A.1 VNI West – Stage 1 (Early Works) – Contingent Project Application

Principal application document

21 December 2023

Transgrid

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Contents

A message from our CEO....1

Executive Summary....3

Contingent Project Application and timing....3
The Project....3
A project of national significance....5
Direction in AEMO's 2022 ISP to proceed with early works....6
Scope of our Stage 1 activities....6
Our capex forecast....8
Basis of capex estimate....9
Incremental Revenue requirement and customer bill impact....10
Customer consultation and support....11
Capital Expenditure Sharing Scheme (CESS)....12
Commercial viability of the Project....13

1. Introduction....15

1.1. Contingent Project Application and timing....15
1.2. This Principal Application....15
1.3. Compliance with the NER....16
1.4. Structure of this document....16
1.5. Structure of the Stage 1 Application for VNI West....17

2. Project Overview....19

2.1. A project of national significance....19
2.2. Direction from AEMO to proceed with Stage 1 (early works)....20

3. Regulatory Requirements....22

3.1. Regulatory requirements....22
3.2. Trigger events....23
3.3. Project timing....24
3.4. Customer and other Stakeholder engagement....25

4. Capex forecast....32

4.1. AEMO's definition and approval of Stage 1 activities....32
4.2. The scope and outcomes of our Stage 1 activities....33
4.3. Our Stage 1 capex forecasting method....41
4.4. Our Stage 1 capex forecast....42

4.5. Basis of capex estimate 47
4.6. Independent engineering verification of our Stage 1 Capex (early works).. 49
4.7. Capex threshold 49
4.8. Application of the CESS 49

5. Forecast Revenue and impact on customers' bills 51

6. Guide to compliance 54

Appendix A Revenue Application 56

A.1 Weighted average cost of capital (WACC) 56
A.2 Asset lives 57
A.3 Incremental regulatory depreciation 58
A.3a Appendix - AER Information Request – As incurred depreciation 59
A.4 Tax allowance 62
A.5 Debt and equity raising costs 62
A.6 Incremental revenue requirements for each year to end of period 63
A.7 Amended ABBRR and MAR 64

7. Abbreviations 65

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A message from our CEO

I am delighted to provide our Stage 1 Contingent Project Application for the delivery of VNI West, which will be one of our largest capital projects since construction of our existing network. VNI West involves construction of 500 kV double-circuit overhead transmission line. It is a joint Transgrid and AEMO Victoria Planning (AVP) project that will provide a second transmission interconnection between Victoria and NSW.

We recognise the urgency of the energy transition and are strongly committed to playing our role in the delivery of transmission infrastructure to achieve AEMO's Optimal Development Path. We stand ready to begin delivery of VNI West, which AEMO has confirmed to be in the long-term interests of Australian energy consumers. The project is critical to secure reliable, renewable energy for more than eight million people across New South Wales, as the Australian energy sector adjusts to the inevitable retirement of aged coal-fired power plants.

We acknowledge that VNI West is a significant investment for NSW consumers. We also appreciate the Government's acknowledgement of the financeability issues facing TNSPs in the development of these nation-critical mega projects and the creation of the Rewiring the Nation fund to support accelerated delivery while longer-term regulatory reform is undertaken to resolve the financeability challenges of these mega projects.

We also acknowledge the concerns of communities and landowners about the impacts of VNI West. We have been rigorous to ensure that:

- We continue to undertake significant community, stakeholder and consumer representative engagement and selected the route that best balances cost, environmental impacts and amenity impacts for local communities;
- Every practicable opportunity has been taken to reduce the cost to consumers, including embedding innovation in the design and technical solutions to deliver the most cost-efficient outcome, locking in long-lead equipment on a program basis to reduce cost and time and engaging reputable delivery partners via a competitive process;
- Our contracting model aligns our objectives with those of our delivery partners and consumers, with in-built incentives to deliver VNI West at the lowest cost; and
- Foreseeable risks have been appropriately accounted for and mitigated wherever possible.

These initiatives and others have resulted in a design, project plan, procurement and contracting model that, based on our many decades of experience, collectively provide, the best solution, to the significant challenges they seek to address, at the lowest possible cost to consumers while meeting the Integrated System Plan (ISP) timetable. This approach is also consistent with the National Electricity Objective to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers. It covers price, quality, safety, reliability, and security of supply of electricity as well as the reliability, safety and security of the national electricity system.

Undertaking these Stage 1 activities will ensure that the Project is delivered at the lowest sustainable cost to maximise benefits to customers, noting the overall cost saving to consumers is $847 million, comprising:

- $60 million for securing Long Lead Equipment (LLE) for transformers, reactors, conductor and steel through our Powering Tomorrow Together (PTT) program (this is the combined savings to consumers across our PTT program for LLE), and

- $787 million from the investment synergies, which arise from undertaking the PEC enhancement and Gugaa integration Design and Construction (D&C) works as part of our Stage 1 Activities. This will ensure that overall, this suite of ISP projects is delivered at the lowest sustainable cost for consumers.

We have received our feedback loop confirmation from AEMO, prior to this submission. AEMO has confirmed the project continues to optimise benefits to consumers and it remains on the Optimal Development Path (ODP). AEMO has undertaken its feedback loop assessment using its 2023 IASR and Draft 2024 ISP, published on the 15 December 2023.

AEMO's Draft 2024 ISP has taken into account the updated costs of VNI West (as reflected in this Application) and all other major projects as well as the latest expected timing of wider developments in the NEM, including the revised delivery date for Snowy 2.0.

We stand ready to proceed with the delivery of VNI West for the benefit of consumers and to advance Australia's emission reduction targets. However, financeability of VNI West remains a key challenge.

We have been working with the Clean Energy Finance Corporation (CEFC) to develop a concessional financing package via the Rewiring the Nation program. The Federal and Victorian governments announced that the CEFC will provide a concessional loan of $750m.This will assist Transgrid to make the significant financial commitment required to deliver this multi-billion-dollar nation-critical project. However, given the current economic conditions, the Rewiring the Nation fund is limited in its ability to provide a complete resolution to the financeability issue, as such we appreciate the AER's consideration of limited further support to enable the VNI West project to be financed.

To ensure we are best able to proceed with early works for VNI West, we respectfully request the following:

- approval from the AER for incremental revenue commensurate with the capital and operating costs of VNI West as we have proposed in this Application;
- confirmation from the AER that the CESS regime will not apply in relation to VNI West, given critical differences in the scale and complexity of VNI West relative to the context in which CESS was designed to apply;
- approval from the AER for the establishment of a new asset class for biodiversity offsets to enable depreciation of these costs over the weighted average of the standard lives of all other depreciating assets;
- approval from the AER to adopt as incurred depreciation for all depreciable asset classes.

We have worked closely with our investors in developing this Application. Our investors are well across the equity investment required to deliver VNI West and plan to progress their equity commitments through their internal approval processes based on the risk profile contemplated in our Application and based on the confirmation of Transgrid's Baa2 or equivalent rating. Binding equity commitments will be sought at the time of a final investment decision.

As a pivotal component of AEMO's Optimal Development Path to support the energy transition, Transgrid proudly stands ready to deliver this nation-critical project.

Brett Redman
Chief Executive Officer
December 2023

Executive Summary

Contingent Project Application and timing

We are pleased to provide our final Contingent Project Application for early works (Stage 1 Application or CPA-1) for the Victorian to New South Wales (NSW) Interconnector West (VNI West or the Project). This is the Principal Application document, which sets out our proposed expenditure, the associated incremental revenue requirement and the indicative customer bill impacts for Stage 1 activities.

The timing for the submission of this Stage 1 Application is driven by our commitment to complete the required early works in line with the State and Federal Governments accelerated timeframes to deliver the Project by 2028 to ensure that the customer benefits from the project can be delivered as soon as possible. In particular, commencing work now to identify land and negotiate the establishment of biodiversity stewardship sites is critical to minimise costs to consumers and assist to meet the target delivery date, noting that these take around two to three years to establish and are required prior to construction commencing. Our strong preference is to obtain a final determination from the AER by February 2024, so that Transgrid can meet its contractual commitments and avoid the erosion of customer benefits as a result of project delay.

We acknowledge that to date D&C activities and costs have not been included in Stage 1 Applications. However, the construction timeframes for PEC and Humelink, to which the PEC enhancement and Gugaa integration works relate, require us to undertake the D&C activities in VNI West Stage 1 to realise the synergies and costs savings from concurrent investment. We have therefore reflected the cost of these activities in this Stage 1 Application. Further, undertaking the D&C works for the PEC enhancement is in line with AEMO's expectation that Stage 1 activities for VNI West would include 'strategic network investment.'

The costs in this Application reflect the Stage 1 activities associated with the preferred option (Option 5A) identified by the Regulatory Investment Test for Transmission (RIT-T) Project Assessment Conclusions Report (PACR) for VNI West, which was published on 27 May 2023.

On 26 June 2023, Moorabool and Central Highlands Power Alliance Inc. (MCHPA) lodged a dispute under clause 5.16B of the National Electricity Rules (NER or Rules) on the grounds that the PACR does not comply with specific provisions of the NER. The AER's Determination did not uphold the dispute and found that no amendments are required to the PACR. [1]

We have submitted our feedback loop request to the Australian Energy Market Operator (AEMO) and they have confirmed a positive feedback loop and the project remains on the ODP. The positive written feedback loop confirmation from AEMO is required to satisfy the trigger events for actionable ISP projects.[2] These trigger events must be satisfied prior to us submitting our formal Stage 1 Application to the AER.

The Project

VNI West is a joint Transgrid and AEMO Victoria Planning (AVP) project that will provide a second transmission interconnection between Victoria and NSW. It is a key component of the energy market transition and will:

- harness clean, low-cost electricity from renewable energy zones (REZs) in both states and make better use of Snowy 2.0's deep storage. This in turn will help to reduce carbon emissions and improve the reliability and security of electricity supply as ageing coal-fired power stations are retired. This is

1 See https://www.aer.gov.au/victoria-nsw-interconnector-west-vni-west-rit-t-dispute
2 Rule 5.16A.5 Actionable ISP project trigger event.

expected to put downward pressure on energy costs by lowering overall power system investment and dispatch costs across the National Electricity Market (NEM), and

- provide interconnector diversity by creating multiple physical interconnector routes between Victoria and NSW that have no geographic points in common. This diversity will improve resilience of the network to extreme climate conditions, thereby improving overall system security.

AEMO's 2022 ISP,[3] has defined VNI West as a staged actionable ISP project, with no decision rules:[4]

- Stage 1 is to complete the early works by approximately 2026, and
- Stage 2 is implementation of the Project with a target delivery date of July 2031 (or earlier).

Subsequent to the 2022 ISP, the State and Federal Governments have provided concessional financing under the Rewiring the Nation plan to accelerate the delivery of VNI West to 2028, to ensure that the customer benefits from the Project can be delivered as soon as possible.[5]

Importantly, achieving the 2028 target delivery date is subject to undertaking early works activities to obtain the necessary planning and environmental approvals, secure land and easements, progress detailed design, establish biodiversity stewardship sites and engage with the community and landholders. These activities are expected to take around two to three years to complete.

Transmission Company Victoria (a wholly owned subsidiary of AEMO) has already commenced early works for the Victorian portion of the Project.[6]

This Application covers the Stage 1 activities for the Project, which will enable us to:

- determine the prudent and efficient Stage 2, Project delivery, cost by refining the Project scope through further detailed design activities, with a focus on innovation, cost-effective design. Our Stage 2 Contingent Project Application (Stage 2 Application or CPA-2) will reflect the bulk of the Project's costs. We expect to determine a Stage 2 (Delivery) capex forecast in line with an AACE[7] class 2 to 3 cost estimate to provide confidence regarding the accuracy of our cost estimates.
- secure the cost savings for consumers from our programmatic approach to delivering the ISP projects, which we are responsible for delivering. This approach is known as the Powering Tomorrow Together (PTT) program and involves the integrated delivery of VNI West, Humelink and Project EnergyConnect (PEC or EnergyConnect) and has been established to accelerate the delivery of transmission infrastructure and drive costs down through economies of scale and scope. The combined cost saving for consumers from the PTT program in respect of long lead equipment (LLE) in this Stage 1 Application is estimated to be $60 million
- identify, explore and manage the project risks. This will allow us to mitigate and/or diversify the Project's risks so that the residual risk costs included in our Stage 2 Application are as low as possible

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3 This document refers to AEMO's 2022 ISP, as it is the most recently completed ISP in accordance with the NER. It should be noted that the Draft 2024 ISP, published on 15 December 2023, confirms AEMO's 2022 ISP conclusions in relation to VNI West, including its proposed timings.
4 AEMO, 2022 ISP, June 2022, p. 74
5 AEMO, Transgrid, VNI West Project Assessment Conclusions Report Volume 1: identifying the preferred option for VNI West (VNI PACR), May 2023, p.30. The PACR explains that concessional financing of $750 million from the Clean Energy Finance Corporation (CEFC) will ensure that the completion date for VNI West can be accelerated to 2028 from the 2031 date set out in the 2022 ISP (see table 1, page 13)
6 These early works are enabled in Victoria by the February 2023 *National Electricity (Victoria) Act* 2005 (NEVA Order)
7 Association for the Advancement of Cost Engineering (AACE) International – cost estimation classification system

- achieve the target delivery date of 2028 by progressing activities on the critical path to ensure that construction can commence as soon as possible following the approval of our Stage 2 Application. [8] Activities on the critical path include securing LLE, undertaking continued stakeholder engagement, acquiring access to land and establishing biodiversity stewardship sites using Biodiversity Stewardship Agreements (BSA), and
- realise investment synergies arising from undertaking D&C works associated with the integration of VNI West with Humelink and PEC. This will ensure that the suite of ISP projects for which we are responsible are delivered at the lowest overall sustainable cost for consumers. We estimate that the cost saving to consumers is $787 million from undertaking these D&C work packages as part of our VNI West Stage 1 activities.

Undertaking these Stage 1 activities will ensure that the Project is delivered at the lowest sustainable cost to maximise benefits to customers, noting the overall cost saving to consumers is $847 million.

Unless otherwise stated, all expenditure forecasts in this Application are expressed in real 2022-23 dollars, and all revenue forecasts are expressed in nominal terms, consistent with our 2023-28 Revenue Determination.

A project of national significance

VNI West will be one of our largest capital projects since construction of our existing network. It involves construction of 500 kV double-circuit overhead transmission line between Victoria and NSW, connecting Western Renewables Link (at Bulgana) with PEC (at Dinawan) via a new terminal station near Kerang, and crossing the Murray River north of Kerang.

In 2021, the Australian Government identified VNI West as a key component of Australia's Long Term Emissions Reduction Plan. The Plan highlighted that VNI West is expected to provide additional electricity transfer capacity between Victoria and NSW, unlock electricity from Snowy 2.0 to the Victorian market and unlock two REZs.[9]

AEMO's 2022 ISP reconfirmed the need for VNI West to increase interconnection between Victoria and NSW and the benefits it will provide to consumers.[10] VNI West has been a key project in AEMO's ISPs since 2018.[11] The Victorian Government has also confirmed the importance of the Project, with the issuing of two Orders under the *National Electricity (Victoria) Act* 2005 (NEVA Orders) confirming both the need for, and the required configuration of, the Project.

On 27 May 2023, we published the RIT-T PACR. Consistent with the requirements of the second Victoria NEVA Order relating to the Project, this identifies Option 5A as the preferred option to provide a second transmission link between Victoria and NSW to:

- harness clean, low-cost electricity from REZs in both states
- increase the electricity export capacity from Victoria to NSW, and
- improve the reliability and security of electricity supply coal-fired power stations are retired.[12]

VNI West will also provide interconnector diversity, which will increase the resilience of the network against extreme climate conditions and improve overall system security.

8 AEMO, 2022 ISP, June 2022, p.13. (See Table 1).
9 Australian Government, Australia's Long-Term Emissions Reduction Plan - DCCEEW, 2021
10 AEMO, 2022 ISP, June 2022, p. 74
11 AEMO, 2018 ISP, AEMO, 2018 ISP, July 2018, pp 8-9, 86-88 & 90-92VNI West was previously called SnowyLink,
12 AEMO, Transgrid, VNI PACR, May 2023, p.5

The RIT-T estimates that VNI West Option 5A will deliver $1.4 billion in net benefits (in net present value terms), primarily from avoided, or deferred, costs associated with generation and storage infrastructure, fuel cost savings and REZ transmission expansion cost savings.[13]

Direction in AEMO's 2022 ISP to proceed with early works

AEMO's 2022 ISP directed us to proceed now with Stage 1 activities to achieve the following benefits:[14][15]

- insurance value and system reliance – providing greater system resilience to earlier than projected coal closures. AEMO has assessed that the earlier that coal-fired generation retires, the earlier VNI West is needed[16]
- option value – allowing delivery of the Project as soon as possible or defer it if circumstances change[17]
- protection against rising costs – urgently undertaking further work to drive down costs given the risk to supply chains of increasing global demand for the same infrastructure expertise, materials and equipment.[18] It will also secure the fuel cost savings arising from a reduction in gas generation.
- storage and firming access - it will increase access to Snowy 2.0's deep storage and other firming capacity from interstate,[19] and
- variable renewable energy (VRE) reduction and support – it will reduce VRE curtailment by sharing geographically diverse VRE. It will also support new VRE needed to replace coal-fired generation (particularly in the Murray River and Western Victoria REZs).

As noted earlier, the State and Federal Governments have provided concessional financing under the Rewiring the Nation plan to accelerate the delivery of VNI West to 2028, to ensure that the customer benefits can be delivered as soon as possible. Achieving the 2028 delivery date requires us to start the Stage 1 works as soon as possible.

Scope of our Stage 1 activities

The scope of our Stage 1 activities is in line with AEMO's definition of early works, which includes 'activities such as pre-construction activities that can be undertaken now, while keeping open the option to continue, defer or cancel the project as new information becomes available.[20] For VNI West, AEMO has identified the following as stage 1 activities:[21]

- project initiation – scope, team mobilisation, service procurement
- stakeholder engagement – with local communities, landholders and other stakeholders
- land-use planning – identifying and obtaining all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection and easement acquisition

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[13] AEMO, Transgrid, VNI PACR, May 2023. P. 12
[14] AEMO, 2022 ISP, pp.74 and 80
[15] As already noted, while we refer to the 2022 ISP, as it the most recently completed ISP in accordance with the NER, the draft 2024 ISP published on 15 December 2023 is consistent with the earlier findings.
[16] AEMO, 2022 ISP, pp. 67 and 92
[17] AEMO, 2022 ISP, pp.85 and 86
[18] AEMO, 2022 ISP, pp. 96-99
[19] AEMO, 2022 ISP, p. 74
[20] AEMO, Feedback Loop Notice, 27 January 2022
[21] AEMO, 2022 ISP, p. 75

- detailed engineering design – transmission line, structure and substation design, detailed engineering design and planning
- cost estimation – finalisation, including quotes for primary and secondary plant, and
- strategic network investment – an uplift to the delivered capacity of PEC between Dinawan and Wagga Wagga.[22]

In addition to these pre-construction activities, we have included two design and construction (D&C) packages in our Stage 1 capex. This will ensure that investment synergies between the integration works required for VNI West and the works being undertaken for other ISP projects, in particular PEC and Humelink, are fully realised. We have adopted this approach based on a careful review of our entire program of work for ISP projects, in order to identify synergies and cost savings during the construction phase to ensure these projects are delivered at the lowest sustainable cost for consumers overall. These D&C packages are:

- PEC enhancement to increase the capacity of the transmission line from the Dinawan Substation to Wagga Wagga from 330 kV to 500 kV,[23] and
- Gugaa integration works required to integrate the 500kV PEC enhancement with the Gugaa 500/330kV Substation which is being built as part of Humelink.

We estimate that the cost saving to consumers is $787 million from undertaking these D&C works as part of our Stage 1 activities, rather than Stage 2. This cost saving comprises:

- for the PEC enhancement, approximately $697 million, and
- for the Gugaa integration works, approximately $90 million.

We acknowledge that to date D&C activities and costs have not been included in Stage 1 Applications. However, the construction timeframes for PEC and Humelink, to which the PEC enhancement and Gugaa integration works relate, require us to undertake these D&C activities in VNI West Stage 1 to realise the synergies and costs savings from concurrent investment. We have therefore reflected the cost of these activities in this Stage 1 Application. Further, undertaking the D&C works for the PEC enhancement is in line with AEMO's expectation that Stage 1 activities for VNI West would include 'strategic network investment'.[24]

The AER's approval of our forecast capex is required in order for us to proceed with these investments. As explained above, we regard this bringing forward of works as prudent and efficient, noting that it provides a net saving to customers.

In the case of the PEC enhancement work it would not be practical (or cost efficient) to retroactively upgrade our current investment in PEC to 500kV. This is reflected in the current Federal Government underwriting which has been provided to ensure consumers realise the benefits of the enhancement as part of our VNI West Stage 1 activities.

In relation to the Gugaa integration work, we recognise that the regulatory process relating to our Contingent Project – Stage 2 delivery Application for Humelink has yet to conclude, and so our Final Investment Decision (FID) has yet to be confirmed. Notwithstanding this, to meet the required timing for Humelink we are proceeding on the basis that the regulatory process will result in the revenues required to

[22] AEMO, 2022 ISP, p 75. The Commonwealth Government has underwritten funds to build a component of PEC at a larger capacity such that it removes the need to duplicate lines for VNI West when it is constructed.
[23] The costs and benefits associated with this enhancement have been assessed as part of the VNI West RIT-T.
[24] AEMO, 2022 ISP, p.66.

enable us to make a positive FID, and therefore that the incremental integration works to connect VNI West into the new Gugaa substation will be required. The expected timing of our investment in Humelink means that these integration works are expected to occur as part of Stage 1 of VNI West. We consider it appropriate to include these integration works as part of this Stage 1 Application, rather than lodging a further Application following our FID for Humelink.

Our capex forecast

Table 1 shows that our total VNI West Stage 1 forecast capex is $1,096.33 million, excluding equity raising costs. We will incur most of this capex in the 2023-28 regulatory period.

Our Stage 1 capex is incremental to the capex approved by the AER in its 2023-28 Revenue Determination because it relates to activities that are additional to our normal business activities and would not be incurred other than for undertaking early works for VNI West.

Table 1: Stage 1 capex ($M, Real 2023-23, excluding equity raising costs)

VNI West	2018-21	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Actual	0.15	8.18	10.71	-	-	-	19.04
Forecast	-	-	58.10	499.68	450.11	69.41	1,077.29
Total	**0.15**	**8.18**	**68.81**	**499.68**	**450.11**	**69.41**	**1,096.33**

Notes: 1. Including overheads, excluding equity raising costs. 2. Totals may not add due to rounding.

Our Stage 1 (early works) capex of $1,096.33 million includes:

- direct capex of $890.72 million (81.25 per cent of total capex), and
- labour and indirect capex of $205.61 million (18.75 per cent of total capex).

Our direct capex forecast of $890.72 million comprises:

- $792.87 million for procurement activities (or 72.32 per cent of capex). These activities include:
  - purchasing LLE for transformers, reactors, conductor, steel and power-flow controllers.
  - a D&C work package to enhance the capacity of a component of PEC (which forms part of the scope of the VNI West Project)[25]
  - a D&C work package for the Gugaa integration works, required to connect the enhanced PEC component of the Project at the Gugaa substation (being constructed as part of Humelink), and
  - undertaking pre-construction development, including for substations and transmission lines, specifications and identifying quantities of plant and materials required.
- $97.85 million or 8.92 cent for acquiring transmission line easements including:
  - biodiversity offset costs
  - binding options for transmission line easements, and
  - compulsory acquisition costs
- Our labour and indirect capex forecast of $205.61 million or 18.75 per cent:

[25] Media Release, Minister Taylor, Government supporting delivery of critical transmission infrastructure in Southwest NSW, 28 September 2021. This is per the pre-agreed variation under sub-clause 13.13(a) of the EPC Contract, dated 24 September 2021

- $65.16 million or 5.94 per cent for labour related to internal resource requirements, and
- $138.80 million or 12.66 per cent for indirect non-labour capex, relating to a wide range of professional and consulting services, as well as tender payments and associated facilities costs.

Basis of capex estimate

We have developed our forecast capex based on a detailed scope of works using methods that reflect the specific nature of the costs. This includes externally tendered (competitive) design and construct contracts, manufacture and supply contracts, pricing from suppliers, independent specialist advice, and actual costs for PEC and Humelink. These costs have been independently verified by GHD as being efficient and reflect cost savings for consumers of:

- $60 million for securing LLE through our PTT program, and
- $787 million from the investment synergies, which arise from undertaking the PEC enhancement and Gugaa integration D&C works as part of our Stage 1 activities.

We note that the AER has requested further information on our proposed contingency allowances in response to our draft CPA-1 submission. In addition to responding to this information request, we acknowledge the need to work with the AER to discuss the different sources of risk and how best to manage them given the project tight timeframes and contractual commitments. We therefore look forward to working closely with the AER during the review process to ensure that these uncertainties are managed in the best interests of consumers.

Table 2 summarises our Stage 1 forecast capex and the basis of our forecast capex for each capex subcategory.

Table 2: Stage 1 forecast capex – basis of estimate by sub-category of capex

Direct costs		Millions	Basis of estimate
Procurement			
LLE	Transformers, Reactors	59.29	Competitively tendered manufacture and supply contracts, which set out quantities and costs
	Conductor	34.53	Agreement with suppliers, which set out quantities and costs
	Steel	47.67	Fission independent estimate based on quantities and costs
	Power flow control units	87.40	[redacted] cost estimate for 10-1800 [redacted] units in NSW.
Subtotal		**228.89**	
PEC enhancement	500KV Transmission line enhancement	[redacted]	Contract cost (PEC variation) externally tendered (competitive) D&C contract.
		[redacted]	This is based on a combination of: • our actual property compensation costs, from Ellipse,[26] to acquire easements $19.16M

[26] Ellipse is our enterprise resource planning (ERP) system

Direct costs		Millions	Basis of estimate
			• alignment change request form from the D&C contractor [redacted] • a 330kV line diversion cost of [redacted] • an independent estimate from WSP for biodiversity offset cost $10.12M • independent advice from Fission on the appropriate contingency allowance $57.60M
Subtotal		**345.61**	
Humelink (Gugaa) integration works	Connection of the enhanced PEC component of the Project at the Gugaa substation	168.97	Contract cost (Humelink variation) externally tendered (competitive) D&C contract. This includes contingency based on advice from Fission.
Pre-construction development	Transmission lines and substations	49.40	We have adopted costs based on 4.43% of the total construction cost from PACR based on independent advice from AECOM.
Land acquisition			
Land acquisition	Valuation and acquisition costs	30.73	An independent estimate from JLL
Biodiversity offsets	biodiversity offset liability costs	67.12	An independent estimate from WSP
Total direct costs		**890.72**	
Labour and indirect costs			
Labour	Internal resource requirements	65.16	Bottom-up build of costs over the period from 1 June 2023 to 30 April 2025
Indirect	Professional and consulting services	140.45	Bottom up-build using current available market rates and recent historical data.
Total labour and indirect costs		**205.61**	
Total Stage 1 capex		**1,096.33**	

Incremental Revenue requirement and customer bill impact

Based on our Stage 1 capex forecast, we are seeking the AER's approval to increase our maximum allowed revenue (MAR) for the 2023-28 period. Our required incremental revenue is modest because:

- we are not seeking to adjust our 2023-28 opex allowance as part of this Application, other than adjusting our allowance for debt raising costs as a consequence of the revised capex allowance, and
- our capex is not expected to be commissioned until 30 April 2025 when the early works have been completed.

Table 3: – Incremental maximum allowed revenue – MAR (smoothed) ($M, Nominal)

MAR (Smoothed Revenue)	2023-24	2024-25	2025-26	2026-27	2027-28	Total
2023-28 Decision (updated for the Humelink Early Works Parts 1 and 2)	923.99	960.11	995.98	1,033.19	1,071.78	**4,985.05**
Impact of VNI West Stage 1	-	-	41.86	88.67	82.82	**213.36**
Updated MAR	**923.99**	**960.11**	**1,037.84**	**1,121.86**	**1,154.61**	**5,198.40**

Based on the forecast MAR adjustment, the indicative customer bill impact is an increase of $7.07 per annum for residential customers and an increase of $14.05 per annum for small business customers, commencing in 2025-26. These transmission cost increases will be more than offset by savings in wholesale costs, noting that the VNI West RIT-T estimates that the Project will deliver $1.4 billion in net benefits (in NPV terms) primarily from avoided, or deferred, costs associated with generation and storage infrastructure, fuel cost savings and REZ transmission expansion cost savings.

Customer consultation and support

The size and scale of the energy transition, of which a key project is VNI West, has generated strong reactions from a wide range of stakeholders including local communities, landowners, First Nations people and primary producer groups. Many of these communities will host new transmission infrastructure and renewable energy projects across the NEM. The preservation of the environment, rural amenity and primary production industries are at the heart of these concerns, with a wide range of stakeholders calling for earlier participation in planning processes, and improved compensation and community benefit sharing.

Effective engagement in Stage 1 is critical to secure our social licence[27] to deliver the Project and therefore minimise the risk of the Project being delayed and the associated costs. Our Stage 1 consultation will:

- provide information on the Project timeframes, milestones and engagement processes so that customers have the maximum opportunity to be involved in the Project
- ensure that the community understands the benefits of the project
- facilitate genuine engagement with impacted communities and landholders, to enable them to meaningfully participate in project planning during the early work phase, and
- support us securing access to and commencing negotiations relating to the acquiring of easements over land.

In July 2021, we re-set our community engagement processes[28] based on respectful, effective and transparent engagement with impacted communities and landholders. We have developed a detailed Community and Stakeholder Engagement Plan which outlines for all Major Projects, including VNI West, our engagement approach, with whom we will engage, our engagement timeframes and associated activities. The Plan details a broad range of engagement channels and forums to cater for different interests and availability and ensure that stakeholders at all levels can meaningfully participate in project planning during the early work phase.

[27] Transgrid Social Licence Framework

[28] Transgrid, Review of Humelink engagement process, Findings of the Review - Landholder and Community Advocate, July 2021

These include ongoing and regular briefings with key stakeholders and consumer representatives through established committees and reference groups. We will also undertake community and landholder facing engagement activities such as community information days, town hall meetings, webinars and public displays. These activities will be supported by timely and relevant communications materials including a dedicated website[29], community resources, visualisations[30] and interactive maps[31]. In addition, our engagement team features regionally based Place Managers who bring depth and credibility to our work with landowners and communities through shared experience and local knowledge.

In accordance with our route development process, we have also established a Regional Reference Group to provide guidance on the key social, environmental and technical matters, which will be assessed as we consider corridor options.

We recently established a Community Consultation Group (CCG). The CCG will provide guidance on key matters for consideration during route planning, including the effectiveness and suitability of proposed impact mitigations, and opportunities for community investment and benefit initiatives which would provide a positive social legacy outcome for affected communities.

Capital Expenditure Sharing Scheme (CESS)

As discussed with the AER and our other stakeholders, including the TAC, we do not support the application of CESS to AEMO's ISP projects. This is because in an inflationary and uncertain operating environment with high value, complex and specialised projects, these incentive schemes introduce an asymmetric risk.

The key drivers of this asymmetric risk costs arise from:

- labour shortages
- increasing materials costs and supply chain disruption, and
- other and unquantifiable costs that will arise in a project such as this, given the operating environment and the unique characteristics of ISP Projects including their size and scale.

To safeguard against potential losses (i.e., risk costs) D&C contractors require some cost components in their contracts to be variable. This allows them to offer a lower contract price than they otherwise would if they were forced to price in the risk costs though a fixed price contract.

Given the uncertain and challenging operating environment and contractors not being able or willing to enter into fixed price D&C contracts, the probability of overspending the AER's capex allowance is greater than the probability of underspending it. This asymmetric risk and other uncertainties have been captured in a contingency allowance, which is applied to the base PEC enhancement and Gugaa integration D&C contract costs, and is critical to enable us to deliver the D&C activities on time and on budget.

Further, it would therefore not be in the long-term interest of consumers to apply penalties or rewards based on the CESS for differences between actual and forecast expenditure where these differences are driven by factors other than true efficiency savings or losses. The AER's underlying building block framework already provides an appropriate financial incentive for us to minimise capex. This is because during the regulatory period, revenues are based on forecast capex, such that we do not earn a return on any capex overspend for the duration of the regulatory period. Any capex overspend is rolled into our

[29] The website is designed to provide general information about the Project and facilitate feedback process by providing a one-stop-shop for communications – newsletters, fact sheets, presentations.
[30] Visualisations are used to provide landowners with a 3D visualisation of the towers.
[31] An online engagement platform to support route development engagement.

regulatory asset base (RAB) at the start of the subsequent regulatory period, only then enabling us to earn a return on our actual prudent and efficient capex.

Transgrid would welcome further discussions with the AER regarding the application of the CESS, given the significant exposure that it creates for customers and investors for a project of this nature.

Commercial viability of the Project

We consider that VNI West is in the long-term interests of consumers because it is integral to achieving AEMO's ODP. However, no matter how beneficial VNI West and other major transmission projects will be to consumers, they must be commercially viable in order to proceed. There are two elements to commercial viability:

- The allowed return must be reasonable – it must match the market (risk reflective) cost of capital, and
- The regulatory allowance must be provided in a way that enables network businesses to support the benchmark credit rating (BBB+ under the 2022 RoRI) at the benchmark level of gearing (60% under the 2022 RoRI), while funding network augmentation projects. That is, the regulated cash flows associated with a major project such as VNI West must be sufficient to ensure the financeability of that project.

No business could be reasonably expected to pursue a project that:

- is forecast to generate less than the return that investors in the market would reasonably require, given the risks associated with that project, and / or
- is expected to generate regulated cash flows that are insufficient to support the AER's benchmark credit rating at the benchmark level of gearing.

To address the above issues we have applied as incurred depreciation, the NER already allows the AER to depreciate transmission assets on an as incurred basis, including for ISP projects. The NER outlines the depreciation framework the AER must apply to distribution and transmission assets and does not specifically provide for or prevent depreciation to be recovered from assets on an as incurred basis.

The importance of investors being able to earn the regulated rate of return on these very large projects, and being able to attract the required debt and equity capital is critical to achieving Australia's net zero vision. The regulated return is calculated assuming a benchmark regulated entity and a defined credit rating. The current CEFC commitment is an extremely helpful step, however still falls somewhat short of providing a complete solution, with financeability remaining a very real challenge to ensure these critical projects are delivered in a timely manner.

We acknowledge the complexities arising from current macro-economic challenges, and see this reflected in the Government's acknowledgement of the need for further regulatory reform to help deliver the clean energy transition as well as recent draft rule changes aimed at a sustainable solution for financeability. To this end, we will continue in good faith to negotiate with the CEFC and the AER to resolve appropriate solutions which will enable these projects to be financed and delivered.

We consider that a clear, objective, predictable and quantitative process to assessing the financeability of major transmission projects such as VNI West and for addressing any financeability concerns identified, is required to give investors the confidence to commit to such projects. We therefore welcome the AEMC's recent draft determination which seeks to resolve the financeability issues through a prescriptive approach that provides investor confidence.

In response to Transgrid's email advice to the AER on 17 November 2023, the AER has asked Transgrid to explain its reasons for proposing 'as incurred' depreciation, rather than 'as commissioned' which is the standard approach for transmission regulation. Please refer to appendix A.3a of this document for our detailed response.

1. Introduction

1.1. Contingent Project Application and timing

We are pleased to submit our Stage 1 Application for VNI West. This is the Principal Application document, which sets out our proposed expenditure, the associated incremental revenue requirement and the indicative customer bill impacts for Stage 1 activities.

The timing for the submission of this Stage 1 Application is driven by our commitment to complete the required early works in line with the State and Federal Governments accelerated timeframes to deliver the Project by 2028 to ensure that the customer benefits from this project can be delivered as soon as possible. In particular, commencing work now to identify land and negotiate the establishment of biodiversity stewardship sites is critical to minimise costs to consumers and assist to meet the target delivery date, noting that these take around two to three years to establish and are required prior to construction commencing.

The RIT-T concluded on 16 October 2023, when the AER published its determination on the Project Assessment Conclusions Report (PACR) dispute raised by MCHPA. The AER's Determination did not uphold the dispute and found that no amendments are required to the PACR, which was published on 27 May 2023.

In light of the delay to the conclusion of the RIT-T process, to promote transparency and seek stakeholder feedback, we published the draft Stage 1 Application on 1 September 2023. Early stakeholder engagement is essential due to the scope of the activities and significant costs involved. It provides an opportunity for stakeholders and the AER to provide their views and positions prior to our final Stage 1 Application being lodged, which will in turn assist to expedite the AER's decision-making process. The decision-making process will commence once the AER receives our final Stage 1 Application. A timely decision from the AER is crucial to provide the revenue certainty needed in order to proceed with our Stage 1 activities.

We have received our feedback loop confirmation from AEMO, prior to this, noting that positive written feedback loop confirmation from AEMO is required to satisfy the trigger events for actionable ISP projects.[32] AEMO have confirmed the Project remains on the Optimal Development Path (ODP).

1.2. This Principal Application

This Principal Application relates to Stage 1 activities associated with VNI West. Stage 1 activities have been identified by AEMO as required now to ensure that the project is progressed urgently[33] and will:

- identify, explore and manage key risks and external factors that will impact the Project's overall costs. These works will assist to reduce cost uncertainty and identify reasonable risk cost amounts for Stage 2 (Delivery) of the Project, when the bulk of the costs of delivering VNI West will be incurred. This will ensure that Stage 2 costs are prudent and efficient, and
- progress activities on the critical path to deliver VNI West by the accelerated delivery date of 2028, which is supported by concessional financing from State and Federal Governments under the Rewiring

32 Rule 5.16A.5 Actionable ISP project trigger event.
33 AEMO, 2022 ISP, June 2022, p.93.

the Nation plan. This will ensure that the customer benefits arising from the Project can be delivered as soon as possible.[34]

To help facilitate this acceleration, Transmission Company Victoria TCV (subsidiary of AEMO) has commenced early works for the Victorian portion of the project.[35]

Importantly, achieving the 2028 target delivery date is subject to undertaking early works activities to obtain the necessary planning and environmental approvals, secure land and easements, progress detailed design, establish biodiversity stewardship sites and engage with the community and landholders. These activities are expected to take around two to three years to complete. Our strong preference is to obtain a final determination from the AER by February 2024, so that Transgrid can meet its contractual commitments and avoid the erosion of customer benefits as a result of project delay.

We are committed to delivering the Project at the lowest sustainable, whole of lifecycle cost to maximise benefits to customers. Our capex forecast is efficient and prudent as explained in this Application.

Section 3.2 of this Principal Application explains the relevant trigger events for Stage 1 (early works) and provides an update on their status.

In accordance with clause 6A.8.2 of the National Electricity Rules (NER or Rules), this Principal Application seeks the AER's approval to amend the capex allowance in our 2023-28 Revenue Determination and our revenue requirements and MAR for the 2023–28 regulatory period, so that we can recover the efficient costs of Stage 1 activities.

1.3. Compliance with the NER

This Application and the supporting documents establish the matters in clause 6A.8.2(f) of the NER, being:

- the forecast of the total capex for the Project meets the threshold as referred to in clause 6A.8.1(b)(2)(iii)
- the amounts of forecast capex and incremental opex reasonably reflect the capex criteria and the opex criteria, taking into account the capex factors and the opex factors respectively, in the context of the contingent project
- the estimates of incremental revenue are reasonable, and
- the dates are reasonable.

1.4. Structure of this document

The remainder of this document is structured as follows:

- Chapter 2 describes the Project and the direction from AEMO in its 2022 ISP to proceed with Stage 1
- Chapter 3 sets out the regulatory requirements for this Stage 1 Application
- Chapter 4 sets out forecast capex for the Stage 1
- Chapter 5 sets out forecast incremental revenue for the Stage 1 activities and the indicative customer bill impact

[34] AEMO, Transgrid, VNI PACR, May 2023, p.30. This explains that concessional financing of $750 million from CEFC will ensure that the completion date for VNI West is accelerated to 2028 from the 2031 as set out in the 2022 ISP (see table 1, page 13)

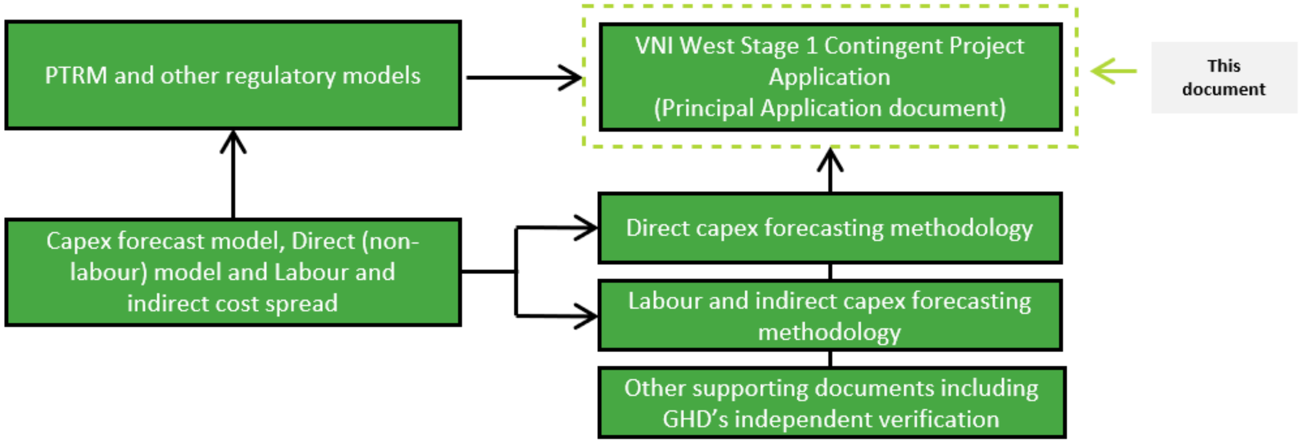
[35] These early works are enabled by the February 2023 *National Electricity (Victoria) Act* 2005 (NEVA Order)

- Chapter 6 sets out how the NER and Guidance note requirements have been addressed, and
- Appendix A is our revenue application.

1.5. Structure of the Stage 1 Application for VNI West

Our Stage 1 Application comprises the attachments and models (illustrated in Figure 1 and detailed in Table 4) as well as other supporting documents. This Principal Application document references these attachments, models and other supporting documents and should be read in conjunction with them.

Figure 1: Stage 1 Application document structure for VNI West



The attachments and models are summarised in Table 4.

Table 4: Documents and models comprising this Application (excluding our other supporting documents)

Document /model number	Name	Content/purpose
A.1	VNI West - Stage 1 Contingent Project Application - Principal Application document	Seeks the AER's approval to amend the forecast capex allowance, revenue requirements and MAR in the AER's 2023-28 Revenue Determination based on Stage 1 costs.
A.1a	AER Information Request Nov 2023 Transgrid Responses	This details Transgrid's responses to AER's Information Request received Nov 2023.
A.2	Direct capex forecasting methodology	Explains and justifies our Stage 1 direct capex including: • summarising the nature and scope of Stage 1 activities • the methodologies we have used to determine our forecast capex, and • how we have verified and validated our forecast capex.
A.3	Labour and indirect forecasting methodology	Explains the bottom-up forecast of labour and indirect support costs required for the development and approvals work, management of the early works program, and overall project management.

Official

Document /model number	Name	Content/purpose
A.4	GHD Advisory Independent capex Review	An independent assessment of the scope, procurement process and forecast capex for Stage 1 (early works).
Capex models		
A.5	Capex forecast model	This model forecasts capex by regulatory asset class and year to 2025-26, sourcing inputs from the Direct Non-Labour Cost Model and the Labour and Overheads Cost Model and applying labour cost escalation and inflation where appropriate.
A.6	Direct non-labour model	This model builds up the procurement and land acquisition costs that input to the Capex Forecast Model.
A.7	Labour and overhead costs spreadsheet	This model builds up the labour and indirect costs (including procurement, project development, community and stakeholder engagement, land and environment, regulatory approvals and other support costs) that inputs to the Capex Forecast Model.
PTRM and other regulatory models		
A.1A	VNI West Stage 1 2023–28 Post Tax revenue Model (PTRM)	Demonstrates the calculations of our incremental revenue requirements and MAR for the 2023–28 regulatory period, based on Stage 1 (early works) costs.
A.1B	VNI West Stage 1 2018-23 Roll-forward Model (RFM)	Rolls forward the RAB and Tax Asset Base (TAB) across the 2018-23 regulatory period, inclusive of Stage 1 (early works) costs
A.1C	VNI West Stage 1 Depreciation Model	Used to determine the forecast regulatory asset base and tax asset base depreciation. This model also calculates the actual tax depreciation for use in the RFM.

In addition, we have provided the AER with other supporting documents that are referenced within the documents listed in Table 4.

2. Project Overview

2.1. A project of national significance

In 2021, the Australian Government identified VNI West in Australia's Long Term Emissions Reduction Plan. The Plan highlighted that VNI West is expected to provide additional electricity transfer capacity between Victoria and NSW, unlock electricity from Snowy 2.0 to the Victorian market and unlock two REZs.[36]

AEMO identified VNI West as key project in first ISP in 2018.[37] AEMO's 2022 ISP, published on 30 June 2022, reconfirmed the need for VNI West to increase interconnection between Victoria and NSW and the benefits it will provide to consumers.[38] The Victorian Government has also confirmed the importance of the Project, with the issuing of two Orders under the *National Electricity (Victoria) Act* 2005 (NEVA Orders) confirming both the need for, and the required configuration of, the Project.

On 27 May 2023, we published the RIT-T PACR, which identified Option 5A as the preferred option. This involves a 500 kV double-circuit overhead transmission line between Victoria and NSW, connecting Western Renewables Link (at Bulgana) with PEC (at Dinawan) via a new terminal station near Kerang, and crossing the Murray River north of Kerang (in the RIT-T).

The RIT-T assessment estimates that VNI West will deliver $1.4 billion in net benefits (in NPV terms) primarily from avoided, or deferred, costs associated with generation and storage infrastructure, fuel cost savings and REZ transmission expansion cost savings.[39]

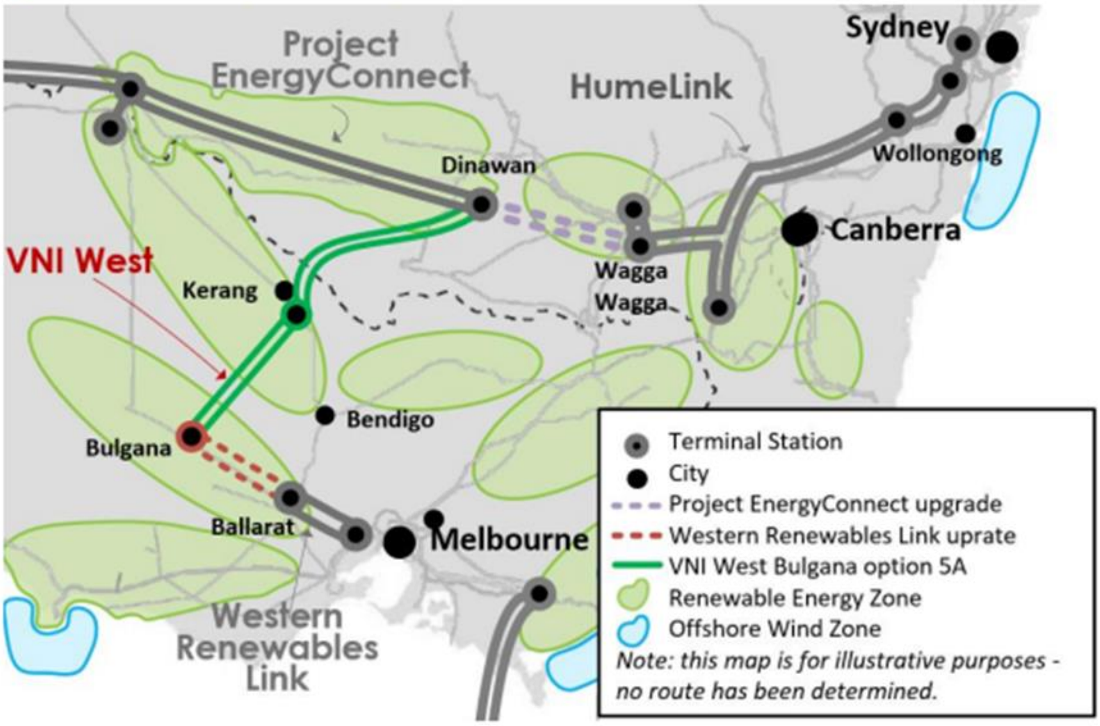
VNI West will be one of our largest capital projects since construction of our existing network. It involves around 377km (approximately 203km between Energy Connect (at Dinawan) and the NSW/VIC border and approximately 174 km on Energy Connect) of new 500 kV transmission lines to provide a second interconnection between Victoria and NSW. It is a key component of the energy market transition and will:[40]

- harness clean, low-cost electricity from REZs in both states
- increase the electricity export capacity from Victoria to NSW, and
- improve the reliability and security of electricity supply coal-fired power stations are retired.

Figure 2 is a map of the proposed 500kV double circuit transmission line routes.

[36] Australian Government, Australia's Long-Term Emissions Reduction Plan - DCCEEW, 2021
[37] AEMO, 2018 ISP, AEMO, 2018 ISP, July 2018, pp 8-9, 86-88 & 90-92VNI West was previously called SnowyLink,
[38] AEMO, 2022 ISP, June 2022, p. 74
[39] AEMO, Transgrid, VNI PACR, May 2023. P. 12
[40] AEMO, Transgrid, VNI West PACR, May 2023, p.5

Figure 2: Map of proposed transmission line routes



2.2. Direction from AEMO to proceed with Stage 1 (early works)

The 2022 ISP[41] has defined VNI West as a staged actionable ISP project at a total cost of $3.39 billion.[42] It has also determined that VNI West contributes roughly $1.8 billion of the $24.5 billion in net market benefits delivered by its ODP in the most likely scenario (step change) at that time.[43] The 2022 ISP defined two stages for the Project and provided a target delivery date of July 2031 or earlier with additional government support: [44]

- Stage 1 – complete the early works by approximately 2026, and
- Stage 2 – implement the Project by July 2031, or earlier with additional government support.

To accelerate the delivery of VNI West to 2028 the State and Federal Governments are providing concessional financing under the Rewiring the Nation plan:

In October 2022, the Federal and Victorian governments announced that the CEFC will provide a concessional loan of $750 million for VNI West. This funding forms part of the first announcement under the Federal Government's wider 'Rewiring the Nation' plan. The concessional financing was announced to ensure VNI West is accelerated from the timeframes outlined in the 2022 ISP, to meet the 2028 target completion date.

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41 As already noted, this document refers to AEMO's 2022 ISP, as it is the most recently completed ISP in accordance with the NER. It should be noted that the Draft 2024 ISP, published on 15 December 2023, confirms AEMO's 2022 ISP conclusions in relation to VNI West, including its proposed timing.

42 This is equivalent to $2.99 billion ($Real 2021). This comprises $491 million for stage 1 and $2.5 million for stage 2.

43 AEMO, 2022 ISP, June 2022, p. 74

44 AEMO, 2022 ISP, June 2022, p. 74

In December 2022, a second announcement under the 'Rewiring the Nation' plan was made, stating that the Federal and NSW governments had signed a $7.8 billion funding deal to unlock eight critical transmission and REZ projects, including VNI West.

The State and Federal concessional financing support is in addition to earlier Federal Government support for NSW early works and the commitment to enhance the Dinawan to Wagga Wagga portion of PEC enhancement. The PEC enhancement involves increasing the capacity of a segment of the transmission line from 300kV to 500kV in order to lower the overall costs of delivering VNI West and minimise the disruption to landholders and the environment in the area.

To help facilitate the accelerated delivery of the Project, TCV has commenced early works for the Victorian portion of the project, as enabled by the February 2023 NEVA Order.

AEMO has assessed that undertaking early works is the first stage. The Project is required to re-enter the feedback loop if, as a result of undertaking the early works, the delivery cost is determined to have increased. AEMO's 2022 ISP and its draft 2024 ISP directs us to proceed now with Stage 1 to achieve the following benefits:[45]

- insurance value and system reliance – providing greater system resilience to earlier than projected coal closures. AEMO has assessed that the earlier that coal-fired generation retires, the earlier VNI West is needed[46]
- option value – allowing delivery of the Project as soon as possible or defer it if circumstances change.[47]
- protection against rising costs – urgently undertaking further work to drive down costs given the risk to supply chains of increasing global demand for the same infrastructure expertise, materials and equipment.[48] It will also secure the fuel cost savings arising from a reduction in gas generation
- storage and firming access – it will increase access to Snowy 2.0's deep storage and other firming capacity from interstate,[49] and
- VRE reduction and support – it will reduce VRE curtailment by sharing geographically diverse VRE. It will also support new VRE needed to replace coal-fired generation (particularly in the Murray River and Western Victoria REZs).

45 AEMO, 2022 ISP, pp.74 and 80
46 AEMO, 2022 ISP, pp. 67 and 92
47 AEMO, 2022 ISP, pp.85 and 86
48 AEMO, 2022 ISP, pp. 96-99
49 AEMO, 2022 ISP, p. 74

3. Regulatory Requirements

The regulatory requirements for actionable ISP projects are contained in:

- clause 6A.8.2 of the NER
- the AER's Process Guideline for Contingent Project Applications,[50] and
- the AER's Guidance Note for Regulation of actionable ISP projects.[51]

The key requirements are outlined below. Chapter 6 of this Application shows how we have satisfied the regulatory requirements.

3.1. Regulatory requirements

Clause 6A.8.2 of the NER sets out the requirements for making an Application to amend a revenue determination to include a contingent project that is an actionable ISP project. Clauses 6A.8.2(a) sets out the requirements that must be satisfied in order for us to lodge an Application, which are that:

- A trigger event under clause 5.16A.5 has occurred; and
- An Application must be made as soon as practicable after the occurrence of the trigger event.

For the reasons set out in Chapter, we consider that these requirements have been satisfied.

Having met the threshold requirements in clause 6A.8.2(a), this Application is required to include the following information specified in clause 6A.8.2(b) of the NER:

(1) an explanation that substantiates the occurrence of the trigger event

(2) a forecast of the total capital expenditure for the contingent project

(3) a forecast of the capital and incremental operating expenditure, for each remaining regulatory year which the Transmission Network Service Provider considers is reasonably required for the purpose of undertaking the contingent project

(4) how the forecast of the total capital expenditure for the contingent project meets the threshold as referred to in clause 6A.8.1(b)(2)(iii)

(5) the intended date for commencing the contingent project (which must be during the regulatory control period)

(6) the anticipated date for completing the contingent project (which may be after the end of the regulatory control period), and

(7) an estimate of the incremental revenue which the Transmission Network Service Provider considers is likely to be required to be earned in each remaining regulatory year of the regulatory control period as a result of the contingent project being undertaken as described in subparagraph (3), which must be calculated:

(i) in accordance with the requirements of the post-tax revenue model referred to in clause 6A.5.2

(ii) in accordance with the requirements of the roll forward model referred to in clause 6A.6.1(b)

50 AER, Process Guideline for Contingent Project Applications under the NER, September 2007.
51 AER, Guidance Note for Regulation of actionable ISP Projects, March 2021.

(iii) using the allowed rate of return for that Transmission Network Service Provider for the regulatory control period as determined in accordance with clause 6A.6.2

(iv) in accordance with the requirements for depreciation referred to in clause 6A.6.3, and

(v) on the basis of the capital expenditure and incremental operating expenditure referred to in subparagraph (b)(3).

Clause 6A.8.2(f)(2) of the NER requires the AER to accept the relevant amounts in this Final Application if it is satisfied that:

> *the amounts of forecast capital expenditure and incremental operating expenditure reasonably reflect the capital expenditure criteria and operating expenditure criteria, taking into account the capital expenditure factors and operating expenditure factors, in the context of the contingent project.*

In addressing these requirements, we have had regard for the AER's:

- Guidance Note for Regulation of actionable ISP projects, and
- Process Guideline for Contingent Project Applications.[52]

We have met regularly with the AER in preparing this Application and the AER's feedback has informed the content and structure of this Final Application and supporting documentation.

3.2. Trigger events

Under the NER, we can submit a CPA for Stage 1 to the AER if we satisfy the trigger events for actionable ISP projects in clause 5.16A.5.[53] Table 5 shows the trigger events for lodging our Stage 1- Application, and how we expect these to be met.

[52] AER, *Process Guideline for Contingent Project Applications under the National Electricity Rules*, September 2007 available at: https://www.aer.gov.au/system/files/ac06907-Final%20guideline.pdf.

[53] Rule 5.16A.5 Actionable ISP project trigger event.

Table 5: Occurrence of the trigger events

Trigger event	Status
Publish the RIT-T Project Assessment Conclusions Report (PACR), which must identify a preferred option that passes the RIT-T.	**Complete** On 27 May 2023, we published a PACR, which identified the preferred option to be 500 kilovolt (kV) double-circuit overhead transmission line between Victoria and NSW, connecting Western Renewables Link (at Bulgana) with PEC (at Dinawan) via a new terminal station near Kerang, and crossing the Murray River north of Kerang – 'Option 5A'. MCHPA lodged a dispute under clause 5.16B of the NER. The AER dismissed this dispute on 16 October 2023.
Obtain written feedback loop confirmation from AEMO that: • the preferred option addresses the identified need and is on the ODP in the most recent ISP, and • at the forecast cost, the Project remains part of the ODP	**Complete** We commenced discussions with AEMO on our draft feedback loop request at the same time we published the draft Stage 1 Application. AEMO has provided its feedback loop confirmation.
There are no outstanding RIT-T PACR disputes - either no disputes were raised or if a dispute has been raised, it has been rejected by the AER or the PACR has been amended accordingly.	**Complete** MCHPA lodged a dispute under clause 5.16B of the NER. The AER dismissed this dispute on 16 October 2023.
The cost in the Stage 1 Application must be no more than the cost included in AEMO's written feedback loop confirmation.	**Complete** Our total capex (actual and forecast) in this Stage 1 Application is within the Stage 1 cost cap set out in AEMO's feedback loop confirmation.

3.3. Project timing

For the purposes of this Stage 1 Application, the applicable dates for the commencement and completion for Stage 1 activities are:

- date for commencement – 1 July 2017, and
- anticipated date for completion – 30 April 2025.

Some of the Stage 1 activities have already started. These activities have needed to pre-date this Application, in order to meet the 2028 target completion date. The proposed timing for the remaining, more substantive, early works activities in this Application reflects a realistic assessment of the required dates for the Stage 1 activities to enable construction to commence as soon as possible following the approval of our Stage 2 Application,[54] in order to meet the target delivery date of 2028.

[54] Subject to our Board making a positive Final Investment Decision (FID).

The Stage 1 completion date is consistent with the accelerated the delivery date of 2028 supported by State and Federal Governments concessional financing under the Rewiring the Nation.

3.4. Customer and other Stakeholder engagement

The size and scale of the energy transition, of which a key project is VNI West, has generated strong reactions from a wide range of stakeholders including local communities, landowners, First Nations people and primary producer groups. Many of these communities will host new transmission infrastructure and renewable energy projects across the NEM. The preservation of the environment, rural amenity and primary production industries are at the heart of these concerns, with a wide range of stakeholders calling for earlier participation in planning processes, and improved compensation and community benefit sharing.

Early and effective engagement in Stage 1 is critical to retaining and improving our social licence to deliver the Project and therefore minimising the risks of the Project being delayed and the associated costs. Our Stage 1 consultation will:

- provide information on the Project timeframes, milestones and engagement processes so that customers have the maximum opportunity to be involved in the Project
- ensure that the community understands the benefits of the project, and
- support us securing access to and commencing negotiations relating to the acquiring of easements over land.

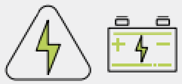
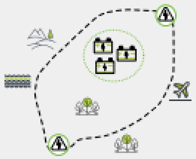
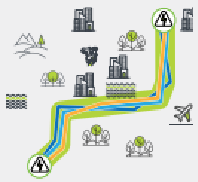
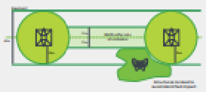
In July 2021, we re-set our community engagement processes[55] based on respectful, effective and transparent engagement with impacted communities and landholders. This re-set was guided by a thorough independent review of the Humelink project conducted by our appointed Community and Landowner Advocate Rod Stowe. Transgrid implemented all 20 recommendations made as part of this review, which included the establishment of independent reference groups.

- The re-set also prompted the development of a standardised approach to route development, which ensures that route planning:
- is informed by regional priorities, industries and development objectives
- balances environmental and social impacts with the technical requirements of the project, and
- allows for consultation and feedback at all stages, including formal exhibition and submissions periods.

Figure 3 overviews Transgrid's approach to route development.

[55] Transgrid, Review of Humelink engagement process, Findings of the Review – Landholder and Community Advocate, July 2021

Figure 3: Transgrid's route development process

Phase	Phase 1 Identify need and potential technical options	Phase 2 Evaluate technical options | area of interest	Phase 3 Corridor identification	Phase 4 Preferred route identification	Phase 5 Environmental assessment	Phase 6 Detailed design and easement finalisation
Diagramatic Example						
Area		Typically between 10 and 50 kilometres (depending on project scale)	Typically between one and 10 kilometres wide	Typically up to around one kilometre wide	Typically up to 200 metres wide (with the potential for wider area(s) up to one or more kilometres wide where further investigation may be required)	Typically around 80 metres (depending on project requirements)
Purpose	To confirm the project requirements and identify technical options to address those requirements	To investigate the range of technical options in order to define a prudent and efficient project solution that aligns with the identified functional requirements for the project within a broad area of interest.	To identify and assess feasible corridor or site location options within the area of interest based on community/stakeholder feedback and high level environmental, technical, social and cost considerations in order to identify a preferred corridor or site area.	To identify a preferred route for the project that can be used to undertake appropriate environmental assessment.	To further refine the route through specific landowner consultation and additional data gathered during the environmental impact assessment.	To finalise the project easement or site boundary in consultation with the landowner.
Engagement focus	· AEMO, AER, Energy Corporation of NSW · Energy industry market · State and/or Federal elected representatives	· Australian Energy Infrastructure Commissioner · Public entities (e.g. Crown Lands, Forestry) · Local Councils · Targeted stakeholder representatives.	· Stakeholder Reference Group (a forum consisting of regional representatives to discuss decision criteria, options and test outcomes) · Consultation with stakeholders regarding identified corridors and/or site options · NSW Department of Planning and Environment.	· Community Consultative Group (a forum of local representatives to discuss decision criteria, options and test outcomes) · Potentially affected landowners · Consultation with stakeholders regarding identified route options · Broader community.	· Community Consultative Group · Affected landowners.	· Affected landowners.
Public Documents	· Project Need Statement	· Project Specification Consultation Report (PSCR) · Project Assessment Draft Report (PADR) · Project Assessment Conclusion Report (PACR)	· Corridor Options and Evaluation Report or Site Options and Evaluation Report · Consultation with stakeholders regarding identified corridors and/or site options · Preferred Corridor Report or Preferred Site Report	· Route Options and Evaluation Report · Preferred Route Report · EIS Scoping Report	· EIS / REF (feedback) · Submissions Report (and if required Amendment Report)	· Ongoing project communications
Decision	**A solution is needed**	**Project solution is chosen (AER approval)**	**Corridor is chosen**	**Route is chosen**	**Narrowed route is chosen (environmental approval)**	**Easement alignment confirmed**

Technical inputs/outputs · Environmental inputs/outputs · Social and/or community inputs/outputs

Early and effective engagement in Stage 1 is critical to securing and retaining the social licence required to minimise the risk of the Project being delayed and the associated costs. Our Stage 1 (early works) engagement will:

- provide information on the Project's timeframes, milestones and engagement processes so that stakeholders have the maximum opportunity to be involved in the Project
- ensure that the communities and stakeholders are consulted on the key planning decisions that affect them
- ensure that the community understands the benefits and costs of the project, and
- support the Project securing access to and commencing negotiations relating to the acquiring of easements over land.

Feedback from the community, landholders and other stakeholders across Transgrid's Major Projects has been instrumental in identifying four non-negotiable pillars that will form the foundation of all our engagement:

- Landowner engagement – we will consult openly and transparently with landowners impacted by the Project and ensure they are treated fairly and respectfully.
- Community engagement – we will engage continuously with communities, landowners, residents, business owners and stakeholders impacted by the Project to keep them informed and ensure their preferences and priorities are reflected in the Project to the greatest extent possible.
- Social legacy – we will partner with the community and other stakeholders to deliver a legacy of positive social and environmental outcomes for our communities.
- Indigenous engagement – we will work respectfully with local Traditional Owners and Elders as well as the Indigenous people and communities throughout the Project.

Our engagement approach is based on genuine consultation through meaningful and transparent dialogue. We are committed to understanding the priorities and preferences of our customers and other stakeholders, keeping them informed and reflecting their feedback to the extent possible in the development of the Project.

We have developed a detailed Community and Stakeholder Engagement Plan, which outlines for all Major Projects, including VNI West, our engagement approach, with whom we will engage, our engagement timeframes and associated activities. The Plan details a broad range of engagement channels and forums to cater for different interests and availability and ensure that stakeholders at all levels can meaningfully participate in project planning during the early work phase.

These include ongoing and regular briefings with key stakeholders and consumer representatives through established committees and reference groups. We will also undertake community and landholder facing engagement activities such as community information days, town hall meetings, webinars and public displays. These activities will be supported by timely and relevant communications materials including a dedicated website[56], community resources, visualisations[57] and interactive maps[58]. In addition, our engagement team features regionally based Place Managers who bring depth and credibility to our work with landowners and communities through shared experience and local knowledge.

[56] The website is designed to provide general information about the Project and facilitate feedback process by providing a one-stop-shop for communications – newsletters, fact sheets, presentations.
[57] Visualisations are used to provide landowners with a 3D visualisation of the towers.
[58] An online engagement platform to support route development engagement.

In accordance with our route development process, we have also established a Regional Reference Group to provide guidance on the key social, environmental and technical matters for consideration in developing viable corridors for assessment. We have established a Community Consultation Group (CCG). The CCG will provide guidance on key matters for consideration during route planning, including the effectiveness and suitability of proposed impact mitigations, and opportunities for community investment and benefit initiatives which would provide a positive social legacy outcome for affected communities.

Table 6 overviews that stakeholder engagement channels and forums relevant to Stage 1 for VNI West.

Table 6: VNI West key action plans

Stakeholder / forum	Description
Transgrid Advisory Committee (TAC)	Whole of business advisory committee with broad representation across consumer, industry, and community advocacy groups.
Australian Energy Infrastructure Commissioner (AEIC)	Monthly briefings on Major Projects portfolio and approach to community and landholder engagement
DISER	Monthly briefings on project deliverability progress against financing requirements
Department of Industry, Science, Energy and Resources (DISR)	Monthly briefings on Major Projects portfolio to ensure planning and assessment is in line with regulatory requirements
VNI West Regional Reference Group (RRG)	Bi-monthly workshops to test route development assumptions and methodology and seek feedback on key constraints for consideration.
VNI West Community Consultation Group (CCG)	To be established. CCGs will provide guidance on route development matters, as well as opportunities to improve social license through the development of tailored, effective and relevant community benefit initiatives.

Table 7 outlines the issues, concerns, and opportunities identified through consultation and engagement to date, and how we have and continue to respond to the feedback we have received.

Table 7 Issues, concerns and opportunities identified through consultation and engagement to date.

Area of Interest / who	Issues / Concerns / Opportunities	Actions in response
Route development • RRG • CCG • Directly impacted landowners • Local members • Local government • Local Aboriginal Land Council (LALCs) • Media • Government	• Route selection process is unclear. • Opportunities for stakeholder input on route selection is unclear. • More regular updates for community groups, individual landowners are needed.	• Collect feedback from landowners on property specific concerns to inform route identification. • Undertake targeted consultation sessions with communities to seek their input. • Provide visual aids and maps allowing input into concept designs where possible. • Provide detailed information on the route alignment planning process.

Area of Interest / who	Issues / Concerns / Opportunities	Actions in response
		• During route development explain how feedback on alternative route options has been considered.
Project justification and need • Directly impacted landowners • Action groups • Community • RRG • CCGs • Media • Government	Concerned that: • project costs outweigh benefits. • costs borne by landowners whereas benefits accrue to the broader community. • lack of engagement with regional communities on the need for, and benefits of, the project. • social legacy program should be co-designed with the community.	• Provide project information via multiple channels. • Embed Place Managers to regularly check in with their communities. • Establish dedicated project website with detailed project information including on project benefits and social legacy program. • Provide FAQs, regular project briefings and newsletters with detailed project information to address specific areas of concern. • Provide access to independent specialist to provide information on technical matters.
Consultation process • Directly impacted landowners • Action groups • Local members • Media • Government	• Engagement should be best practice. • Engagement approach should be locally relevant and face-to-face. • Should increase use of hybrid consultation opportunities to minimise consultation fatigue. • CCGs, community groups and Councils should have greater input in designing our engagement approach.	• Work with local champions and CCGs to identify preferred consultation methods and opportunities. • Publish draft engagement timeline for stakeholder feedback. Regularly update to ensure it remains current. • Offer a broader range of engagement methods to cater for different stakeholders' interests and availability i.e., website, phone, email, letter, interactive map, face-to-face, meetings. • Provide information on how to contact the engagement team. • Record feedback received. • Provide regular updates on how feedback received has been addressed. • Publish regular media updates on digital channels aligned to planning milestones.
Land use • Directly impacted landowners • RRG • CCGs • Represented groups • Local members	• Key concerns raised include the Project's impact on: - cultural heritage - biosecurity - bushfire risk - industrialisation of the local region - land clearing and degradation	• Keep the community updated on our investigations into issues of concern. • Provide information on our environmental assessment and approval process, and how the community / stakeholders can provide input and escalate concerns. • Embed Place Managers to regularly check in with their communities.

Area of Interest / who	Issues / Concerns / Opportunities	Actions in response
• Local government • LALCs • Government	- agricultural land use activities (e.g., disruption of aerial spraying, use of access tracks and vehicle access). • Further discussion on the pros and cons of using public or private land is needed. • Social legacy program should be co-designed with the community so that it addresses their issues.[59]	• Provide information on project benefits. • Collaborate with representative groups on solutions. • Refine messaging on project impacts so it is clear and accessible. • Advocate on behalf of the landowner where appropriate.
Compensation Directly impacted landowners CCG Local members	• Delays to identifying the corridor has prolonged landowner uncertainty. • Process and timeline for land and easement acquisition is unclear.[60] • Compensation for land and easement acquisition is unfair and does not: - compensate for visual impacts - provide royalties or annualised payment - Provide equal compensation to landholders and renewable developers which is unreasonable.	
Visual impact • Directly impacted landowners • CCG • Local members • Local government	• Concerned about a range of visual impact issues including: - the height and material of tower design - the impact on their property value - the industrialisation of the local region - the proximity of towers to residential homes • Provide opportunities for directly affected landowners to discuss options to mitigate	

[59] These include bushfire, cultural heritage, regional development.
[60] Including negotiating compensation for required easements.

Area of Interest / who	Issues / Concerns / Opportunities	Actions in response
	impacts on a case-by-case basis.	

4. Capex forecast

This chapter:

- overviews AEMO's definition and approval of Stage 1 (early works)
- explains the scope of our Stage 1 (early works) activities and the outcomes they will deliver
- overviews our capex forecasting methodology for our Stage 1 (early works) activities
- details our Stage 1 (early works) capex forecast, and
- overviews the independent engineering verification to support our Stage 1 (early works) capex forecast.

Further information on our capex forecast and the scope of our Stage 1 activities is provided in our Capex Forecasting Methodology and Scope Definition supporting documents. These are attachments to this Application.

4.1. AEMO's definition and approval of Stage 1 activities

AEMO defines Stage 1 activities as pre-construction activities that can be undertaken now, while keeping open the option to continue, defer or cancel the project as new information becomes available.[61] AEMO identifies the following activities as likely to fall within Stage 1 for VNI West:[62]

- project initiation – scope, team mobilisation, service procurement
- stakeholder engagement – with local communities, landholders and other stakeholders
- land-use planning – identifying and obtaining all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection and easement acquisition
- detailed engineering design – transmission line, structure and substation design, detailed engineering design and planning
- cost estimation – finalisation, including quotes for primary and secondary plant, and
- strategic network investment – an uplift to the delivered capacity of PEC between Dinawan and Wagga Wagga.[63]

As discussed in section 2.2, AEMO has issued us with a direction in its 2022 ISP and its draft 2024 ISP to proceed now with Stage 1 to achieve the following benefits:[64]

- insurance value and system reliance – providing greater system resilience to earlier than projected coal closures. AEMO has assessed that the earlier that coal-fired generation retires, the earlier VNI West is needed[65]
- option value – allowing delivery of the Project as soon as possible or defer it if circumstances change[66]

[61] AEMO, Feedback Loop Notice, 27 January 2022
[62] AEMO, 2022 ISP, p. 66
[63] AEMO, 2022 ISP, p 75. The Commonwealth Government has underwritten funds to build a component of PEC at a larger capacity such that it removes the need to duplicate lines for VNI West when it is constructed.
[64] AEMO, 2022 ISP, pp.74 and 80
[65] AEMO, 2022 ISP, pp. 67 and 92
[66] AEMO, 2022 ISP, pp.85 and 86

- protection against rising costs – urgently undertaking further work to drive down costs given the risk to supply chains of increasing global demand for the same infrastructure expertise, materials and equipment.[67] It will also secure the fuel cost savings arising from a reduction in gas generation
- storage and firming access – it will increase access to Snowy 2.0's deep storage and other firming capacity from interstate, and[68]
- VRE reduction and support – it will reduce VRE curtailment by sharing geographically diverse VRE. It will also support new VRE needed to replace coal-fired generation (particularly in the Murray River and Western Victoria REZs).

AEMO has assessed that undertaking early works now is a low regret action for consumers.[69]

Further, the State and Federal Governments have subsequently provided concessional financing to accelerate the delivery of VNI West to 2028, to ensure that the Project's benefits are delivered as soon as possible. Achieving the 2028 delivery date requires us to start the Stage 1 works as soon as possible.

The PEC enhancement works were not originally noted in the 2022 ISP works definition however by agreeing to these works being included through the feedback loop AEMO has agreed to these works being included in early works.

4.2. The scope and outcomes of our Stage 1 activities

The scope of our Stage 1 activities is in line with AEMO's definition of early works. Our Stage 1 activities comprise:

- direct and labour and indirect pre-construction activities, and
- two D&C packages.

Our direct Stage 1 capex activities relate to:

- procurement activities including:
  - purchasing LLE for transformers, reactors, conductor, steel and power-flow controllers
  - a D&C work package to enhance the capacity of a component of PEC (which forms part of the scope of the VNI West Project)[70]
  - a D&C work package for integration works required to connect the enhanced PEC component of the Project at the Gugaa substation (being constructed as part of Humelink), and
  - undertaking pre-construction development, including for substations and transmission lines, specifications and identifying quantities of plant and materials required.
- land acquisition activities, which relate to biodiversity offset costs, binding options for transmission line easements, and commencing compulsory acquisition.

Our labour and indirect development and approvals (D&A) activities relate to:

[67] AEMO, 2022 ISP, pp. 96-99
[68] AEMO, 2022 ISP, p. 74
[69] AEMO, 2022 ISP, p.8
[70] Media Release, Minister Taylor, Government supporting delivery of critical transmission infrastructure in Southwest NSW, 28 September 2021. This is per the pre-agreed variation under sub-clause 13.13(a) of the EPC Contract for PEC, dated 24 September 2021

- internal labour resources for undertaking project management and corporate support (labour costs) for procurement, land and environmental activities, and
- indirect activities for a wide range of professional and consulting services, as well as tender payments and associated facilities costs (e.g., data room).

We have included two D&C packages in our Stage 1 capex. This will ensure that investment synergies between the integration works required for VNI West and the works being undertaken for other ISP projects, in particular PEC and Humelink, are fully realised. We have adopted this approach based on a careful review of our entire program of work for ISP projects, in order to identify synergies and cost savings during the construction phase to ensure these projects are delivered at the lowest sustainable cost for consumers overall. These D&C packages are:

- PEC enhancement to increase the capacity of the transmission line from the Dinawan Substation to Wagga Wagga from 330 kV to 500 kV,[71] and
- Gugaa integration works required to integrate the 500kV PEC enhancement with the Gugaa 500/330kV Substation which is being built as part of Humelink.

We estimate that the cost saving to consumers is $787 million from undertaking these D&C works as part of our Stage 1 activities, rather than waiting until our Stage 2 delivery activities. This cost saving comprises:

- for the PEC enhancement, approximately $697 million, and
- for the Gugaa integration works, approximately $90 million.

We acknowledge that to date D&C activities and costs have not been included in Stage 1 Applications. However, the construction timeframes for PEC and Humelink, to which the PEC enhancement and Gugaa integration works relate, require us to undertake the D&C activities in VNI West Stage 1 to realise the synergies and costs savings from concurrent investment. We have therefore reflected the cost of these activities in this Stage 1 Application. Further, undertaking the D&C works for the PEC enhancement is in line with AEMO's expectation that Stage 1 activities for VNI West would include 'strategic network investment'.[72]

The AER's approval of our forecast capex is required in order for us to proceed with these investments. In the absence of the AER's approval, we would not be funded to undertake this work and therefore could not reasonably be required to undertake it. This would disadvantage consumers, who would then face higher costs associated with undertaking these activities separately at a later time.

In the case of the PEC enhancement work it would not be practical (or cost efficient) to retroactively upgrade our current investment in PEC to 500kV. This is reflected in the current Federal Government underwriting which has been provided to ensure consumers realise the benefits of the enhancement as part of our VNI West Stage 1 activities.

In relation to the Gugaa integration work, we recognise that the regulatory process relating to our Contingent Project – Stage 2 delivery Application for Humelink has yet to conclude, and so our FID has yet to be confirmed. Notwithstanding this, in order to meet the required timing for Humelink we are proceeding on the basis that the regulatory process will result in the revenues required to enable us to make a positive FID, and therefore that the incremental integration works to connect VNI West into the new Gugaa substation will be required. The expected timing of our investment in Humelink means that these integration works are expected to occur as part of Stage 1 of VNI West. We consider it appropriate to include these

[71] The costs and benefits associated with this enhancement have been assessed as part of the VNI West RIT-T.
[72] AEMO, 2022 ISP, p.66.

integration works as part of this Stage 1 Application, rather than lodging a further Application following our FID for Humelink.

Our Stage 1 capex will deliver the following outcomes:

- identify, explore and manage the project risks. This will allow us to mitigate and/or diversify the Project's risks so that the residual risk costs included in our Stage 2 Application are as low as possible
- secure the cost savings for consumers from our PTT program in respect of LLE. The combined saving for LLE is estimated to be $60 million
- achieve the target delivery date of 2028 by progressing activities on the critical path to ensure that construction can commence as soon as possible following the approval of our Stage 2 Application. [73] Activities on the critical path include securing LLE, undertaking continued stakeholder engagement, acquiring access to land and establishing biodiversity stewardship sites using BSAs, and
- realise investment synergies arising from undertaking D&C works associated with the integration of VNI West with Humelink and PEC. This will ensure that overall, this suite of ISP projects is delivered at the lowest sustainable cost for consumers. We estimate that the cost saving to consumers is $787 million from undertaking these D&C work packages as part of our VNI West Stage 1 activities.

Undertaking these Stage 1 activities will ensure that the Project is delivered at the lowest sustainable cost to maximise benefits to customers, noting the overall cost saving to consumers is $847 million.

Table 8 details the nature of our Stage 1 activities and how they will contribute to achieving these three outcomes.

Table 8: Stage 1 (early works) activities – nature and outcomes

Category capex	Description	Nature and outcomes
Direct capex		
Procurement	Transformers, reactors, conductor and steel	Our procurement strategy for transformers, reactors, conductor and steel reflects careful consideration of complexity, availability, cost, timeframes and value capture of the equipment. As explained in our Stage 1 Part 2 CPA for Humelink, with the support of the Commonwealth Government we have established the PTT program for the integrated delivery of VNI West, PEC and Humelink. This has allowed us to secure the lowest risk-adjusted price for LLE for VNI West (as well as PEC and Humelink) to meet the Project's delivery date and with a combined savings of $60 million for consumers. We have entered into agreements with the manufacturers to: • leverage the combined buying power across our PTT projects to ensure we can deliver the project at the lowest sustainable cost, and • secure available capacity to meet the substantial order required for VNI West to achieve the 2028 delivery date.
	LLE Power Flow Controllers	Delivery of Power Flow Controllers is estimated to take 18-24 months following placement of orders. As outlined in the VNI West PACR, a critical Stage 1 activity involves assessing the

[73] AEMO, 2022 ISP, June 2022, p.13. (See Table 1).

Category capex	Description	Nature and outcomes
		feasibility and determining the type of power flow controllers that are required to deliver the Project. Subject to this assessment confirming the technology, we would purchase this equipment in Stage 1 to minimise the risk of project delays which would arise if we did not receive this LLE in time. If, however, our assessment determines that an alternative solution (e.g. Phase Shifting Transformers) is required, we would use the revenues associated with the cost of procuring the Power Flow Controllers in this Stage 1 Application to place orders and secure manufacturing slots for that equipment. This would minimise the risk of project delays, which would arise if we did not receive LLE in time. The cost of purchasing Phase Shifting Transformers is expected to be $400 million more than the cost of Power Flow Controllers included in this Stage 1 Application. This would therefore require us to submit a further Stage 1 Application (i.e., Stage 1 (Part 2)) for the additional cost of purchasing the Phase Shifting Transformers. Any delay to purchasing this equipment would impact our ability to achieve the 2028 target delivery date.
	PEC enhancement	PEC involves the construction of a double circuit 330kV transmission line between from Dinawan Substation to the Wagga Wagga Substation, with a target delivery date of 2026. VNI West involves the construction of approximately 157km of double circuit 500kV transmission line in the same corridor by 2028. Enhancing the 330kV PEC transmission line to 500KV (enhancement work) to meet the VNI West Project's requirements will: • avoid the duplication costs associated with first building the 330kV transmission and then subsequently building another 500kV transmission line in the same corridor (within a two-year period), making the initial PEC 330kV transmission line redundant, and • minimise disruption to landholders and the environment in the area resulting in additional savings for consumers. The PEC Enhancement work has been supported by the Federal Government underwriting on the basis that: [74] • 'Building a single line with larger capacity will save consumers hundreds of millions of dollars by removing the need for duplicate lines for the Victoria-NSW West (VNI West) interconnector to be constructed. Importantly, in addition to these consumer savings, delivery of a single corridor now will also minimise further disruption to landholders in the area.' • Increasing the capacity of PEC to 500kV will lower the overall costs of delivering VNI West and minimise the disruption to landholders and the environment in the area.

[74] NSW Minister for Energy an Environment, Media Release - Government supporting delivery of critical transmission infrastructure in Southwest NSW, 28 September 2021

Category capex	Description	Nature and outcomes
		The costs and benefits associated with enhancing this section of PEC to operate at 500kV were assessed as part of the VNI West RIT-T and form a component of the works for the Project. AEMO confirmed in the 2022 ISP and the draft 2024 ISP[75] its expectation that this strategic network investment would form part of the Stage 1 works for VNI West.[76]
	Gugaa integration	Humelink involves the construction of the 500/330kV Substation at Gugaa by 2026. The VNI West Project involves integrating the 500kV section of the PEC enhancement with the Gugaa 500/330kV Substation which is being built as part of Humelink. Without these integration works, the 500kV PEC enhancement, and therefore VNI West, will not be connected to broader transmission network. The integration works involve: • upgrading two 330kV transmission lines being constructed as part of Humelink to connect Gugaa and Wagga Wagga to 500kV. This will connect the 500kV PEC enhancement (discussed above), which finishes at Wagga Wagga, to Gugaa substation where it will interface with Humelink, and • expanding the size of Gugaa substation, allowing the connection of the two 500kV transmission lines (i.e., the PEC enhancement that is occurring as part of VNI West) to Gugaa by adding: - Two new 500kV switchbays and busbar diameters - A new 500kV transformer and associated switchbays The cost of the integration and expansion works at the Gugaa substation is set out as a Separable Portion and pre-agreed variation under the contract with our Humelink delivery partner. Undertaking this work as part of the Humelink project, with a single Principal Contractor (i.e., the Humelink Delivery partner) will benefit consumers by reducing Project risk, driving cost efficiencies, and supporting the 2028 target delivery date for VNI West. In particular, appointing a single Principal Contractor (i.e., the Humelink Delivery partner) to deliver these integration works, which are in close proximity to the investment works to be carried out for Humelink Stage 2, will assist to: • reduce costs by having a single contractor's mobilisation costs • improve accountability and mitigate risk of coordination and interface issues with respect to project design and drawings between the two investments

[75] AEMO, Draft 2024 ISP, p.57.
[76] AEMO, 2022 ISP, p.75.

Category capex	Description	Nature and outcomes
		• eliminate the need to coordinate amongst multiple contractors and subcontractors on different project components, and streamline stakeholder interaction • facilitate smoother communication, coordination, and decision-making processes through a centralised point of contact • promote more efficient resource allocation across the two investment elements, to minimise the potential for delays, and • avoid the need to undertake multiple asset commissioning and upgrades within 12 months of original build (i.e., if undertaken by a single contractor, assets could be commissioned once).
	Pre-construction development – substation and transmission lines	Pre-construction activities include detailed design work, equipment specification and quantities for plant and materials, resource planning and obtaining work permits. These activities need to be finalised as part of pre-construction early works activities so that construction can commence as soon as possible following approval for our Stage 2 (Delivery) Application to meet the 2028 target delivery date. We also expect that pre-construction activities will drive efficiencies and innovation in the Project's design, thereby lowering the construction costs and risks in Stage 2.

Biodiversity offsets		The biodiversity requirements, under the Biodiversity Conservation Act 2016, in NSW involve the following for developments with significant impact on biodiversity:
		• Avoid biodiversity impacts through selection and design to minimise our footprint
		• Mitigate biodiversity impacts through our management measures such as partial clearing, and
		• Offset biodiversity impacts by setting up stewardship sites, purchasing credits or paying directly into the BCF.
		Prior to commencing construction, we must demonstrate that we have acquired the required biodiversity credits to offset the impact of the Project. We can achieve this by either:
		• providing a bank guarantee equal to the value of paying the total liability into the Biodiversity Conservation Fund (BCF). This is the higher cost option, or
		• establishing biodiversity stewardship sites using BSAs. While these are a lower cost option compared to paying into the BCF they take between 2-3 years to establish, because they require:
		  - identification of appropriate land with the relevant flora and fauna, and
		  - establishing agreements with local landholders to develop stewardship sites on that land.
		Establishing stewardship sites as part of Stage 1 will therefore minimise costs to consumers and assist to meet the target

Category capex	Description	Nature and outcomes
		delivery date. The omission of cost for biodiversity offsets was a key learning from our Stage 1 (Part 1) Application for Humelink.
Land acquisitions	Valuation and acquisition costs including options to acquire easements and compulsory acquisition	The Project requires the acquisition of easements over a substantial amount of land that impacts many landholder properties. Land access is a critical step to enable construction to commence. It involves: • determining the compensation to be paid to each landholder • establishing option agreements in order to be able to acquire land in Stage 2 • commencing the compulsory acquisition process in the event amicable agreements cannot be reached with landholders, and • undertaking surveys to identify and protect places of cultural heritage significance along the route. These activities need to be completed before we can commence construction. Our previous experience with land acquisition indicates that having more time to negotiate with land holders helps to build social licence, reduces anxiety, and the potential for compulsory acquisition. This means that completing land acquisitions related activities in Stage 1 will lower the risk costs in Stage 2 and help meet the target delivery date of 2028.
Labour and indirect capex (Development and Approvals)		
Labour and related costs		
Project team resources	Labour and corporate support for project management, procurement, land and environmental activities	Current and additional internal resources will manage the development activities and prepare for the delivery of the Project. All development and approval activities are necessary to be completed to achieve an efficient and timely FID to proceed with the Project following approval for our Stage 2 Application. This timing is critical to align FID and the unconditional execution of contracts so that Stage 2 construction works can proceed according to the critical path to achieve the 2028 completion date. Further, these activities will ensure that we manage delivery of Stage 1 in a prudent and efficient manner.
Indirect Costs		
Project development	Development, engineering, legal and economic support	The following project development activities must be completed for construction to commence as soon as possible following approval of our CPA-2 to meet the 2028 completion date: • legal advice to support land acquisition, procurement and other work activities during Stage 1 • geotechnical reports and survey work for contractors to prepare their pricing • an Owners Engineer to oversee the technical due diligence of the Project, and • other specialist studies to support development activities.

Category capex	Description	Nature and outcomes
		These activities and specialist resources will assist to drive cost efficiency and reduce risk costs.
Procurement	Contractor payments, Transaction management expenses, data room, probity training and support, independent cost estimator, procurement strategy and commercial advisory	We are currently developing a Delivery Strategy which will allow us to undertake the following supporting procurement activities: • market engagement commenced in Dec 2023 • identify a suitable process and program for the procurement of delivery contract(s) in an increasingly heated energy infrastructure market, and • meet the project delivery date of 2028. Our Stage 1 procurement activities cover a range of consulting services, contractor payments, transaction management expensed, probity support as well as an independent cost estimator. These activities will enable us to appoint our delivery partners to ensure construction can commence as soon as possible following approval of our Stage 2 Application to meet the 2028 completion date.
Land and environment	Fees, labour and indirect costs	Development of the Environmental Impact Statement (EIS), land agents' costs, and related activities are scheduled to be undertaken between April 2024 and May 2026. They include: • EIS development work, including seasonal route surveys, the environmental scoping report, technical and route option assessments, and completion of EIS documentation • An EIS application fee payable under the Environmental Planning and Assessment (EP&A) Regulation 2000 based on the capital investment value • 2023 ecological spring surveys have been undertaken, and • land agents and administrative support to lead the engagement with landholders and negotiations to establish options for easements and compulsory acquisitions have commenced. These activities and specialist resources are needed in Stage 1 to meet the 2028 completion date. Further, the EIS will set out conditions of approval, including any actions we need to undertake to mitigate the Project's environmental impact. Completing the EIS in Stage 1 will therefore reduce risk costs in Stage 2.
Community & stakeholder engagement	Stakeholder and community programs including	The local community and landholders will be affected by VNI West. In Stage 1, we need to continue to implement our engagement strategy to improve stakeholder support for the project and meet stakeholder consultation expectations and requirements.

Category capex	Description	Nature and outcomes
	social legacy[77], design and communication and community improvement	These activities are needed to meet the target delivery date of 2028. We also expect that strong stakeholder support for the Project will reduce potential opposition, thereby supporting cost efficiency, including by reducing risk costs.
Regulatory approvals and other support costs	CPA activities and Major Projects program initiatives	These activities are needed to prepare our regulatory submissions and seek the necessary regulatory approvals required before the Project can proceed. They also provide a broader review and rollout of project governance and assurance implementation including consultants and systems for document and cost control, scheduling, contract management, reporting and governance. These activities are needed in Stage 1 to meet AEMO's target delivery date of 2028.

4.3. Our Stage 1 capex forecasting method

As detailed in our Direct Capex Forecasting Methodology and Labour and Overheads Capex Forecasting Methodology, our forecast Stage 1 capex will ensure that the Project is delivered at the lowest sustainable cost to maximise benefits to customers. We have used the following forecasting techniques to derive our Stage 1 capex forecast:

- contracts with suppliers of equipment or design and construction (D&C) contracts (or agreed variations), which have been competitively tendered
- independent cost estimates
- external market-based quotations and valuations – generally, we have used the lowest cost quotations where we have received multiple quotations
- benchmarks of similar projects, such as Humelink
- bottom-up estimates based on recent actual costs, and
- other industry market data and specialist advice.

The forecasting process involved the following three steps.

Step 1 – Define the initial scope and identify the indicative costs

In this step we defined the initial scope for each Stage 1 activity, including by:

- establishing the project team and governance requirements
- identifying the corporate support required for the development and approval activities, and
- identifying required external specialist resources and services.

[77] Social legacy seeks to leverage off the project building a more sustainable energy system – and through its strategic partnership approach, enabling more sustainable, resilient and future focused community programs. This includes community grants, youth traineeships, long-term jobs for indigenous communities, provision of 5G and digital communication.

We obtained prices for these resources and services based on our procurement policies and procedures to establish our initial cost estimate.

Step 2 – Refine the initial scope and costs

In this step, we refined our initial scope and cost estimate by obtaining:

- updated contract cost for PEC enhancement
- outcomes from procurement process that were underway
- non-binding offers from suppliers
- actual costs from recent projects, and
- additional quotations, where necessary, from specialist service providers.

We also re-engaged with service providers to further refine the Project scope and adjust our internal resources, including stakeholder engagement and social legacy programs.

Step 3 – Finalise the early works capex forecast

In this step, we finalised our capex forecast by:

- updating our labour and support activities for our actual costs to May 2023 from Ellipse, our enterprise resource planning (ERP) system
- refining the scope and costs in step 2 to improve the accuracy our capex forecast, and
- comparing our labour and indirect costs with Humelink actual stage 1 costs, which is a comparable project.[78]

4.4. Our Stage 1 capex forecast

Table 9 shows our total Stage 1 capex forecast is $1,096.33 million, excluding equity raising costs. We will incur most of this capex in the current (2023-28) regulatory period.

Our capex is additional to the capex approved by the AER in its 2023-28 Revenue Determination.

Table 9: Stage 1 capex ($M, Real 2022-23)

	2018-21	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Actual	0.15	8.18	10.71	-	-	-	**19.04**
Forecast	-	-	58.10	499.68	450.11	69.41	**1,077.29**
Total capex	**0.15**	**8.18**	**68.81**	**499.68**	**450.11**	**69.41**	**1,096.33**

Notes: Including overheads, excluding equity raising costs

Table 10 and Table 11 detail our Stage 1 total capex of $1,096.33 million (excluding equity raising costs) in terms of:

- direct capex of $890.72 million or 81.25 per cent of total capex, and

[78] Comparative Project Capex worksheet – A.5 Capex Forecast Model

- indirect capex of $205.61 million or 18.75 per cent of total capex

Table 10 shows that our Stage 1 activities relating to direct (non-labour) capex of $890.72 million include:

- $792.87 million or 72.32 per cent of total capex for procurement activities including:
  - $228.89 million or 20.88 per cent for purchasing LLE for transformers, reactors, conductor, steel and power-flow controllers. These LLE can be either sold or repurposed to other projects if VNI West does not proceed to Delivery. This means that consumers are no worse off from purchasing them now. In relation to power flow controllers, as outlined in the PACR, a critical Stage 1 activity involves assessing the feasibility and determining the type of power flow controllers that are required to deliver the Project. If our assessment determines that an alternative solution (e.g., Phase Shifting Transformers) is required then we would use the revenues associated with the cost of procuring the Power Flow Controllers in this CPA-1 to place orders and secure that equipment. As noted earlier, the cost of purchasing Phase Shifting Transformers is expected to be $400 million more than the cost of Power Flow Controllers, and so this would also require us to submit a further CPA-1 (i.e., CPA-1 Part 2) for the additional cost of purchasing the Phase Shifting Transformers. Including LLE in our Stage 1 Application is necessary to meet the target 2028 delivery date and ensure the project is delivered at the lowest sustainable costs.
  - $345.61 million or 31.52 per cent for the PEC enhancement to increase the capacity of transmission line from Dinawan Substation to the Wagga Wagga from 330 kV to 500 kV. This cost estimate comprises:
    - > An updated pre-agreed variation under the EPC contract with [redacted] million.
    - > Our actual property compensation costs, from Ellipse, to acquire easements of $19.16 million.
    - > A route alignment change, based on a cost estimate of [redacted]. Alignment and tower location changes on the Dinawan to Wagga Wagga section of the route are required based on responses from stakeholders to the EIS and would not have been required if this section of the line remined at 330KV. These changes are necessary to enable the finalisation of easement acquisition, reduce biodiversity and heritage impacts and improve safety outcomes.
    - > 330kV line diversion, based on a cost estimate of [redacted]. This work is required to divert the 330kV lines at Dinawan substation to allow the construction of the 500kV substation without any outages on the 330kV PEC lines.
    - > An independent estimate from WSP for biodiversity offset costs of $10.12 million. This is required under the NSW Biodiversity Conservation Act 2016 (BC Act) and the Biodiversity Conservation Regulation 2017 to compensate for the impact on biodiversity caused by the Project.
    - > Independent advice from Fission on the appropriate contingency allowance of $68.82 million comprising Other Construction costs of $57.60 million and D&C contingency of $11.21 million.

    There is a further $11.37 million for labour and indirect costs for PEC enhancement (including labour escalation).

- $168.97 million or 15.41 per cent for the Gugaa integration works required to integrate the 500kV PEC enhancement with the Gugaa 500/330kV Substation which is being built as part of Humelink. As explained in our Stage 1 (Part 2) CPA for Humelink, our recently appointed Humelink delivery partners were selected based on the outcome of a thorough two-stage procurement process to ensure that the construction costs are prudent and efficient and therefore provide the best possible value for money for customers in the prevailing circumstances. Given, however, that the pre-agreed variation costs are currently 'budgetary' and can only be finalised once the scope of the work is confirmed, we have also included a contingency allowance as determined by Fission. This acknowledges that the scope and design is only 10 to 30 per cent defined at this stage because geotechnical investigations and information is limited. Our forecast of $168.97 million comprises:
  > a pre-agreed variation under contracts with our Humelink delivery partners of [redacted] million
  > contingency of [redacted] million, comprising Other Construction costs of [redacted] million and D&C contingency of [redacted] million, and
  > storage and land purchase costs of [redacted] million and [redacted] million respectively.
- $49.40 million or 4.51 per cent for pre-construction development activities which include detailed substation and transmission line design equipment specifications, quantities of plant and materials, and resource plans. We have used the same approach approved by AER for our Humelink CPA-1 to determine these costs. This is based on 4.43 per cent of the total construction cost from PACR based on independent advice from AECOM.

• $97.85 million or 8.92 per cent of total capex for land acquisition and biodiversity costs:
  - $30.73 million or 2.80 per cent for land valuation and acquisition costs including options for acquiring transmission line easements and compulsory acquisition for these landholdings. These costs are based on an independent report from property experts JLL, who have estimated the expected costs of securing land access and acquiring easements. JLL's advice is informed by recent experience with PEC and other high voltage transmission line projects under development in NSW and Victoria, and
  - $67.12 million or 6.12 per cent to offset our biodiversity credit liability. We will achieve this by establishing Biodiversity Stewardship Site(s) concurrently with project development. This will enable us to commence construction immediately following approval of CPA-2, noting that we must demonstrate that we have offset our biodiversity credit liability in full prior to construction commencing. We can achieve this by paying a bank guarantee equal to total liability into the Biodiversity Conservation Fund, however, this is the most expensive option and is significantly more expensive than establishing Biodiversity Stewardship Site(s). There would be insufficient time to pursue the most cost-effective option (establishing Biodiversity Stewardship Site[s]) if funding for biodiversity offsets was sought as part of our Stage 2 Application.

These costs are explained and justified in our Direct Capex Forecasting Methodology and accompanying model.

We note that the AER has requested further information on our proposed contingency allowances in response to our draft CPA-1 submission. In addition to responding to this information request, we acknowledge the need to work with the AER to discuss the different sources of risk and how best to manage them given the project tight timeframes and contractual commitments. We therefore look forward to working closely with the AER during the review process to ensure that these uncertainties are managed in the best interests of consumers.

Table 10: Stage 1 Direct capex by category ($M, Real 2022-23, including overheads)

Category capex	Description	Forecast capex	% of total capex
Direct capex			
Procurement		**792.87**	**72.32%**
LLE	Transformers, Reactors, Conductor	93.82	8.56%
	Tower Steel	47.67	4.35%
	Power flow controller units to control power flows along segments of Transmission Line	87.40	7.97%
PEC Transmission line enhancement	500KV Transmission line enhancement	345.61	31.52%
Humelink substation expansion and interface work	Substation expansion to connect VNI West Transmissions line	168.97	15.41%
Pre-construction development	Transmission lines and substations[79]	49.40	4.51%
Land acquisitions		**97.85**	**8.92%**
Land acquisitions	Cultural heritage, valuation and acquisition costs including options and customer asset relocation	30.73	2.80%
Biodiversity offsets		67.12	6.12%
Total direct capex		**890.72**	**81.25%**

Table 11 shows that our Stage 1 activities relating to labour and indirect capex (development and approvals) of $205.61 million or 18.75 per cent of capex includes:

- undertaking project management and corporate support (labour costs) for procurement, land and environmental activities, at a cost of $65.16 million (or 5.94 per cent of capex)
- undertaking other project management (non-labour cost) at a cost of $6.91 million (or 0.63 per cent of capex)
- undertaking project development activities, including engineering, legal and economic support, at a cost of $37.41 million (or 3.41 per cent of capex)
- undertaking land and environmental planning and approval activities, including environmental impact studies, surveys, preparing an Environmental Impact Statement (EIS), and specialist land agent support, at a cost of $17.38 million (or 1.59 per cent of capex)

[79] Includes detailed design for substations and transmission lines and other pre-construction works and costs.

- supporting the procurement process, including bidder payments and data room services at a cost of $23.45 million (or 2.14 per cent of capex)
- consulting with stakeholders and the community (non-labour), including community support, social legacy, design and communication and community improvement, at a cost of $6.27 million (or 0.57 per cent of capex), and
- seeking necessary regulatory approvals – this includes actual costs for completing the RIT-T process as well as our actual and forecast capex for preparing our Stage 1 and Stage 2 Applications, at a cost of $47.38 million (or 4.32 per cent of capex).

Our labour and indirect capex includes our actual costs to 31 May 2023 and our forecast for the additional resources and associated costs to 30 April 2025 which is when the early works are expected to be completed.

These costs are explained and justified in our Labour and Indirect Capex Forecasting Methodology and accompanying model.

Table 11 Stage 1 Labour and indirect capex by category ($M, Real 2022-23, including overheads)

Labour and indirect capex (Development and Approvals)		Total capex	% of total capex
Labour and related costs			
Project team resources (including contingency costs)	Labour and corporate support for project management, procurement, land and environmental activities	65.16	5.94%
Indirect costs (non-labour) Costs			
Project management		6.91	0.63%
Project development	Actuals	3.50	0.32%
	External legal	28.91	2.64%
	Geotechnical and survey costs	1.48	0.13%
	Early concept design engineering	1.02	0.09%
	Owners engineer	0.80	0.07%
	Project scheduling management	0.85	0.08%
	Specialist studies	0.86	0.08%
Land and environment	Actuals	0.19	0.02%
	EIS Application Fees	1.88	0.17%
	EIS development	9.38	0.86%
	2023 ecological spring surveys	0.21	0.02%
	Land agents	5.71	0.52%

Labour and indirect capex (Development and Approvals)		Total capex	% of total capex
Procurement	Actuals	0.76	0.07%
	Contractor payments	15.00	1.37%
	Transaction management expenses	4.70	0.43%
	Data room services, probity training and support, independent cost estimator and other activities	2.99	0.27%
Community & stakeholder engagement	Actuals	0.40	0.04%
	Social legacy outcomes	4.91	0.45%
	Community engagement	0.07	0.01%
	Community partnership programs	0.25	0.02%
	Media and events	0.64	0.06%
Regulatory approvals and other support costs	RIT-T analysis and documentation and Stage 1 and 2 CPA documentation, modelling and reports	47.38	4.32%
Contingency (on indirect costs)		1.64	0.15%
Total labour & indirect capex		**205.61**	**18.75%**

4.5. Basis of capex estimate

We have developed our forecast capex based on a detailed scope of works using methods that reflect the specific nature of the costs, as shown in Table 12.

Table 12 Stage 1 forecast capex and basis of estimate by sub-category

Direct capex		Basis of estimate
Procurement		
Long-lead time equipment (LLE)	Transformers, Reactors	Competitively tendered manufacture and supply contracts, which set out quantities and costs
	Conductor	Agreement with suppliers, which set out quantities and costs
	Steel	Fission independent estimate based on quantities and costs
	Power flow control units	Smartwires cost estimate for 10-1800 SmartValve units in NSW.

Direct capex		Basis of estimate
PEC enhancement	500KV Transmission line enhancement	This is based on a combination of: • A contract cost (PEC variation) externally tendered (competitive) D&C contract. • Alignment change request form from the D&C contractor • a 330kV line diversion contract variation • an independent estimate from WSP for biodiversity offset • independent advice from Fission on the appropriate contingency allowance
Gugaa integration works	Connection of the enhanced PEC component of the Project at the Gugaa substation	Contract cost (Humelink variation) externally tendered (competitive) D&C contract. This includes contingency based on advice from Fission.
Pre-construction development	Transmission lines and substations	We have adopted costs based on 4.43% of the total construction cost from PACR based on independent advice from AECOM.
Land acquisition		
Land acquisition	Valuation and acquisition costs	An independent estimate from JLL
Biodiversity offsets	biodiversity offset liability costs	An independent estimate from WSP
Labour and indirect capex		
Labour	Internal resource requirements	Bottom-up build of costs over the period from 1 June 2023 to 30 April 2025
Indirect	Professional and consulting services	Bottom up-build using current available market rates and recent historical data.

Our capex forecast is prudent and efficient in accordance with the capex criteria and meets the required capex objectives set out in the NER. This is demonstrated by:

- a rigorous, well-defined and transparent capex forecasting methodology
- the application of our governance framework and process, which has been provided in previous CPAs and is principally unchanged
- the reliance on market testing and expert reports, and
- the independent verification and assessment of our forecast capex as discussed in section 4.6.

Our capex forecast is the lowest sustainable cost to deliver Stage 1 activities and reflects cost savings for consumers of:

- $60 million for securing LLE for transformers, reactors, conductor and steel through our PTT program (this is the combined savings to consumers across our PTT program for LLE), and
- $787 million from the investment synergies, which arise from undertaking the PEC enhancement and Gugaa integration D&C works as part of our Stage 1 Activities.

4.6. Independent engineering verification of our Stage 1 Capex (early works)

We engaged GHD to undertake an independent engineering verification and assessment of the scope of our Stage 1 activities and our Stage 1 capex forecast. GHD's assessment:

- verified that our Stage 1 activities are aligned with the definition of early works
- found that our overall Project timeline is efficient to meet the 2028 project completion date
- confirmed that our procurement costs are prudent and reflect specialist advice
- found that our indirect and external labour costs are prudent and efficient. Supported by tender outcomes, quotations and benchmarking, and
- found that our actual and forecast internal labour costs are prudent and efficient, noting that our actual labour costs are from Ellipse and our forecast labour costs benchmark in line with other ISP projects.

Overall, GHD Advisory considers that the contracting approach adopted detailed below and capital forecast developed to be prudent and efficient having regard to current market conditions, and are required to achieve project timeframes, reduce the final projects costs, and / or reduce schedule and cost risks. GHD's report is provided as an attachment to our Application.

4.7. Capex threshold

The proposed capex of a contingent project is required to exceed either $30 million, or 5 per cent of the MAR for the first year of the regulatory control period, whichever is the greater.

Table 13 shows that the forecast capex satisfies the relevant threshold. This means that the capex is covered by the contingent project requirements of the NER.

Table 13 – Contingent project thresholds ($M, Nominal)

AER Decision First year MAR	5% of MAR	Contingent Project Threshold	Pass / Fail
897.78	44.89	44.89	Pass (as capex > $30 million)

Notes: NER clause 6a.8.1(b)(2)(iii) requires that expected capex is higher than the greater of $30 million or 5% of MAR. The threshold is $44.89 million (being 5% of MAR).

4.8. Application of the CESS

As discussed with the AER and our other stakeholders, including the TAC, we do not support the application of CESS to AEMO's ISP projects. This is because in an inflationary and uncertain operating environment with high value, complex and specialised projects, these incentive schemes introduce an asymmetric risk.

The key drivers of this asymmetric risk costs arise from:

- labour shortages
- increasing materials costs and supply chain disruption, and
- other unforeseeable and unquantifiable costs that will arise in a project such as this, given the operating environment and the unique characteristics of ISP Projects including their size and scale.

To safeguard against potential losses (i.e., risk costs) D&C contractors require some cost components in their contracts to be variable. This allows them to offer a lower contract price than they otherwise would if they were forced to price in the risk costs though a fixed price contract.

We anticipate that like Humelink, we will adopt an incentivised target cost D&C contract in our Stage 2 Application, whereby some components of the contract are fixed and others are variable. This will provide consumers with a higher probability of a lower price outcome. However, it also means that Transgrid is holding the residual risk costs, which have not been fully priced into our forecast capex.

Given the uncertain and challenging operating environment and contractors not being able or willing to enter into fixed price D&C contracts, the probability of overspending the AER's capex allowance is greater than the probability of underspending it.

There is currently no provision in the NER for adjusting the capex allowance approved by the AER for a Major ISP Project to deal with costs arising from the uncertain operating environment in a way that is fair to all market participants, including customers and TNSPs. Currently, we would need to fund the gap in financing the investment for the remainder of the period and would be penalised under the CESS for any overspend, even when the higher levels of expenditure are efficient. This means that we may therefore not have a reasonable opportunity to recover the efficient costs of delivering the Project. In particular, if the CESS applies these projects are expected to generate less than the benchmark rate of return. Investors may therefore not be willing to commit capital to these projects, which is not in the long-term interest of consumers, because these projects are critical to:

- the urgent energy transition, which in turn will drive down energy prices
- support the Australian and NSW Government's commitment to a net-zero future, and
- ensure consumers continue to receive reliable and secure electricity.

It would therefore not be in the long-term interest of consumers to apply penalties or rewards for differences between actual and forecast expenditure where these differences are driven by factors other than true efficiency savings or losses.

Importantly, the AER's underlying building block framework already provides an appropriate financial incentive for us to minimise capex. This is because during the regulatory period, revenues are based on forecast capex, such that we do not earn a return on any capex overspend for the duration of the regulatory period. Any capex overspend is rolled into our RAB at the start of the subsequent regulatory period, only then enabling us to earn a return on our actual prudent and efficient capex.

Transgrid would welcome further discussions with the AER regarding the application of the CESS, given the significant exposure that it creates for customers and investors for a project of this nature.

5. Forecast Revenue and impact on customers' bills

This chapter sets out the incremental revenue forecast for Stage 1 (early works), our updated MAR and the indicative impact on the transmission component of customers' bills.

We have determined our incremental revenue forecast using the same assumptions and approaches recently adopted by the AER in its determination on PEC and the QNI Minor contingent project applications. Table 14 summarises the incremental revenue forecast of $213.36 million ($Nominal) over the 2023–28 regulatory period, broken down by building block component, and briefly explains how we have calculated each component. Further detail is provided in Appendix A.

This shows that incremental revenue we are seeking over the 2023–28 regulatory period is modest because:

- we are not seeking to adjust our current opex allowance as part of this Application, other than adjusting our allowance for debt raising cost as a consequence of the revised capex allowance, and
- our capex is not expected to be commissioned until 30 April 2025 when the early works have been completed.

Table 14 – 2023-28 incremental revenue forecast from Stage 1 (early works) ($M, Nominal)

Building block	$ Million, Nominal	Approach
Return on capital	243.20	Calculated by multiplying the forecast opening capital base (updated to include expenditure on Stage 1 (early works) for a given year by the allowed rate of return adopted by the AER.
Return of capital	(30.97)	Calculated as forecast straight line depreciation for each asset class less indexation of the capital base. The value is negative because indexation is higher than depreciation over the 2023–28 regulatory period.
Opex	2.12	We are not seeking to adjust our current opex allowance as part of this Application, other than adjusting our allowance for debt raising cost as a consequence of the revised capex allowance. Debt raising costs have been calculated using the AER's standard approach.
Revenue adjustments	-	None
Corporate income tax	(6.93)	Calculated as forecast pre-tax income multiplied by the corporate tax rate, less the assumed value of imputation credits.
Annual revenue requirement (i.e., unsmoothed)	**207.42**	
Impact of smoothing	5.94	Calculated by resolving the year 3 to 5 X-factors so that the NPV of the MAR for the 2023–28 regulatory period matched that of the forecast annual revenue requirement for the same period.

Building block	$ Million, Nominal	Approach
Maximum allowed revenue (i.e., smoothed)	**213.36**	

Table 15 details the 2023–28 incremental revenue forecast of Stage 1 (early works) by year.

Table 15: – Incremental revenue forecast (smoothed) ($M, Nominal)

MAR (Smoothed Revenue)	2023-24	2024-25	2025-26	2026-27	2027-28	Total
AER 2023-28 determination (updated for the Humelink Early Works Parts 1 and 2)	923.99	960.11	995.98	1,033.19	1,071.78	**4,985.05**
Impact of VNI West Stage 1	-	-	41.86	88.67	82.82	**213.36**
Updated MAR	**923.99**	**960.11**	**1,037.84**	**1,121.86**	**1,154.61**	**5,198.40**

Table 16 shows the indicative customer bill impact is an average increase of $7.07 per annum for residential customers and an increase of $14.05 per annum for small business customers, commencing 2025-26. These transmission cost increases will be more than offset by savings in wholesale costs, noting that the VNI West RIT-T estimates that the Project will deliver $1.4 billion in net benefits (in NPV terms) primarily from avoided, or deferred, costs associated with generation and storage infrastructure, fuel cost savings and REZ transmission expansion cost savings.

We have applied the same approach to estimating the indicative impact on customer bills over the 2023–28 period that the AER used in its CPA decision on Humelink Stage 1 (early works). We converted our proposed MAR into indicative household and small business bills using forecast energy throughput and typical household and small business bill information, such as the typical bill size and the share of NSW residential and small business bills attributed to transmission charges.

Table 16: Impact of Stage 1 on the transmission component of customers' bills ($ per customer per year, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28
Residential Bills					
AER 2023-28 determination (updated for the Humelink CPA-1 (Parts 1 and 2))	2,076.15	2,076.88	2,076.65	2,076.79	2,077.52
Impact of VNI West Stage 1	-	-	4.33	8.86	8.03
Updated typical customer bill	**2,076.15**	**2,076.88**	**2,080.98**	**2,085.64**	**2,085.55**

	2023-24	2024-25	2025-26	2026-27	2027-28
Small Business Bills					
AER 2023-28 determination (updated for the Humelink CPA-1 (Parts 1 and 2))	5,105.28	5,106.74	5,106.28	5,106.55	5,108.01
Impact of VNI West Stage 1	-	-	8.61	17.60	15.96
Updated typical customer bill	**5,105.28**	**5,106.74**	**5,114.89**	**5,124.15**	**5,123.96**

6. Guide to compliance

Table 17 list the NER requirements for a CPA, and where we have addresses these in our Application.

Table 17: Compliance with NER requirements

NER, clause 6A.8.2(b) requirements	Reference in Application
1. An explanation that substantiates the occurrence of the trigger event	Chapter 3
2. A forecast of the total capex for the contingent project	Chapter 4
3. A forecast of the capital and incremental opex, for each remaining regulatory year which the Transmission Network Service Provider considers is reasonably required for the purpose of undertaking the contingent project	Chapter 4
4. How the forecast of the total capex for the contingent project meets the threshold as referred to in clause 6A.8.1(b)(2)(iii)	Chapter 4
5. The intended date for commencing the contingent project (which must be during the regulatory control period)	Chapter 3
6. The anticipated date for completing the contingent project (which may be after the end of the regulatory control period) and	Chapter 3
7. An estimate of the incremental revenue which the Transmission Network Service Provider considers is likely to be required to be earned in each remaining regulatory year of the regulatory control period as a result of the contingent project being undertaken as described in subparagraph (3), which must be calculated: (i) in accordance with the requirements of the post-tax revenue model referred to in clause 6A.5.2 (ii) in accordance with the requirements of the roll forward model referred to in clause 6A.6.1(b) (iii) using the allowed rate of return for that Transmission Network Service Provider for the regulatory control period as determined in accordance with clause 6A.6.2 (iv) in accordance with the requirements for depreciation referred to in clause 6A.6.3, and (v) on the basis of the capex and incremental opex referred to in subparagraph (b)(3).	Chapter 5 and Appendix A

Table 18 lists the CPA requirements in the AER's Guidance Note and where we have addressed these in our Stage 1 Application.

Table 18: Compliance to AER Guidelines

AER Guideline requirement	Reference in Application
Stakeholder engagement (section 2.2)	
Overview of stakeholder engagement approach and feedback received	Chapter 3.
Project governance (section 2.4)	

AER Guideline requirement	Reference in Application
Project governance framework and processes, including key roles, accountabilities and responsibilities	Our project governance framework has been provided in previous CPAs and is principally unchanged.
Project (including risk) reporting, monitoring and evaluation arrangements	
Any supporting assurance arrangements	
Project Plans (section 2.4.2)	
High level delivery schedule, with key milestones and timeframes	Refer to VNI-W High Level Program for delivery schedule, key milestones, dependencies and decision points.
Key dependencies and decision points for the project	
Project resourcing and capability arrangements	Refer to A.3 Labour and indirect forecasting methodology
Risk management framework and plan	Refer to the VNI-W Risk Management Framework and plan
Established arrangements for post completion project review	Transgrid's Project Management Manual outlines the process for post completion project reviews.
Procurement strategy, processes, and outcomes (section 2.5)	
Overview of procurement strategy, including scope of work packages	Our procurement process is outlined in our Capex Forecasting Methodology.
Tender Evaluation Plan(s), including roles and responsibilities of evaluation team	
Overview of procurement process(es), including summary of activities and timeline	
Outcomes of procurement activities	
Tender Evaluation and Probity Report(s)	
Risk assessment (section 2.6)	
Detailed risk register containing identifiable projects risks, and	The risk assessments will be developed during the D&A phase for the Stage 2 Application. Risk in the Stage 1 Application has been considered for each activity and associated cost using a qualitative approach to determining the mid-point (i.e., P50) estimate of the forecast costs.
A summary of the efficient mitigation steps taken for the relevant risks	
An assessment for each residual risk	

Appendix A Revenue Application

This Appendix A sets out our incremental revenue forecast for the Stage 1 (early works), having regard for clause 6A.8.2(b)(9) of the NER.

As discussed in Chapter 5, on the basis of our Stage 1 capex forecast, we are seeking the AER's approval to increase our allowed our 2023–28 MAR and tariffs. This Appendix A shows:

- The impact to *unsmoothed* revenue (i.e., the Aggregate Building Block Revenue Requirement (ABBRR)) over the 2023-28 regulatory period, and
- The impact to MAR (or *smoothed* revenue) over the 2023–28 regulatory period.

Table 19 sets out the incremental MAR for Stage 1 activities for the 2023-28 regulatory period. This has been calculated using the PTRM adopted by the AER in its recent decision on the Humelink Stage 1 (Part 2) CPA.[80]

Table 19: Incremental MAR ($M, Nominal)

MAR (Smoothed Revenue)	2023-24	2024-25	2025-26	2026-27	2027-28	Total
AER 2023-28 determination (updated for the Humelink CPA-1 (Parts 1 and 2))	923.99	960.11	995.98	1,033.19	1,071.78	**4,985.05**
Impact of VNI West Stage 1	-	-	41.86	88.67	82.82	**213.36**
Updated MAR	**923.99**	**960.11**	**1,037.84**	**1,121.86**	**1,154.61**	**5,198.40**

The rest of this Appendix A:

- identifies the weighted average cost of capital (WACC) and standard asset life assumptions adopted for the 2023–28 regulatory period
- sets out projected regulatory depreciation, tax allowance, debt and equity raising costs, unsmoothed revenue requirements and MAR for the 2023-28 regulatory period, and
- details the potential customer bill impact from the incremental revenue requirements resulting from the Project for the 2023–28 regulatory period.

A.1 Weighted average cost of capital (WACC)

We have calculated the incremental revenue for Stage 1 activities using the same WACC assumptions as those adopted by the AER in its 2023-28 Revenue Determination. This is consistent with the requirements of clause 6A.8.2(b)(4)(ii) of the NER.

The WACC parameters are set out in Table 20.

[80] Throughout this Appendix A we have presented any revenue forecasts in end of year nominal terms.

Table 20: WACC parameters

Parameter	AER Approved Value	
Forecast inflation	2.92%	
Value of imputation credits	57.00%	
Gearing	60.00%	
Nominal pre-tax return on debt	4.63%	for 2023-24
	4.59%	for 2024-25
	4.72%	for 2025-26
	4.82%	for 2026-27
	4.97%	for 2027-28
Nominal post-tax return on equity	7.48%	
Nominal vanilla WACC	5.77%	for 2023-24
	5.75%	for 2024-25
	5.82%	for 2025-26
	5.88%	for 2026-27
	5.97%	for 2027-28

A.2 Asset lives

We have allocated our forecast capex for Stage 1 activities across regulatory asset classes, as detailed in our Direct Capex Forecasting Methodology, provided as an attachment to this Application. Capex is depreciated in the PTRM using the standard asset lives used in the AER's 2023–28 Revenue Determination, with two exceptions:

- for equity raising costs, we have updated the standard life for this asset class from 'n/a' to 40.3 years using the approach adopted by the AER in its recent determinations, and
- we have added a new asset class for Biodiversity offset liabilities to enable us to depreciate these costs over the weighted average of the standard lives of all other depreciating assets. This will assist to ensure that the project is financeable.

The applicable standard asset lives are set out in Table 21.

Table 21: Asset lives

Asset Category	Standard Life (years)	Explanation
Transmission lines	50.00	As per the AER's 2023–28 Revenue Determination.
Substations	40.00	
Land and easements	n/a	

Asset Category	Standard Life (years)	Explanation
Biodiversity offsets	45.58	Calculated as the weighted average of the standard lives of all other depreciating assets for the VNI West stage 1 activities using the same approach as that used to determine the standard life for equity raising costs.
Equity raising costs	41.52	This is calculated as the weighted average standard life for forecast net as incurred capex.[81]

Note: Only asset classes that attract the Project capex are shown.

A.3 Incremental regulatory depreciation

Table 22 sets out our forecast incremental regulatory depreciation for the 2023–28 regulatory period for Stage 1 activities, consistent with clause 6A.8.2(b)(7)(iv) of the NER. This forecast has been calculated using the AER's most recent PTRM for the 2023-28 period, projected incremental capex, and the asset lives in section A.2.

As discussed above, to help improve the financeability of the VNI West project we have set forecast as commissioned capex for all asset class to match forecast as incurred capex. In effect, this leads to forecast capex on all depreciable assets being depreciated on an as incurred rather than as commissioned basis, bringing forward the timing of when depreciation is allowed.

Incremental regulatory depreciation is negative over the 2023–28 regulatory period. This is because the long-lived nature of the assets leads to indexation being higher than real straight-line depreciation earlier in the lives of those assets. This relationship will reverse later in the assets' lives, leading to positive regulatory depreciation.

Table 22: Incremental regulatory depreciation ($M, Nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
AER 2023-28 determination (updated for the Humelink CPA-1 (Parts 1 and 2))	89.91	102.92	137.24	165.97	156.38	652.41
Impact of VNI West Stage 1	(1.01)	(5.52)	(8.23)	(8.37)	(7.85)	(30.97)
Updated regulatory depreciation	**88.90**	**97.40**	**129.01**	**157.60**	**148.53**	**621.44**

[81] See, for instance, AER, April 2019, *Final Decision, Power and Water Corporation, Post-tax Revenue Model,* PTRM input sheet, W327 cell. Net commissioned capex was used in the weighted average, rather than net as incurred capex, as the former is used to calculate regulatory depreciation in the 'Assets' sheet of our PTRM.

A.3a Appendix - AER Information Request – As incurred depreciation

In response to Transgrid's email advice to the AER on 17 November 2023, the AER has asked Transgrid to explain its reasons for proposing 'as incurred' depreciation, rather than 'as commissioned' which is the standard approach for transmission regulation.

In addressing this information request, the AER asked Transgrid to address four questions which relate to different aspects of the regulatory framework, including: the National Electricity Rules (**NER**) requirements; regulatory incentives; financeability considerations; and the National Electricity Objective.

In this response, we address each of these questions in turn in relation to early works expenditure, which is the subject of this CPA-1 submission. In our CPA-2 submission for Humelink, we separately address these questions in relation to construction expenditure.

Q1. Please explain how the change proposed is consistent with the NER requirement for depreciating the value of the ISP assets in the RAB using a profile that reflects the nature of the assets over their economic life? This should take into account the nature of the transmission assets, which are very different to distribution assets.

The NER already allows the AER to depreciate transmission assets on an as incurred basis, including for ISP projects. The NER outlines the depreciation framework the AER must apply to distribution and transmission assets and does not specifically provide for or prevent depreciation to be recovered from assets on an as incurred basis.

This observation was recently made by the Australian Energy Market Commission (the Commission) in its draft determination on financeability, in which it considered a Rule change request from the Chris Bowen, Commonwealth Minister for Climate Change and Energy which proposed an amendment to allow biodiversity costs to be depreciated on an 'as incurred' basis:[82]

> "The Commission considers that the NER already allows the AER to depreciate transmission assets on an as incurred basis, including for ISP projects. Therefore, there is no need to amend the NER specifically to allow depreciation of biodiversity assets on an as incurred basis."

In making this observation, the Commission is aware that:

- the depreciation provisions in the NER are identical for transmission and distribution network; and
- the AER has adopted an 'as incurred' depreciation approach for distribution assets.

It is therefore open for the AER to adopt an 'as incurred' depreciation approach for transmission assets. In considering whether the AER should adopt an 'as incurred' approach, it is important to consider the requirements of clause 6A.6.3(b)(1) of the NER, which requires that:

> "The depreciation schedules must [….use] a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets"

While 'depreciation schedule' is not defined in the NER, Transgrid considers it reasonable to interpret this clause as referring only to the profile of depreciation, rather than the start date. On this interpretation, this provision is only addressing the type of depreciation (e.g. straight-line or annuity depreciation) and the

[82] AEMC, Draft rule determination, National Electricity Amendment (Accommodating financeability in the regulatory framework) Rule 2024, 14 December 2023, p.36

economic life of the asset (e.g. whether it is shorter than the technical life of the asset), rather than when depreciation should commence (i.e., whether it is 'as incurred' or 'as commissioned').

If, however, clause 6A.6.3(b)(1) of the NER is interpreted more broadly to include the start date for depreciation, Transgrid's view is that the nature of early works expenditure would support an 'as incurred' approach. In particular, the Commission has defined early works activities as follows:[83]

> "Any activity which commences prior to construction […] if the activity can be justified as being necessary to:
>
> - improve the accuracy of project cost estimates, and
> - ensure that a project will be delivered within the timeframes specified by the most recent Integrated System Plan."

The Commission has also expressed the view that early works expenditure should be recoverable, whether or not the project proceeds:[84]

> "The Commission considers that it is important for TNSPs to have certainty that they can recover at least their efficient costs for preparatory activities and early works."

We note that the AER accepted the Commission's definition of early works activities in its recent revenue determination for Marinus Link: [85]

> "We consider the scope of works proposed by Marinus Link are consistent with the Australian Energy Market Commission's (AEMC) definition of early works.[…]
>
> We consider these works critical to improving the accuracy of cost estimates and delivering the project in accordance with AEMO's 2022 ISP."

The nature of early works expenditure, therefore, is that it provides benefits to customers in terms of improving the project cost estimates and ensuring that the project can be delivered on time. These benefits begin to accrue as the expenditure takes place (i.e., consistent with 'as incurred' depreciation), not when the actionable ISP project is commissioned. Furthermore, if early works expenditure could only be depreciated on an 'as commissioned' basis, there would be no certainty that the expenditure could be recovered, which would contrary to the Commission's views.

These observations lead to the conclusion that it is reasonable to adopt 'as incurred' depreciation to early works expenditure. Specifically, Transgrid considers that it better reflects the purpose of the expenditure and the services it provides, which do not depend on the commissioning of the ISP project. As explained, early works activities have a purpose that is distinct from and separate to the construction of the ISP project, in accordance with the Commission's statements noted above.

Q2. Please explain how the change would provide incentives for the efficient provision of the assets, including efficient completion

Transgrid is aware that it has been argued that 'as incurred' depreciation provides weaker incentives to complete a project compared to 'as commissioned' depreciation.

As explained in our answer to Q1, CPA-1 early works activities differ in different in nature to CPA-2 'construction costs' because early works activities are directed at:

[83] AEMC, Final Report, Transmission Planning and Investment Review, Stage 2, 27 October 2022, p.41
[84] AEMC, Transmission Planning and Investment Review – Stage 2, 27 October 2022, p.38
[85] AER Determination, Marinus Link Stage 1, Part A (Early works), December 2023, p.iv

- improving the accuracy of project cost estimates, and
- ensuring that a project will be delivered within the timeframes specified by the most recent Integrated System Plan.

As early works does not result in any commissioning, there are no incentives to delay these activities. On the contrary, there are strong incentives to complete the early work so that CPA-2 can be lodged. In our view, therefore, there is no reason to suppose that applying 'as incurred' depreciation to early works expenditure would adversely affect the incentive to complete this work in a timely manner.

In our Humelink submission, we consider the incentives for project completion in applying 'as incurred' depreciation to construction expenditure, which is the subject of our CPA-2 submission for Humelink.

In relation to the efficient provision of 'early works' expenditure (as opposed to incentives for project completion), we are not aware of any reason why adopting 'as incurred' depreciation would weaken the incentives to complete the work prudently and efficiently. As already noted, the distribution networks are subject to 'as incurred' depreciation and we are not aware of any evidence that these businesses are less efficient as a result of adopting this depreciation model.

Q3. Please explain why the change is needed from a financeability perspective taking into account any government assistance it has received from the CEFC

The importance of investors being able to earn the regulated rate of return on these very large projects, and being able to attract the required debt and equity capital is critical to achieving Australia's net zero vision. The regulated return is calculated assuming a benchmark regulated entity and a defined credit rating. The current CEFC commitment is an extremely helpful step, however still falls somewhat short of providing a complete solution, with financeability remaining a very real challenge to ensure these critical projects are delivered in a timely manner.

We acknowledge the complexities arising from current macro-economic challenges, and see this reflected in the Government's acknowledgement of the need for further regulatory reform to help deliver the clean energy transition as well as recent draft rule changes aimed at a sustainable solution for financeability. To this end, we will continue in good faith to negotiate with the CEFC and the AER to resolve appropriate solutions which will enable these projects to be financed and delivered.

In the case of VNI West, this CPA-1 includes expenditure relating to biodiversity offsets and construction of related projects (such as the PEC enhancement and Humelink Gugga Integration), the size of which raises financeability issues. The adoption of 'as incurred' depreciation will assist in alleviating these financeability issues.

We have been negotiating a concessional loan to support VNI West CPA 1 from the CEFC.

For completeness, appropriate adjustment mechanisms have been included in the concessional arrangements that protect consumers, via reduction in the concessional loan to ensure there is no over-recovery resulting in Transgrid earning more than the regulated return.

Q4. Please explain why the change is in the long term interest of consumers and best promotes the NEO.

As explained in answer to Q1, the benefits from early works expenditure begin to accrue as the expenditure takes place (i.e., consistent with 'as incurred' depreciation), not when the actionable ISP project is commissioned. For that reason, the 'as incurred' depreciation will result in a price profile for network services that more accurately reflects the efficient costs of providing these services. While the positive impact in terms of promoting the NEO is likely to be small, given the modest price impact of 'as incurred' depreciation, it is reasonable to conclude that the change is consistent with promoting the NEO.

For construction expenditure, which is considered in our CPA-2 submission for Humelink, the impact on the NEO in adopting ‘as incurred’ depreciation is substantially greater.

A.4 Tax allowance

Table 23 sets out the incremental forecast net tax allowance for the 2023–28 regulatory period attributed to Stage 1 activities. This has been calculated using the PTRM and projected incremental capex.

We have not made any other changes to the net tax calculation from that used in the AER’s 2023–28 Revenue Determination.

Table 23: Incremental net tax allowance ($M, Nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
AER 2023-28 determination (updated for the Humelink CPA-1 (Parts 1 and 2))	24.15	20.37	16.00	22.30	25.02	107.84
Impact of VNI West Stage 1	0.02	(1.32)	(2.12)	(1.94)	(1.57)	(6.93)
Updated net tax allowance	**24.17**	**19.05**	**13.88**	**20.37**	**23.45**	**100.91**

A.5 Debt and equity raising costs

Our forecast incremental revenue includes allowances for debt and equity raising costs, consistent with the AER’s 2023–28 Revenue Determination. Both costs are calculated automatically within the PTRM.

Debt raising costs are included within the opex building block and are calculated as follows:

- projected opening RAB at the start of each regulatory year is multiplied by assumed gearing (of 60%) and the debt raising cost benchmark (of 0.083%).
- Equity raising costs are included within the capex forecast and recovered via the return on and of capital building blocks. These costs are calculated as follows:
  - retained cash flows are projected by subtracting opex, interest payments, revenue adjustments, tax payable, and dividends from projected smoothed (i.e., MAR) revenue
  - equity raising is projected by subtracting retained cash flows from the equity funding component of projected capex (assuming 60% gearing), and split between distribution reinvestment and external equity raising sources, and
  - equity raising costs are calculated by multiplying the two sources by assumed benchmark equity raising cost rates.

Table 24: Incremental debt and equity raising costs ($M, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Debt raising costs						
AER 2023-28 determination (updated for the Humelink CPA-1 (Parts 1 and 2))	4.53	5.03	5.17	5.08	4.99	24.79
Impact of VNI West Stage 1	0.04	0.29	0.51	0.54	0.53	1.91

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Updated debt raising costs	**4.56**	**5.32**	**5.68**	**5.62**	**5.51**	**26.70**
Equity raising costs						
AER 2023-28 determination (updated for the Humelink CPA-1 (Parts 1 and 2))	-	-	-	-	-	-
Impact of VNI West Stage 1	3.47	-	-	-	-	3.47
Updated equity raising costs	**3.47**	**-**	**-**	**-**	**-**	**3.47**

A.6 Incremental revenue requirements for each year to end of period

Table 25 details the incremental Annual Building Block Revenue Requirement (ABBRR) for Stage 1 (early works) for the 2023-28 period based on the forecasts provided above and using the PTRM.

Table 25: Incremental revenue requirements ($M, Nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
AER 2023-28 determination updated for the Humelink CPA-1 (Parts 1 and 2))						
Return on capital	525.35	599.12	641.29	655.99	672.42	**3,094.18**
Regulatory depreciation	89.91	102.92	137.24	165.97	156.38	**652.41**
Opex	212.59	235.17	243.76	251.85	260.28	**1,203.65**
Revenue adjustments	12.42	(8.44)	(19.51)	(19.15)	(26.45)	**(61.13)**
Net tax allowance	24.15	20.37	16.00	22.30	25.02	**107.84**
Unsmoothed revenue requirement	**864.41**	**949.13**	**1,018.78**	**1,076.96**	**1,087.65**	**4,996.94**
Impact of VNI West Stage 1						
Return on capital	4.54	34.87	63.67	69.35	70.88	**243.20**
Regulatory depreciation	(1.01)	(5.52)	(8.23)	(8.37)	(7.85)	**(30.97)**
Opex allowance	0.04	0.31	0.56	0.60	0.61	**2.12**
Revenue adjustments	-	-	-	-	-	**-**

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Net tax allowance	0.02	(1.32)	(2.12)	(1.94)	(1.57)	**(6.93)**
Unsmoothed revenue requirements	**3.59**	**28.22**	**53.88**	**59.65**	**62.07**	**207.42**
Updated						
Return on capital	529.89	633.89	704.96	725.34	743.30	3,337.38
Regulatory depreciation	88.90	97.40	129.01	157.60	148.53	621.44
Opex allowance	212.63	235.48	244.32	252.45	260.89	1,205.76
Revenue adjustments	12.42	(8.44)	(19.51)	(19.15)	(26.45)	(61.13)
Net tax allowance	24.17	19.05	13.88	20.37	23.45	100.91
Unsmoothed revenue requirements	**868.00**	**977.36**	**1,072.66**	**1,136.61**	**1,149.72**	**5,204.35**

A.7 Amended ABBRR and MAR

The AER's final decision on the ABBRR for the 2023–28 regulatory period is set out in Table 26, together with the calculation of the amended revenue required for Stage 1 activities.

Table 26: Amended ABBRR ($M, Nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
AER 2023-28 determination (updated for the Humelink CPA-1 (Parts 1 and 2))	864.41	949.13	1,018.78	1,076.96	1,087.65	**4,996.94**
Impact of VNI West Stage 1	3.59	28.22	53.88	59.65	62.07	**207.42**
Updated annual revenue requirements	**866.00**	**977.36**	**1,072.66**	**1,136.61**	**1,149.72**	**5,204.35**

Table 27 sets out the updated MAR for the current regulatory period.

Table 27: Amended MAR for the 2023-28 regulatory period ($M, Nominal)

MAR (Smoothed Revenue)	2023-24	2024-25	2025-26	2026-27	2027-28	Total
AER 2023-28 determination (updated for the Humelink CPA-1 (Parts 1 and 2))	923.99	960.11	995.98	1,033.19	1,071.78	**4,985.05**

MAR (Smoothed Revenue)	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Impact of VNI West Stage 1	-	-	41.86	88.67	82.82	**213.36**
Updated MAR	**923.99**	**960.11**	**1,038.02**	**1,122.26**	**1,155.02**	**5,199.40**

7. Abbreviations

The following abbreviations are used in this Stage 1 Application.

Abbreviation	Definition
AACE	Association for the Advancement of Cost Engineering
ABBRR	Annual Building Block Revenue Requirement
AEIC	Australian Energy Infrastructure Commissioner
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AVP	AEMO Victoria Planning
BC Act	NSW Biodiversity Conservation Act 2016
BCF	Biodiversity Conservation Fund
BSA	Biodiversity Stewardship Agreement
CCG	Community Consultation Group
CEFC	Clean Energy Finance Corporation
CESS	Capital Expenditure Sharing Scheme
CPA or Application	Contingent Project Application
D&A	Development and approvals
D&C	Design and construction
DISER	Department of Industry Science Energy and Research
EIS	Environmental Impact Statement
ENA	Energy Networks Australia
EP&A	Environmental Planning and Assessment
FID	Final Investment Decision
ISP	Integrated System Plan
kV	kilovolt
LALC	Local Aboriginal Land Council

Abbreviation	Definition
LLE	Long Lead Equipment
MAR	Maximum allowed revenue
MCHPA	Moorabool and Central Highlands Power Alliance Inc.
NEM	National Electricity Market
NER or Rules	National Electricity Rules
NEVA	National Electricity (Victoria) Act 2005
NPV	Net present value
NSW	New South Wales
ODP	Optimal Development Path
PACR	Project Assessment Conclusions Report
EnergyConnect or PEC	Project EnergyConnect
PTRM	Post tax revenue model
PTT	Powering Tomorrow Together
RAB	Regulatory Asset Base
REZ	Renewable energy zone
RFM	Roll forward model
RIT-T	Regulatory Investment Test for Transmission
RRG	Regional Reference Group
Stage 1 Application or CPA-1	Contingent Project Application for early works
Stage 2 Application or CPA-2	Stage 2 Contingent Project Application for delivery
TAB	Tax Asset Base
TAC	Transgrid Advisory Committee
VNI PACR	VNI West Project Assessment Conclusions Report
VNI West or the Project	Victorian to New South Wales (NSW) Interconnector West
VRE	Variable renewable energy
WACC	Weighted Average Cost of Capital
WRL	Western Renewables Link