Submission on VNI West Consultation Report – Ted Woodley 4 April 2023

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I wish to submit comments and questions on the VNI West Consultation Report, dated 23 Feb 2023.

The latest Report and its accompanying VNI West PADR Submissions Report fail to address most of the issues raised in my Submission on VNI West PADR, dated 9 Sep 2022, and the jointly authored paper 'Assumed operation of Snowy 2.0 in VNI West PADR – some comments', dated 8 Dec 2022.

This Submission focuses on those unaddressed issues, particularly the implausible modelling assumptions and outcomes that continue to be applied to 'justify' the benefits from building VNI West, now estimated to be $4 billion. The Submission has four sections:

1. **Implausible modelling assumptions/outcomes**

   The model continues to assume that developers, for some inexplicable reason, will defer constructing renewable generators, storage and gas plant in the next few years due to the knowledge that VNI West will be built in the future. The model then replaces that unsupplied renewable energy by generation from existing coal power stations through to 2039. The avoided renewable energy construction costs are then deemed as benefits from building VNI West even though this contrived modelling and extended operation of coal stations runs counter to every government renewable energy transition and emission reduction policy.

   Equally inconceivably, the model then assumes that after VNI West is commissioned in 2031 the deferred renewable generators are subsequently built at 'higher quality' locations in NSW and Queensland. Not only is this another implausible contrivance but the proposed interstate locations are of no better quality and are much further away from Victorian load centres.

2. **Unexplained increases in estimated benefits since the PADR**

   The latest model forecasts even higher benefits from building VNI West, but without reasons. Avoided generation/ storage cost benefits are now $2.9bn (up $1.7bn, 130%), cumulative gross benefits are $3.9bn (up $1bn, 35%), and net benefits are $1.4bn (up $0.7bn, 100%).

   There is no update on the estimated cost of VNI West, which has doubled from $1.55bn in the 2018 ISP to $3.3bn in the PADR (for a shorter line and less substations). One would expect there to be further escalations (in real terms), especially as the project will not start construction for another three years and not be completed for another eight years.

3. **VNI West doesn't increase usage of Snowy 2.0 or transmission to Melbourne**

   The Report reveals that the latest design and route for VNI West will not increase the utilisation of Snowy 2.0 or its transmission capacity to Victoria, as was previously claimed as a major reason for building VNI West. However, it is now claimed that VNI West will enable increased efficiency of Snowy 2.0, though this is unquantified. Even if there were such a benefit it would more likely flow to Snowy Hydro's bottom-line than to electricity consumers.

4. **Unrealistic Snowy 2.0 capacity factor**

   The modelling continues to assume an unattainable capacity factor for Snowy 2.0 of over 50% for pumping/ generating. That is an average of over 1,000 MW continuously 24/7, 365 days a year. As Snowy 2.0 will be the most inefficient and inflexible storage on the NEM, other pumped hydro stations and batteries would have to operate at even more unrealistic capacity factors.

These perverse modelling assumptions and outcomes continue to be far removed from what would happen in reality and continue to fail to justify building VNI West.

Contents

VNI West is the abbreviated term for the **V**ictoria to **N**SW **I**nterconnector, **West** route

1 Implausible modelling assumptions/outcomes

The latest modelling continues to be based on the assumption in the Project Assessment Draft Report (PADR) that VNI West will somehow trigger developers to defer or avoid the construction of renewable generators, storage, and gas before VNI West is commissioned, hence 'avoiding' the cost of installing this generation/storage for up to eight years.

The modelling assumes that the output that would have been generated by the avoided projects in the Base Case will be replaced by a commensurate increase from coal generation at no capital cost, as it is already built and operating.

The model then assumes that the deferred renewable generators are built after VNI West is commissioned in 2031, but in different locations, particularly in NSW and Queensland.

Extending the use of coal generation and hence deferring the capital expenditure on new renewable generation and storage (and some gas generators as well) all seems to be contrived to justify building VNI West.

1.1 Improbable impacts of VNI West on forms of generation output

The Consultation Report provides a comparison of generation output with and without VNI West – see Figure 1:

> *"Figure 11 summarises the difference in generation and storage output modelled for Option 5 (in TWh), compared to the base case."* (p43 Consultation Report)

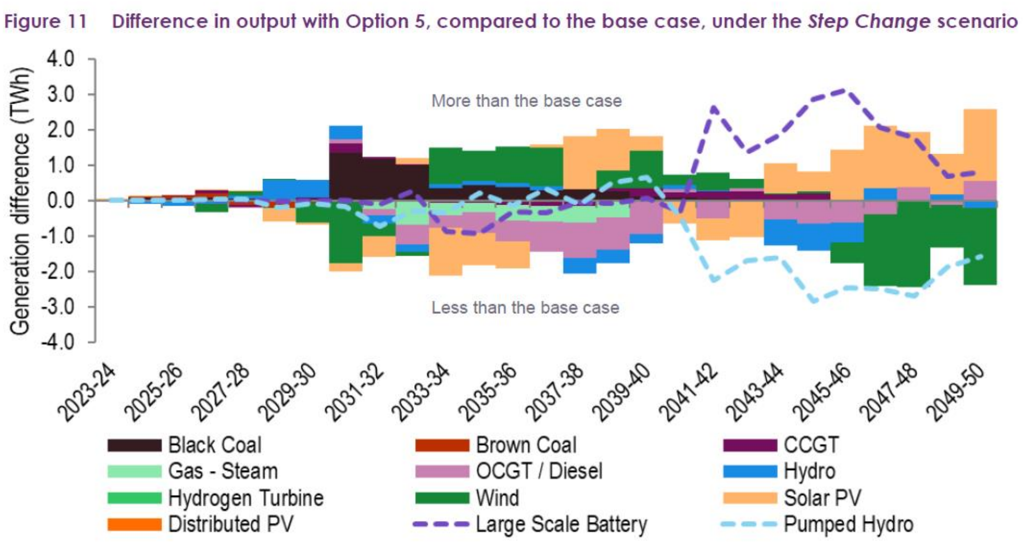

Figure 1 – Generation difference with and without VNI West (Consultation Report Fig 11)

Figure 1 is markedly different to the equivalent figure in the PADR (Figure 2 below), though still has similar implausible outcomes from building VNI West, particularly decreased renewable output and increased coal output over the 2030 decade.

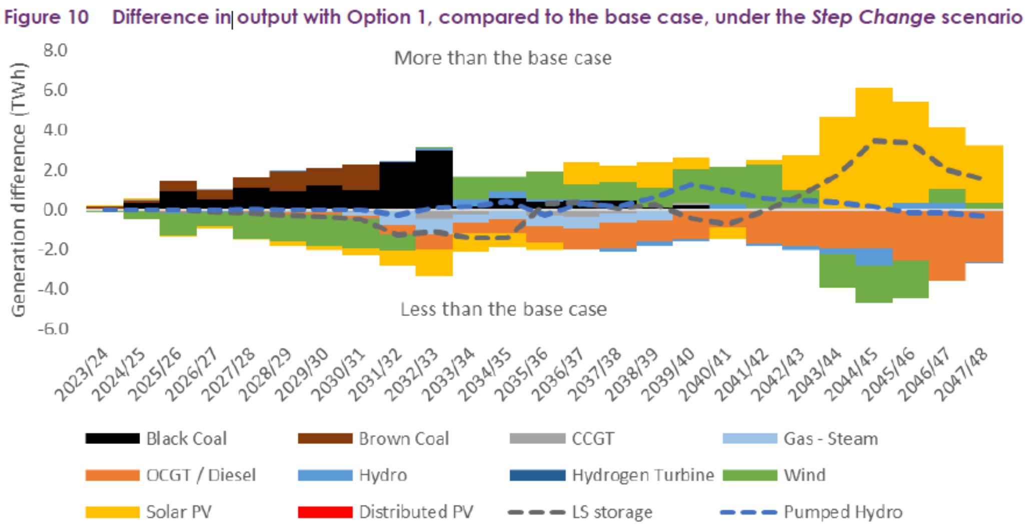

Figure 2 – Generation difference with and without VNI West (PADR Fig 10)

The Consultation Report does not provide reasons for the significant changes in generation output (Figure 1) compared to the PADR (Figure 2).

Some apparent anomalies are discussed below.

1.1.1 Why would VNI West result in less wind and solar output?

How does a decision to build VNI West result in less wind output (dark green bars in Figure 1) in the years before it is commissioned (2026-27 and 2029-30 to 2031-32)? Also, why would wind output be significantly less from 2045-46 to 2049-50 due to VNI West being built fifteen years earlier?

Similarly, why does VNI West result in less solar PV output (light ochre bars) in most years from 2027-28 to 2034-35?

Intuitively one would expect the construction of additional transmission capacity would enable more renewable output, not less.

The model does result in (slightly) more renewable generation over the period to 2050 due to construction of VNI West. However, the model forecasts less solar output through to the end of the 2030's, less wind output to the mid-2030's and no additional wind output through to 2050.

1.1.2 How could VNI West result in additional coal generation?

Figure 1 depicts additional black coal generation (black bars) if VNI West is built compared to the Base Case. This additional coal generation is forecast to occur from 2030-31 to 2038-39, up to eight years after VNI West is commissioned.

Previously, the PADR forecast even greater additional black and brown coal generation both before and after VNI West's commissioning (Figure 2). Why is it now forecast that only black coal output will increase, not brown coal as well, with its lower marginal cost of production?

Nevertheless, how is it conceivable that VNI West would result in additional coal fired generation for eight years after VNI West is commissioned? Isn't this the opposite of what might be expected or hoped for?

This modelling is both inexplicable and contrary to government energy transition and emission reduction policies.

1.1.3 How would VNI West vary hydro output?

Why does the amount of hydro output vary if VNI West is built?

- extra hydro generation (dark blue bars in Figure 1) from 2028-29 to 2030-31
- less hydro generation in 2025-26, 2031-32 to 2032-33, 2037-38 to 2039-40 and 2043-44 to 2045-46

Annual hydro output is determined by the available water not the makeup of the transmission network. For example, the Snowy Water Licence dictates the annual volumes of water transferred to the Tumut and Murray systems, regardless of the operation of the NEM.

The PADR (Figure 2) also forecasted differences in hydro output if VNI West is built, but less so and not before VNI West's commissioning.

1.1.4 How could VNI West result in hydro spilling?

> *"However, there are some periods in the year where some generation including hydro and renewable will spill either on an economic basis or due to constraints such as network constraints. Wind generation is expected to compete with hydro generation, particularly in Tasmania, and as hydro has higher running costs compared to wind, this results in more hydro spill relative to the base case."*
> (p74 Submissions Report)

In practice hydro storages never spill, other than due to unpredicted weather events.

Is this reference to hydro spilling a misnomer and just referring to when hydro is available for dispatch but isn't, which happens to be most of the time? That is, there is no physical spill of water, just hydro capacity not being dispatched.

If so, why is the amount of 'spill' exacerbated by VNI West being built? This seems counterintuitive. Shouldn't there be less spill with more transmission capacity and hence less network constraints?

1.2 Impact of VNI West on location of new wind and solar

> *"The proposed construction of VNI West is expected to influence the decisions of the developers of renewable generators and batteries on where to build and, in some cases, to defer or avoid their construction. Specifically, it is expected to result in higher quality (with better transmission access) renewable investments replacing lower quality REZs (which also need transmission upgrades) to meet overall state and federal emissions targets. The model forecasts an increase in renewable capacity in REZs directly benefitting from improved transmission access with VNI West."* (p69 Submissions Report)
>
> *"In addition, with the improved access to a diversity of resources provided by this option, more investment in higher quality REZs such as Central West Orana (N3) and Darling Downs (Q8) is forecast.*
> *On the other hand, Option 5 reduces the capacity otherwise forecast in the remaining Victorian REZs, particularly Ovens Murray (V1) and Gippsland (V5), as well as other regions REZs such as Wagga Wagga (N6), and some Queensland and Tasmanian REZs."* (p42-43 Consultation Report)

Why would the prospect of VNI West being built influence the decisions of developers of Victorian renewable generators and batteries to defer or avoid their construction and then also to decide to relocate those renewable generators interstate many years later in supposedly windier and sunnier locations interstate?

Wind and solar capacity factors in Western Victoria are similar to the supposed higher quality REZs in NSW (Central West Orana) and Queensland (Darling Downs) – see Figure 3. In fact, the Western Victoria wind resource is superior.

REZ	Wind		Solar
	High quality	Medium quality	
Western Victoria	41%	37%	23%
South West Victoria	41%	39%	not available
Gippsland	39%	34%	20%
Central North Victoria	33%	31%	26%
Central West Orana	37%	34%	27%
Darling Downs	39%	34%	27%

Figure 3 – REZ renewable energy capacity factors (EY Report Table 25)

Also, the quality of renewable resources in other Victorian REZs are not that dissimilar, especially when other relevant siting factors are taken into consideration such as the availability of transmission capacity in the case of the Gippsland REZ. Also, is it realistic to expect VNI West to result in renewable resources being re-located to the Darling Downs, 2,000 km away, and to NSW?

It is far cheaper to utilise renewable generation resources as close as possible to the load centres, both in terms of the capital and operating costs of new transmission.

There appears to be no sound basis for this modelling assumption and for such a response from wind/solar developers.

Also, is it realistic to assume that the Victorian Government would support less wind and solar projects being built in Victoria prior to 2031, so that replacement projects can be built in NSW and Queensland later? This modelling assumption runs counter to the Victorian Government's energy transition and regional development policies.

1.3 Revised carbon budgeting fails to resolve fundamental implausibility

> *"As part of their queries about consistency with government policies to increase renewable generation and reduce emissions, some submissions were concerned that the PADR modelling forecast more coal generation with VNI West in place than under the base case and a slower transition to renewables, and that some renewable generation is deferred with VNI West compared to the base case*
> *To address these concerns raised in submissions, the modelling of the carbon budget has been updated since the PADR and now assumes a discrete carbon budget applies in each decade to limit the transfer of emissions savings between early and late model years. Discrete budgets were crafted from the 2022 ISP outcomes."* (p23 Submissions Report)
>
> *"AVP and Transgrid therefore believe that the changes to the carbon budget approach has led to results that are more intuitive, more consistent with the 2022 ISP and stakeholder expectations and more aligned with government policy intent."* (p64 Submissions Report)

Amending the carbon budget to apply to each decade rather than the full period to 2048 may have muted the perverse outcomes, but it fails to address their fundamental implausibility. Why is it necessary to model a decadal carbon budget at all?

2 Unexplained increases in estimated benefits since the PADR

2.1 Why have cumulative gross benefits increased by $1bn (35%)

2.1.1 PADR gross benefits of $2.8bn

The PADR estimated cumulative gross market benefits of VNI West of $2,795 million (Step Change, Option 1, 2047/48) – see Figure 4.

> *"Figure 8 below presents the estimated cumulative expected gross benefits for Option 1 for each year of the assessment period under the Step Change scenario. It shows that, while benefits from avoided/deferred generation costs accrue straightaway, benefits from avoided fuel consumption begin accruing from commissioning in 2031-32 and accrue steadily from there."* (PADR)

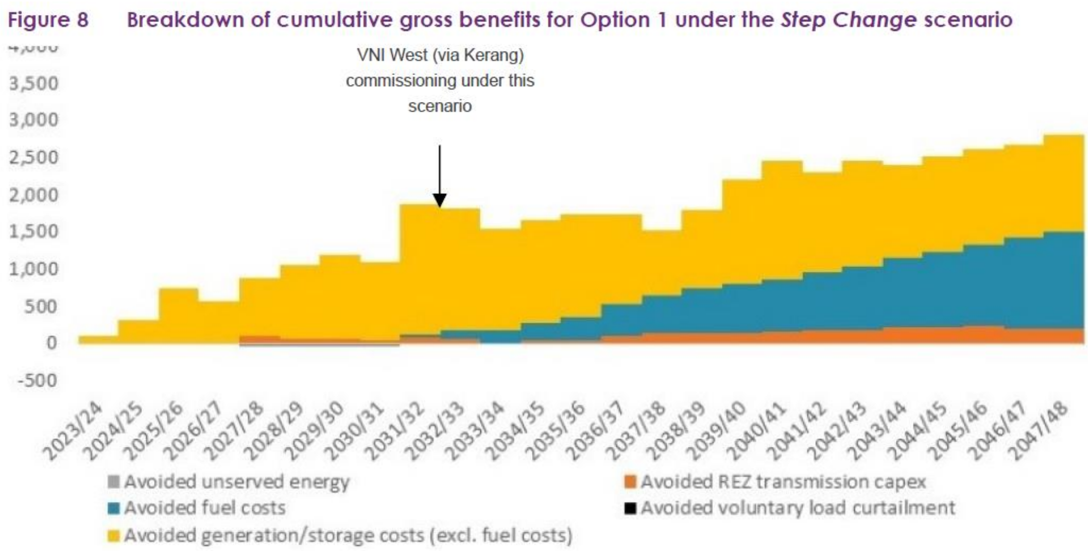

Figure 4 – Cumulative gross benefits from VNI West (PADR Fig 8)

2.1.2 Consultation Report gross benefits of $3.7 Option 1 ($3.9bn Option 5)

The Consultation Report now estimates gross benefits of $3,743 million for the same design (Step Change, Option 1, 2050 EY Report Table 2).

No reason is provided for the almost $1 billion increase (35%) in gross benefits compared to the PADR.

The now-preferred Option 5 has an even higher gross benefit of $3,921 million (EY Table 2).

The cumulative gross benefits are graphed in the Submissions Report for Option 3A, which has a slightly higher benefit than Option 5, of $4,253 million (see Figure 5), but commensurately higher cost.

> *"Figure 1 presents the breakdown of cumulative gross benefits for Option 3A under the Step Change scenario presented in the Consultation Report on the options using both the approach applied in the PADR (on the lefthand side) and the annualised approach applied now/for the PACR (on the right-hand side). It shows that:*
>
> - *The pattern of avoided generation/storage costs (excluding fuel costs) differs across the two approaches, with benefits appearing to accumulate more gradually under the annualised approach.*
> - *The choice is purely presentational and that, irrespective of the approach applied, the*

same cumulative gross benefits are reached by the end of the period (in present value terms)." (p25 Submissions Report)

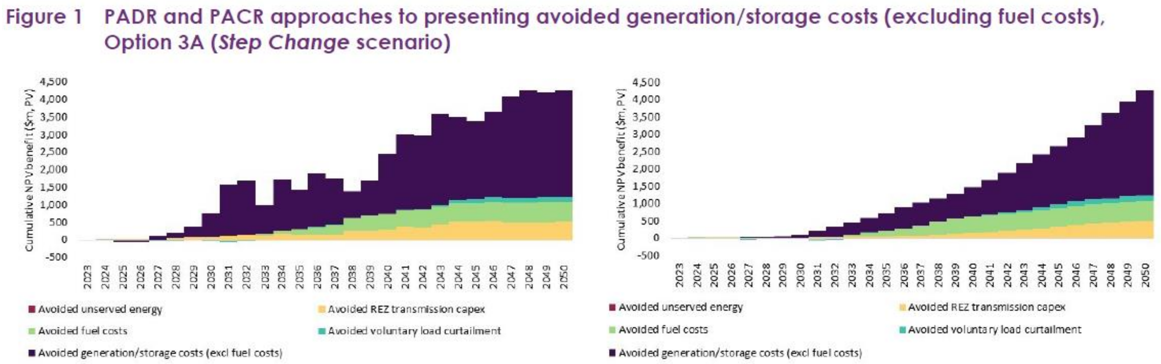

Figure 5 – Cumulative NPV gross benefit from VNI West (Submissions Report Fig 1)
left: PADR presentation, right: annualised presentation

Figure 5 was provided in the Submissions Report because of:

> *"an apparent misinterpretation of the PADR results in some points raised in submissions. Specifically, all charts in the PADR showing the breakdown of cumulative gross benefits for Option 1 presented the entire capital costs of these plant in the year avoided to highlight the timing of the expected market benefits capacity difference (despite the generator and storage capital costs actually being included in the market modelling on an annualised basis). This was purely a presentational choice"* (p25 Submissions Report)

2.2 Why have avoided generation/storage benefits increased $1.7bn (130%)?

The PADR estimated cumulative gross benefits from building VNI West of $2,795 million by 2047-48, primarily from avoided generation/storage costs ($1,295 million) and avoided fuel costs ($1,300 million). The proportionate contributions from avoided generation/storage costs and avoided fuel costs were one:one (see Figure 4).

The Consultation Report estimated gross benefits of $3,921 million by 2050 (see Figure 5), again primarily from avoided generation/storage costs ($2,946 million) and avoided fuel costs ($569 million).

However, avoided generation/storage costs have increased $1,651 million (130%) and now outweigh avoided fuel costs five:one. They actually exceed the total benefits in the PADR.

The significantly higher proportion of avoided generation/storage costs is evident when comparing Figure 4 (ochre bars vs dark blue bars) with Figure 5 (purple bars vs green bars).

Why have avoided generation/storage costs increased $1,651 million (130%) compared to the PADR?

On the other hand, why have avoided fuel costs reduced by $731 million (56%)?

2.3 The value of avoided costs from the initial deferrals appears to be about $1.6bn

The left diagram of Figure 5 shows *"the entire capital costs of these plant in the year avoided to highlight the timing of the expected market benefits capacity difference".*

Hence, the value attributed in the model to avoided generation/storage costs excluding fuel costs (purple bars) from not building so much renewable generation and storage prior to VNI West's commissioning in 2031 appears to be approximately $1.6 billion NPV.

Is this the magnitude of costs avoided by the implausible deferrals of renewable projects?

2.4 Why have net benefits doubled to $1.3bn?

The PADR estimated net benefits to be $687 million, Option 1 weighted scenario.

However, the Consultation Report now estimates net benefits of $1,299 million for Option 1 ($1,388 million for Option 5).

No explanation is provided as to why the net benefits have almost doubled.

Also puzzling is why the increase in net benefits is (slightly) less than the increase in gross benefits.

2.5 Cost estimates likely to be understated

> *"The capital cost estimates are considered to be at an accuracy of ±30%, which AVP and Transgrid consider to be 'Class 4' estimates."* (p55 Consultation Report)
>
> *"The cost estimates reflect the best available estimates at this stage of the investment process. As part of the contingent project process, Transgrid will seek a 'feedback loop' confirmation from AEMO (as national planner) in line with the actionable ISP framework ahead of lodging a CPA for investment in VNI West"* (p51 Submissions Report)

I previously commented that the estimated cost of VNI West has increased 110% in the past four years, from $1.55 billion in the 2018 ISP to $3.26 billion in the PADR (for a shorter line and fewer substations).

One would expect there to be further escalations, especially as the project will not start construction for another three years and not be completed for another eight years. Also, local opposition to the project is consolidating, adding further financial costs, let alone social and environmental costs.

2.6 VNI West's costs likely to exceed its benefits

VNI West's estimated payback period of 2046 is looking wildly optimistic, when accounting for underestimated costs and overestimated benefits. In fact it appears that there is no net benefit from building VNI West.

3 VNI West does not enable increased use of Snowy 2.0 or transmission to Melbourne

A primary justification for constructing an additional interconnector between Victoria and NSW has been to unlock the full potential of Snowy 2.0 to supply Victoria, particularly to the Melbourne load centre. The original name for the proposed interconnector was SnowyLink South.

> *"The opportunity to increase interconnection between Victoria and New South Wales was included as part of the 2018 ISP, referred to as SnowyLink. VNI West was identified as an 'actionable ISP project' in the 2020 ISP and this status continued in the 2022 ISP."*
> *"The 2022 ISP highlighted that VNI West will increase access to Snowy 2.0's deep storages and other firming capacity."* (VNI West PADR)
>
> VNI West will *"unlock the full potential of Snowy Hydro 2.0"* (VNIW RIT-T Progress Update 2 Dec 2022).

However, the Consultation Report now confirms this is no longer the case. The latest route and design for VNI West will not increase Snowy 2.0's utilisation or transmission capacity to Melbourne.

3.1 PADR forecasted marginal increase in Snowy 2.0 use from VNI West

> *"PADR modelling forecast a marginal increase of Snowy 2.0 capacity factor with VNI West."* (p27 Submissions Report)

Figure 6 is a graph of the impact of VNI West on Snowy 2.0's generating capacity factor in the PADR, provided in the Submitter Session's background information Matter 8 (1 December 2022).

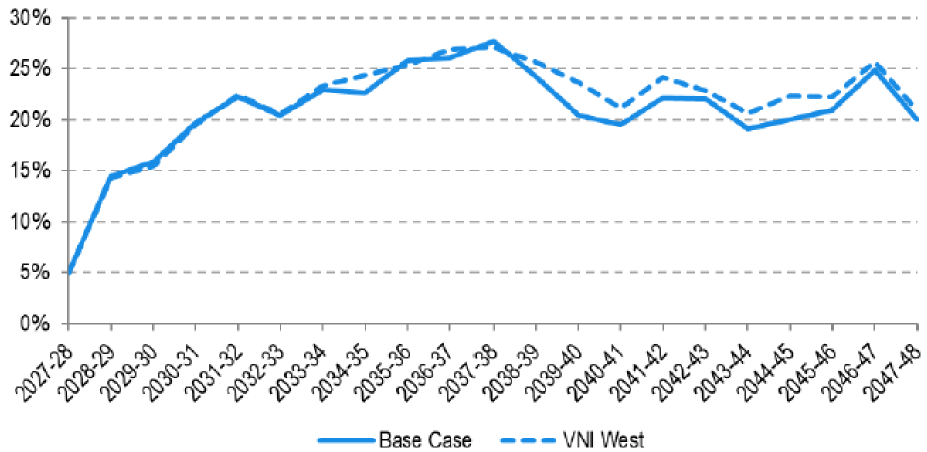

Figure 6 – Snowy 2.0 Generating Capacity Factor PADR (AEMO/TransGrid Dec 2022)

As shown, the PADR estimated that VNI West would enable a very marginal increase in Snowy 2.0 use of a few percent.

3.2 Consultation Report now forecasts no increase in Snowy 2.0 use from VNI West

> *"In the additional options modelling, with the changes in the methodology including treatment of carbon budget, the annual capacity factor of Snowy 2.0 in the base case, Option 3A and Option 5 is more similar than in the PADR.*
> *For example, Figure 3 shows the annual capacity factor of Snowy 2.0 in the Step Change scenario undertaken as part of the additional options analysis. In the years after VNI West commissioning*

(2031) the average capacity factor of Snowy 2.0 in all three states of world is around 20% for generation." (p27 Submissions Report)

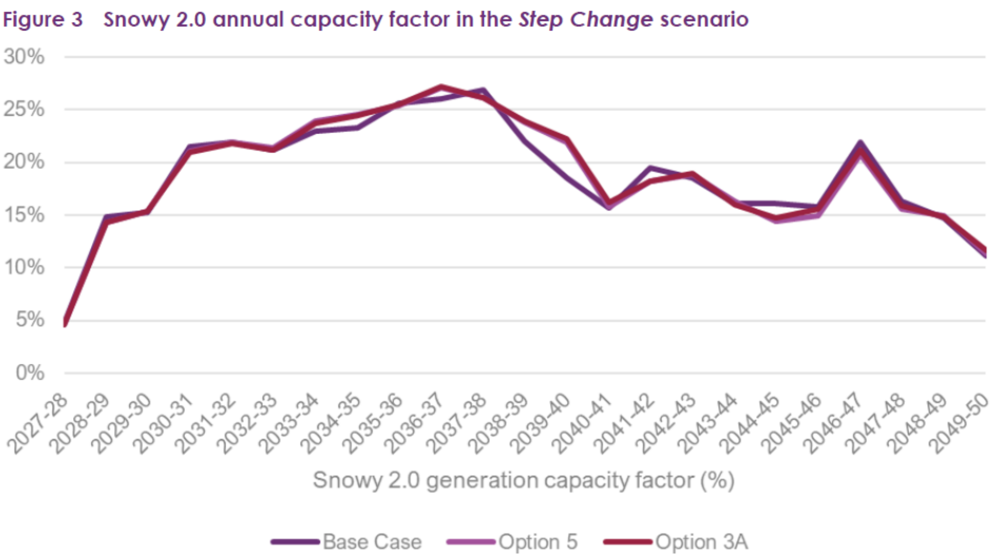

Figure 7 – Snowy 2.0 capacity factor with and without VNI West (Consultation Report Fig 3)

The latest modelling confirms that VNI West will have no impact on Snowy 2.0's utilisation – the difference shown in Figure 5 of less than 1% is less than the errors inherent in such long-range modelling.

3.3 Now claimed that VNI West will improve Snowy 2.0's efficient use, but unquantified

In this updated modelling, market benefits of VNI West associated with Snowy 2.0 are related to more efficient utilisation rather than increased utilisation of Snowy 2.0. However, these benefits have not been isolated and quantified separately." (p27 Submissions Report)

The claimed benefit of VNI West for Snowy 2.0 has now shifted from enabling increased utilisation to enabling more efficient utilisation. But no explanation is provided for this more efficient utilisation.

If there are benefits in enabling more efficient utilisation, as claimed, they should be quantified. If not the obvious presumption is that any such benefits are insignificant or else they would have been revealed.

How much of the $3.9 billion of benefits is due to increased utilisation efficiency of Snowy 2.0?

3.3.1 Any market benefits from increased efficiency will likely flow to Snowy Hydro

One would assume that if there were benefits from increased efficiency of Snowy 2.0 utilisation, they would be more likely to accrue to Snowy Hydro's bottom line, and not be passed on to consumers.

3.4 VNI West does not ease constraints for Snowy transmission to Melbourne

Ever since completion of the Snowy Scheme, there have been occasional constraints in transmitting electricity from the Scheme to both Melbourne and Sydney.

According to the Consultation Report the latest recommended configuration for VNI West does not ease those constraints to Melbourne (nor does the configuration of HumeLink ease the constraints to Sydney). Might this mean we can expect there to be a future proposal for further interconnections between NSW and Victoria, and north to Sydney?

The Consultation Report estimates that VNI West will provide additional transfer capability from Victoria to NSW of 1,930 MW, and 1,650 MW from NSW to Victoria. The indicative impact on REZ transmission limits totals 3,410 MW:

- V2 - Murray River: +850 MW
- V3 - Western Vic (WRL timing): +1,460 MW, V3 - Western Vic (VNI West timing): +200 MW
- N5 - South West NSW: +900 MW

As a side issue, why have the Victorian REZ transmission limits changed so markedly from the PADR, whilst the interstate transfer capabilities have remained similar (Victoria to NSW, 1,930 MW; NSW to Victoria, 1,800 MW):

- V2 - Murray River: +1,600 MW
- V3 - Western Vic: +550 MW
- N5 - South West NSW: +900 MW

3.5 Other observations

3.5.1 Snowy 2.0 use now plummeting after ten years

The PADR forecast Snowy 2.0's capacity factor to continue in a range of 20% to 27% for the modelling period, till 2047-48 (Figure 6).

However, the Consultation Report forecasts Snowy 2.0's capacity factor dropping off from a peak of 27% at the end of the 2030's to 11% by 2050 (Figure 7).

No explanation has been provided for this decline by two-thirds.

And it is telling to see that even at a capacity factor of 11%, VNI West has no impact on Snowy 2.0's utilisation.

3.5.2 Snowy 2.0 unlikely to be commissioned before 2030

It is noted that Figures 6 and 7 show Snowy 2.0 operating from 2027-28, in line with Snowy Hydro's recent update of full commercial operation by December 2027.

However, following recent revelations on Snowy 2.0 tunnelling problems and delays the project is unlikely to be commissioned till next decade.

At least this scenario should be modelled as a sensitivity.

Though it would appear from Figure 7 that no matter when Snowy 2.0 is commissioned and whatever its operational capacity factor, VNI West will have no impact on its utilisation, compared to the Base Case.

4 Unrealistic Snowy 2.0 capacity factor

For many years I and others have questioned the impossibility of Snowy 2.0 attaining an estimated annual capacity factor over 20% for generation (alone). Adding pumping operation results in a combined capacity factor over 50% [>20% + >20%/0.76[1] = >46%]. That is, either pumping or generating at full capacity for over half the year.

It is considered to be impossible, practically and commercially, for a pumped hydro station to sustain such a high level of operation and we are unaware of this being attained by any pumped hydro plant world-wide.

Such an unrealistically high capacity factor has featured in many Snowy 2.0 forecasts and is continued in the Consultation Report.

4.1 Previous forecasts of Snowy 2.0's excessive capacity factor

4.1.1 Snowy 2.0 FID (54% combined cf)

The modelling report in the Snowy 2.0 Final Investment Decision, Dec 2018 forecasted a generation capacity factor averaging about 23% [4,000,000/2,000*365*24 = 22.8%] and a pumping capacity factor of about 31% [5,400,000/2,000*365*24 = 30.8%] - see Figure 8.

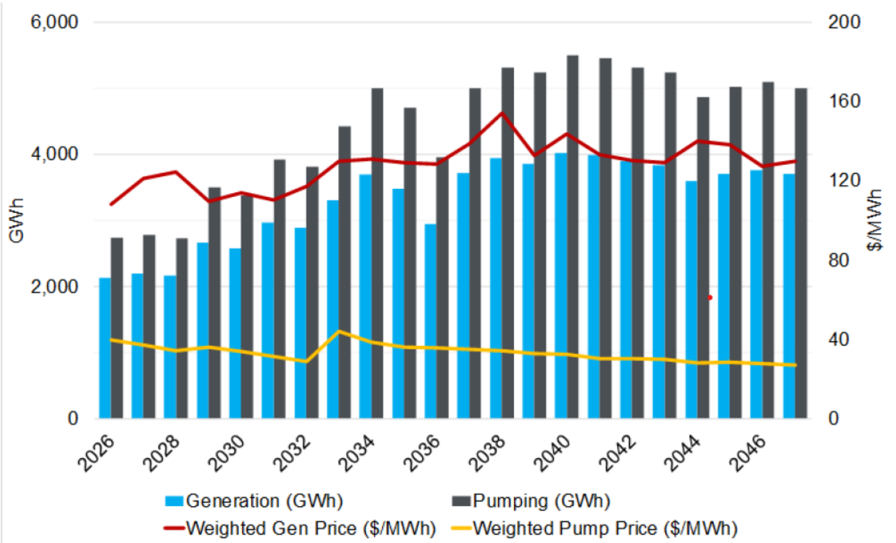

Figure 21: Snowy 2.0 - annual generation and pumping and annual buy and sell prices [Source: FID Base R06 2018]

Figure 8 – Snowy 2.0 Generation/Pumping and Buy/Sell Price (Snowy Hydro FID)

This combined capacity factor of 54% was the basis for the Snowy 2.0 Business Case.

It is noted that this level of operation is much higher than envisaged in the earlier Snowy 2.0 Feasibility Study, Dec 2017, which stated that *"in any given year prior to 2040, the Project will be operated at full capacity for less than 87 hours/year"*.

4.1.2 2020 ISP (23%)

The 2020 ISP did not provide an estimated capacity factor for Snowy 2.0. However, an extrapolation of the combined annual output from Snowy 2.0 and Tumut 3 of around 3,300 GWh, suggests a

[1] Based on a pumping/generation cycle efficiency of 76% in the 2020 ISP, provided by Snowy Hydro. This may be an overestimate (see 4.5).

Snowy 2.0 generation capacity factor of about 10% [3,300,000/2,000*365*24 = 18.8%/2 = 9.4%] if generation is shared. This equates to a combined capacity factor of about 23%. See Figure 9, which is extracted from [AEMO's ISP: Does it leave Snowy 2.0 high and dry, VEPC, 10 Aug 2020](#).

Of course, the Snowy 2.0 capacity factor would be higher if Snowy 2.0 assumed a greater share of generation and vice versa. Tumut 3 has a slightly higher efficiency than Snowy 2.0, suggesting that it may be given priority.

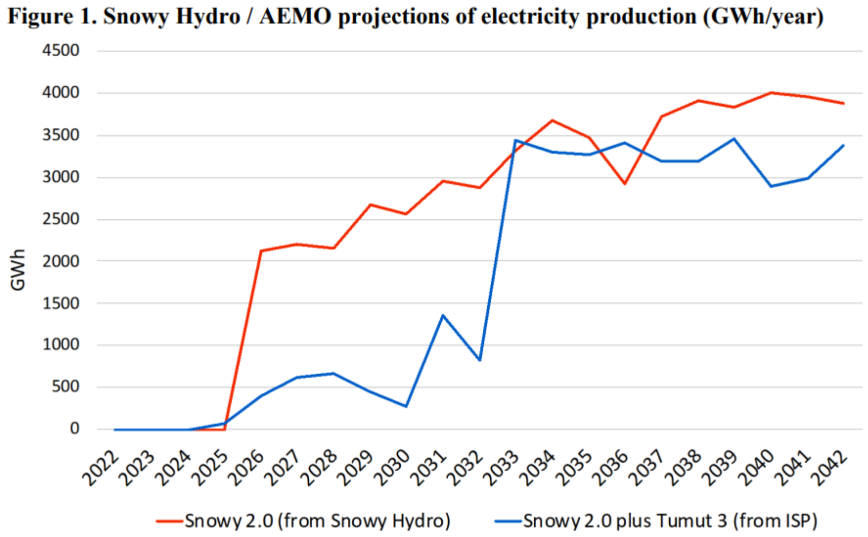

Figure 9 – Snowy 2.0 Electricity Production Projections (Snowy Hydro, AEMO)

It is noted that, whilst the future will be entirely different to the past, the pumping capacity factor for Tumut 3 has averaged less than 2% since its commissioning 50 years ago – in some years it did not pump at all.

4.1.3 HumeLink PACR (58%)

The HumeLink PACR, July 2021, estimated a Snowy 2.0 base case generation capacity factor of 20% in 2035, rising to 25% with HumeLink.

These estimates are almost identical to those applied in the VNI West PADR, which is not surprising as Ernst Young was the consultant for both projects. We disputed the HumeLink modelling results at the time (but did not receive a response) – [A review of the HumeLink Project Assessment Conclusions Report, VEPC, 16 Sep 2021](#) (Section 7.3).

4.2 Consultation Report Snowy 2.0 capacity factor (49% - 63%)

Even though the latest modelling now forecasts that VNI West will have no impact on Snowy 2.0's capacity factor and utilisation, the unrealistically high estimate of 21-27% during the 2030's (Figure 7) impacts the modelling.

This capacity factor in the Consultation Report exceeds all previous estimates.

A capacity factor of 21-27% for generation requires:

- generation at full capacity (2,000 MW) for around 5 to 6.5 hours a day [24*0.21 or 24*0.27], 365 days a year (or at a lower output for a commensurately longer period every day)
- pumping at 2,000 MW for 7 to 8.6 hours a day (pumping capacity factor of 28% to 36%[1])
- either generating or pumping at 2,000 MW for 12 to 15 hours every day (combined capacity factor of between 49% and 63%)

- or, generating/ pumping at over 1,000 MW continuously, 24 hours per day, 365 days per year

Sustained operation at a (combined) capacity factor of 50+% is implausible from both a technical and commercial perspective.

4.2.1 Technical unavailability

There will be times when the full 2,000 MW capacity of Snowy 2.0 is not available:

- due to planned outages - equipment maintenance and repairs (tunnels, generating plant, electrical equipment etc)
- due to unplanned outages
- pumping will be limited when Tantangara Reservoir is full or near full, to avoid spillage; generation will be limited when Tantangara is empty or near empty
- similarly, pumping will be limited when Talbingo Reservoir is empty or near empty; generation will be limited when Talbingo is full or near full
- generation is restricted in wet periods when downstream releases from the Tumut Scheme are constrained, as has been the case from time to time over the past year or so
- there are integration constraints with the operation of Talbingo Reservoir for both Snowy 2.0 and Tumut 3. At times Tumut 3 will need to pump before Snowy 2.0 to provide water to Talbingo, or to generate before Snowy 2.0 to provide space in Talbingo
- transmission outages and restrictions
- one also needs to allow for the time taken to start, stop, ramp up and down, change from generation to pumping and vice versa

4.2.2 Commercial preclusion

Apart from the technical constraints that will preclude Snowy 2.0 from operating at such a high capacity factor, there are of course commercial considerations - there will be times when it is not economic to operate:

- the electricity purchase price is not low enough to warrant pumping
- the sell price is not high enough to warrant generating

This was analysed in AEMO's ISP: Does it leave Snowy 2.0 high and dry, VEPC 10 Aug 2020, which concluded that *"using AEMO's projection of a 12% average annual capacity factor to 2042 delivers a required arbitrage margin of $306/MWh".* Even at a capacity factor of 24% the arbitrage margin needed to recover capital outlays is still $153/MWh.

Operation of Snowy 2.0 will also have to account for transmission losses to its pumps and then to the Sydney/Melbourne load centres and have to purchase RECs for associated energy losses.

4.2.3 Snowy 2.0 will be outcompeted most of the time

For those periods when it may be economic for Snowy 2.0 to pump or generate, it will be in competition with other storages, particularly batteries. Batteries will outcompete Snowy 2.0 in the prominent diurnal storage market, due to greater efficiency (85+% versus 76%[1]), faster response rates (milliseconds versus minutes) and lower transmission costs and losses (closer location to generators and loads).

Also, Snowy 2.0 will be in 'competition' with existing Snowy Hydro generators, all of which will have operational priority to comply with Water Licence requirements for downstream needs, both for the Murray and Tumut systems.

4.2.4 All other PHES and batteries would need to operate at similar or higher capacity factors

If Snowy 2.0 was to operate for such extended periods, one would expect that all other pumped hydro stations would be operating at similar or even higher levels:

- has AEMO assumed that the capacity factors for the other 'competing' pumped hydro stations are similar to those claimed for Snowy 2.0?
- Tumut 3 has a slightly higher efficiency than Snowy 2.0 and hence would be expected to be dispatched by Snowy Hydro first

Surely it is unrealistic to expect that it would be physically possible and economic for Snowy 2.0 and all other pumped hydro stations to generate and pump at full capacity for anything like 12 to 15 hours every day. Also, as batteries are more competitive than pumped hydro it would be expected that their capacity factors would be even higher.

4.3 Snowy 2.0 storage capacity is far less than seven days

> *"The storage capacity of Snowy 2.0 is approximately equivalent to seven days of continuous operation"* (p27 Submissions Report)

This might be the theoretical capacity (350 GWh) based on the 240 GL storage volume in the upper reservoir, Tantangara. But practically, it is not achievable, certainly in a closed cycle:

- to have seven days capacity requires Tantangara to be full in the first place, which is rarely the case
- the lower storage, Talbingo (160 GL), has only two-thirds the capacity of Tantangara. Excess water from Tantangara will be 'lost' downstream from Talbingo into Blowering Reservoir and unavailable for pumping back up to Tantangara (except for the limited storage (30 GL) in Jounama pondage)
- even to attain four days continuous operation [7*160/240] Talbingo would have to have started empty, which it rarely is. Talbingo is the upper storage for Tumut 3 pumped hydro station, and is normally kept close to full to maximise both the available capacity for Tumut 3 and its generation efficiency (with a higher head)
- the practically achievable closed loop capacity of Snowy 2.0 has been estimated to be approximately 45 GWh, equating to one day's generation at 2,000 MW – 'Snowy 2.0 claims don't stack up', NPA, 26 Feb 2020

> *"The model assumes that the storages for the upper and lower ponds are set at the start of the modelling period to a value between maximum and minimum"* (p27 Submissions Report).

This automatically results in much less capacity for Snowy 2.0 than *'seven days continuous operation".*

4.3.1 Further evidence of Snowy 2.0's constrained capacity

> *"The model also accounts for the upper and lower pond minimum and maximum levels and prevents these being breached, even if the market signal favours more cycling if [is] possible"* (p27 Submissions Report)

As noted above, the different capacities of the upper and lower reservoirs and the need to integrate Snowy 2.0's operation with Tumut 3 significantly constrains Snowy 2.0 operation to much less than the mooted seven days continuous operation.

Also, whenever Tantangara is emptied it will take months to be fully re-filled, due to the limited inflow capacity to Talbingo from Eucumbene Dam via Tumut 1 & 2 power stations, and the limited periods when it would be economic to run the Snowy 2.0 pumps.

4.4 Perfect foresight exaggerates Snowy 2.0 usage

> *"Since the market modelling optimisation provides Snowy 2.0 with perfect foresight, it finds the most beneficial time to generate, typically during high fuel cost periods, which tend to coincide with lower intermittent renewable generation levels, and the most beneficial time to pump, typically in low fuel cost periods, which tend to coincide with higher intermittent renewable generation levels. To create a closed loop (no water losses), the methodology then offsets each MWh of generation by an equivalent amount of pumping, taking into account the cyclic efficiency of Snowy 2.0, which is assumed as 76%, based on the IASR"* (p27 Submissions Report)

Is it realistic to adopt a perfect foresight model, as this will not reflect reality. Adopting such a theoretical model means that any 'benefits' from Snowy 2.0 operation will be overstated.

4.5 Snowy 2.0's cyclic efficiency of 76% may be overstated

The performance of pumped-storage schemes is expressed by the 'round-trip efficiency' (RTE[2]) of the pumping/generation cycle:

> *"For the purposes of the [Snowy 2.0 Feasibility] Study, round-trip efficiency has been defined as:*
>
> *RTE = (energy gained during generation)/ (energy required for pumping)*
>
> *The hydraulic head losses from the waterway conduit were combined with the losses due to plant efficiencies (e.g. generator efficiency of 98.5%) to calculate the energy gained during generation and the energy required for pumping. These are combined in the above equation to obtain the round-trip efficiency.*
>
> *The base case achieves the round-trip efficiency target at 1,000 MW output with a value of 75.5%, which is estimated to marginally decrease to 74.5% at end of the design life. At full design capacity (2,000 MW), a round-trip efficiency of 67% is obtained at minimum gross head; this may drop over the design life of the Facilities to 63%."* (Snowy 2.0 Feasibility Study)

It is understood that the assumed cyclic efficiency of 76% in the 2020 ISP and subsequent ISPs was provided some time ago by Snowy Hydro from the Feasibility Study estimate.

It is recommended that an update be sought, now that the station equipment has been ordered and the construction of the water tunnels determined. The modelling could then be based on a more accurate efficiency range related to station output. This is especially relevant if Snowy 2.0 is assumed to operate near capacity for extended periods (see earlier), as the efficiency reduces as output increases.

Also, it is relevant to note that the station efficiency does not incorporate transmission losses (two ways), that are relatively high for Snowy 2.0 due to its isolated location many hundreds of kilometres from REZs and the Sydney and Melbourne load centres.

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[2] "Snowy 2.0 Feasibility Study Facilities Report V2 09" December 2017 https://www.snowyhydro.com.au/our-scheme/snowy20/snowy-2-0-feasibility-study/