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## David Newbery

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# Wind, water and wires: evaluating joint wind and interconnector capacity expansions in hydro-rich regions

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**Abstract**
Countries or regions with a high share of storage hydro and good renewables resources may be able to interconnect to less well-endowed neighbours. To maximise joint benefits, coordinating interconnector and renewables investment is desirable. Suitable long-term contracts ensure that beneficiaries pay and jointly cover the highly dispersed costs and benefits. The article develops a simple model calibrated for Tasmania that demonstrates how this can be quantified and various counterfactuals tested. The key to the simplification is that the value of water is both stable over time and the key driver of outcomes. The economic attraction of proposed wind and interconnector investment depends sensitively on the value placed on $CO_2$ reductions.

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## 1. Introduction

Renewable electricity will be decisive for decarbonising electricity in non-nuclear countries. Integrating variable or intermittent renewables like wind or solar PV creates challenges for managing system security, capacity adequacy, and modelling system needs. Peak to average outputs range from 3 or 4:1 for wind to 4-10:1 for PV. High penetration risks spilling a large surplus unless it can be stored or exported to regions with non-coincident renewable output. Battery electric storage typically buffers for 0.5-4 hours at considerable capital cost, pumped hydro storage can buffer from 8-24 hours at even higher capital cost (and with limited future potential). Building interconnectors to sufficiently non-correlated regions is similarly expensive (Newbery, 2018). In all three cases modelling the system requires detailed hour-by-hour modelling, accounting for the state of storage and/or capacity to inject/export (as in Newbery, 2021a and LaRiviere & Lyu, 2022).

The one case where intermittency is unimportant and modelling the impact of high wind/PV penetration becomes dramatically simpler is where the country or region has an abundance of storage hydro-electricity and good renewables resources. Hydro storage offers 2,700 times global pumped storage capacity, which in turn has nearly 200 times as much capacity as battery electrical storage.[2] This article shows how a wind and hydro-rich region or country can efficiently manage renewable intermittency and offer decarbonisation benefits to its neighbours by investing in both wind and interconnection capacity. There has been considerable interest in whether Tasmania (an Australian state) should invest massively in both wind and interconnection to the state of Victoria, in its "nationally significant *Project Marinus* (an interconnector) and *Battery of the Nation* projects." (Tasmanian Government, 2020). This ambition has been strongly criticized by Mountain (2021) as an expensive way of

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[2] IEAS (at https://www.iea.org/reports/energy-storage ) records 17 GW of installed battery capacity in 2020, which at optimistically 1MWh/MW compares with nearly 3,000 GWh in pumped storage and 2,150 TWh behind dams (the latter two figures for 2016 in Newbery, 2018).

providing unnecessarily long-duration storage when cheaper mainland batteries could meet local requirements at much lower cost. Norway's rich hydro resources have similarly been termed a "Battery for Europe" (Censes, 2013), again with some dissent (Moe et al., 2021). The argument here is not that Tasmania or other hydro-rich regions can displace "batteries" located in their neighbours, but that their hydro resources allow them to provide *local* storage to allow massively expanded intermittent renewables capacity, provided they can export the resulting surplus and hence reduce $CO_2$ emissions in the neighbour (Yang, 2020). This article demonstrates how this may be achieved and how to quantify the costs and benefits of so doing.

The key to the simplification is that stored water in the dams sets a uniform price of water even with complex hydrology and many different dams, as at any moment the hydro generation can be sourced optimally and water values equated (assuming, as is common, that the system is energy, not instantaneous capacity constrained). Given adequate export capacity (explored in this article), intermittency is no longer a problem, so that the main determinant of equilibrium volumes and prices is annual production, avoiding the need for hourly simulation of flows into and out of storage. This article sets out a simple spreadsheet model that can give a quick estimate of the impacts of investments in wind and interconnector capacity. It illustrates the considerable simplification this combination of wind and water can provide to understanding system behaviour, in contrast to the rather black box nature of more sophisticated modelling. It offers transparency for an otherwise rather complex system in which uncontrolled variability poses considerable modelling challenges.

The Tasmanian case is also instructive as its proposed investments would have to overcome a variety of obstacles if it were to rely solely on liberalised market incentives. The viability of investing in more wind depends on the ability to export that wind, while the profit of the proposed interconnector depends on investing in more wind and lowering local prices. Both depend on receiving adequate reward both for the carbon displaced on the mainland and any increased mainland consumer benefits from lower prices, which in turn depend on efficient pricing in the wholesale market and for transmission. These are not inconsiderable obstacles, compounded by ownership fragmentation, multiple jurisdictions, and extensive market power (Bell et al., 2017). Both investments will either need long-term contracts or state underwriting/ownership to overcome these obstacles in Australia. This article shows how to estimate these co-benefits in a simple spreadsheet model that determines the overall benefits and their distribution between various parties to provide guidance on how beneficiaries might collectively finance the investments.

The economics literature on integrating hydro, renewables and interconnection is rather sparse, with most studies examining how to optimise hydro and renewables within an existing area without considering further interconnections (e.g. Huang et al., 2021; Gupta et al., 2019). There is a related and more extensive literature on interconnector economics with increasing renewable generation (LaRiviere and Lyu, 2022; Spiecker et al., 2013; and Yang, 2020), but that is tangential to the concern of this article. NREL (2011, xii) is a useful source of illuminating case studies, including Tasmania, which concludes that "Interconnecting to the Australian mainland, via the addition of the high-capacity HVDC interconnection, significantly increases the ability to integrate wind generation in Tasmania without a negative effect on the energy in storage." The report concludes "In summary, while hydropower systems possess special characteristics and operating constraints, the inherent flexibility of their generators and the potential for energy storage in their reservoirs make them well suited to integrate wind into the power system. As wind penetration increases, the agile hydro generation can address wind integration impacts and this service represents an economic opportunity for many hydro generators." NREL (2011, xv).

## 2. Supporting and integrating variable renewable electricity

Most renewable electricity comes from wind and solar PV, both of which are variable and intermittent, and will need tailored long-term contracts to deliver efficient volumes at an acceptable cost of finance. Part of the justification of providing such support is the carbon displaced by their output, unless this benefit is reflected in an adequate carbon price on fossil generation (LaRiviere & Lyu, 2022). Both wind and PV investments create learning externalities that lower future costs, justifying additional support. Clubs of willing members, such as the European Union with its *Renewables Directives*,[3] or more widely, *Mission Innovation*,[4] may set renewable targets for members in a burden-sharing agreement, and members may then deliver the required support by auctioning contracts to meet the agreed targets.

The contract that offers the lowest cost of capital requires revenue stability and predictability, typically by setting a strike price in a contract-for-difference, CfD.[5] For renewables these are typically based on metered output (to account for the variability of output) for a fixed number of years. Without modification this contract has the undesirable property of incentivising renewable generation to produce even when the wholesale price is below avoidable cost.[6] An efficient support design would avoid this by offering a CfD for an amount highly correlated to local expected output (e.g. forecast wind at that location), but independent of actual metered output. Output decisions would then be based on the market, not the strike price. Efficient location would be delivered by contracts measured not in calendar time but in MWh/MW capacity (i.e. full operating hours, see Newbery, 2021b). In what follows we assume that wind contracts have these required efficiency elements and that markets are competitive, so that their dispatch is driven by efficient wholesale prices. Carbon benefits will require separate evaluation, considered below.

As noted above, variable/intermittent renewable electricity (VIRE) like wind and solar PV have peak output many multiples of their average output, and so risk being in surplus as penetration increases. Hydroelectric dams can release water when VIRE is low, and retain it when VIRE is high, and this could in the case of e.g. Norway and Tasmania, buffer significant levels of VIRE penetration. Dams cannot deal with surplus VIRE (output above demand), but it can be exported. To add to this challenge, VIRE can experience sustained periods (9+ hours) of very low output, requiring alternative energy sources. If fossil generation is to be reduced, that implies either storage (only pumped storage and dams

[3] EC, 2009 and Regulation EU/2018/1999
[4] see http://mission-innovation.net/
[5] A standard CfD specifies an amount, $M$, a strike price, $s$, and a relevant market price, $p$. The issuer of the CfD then receives (or pays) $(s-p).M$, from the purchaser. Depending on $s$ and $p$, the issuer may sell or the purchaser may be willing to pay for the contract.
[6] See extensive references to the literature in Newbery (2021b), and Lamp and Samano (2020).

suffice for these time scales) or imports. Figure 1 illustrates sustained high and low wind output for Tasmania.[7] Building more interconnectors is therefore likely to be an important complement to handling increased VIRE penetration in hydro-rich countries.

In liberalised electricity markets the commercial viability of a merchant interconnector may undervalue its economic value for several reasons. The first is the problem of lumpiness – sub-sea DC interconnectors are typically large (500-750 MW is common for a single line, Britain's recent interconnectors are 700-1,000 MW each). Merchant developers rely on congestion revenue (from price differences across the link). If scale restricts the number of links, the developer will have an incentive to undersize the link to increase price differences. The lumpiness or minimum economic scale can deter competitive entry and unless addressed grants monopoly power to the developer (Brunekreeft et al., 2005, 2006).

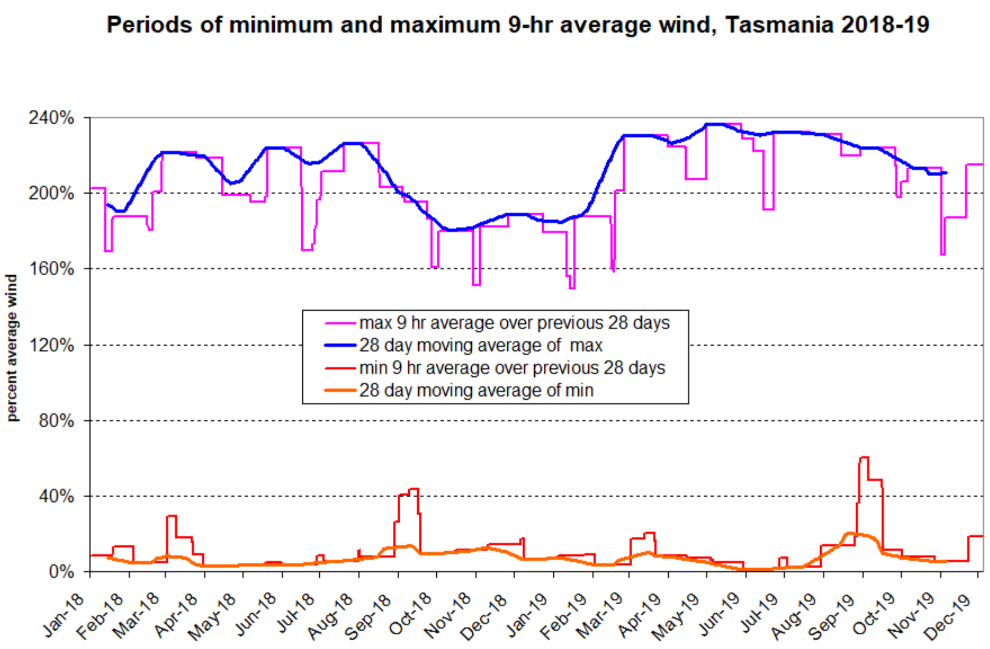


Figure 1 Periods of sustained high and low wind in Tasmania
Note: The highest and lowest outputs over a 9-hr period in a rolling 28-day period are shown as a percent of average wind output.
Source: wind traces from AEMO, average of Musselroe, Bluff Point and Cattle Hill

Second, both ancillary service and congestion revenue depend sensitively on future regulatory and policy changes (e.g. future carbon pricing, network charges, extent of VIRE support and hence penetration). Merchant investors faced with such policy risk require high returns that may make socially desirable investments unattractive. In such cases future policy uncertainty requires some regulatory guarantees to reduce the weighted average cost of capital (WACC) to a level that makes such a durable investment financeable. Thus in the UK, the regulator, Ofgem, may offer a cap and floor to the rate of profit, ensuring that the minimum average annual revenue is no lower than the floor, and taxing away some fraction

[7] The basic graphs show discontinuities as the previous minimum or maximum drops out of the 28-day window, while the centred 28-day averages smooth the series.

(up to 100%) of average revenues above the cap. For normal network investments Ofgem applies a Regulatory Asset Base (RAB) model. The developer or monopoly network owner proposes a business plan for the new investment. Ofgem, after careful scrutiny and negotiation, agrees the investment amount to enter the RAB and the WACC that it will be allowed to receive through the allowed revenue on the current value of the RAB. Each year the RAB is incremented by the allowed investment and decreased by depreciation.

The RAB model is increasingly seen as a useful model for capital-intensive decarbonisation projects, most recently the next proposed nuclear power station in Britain.[8] This is relevant as Basslink went into administration on November 12, 2021. "APA has purchased an interest in the debt of Nexus Australia Management Pty Ltd, the borrowing entity for Basslink. … Should it manage to do so, APA plans to work with stakeholders, including Hydro Tasmania, the state of Tasmania and the Australian Energy Regulator to convert Basslink to a regulated asset."[9]

In the case of connecting a wind-rich region to a fossil-rich region, carbon pricing or its lack may be a critical and problematic determinant of commercial viability (Yang, 2020; LaRiviere and Lyu, 2022). The Australian experience of introducing and then removing a carbon price is just one example. The EU Emissions Trading System has witnessed highly volatile carbon prices lacking (until recently) future credibility. The UK introduced a Carbon Price Floor designed to escalate electricity fossil fuel carbon prices steadily for 19 years but froze it just two years after implementation. Providing investible credibility to a future carbon price remains a largely unsolved problem.

Third, the value of the interconnector is likely to depend on future wind investment (and competition from possible pumped storage schemes), while the economics of wind investment depend critically on the management of surpluses and shortfalls that will be impacted by the amount of interconnection. Coordinating across network, generation, storage and interconnection investments can be hard to decentralise in a liberalised market, given the durability of all of these assets. Bell et al. (2017) argue that this is particularly the case with the very fragmented asset ownership structure in Australia. Again, some form of government or credible counter-party cross-guarantees are likely to be necessary, with the default a regulated interconnector (the preferred European Union model). Similarly, the benefits of an interconnection or link in a complex meshed network can accrue far from the site of the investment, and depend in hard-to-predict ways on all future investments in generation, networks, and load development. While System Operators and consultants can (and do) develop scenarios of future system development and perform social cost benefit analyses for each scenario, the risk facing a private developer not knowing which scenario will develop again raises the WACC. (Bell et al., 2017, use simulations from the 'Australian National Electricity Market' (ANEM) model in their calculations.) Even knowing how other parts of the system will develop is of little comfort if there is no credible way of requiring future beneficiaries to pay.

[8] https://www.newcivilengineer.com/latest/sizewell-c-funding-model-behind-tideway-to-be-used-on-20bn-nuclear-plant-07-07-2021/

[9] https://renewablesnow.com/news/apa-buys-debt-interest-in-tasmania-victoria-link-interested-in-acquiring-asset-762335/

It can be helpful to present the issues that arise in considering interconnection investment in a simple model, while recognising that any investment decision will need a far more fully articulated model to simulate the impact of any interconnector on flows and prices. This article develops such a model to gain some sense of the relative importance of the various issues that arise in liberalised electricity markets and to estimate the reduction in $CO_2$ from the ability to export VIRE to a more carbon-intensive neighbour. Similarly, Yang (2020) develops a simple model of interconnecting "clean" and "dirty" countries, calibrated for various pairs of European countries, to show how carbon impacts depend critically on the price of carbon, but without considering the role of large-scale storage hydro.

## 3. The importance of hydroelectricity

A surprising number of countries (36) provided more than half their generation from hydroelectricity in 2015.[10] Most are relatively undeveloped and this share will fall as electricity demand grows. In Europe, Norway, Iceland, Austria and Switzerland have more than half their generation from hydro (listed in order of the share of hydro generation), while eight countries in Latin America have more than 60% hydro, of which the largest are Brazil, Paraguay, Colombia and Venezuela (ranked in order of hydro generation). Figure 2 shows the top nine countries by total hydro generation and their shares in generation. Thus Paraguay has 100% hydro (shown as 100 on the left axis) and all have over 50%.

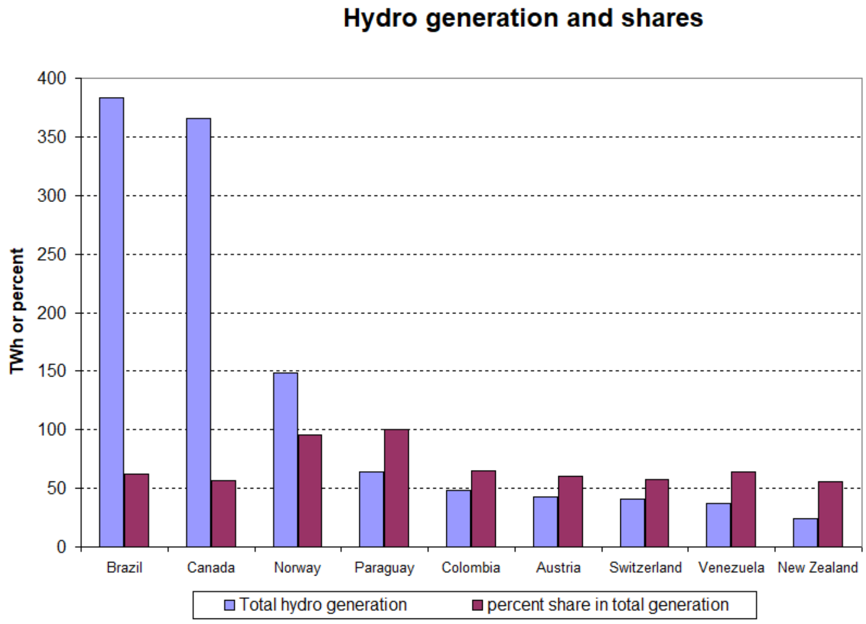


Figure 2 Top nine countries by hydro generation with their hydro share of generation
Source: World Bank and IEA

Some of these countries and islands are connected to neighbours with lower or little hydro resources. Others (China, Canada and the US) have massive hydroelectric capacity where the main issue is investing in more domestic interconnection, as in Texas (LaRiviere and Lyu, 2017). China's rapid wind expansion increasingly requires better connection to

[10] https://data.worldbank.org/indicator/EG.ELC.HYRO.ZS

storage such as the massive Three Gorges Dam.[11] Colombia is at an early stage of interconnecting with neighbouring countries, with 285 MW interconnection to Ecuador and 290 MW to Venezuela (Romero and Dow, 2017). A 400 MW connection to Panama was recently (July 2021) announced.[12]

## 4. The case of Tasmania

Tasmania is unusual in providing 100% renewable electricity from hydroelectricity and wind, although in some years a small amount of gas-fired generation is generated, as figure 3 shows for the year beginning 29 August, 2020. Tasmania is of particular interest as the Australian Government is considering a new interconnector project, *Marinus*, two 750 MW subsea DC links to Victoria. Tasmania already trades with Victoria over the 500 MW DC Basslink, typically importing cheap power overnight and exporting during peak hours. Basslink provides security against drought conditions, although it has recently (early 2018) experienced a long period of outage, during which Tasmanian scarcity prices reached high levels. Figures 3 and 4 show that imports and exports play an important role in balancing supply and demand. While trading is driven by price differences, annual variations in rainfall are also important: in 2019 imports were considerably larger than exports, and conversely in 2018.

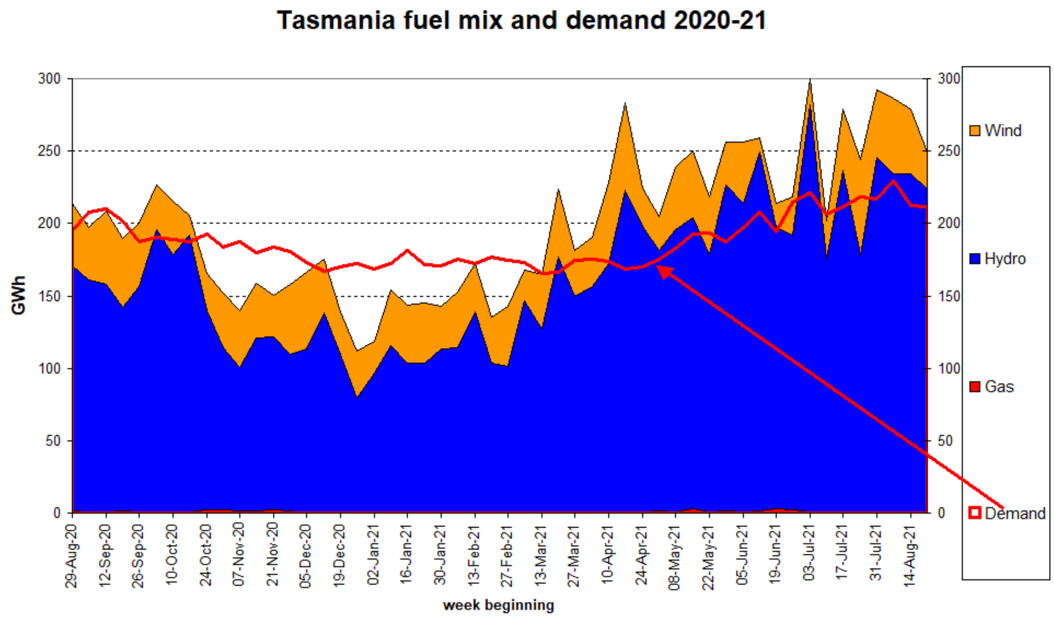


Figure 3 Weekly averages of generation by type and demand, 2020-21.
Source: AEMO at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/data-dashboard

Figure 4 shows the recent evolution of exports (negative values are imports) and demand in Tasmania. Demand and imports are clearly correlated at this weekly resolution.

[11] https://www.offshorewind.biz/2021/12/27/breaking-china-three-gorges-connects-3-1-gw-of-offshore-wind-capacity-in-one-day/
[12] At https://www.bnamericas.com/en/news/governments-of-colombia-and-panama-sign-an-agreement-that-establishes-the-principles-of-the-regulatory-scheme-for-electrical-interconnection-between-the-two-countries

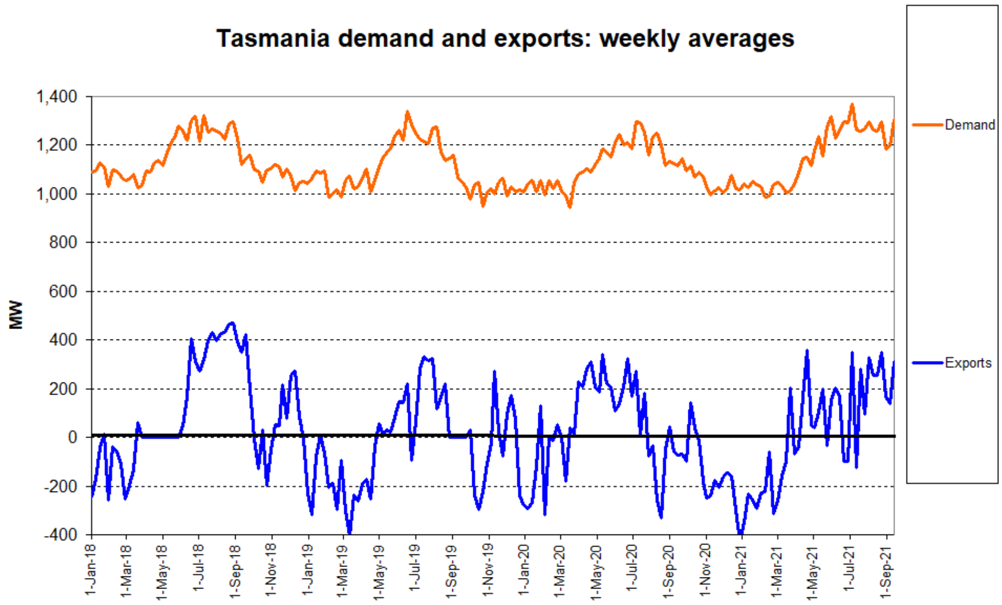


Figure 4 Tasmania domestic demand and net exports, 2018-2021, weekly averages
Source: AEMO data dashboard. Note imports are shown as negative exports.

In July 2021 hydro accounted for 85% of supply, wind 15% and net exports amounted to 8% (*Tasmanian Energy Security Monthly Dashboard August 2021*). The recent evolution of storage is reproduced in Figure 5.

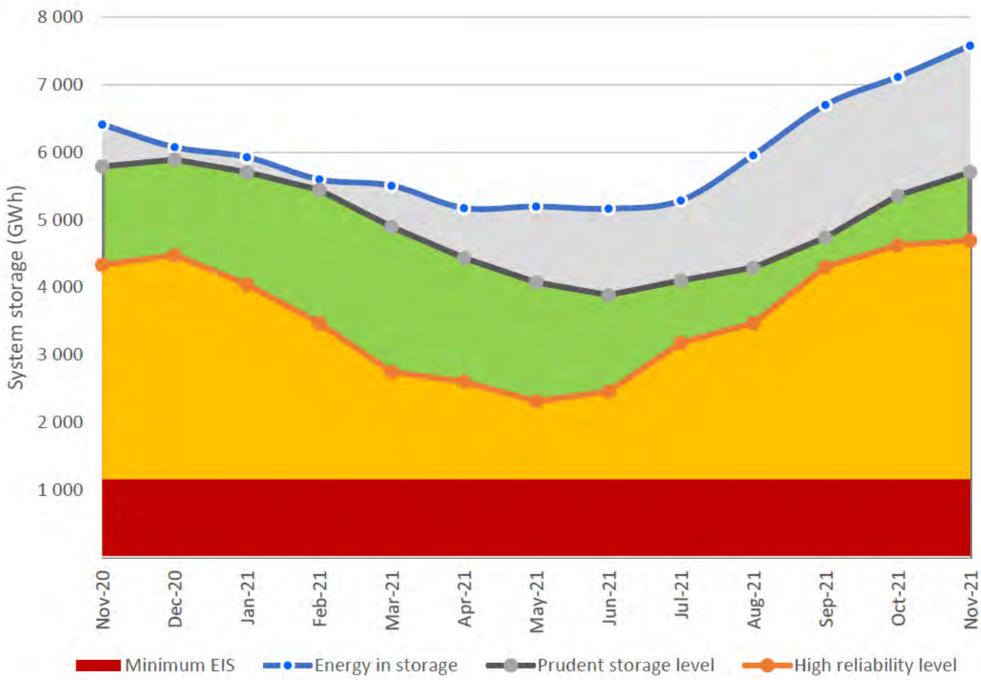


Figure 5 Energy in storage (mainland Tasmania) 2020-21 water year
Source: Energy in *Tasmania Annual Security Review 2020-21 water year* at [https://www.economicregulator.tas.gov.au/electricity](https://www.economicregulator.tas.gov.au/electricity)
Note: The minimum energy in storage (EIS), known as the Great Lake Extreme Environmental Risk Zone, is the level at which extreme risks to aquatic biota and their environment can be avoided.

## 5. A simple model of wind, water and interconnection

Tasmania offers a good example of an isolated region rich in storage hydro and wind resource connected to another region relatively poorer in both, and in the case of Victoria, heavily dependent on brown coal for generation. Thus in calendar 2018 the average capacity factor for three main wind sites[13] in Tasmania was 38% while for two[14] in Victoria it was 28%. The hourly correlation between the two aggregates for the year is only 25%, suggesting that there would be benefits of sharing the wind resource over an interconnector. Bell et al. (2015, table 6) explore correlations more deeply and find that 5-minute correlations between nodes within Tasmania are mostly 90%, and the same nodes have correlations with Victorian nodes of between 40% and 70%. Half-hourly wind correlations between Victorian and Tasmanian wind between 2020 and 2012 were considerably higher at 68% although Tasmanian wind has a low (3% to -5%) correlation with Victorian demand, and it is this correlation that is more relevant for trade. The annual average capacity factor for the oldest windfarm in Tasmania (2017-2021) was 40% with a standard deviation of 2.7%, with 2018 an average year. The average carbon intensity of generation in Victoria in 2018-19 was 0.89 tonnes $CO_2$/MWh.[15] As Tasmania can (with modest additional investment) generate entirely carbon-free electricity, an extra MWh of exported wind could displace this volume of $CO_2$.

Total net exports from Tasmania are pre-determined by total supply less demand: $X – M = W + H – D$, where $X$ is exports, $M$ is imports, $W$ is wind, $H$ is hydro and $D$ demand, all per year. Thus if Tasmania installs additional wind (or solar PV),[16] and as a result increases annual wind output by 1 GWh, it could displace 890 tonnes $CO_2$. In the brief period that Australia has a $CO_2$ tax, in 2012 its level was $A23/tonne. By September 2021 the EU ETS price was around €60/tonne ($A94/tonne), within the Paris target-consistent range. At this latter figure, 1 GWh of extra exported Tasmanian wind would deliver carbon benefits of $A83,000/GWh, at least until coal is phased out or is no longer at the margin. Crucially and quite generally, as wind and hydro output are exogenously determined (by weather), their carbon credit is just driven by $W + H – D$ and hence independent of market conditions.

The main problem with increasing wind penetration is its variability, where both surplus and shortage create problems without the ability to even out supply via storage and trade. Suppose that all Tasmanian hydro can be considered as a single dam,[17] with full capacity of 14,500 GWh,[18] and we take the pattern of hourly wind output and demand for the electricity year 2018-19 as representative.[19] 2018-19 domestic demand was 9,905 GWh,[20] so

[13] Musselroe, Bluff Point and Cattle Hill. These are from the published wind traces that attempt to measure potential output at these sites. Cattle Hill was not commissioned until 2021.
[14] MacArthur and Wagga Wagga.
[15] From Victorian *Greenhouse Gas Emissions Report 2019* and Australian Energy Statistics, Table O
[16] Tasmania has very modest plans for solar PV (17.5 MW because of its poorer resource) while the mainland has a comparative advantage in PV.
[17] This is a reasonable assumption in an integrated system as the value of water in each dam should be equated (Førsund, 1993).
[18] The actual volume is 14,437 GWh for the Great Lake EERZ (*Tasmanian Energy Security Monthly Dashboard Jan 2021*).
[19] The year runs from July 1 to June 30 and ends before the pandemic impacted demand (although *Energy in Tasmania Report 2019-2020* shows little change in demand from the previous year).
[20] NEM data are lower than *Energy in Tasmania Report 2019-2020* data, which appears to include embedded generation (mostly PV).

full capacity was apparently nearly 18 months' demand, but as the dams appear to operate in the range 25-50% full, usable storage varies from about 4½ to 9 months' storage.

In 2018-19 Tasmania had 308 MW of installed wind capacity, but plans to expand this to 3,927 MW (Tasmanian Energy Regulator, 2020), over 12 times the 2018-19 level taken as the baseline. To examine the impacts of expanding wind and increasing export capacity, the simulations reported below consider the effect of scaling up every hour of 2018-19 observed wind output by a factor of between $n$ = 3 and 6 to cover the first stages in the expansion plan (Marinus 1 of 750 MW) and then from 6 to 12 to cover Marinus 2 (an additional 750 MW). While simple scaling may overstate the potential of new sites, it appears that most expansion is in similar areas to the existing farms modelled.

Figure 6 shows two residual demand curves, $r$ where $r = d - w$ ($d$ = demand, $w$ = wind, hourly levels are lower case, capitals denote annual aggregates). The wind resource, $w_r$, is a measure of the wind resource potentially available (measured as the average potential capacity factor in each hour at the three wind farms extant in 2018-19). The available wind, $w_a$, is the amount that is potentially profitable. If the local price falls below the avoidable cost of wind generation (€5-12/MWh according to BEIS, 2020; NREL, 2018, taken here as $s$ = $A10/MWh), then efficiently wind output should be set to zero (by buying replacement power ahead or through regulation-down actions in the balancing market).

The key driver of trade over the interconnector is the value of water, $v$. In the case of Tasmania it is reasonable to assume that the volume of storage is sufficiently high that the value of water is both well-defined and stable over reasonable time periods and that wind capacity is sufficient that there should be little risk of running out of water. In more complex hydro systems with a significant risk of hydro shortages, valuing water is a complex stochastic dynamic optimization problem (Philpott et al., 2016).

It is profitable for Tasmania to export if the export price (that is, the Victorian price, $P$, less the cost of any transmission losses) is above the value of water, in which case Tasmania should export at full interconnector capacity, $K$. The amount of wind that can be dispatched is available wind up to demand, $d$, plus export capacity, $K$, (i.e. $w_a \leq d + K$). If $w_a > d + K$, then $d + K - w_a$ will be spilled, and dispatched wind, $w$, will then be $d + K$, so $w = \text{Min}(w_a, d + K)$. The amount of hydro generation, $h$, will be $h = d + x - w$. The amount of wind spilled, $w_s = w_a - w$, is shown as area A, the triangle between $d - w_r$, the Basslink constraint (dotted) and the y-axis (as $w_a$ depends on unobserved prices, the graph shows $w_r$ which for $n$ = 3 is the same as $w_a$). Without Basslink, the much larger area B that goes up to the x-axis at $r$ = 0, would be spilled. The graphs show 2018-19 hourly demand[21] from which is subtracted hourly wind output for 2018-19 scaled by factor $n$ = 3 or 6, and then ranking the resulting series from highest to lowest to give duration curves.

The highest residual demand occurs when wind is negligible (either through voluntary curtailment or lack of wind), so all curves start from a similar point on the $y$-axis. They increasingly diverge as the wind scaling factor $n$ amplifies the difference in wind. Figure 6 also shows $K$ = -500 MW as a dotted line representing the export capacity of Basslink (with Marinus the constraints would not bind except for a few hours). Consider the case of $n$=6,

[21] NEM hourly demand data for Tasmania was scaled up by a factor 1.04 to give the total annual demand recorded in Tasmania Economic Regulator (2020)

where $d\text{-}w_r < -500$ for 476 hours, at which point it is spilled, so that actual wind dispatched just meets the export limit, as shown.

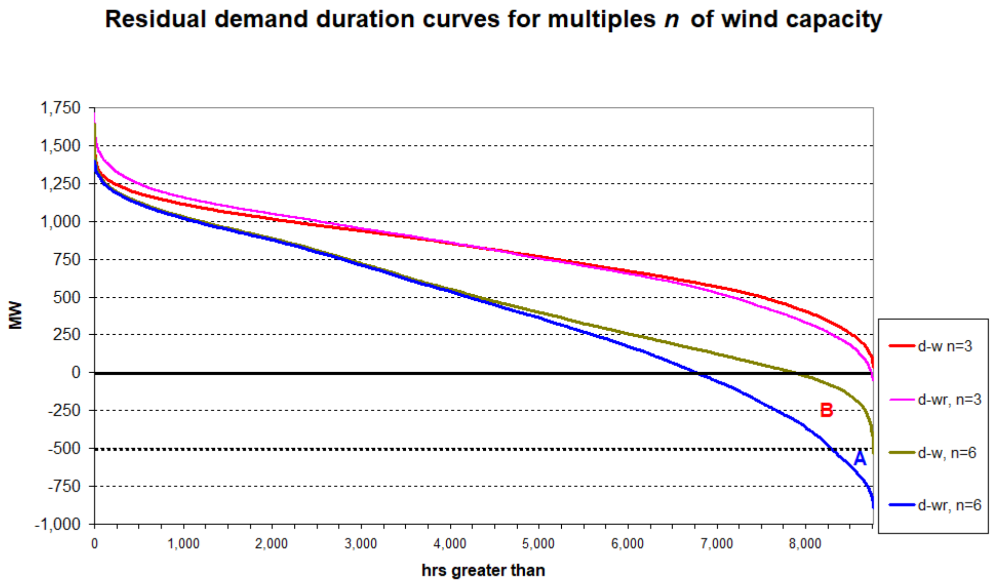


Figure 6 Duration curves for wind less demand for varying ratios of wind capacity.
Source: AEMO data dashboard

The area between the *d-w* curves and the $y = 0$ axis (in bold) is the shortfall between wind and demand and is met by imports or drawing down hydro, depending on the local price relative to the value of water.

5.1 *Modelling interconnection*

The aim is to model an efficiently operated interconnected market of two regions, exemplified by Victoria and Tasmania. Efficient Victorian prices will be equal to the marginal cost of generation. Efficient trade requires the markets to be coupled, in which bids and offers in both markets are cleared in a single auction, with prices equated if trade is unconstrained, and otherwise different. Actual price differences will depend on market design, bidding behaviour and the exercise of any market power, which this discussion assumes is adequately addressed and can be ignored. Bell et al. (2017) argue that market power is particularly problematic in Australia.

Many countries or regions with rich hydro resources are connected to fossil-based neighbours, and in some cases are synchronised with their neighbours, as in the European Union. To a first approximation losses in moving surplus power from the hydro-rich to hydro-poor areas in contiguous regions might be low enough to be ignored. While this is not the case for Tasmania, a model examining lossless links provides a simple insight into the drivers of trade in the more realistic lossy connection case. For key impacts losses turn out to be less significant than might be expected.

In the simplest version the impact of any change in trade is assumed to have no impact on prices on the mainland. The next step is to allow for losses while still holding mainland prices constant. The third step is to quantify impacts on mainland prices assuming no losses. If losses make little difference (as will be shown to be the case) then there may be little need for the final and most complicated step, to allow for losses *and* for changes in predicted trade to impact on prices on the mainland. This sequence has the advantage of illuminating the role of each relaxation of the simplifying assumptions and their significance.

As noted above, the key driver of trade over the interconnector is the value of water, $v$. With no losses, the price in Victoria, $P$, will be the same as the price in Tasmania, $p$, provided the interconnector is unconstrained. If $p$ falls below the avoidable cost of wind generation (taken as $s$ = \$A10/MWh as referenced above), then it is efficient to curtail (not dispatch) the wind. If, as assumed, wind output decisions are based on market prices at the margin (not subsidy or contract prices), then wind farms will voluntarily cease producing: if in any hour $p < s$ then $w_a = 0$ in that hour. If $P > v$, then Tasmania will export wind and hydro at full capacity of the interconnector, so $P > p = v$ (the value of water as hydro is unconstrained). If $P < v$, Tasmania imports its residual demand (demand less wind) up to the full capacity of the interconnector, $p \geq P$. If imports are constrained, then hydro will make up the shortfall and $p = v$. If wind is in surplus, $(0 < w_a - d < K)$, the surplus can be exported without constraint, and $p = P$. (Appendix A defines all the variables and provides equations for calculating the results.) If there is surplus wind after exporting up to capacity, $(w_a - d > K)$, then it will need to be spilled at $p = s$ (as shown in Figure 5) until such time as Tasmania builds enough pumped storage.[22]

Available wind, $W_a$, is the available wind resource, $W_r$, less curtailed wind, $W_c$: $W_a = W_r - W_c$. Dispatched wind, $W=\sum w$, will be available wind less that spilled $W_s$: $W = W_a - W_s$. Net exports are pre-determined by supply less demand: $X - M = W + H - D$, where $X$ is exports, $M$ imports, $W$ is dispatched wind, $H$ is hydro and $D$ demand, all aggregated over the year.

Table 1 shows the results of simulating equilibria for different levels of interconnector capacity, $K$, and wind resource, $W_r$. Table 1 provides the data for the subsequent cost-benefit analyses shown in later tables. The wind potential is taken as varying multiples, $n$, of 2018-19 potential wind, so that in each simulation $W_r = nW_{r,0}$, where $W_{r,0}$ is potential wind in 2018-19.[23] In the first simulation different levels of trade are assumed to have no effect on the wholesale price of electricity in Victoria. The first section of Table 1 gives the assumed interconnector (IC) capacity (500 MW at present, 1,250 MW after Marinus 1 is commissioned, rising eventually to 2,000 MW), and the annual levels of the quantity variables, $D$, $H$, and $W_r$. The model can be solved in a simple spreadsheet using a range of IF statements (see Appendix A), such as IF($h > 0$) then the Tasmanian price is set equal to the value of water: $p = v$. Tasmania will export if $P \geq v$ and otherwise import, as explained above. The spreadsheet then solves for $X$, $M$, $W_s$, while $W_c$ is determined by $p$, set as the import price if $P < v$.

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[22] "On 15 December 2020, the Minister for Energy announced that Cethana was the preferred pumped hydro site and work will be progressed on this site." (Tasmanian Government, 2020 and https://www.cradlecoast.com/lake-cethana-pumped-hydro-energy-storage-phes-project/.) Pumped storage is costly to build and only makes sense if there is sufficient spilled wind.

[23] Properly it should be aggregated over the sites of the proposed new wind farms, but most of their locations are near existing wind farms. Given information about likely commissioning dates and sites it would be simple to update the potential aggregate hourly wind output.

The value of water is shown in the lower panel, together with the demand- and time-weighted Tasmanian price, the Victorian price, congestion revenue and wind profit.

Table 1 Solutions for varying levels of wind and interconnector capacity

| wind multiplier | 1 | 1 | 3 | 3 | 4 | 4 | 6 | 6 |
|---|---|---|---|---|---|---|---|---|
| IC capacity, K, MW | 500 | 1,250 | 500 | 1,250 | 500 | 1,250 | 1,250 | 2,000 |
| Demand, D, GWh/yr | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 |
| hydro, H, GWh/yr | 9,681 | 9,681 | 9,681 | 9,681 | 9,681 | 9,681 | 9,682 | 9,680 |
| wind resource, Wr, GWh/yr | 1,105 | 1,105 | 3,315 | 3,315 | 4,420 | 4,420 | 6,630 | 6,630 |
| spilled, Ws, GWh/yr | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| curtailed wind, Wc, GWh/yr | 11 | 11 | 33 | 33 | 45 | 45 | 67 | 67 |
| dispatched wind, W, GWh/yr | 1,094 | 1,094 | 3,282 | 3,282 | 4,375 | 4,375 | 6,563 | 6,563 |
| H+W-D=X-M | 494 | 494 | 2,681 | 2,681 | 3,776 | 3,775 | 5,964 | 5,962 |
| exports, X, GWh/yr | 2,437 | 5,160 | 3,498 | 5,810 | 4,056 | 6,227 | 7,402 | 8,297 |
| imports, M, GWh/yr | 1,943 | 4,666 | 817 | 3,129 | 281 | 2,452 | 1,439 | 2,335 |
| water value, v, $A/MWh | $89.2 | $96.7 | $64.2 | $91.4 | $45.0 | $88.3 | $80.1 | $98.5 |
| Demand-wt price, $A/MWh | $89.2 | $80.6 | $63.6 | $78.2 | $44.6 | $76.7 | $71.7 | $81.5 |
| time-wt price, $A/MWh | $89.2 | $79.6 | $63.5 | $77.5 | $44.5 | $76.0 | $71.1 | $80.7 |
| Victorian price | $109.8 | $109.8 | $109.8 | $109.8 | $109.8 | $109.8 | $109.8 | $109.8 |
| Congestion revenue $A million/yr | $197 | $347 | $234 | $358 | $298 | $373 | $425 | $503 |
| percent IC revenue top 100 hrs | 34% | 47% | 29% | 46% | 23% | 44% | 39% | 52% |

Notes: based on demand, prices and potential wind for 2018-19, no losses on ICs
Light is with Basslink or Marinus 1, dark with Marinus 2

The first two columns show the impact of commissioning Marinus 1 before wind capacity is expanded. The effect of Marinus is to raise the value of water but depress prices in Tasmania, increasing interconnector (congestion) revenue by $A150 million/yr ($347m-$197m) or by $A200/kWyr of new interconnector capacity. Comparing the third and first column shows the impact of trebling wind capacity but not expanding interconnection. The value of water and Tasmanian prices fall, increasing the price spread across Basslink and increasing revenue by $A37m./yr. Adding Marinus 1 (col. 4) increases Tasmanian prices, considerably raises the value of water, and Marinus 1 earns $A124m./yr or $A165/kWyr, less than the impact of expanding with no increase in wind capacity.

Quadrupling wind but not building Marinus 1 (col 5 vs col 1) hugely reduces prices in Tasmania, and hence the economics of wind investment. The beneficiary is Basslink, increasing its revenue by $A101m/yr from the base case. Adding Marinus 1 restores price levels in Tasmania and congestion revenue increases slightly compared to trebling wind. Increasing wind capacity by six-fold (half way to the planned expansion) with Marinus 1 improves interconnector revenue, and adding Marinus 2 further increases congestion revenue (by $A131/kWyr of the extra 750MW). Appendix B gives the same table for further wind expansions.

The last line in the table gives the percentage of total congestion revenue earned in the most profitable 100 hours and shows how sensitive interconnector revenue is to high price hours. As Victoria becomes more flexible and increases capacity this revenue will be at risk, but if Victoria replaces fossil with renewables but without strengthening interconnection to other states this could increase. The high sensitivity means that a different pattern of Victorian prices may give quite different results, to be explored below.

## 6. Surplus analysis and the economics of wind investment

The data from Table 1 and the underlying spreadsheet can be used to compute the value of the $CO_2$ displaced in Victoria and the profits or surpluses of Tasmanian entities, assuming all interconnectors are owned by Tasmania. The assumed values for various elements are set out in Appendix C. For the moment the supply curve of Victorian generation is assumed flat in each hour, so that the cost of net imports into Victoria is equal to the value of the avoided generation cost, and hence cancels out. This assumption is relaxed below. The top two rows give the combination of interconnector and wind capacity, with the first column the base year, 2018-19.

Table 2 Surplus analysis for Tasmania, 2018-19, lossless interconnectors, per year

| wind multiplier | 1 | 1 | 3 | 3 | 4 | 4 | 6 | 6 |
|---|---|---|---|---|---|---|---|---|
| Interconnector capacity, MW | 500 | 1,250 | 500 | 1,250 | 500 | 1,250 | 1,250 | 2,000 |
| Wind capacity, MW | 308 | 308 | 923 | 923 | 1,231 | 1,231 | 1,847 | 1,847 |
| CO2 benefit,* $m/yr | $91 | $91 | $273 | $273 | $364 | $364 | $547 | $547 |
| Consumer Surplus,** $m/yr | $111 | $200 | $374 | $224 | $570 | $240 | $291 | $190 |
| Hydro revenue, $m/yr | $863 | $936 | $622 | $885 | $436 | $855 | $775 | $953 |
| Wind gross profit,*** $m/yr | $79 | $71 | $151 | $204 | $120 | $265 | $364 | $432 |
| Interconnector revenue, $m/yr | $197 | $347 | $234 | $358 | $298 | $373 | $425 | $503 |
| Total benefit, $m/yr | $1,342 | $1,644 | $1,654 | $1,944 | $1,787 | $2,097 | $2,403 | $2,624 |
| Benefit increase from base, $m./yr | | $302 | $312 | $602 | $445 | $755 | $1,061 | $1,282 |
| average wind gross profit, $/kWyr | $257 | $231 | $163 | $221 | $97 | $215 | $197 | $234 |
| Av. wind gross profit + CO2 value, $/kWyr | $553 | $527 | $460 | $518 | $393 | $511 | $493 | $530 |
| IRR on total wind incl. CO2**** | 23% | 22% | 19% | 22% | 16% | 22% | 21% | 22% |
| marginal wind gross profit +CO2, $/kWyr | | | $413 | $513 | $195 | $493 | $457 | |

* $CO_2$ price = $A94/tonne, value is $A83,304/GWh of dispatched wind
** VoLL = $A15,000, relative to demand weighted price of $A100/MWh
*** Net of annual fixed cost $A24.5/kWyr
**** capital cost $2,345/kW, life = 25 yrs

The internal rates of return (averaged over the entire fleet) are high when including the quite high $CO_2$ price but fall by about 14 percentage points (i.e. from 23% to 9%) when excluding the carbon benefit. Thus the cash flow would require contractual support (at strike prices ideally determined by auction) to drive down the cost of borrowing to something closer to that on regulated assets and make these wind farms profitable under current (zero) carbon prices.

The marginal wind profit is the increase in total wind profit (including $CO_2$ benefit) divided by the increase in capacity (e.g. going from the base case to treble wind, $n = 3$, then from $n = 3$ to $n = 4$, and then to $n = 6$), holding interconnector capacity constant at the value shown in that column. The highest marginal return is moving from current to treble wind with Marinus in place (col 4), and only falls slightly for the next two wind expansions. Without Marinus, marginal return is halved moving from 4 to 6 times current capacity. The incremental net profit (including $CO_2$ benefit) of then adding Marinus 2 is to raise the $n$=6 wind benefit by $A20/kWyr (increased profit/1,847 MW wind capacity).

*6.1 Sensitivity analysis*

Prices vary considerably from year to year (more than either wind or hydro output) and 2018-19 was a relatively high price year with more volatile prices than in earlier years. Thus in calendar 2015 the average price in Victoria was remarkably low at $A36/MWh, with a coefficient of variation (CV) of 105%, compared to 2018-19 where the average price was $A110/MWh with a CV of 363%.

Table 3 Sensitivity of benefits to variations in the volatility and level of Victorian prices

| scenario CV and level as % of 18-19 | 30%/100% | | 65%/100% | | 100%/50% | | 100%/90% | |
|---|---|---|---|---|---|---|---|---|
| Interconnector capacity, MW | 500 | 2000 | 500 | 2000 | 500 | 2000 | 500 | 2000 |
| Wind capacity, MW | 308 | 1,847 | 308 | 1,847 | 308 | 1,847 | 308 | 1,847 |
| IC revenue as % of original | 30% | 29% | 65% | 64% | 50% | 49% | 90% | 88% |
| wind plus $CO_2$ as % of original | 110% | 114% | 106% | 107% | 70% | 71% | 94% | 94% |
| benefit as % of original | 69% | 76% | 76% | 83% | 82% | 80% | 82% | 86% |

Note: the first term in the scenario is the CV, the second the average level of Victorian prices, both as a percent of the original 2018-19 values

Appendix D explains the derivation of Table 3, which shows the effect of varying the CV to 30% or 65% of current Victorian price volatility and varying the average Victorian price on prices and benefits. Reducing Victorian price volatility but keeping the average price unchanged increases all Tasmanian prices in direct proportion to the CV (raising wind and hydro revenue but with an offsetting fall in consumer surplus) and reduces congestion revenue in proportion to the changed CV (which derives much of its value from volatility in Victorian prices given the much lower volatility in Tasmania). Overall benefits fall primarily as a result of lower interconnector revenue by between 25-30%, changing gradually with increases in wind and interconnector capacity (hence only the extremes of wind and interconnector capacity are shown).

Just scaling all Victorian prices to a fraction of 50% or 90% reduces all Tasmanian prices, and hence hydro and wind profit (offset by improved consumer benefits), and scales back interconnector revenue almost in proportion to the fall in average Victorian price (which drives the Tasmanian prices). Overall benefits fall by 14-20%, less than reduction in average Victorian prices as the carbon benefit of wind is preserved and constitutes a large fraction of the benefits. Wind profits without the carbon credit are far more sensitive to average prices, underlying the importance of carbon credits for wind investment.

*6.2 Allowing for losses over interconnectors*

Interconnector losses over Basslink are 3.8%, while those over Marinus will depend on the cross-sectional area of the cable and power flows (losses increase as the square of the current) and are not yet known. Estimates range from 2.5% (EY, 2019) to 4% (Tasnetworks, 2021). The simplest assumption is that all interconnectors have the same loss at 3.8%. That means that Tasmanian export prices are 96.2% of Victorian prices, while import prices are 103.95% of Victorian prices. As a result, there will be a dead band of prices in which Tasmania will neither export nor import, during which periods all residual demand will be met by hydro at the price of water. A slight modification of the previous spreadsheet distinguishing now between the relevant loss-adjusted prices allows a rapid recalculation of the previous two tables. Table 4 reports the (rather modest) differences that losses make to the earlier calculations.

Table 4 Lossy less lossless values, per year

| wind multiplier | 1 | 1 | 3 | 3 | 4 | 4 | 6 | 6 |
|---|---|---|---|---|---|---|---|---|
| IC capacity, K, MW | 500 | 1,250 | 500 | 1,250 | 500 | 1,250 | 1,250 | 2,000 |
| spilled, Ws, GWh/yr | 0.0 | 0.0 | 0.1 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 |
| curtailed wind, Wc, GWh/yr | -0.8 | -0.8 | -2.3 | -2.3 | -3.1 | -3.1 | -4.6 | -4.6 |
| dispatched wind, W, GWh/yr | 0.8 | 0.8 | 2.2 | 2.1 | 3.1 | 3.1 | 4.6 | 4.6 |
| H+W-D=X-M | 1.0 | 0.8 | 2.8 | 4.0 | 2.3 | 2.1 | 4.6 | 4.9 |
| exports, X, GWh/yr | 1 | 0 | 2 | 1 | 1 | 0 | 0 | 0 |
| imports, M, GWh/yr | 0 | -1 | -1 | -2 | -1 | -3 | -4 | -4 |
| water value, v, $A/MWh | -$3.4 | -$3.7 | -$2.5 | -$3.5 | -$1.8 | -$3.4 | -$3.0 | -$3.7 |
| Demand-wt price, $A/MWh | -$3.4 | -$0.9 | -$2.4 | -$0.9 | -$1.7 | -$1.1 | -$1.7 | -$1.0 |
| time-wt price, $A/MWh | -$3.4 | -$0.7 | -$2.4 | -$0.8 | -$1.7 | -$1.1 | -$1.6 | -$0.9 |
| Victorian price | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| CO2 benefit,* $m/yr | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Consumer Surplus,** $m/yr | $35 | $9 | $24 | $9 | $18 | $12 | $17 | $10 |
| Hydro revenue, $m/yr | -$33 | -$36 | -$24 | -$34 | -$17 | -$33 | -$29 | -$36 |
| Wind gross profit,*** $m/yr | -$4 | -$1 | -$7 | -$2 | -$7 | -$5 | -$13 | -$10 |
| Interconnector revenue, $m/yr | $2 | $28 | $7 | $27 | $7 | $26 | $25 | $36 |
| Total benefit, $m/yr | $1 | $0 | $1 | $0 | $0 | $0 | $0 | $0 |
| Benefit increase from base, $m./yr | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| average wind gross profit, $/kWyr | -$12 | -$2 | -$8 | -$3 | -$6 | -$4 | -$7 | -$6 |
| Av. wind gross profit + CO2 value, $/kWyr | -$12 | -$2 | -$7 | -$2 | -$6 | -$4 | -$7 | -$5 |
| IRR on total wind incl. CO2**** | -0.5% | -0.1% | -0.3% | -0.1% | -0.3% | -0.2% | -0.3% | -0.2% |

Notes: as for Tables 1 and 2.

The impacts seem remarkably small - modest falls in Tasmanian prices which transfer revenue from hydro to interconnectors and/or consumers, and the small rise in wind dispatched is more than offset by the fall in prices received, reducing wind profits. Net exports increase slightly as Tasmanian prices fall, and the main impacts are felt when the interconnector seems undersized relative to the wind capacity. The overall benefit change is surprisingly small, as while consumers gain, generators lose.

### *6.3 Allowing for price responses in Victoria, lossless case*

Once either wind and/or interconnector capacity are increased, net exports will increase and can be expected to impact on Victorian prices. The rules for setting prices and trade flows now become more complicated, as the size of the flows will affect mainland prices, which will potentially affect flows. In principle in each hour, Tasmania will have an inelastic supply that depends only on the value of water (if producing) and an assumed inelastic residual demand (if importing) at the local import price (in the lossless case, the Victorian price). Victoria has an assumed inelastic demand and an upward-sloping marginal generation cost curve. The resulting price-sensitive net demand is offered into a notional auction to clear mainland prices and interconnector flows. This simple story hides a number of problems. The first is that the current trade flows are not always efficient, with flows frequently flowing against price differences. The model is set up to solve for an efficient solution, but the initial prices reflect an inefficient equilibrium. We avoid this by assuming that the original Victorian prices are sufficiently close to their value assuming that the interconnector is used efficiently in the base case.

The next problem is to estimate the impact of changing flows on equilibrium prices in Victoria, assuming efficient price-setting in Tasmania (whose prices will depend on the endogenous value of water, the direction of trade and prices in Victoria). Appendix E examines different ways of measuring the slope of the net supply curve in Victoria, none of which is completely satisfactory. The various estimates in Appendix E cluster around \$A35/GW treating Victoria as an isolated state (apart in one case including Basslink), but almost zero over a wide range of residual demands if Victoria and NSW are treated as a single region. That might be increasingly the case if Marinus is built, as mainland grid reinforcement would be needed to spread the trading benefits across states and hence increase the market area and reduce the Victorian price sensitivity to changes in supply. The tentative conclusion is that \$A35/GW is too high and a defensible compromise might be \$A25/GW.

That suggests simulating Tasmanian output and prices assuming that Basslink operates efficiently and calculating the "equilibrium" Victoria prices without any trade flows, on the assumption that they differ from the actual prices by the slope of the estimated supply curve, α, times the net increase in Victorian supply (when Tasmania imports). The slope α is taken as \$A0.025/MW, based on the compromise estimate defended above of \$A25/GW. Thus if Tasmanian net exports increase by $\Delta x$, $P_0$ falls by $\Delta P = \alpha\Delta x$ to $P_1 = P_0 - \alpha\Delta x$ (where $P_0$ is the original Victorian price). The new equilibrium then requires satisfying all the constraints and market conditions in both countries (new prices in both, with Tasmanian prices set equal to the value of water, or the import price, or the avoidable cost of wind). Fortunately, at the observed initial set of prices, efficient flows are either +500 MW or – 500 MW, making it simpler to calculate the no-trade equilibrium prices. The post-trade equilibrium prices will then just depend on the calculated net trade.

With this market coupling, there are three trade regimes, depending on $P$, $v$, and $\delta$, where $\delta = \alpha\Delta K$, and $\Delta K$ is the increase in interconnector capacity, 750 MW with Marinus 1, 1,500 with both stages. If $P > v + \delta$, then $x = K$ as before and wind and hydro are exported, with the Tasmanian price $p = v$. If $P < v - \delta$, then imports are set equal to residual demand ($d - w$) up to the import capacity with surplus spilled, with any unsatisfied demand met from hydro. In between these two prices, trade is set at a level to equate prices across the interconnectors: $P_1 = p = v$ by adjusting net exports so that $P_0 - \alpha\Delta x = v$, or $\Delta x = (P_0 - v)/\alpha$.

In all cases the assumption is that the Victoria prices of 2018-19 correspond to the efficient trade flows over Basslink, so all deviations are relative to this base case. Tables 5 and 6 have the same format as tables 1 and 2, but juxtaposing columns with (darker) and without (lighter) price responses to highlight their impact.

Table 5 Solutions for the case of price responses in Victoria, lossless case

| wind multiplier | 1 | 1 | 3 | 3 | 4 | 4 | 6 | 6 |
|---|---|---|---|---|---|---|---|---|
| price response | No | Yes | No | Yes | No | Yes | No | Yes |
| IC capacity, K, MW | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 |
| Demand, D, GWh/yr | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 |
| hydro, H, GWh/yr | 9,681 | 9,681 | 9,681 | 9,681 | 9,681 | 9,681 | 9,682 | 9,681 |
| wind resource, Wr, GWh/yr | 1,105 | 1,105 | 3,315 | 3,315 | 4,420 | 4,420 | 6,630 | 6,630 |
| spilled, Ws, GWh/yr | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| curtailed wind, Wc, GWh/yr | 11 | 11 | 33 | 33 | 45 | 45 | 67 | 67 |
| dispatched wind, W, GWh/yr | 1,094 | 1,094 | 3,282 | 3,282 | 4,375 | 4,375 | 6,563 | 6,563 |
| H+W-D=X-M | 494 | 494 | 2,681 | 2,682 | 3,775 | 3,776 | 5,964 | 5,963 |
| exports, X, GWh/yr | 5,160 | 2,782 | 5,810 | 3,895 | 6,227 | 4,558 | 7,402 | 6,274 |
| imports, M, GWh/yr | 4,666 | 2,288 | 3,129 | 1,214 | 2,452 | 783 | 1,439 | 312 |
| water value, v, $A/MWh | $96.7 | $90.9 | $91.4 | $83.6 | $88.3 | $78.9 | $80.1 | $67.0 |
| Demand-wt price, $A/MWh | $80.6 | $88.0 | $78.2 | $81.1 | $76.7 | $80.4 | $71.7 | $79.0 |
| time-wt price, $A/MWh | $79.6 | $88.3 | $77.5 | $81.4 | $76.0 | $80.8 | $71.1 | $79.2 |
| Victorian price | $109.8 | $107.0 | $109.8 | $100.8 | $109.8 | $97.6 | $109.8 | $91.4 |
| Congestion revenue $A m./yr | $347 | $206 | $358 | $217 | $373 | $188 | $425 | $138 |
| percent IC revenue top 100 hrs | 47% | 47% | 46% | 46% | 44% | 44% | 39% | 52% |

Price response lowers the value of water but raises other prices in Tasmania. Victorian prices fall increasingly as net exports rise with increased capacity. Trade falls but net exports are stable at each level of capacity but congestion revenue falls as trade is reduced and prices are equilibrated much of the time.  Table 5 shows the consequential revenue and welfare impacts.

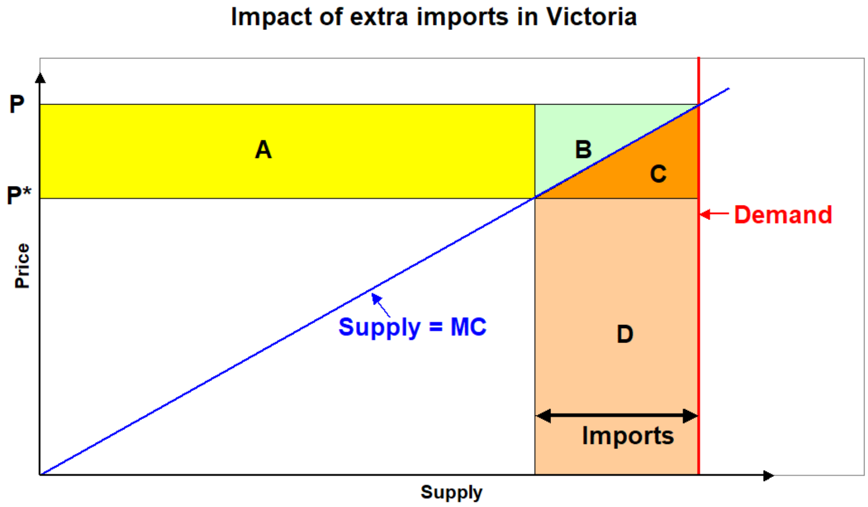


Figure 7 Surplus change in Victoria to increased imports

When prices fall in Victoria, consumers gain and generators reduce output (and cost). If, as is plausible from hour to hour, consumer demand is inelastic, shown in figure 7 as the vertical line, and if the marginal cost of generation slopes up as shown, then imports into Victoria will lower prices from *P* to *P**, consumers will benefit by increased consumer surplus, areas A + B + C, generators will lose infra-marginal rent A+B. and generation costs will be reduced by C + D, but will be replaced by import cost D. The net benefit in Victoria will just be the reduction in generation costs, C, in the linear marginal cost case, one-half the change in price times net imports.

Table 6 Surplus analysis for price response case, lossless interconnectors

| wind multiplier | 1 | 1 | 3 | 3 | 4 | 4 | 6 | 6 |
|---|---|---|---|---|---|---|---|---|
| price response | No | Yes | No | Yes | No | Yes | No | Yes |
| IC capacity, MW | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 |
| Wind capacity, MW | 308 | 308 | 923 | 923 | 1,231 | 1,231 | 1,847 | 1,847 |
| Carbon benefit,* $m/yr | 91 | 91 | 273 | 273 | 364 | 364 | 547 | 547 |
| Cons. Surplus,** $m/yr | 200 | 123 | 224 | 194 | 240 | 202 | 291 | 216 |
| Hydro revenue, $m/yr | 936 | 880 | 885 | 810 | 855 | 764 | 775 | 615 |
| Wind profit, $m/yr | 71 | 79 | 204 | 211 | 265 | 302 | 364 | 500 |
| IC revenue, $m/yr | 347 | 206 | 358 | 217 | 373 | 188 | 425 | 138 |
| Total Tasmanian benefit $A m/yr | 1,644 | 1,379 | 1,944 | 1,705 | 2,097 | 1,821 | 2,403 | 2,016 |
| Vic benefit $A m/yr | $0 | $1 | $0 | $12 | $0 | $23 | $0 | $55 |
| benefit change from slope $A m/yr | | -$265 | | -$227 | | -$253 | | -$332 |
| average wind gross profit, $/kWyr | $231 | $255 | $221 | $228 | $215 | $246 | $197 | $271 |
| Av. wind gross profit + $CO_2$ value, $/kWyr | $527 | $551 | $518 | $524 | $511 | $542 | $493 | $567 |
| IRR on total wind incl. $CO_2$**** | 33% | 34% | 32% | 33% | 31% | 32% | 29% | 30% |
| marginal wind gross profit +$CO_2$, $/kWyr | | | $513 | $215 | $493 | $298 | $457 | $321 |

Note: IRR on wind cost of $A1,600/kW; marginal wind gross profit relative to same IC capacity and same price response, excludes Marinus capital cost.

In table 6 as before the price response cases are darker shaded and show that Victoria gains (a modest amount). Interconnector revenue falls as prices are equalised for a substantial fraction of the time (40% in the case of $n = 4$). Hydro loses from the lower water value while wind gains from higher local prices at the expense of Tasmanian consumers. Carbon values are unchanged. Overall the total Tasmanian surplus (attributing the carbon benefit to Tasmania) falls by 13-17% compared to no price response. The impacts of allowing price response seem quite consistent across different levels of wind penetration with the main impact on Tasmanian consumers and congestion revenue, which is clearly relevant to the way in which Marinus could be funded. In terms of an aggregate cost-benefit analysis there seems little advantage in adding losses to this third model, given the very small changes noted in Table 4.

## 7. Financing wind and interconnection investment

The profitability of wind investment depends on access to a larger market through interconnector investment, and that in turn requires additional wind to export to make the necessary interconnector profit. It is not the intention here to undertake a proper cost-benefit analysis of these investments, but rather to identify issues in how the beneficiaries might pay to deliver the combined programme of investments. For that it is useful to have rough estimates of the costs and benefits to illustrate possible financing models. Tasnetworks (2021, p57) provides relevant data (and has also undertaken a far more comprehensive systems modelling assessment of the investment case). Thus Marinus 1 has a capital cost of $A2,270 million (2020 prices) and the additional 750 MW (Marinus 2) adds a further $A1,210. Annual operating costs are $A28 m for Marinus 1 and an additional $A8.7 m for Marinus 2. The recommended discount rate is taken as 4.8% (or 3.8% in the Slow Change scenario) with a lifetime of 40-60 years, according to Tasnetworks (2021, p57, fn 60 and p90, note 2). Table 7 summarises the relevant cost and benefit information.

Table 7 Summary annual costs and benefits for Marinus

| wind multiplier | 3 | 4 | 3 | 4 | 4 | 5 | 5 | 6 | 6 | 9 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| IC capacity, MW | 500 | 500 | 1250 | 1250 | 2000 | 1250 | 2000 | 1250 | 2000 | 2000 | 2000 |
| wind capacity MW | 923 | 1,231 | 923 | 1,231 | 1,231 | 1,539 | 1,539 | 1,847 | 1,847 | 2,770 | 3,693 |
| Gross wind profit $A m/yr. | $184 | $178 | $211 | $302 | $275 | $408 | $421 | $500 | $517 | $707 | $640 |
| wind capex $A m/yr. | $98 | $131 | $98 | $131 | $131 | $163 | $163 | $131 | $196 | $294 | $392 |
| net wind benefit $A m/yr. | $86 | $47 | $113 | $172 | $144 | $244 | $258 | $369 | $321 | $413 | $248 |
| $CO_2$ benefit $A m/yr. | $273 | $364 | $273 | $364 | $364 | $456 | $456 | $547 | $547 | $818 | $1,084 |
| net wind + $CO_2$ $A m/yr. | $359 | $411 | $386 | $536 | $509 | $700 | $713 | $916 | $868 | $1,231 | $1,332 |
| consumer benefit $A m/yr. | $275 | $523 | $194 | $202 | $209 | $203 | $171 | $216 | $178 | $246 | $341 |
| hydro benefit $A m/yr. | $713 | $421 | $810 | $764 | $804 | $708 | $747 | $615 | $699 | $536 | $430 |
| congestion rev $A m/yr. | $135 | $214 | $217 | $188 | $308 | $156 | $195 | $138 | $155 | $154 | $269 |
| Victoria benefit $A m/yr. | $8 | $18 | $12 | $23 | $18 | $30 | $30 | $47 | $47 | $94 | $130 |
| IC opex + capex $A m/yr. | $0 | $0 | $171 | $171 | $257 | $171 | $257 | $171 | $257 | $257 | $257 |
| Total benefit $A m/yr. | $1,491 | $1,587 | $1,448 | $1,542 | $1,590 | $1,626 | $1,600 | $1,760 | $1,690 | $2,004 | $2,245 |
| rel to base case $A m/yr. | $230 | $326 | $187 | $282 | $330 | $366 | $339 | **$500** | $429 | $744 | **$984** |

Notes: Wind capital cost $A1,600/kW, WACC 4.8% over 25 yrs; Marinus annual opex and capex from Tasnetworks (2021, p57) at 4.8% over 31 years

Looking at the increment in value relative to the base case of no further wind or interconnector investment, stage 1 of Marinus yields increased net benefits up to a 5-fold expansion in wind capacity, but not beyond. Stage 2 (total 2,000 MW) increases benefits once wind has expanded 7-fold (but not before) and continues to rise to a 12-fold increase in wind.

Breaking down the components of total benefit allows us to vary key assumptions such as the price of carbon or the weighted average cost of capital (WACC) for wind and interconnector investments as in Table 8.

Table 8 Sensitivity of net benefits to carbon cost and WACC, per year

| wind multiplier | 3 | 4 | 3 | 4 | 4 | 5 | 5 | 6 | 6 | 9 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| IC capacity, MW | 500 | 500 | 1,250 | 1,250 | 2,000 | 1,250 | 2,000 | 1,250 | 2,000 | 2,000 | 2,000 |
| halve $CO_2$ benefit | -$137 | -$182 | -$137 | -$182 | -$182 | -$228 | -$228 | -$273 | -$273 | -$409 | -$542 |
| rel to base case $A m. | $93 | $144 | $51 | $99 | $147 | $138 | $111 | **$226** | $156 | $334 | **$442** |
| wind WACC 8% real | -$30 | -$40 | -$30 | -$40 | -$40 | -$50 | -$50 | -$60 | -$60 | -$90 | -$120 |
| rel to base case $A m. | $63 | $103 | $21 | $59 | $107 | $88 | $61 | **$166** | $96 | $244 | **$322** |

The first line in the lower panel shows the change in benefits of halving the price of $CO_2$ from $A93.6/t to $A46.8/t. Thus halving the carbon price at treble the wind reduces the benefit relative to the base case (also with halved carbon price) by $A137m/yr. The line below shows the impact on the net gain relative to the base case of further investments, showing that it is still worth expanding wind 6-fold with Marinus 1 and to invest in Marinus 2 at 12-fold. If in addition to the halved $CO_2$ price the WACC for wind investments rises from 3.8% to 8% real, the last line shows that the same result holds. Clearly the amount and coordination of investments is sensitive to these key assumptions, as table 3 demonstrated.

Indeed, if the CV and level of Victorian prices are both halved (as has been witnessed in earlier years) benefits would be reduced to 70-80% of those shown above, or by $A135m/yr for the case of 6-fold wind and Marinus 1 (less than halving the $CO_2$ benefit).

*7.1 Aligning costs and benefits of investments in wind and interconnection*

Net benefits are sensitive to the cost of finance and the value of carbon displaced. Without government or regulatory assurances and contracts the cost of bearing policy risks make these investments problematic and possibly unviable. The monetisation and allocation of social benefits will determine whether each component of the package is delivered in the least cost way. For example, if Australia imposes an adequate carbon tax on generation (as in Britain with its Carbon Price Support), then much of the benefit could accrue to the Tasmanian wind farms as "excess" profit, reducing congestion revenue and prejudicing Marinus. Appendix E shows the dramatic impact of a carbon price on marginal costs and hence prices.

If wind farms could be adequately but not excessively remunerated, then more revenue would be available for the complementary investments. This could best be achieved by auctioning a suitable contract-for-difference (CfD) to determine the strike price. Newbery (2021) argues that the CfD should be an amount equal to the predicted wind output at that location, and for a fixed number of full operating hours, to ensure efficient self-curtailment and location. The volumes auctioned could then be matched to the construction schedule of the interconnector(s). If such CfDs could attract finance at the same real Weighted Average Cost of Capital (WACC) as the assumed Marinus discount rate of 4.8%, the annualised cost (for a 25-year life time) would be $106/kWyr for a projected 2025 cost of $1,600/kW. These figures have been subtracted from the wind gross profits per kWyr in the tables above to determine the benefits remaining to attribute to all other investments.

Mainland benefits appear modest as measured, as all the carbon benefits have been attributed to the wind farms and Marinus, but the reduced emissions (including other air pollutants no valued here) would occur on the mainland, and might be captured there by any carbon taxes, while the resulting higher mainland prices would be fed back as increased interconnector revenue. Without the carbon tax, direct contractual support and certainly assurances to lower the WACC would be necessary. The very rough and ready calculations above suggest that these are justified. As noted above, Basslink has applied for regulated status that should deliver a lower WACC.

*7.2 Caveats and biases in these cost-benefit estimates*

It is unrealistic to assume that the prices and the wind outputs of 2018-19 (for scaling) would be fully representative of the next 25+ years. The sensitivity analysis above already demonstrated the impact of lower average and variability of Victorian prices. A proper social cost-benefit analysis would consider a set of scenarios and attempt to model any interactions of wind output in the connected states and future generation investment (including ambitious mainland renewables targets) and decommissioning on future prices (as in Bell et al., 2017). The scenarios considered in the Marinus studies suggest Victoria will not decommission its lignite plants until the 2030s, but this could change with global pressure to drive out coal. Looking at biases, one might expect the social cost of carbon to increase over time, but renewables should become cheaper and drive down electricity prices, reducing project benefits (although Tasmanian wind resources are better than in Victoria).

The mainland would need additional grid investment to fully benefit from Marinus, so some of the gains attributed to Marinus should properly be allocated to these complimentary reinforcements. Offsetting that, the benefits listed above exclude the potentially appreciable ancillary service gains (Tasnetworks, 2019b), and the value of increased security of supply. To conclude, the purpose of this article is not to undertake a proper social cost-benefit analysis but illustrate how to identify the major determinants of project viability when interconnecting a hydro and renewables-rich region to a fossil-dominated one.

## 8. Conclusions

Given adequate storage hydro to buffer supply and demand fluctuations over an extended period (months rather than weeks), most of the problems of intermittency of variable renewable electricity such as wind and solar PV can be overcome by providing adequate interconnection to less well-endowed regions. The key to the simple model presented here is that if hydro is energy, not capacity, constrained there is a single stable value of water that can guide trade over interconnectors, and which then drives local prices and hence the viability of investment in both additional renewables and interconnection. The other point to stress is that isolated hydro and renewables-rich regions can act as a battery, not for their neighbours but for buffering their own renewables that allows them to expand and provide carbon-free electricity to their neighbours. They are less a *Battery of the Nation* and more a *Battery of the Region/State*.

The model developed in this article has been roughly calibrated for Tasmania, an island state of Australia already connected to the mainland state of Victoria with its heavily lignite-dependent system. Tasmania has been and will be, if plans materialise, entirely carbon-free, and is contemplating major investments in both wind and new interconnectors, Marinus 1 and 2, each of 750 MW. The model identifies the benefits to hydro revenues, carbon savings, interconnector and wind profits, as well as consumer impacts in both countries, and impacts on Victorian generation. The model illustrates the problem of allocating the benefits to ensure efficient and coordinated investment in interconnection and wind capacity and suggests solutions to lower the cost of finance to ensure least cost delivery. The very rough cost-benefit analysis suggests that the projects are indeed socially valuable with an adequate value (or price) assigned to carbon, but that they are unlikely to take place on a merchant basis given the numerous market failures identified by Bell et al. (2017).

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**Appendix A Modelling market coupling across the interconnector**

Table A1 Definition of model variables and parameters

| | |
|---|---|
| $K$ | capacity of interconnector, increases from 500 MW to 1,250 MW and then 2,000 MW |
| $k$ | wind capacity |
| $f$ | the loss factor (3.8%) on the interconnector, |
| $\theta$ | $= 1\text{-}f$ fraction of exports reaching destination |
| $s$ | avoidable short-run cost of wind generation (taken as \$A10/MWh) |
| $o$ | annual operating cost per unit of wind capacity |
| $\alpha$ | slope of net supply curve in Victoria |
| The following variables are measured at hourly resolution | |
| $P$ | price in Victoria, \$A/MWh, $P_0$ initial price, given, $P_1$ final price to be determined |
| $p$ | price in Tasmania, \$A/MWh, variable to be determined |
| $v$ | value of water, \$A/MWh, variable to be determined |
| $c$ | Shadow value of $CO_2$, taken as €60 (\$A94)/tonne $CO_2$ |
| $p_x$ | $= \theta P$ export price in Tasmania, |
| $p_m$ | $= P/\theta$ import price in Tasmania |
| $w_r$ | wind potentially available in a given hr, MW, given; $W_r = \sum w_r$ annual total MWh/yr |
| $w_c$ | = IF ($p_m > s$, 0, $w_r$); $W_c = \sum w_c$, curtailed wind (price below s, withheld), |
| $w_a$ | $= w_r – w_c$, $a$ for available, = IF ($p_m > s$, $w_r$, 0) |
| $w$ | dispatched, |
| $w_s$ | spilled because of demand constraints, $= w_a - w$ |
| $d$ | Tasmanian consumption in hour, MW, given, $D = \sum d_j$, total consumption, MWh/yr |
| $h$ | hydro output, MW, variable, $H = \sum h$, annual hydro output, MWh/yr, given[24] |
| $x$ | export in hr, MW, variable, $X = \sum x_j$, annual exports, MWh/yr |
| $m$ | import in hr, MW, variable $M = \sum m$, annual imports, MWh/yr |
| $n$ | $= x – m$, net exports |
| $m, x$ | $\leq K$ |
| $r$ | $= d – w$ residual demand |
| $r$ | $= h + m – x$, commodity balance, hence $D + X = W + H – M$ |

**In all cases**

Congestion revenue = ABS($(P – p).(x + m)$)

Hydro revenue = $Hv$

Carbon benefit = $\Delta(X – M).c$

Wind revenue = $R = \sum$Max$(0, p – s).w$ , wind profit $= R – k.o$

Consumer benefit = $(p^* - p_d).D = \sum(p^*D - p.d)$ where $p_d = (\sum p.d)/D$ is the demand-weighted price and $p^*$ is a reference high price (properly VOLL but here \$A100/MWh).

If $h > 0$, $p = v$ because hydro is assumed always able to generate sufficient to meet demand if there is adequate water

$w_a$ = IF ($p > s, w_r,$ 0) - Wind only efficiently available if it can recover its avoidable cost

$w$ $= d + x – h – m$

[24] The volume available to generate without violating security levels, determined by annual rainfall.

$h$ = Max(0, $d - w_a + x - m$)

**Case 1 Lossless interconnection, Victorian price insensitive to trade changes**

Find $v$ such that

$x$ = IF($P > v, K$, IF($w_a > d$, MIN($w_a - d, K$), 0))

$m$ =IF($x > 0$, 0, MIN($d - w_a, K$))

$p$ = IF($h > 0, v,$ IF($w_a - d > 0, s+\varepsilon, P$)), $\varepsilon$ small to ensure wind willing to offer. The Tasmanian price $p$ is equal to $v$ (value of water) if hydro is generating, otherwise if importing, then the import price or if wind is spilled, then $p = s+\varepsilon$.

$\sum h \leq H$. Iterate on $v$ until this constraint is satisfied.

**Case 2 Lossy interconnection, Victorian price insensitive to trade changes**

Find $v$ such that

$p_x$ $= \theta P$

$p_m$ $= P/\theta$

$x, m, h, w,$ as above

$p$ = IF($h > 0, v,$ IF($w_a > d, s+ \varepsilon$, IF($x > 0, p_x, p_m$,)))

$\sum h \leq H.$

**Case 3 trade impacts prices in Victoria, lossless case**

$\alpha$ slope of Vic supply curve, \$A/MW = \$0.025

$P_{00}$ price in Victoria with Basslink efficiently used

$P_0$ pre-trade estimated price in Victoria = $P_{00} - \alpha n_0$, $n_0$ = original net exports, +/- 500

$P$ equilibrium price in Victoria after trade

$\Delta K$ increase in capacity from previous pre-Marinus use, 750 or 1,500 MW

$\delta$ $= \alpha\Delta K$, maximum Victorian price impact assuming Basslink fully loaded = \$A18.75/MWh for M1, \$A37.5 with full 1,500 MW

Find $v$ such that

$P$ $= P_0 - \alpha n$

$n$ = IF($P_0 < s+ \varepsilon$, 0, IF($w_a > d$, MIN($w_a - d, (P_0 - s - \varepsilon)/\alpha$), IF($P_0 > v + \delta$, MIN($K$, ($P_0 - v)/\alpha$), IF($P_0 < v - \delta$, MAX($w_a - d$, MAX(–K, ($P_0 - v)/\alpha$)), MAX(($P_0 - v)/\alpha, w_a - d$,)). This ensures that if wind is not spilled until its maximum can be exported, and also ensures that when the capacity is unconstrained trade ensures that prices can be equilibrated

$p$ = IF($h > 0, v,$ IF(ABS($n$) $< K, P, s+ \varepsilon$))

$\sum h \leq H.$

## Appendix B Additional tables

Table B1 Additional solutions for higher wind – price responsive lossless case

| wind multiplier | 5 | 5 | 7 | 8 | 9 | 12 |
|---|---|---|---|---|---|---|
| IC capacity, K, MW | 1250 | 2000 | 2,000 | 2000 | 2000 | 2000 |
| Demand, D, GWh/yr | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 |
| hydro, H, GWh/yr | 9,682 | 9,681 | 9,681 | 9,681 | 8,825 | 7,078 |
| wind resource, Wr, GWh/yr | 5,525 | 5,525 | 7,735 | 8,840 | 9,945 | 13,260 |
| spilled, Ws, GWh/yr | 0 | 0 | 3 | 10 | 23 | 118 |
| curtailed wind, Wc, GWh/yr | 56 | 56 | 78 | 89 | 100 | 134 |
| dispatched wind, W, GWh/yr | 5,469 | 5,469 | 7,654 | 8,741 | 9,822 | 13,008 |
| pot net exports H+W-D | 4,870 | 4,870 | 7,054 | 8,141 | 8,366 | 9,805 |
| exports, X, GWh/yr | 5,363 | 5,476 | 7,321 | 8,326 | 8,533 | 9,932 |
| imports, M, GWh/yr | 493 | 607 | 267 | 185 | 167 | 127 |
| water value, v, $A/MWh | $73.1 | $77.2 | $66.6 | $60.7 | $60.7 | $60.73 |
| D wt price, $A/MWh | $80.2 | $83.3 | $79.6 | $76.3 | $76.1 | $66.8 |
| time wt price, $A/MWh | $80.7 | $83.8 | $79.8 | $76.4 | $76.2 | $66.70 |
| Victorian price | $94.5 | $94.5 | $88.3 | $85.2 | $84.5 | $80.42 |
| Congestion revenue $Amillion/yr | $156.1 | $194.8 | $155.6 | $160.4 | $154.3 | $269.2 |
| percent IC revenue top 100 hrs | 58% | 72% | 61% | 59% | 61% | 61% |

Note: wind capacity cost $A1,600/kW, no losses on IC

Table B2 Surplus analysis

| IC capacity, MW | 1250 | 2000 | 2000 | 2000 | 2000 | 2,000 |
|---|---|---|---|---|---|---|
| Wind capacity, MW | 1539 | 1539 | 2154 | 2462 | 2770 | 3,693 |
| Carbon benefit,* $m/yr | $456 | $456 | $638 | $728 | 818.2 | $1,084 |
| Cons. Surplus,** $m/yr | $203 | $171 | $209 | $243 | 245.8 | $341 |
| Hydro revenue, $m/yr | $708 | $747 | $645 | $588 | 535.9 | $430 |
| Wind profit, $m/yr | $408 | $421 | $586 | $644 | 707.2 | $640 |
| IC revenue, $m/yr | $156 | $195 | $156 | $160 | 154.3 | $269 |
| Total benefit, $m/yr | $1,930 | $1,990 | $2,233 | $2,364 | 2461 | $2,764 |
| average wind profit, $/kWyr | $265 | $274 | $272 | $262 | 255.3 | $173 |
| Av. wind gross profit + CO2 value, $/kWyr | $561 | $570 | $568 | $557 | 550.7 | $467 |
| IRR on total wind incl. CO2**** | 35% | 36% | 35% | 35% | 34% | 29% |
| marginal wind profit, $/kWyr | | | $267.6 | $189.5 | $204.8 | -$72.8 |
| Increased benefit from base | $670 | $729 | $972 | $1,103 | $1,201 | $1,503 |

Source: Table B1

## Appendix C Assumptions behind calculations

The carbon benefit is taken as \$A94/t $CO_2$ displaced (recognising that there are additional benefits from reduced air pollution), and the average carbon intensity of Victorian generation is 0.89 tonnes $CO_2$/MWh, as noted above, giving a value of \$A83,304/GWh of dispatched wind. Consumer surplus is computed as $\sum(\text{VoLL} - p_t).d_t$, where VoLL is the Value of Lost Load, currently \$A12,500/MWh,[25] $p_t$ is the spot Tasmanian price in hour $t$, and $d_t$ is demand in that hour. This gives an excessively high value and as we are only interested in comparisons between scenarios, the sum shown is the extra surplus over purchasing power at a demand weighted price of \$100/MWh, which is above all the Tasmanian weighted prices shown in Table 1.

Hydro revenue is hydro generation times the value of water. Variable O&M costs are about \$A1.5/MWh (IRENA, 2012) and so below the value of water, and hence never influence dispatch decisions. As all hydro costs are the same regardless of wind and trade they can be ignored. Wind cash flow is $\sum(p_t - s)w_t$, where $s$ = \$A10 is the variable cost of wind and $w_t$ is wind output in hour $t$, selling at wholesale prices without any support (as any hedging contracts merely share revenues between parties). Wind *gross* profit is cash flow less annual fixed O&M costs. IRENA (2021) gives the annual on-shore wind fixed costs as \$US 33/kW (\$A24.5/kW) per year (for Denmark, perhaps comparable to Tasmania, higher in the US). This annual fixed cost is multiplied by installed capacity. Interconnector revenue is just congestion revenue (trade volume times price difference), and the total benefit is the sum of these, including the carbon benefit. However, given the arbitrary element in measuring consumer surplus, the relevant comparison is the increase in total benefit compared to the base case (col 1).

Average gross wind profit is computed by dividing total wind gross profit by wind capacity, in \$A/kWyr. The internal rate of return is computed from the investment cost and assumed lifetime of 25 years (ignoring any decrease in output with age and assuming the initial profits continue over the whole life), but adding in the carbon benefit entirely due to increased wind (and assuming that the product of the carbon price and the marginal displacement factor remains unchanged). The investment cost is taken to be the same as Musselroe Wind Farm, 168 MW, which was \$A394 million,[26] or \$A2,345/kW when it was commissioned in 2014. IRENA (2020) shows 2020 on-shore wind costs at \$US1,355/kW, or \$A1,840/kW, reflecting the substantial drop in costs since 2014. Tasnetworks (2019a, p16) give estimated costs as \$A1,800/kW, consistent with this estimate. Wind costs fall by 9% for each doubling of capacity, with IEA projecting growth rates of 11-16% p.a.,[27] indicating an annual decrease of costs of 1-1.5% p.a. so that installation costs could fall to \$A1,600/kW by 2025, further enhancing profitability by 10 percentage points (if prices remain unchanged).

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[25] https://www.aemc.gov.au/rule-changes/nem-reliability-settings-voll,-cpt-and-future-reli

[26] See https://en.wikipedia.org/wiki/Musselroe_Wind_Farm

[27] At https://www.iea.org/reports/renewables-2020/wind

## Appendix D Sensitivity analysis

In order to explore the impacts of lowering the Coefficient of Variation (CV) and/or the level of Victorian prices, the simulations take the original prices, $P_0$ and adjusts them to $\mu A_0 + \alpha(P_0 - \mu A_0)$ , where $A_0$ is the average Victorian price before scaling and $\mu$ and $\alpha$ are adjusted to produce the desired reduction in the CV and average post-adjustment Victorian price. The reason for adjusting the 2018-19 prices rather than taking a different year is to ensure that the same correlation between wind and prices is held constant. Tables C1 and C2 mirror Tables 1, 2 in the text. The lines for capacity, demand and wind resource are the original and unchanged levels, the remainder are the differences caused by that adjusting the mean and variance of prices.

Table D1 Original *less* adjusted results, CV and level 50% of 2018-10 per year

| wind multiplier | 1 | 1 | 3 | 3 | 4 | 4 | 6 | 6 |
|---|---|---|---|---|---|---|---|---|
| IC capacity, K, MW | 500 | 1,250 | 500 | 1,250 | 500 | 1,250 | 1,250 | 2,000 |
| Demand, D, GWh/yr | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 | 10,281 |
| hydro, H, GWh/yr | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| wind resource, Wr, GWh/yr | 1,105 | 1,105 | 3,315 | 3,315 | 4,420 | 4,420 | 6,630 | 6,630 |
| spilled, Ws, GWh/yr | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| curtailed wind, Wc, GWh/yr | 10 | 10 | 31 | 31 | 42 | 42 | 63 | 63 |
| dispatched wind, W, GWh/yr | -10 | -10 | -31 | -31 | -42 | -42 | -63 | -63 |
| X-M=H+W-D | -10 | -10 | -31 | -32 | -42 | -42 | -63 | -63 |
| exports, X, GWh/yr | -6 | 0 | -15 | -1 | -18 | -1 | -8 | -8 |
| imports, M, GWh/yr | 5 | 10 | 16 | 31 | 23 | 41 | 55 | 55 |
| water value, v, \$A/MWh | \$40 | \$45 | \$23 | \$42 | \$10 | \$40 | \$34 | \$47 |
| Demand-wt price, \$A/MWh | \$40 | \$34 | \$22 | \$33 | \$10 | \$32 | \$28 | \$35 |
| time-wt price, \$A/MWh | \$40 | \$33 | \$22 | \$32 | \$10 | \$31 | \$27 | \$34 |
| Victorian price | \$55 | \$55 | \$55 | \$55 | \$55 | \$55 | \$55 | \$55 |
| Congestion revenue \$Amillion/yr | \$138 | \$249 | \$164 | \$253 | \$206 | \$263 | \$299 | \$355 |

Table D2 Original *less* adjusted surplus analysis CV and level 50% of 2018-10 per year

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Interconnector capacity, MW | 500 | 1,250 | 500 | 1,250 | 500 | 1,250 | 1,250 | 2,000 |
| Wind capacity, MW | 308 | 308 | 923 | 923 | 1,231 | 1,231 | 1,847 | 1,847 |
| CO2 benefit,* \$m/yr | -\$1 | -\$1 | -\$3 | -\$3 | -\$3 | -\$3 | -\$5 | -\$5 |
| Consumer Surplus,** \$m/yr | -\$413 | -\$349 | -\$231 | -\$335 | -\$99 | -\$325 | -\$289 | -\$358 |
| Hydro revenue, \$m/yr | \$522 | \$578 | \$333 | \$539 | \$191 | \$515 | \$452 | \$592 |
| Wind net profit,*** \$m/yr | \$44 | \$38 | \$71 | \$108 | \$40 | \$139 | \$185 | \$233 |
| Interconnector revenue, \$m/yr | \$138 | \$249 | \$164 | \$253 | \$206 | \$263 | \$299 | \$355 |
| Total benefit, \$m/yr | \$290 | \$516 | \$334 | \$563 | \$334 | \$589 | \$643 | \$816 |
| Benefit increase from base, \$m./yr | | \$1,568 | \$1,386 | \$1,615 | \$1,387 | \$1,642 | \$1,695 | \$1,868 |
| average net wind profit, \$/kWyr | \$141 | \$124 | \$77 | \$117 | \$33 | \$113 | \$89 | \$127 |
| Net wind profit + $CO_2$, \$/kWyr | \$139 | \$121 | \$74 | \$114 | \$30 | \$110 | \$87 | \$124 |
| IRR on total wind incl. CO2**** | -1% | -2% | -3% | -2% | -4% | -2% | -2% | -3% |
| marginal wind profit +CO2, \$/kWyr | | | -\$355 | -\$370 | -\$274 | -\$355 | -\$330 | |

## Appendix E Calculating price responses in Victoria

*Regression analysis*

A simple linear regression of half-hourly price on half-hourly demand plus net exports (a crude proxy for supply) in Victoria for 2018 suggests that an extra 1,000 MW demand would on average raise prices by $A55/GW (and conversely a decrease in demand would lower prices by the same amount). However, prices will also be impacted by trade flows with other states, discharges from mainland stored hydro, the tightness of supply, and ramping and start-up constraints (which for the brown coal generation are significant). Not surprisingly, although the slope of the supply schedule has a high t-value (t = 23), the correlation coefficient is very low ($R^2$ = 5%). Regressing price on demand alone lowers the coefficient to $A50/GW ($R^2$ = 5%), and on available generation to $A42/GW ($R^2$ = 3%). These problems make it hard to construct a plausible counterfactual with a set of equilibrium prices, trade flows and water usage based on observed data. Instead the next section considers a number of rather more *ad hoc* approaches.

*Duration curve analysis*

Given hourly output by controllable generation it would possible to construct a duration curve, but those data are not available for more than 48 hours at a suitable hourly resolution. Thus figure C1 shows recent duration curves (i.e. each separately ranked in descending order) over a 48-hour period.

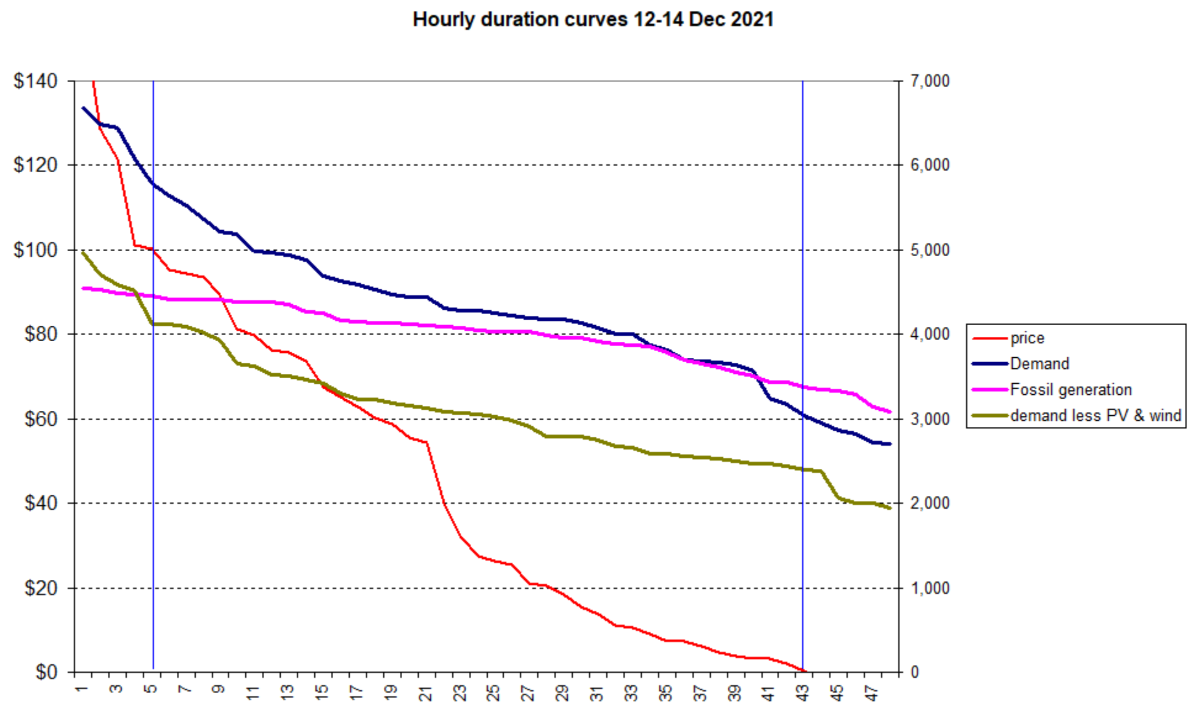


Figure E1 Duration curves for Victorian generation, demand and price, Dec 12-14 2021
Source: AEMO market data portal (see data sources below)

The change between the vertical lines (i.e. the central 38 hours) show demand declining by $A36/GW, fossil generation by $A92/GW and residual demand by $A58/GW.

The data however exclude trade with neighbouring states, so do not give an accurate measure of the impact of Victoria importing an extra GW of wind from Tasmania.

Figure C2 plots the residual demand curve for Victoria, defined as demand less wind and solar PV, ignoring trade with neighbours. Without knowing the absolute volume of trade it is impossible to judge whether that trade has a small or large impact on residual demand to be met by Victorian generation. Again, taking the central 80% of volumes and prices, the slope varies from \$A28/GW (in 2017-18) to \$A43/GW (in 2020-21) with an average of \$A35/GW. This will overstate the slope allowing for trade which will ameliorate the price range.

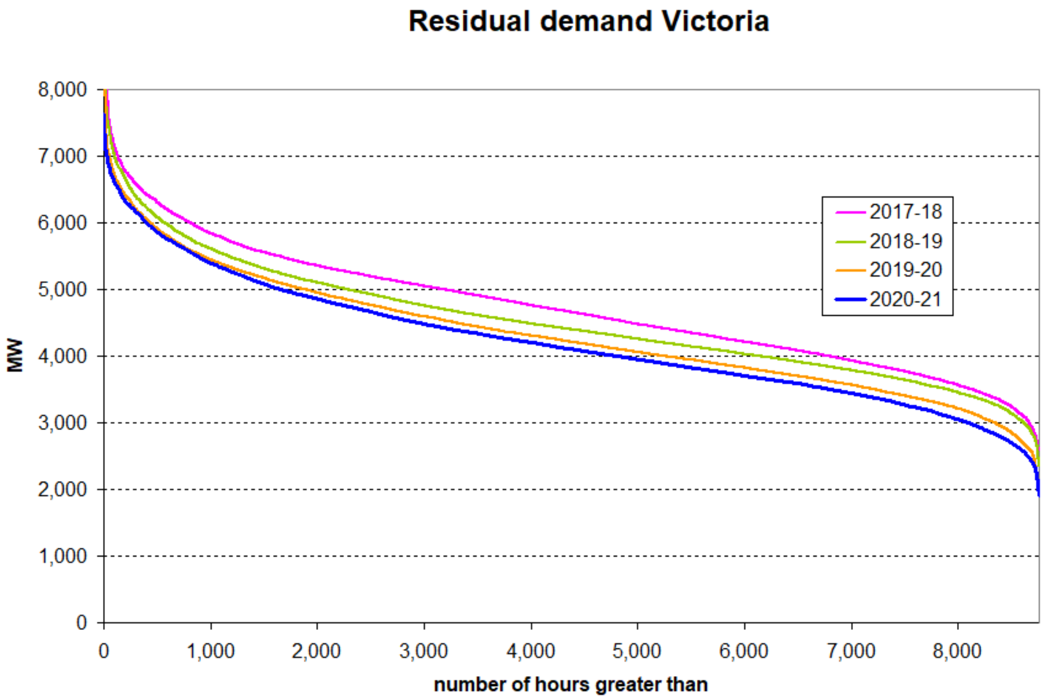


Figure E2 Victoria residual demand duration curves for 2018-19 to 2020-21
See Data sources

The final strategy is to look at the marginal cost of fossil generation in Victoria and neighbours, shown in figure C3. The source gives a detailed cost breakdown, plant size for all existing generators and fuel costs and from that determines the avoidable cost of each generator. That allows he construction of a short-run marginal cost (SRMC) schedule. With no carbon price (i.e. the 2018 situation) brown coal is the cheapest plant followed by CCGTs and then OCGTs running on gas. Brown coal is so cheap that even with very high carbon price (e.g. \$A94/t $CO_2$) the merit order does not change. The slope of the supply curve over the central 75% (i.e. from 10% to 85%) with no carbon price is again \$A38/GW (the slope is shown moving from brown coal to the least efficient CCGT, but not including any OCGTs). The slope becomes progressively less steep as the carbon price rises.

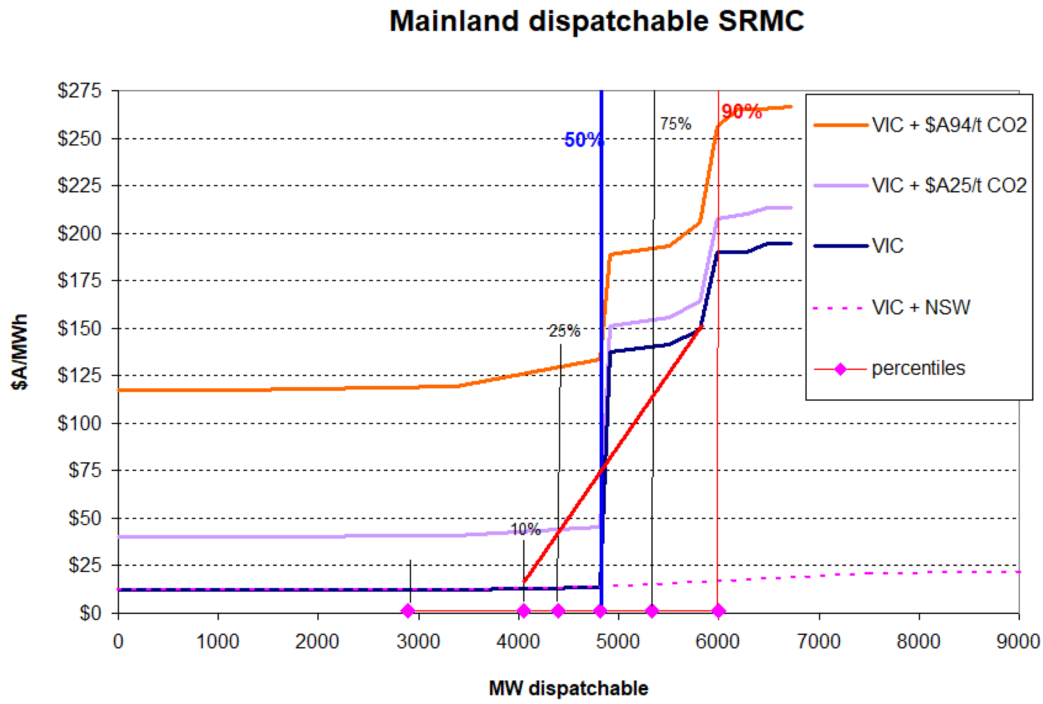


Figure E3 Victoria and NSW dispatchable short-run marginal cost, 2021 fuel prices
Source: *2021 AEMO-NEM data input and assumptions workbook*

If Victoria enjoys unconstrained trade with its near neighbour NSW with its almost as cheap black coal, then the supply schedule is essentially flat. A compromise might be to assume that some fraction of the time that is the relevant supply schedule but at other times Victoria cannot increase its trade with NSW. Prices in VIC and NSW at the 5-min resolution are within 5% of each other 33% of the time in three sample months in 2018 (Jan, Jun, Nov). A defensible average then might be $A25/GW, as used in the paper.

**Appendix F Data Sources**

https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/data-dashboard-nem gives prices and fuel mix by state for up to the last 12 months

wind traces at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2019-isp-database

Utilising 2018-19 wind speed and direction data from DNVGL
Modelling produces half-hourly normalised traces for each wind generator based on the following inputs: Region, Longitude and Latitude. The output is calculated through a power curve relationship by matching the quantiles of the wind speed and power output series

Standard wind speed-power curves used when there is not enough training data

MW traces by multiplying with the name plate rating. For new registered wind farms, the Max Capacity from the Registration Data. For newly committed wind farms, the Nameplate capacity from Gen Info page.

The spreadsheet used in calculations is available from the author (with no guarantee of its accuracy).