tasmania's homes and businesses it has no social or local environmental cost. Its installation will create a demand for many skilled employees. And with an average cost well below the average price of grid supplied electricity, rooftop solar offers the prospects of both profitable supply and lower prices to consumers.

Solar is well suited to supply in Tasmania because it is sunny in the dry season. Tasmania is also in the unique position in the NEM in being able to accommodate greater amounts of variable renewable supply without the need to add battery storage due. Yet rooftop solar production in Tasmania is just one-eighth that of South Australia. It is perplexing that such an advantageous technology has been neglected in Tasmania for so long.

The rest of this submission has been set out as follows: Section Two provides a background on supply, demand and prices. Section Three presents the main analysis. Sections Four to Six draw out the implications of the analysis for electricity consumers and taxpayers. Section Seven briefly comments on solar and Section Eight summarises the main points.

2 Background

This section provides general background information on demand, supply and wholesale prices in Tasmania and, where relevant, Victoria. The information presented here is drawn on later at several points in this submission.

2.1 Demand, supply and price

2.1.1 Demand

Figure 1 shows the annual average demand for grid-supplied electricity in Tasmania, as measured at the main transmission substations. It shows highly consistent demand (measured annually), and no growth over the past twelve years.

Since the population of Tasmania has grown by 13%, average per capita grid consumption of electricity has declined by around 13% over this period. This is consistent with trends on the mainland.

As I noted in my submission to the Senate Inquiry[1], in 2011 AEMO forecast that demand in the NEM (and Tasmania) would grow by 50% by 2024. This is consistent with a long history of demand forecasts that have consistently over-estimated demand growth.

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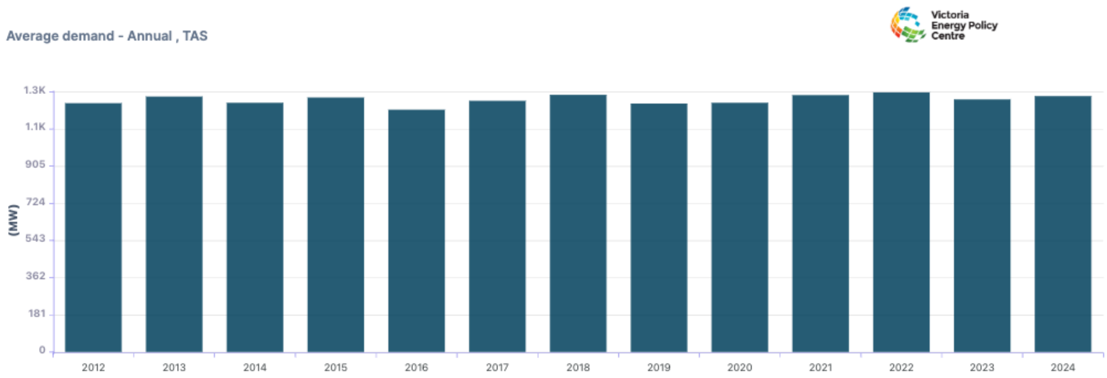
1 https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Energy_Planning_and_Regulation_in_Australia/EnergyPlanning/Submissions

Figure 1. Average annual demand (MW) in Tasmania from 2012 to 31 October 2024

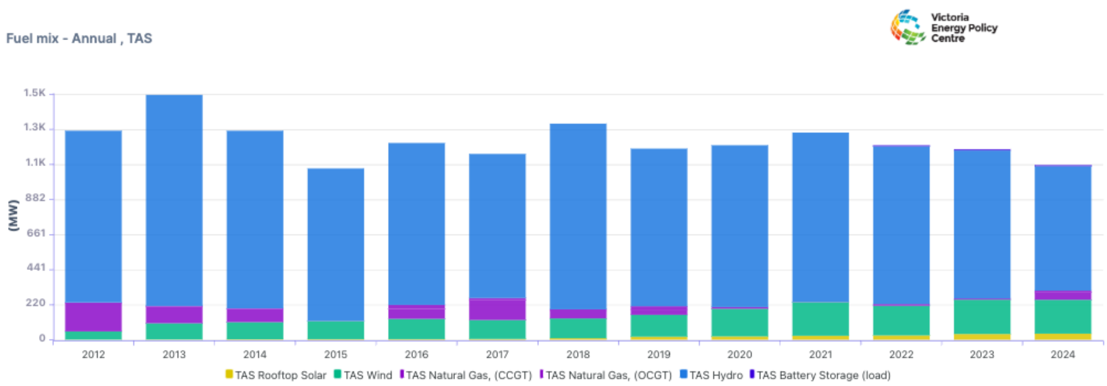


Source: Data extracted from AEMO NEMweb and processed on www.v-nem.org

2.1.2 Supply

Figure 2 shows the average annual production of electricity, by technology type. It shows the very high production in 2013 as Hydro Tasmania ran down its storages in response to the carbon tax which drove sharply higher prices in Victoria. Since then the data shows a reasonable level of inter-annual variability in hydro production. It also shows the gradual growth of wind generation, and the decline in gas generation and tiny contribution from rooftop solar.

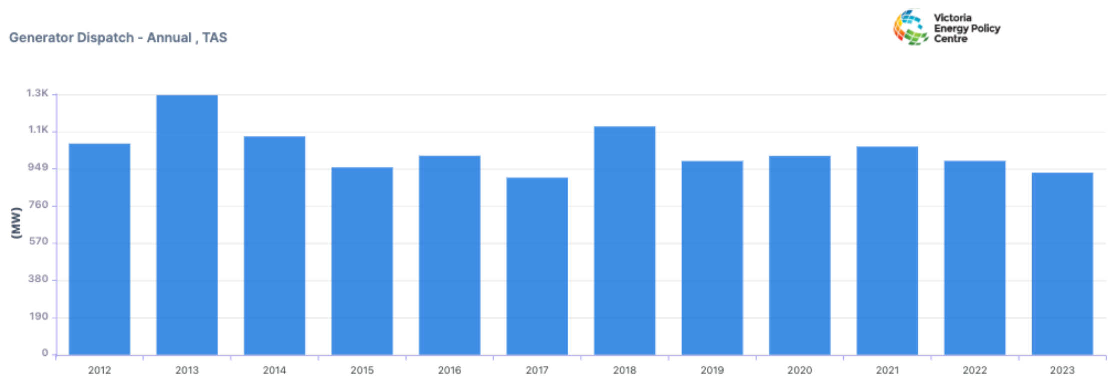
Figure 2. Average annual electricity production (MW) by technology type in Tasmania from 2012 to 31 October 2024



Source: Data extracted from AEMO NEMweb and processed on www.v-nem.org

Figure 3 singles out hydro electricity production in Tasmania. It shows a slight declining trend over this period (production for 2024 is not shown but is likely to be below that in any of the previous years.)

Figure 3. Average annual electricity production (MW) by hydro in Tasmania from 2012 to 2023

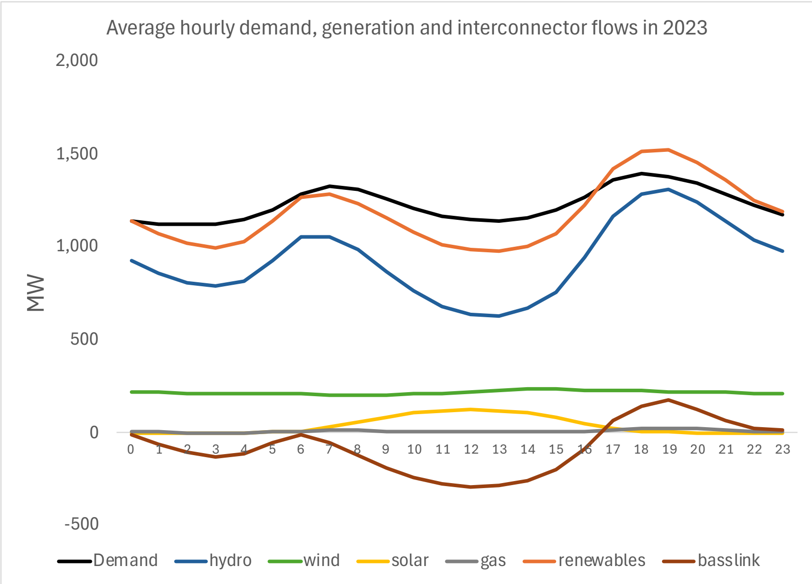


Source: Data extracted from AEMO NEMweb and processed on www.v-nem.org

Figure 4 shows the average value by hour of day, of demand, generation (by technology) and interconnector flows, using 5 minute data of these variables in 2023. It shows that the demand profile in Tasmania is very flat by comparison to the mainland. This is because residential electricity demand is relatively a much smaller proportion of total demand in Tasmania than it is in the mainland states. Wind generation is also interestingly very flat across the day in Tasmania. On the mainland wind generation typically peaks in the evening largely as a result of wind generators' response to lower daytime prices. As we will see later (in Figure 9), such hour of day price variation is smaller in Tasmania than in Victoria.

Figure 4 also shows the small solar bump and that the interconnector on hourly average average imports from Victoria for all hours of the day, except from 5pm to 10pm when it exports to Victoria.

Figure 4. Hour of day average demand, production and interconnector flows by source (MW) in Tasmania in 2023



Source: Author's analysis based on data extracted from AEMO NEMweb and processed on www.v-nem.org

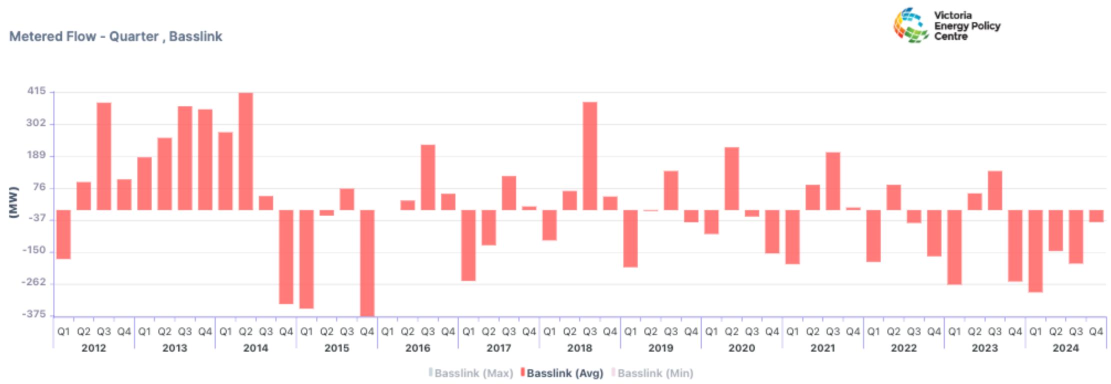
Figure 5, 6 and 7 that show quarterly, monthly and daily average flows on Basslink from 2012 to 31 October 2023 (for the quarterly average) and from 1 January 2023 to 31 October 2024 (for the monthly and daily averages).

The quarterly charts show a regular pattern of exports mainly in the third quarter of the calendar year and imports to Tasmania in the fourth and first quarters. The aberrations during the period of the carbon tax (1 July 2012 to 30 June 2014) are also evident, as is the consistent import into Tasmania during the winter and spring of 2024.

The monthly chart, shows the very heavy imports to Tasmania during the winter of 2024, during the period in which Victoria often experienced periods of low solar and wind generation.

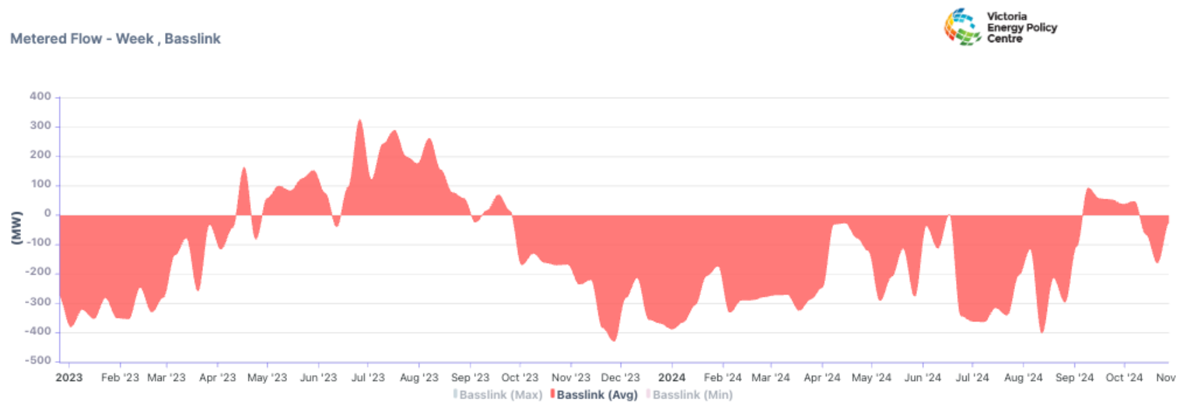
The daily chart shows that despite the heavy imports since October 2023, there have been a few days when Tasmania was a net exporter to Victoria.

Figure 5. Average quarterly interconnector (Basslink) flows (MW) from 2012 to 31 October 2024 (negative is import to Tasmania)



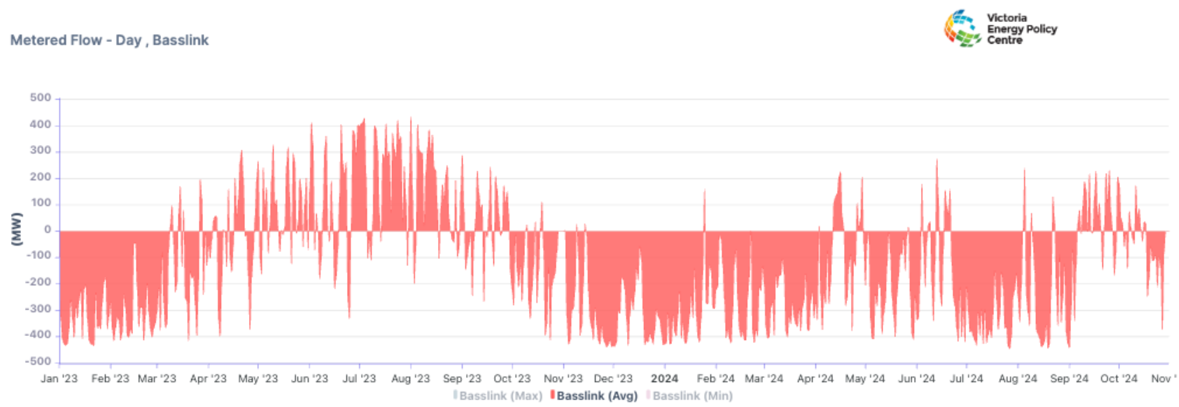
Source: Data extracted from AEMO NEMweb and processed on www.v-nem.org

Figure 6. Average monthly interconnector (Basslink) flows (MW) from January 2023 to 31 October 2024 (negative is import to Tasmania)



Source: Data extracted from AEMO NEMweb and processed on www.v-nem.org

Figure 7. Average daily interconnector (Basslink) flows (MW) from January 2023 to 31 October 2024 (negative is import to Tasmania)

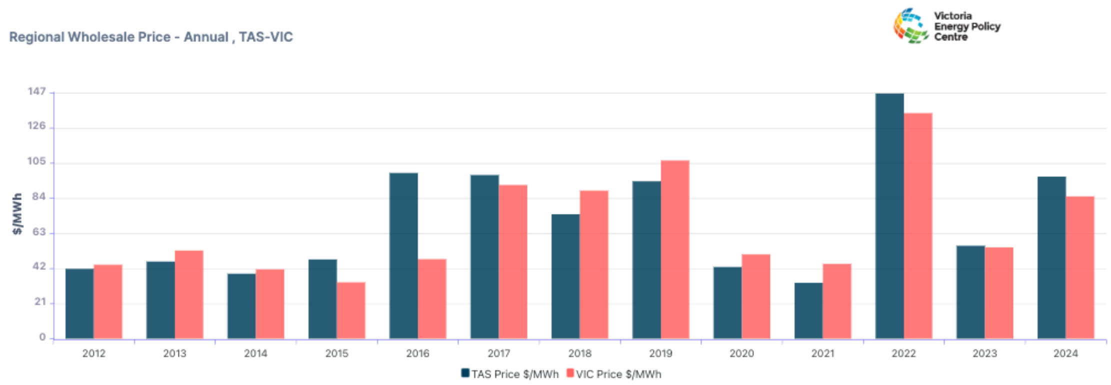


Source: Data extracted from AEMO NEMweb and processed on www.v-nem.org

2.1.3 Prices

Figure 8 shows the annual average spot price of electricity in Tasmania and Victoria from 2012 to 31 October 2023. Generally the gap is small as would be expected considering the strong level of interconnection (Basslink transfer capacity is around 40% of Tasmania's average demand). The average price over this whole period is $71/MWh in Tasmania and $68/MWh in Victoria.

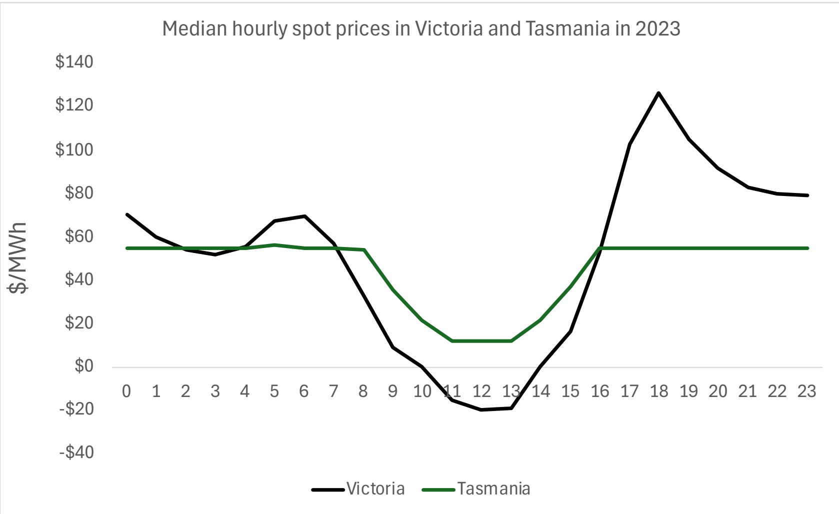
Figure 8. Average annual spot price of electricity in Tasmania and Victoria from 2012 to 31 October 2024 ($/MWh)



Source: Data extracted from AEMO NEMweb and processed on www.v-nem.org

Figure 9 shows the hourly average of the five-minute spot price of electricity in Tasmania and Victoria in 2023. The price pattern is reflected in average hourly operation of Basslink i.e. importing from Victoria other than in the evening. The next sub-section examines Basslink in more detail.

Figure 9. Hourly average spot price of electricity in Tasmania and Victoria in 2023 ($/MWh)



Source: Author's analysis based on data extracted from AEMO NEMweb and processed on www.v-nem.org

2.2 Interconnection (Basslink)

The Tasmanian Government committed to build Basslink as a market network service provider, in 2000. It was built by the National Grid Company, costing $876m,[2] and commissioned in 2005. When it was built it was the longest sub-sea electricity cable in the world. In 2006, Hydro Tasmania agreed a 25 year contract, largely orchestrated by the Treasury Department of the Tasmanian Government, with Basslink Pty Ltd. In the same year, a subsidiary of Singapore's sovereign wealth fund (Temasek) purchased Basslink Pty Ltd from the National Grid Company. The terms of the Basslink Services Agreement are not publicly available but Tasfintalk estimated the annual fee to be about $120m in 2018[3].

In 2021 Basslink went into receivership and APA Group acquired Basslink from its administrator for $773 million and entered a new contract with Hydro Tasmania and Basslink (the Network Services Agreement) which will expire on 30 June 2025. Six months after negotiating the Network Services Agreement, APA applied to the Australian Energy Regulator for approval to impose charges on consumers for its use.

In its application, APA claimed that the benefits of Basslink exceed its costs by a factor of 3-4. But the AER's consultation paper suggests the benefits of Basslink regulatory conversion are highly uncertain. Claimed costs are however very much more certain (AER says they have a present cost of $1.4bn based on a remaining economic life of 21 years). Repaid as an annuity (at 7%) this would result in an annual usage charge of $130m per year for the next 21 years.

Table 1 shows the volume of electricity shipped between Tasmania and Victoria. While the balance between import and export varies considerably, the aggregate volumes are reasonably consistent (except in 2016 during 5 months of which Basslink was out of service). The period 2012 to 2015 is heavily affected by the imposition of the carbon tax

[2] https://tasfintalk.blogspot.com/2018/04/the-case-for-basslink.html

[3] Ibid.

when Basslink predominantly flowed northward to capitalise on higher prices in Victoria. Since then, the years 2019, 2022, 2023 and particularly 2024 (year to date) stand out as years in which Tasmania has imported significantly more electricity than it exported.

Over the seven years since 2017, Tasmania has only exported (shaded blue) more than it imported on two of those years and on only one year (2018) by a large margin. For five of the seven years that it imported more than it exported (shaded beige), the gap between import and export was large.

Expressed as a capacity factor, assuming a 480 MW transfer limit (approximate average of import and export), Basslink has operated at 44% of its continuous peak rating.

Table 1. Basslink volumes imported to Tasmania and exported to Victoria 2012 to 31 October 2024

Year	Volume imported (MWh)	Volume exported (MWh)	Total volume shipped (MWh)
2012	891,405	1,806,999	2,698,404
2013	73,273	2,626,927	2,700,200
2014	1,048,544	1,925,011	2,973,555
2015	2,173,567	717,370	2,890,937
2016	237,751	820,674	1,058,426
2017	1,444,636	926,789	2,371,425
2018	654,459	1,518,059	2,172,518
2019	1,129,615	897,316	2,026,931
2020	1,340,555	1,251,840	2,592,395
2021	1,265,841	1,518,892	2,784,733
2022	1,359,371	698,455	2,057,826
2023	1,769,150	1,077,563	2,846,713
to 31 October 2024	1,904,882	507,964	2,412,846
Average	1,176,388	1,253,374	2,429,762

Source: Author's analysis based on data extracted from AEMO NEMweb and processed on www.v-nem.org

Table 2 shows the revenues that Hydro Tasmania, as the operator of Basslink will have accrued from the import and export (trade) of electricity over Basslink. These trading gains are calculated as the difference between the prices at each end of the interconnector multiplied by the flow of electricity over the interconnector, in each settlement period[4]. The total annual revenue is the sum of the revenue from export plus import. The table shows that on average since 2012, Hydro Tasmania will have made spot market trading profits of $71m per year. Since the Basslink usage cost will have been around $120m over this 13 year period, this suggests that Hydro Tasmania (and hence Tasmanian) has lost around $650m on Basslink over this period. In addition, consumers are likely to have lost as a result of upward pressure on Tasmanian spot prices as Tasmania's average prices were dragged up to (and often above Victoria's prices) as a result of the equalising tendency of the interconnector. Household electricity prices have increased more than in other state in the NEM, since the start of the NEM.[5]

Table 2. Hydro Tas income from trading electricity over Basslink from 2012 to 31 October 2024

Year	Hydro Tas income from Basslink when Tas. importing electricity ($m)	Hydro Tas Basslinkl income when exporting from Tas ($m)	Hydro Tas income from shipping electricity ($m)
2012	$ 15	$ 25	$ 40
2013	$ 1	$ 27	$ 28
2014	$ 14	$ 26	$ 40
2015	$ 49	$ 4	$ 53
2016	$ 3	$ 2	$ 5
2017	$ 32	$ 10	$ 42
2018	$ 8	$ 77	$ 85
2019	$ 30	$ 72	$ 103
2020	$ 25	$ 55	$ 80
2021	$ 26	$ 71	$ 97
2022	$ 61	$ 29	$ 91
2023	$ 62	$ 65	$ 127
to 31 October 2024	$ 68	$ 45	$ 136
Average	$ 30	$ 39	$ 71

Source: Author's analysis based on data extracted from AEMO NEMweb and processed on www.v-nem.org

Finally, Table 3 shows the average price difference between Victoria and Tasmania when Basslink was importing electricity into Tasmania or exporting it to Victoria. It shows that

[4] I have used half-hourly average to ensure consistent measurement over time. Five minute settlement was introduced in October 2021. The difference is likely to be small.

[5] https://www.vepc.org.au/_files/ugd/92a2aa_b287cedcc38b49ca950989b6d1e90920.pdf

on average over this period the difference was $23/MWh when importing and $36/MWh when exporting and the overall difference whether importing or exporting was $29/MWh.

What is the meaning of these numbers? Consider this: through its application for conversion to a regulated interconnector, APA is seeking usage fee income of around $130m per year for the next 21 years.[6] If we assume that Basslink is used as much in future as it has been in the past (2.4 TWh per year) this would mean that the average regulated usage fee for Basslink would be $54/MWh ($130m/2.4 TWh). This is a little under twice as much as the arbitrage income that Hydro Tasmania has received for the electricity it has traded over Basslink[7] over the last 12 years.

Table 3. Average price difference ($/MWh, nominal) between Victoria and Tasmanian when Basslink was importing (to Tasmania) and exporting (from Tasmania) from 2012 to 31 October 2024

Year	Average price difference when importing ($/MWh)	Average price difference when exporting ($/MWh)	Average price achieved per MWh shipped ($/MWh)
2012	$ 17	$ 14	$ 15
2013	$ 14	$ 10	$ 10
2014	$ 13	$ 14	$ 14
2015	$ 22	$ 5	$ 18
2016	$ 12	$ 3	$ 5
2017	$ 22	$ 11	$ 18
2018	$ 12	$ 51	$ 39
2019	$ 27	$ 81	$ 51
2020	$ 18	$ 44	$ 31
2021	$ 20	$ 47	$ 35
2022	$ 45	$ 41	$ 44
2023	$ 35	$ 60	$ 45
to 31 October 2024	$ 36	$ 88	$ 56
Average	$ 23	$ 36	$ 29

Source: Author's analysis based on data extracted from AEMO NEMweb and processed on www.v-nem.org

[6] To put this into context, this is about as much as TasNetworks charge to provide transmission services in Tasmania. Note that their revenue proposal to the AER seeks a little over $110m per year from 2025 to 2030, but calculating the revenue requirement using their proposed asset value and operating cost claim, as an annuity at 7% discount over the remaining life results in an annual revenue requirement of $130m per year.

[7] After accounting for inflation this average will reduce from around 100% to around 70%.

3 Analysis of comparative advantage

This section seeks to understand the economics of generation and storage in Tasmania compared to Victoria and hence the economics of expanding interconnection to Victoria. This is developed through a series of questions and answers as follows:

- First I ask whether Tasmania has a comparative advantage in the production of renewable electricity. This matters since the Government has established a policy to double renewable electricity production in Tasmania, contingent on the construction of MarinusLink. It matters to the economic case for that interconnection whether or not Tasmania has a comparative advantage in renewable electricity production.

- Secondly, I explore whether Tasmania has a comparative advantage in storage. It obviously did in respect of the service provided by Basslink which, when it was developed, had no competitors in the provision of storage. But will this still be the case if MarinusLing is built taking account of the cost of competing forms of storage now available in the market? This is a central question in this analysis.

- Finally, both AEMO and TasNetworks have been enthusiastic supporters of MarinusLink and claim to provide evidence that developing Marinus link will be in consumers' and the publics' interest. Can their analysis be relied upon?

3.1 Does Tasmania have a comparative advantage in the production of variable renewable electricity?

Tasmania obviously does not have a comparative advantage in the production of solar electricity but the gap between Tasmania as a whole relative to Victoria as a whole, considering population location, is not large. But in the capital cities it is notable that the Clean Energy Regulator assumes 1.185 MWh per kW per year of rooftop solar in both Hobart and Melbourne.

What about wind generation? Table 4 shows the average annual generation from wind in Tasmania and Victoria, the (non-coincident) maximum generation (MW) and the annual capacity factor (the ratio of the average to non-coincident). This shows that in all years, the capacity factor was higher in Tasmania than in Victoria, and on average seven percentage points (37%) compared to 30% in Victoria.

Table 4. Capacity factor of wind generation in Tasmania and Victoria

Year	Tas Wind average (MW)	Tas wind max (MW)	Vic wind average (MW)	Vic wind max (MW)	Annual capacity factor - Tasmania (%)	Annual capacity factor - Victoria (%)
2012	53	139	204	849	38%	24%
2013	103	409	298	907	25%	33%
2014	108	306	290	1,044	35%	28%
2015	113	306	361	1,167	37%	31%
2016	128	305	404	1,283	42%	31%
2017	119	306	411	1,444	39%	28%
2018	125	306	515	1,605	41%	32%
2019	138	306	600	1,879	45%	32%
2020	174	561	767	2,578	31%	30%
2021	211	560	992	3,195	38%	31%
2022	186	558	1,119	3,839	33%	29%
2023	216	559	1,265	4,117	39%	31%
				Average	37%	30%

Source: Author's analysis based on data extracted from AEMO NEMweb and processed on www.v-nem.org

Leaving other factors the same, this means that the average cost of wind generation in Tasmania is 19% lower than in Victoria. However, other factors are not the same. In its Integrated System Plan AEMO assume per unit capital outlays for wind in Tasmania (the North West) to be about 5% higher than in Victoria, and connection costs about double those in Victoria.

In addition, with the North West Transmission Development project it is clear that very extensive transmission expansion is needed in Tasmania to accommodate more wind generation as well as for MarinusLink (MarinusLink says $950m will need to be spent on Tasmanian transmission in order to accommodate the first 750 MW MarinusLink cable).

In November 2023 TasNetworks updated the budget of the North West Transmission Development (NTDP) Project to $1.5bn (2023 dollars) for 238 km of new lines[8]. To put this into context, the entire transmission grid in Tasmania is currently valued at $1.6bn. The NTDP (even if it is built to TasNetworks' currently stated budget - which is almost certain to be significant under-estimate) would therefore roughly double the regulated value of the Tasmanian transmission network, with all additional costs to be recovered from Tasmanian electricity customers.

Victoria, by comparison, has ample scope to increase wind generation in the Gippsland region with very little or no incremental shared grid transmission expansion.

Furthermore development in wind generation technology is improving the ability to harness energy from weaker winds. And, as the penetration of wind and solar generation expands there is increasingly less interest in the annual quantity of wind generation, and more interest in the value of wind generation - higher production in the morning and evening where Victorian wind farms typically have an advantage relative to Tasmanian wind farms.

Taken together, even before considering the cost of getting additional wind generation from Tasmania to Victoria, this evidence suggests that Tasmania does not have a meaningful comparative advantage in wind generation relative to Victoria.

In addition, the Tasmanian Government has said its 200% renewable electricity target is contingent on the construction of MarinusLink. The delivered cost of additional wind generation in Tasmania, to Victoria, must therefore also account for the cost of MarinusLink. Assuming MarinusLink Stage 1 will be built for $3.1bn (this will almost certainly rise) and assuming (optimistically) that MarinusLink operates at the same capacity factor as Basslink (44%, see earlier) and assuming (optimistically) that MarinusLink has the same dollar-per-MW-installed operating cost as Basslink, the annual

[8] https://infrastructurepipeline.org/project/north-west-transmission-developments#:~:text=TasNetworks%20announced%20an%20updated%20project,estimated%20to%20cost%20%24550%20million.&text=The%20scope%20of%20the%20project,238%20km%20of%20transmission%20lines.

cost of MarinusLink (assuming a 40 year life and 7% real cost of capital) will be $113/MWh[9].

So, if Tasmania does not have a meaningful comparative advantage in wind generation and it can be expected to cost $113/MWh to get wind generation from Tasmania to Victoria, how can there be any doubt that MarinusLink can't be justified on the basis of comparative advantage in wind generation?[10]

Minister Duigan may have accepted this reality, as reflected in his recent comments to The Advocate[11] and the Tasmanian Parliament[12] where he sought to justify MarinusLink on the basis of its ability to increase the import of electricity from Victoria during the day when solar generation peaks, and the later resale of that electricity back to Victoria in the evening – in other words for MarinusLink not to be the "battery of the nation" as envisaged by Hydro Tasmania but more like Basslink.

It might be suggested that expanding wind generation at least to a small extent in Tasmania with the objective of selling that additional electricity to Victoria will be competitive if that additional generation uses spare capacity on BassLink (and so does not incur incremental transmission cost). This possibility is examined later in Section 4.

3.2 Does Tasmania have a comparative advantage in the storage of electricity?

As mentioned in the Introduction, Hydro Tasmania describes the "battery of the nation" as "our bold vision to maximise Tasmania's hydropower capacity and add pumped

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[9] This is calculated as follows: operating expenditures are estimated to be $0.106m per MW per year, based on APA's proposals for BassLink. Scaled up for MarinusLink this is $79m per year, which is $1.06bn as a present value at 7% over 40 years. Adding $3.3bn as the estimated capital outlay gives a present cost of MarinusLink of $4.36bn. Annuitised at 7% per year is $327m per year. Assuming a 44% capital for MarinusLink gives a levelized average annual charge of $113/MWh.

[10] For the avoidance of doubt, the fact that generators are not charged to use the shared transmission system in the NEM does not mean that the cost of MarinusLink does not arise. Someone will still have to bear the cost.

[11] "Duigan all for first, cautious on second", The Advocate, 8 October 2024. https://www.theadvocate.com.au/story/8775402/tasmanias-energy-minister-defends-marinus-link-project/

[12] https://tasgreensmps.org/parliament/energy-and-renewables-marinus-link-3/

hydro".[13] The essential claim is that the hydro system has intrinsic, latent, value that can be cost-effectively expanded (through pumped hydro and by expanding wind generation in Tasmania), and so stored and then later re-produced and shipped to Victoria on MarinusLink.

But how much storage capacity does Hydro Tasmania have now? Is there a meaningful amount of latent capacity in the system that can be cost-effectively developed and shipped to Victoria without needing to build a new interconnector ? This is the first important question to consider in answering whether Tasmania has a comparative advantage in the storage of electricity.

Hydro Tasmania does not provide information on the extent to which the Tasmanian power system has latent storage capacity that could be released by expanding Marinus[14]. However analysing the powerflows on Basslink and production by the hydro generators, points to a conclusion on the extent of latent storage in the Tasmanian power system. This is set out in the next sub-sub-section followed by a description of how the economics of the battery of the nation proposal is properly counted, taking this conclusion into account.

3.2.1 Does the Tasmanian power system have untapped storage capacity to share with Victoria without the need for MarinusLink?

Figure 10 is a histogram of the five-minute flows (MW) on Basslink over the period since the start of 2023 to 31 October 2024. This period is chosen since it presents the most up-to-date picture of the production capacity and demand in Tasmania, taking account particularly of the growth of Tasmanian wind generation. The chart shows imports exceeding exports particularly when importing near to the peak capacity of the cable.

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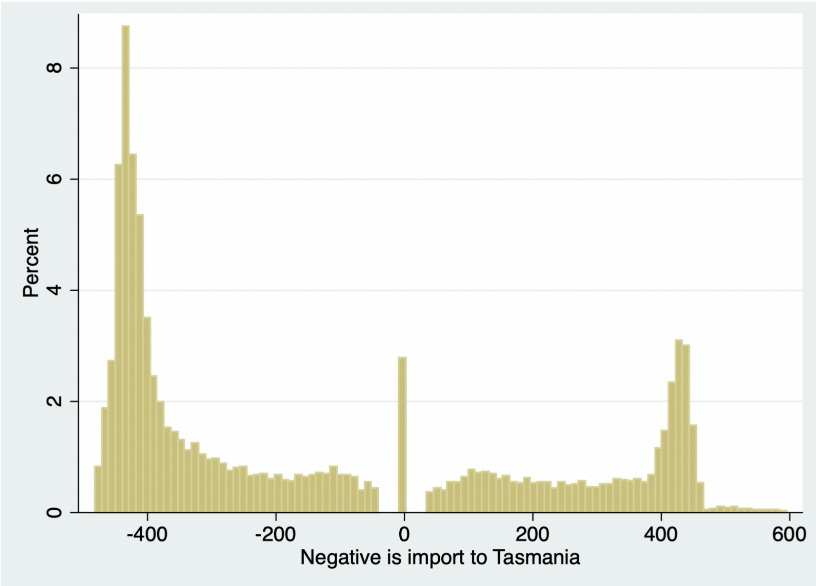
[13] https://www.hydro.com.au/clean-energy/battery-of-the-nation

[14] In its submission to your inquiry, MarinusLink said that the hydro storage capacity in Tasmania is 14,000 GWh. This is sufficient to allow Hydro Tasmania to produce at the average rate it did in 2023 for almost two years continuously. We don't know if Marinus' claim is correct. I asked them for a source for this claim and was told that they had asked Hydro Tasmania who were not able to say what the capacity of their storage was and instead referred them to a marketing blog of an American vendor of market modelling software, wherein the 14,000 GWh claim can be found. Whether or not the total storage capacity when all dams are full is 14,000 GWh or some lesser number is meaningless: the hydro system is never operated from full to empty.

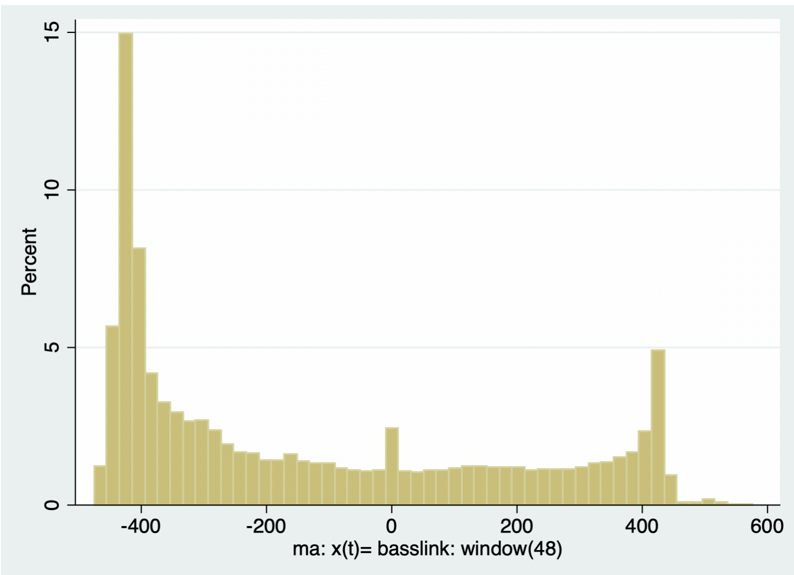
Figure 10. Histogram of Basslink 5 minute flow (MW) from 1 Jan 2023 to 31 October 2024



Source: Author's analysis based on data extracted from AEMO NEMweb and processed on www.v-nem.org

Figure 11 is a histogram of the four-hour rolling average of Basslink flows over the same period. This provides an indication of the sustained direction of trade. The weighting towards import, near the cable limit, is even more pronounced. This too points to a conclusion that the limitation on the export and trade of electricity with Victoria lies with the storage capacity of the Tasmanian power system, not with Basslink.

Figure 11. Histogram of 4-hour moving average of Basslink flow from 1 Jan 2023 to 31 October 2024



Focussing now on Hydro Tasmania's hydro generation, Table 5 presents an analysis of five-minute data in 2024 (year to 31 October) to find the highest average hydro generation over 1, 24 and 48 hour time periods, and then for these periods the average Tasmanian demand plus Basslink export minus Basslink imports. This provides insight into the extent to which hydro generation in Tasmania is able to meet Tasmanian demand plus exports minus imports, at the time that hydro generation is most plentiful and generation from other sources (solar, wind and gas) was by implication least available in Tasmania. The table shows that for all these time periods the average hydro generation in each of the three periods falls short of the average demand plus net export. These results support a conclusion even when hydro production is at its high sustained levels (for 1, 24 and 48 hours respectively) hydro production is not sufficient to meet Tasmania's demand plus net exports. This suggests limitations in hydro generation, not in interconnector capacity, in providing a storage service to Victoria.

Table 5. Highest average hydro production, Tasmanian demand plus exports minus imports over 1 hour, 24 hours and 48 hours

Moving average duration (hours)	Hydro production (MW)	Average demand + net export (MW)
1	2011	2558
24	1464	1754
48	1381	1600

Finally we look at the data from Victoria's point of view. The claim that is often made[15] with respect to the "battery of the nation" is that it will provide "deep storage" that will be able to support Victoria during the times particularly in autumn and winter, of solar and wind droughts. Does Tasmania provide such deep storage now?

Table 6 below presents the results of an analysis of the 12-hour rolling average of variable renewable (wind and solar) generation in Victoria from the start of 2023 to 31 October 2024. The 12-hour rolling average measure in each five-minute interval is the average of the previous 12 hours' values of that measure. For this rolling average data we have then selected the lowest 2,400 five-minute data points (i.e. 200 hours in total over this period).

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[15] See for example from Hydro Tasmania here: https://www.hydro.com.au/clean-energy/battery-of-the-nation/battery-of-the-nation-FAQs

These data therefore capture the points at which renewable electricity has been sustained at the low levels for the previous 12 hours. The table shows that the average of the lowest 2,400 five-minute values of the rolling 12-hour generation in Victoria from variable renewables was just 143 MW.

The table shows (in the second data row) that Victorian prices at these times were high ($299/MWh on average). This is as expected as production from coal and even more expensive gas was at high levels at these times to meet the Victorian demand.

What did Basslink do at these times? The third data row shows average export of just 183 MW (on a cable with continuous export limit of about 480 MW). Evidently Tasmania is not currently able to provide a "deep" storage service to Victoria that is anywhere near to the limit of Basslink's transfer capability.

Table 6. Rolling 12 hour VRE lows in Victoria, lowest 200 hours' worth

Variable	Obs	Mean	Std. Dev.	Min	Max
vicre_12hr	2,400	143.6157	53.8927	32.34882	230.4352
vicpricemwh	2,400	299.9212	1263.895	-20	17500
basslink	2,400	183.0588	265.9588	-479.2	592.7

What about Basslink's contribution to Victoria over a rolling 24-hour period calculated in the same way as the rolling 12 hour period? These results are shown in Table 7. Average wind and solar generation in Victoria ("vicre_24hr") is higher over the rolling 24 hour period since a 24-hour rolling period is catching solar as well (which is not caught in the 12 hour whose minimum will be at night), but prices are higher ($310/MWh) (as expected) and Basslink average exports (156 MW) are even lower.

Again we see that Tasmania is not currently able to provide a "deep" storage service to Victoria, and the limitation in this is not the capacity of Basslink but rather the storage and generation capacity of the Tasmanian power system.

Table 7. Rolling 12 hour VRE lows in Victoria, lowest 200 hours' worth

Variable	Obs	Mean	Std. Dev.	Min	Max
vicre_24hr	2,400	486.3599	117.0313	211.156	615.4081
vicpricemwh	2,400	310.6453	1162.779	-36.57	16893.41
basslink	2,400	156.814	277.38	-477.4	592.7

In summary, these analyses all point in the same direction: the limitation in Tasmania's provision of a storage service to Victoria is not the size of the existing interconnector, but the power and energy storage capacity of the hydro system in Tasmania. These analyses reveal, as might be expected, that the Tasmanian hydro system has been engineered to meet Tasmania's demand, not Tasmania's demand plus the capacity of Basslink, for any extended period of time.

This suggests that there may be potential to expand the storage service that Hydro Tasmania provides to Tasmania and to Victoria by expanding renewable electricity production in Tasmania to enhance the storage capacity of the existing hydro capacity and that there is no need to expand the interconnection to achieve that. Later we suggest that expanding rooftop solar in Tasmania will be cheapest and easiest way to do that.

3.2.2 The economics of "battery of the nation"

In VEPC's previous advice to the Bob Brown Foundation on the economics of MarinusLink[16], we stopped short of analysing the extent of surplus storage capacity in the Tasmanian power system. Rather, our focus was to compare the cost of MarinusLink to that of commercially available storage (all lithium-based electro-chemical) in Victoria. This provided the basis to the conclusion that, even if we assumed that Tasmania had surplus power and storage capacity in its system and so could provide a storage service with no incremental cost, it would be cheaper to develop batteries in Victoria than to develop MarinusLink.

[16] These can be found here and here

Those reports concluded that an eight hour storage service (i.e. a storage device able to produce its peak capacity for eight hours) would be cheaper than could be provided through MarinusLink even assuming that the electricity export to Victoria on MarinusLink could be provided by the Tasmanian power system without any additional capital expenditure to expand generation or storage in the Tasmanian power system.

Since those reports (produced in 2020 and updated in 2021) the announced cost of MarinusLink has more than doubled[17] and the cost of batteries has declined even more quickly than AEMO had assumed (we had used AEMO's assumption on battery costs). As a consequence, lithium-based battery capacity is growing quickly. There are now 28 front-of-meter grid-scale batteries operational in the NEM with non-simultaneous peak production of 1400 MW in July 2024 (of which Victoria has six grid-scale batteries with non-simultaneous peak production of 492 MW). Almost 4,000 MW of additional lithium storage started construction in the NEM in the first nine months of 2024.[18]

The analysis in the previous sub-sub-section showed that Tasmania does not provide a deep storage service of any consequence to Victoria, and the limitation is not the size of the connection (Basslink) but capacity limits in the Tasmanian power system in meeting its own demand plus exporting to Victoria for extended periods.

The correct calculation of the economics of generation plus storage expansion in Tasmania for the purpose of delivering the BoTN vision (which includes Marinus) must therefore account for the *additional* generation and storage costs in Tasmania plus the cost of MarinusLink, and compare this to the cost of providing a comparable storage service in Victoria.

Quite how much storage and generation needs to be expanded in Tasmania to provide an additional 750 MW of deep storage to Victoria, promised by MarinusLink is uncertain. AEMO's 2024 ISP says that 400 MW of hydro capacity (for example re-powering Tarraleah), 600 MW of Cethana pumped hydro and 1,956 MW of additional wind

[17] Taking account of MarinusLink plus the necessary North West Transmission Development.

[18] https://www.pv-magazine.com/2024/10/24/australia-has-7-8-gw-of-utility-scale-batteries-under-construction/

generation in Tasmania is needed. In round numbers, using the costs in AEMO's 2024 ISP Input and Assumptions, the capital outlay for this will be around $15bn of which $1.8bn for Cethana and $7.8bn for 3,000 MW of additional wind generation. MarinusLink (Stage 1) adds another $4bn[19], $1bn for 400 MW of additional hydro capacity and $0.4bn for Tasmanian on-shore transmission expansion not counted in the MarinusLink Stage 1 estimate.

It should be stressed that AEMO has a well-established track record of badly under-estimating the transmission cost of the projects that it is promoting, in its successive ISPs. For example in the case of the transmission capacity to get electricity from Snowy 2.0, (to Sydney via SnowyLink North, now HumeLink and Sydney Ring South) AEMO first estimated this at less than $1bn and the latest estimate is more than $6.5bn.

In respect of pumped hydro, the cost of Cethana according to AEMO is almost half the cost of any comparable pumped hydro that might be built in the NEM in future. It should be noted that in its 2024 ISP AEMO has used a capital cost estimate for Cethana ($2400.75/kW) that is below the $2666/kW that the CEO of HydroTasmania had told the Australian Financial Review, in July 2023, that Cethana would cost.[20]

In understanding the comparative advantage of Cethana relative to battery alternatives it is important to understand how battery costs have rapidly declined. In its 2018 "Battery of the Nation" report[21], Hydro Tasmania said[22] that by 2035 it would cost $1.8m per MW to build pumped hydro in Tasmania (in 2017 dollars). In that report it did not the specify the storage (energy) capacity of the pumped hydro that it envisaged.

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[19] This is established by taking Marinus Pty Ltd;s latest lowest bound estimate of the cost of Marinus Link ($3bn) and adding the $1bn of North West Transmission

[20] https://www.afr.com/companies/energy/hydrotas-pumped-hydro-potential-rests-on-policy-decisions-20230719-p5dpel

[21] Hydro Tasmania , 2018. "Battery of the Nation: Analysis of the future National Electricity Market. Exploring a vision where Tasmania plays a significantly expanded role in the NEM".

[22] Ibid, Figure 12.

Hydro Tasmania's website now describes Cethana to be " *a 750MW capacity project with up to 20 hours deep storage duration*" So, this $1.8m per MW cost can be restated as a cost per kWh (if we assumed 20 hour storage capacity) of $90/kWh. [23]

In that same 2018 report. Hydro Tas said 24-hour battery would cost $14m/MWh, so $583/kWh taking account of 24 hour energy storage capacity. In other words, per kWh of storage capacity, Hydro Tasmania said that 24- hour batteries would be 6.5 times more expensive than the 20 hour Cethana. Such a large difference between the cost of 24-hour batteries and Cethena might plausibly have lent support to a conclusion, in 2018, that the cost of Marinus could be justified in order for Victoria to access the much cheaper long duration storage in Tasmania[24].

But in its latest Gencost report (used in AEMO's 2024 ISP) CSIRO has said that 24-hour electro-chemical batteries will cost $132/kWh by 2035 and continuing to decline after that[25]. This can be compared to $120/kWh for Cethana (using AEMO's cost estimate) or $133/kWh (using Hydro Tasmania's cost estimate). It is appropriate to use as the point of comparison, the 2035 cost estimate for batteries since batteries can be developed in a year and AEMO only forecasts that Cethana will enter service in 2035 (and only reach close to its full capacity by 2048).

Taking account of much lower round-trip losses in batteries (circa 12%) versus pumped hydro (circa 25%) the conclusion is that 24-hour electro chemical storage will be much cheaper than Cethana.

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[23] It should be noted however that in its 2019 "pre-feasibility" report, Hydro Tasmania identified several pumped hydro projects and the one with the lowest capital cost per MW was Cethana ($1.5m/MW) which it said would have an 11 hour storage capacity, so giving a cost of $136/kWh.

[24] In their report, Hydro Tasmania do not account for the fact that battery expenditure will be incurred much later than pumped hydro expenditure (because batteries can be built quickly while pumped hydro involves major civil and mechanical works and so takes long). This feature combined with steeply declining battery costs is the basis of the claim that Cethana no longer has a comparative advantage relative to electro-chemical storage.

[25] Table B6, page 87. "Global NZE by 2050"

These conclusions rely on AEMO's and Hydro Tasmania's claim of Cethana costs and CSIRO's claims of 24-hour battery costs, counted when the battery expenditure is likely to be incurred. Are these credible cost estimates? Dealing firstly with AEMO Cethana cost estimate, as explained earlier in this section AEMO has a long history of under-estimating the costs of projects that it promotes. In this case it has used a cost estimate for Cethana that is lower even than Hydro Tasmania's CEO reported 18 months ago.

What about Hydro Tasmania's estimate of the cost of Cethana? As the project developer its cost estimate is likely to be more credible than AEMO's. But questions might be asked of Hydro Tasmania too. It is now seven years since Hydro Tasmania published its BoTN report recommending pumped hydro development in Tasmania and yet there is still no formal costing of Cethana available in the public domain. A web-search of Cethana cost estimates and of Hydro Tasmania's website reveals only a private briefing by Hydro Tasmania's CEO to an Australian Financial Review journalist who then reported what she was told.

Perhaps Hydro Tasmania does, privately, have confidence in its ability to accurately estimate the cost of Cethana. Yet considering the incentives Hydro Tasmania has to demonstrate a comparative advantage, it would surely wish to publicise such cost estimates if it felt confident that they were below the estimates it has casually briefed a journalist on. That Hydro Tasmania has not done so, suggests it may be naïve to accept Hydro Tasmania's public claims of Cethana's cost as any more than an unlikely lower bound estimate of capital cost and an upper bound estimate on storage (energy) capacity. A realistic $/kWh storage cost for Cethana may therefore most likely be well above the estimate we have used here.

What about CSIRO, has it been unduly optimistic in its expectations of the evolution of battery costs in future? Statista publish a global Lithium-ion battery price index[26]. This estimated that lithium battery costs declined by 82% from USD780/kWh in 2013 to USD139/kWh, a compound annual reduction of 16%. By comparison, CSIRO predict 24-hour battery costs will reduce by 11% per annum on their most ambitious scenario or by

[26] https://www.statista.com/statistics/883118/global-lithium-ion-battery-pack-costs/

7% on their least ambitious scenario. In the absence of any plausible argument for a decline in the rate of reduction of battery costs in the coming decade compared to the previous decade, this suggests that CSIRO's projected battery price reductions are unlikely to be optimistic.

The logical conclusion for this is that, evidently, it is now very unlikely that Tasmania has a comparative advantage in the provision of long duration storage.

3.3 Is AEMO's analysis of MarinusLink credible?

This analysis to this point has provided evidence that would suggest that a cost-benefit analysis of MarinusLink must surely conclude that there is no plausible net benefit. Why then has AEMO concluded that the benefits of MarinusLink exceed its costs? In answering this question I start by tracing the history of AEMO's assessment of the case for MarinusLink.

In its inaugural ISP (Integrated System Plan) in 2018, AEMO did not include MarinusLink as a recommended project but said that it would undertake further work "*to better understand how this project may best be incorporated into next year's ISP*".

In the subsequent (2020) ISP, MarinusLink was included but conditional on the Tasmanian Government legislating the Tasmanian Renewable Electricity Target (TRET). The TRET was legislated at the end of 2020 and Marinus Link was then included in the 2022 ISP unconditionally.

VEPC made a submission to AEMO on its Draft 2022 ISP, in which it pointed out that AEMO had assumed around 1,900 MW more wind generation (relative to the capacity installed in 2023/24) is committed to be developed in Tasmania even if MarinusLink is not built. This assumed wind generation expansion reflects AEMO's modelling of the effect of Tasmania's legislated renewable energy target (TRET) of 15 TWh of renewable generation in 2030 and 20 TWh by 2040.

But the TRET is not an unconditional commitment to 200% renewable electricity generation in Tasmania. Indeed, the Tasmanian Energy Minister told the Tasmanian

Parliament that wind generation would not be expanded in Tasmania unless MarinusLink is built.

The effect of AEMO assuming that 1,900 MW of additional wind generation would be built in Tasmania even if MarinusLink was not built – contrary to the legislation and the Minister's statement to the Tasmanian Parliament - is that the cost of building 1,900 MW of additional wind generation[27] was excluded from the calculation of the net benefit of MarinusLink. In this way, AEMO was able to claim that the sector-wide benefits of MarinusLink exceeded its sector-wide costs and so MarinusLink should be included as an actionable project.

AEMO claims that its ISP is designed to give effect to government policies. But in respect of MarinusLink this is not true. The TRET does not establish an obligation for the expansion of renewable electricity in Tasmania and the Tasmanian Energy Minister's own statement to the Parliament is clear that the TRET is contingent on the development of MarinusLink.

AEMO responded to our Draft 2022 ISP submission, in its final 2022 ISP report. AEMO's response to our criticism was that the TRET was legislated. But this was not in contention, and AEMO did not dispute our claim that it had falsely characterised the TRET. But AEMO did say, without evidence, that it had conducted "sensitivity analysis on removing the TRET" (as AEMO had defined it) and concluded that MarinusLink would still proceed without the policy as AEMO had defined it. I asked AEMO to provide the evidence for this sensitivity analysis and they did not reply to my request. AEMO's response to my criticism is also inconsistent with their 2018 ISP (which did not include MarinusLink) and their 2020 ISP which only included Marinus conditional on the TRET.

In 2024, Marinus Pty Ltd admitted that MarinusLink's would cost at least twice as much as what they had previously said it would. AEMO therefore needed to find ways in the 2024 ISP to ensure that the benefits of MarinusLink were still calculated to exceed its now

[27] This is big enough to expand electricity production by about 61% in Tasmania, thus taking Tasmania most of the way to its 200% TRET.

much higher cost. To do this, AEMO's 2024 ISP has changed the "counter-factual" (i.e. what would happen if MarinusLink was not built) in order to raise the cost of the base case, thus increasing AEMO's calculation of the benefit that would arise if MarinusLink was built rather than the counter-factual which excluded MarinusLink[28]. AEMO has proposed an implausible counter-factual in order to achieve this outcome, in two ways:

- First, while AEMO has persisted with its assumption that masses (1,758 MW) of additional wind generation will be built in Tasmania even if MarinusLink is not built, in its 2024 ISP it has now split this into 419 MW of offshore wind and 1,342 MW of additional onshore wind. By comparison, if MarinusLink is built, AEMO say that that no-offshore wind will be built. Since AEMO assumes that off-shore wind will be more than double the cost of onshore wind (almost triple if the offshore wind is floating) this creates a bigger benefit booked to Marinus, by replacing the more expensive off-shore wind with much cheaper onshore wind if MarinusLink is built.
- Second, AEMO assumes in the counter-factual that 400 MW of gas generation with carbon capture and storage (CCS) will be operational in five years' time in Victoria. This rises to 3,300 MW by 2040. Gas with CCS is assumed to be very expensive to build ($4655.33/kW according to AEMO) and operate. Since AEMO assumes that gas with CCS is not built in Victoria if MarinusLink is built (it is replaced by gas generation without CCS) this creates another large source of benefits booked to Marinus. But gas generation with CCS does not exist. It has never been proposed in Australia and does not exist anywhere in the world. It is implausible to have included it in the counter-factual. It is evidently there for the purpose of driving up the estimate of the benefits of MarinusLink.

In summary, AEMO has produced an analysis of the net benefit of MarinusLink that relies on a specification of energy policy in Tasmania that is clearly inconsistent with the legislated policy. The effect of this is to understate the cost of MarinusLink. AEMO also relies on technology assumptions (off-shore wind and gas with CCS) in its counter-

[28] The benefit arises by avoiding the higher expenditure in the counter-factual that MarinusLink is not built.

factual that are not credible. The effect of this is to overstate the benefits of building MarinusLin (which are claimed to arise by obviating the need for such off-shore wind and gas with CCS). The combination of excluding costs and over-stating benefits gives AEMO the result they were seeking to demonstrate: that building MarinusLink presents a net benefit.

On its website, AEMO describes itself as an independent expert.[29] Why then has AEMO produced such a biased analysis? The answer is that AEMO is not an independent organisation. It is a private company limited by guarantee and answerable to its members. Its members include the State of Tasmania, TasNetworks and Hydro Tasmania. AEMO's analysis of MarinusLink has evidently been crafted to deliver conclusions in line with the clear wishes of these organisations.

3.4 Why does Hydro Tasmania continue to support the "Battery of the Nation" proposal?

Hydro Tasmania is a respected organisation. Its 2018 report enthusiastically set out a proposal for Tasmania to become "the battery of the nation". Since then, many things have under-mined this vision:

1. Interconnection is now estimated to be twice as expensive as first claimed and further substantial increases are surely likely.
2. TasNetworks has estimated a doubling of the regulated asset value in Tasmania will be needed for the on-shore Tasmanian transmission development needed to implement the BoTN vision, leading to massive increases in transmission tariffs.
3. Basslink Pty Ltd has gone bankrupt and its new owner is seeking regulatory protection, to impose its costs onto consumers.

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[29] "*AEMO provides the detailed, independent planning, forecasting and modelling information and advice that drives effective and strategic decision-making, regulatory changes and investment.*" https://www.aemo.com.au/about/what-we-do. To be fair however our word search for "independent" in the five ISPs that AEMO has completed reveals that AEMO has not made the claim that it is independent in its development of the ISP.

4. Electro-chemical battery costs have declined significantly and are expected to continue to do so.
5. Hydro Tasmania has made clear that it now needs to spend $1.6bn just to maintain its existing generation capability.
6. The Government of Tasmania has proved willing to foist long term wind purchase contracts onto Hydro Tasmania and is likely to wish to continue to do so for the enormous increase in wind generation that it envisages.
7. Public finances in Tasmania, Victoria and the Commonwealth are now very much more constrained since Covid, their governments' enormous infrastructure programs and increases in the cost and quantity of government services unrelated to either Covid response or infrastructure expansion. Fiscal constraints and a nascent interest in productivity can now be expected to greatly affect these governments' willingness to countenance large capital outlays in the absence of convincing argument that such outlays will provide benefits that exceed their costs.

A decision to proceed with BoTN and Marinus now depends on Tasmania's ability to shift almost all of the cost of BoTN (not just Marinus) onto consumers in Victoria and tax-payers in Australia. The analysis in this submission suggests there is good reason, in comparative economics, for electricity consumers in Victoria and tax-payers in Australia to reject such cost shift (as we elaborate further in the coming sections).

With the enormous downside risk that BoTN now presents to Hydro Tasmania it is not surprising that, seven years after its 2018 BoTN vision report, Hydro Tasmania must be desperately seeking an escape route (even if only behind closed doors for now).

4 Should Victorian electricity consumers reasonably be expected to pay for the use of MarinusLink?

We have now assembled most of the evidence needed to broach the question of whether Tasmania has a comparative advantage in the provision of renewable electricity and storage, and whether this comparative advantage is sufficiently large as to defray the cost of MarinusLink. If so, Victorian electricity consumers can reasonably be expected to contribute to the payment for the use of MarinusLink.

In Section 3.1 (see footnote 4) I estimated the annual revenue requirement of MarinusLink Stage 1 to be $327m per year over 40 years. Assume that MarinusLink operates at the same average capacity factor as Basslink, this works out to $113 per MWh shipped over MarinusLink. The question therefore is whether wind generation and storage in Tasmania can be provided so much more cheaply in Tasmania than Victoria (i.e. the "battery of the nation" proposition) as to defray the cost of shipping production (or stored electricity) from Tasmania to Victoria on MarinusLink.

If electricity can be produced or re-produced in Tasmania for $113/MWh less than in Victoria, then rational Victorian electricity consumers should be willing to pay $113/MWh for the use of MarinusLink to import the cheaper electricity from Tasmania. If, for argument's sake, we assumed that MarinusLink Stage 1 operated at its full 750 MW capacity all the time sending electricity to Victoria for its whole life, then the hurdle will reduce from $113/MWh to $50/MWh.

Taking the most optimistic albeit unrealistic assumption that MarinusLink exports all the time, in deciding whether Victorian electricity consumers should reasonably be expected to pay for the use of MarinusLink, the question will be whether Tasmania has a comparative advantage in electricity production or re-production that is worth at least $50/MWh. The answer is to this question is, emphatically, not:

- For wind generation, as set out in Section 3.1, if there was any comparative advantage in wind generation in Tasmania it is likely to be small (at most a few dollars per MWh).

- In the case of deep storage, Section 3.2 concluded that it is now very unlikely that Tasmania has comparative advantage in the provision of long duration storage.

It might be argued that increasing renewable generation in Tasmania will increase the amount of electricity that can be stored in Tasmania (by holding back the water for later use) and hence exported to Victoria. There may (possibly) be considerable scope to increase storage capacity in Tasmania in this way. Despite considerable expansion of wind generation in Tasmania over the last decade, Tasmania is still typically in electricity deficit (see Table 1). The earlier analysis of Basslink showed that Victoria-Tasmania price differences were much too small to ensure profitable arbitrage over Basslink. Since MarinusLink is massively more expensive per MWh than Basslink, the case for renewable electricity expansion to leverage the existing hydro storages for the export of re-produced electricity is even weaker with MarinusLink than Basslink.

The inevitable conclusion from this analysis is that MarinusLink will have no or at best inconsequentially small benefit to Victoria's electricity consumers (much like Basslink). It works the other way around too. Victoria has no comparative advantage in wind electricity production relative to Tasmania. It is likely to have a small advantage in solar generation, but much too small to justify the cost of building MarinusLink to ship it to Tasmania.

It follows from this that MarinusLink will be a dead-loss, even moreso than Basslink has proven to be. It will surely be untenable for the Victorian Government to ask Victorian electricity consumers (or Victorian tax-payers) to contribute to an enormously expensive new interconnector to Tasmania to buy renewable electricity or re-produced renewable electricity from Tasmania, when that electricity or re-produced renewable electricity can be provided more cheaply in Victoria.

5 Should Australian taxpayers (reasonably) be expected to pay for the use of MarinusLink?

The analysis in the previous sections has concluded that Tasmania does not have a comparative advantage in renewable electricity production or in storage, and so building a new interconnector and charging consumers for its use can't be justified. Charging tax-payers instead of consumers for MarinusLink does not fix the problem that Tasmania does not have a comparative advantage in renewable electricity production or storage. It follows that Australian tax-payers can't reasonably be expected to pay for MarinusLink.

We note however that respected Tasmanian economist, Saul Eslake, has argued that MarinusLink is in the public interest "*therefore the feds should pay for most of it*".[30] I asked Mr Eslake to substantiate his conclusion. In correspondence with me he explained that his view was based on information presented to the Board of Hydro Tasmania during the latter part of his tenure as Director of Hydro Tasmania (he left the Board in September 2018) and that he had not had updates on that information since he left the Board.

Mr Eslake's opinion is consistent with the information that Hydro Tasmania published in its 2018 report on the expected cost of 24-hour battery relative to pumped hydro storage (6.5 times higher), and the expected cost of Marinus at that time. But, as explained in Section 3.2.2, MarinusLink is now expected to cost more than twice as much as expected in 2018, and 24-hour batteries are comparable to Cethana PHES in capital outlay and much cheaper to operate.

The Australian Government has, so far, been an enthusiastic supporter of MarinusLink and has committed to 49% ownership of MarinusLink Pty Ltd and to making "Rewiring the Nation" loan capital available to it. We presume this reflects advice from AEMO (which we have concluded at set out in Section 3.3 is not credible) and which fails to recognise the economics of 24 hour batteries compared to Cethana using currently

[30] "Marinus can play important role … if it doesn't get nuked: Eslake", 11 October 2024. Sean Ford, The Advocate.

available information instead of information advanced by Hydro Tasmania seven years ago.

6 Should Victorian electricity consumers be expected to pay for the use of Basslink?

Section 2.2 provided a description of Basslink and noted APA's application to convert Basslink from a market network service provider to a regulated network service provider, i.e. to secure stream of regulated charges imposed on electricity consumers fopr at least the next 21 years. Obviously APA is keen on conversion since it hopes that it will achieve through regulatory protection a much higher income than it will obtain from Hydro Tasmania, or itself directly if it chose to become a market network service provider.

Hydro Tasmania is enthusiastically supporting the conversion of Basslink to a regulated network service provider. This is perfectly understandable. As explained earlier, I estimated that Hydro Tasmania is likely to have lost $650m over the last 13 years as a result of Basslink arbitrage income falling well short of the payments Hydro Tasmania was required to make for the use of Basslink.

The Tasmanian Government is also enthusiastically supporting the conversion, surely on the same grounds, and the hope that a large part of the regulated charges for the use of Marinus might be paid by Victorian electricity users.

Needless to say the Victorian Government is not supporting the regulatory conversion of Basslink on the terms proposed by APA, and again presumably for exactly the same reasons that Hydro Tasmania and the Tasmanian Government is supporting conversion.

The issues here are straightforward. As set out in Section 2.2, Basslink's market value has been significantly lower than the payments required under the original Basslink Services Agreement. And, as set out in Section 2.2, APA has proposed an asset valuation and operating cost allowance which, I estimate, will require comparable annual income as paid under the original BSA. Assuming Basslink usage at the average level over the last 13 years, this will translate into a usage charge of $54/MWh which is just a little under twice the average price that Hydro Tasmania has received for the electricity it has traded over Basslink over the last 13 years. How can such outcome possibly be in the interest of consumers in Tasmania or Victoria?

Basslink does have economic value to consumers in Tasmania and Victoria as evident on the positive arbitrage margins on export and import (Table 3) and if Basslink was converted to a regulated interconnector, it would be reasonable to charge consumers (in Tasmania and Victoria based on whichever is importing from the other) at this rate. This would however mean that APA would need to accept a regulated asset value and operating cost allowance that is around half as high as they have sought from the Australian Energy Regulator.

7 Untapped potential of rooftop solar in Tasmania

Tasmania has by far the lowest share of rooftop solar as a share of its regional electrical demand (3.29%) compared to South Australia (26.04%), Queensland (14.23%), NSW (11.85%) and Victoria (11.82%) for 2024, year to 21 November. Yet, solar PV offers by far the lowest levelised cost of new electricity in the NEM. For example in the 2024 Gencost report, CSIRO estimated the levelised average cost of solar PV at $50-$75/MWh compared to on-shore wind (the next cheapest) at $75-$110/MWh. Tasmania has the particular advantage, unavailable elsewhere in the NEM, of a hydro system with the capacity to store surpluses for later use. This means that, unlike the rest of the NEM, there is little need to expand storage in Tasmania to gain the full advantage from rooftop solar. And solar in Tasmania has the particular advantage of being most abundant in the dry season, when it is most needed.

Minister Duigan has justified the construction of MarinusLink on the basis that, like Basslink, it will be able to import electricity from Victoria when solar is plentiful in Victoria and so prices are low. While Basslink can do this without incurring incremental cost, Tasmania would be very much better off expanding its own rooftop solar supply (which will have a comparable cost to Victorian rooftop solar) rather than incurring the enormous expense (or expecting Victorians or Australian taxpayers to incur enormous expense) to build Marinus to increase imports of a product that can be made just as cheaply in Tasmania.

The argument works in reverse too. In their verbal presentation to your Inquiry[31] Hydro Tasmania stress the value of interconnection as a support to Tasmania in dry years and that as renewable generation grows so it will become more valuable. But Basslink is valuable as a support to Tasmania because Tasmania has been so slow in expanding solar electricity in Tasmania. And it will be much cheaper to expand solar production in Tasmania than building MarinusLink to import Victoria's electricity.

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[31] https://www.parliament.tas.gov.au/committees/joint-committees/select-committees/energy-matters/broadcasts/tuesday-12-november-2024, from minute 44.

The expansion of rooftop solar in Tasmania is, surely, therefore the quickest and cheapest way to expand electricity supply in Tasmania with the lowest social and environmental impact of all currently available technologies. And with an average cost of production well below the average wholesale price it will be able to deliver profitable supply, reduce wholesale prices in Tasmania and increase the quantity of surpluses that Tasmania can profitably export to Victoria in the evening. It is perplexing that with such advantages Tasmania's energy policy has failed to capitalise on the enormous advantages in rooftop solar that are so readily to hand.

8 Summary of the main points

1. The "Battery of the Nation"(BoTN) and MarinusLink project as currently envisaged in AEMO's Integrated System Plan (ISP) is a massive re-engineering of electricity supply in Tasmania. The expected capital outlay of BoTN and MarinusLink is $15.3bn (circa $30,000 per Tasmanian household). Considering AEMO's track-record of badly under-estimating the costs of the projects it promotes, if BoTN and MarinusLink is ever developed as AEMO has set out in its ISP, the actual cost is likely to be considerably higher than this.
2. Tasmania has previously had a comparative advantage in electricity storage but this is no longer the case as a consequence of the actual and expected continuing reduction in battery costs. By 2035, CSIRO's estimate of the capital cost of 24-hour battery and AEMO's estimate of the capital cost of Cethana Pumped Hydro power station are comparable, and it will be much cheaper to operate batteries than Cathana. Consequently Tasmania no longer has a comparative advantage in the provision of deep storage.
3. Tasmania does not have a comparative advantage in the production of electricity from the wind or sun.
4. AEMO's justification for MarinusLink is based on the claim that Tasmania's Renewable Electricity Target is an unconditional commitment to expand renewable generation in Tasmania (it is not), and on unrealistic assumptions of the generation expansion in Tasmania (off-shore wind farms) and in Victoria (gas generators with carbon capture and storage) if Marinus is not built. AEMO is a company limited by company answerable to its members (which include the State of Tasmania, Hydro Tasmania and TasNetworks). It is not an independent expert, and its analysis of MarinusLink reflects its members' perception of their own best interests.
5. Tasmania does not currently provide a deep storage service to Victoria of any consequence. This is not explained by limitation in the size of the existing interconnector but by limitation in the storage capacity and electricity production in Tasmania.
6. Without a comparative advantage in either production or storage, incurring additional expenditure to expand interconnection between Victoria and Tasmania will not be in the interest of taxpayers or electricity consumers. It would

therefore not be reasonable to expect electricity consumers in Victoria or Tasmania, or Australian taxpayers, to pay for the usage of MarinusLink.

7. To the extent that the Australian Government seeks to impose the cost of MarinusLink on taxpayers or induce the Government of Victoria to impose the cost of MarinusLink onto its electricity consumers, it will be undermining the delivery of the emission reduction targets it has set itself by wastefully directing resources at projects that are not competitive.
8. It would not be reasonable to ask Tasmanian or Victorian electricity consumers to pay for the use of Basslink based on the regulated asset value and operating cost allowance sought by APA networks. Charges for Basslink usage that are consistent with an asset valuation about half the level proposed by APA, may be reasonable.
9. Expanding rooftop solar generation in Tasmania provides the cheapest source of new supply that has no social or local environmental cost. It will provide a benefit to individual electricity consumers and to all consumers. It will enhance the quantity and value of storage capacity provided by Hydro Tasmania, reduce network losses, improve energy security, reduce Tasmania's reliance on Victoria for summer electricity supply, improve the value of electricity traded across Basslink and will create a demand for skilled workers and tradespeople. Tasmania lags far behind the mainland in the development of rooftop solar. It is perplexing that with such advantages Tasmania's energy policy has failed to capitalise on the enormous advantages in rooftop solar that are so readily to hand.

Massively expanding behind-the-meter battery-backed photovoltaics (PV) on business properties

A policy proposal that offers a rare combination of potentially huge upside and easily managed downside risk

August 2024

Victoria Energy Policy Centre

VICTORIA UNIVERSITY

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Executive summary

This paper examines policy to encourage the uptake of large-scale battery-backed rooftop solar PV on the premises of Australia's commercial and industrial properties. The idea it examines is turning commercial and industrial properties located in and around Australia's cities, towns, villages and farms into major sources of electricity generation and storage, for supply to the grid.

The idea is motivated by the urgent need to expand emission-free electricity to replace coal generation that is scheduled to close over the coming decade, and in a way that presents little or no social and local environmental costs. Such social and local environmental costs are now plainly evident in some farmed wind and solar proposals and with their attendant transmission expansion requirement.

The "Business Power" policy discussed in this paper considers the merit of encouraging the development of large-scale battery-backed rooftop PV, capable of behind-the-meter trading in the electricity wholesale market, in supplying electricity to the grid. Suitably developed, this resource might be expected to supply at least a quarter of the electrical energy consumed in Australia each year, and much of that supply will occur when the sun is not shining.

The proposal that is assessed here involves floor prices for electricity that is fed into the grid at certain times of the day from rooftop solar PV and from behind-the-meter batteries:

- A "solar feed-in floor price" is proposed for feed-in before 11am and after 2pm.
- A "battery discharge floor price" is proposed for feed-in between 6pm and 9pm.

Such combination is likely to result in more electricity supplied to the grid before 11am and after 2pm, more electricity storage from rooftop PV between 11am and 2pm and more electricity supply to the grid between 6pm and 9pm, when the stored electricity is discharged to the grid.

The assessment of these proposals examines financial viability, policy cost as a proportion of revenues and costs, implicit greenhouse gas abatement cost, policy support yield, the cost-effectiveness of battery backed rooftop solar and the impact on electricity prices. The analysis concludes that a solar feed-in floor price of $100/MWh and battery discharge floor price of $200/MWh is likely to deliver financially viable battery-backed solar PV. While such floor prices would at times be higher than wholesale prices, it will deliver greenhouse gas abatement at a cost that is well below the levels determined pursuant to guidelines from the Ministerial Council on Energy.

The analysis also suggests this model of battery-backed rooftop solar is likely to be cost-effective compared to alternatives (recognising that such cost comparisons are nonetheless fraught) and that Business Power has a prospect of paying for itself in wholesale and retail price reductions. This might be expected even after taking account of the recovery of policy costs.

The analysis also finds that Business Power is likely to be more efficient than the existing certificate scheme (which is in the process of being phased out) in expanding emission-free electricity. Unlike existing policy, Business Power also provides incentives for behind-the-meter storage expansion.

Suggested implementation arrangements include establishing a “Business Power Authority” to disburse Business Power floor price payments and to recover the cost of this from consumers via regulated distribution network service providers. An alternative would be to recover some or all of the policy cost from taxpayers. There is no compelling economic reasoning to prefer one rather than the other.

There are many uncertainties here: are the floor prices too high or too low; will network service providers seek to support or undermine this; will the policy reduce electricity prices; will customers be attracted to it? Perhaps some uncertainties might be reduced through further study. However, there are many uncertainties in policy and technology. Trying to narrow such uncertainty through apparently sophisticated modelling often misdirects more than it enlightens. The most valuable learning here, as with many other energy policy ideas, will come by doing.

Policy makers should rightly be wary of unintended consequences and governments’ track record of picking losers. In this regard, it is notable that Business Power has a particular attraction, relative to most other energy policies, that customer and taxpayer risks can easily be managed by closing the scheme to new participants, if it becomes evident that the policy is not succeeding as hoped. Learning by doing will be inexpensive.

The cautious conclusions that characterise the analysis in this document should therefore not be misconstrued as equivocation as to the merits of Business Power. To the contrary, while success is not guaranteed, there is good reason to be optimistic, and that little will be lost by trying. Few energy policies offer this combination of potentially huge upside and easily managed downside risk. Policy makers, market participants and interest groups are encouraged to lose no time in their detailed consideration of this.

1. Introduction

This discussion paper explores the possibility of policy to encourage the uptake of large-scale battery-backed rooftop solar PV on the premises of Australia's commercial and industrial properties, not just for self-consumption but also in order to provide a major new source of firmed[1] zero-emission electricity to the grid.

While rooftop PV on commercial and industrial premises is becoming popular, policy currently encourages this to be sized for self-consumption, and there is no policy applicable to the industrial and commercial sector, to encourage PV production to be stored for later use, and for dispatch into the interconnected electricity grid.

The purpose of this document is to explore ideas and present analysis of them, for discussion. If these ideas find a receptive audience, more work will need to be done to consider their implementation. There is no reason that Business Power should necessarily be Australian Government rather than jurisdiction government policy, but the working assumption here is Australian Government policy. In addition, the analysis in this paper focusses on the National Electricity Market covering the south and eastern states. The conclusions of this analysis are likely to apply also in Western Australia and the Northern Territory, though feed-in floor prices will need to be tuned for their circumstances.

1.1 Context

The owners of 10 coal-fired power stations have issued notice of their intention to close them by 2040[2]. These power stations produced 87 TWh in 2023 of which 41 TWh in New South Wales (NSW), 23 TWh in Victoria and 23 TWh in Queensland.

The Australian Energy Market Operator (AEMO), in its latest Integrated System Plan (ISP) said it expects that all but a few coal generators will be closed by 2035, and all will be closed by 2040. AEMO's forecast requires replacing almost twice as much production as required to meet owners' announced closure dates, over the coming decade.

Market participants are not proposing to replace existing coal production with new coal, or other low marginal-cost base-load capable generation such as nuclear. Some gas generation capacity expansion is expected, but AEMO suggests that the share of electricity sourced from gas, measured annually, will be largely unchanged over the coming decade and when required at full capability during weather-dependent

[1] The term "firm" has found common use in the electricity industry to describe outcomes in which the variability of wind and solar generation is compensated for either through the addition of dispatchable energy or by storing variable renewable electricity for later consumption. There is no common understanding of just what, exactly, would qualify as "firmed". In this paper we refer to it as storing solar each day, particularly production between 11am and 2pm and then making that stored electricity available to the grid between 6pm and 9pm.

[2] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

renewable droughts, it is questionable whether there would be sufficient gas supply and gas pipeline and storage capacity to meet such infrequent demand. AEMO (and market participants) expect that renewable generation from farmed wind, solar PV and rooftop solar PV will dominate new supply.

Looking backwards, over the last four years to 2023, renewable generation grew on average by 7.8 TWh per year of which 2.2 TWh from farmed solar, 2.5 TWh from wind and 3.1 TWh from rooftop PV. Within the rooftop PV category, over this period rooftop systems larger than 15 kW but less than 100 kW and so mainly on commercial and industrial roofs, have grown on average by 500 MW per year, equivalent to approximately 1.4 TWh per annum while those smaller than 15 kW (mainly house household roofs) have grown on average by 2,500 MW per year, equivalent to approximately 4TWh per annum.

Nearly a decade ago, the Clean Energy Finance Corporation estimated rooftop solar production potential in 2016 of 38 TWh per year in commercial and industrial zones[3]. This is equivalent to a little under one quarter of end-use electrical demand in 2016. The CEFC also said that this was likely to underestimate the actual potential. Increases in rooftop space and in PV panel efficiency are also likely to substantially increase the CEFC's 2016 estimate.

In Victoria, electricity distributors Citipower/Powercor/United have estimated that Victoria alone has 56.3 TWh of rooftop solar potential, of which only 7% had been developed and of which only a small proportion was on the roofs of factories, warehouses and similar commercial and industrial buildings. By comparison the total end-use demand for electricity in Victoria in 2023 was 47 TWh. These distributors' therefore estimate that rooftop PV annual electricity production potential is more than the total end-use demand for electricity in Victoria in 2023

The future rate of renewable electricity expansion and the extent to which this is from farmed wind and solar rather than rooftop PV is far from certain. AEMO's most recent ISP predicts that more rooftop PV capacity will be added than either farmed solar or wind capacity. Their prediction of farmed wind and solar is however predicated on massive transmission capacity expansion, and therefore subject to the objections in relation to competing uses of land as well as the challenges of obtaining environmental approval for the development. All the transmission projects that AEMO has instructed for development are running far behind schedule and the latest cost estimates are several multiples of initial estimates. Transmission expansion – particularly of ultra-high voltage interconnectors - is encountering fierce opposition from affected communities.

Taken together, the demand for new (clean) generation to replace coal generation and evidence of challenges in the expansion of consequent transmission, suggests that

[3] https://www.cefc.com.au/insights/market-reports/how-much-rooftop-solar-can-be-installed-in-australia/

opportunities for electricity production (and storage) much closer to customers loads is likely to be particularly valuable.

The Australian Government has introduced a Capacity Investment Scheme (CIS) that seeks to expand renewable generation by 23 GW over the four years to 2027[4]. While this scheme does not specifically exclude behind-the-meter generation and storage, it is not likely to be useful to the expansion of rooftop PV and behind-the-meter storage in the commercial and industrial market segment. This is because the CIS will require that behind-the-meter generation and storage be aggregated and offered in large chunks, in competition with large scale front-of-meter generation and storage projects that do not need to be aggregated. The large transaction costs of such aggregation means that behind-the-meter opportunities cannot be expected to compete effectively in the CIS.

Furthermore, the Renewable Energy Target certificate scheme currently available for rooftop PV installations smaller than 100 kW is gradually phasing down to zero in 2030. Therefore, existing policy is tilting against what might be one of the easiest and most efficient sources of firmed clean energy, that can be delivered quickly.

The failure to prioritise decentralised production is also at odds with policy and developments in other countries/regions with similar solar potential and similarly ambitious decarbonisation objectives. For example, in Italy, a renewable energy communities decree[5] enacted in 2023 prioritises decentralised solar and storage particularly on rooftops. In Germany, rooftop solar accounted for 72% of PV expansion in 2023 and in Europe the Rooftop Solar Standard which currently applies to new non-residential and public buildings and to existing non-residential builds is expected to double rooftop solar capacity over the next four years[6].

In this context, this paper explores the merits of policy support for either rooftop PV, or behind-the-meter battery or the combination ("battery-backed solar") in the industrial and commercial premises (factories, warehouses, large farm sheds, shopping centres, offices, covered parking lots and so on). These are located mainly on the fringes of cities, towns, villages and on farms.

This policy – "Business Power" – encourages rooftop PV (and storage) to be sized so as to maximise the export of electricity to the grid. By contrast existing policy encourages rooftop solar sized for self-consumption, and there is currently no policy support for behind-the-meter storage.

[4] https://www.dcceew.gov.au/energy/renewable/capacity-investment-scheme

[5] https://cms.law/en/ita/publication/green-light-from-the-eu-for-the-italian-cer-renewable-energy-communities-decree

[6] https://www.solarpowereurope.org/press-releases/eu-rooftop-solar-standard-alone-could-solar-power-56-million-homes

1.2 Layout

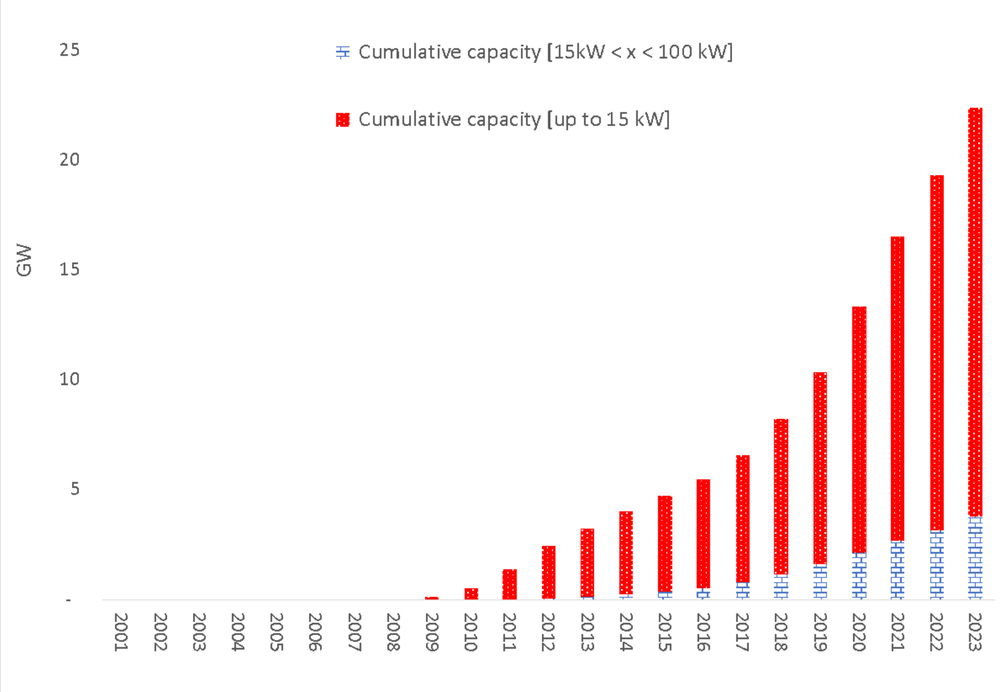
The second section provides a history of rooftop PV outcomes and of the policy support that the sector has enjoyed. Rooftop PV is one of Australia's energy policy success stories and a reasonable review of that is important in setting the context to the Business Power proposal. Section Three examines the economics of solar and storage. It is widely known that solar PV costs have declined steeply over the last 20 years and that (electrochemical) battery costs are declining rapidly too. Why then is policy support needed? This section answers this question. Section Four defines and then evaluates Business Power policy options and Section Five discusses the analysis and other issues that arise from it. Section Six briefly examines implementation issues.

2. A history of rooftop PV outcomes and policy in Australia

Australia already has, per capita, the highest penetration of rooftop PV of any country[7]. In 2023 rooftop PV provided 11% of the electricity produced in the National Electricity Market (NEM). By comparison wind farms provided 13%, hydro 7% and farmed (ground based) solar 7%[8]. This section presents relevant information about rooftop PV outcomes and about the policy support that has contributed to those outcomes.

Figure 1 shows the cumulative installed PV capacity to end 2023. It shows total capacity of 23 GW by end 2023 of which 7GW in rooftop systems bigger than 15 kW and smaller than 100 kW on commercial and industrial customers' rooftops, and the remaining 18 GW in systems smaller than 15 kW, almost all of which are on household roofs. Larger systems started to grow later than household systems but are now an increasing proportion of the total.

Figure 1. Cumulative installed Australian rooftop PV capacity (GW) to end 2023



Source: Data from Clean Energy Regulator, author's analysis.

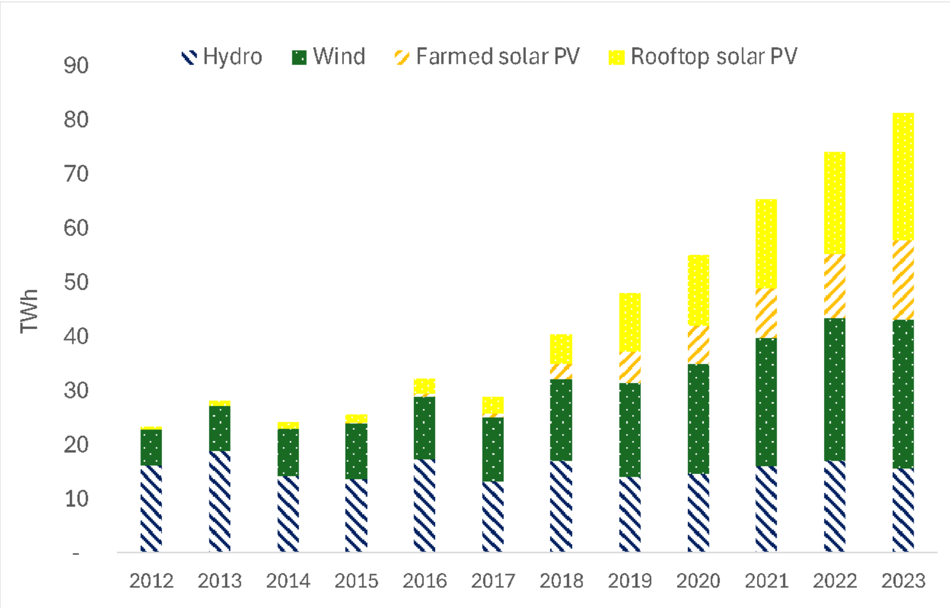
The mix of rooftop solar on household rooftops and business premises rooftops in the Australia (4 to 1) can be compared with that in the EU (1 to 1.5)[9]. So, rooftop solar on business premises in Australia is just 1/6th as large relative to households in Australia, it is on business premises relative to households in Europe. The relative proportion of

[7] https://iea-pvps.org/wp-content/uploads/2023/04/IEA_PVPS_Snapshot_2023.pdf
[8] https://www.v-nem.org
[9] https://www.solarpowereurope.org/insights/outlooks/eu-market-outlook-for-solar-power-2023-2027/detail

rooftop to ground-mounted solar in Australia (1.5 to1) is however not too dissimilar to this ratio in Europe (2 to 1)[10].

Figure 2 presents data on the average annual production (MW/year) of renewable electricity in the NEM, distinguishing hydro, wind, large scale (farmed) solar and small scale (mainly rooftop) solar. The more rapid expansion of rooftop PV relative to the other three is evident from this.

Figure 2. Electricity production (TWh per year) from renewable sources in the NEM, 2012 to 2023



Source: www.v-nem.org

Figure 3 shows the average hour-of-day profile of electricity production of rooftop PV in the four mainland states of Australia compared to the other main sources, in 2023. It shows that, proportionately, rooftop PV is bigger in South Australia than the other states where, in the middle of the day, rooftop PV accounts for around a half of electricity production.

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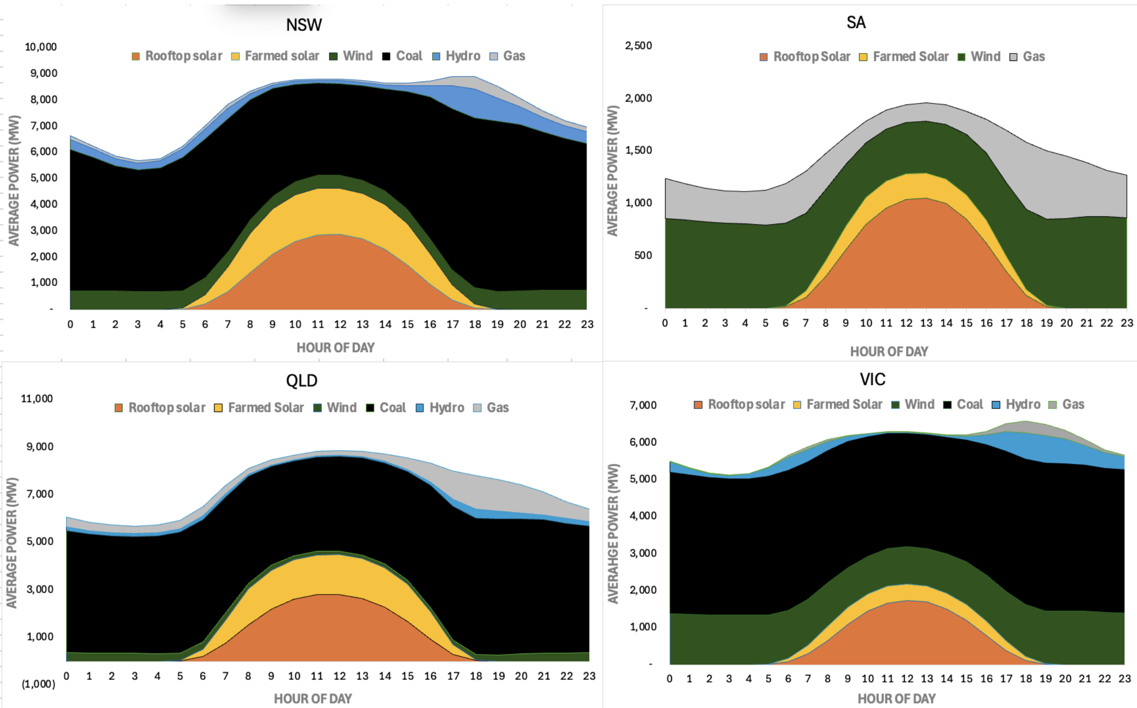
10 https://www.solarpowereurope.org/press-releases/eu-rooftop-solar-standard-alone-could-solar-power-56-million-homes

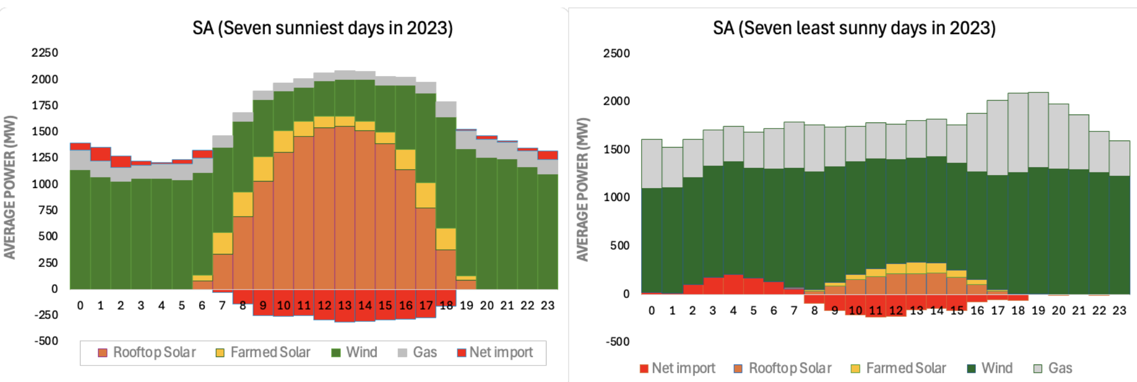
Figure 3. Average power (MW) by fuel type by hour of day in 2023 in mainland NEM regions



Source: www.v-nem.org, author's analysis

Figure 4 narrows the focus to the seven sunniest days (left hand chart) and seven least sunny days in South Australia in 2023 to show the average hourly production by fuel type. On the sunniest days, rooftop PV provides most of the energy between 7am and 5pm, gas generation was reduced to a small sliver (which was constrained on) and reasonable exports occurred over much of the day. On the least sunny day, gas plays a bigger role, but wind generation a much bigger role and SA was again exporting during the day, albeit less than on the sunniest days. In fact, in 2023, there were 34 five-minute time intervals in which rooftop PV production exceeded South Australia's entire electrical demand. The average excess at these times (15 MW) was exported.

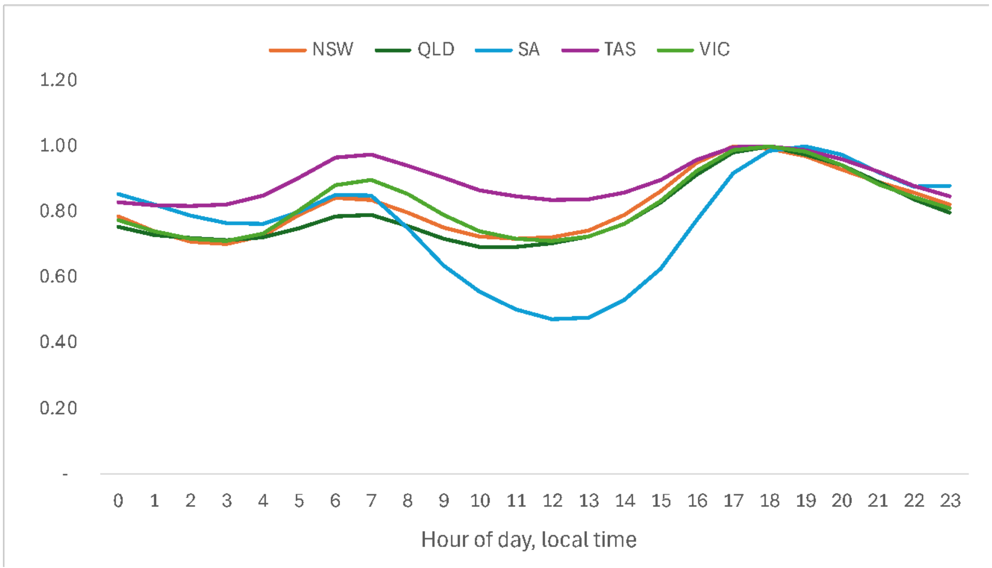
Figure 4. Average power (MW) by fuel type by hour of day for the seven sunniest days (left hand) and seven least sunny days (right hand) in South Australia in 2023



Source: www.v-nem.org, author's analysis.

The previous charts have shown the pattern of production across the day. Another perspective is provided by looking at the time profile of demand as measured on the transmission system (rooftop solar is almost always fully absorbed on the distribution system). Figure 5 shows the average demand by hour of day normalised relative to the peak demand, for the five NEM regions in 2023. Comparing Tasmania and South Australia, the effect of the difference in the state with the lowest and highest market share of rooftop PV is evident in the much greater dip in demand as measured on the transmission system in South Australia during the middle of the day.

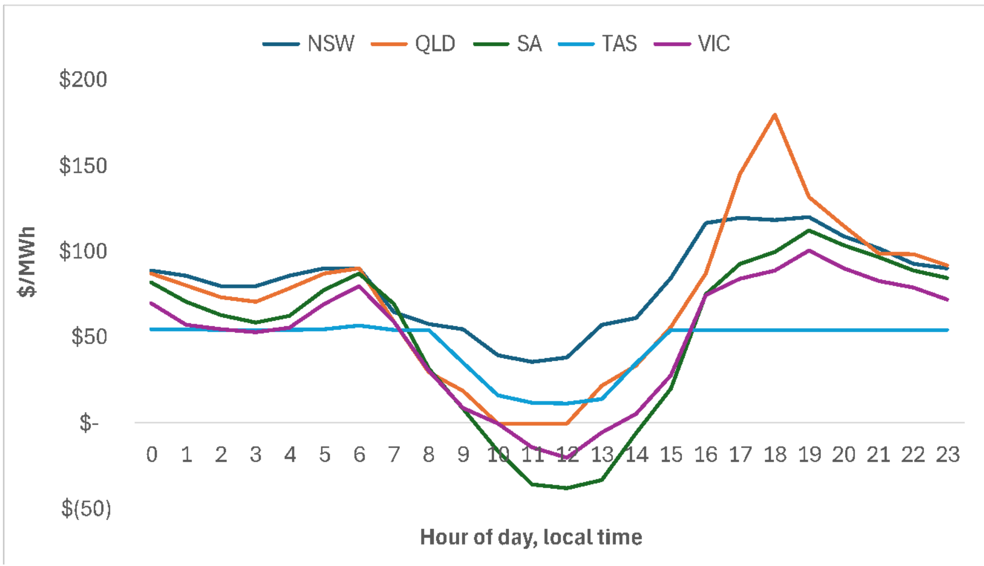
Figure 5. Normalised average hourly demand measured on the transmission system in mainland NEM region by hour of day in 2023



Source: www.v-nem.org, author's analysis.

How has rooftop PV affected prices in the mandatory wholesale market? Econometric studies can shed light on this at points in time, but the effect changes over time depending on many factors. However, the picture is sufficiently stark as to confidently conclude that rooftop solar is likely to have played a big role in reducing wholesale prices so far. Figure 6 shows the average of the median of the 12 five-minute wholesale (spot) electricity market price by hour of day in 2023 in the mainland NEM regions. It shows that in South Australia this hourly price was negative between 9.30am and 2.30pm. In Victoria it was negative between 10.30am and 1.30pm and in Queensland and NSW it was small or close to zero in the hours either side of the middle of the day. The large supply of rooftop PV in the middle of the day is likely to have been the main factor in explaining this outcome.

Figure 6. Average of the median of the 12 five-minute spot prices by hour of day in each NEM region in 2023

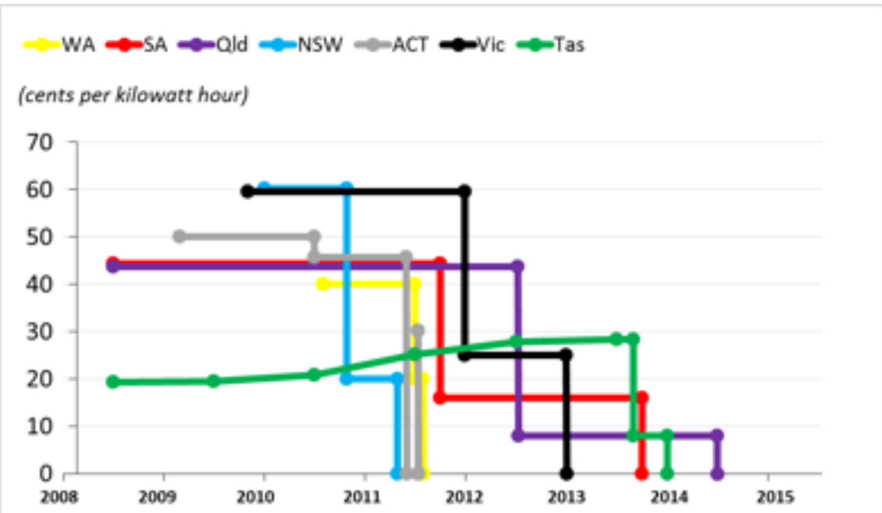


Source: www.v-nem.org, author's analysis.

2.1 Policy

Australia's rooftop PV outcomes have been supported by policy by state governments and more so through federal government renewable electricity policy. Figure 7 shows the premium feed-in tariffs (cents per kWh) available to households for the export of rooftop PV to the grid (or for total rooftop solar generation as was the case in NSW) offered by the seven jurisdictional governments that offered them. It shows that by June 2015 premium feed-in rates were no longer available in any jurisdiction.

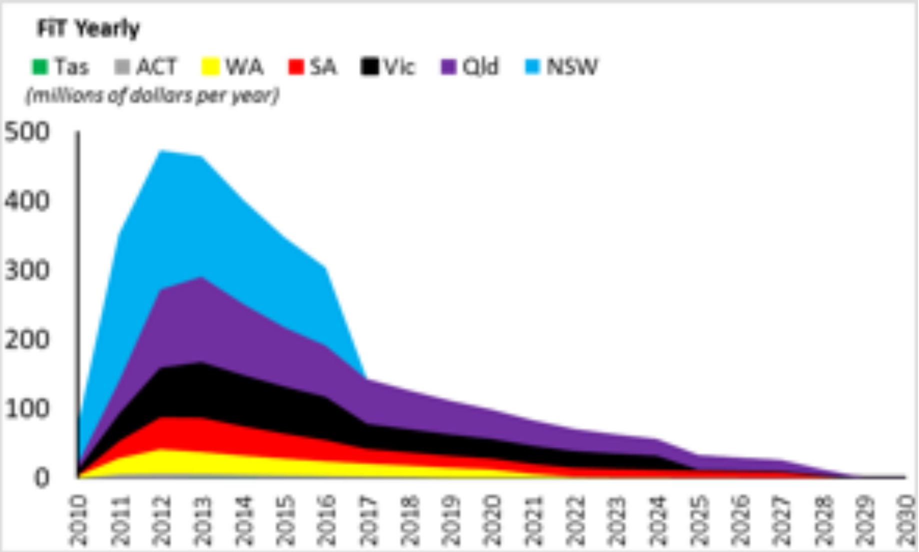
Figure 7. Jurisdiction government rooftop solar feed-in rates



Source: Mountain B.R and Szuster, P. 2015 "Solar, Solar Everywhere: Opportunities and Challenges for Australia's Rooftop PV Systems". IEEE Power and Energy, Vol 13, Issue 4, p.53-60.

The cost of these feed-in tariff policies were recovered mainly from consumers through regulated charges applied to all households and in some cases to all customers. Figure 8 shows the estimated annual cost (2014 dollars) of these policies in each jurisdiction. Mountain and Szuster (2015) estimate the aggregate value of these subsidies to be $4.5bn (2014 dollars).

Figure 8. Jurisdiction government mandated premium feed-in tariff aggregate payments from 2010 to 2030 ($million, 2014)

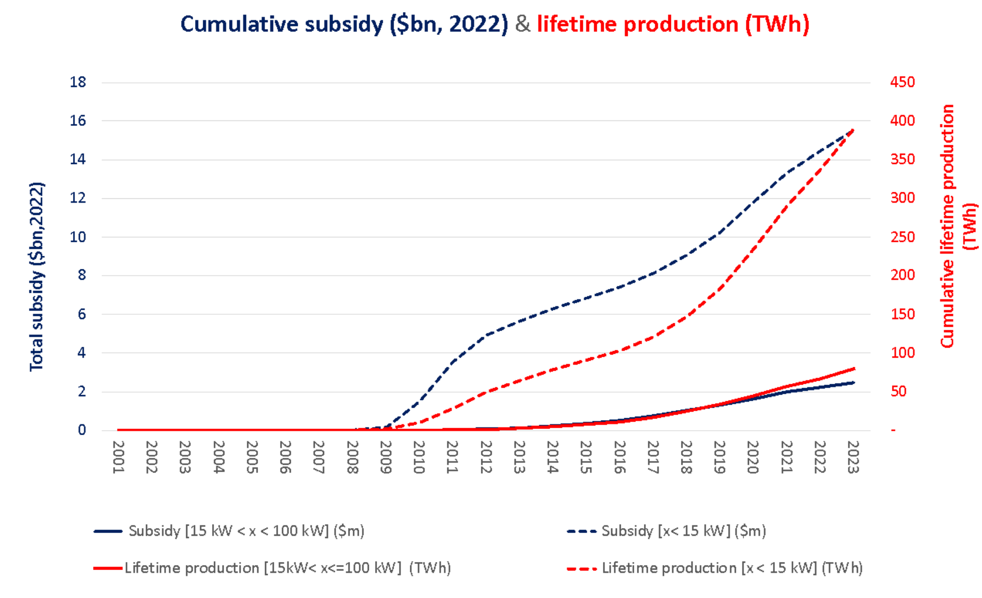


Source: Mountain B.R and Szuster, P. 2015 “Solar, Solar Everywhere: Opportunities and Challenges for Australia's Rooftop PV Systems”. IEEE Power and Energy, Vol 13, Issue 4, p.53-60.

Much greater policy support for rooftop PV (about 4 times more) has been provided through federal policy than through state governments. Both state and federal policy costs have been paid by consumers (not taxpayers) through regulated charges in the case of feed-in tariffs or through certificate obligations that retailers are likely to have fully recovered from their customers.

Figure 9 shows our estimate of the total value of the subsides (left hand axis) and life-time electricity production (right hand axis) of rooftop PV systems smaller than 15 kW (the dotted lines) and rooftop PV systems between 15 kW and 100 kW (the solid lines). The cumulative total lifetime production (TWh) from the subsidised systems is shown on the right-hand axis. The chart shows that by 2023, the sub-15kW systems will have lifetime production of just under 400 TWh and that just under $16bn of subsidy has been paid for this. For the 15 to 100 kW systems, lifetime production for the systems installed by the end of 2023 is about 75 TWh and a little over $2bn subsidy has been paid for this. The much lower subsidy for the 15-100 kW systems is explained in Figure 10.

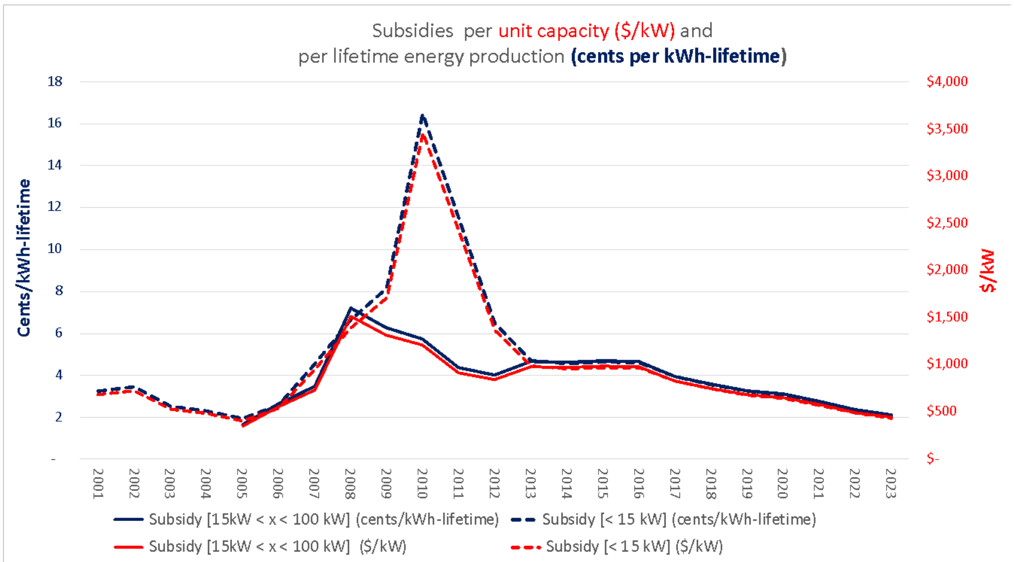
Figure 9. Cumulative federal government policy support and lifetime production of rooftop PV ($million, TWh 2022)



Source: Dated supplied by Clean Energy Regulator, author's analysis.

Figure 10 shows our estimate of the value of the certificate subsidy per kWh-life (coloured in blue and measured on left hand axis) and per kW of additional capacity (coloured in red and measured on right hand axis) of rooftop PV systems smaller than 15 kW (dotted) and between 15 kW and 100 kW (solid). It shows that by 2023, the value of the subsidy had become 2 cents per kWh-lifetime or expressed per kW, $500/kW. The surge in the subsidy for sub 15 kW systems between 2009 and 2013 was the result of an explicit subsidy push that multiplied the eligible certificates by a factor 5 times their base level. As the chart shows, this peaked in 2010 but then quickly dissipated.

Figure 10. Rooftop PV subsidy ($ per kW) and (cents per kWh-lifetime)



Source: Dated supplied by Clean Energy Regulator, author's analysis.

In summary, the relative lag in the development of rooftop solar in the business sector, relative to households might be explained in part by business-scale users never being eligible for the super-high federal or state incentives; business electricity prices being somewhat lower than households thus reducing the savings available from self-generation and businesses less subject able to respond to the impulse for early adoption for environmental action that motivated many early household installers.

3. The economics of behind-the-meter electricity production and storage: Is policy needed?

If the model of Business Power explored in this paper is financially attractive to investors and customers there is no need to consider policy support for it. It is therefore necessary first to establish the economics to demonstrate that support is likely to be needed if there is a desire to rapidly expand grid-oriented battery-back solar. If policy support is needed (and the first part of this section concludes it is) then it is necessary also to make the case for considering policy support: why not leave decisions on behind-the-meter solar and storage to the market? The last part of this section considers that.

3.1 Rooftop PV

We start by estimating the levelised cost of electricity (LCOE) of rooftop PV mounted on factory roofs. The method and assumptions used in the estimate are set out in Appendix A. LCOE measures the average cost of production, taking account of the opportunity cost of money at the assumed discount rate.

Table 1 shows our estimate of the LCOE of Business Power ranging between $81 and $99/MWh in the five regions of the NEM based on contemporary cost estimates (Appendix A for details). The state variation is explained by differences in the extent of solar irradiance. This estimate does not account for the subsidies available under the Australian Government's Renewable Energy Target (RET) policy[11]. The after-subsidy LCOE is likely to be about $10-$15/MWh lower.

Table 1. Levelised cost of electricity of rooftop solar PV ($/MWh)

	NSW	QLD	SA	TAS	VIC
Levelised cost of electricity (S/MWh)	$88	$81	$81	$99	$95

This LCOE is below the variable consumption rate that most customers in the commercial and industrial sector pay for grid-supplied electricity. This suggests that self-consumption will reduce electricity bills and so rooftop PV sized for self-consumption is likely to continue to grow even if existing policy support is ended.

What about the economics of rooftop PV focussed on the export of electricity to the grid? Comparing the average cost with the price received for rooftop PV grid sales informs this. Table 2 shows the volume-weighted average spot price value of rooftop PV for the last six full years, and the first four months of 2024 (Appendix B presents the methodology for the calculation). The table shows that the weighted-average spot price value over this period ranges between $31 and $68 per MWh (in South Australia and NSW respectively). Excluding 2022 (during which period wholesale prices were heavily affected by the Russian invasion of Ukraine and the consequential increase in wholesale market prices)

[11] https://cer.gov.au/schemes/renewable-energy-target

the spot price value of rooftop solar has declined over the period. This is consistent with the impact of rooftop solar on wholesale prices as shown in Figure 6 and discussed earlier. Comparing the spot price value of rooftop solar in Table 2 with the LCOE in Table 1, it is evident that selling rooftop PV electricity into the wholesale market at the spot price is unlikely to be profitable. Of course, in practice very little rooftop PV that retailers will buy from customers is likely to be transacted at the spot price. Instead, most will be priced at a flat feed-in rate that is likely to be fixed for reasonably long periods (a year or more). Such rates might in some cases be more attractive than volume-weighted spot prices, but this is unlikely to be such as to make up the gap to the LCOE. Flat feed-in rates may come to reflect volume-weighted spot prices albeit lagged.

Table 2. Volume-weighted average spot price of rooftop solar ($/MWh)

	Volume-weighted average spot price value of rooftop PV ($/MWh)				
	NSW	QLD	SA	TAS	VIC
2018	$84	$74	$91	$83	$99
2019	$77	$56	$43	$94	$104
2020	$65	$30	$25	$44	$43
2021	$41	$38	$25	$29	$14
2022	$103	$93	$51	$95	$50
2023	$47	$24	$2	$40	$ (4)
To 30 April 2024	$56	$51	$1	$45	$18
Average	$68	$52	$31	$61	$46

3.2 Behind-the-meter batteries

Are behind-the-meter batteries financially viable? To answer this we start by establishing the LCOE of such batteries. We assume a two-hour battery (i.e. one able to discharge at its peak power rating for two hours). This is a common duration for behind-the-meter batteries in the commercial and industrial sector. Our estimate is $395/MWh (assuming the battery is charged from the grid) or $335/MWh assuming the battery is charged from behind-the-meter PV, based on the assumptions and method set out in Appendix D. Battery costs, like solar PV costs, have declined quickly and are expected to continue to do so, and so this estimate is likely to decline in future.

What income might the battery expect to receive in providing energy market arbitrage services[12]? This depends on the difference between the price paid for electricity to charge and the price received when discharging. In some cases, these prices might be known, for example if a battery charges at tariff rates for off-peak electricity and then provides electricity for self-consumption at peak tariff rates. However, the Business Power proposal

[12] Other possible sources of income include the provision of network support, demand tariff optimisation, the provision of ancillary services to the wholesale market. We do not focus on these sources of income in our evaluation since these are niche services with a relatively small demand, although network support might become more significant in future. We are focussed on the dominant service that batteries will be asked to provide: shifting energy from one time period to another.

is a battery or battery-backed solar focussed on export to the market, not only for self-consumption. Accordingly, the relevant calculation is of the price paid when charging from the grid and price received when discharging to the grid.

To estimate such prices, we use five-minute wholesale market prices. This implicitly assumes that even if the rooftop PV is charging the battery, such electricity is priced at its opportunity cost, which is assumed to be the five-minute spot market price of electricity.

In addition, we allow 6 cents per kWh as the network charge to be paid when withdrawing electricity from the grid. The actual price paid might vary from this but is more likely to be lower than higher than this, assuming distributors seek to encourage charging at times when solar production is plentiful (when batteries are most likely to be charging). The allowance for network costs when charging the battery is likely to under-state revenues to the extent that the battery is mostly charged from rooftop PV rather than the grid.

In addition, for these calculations it is necessary to make assumptions on how effectively the battery will be operated: to what extent will operators be able to charge at the cheapest price and discharge at the highest? This can’t be known with certainty. We have chosen two cases to illustrate the likely range:

- The first assumes that batteries are set to charge between 11am and 2pm when prices are most likely to be at their lowest (see Figure 6), and discharge between 6pm and 9pm when prices are most likely to be at their highest. This is repeated daily and the battery is assumed to be fully charged and discharged once each day.
- The second also assumes that the battery charges and discharges once each day but that the operator has perfect foresight of prices each day so that the battery is charged at the average of the cheapest prices each day with the total charge volume equal to the battery capacity and that it is fully discharged at the average of the most expensive prices each day. [13]

The results of this analysis (using five-minute prices over all days in the four years from 2020 to 2023 and then taking the average of the result) is shown in Table 3. Comparing the estimated LCOE of the battery ($395/MWh) with the gross trading margins suggests that a market-focused behind-the-meter battery is unlikely to be profitable if the battery is operated passively. Queensland comes the closest to profitable operation, but with trading margins that are still only about half as high as the LCOE. However, Table 3 also shows that in South Australia, NSW and Queensland a trading strategy assuming perfect foresight delivers trading margins above the levelised average cost and so on this measure, a grid-export oriented behind-the-meter battery is likely to be profitable.

[13] The average of the cheapest and most expensive is the average of the lowest 24 five minute and highest 24 five minute prices respectively each day.

Table 3. Average trading margin assuming passive operation and perfect foresight operation in each NEM region ($/MWh)

	Trading margins ($/MWh) using 2020-2023 spot prices				
Battery operating assumptions	**SA**	**VIC**	**NSW**	**QLD**	**TAS**
Passive: charge each day at average price between 11am & 2pm; discharge at average price between 6pm & 9pm	$160	$112	$107	$191	$34
Perfect foresight: charge each day at average of 24 lowest 5-minute prices; discharge at average of 24 highest 5-minute prices	$596	$275	$400	$709	$210

A passive trading strategy is likely to be too pessimistic about the ability of a competent battery operator to predict market prices. But perfect foresight is almost certainly too optimistic (if it was not then the consequent storage investment might be expected to compete the profits away in which case these trading margins would not be sustainable anyway). The conclusion from this is that, behind-the-meter storage oriented to grid-supply is likely to require policy support if it is to expand quickly.

3.3 Why does business power merit consideration?

Analysis in the next section considers the extent to policy support needed to make battery-backed solar financially attractive. Before proceeding there, it is helpful first to survey possible arguments for why such support might be considered. We suggest ten arguments:

1. First, with a few exceptions almost all electricity production in the NEM has relied on policy support for its development. This was true for coal generation (all developed by governments, albeit in a few cases in partnership with private investors/operators); almost all gas generation (invariably developed by government-owned corporations or where not supported through obligation schemes or government grants); all hydro capacity of any consequence (owned and developed by government-owned corporations); all pumped hydro (either developed by government-owned corporations and in the single case where not supported by grants and concessions); and almost all renewable generation and storage (whether in-front or behind customers' meters). It might be argued that it was a mistake that policies had driven such investment and that it should have been left to private investors and rivalrous processes to determine investment. It would be consistent with this argument to suggest that two wrongs don't make a right and so policy support for Business Power is not justified. However, this ignores the reality that there is cross-party and crossbench political support for continued intervention to support investment in electricity production. The reality is that such intervention will occur and so the issue to be grappled with in pursuit of customers' and the public's best interest, is the appropriate allocation of public resources recognising this reality.

2. Second there is cross-party and almost unanimous crossbench support in Australia's national and jurisdictional parliaments for policy to reduce greenhouse gas emissions. This consensus has developed over time and is now well established (albeit that differences remain on the urgency and the price that taxpayers and electricity consumers are willing to pay for reductions). Yet our governments have chosen not to charge emitters for their greenhouse gas emissions. This leaves no alternative other than to pursue policies that support the expansion of zero or low emission electricity production. Business Power is one such approach. This does not mean that Business Power is necessarily justified, but rather that its consideration and evaluation is justified on the grounds of its contribution to emission reductions.

3. Third, social and environmental costs associated with farmed wind and solar are, evidently, significant. Such costs are now a major political, social and economic concern. Business Power expands clean energy (and storage) in a way that presents no social or local environmental costs.

4. Fourth, the electricity market is a final-price mandatory spot market. When variable renewable generation is at or close to the last generating unit to be dispatched to meet demand, market prices can be close to zero or negative. All dispatched generators receive this price and all electricity sourced from the wholesale market pays this price. While producers and retailers can (and do) swap volatile 5-minute spot prices for longer term fixed prices, spot market outcomes ultimately drive such fixed prices. It might be suggested that market prices are signalling abundant supply in the middle of the day and hence it would be inappropriate to provide policy support to increase the supply of rooftop solar even if, backed by battery, some large part of that solar is likely to be stored for later use when the demand/supply balance is tighter. The counter to this argument is that almost all generation (and storage) capacity expansion in the NEM is supported by policy outside the wholesale market. As such, investors do not actually rely exclusively or even heavily on spot prices to motivate investment. In other words, the spot market has become a mechanism for scheduling and dispatch, not a mechanism that is expected to fully reward investment. To disregard this in considering the merit of Business Power will be to deny the possibility of investment opportunities that may have a higher policy yield than alternatives. Again, this is not to suggest that Business Power is necessarily deserving of policy support, but it does suggest it should be considered for this reason.

5. Fifth, Business Power is likely to result in a flatter (less peaky) load profile on both transmission and distribution networks. This is likely to defer or permanently avoid network augmentation expenditure[14], thus reducing network charges for all customers.

[14] There are many examples around the various distribution grids. For one example see https://www.energex.com.au/__data/assets/pdf_file/0011/1079336/Pimpama-East-and-Stapylton-Notice-of-No-Non-Network-Options.pdf

6. Sixth, the flatter load profile that Business Power will deliver is likely to reduce demand-weighted average prices in regulated default offers, and in retailers' market offers.

7. Seventh, decentralisation of energy production pursuant to Business Power will reduce network losses on both distribution and transmission networks, thus reducing both grid-supplied energy charges and network charges.

8. Eighth, locating storage low down in the network, as Business Power does, is likely to reduce solar curtailment on feeders thus reducing energy losses and distribution network augmentation needs.

9. Ninth, Business Power is likely to facilitate the installation of EV chargers at places of work, so providing a co-benefit for the decarbonisation of private transport.

10. Tenth, Business Power can easily be closed to new participants. If the policy is not working as hoped it can be quickly turned off. This means taxpayers and consumers only face a small downside if Business Power turns out to be a loser.

4. Policy options and their evaluation

This section proposes options for policy support and then evaluates them. It works through policy design options and then evaluates the chosen options.

4.1 Policy support options

In the suite of possible policies, should support be considered only for behind-the-meter solar or only for behind-the-meter storage or only for battery-backed solar? Taking account of the central objective – the rapid replacement of coal generation scheduled to close – expanding both production and storage will be valuable. A valid case for policy support for all three exists and so we develop and evaluate options for all three in this sub-section.

Should policy support be paid out up-front at the time a facility is commissioned or over time based on production? Existing policy provides capital support for behind the meter production smaller than 100 kW or production support for systems bigger than this. The origin of the distinction lies largely in the administrative cost of administering a production subsidy. We suggest that with the evolution of the electricity market, specifically the very large role that rooftop solar plays (and is expected to continue to play), it has become more important to focus policy on production even for smaller systems. Production subsidies can ensure quality and reliability (the support is not collected unless the system produces) and with production support, it is possible to focus on the time of day that production will be most valuable.

Market prices suggest that policy support to increase supply between 11am and 2pm is not warranted. Although the market is still far from fully supplied at these times (even in South Australia), continued organic growth[15] of rooftop PV is likely to mean a market that is fully supplied for almost all days between 11am and 2pm in due course. Outside of these hours, the market is still not well supplied. Policy support for rooftop solar production outside the 11am to 2pm period can provide incentives for easterly and westerly panel orientation.

With respect to storage, the profile of hourly demand and market prices shows that storage discharge between 6pm and 9pm is more likely to be valuable than at other times of the day. Accordingly, we assess policy to support discharge between 6pm and 9pm.[16]

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[15] See for example: https://www.sunwiz.com.au/a-closer-look-at-some-record-breaking-commercial-pv-market-segments/?utm_campaign=a-closer-look-at-some-record-breaking-commercial-pv-market-segments&utm_medium=email&_hsenc=p2ANqtz-9yLvppEQWbC7nb3uTXNicxuuoTLw37gaxDNoQwOGHKcThxvBV0pCmAJ0UQgIzo1jHlb_7SENYHHL0b_GZJ6lenRIjpG6zNu7z4SmFOfooyUO5tdhc&_hsmi=316253875&utm_content=316253875&utm_source=hs_email

[16] There is no need to establish incentives to find the cheapest charge times: if exposed to spot prices, battery operators have a powerful incentive to find such times themselves.

Finally, what form should production support take: a fixed feed-in price or a floor price? Fixed (i.e. non time-varying) feed-in prices have been the norm for rooftop PV policy so far. Feed-in prices have the advantage of simplicity. However, it is now increasingly important that the operation of behind-the-meter production and storage faces similar incentives to ensure efficient dispatch as large scale (front of meter) production and storage. Accordingly, taking on the additional complexity of market price exposure – by providing policy support in the form of a time-dependent floor price - is merited[17]. A floor price provides incentives for efficient dispatch.[18]

We note also the developments in electricity retailing mean that it is now easily possible to provide retail consumers with exposure to spot market prices (many thousands of households have chosen such retail arrangements) and so the additional complexity is likely to prove easy to surmount in the target market of even more sophisticated commercial and industrial consumers. We note however, that adoption of the proposals here do not require that business customers be exposed to spot prices. The operation of the policy does not require customer exposure to spot price structures.

It might be suggested that feed-in floor prices and the times they apply should vary over the seasons, and between the states. This will however greatly increase the complexity of the scheme. Such additional complexity is unlikely to be worthwhile. The objective of the floor prices is to increase supply when the balance between supply and demand is more likely to be tight, and to provide policy support that is likely to make Business Power bankable. The objective is not to optimise battery backed behind the meter solar dispatch in each five-minute interval. This can be left to the market through the prices that participants will see.

The next issue to consider is how long (for how many years) floor prices should be available for? Shorter periods will require relatively higher floor prices to achieve the same level of policy support as longer periods. We have assumed 20 years for solar and 10 years for batteries, based on the likely operating life of solar/batteries before refurbishment or life extension is contemplated. Shorter periods may be preferable to some customers. Further consideration of this can be left to detailed implementation.
In summary, three policy support options are considered and evaluated:

1. Rooftop PV floor price ($/MWh) for production before 11am or after 2pm for 20 years.
2. Battery discharge floor price ($/MWh) for battery discharge between 6pm and 9pm for 10 years.

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[17] We note also strong regulatory support for behind-the-meter participation in wholesale markets. See for example: https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

[18] The floor price policy does not limit whatever commercial arrangements service providers and commercial/industrial customers might agree. The floor price relative to the 5-miute spot price is the basis of Business Power top-up policy payments but does not prescribe that the entity that receives the top-up payments has to contract with customers using five-minute prices.

3. Battery-backed solar with floor price for rooftop PV production before 11am or after 2pm for 20 years as well as floor price for battery discharge between 6pm and 9pm for 10 years.

4.2 Evaluation

How should the policy support options be evaluated? We consider four measures here:

1. **Viability:** for the modelled level of support**,** is the present value of revenues less costs likely to be positive, and so will pursuit of that Business Power option be investable?
2. **Value-for-money Criterion 1**: how much of the spot market revenue is accounted for by policy support? This measures how dependent revenues are on policy support. But Criterion 2 also matters (policy support might be a large proportion of revenues but a lower proportion of costs).
3. **Value-for-money Criterion 2:** how does the policy support compare to the cost of the rooftop solar/battery/battery-backed solar? This measures much of the cost is met through policy support.
4. **Implied greenhouse has (GHG) abatement cost:** what is the value of the policy support per tonne of GHG emissions abated as a result of the policy? Since the main rationale for a Business Power policy is to decarbonise electricity supply, the assessment of policy proposals in terms of their GHG abatement costs is an important metric in policy assessment.

In the Discussion (next section) we also introduce “policy yield” (how much investment per dollar of policy support) in evaluating alternatives.

4.2.1 PV-only policy support assessment

Table 4 presents the results of the assessment, using the calculations set out in Appendix E.

Table 4. PV-only floor price evaluation

Average sales price ($/MWh)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	59	30	26	43	17
$100	88	73	77	77	65
$130	103	89	92	94	80
$150	114	101	103	105	91
NPV ($m)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	$0.20	$0.39	$0.42	$0.35	$0.51
$100	$0.00	$0.06	$0.04	$0.14	$0.20
$130	$0.10	$0.06	$0.08	$0.03	$0.10
$150	$0.18	$0.15	$0.16	$0.04	$0.03
Policy support as % of revenue					
	NSW	**QLD**	**SA**	**TAS**	**VIC**
$100	33%	59%	66%	45%	74%
$130	43%	67%	71%	54%	79%
$150	48%	71%	74%	59%	82%
Policy support as % of levelised cost					
	NSW	**QLD**	**SA**	**TAS**	**VIC**
$100	32%	53%	62%	35%	51%
$130	50%	73%	80%	51%	66%
$150	62%	88%	93%	63%	78%
Implied carbon price ($/tonne$CO_{2-e}$)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
$100	$29	$43	$39	$27	$37
$130	$44	$60	$51	$39	$49
$150	$55	$71	$59	$48	$57

The first block of numbers shows the effect of different floor prices on the average annual price received. For example, a $100/MWh floor price for production before 11am and after 2pm raises the average sales price by around $30/MWh to $40/MWh in each state, relative to the "No floor" case.

The second block of numbers (NPV) tables shows that grid-oriented rooftop solar (i.e. excluding the value from self-consumption) would not be profitable in any NEM region without policy support. At a floor of $100/MWh, rooftop solar would be close to viable (assuming a 7% discount rate) in all NEM regions except Tasmania and Victoria.

Focussing further on the $100/MWh floor (again only payable for PV injected to the grid before 11am or after 2pm) the third block reveals that such floor would provide support that adds up to between 33% (NSW) and 74% (in VIC) of the spot market revenue of solar. This level of policy support accounts for a similar level of the total cost of rooftop PV. The last set of numbers (Implied carbon price) shows that, when expressed per tonne of greenhouse gas abated, a $100/MWh floor would deliver abatement at a cost of between $27 and $43 per tonne of carbon-dioxide equivalent abated.

4.2.2 Battery-only policy support evaluation

Table 5 presents the results of the evaluation of a floor price for battery discharge between 6pm and 9pm using the calculations set out in Appendix F. The first set of numbers show the "gross arbitrage margin" which is the difference between the average price received when discharging and price paid when charging, per MWh discharged. This analysis assumes that battery operators achieve gross margins halfway between the high point (which assumes they have perfect foresight of spot prices) and the low point (which assumes batteries are charged at the average price each day between 11am to 2pm and discharged at the average price between 6pm and 9pm).

The table shows that adding a floor price of $200 for discharge between 6pm and 9pm will deliver margins in SA and QLD that are above the levelized cost of electricity of $335/MWh (assuming the battery is charged from behind the meter solar or $395/MWh (assuming the battery is charged from electricity drawn from the grid).

The second group of numbers (NPV) shows that with a floor price of $200/MWh for discharge between 6pm and 9pm, a behind-the-meter battery (but which is assumed to be charged from the grid) is likely to be profitable or close to profitable in all NEM regions (assuming a 7% discount rate).

The third set of numbers shows that a $200/MWh floor price provides support that is a small proportion of revenues (21% or less) in the mainland NEM region (it is a higher proportion in Tasmania where hydro storage already smooths daily prices and so arbitrage margins are less attractive).

Table 5. Battery-only floor price evaluation

Gross arbitrage margin ($/MWh)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	$254	$351	$378	$122	$194
$100	$263	$458	$392	$148	$210
$200	$311	$495	$442	$219	$267
$300	$379	$558	$511	$304	$342
$400	$469	$642	$596	$398	$434
NPV ($m)					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	$0.08	$0.02	$0.04	$0.22	$0.15
$100	$0.07	$0.13	$0.06	$0.19	$0.13
$200	$0.03	$0.17	$0.11	$0.12	$0.07
$300	$0.05	$0.23	$0.18	$0.03	$0.01
$400	$0.14	$0.32	$0.27	$0.07	$0.10
Policy support as % of revenue					
Floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
No floor	0	0	0	0	0
$100	4%	23%	4%	18%	8%
$200	15%	7%	11%	32%	21%
$300	18%	11%	14%	28%	22%
$400	19%	13%	14%	24%	21%

4.2.3 Battery-backed solar policy support evaluation

Table 6 presents the evaluation of battery-backed solar using the calculations set out in Appendix G. Two different combinations of feed-in prices for battery and solar are used. The first combination is a $200/MWh floor for battery discharge between 6pm and 9pm and a solar feed-in floor for solar fed-in before 11am and after 2pm.

The second combination is a $300/MWh battery floor and a $130/MWh PV floor. This combination reveals a positive NPV, or close to, it in all regions. This policy support expressed as a percentage of revenue is between 28% and 56% in the mainland states, and expressed as a percentage of cost is 31% to 57%. While these are relatively high, the implied GHG abatement cost (between $22 and $37/MWh abated is well below the Australian Energy Market Commission's estimate of the value of emission reduction in the electricity, calculated according to the Ministerial Council of Energy's methodology ($70 per tonne of $CO_{2\text{-}e}$ in 2024 rising to $146 per tonne $CO_{2\text{-}e}$ in 2034[19]).

Table 6. Battery-backed solar floor price evaluation

$200 Battery floor, $100 PV floor	NSW	QLD	SA	TAS	VIC
NPV	$0.03	$0.10	$0.08	$0.26	$0.27
Policy support as % of revenue	28%	45%	43%	52%	56%
Policy support as % of cost	27%	49%	46%	33%	40%
Implied carbon price	$19	$32	$23	$23	$23
$300 Battery floor, $130 PV floor	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
NPV	$0.15	$0.29	$0.26	$0.07	$0.09
Policy support as % of revenue	39%	53%	52%	56%	65%
Policy support as % of cost	45%	69%	66%	52%	58%
Implied carbon price	$32	$45	$33	$32	$34

[19] https://www.aemc.gov.au/sites/default/files/2024-03/AEMC%20guide%20on%20how%20energy%20objectives%20shape%20our%20decisions%20clean%20200324.pdf

5. Discussion

The analysis in the previous subsection concluded that a floor price for rooftop PV of \$100/MWh for feed-in before 11am and after 2pm is likely to yield profitable investment and although such floor delivers income that is a reasonably large proportion of total income and total cost, it is nonetheless cheap in greenhouse gas abatement terms.
The analysis also revealed that a \$200/MWh floor for battery discharge from 6pm to 9pm also likely leads to profitable investment, and policy support that is a small proportion of revenues and costs.

The combination of these two floors and a battery sized so that 1kW of solar is required to be matched with at least 2 kWh of storage delivers investment that is likely to be profitable and at a GHG abatement cost that is well below the AEMC's estimate (\$70 per tonne of $CO_{2\text{-}e}$ in 2024 rising to \$146 per tonne $CO_{2\text{-}e}$ in 2034[20]).

The suggested combination of storage capacity and rooftop PV capability is likely to result in almost all the Business Power rooftop PV production during winter being stored for discharge to the market in the evening. In summer, the combination will result in about half the solar production being consumed during the day and half being stored for later discharge. This pattern of operation can be expected to bring downward pressure on wholesale prices during the day and even more so during the evening peak periods, when supply is maximised.

Five further aspects are considered in assessing the Business Power proposals:

- Policy support yield;
- Average cost;
- Impact on electricity prices;
- The recovery of policy support costs; and
- Uncertainty.

5.1 Policy support yield

What is the likely "policy support yield" i.e. what is the amount of additional production or storage (or both) that is likely to be delivered per dollar of policy support? This is quantified in Table 7 which shows that \$1bn of policy support for battery-backed solar can be expected to deliver 2.7 TWh of additional electricity production per year, and 2 GWh of additional storage capacity. This calculation assumes that \$1 of public subsidy leverages a further \$3 of private investment (so \$4 in total) as appears to be the case under the existing small-scale certificate scheme.

[20] https://www.aemc.gov.au/sites/default/files/2024-03/AEMC%20guide%20on%20how%20energy%20objectives%20shape%20our%20decisions%20clean%20200324.pdf

The table also shows that the battery-only policy delivers more storage and the PV-only policy delivers more production than the battery-back solar policy (as would be expected because the battery-backed solar policy support is helping to fund both storage and solar production).

Are these good numbers or not? It is possible to get a sense of this by comparing the policy support yield under the existing small-scale certificate scheme. As is shown in Figure 10, two cents per kWh of policy support is being paid per kWh-lifetime of rooftop solar production. Re-stated, one dollar of policy-support is delivering 50 kWh-lifetime of new rooftop production. Table 7 shows that $1 of policy support for battery-backed solar is likely to deliver 67 kWh-lifetime of new solar production *as well as* 2-Watt-hours of storage capacity. On renewable production alone, the battery-backed solar policy support is therefore appreciably more efficient than the existing small-scale certificate scheme.

Table 7. Policy support yield

	Battery and solar	Battery only	PV only
Additional direct annual renewable generation (MWh)	2,679,002		4,816,097
Annual GHG emission reduction (tCO_{2-e})	2,679,002		4,816,097
Additional storage (energy) capacity (MWh)	2,059	2,633	

Another way to understand Business Power policy yield compared to existing rooftop solar policy is to compare the outcomes under the existing policy, with the outcomes that this analysis of Business Power predicts. Taking NSW as an example, in 2023 the total installed rooftop PV capacity of 5,560 MW produced 7,800 GWh of production. We estimate a total of $4.2bn of policy support was paid in getting to the 5,560 MW of installed rooftop PV. Under Business Power, our analysis suggests that $4.2bn of policy support would deliver 11.3 GW of additional rooftop PV capacity as well as 8,650 MWh of additional storage. This suggests that, by comparison, Business Power is likely to be twice as efficient as existing policy has been in expanding behind-the-meter renewable electricity, and will expand storage at (in relative comparisons, no additional cost).

5.2 Average cost

The assessment has assumed a hypothetical 490kW PV system and 245 kW (490 kWh) battery. The present cost of this we estimate to be $0.96m and the present value of production over its useful life is 8,175 GWh. With a 10-year battery life, it will be necessary to be replaced after 10 years and so to ensure 20 years of battery-backed solar, the present cost is $1.2m and the levelised cost of electricity (LCOE) of this battery-backed solar system is $134/MWh.

In this specific case, this will deliver a device capable of firm supply (charging from the grid is possible when solar is inadequate) equal to 490 kWh per day for 20 years (or a little less than 12 times as much per day) for a commensurately shorter number of years. It is also capable of variable supply of around 700 MWh per year, from the rooftop solar.

How can this functionality and levelised cost be compared to alternatives? There is no certain way to do this, but comparing the levelised costs of other technologies helps to provide a sense of comparative cost-effectiveness.

For example, CSIRO[21] says that the LCOE of open cycle gas turbines (which are capable of firm continuous supply at peak capacity typically for at least eight hours) is $140-$240/MWh (before accounting for emission costs).

The average cost of supply by Stanwell Corporation (which has a portfolio of 3,300 MW of coal and another 700 MW of gas and hydro) provides another point of comparison. Information from Stanwell's annual report suggests $180/MWh[22] (again, no emission costs are charged).

Another point of comparison is a recently approved windfarm in NSW, which a reported LCOE of $110/MWh.[23]

The functionality of each of these alternatives, differ from each other and from Business Power. This is unavoidable. Nevertheless, these comparisons lend weight to a suggestion that battery-backed solar is a cost-effective option considering the functionality it provides[24].

In addition, we note that in this cost comparison we have not accounted for the very large (positive) externalities associated with Business Power relative to large scale front-of-meter alternatives (i.e. the avoidance of social and environmental costs, transmission expansion costs and greenhouse gas emission costs).

5.3 Impact on electricity prices

It is impossible to be certain about the impact of the battery-backed solar (or the rooftop PV only or battery-only) options on electricity prices. Policy makers might choose to recover some or all policy costs from taxpayers. But even if they choose to recover policy costs from consumers, the effect on prices will still be uncertain. This uncertainty can be attributed in large part to the changing context of the industry particularly the rate of new generation and storage entry and the rate of coal generation closure. Even if coal generators close at the rate their owners have said they will close them (which as noted

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[21] https://www.csiro.au/en/research/technology-space/energy/gencost

[22] Derived from cost information reported on page 76 of financial statements: https://www.stanwell.com/wp-content/uploads/Stanwell-ANNUAL-REPORT-2022-23-FINAL.pdf

[23] https://reneweconomy.com.au/fate-of-contested-hills-of-gold-wind-project-delayed-again-as-developer-fights-for-more-turbines/

[24] Business Power applications – assuming the policy support requirement of 2 kWh of storage per kW of rooftop PV, is likely to result in around 50% of solar production (i.e. the amount produced between 11am and 2pm) being transferred from the middle of the day to the evening, annually. Effectively all of the solar production from mid-autumn to mid spring is likely to be transferred to the evening and about half of the summer PV production between 11am and 2pm is likely to be transferred to the evening.

is much slower than the rate that AEMO assumes) there will still be a huge demand for new generation (and storage).

However, the evaluation has concluded that Business Power is likely to have a higher policy yield than existing renewable electricity policy; it found low implied GHG abatement costs and levelised costs that are competitive with alternatives, including existing coal-fired generation (even without counting avoided externalities). Taken together, these conclusions suggest that even if the Business Power cost is fully recovered from consumers (rather than taxpayers) the policy may be expected to pay for itself in offsetting wholesale price reductions.

5.4 The recovery of policy support costs

As discussed earlier, Business Power is motivated by several policy objectives of which the two most important are reducing GHG reductions from the electricity sector at a greater rate than would happen if the sector was left to itself; and stimulating electricity supply, particularly in the evening.

The first objective originates in Australia’s contribution to solving a global problem. This might suggest that the public in general, not electricity consumers, should pay for policy support in pursuit of this objective.

On the other hand, Business Power will benefit electricity consumers and, in this respect, consumers should pay for it, as they have for almost all renewable electricity policy support hitherto. Considering that consumers (and voters) seem to have (largely) supported arrangements for the recovery of renewable electricity policy support hitherto (or at the least do not seem to be trenchantly opposed to it) it might be suggested that Business Power payments might be recovered in the same way.

There would be many ways to recover costs from electricity consumers. We suggest the creation of a Business Power Administrator that would make floor price payments to Business Power recipients. The Business Power Administrator would then recover the cost of these payments in charges to regulated distribution network service providers (DNSPs). This could be calculated as a single region-wide price (distinguishing the regional markets across Australia) price per customer or per MWh distributed, or the charges could be specified per distributor based on the payments to the Business Power recipients served by that distributor.

5.5 Uncertainty

Finally, this discussion of the evaluation and the conclusions that arise from it, should be mindful of the unavoidable uncertainty of this analysis. The evolution of technology costs in future; the extent to which battery operators will make the most of market prices and how wholesale prices might evolve are particularly uncertain.

It also impossible to be certain how receptive building owners will be to the opportunity to develop grid-oriented batteries and rooftop PV on their premises. Some owners may particularly value the opportunity to export electricity to the grid by way of demonstrating (to their customers) contributions that they are making to their communities in the provision of clean electricity. It will also further their own emission reduction objectives. But it is not clear just how valuable building owners will consider this.

Some (probably most) Business Power participants may extract value from battery-backed solar in allowing them to reduce network demand charges and substitute more expensive grid supply for their own consumption. But again, the value that building owners see in these will vary greatly from one to the other and this will only be revealed once the policy is implemented. We have not formally accounted for this in our analysis, other than to the extent that the policy support levels implicitly assume some amount of value will be extracted through self-use of some of the capacity offered by the battery-backed solar.

We note in a recent release[25] that the Energy Network Association has called for policy support for expansion of rooftop solar in the commercial and industrial sector. To the extent the Association represents the views of its members this might suggest distributor support for Business Power. On the other hand, the Association is also lobbying for distribution level storage to be in front of customers' meters. Such preference is consistent with the incentives provided through their regulation. This might suggest that in practice at least some distributors will be ambivalent about Business Power and others might be hostile to it, as some have been to residential rooftop solar and behind-the-meter batteries. Such antipathy will require an effective regulatory response and to the extent that such response is not forthcoming, it will undermine the prospects for Business Power.

Finally, many of the calculations here are complicated and intricate. Different analytical approaches can result in different conclusions. All formulas are in the appendices and to allow detailed review of this analysis by others all data, code and post-processing is available on reasonable request.

[25] https://www.energynetworks.com.au/assets/uploads/The-Time-is-Now-Report-ENA-LEK-August-2024.pdf

6. Implementation and suggested next steps

Implementation details and next steps are suggested here.

6.1 Feed-in floor price eligibility and conditions

1. Recipients must be located in a NEM-region and their supply must be three-phase (variations of this proposal for the Southwest Interconnected System and North-West Interconnected System will need to be considered separately).
2. Minimum of 15 kW rooftop PV; no upper limit.
3. Battery (kWh) storage capacity must be at least twice the battery's continuous peak power (kW) rating, per day (i.e. "two-hour" battery).
4. Battery (power) capacity must be at least equal to rooftop PV DC inverter capacity.
5. Batteries must have a minimum storage power/energy capacity of 15kW/30 kWh. No upper limit on battery power/energy capacity.
6. Business Power floor price recipients are required to forego RET subsidies by voluntarily surrendering certificates that they may be entitled to.
7. Floor price rates are not subject to ex-post adjustment over their term.
8. Recipients are required to start production within 24 months of their eligibility for feed-in floor prices.

6.2 Payments and cost recovery

1. Floor price payments made by retailer/agent to customer, with back-to-back recovery of the gap between spot prices and floor prices charged to the "Business Solar Administrator".
2. Business Power Administrator to recover its costs in charges to be recovered from all customers through distribution network service providers.

6.3 Business Power Administrator

It is anticipated that if Business Power is to be established as a Commonwealth policy, primary legislation will be needed. The Business Power Administrator (BPA) will need to be established through this legislation. Further investigation should consider whether BPA should be stand-alone or whether the Clean Energy Regulator be tasked with the BPA's obligations. Regardless, it is suggested the legislation oblige BPA to publish an annual report which should include information on:

1. Market and customer outcomes and value for money
2. Market and non-market barriers with particular regard to the actions of regulated network service providers.

6.4 Worked example

This worked example illustrates the operation of the feed-in floor price.

- ABC Pty Ltd in Brisbane takes up the Business Power incentive for on-site solar battery and installs a 500 kW PV system and a 500kW/1,000kWh battery. ABC has very little daytime load and so self-consumes very little of its own solar. The battery shifts 1000 kWh from the day to the evening. This is equal to about half the solar system's daily production in summer and more than all of the solar system's daily production in winter.
- The $100/MWh PV floor price kicks in whenever Queensland spot prices dip below $100/MWh and the effect of this is to raise ABC's PV income in 2025 from $22.8k to $55.5k for the rooftop solar production that it exports to the grid. ABC's retailer pays $55.5k to ABC and charges the Business Power Administrator $32.7k ($55.5k-$22.8k).
- The $200/MWh Battery floor price kicks in when QLD spot prices dip below $200/MWh and the battery is discharging between 6pm and 9pm. The battery discharges fully once each day during the year and the floor price raises ABC battery's income from $128.1k to $167.2k.
- ABC's retailer (who has been contracted by ABC to operate their PV and battery) pays $167.2k to ABC and charges the Business Power Administrator $39.1k ($167.2k - $128.1k).
- The Business Power Administrator add the $32.7k and $39.1k along with all other payments in the area of supply of ABC's distribution network service provider and invoices the DNSP for this.
- The DNSP recovers the total payment to the Business Power Administrator in charges the regulator allows it to include in its regulated distribution use of system tariffs.

Appendix A. Levelised cost of electricity of rooftop solar

$$LCoE\_solar_s = \sum_{y=1}^{20} \frac{\frac{O\_solar_y}{(1+r)^y} + C\_solar_0 . A}{\frac{P_s . A}{(1+r)^y . (1+d)^y}}$$

Where,

C_solar_0	Installed cost ($ per kW) before STC subsidy	$1,168				
r	Discount rate (%)	7%				
A	Capacity (kW)	490				
d	Annual panel degradation (%)	1%				
O_solar	Operating costs (percentage of C_solar_0.A) per annum	1%				
y	Life (years)	20				
P_s	PV production (MWh p.a. per kW)	NSW	QLD	SA	TAS	VIC
		1.40	1.52	1.50	1.24	1.29

Appendix B. Volume-weighted average price (VWAP) of rooftop solar production in the NEM from 2018 to 2023

$$VWAP\_NEM_{s,y} = \frac{\sum_{i=1}^{n} (V_{s,y,i} . P_{s,y,i})}{\sum_{i=1}^{n} V_{s,y,i}}$$

Where,

s is State (NSW, VIC, QLD, SA, TAS),
y is Year (2018 to 2023),
i is the 5-minute trading intervals in year, y
$V_{s,y,i}$ is the number of 5-minute trading periods from period starting 00h00 on 1 January 2018 to period ending 24h00 on 31 December 2023.
$P_{s,y,i}$ is the 5-minute price ($/MWh) at the Regional Reference Price in each State
$V_{s,y,i}$ is rooftop solar generation (MWh) in each 5-minute period trading period

All data sourced from www.v-nem.org, originally published by AEMO.

Appendix C. Calculation of storage arbitrage margin

Passive strategy

$$AMPS_s = \sum_{d=1}^{1096} \frac{\left(DP_{s,d} - CP_{s,d}\right)}{1096}$$

$AMPS_s$ *is the arbitrage margin in state, S, assuming the passive arbitrage strategy.*

Where,

$$CP_{s,d} = \sum_{i=132}^{168} \frac{P_{s,d,i}}{36}$$

$$DP_{s,d} = \sum_{i=216}^{252} \frac{P_{s,d,i}}{36}$$

P is the 5-minute price ($/MWh) at the Regional Reference Price in each State
d is the 1096 days from 1 January 2020 to 31 December 2023 inclusive
S is State (NSW, VIC, SA, QLD TAS)
i is 5-minute trading intervals from 133(11h00) to 168(14h00) and 217(17h00) to 252(21h00) in each day, *d.*

Perfect foresight

$$AMPF_{s,d} = \sum_{d=1}^{1096} \frac{\left(DPF_{s,d} - CPF_{s,d}\right)}{1096}$$

$AMPF_s$ *is the arbitrage margin in state, S, assuming perfect foresight.*
Where,

$$CP_{s,d} = \sum_{x=1}^{24} \frac{PL(x)_{s,d}}{24}$$

$$DP_{s,d} = \sum_{y=1}^{24} \frac{PH(y)_{s,d}}{24}$$

$PL(x)$ *and* $PH(y)$ are the lowest and highest 24 5-minute prices in each day for x, y = 1 to 24
d is days from 1 January 2020 to 31 December 2023 inclusive
S is State (NSW, VIC, SA, QLD TAS)

Appendix D. Levelised cost of electricity per MWh discharged from storage

$$LCoE_{Battery} = \sum_{i=1}^{10} \frac{\frac{O\_battery_i + N_i}{(1+r)^i} + C\_battery_0 . E + \frac{RV}{(1+r)^{10}}}{\left(\frac{E * 365}{(1+R_t).(1+r)^i.(1+d)^i}\right)}.$$

Where

$LCoE_{Battery}$ is the levelised of cost of electricity, $ per MWh discharged from the battery which is assumed to be fully discharged once per day for 10 years.

$C\_battery_0$	Installed cost per kWh of storage capacity	775	$/kWh
E	Storage (Energy) capacity	490	kWh
P	Storage (Power) capacity	245	kW
i	Life (years)	10	numbe r
RV	Residual value at the end of life (% of installed cost)	30%	%
r	Discount rate	7%	%
d	Annual degradation	1%	%
R_t	Round-trip loss	15%	%
$O\_battery$	Annual operating cost (% of capital outlay)	1%	%
N_i	Network use of system charge if importing from the grid	$ 60.00	$/MWh

Appendix E. Policy evaluation: rooftop PV policy support

Net Present Value (NPV_Solar)

$$NPV\_Solar(f\_solar)_s = VWAP(f\_solar)_s * C_{solar_0} . A - \left(\sum_{y=1}^{20} \frac{O_{solar_y}}{(1+r)^y} + C_{solar_0} . A\right)$$

Policy Support as % of Revenue (PSR)

$$PSC_s\ (f\_solar = 0) = 0$$

$$PSC_s = \frac{VWAP(f\_solar)_s - VWAP(f\_solar = 0)_s}{VWAP(f\_solar)_s} * 100$$

Implied Carbon Price ($ / tCO_2-e)

$$ICP_s = \frac{(NPV\_Solar(f\_solar)_s \; - NPV\_Solar(f\_solar = 0)_s\,) * GF_s}{y.A.P_s}$$

Where:

A	Capacity (kW)	490				
y	Life (years)	20				
P_s	PV yield (MWh p.a. per kW)	NSW	QLD	SA	TAS	VIC
		1.40	1.52	1.50	1.24	1.29
GF_s	Greenhouse intensity tCO_2-e per MWh	1	1	1.3	1.3	1.3

$$VWAP(f_{solar})_s = \frac{\sum_{h=1}^{24} V_{s,h}.P(f_{solar}, h)_{s,h}}{\sum_{h=1}^{24} V_{s,h}}$$

$$P(f\_solar)_{s,h} = \sum_{i=1}^{4380} \frac{P(f_{solar}, h)_{s,h,i}}{4380}$$

$P(f_{solar}, h)_{s,h,i}$ is the higher of the 5 minute Regional Reference Price in each state, S, and f_solar (the solar floor price) which can take the value {0, 100, 130, 150} for all i in 2023 before 11h00 and after 14h00. For all other trading intervals, i in 2023, it is the Regional Reference Price in each State. All prices are adjusted from NEM-time to the local time in each State.

h takes the value 0 to 23 corresponding to the 24 hours of a day starting at 0h00 and ending at 24h00
is the 365 days in 2023

$V_{s,h}$ is obtained from the https://pvwatts.nrel.gov/ based on the latitude and longitude of the capital city in each state and using the following input assumptions:

Module Type	Standard
Array Type	Fixed (open rack)
Array Tilt (deg)	20
Array Azimuth (deg)	0
System Losses (%)	14.08
DC to AC Size Ratio	1.2
Inverter Efficiency (%)	96
Albedo	From weather file
Bifacial	No
Monthly Irradiance Loss (%)	0

Appendix F. Policy evaluation battery policy support

Gross Arbitrage Margin (GAB)

$$GAB(f\_battery)_s = \frac{(AMPS(f\_battery)_s + (AMPF(f\_battery)_{s,d})}{2}$$

Where,

$$AMPS(f\_battery)_s = \sum_{d=1}^{1096} \frac{\left(DP(f\_battery)_{s,d} - CP_{s,d}\right)}{1096}$$

$$CP_{s,d} = \sum_{i=133}^{168} \frac{P(c)_{s,d,i}.(1 + R_t)}{132}$$

$$DP(f\_battery)_{s,d} = \sum_{i=217}^{252} \frac{P(f\_battery)_{s,d,i}}{132}$$

$P(c)$ is spot price
$P(f)$ is the higher of the 5 minute price at the relevant Regional Reference Node and f if $132 < i < 252$
d is days from 1 January 2020 to 31 December 2023 inclusive
s is State (NSW, VIC, SA, QLD TAS)
i is 5-minute trading intervals ending 133 (11.05am) to 168 (2pm) and 217 (6.5pm) to 252 (9pm)
R_t is round-trip losses and takes the value of 15%

$$AMPF(f\_battery)_{s,d} = \sum_{d=1}^{1096} \frac{\left(DPF(f\_battery)_{s,d} - CPF_{s,d}\right)}{1096}$$

Where,

$$CP_{s,d} = \sum_{x=1}^{24} \frac{PL(x)_{s,d}}{24}$$

$$DPF(f\_battery)_{s,d} = \sum_{y=1}^{24} \frac{PH(y, f\_battery)_{s,d}}{24}$$

$PL(x)$ is the lowest 24 (x = 1 to 24) 5 minute prices in each day
$PH(y, f_battery)$is the higher of each of the 24 (y = 1 to 24) highest 5 minute prices, and $f\_battery$, for each day
d is all days from 1 January 2020 to 31 December 2023 inclusive
s is State (NSW, VIC, SA, QLD TAS)
$f\_battery$ can take the value {0, 100, 200, 300, 400}

Net Present Value (NPV)

$$NPV(f\_battery)_s = GAB(f\_battery)_s * E - LCoE_{Battery} * \sum_{i=1}^{10}\left(\frac{E * 365}{(1+R_t).(1+r)^i.(1+d)^i}\right)$$

Policy Support as % of Revenue (PSR)

$$PSR(f\_battery)_s = \frac{(NPV(f\_battery)_s - NPV(f\_battery = 0)_s +}{NPV(f\_battery)_s + \sum_{i=1}^{10}\frac{O_i + N_i}{(1+r)^i} + C_0.E + \frac{RV}{(1+r)^{10}}} * 100$$

Appendix G: Policy evaluation battery+rooftop PV policy support

NPV

$$NPV(f\_solar\_battery)_s = NPV(f\_battery)_s + NPV\_Solar(f\_solar)_s$$

Policy Support as % of Revenue (PSR)

$PSR(f\_solar\_battery)_s =$

$$\frac{NPV(f\_solar\_battery)_s - NPV(f_{solar} = 0)_s - NPV(f\_battery = 0)_s}{NPV(fsolar\_battery)_s + \sum_{y=1}^{10}\frac{O_y + N_y}{(1+r)^y} + C_0.E - \frac{RV}{(1+r)^{10}} + \sum_{y=1}^{20}\frac{O_y}{(1+r)^y} + C_0.A}$$

Implied Carbon Price (\$ / tCO_2-e)

$ICP(f\_solar\_battery)_s =$

$$PSR\left(f_{solar_{battery}}\right)_s . \frac{NPV(f_{solar})_s + NPV\left(f_{battery}\right)_s + \sum_{y=1}^{10}\frac{Oy + Ny}{(1+r)^y} + C_0.E - \frac{RV}{(1+r)^{10}} + \sum_{y=1}^{20}\frac{Oy}{(1+r)^y} + C_0.A}{10.E + 20.A.P_s}$$