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Mr Daniel Westerman
Chief Executive Officer
Australian Energy Market Operator

Cc:
Mr Drew Clarke, Chairman, Australian Energy Market Operator
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5 April 2023

Dear Mr Westerman

VNI-West Consultation Report – Options Assessment

The attached document is our submission to AEMO Victorian Planner (AVP) on its VNI-West Consultation Report – Options Assessment. This submission has been written in the short time between the publication of the Consultation Report in mid-February and the closing date for submissions – 5 April. We understand that this is the last opportunity for input before the finalisation of AVP's assessment of options that combine VNI-West with the Western Renewables Link (hereafter "WRL-VNI"). We have therefore committed considerable effort to this submission.

We are addressing this letter to you since the accountability for this Consultation Report rests with AEMO. AVP is, after all, a delegation of AEMO staff.

We acknowledge with thanks the effort that AVP representatives have made to engage with us and to answer our questions in the course of preparing this submission. We note however that many questions remain unanswered. We also acknowledge with thanks the valuable contribution of our network of peers and the representatives of well-informed interest groups, to this submission.

Starting with cost estimates (where it is possible to get the strongest grip) we contend that AVP has badly under-estimated the costs of its various options particularly of the one it prefers. We estimate that WRL-VNI alone can be expected to double transmission charges in Victoria. In addition, AVP has not costed the additional 500 kV and other augmentations in Victoria that flow from the decision to construct WRL-VNI. These will cost at least as much as WRL-VNI. **The decision to commit to WRL-VNI is therefore a decision to roughly triple charges for transmission services in Victoria.**

On benefits, AVP has produced an implausible analysis. AVP's claim of WRL-VNI benefits depend on unrealistic assumptions on the location of new renewable generation in Victoria, and they depend on unreasonable penalisation of renewable production in the Gippsland REZ. This penalisation of Gippsland has been a feature since AEMO's first Integrated System Plan in 2018.

The Latrobe Valley 500 kV and 220 kV network to Melbourne are jewels in Victoria's electrical crown. This radial network to Victoria's main load centre already has plenty of available hosting capacity, unlike almost all of Victoria's transmission network except the 500 kV network to Portland. It can also easily be expanded along already vacant easements, to nearly double its current 9,450 MW (summer) rating, at no great cost.

Once expanded it offers sufficient capacity to accommodate all of the Victorian Government's planned offshore wind plus masses of onshore wind and solar in the east and south east of Victoria. Even before expanding it, it already has plenty of spare capacity to easily host all the renewable generation needed to meet the Government's 2030 renewable energy targets.

This marvellous transmission infrastructure – by far the highest capacity corridor in Australia and probably the Southern Hemisphere – presents enormous advantage to Victoria in the delivery of the Victorian Government's rapid decarbonisation policy.

Yet AVP has undermined this corridor by placing flawed wind and solar build limits, transmission limits, transmission and hosting penalties that hobbles the Gippsland REZ. This, along with other errors, drives the location of new renewable entry along the 500 kV corridor AVP is seeking to develop.

AVP claims that it presents an economically sound analysis. It has not, not even in the slightest. Instead it has biased the outcome through flawed inputs and analysis and in so doing it has produced an implausible claim of the benefit of WRL-VNI.

To be clear, once taking AVP's spreadsheets apart and uncovering what is really going on, it becomes evident that the cornerstone of AVP's justification for the development of WRL-VNI, is to be able to import electricity generated by batteries in New South Wales in order to displace more much more expensive pumped hydro generation that would otherwise be developed in Victoria from the 2040s.

In other words, AVP is inviting us to believe that developing WRL-VNI and so doubling transmission charges (and then spending at least the same again in the 15 years that follow WRL-VNI's commissioning) in the process actually **tripling** Victoria's transmission charges is justified in order that cheap batteries in New South Wales can displace much more expensive pumped hydro generation in Victoria. But why not just build the batteries in Victoria and avoid tripling transmission charges? This is utterly bizarre. We can't believe that you would think this credible.

Such a profound failure of transmission planning demands an explanation. AEMO alone can answer this, but it behoves us to speculate. It would seem to us that the "NEMlink" vision - a single 500 kV transmission line stretching from Melbourne (with cable extension to Tasmania) to Townsville - that AEMO first presented in its inaugural National Transmission Network Development Plan in 2010, has progressively morphed into AEMO's defining corporate mission.

Technology change – the incredible reduction in solar and wind costs and the rise of batteries over the last decade – has turned that dream into little more than a nostalgic artefact. Yet the "actionable ISP" rules have provided AEMO with enormous authority to impose its vision, and AEMO is determined to deliver it regardless of its costs and benefits.

The transmission monopolies often support this vision. It will greatly expand their regulated assets and hence revenues. They and AEMO, the master planner, must be held accountable for the "actionable ISP" transmission expansion in their areas. But in

Victoria, AEMO is the transmission planner and AEMO alone is accountable for planning WRL and the Victorian components of VNI-West.

Our critique has examined the situation in Victoria, but we would expect the same conclusions apply in respect of the NSW part of WRL-VNI. In defending its analysis, AVP staff repeatedly told us that the same assumptions were made in the development of the ISP, as for WRL-VNI. The concerns we draw attention to here are therefore also relevant to AEMO's Integrated System Plan and so this critique also calls that plan into question.

AVP's analysis is so detached from reality and the norms of power system engineering and energy economics analysis and of accepted professional ethics, that a measured and constructive critique of it has been tremendously difficult. But the issues here matter greatly: AVP's decision will have a big impact on consumers, the environment, the economy, many individuals and local communities and on the delivery of the Victorian Government's renewable energy policies. Therefore we have engaged with this and with AVP's previous assessments. After this long process, we are left with no option but to conclude on the basis of the evidence and argument in our submission, that AVP has delivered a recommendation that relies on biased, flawed and in parts dishonest analysis. We appreciate the seriousness of these allegations but our duty to our professions leaves us with no option but to make them.

Considering the urgency of the situation in Victoria, it is incumbent on us to propose a credible alternative. We will be setting this out in a forthcoming report.

Yours sincerely,

S Bartlett

Professor Simon Bartlett, AM.

Professor Bruce Mountain,
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Executive Summary

This document has been prepared by Simon Bartlett and Bruce Mountain and is submitted to the AEMO Victorian Planner (AVP) and TransGrid, pursuant to their invitation for submissions on the VNI West Consultation Report Options Assessment ("Consultation Report").

AVP's recommendation in the Consultation Report for the development of the Western Renewables Link and VNI West ("WRL-VNI") will, if accepted by the Government of Victoria, be the most significant development in the Victorian transmission system in more than 50 years. It will open up a new 500 kV corridor cutting through the heart of western and northern Victoria and then deep into New South Wales.

We have been active in the consultation on this project and on the separate predecessor project assessment reports for the Western Victoria Transmission Project (since renamed the Western Renewables Link) and VNI-West. We acknowledge AVP's efforts in responding to our questions in the short period between the publication of the Consultation Report and the closing date for submissions. We also acknowledge with gratitude the excellent debate and information provided by numerous interested parties and colleagues, in the preparation of this submission.

In this submission we conclude that the development of WRL-VNI will be a monumental mistake. Specifically:

1. WRL-VNI will drastically increase the exposure of Victoria's power system to natural disasters and terrorism risk.
2. Recovering the capital outlay in WRL-VNI will increase transmission charges in Victoria by at least 70%. The ongoing operation and maintenance charge will increase transmission charges by a further 25%. In round numbers WRL-VNI will therefore double transmission charges in Victoria.
3. WRL-VNI will also detrimentally affect the efficiency of the Victorian power system by wasting existing transmission capacity (the extensive 500 kV and 220

kV network from the Latrobe Valley to Melbourne) and forcing the development of renewable electricity in locations that are further away from Victoria's main load centre and will have a large part of their renewable energy wasted by spillage due to severe congestion on VNI West. This too will push prices up relative to what they otherwise would be.

4. The development of WRL-VNI will delay the transition to renewable electricity in Victoria. It will do this by forcing new renewable entry to wait on the completion of this massive transmission augmentation (which is likely to take eight years to complete). It also undermines the development of onshore renewable generation in Gippsland and adjacent areas and thus wastes the capacity of Victoria's most valuable electrical transmission infrastructure connecting the Latrobe Valley to Melbourne.
5. WRL-VNI lays the foundations for massive additional 500 kV transmission developments in west, central and northern Victoria. This is likely to involve additional expenditure at least as big as WRL-VNI to follow in the decade after WRL-VNI is completed.
6. Finally, when it was first proposed, VNI-W was christened "Snowylink South" and its rationale was claimed to be making the capacity of the promised Snowy 2.0 pumped hydro station available to Victoria. But WRL-VNI, according to AVP, makes no perceptible difference to the dispatch of Snowy 2.0 and in reality Snowy 2.0 will become choked by the congestion on VNI West and Humelink. Instead. of any gain from Snowy 2.0, AVP's analysis contends that the bulk (75%) of the benefit of WRL-VNI lies in the substitution of pumped hydro generation in Victoria by batteries in NSW.

These conclusions arise from our critique of AVP's analysis of the costs and benefits of WRL-VNI. The detail of this critique is set out in the appendices of this submission and the main points are set out in the next four sections of this submission.

Costs have been under-estimated

AVP's cost estimation errors reflect numerous specific errors identified in Appendix A. In summary:

- We estimate AVP have understated the build cost of its preferred option by $1,220m (38%) and understated the operating cost of its preferred option by $5.1bn over 50 years, or $1,012m stated as a present value (PV) in 2020/21.
- We estimate AVP's calculation of gross benefits of its preferred option of $3,921m PV is not plausible, and has been overstated by $5,185m PV, giving a (gross) detriment of $3,921m - $5,185m = - $1,264m PV. For the avoidance of doubt this disbenefit is before deducting the cost of WRL-VNI. The additional detriment (separate to the cost of WRL-VNI) will be expressed in electricity markets in the form of electricity prices that will be higher than they otherwise would be.
- After accounting for the Victorian share of the cost of WRL-VNI, we estimate a total net detriment of WRL-VNI of $6,778m stated as a PV in 2020/21.

Benefit estimates are not plausible

The benefit estimation errors are set out in detail in Appendix B with additional relevant information in Appendices C, D and F. There are two overriding assumption/modelling errors that merit elevation in this summary. The detail of these errors are set out in Appendices D and F:

- AVP have intentionally hobbled the on-shore development of renewable electricity to the east and south of the Latrobe Valley by setting hard limits on wind and soft limits on PV capacity (plus penalties for any PV above 500 MW) that bear no relation to the development potential in Gippsland. AVP have also adopted a Gippsland transmission limit of 2,000 MW, beyond which steep penalties apply. The actual transfer limit from Gippsland to Melbourne is at least 9,450 MW at 40 degrees celsius and 12,500 MW at 10 degrees celsius[1]. VENCorp's 2005 Vision 2030 report[2] showed that the transfer capacity (which it said was 9450

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[1] Based on on AEMO published transmission equipment ratings www.nemweb.com.au - /Reports/Current/Alt_Limits/

[2] Specifically it concluded that an 85% capacity increase could be achieved for $420m. Reference: VENCorp 2005, "25 Year vision for Victoria's energy transmission networks". Page 58. Available from

MW, consistent with the 40 C rating) can be almost doubled at no great expense using existing 500kV easements, and can be increased by 30% for an inconsequentially small outlay. AEMO's transfer limit is about 3000 MW less than the "spare" capacity (assuming that coal generators have a firm transfer right as AVP assumes, contrary to the National Electricity Law) and 7,450 MW below the actual transfer limit.

- AVP have also assumed transmission expansion costs from Gippsland to its nearest load centre ($0.57m/MW) that apply for transfers above its 2,000 MW limit. But we know from the existing transfer limit that no expenditure is required up to its existing 9,450MW. And even above this amount, VENCorp's analysis provides a marginal cost (albeit in 2005$) of $0.05m/MW. Even if we increased this by 75% to state it in 2023$, that is still less than one-fifth of the amount that AEMO assumes.
- AVP's modelling assumes perfect foresight on behalf of investors but then it ignores the enormous level of spilled production from wind generation and even moreso solar generation located along the WRL-VNI 500 kV corridor. Such renewable expansion would obviously not occur in the places AVP forecast if developers with the perfect foresight AVP assumes, know of the huge spilled production AVP forecast they will experience. AVP's modellers, EY, have described such spills as "economic" (i.e. that they reflect efficient overbuilding of solar and wind). This is not correct: they arise as a consequence of a modelling approach that, completely absurdly, is unaware of the spillage of the generation entry that it predicts.

The consequence of these flaws results in AVP's modelling driving renewable generation entry (particularly solar) to the far inland parts of the Victorian network that consequently experience severe network congestion. In AVP's Base Case this then drives the development and extreme running of gas-fired generation and expensive pumped hydro storage in Victoria. AVP's solution to this assumed Base Case is the construction

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https://www.vgls.vic.gov.au/client/en_AU/vgls/search/detailnonmodal?qu=Energy+consumption.&d=ent%3A%2F%2FSD_ILS%2F0%2FSD_ILS%3A169664%7E%7E0&ps=300&h=8. Even if we double VENCorp's estimate, this is by far the cheapest large capacity augmentation option of all possibilities in Victoria.

of WRL-VNI, whose main benefit is claimed to be that it allows batteries in NSW to replace the hugely expensive pumped hydro storage in Victoria. This is explained in detail in Section 2 with further relevant detail in Appendices B, C and D.

In other words, AVP effectively contend that the investment in a massive 500 kV line to NSW, that will double the cost of transmission in Victoria, is needed to connect batteries in NSW to displace pumped hydro in Victoria. This is ridiculous, not least when taking account of AVP's assumption that batteries could be developed just as cheaply in Victoria as NSW.

We note in addition that this is a completely different rationale for the justification of VNI-West that AVP claimed in the draft assessment of VNI-West and in the final assessment and then updated final assessment of WRL. We also note that the reason for the bizarre generation/storage development program is because it is developed by the Plexos simulation program that locates all of Victoria's load and generation at Melbourne with no knowledge of the VNI congestion and REZ renewable spillages that occur in the subsequent phase of the process.

It might be argued in defence of AVP's pessimism on the prospects for renewable generation in Gippsland, that this reflects a genuine lack of renewable developer interest in Gippsland. Indeed comparing the huge number of aspirant developments in Western Victoria with a much smaller number in Gippsland would seem to bear this out. But the demand for renewable generation expansion in a REZ zone is likely to be heavily influenced by AEMO itself: developers can rationally be expected to respond to AEMO's antipathy towards a REZ zone by moving instead to areas that AEMO supports, particularly if AEMO's recommendations are supported by the Victorian Government.

There is nonetheless evidence to suggest that in spite of AEMO's antipathy to renewable development in Gippsland, there is considerable interest in developing renewable energy in Gippsland. Ausnet's G-REZ unregulated transmission development has, apparently, drawn enormous interest from renewable energy developers. And, in the 2020 version of the ISP, AEMO itself recorded 4,840 MW of connection applications/reviews from wind and solar developers in the Gippsland REZ.

Choice of discount rates and the treatment of Offshore Wind is biased

AVP develops various sensitivities including the effect of using different discount rates and the existence of offshore wind. We suggest the sensitivities on each of these should have been brought into the central case, and the assumptions AVP has used on discount rates and offshore wind in the central case should be sensitivities. Such changes, even leaving aside all our other criticisms of AVP's estimates of costs and benefits, would reveal all WRL-VNI options to have large net detriments.

VNI presents huge reliability risk

The optimal transmission development path (*ODP*) in the *ISP* (combined with the Queensland Energy Plan) relies on a single, heavily-loaded, double-circuit 500kV AC transmission line for most of backbone grid stretching 3,000km from Melbourne to Townsville.

VNI West, the Victorian element of that backbone, will have around 1,500 single transmission towers between Sydenham near Melbourne and Gugga in NSW, each being a single-point-of failure for the largest electricity supply, by far, to Victoria according to AEMO's projections.

The likelihood of severe lightning, destructive winds, fierce bushfires, widespread flooding, terrorism or even military attacks on Australia's critical infrastructure, will increase further as the climate changes.

AEMO forecasts VNI will operate for up to 2,900 hours a year by 2050 at its maximum import to Victoria. An instantaneous and/or pronged outage of both 500kV circuits on this transmission line would immediately interrupt Victoria's largest electricity supply, causing a state-wide blackout to Victoria with extensive electricity rationing until the damage is rectified.

We have additional subsidiary but nonetheless significant power system security concerns:

1. System restart requirements for each state may also have been overlooked in developing the *ODP*. These are essential facilities to restart their power systems following a complete state-wide blackout which is certain to occur by following the *ODP*.
2. The Consultation Report recommends routing VNI West even further west which increases VNI West/WRL's length by 146kms costing ~$600m and reducing its interconnector transmission limit to Victoria even further to below 1,475MW, except for the risky assumption of series compensation for only option 5.
3. Option 5 omits the new 500kV/220kV substations at Ballarat and Bendigo which will increase the constraints on the existing 220kV networks requiring the installation of 400MVAr of FACT's devices at the existing Kerang 220kV substation as well as new 220kV transmission lines to Bendigo only seven years after VNI West to "keep the lights on" in Bendigo.
4. No Sub-synchronous Resonance Studies (SSR) appear to have been undertaken by AEMO to prove the practicality of their proposed series compensation of option 5, despite this being an obvious threat to power system security and a mandatory requirement in parts of the United States. AEMO's last recommendation to install series compensation on the Heyward interconnection in 2013 has only delivered 90MW of the 190MW increased interconnector limit from South Australia to Victoria, yet AEMO is now assuming the Heyward interconnector limit will increase another 200MW as soon as Project Energy Connect is completed. This has serious ramifications for the reliability of electricity supply for Victorians. Progressing VNI West option 5 will significantly increase the risks of state-wide blackouts and extended electricity rationing in Victoria.

Conclusion

That AVP has produced such deeply problematic analysis begs an explanation. We suggest it can be explained by AEMO's dogged, ideological, pursuit of the 500kV "NEMLink" vision, set out in its inaugural National Transmission Network Development Plan in 2010, for a 500 kV network deeply connecting the five regions of the NEM. That vision was established at a time that solar PV cost 10 times as much per MWh and wind generation cost three times what it costs now and batteries were not a viable storage technology. AEMO's vision has long since been overtaken by events, but yet it sticks to it in defiance of the facts and at the expense of consumers, the environment, reliable supply and rapid progress in the transition to renewable energy. We urge AEMO to think again.

1 AVP has greatly underestimated the cost of WRL-VNI

Appendix A presents our critique of the AVP estimation of the build and operating cost of Option 5. We find apparent non-compliances, errors, omissions, and erroneous assumptions that together understate the capital cost of Option 5 by $1,220m with a Present Value (PV) of $762m in 2020/21. This increases the estimated capital cost of Option 5 ($3,282m) by 38% to $4,516m as summarised below:

Table 1: Adjustments to the capital cost of VNI West Option 5

		% increase
VNI WEST Option 5 BUILD COST IN REPORT	**$3,282m**	
understated 500kV transmission line costs	$239m	7.3%
understated WRL uprating cost	$109m	3.3%
length of 500kV lines	$106m	3.2%
220 kV line from new Kerang to existing Kerang	$70m	2.1%
understated VIC substation costs.	$192m	5.8%
understated Dinawan to Gugga upgrade cost.	$318m	9.7%
understated Victorian easements for option 5	$100m	3.0%
under-priced series capacitors and power flow controllers	$100m+	3.0%
TOTAL UNDER-STATEMENT OF Option 5 BUILD COST	**$1,220m**	**38%**
ADJUSTED VNI WEST Option 5 BUILD COST	**$4,516m**	**138%**

The annual operating, maintenance, refurbishment and component replacement costs of Option 5 appear to be understated by $102m p.a. This is $5.1bn over the 50-year economic life of the project with an PV to 2020/21 of $1012m.

Together, the $762m increase in the PV of its capital costs and $1,012m PV increase in its annual costs increases the cost of VNI West Option 5 by $1,774m PV to $5056m PV (30 June 2021). Since the main capital expenditures will start from 2025 and the annual operating expenditures incurred over the life of the asset the actual cash cost and hence the value that will be included in the calculation of the regulated asset base and annual revenues will be significantly (at least 30%) higher than this.

In addition, AEMO has not costed the additional 500 kV and other augmentations in Victoria that flow from the decision to construct WRL-VNI. These will cost at least as much as WRL-VNI. The decision to commit to WRL-VNI is therefore a decision to roughly triple charges for transmission services in Victoria.

2 AVP’s estimation of WRL-VNI benefits is not credible

Appendix B sets out our detailed critique of AVP’s calculation of benefits. We summarise the main points of it here, but start by reprising the critical errors in AVP’s calculation of benefits firstly for the Western Victoria Transmission Project (WVTP) in the 2019 Project Assessment Conclusions Report (PACR), then in the “Analysis for the purposes of clause 5.16.4(z3) of the National Electricity Rules” for what had by then been renamed the “Western Renewables Link”, then for VNI in AEMO’s 2022 Project Assessment Draft Report (PADR).

The picture that emerges from this is a series of thoroughly unrealistic (and changing) assumptions as AVP has desperately sought to justify WRL, then VNI West. This is important context to AVP’s latest attempt to justify WRL-VNI, which now has completely new Base Case assumptions that bear no resemblance to those in the WRL PACR and VNI-West PADR (and an unknown relationship to the “5.16.4(z3)” report because the Base Case was never published for that report).

In the 2019 WVTP PACR AVP assumed that VIC’s brown coal generation continued to operate until 2074. This created a source of benefits in expanding renewable generation in order to substitute such fossil fuels. Such assumption was obviously inconsistent with VIC and Australian Government emission reduction and renewable energy policy and this alone rendered its benefit calculation unreliable.

In the “5.16.4(z3)” report the Base Case was never published, but AVP’s benefit estimates in that case were no longer based on the assumption that Victoria’s brown coal generators would operate until 2074. Instead the bulk of the benefit was attributed to cutting out a large part of the cost of WRL on the basis that VNI West would be built. In effect, AVP gave WRL a credit of $242m PV for deferring its own expenditure which is illogical and non-compliant. AVP’s assessment of VNI West then excluded these costs on the basis that WRL would be developed. And so, magically, they managed to disappear from both VNI West and WRL as discussed in more detail below. In addition, AVP’s benefit assessment in “5.16.4(z3)” made no mention of any benefit from avoided storage (which as we show in Appendice B and C accounts for the vast bulk of the claimed benefit of WRL-VNI in the Consultation Report).

In the 2022 VNI West PADR, again AVP assumed VNI West would increase production from brown coal relative to the Base Case and this featured in the benefits AVP claimed for VNI West. As discussed AVP also excluded the costs of upgrading the transmission line from Sydenham to North Ballarat and its proposed new North Ballarat 500 kV substation. AVP's claim that the benefits of VNI-West exceeded its costs depended on this. In other words, AVP had excluded these costs from both VNI-West (in its entirety) and from WRL (from when VNI-W entered service). Effectively therefore AEMO simply assumed away a large portion of the cost of both WRL and VNI-West.

In the VNI West PADR there was no claim VNI West would produce any benefit in avoiding storage costs in Victoria (which AVP now claim is about 75% of the benefit of building WRL-VNI).

For WRL-VNI, Figure 7 of the Consultation Report shown below for the Step Change scenario, the claimed cumulative gross benefits for Option 5, comprises:

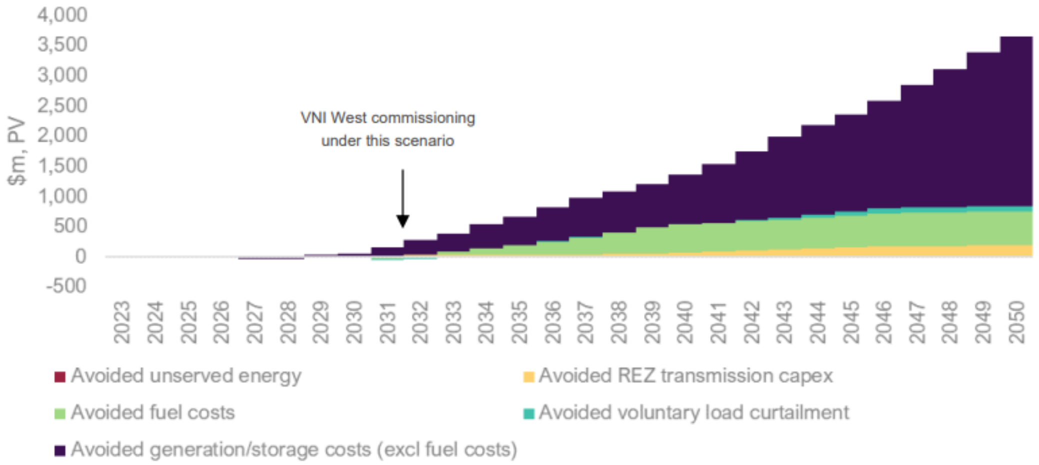
a) avoided generation/storage costs (by far the largest benefit – 75% of the total) that appears to grow until 2037, when they cease growing, but start again growing exponentially during the 2040's reaching $2,700m cumulative PV in 2050.

b) Fuel cost savings grow to $500m cumulative PV by 2040, when they cease growing during the 2040's. This means there are virtually no fuel savings, due to Option 5 beyond 2040, and also out to 2080.

c) Avoided REZ transmission costs are immaterial until 2039, but grow during the 2040's – very strange.

d) Avoided involuntary load curtailment are also immaterial until the 2040's – again strange.

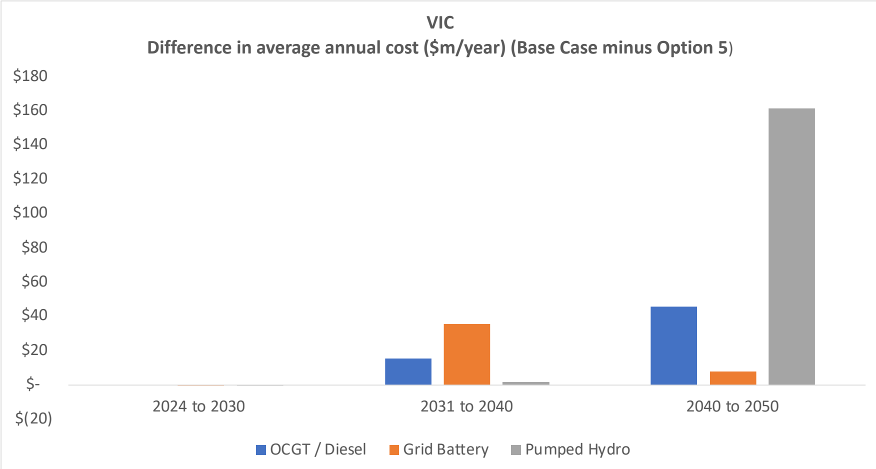
Figure 7 Breakdown of cumulative gross benefits for Option 5 under the *Step Change* scenario



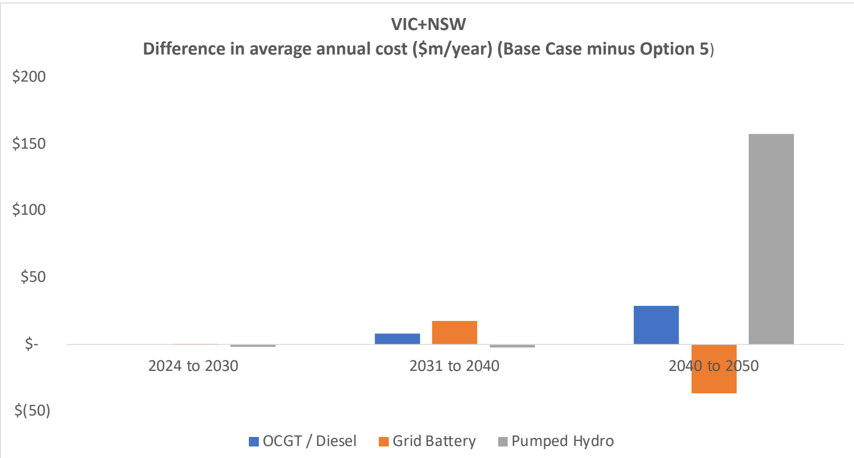
The last three categories combined, reach around $400m PV by 2040, but somehow grow to $800m by 2050.

Appendices B, C, F and G provides evidence and reasoning to conclude that the claimed market benefits arise from non-compliances with the National Electricity Law and National Electricity Rules, a completely implausible Base Case and extreme VNI West/WRL congestion causing huge spills of renewable energy attributable to AVP's assumption that vast amounts of new PV and wind power are installed in the REZ's along the path of WRL/ VNI West.

The claimed "avoided generation/storage costs" which accounts for 75% of the claimed benefit, bears particular scrutiny. Understanding this is very important in understanding AVP's conclusions. Below we reproduce Figure 2 from Appendix B. The figure shows the difference in the annual average annual cost ($m/year) in Victoria for Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050. To produce this chart we have used AVP's model outputs on the difference in capacity and priced it at an annual cost we calculated using AEMO's 2022 ISP assumptions on cost of capital, asset life and fixed operating costs. The chart shows that the main effect of building WRL-VNI is to reduce expenditure on pumped hydro by $160m per year on average over the decade from 2040. It also reduces expenditure on OCGT and batteries but in both cases by much less than on pumped hydro.



Analysis of the differences between Option 5 and the Base Case in each NEM region, reveals that, as expected, WRL-VNI also has a big effect on NSW. We can see the net effect of WRL-VNI on NSW and VIC by adding the numbers shown in the figure above, for NSW and VIC. This is shown in the figure below.



What we see in this figure, and comparing it to the previous one, is that WRL-VNI reduces expenditure on pumped hydro in Victoria (by about $160m per year) and replaces it with more expenditure in NSW (about $35m) per year in NSW. We can see from this that this net difference makes up most of the "Avoided generation/storage costs" which as noted repeatedly in this submission is 75% of AVP's estimate of the total benefit of WRL-VNI.

We therefore asked AVP to specifically identify which pumped hydro is avoided. They said in reply:

"*Without VNI West, the model forecasts a need for PHES in Victoria which is partly to firm renewable generation in this state after coal retirement. This is 24-hour PHES using cost and technical assumptions from the ISP 2022. They are not specific projects, rather the model is allowed to build PHES with different storage hours, based on the IASR, in potential locations in the NEM. With VNI West and increased Western Victoria REZ (V3) and Murray River REZ (V2) transmission capacity as well as increased interconnection with NSW, more diversified generation is forecast which supplies the demand in Victoria (as well as other states) at lower costs than building PHES in Victoria. There is a reduced need for PHES construction in Victoria.*"

We have established above the main effect in OCGT, battery and PHES – which is that PHES in Vic is substituted by batteries in NSW. But AEMO's response suggests that it is not just this, but that it is also "more diversified" generation. To be clear, all of this "more diversified" generation not already accounted for in our analysis of OCGT, batteries and PHES, is wind and solar. So, what AVP is saying is that "more diversified" wind and solar explains the benefit of WRL-VNI.

Is this true? AEMO do not have any classification of "more diversified" generation benefits. And the classification "deferred generation/storage" is a deferral benefit not a diversification benefit. For argument's sake let's give AVP the benefit of the doubt and imagine that what they meant by "deferral" benefit also included "more diversified" benefit. Then the question arises does such benefit actually exist? To be plausible and to be able to explain any non-trivial benefit, it must be the case that there is some systematic difference in the pattern of wind and solar production in V3, V2 and NSW in the case with WRL-VNI than in the Base Case.

We can immediately dismiss diversification benefits from solar. We know that this is extremely highly correlated everywhere in NSW and VIC. Putting solar in the Murray Valley means absolutely nothing for diversity benefit relative to putting it in Gippsland or NSW.

What about wind? Perhaps there are some systematic variations in wind generation in the regions of Vic and between Vic and NSW. We are certainly not aware of such differences. To the contrary, our various studies over the years find very high correlations in the pattern of of wind production in the regions of Victoria and between Victoria and NSW. For AVP's answer to be plausible, not only does there have to be a statistically significant difference in wind production patterns in V3, V2 and NSW relative to the rest of Victoria, but that such differences are given effect through WRL-

VNI. And that statistical difference has to be so massively useful that it has a meaningful dent on the demand for 24 pumped hydro that AVP assumes would otherwise occur.

This is completely fanciful. If such a "diversification" difference existed and could be expected to have had a meaningful impact on the demand for super-expensive ultra-long duration storage, it would long since have been established and documented and would have formed a major part of an *a priori* argument on the case for WRL-VNI. It does not. Rather, like so much of AVP's Consultation Report, under scrutiny it whithers.

Appendix B sets out our detailed scrutiny of other aspects of the AVP's benefits assessment. In summary, AVP's WRL-VNI Consultation Report assesses the scenario weighted market benefits of Option 5 to be $3,921m PV. Our review concludes that the gross market benefits of Option 5 have been overstated by at least $5,185m PV, so the actual (gross) benefit is $3921m - $5185m = - $1261m. In other words, even before deducting the cost of WRL-VNI, we estimate it will deliver a detriment of $1261m. Our calculation (all stated as a PV in 2021) is broken down as follows:

overstatement of deferring capex on generation and storage	$2,000m
overstatement of fuel cost savings	$800m
overstatement of savings from deferring/avoiding REZ transmission	$274m
overstatement of savings in voluntary load curtailment	$164m
overstatement of terminal value	$347m
double counting Humelink market benefits already claimed	$1,600m
TOTAL over statement of market benefits	**$5,185m**

3 AVP's selection of discount rate and Offshore Wind is biased

AVP develops various sensitivities including the effect of using different discount rates and the existence of offshore wind. We suggest the sensitivities on each of these should have been brought into the central case assumptions, and the assumptions AVP has used on discount rates and offshore wind in the central case should be sensitivities. Such changes, even leaving aside all our other criticisms of AVP's estimates of costs and benefits, would reveal WRL-VNI has big net detriment for all options AVP examined.

3.1 Discount rate

It is now widely accepted in financial markets that risk has been re-priced following a period of record low real rates in the period preceding and during the Covid response. AEMO is, correctly, accounting for this in the selection of discount rates to be applied in its forthcoming ISP, specifically by increasing the central rate to 7%, from the 5.5% used in the Consultation Report and in the 2022 ISP.

In its sensitivity analysis, AVP finds that the NPV of all its options is inconsequentially small at a rate of 7.5%. A similar outcome would occur at the rate of 7%.

AVP insists that 5.5% is the correct rate to use in its assessment of WRL-VNI on the basis that this is consistent with the AER's Cost/Benefit Assessment (CBA) Guidelines. But the AER's CBA Guidelines does not bind AVP to use a rate of 5.5%, as AVP claims it does. Much more importantly than some bureaucratic claim, is the essential substance of the issue here. The assessment of WRL-VNI is on foot now. It would be ridiculous if AVP priced the components of WRL-VNI using irrelevant historic costs. In exactly the same way it is ludicrous that AVP should choose a discount rate that fails to properly reflect the cost of risk now, and which AEMO does not dispute should be applied in its forthcoming ISP.

3.2 Offshore wind

AVP's offshore wind (OSW) sensitivity shows that its estimate of the net benefit of WRL-VNI is roughly halved. If we combined this sensitivity with the correct discount rate, the net benefit of all options would be deeply negative.

AVP defends its treatment of OSW as a sensitivity on the basis that it is not sufficiently certain that OSW will proceed. So, despite the Victorian Government having spent many tens of millions of dollars on promoting the development of OSW, despite OSW developers having already committed many hundreds of millions of dollars to the development of Victorian OSW, despite the Victorian Government having taken its OSW target to the electorate and committed to legislating it, AVP decides that it should not rise above a sensitivity and that the central case should be that OSW is not developed.

Certainly it would be fair to say that OSW is not certain to proceed. There are many uncertainties and AVP has to make a judgement on how to consider them. By relegating OSW to a sensitivity, AVP's judgement is that over the life of WRL-VNI, OSW in Victoria will not proceed. We consider that this is biased, on the basis of an examination of other uncertainties: the growth of hydrogen, the development of Marinus Link and coal generation closure.

- Firstly on hydrogen, AVP develops a "hydrogen superpower" scenario. The demand and supply of hydrogen in the NEM is extremely uncertain. Nothing is legislated and no firm investment decisions have been made by any participant in the NEM to produce or consume hydrogen. Nevertheless AEMO has constructed an analysis that assumes demand and supply and using these assumptions it estimates that WRL-VNI will have a huge net benefit. Although this scenario is given much less weight than its favoured "step change" it nonetheless has a meaningful impact on the weighted outcome, simply because the "hydrogen super-power" scenario produces outcomes that are so favourable to WRL-VNI. Despite the huge uncertainty about hydrogen, AVP brings it into its central scenario assumptions.
- Second on coal generation closure, this too is certain. Energy Australia has indicated that it intends to close Yallourn in 2026, and the Government has contracted with EA to possibly bring this forward or to defer it, depends on the circumstances. AGL has said it intends to close Loy Yang A by 2035. It has not made a firm commitment to this and has said its closure by that date will depend on the circumstances. Alinta has made no commitment to close Loy Yang B. Yet despite all this, AVP assumes Victoria's brown coal is substantially gone by 2030 and completely gone by 30 June 2032. So, while coal closure is uncertain AVP

chooses coal generation assumptions in its central scenario that are contradicted by the evidence (and for the avoidance of doubt inconsistent with the assumptions in its 2022 ISP).

- Third on Marinus Link, AVP includes Marinus Link because the Tasmanian Government legislated its 200% renewable energy target (TRET) – which AEMO had said was a precondition for its inclusion of Marinus Link in the ISP. But, as we have repeatedly pointed out, the TRET does not legislate the funding of Marinus and neither does it even legislate the development of 200% renewable energy in Tasmania. It only legislates that the relevant department must report annually on renewable electricity development in Tasmania. As if to eliminate any doubt, the Tasmanian Energy Minister has made clear that the Tasmanian Government will not itself fund Marinus and neither will it impose all of the cost of it onto Tasmanian consumers and neither will it deliver the 200% renewable electricity target unless Marinus is developed. So, despite the fact that Marinus Link's development is highly uncertain, apparently much less certain than Victorian OSW, AVP bring it in to its central scenario.

These are three examples, amongst many others, of the clear bias in AVP's treatment of Victorian OSW, relative to its treatment of the many other uncertainties inherent in estimation of the net benefit of WRL-VNI. On each of the uncertain assumptions AVP adopts a choice favourable to its calculation of the net benefit of WRL-VNI. One the two that are clearly not favourable – Victorian OSW, like the appropriate discount rate – it relegates to a "sensitivity", quickly to be dismissed.

4 WRL-VNI wastes VIC’s existing 500 kV networks; and lays the foundation for massive further transmission

Table 1 of the Consultation Report claims that Option 5 will provide 3,410MW of additional renewables hosting capacity comprising Murray River REZ (850MW), Western VIC REZ (1,460MW by WRL +200MW by VNI West), and South West NSW (900MW). Appendix E sets out our review of this and Appendix F provides a specific focus on AVP’s stifling of capacity in the Gippsland REZ. In summary, we find that:

1. Only 1,005MW (29%) of that additional 3,410MW is used to host new renewables in the first ten years after the completion of WRL and five years after the completion of VNI West, and much is never used. Worse still, new 220kV transmission lines are required between Kerang and Bendigo seven years after VNI West is operational and between Bendigo and Ballarat three years later because Option 5 bypasses Bendigo. However, the ~$350m cost of those new lines and easements are not included in the report.
2. There is severe congestion of VIC’s interconnections from 2034/35 onwards especially during the daytime when the solar PV is all running and fully loading VNI West Option 5. This requires VIC’s OCGT’s to be run at unprecedented levels between 30 and 100 times their current operating hours. For the same reason, VIC more than doubles its installed capacity of OCGT’s by 2047/48.
3. Additional new 500kV transmission lines are required in the Option 5 modelling including another Wagga Wagga to Dinawan 500kV line by 2036/37, another 500kV line from Sydenham to Ballarat or Bulgana by 2041/42 and a a 500kV line to Shepparton by 2045/46.
4. As set out in Appendix F in detail. AEMO has knobbled the development of renewables in the Gippsland REZ through the imposition of absurdly unrealistic hosting limits and transmission limits, each with large monetary penalties for exceedance.

The conclusions we draw from this are as follows:

1. AVP has developed plans that waste the huge transmission capacity between Melbourne and the Latrobe Valley. There is no reasonable basis for AEMO's stifling of renewable generation expansion in Gippsland.
2. AVP has ignored the consequential transmission expansion that follows WRL-VNI. We expect these consequential expansions will at least double the cost of WRL-VNI. These costs have not been brought into AVP's assessment

5 WRL-VNI will make the power system less secure and more vulnerable to weather and terrorism risk

The optimal transmission development path (*ODP*) in the *ISP* (combined with the Queensland Energy Plan) relies on a single, heavily-loaded, double-circuit 500kV AC transmission line for most of backbone grid stretching 3,000km from Melbourne to Townsville.

VNI West, the Victorian element of that backbone, will have around 1,500 single transmission towers between Sydenham near Melbourne and Gugga in NSW, each being a single-point-of failure for the largest electricity supply, by far, to Victoria according to AEMO's projections.

The likelihood of severe lightning, destructive winds, fierce bushfires, widespread flooding, terrorism or even military attacks on Australia's critical infrastructure, will increase further as the climate changes.

AEMO forecasts VNI will operate for up to 2,900 hours a year by 2050 at its maximum import to Victoria. An instantaneous and/or pronged outage of both 500kV circuits on this transmission line would immediately interrupt Victoria's largest electricity supply, causing a state-wide blackout to Victoria with extensive electricity rationing until the damage is rectified.

We have additional subsidiary but nonetheless significant power system security concerns:

1. System restart requirements for each state may also have been overlooked in developing the *ODP*. These are essential facilities to restart their power systems following a complete state-wide blackout which is certain to occur by following the *ODP*.
2. The *consultation report* recommends routing VNI West even further west which increases VNI West/WRL's length by 146kms costing ~$600m and reducing its interconnector transmission limit to Victoria even further to below 1,475MW, except for the risky assumption of series compensation for only option 5.

3. Option 5 omits the new 500kV/220kV substations at Ballarat and Bendigo which will increase the constraints on the existing 220kV networks requiring the installation of 400MVAr of FACT's devices at the existing Kerang 220kV substation as well as new 220kV transmission lines to Bendigo only seven years after VNI West to "keep the lights on" in Bendigo.
4. No Sub-synchronous Resonance Studies (SSR) appear to have been undertaken by AEMO to prove the practicality of their proposed series compensation of option 5, despite this being an obvious threat to power system security and a mandatory requirement in parts of the United States. AEMO's last recommendation to install series compensation on the Heyward interconnection in 2013 has only delivered 90MW of the 190MW increased interconnector limit from South Australia to Victoria, yet AEMO is now assuming the Heyward interconnector limit will increase another 200MW as soon as Project Energy Connect is completed. This has serious ramifications for the reliability of electricity supply for Victorians. Progressing VNI West option 5 will significantly increase the risks of state-wide blackouts and extended electricity rationing in Victoria.

Appendix A: Understatement of Capital Cost Estimates and Capitalised Annual costs for Option 5

This appendix provides the detail under-pinning our conclusions presented in the body of the submission that AVP has substantially under-estimated the capital and operating costs of Option 5.

5.1 Understatement of VNI West Option 5 Capital Costs

5.1.1 Understated 500kV transmission line costs

Table 5 of the Consultation Report (repeated below) presents the estimated costs for Option 5 for the NSW and VIC parts of VNI West.

Table 2: Break-down of VNI West capital costs in the *Consultation report*

Table 5 Summary of the credible options assessed in this report – capital costs, $m in FY2020-21 dollars

Cost component	Option 1 (to north of Ballarat)		Option 1A (to north of Ballarat with spur uprate to 500 kV)		Option 2 (to north of Ballarat plus non-network)		Option 3 (to Waubra/Lexton)		Option 3A (to Waubra/Lexton with spur uprate to 500 kV)		Option 4 (to Bulgana via Bendigo)		Option 5 (to Bulgana)	
	NSW	VIC	NSW	VIC	NSW	VIC	NSW	VIC	NSW	VIC	NSW	VIC	NSW	VIC
Stage 1 – Early works														
Early works – Property/access/ easements	66	69	66	85	83	86	66	76	66	84	66	67	66	59
Early works – other	50	88	50	88	50	88	50	88	50	88	50	88	50	60
EnergyConnect enhanced	182	-	182	-	182	-	182	-	182	-	182	-	182	-
Stage 2 – Implementation														
Substation/ terminal station works	354	641	354	810	354	641	354	704	354	791	354	681	354	415
Line works	751	692	751	954	751	692	751	807	751	958	751	1,080	751	912
Battery costs	-	-	-	-	288	295	-	-	-	-	-	-	-	-
Power flow controllers / series compensation	183	89	183	89	183	89	183	89	183	89	183	89	183	164
Biodiversity offset costs	66	24	66	24	66	24	66	24	66	24	66	28	66	22
Total (by state)	1,651	1,603	1,651	2,050	1,957	1,916	1,651	1,788	1,651	2,034	1,651	2,034	1,651	1,631
Total (all states)	3,254		3,701		3,873		3,440		3,685		3,685		3,282	
WRL – Incremental costs for alternate options (included in the totals above but separately itemised here as well for transparency)														
Included cost	-	-	-	447	-	-	-	182	-	427	-	315	-	315
WRL uprate length				104 km				42 km		104 km		104 km		104 km
Approximate line length [A]	184 km	229 km	184 km	229 km	184 km	229 km	184 km	230 km	184 km	230 km	184 km	268 km	184 km	205 km
Quantity substations/ terminal stations [B]	-	2	-	2	-	2	-	2	-	2	-	2	-	1

A. Approximate line length is the indicative total length (in kilometres) of lines between PEC (at Dinawan) and the connection point to WRL. As a route has not yet been determined, line length has been taken as the centre of the area of interest and includes both 500 kV and 220 kV lines, where cutting into the existing 220 kV network. Option 5 line length on the Victorian side is lower than all other options, however the total system path length between nodes is longer, which is what impacts on impedances.
B. Quantity substations/ terminal stations is the quantity of terminal stations along the VNI West project and excludes the Dinawan and WRL connection point terminal stations.

The average $4.08/km (i.e., $751m/184km) of the VNI West 500kV line works in NSW is 40% higher than the average $2.91m/km (i.e. ($912m - $315m) / 205km) in VIC. The $315m for uprating WRL must first be removed as it is not part of the 205kms of 500kV lines from Bulgana to the border. The explanation given by AEMO/TransGrid on 17/03/2023 that the difference is due to the cost of 220kV line works and other minor differences cannot be correct as the cost of upgrading the 220kV WRL lines has been removed from this calculation and the same materials and labour is required to build the same 500kV lines on either side of the border. The latest ABS statistics show that there is almost no difference in the labour productivity in the construction sector in NSW and VIC.

An examination of Table 3 from AEMO's November 2022 WRL cost-benefit report (below) shows that an allowance of approximately 40% (i.e., 38.5% for option C2 and 40.1% for option B3) should be added to the TCD baseline cost estimates to allow for adjustments, known risks, unknown risks and indirect costs. Both reports use baseline costs derived from AEMO's current Transmission Cost Database (TCD), however the required 40% allowance appears to have been omitted from the estimated cost of the Victorian components of VNI West, for both transmission lines and substation costs.

Table 3 TCD outputs for Option C2 and Option B3 – $ million (2021)

	Option C2	Option B3
1. Baseline Cost	532	364
2. Adjusted Baseline Cost	556	380
3. Known Risk Allowance	29	16
4. Unknown Risk Allowance	98	68
5. Total Indirect Cost	55	46
6. Total Expected Project Capital Cost	737	510

The Baseline Cost is based on the building block costs in the TCD

An analysis of the WRL project costs in the spreadsheets for the WRL and VNI West combined assessment confirms that the WRL cost estimates in that analysis are $727m being almost the same as the $737m in Table 3 of the updated WRL assessment and also include the 40% allowance for both lines and substations. However, the 40% has not been included in the cost of lines and substations in the VIC part of VNI West Option 5.

The apparent omission of the 40% contingency allowance that must be added to TCD cost estimates totals $239m for the VIC line's costs calculated as 40% of $2.91m/km for the 205kms of 500kV line in VIC in Table 5 of the Consultation Report. Similarly, the missing 40% for VIC substations is calculated below.

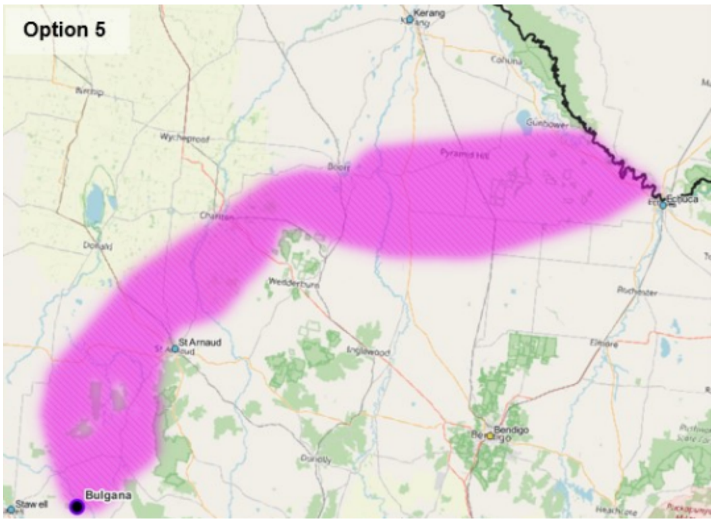
5.1.2 Understated WRL Uprate cost

Appendix A.2 of the Consultation Report "Cost estimating methodology for the VIC components" confirms that there is no risk allowance in the VIC 500kV transmission line cost estimates which are based solely on TCD cost estimates. The only allowance for a contingency above the TCD cost estimates is in estimating the WRL uprate costs, however in that case the contingency has been incorrectly applied as shown below. The incremental costs attributed to VNI West for uprating WRL has been calculated as follows:

> "To estimate these costs, the per kilometre cost for the current 220 kV line was subtracted from the current market cost for the 500 kV line, while still accounting for known risks by means of an added 30% contingency. The higher voltage line will also require a wider easement[.]" Reference from Consultation Report

The correct calculation would be to first increase the TCD cost estimate for the 500kV line by 40% (to allow for adjustments and overheads as well as known and unknown risks) subtract AusNet's costs for the 220kV line no longer required (noting AusNet would have included appropriate contingencies in their contract sum), add in the cost of the additional Waubra 220 kV works and AusNet's required profits for the uprating and any wasted expenditure on the 220kV line works. The approach used has omitted the 40% contingency required for TCD cost estimates for a 500kV line (i.e., 40% of $2.91m/km for 104kms (i.e., $121m), only added a 30% contingency on the difference between AusNet's price for the 220kV line and the TCD price for 500kV (i.e., $32m), has omitted the cost of the Waubra works for Option 5 ($20m?) and it's unclear how or where AusNet's wasted expenditure to date and their required profit margin is included. The $315m allowed in Option 5 appears to be understated by at least $109m and it is impossible to check how much has been included for the last two items due to the lack of transparency and the use of incremental costs instead of the full cost as required in the RIT-T instrument.

5.2 Length of 500kV transmission lines

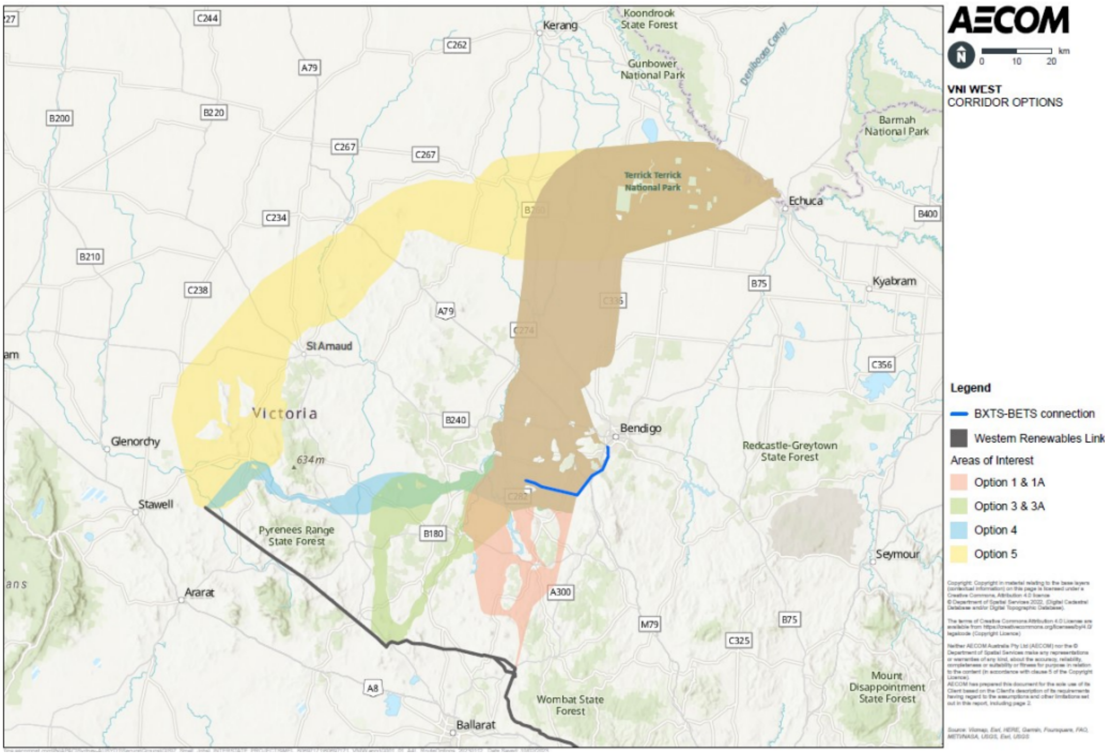


The Line Works section of the Consultation Report on page 100 explains that the total length of 500kV line between the WRL/VNI connection point and the NSW border have been refined using a preliminary desktop approach of avoiding constraints within the study areas illustrated in figure 26 (see alongside for Option 5).

However, the PADR uses exactly the same words for refining the line lengths between the PSCR and the PADR but does not disclose the line lengths. The only line lengths given in the Consultation Report are those in Table 5 which are repeated in the table below. These line lengths are qualified by a note under table 5 saying they are the lengths of the centrelines of the study areas for each option, as illustrated in figure 26. The line lengths have been calculated independently by three different stakeholders starting from the centreline of the study areas and then avoiding mapped constraints. In accordance with standard route estimating practice, an additional 5% has been added to allow for the route diversions likely to occur during the EIS and landowner consultation phase. This 5% is considered to be conservative compared with the route diversions already being implemented by AusNet Services in their WRL consultation on the ground. The three independent measurements were within one or two kms of each other and all had the same large difference to the line lengths in the Consultation Report.

Figure 55 from the Consultation Report, repeated below shows clearly that option 5 is much longer than option 1. Using the scale on this figure, the total length of the 500kv lines between Ballarat and the border crossing point downstream of Euchuca is ~335km via WRL and option 5 compared with a ~189km for option 1. The additional 146km would cost $m596 at $m4.08/km. This is the increased cost of the 500kV transmission lines from moving the WRL/VNI West connection point from Ballarat to Bulgana. The blue line in figure 55 appears to be a new 35km long 220kV transmission line between the new Bendigo 500kV/220/kV substation (BXTS) and the existing Bendigo 220kV substation (BETS).

Figure 55 Areas of interest for indicative alignments



The following table compares the 500kV route lengths in Table 5 of the Consultation Report with the route lengths determined by the three independent assessments. It appears that all options except Option 5 have been over-estimated by 36km to 48km and that Option 5 has been under-estimated by 23 km. Every local knows that Bulgana is further away from the crossing point near Euchuca, than North Ballarat or Walcha, and knows that the lengths in Table 5 are clearly wrong. Costing the difference in length for each option at the NSW 500kV line cost of $4.08m / km results in the cost differences in Table 4 below.

Table 4 Comparison of length of VIC 500kV line lengths between *Consultation Report* and independent assessments

	Length in Consultation Report	Independent length	Difference	Cost at $4.08m/km
Option 1, 1A, 2	229 km	189 km	(40 km)	($m163)
Option 3, 3A	230 km	194 km	(36 km)	($m147)

Option 4	268km	220km	(48km)	($m196)
Option 5	205km	231 km	+26 km	**+ $m106m**

.

The differences in line lengths alone, would change the ranking of the 7 options and their relative scenario weighted net benefits as shown in Table 5, based on the above differences and the scenario weighted net benefits in figure 13 of the *Consultation Report*

Table 5: Impact on option ranking of correcting line lengths in the Consulation Report

Option	Net benefit Figure 13	Cost adjustment	PV difference	Adjusted net benefit	ranking	losing margin
Option 1	**$m 1,299**	**($m 163)**	**($m 101)**	**$m 1,400**	**3**	**$99m 7.0%**
Option 1A	**$m 1,344**	**($m 163)**	**($m 101)**	**$m 1,445**	**2**	**$21m 3.7%**
Option 2	**$m 1,146**	**($m 163)**	**($m 101)**	**$m 1,247**	**7**	**$252m 19.9%**
Option 3	**$m 1,285**	**($m 147)**	**($m 91)**	**$m 1,394**	**4**	**$105m 7.5%**
Option 3A	**$m 1,408**	**($m 147)**	**($m 91)**	**$m 1,499**	**1**	**Winner**
Option 4	**$m 1,144**	**($m 196)**	**($m 121)**	**$m 1,265**	**6**	**$2434 18.5%**
Option 5	**$m 1,388**	**+$m 106**	**+$m 65**	**$m 1,323**	**5**	**$176m 13.3%**

Option 3A is the clear winner delivering an additional $176m PV of net benefits compared with Option 5 and being $21m PV (3.5%) ahead of option 1A In the Consultation Report, Option 5 already has 1% lower net benefit than option 3A however, the obvious mismeasurement of line lengths increases their relative PV of net benefits by $156m resulting in Option 5 being ranked 5th trailing 13.3% behind option 3A. Option 3A also delivers much greater VIC hosting capacity(6,490MW) than all other options with the second ranked option 1A delivering only 4,710MW. Option 3A's VNI VIC import limit is the same as Option 5, but avoids risky and complex series compensation of VNI West.

In addition, option 3A doesn't bypass Bendigo, so it avoids increasing the loading and congestion of the existing Kerang to Bendigo 220kV line, avoiding the additional power flow controller at Kerang and constructing new 220kV transmission lines between Kerang and Bendigo, and between Bendigo and Ballarat. This would be a substantial savings and avoid the socio-environmental impacts of those lines. Those additional costs would be substantial and would further increase the net benefit of option 3A over Option 5.

5.3 Additional transmission line to existing Kerang substation and VNI transmission limit

All options appear to require a new ~50km 220kV line to the existing Kerang substation. The study area maps in Figure 26 show that for all options, the centreline of the study areas is more than 50kms from Kerang, and that there are many constraints in the path of the required new 220kV transmission line from the new 500kV Kerang substation to the existing Kerang substation. Based on a 220kV transmission line cost of $1.4m/km this ~50km 220kV line would cost **around $70m** that should be added to the cost of all options, including Option 5.

The total length of WRL/VNI West in VIC is approximately 275km (option1), 327km (option 3A), 410km (option 4) and 421km (Option 5). The increased length for options 3A, 4 and 5 are 19%, 49% and 53% respectively. These much longer lengths would increase the impedance of VNI West in VIC by the same amounts, causing more power to flow via the existing VNI than VNI West. This would reduce the combine VNI interconnection limits particularly for imports to VIC. This is shown in Table 1 of the *Consultation Report* where the additional VNI capacity for imports to VIC are much lower than the ~6,000MW thermal capacity of the two new 500kV circuits, being only 1,800MW for options 1, 1A and 2; reducing to 1,650MW for options 3 and 3A and diving to only 1,475MW for option 4.

It would have been even lower for Option 5, except for the unproven assumption that series compensation can be safely and successfully applied to Option 5 to compensate for the extra 53% length of that option compared with option 1. It is unclear why there is not also a requirement to increase the capacity of the power flow controllers in both states on the existing VNI, although it is acknowledged that additional power flow controllers would be required at Kerang 220kV but only for Option 5 (?).

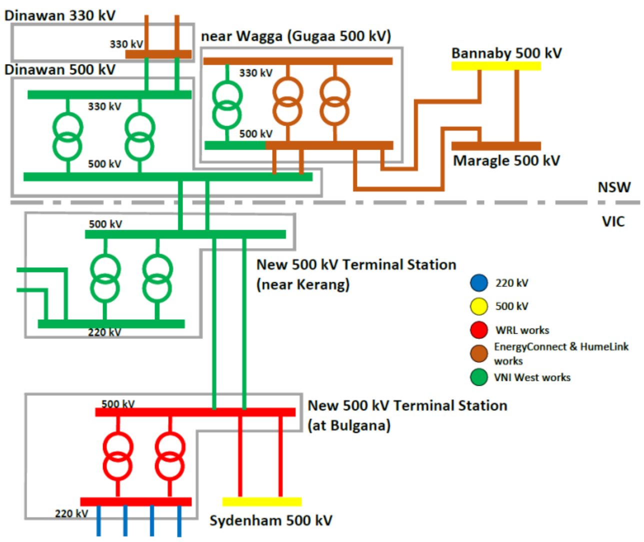
No details are provided of the power flow controllers and series compensation nor is their acknowledgement of the increase in risk and operational complexity of these FACT's devices. It is likely that the net increase in the overall VNI import capacity to VIC may be even lower than the figures in table 1 of the Consultation Report and their cost will be much greater than allowed in Table 3 of the Consultation Report. These issues are not adequately addressed in the Consultation Report.

5.4 Under-statement of VIC Substations Costs

Table 5 of the Consultation Report claims that there are no new substations required in NSW and only one in VIC yet the estimated cost of VIC substations in Option 5 is $418m compared with $354m in NSW. In truth, a new 500kV substation is required at Dinawan and two new substations (a 500kV substation and a 220kV substation are required at Kerang, which simplistically, would result in the VIC substation costs being twice the NSW substation cost (i.e., $708m being twice $354m compared with the $418m in Table 5. A closer look below of the required scope of substation works for Option 5 confirms that the VIC works are much greater than the small cost difference implies:

a. Gugga and Bulgana substations have similar scope of works as both require two additional 500kV switching bays and reactors. Gugga also requires a transformer. Bulgana appears to require four outgoing 220kV feeders shown in blue not required at Gugga or North Ballarat, but it is unclear what their purpose is in the Consultation Report. Bulgana substation may also be required to provide the additional land and various services to the series compensation facilities.

Figure 38 Single-line diagram for Option 5



b. Dinawan requires the establishment of the brown fields 500kV substation with two transformers adjacent to the PEC 330kV substation.

c. Kerang requires green-field 500kV and 220kV substations requiring extensive excavation and civil engineering works with two transformers, with an access road, auxiliary power supplies, water supply, emergency diesel generators, duplicated telecommunications facilities and security fencing none of which are required at Gugga or Dinawan. It also must provide connections and services to the series compensation at Kerang and the 220kV power flow controllers. These substation servicing costs will be in addition to the costs of the power flow controllers and series compensation and their additional substation costs in Table 5. It is estimated that these additional works would easily add more than $25m to $50m to the equivalent brown-field substation costs in NSW.

d. There are also the additional costs of redesign, scope change, relocation and plant storage costs to vary the existing contract with AusNet Services to enable relocation of the North Ballarat substation to Waubra or Bulgana. Based on the difference between the substation costs between options 1 and 3, these variation costs appear to be around $63m. This alone accounts for the $64m difference between the NSW and VIC substation components, without allowing for the large scope difference at Kerang described above.

The Consultation Report explains that the VIC substation cost estimates come from the TCD, and there is no evidence that the required 40% contingency has been added for adjustments and risks, as was included in Table 3 of the AEMO updated WRL assessment. The inclusion of the required 40% alone would increase the $418m to $585m adding $167m. Including the $25m in (c) above would take the total under-statement of VIC substation costs to at least $192m bringing the total cost of VIC substations to at least $610m which is 1.7 times the $354m NSW figure. This is considered to be a reasonable comparison given that two substations are required in VIC and only one in NSW as well as the increased scope of work in (c) above.

5.5 Underestimation of Dinawan to Gugga upgrade costs

Table 5 of the Consultation Report includes $182m for building the 163km Dinawan to Wagga Wagga section of Project Energy Connect (PEC) at 500kV instead of 330kV. In the Consultation Report, TransGrid claims this amount is based on an option negotiated with the PEC contractor plus TranGrid's additional costs to build the 163km section of PEC between Dinawan and Wagga Wagga at 500kV instead of 330kV. However, the figure does not include the additional; **$69m** for building the ~15km section of 500kV transmission line from Wagga Wagga substation to Gugga 500kV substation (or the equivalent extra distance of going direct to Gugga). An additional 15kms of 500kV transmission line would cost $61m based on $m4.08/km calculated from Table 5 plus $8m for the associated easements costed at $m0.54/km (as calculated in section 4.6 below).

The Consultation Report states that the $m182m is based on an option negotiated at the time the PEC construction contract was awarded to Secure Energy, a co-venture between Clough Engineering (now in Administration) and Elecnor an Italian transmission construction company with no Australian transmission construction experience. It is understood that the Australian transmission construction industry was astonished when TransGrid awarded the PEC contract to Secure Energy. . Although Clough's replacement has not been announced, it is understood that Elecnor is now solely responsible for delivering the PEC contract. In early December 2022, TransGrid was reported as saying that Elecnor had already taken measures to allow it to continue with construction of PEC but no details have been provided. Elecnor commenced working in Australia in 2014 and has since been constructing two northern NSW solar farms, a VIC solar farm in pre-investment phase near Bendigo and the Baroota pumped storage scheme in South Australia, that is not proceeding. . . Elecnor is facing major challenges with the PEC contract given rapidly escalating costs, spiralling interest rates, skilled labour shortages, the threat of a global recession and ongoing COVID impacts. It was recently reported by the financial review that there have already been substantial delays and cost over-runs with PEC. It is also understood that Elecnor is now staggering to meet its commitments due to the shortage of experienced transmission line construction personnel and other factors. The likelihood that Elecnor can honour its extremely low optional price to uprate PEC appears negligible.

Following is an estimate of the expected cost of uprating PEC to 500kv, based on publicly available cost estimates provided by ElectraNet for the PEC 330kV line and TransGrid for the 500kV line for VNI West..

As calculated in 2.1, the average cost of the NSW 500kV transmission line is $m4.08/km. The corresponding average cost of PEC's 330kV double circuit transmission line has been estimated to be $m1.49/km calculated from ElectraNet's $m258m for its 205kms of PEC transmission lines in their AER Contingent Project Application approved by the AER in May 2021 noting that TransGrid's application did not separate transmission lines from substations. The $m258 has been increased by the average 7.3% project delivery costs and the 3.6% risks allowances in ElectraNet's application and escalated by 10% to allow for cost increases for the three years from 2017/18 to 2020/21, being the respective reference dates for the PEC and VNI West cost estimates. The adjusted figure of $m315 has been divided by the 205km length of PEC in South Australia to give $m1.54/km for 330 kV transmission lines, excluding easement costs. The TransGrid estimate of $m4.08/km for 500kV line is 2.65 times the $m1.54/km ElectraNet estimate for a 330kV line, which is reasonable given the 2 to 3 times multipliers for labour and materials. ElectraNet has verbally confirmed that their portion of PEC is on schedule and on budget. Based on these cost estimates, the incremental cost of increasing the voltage of PEC would be $m2.54/km which for the 163km to be uprated, would total $m414. This is $m232 greater than the $m182 allowance included in the VNI West cost estimate. An allowance should also be included for the wider easement required for a 500kV line compared with a 330kV line. Based on the $66m easement cost for the 184km of VNI West in NSW, this would amount to an additional $17m to increase the width of the easement from 70m to 100m to suit a 500kV line.. The total additional incremental cost for upgrading the 163km of PEC is therefore estimated to be **$m249** (i.e., $m232 + $m17)

5.6 Easement Costs

Table 5 of the Consultation Report includes $66m for the NSW easements along the 183kms of 500kV line from Dinawan to the Victorian border assuming 85% is located on private land. This does not include the cost of widening the easement between Dinawan and Wagga or the cost of the 15km of 500kV easements between Wagga Wagga and Gugga. The $66m is equivalent to $m0.42/km for each km of private land crossed by the NSW component of VNI West. In addition, the NSW arrangement for hosting high voltage (HV) transmission lines pays landowners $10k/km p.a. for 20 years, escalated at

CPI, for each new 330kV or 500kV transmission line crossing their land payable from the energisation date of the line.

The PV of the $10k/km, over 20 years at 5.5% pa discount rate would be $m0.12/km/line discounted to the time the line is energised. Adding this payment to the easement rate, gives a combined rate of $0.54m/km, which for the 156kms of private land in NSW is $84m, being the $66m easement estimate plus $18m for the line hosting payment (which has been included as an operating cost in the *Consultation Report.*

Table 5 of the *Consultation Report*, only includes $59m for easement costs in Victoria for option 5 for the stated 205 kms of line plus the easement widening for 104km of WRL. Rows 194 and 199 of the Houston Kemp report shows that $42.7m was included for the 500KV Victorian easements for option 5, and that another $15.9m was included for widening the WRL easement.to uprate WRL. These components total 58.6m aligning with the $59m figure. Using the $42.7m figure for the 205km of option 5 in Victoria, and assuming that 85% of that route is on private land, the Victorian 500kV easement cost averages $0.245m/km for option 5, which is only 58% of the NSW easement rate. The *Consultation Report* does not include the proposed Victorian easement hosting rate of $8,000/km for 25 years, which itself does not appear to include CPI escalation and covers only WRL, VNI West and Marinus Link. The NSW arrangements escalates at CPI and covers any new transmission line required by the ISP or for REZ transmission, including both 500kV and 350kV/220kV lines. The Victorian arrangements are silent on those points. The NSW arrangement covers each transmission line (supported by a single tower) on the easement, whereas this is not mentioned in the Victorian arrangements. Assuming the $8,000/km does not escalate, the NPV of the Victorian payments would be $0.084m/km (based on Victorian landowners missing-out on a compounding CPI increase assumed to be just 2.5% each year over the 25 years. This is 30% lower than the equivalent NSW hosting rate as well as not covering multiple lines on the easement or projects other than the three listed projects. The combined Victorian rate is $0.33m/km which is 39% lower than $0.54m/km NSW combined rate, despite land values being higher along the Victorian part of option 5 than in NSW.

The 39% difference is considered to be unsustainable from an equity and political perspective and may destroy any remaining social licence for new transmission lines in Victoria. It appears almost certain that the Victorian combined rate will increase to align with the NSW rate by the time the easements are granted. Compulsorily resuming the Victorian easements at such low rates, may be rejected if landowners appeal and would further increase community opposition to new transmission lines in Victoria. Based on the Victorian overall easement rates matching the $0.54m/km rate in NSW, and using 85% of the easement lengths in table 3 above, and assuming that uprating WRL requires its easement width to be increased from 60m to 100m, the total combined easement expenditure for option 5 in Victoria would be $143m as calculated below plus $m16 for 50kms of 60m wide easement for the new 220kV line required to connect VNI West to the existing Kerang substation. This would total $159m being **$100m greater** than the $59m included for option 5 in Table 5 of the Consultation Report.

Table 6: Calculation of easement costs for each VNI West option

Option	*VNI West*	*easement 85% at $m0.42/km*	*WRL uprated*	*Easement 85% at $m0.26/km*	*Total easements*	*Hosting 85% at $m0.12/km*	*Total cost*
1	*189km*	*$m67.5*	*0km*	-	*$m67.5*	*$m19.3*	*$m 86.8*
1A	*189km*	*$m67.5*	*104km*	*$m27.0*	*$m94.5*	*$m29.9*	*$m124.6*
2	*189km*	*$m67.5*	*0km*	-	*$m67.5*	*$m19.5*	*$m 87.0*
3	*194km*	*$m82.1*	*47km*	*$m12.2*	*$m95.5*	*$m28.2*	*$m123.7*
3A	*194km*	*$m82.1*	*104km*	*$m27.0*	*$m109.1*	*$m34.1*	*$m143.2*
4	*220km*	*$m95.7*	*104km*	*$m27.0*	*$m122.7*	*$m37.9*	*$m160.6*
5	*231km*	*$m81.7*	*104km*	*$m27.0*	*$m108.7*	*$m34.0*	*$m142.7*

5.7 Victorian Easement Tax Understatement

The Victorian Government levies an easement tax on electricity transmission companies, of 2.5% of the total value of the land occupied by their transmission line easements. In 2022/23, the land tax paid by AusNet Services totalled $m191 for approximately 6,500kms of their transmission lines. Assuming an average easement width for each line of 60m, this is equivalent to an easement tax of $4,900/ha for each hectare of transmission line easement. In 2021, the cost of rural land in Victoria increased by 30% to an average of $10,583/ha. Rural land in the vicinity of the route for option 5 is currently selling for $6,000/ha to $50,000/ha depending on its size, and is typically $10,000/ha to $20,000/ha. At a 2.5% pa land tax rate, this would be equivalent to $250/ha to $500/ha for option 5. Along the WRL 220kV route, land values are typical double that of option 5, which would result in an easement tax of $500/ha to $1,000/ha p.a. For the purpose of estimating the additional land tax payable for each option, the midpoint of these ranges has been used, together with a 100m wide easement (sufficient for twin double circuit 500kV lines, and an 40m easement widening for WRL, and 85% being on private land.

Table 7: Calculation of Victorian Easement tax for each option

option	500 kV length	500kV easement ha	Easement tax	WRL easement widening ha	Easement tax	Total tax
1	189km	1,606 ha	$602k pa	-	-	$602k pa
1A	189km	1,606 ha	$602k pa	42 ha	$315k pa	$917k pa
2	189km	1,606 ha	$602k pa	-	-	$602k pa
3	194km	1,649 ha	$618k pa	19 ha	$142k pa	$750k pa
3A	194km	1,649 ha	$618k pa	42 ha	$315k pa	$933k pa
4	220km	1,870 ha	$701k pa	42 ha	$315k pa	$1,016k pa
5	231km	1,964 ha	$737k pa	42 ha	$315k pa	$1,052k pa

The annual land tax payment for each option in the Consultation Report is given in the Houston and Kemp spreadsheets, under opex, which lists the following land tax amounts in 2020/21 prices and which are payable every year starting when the easements are gazetted until finally relinquished. Given that land values are escalating well above the CPI, a discount rate of 0% pa has been used assuming rural land prices increase at 5.5% p.a. in real terms.

Table 8: Annual VIC tax for each of the 7 options in the Consultation Report

VIC land tax	
Jun-21	Jun-22
853,366	905,803
1,023,098	1,085,965
853,366	905,803
881,216	935,365
974,797	1,034,696
687,220	729,448
467,779	496,523

Table 9: Comparison of VIC land tax between Consultation Report and Table 7

Option	Land tax in Consultation Report $k pa	Land tax estimated above $k pa	Difference $k pa	PV for 60 years
1	$k 853	$k 602	$k 251	$m 15
1A	$k 1,023	$k 917	$k 106	$m 6
2	$k 853	$k 602	$k 251	$m 15
3	$k 881	$k 750	$k 131	$m 8
3A	$k 975	$k 933	$k 42	$m 3
4	$k 687	$k 1,016	($k 329)	($m 20)
5	$k 468	$k 1,052	($k 584)	($m 35)

The Consultation Report appears to have understated the easement tax for option 5 by $35m PV and overstated the easement tax for options 1 and 2 by $15m PV.

5.8 Cost of 500kV line Series Compensation and additional Power Flow Controllers

As explained in 4.3 above there is likely to be an increase in the required capacity of the power flow controllers along the existing VNI in both NSW and VIC for options 4 and 5. Controllable series compensation would be required for both options to compensate for the 49% and 53% increase in the reactance of the 500kV line in VIC between Sydenham and the border. As WRL and Option 5 are similar lengths, this could require 40% series compensation of both WRL and Option 5. Some experts consider 40% series compensation to be a practical limit. Additional devices are also required in Option 5 to reduce the power flow on the existing 220kV line between Kerang and Bendigo. However, there is no increase in the cost of power flow controller in NSW and VIC in for options 2, 3 and 4 and only $75m extra is included for Option 5. This is considered to be inadequate to cover the cost two installations of 40% series compensation and the additional power flow controllers required for Option 5. The Consultation Report does not disclose the assumed amount of 500kV series compensation or where it would be installed. Nor does it disclose the proposed technology, amount, location and cost of the power control devices to limit power flow on the existing Kerang to Bendigo 220 kV line. In addition, the substation component of the series capacitors and power flow controllers in Option 5 is based on the TCD cost estimates which do not include the required 40% allowance for risk. The total understated cost of the devices in NSW and VIC for Option 5 is difficult to quantify without more information as there is virtually no information provided in the Consultation Report. however the understatement of the costs of these devices and their associated substation costs is conservatively estimated to exceed $100m. It is noted that the PADR for the series compensation to upgrade the Heyward interconnection by an additional 190MW in both directions has only delivered an additional 90MW import to VIC from South Australia to 550MW (and even lower for some contingencies) despite the 7 years since its commissioning in 2016. Yet the *Consultation Report* assumes that this will increase to 750MW as soon as Project Energy Connect is operational, which is an unbelievable assumption to make.

5.9 Understatement of annual costs to operate, maintain, refurbish and replace VNI West assets

The annual costs of operating, maintaining, refurbishing and replacing components of VNI West Option 5 (including direct overheads) appear to be understated by $m101 pa, due to the Consultation Report only allowing 1% pa of the capital cost of option 1 (excluding the cost of transmission line easements and environmental offset payments). Based on the assessment described below, which uses the "AER's 2022 Annual Benchmarking Report – Electricity Transmission Network Service Providers" it is demonstrated that the Consultation Report should instead be using a figure exceeding 3% pa. When the 3% pa is applied to the estimated $4,516m capital cost of Option 5 in Table 1 on page 15 of this submission, less the $88m for environmental offset payments, the annual costs of Option

5 over its assumed 50-year life-cycle would be $134m p.a. compared with the $32m p.a. assumed in the Consultation Report. The additional $102m p.a. would have a net present value to 2020/21 of $1,012m.

5.9.1 Disclosure Requirements for Operation and Maintenance cost

NER Clause 5.16.A.4(d) and clause 4.52 of the *Guidelines*, require the RIT-T proponent to quantify O&M costs for each credible option and to provide a breakdown of the O&M costs in the PADR. This is because O&M costs, at 3% p.a. of the capital cost, over the life-cycle of the transmission asset, total 150% of the investment over a 50-year life and have an PV of 50% of the investment's PV.

The table of responses to PADR questions on page 54 of the PADR Submissions Report (which is part of the Consultation Report) states "AVP and Transgrid note that, while there is a requirement to quantify O&M costs under the paragraphs and clauses cited, there is no requirement to provide a breakdown of O&M costs under the RIT-T, including in either paragraph 5 of the RIT-T or NER Clause 5.15.A.3(b)(6)(ii), as suggested" They go on to state "the RIT-T proponent is not required to separately quantify each class of cost'. However, their responses do not mention their apparent non-compliance with NER Clause 5.16.A.4.(d) or clause 5.52 of the Guidelines in both the PADR and the *Consultation Report*, which clearly require a breakdown of O&M costs to be provided in the PADR. Moreover, AVP and Transgrid state in the introduction to the Consultation Report that "As jurisdictional planners, AVP and Transgrid are responsible for undertaking the RIT-T, and the Australian Energy Regulator (AER) monitors and enforces compliance with the process." All stakeholder and the AER would expect AEMO and TransGrid to comply with all regulatory requirement and not leave it to the AER or stakeholders unfamiliar the complex rules and Guidelines to identify their non-compliances.

Significantly, in Appendix A1 of the VNI West PADR, AEMO and TransGrid state "This section sets out a compliance checklist which *demonstrates the compliance of this PADR with the requirements of **clause 5.16A.4(d)** of the National Electricity Rules version 180 and Table 14 of the CBA Guidelines.* Then goes on to state that clause 5.16A.4(d) "include a quantification of the costs, including a breakdown of operating and capital expenditure for each credible option". They go on to state that "RIT–T proponents are required to identify breaches of the CBA guidelines, if any, in their compliance reports and provide an explanation for the breach" and that they have complied with this Requirement. Yet this is clearly untrue. The response in the Consultation Report by AEMO and TransGrid to Stakeholder feedback on their non-compliance with the regulatory Requirement to provide a breakdown of their 1% O&M, appears to be to attempt to publicly discredit the stakeholder however they clearly knew their obligations under clause 5.16A.4(d) and appear to have misled stakeholders and the AER about their known non-compliance with that clause and clause 5.52 of the Guidelines and apparently falsified their declaration of compliance.

5.9.2 Justification of 1% pa annual costs

Section 2.5 of the PADR Submissions Report states that "*AEMO reviewed recent revenue determinations, contingent project applications and RIT-Ts, and concluded that 1% was reasonable for ISP purposes as the cost of major projects in the ISP are dominated by transmission lines rather than substations. While the modelling applies operating expenditure (opex) costs consistently throughout the modelling horizon, opex costs are realistically expected to start low and grow as assets age. It is also noted that the Australian Energy Regulator (AER) will review and approve network expenditure from one revenue period to the next, so only the efficient and prudent project costs are expected to materialise*". However, the transmission line component of Option 5 is $597m (i.e., $912m less $315m, WRL upgrade costs) and the substation component is $639m (i.e., $415m + $164m for flow controllers and series compensation + $60m for early works other costs being mostly for transformers, reactor etc). Thus the $639m substation component exceeds the $m597 transmission line component.

This means that for Option 5, AEMO/TransGrid have incorrectly justified their 1% figure by stating that capital costs are dominated by transmission lines. It is known that substations have percentage operating costs more than double those of transmission lines and that electronic equipment such as substation secondary systems, power flow controllers and series capacitors are typically three times that of transmission lines noting they must be replaced several times during the 50-year life of transmission lines. AEMO and TransGrid have also admitted that operating costs start low and grow as assets age. Under the RIT and NER, RIT-T proponents must quantify operating costs throughout the modelling period and also include all annual costs as the assets aged beyond the modelling period in their determination of the assets terminal value taking into account the high costs of refurbishment and component replacement.

AEMO justifies the 1% operating cost by saying that the same percentage is used for the ISP, recent RIT-T's and in Contingent Project Applications (CPA) for the AER to consider approving substantial increases to the allowable capital cost of projects under construction. However, AEMO's WRL PACR allowed 3.5% for Option C2 only 4 years ago yet reduced this to 1% in the AEMO updated WRL assessment in November 2022. No explanation was given for the 72% reduction in WRL's operating cost nor has the ISP ever explained the basis for the 1% it assumes. The Humelink PACR assumed only 0.5% operating cost and only just passed its RIT-T. Given that a more realistic 3% would represent 50% of the PV of transmission capital costs, assuming much lower percentages could significantly bias the outcomes of these recent applications used by AEMO/TransGrid in the Consultation Report.

The omission of easement costs in the capital that is used to apply the 1% is inconsistent with the known fact that the annual cost of monitoring and managing easements twice a year for regrowth, rogue trees on the edge of the easement and non-compliances of easement use by others is one of the highest and fastest growing costs of transmission companies and far in excess of 1% of the easement costs. The operating costs of easements should be separately estimated and explained, however for the purpose of this exercise, the same 3% p.a. rate has been applied to their capital cost.

5.9.3 AER's Annual Benchmarking Report – Electricity Transmission Network Service Providers.

AEMO and TransGrid do not mention in the *Consultation Report* the AER's annual benchmarking of the NEM TNSP's annual costs nor have they used it to provide a comprehensive basis for the annual operating costs of Option 5. The AER's comprehensive report is publicly available on the AER's website and provides the average annual expenditures, for the last five years, of each TNSP's funded from both their operating fund and capital fund. It also provides their average annual depreciation on their assets. It is essential to know that for the last five years the capital expenditure of the NEM TNSPs has been almost entirely used to refurbish assets and to replace asset components. It's also important to know that Powerlink uses a larger "unit of plant" (i.e., part of their accounting practices to break down a project into sub-components) than the other TNSP’s which means they often fund replacement expenditure from their operating fund whereas the other TNSP’s would fund it from their capital fund. It is therefore essential to combine their operating and capital expenditures to determine their annual total operating expenditure on their transmission assets.

It is also essential to determine the percentage using their un-depreciated asset value rather than their depreciated asset value. This can be accurately estimated by multiplying their annual depreciation by 40 years, being the typical average economic life of their transmission assets. Typically, transmission lines have a 50-year economic life, substations 40 years, reactors 25 years and substation secondary systems, telecommunication systems and metering 15 years. This refinement to the annual benchmarking report has been suggested to the AER, who have yet to respond to this suggested improvement to their annual benchmarking report.

Table B.2 of the AER’s 2022 Benchmarking Report (*AER report*) can be used to demonstrate that the annual expenditure by the four eastern state TNSP’s are all close to 3.3% pa of their undepreciated asset bases. While AEMO and TransGrid may argue that 1% is reasonable for routine O&M of transmission lines in good condition, they must allow for the much higher routine substation O&M costs and the high easement operating costs, as well as non-routine annual costs that are funded from the capital budget by most NEM TNSPs.

Table B.2 of the *AER report* lists the OPEX, CAPEX, RAB and depreciation for the NEM TNSP’s ElectraNet, Powerlink, TransGrid, AusNet Services and TasNetworks. Given that most of the CAPEX spent by these TNSP’s in the last five years has been to refurbish and replace their ageing transmission assets, with very little spent on network augmentations, both the OPEX and CAPEX annual expenditures must be considered in estimating their total average annual expenditure on their transmission assets over their full life-cycle.

If these adjustments are made to the benchmarking data in Table B.2, the comparative results are as Tas Networks follows:

	Total undepreciated asset value $million	Operating Fund expenditure % p.a.	Capital Fund expenditure % p.a.	Combined annual expenditure % p.a.
Electranet	$4,760m	2.1% p.a.	3.0% p.a.	5.1% p.a.
Powerlink	$12,000m	1.8% p.a.	1.2% p.a.	3.0% p.a.
AusNet Services	$7,360m	1.2% p.a.	2.1% p.a.	3.3%p.a.
TasNetworks	$2,520m	1.2% p.a.	1.9% p.a.	3.1%p.a.
TransGrid	$11,400m	1.5% p.a.	2.0%p.a.	3.5%p.a.

Leaving aside ElectraNet, which owns many lower cost 66kV substation assets and service a comparatively greater distances with a lower demand density, the other four TNSP's have quite similar overall annual expenditures expressed as a percentage of their undepreciated asset bases being 3.25% pa plus or minus 0.25% pa. The overall percentages are tightly clustered around 3.25% pa and their relativity may correspond to their efficiency in operating, maintaining, refurbishing and replacing their existing transmission assets.

The relative split between OPEX and CAPEX reflects the different definitions of "unit of plant" between Powerlink and the other TNSP's with Powerlink's OPEX (1.8%) being 1.5 times the 1.2% of AusNet and TasNetworks and 1.2 times TransGrid at 1.5%. Powerlink's CAPEX (1.2%) is around 60% of AusNet, TasNetworks and TransGrid's 2.0%. ElectraNet is an outlier.

It is also noted that the assumed O&M costs in AEMO's WRL PACR was 3.5% pa of its total capital investment for the preferred option C2 very close to the 3.3% p.a. for AusNet Services.

Recent assumptions in the AEMO ISP and the VNI West PADR that O&M costs would be only 1.0% pa and in the case of Humelink only 0.5% pa of their respective investment costs, with no ongoing capital expenditure to refurbish or replace "units of plant" as the asset age, appear to be unrealistic

The above analysis based on the most recent AER Benchmarking indicates that a figure between 3.0% p.a. and 3.5% p.a. is believable taking into account the total life-cycle expenditure on transmission assets.

This is a critical assumption as a 3.3% pa annual expenditure over the 50-year life of a transmission asset would total 165% of its construction cost and have a PV exceeding 50% of the PV of its construction cost. Assuming only 1% pa would be equivalent to only 16% of the PV of the construction cost. The missing 34% (50% - 16%) could mean that the net benefit of a new transmission project could be over-stated by 34% of the PV of its construction cost.

TransGrid annual expenditure averages 3.5% p.a. slightly higher than AusNet Services' 3.3% This suggests that the operating cost for VNI West, based on the average of AusNet Services and TransGrid would be 3.4% p.a. Even with a 10% productivity improvement, the operating expenditure would be in excess of 3% p.a.

Based on a 3% figure, the annual costs of Option 5 would be $134m pa by applying the 3% to the estimated $4,460m capital cost of Option 5 less the $88m for environmental offset payments. This is $102m greater than the $32m p.a. assumed in the *Consultation Report*. Over the 50-year operating life and using a 5.5% discount rate, the net present value of the $102m pa under-stated annual costs of Option 5 would have a net present value to 2020/21 of $1,012m, assuming Option 5 is commissioned in mid-2031

6 Appendix B: Critique of benefit calculation

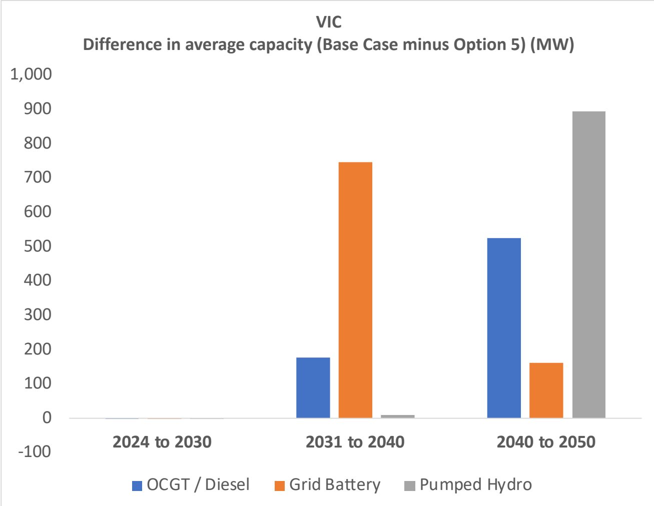
6.1 Storage cost benefits from WRL-VNI reflect biased input assumptions and flawed modelling

AVP claim small benefits arising from the differences in the production of renewable energy between the Base Case and its five options. This is credible. It reflects the fact that variable renewable energy is inexpensive and consequently differences in the location of renewable electricity attributable to the construction of WRL-VNI are small. The important conclusion from this is that it can not be claimed that WRL-VNI creates any meaningful level of benefit by facilitating the development of renewable electricity in locations where there are better renewable resources.

AVP's description of WRL-VNI's benefits shows that 75% of the total benefit (for Option 5, Step change for example – see Figure 7) is what AVP call "Avoided generation/storage costs (excluding fuel costs)". To analyse AVP's results we examined the model's output in respect of capacity in "OCGT/diesel", "batteries" and Pumped Hydro Electricity Storage "PHES", comparing the Base Case and Option 5. These are the three categories of dispatchable generation where differences exist comparing the results with WRL-VNI (the various options) and without WRL-VNI (the Base Case).

To see the effects more clearly we break the study periods into three roughly decade long groups. The result of this analysis, for VIC, is shown in Figure 1 below.

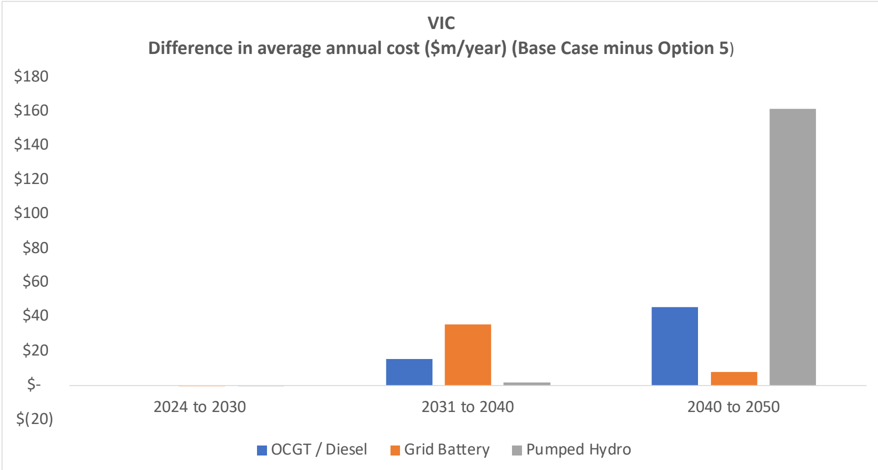
Figure 1. Difference in VIC average annual capacity (MW) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050



What Figure 1 shows is that, relative the Base Case, WRL-VNI reduces expenditure on new capacity for gas (OCGT), batteries and pumped hydro. It shows no meaningful effect until the decade from 2031 to 2040 during which on average this around 150 MW more OCGT/diesel and around 750 MW more grid battery capacity. In the years from 2040 to 2050, there is around 500 MW more OCGT/diesel, 150 MW more battery and 900 MW more PHES capacity if VNI—WRL is not built.

To establish the benefit that arises from these differences we work out annuitized costs using the build costs and technical lives assumed by AEMO in the 2022 ISP and the 5.5% real pre-tax cost of capital. The outcome of this analysis for VIC is shown in Figure 2 below:

Figure 2. Difference in average annual cost ($m/year) in VIC for Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050



What Figure 2 shows is that AVP's analysis leads to the conclusion (costed at the ISP build cost assumptions) that VIC would avoid around $50m per year in expenditure on OCGT/Diesel ($10m) plus battery ($40m) over the decade from 2031 to 2040. Over the decade from 2041 to 2050 the VIC region would avoid about $200m per year (of which PHES is about $160m per year) that would otherwise be spent on PHES and Gas/OCGT if VNI-West was built. As we noted earlier, this accounts for circa 75% of the total benefit of WRL-VNI according to the Consultation Report.

WRL-VNI, according to the Consultation Report, effectively allows batteries in NSW to substitute for PHES in VIC. This can be seen by adding together the outcomes in NSW and VIC. This is shown in Figure 3 below:

Figure 3. Difference in VIC+NSW average annual capacity (MW) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

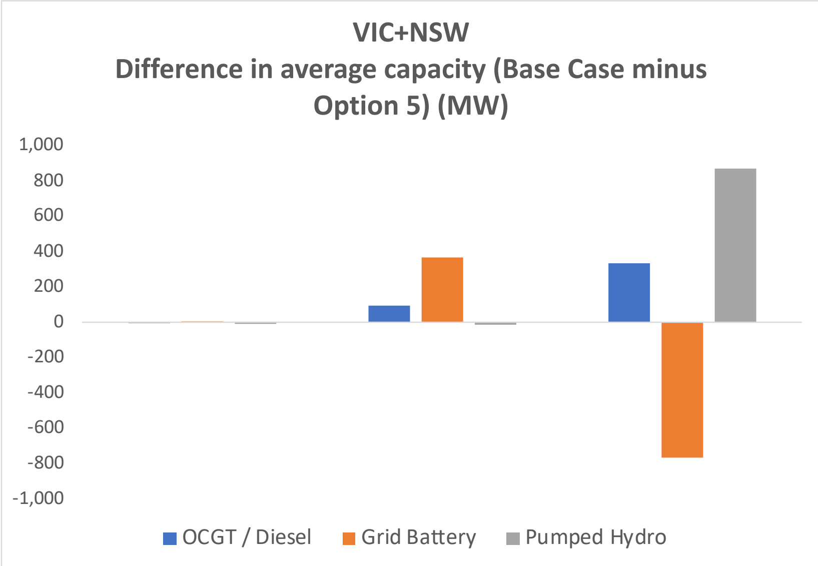


Figure 3 shows that PHES (and to a lesser extent OCGT/diesel) in VIC is substituted by batteries in NSW. To quantify this substitution benefit, we used the ISP build cost assumptions (as before), this results in the net position of VIC+NSW in

Figure 4 below:

Figure 4. Difference in average annual cost ($m/year) in VIC+NSW for Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

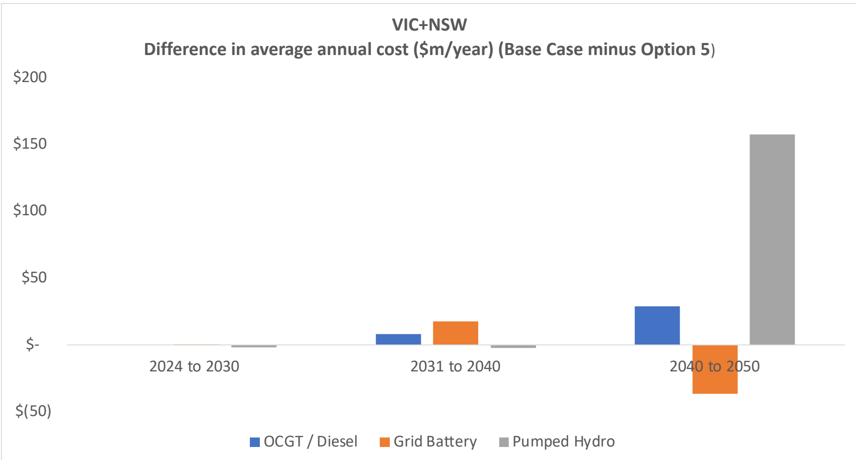


Figure 4 shows that aggregated across NSW+VIC the dominant benefit for WRL-VNI is the avoidance of $160m p.a. associated with the construction of PHES in VIC. Of course the NEM is an interconnected market, but as shown in Appendix D the effect of WRL-VNI in other regions is small. For ease of reference, the aggregate net benefit across these three generators is shown in Table 1 below

Table 1. Aggregate net benefit by technology

NSW+VIC+SA+TAS+QLD	2024 to 2030	2031 to 2040	2040 to 2050	Average annual (2031-20	
OCGT / Diesel	$ (2)	$ 4	$ 28	$ 16	
Grid Battery	$ 0	$ 19	$ (17)	$ 1	
Pumped Hydro	$ 2	$ 18	$ 202	$ 110	
Total	$ 0	$ 41	$ 212	$ 127	

This now sets out all the information needed to assess AVP's analysis of storage cost benefits.

The first observation is that the average annual net benefit across the NEM ($127m per year) see Table 1 above – which as noted AVP's analysis finds to be 75% of the benefit of WRL-VNI – falls well short of providing anywhere near the benefit needed to justify the outlay in WRL-VNI.

Secondly, leaving aside possible computational errors in how AVP have valued this benefit, the assumption that PHES is installed in VIC in the Base Case demands a plausible explanation. In the ISP, AEMO assume that PHES costs are comparable in VIC and NSW and likewise that battery costs are comparable in NSW and VIC. We know also, as discussed, that WRL-VNI makes no meaningful difference to Snowy 2.0 dispatch (in fact it is often slightly lower with WRL-VNI than without it). How then can it be that building WRL-VNI results in the substitution of PHES in VIC by batteries in NSW? If they cost the same in NSW and VIC, why could the batteries not be developed in Vic instead of placing the batteries in NSW and this needed the additional expense of the much more expensive WRL-VNI to get their output to VIC ?

The answer to this seems to lie in the forced REZ development program in AVP's analysis which results in very high spillages of renewable energy in Victoria. This wastage of hydro-electric, wind and solar renewable energy must be replaced by installing even more renewables and growing production from OCGT located near to Melbourne, mainly. However the "optimal" amount of each type of generation is determined in the first stage of AEMO's optimisation process which uses the simulation package Plexos and an extremely simple model of the NEM transmission grid. It places all load and generation in each state at a single location and does not know about the congestion and renewable energy spillages in the second phase of the simulation. The first phase also determines the operating profiles of PHES and Hydro without any transmission constraints. Along comes the second phase with some representation of the network, but with the interconnectors and rural REZ's sharing the same single 500kV transmission line. There are renewable energy spills everywhere and the skinny 500kV transmission line becomes hopelessly constrained especially in the daytime when all the PV is generating simultaneously.

However the second phase cannot make changes to the generation/storage installation program, including increasing the amount or changing the location of the renewables determined by the first phase. So the gas turbines have to work overtime to make up for the spilled renewables and constrained interconnectors, hence the ridiculous fuel costs. The situation deteriorates in the last decade to such an extent that the interconnected grid becomes a parking lot, so the model builds much more transmission. The increasing interconnector congestion and constraints in AVP's model require all Victorian OCGT's to operate at over 1,000 hours a year, around 100 times their current hours of operation. This causes the growth in fuel costs progressively though-out the study period and particularly during the 2040's in both Option 5 and the flawed Base Case.

During the 2040's. the combination of the very high assumed load growth in Victoria and the complete closure of all existing coal stations and CCGT's , drives up the average duration for running peaking plant even in the first phase of the simulation process that also determines how much storage capacity is required hours of operation. The counterfactual is even more constrained by the elimination of intra-regional transmission upgrades as well as the artificial Gippsland REZ constraints, thereby preventing the development of Victorian renewables. This appears to be the driver of the increased need for energy storage and even new pumped storage in VIC in the counterfactual in the decade from 2040 to 2050. Even when WRL-VNI is developed (and batteries in NSW replace the PHES in Victoria thus creating the vast bulk of the benefit of WRL-VNI in AVP's assessment) the interconnectors are still completely congested for 33% of the time by 2050.

The origin of the problem here is AVP's modelling of renewable generation entry in Victoria. An examination of the E&Y spreadsheets, as summarised in Appendix E, demonstrates that Option 5 significantly increased the congestion on both the existing

VNI (causing large spillages at Victoria's hydro-electric stations) and REZ's along the pathway of VNI West.

This reaches unimaginable levels from 2039 onwards due to the forced development of wind power and PV at REZ's along VNI West, rather than the far better option of developing renewables in the Gippsland REZ, utilising its 3,500MW of already spare transmission capacity which will increase to 9,450MW as coal stations close and can be easily and cheaply increased to around 17,000MW by just two short 500kV transmission lines built on existing, unoccupied spare 500kV easements. The rapid development of PV along VNI West in the 2040's constrains VNI (both routes) for 3 to 6 hours a day on average, due to its inability to transmit the PV generation which has almost no diversity) and results in PV spillages up to 50% at these REZ's.

The Gippsland REZ has its transmission limits constrained to nil PV until 2039/40 and then to only 500MW until 2042/43 and its wind power constrained to 500MW until 2028/29 and then to 2,000MW for the entirety of the modelling period.

The mechanism used to achieve this outcome in the ISP and the Consultation Report is explained in Appendix F, and also adds $millions of REZ expansion penalty charges and artificial REZ transmission expansion costs, particularly to the Base Case.

The Base Case is even more heavily constrained by also preventing the development of any intra-regional transmission in Victoria. Even though the PADR argued strongly that WRL is an anticipated project (which should also be installed in the Base Case), the installed wind power in Western Victoria REZ in the Base Case barely changes for the entire 27 years in the Base Case. The very high renewable energy spills combined with the extreme congestion of Victoria's interconnectors (for up to 33% of the year) is the cause of the exponential growth in the savings of generation/storage which is the basis of the vast bulk of the benefits claimed for Option 5. The obvious development path for the Base Case of using the existing transmission capacity of the Latrobe Valley to host renewables and battery storage in Gippsland REZ is not allowed to take place in the ISP and in your Consultation Report.

Had the Base Case been correctly modelled by allowing the efficient development of the Gippsland REZ, there would have been no or much smaller spilled renewables and the interconnectors would not have constrained in Option 5 (and even moreso in the Base Case). The model would not have installed PHES in Victoria in the 2040s and the vast bulk of the benefit of WRL-VNI would have disappeared into thin air.

In other words, there is no good reason for PHES to have existed in the Base Case in Vic, and by implication the vast bulk of AVP's claimed benefit for WRL-VNI in substituting it in NSW has no plausible foundation.

6.2 REZ Zone transmission avoidance benefits are not legitimate

Paragraph 28 of the RIT states "Appropriate market development modelling will determine which modelled project to include in a given state of the world". Section 4.3.2 of the Guidelines, requires the base case (Base Case)to be "business as usual with no significant investment" to be consistent with NER clause 5.15A.3(b)(1) and RIT paragraph 7.

These rules are required to accurately determine the economic timing of future transmission projects as they can significantly influence market benefits. These regulatory requirements prevent "locking in" future REZ transmission augmentations that may be avoided/delayed by any VNI West option.

However, the end of section 8.2 on page 73 of the VNI West PADR states "in this RIT-T assessment, other major transmission projects identified in the ISP optimal development path are assumed to be developed in all 'states of the world', including the counterfactual." These forced multi-$billion REZ transmission investments distort the generation development program and dispatch by erroneously making it economic to develop REZ's with higher wind/solar resources and higher energy production but otherwise having higher REZ transmission costs. As the REZ transmission has been forced, it would be impossible to avoid/defer any of this future REZ transmission. Page 26 of the E&Y report for the PADR reveals that the $204m PV market benefit savings from "avoiding/deferring REZ transmission" has been calculated for every REZ where new generation exceeds its initial transmission limits using incremental REZ transmission costs in $/MW of REZ modelled generation. These limits are set artificially low for Gippsland REZ and its $/MW transmission price is set artificially high to effectively block the development of the Gippsland REZ which results in Victoria depending on the REZ's along VNI West and in other states. Together with the forced transmission in other states in the PADR, this generates the imaginary savings in REZ transmission credited to VNI West in the PADR of $204m PV. This is further discussed in section 5.4 below for the Consultation Report.

6.3 The fuel cost saving benefit is not plausible

Section 0 above explains how the forced REZ development program in the Consultation Report generates very high spillages of renewable energy in Victoria. This wastage of hydro-electric, wind power and solar renewable energy must be replaced by installing even more renewables or running the fossil fuelled generation harder, although it has already been closed down, except for the growing amounts of OCGT's. The increasing interconnector congestion and constraints require all Victorian OCGT's to operate at over 1,000 hours a year some 100 times their current hours of operation. This is what causes the growth in fuel costs progressively though-out the study period and exponentially during the 2040's in both Option 5 and the flawed counterfactual. The OCGT fuel costs in VIC exceed 50% of Victoria's current expenditure on fuel state-wide and the increased CO2 emissions is equivalent to putting all of VIC's cars back on the road for 1.5 years. Both clearly outrageous yet AEMO uses these studies to justify WRL/VNI West.

Had the Base Case been correctly modelled by allowing the efficient development of the Gippsland REZ, there would have been no spilled renewables and constrained interconnectors to Victoria, necessitating the very large expenditures on OCGT fuel costs that occurs in Option 5. It is considered that much of the $400m PV fuel cost savings that have been incorrectly credited to Option 5 up to 2039 are incorrect, and that all $800m PV credited during the 2040's should be disallowed. This would reduce the fuel cost savings attributed to Option 5 by more than $800m PV.

6.4 The claimed benefit of WRL-VNI deferring other transmission is not plausible

Section 4.3.2 of the RIT-T *Guidelines,* requires the base case (Base Case) to be "business as usual with no significant investment" to be consistent with NER clause 5.15A.3(b)(1) and *RIT* paragraph 7. This is to ensure that *VNI*'s benefits only relate to *VNI*, that they are correctly assessed compared with not implementing *VNI* and that benefits are not over-stated. It prevents crediting *VNI* with market benefits for avoiding/deferring any future ISP project such as QNI Connect or the New England REZ augmentation project. The market benefits from these significant investments and the timing of these investments must be justified from savings in generation/storage capital investment and fuel cost savings in the market modelling, and not incorrectly credited as a market benefit to *VNI*.

In the Consultation Report, the forced development of these very same future ODP projects has incorrectly and non-compliantly credited *VNI* with a $274m PV savings from REZ transmission deferrals**.** Paragraph 28 of the *RIT* states "Appropriate market development modelling will determine which modelled project to include in a given state of the world". Section 4.3.2 of the *Guidelines*, requires the base case (Base Case) to be "business as usual with no significant investment" to be consistent with NER clause 5.15A.3(b)(1) and *RIT* paragraph 7. These rules are required to ensure that the market development modelling is optimal by justifying any expenditure on future transmission projects (including REZ transmission) from the associated savings in generation/storage capital and fuel cost savings.

The end of section 8.2 on page 73 of the *Consultation Report* states "*in this RIT-T assessment, other major transmission projects identified in the ISP optimal development path (ODP) are assumed to be developed in all 'states of the world', including the counterfactual.*" This is equivalent to treating every project in the *ODP* as actionable projects, automatically developed at no cost, causing their benefits to be credited to *VNI*. This forced and free multi-$billion *ODP* investment would distort the generation development program and dispatch by erroneously making it economic to develop REZ's with higher wind/solar resources and higher energy production but ignoring the substantial REZ transmission investments required.

At the middle of page 21 of the PADR Submissions report attached to the Consultation Report, it states *"In the PADR locked-in transmission augmentations are made in line with the CBA Guidelines. Some future ISP projects are also locked in relevant scenarios in the base case and VNI West options, namely Queensland – New South Wales Interconnector (QNI) Connect and New England REZ Extension…The locked in projects are the same in each scenario's base case and with the VNI West options and there are no benefits associated with avoiding or deferring these. Other future projects including REZ transmission expansions are modelled as transmission options built at least-cost in accordance with the CBA Guidelines on "modelled projects*".

AEMO/TransGrid appear to have been caught-in-the-act by their apparent non-compliance in the PADR, and have substituted that with an even greater non-compliance in the Consultation Report by locking in $1,250m for QNI Connect in 2032/33 and $1,237m to augment the New England REZ transmission in 2035/36. The same regulatory obligations disallow locking in any future project and require them to be modelled outcomes in the market modelling. Despite giving implausible reasons for their ongoing non-compliance, it appears that non-compliantly and incorrectly forcing the development of renewables and REZ's in Queensland is essential to achieving their required outcome in the Consultation Report. The 33% larger market benefit from delaying/avoiding intra-regional transmission is testimony to the need to boost this imaginary and non-compliant savings to help justify the additional $600m from changing the WRL/VNI West connection point.

Section 8.3.2 on page 77 of the *PADR* states "New generation capacity is connected to locations in the network where it is most economical from a whole of system cost". However, the non-compliances in the Consultation Report of forcing the development of QNI Connect and the New England REZ Expansion in turn force the development of Queensland REZ's from 2035/36 onwards and increasingly during the 2040's that generates the savings in REZ transmission in NSW and Victoria that is then claimed to be a market benefit of Option 5 in the Consultation Report. The E&Y report claims VNI unlocks diverse VRE resources, however this is incorrect as that is caused by the massive forced investment in Bayswater and Queensland which have been non-compliantly and incorrectly modelled in the Consultation Report.

An examination of the E&Y spreadsheets reveals that the Consultation Report relies on Queensland for 99% of its $m274 PV REZ transmission savings yet still requires $3,121m to be invested in Queensland REZ transmission for Option 5. Clearly the $274m PV must be disallowed

6.5 The Terminal Value of WRL-VNI is not reasonably established

Clause 3.12 of the *Guidelines* requires the terminal value at the end of the modelling period" to represent a credible option's expected costs and benefits over the remaining years of its economic life after the modelling period". This is because the economic assessment must allow for costs and benefits during the remaining 31 years when there are substantial annual costs, and possibly ongoing benefits.

The terminal value in the PADR and the *Consultation Report* is illogical and non-compliant as it is "the undepreciated value of capital costs at the end of the analysis period", which in the Houston Kemp report is $1,736m ($347m PV). By comparison, the WRL Updated Cost Benefit Analysis assumed that beyond the modelling period, costs and benefits would neutralise each other, which is equivalent to having a terminal value of zero. The examination below of four material benefits in the *Consultation Report* indicates that VNI West's Terminal value would be negative rather than the $347m PV included in the Consultation Report.

a) Avoided REZ transmission capex. These benefits will not occur, for the reasons above.

b) Avoided and deferred investment in generation/storage is unlikely to continue beyond 2039 and certainly not beyond the study period for the reasons given in section 3 above. This is consistent with the transition to renewables being largely completed by 2032.

c) Fuel cost savings beyond the study period will not occur due to the reasons described above. This is consistent with the NEM reaching net zero carbon emissions with no burning of fossil fuels to underpin fuel cost savings after 2050. Assuming that the OCGT's would burn green hydrogen would require an investment of some $70bn to install an additional 50,000MW's of wind/solar power, associated transmission, 10,000MW of electrolysers and 100% hydrogen capable OCGTs

d) Savings in voluntary load curtailment would be immaterial for the reasons given above

We therefore conclude that there is no reason to include any part of the $347m PV Terminal Value of Option 5.

6.6 Unrealistic operation of Snowy 2.0 may have exaggerated the benefits of *VNI*

Ted Woodley submitted a report in December on his concerns with the exceptionally high annual capacity factors for Snowy 2.0 which may have exaggerated the *VNI* market benefits. His continual questions on this point have never been addressed. The ISP market modelling methodology report and the E&Y and H&K reports on *VNI* indicate the likely cause. The methodology report explains that the PHES operation is determined in the market development modelling phase which optimises the PV of capital costs, O&M and fuel costs only over the modelling period. This part of the model locates all NSW generation at the single Sydney Node. Likewise for all Victorian generation being located at the Melbourne node. This means that there are no transmission limits within NSW or Victoria when determining the Snowy 2.0 operation.

Yet in the next phase of the dispatch model, there is extreme transmission congestion in the REZ's along the interconnectors (see Appendix E). The assumed massive amounts of PV with no diversity chokes the interconnectors also immediately they are commissioned. As discussed in this section and in the appendices drives investment in OCGT's and PHES.

In the NEM in reality, PHES self-commits and is dispatched according to bid prices which rarely recover capital costs except during infrequent high-priced periods. This alone could explain the large disparity in capacity factors. The methodology report also explains that the chronological nature of demand, available storage and VRE variability are severely compromised to reduce computing time.

The required PHES storage duration is estimated from its "firm contribution factor" calculated from the duration of consecutive peak loads from the ESOO, with apparently no consideration of wind or solar droughts or variability. As only 2-day types are used to represent each month with only 8 dispatch intervals each day, and because forced outages are not modelled, the modelled operation of PHES including Snowy 2.0 is not a credible representation and can't be relied upon.

6.7 Overstatement of Savings in Voluntary Load Curtailment

The increasing amount of voluntary load curtailment appears to be caused by the extreme congestion on VNI combined with the extreme spillages of renewable energy at REZ's along VNI West and the deratings of the OCGT's assumed in the model to represent forced outages of the OCGT units. It is also clear that the amount of voluntary load curtailment would have been lower had a realistic Base Case been assumed based on developing the Gippsland REZ. For this reason, the market benefits attributed to Option 5 for a savings in voluntary load curtailment are not credible.

6.8 Double counting of benefits from Humelink

The "Take out one at a time" (TOOT) methodology that underpins the ISP's benefits calculations and the CBA assessments undertaken for the AER to justify cost blowouts of projects being implemented, double counts benefits from other actionable projects lying along the same development path. This is a major factor in exaggerating the benefits along the Melbourne to Sydney flow path comprising WRL, VNI West, Humelink, PEC and the Sydney Ring Southern option.

The TOOT methodology can be likened to attributing the value of a bicycle to each and every link in its bicycle chain (take out any link and the the chain and bicycle is rendered useless). On this, flawed, approach almost any expenditure can be justified. An example of this is Humelink's PACR, when in 2035/56, it was credited with a large part of the benefits of VNI. As soon as the final link in the chain, VNI West. is inserted in 2034/35 (being an "actionable ISP project"), the gross benefits of Humelink jumped $1,600m PV. Between this and gross understating of Humelink's annual operating costs at only 0.5% pa, Humelink net benefits of ~$500m would have been a net cost to customers of $2,200m PV thus dismally failing its RIT-T.

7 Appendix C: Additional details on storage benefit evaluation

This appendix presents additional charts to those referred to Appendix B to substantiate claims made in that appendix.

Figure 5. Difference in VIC average annual capacity (MW) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

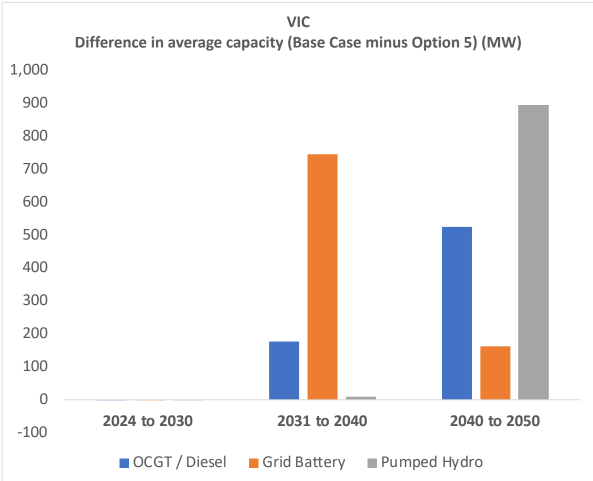


Figure 6. Difference in NSW average annual capacity (MW) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

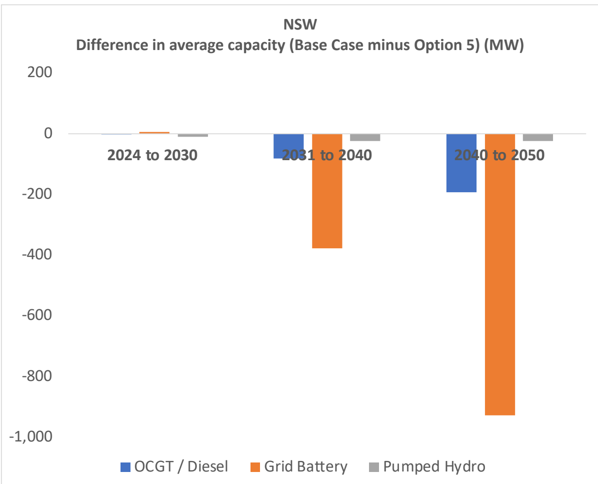


Figure 7. Difference in SA average annual capacity (MW) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

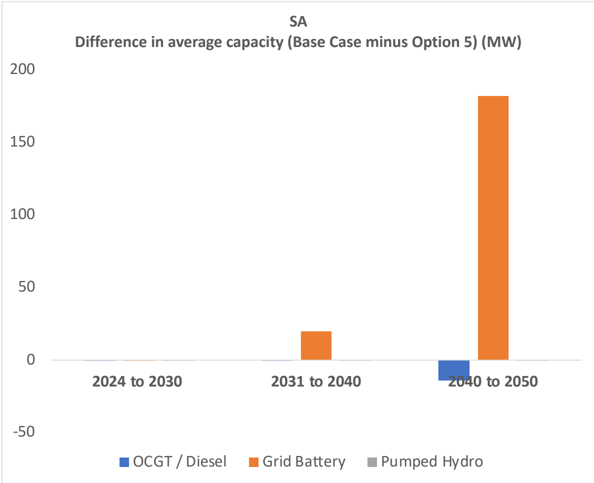


Figure 8. Difference in QLD average annual capacity (MW) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

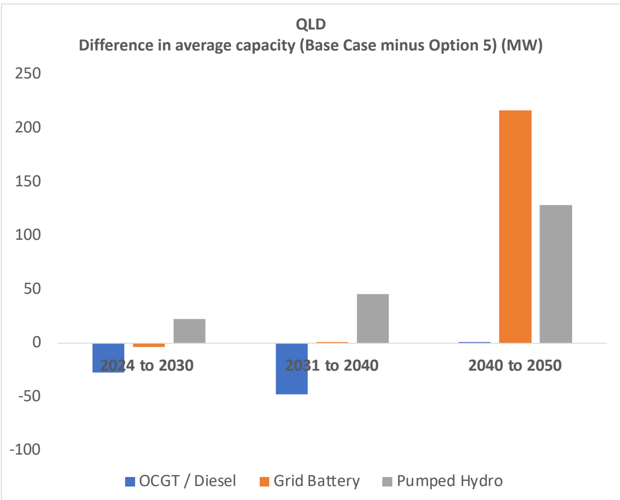


Figure 9. Difference in TAS average annual capacity (MW) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

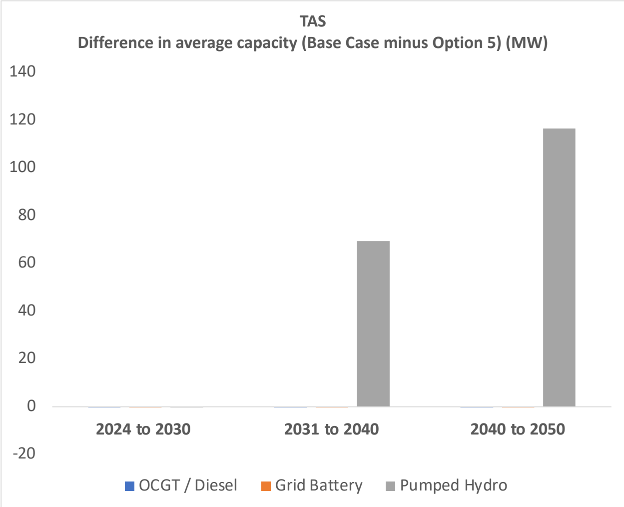


Figure 10. Difference in VIC+NSW average annual capacity (MW) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

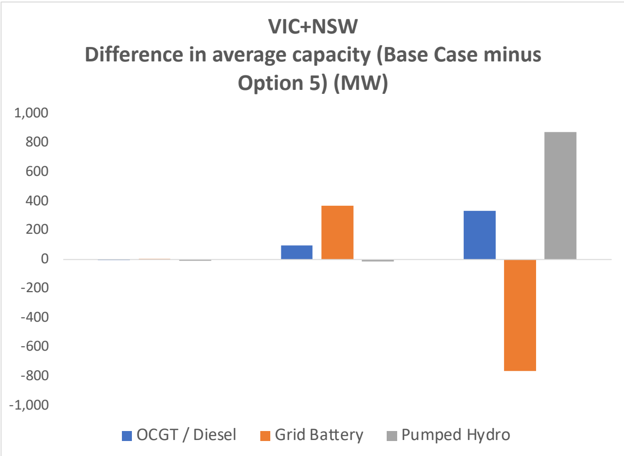


Figure 11. Difference in VIC+NSW average annual cost ($m/year) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

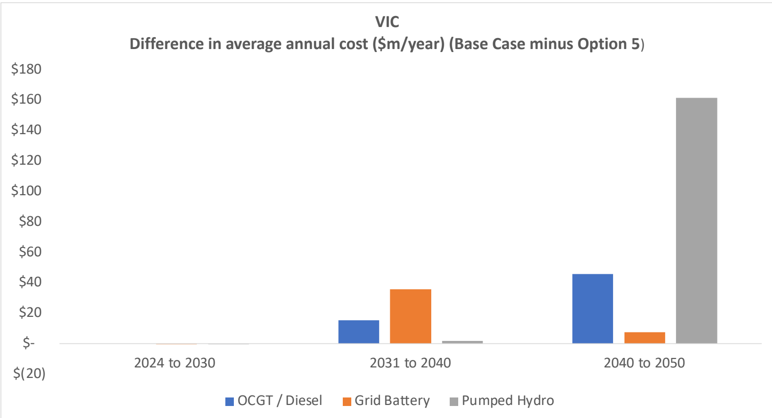


Figure 12. Difference in VIC+NSW average annual cost ($m/year) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050

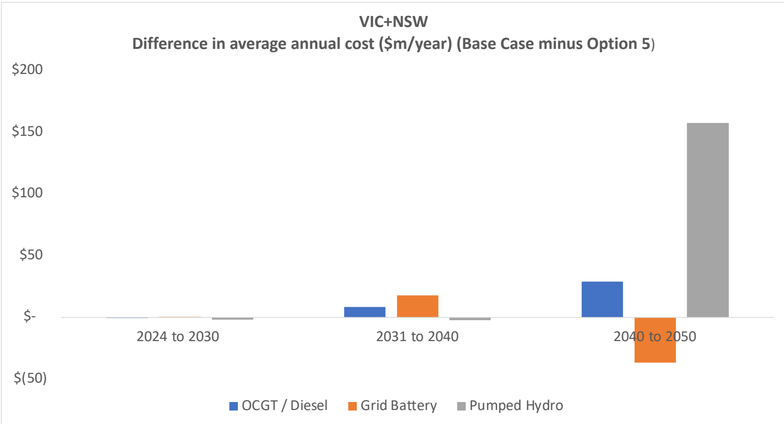
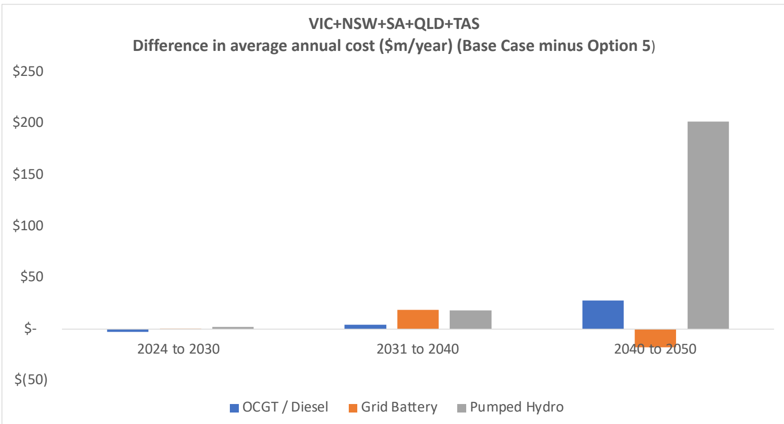


Figure 13. Difference in VIC+NSW+SA+QLD+TAS average annual cost ($m/year) in Base Case minus Option 5 for OCGT/Diesel, Grid Battery and Pumped Hydro 2024 to 2050



8 Appendix D: Quantification of the relative economics of variable renewable energy resources versus transmission

This appendix presents our analysis in support of our finding that inter-REZ zone differences in the productivity of wind and solar are much too small in VIC to justify the construction of WRL-VNI.

AEMO's analysis ostensibly seeks to account for the relative economics of production and transmission by adopting transmission expansion costs ($/MW) in each REZ zone that, prima facie, seek to do the same calculations that we are done here. However AEMO's analysis is ultimately a black box, and the relative economics of production and transmission are muddied by other "penalties" and transmission capacity constraints in AEMO's model. This is explained in more detail in Appendix E and F. As we have set out many times in this submission, such VRE constraints have no basis in fact and they bias the true relative economics of transmission and renewable electricity generation.

The analysis in this appendix presents a clear understanding of the relative economics of transmission and generation unpolluted by the imposition of other limits and constraints as AEMO has done.

Table 2 below presents the cost, life and cost of capital assumptions we have used. The cost assumptions come from the ISP's Inputs and Assumptions worksheets for 2030. These numbers are a little lower than now, but much higher (particularly for solar) than AEMO projects them to be by 2050. As renewable electricity production gets ever cheaper, so the value of VRE productivity relative to transmission costs (which do not decline) declines over time.

Table 2. Build cost, operating cost and cost of capital assumptions

	Capital cost ($'000/MW)	Fixed + variable operating cost ($/kW/year)	Economic life	Cost of capital	Source
Wind	1848	26.7	25	5.5%	ISP, Step change, 2030, Vic (medium) for Fixed O&M
Solar	968	18.14	25	5.5%	ISP, Step change, 2030, Vic (medium) for Fixed O&M

Table 3 shows the average annual capacity factor of wind in the seven VIC REZ zones. These data are drawn for the "medium" wind in the ISP Input and Assumptions worksheets. These numbers are turned into average annual production costs using the information in Table 2, which can then be expressed as an average annual cost per MW per year. In the table the average annual cost has been ranked from lowest to highest and in the second-last column the difference in the annual cost wind in each REZ zone is expressed relative to wind in the cheapest REZ zone. So, for example, the average cost of "medium" wind is $19,000 per MW per year higher in Gippsland than in South West VIC or $10,000 per MW per year higher in Western VIC than in South Western VIC. By deduction, the average cost of wind generation is $9,000 per MW per year higher in Gippsland than in Western VIC.

Table 3. The annual cost of wind in VIC REZ zones

Wind	Capacity factor	Average cost ($/MWh)	Average annual cost ($'000/MW/year)	Increase in average annual cost relative to cheapest REZ ($'000/MW/year)	Source
South West Victoria	39%	$ 40	$ 138	$ -	Capacity factor is 10 year average to 2021 for medium wind, in 2022 ISP Input and assumptions
Ovens Murray	37%	$ 42	$ 144	$ 6	
Western Victoria	36%	$ 43	$ 148	$ 10	
Gippsland	34%	$ 46	$ 156	$ 19	
Central North Vic	31%	$ 51	$ 173	$ 35	
Murray River	30%	$ 53	$ 181	$ 43	
		$ 46	$ 157	$ 19	

Table 4 presents the same information as
Table 3 but this time for solar. Here we can see that the difference in solar productivity between Western VIC and Gippsland means that the average cost of producing electricity from solar resources is $12,000 per MW per year higher in Gippsland compared to Western VIC.

Table 4. The annual cost of large scale PV in Vic REZ zones

Solar	Capacity factor	Average cost ($/MWh)	Average annual cost ($'000/MW/year)	Increase in average annual cost relative to cheapest REZ ($'000/MW/year)	Source
Murray River	27%	$ 30	$ 72	0	Capacity factor is 10 year average to 2021 for Solar PV, in 2022 ISP Input and assumptions
Central North Vic	26%	$ 32	$ 77	$ 5	
Ovens Murray	24%	$ 35	$ 83	$ 11	
Western Victoria	23%	$ 36	$ 86	$ 14	
South West Victoria	21%	$ 39	$ 94	$ 22	
Gippsland	20%	$ 41	$ 98	$ 26	

How do these VRE production cost differences compare to transmission costs, or specifically to the cost of WRL-VNI? To estimate this we use our estimate of the capitalised build cost plus operations and maintenance cost, as set out in Appendix A, and AEMO's claim of WRL-VNI hosting capacity. Using a 50 year asset life and 5.5% cost of capital, these are then turned into annualised charges needed to recover the cost of construction, operations and maintenance as shown in Table 5 below. The last row shows this to be $136,000 per MW per year.

Table 5. The annual cost per MW of WRL-VNI

		Source
VRE Hosting capacity (MW)	3410	VNI and WRL. AEMO report
Construction cost ($m)	**4502**	Our estimate
Cost per MW of additional hosting capacity ($m/MW)	1.32	Calculated
Annualised value of construction cost ($m/MW/year)	$ 0.08	Calculated
Fixed + variable O&M per year (% of build cost)	3%	Our estimate
Fixed + variable O&M ($m/MW/year)	$ 0.04	Calculated
Annualised cost (construction, operation and maintenance) ($'000/MW/year)	$ 118	Calculated

Comparing the transmission cost information in Table 5 with the VRE production costs differences in

Table 4 and

Table 3, we can see that per MW of wind the cost saving of $9000 per MW per year of locating wind in Western VIC rather than Gippsland, will be offset $118,000/$9, 000 = 13 times by the much higher cost of WRL-VNI. With respect to solar PV, the difference will be $118,000/$12,000 = 10 times.

Of course this analysis ignores "Rez zone" (i.e. intra-regional) developments costs and it ignores connection costs. It might be that once these are considered the relative advantage of Gippsland to Western Vic might diminish (or it might increase). With such a big advantage for Gippsland relative to Western Victoria, Gippsland's "REZ-zone" transmission costs would have to be extraordinarily large relative to those in Western Vic to make it cheaper to develop wind and solar in Western Vic and incur the cost of WRL-VNI, than to develop wind and solar in Gippsland.

9 Appendix E: Renewables Hosting by VIC REZs, and Corresponding Spillage of Renewable Generation

Analysis of the E&Y spreadsheet for Option 5 shows how much new solar and wind-power is modelled to be installed in the six VIC REZ's and South-West NSW REZ for each year during the study period to 2047/48. The forecast installed capacities for each REZ have been compared with the "existing" REZ hosting capacity (CAP) from the ISP Data and Assumptions spreadsheet, plus the increased hosting capacities from table 1 of the *Consultation Report.*

The CAP limits the development of new renewables at each REZ, although it appears from the results that REZ's with high spillages of renewable energy are limited to their existing/committed capacity, or in the case of Western VIC, to its existing/committed capacity plus exactly 700MW. If the E&Y model considers installing more renewables than the CAP, it needs to justify any additional renewables capacity at the incremental transmission cost from the ISP. Note that 700MW is the ISP input data for the Western VIC transmission limit for new "High" wind power. It appears that only 700MW of additional "high" wind power could be economically justified through to 2036 even though the WRL upgraded to 500kV to Bulgana is claimed in the Consultation Report to increase the Western VIC REZ hosting capacity by 1460MW in 2027 and another 200MW in 2031. The cost of the upgraded WRL project is not stated in the Consultation Report but must be more than $1,052m being the $737m in the updated WRL assessment plus the $315m upgrading cost in the Consultation report. As only 700MW of additional wind power is actually installed, its incremental transmission cost is at least $1.5m/MW, well above its assumed $0.89m/MW in the ISP data and vastly greater that the $0.02m/MW being the actual cost of increasing the Gippsland REZ transmission capacity beyond its existing 9,450MW to 11,200MW by minor works. It appears that the only "high" wind power can be justified at Western VIC REZ up to the artificial 700MW transmission limit defined in the ISP data. No "medium" wind power is justified, because of its lower capacity factor (36% p.a. for "medium wind" compared with 41% p.a. for "high wind") even though the 500kV WRL to Bulgana had been commissioned in 2027 , 10 years earlier. Of course, WRL is not justified at a transmission cost of $1.5m/km when there is already more than 3,500MW of free, unused existing transmission capacity lying idle at Gippsland REZ.

These incremental costs are defined for successive tranches of transmission defined in ISP, and listed in the last column of Table 1 below. It is crucial that the existing REZ hosting capacities from the ISP are accurate, as it is essential that the unutilised existing hosting capacity is all used before investing in transmission for another REZ, otherwise unnecessary transmission augmentations will be forced to occur elsewhere, when no transmission investment is required at an existing REZ (such as Gippsland and South-West Vic).

Particular attention is paid to the Western VIC REZ where WRL Option 5 increases its hosting capacity by 1,460MW + 200MW; south-west NSW REZ where Option 5 provides an additional 900MW; and Murray River REZ where Option 5 bypasses Bendigo cutting its additional hosting capacity from 1,600MW to 850MW. The utilisation of the unused hosting capacity at Gippsland REZ and South West Vic REZ is crucial to the outcomes of the modelling for Option 5 and the ISP.

9.1 Existing Renewables Hosting Capacity of VIC REZ's

The hosting capacity of the existing transmission network servicing each REZ is critical information that is found in the data and assumptions file for the 2022 ISP in a spreadsheet tagged "build limits" which lists the maximum hosting capacities of the 6 VIC REZ's for their existing transmission networks, as summarised in Table 1 below. The combined limit is the limit due to the existing transmission network and that applies to the total installed capacity of wind and PV at the REZ (unless the wind or PV has been set to a lower figure or Nil.

In the case of V3 (Western Vic), the combined limit is 1,250MW, 684MW below its already installed/committed wind capacity and note 4 says that the 1,250MW includes the transmission capacity of WRL. That is the reason there are ~37% to 40% wind-power spills at V3 before WRL is completed (see Table 6).

V2 (Murray River) existing solar capacity is also well above its existing transmission capacity as is N5 (S-W NSW) and both have high PV spillages until PEC is commissioned. Columns 2 and 3 give the maximum amounts of renewables that could ultimately be developed in each REZ, although the split between wind and PV appears arbitrary. The transmission cost in the last column is the cost/ MW for the first tranche of additional transmission beyond its existing transmission network, except for V3 which is after WRL is completed. Details of AEMO's tranches of REZ transmission augmentation can be found in the ISP Data and Assumptions spreadsheet "REZ augmentation options" including a description of the required transmission assets, their TCD cost, the additional hosting capacity and the $m/MW transmission cost for each tranche.

Table 1: : ISP input data for each VIC REZ and south West NSW REZ

Notes: V3 assume WRL completed, V5 will increase as coal stations close

REZ	Max Wind (high)	Max Wind (medium)	Max Large solar PV	Combined limit	Existing /committed capacity	$m/MW transmission cost
V1 Ovens Murray	Nil	Nil	1,000MW	350MW	0MW	-
V2 Murray River	Nil	Nil	4,700MW	440MW	679MW PV*	1.08
V3 Western Vic	700MW	1,900MW	400MW	1,250MW	1,934 MW* wind	0.89
V4 Sth-West Vic	861MW	2,582MW	Nil	2,500MW	2,406MW wind	0.62
V5 Gippsland	500MW	1,500MW	500MW	2,000MW	0MW	0.57
V6 C-N VIC	400MW	1,200MW	1,700MW	650MW	402MW	0.80
N5 S-W NSW	1,100MW	3,200MW	3,200MW	550MW	1,501MW PV*	0.94

* Note: existing hosting capacity is already exceeded

The constraints for **Gippsland REZ** appear far too low, although they are extracted from the ISP 2022 data. Experienced power engineers know that the 500kV and 220kV transmission to the Latrobe Valley was "gold-plated" and built for further growth in its generation capacity. According to the VENCORP Vision 2030 report, the existing transmission network has a firm capacity of 9,450MW which can be increase quickly and cheaply to 11,200MW by minor works costing ~$36m in current prices. Currently it only services 4,425MW of coal fired capacity comprising Yallourn W (1,330MW), Loy Yang A (2,030MW) and Loy Yang B (1,065MW). These are maximum sent-out MW's after subtracting power needed to run power station auxiliaries. There are also the Jeeralang A and B OCGT power stations which are now 50 to 55 years old and whose sole purpose is to black-start the nearby power stations. and do not require access to the spare transmission capacity. Basslink may use 500MW but again is unlikely to be importing to

Victoria at its full capacity unless there are outages of the coal fired units. Likewise for Marinus link. In any case their (Basslink+Marinus Link) total combined import to VIC would be around 1,250MW for security reasons. The existing fossil fuel generators, Basslink or Marinus do not have firm access rights to the Latrobe Valley transmission and would usually bid higher than the zero price bids from renewable generators. So, if anything, the Gippsland renewables may have greater access to the VIC reference node at Thomastown than the other competing users. There is more than enough transmission capacity for both onshore renewables and offshore wind power as the Gippsland REZ transmission capacity can be increased beyond 11,200MW to 17,620MW by constructing two additional 500kv circuits on existing unused 500kV easements.

However the ISP has an initial transmission limit of only 2,000MW for the Gippsland REZ and notes that this will increase as more coal stations retire. Not only is the 2000 MW far below the "spare" capacity now, but by deducting the capacity of the coal generators and Tasmanian interconnectors, AEMO effectively confers a firm access right to the existing fossil-fuelled generators, to Basslink and to Marinus Link. Such rights do not exist in the National Electricity Law or the real market dispatch so AEMO's approach is unlawful.

This deserves special mention and so for easy of reference and access, these points are repeated in the stand-alone Appendix F.

Based on the combined limits, before penalties are invoked:

- V1 cannot install wind and its new PV capacity is limited to 350MW.
- V2 cannot install wind and its new PV capacity is limited to 440MW.
- V3 can install 1250MW (plus 1,460MW for Option 5) of additional renewables but new PV is capped to 400MW.
- V4 cannot install PV but can install up to 2500MW wind.
- V5 can install up to 500MW of PV and 2000MW of wind, without allowing for further coal closures. The wind limit is a hard limit and can not be exceeded in any circumstances
- V6 has a combined limit of 650MW.

- N5 in NSW can host up to 550MW but already has 1,501MW of PV installed or committed.

Up to these limits, the REZ transmission is free. To exceed these limits, additional REZ transmission is required, priced according to the last column of Table 1. V4 has the lowest incremental transmission cost and which is actually its tranche 2 option and bypasses tranche 1 at $m0.22/MW with an additional 2,000MW for $442m. V5 is next at $0.62m/km, based on building a single circuit 500kV transmission line from Mortlake to Moorabool to Sydenham at a cost of $930m to provide an additional 1,500MW of hosting capacity. The spreadsheets indicate it is needed by 2033/34 for Option 5, only 2 years after VNI West. V6 and V3 can be expanded beyond their combined limits, but must pay a transmission cost of $m0.8MW to $m0.89/MW respectively. V2 can only provide PV and has high transmission costs of $m1.08/MW. There is no information for V1 in the ISP spreadsheet.

The so called economic development of the optimal generation/storage plan is severely constrained by artificial and unrealistic limits and constraints, as well as apparently grossly incorrect incremental costs of REZ transmission.

9.2 Overall Cost of New Renewables at each REZ before and after existing hosting capacity is exceeded

Each REZ has different intensities of solar and wind resources as reflected by the annual capacity factors (a.c.f.) determined by AEMO for each REZ in the table below and listed as input data in the ISP data and assumption file under the spreadsheet page labelled “build limits”.. The capital cost of wind power is much higher than PV and the connection costs vary especially for V5 which should not require grid strengthening. The capital costs have been converted into $/MWh of energy generated using the 5.5% discount rate, economic lives of 30 years for PV and 25 years for wind power, and O&M costs from the ISP see second last column). The last column includes the additional transmission costs should the existing REZ hosting capacity be exceeded, according to the ISP data.

Table 2: Resource intensities, development costs and $/MWh energy costs for each REZ
Note: *existing hosting capacity is already exceeded, so use last column, **not exceeded

REZ	Wind a.c.f with no spills	PV a.c.f With no spills	$/kw wind	$/kw PV	Before existing hosting capacity is exceeded $/MWh	After existing hosting capacity is exceeded $/MWh
V1 Ovens Murray	37%	24%	2259	1724	Wind 60 PV 64	Wind ? PV ?
V2 Murray River	30%	27%	2259	1724	Wind 74 PV 57	Wind* 106/PV 89
V3 West VIC	36%	23%	2259	1724	Wind 61 PV 60	Wind 78/PV 89*
V4 Sth-West Vic	39%	21%	2230	1695	Wind 56 PV 72**	Wind 79 PV 89
V5 Gippsland	34%	20%	2096	1577	Wind 61 PV 72**	Wind 79 PV 100
V6 C-N VIC	31%	26%	2332	1791	Wind 73 PV 62**	Wind 101 PV 92

For REZ's still with unused hosting capacity, the comparative energy costs are those in the second last column. REZ's that have already exceeded their hosting capacities, i.e. V2 and V3, use the costs in the last column.

Note that these costs do not include the huge costs of WRL and VNI West , nor do they include the effect of spilled renewable energy due to network congestion, which would increase the costs by the percentage of spilled energy.

The highest spillage is at REZ's located on interconnectors (especially VNI West) as as its single 500kV transmission line has to service the REZ as well as interstate power exchanges. An exception is V5 which utilises the Latrobe Valley transmission with huge existing transmission capacity. Based on this comparison, the cheapest renewable energy source would be wind at V4 ($56/MWh, however there is only around 94MW available according to Table 1) followed by wind at V5 ($61/MWh which has been artificially constrained to only 500MW until 2028/29 and even then constrained to only 2,000MW). Wind at V1 ($60/MWh) has been prohibited. The existing PV hosting capacity at most REZ's is quite small, except for Gippsland REZ, however it appears to be restricted to nil MW's until 2039/40 when just 500MW is allowed.

9.3 Additional REZ Hosting Capacity with existing network and delivered by Option 5 (from Table 1 of the Consultation Report)

The existing hosting capacity for each REZ is given in Table 1 above and the additional REZ hosting due to Option 5 is given in Table 1 of the Consultation Report. Combining these amounts for each REZ gives the following total hosting capacities. The amounts of existing and committed renewables for each REZ has been assumed to be the amounts installed in the first year 2023/24 in Table 3 (from Option 5) Following is a summary of the hosting capacity for each REZ:

- V1 – Ovens Murray REZ – existing renewables nil. 350MW of additional hosting capacity (from Table 1), and maximum of 1,000MW if transmission expanded
- V2 – Murray River REZ – existing renewables 679MW exceeding existing hosting capacity of 440MW (Table1), Option 5 adds only 850MW taking its hosting capacity to 1,290MW in 2031/32. Note that the other options would have provided an additional 1,600MW, taking its total hosting capacity to 2,040MW by 2031/32. Maximum hosting capacity of 4,700MW PV but nil wind, following further transmission augmentations
- V3 – Western VIC REZ – existing hosting capacity 1,250MW but already has 1,934MW of wind power. Increases by 1,460MW to 2,710MW in 2027 (WRL), and another 200MW to 2,910MW in 2031 with Option 5. However, V3's maximum hosting capacity in the ISP is 1,900MW wind and 400MW PV. It appears from the Option 5 spreadsheets, that the maximum wind hosting capacity was increased to its existing wind capacity of 1935MW by exactly 700MW to 2,635MW for the ten years after WRL.
- V4 – South West VIC REZ – existing hosting capacity of 2500MW (Table 1), all wind power.
- V5 – Gippsland REZ – no existing renewables. Additional hosting capacity of 500MW PV and 2000MW wind, increasing as coal stations close (Table 1).

- V6 – Central-North Vic REZ – existing renewables 402MW with combined limit of 650MW and maximums of 1,200MW PV and 1,700MW PV.
- N6 - South Western NSW REZ – existing/committed renewables 1501MW (in 2024/25) with an existing hosting capacity of 650MW and maximums of 1,700MW wind and 1,700MW PV. N6 is not located in VIC and must compete with Snowy 2.0 and all NSW generation to access the low 1650MW import limit of VNI West.

The following questions arise:

1. Is the extra 900MW for N6 going to be used and how will it get to VIC ?
2. Does V3 really need 2,910MW of hosting capacity or is it mostly for existing wind power?
3. What are the implications of halving the 1600MW hosting capacity to V2 to 850MW?
4. What's going on in V4 with its use of the existing 500kV lines to Portland?
5. Why isn't V5 developed first as it has huge existing hosting capacity?
6. What other new transmission lines are required for Option 5 to expand the hosting capacity of REZ's?

These questions are answered through the following analysis that scrutinises the E&Y spreadsheets.

<u>Renewable Generation Capacity in VIC REZ's 2023/24, 2026/27, 2030/31 and 2047/48</u>

The modelled amounts of large solar (PV) and wind power for Option 5 for each REZ and each year can be found in the E&Y spreadsheet Option5_REZ_capacity for the Step Change Scenario. The amounts are listed in Table 3 below for 23/24 (i.e., existing and committed capacity), 2026/27 (just prior to WRL commissioning), 2030/31 (just prior to VNI West commissioning), 2039/40 (8 years after VNI West) and 2047/48 (another 8 year later and the last year of results). Note the results for 2048/49 and 2049/50 have been removed by AEMO but used to increase the benefits.

Table 3: Total Renewables installed at each VIC REZ for Option 5

REZ	V1 Ovens M	V2 Murray River	V3 West Vic	V4 S-W Vic	V5 Gippsland	V6 C-N Vic	Non REZ	Total
23/24 PV	0	679	0	0	0	402	1	1082
Wind	0	0	1934	2023	0	0	165	4122
TOTAL	**0 MW**	**679 MW**	**1934 MW**	**2023 MW**	**0 MW**	**402 MW**	**166 MW**	**5204 MW**
26/27 PV	0	679	0	0	0	402	1	1082
Wind	0	0	1935	2809	500	0	164	5408
TOTAL	**0 MW**	**679 MW**	**1935 MW**	**2809 MW**	**500 MW**	**402 MW**	**165 MW**	**6490 MW**
30/31 PV	0	679	0	0	0	402	1	1082
Wind	0	0	2635	2983	2000	362	163	8143
TOTAL	**0 MW**	**679 MW**	**2635 MW**	**2983 MW**	**2000 MW**	**764 MW**	**164 MW**	**9225 MW**
39/40 PV	633	1841	400	0	500	411	-1	3784
Wind	0	0	2797	4856	2000	686	145	10484
TOTAL	**633 MW**	**1841 MW**	**3197 MW**	**4856 MW**	**2500 MW**	**1097 MW**	**144 MW**	**14268 MW**
47/48 PV	1043	2369	1913	0	2474	1577	3	9379
Wind	0	0	3576	3781	2000	1600	57	11014
TOTAL	**1043 MW**	**2369 MW**	**5489 MW**	**3781 MW**	**4474 MW**	**3177 MW**	**60 MW**	**20393 MW**

Table 4 contains the total generating capacity in VIC for the same years for each technology. These totals were found in the spreadsheet tagged Option5_Capacity. There is no more large scale solar (PV) installed anywhere in VIC until VNI is commissioned, then V2 immediately jumps to 1,421MW (immediately 131MW above its Option 5 hosting limit) reaches 1,841MW by 2039/40 close to its 2,040MW hosting limit for all other options, and grows to 2,369MW by 2047/48. By 2039/40, PV is built in every REZ except V4 (where PV hosting is "blocked"). V2 is the clear PV leader however its $89/MWh PV cost is well above V5's $72/MWh had it been allowed to develop. Over the next 8 years to 2047/48, the total PV capacity almost triples to 9,379MW, with V5 leaping to first place in 2043/44 having its 500MW artificial CAP removed. V2 has built more 220kV transmission to Bendigo to regain most of the hosting capacity lost from Option 5 bypassing Bendigo.

Table 5: Total Victorian generating capacity by technology

	PV	Wind	PHES	Batteries	VPP	OCGTs	HYDRO	Coal/Gas	TOTAL
start	1082	4122	0	375	56	1900	2264	5320	15119
pre WRL	1082	5408	0	375	408	1900	2264	3870	15307
pre VNI	1082	8143	0	516	1224	1900	2264	1660	16789
2039/40	3784	10484	0	1187	3687	1915	2264	0	23320
2047/48	9379	11014	16	3399	5299	4101	2264	0	35471

VIC's wind capacity commences at 4122MW, increases 1286MW to a "pre WRL" total of 5408MW and another 2735MW to the "pre VNI West" total of 8143MW. This is followed by a growth of 2341MW to 2039/40 and only 530MW to 2047/48. There are wind CAPS to prevent wind in V1 and V2 and an artificial 500MW wind CAP in V5 from the start until 2028/29 when it is raised to 2000MW from 2030/31 onwards. This limits the pre-WRL wind growth to exactly 500MW at V5 with the remaining 786MW at V4. No growth occurs in V3 as it is already well over its CAP with 40% wind spills. The 2735MW growth between pre-WRL and pre-VNI West is led by V4 (exactly 1500MW from lifting its artificial CAP, V3 with exactly 700MW (?) more installed, V4 (174MW) and V3(362MW) being minor. Note that WRL provides 1460MW of additional hosting capacity yet only 700MW is used so far.

Over the next 8 years to 2039/40, the 2,341MW of wind comes from V4 (1,873MW), just exceeding its new 4,000MW cap from its new 500kV line and onto its next tranche of transmission, V5 (324MW), V6 (162MW) and non-REZ (-18MW). In the last 8 years the 530MW of additional wind is increased to 1693MW by 1075MW of premature retirements in V3 and 88MW of non-REZ wind (noting that wind farms are given a 30 year economic life). The 1693MW comes from V6 (914MW wind + 1166MW PV) and V3 (779MW wind + 1513MW PV), without moving the wind CAP at V5 (although its PV CAP is lifted allowing another 1974MW of PV. Another 500kV line is required at V3 and the third VNI interconnections, via Shepparton helps out V6.

Following is a discussion for each VIC REZ of its total forecast renewables capacity compared with its hosting capacity, and where there is a substantial deficit in hosting capacity, the likely new transmission capacity required to support each REZ, beyond Option 5 and its required timing.

- **V1: Ovens Murray REZ** along the existing VNI route has only 350MW of existing, unused hosting capacity. It requires 428MW in 2037/38, 633MW in 2039/40 and

1000MW in 2041/42. This may require an additional 330kV transmission line by 2039/40 between Dederang and Melbourne. There is no mention of a future transmission project for V1 in the 2022 ISP.

- **V2: Murray River REZ** from Bendigo to Kerang to Redcliffs is primarily a PV REZ. While PEC connects to Redcliffs, the ISP does advise the increase in V2's hosting capacity from PEC. VNI West options 1 to 4 increase its hosting capacity by 1,600MW, but Option 5 by only 850MW as it bypasses Bendigo. V2's existing 679MW of PV may already constrain its existing transmission network as the ISP only indicates 330MW of hosting capacity. The spreadsheet has V2 remaining at 679MW until VNI West is commissioned and immediately increases by around 850MW to 1500MW and remains at that level for the next 7 years. It increases by 350MW in 2039/40 and another 300MW in 2042/43, reaching 2369MW by 2047/48. This is similar to the additional 1600MW of V2 hosting capacity from all other VNI West options. It appears that the market modelling for Option 5 has 220kV transmission augmentations in 2039/40 and 2042/43 probably by building another 220kV line between Kerang and Bendigo and Bendigo to Ballarat. This is alluded to in the *Consultation Report* however its cost is not included in Option 5.
- **V3: West Vic REZ** runs from Ballarat to Horsham via Bulgana and its 1,934MW of existing wind-farms are serviced by constrained 220kV lines well over their 1,250MW hosting capacity, hence the 40% spills of REZ wind power. WRL (extended to Bulgana) is claimed to increase V3's hosting capacity by 1460MW to 2,710MW and VNI West's Option 5 by another 200MW, to 2,910 MW. However there is only an exact 700MW increase in V3's installed capacity to 2,635MW for ten years until 2036/37, still below the WRL new hosting capacity and not using the 200MW from VNI West. It seems that half of the additional 1,460MW of hosting capacity is used by the existing REZ wind power to ease the pain of the 40% spills and only 700MW is used to install additional VIC wind power. In 2041/42, a substantial transmission augmentation is required for V3 to increase its hosting capacity by 800MW in 2041/42 and 1,900MW by 2046/47. Option 5 also prematurely retires up to 400MW of wind power at V3, but rebuilds them a few years later. Increasing the REZ transmission capacity by 2041/42 could require the establishment of the Ballarat 500kV/220kV substation and another 500kV transmission line from Sydenham to Ballarat or Bulgana depending on the location of the new PV and windfarms. The option of a new double circuit 220kV

line from Murra Warra to Horsham to Bulgana as proposed in the ISP would only provide an additional 1000MW of hosting capacity. Additional 220kV connection lines and substations would also be required in the REZ to connect the new renewables to the 500/220kV substations.

- **V4: South-West Vic REZ** is along the existing 500kV network to Portland. Its hosting needs for Option 5 jump by 2,000MW to 4,973MW in 2032/33, peak at 5,399MW in 2039/40 and decline to 3,781MW by 2047/48. This is 2,900MW above V4's existing 2,500MW hosting capacity from its existing 500kV transmission network. The increased grid congestion and the importance of the 500kV network to the Portland smelter and the Heyward interconnection would demand reinforcing the 500 kV network. The first tranche augmentation for V4 in the ISP is to build a 500kV transmission line from Mortlake to Moorabool to Sydenham to provide an additional 1,500MW of transmission capacity to V4, so a double circuit 500kV line might be required by 2033/34 just 2 years after VNI West. However, the 20% decline in V4's hosting capacity by 2047/48, due to the premature retirement of 1,075MW of wind power would push up transmission charges still further due to its lower utilisation.
- **V5: Gippsland REZ** along the existing 220kV and 500kV network from the Latrobe Valley is believed to have more than 8,000MW capacity, and now only services 4,425MW of generation that Option 5 retires by 2032. As set out in Appendix F renewables hosting is capped in Option 5 and the ISP to 500MW of wind power and nil PV until 2029/30 when its wind cap is increased to only 2,000MW. This appears to have distorted the economic development of REZs in VIC and interstate and biased the optimal development program of the NEM towards long distance interconnections to other states where such large existing REZ's may not exist or may not be artificially capped.
- **V6: Central-North VIC REZ:** The V6 REZ around Shepparton already uses 400MW of its existing 650MW of hosting capacity. This increases to around 1,000MW by 2039/40 and jumps to 2,560MW in 2045/46 when Option 5 appears to assume that a third VNI 500kV interconnection would be built between north of Melbourne and Wagga Wagga via Shepparton.

9.4 Transmission constraints and spilled PV and wind generation

It is well known that the 220kV VIC network in Western VIC is heavily congested and that existing renewable generation is often constrained by AEMO. This often results in renewable energy being "spilled" at both PV and windfarms due to the transmission constraints. The results in the spreadsheets can be used to determine the predicted level of spilled generation at each REZ, for each year for PV and wind installed at each REZ.

Where HVAC interconnectors share the REZ transmission to REZ's, significant transmission congestion occurs, as the power flow from the REZ aligns with the direction of the interconnector power flow due to the NEM wide economic dispatch. This results in much greater transmission congestion and renewable energy spills for REZ's located on the interconnection path, which is the philosophy of the NEM network design for the ISP. The philosophy adopted overseas is to use separate HVDC interconnections to avoid this happening.

Following are the amounts of energy predicted to be spilled for PV and wind in the V3 Western VIC REZ to be serviced by the proposed HVAC interconnector comprising WRL, VNI West, Humelink and the Sydney Ring, and which share the single 500kV transmission line with PEC between Dinawan and Wagga Wagga. The results are expressed as the percentage of renewable energy forecast to be spilled expressed as a percentage of total energy generated in the V3 REZ for both PV and wind. The annual capacity factors of VIC OCGT's and hydro-electric spills is shown as they are correlated with the constrained interconnection and spilled renewable generation in VIC.

Table 6: Spillage of wind and PV at Western VIC REZ and increased operation of OCGT's due to Congestion

	2023/24	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**
Wind spill	37%	40%	39%	38%	6%	11%	8%	15%
PV spill	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OCGT annual capacity factor	0.1%	0.1%	0.2%	0.9%	0.5%	0.9%	0.6%	2.6%
OCGT MW	1900	1900	1900	1900	1900	1900	1900	1900

	2031/32	**2032/33**	**2033/34**	**2034/35**	**2035/36**	**2036/37**	**2037/38**	**2038/39**
Wind spill	0%	9%	10%	12%	6%	2%	13%	7%
PV spill	N/A	N/A	N/A	17%	15%	10%	27%	23%
OCGT annual capacity factor	0.4%	2.1%	2.6%	5.8%	2.8%	2.9%	4.7%	4.0%
OCGT MW	1900	1900	1730	1730	2278	2278	2355	2355
	2039/40	**2040/41**	**2041/42**	**2042/43**	**2043/44**	**2044/45**	**2045/46**	**2046/47**
Wind spill	12%	2%	13%	12%	16%	7%	5%	18%
PV spill	21%	25%	50%	23%	27%	22%	15%	35%
OCGT annual capacity factor	12.0%	10.2%	5.8%	7.7%	12.0%	5.9%	6.4%	9.0%
OCGT MW	1915	1915	1915	1821	2913	4685	4685	4685

The PV spills are two to five times the wind spills in percent. This is because there is almost no diversity between PV generation across the NEM resulting in high levels of network congestion across the transmission networks especially the interconnections.

A 25% PV spill means that the transmission network is congested for around 3 hours a day (i.e., 25% of 12 hours a day). Wind spillage is lower in percent because wind generation can occur throughout the day although most REZ's tend to have higher levels of wind generation overnight. A 12% wind spill means that the congested network is constraining wind for the equivalent of 3 hours a day (i.e. 0.12 * 24 hours). It's likely that these are the same 3 hours for PV and wind power.

The amount of PV in V3 increases substantially from 2041/42 onwards driving the record 50% spillage in PV being an average of 6 hours per day. The wind spillage ranges from ¼ to ½ of PV spillage.

9.5 What Additional Transmission may be required beyond Option 5?

The E&Y spreadsheet tag Option_REXTxcost shows the additional annual capitalised cost for the additional transmission investments that are required for each state. The annualised costs for VIC indicate that there are two REZ transmission investments; one being around $845m in 2033/34 (see (d) below) and the second being around $412m in 2045/46 (see (f) below). However, the cost of those augmentations is likely to be much higher and the above analysis has identified the following additional REZ transmission to each REZ that appear to be included following Option 5 in the market modelling:

a) Ovens Murray REZ: An additional 330kV transmission line by 2039/40 between Dederang and Melbourne.
b) Murray River REZ: augmentations in 2039/40 and 2042/43 possibly by building another 220kV line between Kerang and Bendigo and Bendigo to Ballarat. Or advance to 2039/40 a new double circuit line from Redcliffs to Wemen to Kerang.
c) Western Vic REZ: North Ballarat 500kV substation and another 500kV transmission line by 2041/42 from Sydenham to Ballarat or Bulgana; or a new 220kV line from Murra Warra to Horsham to Bulgana.
d) South West Vic REZ: a 500kV transmission line from Mortlake to Moorabool to Sydenham by 2033/34
e) Gippsland REZ: none required due to existing transmission network to the Latrobe Valley
f) Central-North Vic REZ: new 500kV transmission line and substation between the Shepparton area and Melbourne by 2045/46. This could be part of another VNI 500kV interconnection between north of Melbourne and Wagga Wagga passing through this REZ.
g) In addition to the above, all REZ's will require new 220kV lines and substations to connect to the new renewable generation in each REZ.

9.6 Answers to the six questions

9.6.1 Is the extra 900MW for N6 going to be used and how will it get to VIC?

Only an extra 346MW of PV is built in N6 between now and 2037/38. Then a very large amount of new PV is installed in N6 starting with 2,500MW between 2037 and 2039 which will choke the interconnection between Kerang and Wagga Wagga, during daylight hours. So, the extra 900MW of N6 hosting capacity will not be used however, the modelled explosion in N6 solar in Option 5 will render VNI useless in the daytime from 2037 onwards.

9.7 Does V3 really need an extra 1,460MW of hosting capacity from WRL or the additional 200MW from VNI West?

No. Artificial caps appears to have limited the use of the 1,460MW of additional V3 hosting capacity to develop exactly 700MW of new "High" wind power for the 10 years after WRL is completed. The remaining 760MW is used to benefit existing renewables at the REZ who are spilling some 40% of their generation due to congestion of the existing 220kV network. The additional 200MW from VNI West Option 5 is never used.

9.7.1 What are the implications of halving the 1600MW hosting capacity to V2 to 850MW.

This reduction is caused by Option 5 bypassing Bendigo. The 850MW is used immediately Option 5 is completed. The 1600MW is needed anyway and has been achieved by building another 220kV line between Kerang and Bendigo and Bendigo by 2039/40 or earlier. The ~$350m cost has not been included in the Option 5 analysis.

9.7.2 What's going on at V4 REZ with its use of the existing 500kV network?

V4 uses the existing 500kV network that supples the Portland smelter and interconnection to South Australia. It has around 2,500MW of existing renewables hosting capacity and exceeds that by 2033/34 and peaks at 5400MW in 2039/40. The favoured transmission augmentation is another 500kV transmission from Mortlake to Moorabool to Sydenham that makes 200MW irrelevant.

9.7.3 Why isn't V5 developed first as it has more than 9,000MW of existing transmission capacity?

This is examined in detail in Appendix F.

9.7.4 What other new transmission is required for Option 5 to expand the hosting capacity of REZ's?

(a) Dinawan to Gugga 500kV line in Option 5 in 2037/38
(b) Augmentations in 2039/40 and 2042/43 possibly by building another 220kV line between Kerang and Bendigo and Bendigo to Ballarat.
(c) another 500kV transmission line by 2041/42 from Sydenham to Ballarat or Bulgana; or a new 220kv line from Murra Warra to Horsham to Bulgana.
(d) another 500kV transmission from Mortlake to Moorabool to Sydenham
(e) An additional 330kV transmission line by 2039/40 between Dederang and Melbourne.
(f) new 500kV transmission line and substation between the Shepparton area and Melbourne by 2045/46.
(g) All renewables, large scale battery storage and OCGT's will require 220kV lines and substations expansions to connect to the transmission network

10 Appendix F: AEMO's undermining of the development of renewable energy in the Gippsland REZ

For ease of access and reference this appendix consolidates into one place, and expands upon, the evidence and argument on AEMO's undermining of the development of renewable energy in the Gippsland REZ.

Since 2020 the AEMO ISP, and as a consequence the AEMO/TransGrid Consultation Report, has been using grossly under-stated land areas for the Gippsland REZ to determine renewable energy potential. AEMO has applied penalties for renewable expansion above those levels. AEMO has also established ridiculously low transmission limits and applied penalties for transfers above that limit. This has been done in order to undermine the development of renewable energy in Gippsland.

10.1 The Latrobe Valley to Melbourne transmission limit

The 2002 VENCORP Planning Report "Optimising the Latrobe Valley transmission capability to Melbourne"[3] said that the existing 220kV transmission system could handle the 1,500MW output from Yallourn W, and that the 500kV transmission system has a firm transmission capability of 5,860MW. In total this is a capacity, measured at that time, of 7,360MW.

In that 2002 report, various options are evaluated to increase the capacity of the network, with estimated costs in the table below. The options increased the capacity of the 500kV network by between 1,540MW to 2,650MW at estimated costs of $m0.002/MW to $m0.027/MW in 2002 prices. The first two of these options were implemented increasing the 5,860MW transmission capacity by 1,540MW and 2,030MW to the current capacity of 9,450MW.

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[3] VENCorp 2002. "Optimising the Latrobe Valley to Melbourne Electricity Transmisison Capacity".

Option	Description	Additional MW capacity of the 500kV network	Estimated cost $m in 2002 prices	Incremental cost $m/MW
1	minor works	+1,540MW to 7,400MW	$2.6m	$m 0.002/MW
2	run 4th 500kV line at 500kV - Rowville option	2,030MW to 7890MW	$24m	$m 0.012/MW
3	Run 4th 500kV line at 500kV - Cranbourne option	2,030MW to 7890MW	$36m or $38m	$m0.019/MW
4	Build new 500kV line	2,650MW to 8,500MW	$71m	$m0.027/MW

A report prepared by VENCorp in November 2005 "Vision 2030" stated that at that time the networks were able to transfer 9,450MW from the Latrobe Valley to Melbourne. It said in addition that this capacity could be quickly and cheaply increased by Option 1 to 11,200MW for only $22m at 2005 prices and then by options 2 and 4 to 17,620MW by building two 500kV lines on existing vacant easements.

This is sufficient capacity to enable the Gippsland REZ alone with its good wind and solar resources onshore and offshore to produce enough renewable electricity to deliver Victoria's transition from coal to renewables without any need for WRL, VNI West or Marinus link. The Gippsland REZ, based on the existing Latrobe Valley transmission network, should therefore be the cornerstone for Victoria's transition to renewables.

Not only is it the highest capacity existing transmission network in Australia (and probably the Southern Hemisphere) but it is located on a radial from Melbourne so it avoids congesting the interconnectors to NSW and South Australia as well as becoming congested itself from renewables in central and northern Victoria and South-west NSW.

10.2 AEMO has undermined the Gippsland REZ through the imposition of build limits, transfer limits and penalties

The 2022 ISP Data and Assumptions spreadsheet (refer to tag "Build Limits") specifies a limit on the transmission capacity of the Gippsland REZ available for renewables as

500MW of high-quality wind power, 1,500MW of medium wind, and 500MW for PV with a combined transmission limit of 2,000MW.

These transmission limits are derived by AEMO with no consideration of the existing 9,450MW of transmission capacity available for use by all generators in the Gippsland REZ as well as Basslink, Marinuslink and offshore wind. If Gippsland renewables exceed any of these artificial transmission limits there is a transmission charge imposed of $570,000/MW of exceedance, despite there being 9,450MW of free transmission capacity that every generator and Basslink/Marinuslink is entitled to use. Yet, only the Gippsland renewables are constrained by artificial, much lower transmission limits above which huge imaginary transmission charges makes it uneconomic to exceed.

AEMO's specification of the area of land in the Gippsland REZ that is available for renewables also constrains renewables expansion in Gippsland. This land area is defined (by AEMO) to be only 4,947 km2 of which AEMO says only 5% is available for wind power and 1% is available for PV. The area shrinks to just 247 km2 for wind power and 49 km2 for PV.

Since wind power needs 24 ha/MW, only 1,030MW of wind power is possible before an artificial land use penalty of $250,000/MW or $10,416/ha applies for any additional wind power up to AEMO's hard limit of 2,000 MW. Since PV needs 2ha/MW, the maximum capacity of PV is 2,474 MW before it too is penalised $250,000/MW. The tiny land area limits the development of PV to 2,474 MW and wind power to 1030 MW beyond which a $250,000/MW land penalty applies.

In addition, AEMO applies a 2,000MW transmission limit for renewable generation only in the Gippsland REZ, beyond which a transmission cost of $570,000/MW applies. This charge may even commence at 500MW for PV. This is despite the 2005 VENCorp report having established that the Latrobe Valley has existing transmission capacity of 9,450MW and is able to be extended to more than 17,000MW cheaply and quickly by minor substation works and new 500 kV lines built on existing easements as discussed above.

During a consultation that we attended AEMO and EY claimed, without evidence, that there was a stability constraint on Latrobe Valley to Melbourne transfer. Our investigations have not uncovered a stability limitation that would explain the low transmission capacities only applicable to renewables located in the Gippsland REZ in the ISP and in the Consultation Report. AEMO also explained that the tiny land use area is necessary because of social licence issues in the Gippsland REZ, however the Gippsland REZ covers a very large area.

The combined hosting and transmission penalty charges of $905,000/MW exceeds the capital cost of PV and is 48% of the cost of wind power. In this way, AEMO constrains the development of wind and solar in the Gippsland REZ to the artificial transmission limits and land areas it controls through the input data to the ISP used in the Consultation Report.

With such build limits, transfer limits and penalties it is now clear why the Gippsland REZ is not developed for renewables in the ISP and the Consultation Report despite having the strongest transmission network in the southern hemisphere, plenty of land, and good wind and solar resource.

11 Appendix G: Apparent non-compliances of VNI west Consultation Report with RIT-T instrument, NER clause 5.15 & 5.16 and AER Cost/Benefit Guidelines

In early January 2023, AEMO, TransGrid and the AER were advised of the 15 apparent non-compliances of the VNI West PADR and their proposed approach to the PACR with the RIT-T instrument, NEC Clauses 5.15 and 5.16 and the AER Cost Benefit guidelines. Set out in this appendix in black, is the report submitted to them three months ago. There have been no questions, responses or discussion of these serious allegations other than a Ministerial Order exempting WRL and VNI West from complying with these regulations and AEMO/TransGrid issuing the Consultation Report which attempts, but fails, to justify a few of these non-compliances and demonstrates that 12 of the 15 non-compliances remain in the Consultation Report.

Shown in red in this Appendix is the status of the 15 apparent non-compliances in the Consultation Report. This report was submitted to the AER in early March, to assist them to verify the apparent non-compliances and to include verified non-compliance on the AER Compliance Register for attention by AEMO and TransGrid in the PACR. It is included in this submission to AVP in the interests of public transparency.

11.1 The 15 apparent non-compliance and the 12 that remain in the Consultation Report

This appendix identified 15 apparent non-compliances and major errors with the VNI West PADR, the proposed approach to the PACR and other potential non-compliances. The estimated overstated net market benefits of VNI West could total **$1,715m PV**, resulting in a net cost of $830m PV for the Step Change scenario and around $700m PV for the scenario weighted net cost. This could be contrary to the National Electricity Objective and could significantly increase the electricity costs for NSW and Victorian electricity users. Section 4 below lists some major apparent flaws in the PADR that could invalidate the whole analysis.

The VNI- west Consultation Report still has 12 apparent non-compliances as summarised below. the estimated overstatement of net market benefits totals $2,188m PV for the step-change scenario as quantified below, not including the apparent non-compliances in sections 3 and 4. this would reduce the $1,842m PV net benefit in the Consultation Report to a net cost to customers of $346m PV.

In addition, the apparent non-compliances sections 10.4 ands 10.5 below have yet to be quantified and other inconsistencies, errors and omissions have been identified that will increase the net cost to consumers by at least $1bn taking the net cost to consumers to over $1,350m PV. Proceeding with VNI-West on that basis would be contrary to the National Electricity Objective as stated in the National Electricity Law (which AEMO and Transgrid must comply with despite the recent Ministerial Order).

11.2 VNI West PADR - Apparent Non-Compliances and Major Errors

a) **Omission of two new line exits and associated substation bays**: Paragraph 5 of the RIT defines costs as "the present value of the direct costs of a credible option". This is to ensure that the full cost of an option is included and that works required for the project but provided in another project are included. The costs of the two new 500kV line exits and associated 500kV substation bays at North Ballarat substation, necessary for VNI West, do not appear to be included in the VNI scope on page 54 of the VNI West PADR.

CORRECTED IN CONSULTATION REPORT

b) **Major uncertainty in transmission line cost estimates:** Paragraph 6 of the RIT states that "if there is a material degree of uncertainty in the costs of a credible option, the RIT–T proponent must calculate the expected cost of the option under a range of different reasonable cost assumptions. This is to include in the cost estimate, an appropriate allowance for the risk of increased costs due to major uncertainty. Page 104 of the VNI West PADR states that "transmission line costs are highly dependent on site-specific matters" yet the route for VNI West is yet to be identified. Uncertainties with the government requirement to purchase Australian made components, social licence, contractor competition, cost of components, labour shortages, COVID impacts and the impacts of Clough administration on PEC increases the risk to VNI West's costs.

NOT ADDRESSED IN CONSULTATION REPORT. THE VICTORIAN CAPITAL COST ESTIMATES HAVE NOT INCLUDED THE 40% RISK ALLOWANCE ON TOP OF THE TCD COST ESTIMATES THAT AEMO INCLUDED IN TABLE 3 OF THE UPDATED WRL COST-BENEFIT ASSESSMENT IN NOVEMBER 2022. THE ESTIMATED COSTS/KM OF 500kV TRANSMISSION LINE IN NSW ARE 40% HIGHER THAN THE COSTS IN VICTORIA. THIS OMISSION <u>UNDERSTATES THE COST OF VNI WEST BY $366M PV.</u>

c) Market Benefits from avoiding/deferring other transmission investments Section 4.3.2 of the Guidelines, requires the base case (Base Case)to be "business as usual with no significant investment" to be consistent with NER clause 5.15A.3(b)(1) and RIT paragraph 7. This is to ensure that VNI West benefits only relate to VNI West, that they are correctly assessed compared with not implementing VNI West and that benefits are not over-stated. It prevents crediting VNI West with market benefits for avoiding/deferring any future ISP project such as the Western Victorian REZ reinforcement project or future REZ investments, given the uncertainty of the need and timing of future transmission projects so far in the future.

CONSULTATION REPORT <u>STILL HAS THIS APPARENT NON-COMPLIANCE</u> – BUT THIS TIME IT HAS "LOCKED IN "QNI CONNECT AND THE FUTURE NEW ENGLAND REZ AUGMENTATIONS IN ALL STATES OF THE WORLD AT ISP TIMING RATHER THAN THESE INVESTMENTS BEING MODELLED PROJECTS AS REQUIRED IN THE RIT-T (SEE BELOW)

d) Forced development of intra-regional ODP and savings from REZ transmission deferrals. Paragraph 28 of the RIT states "Appropriate market development modelling will determine which modelled project to include in a given state of the world". Section 4.3.2 of the Guidelines, requires the base case (Base Case)to be "business as usual with no significant investment" to be consistent with NER clause 5.15A.3(b)(1) and RIT paragraph 7. These rules are required to accurately determine the economic timing of future transmission projects as they can significantly influence market benefits. These regulatory requirements prevent "locking in" future REZ transmission augmentations that may be avoided/delayed by any VNI West option. However, the end of section 8.2 on page 73 of the VNI West PADR states "in this RIT-T assessment, other major transmission projects identified in the ISP optimal development path are assumed to be developed in all 'states of the world', including the counterfactual." These forced multi-$billion REZ transmission investments would distort the generation development program and dispatch by erroneously making it economic to develop REZ's with higher wind/solar resources and higher energy production but otherwise having higher REZ transmission costs. As the REZ transmission has been forced, it would be impossible to avoid/defer any of this future REZ transmission. Page 26 of the E&Y report reveals that the $204m market benefit savings from "avoiding/deferring REZ transmission" has been calculated for every REZ where new generation occurs using incremental REZ transmission costs in $/MW of REZ modelled generation, however transmission is a "lumpy investment" that cannot be incrementally increased. It is this artificial $/MW REZ transmission cost that has erroneously and non-compliantly credited VNI West with a $204m PV market benefit from avoiding/deferring REZ transmission investments.

CONSULTATION REPORT CLAIMS IT HAS STOPPED THIS NON-COMPLIANCE, HOWEVER, IT NOW "LOCKS-IN" THE FUTURE PROJECTS QNI CONNECT ($1.25bn in 2032/33) AND THE NEW ENGLAND REZ TRANSMISSION AUGMENTATION ($1.237bn in 2035/36) APPARENTLY <u>ERRONEOUSLY AND NON-COMPLIANTLY CREDITING VNI WEST WITH A $274m PV MARKET BENEFIT</u>.

e) VNI West Operation and Maintenance cost (O&M): NER Clause 5.16.A.4(d) and clause 4.52 of the Guidelines, require the RIT-T proponent to quantify O&M costs for each credible option and to provide a breakdown of the O&M costs in the PADR. This is because O&M costs, at 3% p.a. of the capital cost, over the life-cycle of the transmission asset, total 150% of the investment over a 50-year life and have an PV of 50% of the investment

In the Consultation Report (*report)*, the table of responses to PADR questions on page 54 of the PADR Submissions Report states "AVP and TransGrid note that, while there is a requirement to quantify O&M costs under the paragraphs and clauses cited, there is no requirement to provide a breakdown of O&M costs under the RIT-T, including in either paragraph 5 of the RIT-T or NER Clause 5.15.A.3(b)(6)(ii), as suggested" AEMO and TransGrid go on to state "the RIT-T proponent is not required to separately quantify each class of cost'. However, their responses do not mention their apparent non-compliance with NER Clause 5.16.A.4.(d) or clause 5.52 of the Guidelines in both the PADR and the *report*, <u>which clearly require a breakdown of O&M costs to be provided in the PADR</u>. Moreover, AVP and TransGrid state in the introduction to the *report* that "As jurisdictional planners, AVP and TransGrid are responsible for undertaking the RIT-T, and the Australian Energy Regulator (AER) monitors and enforces compliance with the process." All stakeholder and the AER would expect AEMO and TransGrid to comply with all regulatory requirement and not leave it to the AER or stakeholders unfamiliar the complex rules and Guidelines to identify any non-compliances.

Significantly, in Appendix A1 of the VNI West PADR, AEMO and TransGrid state "This section sets out a compliance checklist which *demonstrates the compliance of this PADR with the requirements of **clause 5.16A.4(d)** of the National Electricity Rules version 180 and Table 14 of the CBA Guidelines.* Then goes on to state that clause 5.16A.4(d) "include a quantification of the costs, including a breakdown of operating and capital expenditure for each credible option". They go on to state that "RIT–T proponents are required to identify breaches of the CBA guidelines, if any, in their compliance reports and provide an explanation for the breach" and that they have complied with this Requirement. Yet this is clearly untrue. The response given by AEMO and TransGrid to stakeholder feedback on their non-compliances with the regulatory Requirements, appears to discredit the stakeholder wherever they can, however they clearly know them
obligations under clause 5.16A.4(d) and appear to have misled stakeholders and the AER in both the PADR and the Consultation Report about their known non-compliance with that clause and clause 5.52 of the Guidelines.

Paragraph 5 (Page 53 of the PADR states that the 'annual routine O&M costs are assumed to be 1% of capital costs of transmission assets, excluding easement costs and environmental offset costs.". There is no breakdown given of the O&M costs.

Section 2.5 of the PADR Submissions Report attached to the Consultation Report states" *AEMO reviewed recent revenue determinations, contingent project applications and RIT-Ts, and concluded that 1% was reasonable for ISP purposes as the cost of major projects in the ISP are dominated by transmission lines rather than substations. While the modelling applies operating expenditure (opex) costs consistently throughout the modelling horizon, opex costs are realistically expected to start low and grow as assets age. It is also noted that the Australian Energy Regulator (AER) will review and approve network expenditure from one revenue period to the next, so only the efficient and prudent project costs are expected to materialise*". However, the transmission line component of option 5 is \$597m (i.e., \$912m less \$315 WRL upgrade costs) and the substation component is \$639m (i.e., \$415m + \$164m for flow controllers and series compensators + \$60m for early works other costs being mostly for transformers, reactor etc). This means that for option 5, AEMO/TransGrid have incorrectly justified their 1% figure by stating that capital costs are dominated by transmission lines. It is known that substations have percentage operating costs more than double those of transmission lines and that electronic components of substation secondary systems, power flow controllers and series capacitors are many times that of transmission lines noting they must be replaced several times during the 50-year life of transmission lines. AEMO and TransGrid have now admitted that operating costs start low and grow as assets age. Under the RIT and NER, RIT-T proponents must quantify operating costs throughout the modelling period and also include the operating costs as the assets aged beyond the modelling period and must be refurbished and replaced, in their determination of the assets terminal value.

The 1% in the PADR and Consultation Report was stated to be only for routine maintenance of transmission lines when they are in new condition and do not include easement inspections to assess and manage fire risks and treat regrowth which are very substantial. No allowance is included for non-routine expenditure for ageing transmission assets beyond the modelling period when large expenditures are required to refurbish rusting steel on transmission assets and deteriorating insulation; to replace obsolete substation electronic equipment; and end of life replacement of substation plant, transformers and reactors. These non-routine costs would exceed routine transmission line maintenance by a large amount.

APPARENT NON-COMPLIANCE CONTINUES IN CONSULTATION REPORT. THE NOV 2022 AER TNSP BENCHMARKING REPORT HAS BEEN USED TO DEMONSTRATE THAT THE TOTAL ANNUAL COSTS OF ALL EASTERN STATE TNSP'S AVERAGED 3.3% PA OF THEIR UNDEPRECIATED ASSET VALUES OVER THE LAST 5 YEARS.

	Total Assets Cost $million	Operating Fund % p.a.	Capital Fund % p.a.	Overall Annual Cost % p.a.
Electranet	$4,760m	2.1% p.a.	3.0% p.a.	5.1% p.a.
Powerlink	$12,000m	1.8% p.a.	1.2% p.a.	3.0% p.a.
AusNet Services	$7,360m	1.2% p.a.	2.1% p.a.	3.3%p.a.
TasNetworks	$2,520m	1.2% p.a.	1.9% p.a.	3.1%p.a.
TransGrid	$11,400m	1.5% p.a.	2.0%p.a.	3.5%p.a.

BY ASSUMING ONLY 1% IN THE CONSULTATION REPORT INSTEAD OF SAY 3%, THE COST OF VNI WEST HAS BEEN UNDER-STATED BY $1,012M PV. NO BREAK-DOWN OF THE O&M IS GIVEN AND THE ONLY EXPLANATION IS GIVEN FOR THE 1% IS THAT THE PROJECT IS MOSTLY TRANSMISSION LINE (WHICH IS INCORRECT AS) AND THAT THE 1% HAS BEEN USED IN THE ISP, CPA's AND RECENT RIT'S WHICH MAY DAMAGE THE CREDIBILITY OF THOSE DOCUMENTS, ESPECIALLY HUMELINK WHICH ASSUMED 0.5%. THE FACT THAT THE AER ULTIMATELY APPROVES AEMO's and TRANSGRID's OPERATING COSTS IS OF LITTLE COMFORT TO ELECTRICITY USERS IF A GROSSLY INADEQUATE ALLOWANCE OF ONLY 1% HAS BEEN USED TO JUSTIFY AN UNDERSTATED INVESTMENT COST THAT WILL ALSO BE PASSED THOUGH WHEN THE AER ROLLS-IN THE ACTUAL CAPITAL EXPENDITURE ON THE ASSET.

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f) Determination of Terminal Value. Clause 3.12 of the RIT-T Application Guidelines requires the terminal value at the end of the modelling period" to represent a credible option's expected costs and benefits over the remaining years of its economic life after the modelling period". This is because the economic assessment must allow for costs and benefits during the remaining 33 years when there are substantial ongoing routine and non-routine O&M costs, and possibly ongoing benefits. However, the terminal value in the PADR is non-compliant as it is "the undepreciated value of capital costs at the end of the analysis period", which in the Houston Kemp report is $2,075m ($489m PV). The examination below of the three largest benefits in the PADR indicates that VNI West's market benefits beyond the modelling period are unlikely to exceed its O&M costs, hence its terminal value would be negative rather than the $489m PV included in the PADR:

i. Avoided REZ transmission capex. These benefits will not occur, even during the study period, due to the apparent non-compliances with the RIT, NER and Guidelines in 1(d) above.

ii. Avoided and deferred investment in generation/storage is likely to be a cost beyond the modelling period as this saving averaged -$42m p.a. over the final 7 years of the modelling period (refer H&K report, tag S1, line 131). This is consistent with the transition to renewables being largely completed by 2040.

iii. Fuel cost savings beyond 2050 could be minimal as the NEM would have reached net zero carbon emissions with no burning of fossil fuels to underpin fuel cost savings. The average $71m p.a. fuel cost savings in the final seven years (refer H&K report (tag S1, line 129) may be created by apparent non-compliances in the generation development program and market modelling (refer 3(c), 3(d) and 4(a)).

g) Even if there are some market benefits beyond the modelling period, they are unlikely to exceed the $2bn for routine and non-routine O&M costs of VNI West in 1(e) above with a $214m PV). The PADR is also non-compliant with Clause 4.3.9 of the Guidelines "Proponents to explain and justify the assumptions underpinning the approach to calculate the terminal value", to ensure transparency of key assumptions.

THIS APPARENT NON-COMPLIANCE CONTINUES IN THE CONSULTATION REPORT. THE USE OF "BREAK-EVEN POINT" IS NON-COMPLIANT AND MISLEADING GIVEN THAT THE TERMINAL VALUE OF VNI-WEST IS NEGATIVE (DUE TO ITS HIGH O&M COSTS AND THE MINIMAL BENEFITS BEYOND 2050). THE CONSULTATION REPORT HAS NON-COMPLIANTLY CREDITED VNI WEST WITH A RESIDUAL VALUE OF $1976M WITH AN PV OF $396M.

h) Cost underestimation Dinawan to Gugga Table 4 of section 6.1 of the VNI West PADR demonstrates that VNI West's cost has already been under-estimated by $289m ($146m PV) by using incorrect incremental costs to build PEC at 500kV instead of 330kV between Dinawan and Gugga. This incremental cost is included at just $182m being a federal government loan to TransGrid, whereas a more realistic cost would be $471m calculated from the data in Table 4, and $289m more than the federal government loan.

THIS UNDERESTIMATION CONTINUES IN THE CONSULTATION REPORT JUSTIFIED BY SAYING IT IS A CONTRACT OPTION NEGOTIATED FOR THE PEC CONTRACT. GIVEN THAT ONE OF THE PEC CO-VENTURE PARTNERS, CLOUGH ENGINEERING IS ALREADY IN ADMINISTRATION AND NO-ONE HAS COME FORWARD TO TAKE OVER CLOUGH's SHARE, AND THE OTHER PARTNER, ELECNOR HAS NEVER BUILT A TRANSMISSION LINE IN AUSTRALIA, IT IS UNLIKELY THAT THE CONTRACT OPTION WILL BE HONOURED. THE REAL ADDITIONAL COST BASED ON TRANSGRID'S RECENTLY PUBLISHED PRICES FOR 500kV AND ELECTRANET's PRICE FOR THEIR PEC 330kV TRANSMISSION LINE IS $471M BEING $289M MORE THAN THE $182M ALLOWED IN THE CONSULTATION REPORT PLUS $69M FOR THE 15 KM FROM WAGGA WAGGA TO GUGGA SUBSTATIONS

11.3 PACR Non-Compliances from Changing VNI/WRL Connection Point and Using Incremental Costs

a) Not meeting identified need. Paragraph 2(b) of the RIT requires actionable projects to meet the identified need set out in the ISP. Paragraph 2(c)(iii) of the RIT requires all new credible options to meet the identified need. This is to ensure that every option aligns with the holistic plan of the ISP and that the comparison of options isn't distorted by selecting lower cost options that don't comply. The identified need of VNI West technically requires VNI West to connect to the existing or anticipated 500kV network in Victoria, the nearest point being the anticipated North Ballarat substation. The new VNI West/WRL connection point is not part of the existing or anticipated 500kV transmission network, hence these options don't comply. This could reduce the VNI West cost by up to $810m ($414m PV), and bias the comparison of options.

THE CONSULTATION REPORT <u>CONTINUES</u> WITH THIS APPARENT NON-COMPLIANCE AND SAYS THAT TRANSGRID AND AVP DON'T AGREE BUT WITHOUT ANY EXPLANATION. THE REPORT CLAIMS THAT ITS "WRL+VNI WEST" ANALYSIS COVERS THIS POINT. HOWEVER, THAT ANALYSIS IS TOTALLY FLAWED BY ASSUMING A BASE CASE THAT ARTIFICIALLY BLOCKS THE DEVELOPMENT OF THE GIPPSLAND REZ WITH GOOD WIND AND SOLAR RESOURCES AND SUBSTANTIAL EXISTING 500KV NETWORK WITH GW's OF FREE AND SPARE HOSTING CAPACITY AS VICTORIA'S COAL FIRED STATIONS RETIRE.

b) Extending WRL is not an anticipated project. Paragraph 27 of the RIT states that the "RIT-T proponent must use the ISP…. to include anticipated projects in all relevant states of the world" This is to ensure that the correct scope and cost of anticipated projects are included for all options, aligns with the ISP, and with the PADR for that project. Section 5.3 of the 2022 ISP includes WRL as an anticipated project, and Appendix 5 defines WRL as "including the new 500kV/220kV terminal station north of Ballarat….as well as new 220kV lines from Bulgana through to North Ballarat.", being the preferred option in the WVRI PACR. Extending the 500kV part of the WRL project beyond Ballarat to different VNI West/WRL connection points increases the cost of WRL by different amounts which were not justified in the WVRI PADR.

THE CONSULTATION REPORT CLAIMS THAT WRL IS AN ANTICPATED PROJECT HOWEVER THAT IS NOT CORRECT FOR THE EXTENSION OF WRL TO BULGANA AT 500KV. <u>CONTINUES WITH THIS APPARENT NON-COMPLIANCE</u>

c) Extending WRL may not happen. The RIT glossary states that an anticipated project "must be in the process of meeting at least three of the five criteria for a committed project". This is to avoid assuming that projects are almost certain to proceed when there is a high risk that they won't, thereby invalidating the preferred option. An extension of WRL 500kV west from Ballarat is not in the process of meeting at least three of these criteria. There is a high risk that changing the 220kV VRL lines to 500kV lines and building a large new 500kV substation will destroy relationships with communities already alienated against WRL.

THE CONSULTATION REPORT CONTINUES WITH THIS APPARENT NON-COMPLIANCE. SINCE THE RELEASE OF THE CONSULTATION REPORT, COMMUNITY CONCERN HAS ESCALATED ALONG THE PROPOSED ROUTE FOR OPTION 5. AS WELL AS THE 50KMS OF NEW 220KV TRANSMISSION LINE BETWEEN THE NEW KERANG SUBSTATION AND THE EXISTING KERANG SUBSTATION COSTING AN ESTIMATED $70M

d) Re-apply RIT to VNI West Compliance with NER clause 5.16A.4(o) and 5.16A.4(n) would define a change to the option in the VNI West PADR as a material change in circumstances, requiring the RIT to be re-applied, unless otherwise determined by the AER. This is to ensure that the vital consultation processes and stakeholder input occurs given that they did not occur in the VNI West PSCR and PADR.

RESPONDED TO BY VICTORIAN GOVERNMENT ISSUING A MINISTERIAL ORDER EXEMPTING COMPLIANCE WITH CLAUSES 5.15 AND 5.16 OF THE NER OR HAVING TO RE-APPLY THE RIT-T TO VNI WEST. HOWEVER, PROCEEDING WITH VNI WEST MAY BE CONTRARY TO THE NEO

e) Re-apply RIT to WRL Compliance with NER clause 5.15.4 (Z4) and 5.15.4 (z3) defines a change to the option in the WVRI PADR as a material change in circumstances, requiring the RIT to be re-applied, unless otherwise determined by the AER. This is to ensure that the vital consultation processes and stakeholder input occurs given that they did not occur in the WVRI PSCR, PADR and PACR.

RESPONDED TO BY VICTORIAN GOVERNMENT ISSUING A MINISTERIAL ORDER EXEMPTING COMPLIANCE WITH CLAUSES 5.15 AND 5.16 OF THE NER OR HAVING TO RE-APPLY THE RIT-T TO WRL, HOWEVER PROCEEDING WITH WRL MAY BE CONTRARY TO THE NEO

f) Incremental costs. Paragraph 5(a) of the RIT and NER 5.15A.3 (b)(6)(i) state that costs in constructing each option must be included (not the incremental costs). Paragraph 5(b) of the RIT and NER 5.15A.3 (b) (6) (ii) likewise requires the cost of operating and maintaining each option to be included (not the incremental cost). Clause 4.3.4 on page 58 of the AER Cost/Benefit Guidelines, requires the present value of a credible option's direct costs (not incremental costs). This is to ensure that the full costs of each option are included and justified rather that under-stating the cost by using lower and incorrect incremental costs (see 1(g). If the cost of VNI West between Ballarat and Bulgana is similarly under-estimated to1(g), instead of full costs as required in the RIT and NER, the cost of VNI West could be under-estimated by $259m. ($131m PV).

THE CONSULTATION REPORT HAS <u>IGNORED THIS APPARENT NON-COMPLIANCE</u>, AND AS PREDICTED HAS UNDERSTATED THE INCREMENTAL COST OF UPGRADING THE BALLARAT TO BULGANA SECTION FROM 220KV TO 500KV BY <u>AT LEAST $106M</u> AS WELL NOT JUSTIFYING THE ADDITIONAL COSTS OF WRL BY RE-RUNNING ITS RIT-T.

11.4 Additional Potential Non-Compliances of VNI West PADR and PACR

a) Interconnector limits in the E&Y report appear too high (e.g., Dinawan to Gugga is modelled at 2,700MW/3,000MW whereas the VNI West limits in the PADR are stated as being 1,800MW/1930MW. This could incorrectly increase the benefits of VNI West.

THE CONSULTATION REPORT CLAIMS THIS IS CORRECT AS THERE IS A 330KM 330KV LINE IN PARALLEL TO THE 500KV LINE. HOWEVER, THE 2,700MW/3,000MW ARE THERMAL LIMITS RATHER THAN THE MUCH LOWER STABILITY LIMITS WHICH REQUIRE STABILITY STUDIES TO BE UNDERTAKEN AND THE LOWER LIMITS TO BE APPLIED IN THE MARKET BENEFIT STUDIES.

b) Economic Dispatch and Optimal generation development locations. Section 8.3.2 on page 77 of the PADR states "New generation capacity is connected to locations in the network where it is most economical from a whole of system cost". However, the non-compliances in 1(d) and potential error in 3(a) and 4(a) could lead to an incorrect generation development program where REZ's with higher wind/solar resources are incorrectly developed by forcing REZ transmission investments and optimistic transmission limits. The E&Y report claims VNI West unlocks diverse VRE resources, however this may be due to non-compliances. An overstatement of just 10% would be equivalent to $130m PV reduction in the net benefit of VNI West.

AS THE CONSULTATION REPORT <u>CONTINUES</u> WITH THE APPARENT NON-COMPLIANCE IN 1(d) AND 4(a), THE GENERATION DEVELOPMENT PROGRAM CONTINUES TO BE HEAVILY WEIGHTED TOWARDS OCGT's. THE ARTIFICIAL BLOCKING OF THE DEVELOPMENT OF THE GIPPSLAND REZ (WITH GOOD NEWABLE RESOURCES, NO RENEWABLES SPILLAGE AND HUGE EXISTING TRANSMISSION CAPACITY) HAS FORCED THE DEVELOPMENT OF OTHER REZ'S THAT REQUIRE COSTLY TRANSMISSION AUGMENTATIONS SUCH AS WRL AND VNI WEST. THESE TRANSMISSION LINES BECOME SEVERELY CONGESTED CAUSING VERY HIGH SPILLAGE OF RENEWABLE GENERATION AND SHORTAGES OF POWER AT THE MELBOURNE NODE

c) Fuel cost savings. Fuel cost savings could also be too high due to the additional energy being generated from REZ's with higher solar and wind resources and lower transmission losses due to the inclusion of all intrastate REZ transmission augmentations in all states of the world and transmission limits being too high. An overstatement of just 5% would be equivalent to $65m PV reduction in the net benefit of VNI West.

THE CONSULTATION REPORT IGNORES THIS COMMENT. THE SHORTAGES OF POWER AT THE MELBOURNE NODE COMBINED WITH THE EXCESSIVE AMOUNTS OF OCGT's AT THE MELBOURNE NODE, CAUSE GROSSLY

EXAGERATED FUEL COSTS THAT BECOME BIZARELY EXCESSIVE IN THE SECOND HALF OF THE MODELLING PERIOD. THIS HAS EXAGERATED FUEL COST SAVINGS BY MUCH MORE THAT THE 5% ESTIMATED ABOVE. THE SEVERE CONGESTION ON WRL AND VNI WEST IS OBVIOUS FROM THE SPILLAGES OF RENEWABLE GENERATION (WIND, PV AND HYDRO) WHICH FOR PV, AVERAGE 24% after VNI WEST IS COMMISSIONED AND REACH 50% IN 2041/42.

d) Capacity factor of Snowy 2.0 Stakeholders commented to AEMO that the capacity factor of Snowy 2.0 in the PADR is unrealistically high. Despite a main stated benefit of VNI West being "unlocking the full capacity of Snowy 2.0", there is no information in the PADR or the E&Y report on how Snowy 2.0 was modelled in the market modelling. The PADR states that Snowy 2.0 displaces gas turbines, yet paragraph 4(a) below indicates that the apparent non-compliance with paragraph 27 of the RIT may have significantly overestimated the capacity factor of OCGT's and hence Snowy 2.0. Even just a 5% reduction in the market benefits credited to VNI West for fuel savings would reduce the VNI benefits by $65m PV.

THE CONSULTATION REPORT <u>CONTINUES</u> WITH THIS APPARENT NON-COMPLIANCE AND DOES NOT EXPLAIN WHY THE SNOWY 2.0 ANNUAL CAPACITY FACTORS ARE SO HIGH. A SUBSEQUENT THEORY ON WHY THIS IS OCCURING WAS SUBMITTED TO TRANSGRID AND AEMO BUT THEY HAVE NOT RESPONDED TO THIS IN THE REPORT.

e) Including low interest government loans as a financial benefit to VNI West appears non-compliant with paragraph 5(a) of the RIT and NER 5.15A.3 (b)(6)(i) which define "costs as the present value of the direct costs of a credible option, where costs are incurred in constructing or providing the credible option;". Financing costs are not part of the definition of costs nor are they a compliant class of costs under the RIT and NER 5.15. Some loans are conditional on advancing VNI West completion to 2028 from the optimal 2031 determined in the 2022 ISP which could increase the net cost to customers by a further $150m PV.

THIS IS <u>NOT AN ISSUE</u> IN THE CONSULTATION REPORT – PLEASE IGNORE

11.5 Major Apparent Flaws in PADR that might invalidate the PADR and PACR

f) Market development modelling and VNI West market benefits. Paragraph 29 of the RIT states "Market development modelling must (for actionable ISP projects) or may (for other RIT–T projects) be adopted from the ISP, insofar as practicable." This is a key requirement to ensure that the generation development programs derived from the market modelling are on a least cost basis taking into consideration upfront capital costs and the PV of annual fuel and O&M costs over the infrastructure's full economic life. Page 74 of the 2021 ISP Methodology report states "For the ISP, capital investment for generation, storage and transmission infrastructure is converted into an equivalent annual annuity to allow like-for-like comparison of assets". However, section 8.2.1 of the PADR, indicates that capital investment is used instead of an equivalent annualised annuity "the market modelling finds that there are large amounts of avoided new generation and storage investments". Section 8.3.2 on page 78 of the PADR and "compare options" page of the E&Y workbook confirms that the market modelling only calculates the PV of annual fuel and O&M costs over the modelling period instead of the full economic life of the investment "The Long-term Investment Planning is determined such that……. The overall system cost spanning the whole outlook period is optimised". This apparent non-compliance could have a major financial impact, as the generation development program and fuel costs could be heavily biased towards low investment/high fuel cost OCGT's fuelled by expensive, CO2 emitting gas, towards the end of the modelling period. This aligns with the generation development plan for the final 7 years (see E&Y report for Step Change tags "option 1 generation" and "capacity") which has:

a. 2,373MW of modelled new OCGT's in final 7 years compared with 1,370 MW reduction in first 12.
b. including 683MW in Qld and 1,705MW in Victoria despite Victoria's roadmap to zero emissions
c. OCGT's average annual capacity factor increase from 7.9% to 12.3% (was 0.3% in first year)
d. increasing OCGT CO2 emissions by 7mtpa equivalent to putting 1.5million cars back on the roads

g) The high annual capacity factors for OCGT's could explain why Snowy 2.0 has such high-capacity factors noting that the PADR states that Snowy 2.0 displaces OCGT's. The increase in total energy generation from each technology over the final 7 years and the final 3 years is as follows:

Technology	2042 – 2048 final 7 years	2046-2048 final 3 years

OCGT's	97% increase	47% increase
Wind	23% increase	17% increase
Solar	25% increase	1% reduction
Batteries	4% increase	13% reduction
Pumped Storage	4% reduction	7% reduction

h) It appears that OCGT's are firming renewables rather than battery storage and pumped storage. This would be expected if the market modelling optimises the up-front capex plus the PV of fuel and O&M costs only over the modelling period. Although E&Y claim that "capital costs are annualised for modelling purposes, the OCGT costs included in the determination of market benefits of VNI West are calculated from changes in their capex and PV of opex and fuel costs only to 2047/48. Even if the market modelling is compliant, clause 4.3.9 of the RIT Application Guidelines requires a modelling period at least equal to the ISP (i.e., to 2049/50). Where the modelling period is shorter than the life of the credible option, any relevant terminal values must be included in the discounted cash flow and explained and justified. The VNI West PADR and PACR do not include any terminal values for modelled OCGT's, yet they are likely to be negative due to the high OCGT fuel costs beyond 2047/48. The over-statement of the market benefits credited to VNI for deferring investment in generation/storage and fuel cost savings, could be so large as to invalidate the VNI West PADR and PACR.

SOME OF THESE APPARENT NON-COMPLIANCES HAVE NOW BEEN RECTIFIED BUT NOT ALL. WHILST THE MODELLING PERIOD HAS BEEN EXTENDED TO 2049/50 IT IS STILL NOT EQUAL TO OR GREATER THAN THE ISP MODELLING PERIOD WHICH GOES TO 2050/51. STRANGELY, THE RESULTS FOR 2048/49 AND 2049/50 HAVE BEEN REMOVED FROM MOST OF THE E&Y SPREADSHEETS. IT IS NOTED THAT 2/3rds OF THE SAVINGS IN GENERATION/STORAGE COSTS AND FUEL COST SAVINGS ACCRUE FROM 2039/40, NINE YEARS AFTER VNI WEST IS COMMISSIONED. CLEARLY, THESE SAVINGS HAVE NOTHING TO DO WITH VNI'S IMPACTS BUT ARE CAUSED BY APPARENT NON-COMPLIANCES AND ERRORS EXPLAINED ABOVE AS WELL AS THE APPARENT BLOCKING OF RENEWABLE GENERATION DEVELOPMENTS IN THE GIPPSLAND REZ

i) No approximates of realistic bidding in market modelling Paragraph 22 of the RIT states that a "Reasonable scenario means a set of variables or parameters that may include 22(h) "generation bidding behaviour using: (i) short run marginal cost; and (ii) approximates of realistic bidding". The inclusion of approximates of realistic bidding is required to forecast realistic future wholesale electricity prices and to check whether investors in new generation/storage infrastructure would earn sufficient revenue from the market to provide a return of and on their investment to justify investing and inform retirement decisions in the model". The VNI West PADR uses only short-run marginal costs based on fuel costs and incremental O&M costs for all generation. This apparent non-compliance with RIT paragraph 22(h)(ii) would:

a. distort the optimal generation dispatch compared with using approximates of realistic bidding
b. grossly under-estimate future wholesale electricity prices given that short run marginal costs of renewable generation are assumed to be zero in the PADR and almost zero for energy storage
c. not provide investors with a return of their considerable investment or return on that investment
d. advance the modelled retirement dates of existing coal fired power stations

THIS APPARENT NON-COMPLIANCE <u>CONTINUES</u> IN THE CONSULTATION REPORT. IT IS BELIEVED TO HAVE ALSO OVER-ESTIMATED THE OPERATUION OF SNOWY 2.0. WHILST THE CONSULTATION REPORT CLAIMS TO HAVE ADOPTED THE SAME RETIREMENT DATES FOR EACH SCENARIO FOR THE BASE CASEAND OPTIONS, THE RETIREMENT DATES ARE TAKEN FROM THE ISP WHICH ADVANCED THE RETIREMENT DATES AHEAD OF THE DATES ADVISED BY THE OWNERS OF EACH POWER STATION. THIS APPEARS INCONSISTENT WITH THE *GUIDELINES* WHICH DO NOT ALLOW RETIREMENT DATES TO BE ADVANCED. THIS ADVANCEMENT HAS ARTIFICIALLY REDUCED THE CARBON BUDGETS AND ARTICIALLY CONSTRAINED THE OPTIMAL PLANT PROGRAMS SUBSTANTIALLY INCREASING THE GENERATION/STORAGE CAPITAL AND FUEL COST SAVINGS

12 Appendix H: Reliability and Security of Victoria's Electricity Supply with Option 5

The optimal transmission development path (*ODP*) in the *ISP* (combined with the Queensland Energy Plan) relies on a single, heavily-loaded, double-circuit 500kV AC transmission line for most of the backbone grid stretching 3,000km from Melbourne to Townsville.

VNI West, the Victorian element of that backbone, will have around 1,500 single transmission towers between Sydenham near Melbourne and Gugga in NSW, each being a single-point-of failure for the largest electricity supply, by far, to Victoria according to AEMO's projections.

The likelihood of severe lightning, destructive winds, fierce bushfires, widespread flooding, terrorism or even military attacks on Australia's critical infrastructure, will increase further as the climate changes.

AEMO forecasts VNI will operate for up to 2,900 hours a year by 2050 at its maximum import to Victoria. An instantaneous and/or pronged outage of both 500kV circuits on this transmission line would immediately interrupt Victoria's largest electricity supply, causing a state-wide blackout to Victoria with extensive electricity rationing until the damage is rectified.

We have additional subsidiary but nonetheless significant power system security concerns:

1. System restart requirements for each state may also have been overlooked in developing the *ODP*. These are essential facilities to restart their power systems following a complete state-wide blackout which is certain to occur by following the *ODP*.
2. The *consultation report* recommends routing VNI West even further west which increases VNI West/WRL's length by 146kms costing ~$600m and reducing its interconnector transmission limit to Victoria even further to below 1,475MW, except for the risky assumption of series compensation for only option 5.

3. Option 5 omits the new 500kV/220kV substations at Ballarat and Bendigo which will increase the constraints on the existing 220kV networks requiring the installation of 400MVAr of FACT's devices at the existing Kerang 220kV substation as well as new 220kV transmission lines to Bendigo only seven years after VNI West to "keep the lights on" in Bendigo.
4. No Sub-synchronous Resonance Studies (SSR) appear to have been undertaken by AEMO to prove the practicality of their proposed series compensation of option 5, despite this being an obvious threat to power system security and a mandatory requirement in parts of the United States. AEMO's last recommendation to install series compensation on the Heyward interconnection in 2013 has only delivered 90MW of the promised 190MW increased interconnector limit from South Australia to Victoria, yet AEMO is now assuming the Heyward interconnector limit will increase another 200MW (i.e. from 550MW to 750MW) as soon as Project Energy Connect is completed. This courageous assumption alone has serious ramifications for the reliability of electricity supply for Victorians. Progressing VNI West option 5 will significantly increase the risks of state-wide blackouts and extended electricity rationing in Victoria.

12.1 The ISP increases Victoria's power system security and reliability risks

12.1.1 A single heavily loaded 500 kV double-circuit HVAC transmission line massively increases risk through exposure to severe lightning, destructive winds, bushfires, flooding, terrorism and even military attack

The southern part of the Optimal Flow Path (*ODP*) developed by AEMO in their Integrated System Plan (*ISP*) includes a single 500kV, double-circuit high-voltage alternating-current (HVAC) transmission line supported by 2,500 towers along its entire 1,025 km route from Sydenham, Victoria to Barnaby, NSW. (*southern interconnection*). The *southern interconnection* weaves its way past Snowy 2.0 and through Victorian and NSW rural REZ's where the *ISP* installs excessive amounts of wind-power and PV. As these renewables and Snowy 2.0 also rely on the same HVAC interconnection, extreme congestion quickly develops especially during midday hours when all the PV generates simultaneously congesting the interconnector and spilling vast amounts of renewable energy at each REZ and the existing Snowy hydro-electric scheme along the existing VNI route.

The percentage of the year that VNI (i.e., VNI West combined with the existing VNI) is forecast to be operating congested at its maximum import capacity to Victoria is illustrated in figure 12 of the Consultation report as follows:

Figure 12 Flow duration curve – base case (top), Option 5 (centre) and Option 3A (bottom)

For option 5 using the horizontal line at the bottom of the middle figure, it starts at 4% (i.e., 100% - 96%) and rapidly increases to 33% (i.e., 100% - 67%) only 18 years after VNI West commissioning. Option 5 quickly becomes constrained, compared with option 3A, at full import to Victoria, reaching 33% (i.e., 2,900 hours a year only 18 years after option 5 is commissioned). The durations are much less for option 3A but still reach 21% (i.e., 100% - 79%). Although the durations are longer in the base case, the power flowing into Victoria across VNI is only 400MW which is a minor contingency that the Victorian power system would easily withstand. However, the instantaneous tripping of 2,000MW in option 5 (most of which is on VNI West), is so large to cause an immediate or cascading collapse of most of the Victorian power system. This may also collapse the South Australian and NSW power systems at the same time.

AEMO admitted at a Stakeholder presentation on 27rd March 2023 that their Consultation report has not modelled or investigated the implications to the security of electricity supply to Victoria, should there be an instantaneous or prolonged outage of both 500V circuits on WRL/VNI West.

That 500kV transmission line has around 1,500 single transmission towers between Sydenham and Gugga in NSW, each being a single-point-of failure for the largest electricity supply by far to Victoria. The likelihood of severe lightning, destructive winds, fierce bushfires, widespread flooding, terrorism or even military attacks on Australia's critical infrastructure, especially VNI West will increase further with climate change and growing social discontent and international discord. AEMO forecasts VNI will operate for up to 2,900 hours a year by 2050 at its maximum import to Victoria. An instantaneous and/or pronged outage of both 500kV circuits on this transmission line would immediately interrupt Victoria's largest electricity supply, causing a state-wide blackout to Victoria with extensive electricity rationing until the damage is rectified.

The ISP's power system security implications also apply to other states. In fact the ISP is forecasting extreme loadings on all interstate interconnections. The spreadsheets for the *ISP* include estimates of the annual energy imports and exports for each state that are summarised below. The very large increases in interstate electricity flows indicate large increases in the dependency of South Australia, Victoria and NSW on electricity generated in other states imported over new long-distance interconnections. In the case of Tasmania, an unexpected interruption to its very large exports to Victoria could black-out Tasmania. Following is a state-by-state commentary

1. **Tasmania:** Tasmania's net imports average of 229MW in 2023/24 which turns around the next year to a net export of 177MW in 2024/25, increasing to 1,370MW by 2032/33 and remains at those high levels. The immediate turnaround in 2024/25 is due to Tasmania's existing dams being almost emptied to support the mainland. The vulnerability of long undersea HVDC cables has already been demonstrated to Tasmania on at least two occasions. There may be risks to Tasmania following an unexpected instantaneous trip of such large exports

depending on the ability of the Tasmanian power system to "ride-though" the event. Depending on the failure, there could be extended rationing of electricity in Tasmania as its dams may already be depleted.

2. **South Australia:** Over the first five years, South Australia moves from exporting an average of 450MW to Victoria to importing the equivalent of 863MW for 60% of the time. Over the following decade this increases to importing an average of 918MW for 75% of the time. This is a large portion of the total South Australia demand. The sudden failure of either the Heyward or PEC interconnectors, could destabilise the South Australian network and a sustained interconnector outage may result in extended electricity rationing in South Australia. There have been recent long duration interconnector outages from extreme wind gusts collapsing multiple transmission towers in South Australia and Western Victoria.

3. **Victoria:** Victoria is forecast to quickly change from net exports averaging 621MW's in 2023/24 to importing the equivalent of 3,050MW for 80 % of the time by 2032/33 being half of Victoria's demand. This must substantially increase Victoria's risks of electricity supply blackouts and sustained electricity rationing. Its biggest risk is likely to be faults on the 1,000km 500kV single-tower transmission line between Barnaby, NSW and Melbourne tripping both 500kV circuits due to severe lightning, bush fires, tower collapse from destructive winds, or sabotage, possibly taking weeks to repair, or even longer in severe floods. This interconnector, not only carries the power imported from NSW, but also from extensive renewable generation from Western Victoria REZ and the Murray River REZ.

4. **NSW:** With the ISP's accelerated closure of coal-fired power stations, NSW immediately moves from having balanced exports and imports averaging around 700MW each way in 2023/24 to imports of around 1,400MW, 60% of the time in the next year and doubling to around 3,000MW import/exports five years later. These large power flows are primarily on the 850km single-tower 500kV transmission line between Bulgana, Victoria and Barnaby, NSW. In addition to the Victorian imports, the line between Dinawan and Sydney must also transmit power from Energy Connect, and the new renewables in South-Western NSW and to/from Snowy 2.0. The critical 175km section from Dinawan to Gugga must

transmit the combined imports/exports to NSW from both South Australia and Victoria, but has little 330kV network in parallel. AEMO is mistakenly rating this line section using thermal transmission limits. However, it's likely that its voltage stability limit or its oscillatory stability limit will be much lower. In any case, an unexpected outage of both circuits on this 500kV line would result in instability of the power system with black-outs like to occur in NSW, Victoria and South Australia. There is also the 730kms of single-tower 330kV interconnector from Dinawan to South Australia and the 600kms of single-tower 500kV interconnector from Dinawan to Melbourne. NSW's risks of blackouts and extended shortages of electricity supply will be much higher than in the past due to outages of both circuits on these single-tower, extremely long transmission lines due to severe lightning, bushfires, destructive winds which will increase with climate change or sabotage or war. Ground access to ascertain the damage and to undertake repairs may be impeded by the increasing flooding in NSW and Victoria. Reinforcing QNI and building a 500kV line from New England to Bayswater, will increase NSW's interconnection risks for power imported from Queensland or generated in northern NSW.

5. **Queensland:** The forecast electricity flows on QNI progressively increase over the next ten years to average flows of around 1,100MW in both directions. The QNI exports increase to around 1,500MW over the following 10 years as Queensland installs more generation than needed for its own needs, requiring a duplication of the existing QNI. While Queensland has the highest assumed load growth, it also has the highest proportions of wind and solar generation due to the ISP identifying higher solar and wind potential in central and north Queensland despite the very high costs of intrastate transmission augmentations to enable its development. In the *Consultation report* many of these Queensland augmentations appear to have been forced by TransGrid and AEMO non-compliantly and illogically treating the augmentations between Bayswater and Queensland as actionable projects that take place in all states of the world. This may be the reason for the ISP making Queensland the NEM's pumped storage capital with 6092MW built by 2050 although an apparent error in the ISP algorithm prematurely retired 802MW of that capacity. Fortunately, the 2022 ISP was unaware of Queensland's excellent PHES sites reserved 40 years ago. All of Queensland's 3,553MW's of existing gas fired power stations are retired during

the modelling period, and are not replaced until 2045/46 with 1,595 MW of new OCGT's. As the forecast QNI interconnector flows are a much smaller proportion of total load, the increased risks to power system security in Queensland may be lower than other states. However, the 2021 Callide B event tripped QNI when it surged to 1064MW north after starting at 334 MW south, due to cascading generator trips in central Queensland caused by the HVAC grid propagating both low and high voltages to power stations over 100kms away. The weakness of the NEM's current interconnections prevents that happening across state borders, however stronger 500kV interconnections may enable cascading events similar to those that blacked-out north-east USA and other countries to spread across the NEM. The 2024 ISP will aim to integrated the Queensland Energy Plan into the ISP which is also based a 1,700km single tower 500kV backbone with two massive pumped-storage schemes with high construction and operational risks, which itself will create severe reliability risk within Queensland.

12.2 Option 5 in the Consultation Report exacerbates Victoria's reliability risk

12.2.1 The additional length of Option 5 compared with all other options adds additional risk

The total length of WRL/VNI West in Victoria is approximately 275km (options 1, 1A and 2), 327km (option 3 and 3A), 410km (option 4) and 421km (option 5). The increased length for options 3/3A, 4 and 5 are 19%, 49% and 53% respectively, compared with options 1/1A/2. These much longer lengths would increase the impedance of WRL/VNI West in Victoria by the same amounts, causing more power to flow via the existing VNI than VNI West. This would reduce the combined VNI interconnection limits particularly for imports to Victoria. This is shown in Table 1 of the *Consultation Report* where the additional VNI capacity for imports to Victoria are much lower than the ~6,000MW thermal capacity of the two new 500kV circuits, being only 1,800MW for options 1, 1A and 2; reducing to 1,650MW for options 3 and 3A and diving to only 1,475MW for option 4. It would have been even lower for option 5, except for the unproven assumption that series compensation can be safely and successfully applied to option 5 to compensate for the extra 53% length of that option compared with options 1, 1A and 2.

In addition, as explained earlier the extra 146km length of WRL/WNI West for option 5 has resulted in VNI operating at its maximum import to Victoria for 2,900 hours a year by 2050 which increases Victoria's risk of black-outs and electricity rationing. This is due to the increased congestion on VNI West that also results in significantly increased spillage of renewable generation at Murray River REZ and Western Victoria REZ relying on VNI West and at the Victorian hydro schemes that rely on the existing VNI for transmission.

12.2.2 Series compensation for Option 5 adds additional risk

The *Consultation Report* acknowledges that additional power flow controllers would be required at Kerang 220kV along with series compensation of the 500kV line for option 5. No details are provided of the power flow controllers and series compensation nor is there an acknowledgement of the increase in risk and operational complexity of these FACT's devices.

Controllable series compensation would be required for both options 4 and 5 to compensate for the 49% and 53% increase in the reactance of the 500kV line in Victoria between Sydenham and the border. As WRL and option 5 are similar lengths, this could require 40% series compensation of both WRL and option 5. Some experts consider 40% series compensation to be a practical limit. Additional devices are also required in option 5 to reduce the power flow on the existing 220kV line between Kerang and Bendigo. The *Consultation Report* does not disclose the assumed amount of 500kV series compensation or where it would be installed. Nor does it disclose the proposed technology, amount, location and cost of the power flow control devices to limit power flow on the existing Kerang to Bendigo 220 kV line. No Sub-synchronous Resonance Studies (SSR) appear to have been undertaken by AEMO to prove the practicality of their proposed series compensation of option 5, despite this being an obvious threat to power system security and a mandatory requirement in parts of the United States There have been instances overseas where SSR's have resulted in fatigue failure of the main shaft between the generator and turbine causing catastrophic damage to the generating unit. This is particularly a risk where series compensation is used on HVAC transmission lines between generators with double wound induction generators now being installed on all 6 Snowy 2.0 units and normally used in large wind turbines generators such as those in Western Victoria REZ. The last time in Australia that series compensation was justified and implemented was the AEMO/ElectraNet PADR in 2013 to upgrade the Heyward interconnection by an additional 190MW in both directions. Despite years of system tests, it has only delivered an additional 90MW import to Victoria from South Australia from 460MW to 550MW (and even lower for some contingencies) despite the 7 years since its commissioning in 2016. Yet the *Consultation Report* assumes that this will increase to 750MW (from 550MW to 750MW) as soon as Project Energy Connect is operational and without doing anything to the Heyward interconnection.