VEPC submission to
The Australian Energy Market Operator's
2022 Draft Integrated System Plan

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Victoria Energy Policy Centre

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Executive summary

This document is the Victoria Energy Policy Centre's submission to the Australian Energy Market Operator (AEMO) on its Draft 2022 Integrated System Plan (ISP).

The Draft 2022 ISP continues a long-established philosophy within AEMO - generally supported by transmission network service providers - to expand interconnection between the National Electricity Market (NEM) regions. In the transition to renewable energy, AEMO has consistently advocated for stronger interconnection.

There may well be value in additional interconnection, but there are many competing alternatives, most of which can be built quickly and do not suffer as greatly from the high level of uncertainty that affects long-lived assets like transmission lines. In this context, the superiority of transmission must be convincing if it is to be preferred to its alternatives.

The three major interconnectors canvassed in the ISP are the Marinus Link sub-sea cables between Tasmania and Victoria ($3.5bn), the HumeLink lines between Snowy 2.0 and Sydney ($3.3bn, +50%/-30%) and the VNI-West interconnection between Victoria and New South Wales ($2.9bn). In this submission we do not comment on the approval of the $2.3bn EnergyConnect interconnector between South Australia and New South Wales which is now under construction, and which was subjected to a regulatory approval by the AER, a system of regulation that has since been replaced by AEMO's "actionable ISP" regime.

Taken together, these three proposed interconnectors and EnergyConnect will add $12bn to the regulated asset value of transmission in the NEM (and quite possibly significantly more if costs continue to escalate). The largest impact on the regulated transmission asset base (RAB) will be in NSW. In particular, assuming that NSW does not bear any of the cost of Marinus Link, but that it bears the majority of the cost of EnergyConnect, all of HumeLink and approximately half of VNI-West, the RAB of transmission assets in NSW (currently approximately $7bn) will almost double, and with it electricity transmission prices. The effect of this price increase on the bills of individual end-users in fractional terms will be most pronounced for larger end-users for whom transmission is proportionately a much larger part of their bills than for residential or small business consumers, for whom distribution system costs form a larger part. However, relying on renewable energy and storage resources that are a long way from consumers is likely to also require additional investment in distribution and sub-transmission networks, such as that envisaged around Sydney, which the ISP does not consider in the assessment of HumeLink, and which will also flow through to larger bills for residential and small business consumers.

What will this near doubling of transmission charges in NSW achieve? According to the information in the Draft ISP, at best it will be able to get about 2,200 MW more transfer capacity to the Bannaby substation west of Sydney. This is about 15% of the simultaneous peak demand in Sydney. How can it be plausible to more than double transmission charges in NSW but only expand import capacity to the main load centre by 15% of the NSW maximum demand?

As noted the actual increase in transmission prices associated with these interconnectors will be even greater as the ISP also envisages significant reinforcing to get additional capacity into and around Sydney/ Newcastle/ Wollongong ($3.2bn).

In this submission we focus on the Marinus Link and HumeLink proposals (which are the most advanced) and raise preliminary concerns about the VNI-West interconnector (which AEMO strongly supports but has yet to be formally proposed).

Marinus Link

We conclude that the benefits of Marinus Link are unlikely to exceed its costs, while AEMO concludes the opposite (in fact, that Marinus Link is purported to have the largest net benefits of all transmission projects considered). The main point of disagreement is AEMO's assumption that around 1,900 MW more wind generation (relative to the capacity installed in 2023/24) is committed to be developed in Tasmania even if Marinus Link is not built. AEMO's analysis shows that much of this wind generation and an increasing chunk of existing hydro generation will be spilled without Marinus Link. The 1,900 MW of new wind generation reflects AEMO's modelling of the effect of Tasmania's legislated renewable energy target (TRET) of 15 TWh of renewable generation in 2030 and 20 TWh by 2040. But 1,900 MW of additional wind generation without a market to sell its production in is implausible. We can be quite sure that if Marinus Link is not built the TRET will not be achieved (the TRET has no enforcement mechanism). Either way, the existence of the TRET provides no reasonable basis to assume that 1,900 MW of additional wind generation is 'committed' (AEMO's assumption) to be built in Tasmania without Marinus Link. Indeed, the Tasmanian Energy Minister told the Tasmanian Parliament that the TRET would not be achieved without Marinus Link.

Since AEMO has assumed that 1,900 MW of additional wind generation would be built in Tasmania even if Marinus Link is not built, AEMO doesn't include the cost of this wind plus necessary intra-regional transmission in Tasmania (in total about $5-$6bn) in its modelling of the cost associated with Marinus Link because the expenditure is assumed to be incurred irrespective of Marinus Link. Had this not been assumed, the cost of Marinus Link would exceed its benefits.

HumeLink

HumeLink is motivated entirely by the desire to connect Snowy 2.0 to the Sydney region load centre via the high voltage substation at Bannaby. AEMO does not contest this. For example, in its "ISP Feedback Loop Notice" of 27 January 2022, AEMO describes HumeLink as "… a proposed transmission upgrade connecting the Snowy Mountains Hydroelectric Scheme to Bannaby". TransGrid's Project Assessment Conclusions Report (PACR) shows that the vast bulk of the benefit of this project is to substitute for storage that would otherwise be developed elsewhere in NSW, particularly storage that would be more favourably located closer to the Sydney region load centre. TransGrid's ISP modelling shows that HumeLink offers almost no benefit to renewable generators in NSW, Vic or SA in terms of enhancing their transmission pathways to load centres. Hence, in calculating the net benefit of HumeLink it is necessary to count the cost of Snowy 2.0 against the cost that it avoids (its benefits). AEMO does not do this on the basis that Snowy 2.0 is already 'committed' by Snowy Hydro and the Australian Government. But 'commitment' to build Snowy 2.0 does not change the economic (or physical) reality that its operation depends on HumeLink. If the cost of Snowy 2.0 is correctly taken into account, HumeLink very clearly presents a substantial net detriment. Failing to properly account for the cost of Snowy 2.0 will force NSW electricity consumers to bear deadweight losses (through regulated transmission charges) that originate in Snowy Hydro's decision to develop Snowy 2.0 at a remote location requiring hundreds of kilometres of transmission lines that Snowy Hydro is unwilling to pay for.

Might it nonetheless be worthwhile to build HumeLink? This is a question that should be put to Snowy Hydro: if it is willing to pay for transmission (as a customer contribution) up to at least the deadweight loss associated with HumeLink, then it may be reasonable to ask consumers to pay the remainder of the net benefit of the project (if indeed there is any - the dead-weight loss will probably exceed the cost of HumeLink) through regulated charges.

This is in effect the approach that was adopted with another remote pumped hydro generator (Kidston) where in that case the Queensland Government chose to accept the cost of the transmission augmentation, rather than force its cost on to electricity consumers.

It might be suggested that such cost allocation issues have little to do with the ISP. But in its ISP analysis, by ignoring that HumeLink is built almost exclusively for Snowy 2.0's benefit (and therefore showing a net benefit in the ISP analysis of HumeLink), HumeLink becomes an "actionable" project and its cost is foisted onto electricity consumers through regulated charges. Correcting for this error in its cost/benefit analysis opens the way for a solution that would require Snowy Hydro to bear its share of the cost of a transmission line built almost entirely for its benefit. The end result may be increased storage located closer to the Sydney region load centre, which the cost/benefit modelling in the RIT-T and ISP shows would provide higher net benefits.

Other issues

We identify five other issues:

1. AEMO and its ISP process has now assumed a much broader role, not just in planning the development of major transmission augmentations, but also in regulating their development. If this is to be sustained then regulatory

arrangements need to developed for AEMO to justify its selection of transmission augmentations that maximise net benefits, in order to protect consumers from monopoly abuse, and to protect against the crowding-out of private risk taking in contestable markets.

2. All of Australia's governments have now adopted policies to reduce greenhouse gas emissions (GHG). Yet AEMO has not formally brought GHG into its assessment of actionable projects. It is essential that AEMO does this so that the projects it approves are consistent with the Australian Government and jurisdictional governments' "net-zero-by-2050" GHG policies.
3. AEMO's hydrogen super-power scenario should reflect the more likely outcome that major loads such as hydrogen will be largely self-supplied. It may be better to remove this scenario from the ISP to attempt to remedy the modelling shortcomings.
4. We identify various concerns in the details of AEMO's analysis of Marinus Link and HumeLink and Snowy Hydro's recyclable storage capacity.
5. The NER gives the ISP "a planning horizon of at least 20 years". AEMO has "extended the ISP's planning horizon to 2050 to reflect Australia's net zero emissions target." While understandable for that reason, extending the planning horizon beyond 20 years substantially increases the uncertainty associated with the later years in the planning period and exposes the ISP conclusions to greater risk of error.

Recommendations

The main conclusions of this submission are that the "actionable ISP" regime has made AEMO responsible for undertaking cost/benefit analyses to decide whether major transmission augmentations should proceed, and that the existing RIT-T regulatory test is now little more than a self-assessment. We have concluded that in this new context the analysis that AEMO has done to approve actionable transmission projects is not adequate. We also find that AEMO has made errors in its approval of the two largest actionable projects and, when corrected, these projects should not be "actionable".

While we recognise that AEMO has suggested staged approval of its actionable projects, it has nonetheless endorsed those projects and established precedents that will bind its future decisions. As such we do not think that our concerns can be addressed effectively through AEMO's staged approval process.

We appreciate that addressing the errors we identify will up-end the ISP and the two major projects it approves. Such a radical departure can not be contemplated lightly. But we think it is essential that AEMO seriously considers it. Huge investment in transmission is needed to accommodate the expansion of renewable generation. There is a big public and electricity consumer interest in ensuring that these transmission dollars are well spent. The approval of HumeLink and Marinus Link set bad precedents that must be rectified if there is to be any hope of preserving the public and electricity consumers' interests.

Recognising the seriousness of these issues and the difficulty of addressing these issues at this late stage in the development of the ISP, we suggest that AEMO ask ministers to refer the issue of the appropriate calculation of the costs and benefits of joint-products such as Battery of the Nation/Marinus Link or Snowy 2.0/HumeLink, and of the appropriate regulatory arrangements for "actionable" projects, to the Productivity Commission for advice. The 2022 ISP should be finalised after the Productivity Commission has provided its advice.

1 Introduction

The ISP reflects AEMO’s considerable expertise in power system and market analysis and in power system operation, and has benefited from the efforts of many others. The ISP has ramifications in many areas, perhaps most significantly in the development of interconnectors or other major transmission augmentations, where AEMO’s decision to classify transmission augmentations as “actionable” effectively means AEMO is now the main decision-maker on those interconnectors.

We focus this submission on the most important outcomes of the ISP: AEMO’s conclusions on the Marinus Link and HumeLink “actionable ISP” transmission projects (Section 2). We also comment on the regulatory arrangements that define the “actionable ISP” regime (Section 3). Section 4 identifies other, typically more detailed, issues. Appendix A presents a submission to the AER outlining many issues related to the design of HumeLink that should have been considered in both the RIT-T and ISP before the project was deemed to be actionable.

2 Calculation of the net benefits of Marinus Link and HumeLink

We suggest that AEMO has failed to properly account for the relationship between transmission augmentations and their associated generation/storage developments in the case of Marinus Link and HumeLink. As a result AEMO is recommending augmentations that will impose big and unnecessary costs on electricity consumers, and possibly also tax payers, when cheaper alternatives are available. These unnecessary augmentations also crowd out cheaper and more effective investments that the private sector would otherwise make. AEMO's approval of HumeLink and Marinus Link will undermine the widely shared objective of rapid and efficient transition to renewable electricity in the National Electricity Market.

2.1 Marinus Link

In its analysis AEMO assumes that almost 1,900 MW of additional wind generation will be developed in Tasmania even if Marinus Link is not built. This assumption is evident in CDP13 (the development path in which Marinus Link is not built) which assumes that wind generation capacity in Tasmania will increase from 563 MW in 2023/24, to 1,426 MW in 2030/31, to 2,425 MW in 2038/39 (i.e. an overall increase of 1,862 MW relative to 2023/24)[1].

On the other hand, AEMO assumes that 2,547 MW of additional wind generation will be built in Tasmania by 2030/31 if Marinus Link is built (i.e., CDP12, modified to account for the delay in Marinus Link's completion from 2029/30 to 2030/31 advised by TasNetworks)[2]. Therefore, AEMO is projecting that 75% of the increase in wind

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[1] Specifically, rows 1048 to 1050 in the "Rez Generation Capacity" tab of the Draft ISP Results workbook.

[2] Surprisingly, CDP12 assumes no further wind generation is built thereafter, whereas CDP13 assumes a further 1,000 MW by 2038/39.

generation in Tasmania will happen even if Marinus Link is not built, albeit eight years later than if Marinus Link was built.

Having assumed that ~ 1,900 MW of additional wind generation in Tasmania (and the necessary intra-Tasmania transmission augmentations) is to be built regardless of whether Marinus Link is built, AEMO has not included the cost of the additional wind generation, which we estimate at around $5-6bn [1,862 MW x ~$3m/MW including intra-regional transmission], in its calculation of the net benefit of Marinus Link and its associated generation and storage investment.

AEMO's modelling of annual energy production shows that 1,900 MW of additional wind in Tasmania in CDP13 increases total Tasmanian electricity production by around 14 TWh per annum, a little less than the 15 TWh by 2030 and 20 TWh by 2040 legislated in the TRET. AEMO provided no explanation for assuming 1,900 MW of additional wind generation, but it would seem (assuming no spillage) to be consistent with the TRET annual production target. However, AEMO's modelling of annual energy production shows that annual energy production in CDP13 in fact falls short of the legislated requirement by 2040. This is because it is impossible to produce more than 14 TWh p.a. of electricity in the Tasmanian power system with annual demand of around 10 TWh and maximum export capacity (on Basslink - assuming it doesn't break down) of ~4 TWh p.a. As a result, by forcing 1,900 MW of new wind generation into Tasmania the model has no option but to spill much of the wind generation and also a fair chunk of the production from Hydro Tasmania's existing hydro generation capacity. The CDP13 modelling results show this.[3]

Of course, forcing 1,900 MW of new wind generation into a market with no demand for that wind generation, will effectively bankrupt the Tasmanian power sector by stranding

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[3] For example, the wind capacity difference between CDP12 and CDP13 drops 59% from 1,684 MW to 685 MW between 2030/31 and 2038/39, but the difference in generation only drops by 31% from 8,239 GWh to 5,692 GWh. Or, put differently, the wind generation capacity in CDP13 increases but aggregate renewable production is unchanged. Effectively the large amount of wind generation that AEMO assumes will be built in Tasmania even if Marinus is not built is spilled. This is even after assuming that hydro generation will decline if Marinus is not built (i.e. the hydro is also being spilled in response to the additional wind generation).

much of Hydro Tasmania's existing hydro capacity and because much of the additional wind generation will be spilled. For this reasons the TRET, without Marinus Link, is not plausible. In fact, the TRET has no enforcement mechanism - it does not oblige any party to contract to buy or to produce additional electrical energy. The only obligation established in the legislation is for the Director of Energy Planning to report, annually, on progress made towards meeting the renewable energy targets set out in Section 3C of Act.

Without Marinus Link, the TRET will therefore make no difference to electricity capacity or production in Tasmania. The Tasmanian Government recognises this. For example, in the second reading speech for the bill to introduce the TRET, the Tasmanian Energy Minister said:

"… *the interim and final targets (of the TRET) will only be achievable with the full commissioning of Marinus Link (i.e. both 750 MW cables*). "

Therefore, it is not correct for AEMO to have assumed that 1,900 MW of additional wind generation will be built in Tasmania if Marinus Link is not built.

Remedying this modelling error means taking out the 1,900 MW assumed in CDP13 and so deducting the $5-6bn cost of the additional wind capacity from the net market benefit calculation of Marinus Link ($4.6bn). In addition to this, discounting to the start of Marinus' main cash flows (discussed later) and also accounting for the failure to adjust for Marinus/Basslink outages (discussed later) means that Marinus Link is likely to present a net detriment, possibly a significant one.

This can be no surprise: in our own studies[4] we use TasNetworks' costs for Marinus Link and AEMO's assumptions of battery costs and find it would be cheaper to provide storage in Victoria than build Marinus Link.

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[4] https://www.vepc.org.au/_files/ugd/cb01c4_91b44275f6b145fd92e4818713ab2107.pdf and https://www.vepc.org.au/_files/ugd/92a2aa_9505525e3eed4dfe904878df3c53aa99.pdf

Finally, a critical issue not addressed in the ISP is who will pay for Marinus Link. The Marinus Link PACR suggests that all NEM jurisdictions should contribute in proportion to their demand. However, this proposal has no chance of support from any state other than (possibly) Tasmania. Even leaving aside the modelling issues, how can it be reasonable to include Marinus Link as an actionable project in the ISP in the absence of certainty that any of the state governments, other than Tasmania, are willing to contribute to its financing?

2.2 HumeLink

Snowy Hydro would not have decided to develop Snowy 2.0 without transmission expansion to power its pumps and make its production available to customers. The implication of this is that when calculating the benefits of HumeLink, the cost of Snowy 2.0 should have been included for exactly the same reason that the benefits of Snowy 2.0 (avoided storage dispatchable generation elsewhere in NSW) are used in the calculation of the benefits of HumeLink.

AEMO has not included the cost of Snowy 2.0 when it calculates the net benefit of HumeLink. Instead, pursuant to its assumption that Snowy 2.0 is a “committed project”, AEMO assumes that its cost is sunk and so not affected by the construction of HumeLink.

To correct AEMO’s error, it is necessary to deduct the present cost of Snowy 2.0 (currently at least “around $6bn”) from AEMO’s estimate of the net benefit of HumeLink ($1.3bn). This means HumeLink is in effect associated with a net detriment of around $4.5bn. No doubt this will grow even bigger from almost certain further cost blow-outs on Snowy 2.0 and HumeLink.

Appropriately reflecting the net detriment associated with HumeLink will open the way for a suitable allocation of costs and benefits. If Snowy Hydro is willing to fund HumeLink to the lesser of its cost and its deadweight loss, then consumers may reasonably be asked to pay for any remaining difference (if positive) between the deadweight loss (the net detriment charged to Snowy Hydro) and the cost of HumeLink.

(we doubt that such difference will be positive – the net detriment is likely to exceed the cost).

2.3 VNI-West

AEMO has calculated that VNI-West has an even higher net benefit than HumeLink. AEMO suggests that the main value of VNI-West is to allow Victoria to access Snowy 2.0. But Snowy 2.0's value in providing dispatchable capacity to Victoria/NSW will depend in the how much of that capacity is simultaneously needed in NSW/Victoria. Snowy 2.0 can not provide dispatchable capacity that is being used to meet demands in NSW and at the same time provide such production to meet demand in Victoria. AEMO seems to recognise this with its recognition that in a "decision rule" for VNI-West that "material volumes of dispatchable capacity" are not withheld in NSW or Victoria. AEMO should make clear how it has modelled Victoria's access to Snowy 2.0 and to clarify what is meant by "material volumes of dispatchable capacity".

AEMO also counts as a benefit of VNI-West, that Victoria gains access to renewable energy generated outside of Victoria (and also generated inside Victoria to the extent that the renewable generation is generated in Victoria and connects to VNI-West). It is clear that the Victorian part of VNI-West will provide a valuable service in the connection of renewable generation inside Victoria. But less than half of the cost of VNI-West is in Victoria - the majority of the cost of VNI-West is likely to be in NSW.

The value of renewable generation outside Victoria, to Victoria, depends on that generation being cheaper than generation in Victoria and that the "foreign" production is generally positively correlated to residual demand in Victoria and negatively correlated to renewable generation in Victoria (or it would be cheaper to develop the production in Victoria). We expect that it is generally unlikely that remote (inter-state) generation will be so much cheaper that Victorian consumers would be better off after also paying for the additional transmission, or that the remote renewable production will be better correlated with Victoria's residual demand. AEMO's claim that Victoria will benefit from renewable generation outside Victoria depends on these conditions. In addition, cost-sharing issues will surely bedevil VNI-West, just as for Marinus Link (most of the cost of VNI-West is in NSW and it is even more difficult to see how NSW benefits from VNI-West than it is to see how Victoria will benefit from it). This being the case, NSW consumers will surely (and not unreasonably) be reluctant to pay the (larger) part of the cost of VNI-West.

3 Regulation of transmission development

Our assessment of the way that the "actionable ISP" regime is working in practice is that "actionable project" determinations by AEMO in the ISP process has replaced AER approvals, as the critical approval. AEMO's approval is needed to allow network service providers to apply to the AER to approve their actionable project expenditure proposals.

While network service providers are still required to complete a project assessment, and the AER can allow objections to it by interested parties, the AER does not itself decide on the project assessments or network service providers' responses to objections. In addition there is no formal relationship between the conclusions of a RIT-T and the information that AEMO uses in its ISP, or the conclusions that AEMO reaches in its own actionable ISP assessment.

The project assessments that the network service providers undertake are therefore best described as self-assessments. Neither the AER nor AEMO having any right or obligation to assess whether the self-assessment is correct.

As a result, we think that how this new "actionable project" regime is now working in practice is that regulatory accountability is falling into the cracks between AEMO and the AER and disappearing without trace. In the rest of this section, we explain how we have come to this view.

We have interacted with the AER in the context of the HumeLink Project Assessment Conclusions Report (PACR) (see in particular the VEPC Paper[5] on the PACR) and the

[5] https://www.vepc.org.au/_files/ugd/92a2aa_52bec342cb1e4c2292c4d259f4049f6d.pdf

objections to the PACR raised by interested parties including NSW landholders. It would appear that the AER now does not play any substantive role in the regulatory approval of transmission. For example the AER has not critiqued the PACR or its Addendum, has not passed any judgement on the PACR's conclusions and has not itself sought any further assessment or change to TransGrid's analyses.

The AER only became involved in the HumeLink PACR after interested parties in NSW that will be directly affected by HumeLink, objected to aspects of the PACR. The AER accepted one aspect of their objection and required TransGrid to re-examine a route design option – a relatively small component of the PACR. TransGrid responded by submitting an "addendum" to the PACR. The AER has not assessed the "addendum" or passed any judgement on it. We, and the interested parties, have found TransGrid's addendum to be inadequate and have raised this with the AER (this is set out in Appendix A). No response has yet been received from the AER.

Regardless of the merits of the HumeLink Addendum, AEMO merely noted in its ISP Feedback Loop Notice (27 January 2022) that "*In December 2021, Transgrid completed a RIT-T to assess the technical and economic viability of the project. The RIT-T estimated net market benefits for the project of $491 million. TransGrid's feedback loop request provides that the cost estimate for the project is $3,317 million, which includes $330 million for early works*". AEMO did not even mention that the PACR's estimate of net benefits ($491m) differs significantly from the ISP estimate or that the PACR includes competition benefits and the ISP doesn't. In fact, the ISP specifically excludes competition benefits, rightly so in our view[6].

With respect to the AER's 'oversight' of AEMO's ISP role, this has been restricted to a short commentary on a couple of general issues (in particular, the extent to which coal-fired generators might be more flexible than AEMO may have assumed and so may not close as soon as AEMO suggests might happen). This can not in any sense be considered to be a meaningful, comprehensive, independent review of AEMO's ISP work, nor an in-

[6] *"AEMO has not included competition benefits in the assessment of the Draft ODP due to the significant uncertainty surrounding key assumptions that would need to be made in the calculation of these benefits."*

depth analysis of the Optimal Develop Path or the transmission projects that are in the ODP.

AEMO, by contrast with the AER, now seems to have assumed the dominant role in the regulation of new transmission developments. By determining the "actionable" projects, AEMO is able to define which projects are eligible for inclusion in transmission network service providers' regulated asset bases and hence which costs are imposed on consumers in regulated charges. As we understand it, unlike the AER's regulatory decisions, there is no path for review of the merits of AEMO's decisions or for judicial review. There are no defined legal obligations that AEMO is required to meet in reaching its decisions.

The supreme authority that AEMO now has, makes transparency and public disclosure even more important so that AEMO's decisions might at least be debated transparently in public fora.

Our analysis of the Draft ISP leads us to the conclusion that AEMO should do more to acquit its new regulatory obligations adequately. For example, for HumeLink AEMO has accepted TransGrid's preferred design, route, connection point and costs - and included them in the ISP analysis without any apparent assessment or scrutiny. AEMO did not consider alternatives to HumeLink or produce any ranking.

AEMO has also not explained how it intends to ensure that the costs of a project that it approves, will be controlled. For example, AEMO says that a decision-rule for progressing to HumeLink Stage 2 is that the total project cost can not increase "materially" from $3.3bn[7]. But what does "materially" mean and how will AEMO enforce its request on Transgrid to drive down costs and its warning to disallow HumeLink if its costs rise above $3.3bn? All that TransGrid has so far provided to AEMO is an estimate of the costs of the second stage with a +50%/-30% range. The PACR states that "*there is currently a high degree of uncertainty in relation to the accuracy of the capital cost estimates*." What will AEMO do if the outturn cost is much higher? Similarly, how did

[7] *"project costs cannot materially increase from the current estimate of $3.3 billion. Further work to drive down costs should be undertaken urgently"*

AEMO assess TransGrid's Stage 1 HumeLink application (for $330m) (which AEMO approved just two days after TransGrid's applied for it)?

It might be argued in AEMO's defence that since the AER determines what goes into TransGrid's RAB, it is the AER, not AEMO that is the decision-maker on cost allocation. But prior to the AER's consideration of TransGrid's Stage 1 HumeLink contingent project allowance, Transgrid needed to secure AEMO's approval for its Stage 1 contingent project. It is only after AEMO's approval of TransGrid's application, that the AER becomes involved. However, the AER has not scrutinised the need for HumeLink nor the chosen route or the full project cost or the estimated benefits. Rather, the AER's job is the much smaller one of assessing whether whatever TransGrid has decided to do in Stage 1, has been reasonably costed and, presumably, that it exceeds TransGrid's estimate of benefits (taken at face-value).

The conclusion from this analysis is that AEMO is now the primary decision-maker on transmission augmentation (particularly interconnectors) and that it has effective control over all major decisions. It seems that only minor parts of the regulatory task - approving the costing of whatever AEMO seems to think should happen - remain with the AER.

AEMO needs to respond to the reality that it now has largely unfettered authority not just to plan all major augmentations to the transmission system, but also to direct, in large measure, the implementation of the plans it approves.

Both the planning and implementation are, substantially, economic regulation tasks that AEMO has hitherto had little experience in. For example, in its ISP cost/benefit analysis AEMO focuses on a scenario and development path-based analysis. But in its approval of transmission augmentations, AEMO is not deciding between scenarios or development paths, it is deciding on specific transmission augmentations. The cost/benefit analysis must therefore be specific to those proposals and all analysis made publicly available for discussion, before the ISP is finalised. This has not occurred. For example, whereas the HumeLink PACR presents results of costs and benefits of various routes and options, the ISP presented a single figure of net benefit (and as it turns out a much higher number than in the PACR) without any explanation or description of how this number was arrived at, what options were considered and so on.

It is vital that AEMO develops and applies a regulatory framework and mechanisms for systematic information disclosure and public review before AEMO finalises its decisions, to provide confidence that AEMO will protect consumers from monopoly abuse in the development and execution of its "actionable" ISP projects. This is important in general but particularly so since there is no mechanism for merits or judicial review of AEMO's "actionable ISP" decisions.

4 Other issues

4.1 Accounting for greenhouse gas emissions

The Australian Government and the jurisdictional governments have emission reduction policies that require net zero emissions by 2050. While none of the governments have policies to explicitly price emissions, they are all seeking to introduce scarcity through their policies. Even though not explicitly priced, emissions are now clearly a significant component in energy policy. Yet AEMO has not yet included emissions in its assessment of competing alternatives or in its selection of actionable projects. While we can understand that pricing emissions is still politically problematic in Australia, reporting at least the volume of emissions is surely essential to indicate that the decisions it makes will deliver the governments' emission reduction policy.

4.2 Calculating the net present value in 2021 is not useful and potentially distorts the NPV calculation

It is not clear how AEMO has calculated the NPV of the various transmission projects to 2021.

One approach is to calculate the present value of the cash flows for each project to the year that the cash flows on that project begins, and then take those present values back to 2021 by discounting them back to 2021 at the same discount rate. Such a 2021 NPV really has no tangible or useful meaning as an expression of the economic net benefits of future cash flows. It means nothing, for example in understanding whether future transmission developments are economically beneficial (or the value of those benefits). It also means nothing for consumers in terms of price impacts or investors as an estimate if the viability of their investments.

Another approach that AEMO might have used is to discount back to 2021, all the cash flows that occur in future of the various transmission projects in the various CDPs (i.e.

without the interim step of discounting the present value of the cash flows to the start of each project and then discounting those net present values back to 2021 – as described above). Cash is not going out the door in 2021 on any of the transmission augmentations that AEMO is approving. HumeLink will be the earliest (other than EnergyConnect which has already been approved). Expenditure on Marinus Link and VNI-West lie much further into the future. For each project that AEMO is assessing, the calculation of the net present value of the benefits and costs should be brought back to the point at which that project would begin construction (or the main cash flows start) in order to assess the net benefits of that project at the time that cash flows are committed to it. The reason for this is that, if instead, cash flows are discounted back to some earlier period (i.e. 2021) this distorts the calculation of the net present value because expenditure (which always occur before revenues) is discounted more relative to income if the net present value is calculated to the start of the period that cash flows occur, than would happen if discounted to some much earlier period[8].

To see this intuitively, consider how the NPV of a hypothetical project might vary if calculated to the start of the period that cash flows occur (say 2021) or if that same project is assumed to be deferred to some much later period, say 100 years and the NPV again calculated to 2021. In the first case imagine that the NPV is $1bn. In the latter case the NPV would be much smaller (say $0.01bn) because all cash flows are being much more heavily discounted. Depending on the timing of the cash flows and the chosen discount rate, the NPV in the two different calculations may also flip sign from positive to negative or vice versa. The important point here is that the latter estimate fails to correctly state the NPV of the project because it has been distorted by applying different discount

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[8] For example consider a discount rate of 5%. The discount factor in the first year is 1/(1.05) = 0.95 and the discount factor in the 40th year is 1/(1.05)^40= 0.142. But now imagine that these cash flows were discounted to some period 10 years earlier. Now the discount factor applying to the first year's cashflow is 1/(1.05)^10 = 0.614 and the discount factor applying to the 40th year's cash flow is 1/(1.05)^50 = 0.087. Comparing the discount factor applied of the first and fortieth year in the first case it is 0.95-0.142= 0.81. But with the second case, the difference is now 0.614-0.087 = 0.526. By shifting the whole calculation 10 years earlier, costs (which dominate in the early years are being discounted less severely relative to benefits which only arise later after the main costs occur than if costs and benefits were discounted back to the year in which the main costs begin.) So by drawing the present value calculation to a point that is long before the cash flows occur (and the actual investment decision is made) AEMO is understating the true present value of costs relative to benefits.

factors to costs and revenues than would apply if the NPV is calculated to the start of the period that cash flows are incurred as described in Footnote 8.

To address this concern, we suggest that AEMO should not attempt to calculate a 2021 NPV of future cash flows. Instead, it should calculate the NPVs for each transmission project and then, if AEMO really wishes to state a single NEM-wide NPV, state that aggregate NPV in constant currency of whatever year AEMO chooses. This would be a more useful expression of the net benefit of transmission augmentations, although we suggest still hardly worth stating.

4.3 Hydrogen superpower

The Hydrogen Superpower scenario predicts very attractive net benefits from transmission augmentations. We have two main concerns with it:

- First the scenario assumes that all the electrical demand for hydrogen production will come from the grid. But surely this is unrealistic? Hydrogen production through electrolysis is even more electricity intensive than aluminium production. The incentives for self-supply are enormous: self-supplied electricity is likely to be very much cheaper than grid supplied electricity, and hydrogen producers will want to prove that their hydrogen is renewable. The opportunity for self-supply is significant (abundant land in the locations most likely to host electrolysers). It surely should be the default assumption that any large amounts of electrolysis-based electricity demand will be self-supplied[9].

- Secondly, surely it is impossible to develop any sort of plausible estimate of hydrogen production in Australia. Large scale hydrogen production from electrolysis has a very long way to go before being considered an "industry"[10].

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[9] Interesting responses from a senior AGL representative on these issues are particularly germane – see https://reneweconomy.com.au/agl-says-green-energy-hubs-best-path-to-zero-carbon-grid-transmission-too-slow/

[10] The largest hydrogen plant in Australia is a little over 1 MW and the largest globally (in Canada) is just over 20 MW.

> The inclusion of the hydrogen superpower scenario in the weighted average "net benefit" calculation greatly distorts the analysis (although it has only been accorded a 17% weighting) because the net benefit (in the superpower scenario) is many times higher than the net benefit in any of the other scenarios (because the superpower scenario assumes, implausibly surely, that hydrolysis demand will be grid-supplied).

4.4 Institutional dynamics

We see two areas of institutional dynamic that we think are relevant. First, technology change in the electricity sector is rapid and uncertain. This makes reliable forecasting impossible. While AEMO has deep resources and expertise, its forecasts could be, or could be seen to be, influenced by its institutional role. AEMO's power system responsibility breeds conservatism and caution with a view to minimising the risk of shortages. This can be seen in AEMO's long history of over-estimating the rate of demand growth. For example, a decade ago AEMO predicted that the electricity supplied by the grid in 2021 would expand by 26 per cent (62 terawatt hours). In fact, it has contracted by 9 per cent (18 TWh). Similarly in 2011 AEMO predicted that just 1.5 per cent of demand would be supplied by rooftop solar in 2021. It is 11.5 per cent. Such examples are not given to criticise AEMO but as a demonstration of asymmetry.

Scenario analysis - such as AEMO has done - provides information on the impact of different assumptions. We suggest that more could be done to model the impact of rapid load defection and possibly even wide-scale grid defection. For example, how might the net benefits of Marinus Link, HumeLink and VNI-West be affected by continued reductions in the demand for grid-supplied electricity or even more rapid reduction in battery storage costs than AEMO has assumed?

Secondly, as the power system operator, AEMO is the single most important entity responsible for keeping the lights on. Interconnection (generally) increases the reliability of the power system. AEMO decides on the development of interconnectors and since consumers can ultimately be forced to pay for them, AEMO can be confident in most cases that they will be developed if AEMO approves them. Interconnector development is therefore a likely way for AEMO to increase the reliability of the power system and hence reduce reliability risk that AEMO is ultimately held accountable for managing.

On the other hand, AEMO can not directly control the development of the alternatives to interconnection that also improve reliability (such as large scale or distributed or behind-the-meter batteries, or demand-side response, or distributed generation). By deduction we suggest that AEMO is more likely to give the benefit of the doubt to those options such as interconnection, that it can select and for which it has much greater control over implementation.

On the same logic it is to be expected that AEMO has an institutional preference for projects such as Battery of the Nation and Snowy 2.0 because they are "on the table" and they have enthusiastic (government) sponsors. They are therefore more likely to be developed if AEMO approves their necessary transmission augmentation and so AEMO may feel it can bank on them even if better alternatives exist that AEMO can not direct to the same extent.

Options to reduce the effect of institutional preference might include institutional changes (such as separating transmission planning from power system operation), regulation, or by fundamentally changing what it means for a project to be "actionable".

It may be premature to consider institutional change now. But there is advantage in a candid recognition of AEMO's institutional preferences; and consideration of regulatory design. Such recognition by AEMO should encourage it to redouble efforts to increase transparency particularly in contentious areas such as cost/benefit analysis.

4.5 Marinus Link modelling

In determining the benefits of Marinus Link, the existing Basslink should be fully loaded first before any use of Marinus Link. If this is not the case then the benefit of additional capacity in Marinus Link will have been overstated. Has it been modelled that way?

The ISP assumes there are no transmission outages. This is reasonable for transmission lines, where there is usually an alternate path – the "n-1" operational/planning redundancy – and outages are usually of only a relatively short duration. However, in the case of sub-sea cables there is usually no alternate path and outages can extend for a considerable time. In the past Basslink has been out of service for up to seven months, with subsequent damages claims of a hundred million dollars. While Basslink will provide a partial 'backup' for Marinus Link and vice versa, if one or both of the Marinus Link cables are out of service this will result in a substantial loss of transmission capacity between Tasmania and Victoria. Properly accounting for Marinus outages may result in quite a different development of the power system than that assumed in the ISP (i.e. Victoria will discount the reliability of Tasmania supplies and hence is likely to build more of its own storage/dispatchable generation than assumed in the ISP). It is essential that this risk is evaluated and incorporate in the Marinus Link cost/benefit assessment.

4.6 HumeLink modelling

The ISP net benefit estimate for HumeLink is $1.3bn (Step Change), based on the 'strictly rules-based optimal timing' of 2028-29.

However, TransGrid's PACR estimated a net market benefit of $491m for their preferred option, including competition benefits of some $442m. The net benefit without competition benefits (which AEMO rightly excludes in the ISP) is just $49m. When the PACR estimate is also adjusted for the construction of Kurri Kurri and Tallawarra B Gas Power Stations proceeding and for VNI-West being delayed (-$248m), all of which are now certain, the estimated net benefit from TransGrid's PACR analysis of HumeLink becomes negative $199m. How might the $1.5bn gap between AEMO's assessment and TransGrid's be explained? Even allowing for the different scenarios, the gap is substantive and should be addressed in the ISP.

4.7 Characterisation of Snowy 2.0

We found the two charts of Figure 22 of the ISP (storage capacity and storage depth) confusing because they mix up type of storage and storage depth. The left-hand chart (installed capacity) shows that storage devices with duration of less than 12 hours are by far expected to dominate storage installations in the NEM. This is consistent with the publications of the Department of Energy in the United States Government, based on work done by the National Renewable Energy Laboratory, which predict a weighted average duration of storage of around 6 hours in their deep electrification and full decarbonisation by 2050 scenario for the United States. AEMO's analysis (the left-hand chart of Figure 22) seems to reach a similar conclusion for the NEM.

The right-hand chart is distorted by the display of Snowy 2.0 as having 350 GWh of storage. This is not in any sense a meaningful statement of Snowy 2.0 storage. We have set this out in detail in previous studies and concluded that Snowy 2.0 only provides 170 GWh of recyclable storage[11]. We note here in addition:

- the claimed 350 GWh of capacity of Snowy 2.0 will rarely be available - Tantangara will rarely be full (as demonstrated in the previous ISP) and will sometimes be empty
- the need to keep spare 'flood mitigation' capacity in Tantangara at times to avoid spilling – e.g. before the snow melt and during wet periods when no generation in the Tumut Scheme is permitted to avoid exacerbating downstream flooding. Also, there will be a constraint on operation of Tantangara to preclude any spilling to avoid pest fish (including Redfin Perch – a Class One noxious pest), that will be transported up from Talbingo Reservoir, infesting the Upper Murrumbidgee River with devastating impacts on threatened native fish.
- the extensive time taken to recharge Tantangara Reservoir (some months), given the limited inflows from Eucumbene Dam into Talbingo Reservoir and the availability of cheap electricity for pumping (which is likely to be limited at times when sustained generation is worthwhile)
- Talbingo only has two-thirds the capacity of Tantangara at best and conflicts arise in the joint use of Talbingo by Snowy 2.0 (as its downstream storage) and Tumut 3 (as its upstream storage) and the inherent conflict of wishing to minimise

[11] https://theconversation.com/snowy-2-0-will-not-produce-nearly-as-much-electricity-as-claimed-we-must-hit-the-pause-button-125017#:~:text=When%20you%20subtract%20the%2060,half%20the%20claimed%20storage%20capacity.&text=Snowy%202.0%20would%20never%20produce,to%20run%20it%20this%20way.

Talbingo levels for Snowy 2.0 availability (and efficiency) but maximise levels for Tumut 3 availability and efficiency.

A reasonable depiction of stored energy in the NEM should count the energy stored in water in all dams, coal and biomass in accessible stockpiles, gas stored in tanks, LNG and pipelines and the capacity of batteries. Alternatively, if AEMO wishes to depict dispatchable recyclable storage (as we understand that AEMO is actually seeking to do) AEMO should determine a number for Snowy 2.0 that reasonably reflects its usable recyclable storage capacity, and not just assume its top dam is full and that all of that capacity is always available to be released continuously regardless of the constrained storage in the lower reservoir.

A related issue is the modelling of generation between Tumut 3 in pumped hydro mode and Snowy 2.0. For example, is Tumut 3 loaded first till it reaches capacity, or are both stations loaded equally, or is Snowy 2.0 loaded first followed by Tumut 3?

As with Marinus Link and Basslink, from the perspective of a Business Case justification the existing asset (Tumut 3) should be loaded to capacity before a proposed new asset (Snowy 2.0) is utilised.

Also, the IASR Workbook quotes Snowy Hydro advice that Tumut 3 is marginally more efficient than Snowy 2.0 (78% vs 76%), so it should be accorded first use preference in the model.

The ISP seems to be forecasting Snowy 2.0 to be partially available in 2025-26 and fully available in 2026-27. If this is achieved (which many experts doubt, especially as works are already behind schedule), Snowy 2.0's output will be restricted if HumeLink is not completed by 2025-26, as Snowy 2.0 will at best only be connected to Line 64 (UTSS-LTSS) at the proposed Maragle Substation.

It would appear from the Network Capability Worksheet that Snowy 2.0 can generate/pump up to 660 MW prior to HumeLink. Is this correct and has it been checked against current stability constraints? The ISP doesn't appear to have published projections for Snowy 2.0's operation and it is recommended that they be included, together with other pumped storages.

We noted in the VEPC Paper[12] that the PACR assumes Snowy 2.0 will ramp up to capacity factors of 25% for generation and 33% for pumping by 2035, which are incredibly optimistic assumptions, especially when such operation would be in addition to the operation of Tumut 3. This adds further doubt to TransGrid's market benefit estimate and increases the disparity with AEMO's net benefit (see earlier discussion). It would have been helpful had the draft 2022 ISP updated the sensitivity analysis in the previous ISP, of a four-year delay in the commissioning of Snowy 2.0.

[12] https://www.vepc.org.au/_files/ugd/92a2aa_52bec342cb1e4c2292c4d259f4049f6d.pdf

Appendix A: Comments on HumeLink PACR Addendum

This document was submitted to the AER on 17 January 2022 in response to TransGrid's HumeLink PACR Addendum[13] that TransGrid submitted to the AER following objections to HumeLink by interested parties.

As expected TransGrid contends that *"the preferred option remains a new 500 kV double-circuit lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby (Option 3C)"*.

The PACR Addendum provides a rather biased portrayal of net benefit estimates, based on uncertain costs and arguable forecasted benefits.

However, despite TransGrid's spin, the updated figures actually indicate that Option 3C is not the clear-cut best option. The estimated net benefit of 1C-new is superior to that for 2C and 3C, though similar in the context of a $3+bn project.

But more relevantly, the updated information shows that the estimated net benefit of all options is negative. This is even ignoring the contention in the VEPC Paper 'A review of the HumeLink PACR'[14] that Snowy 2.0 costs ought be included in the analysis, rendering a negative net benefit for HumeLink exceeding $4bn.

If the project must proceed because of the need to connect Snowy 2.0, selection of the preferred option should include factors other than the current mathematical calculation of estimated net benefits.

Proceeding now with Option 3C is arguably the worst approach.

Option 1C-new is the cheapest and has the least-worst net benefit. It could be built to

[13] Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink) (transgrid.com.au)

[14] https://www.vepc.org.au/_files/ugd/92a2aa_52bec342cb1e4c2292c4d259f4049f6d.pdf

enable connection of Snowy 2.0, with the Maragle-Wagga Wagga leg (of Option 3C) being deferred till/if it can be justified. In this case Snowy Hydro should be required to pay for all of 1C-new, as it is effectively a Connection Asset for Snowy 2.0's sole benefit.

On the other hand, Option 2C is the best route from a network perspective, providing the greatest long-term benefits for NSW.

And whichever option is selected, connecting HumeLink to Snowy 2.0 via Lower Tumut Switching Station rather than the proposed Maragle Substation has network benefits and a lower cost.

The PACR and its Addendum are deficient and flawed. The RIT-T process should not progress until these crucial issues are comprehensively addressed.

1. **Cost is highly uncertain and 'at the limit'**

The Addendum repeats the qualification in the PACR that *"there is currently a high degree of uncertainty in relation to the accuracy of the capital cost estimates."*

But it then adds the assurance that *"consumers can therefore have confidence that any increase in the cost estimate for the preferred option will only result in the project proceeding if AEMO confirms that it remains part of the ISP at the higher cost."*

However, AEMO's 2022 Draft Integrated System Plan (ISP p65) indicates that the current estimated cost for HumeLink of $3.3bn is already at the maximum level (and even hinting that it is already beyond it) and the project could not be justified if there is a further increase:

> *"project costs cannot materially increase from the current estimate of $3.3 billion. Further work to drive down costs should be undertaken urgently … As part of any feedback loop between stage 1 and stage 2, net market benefits will be reassessed to confirm the project still remains part of the ODP [Optimal Development Path] in the latest ISP."*

With no headroom for further cost increases, the RIT-T process should be put on hold until the cost is more accurately determined. The estimated cost has already increased from $1.3bn in the PADR, just 18 months earlier. If the RIT-T process were allowed to proceed it will be much more difficult to stop the project or change to another route option when more accurate cost and benefits data becomes available.

2. **The route and design are still being assessed**

TransGrid has just embarked on investigating alternate routes from Maragle to Bannaby and building part or all of the lines underground, as a response to widespread landholder opposition. It would be pre-emptive to continue to progress Option 3C whilst these studies are underway, unless of course TransGrid has no intention of seriously considering the alternate routes or of undergrounding.

Also, TransGrid has not considered using existing easements and upgrading existing 330 kV lines to minimise costs and impacts. Such an approach has the potential to lower construction costs and lessen environmental impacts and biodiversity offset costs.

3. **Benefits are overstated and tenuous**

The VEPC Paper questioned the validity of the PACR's benefit calculations in many respects.

One example is the assumed operation of Snowy 2.0, generating or pumping at an average of 1,200 MW for 24 hours/day every day of the year.

The Addendum makes it clear that market benefits are largely derived from avoided capital costs from 2030 onwards, decades into the future:

> *"Market benefits of all options are primarily derived from avoided/deferred generation and storage capital costs (shown by the blue sections of each bar in Figure 7 respectively).*
>
> - *These benefits are primarily driven by avoided/deferred large-scale storage (LS battery) developments and avoided solar developments from 2030. While the deferred LS battery capacity starts to be built in the late 2030s, avoided open cycle gas turbine (OCGT) build from the late 2030s and pumped hydro from the early 2040s results in further market benefits."*

Justifying a $3+bn project on assumptions for benefits not starting till 2030 and then continuing for decades into the future is highly problematic. The prudent approach is to delay a decision or proceed with the minimum build (i.e. Option 1C-new). This would be in line with the ISP, which recommends an *"actionable HumeLink timing"* and concludes that the 'strictly rules-based optimal timing' is 2028-29.

4. Competition benefits should not be included

Contrary to the Addendum anticipating that *"AEMO will need to consider competition benefits in applying the feedback loop to HumeLink"*, the ISP states that *"AEMO has not included competition benefits in the assessment of the Draft ODP due to the significant uncertainty surrounding key assumptions that would need to be made in the calculation of these benefits."*

The PACR has inappropriately applied competition benefits to 'try to get the project over the line'. AEMO doesn't consider competition benefits to be sufficiently robust to be applied in the Optimal Development Path process, and likewise they should not be used in the RIT-T process or the determination of the preferred option. If the AER 'condoned' the application of competition benefits it would be flying in the face of AEMO's determination.

5. **Sensitivity adjustments are now certain**

The original PACR, and now the Addendum, includes sensitivity analyses for Kurri Kurri and Tallawarra B Gas Power Stations proceeding and for VNI-West being delayed.

Each of those possibilities is now practically certain and should be included in the net benefit analysis:

- the Commonwealth Government has committed $600m for construction and the NSW Government provided planning approval on 20 December 2021
- Tallawarra B has received $83m in support from both the NSW and Commonwealth Governments
- the ISP indicates the earliest date for VNI-West as July 2031

From the Addendum the consequent adjustments to the estimated net benefits range from -$90m (1C-new) to -$248m (2C & 3C) – see Table 1. The adjustments result in all options having negative net benefits when competition benefits are excluded, 1C-new being -$50m and 3C being -$199m.

	1C-new	2C	3C
No competition benefits	$40	-$33	$49
Adjust for KKPS, Tallawarra B and VNI-West delay	-$50	-$281	-$199
Include competition benefits	$335	$399	$491
Adjust for KKPS and Tallawarra B	$180	$250	$334
Impact of KKPS and Tallawarra B	-$155	-$149	-$157
Adjust for VNI-West delay	$400	$300	$400
Impact of VNI-West delay	$65	-$99	-$91
Impact of KKPS, Tallawarra B and VNI-West delay	-$90	-$248	-$248
Adjust for KKPS, Tallawarra B and VNI-West delay	$245	$151	$243

Table 1 – Net Benefits Central Scenario ($million)

Of course, further major generation and storage projects will reduce the benefits even further. One such project that seems likely to proceed is the 635 MW Port Kembla Gas/Hydrogen Power Station, which again has received $30m of Commonwealth Government support.

6. Overstated case for 3C

The Addendum repeatedly overstates the case for Option 3C, for example:

> *"The assessment in this PACR addendum finds that Option 3C has the highest expected net benefit of $49 million under these assumptions and is one of two options with a positive expected net benefit. Option 1C-new is the second-ranked option with estimated positive net benefits of $40 million, which is 18 per cent lower than Option 3C."*

Classifying the ranking as a 18% difference is highly misleading. The difference in net benefits is only $9m, in a cost of $3.3bn, which is miniscule (0.3%). A more balanced conclusion would have been that 1C-new and 3C are equal-first in this analysis.

7. Simplifying the net benefit estimates

The Addendum has a confusing array of net benefit figures for numerous scenarios, with and without competition benefits.

Accordingly, Table 1 attempts to provide a representative set of figures on a common basis, including the sensitivity adjustments. The green shading indicates the best or equal-best option for each comparison and the yellow shading indicates the most relevant comparison.

The Central Scenario was chosen as it was the basis of the PACR and is the only scenario with full details that could be gleaned from the Addendum. Of course other scenarios will have differing estimated benefits. The Step Change Scenario, which appears to be closer to the current trajectory, will have higher benefits. But whichever scenario is modelled, the estimated net benefits are either negative or marginal.

Under the Central Scenario, Option 1C-new is the best or equal-best option, except when competition benefits are included and without adjusting for KKPS, Tallawarra B and VNI-West delay, which, not surprisingly, happens to be the key comparison referred to by TransGrid.

8. HumeLink does not have a net market benefit

The VEPC Paper referred to the fundamental error of the PACR including Snowy 2.0's benefits but not its cost. When proper account is taken of Snowy 2.0's cost HumeLink has a net cost exceeding $4 billion.

But even setting aside that fundamental error, it is now clear that on TransGrid's own figures HumeLink has a net cost, varying from -$50m (1C-new), to -$199m (3C) to -$281m (2C) (see yellow-shaded row in Table 1). Option 1C-new is the clear 'winner', $149m better than the second-placed Option 3C, though still negative.

9. The revised cost estimates don't seem credible

As with the benefit estimates, there are also many questions on the latest cost estimates (Table 2).

Option 1C	Lines	1,411,002,211
Option 1C	Substation	289,269,038
Option 1C-new	Lines	1,544,607,246
Option 1C-new	Substation	264,027,937
Option 3C	Lines	1,795,790,891
Option 3C	Substation	547,430,760
Option 1C	BioCosts - Lines	1,294,347,643
Option 1C	BioCosts - Substation	24,381,108
Option 1C-new	BioCosts - Lines	821,227,995
Option 1C-new	BioCosts - Substation	23,936,823
Option 3C	BioCosts - Lines	893,734,554
Option 3C	BioCosts - Substation	29,043,795

Table 2 – Costs for 1C, 1C-new and 3C (PACR Addendum Model Results)

The most obvious is why the cost of the lines for Option 1C-new ($1,545m) is $134m higher than for Option 1C ($1,411m). Option 1C-new is double-circuit for its full length (272 km[15]), whereas 1C is double-circuit for 132 km west of Bannaby and then two single circuits for the remaining 140 km to Maragle (PACR p28, footnote 75).

Typically a double-circuit line is around 70% the cost of two single-circuit lines, so 1C-new should be significantly cheaper than 1C. Starting from the estimated line cost of 1C as the base, the line cost for 1C-new should be about $1,194m [$1,411m*(1.0 – 0.3*140/272)], which is some $351m less (23%) than the estimate in the Addendum.

If the explanation is that TransGrid has updated/increased its unit cost estimates for the Addendum, then similar adjustments would be applicable for 2C and 3C as well, meaning that the estimated line costs for Options 2C and 3C should also have increased

[15] The lengths of Options 1C-new and 3C are 272km and 366km (AER Determination Table 2)

by around 20%. If so, the estimated cost for Option 3C would now be approximately $3.7bn.

A second question concerns the much higher line and biodiversity offset cost estimates for 1C-new compared to 3C:

- the line cost for 1C-new is $5.7m/km [$1,545/272km], 16% higher than for 3C, being $4.9m/km [$1,796/366km]
- the biodiversity cost for 1C-new is $3.0m/km [$821m/272km], 25% higher than 3C, being $2.4m/km [$894m/366km]

There isn't any obvious reason for such a large difference in costs, especially as 1C-new covers the same route as 3C, only 94 km shorter. The only possible explanation is that both the line and biocost for the Blowering to Gugaa section of 3C are considerably less than the cost of the Bannaby to Maragle section. This doesn't seem plausible.

If the actual cost of 1C-new is $350m cheaper than the Addendum's estimate, this will transfer straight through to the net benefit, resulting in Option 1C-new having a net benefit of more than $500m better than Option 3C (excluding competition benefits). But as noted in Section 8, all HumeLink options still incur a net cost.

10. Other Factors need to be considered

The continued application of just the estimated net benefits in determining the best option is inappropriate. There are many other highly relevant factors that should be considered, such as network advantages/disadvantages, maintenance, exposure to bushfires and lightning, external losses, environmental, landowner and community impacts.

In particular, there will be a substantial environmental cost for this project over hundreds of kilometres and every action should be taken to minimise that impact. Over 360 kilometres of public and private lands will be impacted. TransGrid is receiving increasingly hostile opposition from local communities, creating social trauma and considerable costs and delays for TransGrid.

11. Option 3C has limited network capacity

The PACR estimates almost identical additional transmission capacity for all three options, of around 2,500 MW.

However, the ISP (Figure A5.4.3) states that the additional network capacity of HumeLink (Option 3C) is *"2,200 MW in both directions [presumably Wagga Wagga to Bannaby]. REZ network limit increase 1,600 MW in N6"*. (It is noted that the accompanying figure could be misleading, as the electrical connection is actually a triangular loop arrangement between Bannaby, Maragle and Wagga Wagga (renamed Gugaa), not a T-section. There is no electrical junction at Blowering.)

Whatever the correct network capacity, whenever Snowy 2.0 is generating at its full 2,040 MW rating there will only be minimal transmission capacity available for south-north flows from Project Connect, VNI-West and 1,600 MW of expected REZ generation. Whilst there will be diversity between the times of transmission, the question is, will HumeLink 3C be sufficient over the ISP's 2050 timeframe?

12. Option 2C is superior to 3C

The VEPC Paper outlines the advantages of Option 2C over 3C.

One of the most significant is that, contrary to the PACR, Option 2C provides significantly greater firm transmission capacity between Gugaa and Bannaby than 3C, due to its shorter direct route, rather than 3C's extended loop configuration.

Option 2C could provide up to 3,500 MW, the capacity of a single 500 kV line, from Gugaa to Bannaby in a double-circuit configuration.

For a similar cost and benefit, Option 2C enables an extra 1,000 MW of transmission capacity compared to Option 3C.

13. **LTSS is superior to Maragle**

The VEPC Paper outlines the numerous advantages of Lower Tumut Switching Station being the connection point between Snowy 2.0 and HumeLink.

And it would reduce the cost of HumeLink by hundreds of $millions.

14. **Who will pay for HumeLink?**

The 'elephant in the room' is who is going to pay for HumeLink, particularly pertinent for a project with negative benefits and based on highly contestable estimates.

The AER might well respond that this is not a matter for it in the RIT-T process and it will only intervene if there is no net consumer benefit estimated. Though, as demonstrated in this Paper, there is no net benefit, contrary to TransGrid's assertions.

HumeLink is the most expensive transmission project to ever be built in NSW and its capacity, route, timing, design and cost has been determined by the need to connect Snowy 2.0 to the grid. Were Snowy 2.0 not being built, HumeLink would not be needed till much later, it would take a much shorter and direct route between Bannaby and Gugaa, it would be less susceptible to outages from bushfires and lightning strikes, have lower electrical losses, have greater capacity and be much cheaper.

Snowy Hydro insist it has no responsibility for HumeLink or its cost, yet are expressing increasingly agitated concerns that it may not be built in time for Snowy 2.0's commissioning, scheduled for 2025-26 (though that looks to be optimistic).

As noted in the Draft ISP *"commissioning HumeLink in 2026-27 results in a reduction in weighted net market benefits of $284m, compared to waiting for reassessment in the 2024 ISP".*

At this stage the expectation is that HumeLink will be 'approved' as a regulated asset paid for by electricity consumers. This would be plainly unjust.

Surely this issue needs to be resolved before the RIT-T process goes any further and AER has a role in that determination.

15. Summary

Despite TransGrid's contention that the preferred option remains Option 3C, a proper assessment of TransGrid's latest estimates indicates this to be inconclusive at best, and flawed at worst.

Costs

i) the capital cost estimates have a *"high degree of uncertainty"* and other route options are still being considered, including undergrounding
ii) AEMO's ISP states that *"project costs cannot materially increase from the current estimate of $3.3 billion. Further work to drive down costs should be undertaken urgently"*
iii) costs could be reduced by using existing easements, upgrading existing 330 kV lines, connecting to LTSS rather than Maragle, and adopting Option 1C-new
iv) there appear to be anomalies in the estimated costs of the options – the cost gap between 1C-new and 3C may be larger

Benefits

i) competition benefits should not be included in the RIT-T process, following AEMO's decision to not include them in the assessment of the Optimal Development Path
ii) other benefits are overstated, particularly the assumed operation of Snowy 2.0

Net benefits

i) removing competition benefits and adjusting for Kurri Kurri and Tallawarra B Gas Power Stations proceeding and VNI-West being delayed, results in substantial negative net benefits for all options
ii) Option 1C-new has the least-worst negative net benefit (-$50m). Option 3C is -$199m
iii) net benefits get even more negative if the apparent costing anomalies are verified
iv) if Snowy 2.0 costs are included in the net benefit calculations, the negative net benefit for all options exceeds $4bn
v) Option 3C is not the best option, on financial or other grounds

Other issues

vi) there are many other relevant factors that should be considered, such as network advantages/disadvantages, exposure to bushfires and lightning, environmental, landowner and community impacts
vii) Option 2C has significant network advantages over 3C as does connection via LTSS rather than Maragle. Option 1C-new is the cheapest option with the least-worst net benefit
viii) resolution of who is to pay for HumeLink needs to be resolved before the RIT-T process goes any further

Clearly, the PACR and its Addendum are flawed. The AER should not 'approve' of the RIT-T progressing to the next stage before undertaking a rigorous assessment, especially for such an expensive and controversial project.