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Pumped hydro and pumped-up prices: the case of Australia's largest pumped hydro generator

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Abstract

The expansion of variable renewable generation means increasing dependence on electrical storage to meet varying demands. The Australian Government is funding the development of the "Snowy 2.0" pumped hydro generator to expand storage. Its revised business case claims that Snowy 2.0 will operate at close to its full capacity in exchange for gross margins of $75/MWh, for the foreseeable future. This paper examines an existing pumped hydro plant of comparable capacity, Tumut 3, to test this claim. It finds that Tumut 3 operates at around a fifth of its capacity even when gross margins are more than five times Snowy Hydro's claim of the gross margin that will motivate Snowy 2.0 to operate at close to its full capacity. Snowy Hydro has withdrawn Tumut 3 from the market in order to drive up prices and so its profits. While expected coal generation closure will expand the demand for storage in future, Snowy Hydro will continue to have incentives to withhold production in order to increase prices and so its profits. Analysis here suggests that offering Tumut 3 to the market at its avoidable cost would have reduced wholesale prices between 5pm and 8pm by 40% or, equivalently by 33% over the full period, from the start of 2023 to end of 2024 leaving other factors unchanged. While lower electricity prices will be attractive to consumers, taxpayers will need to bear a greater share of the cost of storage and renewable electricity needed to meet the state and federal government's emission reduction policies. Careful evaluation of the public costs and benefits associated with Snowy Hydro's market dominance would be valuable. If policy makers wish to address Snowy 2.0's market power, many options for the regulation, restructuring and privatisation of Snowy 2.0, and allocation of future storage subsidies, might be considered.

Keywords: pumped hydro, market power, storage economics, oligopoly

JEL Classifications: D22, D24, D43, L13, L41, L94

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1 Introduction

The expansion of variable renewable generation results in greater dependence on electrical storage to meet varying demand. The Australian Government is funding the development of the 2,200 MW Snowy 2.0 pumped hydro generator to expand storage. In August 2023 Snowy Hydro, the owner and operator of most of Australia's hydro generation capacity and its largest pumped hydro generator, released a revised business case for Snowy 2.0. In the revised business case[2], Snowy Hydro claims average annual revenue per MWh sold of around $200/MWh (nominal) and average pumping costs of around $100/MWh (nominal) in the period they project to (2040). After adjusting for claimed round-trip losses (25%) this means Snowy Hydro expects a gross margin of $75 per MWh that it generates. With this expected margin, Snowy Hydro says that Snowy 2.0 will generate around 5,000 GWh and pump around 7,000 GWh per year (a little less in the first three years of full commercial operation and a little more for the next seven years of their forecast period). This translates into an 87% average annual capacity factor for the foreseeable future[3].

Snowy Hydro has not provided any justification for these claims, it has not released its modelling and the Australian Government, Snowy Hydro's owner, has refused requests to release the modelling. Considering the importance of storage in the transitioning electrical system, this study is motivated to understand whether it is reasonable to suggest that Snowy 2.0 will operate close to its full capacity and whether a gross margin of $75/MWh is likely under such operation.

The future is uncertain. The replacement of coal generation in the National Electricity Market (NEM) and its replacement by wind and solar generation (mainly) and storage (chemical batteries mainly but also Snowy 2.0) as claimed by the Australian Energy Market Operator (AEMO)[4], will result in a pattern of demand and supply for storage that is very different to that in the market now. Nonetheless, examining the operation of storage in the market now, specifically the volume of generation and pumping and the prices received when generating and paid when pumping, provides a reference against which the plausibility of Snowy Hydro's updated business plan for Snowy 2.0 might be assessed.

The focus in this analysis is therefore on the operation of the existing Tumut 3 pumped hydro power station in News South Wales (NSW). Tumut 3 was commissioned in 1973. It has comparable peak generation capacity to Snowy 2.0 (1800 MW versus 2,200 MW) but it differs in other ways: much smaller upper reservoir; consequential hydrological inflows; pumping capacity that is around 1/3rd the generation capacity; and limitations on the ability to switch rapidly between generating and pumping. These features have been taken into account in this analysis.

This paper presents analysis based on direct fieldwork observation, in the tradition of Coase - see (Reid, 2015). This fieldwork observation reveals information on the operation of the market for storage and specifically the exercise of market power in storage

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2 https://www.snowyhydro.com.au/wp-content/uploads/2024/05/Snowy-2.0-Updated-Business-Case.pdf

3 This is based on production plus pumping of 14 TWh per year divided by 2,200 MW capacity adjusted for a 29% round-trip loss based on average pumping of 7,000 GWh and average generation of 5,000 GWh.

4 https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp

operation in the context in which the storage operator almost completely dominates the provision of peaking electricity in the relevant market. This finding prompted a search for relevant literature[5] that might explain such observations or provide a theoretical foundation to understand them. Garcia et al. (2001) and Andrés-Cerezo & Fabra (2023) noted the paucity of literature on the relationship between storage and market power in electricity markets.

Garcia et al. (2001) develop a simplified oligopoly model where hydro generators engage in dynamic Bertrand competition in order to understand the effect of strategic behaviour and particularly of market price caps. Bushnell (2003) posits that with a Cournot oligopoly, strategic hydro producers exercise market power by shifting hydro production from peak to off-peak periods in order to avoid depressing market prices when their infra-marginal production is larger. Schill & Berlin (2009) perform Cournot simulations of the German electricity market and conclude that strategic firms have incentives to underutilize storage facilities, in line with their theoretical predictions.

Of most relevance to this study, Andrés-Cerezo & Fabra (2023) developed a stylised theoretical analysis of the effects of vertical integration between generation and storage, which is common in most electricity markets in practice and certainly for Snowy Hydro. They conclude that markets will not deliver optimal incentives regarding storage decisions unless there is enough competition in both the generation and the storage segments. They suggest that the mechanisms designed to grant public support should take into account that market structure matters; that is, the same storage capacity in the hands of competitive storage owners is more socially valuable than if it is allocated to large storage firms or to generators. Their theoretical analysis is consistent with the observations in this empirical study and their policy suggestions are echoed in this paper.

This paper finds that Snowy Hydro has withdrawn Tumut 3's capacity in order to maximise its proceeds, across its portfolio of generation, in the provision of peaking generation in NSW. It also finds that competition in the provision of storage services in NSW is likely to substantially reduce wholesale prices and consequently Snowy Hydro's profits.

In response to the question that originally motivated this research, the analysis here of Tumut 3's operation casts doubt on Snowy Hydro's claim that it will operate Snowy 2.0 at its full capacity in exchange for gross margins of $75/MWh. Tumut 3 operates at a fifth of its capacity even when gross margins of more than five times this amount are available. While expected coal generation closure will increase demand for storage in NSW, this analysis suggest that Snowy Hydro will continue to have powerful incentives to withhold production in order to increase prices and so its profits.

The next section provides background on Tumut 3's operation over the last decade, and of price and demand in the NSW electricity market. The third section sets out various analysis to describe and quantify the extent of Tumut 3's exercise of market power. The fourth section presents a simulation of the effect of higher Tumut 3 operation on spot electricity prices. The fifth section discusses the findings and the final section concludes.

[5] The industry press in Australia has occasionally examined pumped hydro operation and the possible exercise of market power, although only for the smaller Wivenhoe pumped hydro station near Brisbane in Queensland - see https://reneweconomy.com.au/why-australias-biggest-battery-said-no-to-an-offer-too-good-to-refuse-40877/

2 Background

Tumut 3 is the largest (of three) pumped hydro generators in the five Australian States that together comprise the National Electricity Market. It was commissioned in 1973 and substantially refurbished in 2012. It has six generating turbines each capable of generating 300 MW, and three pumps each capable of pumping 200 MW. It has an upper reservoir (Talbingo) that is capable of storing enough water to generate at full capacity for 33 hours.

In addition to being a pumped hydro generator, Tumut 3 also receives hydrological inflows to its upper reservoir from the Tumut River, that have previously passed through the Tumut 1 and Tumut 2 hydro generators. Tumut 3 is a relatively inflexible generator. Switching between generating and pumping for the three combined units takes about 15 minutes due to the need to dewater the appropriate turbine. This means that Tumut 3, unlike chemical batteries, can’t switch quickly between pumping and generating. However once synchronised its generators can ramp at around 60 MW per minute per unit and so when not switching from pumping to generation, the station is able to ramp from zero to its maximum output of 1800 MW within one five-minute trading interval.

Table 1 presents information on Tumut 3’s operation over the last decade based on five-minute production and price data sourced from the Australian Energy Market Operator and extracted from www.v-nem.org.

Table 1. Tumut 3 statistics on pumping and production for the decade to end 2024

Year	Average pumping (MW) (1)	Average generation (MW) (2)	Average load when pumping (MW) (3)	Average generation when producing (MW) (4)	Total pumping (MWh) (5)	Total generation (MWh) (6)	Volume-weighted pumping price ($/MWh) (7)	Volume-weighted generating price ($/MWh) (8)	Difference in volume-weighted charging and generating price ($/MWh) (9)	Total pumping cost ($m) (10)	Total income ($m) (11)	Gross margin ($m) (12)
2015	1	37	217	285	8,618	325,393	$29	$126	$49	$0	$41	$41
2016	1	82	222	354	11,636	718,679	$37	$116	$71	$0	$84	$84
2017	22	48	277	341	194,926	419,614	$68	$291	$441	$13	$122	$109
2018	14	67	311	347	122,841	583,015	$60	$134	$55	$7	$78	$71
2019	28	54	283	344	241,492	471,895	$54	$152	$120	$13	$72	$59
2020	8	60	291	385	67,778	524,578	$46	$244	$258	$3	$129	$125
2021	30	78	359	377	260,263	680,368	$34	$283	$193	$9	$193	$184
2022	49	107	394	382	430,128	939,013	$159	$380	$189	$68	$356	$288
2023	45	93	349	386	393,565	815,148	$16	$262	$234	$6	$214	$208
2024	93	96	271	438	621,243	843,076	$34	$645	$611	$21	$515	$494
Average	**29**	**72**	**297**	**364**	**235,249**	**632,078**	**$54**	**$263**	**$222**	**$14**	**$180**	**$166**

In Table 1:

- The first data column shows a gradual (but not monotonic) increase in Tumut 3 pumping over the decade, from just 1 MW on average a decade ago to 93 MW in 2024. Average generation (second column) is commensurately higher and affected by water inflows from the Snowy River, as explained.

- The 3rd and 4th columns show average generation and load calculated over the hours that Tumut 3 is either pumping or generating, and it shows that these are much closer to each other than when the average is calculated over the whole year. What this means is that Tumut 3 pumps much harder when it pumps (it has a nominal pumping capacity of 600 MW) than it generates when it generates (nominal generation capacity of 1800 MW) and that it is generating for about twice as long as it is pumping.

- The 5th and 6th columns show the total volume of electricity pumped and generated per year over the decade. On average about three times as much electricity was generated as was pumped. After adjusting for round-trip pumping losses (25%) this means that about three-quarters of the production from Tumut 3 is hydro electricity rather than pumped-hydro electricity.

- The 7th to 9th columns show the volume-weighted spot price when pumping and when generating and their difference. It is evident that the gap between the two has been gradually growing, and that it ranges widely, between a factor of less than two (generating price received compared to pumping price paid) and nine[6].

- Columns 10 to 13 compare the total amount paid (at spot prices) to pump electricity, the amount received from generating electricity and their difference (the "gross margin"). These show a rising trend but nonetheless large inter-annual variability. The last column reveals the importance of Tumut 3 to Snowy Hydro's profits. For example in 2024 (calendar year) the gross margin on Tumut 3 ($494m) might be compared to Snowy Hydro's declared Earnings before interest and tax (financial year to 30 June 2024) of $596m[7].

The two charts in Figure 1 present information on the frequency of different levels of pumping and generation (measured in five-minute intervals) in 2023 and 2024. The pumping data shows that the most frequent pumping levels cluster somewhat around the nominal (name plate) pumping capacity of the three pumping units (200 MW each). The generating data shows that Tumut 3 seldom generates more than 900 MW (half the 1800 MW nominal capacity) and a mode of about 200 MW.

Figure 1. Density of pumping loads and generating output 2023 & 2024

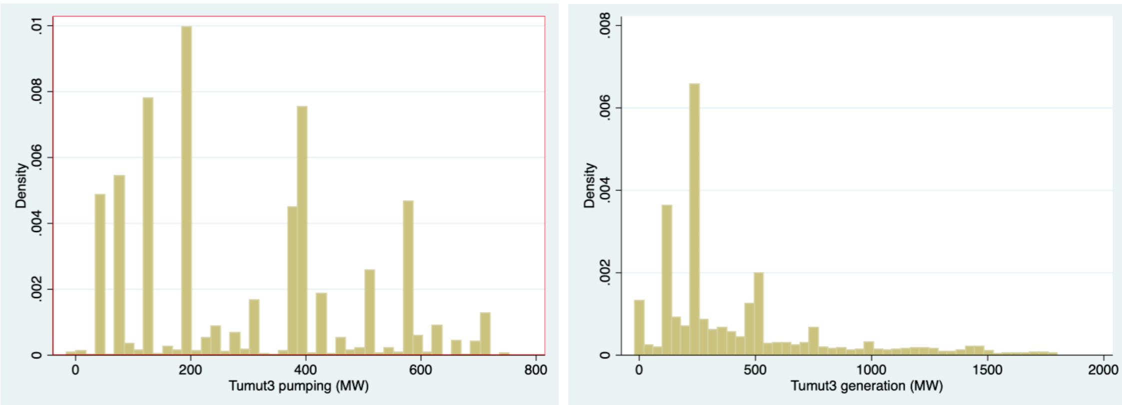


Figure 2 shows the average of the five-minute measure of pumping load at Tumut 3, by hour of day from 2015 to 2024. It shows increases mainly since 2021, in the middle of the day, corresponding to lower wholesale prices in the middle of the day as a result of increasing rooftop solar supply.

[6] These prices exclude the (typically small) effect of marginal loss factors.

[7] https://www.snowyhydro.com.au/wp-content/uploads/2024/10/SnowyHydro-Annual-Report-2023-24.pdf

Figure 2. Tumut 3 average pumping (MW) by hour of day, 2015 to 2024

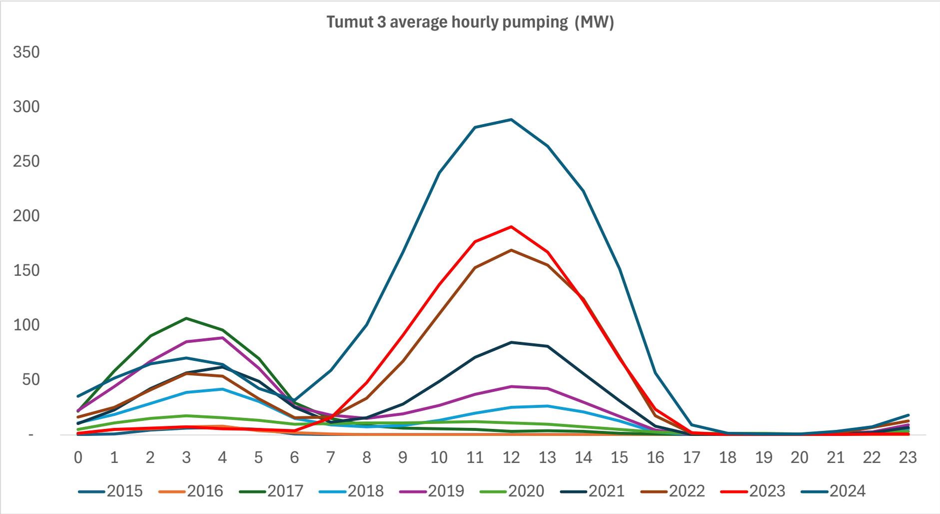


Figure 3 shows the average of the five-minute measure of generation at Tumut 3, by hour of day, from 2015 to 2024. The rising peak in the evening from 5pm to 10pm corresponds to rising prices in that period as coal generation has left the market and not yet been replaced by storage or variable renewable generation.

Figure 3. Tumut 3 average generation (MW) by hour of day, 2015 to 2024

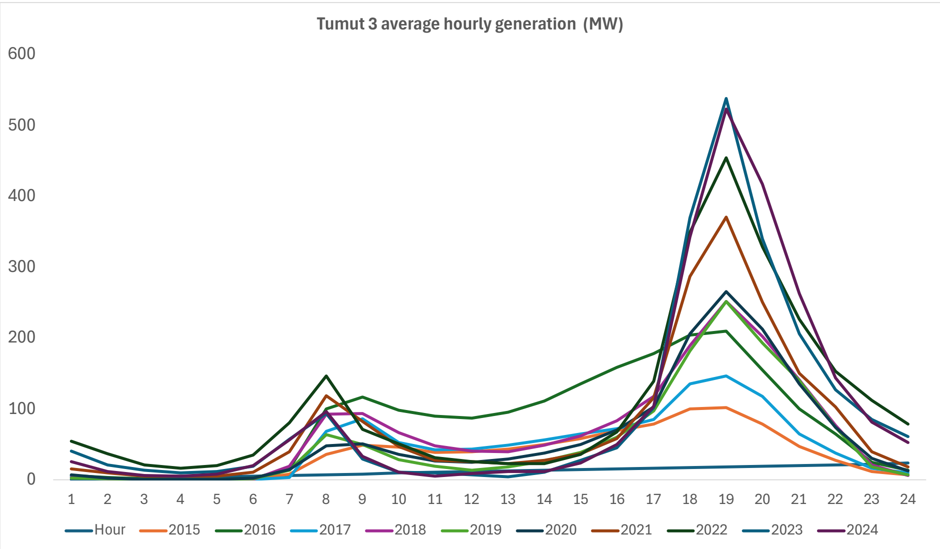
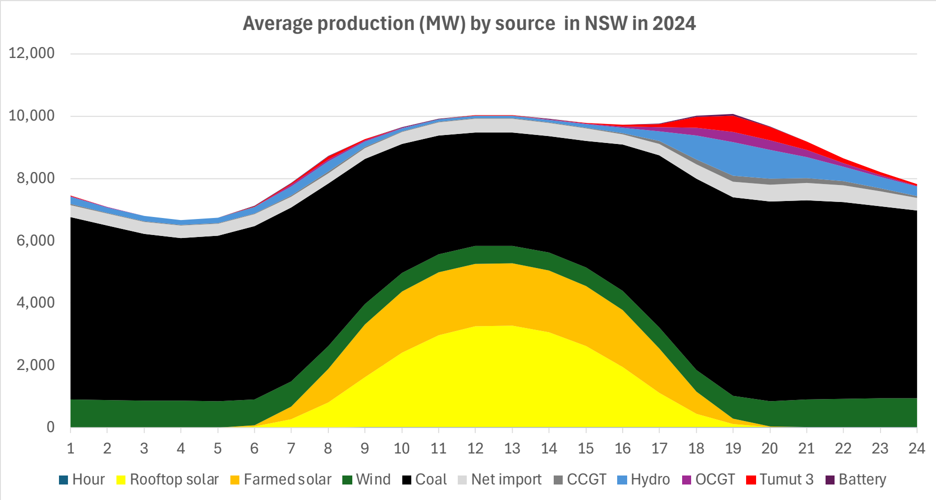


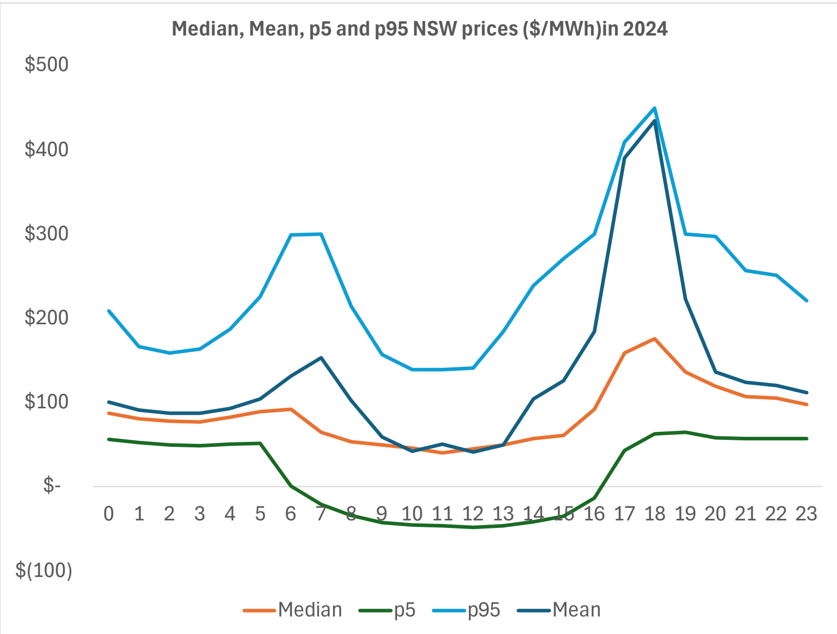
Figure 4 shows the average of the five-minute production of electricity, by generation technology, by hour of day in 2024. Tumut 3's generation (in red) is visible relative to that of hydro, open cycle gas generation (OCGT), combined cycle gas generation (CCGT) and coal (its main competitors) during the evening hours.

Figure 4. Generation mix in NSW, by hour of day, in 2024



To get a sense of the dispersion of five-minute spot market prices in the 24 hours of a day, Figure 5 shows the 5th percentile, median, mean and 95th percentile of five-minute prices in NSW in each day. It shows the lowest dispersion in the early morning and middle of the day when the market is well supplied relative to demand (and so coal generation is consistently price-setting at both periods) but much higher dispersion in the morning and evening peak when tight supply/demand balances can lead hydro, pumped hydro and gas generators to typically set market clearing prices.

Figure 5. Spot price dispersion in NSW in 2024



Noting from Figure 4 that Tumut 3 generates mainly between 5pm and 10pm, and noting the pattern of prices across the hours of the day, begs deeper insight into the spot prices received by Tumut 3 when it produces. Table 2 below shows that just under half Tumut 3's production was sold at a price below $150/MWh and almost a quarter at a price below $100/MWh, and that just under one third of the production was sold at a price above $250/MWh. The highest priced 10% of production was sold at an average price above $400/MWh. This average reflects a few extreme price events. Excluding spot prices above $1000/MWh, the average price in 2024 dropped from $645/MWh to $183/MWh.

Table 2. Production (MWh) in 2024 by received spot price in bands ($/MWh)

Price band ($/MWh)	Production (MWh)	Percent of total	Cumulative percent of total
Less than -$50	9,069	1%	1%
-$50 to $0	9,670	1%	2%
$0 to $50	24,838	3%	5%
$50 to $100	154,178	18%	23%
$100 to $150	208,394	25%	48%
$150 to $200	90,673	11%	59%
$200 to $250	66,378	8%	67%
$250 to $300	141,325	17%	84%
$300 to $350	41,248	5%	88%
$350 to $400	16,096	2%	90%
$400 or more	81,206	10%	100%
TOTAL	**843,076**		

3 Analysis

How does Tumut 3 compete with other types of peaking generation (hydro, open cycle, and combined cycle gas generation) in the NSW electricity market? What can be learned from the dispatch of Tumut 3 that is relevant to the assumed operation of Snowy 2.0 and what does the data on Tumut 3's pumping and generation reveal about competition in the market for the services provided by storage? What is the impact to consumers of this? These are the main questions explored in this analysis. Answers to these questions are sought through five analyses:

1. In the first, Tumut 3's production is compared to those of its competitors by examining its dispatch in segments that are determined on the basis of the output of its two competitors: peaking gas generators and hydro generators. The purpose is to uncover how Tumut 3 is dispatched in comparison to generation from these other sources. This leads to conclusions about where Tumut 3 fits, in the price-based order for the dispatch of peaking generation.
2. In the second, Tumut 3's operation is analysed in quartiles that are determined based on its daily production. The prices Tumut 3 received for its production and paid for its pumping are then compared. This leads to tentative conclusions on the extent which the operation of Tumut 3 reflects the exercise of market power.
3. In the third, the tentative market power conclusions from the second analysis are deepened through an analysis of NSW spot prices when generators of different types are operational in NSW.

Data used in this analysis is sourced from the Australian Energy Market Operator's NEMWeb portal and extracted from www.v-nem.org and is available from the author on reasonable request. The Stata "Do" file used in this analysis can be found at the Github repository: https://github.com/BruceMount/Tumut-3-and-Snowy-2

3.1 Segmental analysis of Tumut 3 generation compared to its competitors

Table 3 presents an analysis of electricity production and demand from the late afternoon to early evening (from 4pm to 9pm) from the start of 2023 to the end of 2024, focussing on the production from three main sources of electricity (in addition to coal-fired generators) that are dispatched to meet the late afternoon and early evening peak demand (from 4pm to 9pm)8, as discussed in the previous section and shown in Figure 4. These “peaking” generation sources are hydro (all of which is owned by Snowy Hydro), Tumut 3 pumped hydro (owned by Snowy Hydro) and two similarly sized OCGT, one Colongra (724 MW) which is owned by Snowy Hydro, and the other Uranquinty (695 MW) by Origin Energy. There are also two CCGT - Smithfield (125 MW) and Tallawarra (738 MW). While electro-chemical battery capacity is growing quickly in NSW, it is still too small to count as a major source of peaking supply in the 4pm to 9pm window.[9]

Table 3. Segmentation of 5-minute peaking generation in NSW in 2023 and 2024

	Hydro + OCGT between 0 and 200 MW	Hydro + OCGT between 200 and 600 MW	Hydro + OCGT between 600 and 1,000 MW	Hydro + OCGT between 1,000 and 1,400 MW	Hydro + OCGT between 1,400 and 1,800 MW	Hydro + OCGT between 1,800 and 2,200 MW	Hydro + OCGT between 2,200 and 2,600 MW	Hydro + OCGT > 2,600 MW
No. of 5 minute intervals	98,005	49,980	24,830	9,821	4,758	2,327	1,500	1,525
Average price ($/MWh)	54	100	134	177	239	392	768	1,382
Average Operating Demand (MW)	7,068	7,730	8,577	9,347	9,849	10,037	10,280	10,828
Average Net Load (MW)	5,202	6,633	7,716	8,565	9,150	9,361	9,572	10,098
Average Tumut3 (MW)	1	46	161	319	491	798	1,145	1,394

The analysis in Table 3 segments five-minute peaking generation data into seven groups based on the aggregate generation of hydro plus OCGT. The seven groups go from less than 200 MW to more than 2,600 MW. In each of the five-minute trading intervals in these segments, the production of Tumut 3 is measured and the average production of Tumut 3 in each segment is reported in the last row of the table.

Table 3 reveals average prices ranging between $54/MWh and $1,382/MWh (the second data row), and average Operating Demand (the demand measured on the transmission system) ranging between 7,068 MW and 10,828 MW (the third data row) across the seven segments. The Net Load (fourth data row) is a measure of the difference between Operating Demand and variable renewable electricity (wind and solar) and so is the demand that is met by dispatchable resources (hydro, pumped hydro, coal, gas and batteries).

In the first segment (the first data column), Tumut 3 hardly runs (averaging just 1 MW over these periods). Tumut 3’s average production is at its highest (as might be expected) when hydro plus OCGT production is at its highest (above 2,600 MW in the last column).

The last four columns of the table show that even when average prices are above $239/MWh (the fourth last column) Tumut 3 average production (491 MW) is less than a third of its capacity (1,800 MW). Even where average prices are extremely high ($1382/MWh on average) Tumut 3’s average production (1,392 MW) is not more than three quarters of its capacity.

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[8] In addition, of course, to cheaper generation from coal, renewables and interconnector imports.

[9] Batteries in NSW are mainly dispatched to provide services in the rapid response ancillary services market. As battery capacity expands, it will however become relevant in analyses of Tumut 3’s operation.

3.2 Quartile analysis of Tumut 3 generation and pumping

The previous analysis provided preliminary insight into how Tumut 3 is being operated relative to its OCGT and hydro competitors, to provide electricity during peak periods. It revealed that despite high sales prices, Tumut 3 was operated well below its capacity. Might such operation be explained by high prices to pump electricity? Or does it suggest that Tumut 3 would seem to be operating well below the level that might be expected in a competitive market?

To answer this question, Tumut 3's production (and pumping) is examined by dividing Tumut 3's daily-aggregated production, for all days in 2023 and 2024, into quartiles. The results presented in this sub-section cover the full period, and the appendices present the results for 2023 and 2024 separately. The findings here are consistent with each of 2023 and 2024 analysed separately (set out in Appendices A and B).

This analysis, set out in Table 4 below, compares the amount generated (and prices paid when generating) with the amount pumped (and prices paid when pumping) to reveal the extent to which production and pumping capacity is used relative its potential, and relative to the (apparent) opportunity for profitable arbitrage (i.e. pumping when prices are low and selling when prices are high). By segmenting the daily production into quartiles it is possible to analyse production decisions taking account of the sale and purchase prices during the days in those quarters and so conclude on the extent to which Tumut 3 may be, apparently, foregoing profits in the different market conditions measured in each quartile.

Table 4. Quartile segmentation of Tumut 3 generation in 2023 and 2024

2023 and 2024					
	QUARTILE				
	First	Second	Third	Fourth	All
Tumut3 total production (MWh)	60,860	275,352	471,488	850,524	1,658,224
Total peaking production (hydro+Tumut3+OCGT+CCGT) (MWh)	1,332,034	2,035,957	2,720,547	4,292,043	10,380,581
Tumut 3 production as share of all peaking production (%)	5%	14%	17%	20%	14%
Tumut 3 generation from pumped hydro as % of theoretical maximum pumped-hydro generation	11%	14%	14%	21%	17%
Weighted average price when generating ($/MWh)	$ 86	$ 117	$ 144	$ 561	$ 227
Tumut 3 total pumping (MWh)	241,659	270,606	247,172	255,365	1,014,802
Tumut 3 total pumping as % of theoretical maximum	11%	13%	14%	18%	14%
Weighted average price when pumping ($/MWh)	$ 10	$ 5	$ 38	$ 52	$ 26
Potential gross margin ($/MWh sold) after accounting for round-trip losses	$ 73	$ 110	$ 93	$ 492	$ 192

In considering this analysis it is important to recall relevant technical features of Tumut 3. Specifically:

- Tumut 3 has an upper reservoir that has sufficient capacity to allow Tumut 3 to generate at its full capacity for about 33 hours, if the reservoir was full.
- Tumut 3 has pumping capacity that is one third of its generation capacity and round-trip losses of around 25% which means that each hour of generation at full (generating) capacity from pumped water, requires four hours of pumping at full (pumping) capacity. This means that, over a 24 hour day, if Tumut 3 generates at full capacity for 4.8 hours, it must pump at full capacity for 19.2 hours.
- Tumut 3 receives hydrological in-flows from the Tumut River via Tumut 1 and Tumut 2. These inflows vary from one year to the next and, as explained in Section 1, have averaged 455 GWh per year. This needs to be taken into account in working out the theoretical maximum pumped hydro generation, and theoretical maximum pumping energy.

The main observations from the results in Table 4 are as follows:

1. The first data row in shows Tumut 3's production for the days in the quartiles (or in the last column, all of the 731 days in 2023 and 2024). It shows large variation across the quartiles - the production in the fourth quartile was more than 10 times the production in the first.
2. The second data row show production from all peaking generators (Tumut 3 plus hydro, OCGT and CCGT) and the third row expresses Tumut 3's production as a share of the total. The variation in peaking generation across the quartiles is much lower than the variation in Tumut 3. As expected, Tumut 3's share of peaking generation increasing across the quartiles. This is consistent with the conclusion in the previous sub-section.
3. The fourth data row shows Tumut 3's production from pumped storage as a share of the theoretical maximum pumped storage generation in each quartile[10]. This shows consistently low utilisation of Tumut 3 as a pumped hydro generator. Even in the fourth quartile of most intensively used days, Tumut 3 produced only slightly more than a fifth of its pumped hydro potential even when gross margins averaged $382/MWh – last row).
4. The fifth data row shows the weighted average spot price received for Tumut 3 production in the days in each quartile. As expected, it increases: Tumut 3 produces more when prices are higher. The very high average price in the fourth quartile reflects the effect of a small handful of extreme (circa $17,000/MWh) five-minute spot prices in 2024. As the appendix shows, the average price in the top quartile for 2023 was much lower than in 2024.
5. The sixth data row shows the volume of electricity consumed for the days in each quartile. Interestingly there is only a small variation from one quartile to the next: Tumut 3 is not pumping more on the days that it generates more.
6. The seventh data row shows the volume of pumping energy as a percentage of the theoretical maximum pumping energy[11]. Here we see an increase across the quartiles. The increase across quartiles (when expressed as a percentage maximum theoretical pumping capacity) despite little change in the volume of total pumping across quartiles, is explained by the decline in the theoretical maximum pumped hydro energy.[12] Leaving this interesting detail to one side, the main observation here is that Tumut 3 is consistently pumping electricity at a rate far below its capacity.
7. The eighth data row shows low weighted-average pumping prices in the first and second quartiles, increasing in the third and fourth. By implication, on the days that Tumut 3 produced more electricity, when sales prices were typically higher, it also paid more to pump electricity, even though the volume of electricity purchased to pump was not much higher on those days.

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[10] The numerator is the actual pumped hydro generation in the quarter. This is calculated at 75%(to account for round trip losses) of the electricity purchased to pump in each quarter. The denominator is the theoretical maximum hydro generation. This is calculated as 4.8 (the number of hours per day that Tumut 3 can operate at capacity from pumped water) multiplied by 1800 MW multiplied by the number of the days in the quarter less the production from hydrological inflows (which is total generation in the quarter less the pumped hydro generation).
[11] The numerator is the actual pumped hydro generation in the quarter. The denominator is the difference between (a) the maximum possible pumping electricity (600 MW nominal multiplied by the number of days in the quarter and then by the ratio of the maximum pumping operation per day - 4 out of 5 hours of a 24 hour day) and (b) the electricity produced from hydrological inflows explained in the previous footnote.
[12] This decline can be attributed to the greater amount of hydrological generation (i.e. not pumped hydro generation) when prices are higher (as might be expected).

8. The final data row answers the main question of this analysis: how profitable (measured as "gross margin" so after the cost of sales but before deducting operating costs) has it been to pump water and then generate from it (as distinct from unpumped hydro generation) at Tumut 3 for the days in each quartile. The row shows, as expected, that gross margin goes up across the quartiles. It also shows very healthy margins (on average $57/MWh in the least profitable quartile, rising to $382/MWh in the fourth quartile), and averaging $151/MWh over the two years.

The main result of this analysis – that there are large margins to had from pumped-hydro operation of Tumut 3 and yet very low utilisation of Tumut 3 relative to its potential - begs the question why Tumut 3 had such low utilisation. The final sub-section considers this.

3.3 Analysis of market prices when hydro, pumped hydro and gas is generating

The preliminary analysis earlier established that Tumut 3 was typically dispatched after hydro but before OCGT and most (but not all CCGT generation), in meeting peaking electrical demands in NSW. The previous section established that the volume of Tumut 3's generation from pumped water responded to market prices, but also that even though Tumut 3 was seldom used there were still, apparently, substantial margins to be had by pumping water and generating from the pumped water. This points to the need to understand why the opportunity to increase pumping and generation in order to capture such (apparently) substantial margins had been foregone.

Understanding market prices when hydro, pumped hydro and gas generators are producing, provides information that is useful in answering this question. Table 5 below examines the number of five-minute trading intervals and average prices and generation in those intervals during which different generators, classified by technology, were producing (these are the rows in the table). Appendix B contains the results for 2023 and 2024 separately.

Table 5. Average prices ($/MWh) and generation when different technologies are generating

2023 and 2024							
Dispatchable generators producing	Number of five-minute intervals	Average price ($/MWh)	Coal average generation (MW)	Hydro average generation (MW)	CCGT average generation (MW)	Tumut 3 average generation (MW)	OCGT average generation (MW)
Coal	1,384	$ 59	5308	0	0	0	0
Coal + hydro	46	$ 55	4350	123	0	0	0
Coal + hydro + CCGT	133,096	$ 69	4683	197	59	0	0
Coal + hydro + CCGT+ Tumut 3	25,861	$ 121	5835	652	118	303	0
Coal + hydro + CCGT+ Tumut 3 + OCGT	21,440	$ 391	6320	1095	258	558	404

The table shows the lowest average price ($59/MWh) occurred when coal generators but not hydro, Tumut 3 or gas were generating (leaving aside the very few intervals when coal and hydro but not CCGT were generating). By far the most common combination was coal, hydro and CCGT, and the average price was only slightly higher ($69/MWh) when these generators were all producing at the same time.

When Tumut 3 was generating but not OCGT, the average price was much higher ($121/MWh) and yet Tumut 3's average dispatch was only 303 MW. When OCGT were generating, the average price was higher still ($391/MWh) and yet average Tumut 3 average dispatch (558 MW) was less than a third of its peak capacity (1800 MW).

Taking account of Snowy Hydro's ownership of all hydro generation and of Tumut 3 and more than half of the OCGT capacity in NSW, this analysis provides strong evidence that Snowy Hydro has responded to the powerful incentive it has to withhold Tumut 3 production from the market so as to drive prices up. This is most obviously the case in withholding Tumut 3 production in order to drive the dispatch of much higher gas generation, from which Snowy Hydro will have gained through the production from its gas generator and from Tumut 3 and from its hydro generation. The dispatch of the two OCGT generators also supports this conclusion. Of the two comparably-sized OCGT, Snowy Hydro' Colongra was dispatched at just one quarter of the level of Origin Energy's Uranquinty OCGT, on average.

Snowy Hydro also has a powerful incentive not to have Tumut 3 compete with its hydro generators. Table 5 shows that when hydro competes with coal and CCGT and when Tumut 3 is not producing, average prices are much the same as when coal generators are setting them, as would be expected. If Snowy Hydro dispatched Tumut 3 so as to compete with its hydro it would achieve higher sales volumes (bt taking volume away from the CCGT mainly) but lower prices for its hydro (which could no longer enjoy the large infra-marginal rent arising from Tumut 3's higher prices, which are evidently achieved by limiting the production from Tumut 3. Such downward price effect would reduce income more than higher sales volumes would increase it, thus delivering lower income and hence profits to Snowy Hydro.

4 The scope for Tumut 3 to reduce electricity prices

The analysis to this point has concluded that Snowy Hydro has responded to the powerful incentive it has to withhold Tumut 3 production from the market so as to increase prices and so its profits. This begs the question of how wholesale (spot) prices might change if Tumut 3 was offered to the market at a price that at least recovers its avoidable costs? This question has no certain answer, it will depend on many factors including how other competitors in NSW and elsewhere in the NEM respond. This section presents analysis in pursuit of answers to this question, on the basis of various simplifying assumptions.

The analysis starts with the observation of Tumut 3's prices and production in 2023 and 2024 together as shown in Table 5[13]. That table shows a large increase in average market prices when Tumut 3 was generating (along with CCGT), and then another step up when Tumut 3 was generating and OCGT were also generating. This leads to the observation that reducing Tumut 3's offer price might be expected to reduce market prices to the extent that it then displaces more expensive gas generators, particularly the OCGT, and the portion of the CCGT production that is offered to the market at very high prices.

The extent of the price effect depends on Tumut 3's ability to displace gas and imports from the market altogether (it is, conservatively, assumed here that other generators do not reduce their offers in response to greater competition from Tumut 3). In the case of OCGT displacement, the price effect is easy to calculate because although OCGT have an upward sloping supply curve, the minimum offer price is well above the avoidable costs of Tumut 3 generation: whenever OCGT is fully displaced by currently unused Tumut 3 capacity, it is assumed spot prices reduce to Tumut 3's level.

Accounting for CCGT, is complicated by the fact that CCGT production has an upward sloping supply curve with a low minimum price. Table 5 shows average CCGT production of 59 MW when spot prices averaged \$69/MWh, and CCGT production at much higher levels when market prices are higher. Regressing CCGT production against market prices excluding outliers (when prices exceed \$1000/MWh) reveals a constant of 8.8 ($p<0.000$) and coefficient of 0.89 ($p<0.000$). For the assumed new Tumut 3 offer price of \$49/MWh (explained later) this suggests 53 MW of CCGT production when market prices are at this level. Accordingly, CCGT production in excess of 53 MW is added to the OCGT in the calculation of the level of gas displacement by Tumut 3, that is needed in order for Tumut 3's revised offer price to be assumed to set spot prices.

Accounting for the relationship between imports and NSW prices is, like CCGT, complicated by the fact that imports also have an upward sloping supply curve with an implied minimum price below the avoidable cost of Tumut 3 generation. Table 6 below presents relevant information on average interconnector imports, prices and regional price differences for the five-minute trading intervals from the start of 2023 to the end of 2024. It shows small price separation between NSW and Queensland either when Tumut 3 was not generating, or when Tumut 3 was generating but there was also no generation from peaking gas in NSW. However, prices were considerably higher in NSW than in Victoria particularly when Tumut 3 was generating and even moreso when OCGT was also generating, in which case prices in NSW were also considerably higher than in Queensland. These regional price differences point to constrained interconnectors when OCGT generators were producing in NSW.

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[13] Appendix C presents the results for 2023 and 2024 separately.

Table 6. Interconnector imports and regional prices differences contingent on Tumut 3 generation from start of 2023 to end of 2024

	Number of five-minute settlement periods	Imports to NSW (average) (MW)	NSW spot price (average) ($/MWh)	Difference between NSW and Queensland price (median /average) ($/MWh)	Difference between NSW and Victoria price (median /average) ($/MWh)
Tumut 3 not generating or pumping	135,959	705	$75	$3/$10	$12/$25
Tumut 3 generating but not OCGT	22,044	714	$121	-$2/-$7	$21/$41
Tumut 3 and OCGT generating	18,996	766	$391	$6/$120	$17/$207

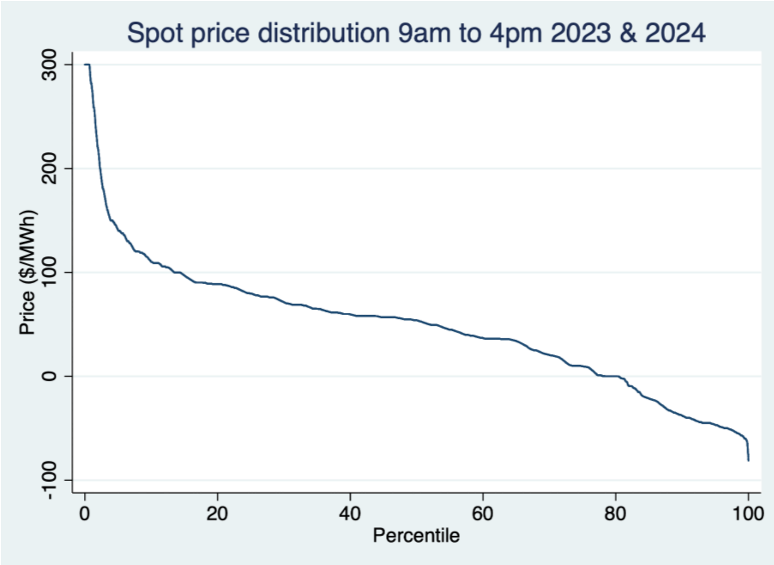
To estimate the relationship between imports and NSW market prices, the net import over the interconnectors with Victoria and Queensland is regressed against NSW prices excluding outliers (when prices exceed $1000/MWh). This reveals a constant of 703 ($p<0.000$) and coefficient of 0.066 ($p<0.000$). The suggests Tumut 3 (with assumed offer price of $49/MWh) will be required to displace interconnector imports above 703 MW in order to be able to reduce NSW prices to Tumut 3 offer prices (by implication the first 703 MW of imports are offered at prices below the assumed Tumut 3 offer price).

This analysis depends on the price that Tumut 3 is assumed to be offered to the market. Before explaining the results of the main analysis (in Table 8), it is necessary to justify the assumed Tumut 3 offer price. The actual average price when Tumut 3 pumped in the 61,404 five-minute intervals that it pumped over 2023 and 2024, was $59/MWh. However the weighted average price it paid when it pumped was just $16/MWh in 2023 and $31/MWh in 2024. Taking the higher of these and grossing up for round-trip losses of 25% gives an average price of $39/MWh and adding $10/MWh for other avoidable costs, gives an assumed average avoidable cost of Tumut 3 of $49/MWh.

The question that then arises is whether there is sufficient electricity available in the market when Tumut 3 pumps so that prices will not rise if Tumut 3 needs to pump more so that it has the additional electricity needed to later displace gas generation and interconnector imports when Tumut 3 generators. The additional pumping required to provide Tumut 3 with the energy needed to displace gas and interconnectors imports using the method described above, is 57 MW (expressed as annual average) or 140 MW if all of this pumping is assumed to occur in the seven hours from 9am to 4pm. To put this in perspective, this additional pumping is a little over half the average actual pumping from the start of 2023 to the end of 2024.

Is this additional 140 MW of demand over the period 9am to 4pm likely to result in higher prices in these hours? To answer this, the spot price duration curve for 2023 and 2024 in Figure 6 shows the distribution of spot prices between 9am and 4pm in 2023 and 2024. It shows the 60th percentile price is around $45/MWh and the curve is gently sloping 10 percentage points either side of this. The distribution of grid demand (measured at the transmission system) ranges between 5,807 MW and 7,351 between the 25th and 75th percentiles. Taken together this suggests that adding 140 MW between 9am and 4pm is unlikely to meaningfully raises prices over this period. This is reinforced by regressing the log of pumping volume against prices (when they are greater than zero) between 9am and 4pm which does not find a statistically significant relationship between pumping volumes and market prices.

Figure 6. NSW spot price duration curve for 2023 and 2024



It is now possible to present the results of the analysis of the effect of the revised Tumut 3 offer price ($49/MWh), on market prices, in Table 8. The two data columns in Table 8 show (for 2023 and 2024 together) the effect of the additional 49 MW (on average) of Tumut 3 generation on production and prices. In the period from 5pm to 8pm (when gas was most often generating) this means an increase of 140 MW on average from Tumut 3, taking its average production over these hours from 422 MW to 562 MW.

The effect of this, at Tumut 3's revised offer price of $49/MWh, is to reduce the average spot price when Tumut 3 is generating from $243/MWh to $134/MWh (third data line in Table 7). In the period from 5pm to 8pm and when Tumut 3 is generating over this period, average prices reduce from $334/MWh to $203/MWh (fourth data line). Average spot prices over the full period (irrespective of whether Tumut 3 is producing) reduce by 33% from $114/MW to $76/MWh, and over the period from 5pm to 8pm by 40% from $281/MWh to $170/MWh. Appendix C presents the results for 2023 and 2024 separately.

Table 7. Generation and price outcomes from start of 2023 to end of 2024 with Tumut 3 generation displacing peaking gas and imports as far as possible

	2023 & 2024	
	Actual	New
Average T3 generation (MW)	95	142
Average T3 generation between 5pm and 8pm (MW)	422	562
Average spot price when T3 is generating ($/MWh)	$243	$134
Average spot price when T3 is generating between 5pm and 8pm($/MWh)	$334	$203
Average spot price over period ($/MWh)	$114	$76
Average spot price between 5pm and 8pm ($/MWh)	$281	$170

This analysis has found that relatively small changes in Tumut 3 generation (increasing average generation by just 47 MW by increasing pumping by 59 MW) can have a dramatic effect on average prices by displacing gas generation and imports mostly between 5pm and 8pm. This assumed pattern of Tumut 3 operation (and its offer price) is what might be expected in a workably competitive market in the conventional neoclassical meaning of this term.

This analysis does not take account of transmission constraints *within* NSW that could undermine Tumut 3's ability to displace generation needed to meet demand at the main load centres. The Australian Energy Market Operator has suggested that transmission constraints contributed to high prices in some instances in the fourth quarter of 2024[14]. However intra-regional transmission congestion is not a widely cited explanation of very high prices in NSW and the consistency of the results in 2023 and 2024 suggest possible transmission congestion effects in some instances in 2024 is unlikely to undermine the main conclusions of this study.

5 Discussion

The main conclusion from the analysis in the previous sections might be summarised as follows:

1. Tumut 3 is currently typically dispatched after hydro generators but before open cycle gas turbines in the NSW electricity market. Although its utilisation has increased over the last decade, as a pumped-hydro generator it operates at about a fifth of its potential annual average.
2. Tumut 3's operation is withheld from market in order to increase spot prices. Snowy Hydro has powerful incentives to withhold Tumut 3 from the market since Snowy Hydro by owns most of the peaking generation capacity in NSW, and so it can sacrifice small volumes to competitors in exchange for much higher spot prices which it can monetise in spot market sales or in the sale of financial hedges.
3. If Tumut 3 was operated so as to maximise the displacement of gas generation and to offer its production at a price that is easily likely to recover its avoidable costs, it would have reduced the average spot price over 2023 and 2024 together by 33%. In period from 5pm to 8pm it would have reduced average spot prices by 40%.

These conclusions have important policy implications. Offering Tumut 3 to the market at its avoidable cost can be expected to reduce spot prices, as this analysis finds. While customers will benefit from such lower prices, lower market prices will make investment in storage and renewable electricity less attractive. Since the Australian Government and the NSW State Government are pursuing policies to decarbonise electricity supply, lower electricity prices will inevitably mean that more public support will be needed to deliver the required capacity expansion.

Finally, to return to the question that motivated this study, the conclusions from this analysis undermines Snowy Hydro's claims that it would operate Snowy 2.0 at close to its capacity for the $75/MWh gross margin that it claims this will deliver. How can it be plausible to claim that Snowy Hydro would operate Snowy 2.0 at close to its maximum capacity in return for $75/MWh, when Tumut 3 operates at around a fifth of its capacity even when gross margins of more than five times this amount are available?

While the demand and supply for storage will change considerably as coal generation in NSW is withdrawn, Snowy Hydro's dominance of peaking generation and storage will

[14] See https://aemo.com.au/-/media/files/major-publications/qed/2024/qed-q4-2024.pdf?la=en

continue to provide very powerful incentives to withhold production from Tumut 3 and Snowy 2.0. This analysis lends weight to the theoretical analysis in Andrés-Cerezo & Fabra (2023) that market structure matters in designing mechanisms to grant public support for storage: storage capacity in the hands of competitive storage owners is more socially valuable than in the hands of large storage firms or generators.

6 Conclusions

As the NSW electrical system transitions to increasing dependence on variable renewable electricity, the expansion and operation of storage becomes increasingly important. The Australian Government is funding the development of the massive Snowy 2.0 pumped hydro generator. Its updated business plan has projected that Snowy 2.0 will operate at close to its capacity in exchange for gross margins of $75/MWh for the foreseen future. This paper has sought to test this assumption by examining how Tumut 3, a 52 years old pumped hydro generator of comparable power capacity to Snowy 2.0, has been operated over the last decade.

The study finds that Snowy Hydro has withdrawn Tumut 3's capacity from the market in order to maximise its profits across its portfolio of generation, in its provision of peaking generation in NSW. Tumut 3 operates at a fifth of its capacity even when gross margins of more than $375/MWh are available. How then can it be plausible to claim that Snowy 2.0 will operate at close to its capacity in exchange for gross margins of just $75/MWh on average?

The analysis here finds that offering Tumut 3 at its avoidable costs and so dispatching it so as to maximise its displacement of gas generation and interconnector imports will decrease prices between 5pm and 8pm by 40%, or equivalently, reduce annual average prices by 33% over the period from the start of 2023 to the end of 2024. While electricity consumers will find this attractive, lower electricity prices will reduce Snowy Hydro's profits and will demand higher public subsidies to fund the development of Snowy 2.0 and for other storage and renewable electricity that policy makers are seeking to rapidly expand.

While expected coal generation closure will radically change the market for storage in NSW, Snowy Hydro will continue to have powerful incentives to withhold production in order to increase prices and so its profits. Careful examination of the public costs and benefits associated with Snowy Hydro's market dominance will be valuable.

If policy makers wish to reduce Snowy 2.0's market power, as the results of this analysis suggests they might wish to consider, many options for regulation, restructuring and privatisation of Snowy 2.0, and for the allocation of storage subsidies, might be considered.

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Appendix A

Table 8. Quartile segmentation of Tumut 3 generation in 2023

2023					
	QUARTILE				
	First	Second	Third	Fourth	All
Tumut3 total production (MWh)	37,358	142,973	402,650	232,168	815,148
Total peaking production (hydro+Tumut3+OCGT+CCGT) (MWh)	402,650	750,498	1,515,486	2,233,122	4,901,755
Tumut3 production as % of peaking production	9%	19%	27%	10%	16%
Tumut 3 generation from pumped hydro as % of theoretical maximum pumped-hydro generatio	9%	12%	15%	10%	11%
Weighted average price when generating ($/MWh)	$ 89	$ 119	$ 144	$ 384	$ 184
Tumut 3 total pumping (MWh)	102,520	119,852	91,271	79,921	393,565
Tumut 3 total pumping as % of theoretical maximum	9%	11%	8%	7%	36%
Weighted average price when pumping ($/MWh)	$ 6	$ 8	$ 37	$ 55	$ 26
Potential gross margin ($/MWh sold) after accounting for round-trip losses	$ 82	$ 108	$ 95	$ 311	$ 149

Table 9. Quartile segmentation of Tumut 3 generation in 2024

2024					
	QUARTILE				
	First	Second	Third	Fourth	All
Tumut3 total production (MWh)	24,382	134,707	444,521	239,466	843,076
Total peaking production (hydro+Tumut3+OCGT+CCGT) (MWh)	444,521	610,008	1,173,757	2,094,231	4,322,517
Tumut3 production as % of peaking production	5%	22%	38%	11%	19%
Tumut 3 generation from pumped hydro as % of theoretical maximum pumped-hydro generatio	8%	11%	24%	11%	17%
Weighted average price when generating ($/MWh)	$ 67	$ 107	$ 154	$ 1,330	$ 414
Tumut 3 total pumping (MWh)	140,499	143,351	183,674	153,713	621,237
Tumut 3 total pumping as % of theoretical maximum	13%	13%	17%	14%	57%
Weighted average price when pumping ($/MWh)	$ 28	$ 28	$ 41	$ 52	$ 37
Potential gross margin ($/MWh sold) after accounting for round-trip losses	$ 30	$ 70	$ 100	$ 1,260	$ 365

Appendix B

Table 10. Average prices ($/MWh) and generation when various generators are setting prices in 2023

2023							
Dispatchable generators producing	Number of five-minute intervals	Average price ($/MWh)	Coal average generation (MW)	Hydro average generation (MW)	CCGT average generation (MW)	Tumut 3 average generation (MW)	OCGT average generation (MW)
Coal	108	$ 50	3741	0	0	0	0
Coal + hydro	42	$ 54	4284	122	0	0	0
Coal + hydro + CCGT	73,254	$ 69	4625	224	85	0	0
Coal + hydro + CCGT+ Tumut 3	15,138	$ 115	5817	673	150	291	0
Coal + hydro + CCGT+ Tumut 3 + OCGT	9640	259	6244	1132	276	554	375

Table 11. Average prices ($/MWh) and generation when various generators are setting prices in 2024

2024							
Dispatchable generators producing	Number of five-minute intervals	Average price ($/MWh)	Coal average generation (MW)	Hydro average generation (MW)	CCGT average generation (MW)	Tumut 3 average generation (MW)	OCGT average generation (MW)
Coal	1,276	$ 60	5441	0	0	0	0
Coal + hydro	4	$ 62	5039	133	0	0	0
Coal + hydro + CCGT	59,841	$ 69	4753	163	26	0	0
Coal + hydro + CCGT+ Tumut 3	10,723	$ 128	5860	623	72	318	0
Coal + hydro + CCGT+ Tumut 3 + OCGT	11000	$ 499	6383	1064	243	561	429

Appendix C

Table 12. Generation and price outcomes in 2023 and 2024 with Tumut 3 generation displacing peaking gas and imports as far as possible

	2023		**2024**	
	Original	New	Original	New
Average T3 generation (MW)	93	145	96	138
Average T3 generation between 5pm and 8pm (MW)	415	647	428	615
Average spot price when T3 is generating ($/MWh)	$171	$79	$321	$194
Average spot price when T3 is generating between 5pm and 8pm ($/MWh)	$240	$116	$436	$298
Average spot price over period ($/MWh)	$96	$61	$131	$91
Average spot price between 5pm and 8pm ($/MWh)	$212	$107	$349	$233