APPARENT NON-COMPLIANCES OF VNI WEST PADR AND PACR WITH RIT-T INSTRUMENT, NER CLAUSE 5.15 & 5.16 AND AER COST BENEFIT GUIDELINES

Below are 15 apparent non-compliances and major errors with the VNI West PADR (*PADR*), the proposed approach to the PACR *(PACR*) and other potential non-compliances with the RIT-T instrument (RIT), NER clauses 15.5 and 15.6 (*NER*) and the AER Cost Benefit Guidelines for Actionable Projects (*Guidelines*). The estimated overstated net market benefits of VNI West (*VNI*) could total **$1,715m NPV**, resulting in a net cost of $830m NPV for the Step Change scenario and around $700m NPV 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

1. *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*, do not appear to be included in the *VNI* scope on page 54 of the *PADR*.

(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 *PADR* states that "transmission line costs are highly dependent on site-specific matters" yet the route for *VNI* 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's administration on PEC increases the risk to *VNI*'s costs.

(c) **Market Benefits from avoiding/deferring other transmission investments** Section 4.3.2 of the *Guidelines,* requires the base case (counterfactual) 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 the Western Victorian REZ reinforcement project or future REZ transmission investments, as these investments and the timing of these investments should be justified from savings in generation/storage capital investment and fuel cost savings in the market modelling, and not credited as a market benefit to *VNI*.

(d) Forced development of future ODP has incorrectly credited *VNI* with $204m savings from REZ transmission deferrals. Paragraph 28 of the *RIT* states "Appropriate market development modelling will determine which modelled project to include in a given state of the world". Section 4.3.2 of the *Guidelines*, requires the base case (counterfactual) to be "business as usual with no significant investment" to be consistent with NER clause 5.15A.3(b)(1) and *RIT* paragraph 7. These rules are required to ensure that the market development modelling is optimal by justifying any expenditure on future transmission projects (including REZ transmission) from the associated savings in generation/storage capital and fuel cost savings. However, the end of section 8.2 on page 73 of the *PADR* states "in this RIT-T assessment, other major transmission projects identified in the ISP optimal development path (*ODP)* are assumed to be developed in all 'states of the world', including the counterfactual." This is equivalent to treating every project in the *ODP* as actionable projects, automatically developed at no cost, causing their benefits to be credited to *VNI*. This forced and free multi-$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. This would exaggerate the savings in generation/storage investments and fuel cost savings credited to *VNI*. As the future REZ transmission investments have been forced, it would be illogical to then avoid/defer any of these future REZ transmission augmentations. Page 13 of the E&Y VNI Market Modelling report confirms that the long-term investment planning decisions only include generation/storage investments and generation dispatch and not investment and timing of REZ transmission augmentations and; that these decisions do not include consideration of REZ transmission costs. However, Page 26 of the E&Y report indicates that a REZ transmission expansion cost has been added, calculated from the amount of modelled generation added to each REZ multiplied by an incremental REZ transmission cost in $/MW. This would artificially credit *VNI* for savings from avoiding/deferring REZ transmission despite the modelling methodology including zero cost in determining the amount of generation/storage installed in each REZ. It is the forcing of the ODP at zero cost, combined with the artificial crediting of REZ transmission costs that has non-compliantly and incorrectly credited *VN*I with a **$204m NPV** market benefit from avoiding/deferring REZ transmission investments. In any case, the cost of REZ transmission is justified from savings in generation/storage capital investment and fuel savings for REZ's with higher solar/wind resources, hence any change in timing of REZ transmission investments cannot be credited to *VNI*.

(e) ***VNI* Operation and Maintenance cost (O&M):** Paragraph 5(b) of the *RIT*, NER Clause 5.15.A.3(b)(6)(11) and clause 5.22.5 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 only 1% of the capital cost, total 50% of the investment over a 50-year life and also increase substantially as the asset ages. Paragraph 5 on page 53 of the *PADR* states that the 'annual routine O&M costs are assumed to be 1% p.a. of capital costs of transmission assets, excluding easement costs". There is no breakdown or justification given of the O&M costs. The WRL PACR estimated its O&M costs at 3.5% p.a. and AusNet Services total operating expenses are 8% of its RAB. Table B.2 of the AER's 2022 Benchmarking 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 1% may be reasonable for routine O&M of transmission lines in good condition, routine substation O&M costs are typically 2% pa and routine easement inspections to assess and manage fire risks and treat regrowth are even higher. The *PADR* makes no allowance for non-routine expenditure for ageing transmission assets beyond the modelling period when substantial non-routine expenditure is required to refurbish and replace ageing assets. Non-routine costs could exceed routine O&M costs beyond the modelling period. Even at just 2% p.a. total O&M costs during the remaining 33 years could total $2bn ($214m NPV to 2021), and total $3.3bn NPV using the 3.3% pa derived from the 2022 AER Benchmarking report.
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(f) **Determination of Terminal Value.** 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 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 NPV). In 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 the three largest benefits in the *PADR* indicates that *VNI's* Terminal value may be negative rather than the $489m NPV included in the *PADR*:

(1) 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.
(2) Avoided and deferred investment in generation/storage is likely to be negative 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.
(3) 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 to 3 and 4 below). Assuming that the OCGT's would burn green hydrogen has been estimated to 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.

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, assuming just 2%pa, in 1(e) above with a $214m NPV). The *PADR* is also non-compliant with Clause 4.3.9 of the Guidelin**es "**Proponents to explain and justify the assumptions underpinning the approach to calculate the terminal value", to ensure transparency of key assumptions.

(g) **Cost underestimation Dinawan to Gugga** Table 4 of section 6.1 of the *PADR* demonstrates that *VNI's* cost has already been under-estimated by $289m **($146m NPV**) 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.

2. *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* technically requires *VNI* 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 NPV**), and bias the comparison of options.

(b) **Impact on WRL cost and net benefits** By changing the VNI West/WRL connection point to Bulgama, around 100kms of VNI West 500kV transmission line has been removed from VNI West as well as the new 500kV/220Kv Bulgama substation. Based on the $8.2m/km average cost of VNI West, this would reduce VNI West's cost by $810m ($414m NPV). Transferring the $810m to WRL and advancing the required investment by five years from 2031 to 2026, would increase the cost of WRL by $541m NPV less any savings from adjusting the 220kV scope of WRL. However, as the WRL PACR did not include these additional costs, and AEMO is reluctant to re-apply the RIT-T to WRL, **the VNI West $800m savings from changing the connection point appear to be removed from VNI West and hidden under the WRL PACR "pillow**".

(c) **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 WRL PACR. Extending the 500kV part of the WRL project beyond Ballarat to different *VNI*/WRL connection points increases the cost of WRL by different amounts which were not justified in the WRL PACR.

(d) 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**.**

(e) Re-apply RIT to *VNI:* Compliance with NER clause 5.16A.4(o) and 5.16A.4(n) would define a change to the option in the *PACR* as a material change in circumstances, requiring the RIT to b*e 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.*

(f) 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 WRL PACR 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 WRL PSCR, PADR and PACR. Also that the increase in WRL from changing the VNI West/WRL connection point in (b) above are considered in the WRL PACR

(g) **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 or annualised 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 *Guidelines,* requires the present value of a credible option's direct costs (not incremental costs or annualised costs). Paragraph 4 of the *RIT* requires "Any cost or market benefit that cannot be measured as a cost or market benefit to those who produce, consume and/or transport electricity in the market must not be included in any analysis under the RIT–T" . These regulatory requirements are to ensure that (a) the full cost of construction is used which can be measured and audited rather than theoretical, unmeasurable concepts such as incremental costs and annualised cost. (b) to avoid under-stating or over-stating the full construction costs. The next stages of the regulatory process (eg Contingent Project Application and then rolling the asset cost into the asset base) needs to be auditable and not arbitrary adjusted by incremental cost assumptions. Measuring incremental costs is impossible as it requires knowledge the actual cost of construction as well as the theoretical cost had the asset been built at a lower voltage. If the cost of *VNI* between Ballarat and Bulgana is similarly under-estimated to1(g), instead of using full construction costs as required in the *RIT and NE*R, its cost could be under-estimated by $259m. **($131m NPV**).

(h) **Increase TCD Cost Estimates by ~40% for adjustments and risks**: AEMO has advised that incremental costs will be estimated in the *PACR* by using the Transmission Cost Database *(TCD*). However, Table 3 of the WRL updated cost-benefit assessment required *TCD* cost estimates to be increased by approximately 40% to allow for adjustments and allowances for known and unknown risks. Failing to apply these contingency allowances could further underestimate the cost of *VNI* by a large amount.

3 Additional Potential Non-Compliances of *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). The increase in the *VNI* limits in the *PADR* are stated as being 1,800MW/1930MW and the power flowing on the 500kV *VNI* lines is likely to be higher due to its lower reactance. A recent AEMO report on the expected increase in South Australia's import/export limits post the completion of Project Energy Connect indicated that the South Australian interconnector limits in the *PADR* may be optimistic. There may be considerable issues with "loop flows" with the parallel operation of VNI, PEC, Heyward and the existing VNI. This could incorrectly increase the benefits of *VNI* compared with the benefits actually delivered.

(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), possibly optimistic interconnector limits in 3(a) and possible non-compliances in 4 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 there is excessive peaking plant operation (i.e. OCGT's and PHES) towards the end of the study period. The E&Y report claims VNI unlocks diverse VRE resources, however this is incorrect as it requires interstate investments in REZ transmission which has been non-compliantly and incorrectly modelled in 1(d). An overstatement of just 10% would be equivalent to **$130m NPV** reduction in the net benefit of *VNI.*

(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, lower transmission losses due to the forcing of the ODP, transmission limits being too high and the apparent dispatch non-compliances in 4. An overstatement of just 5% would be equivalent to **$65m NPV** reduction in the net benefit of *VNI*.

(d) Including low interest government loans as a financial benefit to *VNI* may be factored into the *PACR* due to the large loans being offered by the Federal and State governments. That would appear 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*. 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 NPV**.

4 Apparent non-compliances affecting long-term development plan and dispatch in *PADR and PACR*

(a) **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. 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 (refer 4(b)) which optimises the NPV of capital costs, O&M and fuel costs only over the modelling period. This could increase the operation of OCGT's and PHES which displace OCGT's. In the NEM, 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 could be significantly impacted. *RIT* paragraph 22 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 obtain realistic dispatch in the market modelling, especially for peaking plant (OCGT's and PHES) as well as realistic forecasts of future wholesale electricity prices and to check whether investors in new generation/storage infrastructure would earn a commercial return on their investment. The *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) could distort the optimal generation dispatch compared with using approximates of realistic bidding and overstate the annual capacity factor of Snowy 2.0. The PADR states that Snowy 2.0 displaces gas turbines, yet paragraph 4(b) 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 NPV**.

(b) **Unrealistic final assessments of benefits due to market development modelling and determination of 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 program derived from the market modelling are on a least cost basis taking into account upfront capital costs and the NPV of annual fuel and O&M costs over the <u>full economic life</u> of the modelled generation and storage investments. Page 74 of the 2021 ISP Methodology report states "For the ISP, capital investment for generation, storage and transmission infrastructure is converted into an <u>equivalent annual annuity</u> to allow like-for-like comparison of assets". However, section 8.2.1 and 8.3.2 of the *PADR*, and an analysis of the E&Y and H&K reports confirms that the optimal generation development program and *VNI* market benefits have been calculated from the NPV of the generation/storage up-front capital investments plus the NPV of O&M and fuel costs over only the modelling period with no allowances for terminal costs. This would bias the generation development program towards low investment/high fuel cost OCGT's fuelled by expensive, CO2 emitting gas, towards the end of the modelling period, with very high capacity factors. This is observed in the generation development plan, in the final 7 years (see E&Y report for Step Change "option 1 generation" and "capacity") which has:

a. 2,373MW increase in 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 increasing 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 NEM roads

The increase in total energy generation from each technology over the final 7 years indicates that OCGT's are firming renewables rather than battery storage and pumped storage, however it lacks credibility as this would require a 12.3% capacity factor, on average, for the OCGT's. Clause 4.3.9 of the *Guidelines* requires a modelling period at least equal to the ISP (i.e. to 2050/51) and when 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 *PADR* modelling period ends in 2047/48 and does not include or explain any terminal values for the new 2,373MW's of OCGT's, yet they could be large negative amounts due to their large and growing O&M and fuel costs beyond 2047/48 in a net zero carbon emissions world. These apparent non-compliances may have overstated the market benefits credited to *VNI* for deferring investment in generation/storage and fuel cost savings, to such an extent as to invalidate the *PADR and PACR*.

(c) **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 have realistic generation dispatch, forecast realistic future wholesale electricity prices and to check whether investors in new generation/storage infrastructure would earn sufficient revenue from the market to justify investing and to inform retirement decisions in the model". The *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 an adequate return of their considerable investment on generation/storage
d. advance the modelled retirement dates of existing coal fired power stations
e. exaggerate the operation of peaking plant (e.g. OCGT's and PHES)

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