20 December 2021

Ms Anna Collyer
Chair
Australian Energy Market Commission
Level 15, 60 Castlereagh Street
SYDNEY NSW 2000

By electronic submission

Dear Ms Collyer

Rule change request - Dual-Floor Price - Transmission Access Risk

Snowy Hydro submits the attached request for the Australian Energy Market Commission (AEMC) to amend the National Electricity Rules (NER).

Dispatchable generation faces increasing transmission access risk due to the growth of wind and solar plants. As thermal assets retire and are replaced by weather-dependent forms of generation capacity, it is critical that the NEM sustains an adequate level of dispatchable generation. The Australian Energy Market Operator (AEMO) forecasts that the NEM will require between 6-19GW of new dispatchable resources to backup renewables by 2040. However, this target is at risk without addressing transmission access risk for dispatchable generation.

This proposal seeks to reduce transmission access risk for dispatchable generation by lifting the bid price floor of semi-scheduled generation. This will support capacity revenues for firm assets and lower the cost of hedging contracts, without materially affecting the energy revenue stream of renewables.

Feel free to contact me if you have any questions using the address details below.

Yours sincerely,

Leigh Creswell

Leigh Creswell

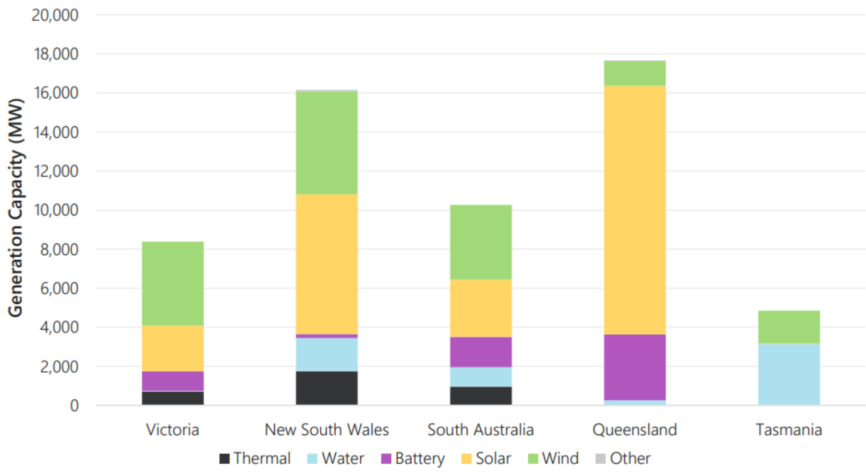
Snowy Hydro Limited

1. Background

Growth of Renewables

The National Electricity Market (NEM) is experiencing rapid structural change, as bulk intermittent renewable energy replaces dispatchable baseload energy. This is due to legislated renewable targets and simple economics. The levelised cost of energy of new, utility-scale wind and solar generation is significantly lower than new thermal capacity. This is borne out by real-world developments in the NEM: the overwhelming majority of incremental generation capacity in the last decade has been wind or solar. Furthermore, the Australian Energy Market Operator 2021 Electricity Statement of Opportunities (ESOO) estimated that of the 121 GW planned but as yet uncommitted projects, some 67% are variable renewable energy (VRE).

Figure 1: Proposed projects by type of generation and NEM region, beyond those already committed[1]

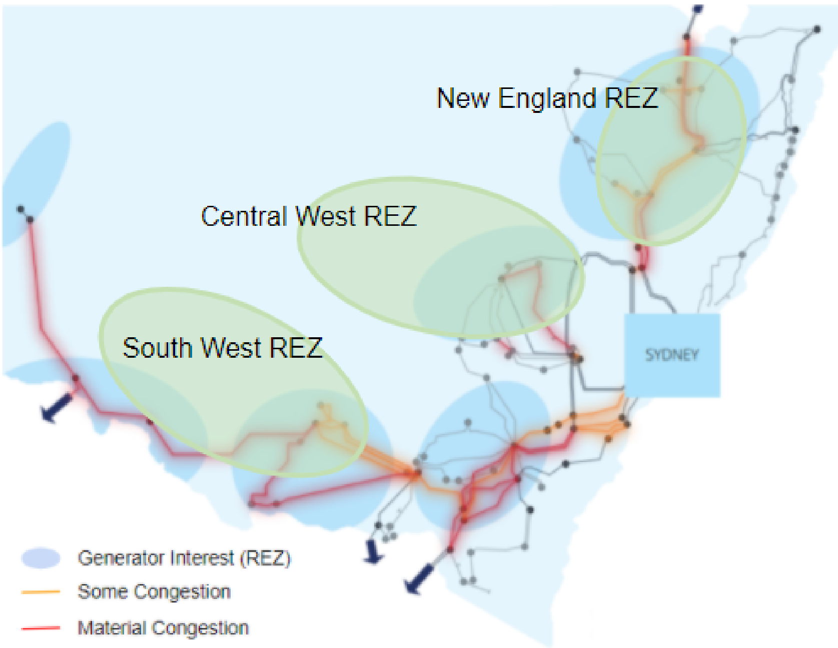


New VRE projects are more geographically diverse than the thermal assets they are replacing. This is creating competition for transmission access for some dispatchable generators, and this competition is expected to increase significantly once more renewables are commissioned.

Figure 2 below highlights the congestion problem in NSW. Utilisation of the transmission system is at capacity already, so there is little spare capacity available for new renewables. There are currently more than 6,000MW of applications for new renewable generation, but this capacity is unable to be developed until transmission infrastructure is upgraded.

[1] July 2020 Generation Information, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nemforecasting-and-planning/forecasting-and-planning-data/generation-information.

Figure 2: NEM Congestion in Regional Areas (REZs)[2]



In the short term, this issue will primarily affect dispatchable generators at Tumut, Murray, Uranquinty and Southern Hydro, as they compete with renewable generators in the transmission path between the Snowy Mountains region and Melbourne/Sydney. However this problem will ultimately be transferred to other parts of the network. This is not simply a problem peculiar to Snowy Hydro, it is one that will ultimately be faced by dispatchable assets all over the NEM.

As the Energy Security Board (ESB) identified in the Post 2025 Market Design, REZs are often located on interconnector flow paths, which will likely reduce the value delivered by interconnectors. This will continue to increase constraint costs, which has been a growing problem across the NEM.

Some congestion in the network can always be expected, for example even after AEMO's Integrated System Plan is delivered. This is because it is inefficient to build a network that is never or only rarely utilised to its capacity. However, as described further below, the existence of congestion does not justify transmission access reform, which would create more problems than it would solve. In any event, this rule change does not seek to address congestion generally. Rather, it aims to ensure a sustainable level of dispatchable capacity in the NEM, focusing on congestion arising from an externality associated with the growth of wind and solar projects.

[2] Snowy Hydro internal analysis

Market Design

The NEM is structured around two complementary markets. The spot market is concerned with maintaining the physical security of the network by instantaneously matching supply and demand. The contracts market, on the other hand, allows buyers and sellers to financially manage their short and long-term energy needs. Most of the 'real commerce' takes place in this market, highlighting participants' desire to stabilise their energy costs and revenues through contracts, rather than be exposed to the volatility in the spot market. Since the inception of the NEM, contract market volumes have averaged 200-400% of the spot market. This suggests that outcomes in the contract market are, in economic terms, more important than those that occur in the NEM. It follows that an efficient, functioning contracts market is critical to achieving the National Energy Objective (NEO).

Generators' ability to offer contracts depends on their having adequate transmission access. Generators need confidence in their ability to defend their contract obligations, and this depends on having a reasonable certainty of dispatch during the periods in which they are likely to make payments under those contracts. The issue is acute for providers of capacity (peak) contracts[3], since a small number of dispatchable intervals usually account for the majority of revenue paid out under those contracts. A generator that fails to secure dispatch (i.e. transmission access) during those intervals will suffer severe financial losses. This is not simply a problem for generators. It ultimately becomes an issue for load (retailers), because it encourages generators to reduce the volume of contracts offered to the market and/or impose a 'volatility premium' to contract price, increasing energy costs.

This issue is also important in the NEM as an energy-only market, because capacity generators have only a small number of opportunities to recover their fixed costs. They need certainty of dispatch during high price events in order to remain financially viable.

2. Nature and Scope of the Issue

The influx of renewables is harming dispatchable generators' ability to sell firm contracts. Utility-scale renewable generation assets are typically developed on the basis of power purchase agreements (PPAs), long term offtake agreements whereby the buyer agrees to buy some or all of the output of the project. In contrast to contracts offered by owners of dispatchable assets, the energy sold under PPAs is usually based on the metered output of the plant. In other words, buyers under PPAs receive intermittent, weather dependent output. The value offered by these contracts reflect the physical capabilities of wind and solar developments; they supply cheap energy but, because they are weather-dependent, they offer comparatively little 'capacity value' ie. the ability to generate on demand.

[3] While the issue particularly affects capacity generators, it is a problem for all providers of fim contracts, ie. scheduled generators.

In general, it is economically important that dispatchable assets have firmness of dispatch during periods of volatility, because they typically offer price insurance against such events. During congestion, which often coincides with high prices, owners of dispatchable assets often need to bid at the market floor price (MFP) in order to secure dispatch and defend their contracts. However, a peculiarity of many PPAs is that, by virtue of negative price risk being allocated from the generator to the PPA counterparty, they encourage renewable assets to also bid at the MFP during those periods, displacing dispatchable generators during periods when 'firmness' is most important to the market.

Owners of renewable assets ought to have no such incentive. They are selling energy, not capacity, and the financial viability of those assets depends largely on their annual capacity factors, rather than dispatch in any particular dispatch interval. Given that generation from renewable assets in a given dispatchable interval cannot be known in advance, neither owners nor offtakers can assume those assets will offer protection against a period of volatility and there is little benefit from those assets ever bidding below their short-run marginal cost in order to ensure dispatch.[4]

However, as discussed above, under many PPAs, the seller receives a fixed price for all generation in all periods, even during negative pricing, and this incentivises owners of renewable plant to also bid at the MFP. The effect of this arrangement is to transfer the impact of dispatch at negative prices from sellers of PPAs to buyers, and also to generators who face negative price risk. It also means that dispatchable generators are less likely to secure dispatch during these periods. Faced with this risk, providers of firm contracts will need to impose a "transmission risk premium". Alternatively, if the risk is too high, contracts won't be offered at all, which may make investment in new assets unviable given an uncertain revenue stream and in turn raise prices for consumers. By way of example, this risk has caused Snowy Hydro to reduce its target level of contracting in NSW by 300MW in each Q1 since Q1 21. Likewise in other quarters, when planned transmission outages are common, it has reduced its target contracting by 400MW more than it previously did during transmission outage conditions. In Victoria the risk is more uncertain, but Snowy places a $2/MWh premium on the last 100 MW of target contracting to reflect this transmission access risk.

This is a problem for the NEM, because unlike weather-dependent generators, peaking assets rely on price spikes to fund their fixed capital costs. The financial viability of peaking capacity quite literally depends on their having market access during those periods. The consequence is revenue inadequacy ('missing money') for plant owners and a disincentive for investment in peaking assets, which are becoming more important to manage the growth of VRE. This revenue inadequacy is heightened for those peaking generators that have sold fixed-volume or load-following contracts, who then need to make difference payments under these contracts without commensurate spot market revenues.

[4] See further below in section 4

It would be wrong to dismiss the problem on the basis that it does not create any immediate shortfall in supply. In the periods during which this issue arises, the market continues, in a narrow, physical sense, to be settled. However, focusing narrowly on spot settlement outcomes ignores the long-term harm to system security and consumer energy costs if this problem is allowed to continue to develop. The shortfalls in capacity revenues it creates will ultimately reduce efficient levels of capacity investment, jeopardising the market's ability to meet future price spikes (when VRE may be unavailable to meet demand). In general, load/market customers seek to avoid exposure to the spot market and so require affordable and reasonably accessible contract cover to manage their energy costs. Without reform, energy contracts will become more costly and the contracts market will become more illiquid.

Access Reform

It would be incorrect to infer that the problems described above justify transmission access reform. This rule change is targeted at a particular problem associated with congestion, ie. uncertain dispatch for scheduled plant, which inflates consumer contracting costs and reduces capacity revenues for dispatchable assets. It does not seek to influence locational decisions, but is rather concerned with maintaining system security. This is a targeted solution which avoids the drawbacks of access reform; it will not create an actual or *de facto* local marginal price or expose generators to a complicated system of rebates designed to change the compensation they would otherwise receive for a unit of output. Unlike access reform, all generators will continue to be paid the Regional Reference Price and contracts will not be disrupted. Furthermore, unlike access reform, it does not require any complicated changes to the Rules and should not impose significant implementation costs on AEMO. As a result, this rule change proposal will reduce the cost of contracting and will increase rather than impair contract liquidity.

Network Augmentation

The most effective method to address network congestion is by increasing transmission capacity. In that respect, Snowy Hydro supports AEMO's Integrated System Plan, and in particular the need to construct actionable ISP Projects. However, the increased transmission capacity offered by those projects will not be available for a number of years, and in any event, it is neither possible nor desirable to eliminate all congestion. Network upgrades and generation development will never be in step, and network upgrades are likely to always be a "step behind" generation upgrades. This rule change reduces the risk faced by scheduled generators while waiting for new transmission capacity and is less costly than over-building the network to guarantee dispatch. Furthermore, network upgrades will not prevent congestion during transmission equipment outages, which is a major risk for scheduled generators and reduces contracts being offered in periods when line outages are planned. This rule change complements transmission augmentation and represents an efficient means for dealing with congestion without the costs associated with access reform.

3. How the Proposed Rule Would Address the Issue

In determining the priority order for transmission access, AEMO's dispatch engine ('NEMDE') trades off two things: bid price and transmission constraint coefficients. Each of these factors impact generators' transmission access. During congestion, competing generators bid at the Market Floor Price ('MFP', ie. -$1000/MWh) to try to guarantee dispatch. As all generators have the same (floor) bid price, NEMDE determines transmission access priority based purely on which generator has the (often very slightly) lower transmission constraint coefficient. This means that a wind or solar farm may displace dispatchable capacity based on marginal differences in their constraint co-efficient.

This rule change proposes a simple solution, by raising the MFP for semi-scheduled generators to -$100/MWh, while leaving the MFP for scheduled generators at -$1000/MWh.

This change would mean improved certainty of dispatch for dispatchable plant (in technical terms, a wind or solar farm would need to have a transmission constraint coefficient at least 6% lower than dispatchable plant to gain priority transmission access). This change will benefit the market as a whole as it offers more certain capacity revenue to dispatchable generation, increases the 'price signal' for capacity investment, lowers contract costs to retailers and hence electricity costs for consumers. It also facilitates investment in dispatchable generation that future VRE will depend upon for firming, enabling the transition to a decarbonised NEM.

While it might be possible to improve market access for dispatchable plant by adjusting constraint co-efficients, we believe the primary solution lies in differential floor prices based on generation characteristics. The MFP, along with other reliability settings in the NEM (the Market Price Cap, the Cumulative Price Threshold and the Administrative Price Cap), are regularly assessed by the Reliability Panel, whereas constraint coefficients ultimately reflect physical characteristics of the transmission network. Adjusting the MFP for semi-scheduled plant is therefore the least disruptive option.

4. How the Proposed Rule will Contribute to the Achievement of the National Electricity Objective (NEO)

Overview

The proposed rule will contribute to the NEO in the following respects:

- by reducing the transmission risk premium for dispatchable assets during periods of market volatility, the proposal will increase the availability and lower the cost of contracted energy for Market Customers. Retailers typically acquire most of their energy through hedging contracts, and so this proposal will put downward pressure on energy prices; and

- by increasing revenue certainty for dispatchable assets, and in particular the ability of asset owners to secure generation revenue in the physical market (ie. the NEM) necessary to defend obligations owed under hedging contracts, the proposal will incentivise investment in dispatchable capacity, providing a market-based mechanism for improving energy market reliability and security.

An advantage of this proposal is that it is relatively cheap to implement, particularly in comparison with other reform proposals aimed at improving resource adequacy in the NEM (such as the Physical Retailer Reliability Obligation). Furthermore, the modelling described in section 5 establishes that the proposal will have, at most, a limited and modest impact on revenues for non-scheduled plant.

Expected Costs and Benefits Analysis

It is important not to take a static view of the NEM in assessing this draft rule change proposal. Lack of firming generation will increasingly become the biggest roadblock to the continued penetration of renewable generation, and this proposal assures the economics of the dispatchable plant needed to firm renewables.

Improving transmission access for scheduled plant on the rare occasions it is needed to defend capacity contracts will lower energy costs, as it avoids a transmission risk premium in capacity contracts. This is important for the economics of future dispatchable plant as it improves their access to a “capacity” revenue stream via capacity contracts. As mentioned, this is important for the continued growth of renewables, as they are reliant on the development of firming capacity generators to firm them. It is not a competition between VRE and dispatchable generators. Policy settings should encourage them to work together using their complementary strengths: renewables as providers of cheap, bulk energy and dispatchable generation as a source of on-demand firming. Without a sustainable level of dispatchable plant, VRE growth will be constrained and the carbon footprint of the NEM will be higher than it otherwise would be.

This change should not materially affect the economics of a semi-scheduled generator as neither asset owners nor offtakers are able to assume they will be generating when the price is high (they can’t as their energy source is intermittent), so dispatch at high prices is only a “bonus”. That is, generation from wind and solar plant during a *particular* high price event could never be assumed in advance, and it follows that there is little dis-benefit in being unable to generate during a particular interval. The economics of a semi-scheduled generator lies in “day to day” energy (ie. its energy, rather than capacity value). This change will not affect renewable generators’ comparative advantage in cheap energy and they will generally enjoy priority in dispatch by virtue of having zero short-run marginal cost. Wind and solar typically contract most or all of their output at a fixed price, and to that extent do not benefit from price spikes (any revenue from price spikes is paid as a difference payment to the offtaker). In the longer term, the rule change will support higher levels of VRE penetration, by sustaining an efficient level of dispatchable assets to maintain system security. In this way the Rule Change contributes to the NEO.

Aside from the few days (and hours) of the year when they may lose dispatch to scheduled generators during high prices and congestion, the only time their dispatch could be affected is when they are competing with scheduled generators bid at -$1000/MWh for physical reasons.

In economic terms, the lowest a renewable generator needs to bid is the negative price of a large-scale generation certificate (LGC), which, given the current LGC forward curve, is forecast to fall to approximately $10/MWh or lower in a few years. So a -$50/MWh floor should be sufficient, but allowing -$100/MWh will take into account legacy PPAs with high LGC values.

While this rule change proposal gives preference to scheduled generators insofar as it provides access to a lower MFP, it does not discriminate against any particular fuel source or asset class; any asset capable of being scheduled would benefit from it. Moreover, as with current rules which distinguish between and impose different rights and obligations upon scheduled and semi-scheduled plant, so this rule change would establish a MFP specific to scheduled generators. Semi-scheduled plant currently enjoy reduced obligations under the NER compared to scheduled generators, and this rule change is no more 'discriminatory' than those provisions. It simply acknowledges the different generation characteristics of particular generation types.

Finally, when semi-scheduled generators are competing with each other, their dispatch will be the same whether they are all bid at -$1000/MWh, -$100/MWh or $0/MWh. As long as they all bid at the same (floor) price, their dispatch is the same (and their revenue is actually higher if they are all forced to bid at a higher price and set a higher market price).

5. Modelling

Snowy Hydro requested Baringa Partners LLP (Baringa), a consultancy, to independently analyse historical curtailment experienced by generators when bidding at the MFP. In Snowy Hydro's view, Baringa's analysis suggests this rule change proposal would have a negligible impact on the aggregate output and revenues of semi-scheduled plant. Baringa's report for this analysis is attached as Annexure A (the supporting workbook, in Excel format, is available on request).

With reference to Table 1 below, Baringa's approach was as follows:

1) calculate the level of curtailment (GWh) currently experienced by scheduled plant when bidding at the MFP for financial years 2020 and 2021 (column A); and

2) calculate the level of curtailment (GWh) currently experienced by scheduled plant when bidding at the MFP for financial years 2020 and 2021, restricted to dispatch intervals when the regional reference price exceeded $300/MWh (column B);

3) calculate the total output of scheduled plant (GWh) during financial years 2020 and 2021 (column C);

4) divided the level of curtailment experienced by scheduled plant in financial years 2020 and 2021 by the total output of semi-scheduled plant for each year (column A/C), and

5) divided the level of curtailment experienced by scheduled plant in financial years 2020 and 2021 during dispatch intervals when the regional reference price exceeded $300/MWh, by the total output of semi-scheduled plant for each year (column A/C).

The results of Baringa's analysis are set out in Table 1 below.

Table 1

Financial Year	A	B	C	A/C	B/C
	Scheduled Plant (GWh)	Scheduled Curtailment (RRP>$300/MWh) (GWh)	Semi Scheduled Plant (GWh)	%	%
2020	537	6.77	20,730	2.59	0.03
2021	329	5.22	25,650	1.28	0.02

Table 1 demonstrates that even if the impact of this draft rule change was to transfer the entirety of the curtailment currently experienced by scheduled plant to semi-scheduled plant when bidding at the MFP, the impact on the total output of renewable generators is modest; between 1.59-2.59% over 2020-2021. The impact during high price periods (over $300/MWh) is negligible, between 0.03-0.02%.

However, these results are conservative, because it is unlikely that all such curtailment would be transferred to semi-scheduled plant. This is because some of the curtailment experienced by scheduled plant when bidding at the MFP (ie. as represented in Table 1) arises from competition for transmission access with other scheduled plant, rather than semi-scheduled plant. In order to adjust the results to exclude this type of curtailment, Snowy Hydro took Baringa's analysis and extended it to consider only those dispatch intervals where:

1) more than 90% of the maximum availability of a generating unit ('DUID') is bid at the MFP; and

2) both the scheduled and semi-scheduled plant was on the left hand side of a binding transmission constraint,

("**Additional Conditions**").

The Additional Conditions are a proxy for periods when scheduled plant is competing for transmission access with semi scheduled plant in order to defend contract positions; a generator bidding less than 90% of its maximum availability at the MFP suggests it was bidding at the MFP for other reasons, like maintaining dispatch above physical min loads

The results of applying the Additional Conditions to the analysis represented in Table 1 are represented in Table 2 below.

Table 2

	D	E	F	D/F	E/F
Financial Year	Scheduled Curtailment (GWh)	Scheduled Curtailment (RRP>$300/MWh) (GWh)	Semi Scheduled Generation (GWh)	%	%
FY 20	166	5.31	19,760	0.84%	0.03%
FY 21	27	2.99	24,951	0.11%	0.01%

Table 2 demonstrates that the impact of the Rule Change proposal on the total output of semi-scheduled plant is likely to be negligible, even for 'normal' or low price periods, ie. less than 1% in the last two years in all periods.

Considering Tables 1 and 2, we can also observe:

- comparing columns A to D, a significant amount of curtailment experienced by scheduled plant does not occur due to constraints when prices are low. That is, to a significant extent scheduled generators are being curtailed during periods when dispatch access is critical for their ability to defend hedging contracts); and

- comparing columns D to E suggests that the majority of the curtailment experienced by scheduled plant in D occurs when prices are lower than $300/MWh. Some of this volume is due to high price sensitivity, i.e. scheduled plant competing for transmission access in order to defend contract positions "incase" the price spikes to a higher level. Some of the volume will also be due to 30 minute settlement, i.e. when the five minute dispatch price is low but the 30 minute settlement price is high. The latter won't occur under five minute settlement, so the volume in "D" will reduce from October 21.

6. Changes to be made in the NER

Amend clause 3.9.6 as follows.

3.9.6 Market Floor Price

(a) The market floor price is a price floor which is to be applied to dispatch prices.

(b) The value of the market floor price is:

(1) for *Scheduled Generators*, $-1,000/MWh; and

(2) for *Semi-Scheduled Generators*, $-100/MWh.

(c) [Deleted]

(d) [Deleted]

(e) [Deleted]

Appendix - Negative Prices

It is worth considering why negative prices exist in the first place. What is their economic rationale?

Electricity supply has a unique set of characteristics. Unlike most other goods and services, physical electricity markets must be cleared in real-time. If oversupply or undersupply are not immediately cleared, the network will destabilise and blackouts may occur.

Oversupply can be managed in two ways:

1) through administrative actions by the market operator, by 'switching off' or tripping supply, usually based on a pre-determined order of priority. Under this approach the floor price is at or near $0; or

2) by allowing the market to assign a clearing value to excess generation. Under this approach the floor price is set at a negative value, and generators signal their willingness to incur a cost to avoid curtailment. When the market is cleared at a negative price, generators pay consumers/load to take electricity generation.

A market approach is more efficient, as it provides more depth in the merit order by allowing generators to reflect the opportunity cost of curtailing their generation in their bids (rather than being administratively determined by a bureaucrat).

Coal plants have significant cycling costs associated with turning off and on in relatively short periods, and so it makes sense for them to pay to stay online in order to avoid those costs. Costs may also arise from contract obligations. Generators that have sold price insurance in the contracts market may wish to ensure dispatch, even at the risk of negative prices, in order to ensure that they are able to defend their obligations under those contracts. In the case of dispatchable plant, these incentives work in favour of system security and energy users, because they provide flexible generation with an incentive to maximise their availability during times of market volatility. For these and other reasons, the NEM adopted a market floor price (MFP) of negative $1,000/MWh.

The growth of wind and solar has complicated the operation of negative prices in the NEM. Government intervention is partly behind this. Renewable generators typically have zero short run marginal cost (that is, they have no fuel costs). This suggests it is efficient for these generators to bid and generate at or above $0. However, renewable generators are also subsidised by renewable energy certificates, and so it is rational for those generators to bid at a negative value up to the value of those certificates. Based on certificate values, this gives a maximum opportunity cost of -$50/MWh for most wind and solar plant, and potentially up to -$100/MWh for some plant operating under legacy contracts. Note, this is well below the current maximum floor price in the NEM of -$1,000/MWh.

However, a problem arises from the way in which wind and solar plant sell their output to customers, which is usually through power purchase agreements (PPAs). This is because these agreements have typically been structured so that the plant owner does not have any incentive to submit economic bids to AEMO, ie. at a price which reflects their cost of generating. This is because under many PPAs, the buyer guarantees to pay the seller a fixed price for all generation they produce in all periods, even during negative pricing, and this incentivises the seller to bid at the maximum negative price, ie. the market floor price. (Not all PPAs, including those signed by Snowy Hydro, operate in this way, but many do). This means that there is no disincentive for renewable generators to withhold capacity at any price, even though it would otherwise be rational for them to do so, because they are fully compensated by the PPA buyer.

This is a type of moral hazard which creates externalities for energy users. It means that wind and solar generation is able to displace dispatchable generation in the merit order, even when they have, or ought to have, a lower opportunity cost of being switched off than other types of dispatchable plant. Energy users must bear the cost of a less secure network, as well as higher costs/payments to capacity owners who must seek a greater capacity premium to maintain revenue adequacy. This problem is magnified by the failure of NEMDE, AEMO's dispatch engine, to adequately distinguish between the characteristics associated with different types of generation. Dispatchable plant, unlike wind and solar, typically has inertia which makes the system more resilient to frequency excursions.

The fact that this characteristic is not appropriately valued by NEMDE ('missing markets') means that wind and solar may be dispatched even though it may lower consumer welfare. This precipitates further market intervention. The problem is particularly noticeable in South Australia, which has a high penetration of variable renewable energy. In that State, AEMO operating constraints have limited wind and solar generation, and have required a minimum level of gas-powered generation to stay online in order to provide essential grid services.

The incidence of negative prices and surplus supply conditions has increased as intermittent generation has grown, and combined by an insufficient increase in interconnection to make efficient use of that surplus generation.

A better approach to managing high levels of wind and solar would be to:

1) recognise the different physical characteristics of generation types (dispatchable vs intermittent/weather dependent) by providing access to different (resource specific) price floors;

2) creating markets for previously unvalued essential system services;

3) improving interconnection to more efficiently utilise excess generation.

Historical curtailment of scheduled and semi-scheduled generators

Final Report

Snowy Hydro

September 2021

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Executive Summary [1]

Snowy Hydro engaged Baringa to quantify the extent of historical curtailment of generators in the NEM

- Snowy Hydro engaged Baringa to undertake historical analysis of the frequency and magnitude of output curtailment of scheduled and semi-scheduled generators in the NEM
- The purpose of the analysis was to quantify the extent to which scheduled and semi-scheduled generators were curtailed in relation to capacity bid at the market price floor (MPF). That is, the analysis focused on those generators and time periods where actual output was below the capacity bid at the MPF (-$1,000/MWh)
- The following additional points are worth noting in relation to the scope of the historical analysis:
  - It was done for all scheduled and semi-scheduled generators in the NEM. In addition, Baringa undertook the analysis just for the Snowy Hydro portfolio of generation assets to examine the extent to which the extent and frequency of curtailment was different for Snowy Hydro generators vs. the NEM overall
  - The comparator analysis also included a comparison of Snowy curtailment against those of competing generators – competitors were those either in the rest of NSW or situated geographically close to Snowy's portfolio (i.e, generators situated either in NSW or VIC, and close to the VIC-NSW border)
  - It covered the period from 1 July 2018 to 30 June 2021 (i.e., three financial years), with the resulting findings separated by time of year to examine potential seasonality effects
- The supporting Excel workbook contains the data underlying the charts and tables presented in this report, as well as additional analysis not presented in this report (for the sake of brevity):
  - the three Scheduled generators (by DUID) across the NEM with the largest curtailment volumes
  - the three Scheduled generators (by DUID) across the NEM with the largest curtailment volumes, and
  - the average volume (GWh) of Scheduled generator curtailment (by DUID) by half-hour and the average volume (GWh) of semi scheduled curtailment (by DUID) by half hour

Executive Summary [2]

Summary of results over the FY19 to FY21 period

- The key findings from the historical analysis over FY2019 to FY2021 can be summarised as follows:
  - Curtailment at the MPF was larger for Semi-Scheduled generators than for Scheduled generators relative to the energy bid in at the MPF. As a proportion of energy bid in at the MPF, Semi-Scheduled generators experienced in excess of 3% curtailment, more than seven times higher than for Scheduled (less than 0.3-0.5% curtailment).
  - A large proportion (more than 65%) of the curtailment of MPF bids experienced by Semi-Scheduled generators is due to System Strength constraints. This is particularly noticeable in SA, where the System Strength proportion is 85%.
  - This finding applied, directionally, even when the analysis was filtered down to examine only those intervals where RRP > $300/MWh (i.e., periods where $300 cap contracts would be 'in the money'). However, the magnitude of the curtailment increased during >$300 periods
  - Curtailment of Semi-Scheduled generators at the MPF typically occurred in shoulder months and quarters (i.e., Q3 of each year, or July – September), whereas curtailment of Scheduled generators at the MPF typically occurred during Q4 (October – December)
  - Curtailment experienced by Snowy assets typically was in the middle of the range of curtailment of five selected generator groups. Namely, Snowy curtailment was typically:
    - higher than the curtailment at the MPF of other Scheduled generators in NSW, and also higher than curtailment at the MPF of Scheduled generators close to Snowy (these generators are either in NSW or in VIC)
    - lower than curtailment at the MPF of other Semi-Scheduled generators in NSW, and also lower than curtailment at the MPF of Semi-Scheduled generators close to Snowy (these generators are either in NSW or in VIC)
  - Snowy curtailment at the MPF was much larger when the corresponding RRP was greater than $300/MWh. This finding was also observed for the other four generator groups
    - Snowy curtailment during RRP > $300 intervals was 3%, during FY2020, the highest curtailment for Snowy over the 3-year time period
    - In this same year (FY20), the largest curtailment share was for other Semi-Scheduled generators (11%), followed by nearby Scheduled generators (7%)

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Introduction to the project [1]

Snowy Hydro engaged Baringa to quantify the extent of historical curtailment of generators in the NEM

- In June 2021, Snowy Hydro engaged Baringa to undertake historical analysis of the frequency and magnitude of output curtailment of scheduled and semi-scheduled generators in the NEM
- The purpose of the analysis was to quantify the extent to which scheduled and semi-scheduled generators were curtailed in relation to capacity bid at the market price floor (MPF). That is, the analysis focused on those generators and time periods where actual output was below the capacity bid at the MPF (-$1,000/MWh)
- This approach means the focus of Baringa's analysis is on historical periods of generator curtailment due to insufficient intra-regional network capacity (i.e., technical/network-based curtailment). The different forms of generator curtailment are discussed in the following slides within this section
- The following additional points are worth noting in relation to the scope of the historical analysis:
  - It was done for all scheduled and semi-scheduled generators in the NEM. In addition, Baringa undertook the analysis just for the Snowy Hydro portfolio of generation assets to examine the extent to which the extent and frequency of curtailment was different for Snowy Hydro generators vs. the NEM overall
  - It covered the period from 1 July 2018 to 30 June 2021 (i.e., three financial years), with the resulting findings separated by time of year to examine and report potential seasonality effects
- The supporting Excel workbook contains the data underlying the charts and tables presented in this report, plus the following additional analysis not presented in this report (for the sake of brevity):
  - the three Scheduled generators (by DUID) across the NEM with the largest curtailment volumes
  - the three Scheduled generators (by DUID) across the NEM with the largest curtailment volumes, and
  - the average volume (GWh) of Scheduled generator curtailment (by DUID) by half-hour and the average volume (GWh) of semi scheduled curtailment (by DUID) by half hour

Introduction to the project [2]

Baringa

Why do generators bid capacity at the market price floor?

- Generators often bid some or all of their capacity at the MPF, for the following reasons:
  - To signal their inflexibility: it is costly to shutdown and, in particular, restart steam-powered turbine generators, and therefore generators are willing to bid at least their minimum stable load at the MPF to avoid the higher costs associated with restarting a unit that has shut down due to operating below its MSL
  - To maximise their dispatch, at times where there are network constraints limiting the flows from the generator to the regional reference node (i.e., the phenomenon of 'race-to-the-floor bidding' behind network constraints under regional/zonal pricing)
  - For semi-scheduled generators, to maximise their dispatch where these generators are defending generation-following hedges (i.e., PPAs) with negative-price risk allocated to the hedge counterparty. With the generator not facing negative price risk, they get paid the PPA strike price whenever they generate, regardless of the level of the spot price. A similar phenomenon exists for those generators that have sold proxy revenue swaps
  - To capture the benefit of high prices in the preceding dispatch intervals of that settlement interval: the NEM currently has 30-minute settlement (30MS). Under 30MS, the settlement price is the equally-weighted average of the six dispatch prices in the six dispatch intervals that comprise that settlement interval (with the first settlement interval in each calendar day starting at 12:00am AEST)
    - Consequently, a high price in a dispatch interval then pushes up the price for that settlement interval (i.e., the settlement price). For example, a price of $15,100/MWh (which is the current market price cap in the NEM) in the first dispatch interval of a given settlement interval would yield a settlement price of $1,683.33/MWh, well in excess of even the most-expensive generator's generation cost, *even when the price in each of the subsequent five dispatch intervals equals the MPF*
    - Some Generators, in response to the price spike in this dispatch interval, then typically (re)bid all their capacity at the MPF in the subsequent dispatch intervals of that settlement interval, to maximise their dispatch and in turn maximise their profits
    - This type of race-to-the-floor bidding is expected to end from 1 October 2021, which is when 30MS ends and five-minute settlement begins

Introduction to the project [3]

What are the forms of generator curtailment?

- A generator is 'curtailed' when its dispatched volume is lower than the aggregate of all the capacity it has offered into the market, at prices equal to or lower than the prevailing market price
- Generator curtailment can be understood in two broad categories: *technical curtailment* driven by network and system constraints, and *market curtailment* driven by regional oversupply of generators (typically, renewables)
  - Technical (or network) curtailment: Curtailment that is due to a lack of network capacity coincident with generator capacity. The forms of technical curtailment include:
    - <u>Thermal ratings-based curtailment:</u> here, generator output is curtailed in order for flows on network components (e.g., lines and transformers) to not exceed their corresponding thermal ratings (either continuous or short-term ratings). These network constraints are applied both pre-contingency ('system normal') and post-contingency basis, the latter being constraints designed for the contingency planning of the outage of a network component on other critical network assets
    - <u>System strength-based curtailment</u>: here, output from *semi-scheduled* generators (i.e., asynchronous generators) is curtailed, and output from *scheduled* (synchronous) generators is simultaneously increased, in order to maintain sufficient fault current (or "system strength") on both a pre- and post-contingency basis
    - <u>Voltage stability-based curtailment</u> and other forms of system security-based curtailment (transient and oscillatory stability)
  - Market (or economic) curtailment: generator curtailment that occurs to rectify regional oversupply situations. Typically, this occurs when there is excess zero marginal cost generation, such as wind and solar, on the system. Prices are typically zero or negative during market curtailment events
- AEMO's *Constraint Formulation Guidelines** contains other reasons for generator curtailment, including curtailment due to 'clamping' of negative inter-regional settlement residues – see Section 5.3 of the *Guidelines*
  - While generator curtailment due to residue 'clamping' is a different basis for curtailment than those listed above, it is worth noting that 'clamping' is also a form of network curtailment

* https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2016/Constraint_Formulation_Guidelines_v10_1.pdf

Introduction to the project [4]

How does curtailment occur in the NEM?

- Technical curtailment occurs in accordance with the formulation of AEMO's constraint equations. These equations represent the physical restrictions necessary – on generator output, load volume, and power flows on network components – for secure and sustainable operation of the power system

- *Tie-breaking rule*: When several generators are bidding at the same price at the RRN and the total available energy is greater than the load to meet, AEMO follows a tie-breaking rule which allocates the generation on a pro-rated basis*

- The NEM Dispatch Engine (NEMDE) operates under the principle of *security-constrained economic dispatch*, which means in the context of curtailment that:
  - Technical curtailment would be applied *first* to generators (to make sure the power system remains in a secure operating state)
  - To the extent there is oversupply of renewables at a regional level afterwards, market curtailment will be applied using the tie-breaking rule

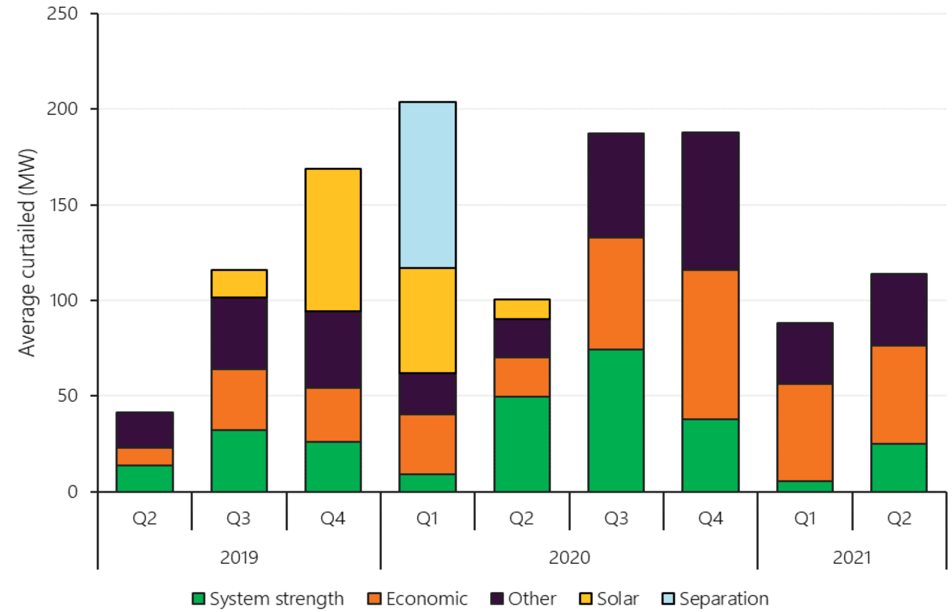
*Clause 3.8.16 of the National Electricity Rules (NER): https://www.aemc.gov.au/sites/default/files/2019-11/NER%20v126%203.%20Market%20Rules%E2%81%A0.pdf

Introduction to the project [5]

Historical incidence of generator curtailment in the NEM

- Network-based curtailment has historically been the larger source of curtailment of variable renewable energy (VRE) generators, than economic/market-based curtailment
- Market-based curtailment comprised less than half of VRE curtailment during both Q2 2021 (45% of average curtailed volumes), and FY2021 (41%) – see RHS graph
- System strength-based curtailment is a key component of network-based curtailment, and has historically been a bigger driver of VRE curtailment than other forms of network curtailment (e.g., thermal ratings-based)
- System strength-based curtailment comprised one-quarter of average VRE curtailment during Q2 2021. This was down from a 3-year high of 50% during Q2 2020
- These proportions are across the VRE fleet and so are likely to differ for specific technologies (e.g., solar PV) and for VRE in different regions
  - As an example of the latter, system strength-based curtailment has impacted VRE generators in QLD and SA more than VRE generators in SA and TAS
- While it is no longer a cause for VRE curtailment, the 'solar' category in the RHS graph relates to curtailment from solar farms in order to maintain voltage stability i.e., another form of network curtailment

Curtailment of VRE generators by basis for curtailment



Source: Figure 50 from AEMO, *Quarterly Energy Dynamics – Q2 2021*, July 2021, available at https://www.aemo.com.au/-/media/files/major-publications/qed/2021/q2-report.pdf

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Baringa's approach

Sequence of steps taken by Baringa to obtain the historical curtailment data

- For each and every dispatch interval over this 3-year period, Baringa undertook the following sequence of steps:

  1. Determine the volume dispatched at the market price floor (MPF) for all dispatch unit identifiers (DUIDs) in the NEM
  2. Obtain the volume available for dispatch at the MPF for all DUIDs in the NEM
  3. Classify each DUID as either Scheduled or Semi-Scheduled, based on AEMO's published Registration categories
  4. As a sensitivity for determining curtailment due to specific constraints:
     a) For other constraints: capture all DUIDs with coefficient > 0 on the LHS of constraint with marginalvalue <> 0, capture the AEMO "limit type" for each of these constraints. Exclude any constraints that have only one DUID.
     b) For interconnector constraints: capture all constraints with an interconnector on the LHS with marginalvalue <> 0. Capture all DUIDs during periods where the constraint is binding on export from that DUID's state. Exclude DUIDs that are already in a binding constraint as per a, above.

- Following the first three steps (the first four steps for the deep-dive into constraint types), Baringa then followed the below three steps in sequential order:

  5. Identify all semi-scheduled DUIDs and scheduled DUIDs with a positive amount of capacity bid at the MPF (from steps 1 to 3). Using this subset of scheduled and semi-scheduled DUIDs, then identify if there were scheduled and semi-scheduled DUIDs included in the list of LHS DUIDs in binding transmission constraints (from step 3)
  6. Calculate the volume of capacity bid by those corresponding scheduled and semi-scheduled DUIDs that was not dispatched
  7. Aggregate the frequency and extent of these instances of curtailment across the financial year (i.e., across the 105,120 dispatch intervals in each of the three financial years),

- Following the above steps, Baringa calculated the annual forgone energy in percentage terms for each and every scheduled and semi-scheduled DUID in the NEM, over the relevant three financial years (FY2019, FY2020, and FY2021)

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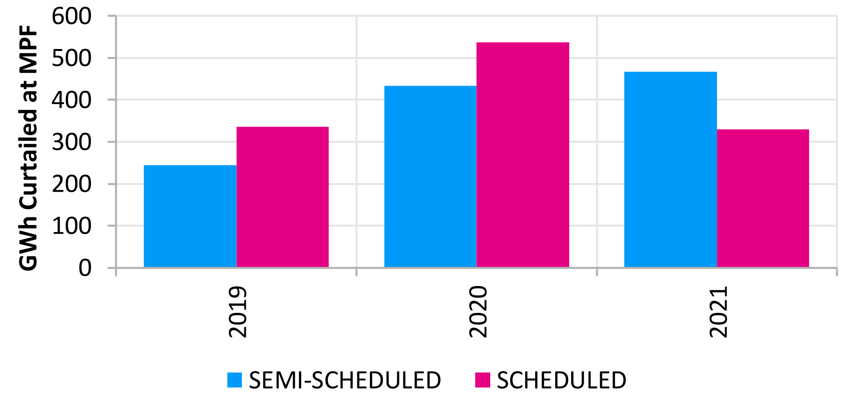
Historical curtailment analysis: NEM-wide [1]

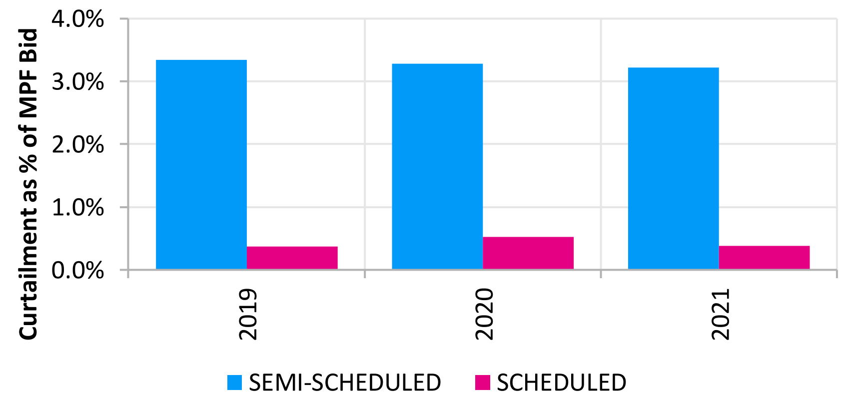
Historical extent of generator curtailment, by generator type and by financial year

- When measured in terms of output volumes curtailed at the MPF, curtailment of Scheduled generators was 1,200 GWh over FY2019-FY2021, around 5% higher than the curtailment of Semi-Scheduled generators (1,140 GWh) over the same period, as per the top chart on the RHS
- In FY2021, the volume curtailed from Scheduled generators was lower than for Semi-Scheduled, in contrast to FY2019 and FY2020
- The bottom chart on the RHS scales the volume of output curtailed at the MPF by the volume of output bid at the MPF
- This shows that output curtailment was a much more material issue for Semi-Scheduled generators than for Scheduled generators, for the FY2019-FY2021 period and aggregated across all Scheduled and Semi-Scheduled generators in the NEM
- As a proportion of energy bid in at the MPF, Semi-Scheduled generators experienced in excess of 3% curtailment in each of FY2019-FY2021, six to seven times higher than for Scheduled generators (less than 0.6% curtailment, over the FY2019-FY2021 period). Curtailment percentages for Semi-Scheduled and Scheduled generators were largely unchanged over the 2019-2021 period
- As these results are aggregated across all Scheduled and Semi-Scheduled generators in the NEM, the following slides provide results disaggregated either by time period or by NEM region

Curtailment at the MPF – total volumes



Curtailment at the MPF – as % of MPF Bid



Historical curtailment analysis: NEM-wide [2]

Historical extent of generator curtailment by generator type – split by calendar quarter or by NEM region

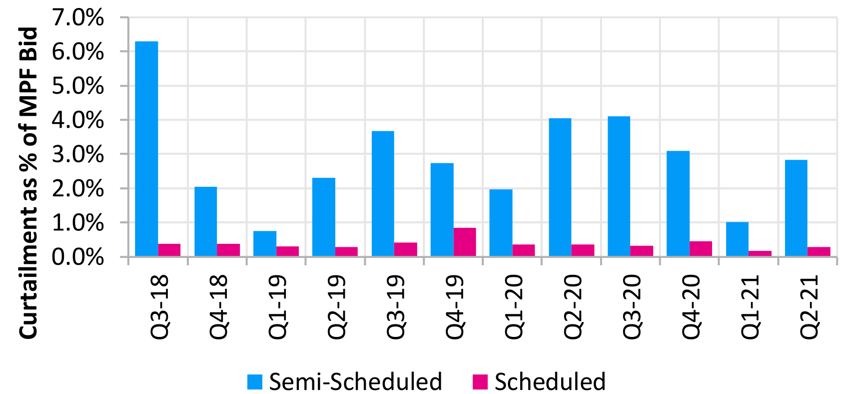
Curtailment by quarter

- The difference in the extent of curtailment between Semi-Scheduled and Scheduled generators is even more significant when measured on a quarterly basis
- The largest differences are observed during quarters with high renewable generation and relatively low demand (namely, Q3, which is July to September), noting the NEM is a summer-peaking system
    - For example, in Q3 2018 over 6% of volume bid by Semi-Scheduled generators at the MPF was curtailed, compared to less than 0.5% for Scheduled generators (see top graph on the RHS)

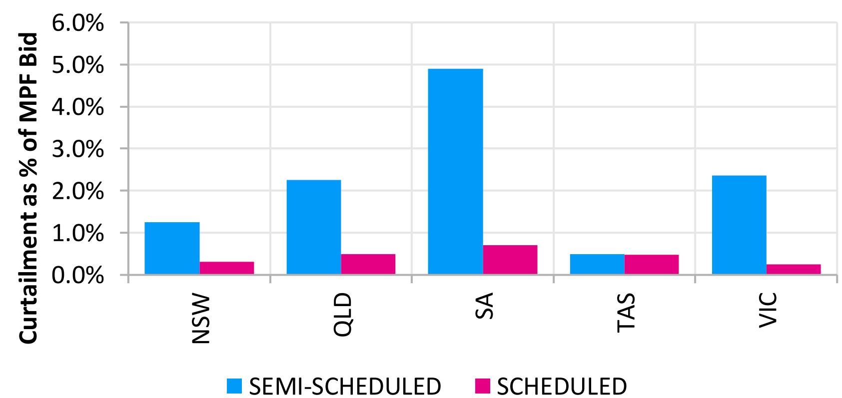
Curtailment by NEM region

- Of the five NEM regions, South Australia (SA) has had the highest curtailment of both Scheduled and Semi-Scheduled generators, over the 2019-2021 period
    - Over this period, nearly 5% of Semi-Scheduled generator output in SA was curtailed at the MPF, exceeding the next highest regions (VIC and QLD, both around 2% curtailment) – see bottom graph on the RHS
    - 0.7% of SA Scheduled generator output was curtailed at the MPF, compared to less than 0.5% in the next-highest region (QLD)
- Over the 2019-2021 period, of the five NEM regions, Tasmania had the lowest curtailment across its Scheduled and Semi-Scheduled generator fleet (0.5% curtailment at the MPF for both types of generators)

Curtailment at the MPF as % of MPF Bid – by quarter



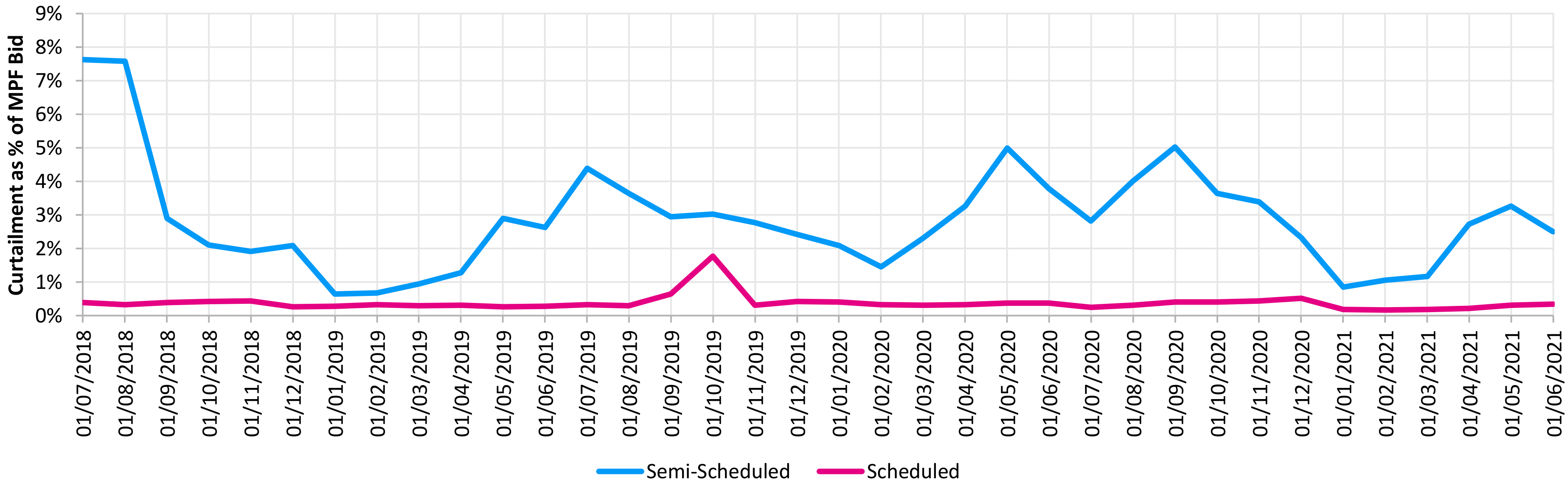
Curtailment at the MPF as % of MPF Bid – by NEM region (over 2019-2021)



Historical curtailment analysis: NEM-wide [3]

Historical extent of generator curtailment, by generator type and by month

Curtailment at MPF as % of MPF bid – over the month starting



- Consistent with the prior slide, July to September are typically the months where Semi-Scheduled curtailment has been the greatest, between July 2018 and June 2021, with a high of 7.6% of volume bid at the MPF in July 2018 (see above chart). Also consistent with the prior slide, January to March were typically the months where Semi-Scheduled curtailment has been the lowest, over the 2018-2021 period (see above chart)
- In contrast, both the level and volatility of Scheduled generator curtailment at the MPF was lower than for Semi-Scheduled. Scheduled generator curtailment at the MPF reached a high of 1.8% during October 2019, but was otherwise well below 1% over the 2018-2021 period. These findings are also consistent with the quarter-by-quarter analysis on the previous slide

Historical curtailment analysis: NEM-wide [4]

Focused on quantifying the historical incidence of network curtailment

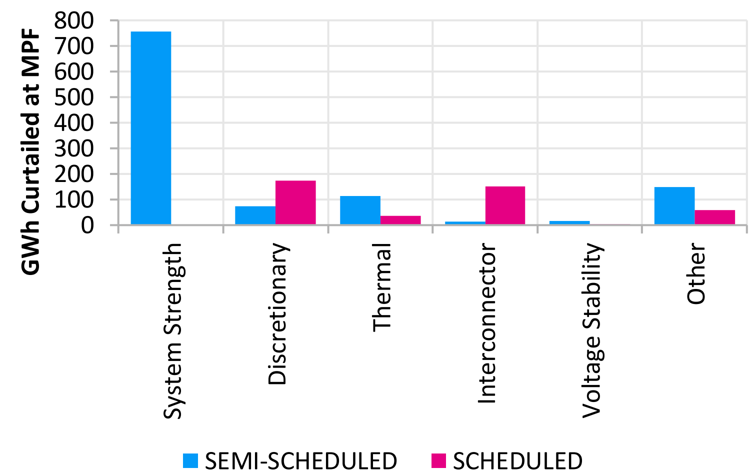
- It is again worth noting that Baringa has focused on the extent of historical generator curtailment due to insufficient intra-regional network capacity (i.e., technical/network-based curtailment). We have not examined, or attempted to examine, the extent of economic or market curtailment

- As such, the amount (in GWhs) of generator curtailment attributable to specific types of network-driven constraints. To briefly recap our approach here (see slide 11 for more details):

  1. For other constraints: capture all DUIDs with coefficient > 0 on the LHS of constraint with marginalvalue <> 0, capture the AEMO "limit type" for each of these constraints.

  2. For interconnector constraints: capture all constraints with an interconnector on the LHS with marginalvalue <> 0. Capture all DUIDs during periods where the constraint is binding on export from that DUID's state. Exclude DUIDs that are already in a binding constraint as per 1, above.

Total curtailment at the MPF – by basis for network curtailment



- The RHS chart therefore shows curtailment volumes for Semi-Scheduled and Scheduled generation by constraint type. Note that the constraint classification comes from AEMO's "limit type" except for *Interconnector* (defined as per 2 above) and *Other*, which is an aggregation of various smaller contributions.

- The total curtailment attributable to specific constraints is lower than the total curtailment (1.5 GWh vs 2.3 GWh), because we have only captured binding constraints with a DUID or interconnector on the LHS. This gap would be made up of binding intra-regional constraints and any other constraints that drive curtailment without limiting interconnector capacity or specific DUIDs.

- System Strength constraints account for more than 65% of the curtailment of Semi-Scheduled generators, consistent with the commentary in Section C. This proportion increases to 85% for Semi-Scheduled generators in SA.

Historical curtailment analysis: NEM-wide [5]

Curtailment experienced across the NEM when RRP > $300/MWh

- In this slide, we focus on the instances of output curtailment at the MPF *where the corresponding RRP was equal to or greater than $300/MWh*

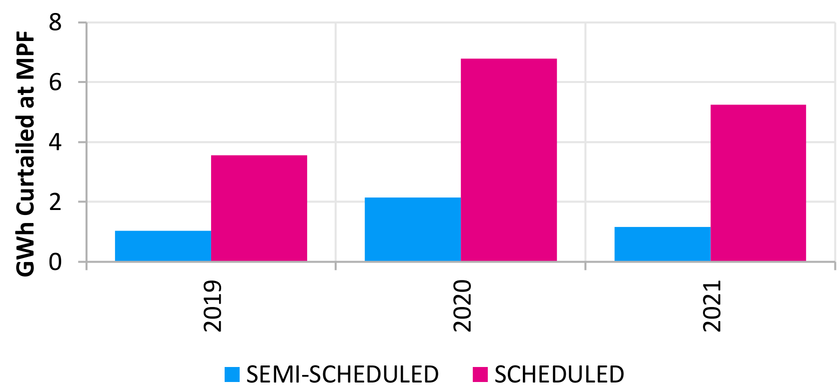
- The rationale for this is to examine whether curtailment is higher or lower during periods of scarcity i.e., in periods where $300-strike cap contracts would be 'in-the-money'

- The graph on the top right reveals curtailment output at the MPF during such periods. Curtailment of scheduled generation is three-and-half-times higher than Semi-Scheduled over 2019-21 (compared with just 5% higher on the base analysis, shown in slide 15)

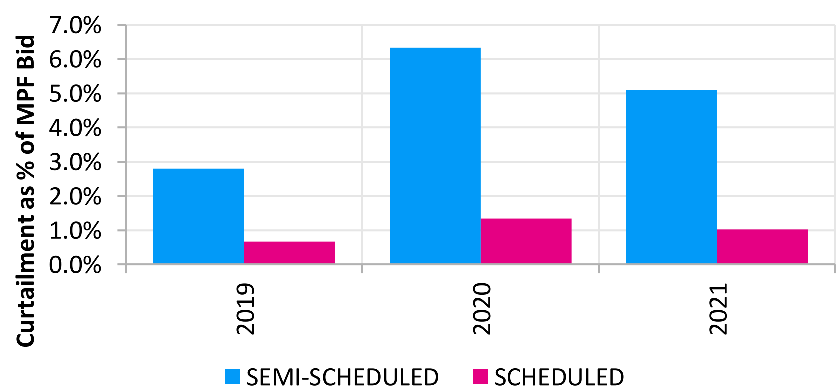
- Curtailment as a percentage of volume bid at MPF is higher for both Scheduled and Semi-Scheduled when RRP is > $300/MWh. Scheduled curtailment increases from 0.5% to 1.0%, while Semi-Scheduled curtailment increases from ~3% to 5.1% over FY19-21.

- Semi-Scheduled generation is still disproportionately curtailed on a percentage basis, 4-5 times the curtailment of Scheduled generation (compared with more than 7x on the base analysis).

Curtailment at the MPF – total volumes, RRP >300



Curtailment at the MPF as % of MPF Bid, RRP >300



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Scope of analysis

Snowy's portfolio and its nearby competitors

- In this section, we apply the same scope of curtailment analysis as in Section D, to the Snowy portfolio. The Snowy assets focused on are all Scheduled generators, and specifically all pumped hydro generators as per the top table on the right (DUIDs provided in brackets)
- For the purposes of comparison, we also analyse the curtailment experienced by Scheduled and Semi-Scheduled generators that are close to these Snowy assets. These nearby generators are located in either NSW or Victoria
- The nearby Semi-Scheduled generators are all wind farms and shown in the middle table on the right
- The nearby Scheduled generators are shown in the bottom table on the right
- In addition to these 'nearby' Scheduled and Semi-Scheduled, our comparator analysis also includes two other groups of generators:
  1. Other NSW-domiciled Scheduled generators (i.e., other than the Snowy portfolio)
  2. Other Semi-Scheduled generators in NSW (i.e., other than those 'nearby' Semi-Scheduled generators that are domiciled in NSW)

Generator (DUID)	Generator (DUID)
Murray pumped hydro (MURRAY)	Upper Tumut pumped hydro (UPPTUMUT)
Tumut 3 pumped hydro (TUMUT3)	Blowering pumped hydro (BLOWERNG)
Guthega pumped hydro (GUTHEGA)	

Generator (DUID)	Generator (DUID)
Boco Rock Wind Farm (BOCORWF1)	Gullen Range Wind Farm (GULLRWF1)
Gunning Wind Farm (GUNNING1)	Woodlawn Wind Farm (WOODLWN1)
Taralga Wind Farm (TARALGA1)	

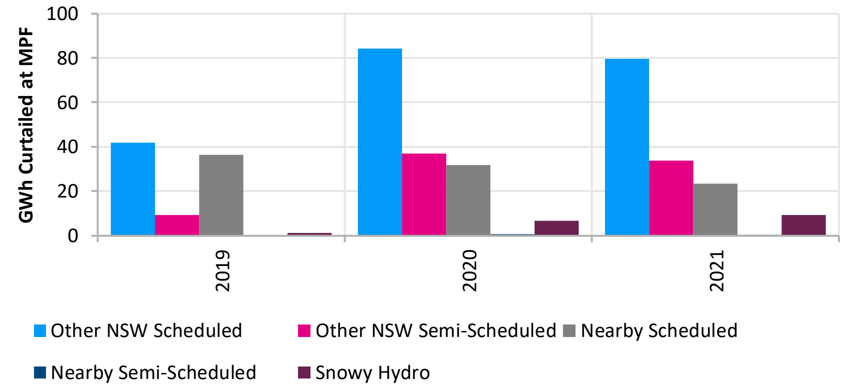
Generator (DUID)	Generator (DUID)
Uranquinty OCGT (URANQ11, URANQ12, URANQ13)	Tallawarra CCGT (TALWA1)
Hume pumped hydro (HUMEV)	Dartmouth pumped hydro (DARTM1)
Bogong/Mackay pumped hydro (MCKAY1)	West Kiewa pumped hydro (WKIEWA1 & WKIEWA2)
Bairnsdale OCGT (BDL01 & BDL02)	

Snowy-specific findings [1]

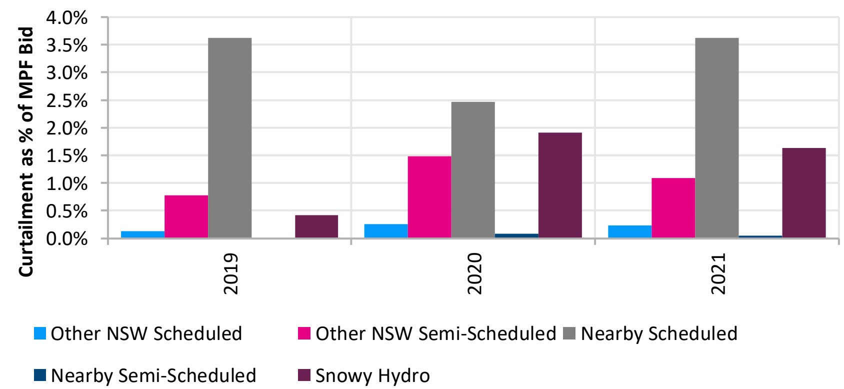
Curtailment experienced by Snowy and its competitors

- A total of 17 GWh of Snowy output was curtailed at the MPF (see top graph). Furthermore, the extent of network-induced curtailment at the MPF experienced by Snowy increased more than 7x from FY2019 to FY2021
- Between 2019 and 2021, the extent of curtailment at the MPF experienced by the selected Snowy portfolio was in the middle of the range of curtailment experienced by other Scheduled generators:
  - Snowy curtailment was lower than for 'nearby' Scheduled generators, in volume terms (top graph on the RHS) and relative to capacity bid at the MPF (bottom graph). For example, in FY2021, 1.6% of capacity bid at the MPF by the Snowy portfolio was curtailed, compared to 3.6% for nearby Scheduled generators
  - Snowy curtailment was higher than for other NSW Scheduled generators, as a share of capacity bid at the MPF. For example, only 0.2% of NSW Scheduled generator capacity was curtailed at the MPF during FY2021, compared to 1.6% for Snowy (see bottom graph)
- Between 2019 and 2021, the extent of curtailment at the MPF experienced by Snowy was higher than for Semi-Scheduled generators:
  - Snowy curtailment was higher than for 'nearby' Semi-Scheduled generators. Virtually no Semi-Scheduled generator capacity bid at the MPF was curtailed over the 2019-2021 period, compared to 0.4% (FY2019) and 1.6% (FY2021) of Snowy capacity bid at the MPF
  - Snowy curtailment was higher than for other NSW Scheduled generators, as a share of capacity bid at the MPF. For example, only 0.2% of NSW Scheduled generator capacity was curtailed at the MPF during FY2021, compared to 1.5% for Snowy

Total Curtailment at MPF (Snowy vs. Competitors)



% Curtailed at MPF (Snowy vs. Competitors)

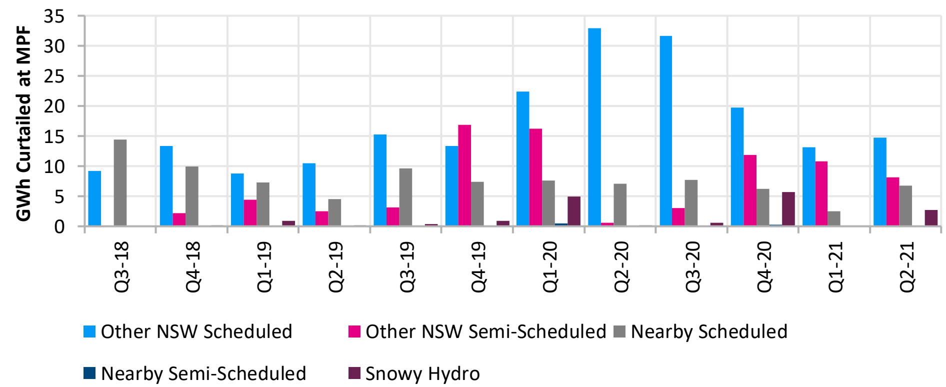


Snowy-specific findings [2]

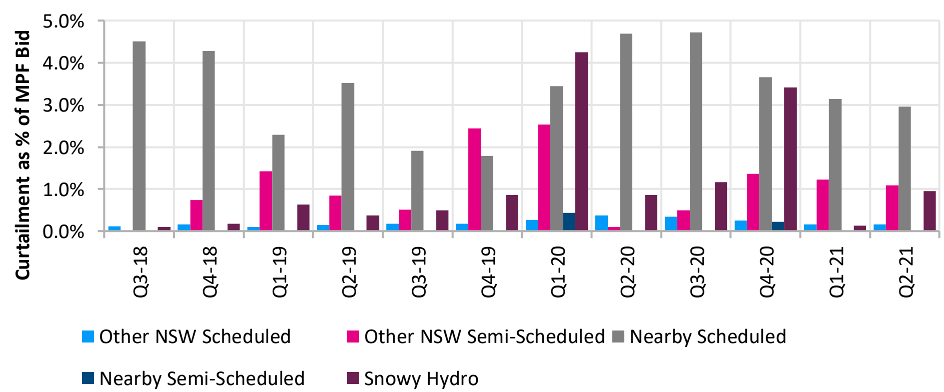
Curtailment experienced by Snowy and its competitors – quarterly analysis

- Similar to the analysis in Section E, we disaggregate the annual results by time frequency and by constraint type. This and the next slide relate to the time frequency disaggregation
- Snowy curtailment was especially high during Q4 2020 (3.4%; see bottom graph on the RHS), and on par with curtailment for nearby Scheduled generators (3.7%). For the other quarters between FY19 and FY21, Snowy curtailment was below that of nearby Scheduled generators
- For all quarters between 2019 and 2021, Snowy curtailment was above that of nearby Semi-Scheduled generators
- The quarterly-level results are generally consistent with the annual analysis:
  - the extent of curtailment at the MPF experienced by Snowy has risen over time, from 0.6% in Q1 2019 to 3.4% in Q4 2020
  - the extent of curtailment at the MPF experienced by the Snowy portfolio was in the middle of the range of curtailment experienced by other Scheduled generators – below 'nearby' Scheduled generators, but above other NSW Scheduled generators
  - the extent of curtailment at the MPF experienced by Snowy was higher than for Semi-Scheduled generators

Total Curtailment at MPF (Snowy vs Competitors)

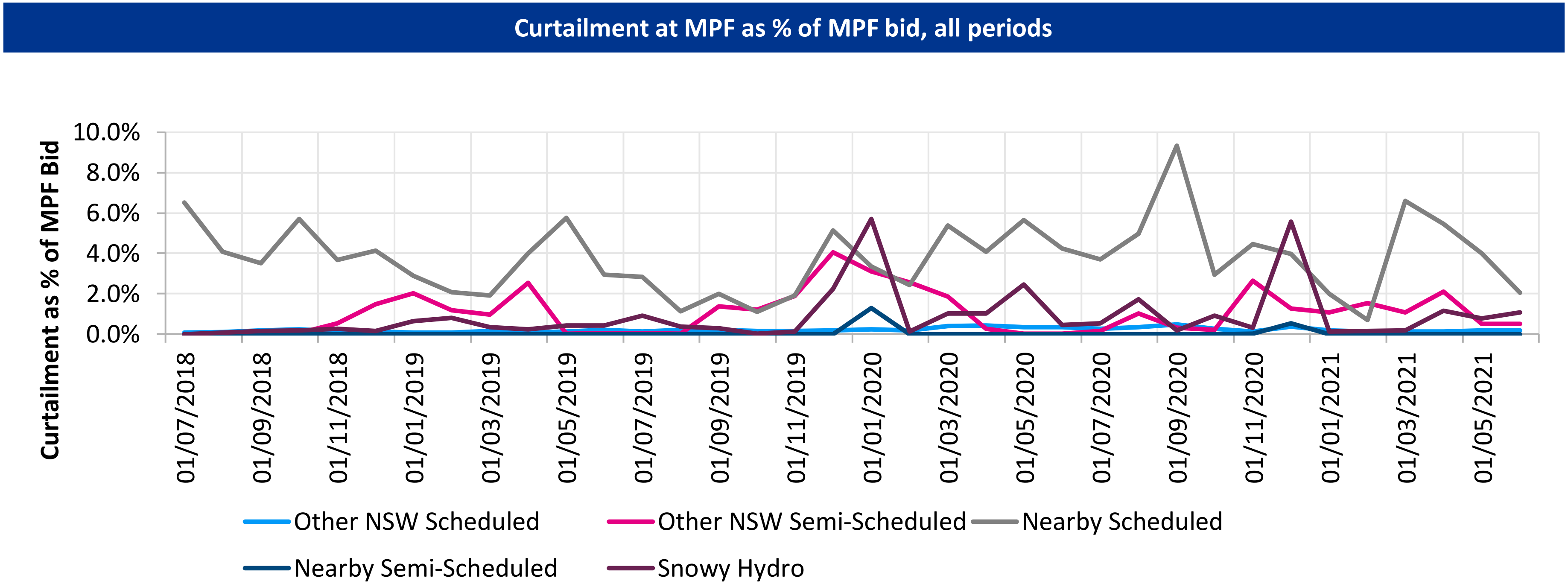


% Curtailed at MPF (Snowy vs Competitors)



Snowy-specific findings [3]

Curtailment experienced by Snowy and its competitors – monthly analysis



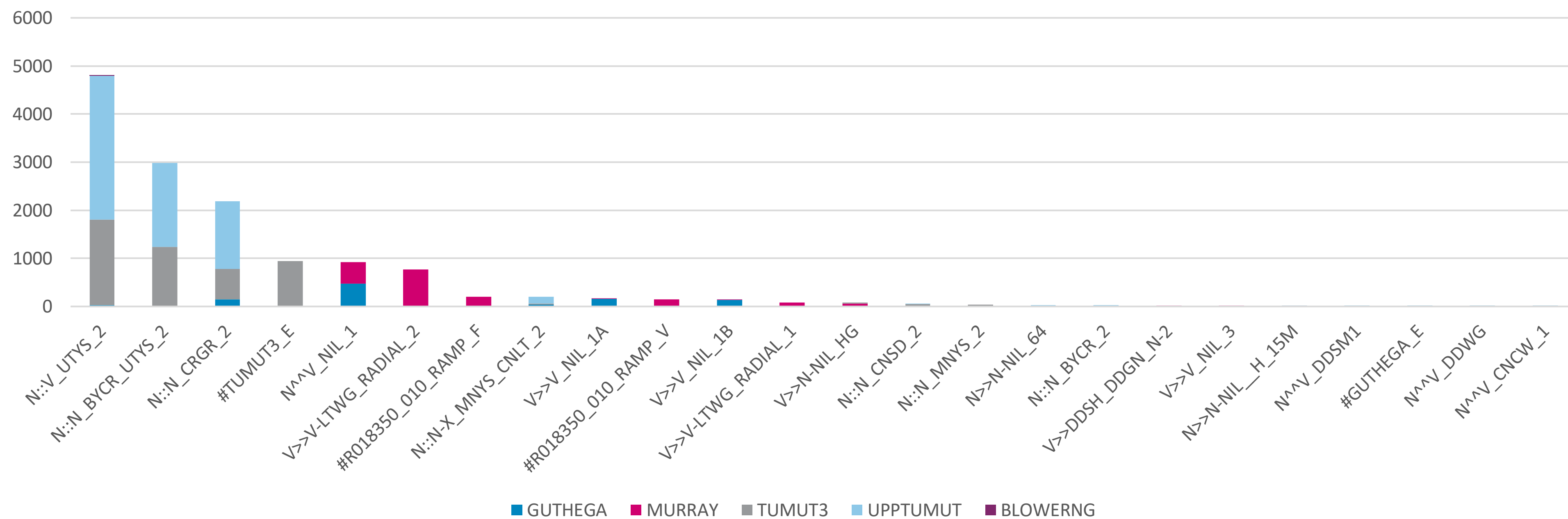
- The monthly analysis shows even greater inter-period volatility in curtailment at the MPF than the quarterly analysis. This is particularly the case for nearby Scheduled generators, whose curtailment at the MPF peaked at 9.3% during September 2020, but previously had virtually no curtailment during FY2020 (i.e., July 2019 to June 2020). While of a lower magnitude, there is also volatility in monthly Snowy curtailment, which peaked at 5.6% during December 2020

- In contrast, monthly curtailment for the other three groups of generators in the graph is much less volatile, the highest of these being for other NSW Semi-Scheduled generators

Snowy-specific findings [4]

Snowy's network-induced curtailment – by constraint type

Snowy curtailment between FY2019 and FY2021 – by constraint equation



- Over one-quarter of the total 17 GWh of Snowy output curtailed at the MPF was due to "N::V_UTYS_2" constraint binding. This constraint is a transient stability-based constraint, which curtails output from Upper Tumut to keep flows within stability limits in the Snowy region for faults at various locations between Yass and South Morang*
- The second largest contributor to Snowy curtailment is also a transient stability-based constraint (between Yass and South Morang) which also impacts output from Upper Tumut. This accounted over one-sixth of the total output curtailed from the Snowy portfolio at the MPF

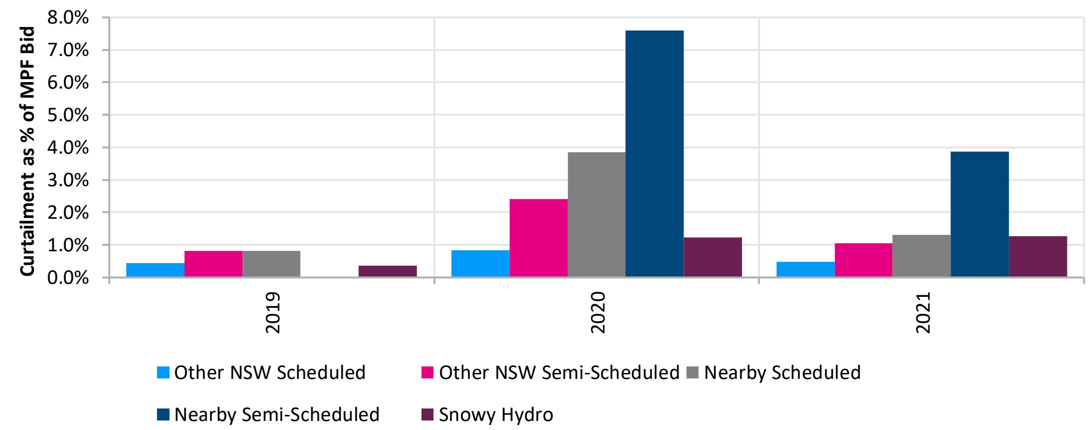
* Source: AEMO, *NEM Constraint Report 2020 summary data*, March 2021, Available at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2020/nem-constraint-report-2020-summary-data.xlsx

Snowy-specific findings [5]

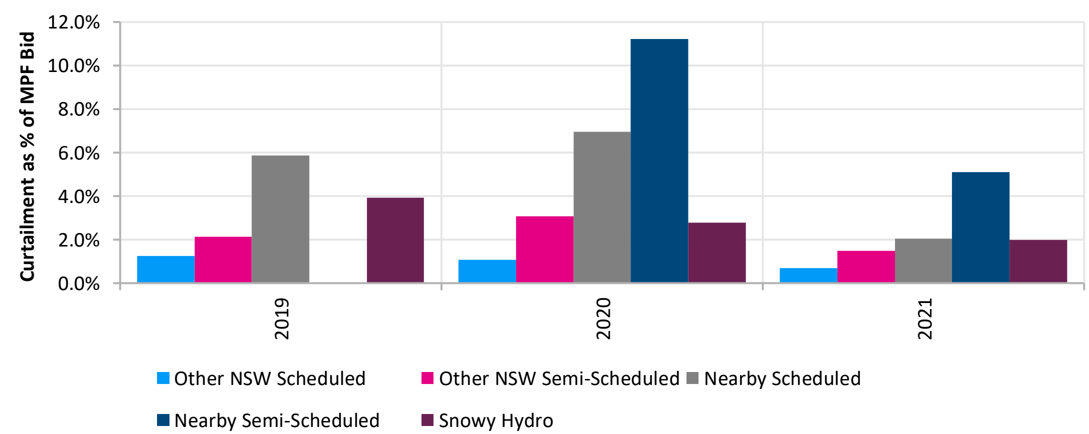
Curtailment experienced by Snowy and its competitors when RRP > $300/MWh

- In this slide, we focus on the instances of output curtailment at the MPF *where the corresponding RRP was equal to or greater than $300/MWh*
- Over 2019-2021, the graph on the bottom right reveals curtailment, relative to capacity bid *in those dispatch intervals where curtailment occurred*, at the MPF was:
  - highest for nearby Semi-Scheduled generators, and lowest for other NSW Scheduled generators. Curtailment of nearby Semi-Scheduled generators peaked at 11% during FY2020, followed by nearby Scheduled generators (7%). Over that year, Snowy curtailment was 3%
  - Curtailment of the Snowy portfolio typically was in the middle of the range of curtailment of the five generator groups. Snowy curtailment was typically higher than for other NSW generators (i.e., both Other NSW Semi-Scheduled, and Other NSW Scheduled)
- Relative to capacity bid, curtailment at the MPF is larger when the RRP is greater than $300/MWh, for all five generator groups
  - This can be seen by comparing the top graph on the RHS with the bottom graph on slide 20

% Curtailed at MPF across all periods, RRP >300 (Snowy vs Competitors)



% Curtailed at MPF, intervals with curtailment , RRP >300 (Snowy vs Competitors)



Snowy-specific findings [6]

Curtailment experienced by Snowy and its competitors when RRP > $300/MWh, on a quarterly basis

- This slide extends the previous one by looking at curtailment at the MPF, at a quarterly frequency
- The findings here are generally consistent with the quarterly analysis for all intervals (i.e., slide 21), namely:
  - curtailment was highest typically for nearby Semi-Scheduled, and lowest for other NSW Scheduled, generators across all quarters between FY19 and FY21
  - Snowy curtailment was especially high during Q4 2020 (5%; see RHS graph), and above curtailment for nearby Scheduled generators (4%). However, the largest curtailment, relative to capacity bid at the MPF, was for nearby Semi-Scheduled generators (20%) during Q4 2020
  - Snowy curtailment typically lay in the middle of the range of curtailment of the five generator groups
- The quarterly-level findings are also consistent with the annual findings for intervals where the RRP > $300 (which was discussed in the previous slide), namely:
  - curtailment at the MPF is larger when the RRP is greater than $300/MWh, for all five generator groups

% Curtailed at MPF across all periods, RRP >300 (Snowy vs Competitors)

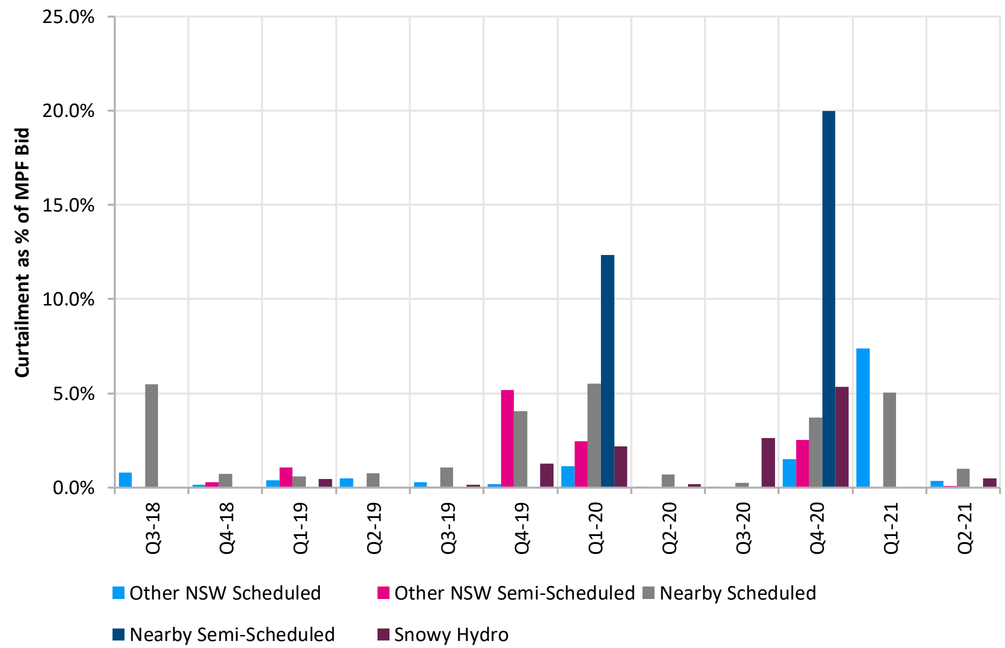


Table of contents

Baringa Partners overview

We determined from the outset that our clients would have a radically different experience when working with Baringa…

- ✓ Deep experts in our chosen disciplines, you could say we're more 'geek' than 'generalist'
- ✓ We often deploy a smaller and more senior team, with core industry experience & specialism
- ✓ We have built a model which means senior delivery experience is hands-on in every client engagement
- ✓ Double digit growth in parallel to Great Place To Work for the last decade - we help our clients do the same!
- ✓ Our proven assets accelerate our clients' strategy, with our methods being flexible rather than dogmatic
- ✓ We genuinely partner with our clients to understand their issues and deliver bespoke & innovative solutions

Our Model

1 Partner : 10 Employees

20+ Business Practices
We are experts in our chosen fields and have deep industry knowledge and capability

6 Offices Worldwide
700 employees and 65 partners across the UK, Ireland, USA, Germany, Singapore and Australia delivering projects globally

For our Consultants

Great Place To Work
Voted top 10 'Great Places to Work' for 12 years running…this creates a highly motivated, engaged and passionate consulting team

Employee Engagement
Our employee Net Promoter Score the highest in the Consulting Industry, in it's in the top 5 % of all businesses worldwide!

Talent Magnet
As a result, we can attract, develop and retain the most talented consultants

For our Clients

Reputation Build On Results
UK's leading advisory firm in Energy, Utilities and Environment for past two years as voted by clients in FT survey

Client Engagement
Our client NPI is in the top 5% across industry and we were voted the UK's leading energy consultancy

Unique Experience
Our clients tell us that they enjoy the distinctive experience of partnering with Baringa

Energy Markets: offerings and capabilities

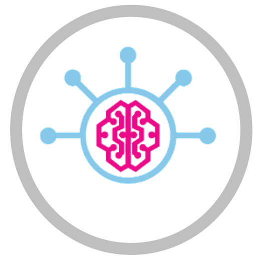
We support our client base with leading edge analytics and market insights

Our offerings

We offer our clients insights and analysis to support business decisions and solve complex problems

- Market reports
- Price projections
- Transaction advisory
- Commercial due diligence
- Opportunity screening
- Business case development
- Offtake and purchase agreements
- Decarbonisation pathways
- Energy system model deployment
- Market design
- Regulatory strategy and submissions
- Expert opinion

Our capabilities



We have a multi-lingual, multi-disciplinary team with expertise in economics, business, science, engineering and analytics

- Strategy development
- Scenario development
- Financial modelling
- Macro-economics
- Regulatory economics
- Econometrics
- Operational research
- Market and asset modelling
- Data science and analytics
- Market research
- Innovation thinking

Our tools

Our analysis is supported by rich data and leading edge analytical tools

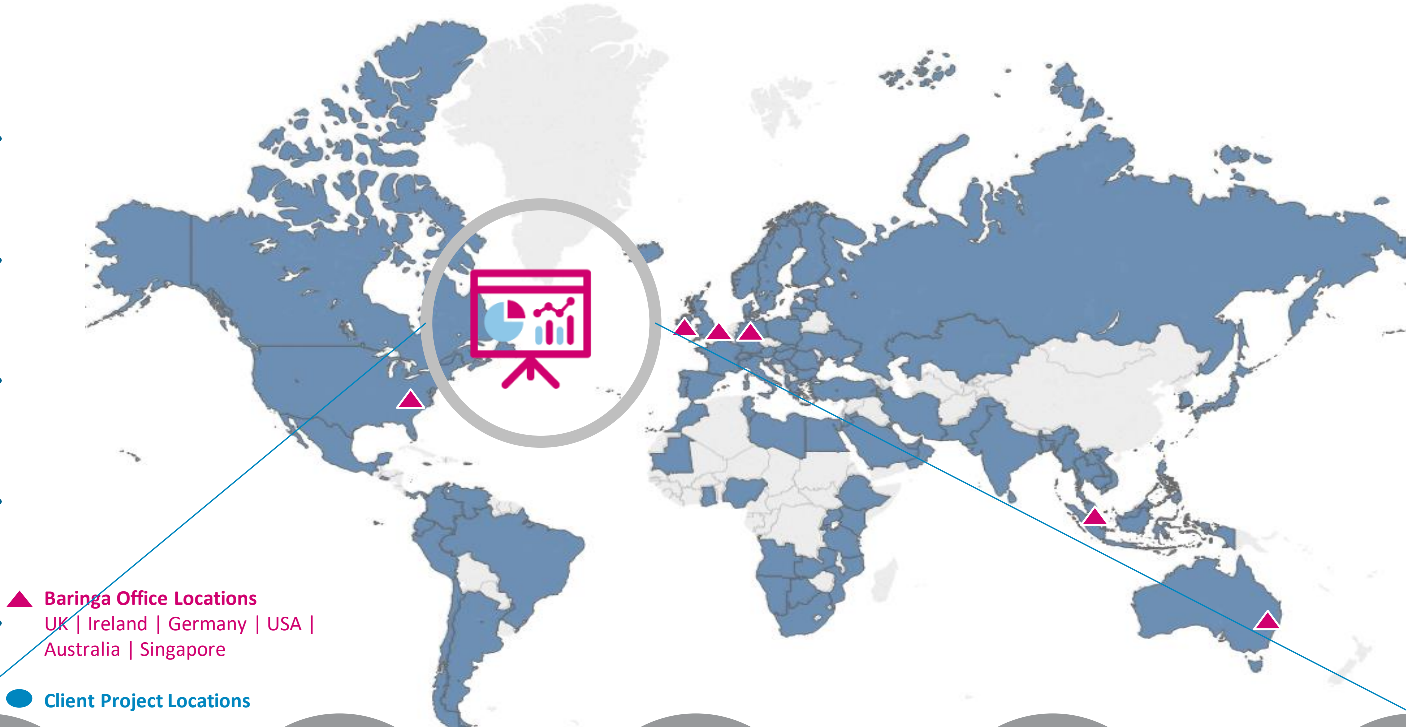
- Power market models
- Whole energy system models
- Energy asset models
- Energy asset databases
- Network simulation and investment models
- Business case templates

Our market footprint

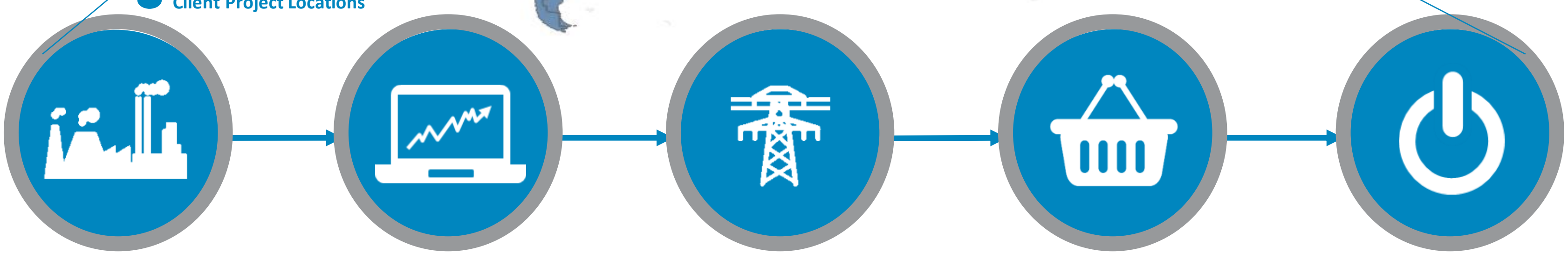
Baringa

We provide global advisory services to a range of clients from our bases in London, Dusseldorf, Dublin, New York, Sydney and Singapore, working right across the value chain

- Government & regulators
- Energy producers
- Utilities
- Energy retailers
- Developers



- Lenders
- Private equity
- Infra & pension funds
- Tech firms
- OEMs



Power generation
Metals and mining

Trading
Energy storage

Gas, Power, Water and H_2 networks

Energy and water retail
Smart technologies

Customers
Electric vehicles

About Baringa Partners

Baringa Partners is an independent business and technology consultancy.

We help businesses run more effectively, reach new markets and navigate industry shifts. We use our industry insights, pragmatism and original thought to help each client transform their business.

Collaboration runs through everything we do. Collaboration is the essence of our strategy and culture. It means the brightest and the best enjoy working here. Baringa. Brighter Together.

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