Plan B Review – Volume 2 - information repository

Version: v4 (Final)

DEECA

Plan B Review
8 March 2024

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1. Introduction

1.1 General

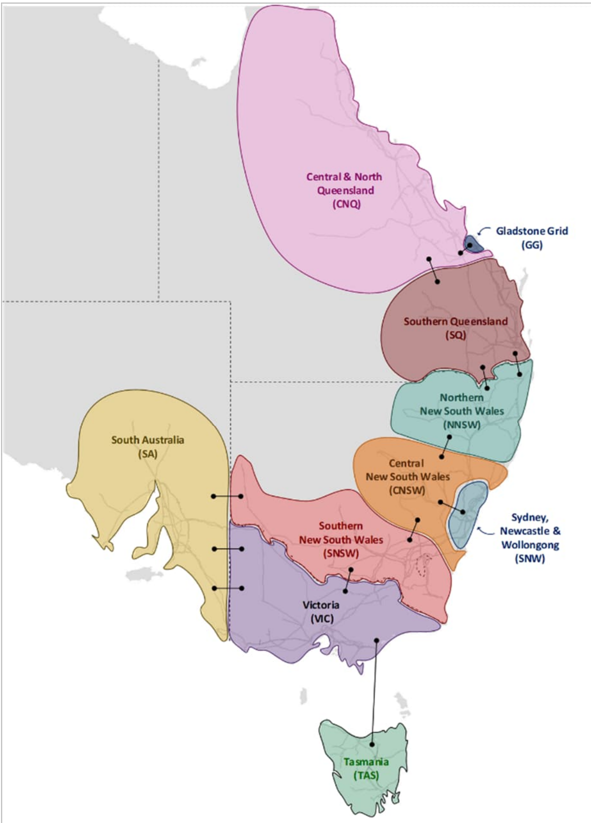
This volume summarises the information gathered to inform the task matters that Jacobs are reviewing on the Plan B[1] review. This volume should be read as support material for the Volume 1 report prepared by Jacobs.

The information is generally assembled along the lines of the task matters Jacobs are addressing in Volume 1, though some materials may have application across more than one area.

1.2 Current configuration

The NEM is a set of five regions (Qld, NSW, Vic, SA and Tas) that were each formerly separate electricity systems, that were joined together by interconnectors to form the overall NEM. NSW and Qld have some additional particular intra-regional transmission constraints such that AEMO presently identifies a sub-regional structure as shown in Figure 1

Figure 1. Sub-regional structure of the NEM[2]



[1] In this review "Plan B" is from: Mountain, B.R., Bartlett, S., Edwards, D. (2023). "*No longer lost in transmission: Expanding transmission need not be at the expense of land-holders, renewables investors, communities, consumers and the environment*". Victoria Energy Policy Centre, Victoria University, Melbourne. DOI: 10.26196/gf0x-ww20

[2] The figure is from the AEMO "Forecasting Assumptions Update Workbook full" dated 20 March 2023

For the present review it is the interconnections between Victoria and NSW that are principally of interest (though South Australia and Tasmania are also materially impacted).

The link between Victoria and NSW (designated as forward flow = flow from Vic to NSW and reverse (negative) flow is to the south) actually comprises four circuits (and a bus tie that is normally open):

- Murray – Upper Tumut 330 kV (1 circuit)
- Murray – Lower Tumut 330 kV (1 circuit)
- Wodonga – Jindera 330 kV (1 circuit)
- Red Cliffs – Buronga 220 kV line (circuit)
- 132 kV bus tie at Guthega (1 circuit which is normally open)

The 330kV circ are in the east of Victoria (circa Wodonga, Dederang) from the Snowy Mountains and the Buronga-Redcliffs connection is a lower capacity connection in the West of Victoria near Mildura.

The current interconnection capacity is listed as shown in Figure 2:

Figure 2. Victorian related interconnector capability (current)[3]

Flow paths (Forward power flow direction)	Forward direction capability approximation (MW) - Notes 1,2&3		
	Peak demand	Summer Typical	Winter Reference
VIC – SNSW (Southern part of "VNI")	870 (with VNI minor)	1,000 (with VNI minor)	1,000 (with VNI minor)
VIC – SESA ("Heywood") - (Note 9)	650	650	650
SESA-CSA	650	650	650
VIC – CSA (Murraylink)	220	220	220
TAS – VIC	462	462	462

Flow paths (Forward power flow direction)	Reverse direction capability approximation (MW) - Notes 1,2&3		
	Peak demand	Summer Typical	Winter Reference
VIC – SNSW (Southern part of "VNI")	400 (with VNI SIPS) - Note 8 (Snowy 2.0 generation or pump load <= 660)	400 (Snowy 2.0 generation or pump load <= 660)	400 (Snowy 2.0 generation or pump load <= 660)
VIC – SESA ("Heywood") - (Note 9)	650	650	650
SESA-CSA	650	650	650
VIC – CSA (Murraylink)	100	200	200
TAS – VIC	462	462	462

Flow paths (Forward power flow direction)	Dominant constraints	
	Forward direction	Reverse direction
VIC – SNSW (Southern part of "VNI")	Transient stability for a fault on a Hazelwood-South 500 circuit or volage stability in Southern New South Wales for loss of largest load in Victoria.	Voltage stability in SNSW for loss of the largest generator in Victoria. Prior to HumeLink service, Snowy 2.0 generation or pump load is limited by a transient stability limit.
VIC – SESA ("Heywood") - (Note 9)	Thermal capacity of Heywood-South East 275 kV line or transient stability limit for loss of the largest generator in South Australia or transient stability limit of loss of South East - Tailem Bend 275 kV line.	Oscillatory stability limit.
SESA-CSA	Transient stability limit for loss of the largest generator in South Australia or transient stability limit of loss of South East - Tailem Bend 275 kV line.	Oscillatory stability limit.
VIC – CSA (Murraylink)	Murraylink thermal capacity. Assumes high renewable generation in North West Victoria during high ambient temperature.	Thermal capability of 132 kV lines between Robertstown and North West Bend
TAS – VIC	Basslink HVDC submarine cable transfer limit.	Basslink HVDC submarine cable transfer limit.

[3] AEMO "2023 IASR Assumptions Workbook" dated 8 September 2023

AEMO has designated a set of Renewable Energy Zones (REZ) over the NEM, being zones where they expect a focus on new renewables to built based on renewable resource levels (such as solar insolation and wind speeds), transmission corridors, levels of industry interest etc).

Within Victoria, there has been an amount of renewable energy generation developed already, and battery storages) and an amount that is in-construction or is "committed" (sufficiently definite that it will be built in the near term). There is also a set of prospective future plants that have been discussed or announced in various development phases but which are not yet committed.

Jacobs has analysed the latest list and sorted the facilities according to which REZ they are in or near (or not in a REZ). Plants smaller than 1 (including rooftop PV) and hydro stations are not shown. These are shown in Table 1 and Figure 3

Table 1. Existing, in-construction and committed PV, wind and BESS in Victoria[4]

Site Name	Nameplate Capacity (MW)	Solar, Wind, BESS	Tag	REZ
Golden Plains Wind Farm East	756.40	W	1W	V4
Stockyard Hill Wind Farm	456.96	W	2W	V3
Macarthur Wind Farm	420.00	W	3W	V4
Ballarat Energy Storage System	30.00	B	4B	V3
Moorabool Wind Farm	312.00	W	5W	
Ararat Wind Farm	240.00	W	6W	V3
Murra Warra Wind Farm - stage 1	225.70	W	7W	V3
Murra Warra Wind Farm - stage 2	209.00	W	8W	V3
Bulgana Green Power Hub - Wind Farm	204.40	W	9W	V3
Kiamal Solar Farm - Stage 1	199.95	S	10S	V2
Bulgana Green Power Hub - BESS	20.00	B	11B	V3
Berrybank Wind Farm (2)	180.60	W	12W	V4
Dundonnell Wind Farm	168.00	W	13W	V4
Mortlake South Wind Farm	157.50	W	14W	V4
Yendon Wind Farm	144.40	W	15W	V3
Mt Gellibrand Wind Farm	138.60	W	16W	

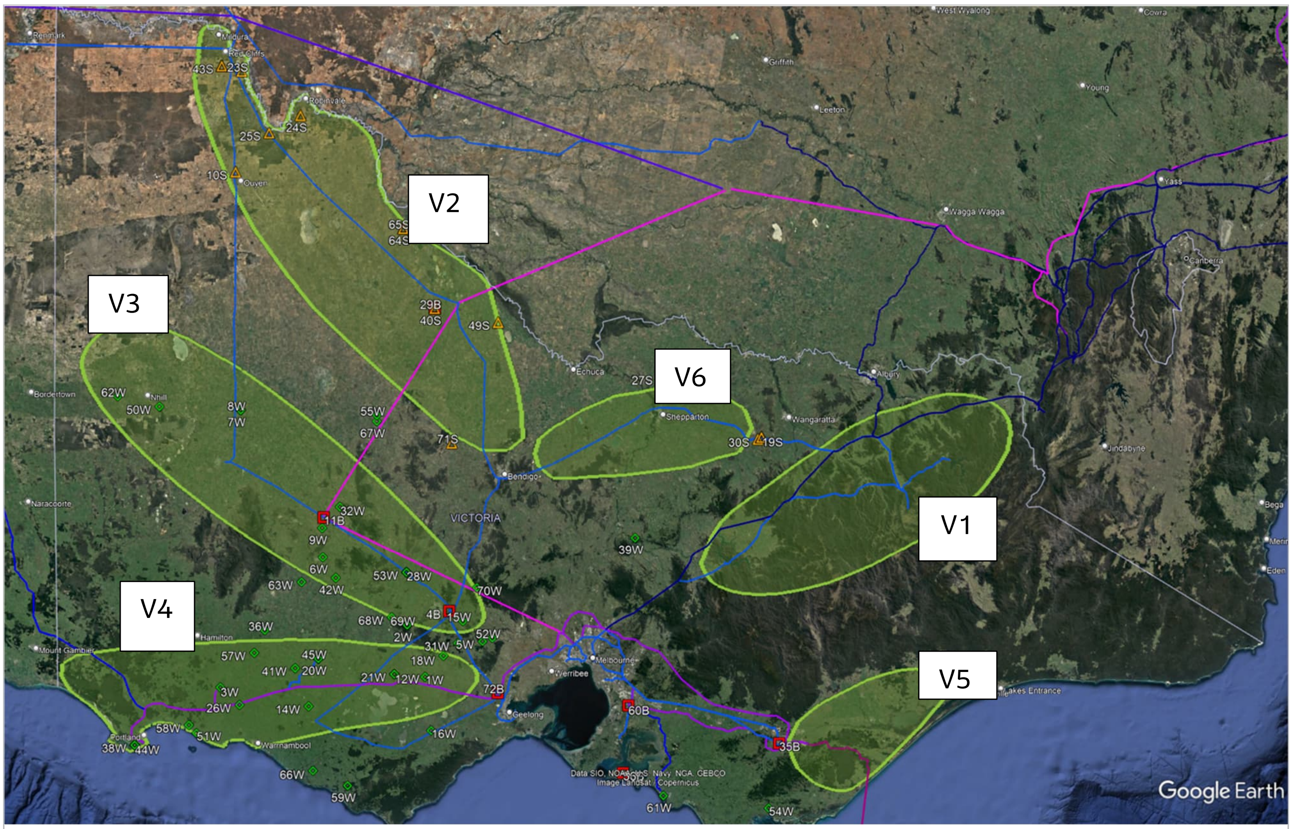
[4] AEMO "Existn and new developments" as at 3 Oct 2023. Note some plants are listed multiple times due to phasing etc

Site Name	Nameplate Capacity (MW)	Solar, Wind, BESS	Tag	REZ
Glenrowan West Solar Farm	132.00	S	17S	V6
Mt Mercer Wind Farm	131.20	W	18W	V4
Glenrowan Solar Farm	126.50	S	19S	V6
Dundonnell Wind Farm (3)	121.80	W	20W	V4
Berrybank Wind Farm	109.20	W	21W	V4
Bald Hills Wind Farm	106.60	W	22W	
Karadoc Solar Farm	104.50	S	23S	V2
Bannerton Solar Park	100.00	S	24S	V2
Wemen Solar Farm	97.50	S	25S	V2
Hawkesdale Wind Farm	96.60	W	26W	V4
Wunghnu Solar Farm	93.50	S	27S	V6
Waubra	93.00	W	28W	V3
Gannawarra Energy Storage System	25.33	B	29B	V2
Winton Solar Farm	85.00	S	30S	V6
Elaine Wind Farm	83.60	W	31W	V3
Crowlands Wind Farm	79.95	W	32W	V3
Waubra (2)	76.50	W	33W	V3
Numurkah Solar Farm	74.00	S	34S	V6
Hazelwood Battery Energy Storage System (HBESS)	200.07	B	35B	V5
Oaklands Hill Wind Farm	67.20	W	36W	V4
Stockyard Hill Wind Farm (2)	64.60	W	37W	V3
Portland Wind Farm	59.45	W	38W	V4
Cherry Tree Wind Farm	57.60	W	39W	
Gannawarra Solar Farm	55.00	S	40S	V2
Salt Creek Wind Farm	54.00	W	41W	V4

Site Name	Nameplate Capacity (MW)	Solar, Wind, BESS	Tag	REZ
Challicum Hills	52.50	W	42W	V3
Yatpool Solar Farm	50.00	S	43S	V2
Portland Wind Farm (2)	47.15	W	44W	V4
Dundonnell Wind Farm (2)	46.20	W	45W	V4
Portland Wind Farm (3)	45.10	W	46W	V4
Yatpool Solar Farm (2)	44.00	S	47S	V2
Numurkah Solar Farm (2)	36.48	S	48S	V6
Cohuna Solar Farm	31.16	S	49S	V2
Kiata Wind Farm	31.05	W	50W	V3
Yambuk	30.00	W	51W	V4
Yaloak South Wind Farm	28.70	W	52W	
Waubra (3)	22.50	W	53W	V3
Toora	21.00	W	54W	
Coonooer Bridge Wind Farm	19.80	W	55W	
Philip Island BESS	5.00	B	56B	
Mortons Lane Wind Farm	19.50	W	57W	V4
Codrington Wind Farm	18.20	W	58W	V4
Ferguson Wind Farm	12.00	W	59W	
Rangebank BESS	200.00	B	60B	
Wonthaggi Wind Farm	12.00	W	61W	
Diapur Wind Farm	8.00	W	62W	V3
Maroona Wind Farm	7.20	W	63W	V3
Swan Hill Solar Farm 1 Unit 1	7.20	S	64S	V2
Swan Hill Solar Farm 2 Unit 1	7.20	S	65S	V2
Timboon West Wind Farm	7.20	W	66W	

Site Name	Nameplate Capacity (MW)	Solar, Wind, BESS	Tag	REZ
Yawong Wind Farm	7.20	W	67W	
Chepstowe Wind Farm - VIC	6.15	W	68W	V3
Stockyard Hill Wind Farm (3)	6.00	W	69W	V3
Leonards Hill	4.10	W	70W	V3
Bridgewater	1.30	S	71S	V2
Victorian Big Battery	300.00	B	72B	

Figure 3. locations of existing and committed plants in Victoria[5]



In Figure 3, 500kV routes are shown in purple, 220kV circuits are shown in blue, and 330kV circuits are shown in dark blue. VNI West, HumeLink and Project Energy Connect are included.

[5] Some tags may be obscured at this scale. The Victorian offshore wind zones near Gippsland and Portland are not shown

A summary of the aggregated capacities (excluding hydro, which is predominantly in REZ V1 and rooftop solar, which is predominantly in Melbourne/Geelong metropolitan areas) shown is provided below in Table 2

Table 2. Summary of wind, solar and BESS capacity in Victoria at present (existing+construction+committed)

	Wind MW	Solar MW	BESS MW	Total
V2	0	698	25	723
V3	2,016	0	50	2,066
V4	2,528	0	0	2,528
V5	0	0	200	200
V6	0	547	0	547
No REZ	723	0	505	1,228
Total	5,266	1,245	780	7,292

The capacities of the 220kV routes Redcliffs-Horsham-Ballarat, Redcliffs-Wemen-Kerang-Ballarat, and Ballarat-Moorabool (one circuit of which goes via Elaine) are of particular importance to this review as they are a major focus pf the Plan B proposal. These are shown in Section 2.3.

1.3 What is VNI West?

1.3.1 Arrangement/configuration

VNI West is an enhancement to the Victoria to NSW interconnector based on 2 x 500kV circuits between Bulgana in Victoria and Dinawan in NSW, with an intermediate substation near Kerang in Victoria. The concept corridor and connections have been adjusted over the timeframe since the upgrade was first proposed. The current arrangement is shown in **Figure 4**. The electrical concept Single Line Diagram (SLD) is shown at **Figure 5**.

The Western Renewables Link (WRL) 2x500kV project which is also under development has been adjusted to connect to the VNI West at Bulgana. The HumeLink 2 x 500kV project in NSW (and which also connects the Snowy 2.0 large pumped hydro energy storage project) has been adjusted to connect to Wagga also. Additionally, the Project Energy Connect (PEC) project linking South Australia to NSW (and Victoria) using 2 x 330kV circuits will also connect at Dinawan and then run from Dinawan to Wagga at 2x500kV (initially operated at 330kV until VNIW is built).

Figure 4. VNI West concept arrangement[6]

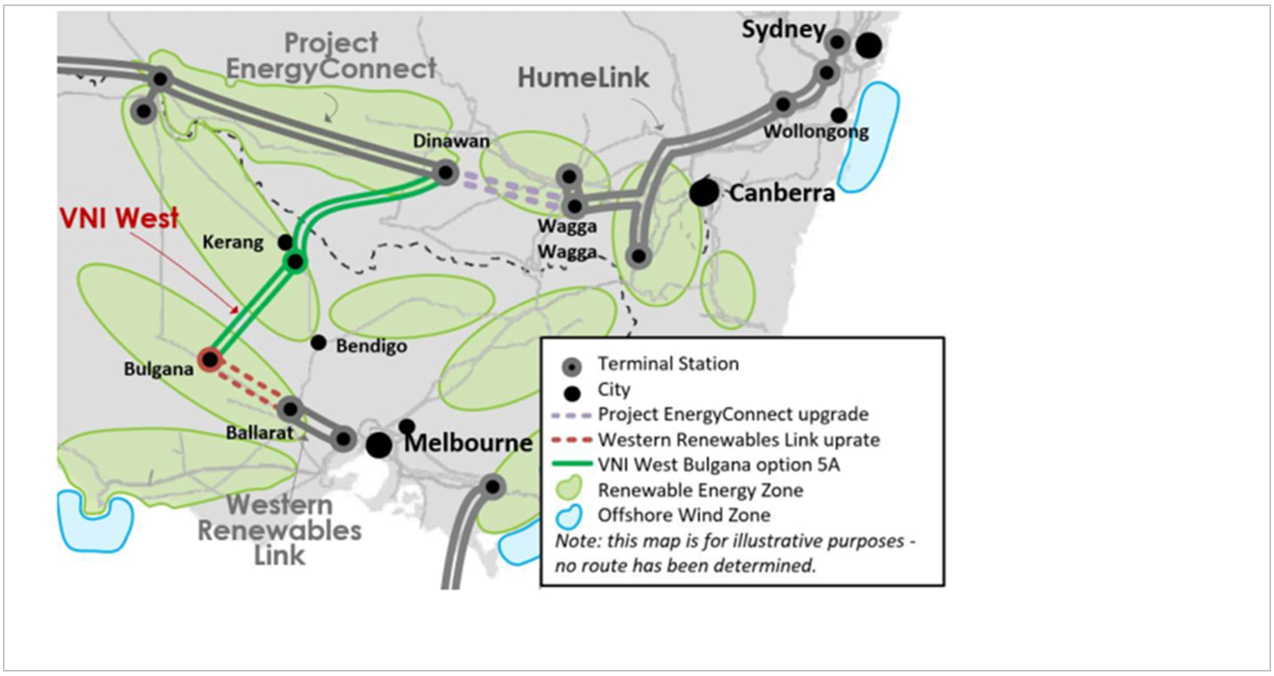
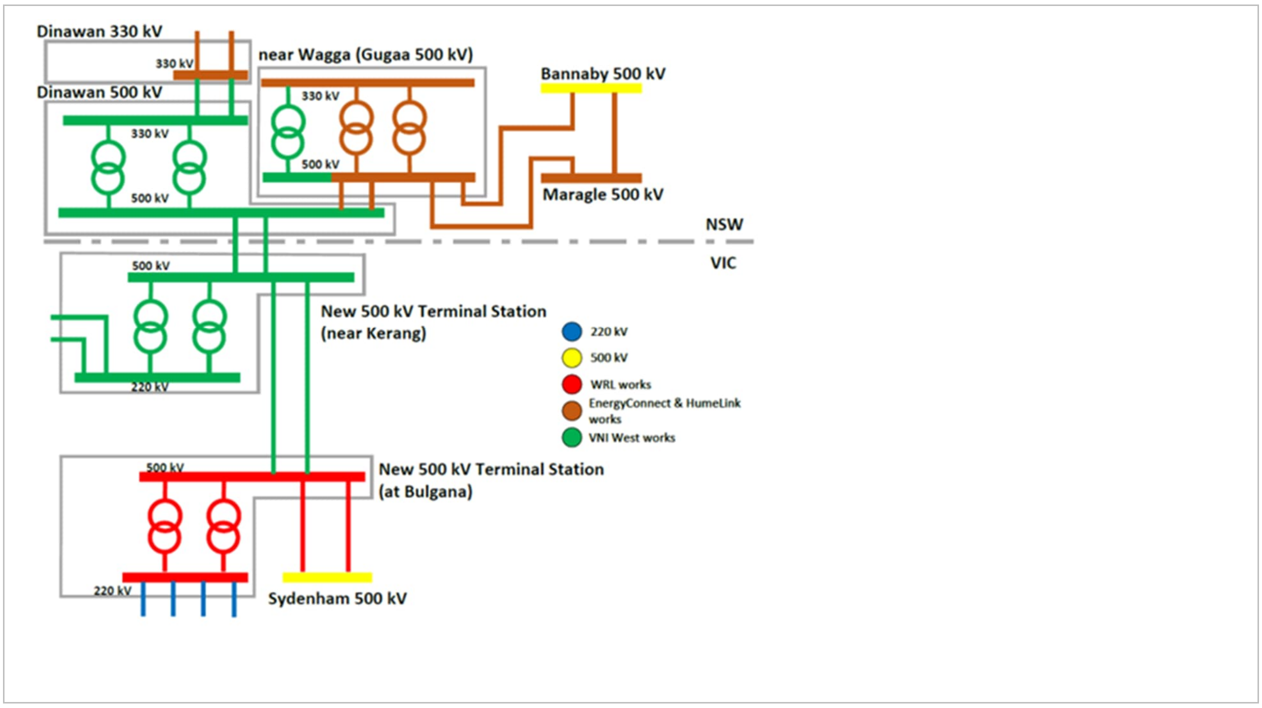


Figure 5. VNI West concept single line diagram[7]



The Snowy 2.0 PHES station under construction will connect at Maragle.

[6] AEMO Victorian Planning and Transgrid "VNI West Project Assessment Conclusions Report Volume 1: Identifying the preferred option for VNI West   Regulatory Investment Test for Transmission ", May 2023 ["PACR"] – At Figure 23 for Option 5A

[7] PACR, op cit, at Figure 21 for Option 5A

1.3.2 VNI West earlier materials

AEMO's Integrated System Plan (ISP) process was a recommendation of the Finkel Review. Observations in the Finkel review report regarding the need (and consequently objectives) intended for the ISP process are given in Figure 6

Figure 6. Extract from the Finkel Review report Executive Summary[8]

This report recommends a way forward. This *Blueprint for the Future Security of the National Electricity Market* focusses on four key outcomes for the National Electricity Market (NEM): **increased security, future reliability**, **rewarding consumers**, and **lower emissions**. These outcomes will be underpinned by the three pillars of an **orderly transition**, **better system planning** and **stronger governance**.

Australia needs to **increase system security** and **ensure future reliability** in the NEM. Security and reliability have been compromised by poorly integrated variable renewable electricity generators, including wind and solar. This has coincided with the unplanned withdrawal of older coal and gas-fired generators. Security should be strengthened through **Security Obligations** for new generators, including regionally determined minimum system inertia levels. Similarly, reliability should be reinforced through a **Generator Reliability Obligation** implemented by the Australian Energy Market Commission (AEMC) and the Australian Energy Market Operator (AEMO) following improved regional reliability assessments. These obligations will require new generators to ensure that they can supply electricity when needed for the duration and capacity determined for each NEM region.

The reliability of Australia's future electricity system will be underpinned by an **orderly transition** that integrates energy and emissions reduction policy. All governments need to agree to an **emissions reduction trajectory** to give the electricity sector clarity about how we will meet our international commitments. This requires a **credible and durable mechanism** for driving clean energy investments to support a reliable electricity supply. Governments need to agree on and implement a mechanism as soon as possible. Ongoing uncertainty is undermining investor confidence, which in turn undermines the reliable supply of electricity and increases costs to consumers.

This report recommends a **Clean Energy Target** as the mechanism for the electricity sector. As part of the orderly transition, generators should also be required to provide **three years' notice of their intention to close**. This will provide time for replacement capacity to be built and for affected communities to plan for change. AEMO should also publish a **register of expected closures** to assist long-term investor planning.

Better **system planning** should see AEMO having a stronger role in planning the future transmission network, including through the development of a **NEM-wide integrated grid plan** to inform future investment decisions. Significant investment decisions on interconnection between states should be made from a NEM-wide perspective, and in the context of a more distributed and complex energy system. AEMO should develop a list of **potential priority projects** to enable efficient development of renewable energy zones across the NEM.

The transition presents significant opportunities to foster innovation. The deployment of new technologies and improved integration of variable renewable electricity generators needs to be supported by **better data**, **early testing of technology**, **cyber threat awareness** and **workforce preparedness**. As we increase our reliance on variable renewable electricity generators, AEMO must have access to the best available **weather impact and forecasting** capabilities. Improved confidence, understanding and management of the NEM will be reinforced by greater data transparency, including a **data dashboard** for power system information.

ISP2018

The first ISP was 2018. Several of the projects that are relevant to VNI West and Plan B were discussed in the 2018 ISP. The Integrated Development Plan (IDP) was also described in general in Figure 7

[8] Dr Alan Finkel AO, Chief Scientist, Chair of the Expert Panel Ms Karen Moses FAICD | Ms Chloe Munro | Mr Terry Effeney | Professor Mary O'Kane AC "Independent Review into the Future Security of the National Electricity Market - Blueprint for the Future", June 2017" at https://www.energy.gov.au/publications/independent-review-future-security-national-electricity-market-blueprint-future

Figure 7. AEMO's Key observations from the Integrated Development Plan for the NEM (Excerpts)[9]

The role of transmission in minimising the cost of supply:

- The transmission network will play a critical role in the transformation of the power system, providing an interconnected energy highway that allows diverse resources to be shared across the NEM more efficiently.
- Increased investment in an interconnected grid provides the flexibility, security, and economic efficiency associated with a power system designed to take maximum advantage of existing resources, integrate variable renewable energy, and support efficient competitive alternatives for consumers.
- The projected portfolio of new resources involves substantial amounts of less energy intensive renewable generation that is geographically dispersed, resulting in a much larger network footprint with transmission investment needed to efficiently connect and share these low fuel cost resources. This will also place a greater reliance on the role of the transmission network.
- Transmission investments will be necessary not only to secure greater geographic diversity of weather dependent resources but also to manage the risk of anticipated but uncontrollable climate effects such as bushfires, droughts (both water and wind) and long duration high heat periods. AEMO will consult and report on the development of a more robust risk management approach to system planning and resilience, including criteria for future investments, in future plans.
- While the modelling of all scenarios showed the need for storage, one scenario implemented Snowy 2.0 in 2025 and Tasmania Hydro pumped storage scheme in 2033 as a specific project path to install large-scale energy storage. These projects require specific transmission development which is shown in the 'Base development plan with storage initiatives'. AEMO will continue to work with project proponents on a design for transmission networks to support these storage initiatives.
- The value of the recommended investment in the grid has been quantified by comparing total costs of supply with the identified transmission against a 'no new interconnection' option. In the modelled case without a more strongly interconnected grid, consumer demand was projected to be met, but through more costly investment in generation and storage, and greater use of GPG. This analysis projects that without further network development, consumers would pay more for energy.

- AEMO estimates that the additional transmission investment proposed in the ISP would deliver net market benefits of around $1.2 billion on a net present value (NPV)[92] basis, compared to the case where no new transmission is built to increase network capabilities between regions (in the modelled Neutral case). The new inter-regional transmission more than pays for itself through efficient investment in, and use of, generation and storage across the NEM. There are other important benefits associated with the plan that are not quantified in the modelling, including benefits arising as a result of enhanced competition and improved power system resilience.
- The benefits of a more strongly connected grid extend beyond NPV savings in resource costs, to include the following:
  - A more interconnected grid supports increased competition across regional boundaries.
  - The analysis also demonstrates that greater interconnection would improve the power system's resilience to be able to manage unexpected events, such as unexpected exits of coal- and gas-powered generation. As a next step, AEMO will do further work to evaluate ways to mitigate against risk of generating plant exiting early due to catastrophic failure. This includes quantifying the benefits of advancing identified longer-term transmission developments in future plans.
  - Transmission investments are also necessary to secure greater geographic diversity on the system and help manage the risk of anticipated but uncontrollable climate effects such as bushfires, droughts (both water and wind), and long duration high heat periods. AEMO will consult and report on the development of a more robust risk management approach to system planning and resilience, including criteria for future investments, in future plans.
- The analysis supports an immediate upgrade of the national network, and a forward plan of efficient network investment over the next 20 years. These investments would provide immediate benefits to consumers by improving reliability and increasing wholesale market competition across the NEM, putting downward pressure on electricity bills.

[9] ISP2018 at Section 6

Figure 8. Detailed network development requirements (excerpts)[10]

Key for indicative timing of transmission development:

Colour	Indicative timing
	2020-2030
	2031-2040

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Country Victoria (CVIC)	A new 220 kV double circuit line between Geelong and Keilor (replace existing Geelong-Keilor No.1 and No.3 circuits)	Increased renewable generation in Western VIC, Moyne and Murray REZs	✓	✓	✓	✓	✓	250	75
	1x220 kV new circuit between Moorabool and Geelong		✓	✓	✓	✓	✓	800	11
	Upgrade the Sydenham-Keilor 500 kV line to its conductor rating (Increase secondary plant limits)	Increased renewable generation in Western VIC, Moyne and Murray REZs and/or import from NSW	✓	✓	✓	✓	✓	800	0.5
	An additional 500/220 kV transformer at Keilor or Coordinate works associated with asset renewal of existing three 500/220 kV transformers with high rated transformers		✓	✓	✓	✓	✓	800	25
	1x500 kV new line between Moorabool and Mortlake	Increased renewable generation in Moyne REZ	x	x	x	✓	x	2000	240
	An additional 500/220 kV transformer at Moorabool		x	x	x	✓	x	1000	25
	2x220 kV new circuits between Ararat and Ballarat; and 1x220 kV new circuit Ararat-Crowlands-Bulgana	Increased renewable generation in Western VIC REZ	✓	✓	✓	✓	✓	1200	146
	1x220 kV new circuit Bulgana-Horsham-Murra Warra		✓	✓	x	✓	✓		136
	1x220 kV circuit between Horsham and Ballarat (third)		✓	x	x	✓	✓	800	233
	1x220 kV new circuit between Red Cliffs and Buronga; and 1x330/220 additional new transformer at Buronga (second)	Increased renewable generation in Murray REZ (VIC)	✓	✓	✓	✓	✓	225	50
	2x220 kV circuits Red Cliffs-Wemen-Kerang (replace existing line)	Increased renewable generation in Murray and Riverland REZ	✓	✓	x	✓	✓	1200	323
	2x220 kV circuits Red Cliffs-Kerang		x	x	x	✓	x	1200	300

[10] ISP2018 at Appendix D.3

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Northern Victoria (NVIC)	2x500 kV new circuits between Ballarat and Sydenham 2x500/220 kV transformers at Ballarat	Increased renewable generation in Western VIC REZ & staged development of SnowyLink	✓	✓	✓	✓	✓	2500	1,550
	2x500 kV new circuits between Ballarat and Bendigo	Development of SnowyLink and increased renewable generation in Murray REZ	✓	✓	✓	✓	✓		
	2x500 kV new circuits between Kerang and Bendigo		✓	✓	✓	✓	✓		
	2x500 kV new circuits between Kerang and Darlington Point		✓	✓	✓	✓	✓		
	2x500/220 kV transformers at Ballarat, Bendigo and Kerang		✓	✓	✓	✓	✓		
	Power flow controller on the Bendigo-Shepparton 220 kV line to limit power flow on this line to its maximum thermal capacity (if necessary).	To divert generation from Western VIC and Murray VIC REZs to NSW via SnowyLink route.	✓	✓	✓	✓	✓		
	Power flow controller on the Murray-Dederang and Wodonga-Dederang 330 kV lines to limit power flow on these lines to their maximum thermal capacity (if necessary).	VIC access to increased generation from Snowy generators including Snowy 2.0 via SnowyLink route.	✓	✓	✓	✓	✓		150
	Automatic load shedding control scheme to manage potential overload on the Murray-Dederang 330 kV lines and Eildon-Thomastown 220 kV line	Increased import from NSW to VIC at times of high demand periods coinciding with high ambient temperature	✓	✓	✓	✓	✓	200	Not available

With respect to the relevant (V2 and V3) REZ's, AEMO assessed that:

The Murray River and Western Victoria REZs:

- Have good wind (Western Victoria) and solar (Murray River) resources available.
- Are identified as short-term priority REZ developments. Although there is currently limited capacity to connect new generation, the ISP identifies benefits to upgrading the transmission network in these areas in the short term. The proposed New South Wales to South Australia interconnector (RiverLink) and the major Victoria to New South Wales upgrade (SnowyLink) would aid in the development of these REZs.
- Are being assessed for network development under the Western Victoria Renewable Integration RIT-T[57]. The MLF resilience for Murray River and Western Victoria will depend largely on the preferred solution to this RIT-T. High capacity network options will provide more robust MLFs that will encourage generator connections in the area.

The following table outlines the Victoria REZ candidates, several key metrics, and the modelled indicative timing in the ISP scenarios.

Table 7 Victoria REZ report card*

REZ name	Solar quality	Wind quality	Spare Network capacity (MW)	Network losses	Priority for generator connections	Network upgrade timing				
						Neutral	Neutral with storage	Slow	Fast	High DER
Murray River (VIC)	C	C	300	E	2	2024	2024	2024	2024	2024
Western Victoria	E	A	0	D	3	2025	2024	2025	2020	2025
Moyne	E	B	2,000	C	1	2037	2037	>2040	2032	>2040
Gippsland	E	D	2,000	A		>2040	>2040	>2040	>2040	>2040
Ovens Murray	N/A†	N/A†	300	A		-	-	-	-	-

* In this table, a grading system has been used where "A" represents a very high grade, "F" represents a very poor grade, and "B", "C", "D" and "E" represent intermediate grades.
† The Ovens Murray REZ was identified for potential pumped hydro generation.

For "Group 1", or near-term, projects AEMO identified a minor Vic↔NSW upgrade, "VNI Minor" at 170MW, and the project that was then undergoing a RITT-T and which became WRL. There was also the minor upgrade from Redcliffs↔Buronga to allow additional RE to flow to/from NSW that became part of PEC.

"Group 2", or medium term/2020's, projects included (what became) Project Energy Connect (PEC), Marinus, and the connection of Snowy 2,0 to the main NSW grid.

It also included "SnowyLink South" to "Increase in transfer capacity between Victoria and New South Wales by approximately 1800MW" with indicative timing of 2034. This became VNI West.

The Base Development Plan was (Figure 9):

Figure 9. Base Development Plan, ISP2018

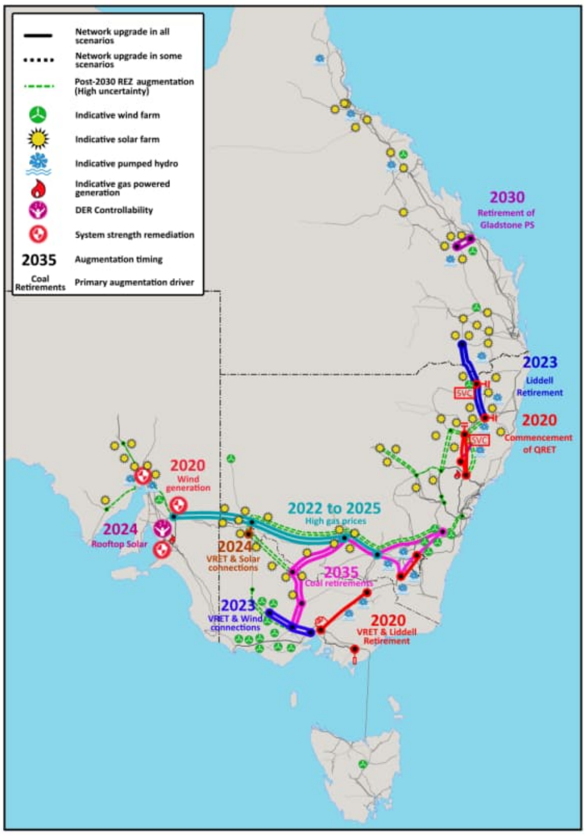


Figure 10. ISP2018 – Upgrades between NSW and Vic (excerpts)[11]

The Victorian Renewable Energy Target (VRET) is expected to result in connection of up to 3,500 MW of renewable generation in the Victorian region by 2025. This, coupled with the projected reduction of available supply in the New South Wales region following the retirement of Liddell Power Station in 2022, is projected to drive a need for additional Victoria to New South Wales transmission capacity in the short term.

Figure 17 outlines the proposed staged upgrades to the interconnector between Victoria and New South Wales. These upgrades are discussed further in the following sections.

- A minor upgrade of the existing corridor is projected to be economic as soon as it can be developed.
- A new high-capacity transmission link (SnowyLink) would improve energy security for both Victoria and New South Wales, supporting the long-term energy transition and providing additional transmission access to the proposed Snowy 2.0 scheme.

[11] At Appendix D.1.2

Stage 2 – Creating a new corridor – SnowyLink

The proposed path (SnowyLink) would create a new corridor for high power transfers between Victoria and New South Wales from Sydenham–Ballarat–Bendigo–Kerang–Darlington Point–Wagga–Bannaby. This option would be most beneficial if large amounts of renewable generation connect in Western Victoria. The SnowyLink option includes the following work:

- Install a Sydenham–Ballarat–Bendigo–Kerang–Darlington Point–Wagga double circuit 500 kV line.
- Install a Wagga–Bannaby–Snowy2.0–Wagga single circuit 500 kV loop.
- Cut-in Lower Tumut – Upper Tumut 330 kV line at connection location of Snowy 2.0, when built.
- Construct 500 kV substations at Ballarat, Bendigo, Kerang, Darlington Point, Wagga, and Snowy 2.0 (or expand existing substations to accommodate 500 kV plant).
- Install six 500/220 kV transformers – two at Ballarat, two at Bendigo, and two at Kerang.
- Install seven 500/330 kV transformers – two at Darlington Point, two at Wagga, and three at Snowy 2.0.
- Install a phase-shifting transformer on the Bannaby – Sydney West 330 kV line.
- Install an additional 330/220 kV 240 MVA transformer at Dederang.
- Install additional reactive plant.

This option would increase the Victoria to New South Wales transfer capability by 2,100 MW towards New South Wales and 1,800 MW towards Victoria. The approximate estimated cost of this option is $2.7 billion.

This large upgrade could provide for a range of economic benefits and risk mitigations to be realised:

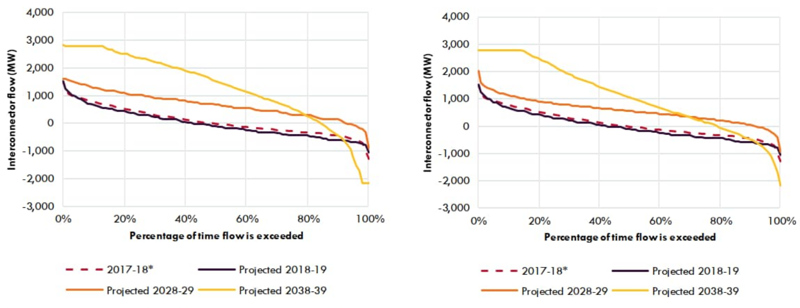
- It is projected to allow for the export of large amounts of renewable generation, installed to meet the VRET, to the New South Wales region.
- It would improve security of supply to both the Victorian and New South Wales regions by allowing for more efficient sharing of diverse generation sources.
- It can be combined with proposed upgrades from South Australia to New South Wales or Victoria (see Section 4.3.4).
- It would allow for strategic projects such as Snowy 2.0, and would improve benefits related to the Battery of the Nation pumped storage initiative.
- By providing a diverse route, it would reduce the risk and impact of bushfires leading to separation of the New South Wales and Victorian regions.
- The higher capacity would provide headroom to be able to minimise impacts of unexpected changes to generation or transmission capacity in the New South Wales, Victorian, and South Australian regions, for example if there was an unexpected failure or closure of a large power station in either region.

Projected interconnector utilisation

Figure 18 demonstrates the recent and projected utilisation of the Victoria to New South Wales interconnector:

- Following suggested upgrades to the interconnector in the early and mid-2020s, the interconnector is projected to provide periods of high transfer to New South Wales.
- After a major upgrade to the interconnector, net transfers from Victoria to New South Wales are projected to increase substantially.
- The peak capacity of the interconnector is projected to be used to improve energy sharing across the NEM.

Figure 18 Projected utilisation of the Victoria to New South Wales interconnector, Base development plan (left) and Base development plan with storage initiatives (right)



* Historic utilisation for 2017-18 does not include June 2018.

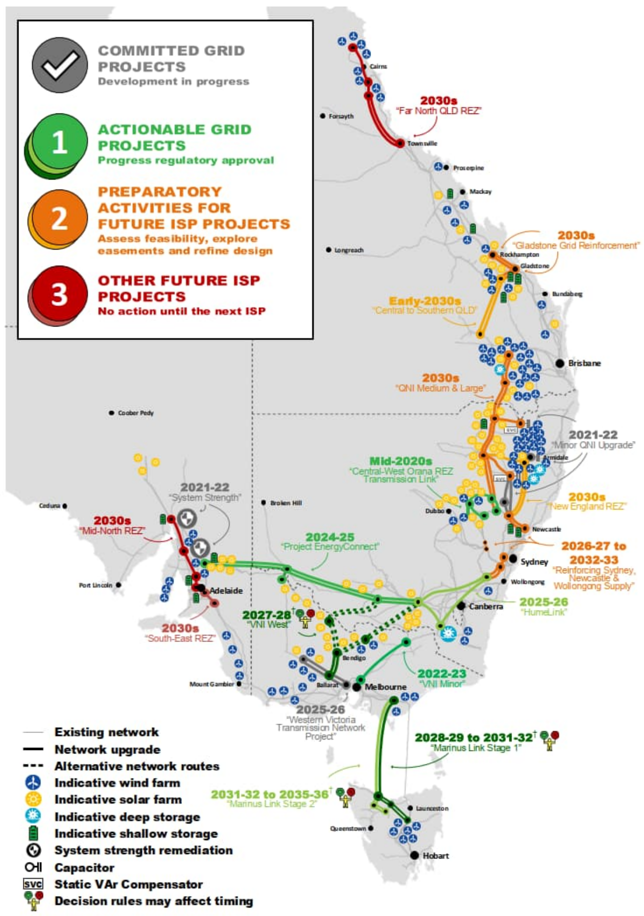
The impact of Snowy 2.0

The SnowyLink development provides transmission capacity between Victoria and New South Wales, and to Snowy 2.0. In scenarios with Snowy 2.0 included, modelling shows projected benefits come from providing access to pumped hydro energy storage to both the Victorian and New South Wales regions.

The analysis with Snowy 2.0 in service in 2025 (that is, the Base with storage initiatives scenario) requires associated transmission development in New South Wales between Tumut and Sydney. The analysis also showed that net market benefits would support increased interconnection capacity in the southern sections to Victoria from 2035 (or earlier if Yallourn Power Station retires). As part of the proposed parallel HVAC network augmentations, power system studies show the need to utilise power flow controllers on the Murray–Dederang and Dederang–Wodonga 330 kV lines for increased transfer from Snowy 2.0 to Victoria.

ISP2020

Figure 11. Optimum Development Path for the NEM, ISP2020



† The timing of these actionable projects is dependent on decision rules.
All dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

VNI West was described as:

Actionable ISP projects with decision rules. These projects are also critical to address cost, security and reliability issues. The decision rules for these projects can be assessed during the RIT-T process and will be confirmed by AEMO during an ISP feedback loop process with the TNSP once the decision rules eventuate.

- *VNI West, a new high voltage alternating current (HVAC) interconnector between Victoria and New South Wales, should be progressed for completion as soon as practicable, which is by 2027-28. Early works for this project should commence as soon as possible for completion in late 2024. This project is currently AEMO's preferred option to maintain system security and reliability in Victoria. It provides a prudent* *pathway to access sufficient dispatchable capacity to deliver into Victoria and, therefore, avoids the risk associated with earlier than planned exit of a major generator. It will also bring forward additional resilience benefits (for example, in case of an extended BassLink outage, a prolonged wind drought or another extended generator or transmission outage), address the increasingly pressing need to manage minimum demand in Victoria, open up new REZs, and provide Victorian consumers access to Snowy 2.0. To deliver positive net market benefits, project costs have to be below $2.6 billion, based on 2020 ISP assumptions. If there is sufficient certainty that no early generator exit will occur or sufficient new dispatchable resources have been or are expected to be added to the Victorian market, it may make sense to slow the project down for later delivery. VNI West is on the least-cost development path in all scenarios except for Slow Change and High DER*.

Marinus was also an Actionable ISP project with decision rules.

Victorian REZ development described[12] in "Phase 1" and "Phase 2" were:

- *Phase 1: The VRE development to help meet VRET in Western Victoria REZ in the mid to late 2020s, supported by the committed Western Victoria Transmission Network Project, and South West Victoria, and Central North Victoria REZ*
- *Phase 2: VRE development in Central North Victoria REZ supported by VNI West (Shepparton route), or Murray REZ supported by VNI West (Kerang route). VRE development in Western Victoria REZ is also supported by VNI West (either Kerang or Shepparton routes). Development of solar in Murray River REZ near Red Cliffs is supported by Project EnergyConnect.*

ISP2022

In the 2022 ISP, VNI West had become Actionable (with the decision rules removed due to the new staging arrangements):

Figure 12. Network projects in the ISP2022 Optimal Development Path[13]

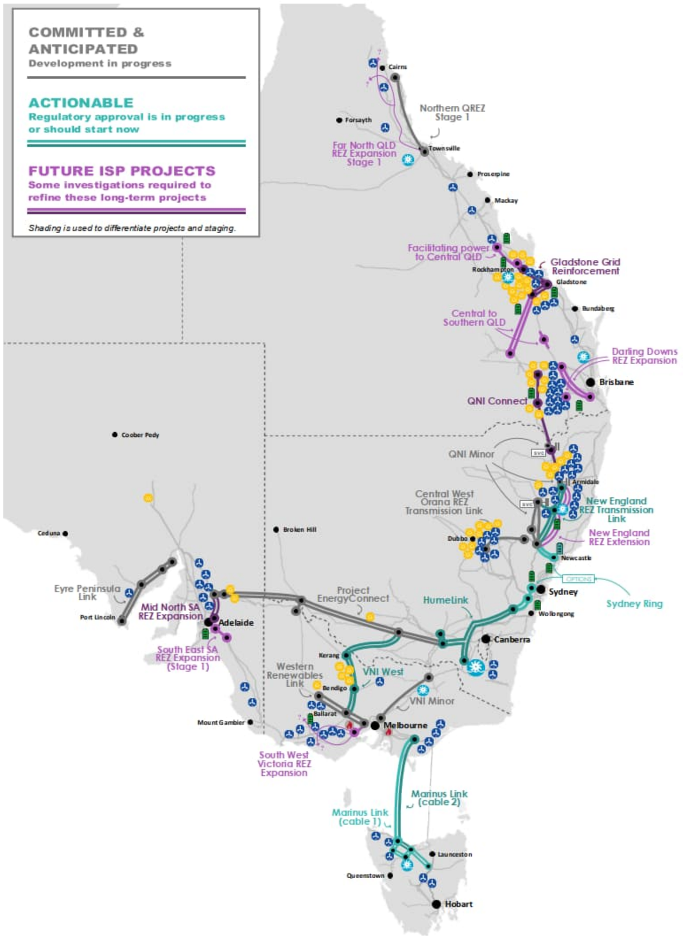
Committed and anticipated ISP Projects	Delivery date advised by project proponent†	
VNI Minor: Victoria – New South Wales Interconnector Minor upgrade	November 2022	
Eyre Peninsula Link	Early-2023	
QNI Minor: Queensland – New South Wales Interconnector Minor upgrade	Mid-2023	
Northern QREZ Stage 1	September 2023	
Central West Orana REZ Transmission Link	July 2025	
Project EnergyConnect	July 2026	
Western Renewables Link *(formerly Western Victoria Transmission Network Project)*	July 2026	
Actionable Projects	**To be progressed urgently – latest delivery date**	**Actionable Framework**
HumeLink	July 2026	ISP
Sydney Ring (Reinforcing Sydney, Newcastle and Wollongong Supply) ¥	July 2027	NSW ‡
New England REZ Transmission Link	July 2027	NSW ‡
Marinus Link	Cable 1: July 2029 Cable 2: July 2031	ISP
VNI West (via Kerang)	July 2031, or earlier with additional support	ISP
Future ISP Projects		
Interconnector projects: QNI Connect		
New South Wales Projects: New England REZ Extension		
Queensland Projects: Central to Southern Queensland, Darling Downs REZ Expansion, Gladstone Grid Reinforcement, Far North Queensland REZ Expansion and Facilitating Power to Central Queensland		
South Australia Projects: South East South Australia REZ Expansion, Mid North SA REZ Expansion		
Victoria Projects: South West Victoria REZ Expansion		
Additional projects to expand REZs and upgrade flow paths beyond 2040, which are highly uncertain and vary between scenarios		

† Reflects the latest project timing for the full release of capacity as advised by the relevant TNSP.
‡ The New England REZ Transmission Link and Sydney Ring project are actionable NSW projects rather than actionable ISP projects. They will progress under the Electricity Infrastructure Investment Act 2020 (NSW) rather than the ISP framework.
¥ The northern part of this project is named the *Hunter Transmission Project* and may include the *Waratah Super Battery* and related upgrades.

[12] ISP2020 at Page 17

[13] ISP2022 at Table 1, Page 13

Figure 13. Map of the ISP2022 Optimal Development Path[14]



† Additional projects to expand REZs and upgrade flow paths after 2040 are highly uncertain, vary significantly between scenarios, and are not shown on this map. See Appendix 5 for more information.

It is only an illustration, however the map is drawn with solar clustered towards the Bulgana-Kerang leg of VNI West and wind at Bulgana. This would be Jacobs' expectation of future V2 and V3 development if no further 220kV upgrades were undertaken west of VNI West.

Amongst other things, AEMO noted[15]:

> *Broadly, action is needed on the following fronts:*
>
> *• Immediate action to progress actionable projects. To protect consumers against the risk of over-investment, the ISP process can tend to make an individual project actionable only when the benefits are clear and the project is somewhat urgent. Yet due to their scale and complexity, these projects are prone to delay, and late delivery could lead to more costs to consumers than early investment. Mechanisms which support earlier progression of projects can deliver cost savings in construction and earlier realisation of benefits. Government support through finance, underwriting or other measures, fast-tracked licencing and environmental assessments, and streamlining of the regulatory framework governing critical transmission projects identified in the ISP, would assist in accelerating their delivery to realise these potential benefits.*

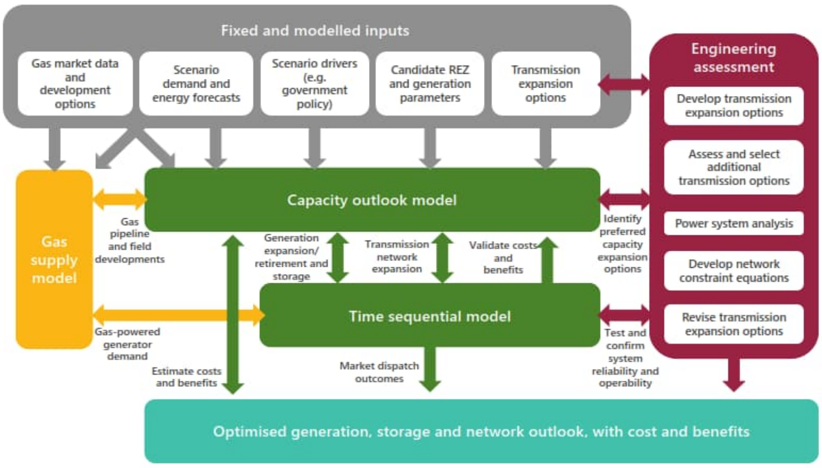
[14] ISP2020 at Figure 2 Page 14

[15] ISP2022 at Page 16

- *[…]*

By the time of ISP 2022 the process is on its third formal iteration, with AEMO refining and adding to the process applied. AEMO provided a schematic of the modelling processes applied:

Figure 14. AEMO overview of the ISP modelling method[16]



The summary description of VNI West is shown in Figure 15:

[16] ISP2022 Figure 10 at Page 35

Figure 15. VNI West summary description in ISP2022

VNI West

VNI West (via Kerang) is a proposed 500 kV interconnector from a substation near Ballarat in Victoria to a new substation named Dinawan in southwest New South Wales.

The project is an actionable ISP project without decision rules, having had decision rules in both the 2020 ISP and the Draft 2022 ISP: see 'Decision rules no longer apply' below. Stage 1 is to complete the early works by approximately 2026, and Stage 2 is to complete implementation by July 2031 (or earlier with additional support, see Section 7.1).

Optimal benefits and timing

The rationale for VNI West being included as part of the ODP is set out step-by-step in Section 6 below, and more extensively in Appendix 6. This is a short summary.

VNI West contributes roughly $1.8 billion of the $24.5 billion in net market benefits delivered by the ODP in the most likely scenario, and delivers value in all scenarios. It will increase access to Snowy 2.0's deep storage and other firming capacity from interstate, support new VRE needed to replace coal-fired generation (particularly in the Murray River and Western Victoria REZs), provide greater system resilience to earlier than projected coal closures, secure the fuel cost savings of needing less gas for generation, and reduce VRE curtailment by sharing geographically diverse VRE.

The optimal timing for delivery of VNI West was explored through multiple CDPs. In *Step Change*, it would be needed by July 2031. Making the project actionable now increases insurance against the potential of earlier-than-anticipated coal closures (other than Yallourn) or delays in the delivery of transmission or dispatchable resources.

For VNI West as in other staged projects, the early works costs are incurred early and the benefits potentially accrued later in scenarios where the project is paused. This makes staging particularly sensitive to higher discount rates (see Section 6.4).

Identified need

The identified need for the VNI West project has not changed since the 2020 ISP or Draft 2022 ISP:

To increase transfer capacity between New South Wales and Victoria to realise net market benefits by:

- *efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in aging generator reliability – including mitigation of the risk that existing plant closes earlier than expected,*
- *facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales through improved network capacity and access to demand centres, and*
- *enabling more efficient sharing of resources between NEM regions.*

Next steps

VNI West was determined to be an actionable ISP project in the 2020 ISP and Draft 2022 ISP, and the RIT-T for this project has been initiated. The following parameters apply for the VNI West project:

- **The RIT-T proponent**: AEMO (Victorian Planner) and Transgrid.
- **Scenarios to be assessed**: *Step Change* (52%), *Progressive Change* (30%) and *Hydrogen Superpower* (18%) – AEMO has not included the *Slow Change* scenario because it carries a low likelihood (4%) and the optimal timing is similar to the *Progressive Change* scenario.
- **ISP candidate options** that must be assessed in the RIT-T: AEMO identifies one option (VNI West via Kerang) to be delivered in two stages – early works, then implementation. The technical specifications of this option are provided in Appendix 5.
- **Non-network options** were not assessed in this ISP but are currently being assessed as part of the RIT-T.
- **Decision rules no longer apply:** The decision rules that were outlined in the Draft 2022 ISP have been removed for the VNI West project. After considering stakeholder feedback, AEMO now considers that decision rules should only apply when they can be very clearly defined (for example, a known policy being legislated or a specific power station announcing its closure). Project implementation (stage 2) remains subject to the ISP feedback loop, which will assess whether the project remains aligned with the latest ISP prior to final investment decision.

  Importantly, removal of the decision rules defined in the Draft 2022 ISP that would trigger the progression of stage 2 do not reduce consumer protections against over-investment. The satisfaction of VNI West's Draft 2022 ISP decision rules would simply have allowed a feedback loop for stage 2 to be requested. The feedback loop assessment itself comprehensively tests alignment with the ODP, including by re-running the ISP modelling if necessary, by considering multiple complex interactions that are unable to be captured within decision rules.
- **Early works** for VNI West may include:
  - **Project initiation** – scope, team mobilisation, service procurement.
  - **Stakeholder engagement** – with local communities, landowners and other stakeholders.
  - **Land-use planning** – identify and obtain 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.
  - **Strategic network investment** – an uplift to the delivered capacity of PEC between Dinawan and Wagga Wagga[71].

RIT-T PSCR

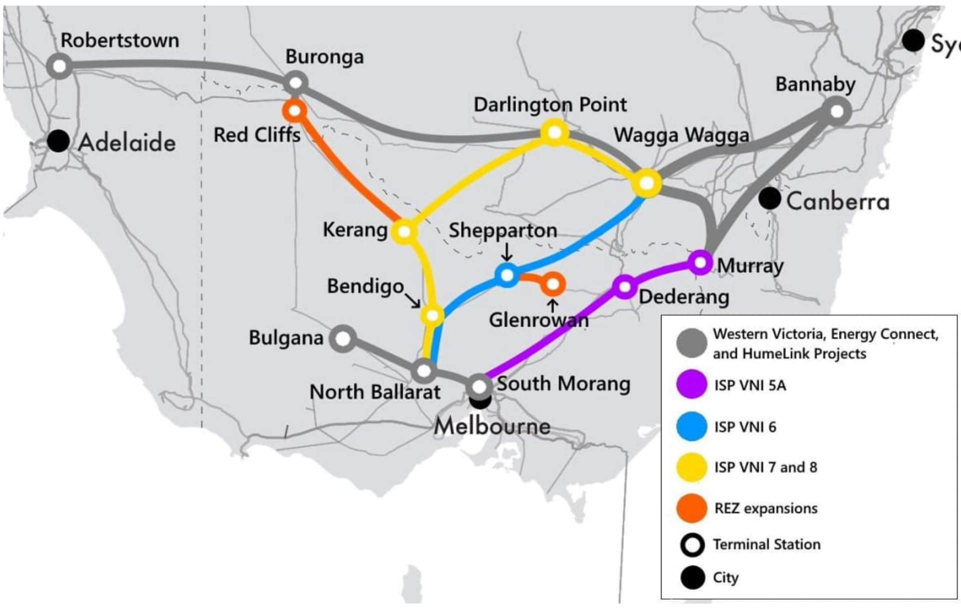
The Project Specification Consultation Report (PSCR) for VNI West was published December 2019. It referenced the optimal development pathway of the ISP2018, and that the ISP2018 "*identified that both short-term and longer-term investments were required to increase interconnection capacity between Victoria and New South Wales to enable more efficient sharing of generation between the states and deliver energy at the lowest cost to consumers*." It also noted that this was also confirmed in the (then) draft 2020 ISP and it noted that the (2019) Victorian Annual Planning Report (VAPR) "*identified the need for additional interconnection to maintain Victorian supply reliability following the withdrawal of further coal-fired generation plant. EnergyAustralia has officially advised that Yallourn Power Station is expected to close its four units from 2029 to 2032*"

It noted that "*AEMO's 2019 VAPR and TransGrid's 2019 Transmission Annual Planning Report (TAPR) identified high volumes of interest in renewable generation connection in northern and western Victoria and southern New South Wales areas, respectively. There is currently over 8 gigawatts (GW) of renewable generation and storage operational or proposed to connect in northern and western Victoria9, with an additional 20 GW in southern New South Wales10. This includes the development of Snowy 2.0, which the Federal Government is supporting as part of its broader energy plan.*

The VAPR identified that, considering projected generation connections, both new and existing generators are expected to experience constrained output due to networks limitations within Victoria and southern New South Wales. Investment to increase the capability of targeted network areas will reduce generation constraints in areas with high quality renewable resources, and is expected to lower overall investment and dispatch costs across the NEM. This will enable more efficient sharing of renewable resources between states encourage diversity of supply sources, and provide better access to hydro storage (including Snowy), providing firm energy to support growing levels of intermittent renewable generation"

The credible options proposed to be evaluated to meet the need were:

Figure 16. Credible options at the PSCR stage[17]



[17] PSCR at Fig 1

The identified interconnector constraints in the PSCR were:

Figure 17. Interconnector constraints identified in the PSCR

Table 2 Interconnector limitations – Victoria to New South Wales flow

Constraint type	Limitation	Proposed solution
Thermal capacity	500/330 kilovolt (kV) transformer at South Morang	VNI Upgrade RIT-T
Thermal capacity	330 kV transmission circuits from South Morang – Dederang	VNI Upgrade RIT-T
Thermal capacity	220 kV transmission circuits from Dederang to Mount Beauty	Nil[A]
Thermal capacity	330 kV transmission circuits from Murray to Upper Tumut and Murray to Lower Tumut	Nil[A]
Thermal capacity	330 kV transmission circuits from Canberra to Upper Tumut and Canberra to Lower Tumut	VNI Upgrade, HumeLink RIT-T
Transient stability	For the potential loss of a Hazelwood to South Morang line	EnergyConnect, WVTNP, VNI Upgrade RIT-T
Voltage stability	For the potential loss of Alcoa Portland Potline (APD) potlines[B]	Constraint update

A. The constraints not currently addressed in other ongoing RIT-Ts (categorised as 'nil') will be considered as part of this RIT-T.
B. This limitation was identified after the publication of the 2018 ISP and 2019 VAPR. This newly introduced voltage stability limitation can restrict transfers from Victoria to New South Wales only under light demand conditions

Table 3 Interconnector limitations – New South Wales to Victoria flow

Constraint type	Limitation	Proposed solution
Thermal capacity	330 kV transmission circuits from South Morang – Dederang	VNI Upgrade RIT-T
Thermal capacity	330 kV transmission circuit from Murray – Dederang	Nil[A]
Thermal capacity	220 kV transmission circuits from Dederang – Mount Beauty – Eildon – Thomastown	Nil[A]
Voltage stability	To prevent voltage collapse in southern New South Wales if a credible contingency event occurs in Victoria or Basslink	(Partially)[B]

A. The constraints not currently addressed in other ongoing RIT-Ts (categorised as 'nil') will be considered as part of this RIT-T.
B. A partial solution is proposed by TransGrid's proposed Wagga 100 MVAr 330 kV Capacitor, described in TransGrid's 2019 TAPR, at https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Documents/2019%20Transmission%20Annual%20Planning%20Report.pdf.

Additionally, there were intraregional constraints identified as shown in Figure 18:

Figure 18. Existing constraints in Victoria and Southern NSW (PSCR)

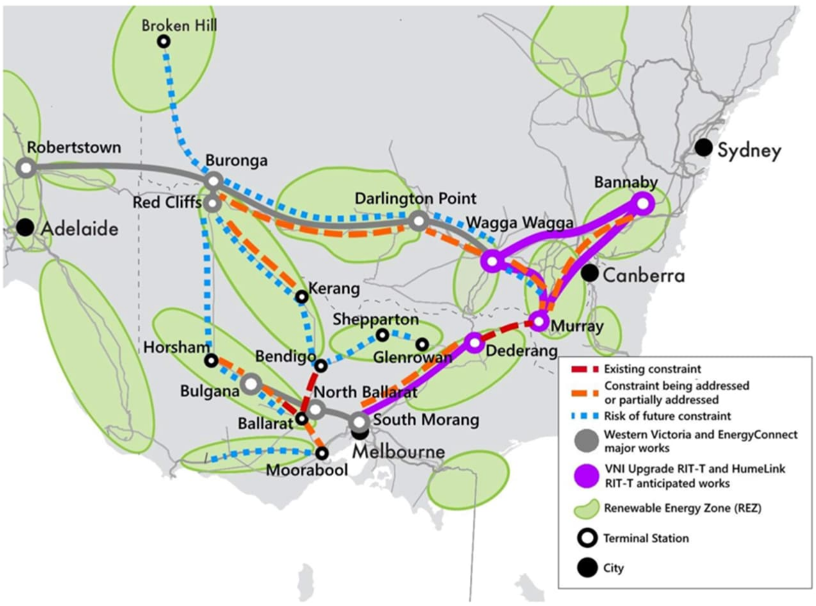


Figure 19. Existing constraints driven by existing generator connections

Constraint type	Limitation	Solution in progress
Thermal capacity	Ballarat – Waubra 220 kV line for a credible contingency (Red Cliffs – Kiamal 220 kV line trip) or Ballarat – Waubra – Ararat 220 kV line for a credible contingency (Ballarat – Waubra –Ararat 220 kV line trip)	WVTNP *(Partially)*
Thermal capacity	Red Cliffs – Wemen – Kerang 220 kV line for a credible contingency (Ballarat – Waubra – Ararat 220 kV line trip)	WVTNP *(Partially)*
Thermal capacity	220 kV transmission circuits from Ballarat to Bendigo	Nil
Thermal capacity	220 kV transmission line No.1 from Ballarat to Moorabool	WVTNP
Voltage stability	Voltage oscillation in north-western Victoria under some system normal and credible outage conditions	Nil

Figure 20. Emerging constraints based on proposed and projected generator development

Constraint type	Limitation	Solution in progress
Thermal capacity	Red Cliffs – Wemen – Kerang – Bendigo – Ballarat 220 kV lines under high generation conditions.	Nil
Thermal capacity	Bendigo – Shepparton – Glenrowan – Dederang 220 kV lines under high generation conditions.	Nil
Thermal capacity	Red Cliffs – Buronga 220 kV line	EnergyConnect *(Partially)*
Transient stability	Stability limitation on generation west of Moorabool during an outage of a 500 kV line in this area	Nil
Voltage stability	Voltage collapse in north-western Victoria for a credible contingency (Ballarat – Waubra – Ararat 220 kV line trip) which may trigger generator very fast tripping schemes	Nil

There are additional existing constraints listed for Southern NSW, mostly with solutions-in-progress based around HumeLink (mainly existing) and Project Energy Connect (emerging constraints).

The PSCR noted[18]:

> *This PSCR analysis considered all committed generation projects in Victoria and New South Wales, as listed on AEMO's Generation Information webpage at 8 August 2019. Approximately 1,200 MW of generation is committed to connect to the transmission network in northern and western Victoria by mid-2020, and 3,000 MW of generation is committed to connect in southern New South Wales by 2025. This includes the development of Snowy 2.0 (2 GW).*
>
> *WVTNP and Project EnergyConnect have completed the RIT-T process and have been included in the preliminary analysis completed for this PSCR. Although their RIT-Ts are not yet complete, when identifying the need for this RIT-T, the modelling performed included the proposed preferred option in the VNI Upgrade RIT-T and options being explored in the HumeLink RIT-T.*
>
> *The MarinusLink RIT-T PADR, published on 5 December 2019, proposed a preferred option to construct an interconnector between Tasmania and Victoria to enable additional renewable generation and storage to be exported from Tasmania to the mainland. While this option has the potential to provide reliability benefits, it does not provide benefits in enabling greater resource sharing or efficient generation development and dispatch within and between Victoria and New South Wales. The MarinusLink proposed preferred option has not been considered in determining and*

[18] At page 23

assessing options presented in this PSCR. However, the RIT-T will be closely monitored throughout this VNI West RIT-T, and PADR modelling will consider the potential impacts of the MarinusLink proposed preferred option and its timing.

PADR:

PADR was published July 2022. Cost base is FY2020/21

Figure 21. PADR high-level description of VNI West (non-preferred option removed for clarity)[19]

Option	Indicative impact on transfer capacity		REZ transmission limit	Capital cost, $m in FY2020-21 dollars*	
	VIC to NSW	NSW to VIC		VIC	NSW
Option 1 – VNI West	+1,930 megawatts (MW)	+1,800 MW	V2 - Murray River: +1,600 MW V3 - Western Vic: +550 MW N5 – South West NSW: +900 MW	$1,605 million	$1,651 million

The weighted net benefit was assessed as $687M

It was noted that "*The VNI West cost estimates used in this PADR differ from that presented in the 2022 ISP by approximately $314 million. As outlined in Section 5.1.2 [of the PADR], this additional contingency cost is in anticipation of some level of route diversion, tower redesign, or screening beyond that included in the cost estimate presented in 2022 ISP*"

In the PADR assessment it was noted that expansion options with similarities to Plan B elements that were included for consideration in the PSCR were not further evaluated as:[20]

> Low-cost options in the 220 kV network suggested in PSCR submissions (ERM Power) were not progressed as 220 kV options were not recommended as part of the 2020 ISP or 2022 ISP. A larger augmentation is required, as this option would not provide significant additional REZ hosting capacity, or interconnection transfer capacity.
>
> Expansions were considered in the PSCR for VNI 6 (Expansion B) and VNI 7 (Expansion A) with new transmission lines to facilitate generation hosting capacity at Central North Victoria (V6) REZ and Murray River (V2) REZ respectively.
>
> The VNI 6 option put forward in the PSCR and 2020 ISP was ruled out in the 2022 ISP, as outlined above. It has therefore no longer been considered in this RIT-T. Studies during the PADR revealed that VNI West already meets the required REZ hosting capacity without the need for an expansion.
>
> However, an expansion may be considered in the future to harness additional renewables.

Plan B made a submission to the PADR – refer Appendix A

PACR

The PACR assessed two options (5 and 5A) on the grounds that the orders made by the Victorian minister in February and May 2023 under the National Electricity (Vic) Act ("NEVA") made other options non-credible at that time.

[19] AEMO and Transgrid, "Victoria to New South Wales Interconnector West, Regulatory Investment Test for Transmission, Project Assessment Draft Report, July 2022 [PADR]

[20] PADR Table 7 at page 64 and 66

Figure 22. Summary of the credible options assessed – transfer capacities and REZ limits[21]

Option	Indicative impact on transfer capability		Indicative impact on REZ transmission limit		Capital cost* $m 2020-21
	VIC to NSW	NSW to VIC	Individually	Total	
Option 5 (near Echuca)	+1,960 MW	+1,710 MW	V2 – Murray River: +1,075 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +200 MW N5 – South West NSW: +900 MW	+3,635 MW	3,406
Option 5A (north of Kerang)	+1,935 MW	+1,669 MW	V2 – Murray River: +1,580 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +200 MW N5 – South West NSW: +900 MW	+4,140 MW	3,499
Sensitivities					
Option 5A (westerly sensitivity)	+1,910 MW	+1,650 MW	V2 – Murray River: +1,460 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +0 MW N5 – South West NSW: +900 MW	+3,820 MW	3,499
Option 5 (without series compensation)	+1,750 MW	+1,500 MW	V2 – Murray River: +800 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +0 MW N5 – South West NSW: +900 MW	+3,160 MW	3,331

* While the capital costs are shown at an aggregate level in this table, they have been broken out by key cost category and state for each option in Section 3.3 of this report; that is, early works, substation works, line works, power flow controllers, property/land access/easements and biodiversity offset costs.

The PACR included a set of market modelling results done by EY. The modelling included a base case (no VNI West, an option 5 (not relevant to this review) and the Option 5A results. The (explicitly) modelled wind and solar generation capacity and generation levels for the Victorian REZs is shown in Figure 23 and Figure 24:

Figure 23. Capacity by Victorian REZ with VNI-W, Step Change, MW[22]

REZ	REZ Name	Technology	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45
V1	Ovens Murray	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	207	207	267	267	1,000	1,000	1,000	1,000
V2	Murray River	Solar	679	679	679	679	679	679	679	679	679	1,819	1,819	2,224	2,224	2,227	2,489	2,489	2,788	2,823	2,823	3,209	3,482	3,482
V3	Western Victoria	Solar	0	0	0	0	0	0	0	0	0	0	0	33	33	263	400	400	400	400	1,522	1,522	1,522	1,531
V4	South West Victoria	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V5	Gippsland	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	121	121	485	500	2,383	2,474
V6	Central North VIC	Solar	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	857	747

REZ	REZ Name	Technology	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45
V1	Ovens Murray	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V2	Murray River	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V3	Western Victoria	Wind	1,934	1,935	1,935	1,935	2,205	2,592	2,635	2,635	2,635	2,635	2,582	2,390	2,390	2,390	2,781	2,781	2,781	2,781	2,781	3,024	2,918	2,606
V4	South West Victoria	Wind	2,023	2,405	2,405	2,809	2,809	2,809	2,885	2,979	2,979	2,979	4,927	4,927	4,927	4,927	5,399	4,979	4,979	4,856	4,856	4,837	4,644	4,644
V5	Gippsland	Wind	0	500	500	500	500	500	1,110	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
V6	Central North VIC	Wind	0	0	0	0	0	0	0	363	363	400	400	400	400	400	400	400	533	654	654	767	767	767

Figure 24. Generation by Victorian REZ with VNI-W, Step Change, GWh[22]

REZ	REZ Name	Technology	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45
V1	Ovens Murray	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	377	402	559	478	1,935	1,834	1,736	1,873
V2	Murray River	Solar	1,254	1,035	1,086	1,088	1,036	998	973	964	1,254	3,690	3,539	4,217	4,296	4,454	4,204	4,186	4,369	4,262	4,784	5,144	4,898	5,136
V3	Western Victoria	Solar	0	0	0	0	0	0	0	0	0	0	0	59	61	489	583	628	653	613	2,452	2,396	2,270	2,506
V4	South West Victoria	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V5	Gippsland	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	206	194	827	882	4,357	4,710
V6	Central North VIC	Solar	951	854	818	845	849	873	877	844	767	839	807	762	798	819	780	766	787	733	759	728	1,166	1,130

REZ	REZ Name	Technology	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45
V1	Ovens Murray	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V2	Murray River	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V3	Western Victoria	Wind	3,823	3,673	3,700	3,768	6,542	7,293	7,654	7,095	8,302	7,595	7,355	6,638	7,086	7,419	7,711	8,224	7,795	8,687	7,750	8,467	7,854	7,711
V4	South West Victoria	Wind	5,851	6,990	7,324	8,981	9,121	8,330	9,084	8,870	10,018	8,867	15,257	15,114	15,660	16,287	15,940	16,562	15,692	17,124	15,248	15,933	15,304	15,679
V5	Gippsland	Wind	0	1,671	1,670	1,668	1,667	1,618	3,466	5,815	6,647	5,991	6,111	5,930	6,119	6,102	5,816	6,152	5,935	6,739	6,058	6,285	6,106	6,254
V6	Central North VIC	Wind	0	0	0	0	0	0	0	986	991	1,115	1,074	982	1,061	1,114	1,080	1,038	1,372	1,713	1,707	1,933	1,660	1,851

The summary of modelled market benefits and their sources in the PACR are shown in **Figure 25** (only Option 5A is now relevant):

---

[21] PACR at Table 5, page 46

[22] Extracted from “EY workbook REZ zone outcomes - Step Change”

Figure 25. Modelled market benefits for VNIW described in the PACR

Table 9 Breakdown of forecast gross market benefits by benefit class under the *Step Change* scenario

	Avoided generation and storage costs (excl. fuel)	Avoided fuel costs	Avoided REZ transmission capital expenditure (capex)	Avoided load curtailment
Option 5	75%	15%	7%	3%
Option 5A	74%	14%	8%	4%

Table 10 Breakdown of forecast avoided/deferred generation and storage costs by technology as a percentage of total forecast gross market benefits under the *Step Change* scenario

	Avoided generation and storage costs (excl. fuel)		Avoided fuel costs	
	Option 5	Option 5A	Option 5	Option 5A
Coal	0%	0%	-2%	-2%
Gas	4%	4%	16%	16%
Wind	33%	34%	0%	0%
Solar	14%	13%	0%	0%
Pumped hydro	22%	21%	0%	0%
Grid-scale battery storage	4%	3%	0%	0%
% of total forecast gross benefits	75%	74%	15%	14%

The PACR included an MCA. Refer to Section 3.7

1.3.3 Objectives of VNI West

As stated in the PADR:

The "identified need' for the VNI West project is to increase transfer capacity between New South Wales and Victoria to realise net market benefits by:[23]

- *Efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in ageing generator reliability – including mitigation of the risk that existing plant closes earlier than expected*
- *Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and Southern New South Wales through improved network capacity and access to demand centres*
- *Enabling more efficient sharing of resources between NEM regions*

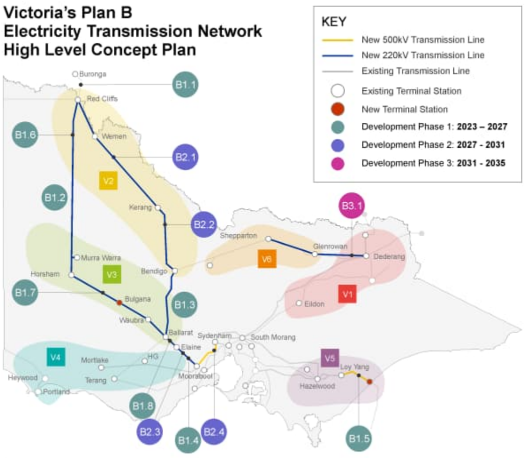
1.4 What is Plan B?

1.4.1 Arrangement/configuration

Plan B is proposed as an alternative to VNI West. It is a set of projects within Victoria as summarised in Figure 26, Figure 27 and Figure 28:

[23] This is footnoted to the 2020 ISP page 87. This was the table of Actionable Projects in that ISP. The need is expressed the same.

Figure 26. Plan B Concept plan[24]



Ref	REZ	Phase 1 Projects
B1.1	V2	Open-circuit Buronga – Red Cliffs 220 kV line
B1.2	V2-V3	Increase maximum conductor temperature on some 220 kV lines
B1.3	V2-V3	On-line dynamic rating Red Cliffs-Ballarat-Moorabool-Sydenham
B1.4	V3	Elaine to Moorabool
B1.5	V5	Gippsland REZ – 500 kV Loy Yang to near Basslink Transition Point
B1.6	V2	V2 220 kV network upgrade: Red Cliffs to Murra-Warra
B1.7	V3	V3 220 kV network upgrade: Murra-Warra to Ballarat
B1.8	V3-V4	V3-V4 220 kV network upgrade Ballarat – Moorabool (line 1)
		Phase 2 Projects
B2.1	V2	V2 220 kV network upgrade: Red Cliffs to Kerang
B2.2	V2-V3	V2-V3 220 kV network upgrade Kerang-Bendigo-Ballarat lines
B2.3	V3-V4	V3-V4 220 kV network upgrade Ballarat-Moorabool (line 2)
B2.4	V4	V4 500 kV S/C Sydenham to Moorabool
		Phase 3 Projects
B3.1	V6-V1	V6-V1 220 kV line Shepparton-Glenrowan-Dedarang

Figure 27. Plan B additional hosting capacity[25]

Table 5. Plan B additional renewable generation hosting capacity (MW)

		V1 Ovens Murray	V2 Murray River	V3 Western Victoria	V4 South West Victoria	V5 Gippsland	V6 Central North	TOTAL
1.1	Open-circuit Buronga – Red Cliffs 220 kV line							
1.2	Increase maximum conductor temperature on some 220 kV lines		160	160				320
1.3	On-line dynamic rating Red Cliffs - Ballarat-Moorabool-Sydenham							
1.4	V3-220 kV Elaine to Moorabool			1,914				
1.5	Gippsland REZ - 500 kV Loy Yang to near Basslink transition point					3,000		3,000
1.6	V2 220kV network upgrade: Red Cliffs to Murra-Warra		957					957
1.7	V3 220 kV network upgrade: Murra-Warra to Ballarat							-
1.8	V3-V4 220 kV network upgrade Ballarat – Moorabool (line 1)							
	Total Phase 1 additional hosting capacity (completed by mid-2027)	-	**957**	**1,914**	-	**3,000**	-	**5,871**
2.1	Minor works at Loy Yang and Hazelwood 500 kV substations							
2.2	V2 220 kV network upgrade:		1,514					1,514

24 Plan B at Page 11

25 Plan B Table 5 at Page 35

Figure 28. Plan B specification description[26]

Appendix D: Specification and costing of Plan B

The estimated capital cost of each project has been derived from relevant project in the AEMO's Draft Transmission Cost Estimates Report, amended where appropriate for changes in the scope of the project relative to the scope of the project from that Report. Details are provided below for each Network Project in Plan B.

	Project	Details of project scope of works	Cost ($million, 2023) including IDC	Cost ($million, 2022) excluding Interest During Construction (IDC)	Easement	Length (km)
1.1	Open-circuit Buronga – Red Cliffs 220 kV line	Daytime - open Buronga - Red Cliffs circuit to avoid overloading V2 & V3 lines			n/a	-
1.2	Increase maximum conductor temperature on some 220 kV lines	Field measurements of conductor clearances by AusNet Services			n/a	-
1.3	On-line dynamic rating Red Cliffs-Ballarat-Moorabool-Sydenham	Weather monitors and telecommunications - installed on some easements.			n/a	-
1.4	Elaine to Moorabool	Elaine - Moorabool, 220 kV D/C, twin Peach conductors, could extend to Ballarat	204	175	spare easement	43
1.5	Gippsland REZ - 500kV Loy Yang to near Basslink transition point	Loy Yang - Giffard, two 500 kV S/C lines, Giffard 500 kV/220 kV substation	842	691	AusNet Services initiated project	130
1.6	V2 220kV network upgrade: Red Cliffs to Murra-Warra	Red Cliffs - Murra Warra, 220 kV D/C, twin Peach conductors	1,003	823	existing easement, ~10 m shift	263
1.7	V3 220 kV network upgrade: Murra-Warra to Ballarat	Murra-Warra - Ballarat, 220 kV D/C, twin Peach conductors	873	716	existing easement, ~10 m shift	229
1.8	V3-V4 220 kV network upgrade Ballarat – Moorabool (line 1)	Ballarat - Moorabool (1), 220 kV D/C, twin Peach conductors, 500 kV/220 kV trans	289	248	existing easement, ~10 m shift	64
2.1	V2 220 kV network upgrade: Red Cliffs to Kerang	Red Cliffs - Kerang, 220 kV D/C, twin Peach conductor	878	720	existing easement, ~10 m shift	230
2.2	V2-V3 220 kV network upgrade Kerang-Bendigo-Ballarat lines	Kerang-Bendigo-Ballarat, 220 kV D/C, Pearl conductors	725	595	existing easement, ~10 m shift	190
2.3	V3-V4 220 kV network upgrade Ballarat-Moorabool (line 2)	Ballarat - Moorabool (2), 220 kV D/C, twin Peach conductors, 500/220 kV transformer	289	248	existing easement, ~10 m shift	64
2.4	V4 500 kV S/C Sydenham to Moorabool	Sydenham - Moorabool, 500kV S/C, quad conductor	316	271	spare easement	63
3.1	V6-V1 220 kV line Shepparton-Glenrowan-Dedarang	Shepparton - Glenrowan - Ballaratt, 220 kV, Peach conductor	542	465	spare easement	175
	TOTAL		**5,962**	**4,952**		**1,451**

1.4.2 Objectives of Plan B

The stated objectives of Plan B are:[27]

Plan B is designed to deliver sufficient transmission infrastructure to deliver Victoria's Renewable Energy Target (VRET) of 65% (of Victorian electricity generation) to be supplied by renewable sources in Victoria by 2030, and 95% by 2035. In addition, Plan B is designed to meet three subsidiary objectives:

• less than 13% curtailment, and marginal loss factors exceeding 0.93 in the Murray River and Western Victoria REZs (i.e. even lower curtailment and smaller marginal losses in the other REZs);

• no Single Points of Failure (SPoF) on new transmission lines that are likely to be defined as Systems of National Significance under the Security Legislation Amendment (Critical Infrastructure Protection) Act 2022 (SLACIP Act); and

• minimising the amount of new land required for transmission by making use of existing transmission networks and easements wherever possible.

[26] Plan B Appendix D at Pages 73-74

[27] Plan B at page 12

1.5 What is Extended VNI West

Extended VNI West is VNI West plus additional transmission upgrades as described in Plan B. This configuration is described in Plan B as[28]:

> *The Extended VNI-West Plan takes AEMO's VNI-West recommendation then adds the 220 kV augmentations needed in Victoria to ensure that VNI-West can actually be useful to Victoria (explained in 4.2), adds an augmentation in the South West to add the 1,500 MW that AEMO claims as part of its VNI-West plans and adds augmentations in the Central North REZ and Gippsland REZ without which AEMO's claimed increase in hosting capacity can't be achieved.*

Figure 29. Extended VNI West[29]

Figure 2. Extended VNI-West plan

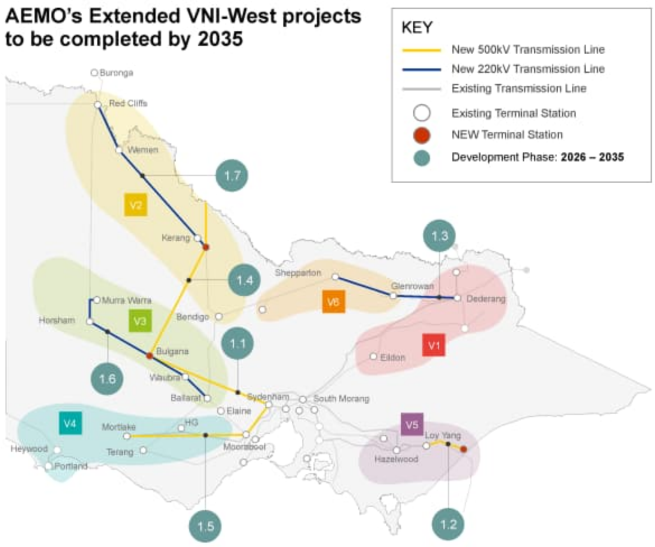


Table 6. Extended VNI-West project summary

	Project	Details of project scope of works	Cost ($million, 2023) including IDC	Cost ($million, 2022) excluding Interest During Construction (IDC)	Easement	Length (km)
1.1	VNI-West 500 kV Sydenham to Bulgana (WRL)	Sydenham to Bulgana option 5A D/C 500kV towers, quad conductors	1,861	1,525	new, parallel existing line part-way	190
1.2	500 kV D/C Loy Yang to Basslink Transition	Loy Yang to new Giffard substation, 500kV D/C line, quad conductors	1,040	853	new green field easement	65
1.3	220kV S/C Shepparton to Dedarang via Glenrowan	Shepparton - Glenrowan - Dederang, 220 kV S/C, twin Lemon conductors	370	317	spare easement	175
1.4	VNI-West Option 5A 500 kV Bulgana to NSW border	Bulgana - New Kerang - near Swan Hill, option 5A, 500 kV D/C, quad conductors	3,057	2,506	new green field easement	236
1.5	500 kV S/C Sydenham to Mortlake	Sydenham - Moorabool - Haunted Gully - Mortlake, 500 kV S/C, quad conductor	1,425	1,102	spare easement to Moorabool	214
1.6	220 kV network for V3 (Western Vic REZ)	Murra Warra to Horsham to Ballarat, 220 kV D/C, twin Lemon conductors	907	744	new green field easement	229
1.7	220 kV network for V2 (Murray River REZ) - 2 D/C lines	Two lines Red Cliffs - Wemen - New Kerang or equivalent, 220 kV D/C, twin Lemon conductors	2,312	1,788	new green field easement	550
	TOTAL		**10,972**	**8,835**		**1,659**

1.6 Other relevant projects

1.6.1 Western Renewables Link (WRL)

1.6.1.1 Western Victorian Renewables Integration RIT

PACR:

From the Executive Summary:

> *This Project Assessment Conclusions Report (PACR) confirms the preferred option recommended in the Project Assessment Draft Report (PADR)6 , and the updated information and assessment presented in this PACR has further strengthened this recommendation. The preferred option will*

[28] Plan B at Page 37

[29] Plan B Figure 2 at Page 37 and Table 6 at Page 38

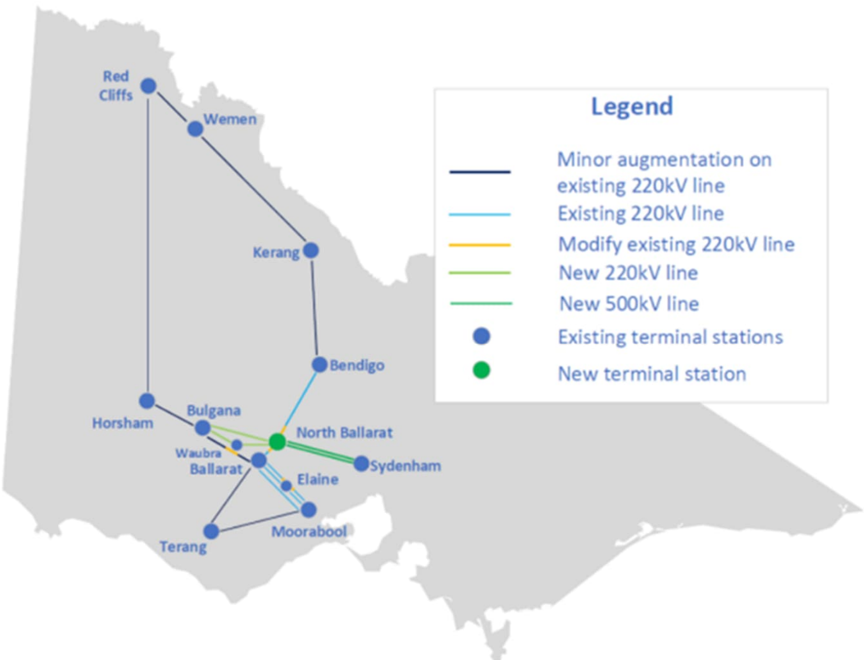
support additional generation connections in the Western Victoria region, and includes the following major components:

• Short term (present to 2021): Minor transmission line augmentations, including wind monitoring and upgrading station limiting transmission plant, carried out for the Red Cliffs to Wemen to Kerang to Bendigo, and Moorabool to Terang to Ballarat, 220 kilovolt (kV) transmission lines.

• Medium term (2021 to 2025): – By 2024: A new North Ballarat terminal station and new 220 kV double circuit transmission lines from North Ballarat to Bulgana (via Waubra). – By 2025: New 500 kV double circuit transmission lines from Sydenham to North Ballarat connecting two new 1,000 megavolt amperes (MVA) 500/220 kV transformers at North Ballarat

*The preferred option is shown in [*Figure 30*], with further details in [*Table 3*]. The preferred option is consistent with the recommendations of the 2018 ISP. It is estimated to cost $370 million and deliver gross market benefits of $670 million and net market benefits of $300 million (all figures in present value). This net market benefit is achieved through: • Significant reductions in the capital and dispatch cost of generation. • Facilitation of future transmission network expansion. • Improvements to the Victoria to New South Wales interconnector transfer limit*

Figure 30. Preferred option for Western Victoria Renewable Integration RIT-T



Note: the locations of the proposed new terminal station and new transmission lines shown in this figure are illustrative only. Matters such as route selection will be considered after the conclusion of the RIT-T process.

Table 3. Options further assessed in the PACR stage (non-preferred option not shown)

Option name	Description	Transmission line section	Thermal capacity of new transmission lines	Cost present value ($M)	Market benefit net present value ($M)
C2 (Preferred option)	Minor augmentations for Red Cliffs to Wemen to Kerang to Bendigo, and Moorabool to Terang to Ballarat, 220 kV transmission lines.	Minor augmentations	Approximately 10% increase to existing transmission line capacity	370	301
	Construction of new North Ballarat Terminal Station, with 2 x 1,000 MVA 500/220 kV transformers.	Bulgana to North Ballarat	2 x 750 MW		
	Connect North Ballarat Terminal Station to existing Ballarat to Bendigo 220 kV single circuit transmission line.				
	Construction of new 500 kV double circuit transmission line from Sydenham to North Ballarat, with 50 MVAr reactors on each end of each circuit.	North Ballarat to Sydenham	2 x 2,700 MW		
	Construction of new 220 kV double circuit transmission line from North Ballarat to Bulgana.				
	Connect one of the new 220 kV transmission circuits from North Ballarat to Bulgana to the existing Waubra Terminal Station.	Ballarat to Elaine to Moorabool	470 MW connected to Elaine Terminal Station		
	Disconnect existing Waubra Terminal Station from existing Ballarat to Waubra to Ararat 220 kV transmission line.				
	Cut in Ballarat to Moorabool 220 kV circuit No. 2 at Elaine Terminal Station.				

The project is now in the procurement stage with AusNet being announced (17/12/2019) as the successful delivery contractor on a build-own-operate model[30]:

> *AusNet Services Group awarded contract to deliver Western Victoria Transmission Network Project*
>
> *AEMO is pleased to announce that, following a multi-stage, competitive tender process, AEMO has selected Mondo, the commercial division of the AusNet Services Group (AusNet Services), to plan, design, construct, own, operate and maintain the contestable transmission augmentations contemplated by the Project Assessment Conclusion Report (PACR) for the Western Victorian Regulatory Investment Test for Transmission (RIT-T).*
>
> *The Western Victorian RIT-T PACR was published in July 2019. It outlined strategic investment to unlock future power system capabilities in the state by reducing the most urgent network congestion in the region and supporting additional generation connections in Western Victoria. This will expand the diversity and availability of energy supply and help to protect consumers from paying more than necessary for their electricity in the long term.*
>
> *The preferred investment set out in the PACR will now be progressed through the Western Victorian Transmission Project (Project) and includes a combination of minor upgrades to existing infrastructure and major transmission works – including a new North Ballarat terminal station and long-distance high voltage transmission lines between Bulgana and Sydenham terminal stations – staged over several years, with the final component expected to be in operation by 2025.*
>
> *AusNet Services will also construct, own, operate and maintain the majority of the non-contestable assets required for the Project, comprising primarily of interface and associated network changes to support the new contestable assets. Australian Energy Operations (AEO) will also undertake important upgrade works to support the Project at its Elaine and Ararat terminal stations.*

It is noted that some aspects of WRL have been amended now between Ballarat and Bulgana to facilitate integration with VNI West.

[30] https://aemo.com.au/initiatives/major-programs/western-victorian-regulatory-investment-test-for-transmission/procurement

2. Area A – Plan B's assessment of VNI West

2.1 Completeness of VNI West

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area A -1	**Completeness of VNI West** Plan B: "AEMO and Transgrid say that VNI-West and a much smaller augmentation of transmission in South Western REZ (by 2034) and an even smaller augmentation in Central Northern REZ (by 2046) is all that is needed to almost completely decarbonise electricity supply in Victoria."

We note that AEMO have indicated that that this assertion was not made by AEMO/Transgrid.

Plan B at Page 25 states:

The objects of the Victorian Act include:

a. to support the development of projects and initiatives to encourage investment, employment, and technology development in Victoria in relation to renewable electricity generation.

b. to promote the transition of Victoria to a clean energy economy.

c. to contribute to the security of electricity supply in Victoria

There are in fact six objectives stated in the Act (refer to Appendix Section A.4 below). The Act is based on (and includes the object of) the target being the proportion of electricity generated in Victoria meeting the statutory target. Plan B suggests:

To the extent that Victoria imports electricity from neighbouring states and if it can be demonstrated that this electricity is produced from renewable sources (a big "if"), then it may not be necessary to greatly expand renewable generation in Victoria (the renewable generation percentage in Victoria would increase if coal or gas is closed in Victoria even if renewable electricity production does not expand in Victoria). Amending the Act to calculate the renewable generation requirement as a percentage of total Victorian electricity consumption would eliminate this confusion. In this report we calculate the required amounts of Victorian renewables needed to comply with the objects of the Act.

Jacobs has gathered materials from the ISP2022 and from the modelling included in the VNI-W PACR materials on the portion of electricity modelled to be generated in Victoria by renewable sources. The PACR values and chart are below. Distributed PV generation is added manually. The ISP values for CDP2 are consistent, Figure 32.

Table 4. Victorian generation in PACR, Step change, Option 5A + distributed PV, GWh

Technology	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Black Coal	0	0	0	0	0	0	0	0	0	0	0	0
Brown Coal	29,023	25,394	23,762	18,596	18,729	15,647	9,967	6,494	5,178	0	0	0
CCGT	0	0	0	0	0	0	0	0	0	0	0	0
Gas - Steam	17	18	71	164	109	229	193	1,013	180	391	341	607
OCGT / Diesel	23	16	39	146	84	143	96	434	69	344	288	876
Hydro	2,748	3,336	3,445	3,267	2,731	4,096	3,418	2,953	2,957	2,698	3,296	3,405

Technology	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Hydrogen Turbine	0	0	0	0	0	0	0	0	0	0	0	0
Wind	10,177	12,813	13,174	14,904	17,822	17,751	20,737	23,279	26,530	24,061	30,273	29,132
Solar PV	2,205	1,888	1,903	1,933	1,885	1,871	1,850	1,808	2,021	4,528	4,346	5,038
Grid Battery	160	149	175	172	165	158	156	430	426	781	668	639
Pumped Hydro	0	0	0	0	0	0	0	0	0	0	0	0
VPP	41	95	210	318	450	541	697	795	863	979	1,092	1,215
Distributed PV	5,719	6,558	7,453	8,386	9,339	10,124	10,744	11,378	11,991	12,545	13,093	13,662
Total RE	20,849	24,596	25,974	28,491	31,777	33,842	36,749	39,419	43,499	43,832	51,009	51,237
Total Gen	49,912	50,024	49,846	47,397	50,699	49,862	47,004	47,360	48,926	44,568	51,638	52,721
Percentage	**42%**	**49%**	**52%**	**60%**	**63%**	**68%**	**78%**	**83%**	**89%**	**98%**	**99%**	**97%**

Figure 31. Victorian generation in PACR, Step change, Option 5A + distributed PV

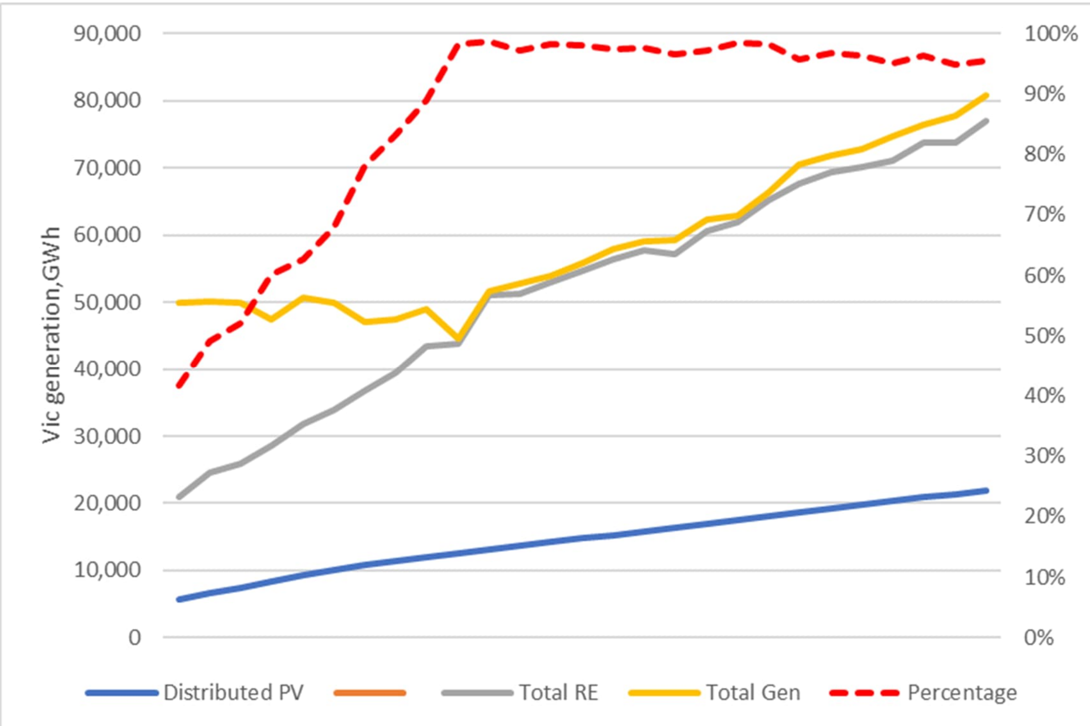
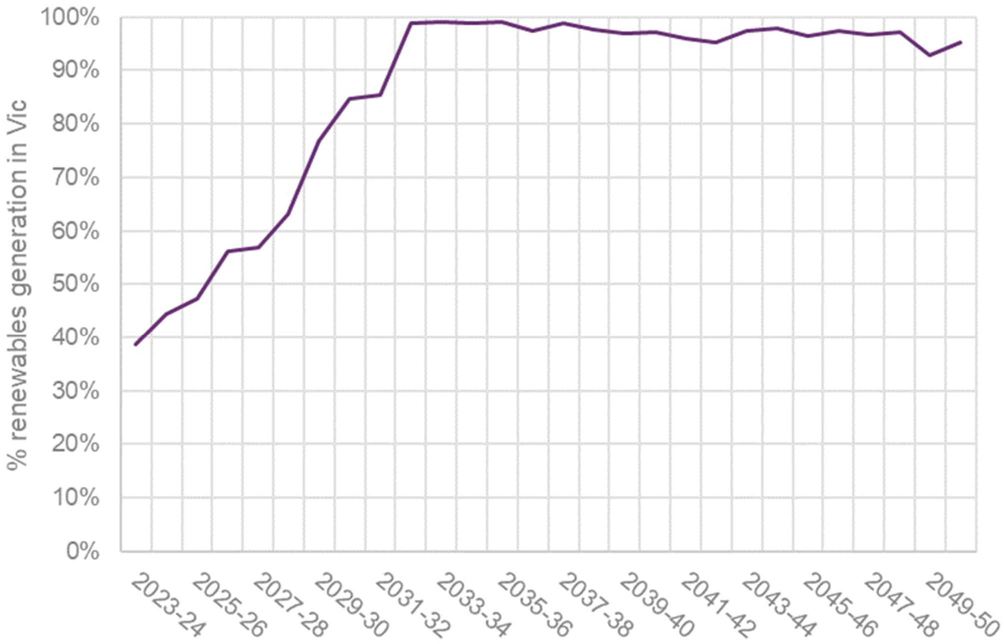


Figure 32. Renewables as a proportion of total generation in Vic, CDP2



Noting that the achievement of the target is a function of the closure dates of Victoria's brown coal generation, the current "expected closure year" [31] of brown coal plants are (Table 5). However, these values are based on formal announcements rather than the modelled closure years which are based on the policies and economic sustainability of the units under the various scenarios used in market modelling.

Table 5. Expected closure dates of brown coal generators

Site Name	DUID	Expected Closure Year	Last Updated
Loy Yang A Power Station	LYA1	2035	13-Oct-2022
Loy Yang A Power Station	LYA2	2035	13-Oct-2022
Loy Yang A Power Station	LYA3	2035	13-Oct-2022
Loy Yang A Power Station	LYA4	2035	13-Oct-2022
Loy Yang B	LOYYB1	2047	20-Aug-2019
Loy Yang B	LOYYB2	2047	20-Aug-2019
Yallourn W	YWPS1	2028	12-Mar-2021
Yallourn W	YWPS2	2028	12-Mar-2021
Yallourn W	YWPS3	2028	12-Mar-2021
Yallourn W	YWPS4	2028	12-Mar-2021

[31] https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2023/generating-unit-expected-closure-year.xlsx?la=en – as at 13 July 2023

Table 6. Initial Build Limits (MW) for Victorian REZs[32]

REZ ID	REZ Name	NTN DP zone	Wind generation total limits (MW)			Solar PV plus Solar thermal Limits (MW)	REZ resource limit violation penalty factor ($M/MW)	REZ Transmission Network limit[33]	Indicative transmission expansion cost ($M/MW)	Distance to nearest load centre (km) - Hydrogen Export scenario	Land area (km²)[9]
			High	Med	Offsh						
V1	Ovens Murray	NVIC	-	-		1,000	0.25	350	-	189	14,802
V2	Murray River	CVIC	-	-		4,700	0.25	440	1.080	297	24,684
V3	Western Victoria	CVIC	700	1,900		400	0.25	1,250[34]	0.890	191	21,705
V4	South West Victoria	MEL	861	2,582		-	0.25	2,500	0.620	89	14,530
V5	Gippsland	LV	500	1,500		500	0.25	2,000	0.57[35]	183	4,947
V6	Central North Vic	NVIC	400	1,200		1,700	0.25	650	0.800	131	6,018
O3	Gippsland Coast	LV	-	-	10,000	-	-	Included in V5 limit	As per V5	222	-
O5	Portland Coast	MEL	-	-	10,000	-	-	Included in V4 limit	As per V4	242	-

[32] AEMO "Forecasting Assumptions Update workbook full" 20 March 2023 version

[33] Intraregional transmission augmentations may be selected by the model if economic to access larger new renewable resource locations.

[34] Western Renewables Link (formerly Western Victoria Transmission Project) augmentation included

[35] Transmission limited total build in this REZ will increase with expected coal power station closures.

Table 7. Vic REZ transmission expansion options[36]

REZ ID	REZ Name	Option	Description	Additional network capacity (MW)	Expected cost ($ million)	Estimate source	Cost estimate class	$/MW	Lead time	System Strength Remediation
V2	Murray River	Option 1	• New double-circuit 220 kV line between Red Cliffs – Wemen – Kerang – Bendigo - north of Ballarat. • Establish new substations close to Redcliff, Kerang and Bendigo. • New 500/220 kV 1,000 MVA transformer north of Ballarat	1,200	1,300	AEMO TCD	Class 5b	1.08	Long	0.106
		Option 2	• New double-circuit 500 kV line between Kerang – Bendigo (including 2 new 500/220 kV transformers at Kerang). • Establish new substations close to Kerang and Bendigo. • Turn the 500 kV line from north of Ballarat to Shepparton into Bendigo (including new 500 kV	1,300	931	AEMO TCD	Class 5b	0.72	Long	

[36] AEMO "Forecasting Assumptions Update workbook full" 20 March 2023 version

REZ ID	REZ Name	Option	Description	Additional network capacity (MW)	Expected cost ($ million)	Estimate source	Cost estimate class	$/MW	Lead time	System Strength Remediation
			substation near Bendigo). *Pre-requisite: VNI West (Shepparton)*							
		Option 3	• New double-circuit 500 kV line between north of Ballarat to Kerang (including 2 new 500/220 kV transformers at Kerang) • Establish new substation close to Kerang.	1,250	1,165	AEMO TCD	Class 5b	0.93	Long	
		Option 4	• New 220 kV double-circuit line from Red Cliffs – Wemen – Kerang • Establish new substations close to Redcliff and Kerang. Pre-requisite: VNI West (Kerang)	800	665	AEMO TCD	Class 5b	0.83	Long	
V3	Western Victoria	Option 1	• Build a new single-circuit 500 kV line from Mortlake to the new 500 kV substation north of Ballarat.	1,200	1,072	AEMO TCD	Class 5b	0.89	Long	Included as connection cost

REZ ID	REZ Name	Option	Description	Additional network capacity (MW)	Expected cost ($ million)	Estimate source	Cost estimate class	$/MW	Lead time	System Strength Remediation
		Option 2	• Build a new double-circuit line from north of Ballarat to Bulgana (with one circuit turning into Ararat and Crowlands). • Replace existing single circuit 220 kV line from north of Ballarat to Ballarat with a double circuit line. • New 1,000 MVA 500/220 kV transformer north of Ballarat. • Series reactor on Crowlands-Ararat-Bulgana circuit.	800	623	AEMO TCD	Class 5b	0.78	Long	
		Option 3	• New 220 kV double-circuit line from Murra Warra to Bulgana via Horsham. • Establish new substation close to Horsham. Pre-requisite: V3 Option 2.	1,000	430	AEMO TCD	Class 5b	0.43	Long	
		Option 4	• New 220 kV single-circuit line from Elaine to Moorabool.	600	152	AEMO TCD	Class 5b	0.25	Long	

REZ ID	REZ Name	Option	Description	Additional network capacity (MW)	Expected cost ($ million)	Estimate source	Cost estimate class	$/MW	Lead time	System Strength Remediation
		Option 5	• New 500 kV double-circuit line from Bulgana to Mortlake.	1,000	772	AEMO TCD	Class 5b	0.77	Long	
V4	South West Victoria	Option 1	• New 500 kV single-circuit line from Mortlake – Moorabool – Sydenham.	1,500	930	AEMO TCD	Class 5b	0.62	Long	Included as connection cost
		Option 2	• New 500 kV single-circuit line from Mortlake to north of Ballarat. • Turn Tarrone – Haunted Gully line into Mortlake substation.	1,200	851	AEMO TCD	Class 5b	0.71	Long	
V5	Gippsland	Option 1	• New 500 kV double-circuit line from Hazelwood to vicinity of Basslink transition station. • Two 500/220 kV transformers • 250 MVAr dynamic reactive compensation	2,000	588	AEMO TCD	Class 5b	0.29	Long	0.106
		Option 2	• New 220 kV double-circuit line from Hazelwood to Bairnsdale.	800	458	AEMO TCD	Class 5b	0.57	Long	
		Option 3	• New 500 kV double circuit line from Hazelwood to Loy Yang	2,000	442	AEMO TCD	Class 5b	0.22		

REZ ID	REZ Name	Option	Description	Additional network capacity (MW)	Expected cost ($ million)	Estimate source	Cost estimate class	$/MW	Lead time	System Strength Remediation
			250 MVAr dynamic reactive compensation							
V6	Central North Vic	Option 1	• New 500 kV substation near Shepparton (including two 500/220 kV transformers). • New 500 kV double-circuit line from north of Ballarat - Shepparton.	1,700	1,364	AEMO TCD	Class 5b	0.80	Long	Included as connection cost
		Option 2	• New 220 kV double-circuit line from north of Ballarat - Bendigo - Shepparton. • Establish new substations close to Bendigo and Shepparton.	900	725	AEMO TCD	Class 5b	0.81	Long	
		Option 3	• New 220 kV double-circuit line from north of Ballarat – Bendigo - Shepparton - Glenrowan. • Establish new substations close to Bendigo and Shepparton.	850	980	AEMO TCD	Class 5b	1.15	Long	
		Option 4	• Replace existing 220 kV single-circuit line from Shepparton to Dederang	600	509	AEMO TCD	Class 5b	0.85	Long	

REZ ID	REZ Name	Option	Description	Additional network capacity (MW)	Expected cost ($ million)	Estimate source	Cost estimate class	$/MW	Lead time	System Strength Remediation
			via Glenrowan with a double circuit line.							
		Option 5	• New 220 kV double-circuit line from Bendigo to Shepparton. • Establish new substation close to Bendigo.	700	476	AEMO TCD	Class 5b	0.68	Long	

Table 8. Candidate Development Paths (CDP), from ISP2022[37]

	Purpose	New England REZ Transmission Link	Sydney Ring	Marinus Link	VNI West	HumeLink	Gladstone Grid Reinforcement
CDP1	*Based on Progressive Change least-cost DP*	Potential actionable	Potential actionable				
CDP2	*Based on Step Change least-cost DP (Progressive Change least-cost with actionable ML and VNI West)*	Potential actionable	Potential actionable	Potential actionable	Potential actionable		
CDP3	*Based on Hydrogen Superpower least-cost DP*	Potential actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable

[37] AEMO "2022 Final ISP results workbook - Step Change - Updated Inputs"

	Purpose	New England REZ Transmission Link	Sydney Ring	Marinus Link	VNI West	HumeLink	Gladstone Grid Reinforcement
CDP4	*Based on Slow Change least-cost DP (Progressive Change without actionable Sydney Ring)*	Potential actionable					
CDP5	*Progressive Change least-cost DP, with Marinus Link actionable*	Potential actionable	Potential actionable	Potential actionable			
CDP6	*Progressive Change, with VNI West actionable*	Potential actionable	Potential actionable		Potential actionable		
CDP7	*Progressive Change, without New England REZ Transmission Link actionable*		Potential actionable				
CDP8	*Step Change, with HumeLink actionable*	Potential actionable	Potential actionable	Potential actionable	Potential actionable	Potential actionable	
CDP9	No actionable projects						
CDP10	Progressive Change least-cost DP, with actionable Marinus Link and VNI West staged	Potential actionable	Potential actionable	Potential actionable	Stage 1 (Early Works)		
CDP11	Progressive Change least-cost DP, with actionable Marinus Link, VNI West staged, and actionable HumeLink	Potential actionable	Potential actionable	Potential actionable	Stage 1 (Early Works)	Potential actionable	
CDP12	Progressive Change least-cost DP, with actionable Marinus Link, and staged VNI West and HumeLink	Potential actionable	Potential actionable	Potential actionable	Stage 1 (Early Works)	Stage 1 (Early Works)	
CDP13	Progressive Change least-cost DP with staged VNI West and HumeLink, but with Marinus Link not available	Potential actionable	Potential actionable	Never available	Stage 1 (Early Works)	Stage 1 (Early Works)	

	Purpose	New England REZ Transmission Link	Sydney Ring	Marinus Link	VNI West	HumeLink	Gladstone Grid Reinforcement
Counterfactual	No future network augmentation other than committed and anticipated projects/ small intra-regional augmentations/ replacement expenditure projects						

Table 9. Generation capacity (MW) in Victorian REZ in selected years for CDP2[38]

REZ	REZ Name	Techn	2024	2025	2030	2035	2040	2045	2050
V0	VIC Non-REZ	Solar	0	0	0	0	0	0	0
V0	VIC Non-REZ	Wind	0	0	81	403	403	403	403
V1	Ovens Murray	Solar	0	0	0	0	0	531	586
V1	Ovens Murray	Wind	0	0	0	0	0	0	0
V2	Murray River	Solar	624	624	624	2,061	2,841	3,561	4,781
V2	Murray River	Wind	0	0	0	0	0	0	0
V3	Western Victoria	Solar	0	0	0	0	400	400	3,746
V3	Western Victoria	Wind	1,923	1,923	1,923	2,571	2,448	3,959	4,667
V4	South West Victoria	Solar	0	0	0	0	0	0	0
V4	South West Victoria	Wind	2,067	2,067	2,979	4,516	5,026	4,639	3,775
V5	Gippsland	Solar	0	0	0	0	0	500	500
V5	Gippsland	Wind	0	480	1,539	2,000	2,000	2,000	2,000

[38] AEMO "2022 Final ISP results workbook - Step Change - Updated Inputs" – REZ Generation Capacity tab, filtered for Victoria, CDP2 and selected years

REZ	REZ Name	Techn	2024	2025	2030	2035	2040	2045	2050
V6	Central North VIC	Solar	378	378	378	378	378	827	1,970
V6	Central North VIC	Wind	0	0	0	400	400	832	1,600
O3	Gippsland Coast	Offshore Wind	0	0	0	0	0	0	0
O5	Portland Coast	Offshore Wind	0	0	0	0	0	0	0

Table 10. Timings of augmentations that eventuate under CDPs

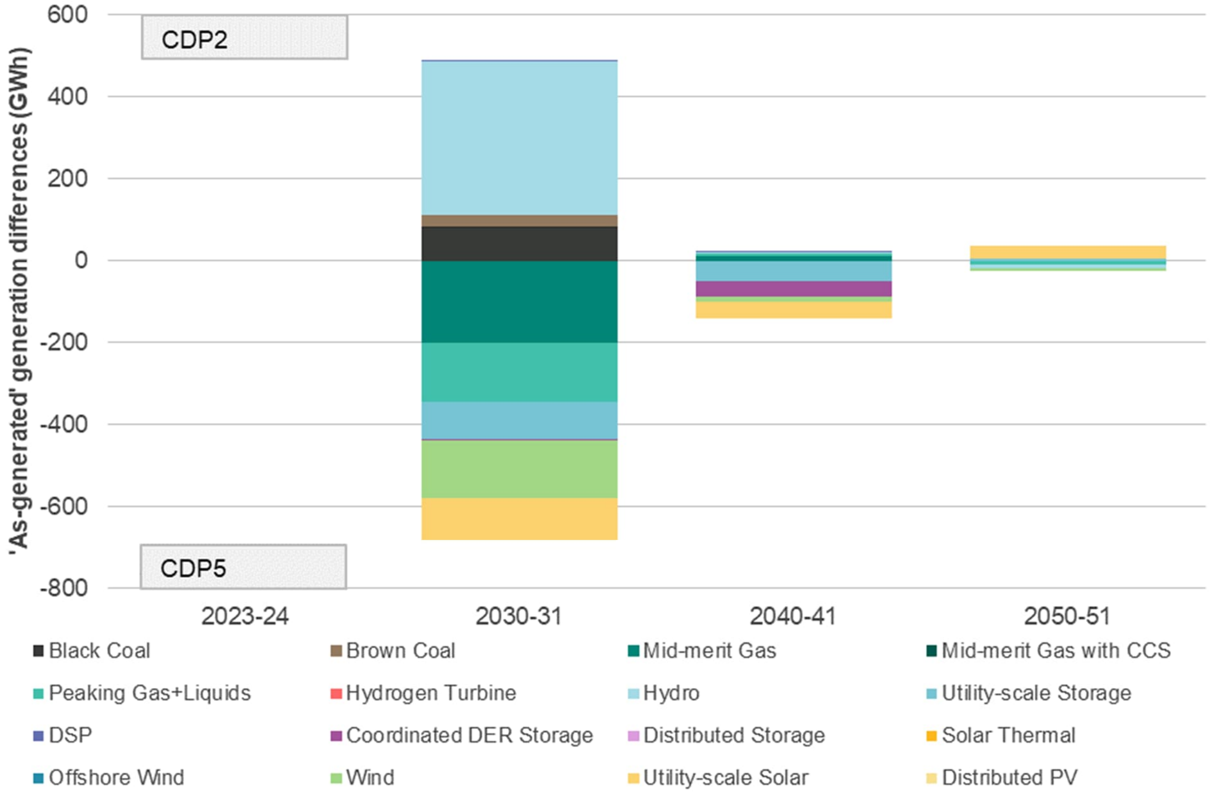
Augmentation	Counter -factual	CDP2	CDP5	CDP6	CDP8	CDP9	CDP10	CDP11	CDP12	CDP13
Gladstone Grid Reinforcement	-	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31
Central to Southern QLD Stage 1	-	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29
Central to Southern QLD Stage 2	-	2038-39	2038-39	2038-39	2038-39	2038-39	2038-39	2038-39	2038-39	2038-39
QNI Connect	-	2032-33	2032-33	2032-33	2032-33	2032-33	2032-33	2032-33	2032-33	2032-33
QNI Connect (Stage 2)	-	-	-	-	-	-	-	-	-	-
New England REZ Transmission Link	-	2027-28	2027-28	2027-28	2027-28	2029-30	2027-28	2027-28	2027-28	2027-28
New England REZ Extension	-	2035-36	2035-36	2035-36	2035-36	2035-36	2035-36	2035-36	2035-36	2035-36
CNSW – NNSW Option 9	-	-	-	-	-	-	-	-	-	-
Sydney Ring	-	2027-28	2027-28	2027-28	2027-28	2029-30	2027-28	2027-28	2027-28	2027-28
HumeLink	-	2028-29	2028-29	2028-29	2026-27	2028-29	2028-29	2026-27	2028-29	2028-29
VNI West (via Kerang)	**-**	**2031-32**	**2032-33**	**2030-31**	**2031-32**	**2032-33**	**2031-32**	**2031-32**	**2031-32**	**2031-32**
VNI Option 6	-	-	-	-	-	-	-	-	-	-
Marinus Link (Cable 1)	-	2029-30	2029-30	2031-32	2029-30	2031-32	2029-30	2029-30	2029-30	-
Marinus Link (Cable 2)	-	2031-32	2031-32	2033-34	2031-32	2033-34	2031-32	2031-32	2031-32	-

Augmentation	Counter-factual	CDP2	CDP5	CDP6	CDP8	CDP9	CDP10	CDP11	CDP12	CDP13
Bayswater to Newcastle port augmentation	-	-	-	-	-	-	-	-	-	-

VNI West only differs in timing in all Step Change CDP outcomes other than the counterfactual.
CDP5 differs from CDP2 only in the delay in timing of VNI West by one year.

Delaying VNI West by a year appears to have a loss of net market benefit of $26M (NPV in $2021)

Figure 33. Impact of deferring VNI West by one year (CDP5 versus CDP2)



Across the NEM, and comparing the impacts of interconnectors and CDP projects generally against the counterfactual indicates that the CDP projects have the impact of enabling onshore wind and solar that would otherwise be made up with offshore wind and natural gas capacity, and in the medium term by dispatchable storage

Figure 34. NEM capacity comparison CDP2 versus counterfactual

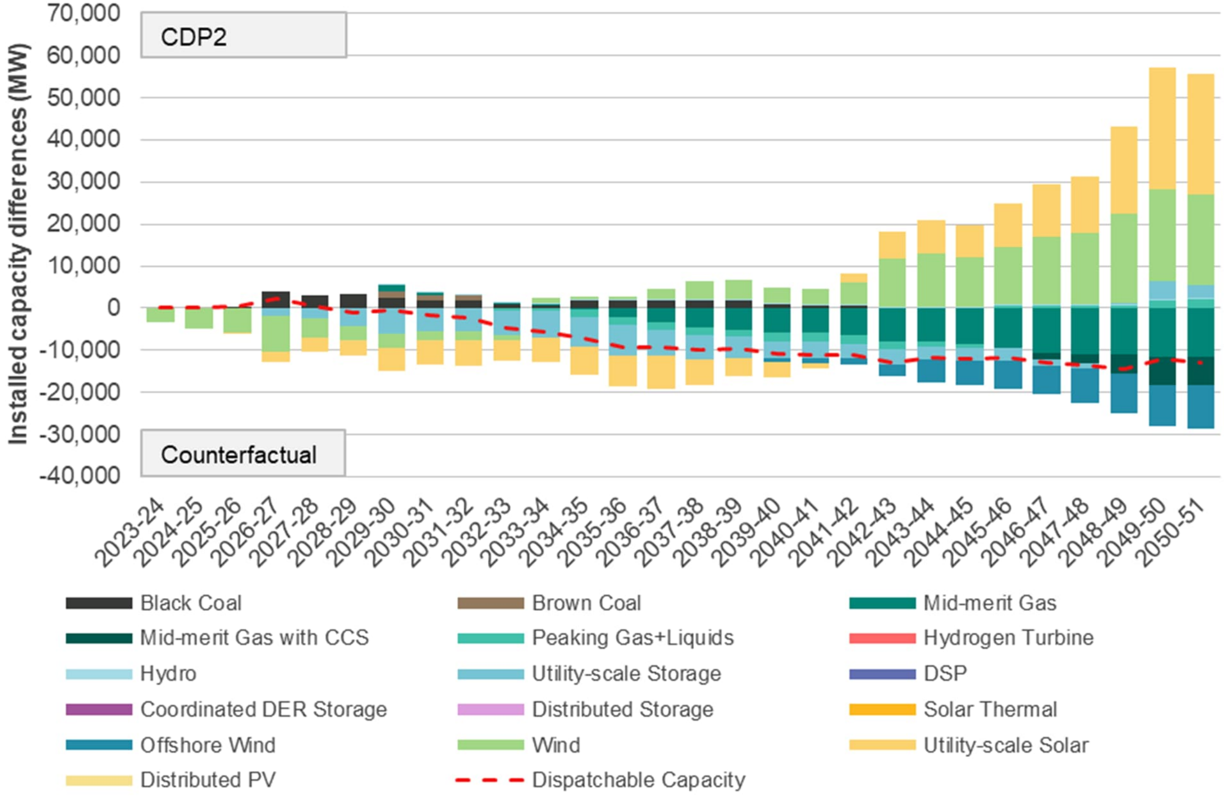
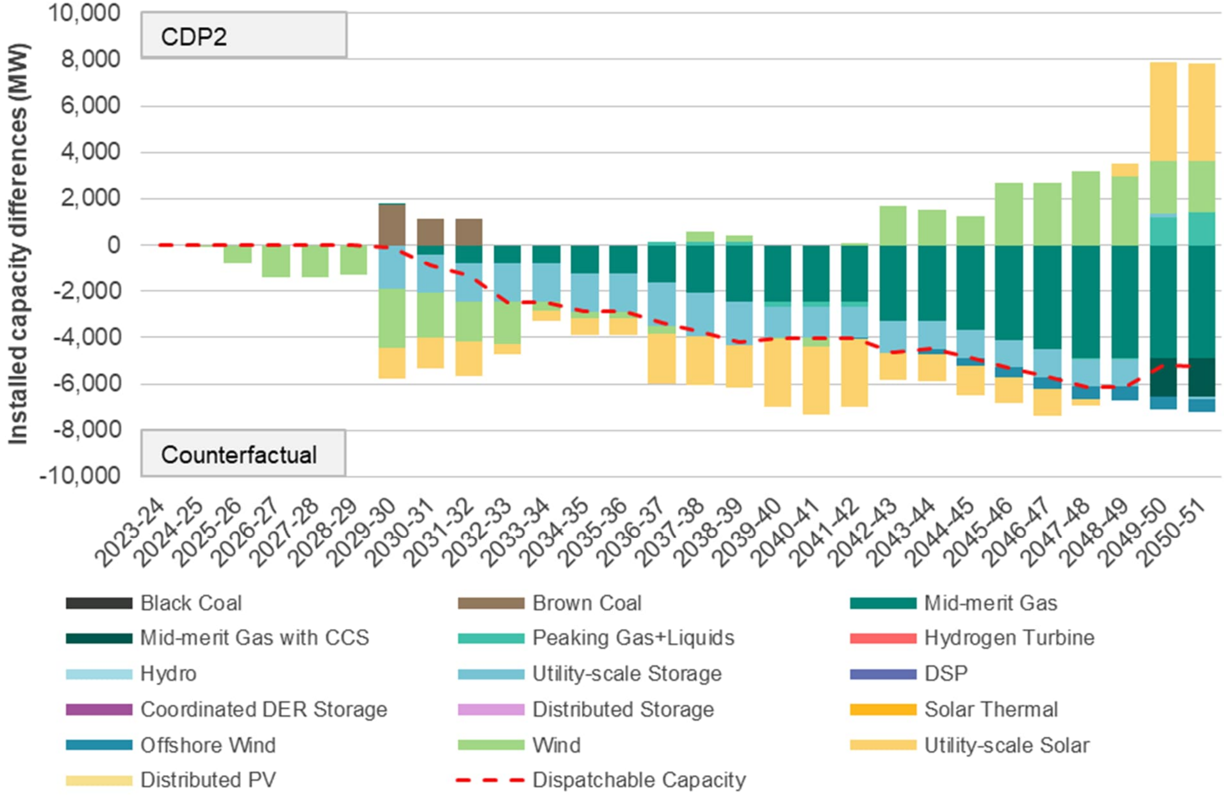


Figure 35. Vic capacity comparison CDP2 versus counterfactual



The PACR notes further development work is expected to follow for Victorian REZs[39]:

> ***Improvements to REZ transmission limits***
>
> *Unlike previous options considered, none of the options or sensitivities decouple Waubra Terminal Station from the existing 220 kV network, as there is no 500 kV terminal station proposed near Waubra/Lexton. Further power system analysis was undertaken to determine if improvements could be made to REZ transmission limits by decoupling Waubra Wind Farm from the existing 220 kV network and establishing a new 500 kV terminal station near Waubra/Lexton. In this analysis, no net increase in Western Victoria REZ (V3) hosting capacity was observed as any generation transferred onto the 500 kV network introduced a new network constraint that offset the benefits of removing it from the existing 220 kV network. Similarly, moving the Waubra Wind Farm connection was found to introduce other constraints that prevented an increase in the Western Victoria REZ (V3) limits over what is achieved in the current options.*
>
> *Both options utilise series compensation on the Bulgana–Kerang 500 kV lines to optimise network load sharing between the existing 220 kV network and the new 500 kV lines and maximise REZ transmission limits, particularly Murray River V2 REZ capacity. This solution manages heavier loading on the Kerang–Bendigo 220 kV line, which is as a result of the options not having a connection to Bendigo, coupled with future load growth projections.*
>
> *Since the Additional Consultation Report, further refinements of the power system model have also identified a slightly higher Option 5 Murray River REZ (V2) limit of 1,075 MW (versus 850 MW in the Additional Consultation Report), which has been reflected in the market modelling in this PACR, and in Table 5 above.*
>
> *As mentioned in the Additional Consultation Report, and as suggested in some of the consultation feedback, additional modifications to the existing network have been identified as potential lower-cost investments for further investigation in future to harness more renewable generation in western Victoria and increase supply to the Bendigo area, if and when needed. These lower-cost minor modifications could include improvements like incorporating dynamic line ratings into the REZ transmission limit modelling, 220 kV power flow control, or control schemes to improve contingency response under higher power transfer levels. Additional modifications include thermal uprate of existing line segments and replacement of end-of-life lines with higher-rated double-circuit lines.*
>
> ***Network congestion in the Bendigo area will continue to be monitored***
>
> *As mentioned above, with the preferred options not having a connection via Bendigo, heavier loading on the Kerang–Bendigo 220 kV line is observed. This heavier loading takes into consideration forecasts for future Bendigo area load growth, as per the Victorian Annual Planning Report which assesses electricity supply to the Bendigo area over the next 10 years. AVP will continue to monitor electricity demand growth in the Bendigo area as part of normal electricity supply planning practices. AVP will also continue to liaise with the local council to understand local developments which need to be considered for electricity supply arrangements to the area.*

[39] PACR at pages 46, 47

2.2 Merits of interconnection

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area A -3	**Merits of interconnection, assumptions** Plan B: "We have identified many concerns about the assumptions and methodology which AEMO has used (set out in our Submission1), none of which AEMO has adequately addressed."
Area A -4	**Merits of interconnection** Plan B: "To get a "first-principles" assessment of the value of increased interconnection between NSW and Victoria we compared the value that would arise if the cheapest wind or solar in NSW displaced the most expensive wind or solar in Victoria (and vice versa) using CSIRO's latest assumptions of costs (AEMO will use these in its forthcoming ISP) and AEMO's latest assessment of all other relevant parameters. We found that the value per MW is less than a quarter of the cost of VNI-West per MW"
Area A -5	**Merits of interconnection** Plan B: "With reference to data on the correlation of wind/solar resources in some REZs in NSW with others in VIC, AEMO also suggests that interconnection is valuable in being able to diversify variable renewable generation. The value of diversification of variable renewable resources is difficult to estimate and it is not yet well understood. But AEMO's data suggests no greater diversification of variable renewable generation between NSW and VIC than it finds within REZs in VIC, or within REZs in NSW"
Area A -9	**Geographic diversity** Plan B: "Furthermore, AEMO's work suggests that the temporal diversity of variable renewable generation is no bigger between neighbouring regions of the NEM than it is within regions, contrary to what has long been suggested to be the case. A failure to respond to this new information has resulted in transmission plans that have become superseded by events and new knowledge.."

Materials specific to Area A-4, Area A-5 and A-9, Geographic diversity" are included below at Section 2.5. In this Section materials related to interconnection generally are included, as it might impact on the relevance of the VNI-W objective that relates to increased interconnection.

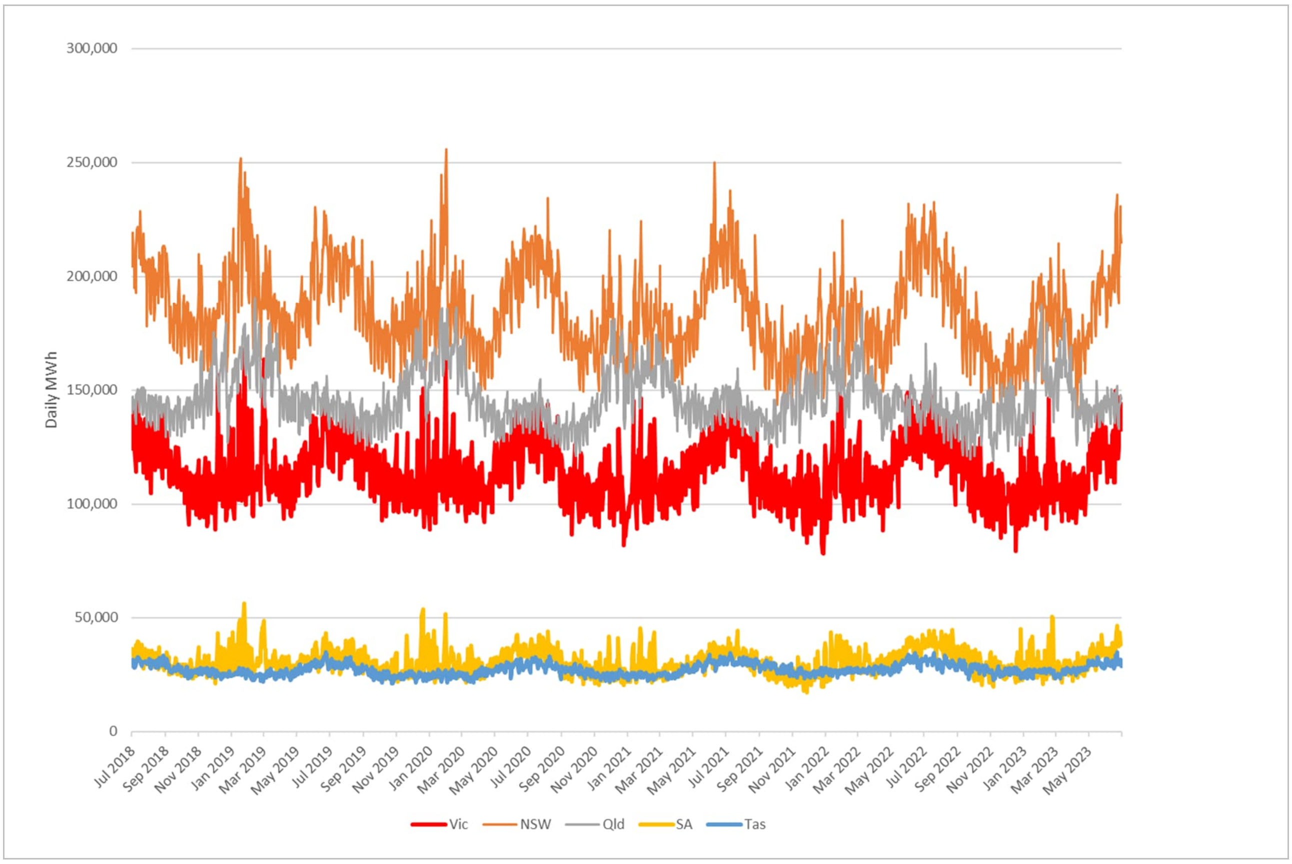
Jacobs' main report (Volume 1) contains a discussion on the merits of interconnection. A discussion on the differences in loads on a daily basis over a five year period is included (refer **Figure 36**). It is noted that the NEM regions loads are not exactly correlated, and that the load on a day in each year may be different from year to year.

There is also variation between the regional loads within a day. The loads for Saturday 1 July 2023 (at 5 minute granularity) are shown in **Figure 37**. All regions were aligned for their evening peaks however the morning peaks (and the middle of the day minimum) were not at the same times. On a particular summer day (1 Feb. 2024) the impact of rooftop PV in the middle of the day appears muted in Victoria and Queensland. It did not rain in Melbourne that day however there were only four hours of sun[40]. On Thursday of the following week (**Figure 39**) there were 12.4 hours of sun and Victoria had a more distinct "dip" in the middle of the day from rooftop PV. NSW and Queensland were muted – Sydney having only 1.5 hours of sun and heavy rain (**Figure 41**), and Brisbane having five hours of sun (**Figure 42**).

[40] Bureau of Meteorology, February 2023 Daily Weather Observations, Olympic Park and Melbourne Airport. bom.gov.au

This is further discussed in Section 2.5

Figure 36. Daily loads in NEM regions, five years to June 2023[41]



[41] Data is 5 minute TOTALDEMAND for each region aggregated to daily quantities, sourced from AEMO "Public Daily" files.

Figure 37. Five minute loads in NEM regions, Saturday, 1 July 2023[42]

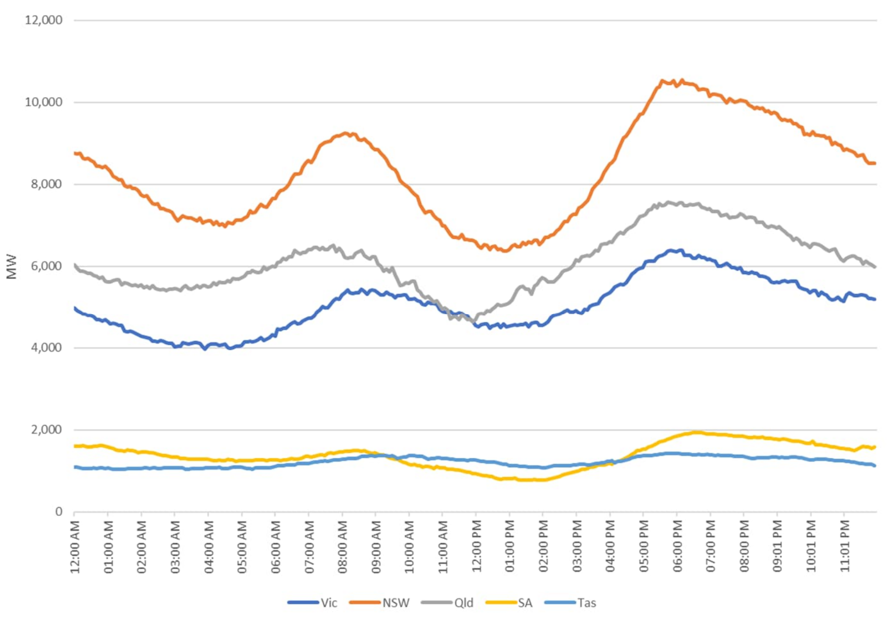
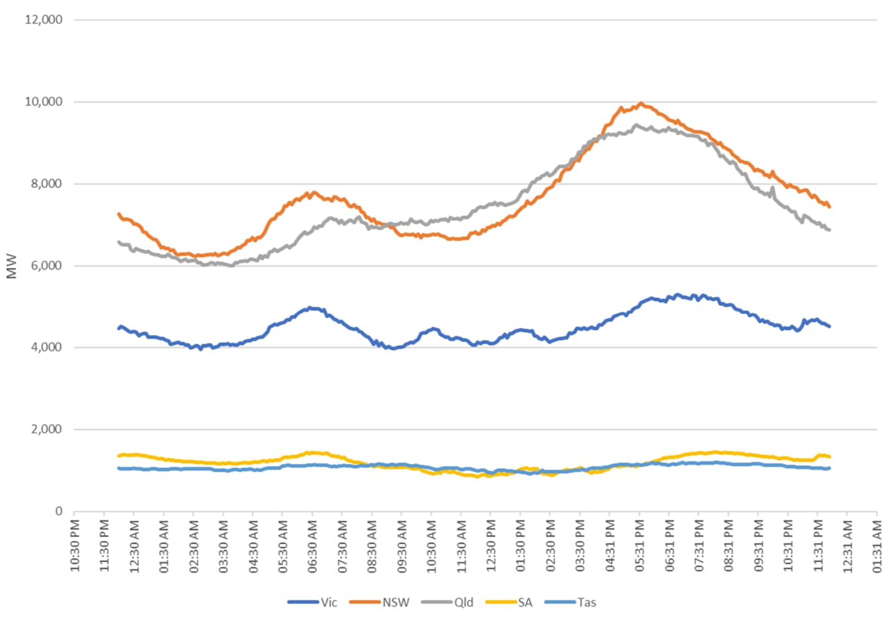


Figure 38. Five minute loads in NEM regions, Wednesday, 1 February 2023[43]



[42] Data is 5 minute TOTALDEMAND for each region, sourced from AEMO "Public Daily" files.

[43] Data is 5 minute TOTALDEMAND for each region, sourced from AEMO "Public Daily" files.

Figure 39. Five minute loads in NEM regions, Thursday, February 2023[44]

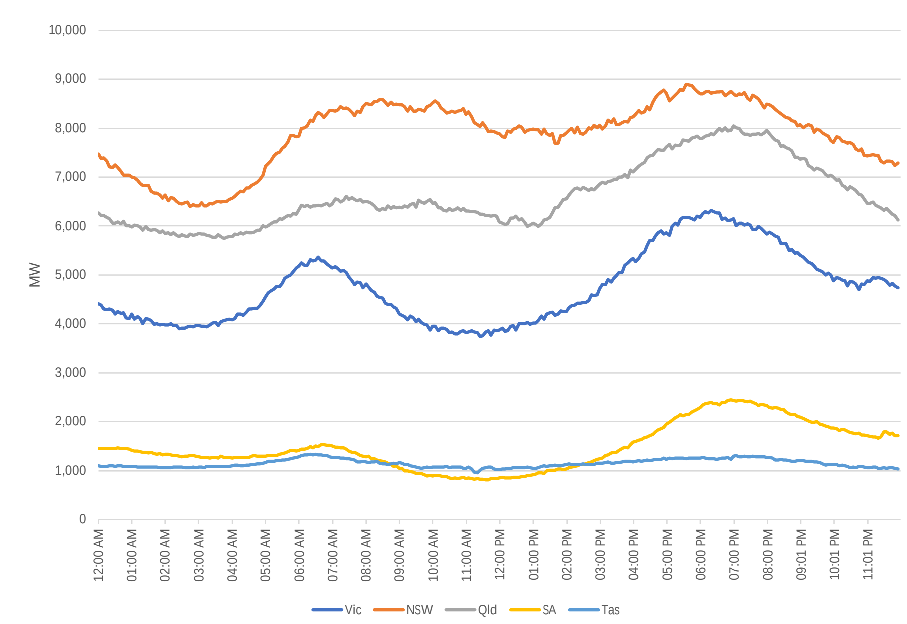


Figure 40. Melbourne weather, February 2023[45]

Melbourne Airport, Victoria
February 2023 Daily Weather Observations

Date	Day	Temps Min	Temps Max	Rain	Evap	Sun	Max wind gust Dir	Max wind gust Spd	Max wind gust Time	9 am Temp	9 am RH	9 am Cld	9 am Dir	9 am Spd	9 am MSLP	3 pm Temp	3 pm RH	3 pm Cld	3 pm Dir	3 pm Spd	3 pm MSLP
		°C	°C	mm	mm	hours		km/h	local	°C	%	8th		km/h	hPa	°C	%	8th		km/h	hPa
1	We	10.2	21.1	0	7.2	4.0	SSW	48	10:57	17.2	63	1	WSW	15	1006.7	18.0	66	7	SSW	22	1006.3
2	Th	9.8	22.6	0	4.4	5.6	WSW	70	15:42	15.4	47	7	WNW	24	998.2	19.4	40	7	NNW	43	990.7
3	Fr	8.9	17.8	8.4	7.2	5.7	W	61	15:37	12.9	67	4	NNW	22	993.1	16.2	50	6	W	28	993.9
4	Sa	9.7	22.0	7.0	4.8	6.6	SW	56	12:43	14.5	85	7	W	31	1004.2	21.5	42	6	WSW	33	1008.2
5	Su	11.4	20.3	0	5.2	1.7	WSW	31	11:28	15.7	75	7	WSW	17	1017.3	19.6	55	7	W	13	1017.5
6	Mo	14.4	22.2	0	4.2	7.5	SSE	33	15:04	16.5	72	7	SW	19	1020.5	20.4	52	3	S	17	1019.6
7	Tu	14.4	22.3	0.2	5.2	8.0	S	35	17:17	15.9	82	8	SW	13	1019.8	20.9	54	3	S	22	1017.9
8	We	13.8	23.5	0	5.8	11.0	S	39	13:48	16.9	68	3	S	15	1017.1	22.7	53	3	S	22	1014.5
9	Th	12.5	28.9	0	8.4	12.4	SSE	33	12:45	17.9	78	1	NW	9	1010.7	27.1	48	1	S	22	1007.0
10	Fr	11.8	28.2	0	6.6	10.2	SSE	31	14:31	14.8	98		N	6	1007.3	27.1	50	3	S	19	1004.0
11	Sa	13.5	29.5	0	6.8	12.5	SSW	39	11:50	18.9	82	1	W	9	1000.5	28.0	46	1	SW	24	1001.3
12	Su	15.5	21.5	0	9.2	6.6	SSE	52	13:48	17.8	69	7	SW	22	1010.1	20.0	43	5	S	37	1011.9
13	Mo	13.8	21.4	0	7.6	8.2	S	46	13:08	16.5	61	7	SW	22	1014.8	19.6	45	7	S	30	1014.0
14	Tu	10.1	23.1	0	6.0	12.7	SSE	41	13:19	16.6	70	1	SE	17	1015.7	22.9	48	1	S	24	1013.6
15	We	10.4	33.5	0	8.0	10.7	N	54	08:32	21.5	59	5	N	35	1013.7	31.8	29	7	NW	17	1011.5
16	Th	17.5	37.5	0	9.4	10.8	N	61	09:27	26.8	41	7	N	37	1013.2	34.8	19	7	WNW	28	1011.0
17	Fr	21.6	41.3	0	15.2	9.9	NNE	65	08:17	27.9	38	5	NNE	46	1009.9	39.5	16	2	NNW	31	1006.6
18	Sa	16.2	24.6	0	12.6	8.2	S	39	17:33	16.8	71	7	SSW	17	1014.3	22.7	50	1	S	15	1014.9
19	Su	12.4	29.1	0	6.8	12.4	SSE	41	15:41	17.9	77	1	SW	7	1019.0	25.8	42	1	SSE	11	1017.2
20	Mo	11.6	27.2	0	6.0	10.1	S	33	15:02	16.7	85	7	W	9	1020.4	26.5	41	1	S	13	1020.4
21	Tu	16.0	21.6	0.2	6.2	6.9	S	50	12:28	16.3	88	8	SSE	22	1027.4	20.7	48	5	S	33	1027.8
22	We	11.3	30.3	0	6.4	11.7	SSE	33	14:42	16.8	74	1	W	7	1024.7	28.3	37	3	ESE	15	1021.0
23	Th	16.1	32.1	0	10.8	12.1	NNE	70	09:12	21.1	48	4	NNE	50	1020.8	30.3	29	5	N	20	1018.7
24	Fr	17.2	32.9	0	11.6	11.9	NNE	65	08:35	22.1	50	4	NNE	43	1017.5	31.7	28	7	NNE	33	1014.3
25	Sa	21.8	27.3	0	15.4	1.1	N	72	07:33	23.6	41	7	N	52	1011.9	23.5	45	8	WSW	19	1012.7
26	Su	13.4	25.9	1.4	3.4	4.6	SW	41	14:51	16.8	71	7	WNW	11	1012.5	24.8	41	6	WSW	22	1011.0
27	Mo	14.8	20.6	0.8	4.0	0.2	SSE	35	15:15	16.6	85	7	SSW	19	1015.4	19.9	62	7	SSW	24	1015.5
28	Tu	14.1	16.6	0	3.8	0.0	S	31	18:24	14.5	92	8	SW	13	1013.2	15.2	95	7	SSW	17	1011.4
Statistics for February 2023																					
Mean		13.7	25.9		7.4	8.0				18.0	69	5		21	1013.2	24.2	45	4		23	1011.9
Lowest		8.9	16.6	0	3.4	0.0				12.9	38	1	N	6	993.1	15.2	16	1	SSE	11	990.7
Highest		21.8	41.3	8.4	15.4	12.7	N	72		27.9	98	8	N	52	1027.4	39.5	95	8	NNW	43	1027.8
Total				18.0	208.2	223.3															

IDCJDW3049.202302 Prepared at 13:01 UTC on Sunday 8 October 2023

[44] Data is 5 minute TOTALDEMAND for each region, sourced from AEMO "Public Daily" files.

[45] http://www.bom.gov.au/climate/dwo/202302/html/IDCJDW3049.202302.shtml

Figure 41. Sydney weather, February 2023[46]

Sydney, New South Wales
February 2023 Daily Weather Observations

Most observations from Observatory Hill, but some from Fort Denison and Sydney Airport.

Date	Day	Temps		Rain	Evap	Sun	Max wind gust			9 am						3 pm					
		Min	Max				Dir	Spd	Time	Temp	RH	Cld	Dir	Spd	MSLP	Temp	RH	Cld	Dir	Spd	MSLP
		°C	°C	mm	mm	hours		km/h	local	°C	%	8th		km/h	hPa	°C	%	8th		km/h	hPa
1	We	20.0	28.7	0	6.4	11.6	WSW	35	23:09	22.2	71	3	WSW	9	1003.8	27.0	55	3	ESE	22	1001.8
2	Th	21.6	29.1	0	6.0	11.4	NE	52	15:49	23.4	77	1	N	11	1000.5	28.9	68	2	NE	26	994.3
3	Fr	22.1	30.6	0	10.6	11.6	SE	37	14:02	22.8	45	1	W	17	995.6	28.1	43	1	ESE	31	994.5
4	Sa	17.5	28.9	0	10.8	12.7	WSW	44	13:47	18.8	45	1	WNW	20	1005.6	27.7	22	1	WNW	22	1004.6
5	Su	17.7	28.0	0	11.2	12.7	E	33	18:40	20.5	50	1	W	15	1015.1	27.4	43	0	E	20	1014.4
6	Mo	20.5	28.4	0	8.6	10.1	ENE	43	15:17	22.8	82	4	ENE	2	1018.1	28.0	65	1	E	30	1015.6
7	Tu	21.8	28.7	0	7.2	4.3	E	28	10:07	24.4	78	7	NNE	11	1016.2	28.4	59	5	E	20	1014.5
8	We	21.1	28.2	0	6.2	2.8	E	41	19:26	23.8	77	7	WNW	7	1015.6	25.8	74	6	ESE	24	1014.3
9	Th	19.4	23.4	27.8		1.5	ESE	56	15:04	22.0	94	8	ENE	19	1013.3	20.8	95	8	E	30	1010.5
10	Fr	17.8	28.0	19.4		12.0	ENE	31	16:40	20.0	97	1	WNW	13	1009.0	27.3	72	2	E	20	1005.7
11	Sa	19.3	30.4	0	8.0	11.0	NE	50	19:56	22.2	88	7	W	11	1006.5	29.9	65	1	NE	26	1002.2
12	Su	21.5	27.3	0	10.8	11.2	S	63	14:35	24.6	53	5	WSW	17	1003.7	26.8	64	1	SSE	37	1004.9
13	Mo	19.1	25.5	0.4	7.2	4.7	SSE	39	04:14	21.4	75	7	SSE	28	1011.0	24.9	60	7	S	22	1010.1
14	Tu	18.3	21.2	3.4	7.2	1.2	SSW	44	05:19	20.2	84	7	SSW	20	1011.8	18.6	99	7	SW	11	1012.8
15	We	18.1	26.9	45.8	1.8	9.0	NE	35	16:35	20.3	93	6	W	13	1017.0	26.1	59	1	E	22	1015.4
16	Th	18.2	28.3	0	7.8	12.3	NE	43	14:18	21.0	77	1	NNE	11	1018.0	27.5	57	2	ENE	26	1014.8
17	Fr	19.6	28.3	0	8.0	12.1	ENE	43	14:13	22.1	83	1	N	7	1016.9	27.6	65	1	ENE	24	1014.3
18	Sa	20.7	30.0	0	8.4	9.2	SW	70	17:48	22.7	85	1	ESE	6	1014.3	29.3	65	4	ENE	17	1010.4
19	Su	20.9	28.7	5.0	13.4	9.0	S	39	00:25	23.4	77	7	SSW	19	1018.9	25.7	74	4	ESE	11	1018.7
20	Mo	21.6	29.4	0	6.0	10.0	ENE	39	14:27	24.0	87	7	N	9	1020.1	28.7	66	1	ENE	24	1017.8
21	Tu	21.1	28.4	0	10.8	10.0	SSE	54	19:07	23.1	89	1	ESE	7	1021.5	27.9	66	1	E	20	1020.3
22	We	18.9	21.6			0.0	SSE	65	03:40	21.0	72	8	SSE	28	1025.6	18.6	91	8	SSE	17	1025.9
23	Th	18.5	24.4		5.0	1.8	ESE	50	06:43	19.0	87	8	E	24	1023.9	22.8	65	7	E	28	1023.4
24	Fr	16.9	26.8		3.6	8.7	ENE	37	14:52	19.9	85	4	WNW	9	1022.0	26.6	53	3	E	24	1019.6
25	Sa	17.7	26.9	0.2	5.4	11.8	NE	41	16:36	18.9	92	1	WNW	13	1018.5	26.1	56	2	NE	20	1015.5
26	Su	18.7	29.4	0	10.0	9.8	WSW	56	22:18	20.5	83	6	NNW	4	1013.1	28.3	61	1	ENE	13	1009.5
27	Mo	20.5	26.2	1.2	8.2	2.7	SSW	37	05:07	23.2	82	7	SSW	15	1012.4	25.6	72	7	SE	15	1011.3
28	Tu	20.8	27.7	2.4	6.2	4.8	E	33	14:50	22.1	86	5	WNW	9	1013.0	27.5	64	5	E	24	1009.1
Statistics for February 2023																					
Mean		19.6	27.5		7.8	8.2				21.8	78	4		13	1013.6	26.4	64	3		22	1011.6
Lowest		16.9	21.2	0	1.8	0.0				18.8	45	1	ENE	2	995.6	18.6	22	0	#	11	994.3
Highest		22.1	30.6	45.8	13.4	12.7	SW	70		24.6	97	8	SSE	28	1025.6	29.9	99	8	SSE	37	1025.9
Total				105.6	194.8	230.0															

IDCJDW2124.202302 Prepared at 13:00 UTC on Sunday 8 October 2023

Figure 42. Brisbane weather, February 2023[47]

Brisbane, Queensland
February 2023 Daily Weather Observations

Most observations from Brisbane City, but some from Brisbane Airport.

Date	Day	Temps		Rain	Evap	Sun	Max wind gust			9 am						3 pm					
		Min	Max				Dir	Spd	Time	Temp	RH	Cld	Dir	Spd	MSLP	Temp	RH	Cld	Dir	Spd	MSLP
		°C	°C	mm	mm	hours		km/h	local	°C	%	8th		km/h	hPa	°C	%	8th		km/h	hPa
1	We	25.3	34.8	0.2	7.6	8.5	E	35	16:06	29.6	62	7	WNW	9	1001.6	33.2	56	5	NE	7	998.5
2	Th	24.9	32.3	0	8.8	5.9	NE	26	15:26	28.7	65	7	E	4	1001.6	29.6	63	7	E	13	997.5
3	Fr	24.1	35.4	0	5.2	9.1	NE	24	16:39	30.0	63	2	WNW	4	998.0	31.3	63	7	NNE	9	996.1
4	Sa	26.4	31.4	0	8.0	0.7	WSW	24	12:01	30.5	56	8	WSW	6	1004.2	23.3	79	8	WNW	4	1005.7
5	Su	21.6	32.4	1.2	3.8	12.5	E	31	17:07	28.3	63	7	SE	11	1013.7	30.7	51	2	E	13	1012.2
6	Mo	21.2	31.1	0	12.0	12.1	E	33	14:26	27.9	53	7	SE	13	1016.6	29.7	48	3	E	13	1013.9
7	Tu	20.4	29.7	0	10.2	8.7	E	26	15:41	27.1	59	7	SE	7	1014.4	28.7	53	7	E	13	1012.5
8	We	21.8	30.5	0	9.2	9.1	E	31	12:47	26.4	54	6	SE	9	1013.4	28.6	42	7	E	9	1010.8
9	Th	21.8	28.8	0.2	9.8	5.1	E	30	10:21	27.0	53	7	E	11	1011.6	26.9	50	7	E	11	1009.1
10	Fr	19.9	31.0	2.4	8.6	10.4	SE	31	11:16	27.5	55	4	SE	9	1007.3	30.2	44	1	ESE	13	1003.5
11	Sa	20.4	33.3	0	8.0	12.6	E	24	16:25	27.4	50	0	SSW	6	1007.2	30.9	44	1	NE	9	1005.0
12	Su	21.6	35.7	0	9.8	11.2	NE	28	17:48	27.7	56	1	NNW	4	1006.0	33.5	38	1	NNE	9	1000.6
13	Mo	24.2	34.4	0	8.6	11.8	ENE	35	15:15	29.9	63	5	SW	6	1005.7	32.4	57	1	ENE	15	1003.1
14	Tu	23.9	30.4	0	9.2	5.5	E	37	14:43	27.9	67	7	SE	7	1007.0	24.6	85	8	ENE	11	1004.5
15	We	19.7	29.1	56.2		9.7	E	35	14:00	25.4	65	2	SSE	7	1013.5	27.9	53	7	ESE	15	1012.5
16	Th	19.0	28.8	0.2	6.8	12.4	ENE	26	15:31	25.9	55	2	SE	6	1018.2	27.1	48	3	ENE	9	1015.4
17	Fr	18.4	29.8	0	8.6	12.0	E	22	12:05	26.0	55	5	SSE	4	1018.1	29.0	47	7	NE	9	1014.2
18	Sa	20.7	31.3	0	1.6	12.3	ENE	22	17:01	26.6	61	4	SW	4	1016.8	28.7	53	1	NE	11	1013.4
19	Su	21.3	30.0	0	7.8	7.3	E	26	14:32	26.7	59	7	SW	2	1017.9	27.9	54	7	ENE	11	1016.5
20	Mo	21.9	28.1	0	9.8	2.7	NE	30	13:29	26.8	59	7	ENE	11	1019.9	27.2	57	8	E	11	1018.5
21	Tu	20.9	29.8	0	4.4	4.6	ENE	30	14:28	25.8	65	8	SE	7	1020.2	28.2	50	7	E	13	1018.1
22	We	20.5	29.3	0.8	6.8	7.7	ESE	33	16:58	22.8	81	7	SSW	7	1018.0	28.1	53	1	ESE	13	1015.4
23	Th	20.3	28.9	3.0	8.4	6.1	SE	33	14:45	26.1	64	7	SE	11	1016.9	28.4	41	5	ESE	13	1014.9
24	Fr	20.1	28.0	0	7.8	5.2	SE	37	13:29	23.5	68	7	SSE	13	1017.2	22.2	80	7	SSE	7	1015.7
25	Sa	18.7	29.0	0.8	5.4	12.0	ENE	26	17:27	25.1	60	1	SE	11	1016.9	28.1	45	1	E	11	1013.6
26	Su	18.6	30.5	0	8.0	12.1	ENE	26	15:57	26.1	63	2	SSE	2	1016.1	28.4	54	7	NE	11	1012.8
27	Mo	20.8	31.1	0	6.2	12.1	NNE	24	16:37	27.4	58	4	WNW	6	1015.2	29.7	52	1	NE	9	1011.1
28	Tu	22.4	30.9	0	7.6	9.7	NNE	22	17:46	26.7	62	6	SW	4	1013.3	29.2	53	1	NE	11	1009.7
Statistics for February 2023																					
Mean		21.5	30.9		7.7	8.9				27.0	60	5		7	1012.4	28.7	54	4		10	1009.8
Lowest		18.4	28.0	0	1.6	0.7				22.8	50	0	#	2	998.0	22.2	38	1	WNW	4	996.1
Highest		26.4	35.7	56.2	12.0	12.6	#	37		30.5	81	8	#	13	1020.2	33.5	85	8	#	15	1018.5
Total				65.0	208.0	249.1															

IDCJDW4019.202302 Prepared at 13:01 UTC on Sunday 8 October 2023

Prior to the recent rule changes and the NEVA, the former RIT-T framework specifically excluded the consideration of externalities or benefits that were hard to monetise within the Cost Benefit Analysis component of the RIT-T. Project Energy Connect (PEC) was assessed during this era. As part of the

[46] http://www.bom.gov.au/climate/dwo/202302/html/IDCJDW2124.202302.shtml

[47] http://www.bom.gov.au/climate/dwo/202302/html/IDCJDW4019.202302.shtml

associated materials related to PEC, FTI Consulting produced a report to Transgrid[48] on the benefits of interconnectors more generally than would just be assessed using the CBA framework of the time.

Some of the other benefits described were:

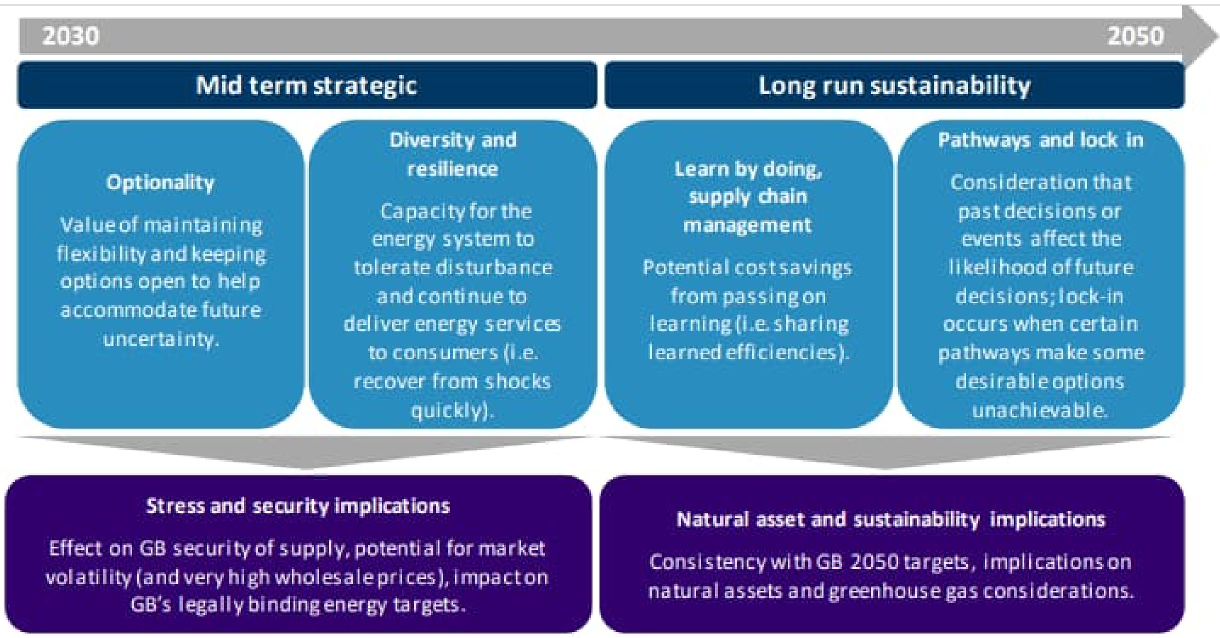
- Residual value – the asset life being longer than the economic and market modelling period
- Connecting new providers of balancing services
- Increasing security of supply
- Supporting decarbonisation measures
- Renewable energy integration
- Societal renewable energy benefits
- Contribution to the diversification of the total number of electricity supply sources
- Contribution to the diversification of physical locations of electricity supply

As part of its report, FTI noted the treatment of hard-to-monetise benefits of interconnectors in other jurisdictions (Great Britain, Europe and New York ISO). FTI stated "*Our key finding is that in all three jurisdictions, hard-to-monetise benefits are considered as part of 'standard' regulatory assessments of interconnectors. While the specific details differ, a common theme across all three jurisdictions is that failing to take hard-to-monetise benefits into account would not provide a complete picture of the transmission investment's merits*.".

A diagrammatic description of Ofgem's framework was included by FTI and reproduced below as:

[48] Available at TransGrid - A.11A - FTI PEC - Wider Benefits Report - September 2020.pdf (aer.gov.au)

Figure 43. Ofgem's framework for assessing hard-to-monetise benefits[49]



Source: Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link).

Refer also Section 3.1

2.3 VNI West doesn't address curtailment

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area A -6	**VNI West doesn't address curtailment** Plan B :"Leaving to one side our critique of the merits of interconnection, our analysis of the results of AEMO's modelling analysis of VNI-West finds that it is not successful in meaningfully addressing the pressing problem of renewables curtailment in Victoria. AEMO's results show a slight reduction in renewable curtailment in those REZs affected by VNI-West in the decade after VNI-West is commissioned. But this is followed by a return to the pre- VNI-West levels of curtailment a decade after commissioning"

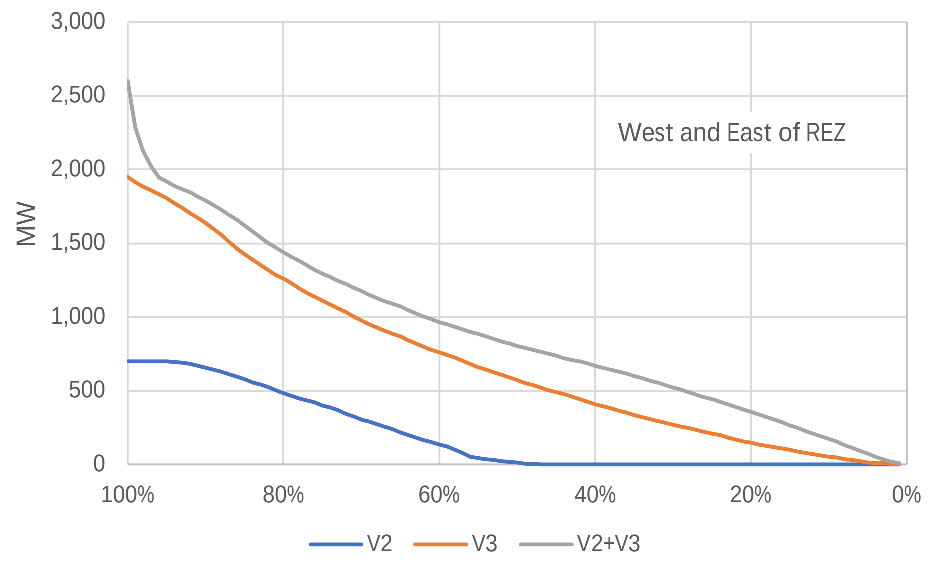
[49] Reproduced from the FTI report, op cit. The embedded link to the source material is : https://www.ofgem.gov.uk/ofgem-publications/117521

Area A -7	**VNI West and curtailment** Plan B: "AEMO also defends its projected curtailment on the basis that it has determined the "efficient" outcome. This is not correct: AEMO has failed to account for generation curtailment (i.e. that curtailed generators will require higher prices than uncurtailed generators in order to compensate their curtailment) in its modelling of the relative economics of variable renewable generation and transmission."

The impacts of generation entrants building plants in areas where the grid was not originally designed for these flows, resulting in curtailment of generation and poor loss factors (a Marginal Loss Factor, MLF, significantly lower than 1.0) is a matter of notoriety in the NEM and particularly in the Redcliffs-Horsham-Ballarat and Redcliffs-Wemen-Kerang-Ballarat "rhombus"[50].

Jacobs has constructed the generation-duration curves for existing+construction+committed solar and wind generation in REZ V2 and V3 (Section 1.2) using the AEMO ISP "traces" for representative outputs of technologies in each REZ over a year.

Figure 44. Indicative solar and wind generation-duration curves in V2 and V3 REZs for existing+construction+committed generation



These values can be compared to the current listed ratings for the circuits below. A high degree of curtailment is indicated because the indicated flows would be above the circuit capacities (see below) for a significant proportion of time..

The existing 220kV lines in the "Rhombus" are single circuit 220kV using Twin Panther conductor (=Twin Lemon). The conductors for these lines have a thermal rating of 417MVA (35°C and 1m/s wind) but the circuits have ratings considerably lower.

[50] This region has been described as the "rhombus of regret" in the industry. Refer for example to "Wind and solar plants hit by massive de-ratings in congested grid", Giles Parkinson, RenewEconomy 8 Mar 2019 at [Wind and solar plants hit by massive de-ratings in congested grid | RenewEconomy]

Table 11. Ratings for the 220kV circuits in the rhombus

Circuit	Conductor	Rating MVA, Dynamic (AEMO 35°C)
BATS-BETS	Single Canary	271
BETS-KGTS	Twin Panther	347
KGTS-WETS/RCTS	Twin Panther	267
RCTS-KMTS	Twin Panther	450
KMTS-MRTS/HOTS	Twin Panther	450 KMTS-MRTS 400 MRTS-HOTS
HOTS-BGTS/CWTS	Twin Panther	400 HOTS-BGTS 450 BGTS-CWTS
CWTS-ARTS	Twin Panther	450
ARTS-WBTS/BATS	Twin Panther	450

Plan B are suggesting rebuilding the 220kV single circuit lines with high capacity double circuit lines (using Twin Peach for 1100MVA/circuit, but in discussion might instead choose twin Sulfur conductor for 800MVA/circuit).

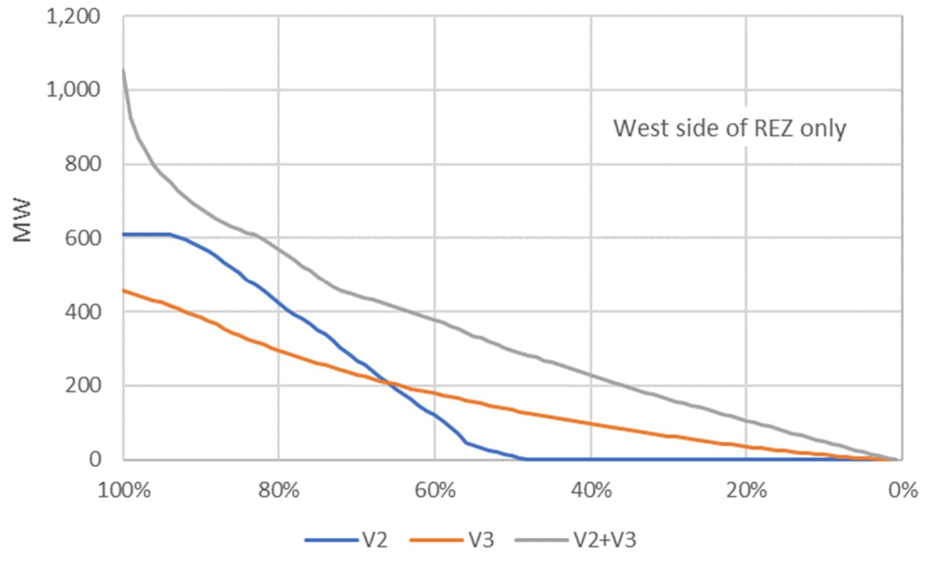
Jacobs has also notionally divided the two REZ into a western and eastern portion. The eastern portion is the portion of the REZ proximate to Bulgana or Kerang or on the eastern side of those terminal stations. Prima facie, generation near VNI West or to the east will gain congestion and MLF relief due to VNI West because some of the load that would otherwise flow on the existing 200kV system would instead flow on the high capacity (low impedance) 500kV system instead. This is a simplified picture because alternate constraint equations may emerge later in evaluations, and when flowing to the South some (a modest fraction) of the VNI West flow itself will spread to the 220kV system (as parallel circuits), however a beneficial effect may still be expected. When VNI West was at low load or flowing from Victoria to NSW (as might be expected in high wind/solar times in V2 and V3 in Victoria) then it is much more likely that generation near or to the east of VNI West will benefit.

Generation to the west of VNI West will not gain a benefit however and must use the existing single circuits (Redcliffs-Horsham-Bulgana and Redcliffs-Wemen-Kerang) for transport of the energy[51]. **Figure 44** is drawn for the subset of generation on the western side of the VNI west in **Figure 45**.

The flows might be compared against the circuit capacities, noting however that any flow from Buronga to Redcliffs would add to the flow and any local loads (eg Mildura and Horsham) would be deducted in practice.

[51] Plan B proposes to upgrade these relevant circuits in its Projects 1.6, 1.7 and 2.1

Figure 45. Indicative solar and wind generation-duration curves in the western sides of V2 and V3 REZs for existing+construction+committed generation



The PACR market modelling outputs (step change scenario) show the generation and capacity modelled in each REZ zone. The implied capacity factor for each can be calculated.

Figure 46. Capacity Factor by Victorian REZ with VNI-W, Step Change[52]

REZ	REZ Name	Technology	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
V1	Ovens Murray	Solar	0.0%	18.4%	18.5%	19.1%	18.2%	16.7%	17.8%	19.0%	17.0%	19.5%	18.8%	18.2%
V2	Murray River	Solar	21.1%	17.4%	18.2%	18.3%	17.4%	16.8%	16.4%	16.2%	21.1%	23.2%	22.2%	21.6%
V3	Western Victoria	Solar	0.0%	14.8%	15.4%	17.4%	18.5%	15.6%	16.8%	17.3%	16.3%	18.9%	18.6%	20.3%
V4	South West Victoria	Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
V5	Gippsland	Solar	0.0%	14.1%	15.5%	16.8%	16.1%	13.5%	14.0%	15.3%	14.3%	15.0%	15.0%	16.4%
V6	Central North VIC	Solar	27.0%	24.2%	23.2%	24.0%	24.1%	24.8%	24.9%	23.9%	21.8%	23.8%	22.9%	21.6%

REZ	REZ Name	Technology	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
V1	Ovens Murray	Wind	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
V2	Murray River	Wind	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
V3	Western Victoria	Wind	22.6%	21.7%	21.8%	22.2%	33.9%	32.1%	33.2%	30.7%	36.0%	32.9%	32.5%	31.7%
V4	South West Victoria	Wind	33.0%	33.2%	34.8%	36.5%	37.1%	33.8%	35.9%	34.0%	38.4%	34.0%	35.4%	35.0%
V5	Gippsland	Wind	0.0%	38.2%	38.1%	38.1%	38.1%	36.9%	35.7%	33.2%	37.9%	34.2%	34.9%	33.8%
V6	Central North VIC	Wind	0.0%	26.9%	25.3%	28.3%	28.3%	27.5%	27.2%	31.0%	31.1%	31.8%	30.6%	28.0%

The capacity factors for V2 and V3 shown are significantly less than the implied capacity factors for generic unconstrained plants in the REZs shown in **Table 12** until VNI-W is installed after which the capacity factors are circa 80% of the unconstrained values for V2 solar and higher for V3 wind (not dissected to the high and low wind categories to enable direct comparison).

[52] Calculated from "EY workbook REZ zone outcomes - Step Change"

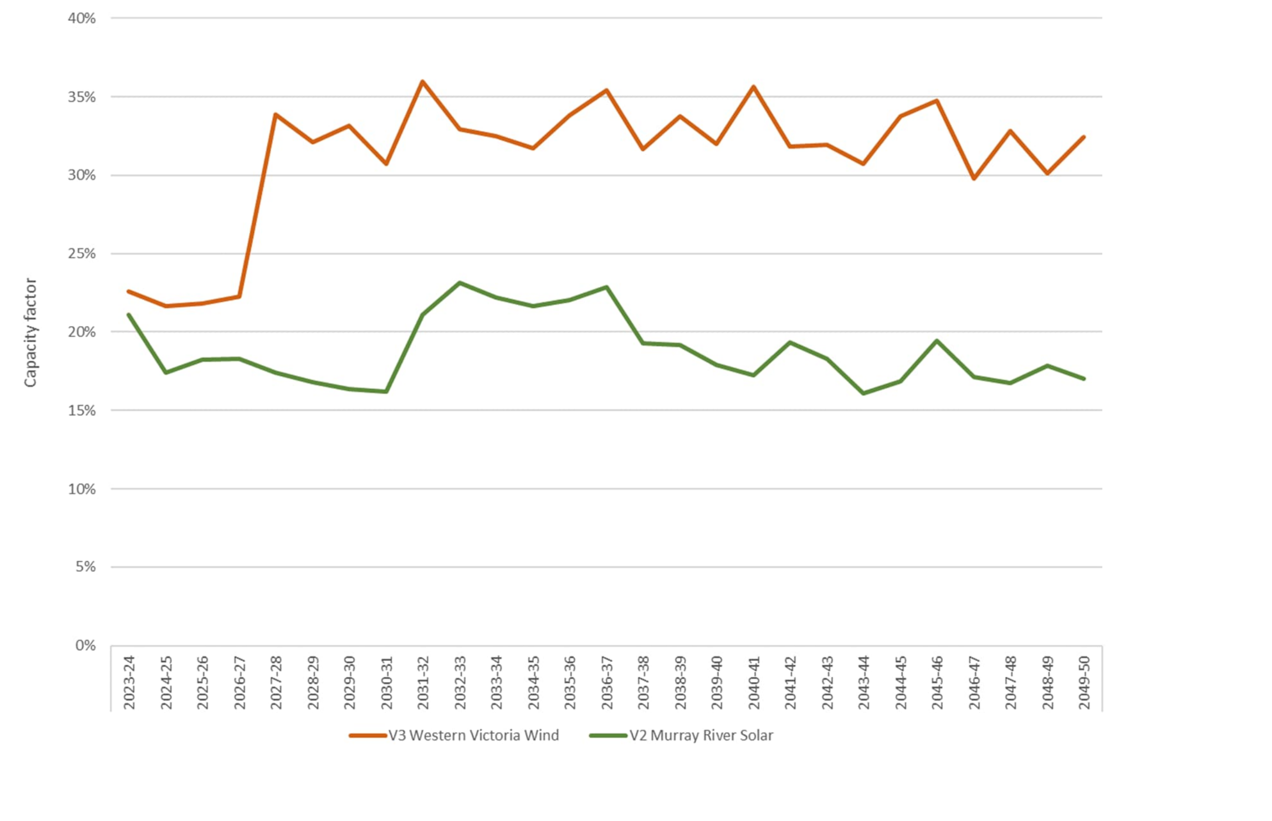
Table 12. Implied capacity factors (unconstrained) for AEMO REZ output traces for Victoria[53]

REZ & tech.	Implied CF		REZ & tech.	Implied CF
V0_SAT	20.5%		V4_SAT	21.4%
V0_WH	37.2%		V4_WH	39.3%
V0_WL	37.0%		V4_WL	37.4%
V1_SAT	24.4%		V5_SAT	20.5%
V1_WH	45.9%		V5_WH	37.4%
V1_WL	37.9%		V5_WL	33.0%
V2_SAT	27.9%		V6_SAT	26.3%
V2_WH	29.1%		V6_WH	32.5%
V2_WL	28.5%		V6_WL	31.1%
V3_SAT	23.2%		V_OSW3	43.6%
V3_WH	39.7%		V_OSW5	43.5%
V3_WL	34.9%			

Over the modelling term to 2050 for the V2 solar and V3 wind capacity factors (**Figure 47**) indicate the step increases with WRL and VNI-W. The V2 Solar CF declines in the longer term again as the solar capacity in V2 is modelled to rise after 2033. The V3 wind capacity factor remains roughly constant consistent with relatively unchanged wind capacity in the REZ modelled from 2030.

[53] Calculated from the AEMO ISP2022dataset, 30 minute granularity. Note SAT = Single Axis Tracking, ie PV, and WH and WL are Wind-High and Low

Figure 47. Capacity factor modelled for V2 solar and V3 wind over period to 2050

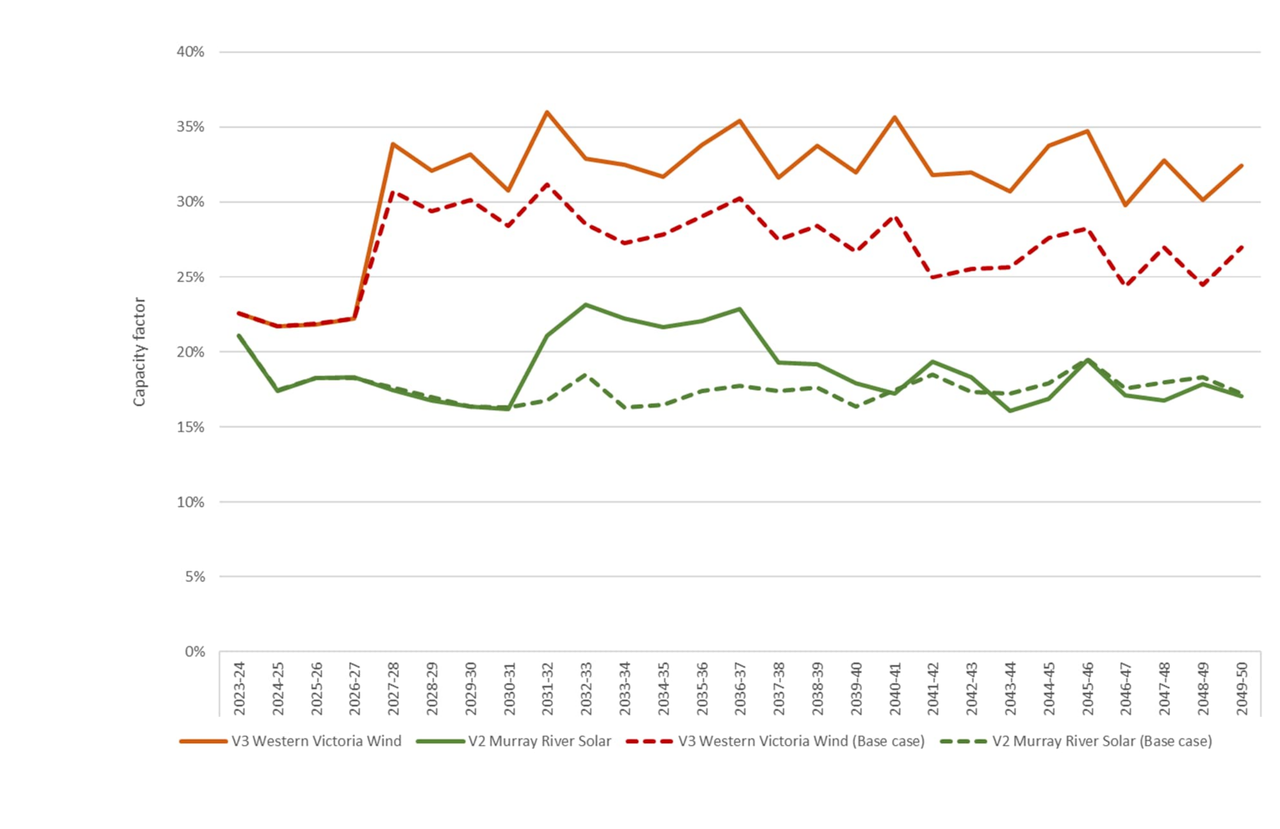


In the Base Case modelling in the PACR the capacity factors in the case of "no VNI-W" can be evaluated. This EY modelling will incorporate constraints produced by the network as well as constraints due to the local load being lower than available generation minus storage minus interconnector capability. The Base Case values are shown in **Figure 48** and compared against the 5A option case in **Figure 49**.

Figure 48. Base case capacity factors modelled for Victorian REZ solar and wind

REZ	REZ Name	Technolog	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
V1	Ovens Mu	Solar (Bas	0%	18%	18%	19%	18%	17%	18%	19%	17%	24%	24%	22%
V2	Murray Ri	Solar (Bas	21%	17%	18%	18%	18%	17%	16%	16%	17%	18%	16%	16%
V3	Western V	Solar (Bas	0%	0%	0%	17%	18%	15%	16%	17%	16%	21%	19%	19%
V4	South We	Solar (Bas	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
V5	Gippsland	Solar (Bas	0%	0%	0%	17%	16%	14%	14%	15%	14%	16%	16%	20%
V6	Central Nc	Solar (Bas	27%	24%	23%	24%	24%	25%	25%	23%	22%	23%	22%	20%
V1	Ovens Mu	Wind (Bas	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
V2	Murray Ri	Wind (Bas	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
V3	Western V	Wind (Bas	23%	22%	22%	22%	31%	29%	30%	28%	31%	29%	27%	28%
V4	South We	Wind (Bas	33%	33%	35%	36%	37%	34%	36%	34%	38%	34%	35%	34%
V5	Gippsland	Wind (Bas	0%	38%	38%	38%	38%	36%	35%	33%	38%	34%	35%	34%
V6	Central Nc	Wind (Bas	0%	27%	25%	29%	29%	29%	28%	30%	31%	31%	30%	27%

Figure 49. Capacity factor modelled for V2 solar and V3 wind – 5A versus Base (dashed)



2.4 Impact on prices (capex, WACC, IDC, opex)

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area A -8	**Impact on prices (capex, WACC, IDC, opex)** Plan B: "Moving onto the impact on prices as a result of its proposals, AEMO says that VNI-West will only raise transmission charges by 25% in Victoria. But AEMO uses 2021 prices, a cost of capital that does not reflect the re-pricing of risk that AEMO is adopting in its forthcoming ISP, ignores interest during construction and understates capital costs and greatly understates operating costs"

Table 13. Market benefits summary in the PACR modelling (NPV, real $2021 $M)[54]

Scenario/sensitivity	Victoria	NEM
Step Change	$3,797	$4,044
Progressive change	$1,725	$1,636
Hydrogen superpower	$4,603	$4,352
Offshore wind	$1,734	$3,129

Table 14. Option 5A capex in model (real $2021, $M)[55]

Capex area	PV		2023	2024	2025	2026	2027	2028	2029	2030	2031	Sum
NSW early works	-37		-23	-20	-4	-3	0	0	0	0	0	-50
NSW 500kV substation works	-191		0	0	0	0	-2	-60	-203	-85	-4	-354
NSW 500kV line works	-430		0	0	0	0	-6	-169	-421	-223	-12	-831
NSW 500kV PEC Enhanced Line Works (Dinawan to Wagga)	-130		0	-163	-18	0	0	0	0	0	0	-182
NSW power flow control and repeater site	-99		0	0	0	0	-1	-31	-105	-44	-2	-183
NSW property/land access/easements	-41		0	0	-39	-33	0	0	0	0	0	-72
NSW biodiversity offset costs	-46		0	0	0	-73	0	0	0	0	0	-73
VIC early works	-44		-28	-24	-5	-4	0	0	0	0	0	-61
VIC 500kV substation works	-204		0	0	0	0	-2	-64	-217	-91	-4	-379
VIC 500kV line works	-400		0	0	0	0	-5	-157	-391	-208	-11	-772
VIC power flow control and repeater site	-88		0	0	0	0	-1	-28	-94	-39	-2	-164
VIC property/land access/easements	-31		0	0	-29	-24	0	0	0	0	0	-53
VIC biodiversity offset costs	-8		0	0	0	-8	-5	0	0	0	0	-12
VIC WRL Option C2 incremental - substation works	-25		0	-6	-21	-9	0	0	0	0	0	-37
VIC WRL Option C2 incremental - lines works	-177		-3	-52	-134	-71	-3	0	0	0	0	-262
VIC WRL Option C2 incremental - power flow control and repeater site	0		0	0	0	0	0	0	0	0	0	0
VIC WRL Option C2 incremental - land/access/easements	-11		-9	-7	0	0	0	0	0	0	0	-16

[54] Net Present Value (NPV) data from EY Results Workbooks for the PACR, 16 May 2023. Option 5A relative to the Base Case

[55] VNI West PACR RIT-T NPV model results

Capex area	PV		2023	2024	2025	2026	2027	2028	2029	2030	2031	Sum
VIC WRL Option C2 incremental - biodiversity offset costs	0		0	0	0	0	0	0	0	0	0	0
Sum	-1,961		-62	-274	-250	-224	-25	-509	-1,430	-691	-35	-3,500

In the Progressive Change scenario the project is deferred after the Early Works stage for completion in 2039. The NPV of the opex is noted as -$255.9M

Table 15. NPV of costs and benefits summary in the PACR modelling (real $2021 $M)[56]

Scenario/sensitivity	NPV
Step Change	1,827
Progressive change	187
Hydrogen superpower	2,025

2.4.1 Discount rate

In the PACR:

> The CBA Guidelines requires the discount rate used in the NPV analysis to be the commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. A central discount rate of 5.50% (real, pre-tax) has been used in the NPV analysis, consistent with the RIT-T requirements and the 2021 IASR

The PACR also notes sensitivities

When selecting inputs for a RIT-T for an Actionable Project the AER now states[57]:

> *Under NER clause 5.16A.2(c)(3), the CBA guidelines must provide guidance as to how the RIT–T proponent must apply the ISP parameters. This is where NER clause 5.10.2 defines ISP parameters as meaning, for an ISP project:*
>
> > • *the inputs, assumptions and scenarios set out in the most recent IASR;*
> >
> > • *the other ISP projects associated with the optimal development path (where ISP projects include actionable ISP projects, future ISP projects and ISP development opportunities); and*
> >
> > • *any weightings specified as relevant to that project.*
>
> *In accordance with the NER[58], the RIT–T instrument specifies that the RIT–T proponent must adopt the most recent ISP parameters, or identify and provide demonstrable reasons for why an addition, omission or variation to the ISP parameters is necessary. Following from the RIT–T instrument, unless*

[56] Net Present Value (NPV) data from EY Results Workbooks for the PACR, 16 May 2023. Option 5A relative to the Base Case

[57] AER, "Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable ", October 2023

[58] NER clause 5.15A.3(7)(iv) directs the RIT–T to specify that the RIT–T proponent must: 'adopt the most recent ISP parameters, or if the RIT–T proponent decides to vary or omit an ISP parameter, or add a new parameter, then the RIT–T proponent must specify the ISP parameter which is new, omitted or has been varied and provide demonstrable reasons why the addition or variation is necessary'

the RIT–T proponent can provide 'demonstrable reasons' for why an addition or variation is necessary, it must apply ISP parameters in its RIT–T application for the actionable ISP project by[59]*:*

> • *Adopting the scenario/s that AEMO has specified as relevant to that RIT–T application, and the* inputs and assumptions from the most recent IASR. For completeness, the IASR will include, as inputs, the discount rate and VCR to apply.
>
> • Adopting the likelihood-based weightings to apply to the scenario/s that AEMO has identified as relevant to that RIT–T application. For clarity, if AEMO determines that one or more scenarios in the IASR should not apply in the RIT–T application, it will effectively assign that scenario/those scenarios a zero per cent weighting for the ISP project and will adjust the relative weightings for the remaining ISP scenario/s accordingly. If AEMO identifies that only one ISP scenario is relevant, it will effectively assign that scenario 100 per cent weight.
>
> • Including other[60] actionable ISP projects across all states of the world.
>
> • Treating non-*actionable ISP projects (that is, future projects and ISP development opportunities) as modelled projects. Further guidance on this is under section […].*

The CBA guidelines require that 'demonstrable reasons' for departing from ISP parameters be limited to where there has been a material change that AEMO would, but is yet to reflect in, a subsequent IASR, ISP or ISP update. For example, this might include a material change in circumstances, such as where the AER has published updated VCR values that AEMO is yet to incorporate in the IASR. Where a material change is not a change in circumstances or facts (for example, a change in the RIT–T proponent's understanding or assessment of the facts, rather than a change in the facts themselves), the RIT–T proponent might choose to attain written confirmation of the change from AEMO.

Moreover, the RIT–T instrument also specifies that if the RIT–T proponent decides to vary the discount rate set out in the ISP parameters, it must still use a commercial discount rate that is appropriate for the analysis of a private enterprise investment in the electricity sector and consistent with the cash flows being discounted[61]*.*

The discount rates identified in the ISP "Forecast Assumptions Update Workbook" of 20 March 2023 are (Table 16):

Table 16. ISP discount rate, pre-tax real

	Central assumption	Lower Bound	Upper Bound	Alternative Upper Bound
Discount rate (%)	5.5%	2.0%	7.5%	10%
WACC, all new generation and transmission (%)	5.5%	2.0%	7.5%	10%

It is noted that interest rates have risen over the past 3 years. The trend in the risk free rate, which underpins the discount rates applied, is shown in Figure 50. The current value (4.37% nom) is

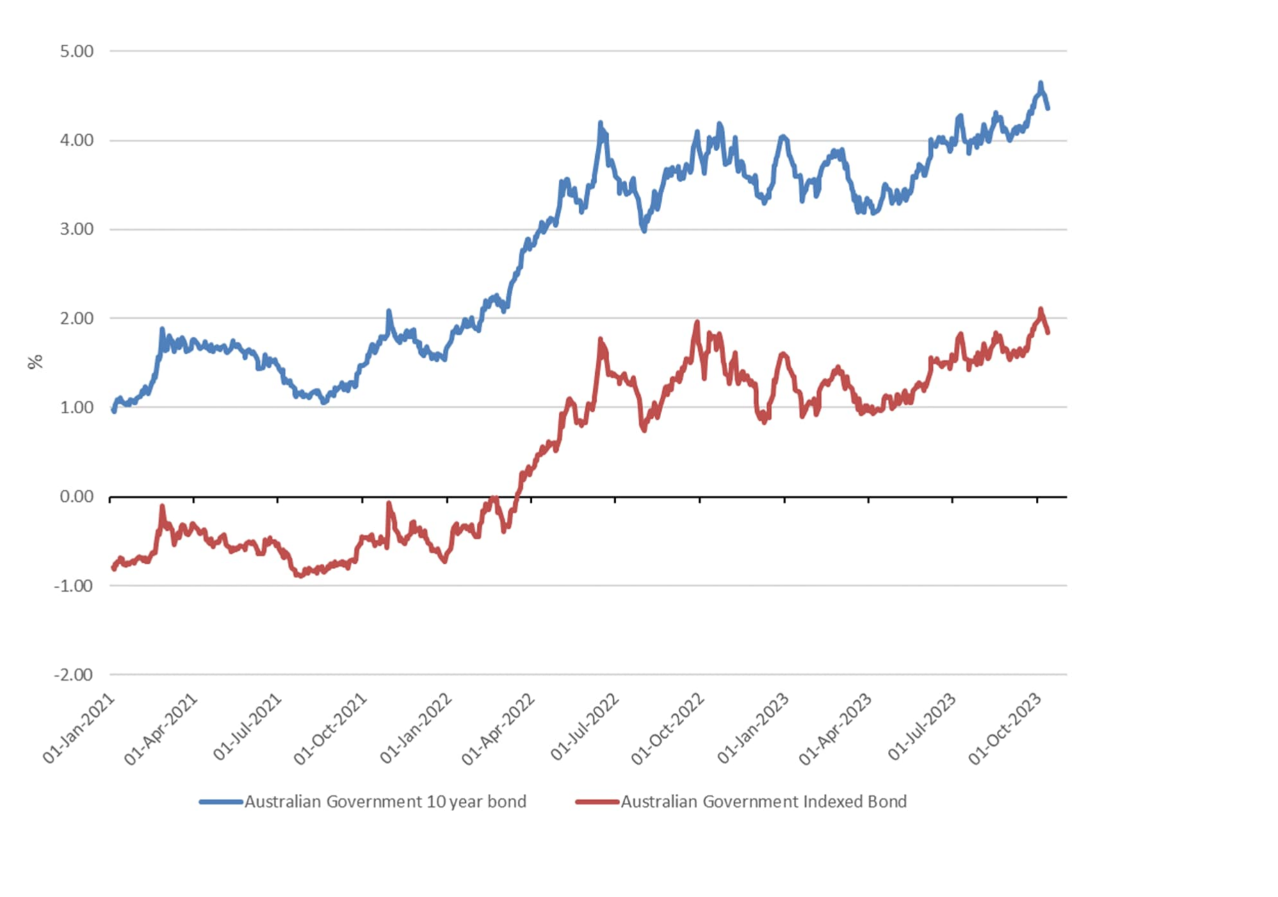
[59] AER, RIT–T, August 2020, paragraphs 7(b), 18, 20(a), 26, 28.

[60] That is, actionable ISP projects other than the project undergoing the RIT–T application, which will not be in the base case

[61] AER, RIT–T, August 2020, paragraphs18–19

approximately 0.77% above the indicative value in AER's latest (24 Feb 2023) "Rate of Return Guideline" value of 3.6%[62]

Figure 50. Indicative changes in the risk free rate[63]



2.4.2 Capex, IDC, opex

An illustrative guide to capex estimate classes is shown in Table 17. The estimate class for a RIT-T assessment would typically be Class 4, with the estimate being improved by further design development and cost estimation through to the construction phase.

[62] file:///C:/Users/rzauner/Documents/Reference%20Material/AER/Rate%20of%20return%20guidelines/2022/AER%20-%20Rate%20of%20Return%20Instrument%20-%20Explanatory%20Statement%20-%2024%20February%202023_1.pdf at page 11

[63] Data is RBA CGS table f02d accessed 12/10/2023 at https://www.rba.gov.au/statistics/tables/#interest-rates

Table 17. Capex estimate classes (loosely following AACi or ANSI)

	Class 5	Class 4	Class 3	Class 2	Class 1
Design completion, propjet specification	Minimal	→	→	→	Design close to complete
Usage	Option screening, concept development Order of magnitude	Study, pre-feasibility assessment Budget estimate	Feasibility assessment prior to investment decision	Bid/tender	Bid/tender Definitive
Methods	Parametric or database costs (eg $/km), judgement/experience	Parametric or database costs (eg $/km), factored estimates (scale factors),	Semi detailed, some budget costs sought for major items	Detailed take-off and formal costing	Detailed take-off and formal costing
Expected accuracy (at 80% confidence) Midrange[64]:	-30% to +50%	-15% to +30%	-15% to +30%	-5% to +15%	-5% to +15%

Capex – refer also Section 3.4

IDC, opex - inhouse

2.5 Geographic diversity

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area A -9	**Geographic diversity** Plan B: "Furthermore, AEMO's work suggests that the temporal diversity of variable renewable generation is no bigger between neighbouring regions of the NEM than it is within regions, contrary to what has long been suggested to be the case. A failure to respond to this new information has resulted in transmission plans that have become superseded by events and new knowledge.."

One of the claimed benefits of VNI West is that it allows (least cost) exploitation of renewable energy resources across regions. Due to seasonal and diurnal variations in output of (especially) wind and solar

[64] A higher range may apply, particularly if there are weak project systems, increased likelihood of scope creep, or if the nature of the project makes it inherently difficult to recognise all factors. Values in the table are not identical to AACi or a particular standard (indicative by Jacobs)

across regions, excess or spare renewable generation in one region can be exported to other regions instead of being spilled. This reduces the need for plant build, improves the capital productivity of the renewable fleet and perhaps reduce the need for fossil fuel generation.

It may also reduce prices at least in the importing region. The potential diversity benefits are claimed in the ISP2022[65] and RIT-T[66] documents.

Plan B, however, suggests the benefits are minimal.

Jacobs has undertaken some analysis and review of the claims using two approaches. First, examining the potential for diversity based on historical generation profiles, and second by examining the results of the analysis or findings of AEMO and Plan B.

Historical analysis

Correlation coefficients at an aggregate level.

The benefits of interconnection can include the sharing of peak reserve capacity (thus requiring less firm generation capacity across the whole system) and sharing of excess renewable capacity across the whole of the NEM, reducing the need for spill.

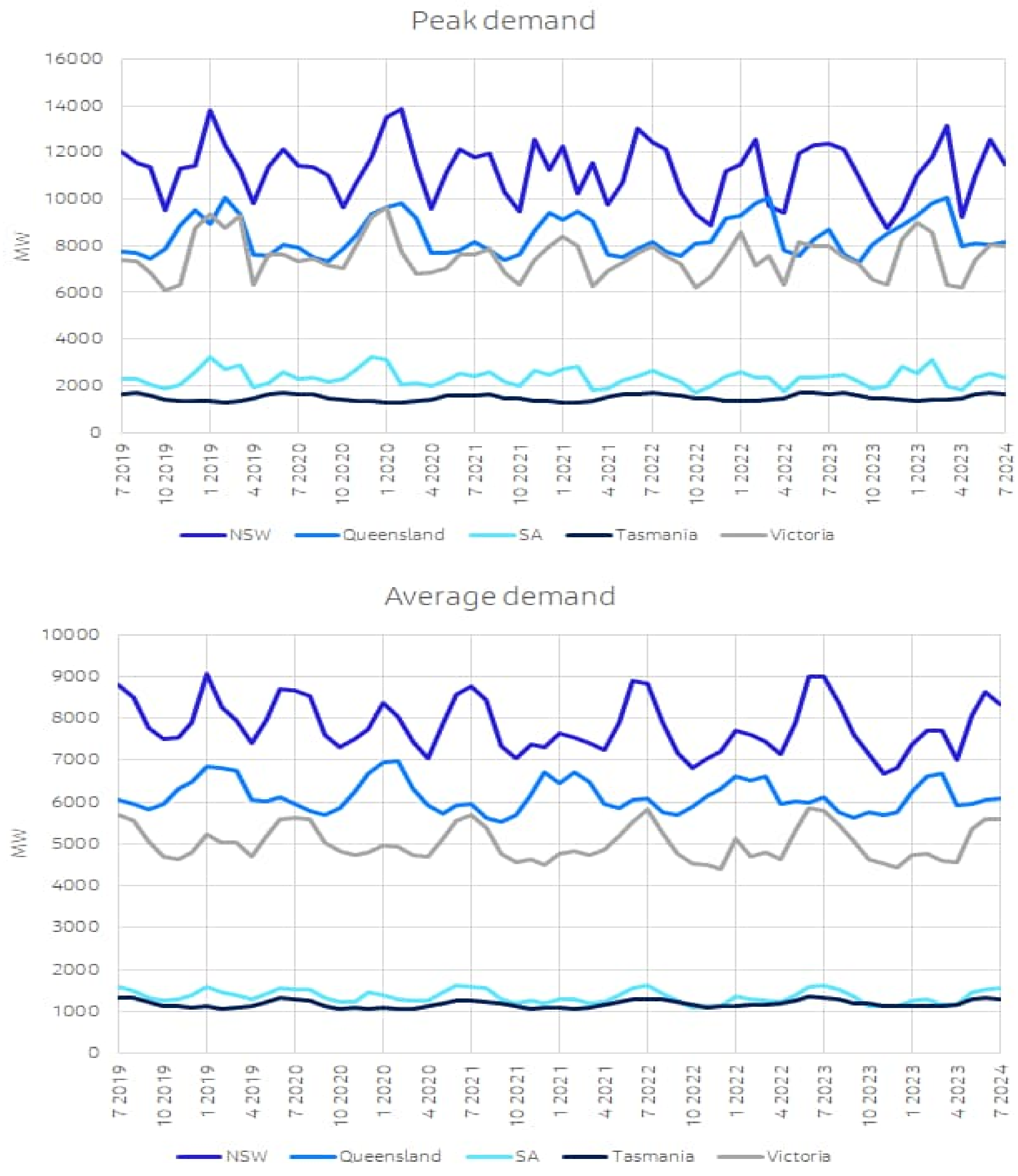
Jacobs undertook analysis of historical half-hourly generation and demand data to see if this purported benefit has any support from historical data. This was done by matching generation and demand across NEM regions to see if there is an opportunity for sharing through natural differences across the regions. A further discussion on demand differences between the regions is also included above in Section 2.2.

For demand Jacobs examined patterns in average demand as well as peak demand across the regions.

[65] ISP2022. For example pages 15 to 17, 25, 40 to 42, 48, 52 to 53, 73 and 79

[66] VNIW PACR for example at pages 66, 70, 120, 128 and 131

Figure 51: Monthly peak and average demand patterns



From historical data from 2019. Observed patterns:

- From a demand point of view, monthly average demand patterns are similar across NSW and Victoria, with a pronounced higher demand during winter months in both States, and lower demand patterns in the spring and autumn months. However, the summer months demand is more affected by type of year in NSW than in Victoria (so during hotter than normal summer it is more pronounced increase in demand – equivalent to winter averages – in NSW).

- Wind generation in Victoria, has pronounced seasonal pattern with higher proportion of wind generation occurring in the late winter and spring months and lower proportions in the later summer autumn and early winter months. Wind generation tends to be more even across the year in NSW.

However, these trends are not consistent across every year. For example, wind generation levels have been high in May and June, across the last two years.

- Although not perfect as dependent on the shares of wind and solar in each State, the monthly generation patterns for total variable renewable generation still show variation in generation patterns across the States, especially in the key early winter and mid to late summer months.

For wind and RE.

Figure 52: Monthly generation patterns - wind

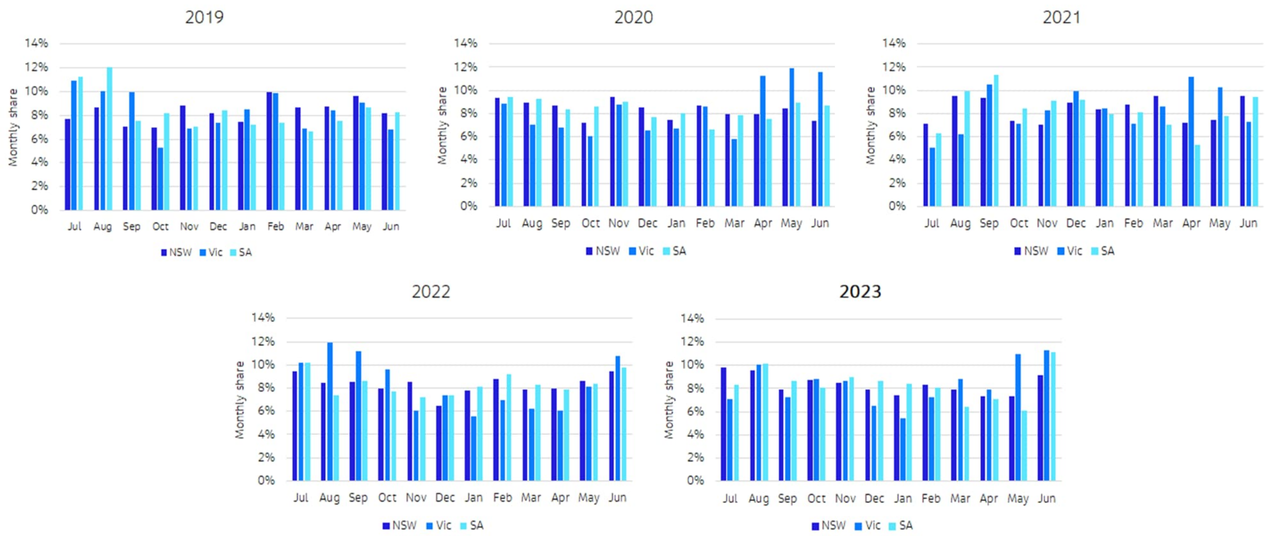
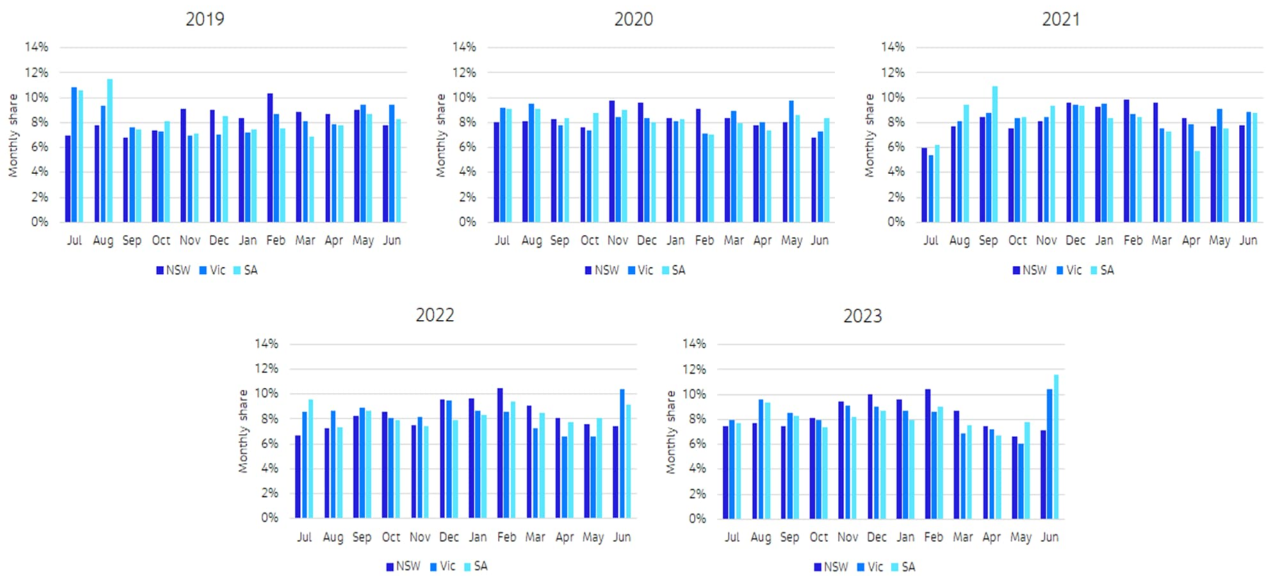


Figure 53: Monthly generation patterns – total variable renewable energy



Level of curtailment historically happens because of both network and market curtailment. Below shows the level of curtailment. From NEOExpress half hourly data.

Another tranche of evidence relates to constraints on flows from Victoria and NSW. Recently, there have been times when prices are positive in NSW but negative in Victoria, and northward flow of available renewable energy generation is constrained. **Table 18** indicates the level of available renewable generation constrained off in Victoria in half hour periods where prices averaged negative in Victoria and positive in NSW, showing an increasing trend for curtailment during these trading intervals.

Whilst not definitive, this analysis does point to a potential benefit from enhanced interconnection, particularly in years where climatic conditions impact on demand levels in each region and lead to variations in wind generation in particular.

Table 18: Curtailed energy in Victoria when prices are negative in Victoria and positive in NSW

FY	2019	2020	2021	2022	2023
Curtailed energy, MWh					
Jul	0	710	0	23,363	23,332
Aug	537	2,132	5,717	24,088	34,885
Sep	502	680	10,223	46,096	17,919
Oct	0	1,260	19,596	55,062	51,905
Nov	0	669	6,760	38,127	72,636
Dec	86	1,028	34,135	77,884	78,754
Jan	0	4,748	25,491	25,100	95,060
Feb	784	164	16,658	26,765	98,046
Mar	0	234	3,859	38,443	80,424
Apr	7	2,655	11,619	17,078	14,835
May	1	2,337	11,230	6,207	14,625
Jun	64	70	6,321	7,106	46,560
% of available energy					
Jul	0%	8%	0%	13%	17%
Aug	9%	16%	27%	13%	14%
Sep	6%	22%	17%	15%	14%
Oct	0%	16%	21%	17%	22%
Nov	0%	18%	14%	22%	23%
Dec	2%	6%	19%	28%	25%
Jan	0%	20%	15%	18%	29%
Feb	16%	7%	15%	20%	30%
Mar	0%	5%	11%	21%	24%
Apr	1%	8%	14%	18%	11%
May	0%	9%	16%	12%	11%
Jun	2%	2%	11%	11%	12%

Indications of the degree of correlation in renewable energy generation levels across NEM regions are shown in the following charts. Each chart is a scatter plot of normalised generation in each half hour interval across a month. Renewable energy generation in a region is normalised to the peak capacity for renewable energy in the month. Each point represents the renewable generation as a total proportion of peak renewable generation capacity in each region for a half hour interval. Generation that is strongly positive correlation across two regions would coalesce along the upward sloping diagonal (from point (0,0) to point (1,0)). Generation that is strongly negatively correlated would coalesce around the negative slope diagonal (from point (0,1) to (1,0)).

The charts indicate a degree of positive correlation across NEM regions although the correlation is less strong the further apart the regions. However, even across adjoining regions there appears to be substantial periods of variation so that the correlations are not strong.

Figure 54: Scatter plot of normalised half-hourly generation levels for total variable renewable energy across States, June 2023

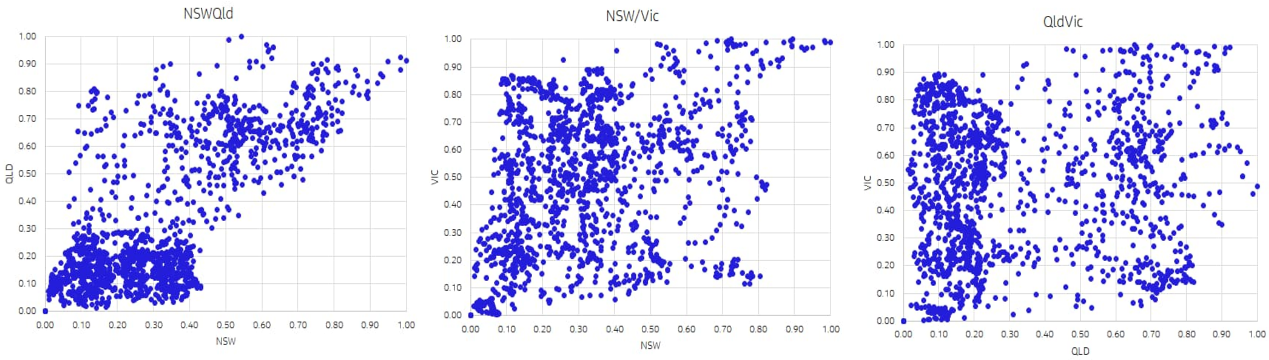


Figure 55: Scatter plot of normalised half-hourly generation levels for total variable renewable energy across States, September 2022

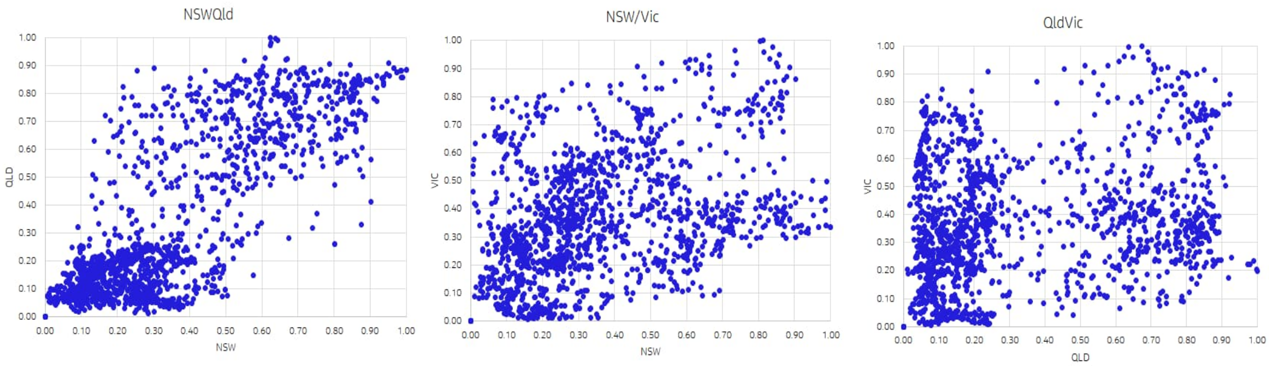


Figure 56: Scatter plot of normalised half-hourly generation levels for total variable renewable energy across States, February 2023

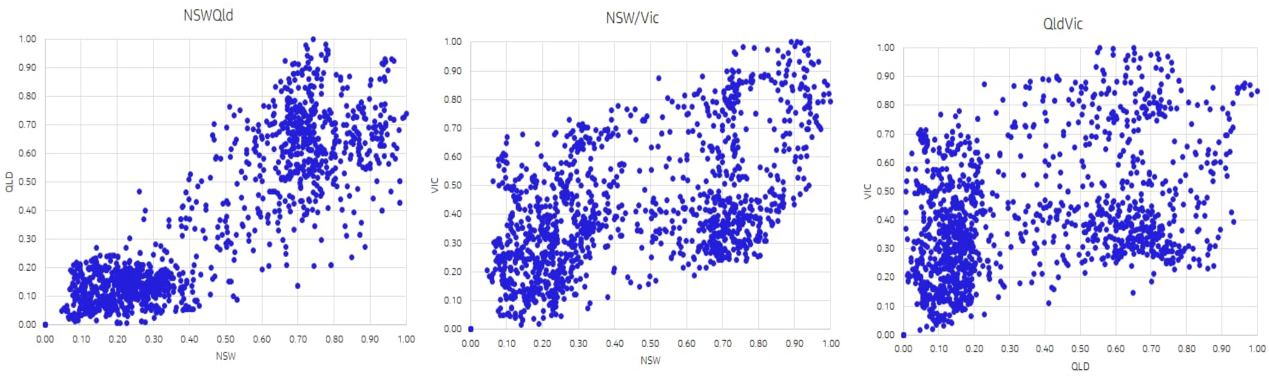
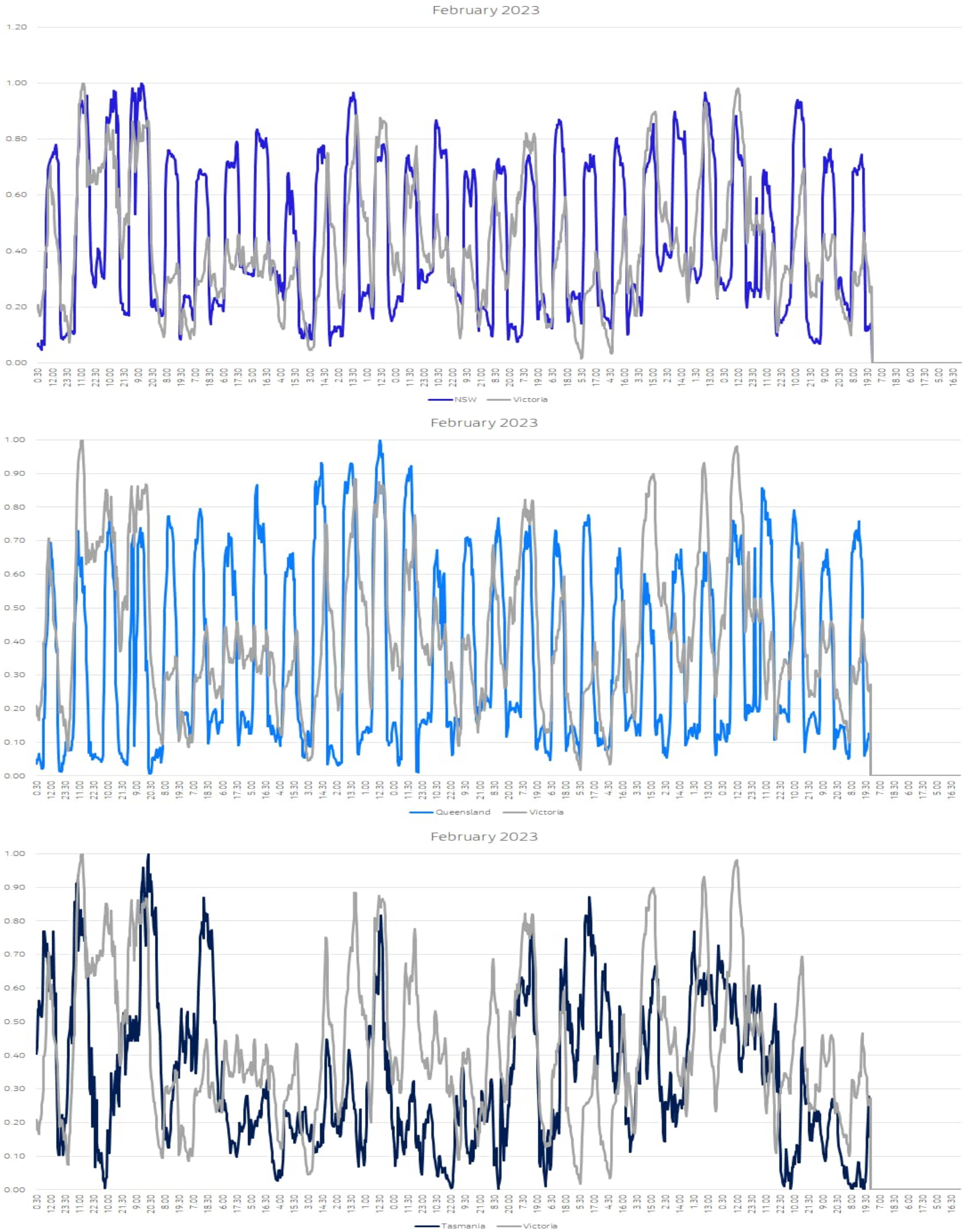


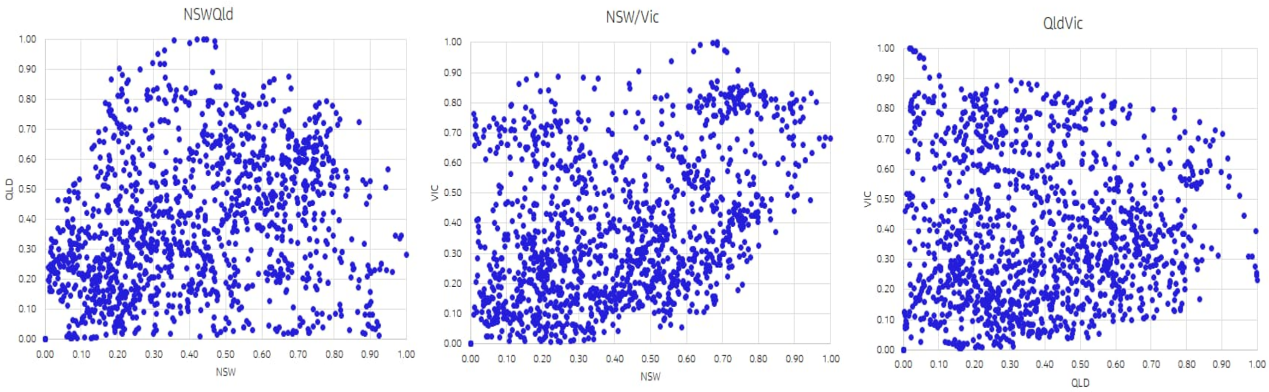
Figure 57: Normalised generation levels for renewable energy, February 2023



Note that indications of a strong correlation does not mean that interconnectors are not useful. If both regions have high renewable generation levels in an half hour period, then flows still occur if in one region the generation is in excess to need and in the other region it is not.

Note also that the correlations in renewable energy generation tend to be strongest in the middle of the day and less strong (if not negative) at other times. This is because of the strong correlations in solar PV generation across regions. Wind generation tends to be less strongly correlated across regions (as the following chart shows for one month), and typically there is tendency in the southern States at least for wind generation to be greatest in the evening and early morning periods.

Figure 58: Scatter plot of normalised half-hourly wind generation levels across States, February 2023



Another perspective can be obtained by looking at daily correlations across select months, as shown in the Tables below. When averaged over the month, the correlation coefficients tend to be higher than when looking at daily correlations (except for NSW/Qld where there is a high level of utility scale solar PV generation). The analysis indicates lower level of correlations when averaged across each day of the month. My interpretation of the data is that there is a level of correlation but there is also a level of lagged correlation reflecting the move of wind fronts from west to east and north to south in some months.

Comment on the negative correlations between SA and NSW and Tas and NSW. VNI west acts as a conduit of flows into NSW from these regions.

Table 19: Correlation coefficients – July 2022

Day	NSW/Qld	NSW/SA	NSW/Tas	NSW/Vic	Qld/Vic	SA/Vic	Tas/Vic
1	0.53	0.20	-0.74	0.50	0.83	0.54	0.09
2	0.91	0.76	-0.68	0.78	0.70	0.90	-0.78
3	0.94	0.26	-0.59	0.95	0.86	0.38	-0.58
4	0.38	0.29	-0.05	0.95	0.27	0.24	-0.25
5	0.89	0.01	-0.62	0.63	0.30	0.71	-0.31
6	0.66	0.65	-0.37	0.77	0.84	0.60	0.04
7	0.91	0.65	0.43	0.73	0.57	0.90	0.78
8	0.86	0.60	0.51	0.41	0.55	0.53	0.78
9	0.80	0.78	0.24	0.81	0.53	0.79	-0.02
10	0.96	0.45	-0.20	0.29	0.30	0.89	0.76
11	0.94	0.45	0.44	0.63	0.43	0.96	0.73
12	0.95	-0.05	-0.64	0.26	0.28	-0.14	0.07
13	0.93	-0.16	-0.73	0.77	0.80	-0.24	-0.86
14	0.96	0.14	-0.35	0.85	0.74	0.17	-0.38
15	0.95	0.21	0.61	0.33	0.22	0.93	0.16
16	0.83	0.53	0.74	0.83	0.84	0.70	0.61
17	0.96	0.42	-0.42	0.53	0.51	0.63	0.11
18	0.78	0.14	0.34	0.57	0.06	0.75	0.86
19	0.94	0.32	-0.28	0.89	0.86	0.26	-0.25
20	0.91	0.03	-0.39	0.12	-0.07	0.76	-0.46
21	0.96	0.00	-0.19	0.74	0.75	0.37	0.20
22	0.90	0.25	-0.10	0.79	0.58	0.53	-0.13
23	0.84	0.64	0.18	0.91	0.70	0.78	0.30
24	0.90	0.67	-0.70	0.16	-0.15	0.31	0.13
25	0.86	0.58	0.48	-0.16	0.11	-0.55	-0.78
26	0.76	-0.36	-0.18	0.67	0.78	0.38	-0.52
27	0.86	0.87	-0.72	0.44	0.20	0.48	-0.21
28	0.95	0.53	-0.89	0.69	0.56	0.49	-0.51
29	0.98	-0.14	-0.21	0.84	0.79	-0.15	0.18
30	0.97	-0.03	-0.11	0.74	0.65	-0.12	0.47
31	0.88	-0.24	-0.10	0.52	0.24	-0.64	0.41

Table 20: Correlation coefficients – October 2022

Day	NSW/Qld	NSW/SA	NSW/Tas	NSW/Vic	Qld/Vic	SA/Vic	Tas/Vic
1	0.96	-0.20	-0.50	0.04	-0.05	0.28	0.26
2	0.98	-0.44	0.46	0.84	0.82	-0.58	0.44
3	0.97	-0.15	0.18	0.91	0.88	-0.15	0.22
4	0.76	0.54	0.35	0.57	0.06	0.62	0.63
5	0.80	-0.57	0.29	0.52	0.11	-0.71	0.77
6	0.59	0.25	0.01	0.84	0.47	0.07	0.03
7	0.82	0.62	-0.20	0.36	0.21	0.82	0.21
8	0.87	0.22	0.16	0.57	0.78	0.58	0.18
9	0.89	0.33	-0.48	0.94	0.80	0.18	-0.22
10	0.98	0.46	0.66	0.80	0.76	0.55	0.24
11	0.97	0.33	0.03	0.65	0.59	0.05	0.54
12	0.70	-0.03	-0.05	-0.05	-0.20	0.81	-0.77
13	0.82	-0.09	-0.76	-0.10	-0.26	0.39	0.19
14	0.90	0.21	-0.50	0.89	0.87	0.59	-0.17
15	0.99	0.71	0.36	0.82	0.81	0.45	0.76
16	0.97	-0.26	0.15	0.91	0.84	-0.11	0.42
17	0.93	-0.03	-0.05	0.65	0.50	-0.14	-0.58
18	0.81	0.76	0.00	0.21	-0.05	0.14	-0.27
19	0.82	-0.02	0.04	0.90	0.60	-0.31	-0.05
20	0.83	-0.10	0.84	-0.05	0.21	0.31	-0.29
21	0.90	0.38	0.53	0.33	0.18	-0.20	-0.30
22	0.89	-0.45	-0.61	0.32	0.50	0.26	-0.16
23	0.89	-0.60	-0.27	0.37	0.00	0.12	0.55
24	0.91	-0.02	0.32	0.63	0.48	0.33	0.86
25	0.93	0.24	-0.26	0.75	0.66	0.47	-0.49
26	0.87	0.38	0.30	0.22	-0.25	0.96	-0.76
27	0.88	0.81	0.28	0.66	0.33	0.24	0.71
28	0.99	0.64	-0.52	0.70	0.69	0.87	-0.43
29	0.99	0.56	-0.09	0.86	0.82	0.58	0.17
30	0.94	0.56	-0.66	0.18	0.21	0.70	0.04
31	0.89	-0.10	0.15	0.10	0.34	-0.63	0.79

Table 21: Correlation coefficients – January 2023

Day	NSW/Qld	NSW/SA	NSW/Tas	NSW/Vic	Qld/Vic	SA/Vic	Tas/Vic
1	0.95	-0.80	0.43	0.86	0.83	-0.74	0.28
2	0.92	0.10	-0.52	0.34	0.16	0.05	-0.25
3	0.91	0.64	0.57	0.67	0.34	0.94	0.90
4	0.86	0.30	0.43	0.95	0.77	0.44	0.36
5	0.91	-0.42	-0.13	0.43	0.15	0.48	0.54
6	0.95	-0.73	0.16	0.88	0.80	-0.68	0.41
7	0.95	-0.13	-0.21	0.29	0.21	0.48	-0.26
8	0.96	-0.47	-0.55	0.51	0.42	-0.31	0.00
9	0.91	0.15	-0.18	0.81	0.54	0.63	0.37
10	0.88	-0.32	0.02	0.73	0.41	0.17	0.17
11	0.87	0.40	0.14	0.67	0.51	0.86	0.68
12	0.91	0.05	0.39	0.48	0.29	0.79	0.88
13	0.94	-0.43	0.57	0.59	0.39	-0.50	0.72
14	0.96	0.11	0.60	0.37	0.36	0.24	0.69
15	0.84	0.74	0.66	0.88	0.77	0.83	0.46
16	0.89	-0.51	0.37	-0.33	-0.23	0.46	-0.39
17	0.97	0.61	0.25	0.72	0.69	0.62	0.50
18	0.97	0.18	0.31	0.33	0.43	0.91	0.85
19	0.82	-0.31	-0.52	0.93	0.84	-0.21	-0.36
20	0.93	-0.80	0.22	0.15	-0.04	0.30	-0.21
21	0.86	-0.46	-0.51	-0.28	-0.22	0.95	0.68
22	0.87	-0.63	0.61	0.49	0.44	-0.60	0.43
23	0.98	-0.30	0.52	0.57	0.53	-0.52	0.53
24	0.91	-0.37	0.50	0.80	0.66	-0.25	0.58
25	0.97	0.13	0.15	0.73	0.65	0.52	0.64
26	0.94	0.00	-0.43	0.67	0.61	-0.07	-0.43
27	0.92	-0.31	0.22	0.43	0.27	0.11	-0.38
28	0.95	-0.28	0.49	0.32	0.10	0.64	0.76
29	0.77	0.06	-0.36	-0.48	-0.44	0.00	-0.10
30	0.78	0.22	0.00	0.49	0.20	0.80	-0.50
31	0.91	0.07	-0.21	0.82	0.67	0.37	0.16

Table 22: Correlation coefficients – April 2023

Day	NSW/Qld	NSW/SA	NSW/Tas	NSW/Vic	Qld/Vic	SA/Vic	Tas/Vic
1	0.93	0.18	-0.23	0.92	0.93	0.09	-0.22
2	0.96	-0.10	0.36	0.71	0.58	-0.08	0.07
3	0.98	0.02	0.00	0.89	0.89	0.01	0.11
4	0.93	-0.35	-0.29	0.26	0.44	-0.33	-0.40
5	0.97	-0.15	0.32	0.84	0.72	-0.51	0.65
6	0.92	0.20	0.21	0.34	0.24	0.73	0.86
7	0.92	0.80	-0.60	0.26	0.01	0.42	-0.15
8	0.96	0.64	0.53	0.86	0.77	0.76	0.67
9	0.98	-0.04	0.12	0.81	0.72	0.37	0.49
10	0.98	0.11	-0.29	0.93	0.91	-0.22	-0.02
11	0.96	-0.19	0.22	-0.14	-0.15	0.70	0.52
12	0.94	0.61	-0.42	-0.19	-0.01	0.31	0.77
13	0.95	-0.17	0.34	0.64	0.55	-0.19	0.12
14	0.98	-0.03	-0.38	0.10	0.14	0.92	0.81
15	0.94	-0.79	0.26	0.35	0.22	-0.05	0.77
16	0.76	0.44	-0.37	0.93	0.77	0.14	-0.10
17	0.97	0.88	0.29	0.77	0.79	0.80	0.63
18	0.97	0.34	0.51	0.90	0.94	0.21	0.69
19	0.97	0.72	0.81	0.96	0.89	0.74	0.88
20	0.98	-0.05	0.08	0.89	0.87	-0.35	-0.21
21	0.99	-0.30	0.07	0.93	0.92	-0.40	0.12
22	0.98	-0.37	-0.27	0.89	0.86	-0.59	0.04
23	0.95	-0.17	-0.63	0.90	0.74	-0.26	-0.73
24	0.98	0.20	-0.28	0.79	0.80	0.22	-0.01
25	0.97	-0.04	-0.33	0.15	0.04	0.77	0.71
26	0.95	0.72	-0.22	0.42	0.27	0.29	0.69
27	0.91	-0.11	0.35	0.73	0.43	-0.23	0.12
28	0.96	0.23	0.56	0.54	0.48	0.81	0.37
29	0.82	0.91	0.08	0.85	0.65	0.77	-0.12
30	0.97	0.98	-0.32	0.99	0.95	0.97	-0.27

On the winter day discussed in Section 2.2 above, the outputs of selected wind farms in each region are shown in Figure 59. The outputs of both the Tasmanian and South Australian plants fell to low levels during the middle of the day. The Queensland plant had the most consistent output across that particular day. The outputs of the NSW and Victorian plants was similar.

On the same day, considering plants in Victoria, **Figure 60** shows that all three plants were similar across the morning while Mt Gellibrand (V4) output fell off in the afternoon. Bald Hills is in the east (not in a REZ) and Ararat is in V3.

Figure 59. Selected wind farm outputs, 1 July 2023 – 5 minute data

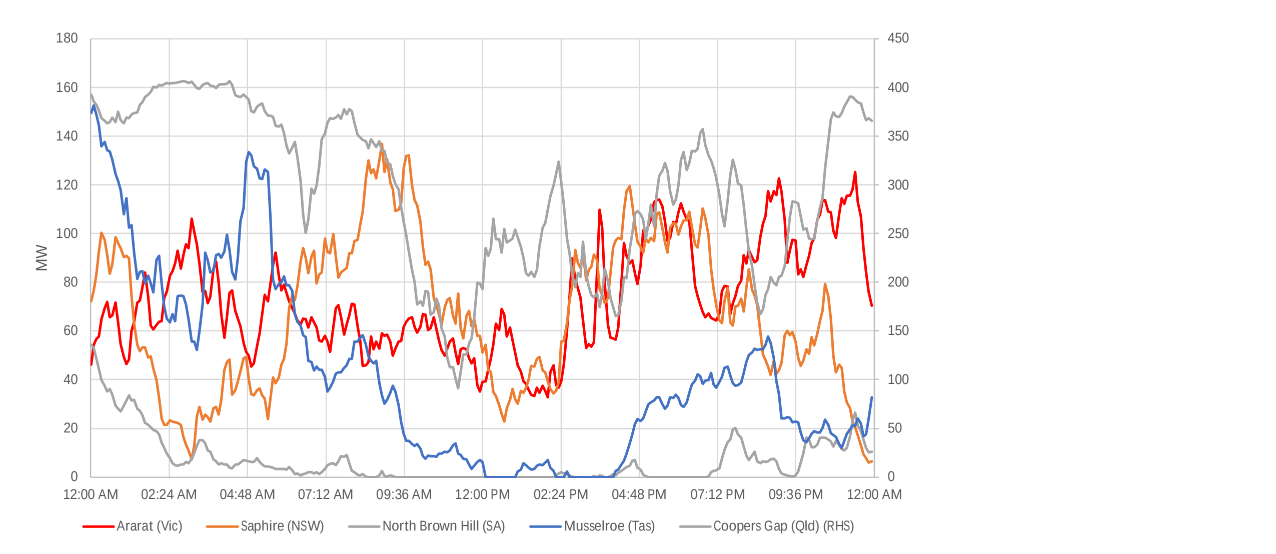
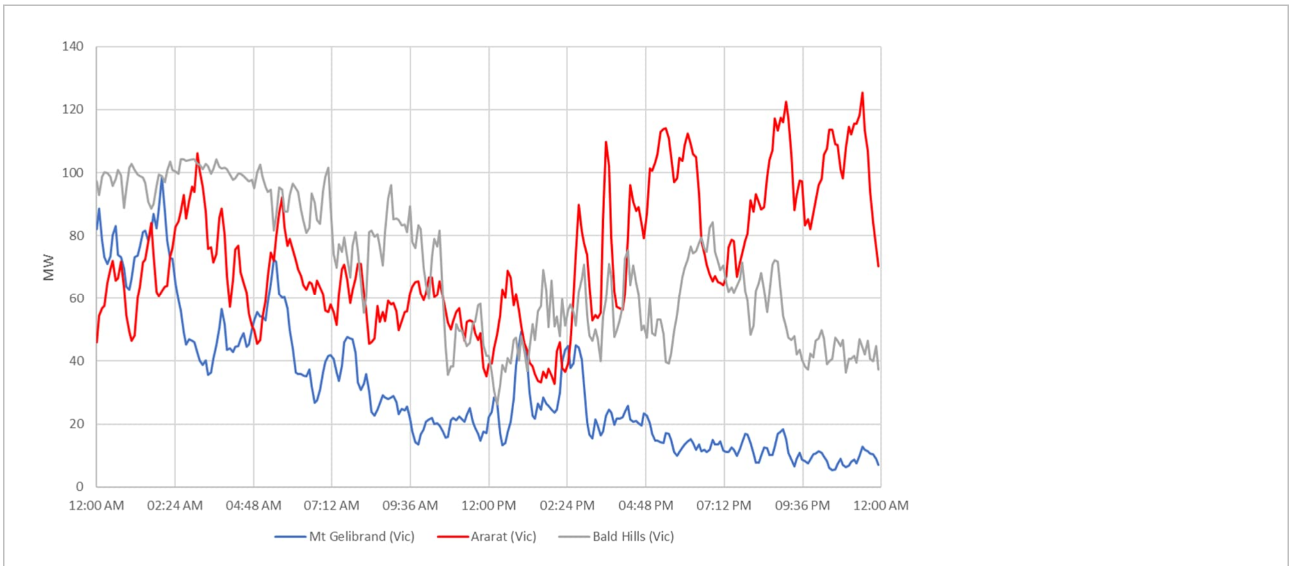


Figure 60. Selected Victorian wind farm outputs, 1 July 2023 – 5 minute data



2.6 VNI West needs to be evaluated as VNI West Extended

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area A -10	**VNI West needs to be evaluated as VNI West Extended** Plan B: "To fairly compare Plan B to AEMO's plan, we could not limit the analysis to VNI-West and the 1,500 MW augmentation that AEMO anticipates in South Western Victoria. Rather we had to include two major projects to augment the 220 kV networks in the Western Victorian and Murray River REZs without which VNI-West will not be able to offer any increase in hosting capacity in Victoria. We also included a necessary augmentation in Gippsland and between Shepparton and Dederang without which AEMO's renewable hosting capacity increases are obviously impossible to achieve. Together this constitutes what we call AEMO's "Extended VNI-West" project, which can be compared with Plan B. "

The materials for this evaluation area are within the other materials noted.

3. Area B - The Plan B strategy outlined in the report

3.1 Hosting capacity

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area B -1	**Hosting capacity** Plan B: "Plan B offers a total variable renewable hosting capacity of 16.8 GW in order to ensure curtailment below 13% in all REZs and to provide greater flexibility and equity between REZs. By comparison, Extended VNI-West offers total hosting capacity of 14.8 GW and average curtailment across all Victoria's REZs of 20% from 2032 (when VNI-West is assumed to be commissioned) to 2050. Plan B has more hosting capacity in the Murray River, Western Victoria, Central North and Gippsland REZs. It will offer comparable hosting capacity to Extended VNI-West in the Ovens Murray and South West REZs"

3.1.1 Hosting capacity in Victoria overall

The Plan B's table which calculates the required RE is shown in **Figure 61**. The AEMO published operational load calculation is shown in **Figure 62**, noting that in the operational load AEMO calculates BESS and PHES pumping losses separately[67].

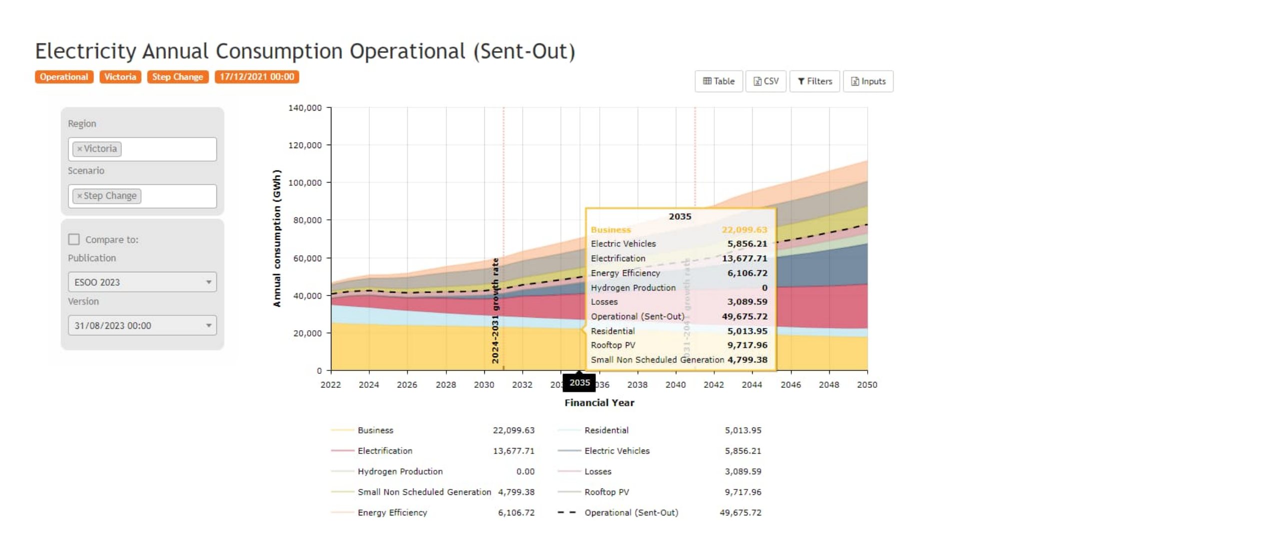
Figure 61. Plan B: "Required renewable electricity meet the VRET target targets in 2023, 2025, 2030 and 2035 (GWh)"[68]

Categories	2023/24	2024/25	2029/30	2034/35
Business	24,729	24,578	23,286	22,100
Residential	9,392	8,903	6,019	5,014
Electrification	5,500	6,563	8,686	13,678
Electric Vehicle charging	41	78	1,983	5,856
Hydrogen production (by AEMO)	nil	nil	nil	nil
Transmission losses	738	738	774	920
Distribution losses	1,638	1,650	1,752	2,170
Losses in grid connected energy storage	31	29	30	129
Losses in VPP's energy storage	7	17	125	213
Losses in distributed batteries	27	45	102	269
Total electricity consumption	42,103	42,601	42,625	50,439
Renewables target	37%[1]	40%	65%	95%
Required renewable energy	15,578	17,040	27,706	47,832

[67] The Draft2024 ISP demand forecasts are now available. Refer to **Figure 74** below.

[68] Table 1, Page 26

Figure 62. ISP2022 load forecast for Victoria, Step Change[69]



In the RIT-T modelling, the amounts of Victorian renewable generation in 2034/35 for the Step Change scenario are shown in Table 25. The values used in Plan B report's calculation of the shortfall are given in **Figure 63**.

Table 23: PACR modelling of VNIW Option 5A in 2034/35, Step Change[70]

	GWh	MW
Hydro	3,405	2,264
Wind	29,132	9,881
Solar PV	5,038	2,660
Distributed PV	12,988	10,956
Sum	50,563	25,761

[69] At https://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational

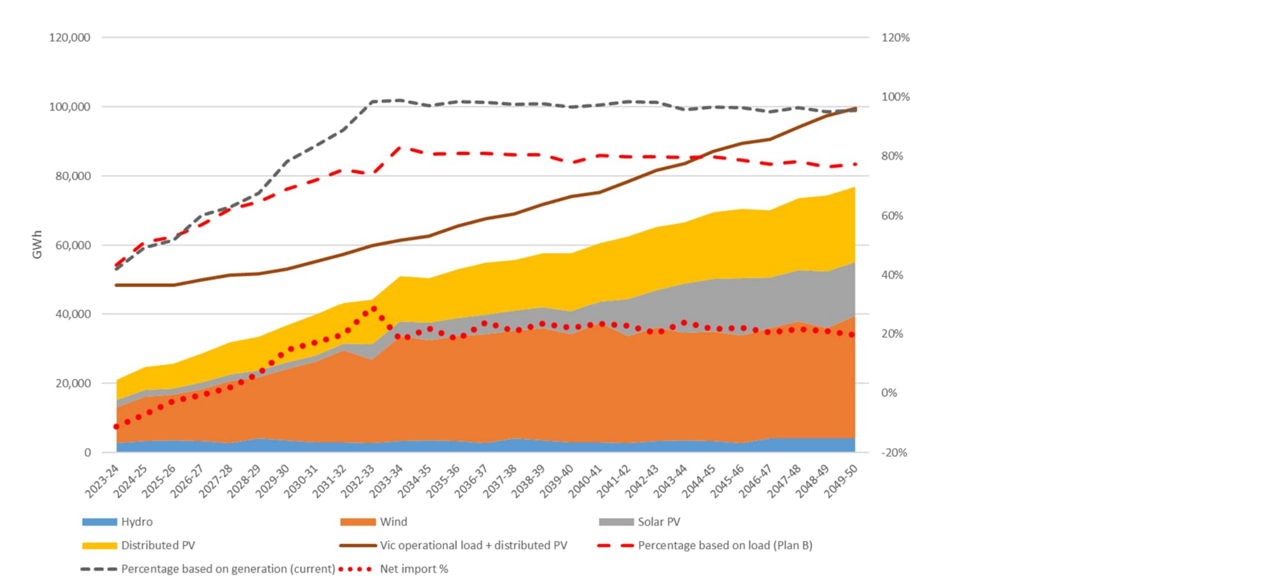
[70] EY results workbook - VNI West Step Change

Figure 63. Plan B: "Large scale renewable energy generation shortfall (GWh)"[71]

Row	Source	2023/24	2024/25	2029/30	2034/35
1	Hydro	2,748	3,336	3,418	3,405
2	Wind (after curtailment)	10,177	12,813	20,737	29,132
3	Large-scale PV (after curtailment)	2,205	1,888	1,850	5,154
4	Rooftop PV (after curtailment)	3,872	4,128	5,100	5,460
5	Total Victorian renewables (after curtailment)	19,002	22,165	31,105	42,691
6	VRET target	37%	40%	65%	95%
7	Required renewable generation	15,578	17,040	27,706	47,832
8	Total electricity consumed in Victoria (see Table 1)	42,103	42,601	42,625	50,439
9	Shortfall in renewable generation compliance (GWh) (negative is shortfall)	0	0	0	5,141
10	Shortfall in renewable capacity (MW)	0	0	0	2,130

The forecast load for Victoria (Step Change scenario) can be compared with the PACR modelling Victorian renewable generation for VNIW (Option 5A). This is shown in **Figure 64**. The net import into Victoria as a percentage of the load is shown (dotted). The calculated VRET percentages under the legislation (% of generation) and under the Plan B report's proposed alternative formulation (%load) are shown (dashed).

Figure 64. Victorian renewable energy generation with VNIW[72]



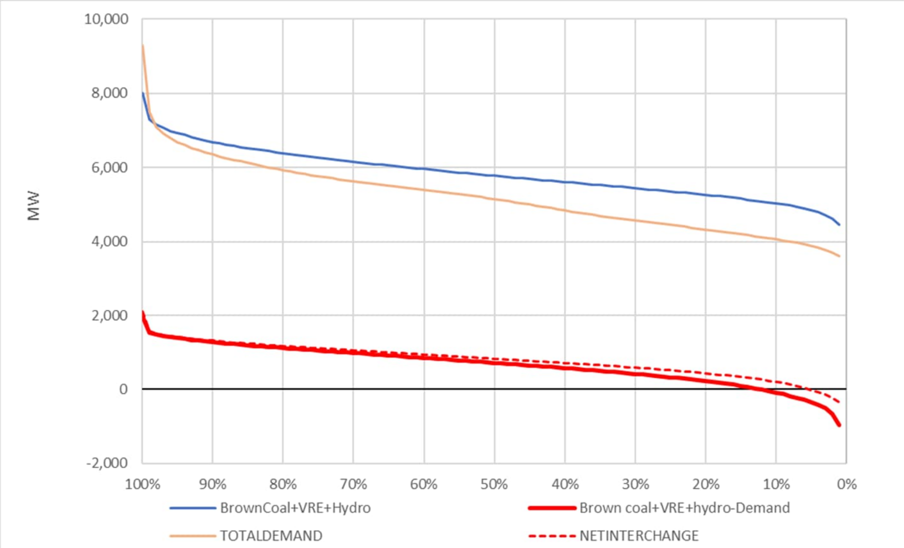
[71] Table 2, Page 27

[72] Generation data is from "EY results workbook - VNI West Step Change" option 5A Generation. Load is from AEMO NATIONAL ELECTRICITY FORECASTING (aemo.com.au), Step change, Victoria, ISP2022

The quantity [Victorian generation] – [Victoria load] can be estimated on a granular timeframe. The quantity is of interest/relevance as positive values must be managed by interconnector (out)flows, storage and curtailment, and negative values must be managed by interconnector (in)flows, generation from storage, peaking (gas) generation and load shedding/demand side response.

To illustrate the impacts of the energy transition, Jacobs has extracted the Victorian data from the financial year preceding the closure of Hazelwood Power Station in early 2017. Refer to Figure 65.

Figure 65. Generation/load/Flow duration curves for Victoria, FY ending Jun 2016[73]



The red line shows Brown coal + VRE + hydro – demand on a five minute basis. The net interchange (ie imports/exports) is shown dashed for comparison. In this period, as applies today, Victoria had three interconnectors of order 500MW each with other regions. Gas fired generation in Victoria only provided 2% of energy in that year[74].

An indication of the balance in 2035 assuming all brown coal has closed at that time (as will be necessary to meet the 2035 VRET target) can be made using the ISP Victorian load trace (with rooftop PV deducted) that is shown in **Figure 66**. The generation side is modelled using the existing+construction+committed VRE in Victoria (Section 1.2), plus FY23 Victorian hydro outputs plus the Plan B additional hosting capacity (with VRE outputs simulated using the AEMO REZ zone 30-minuite representative traces). The corresponding generation/load balance is shown in Figure 67.

[73] Data is from AEMO "Public Daily" datafiles, Public dispatch interval data for regions - energy quantities, 5 minute granularity

[74] 1135GWh from the same dataset.

Figure 66. Representative Victorian load net of distributed PV, 30-minute granularity, FY35[75]

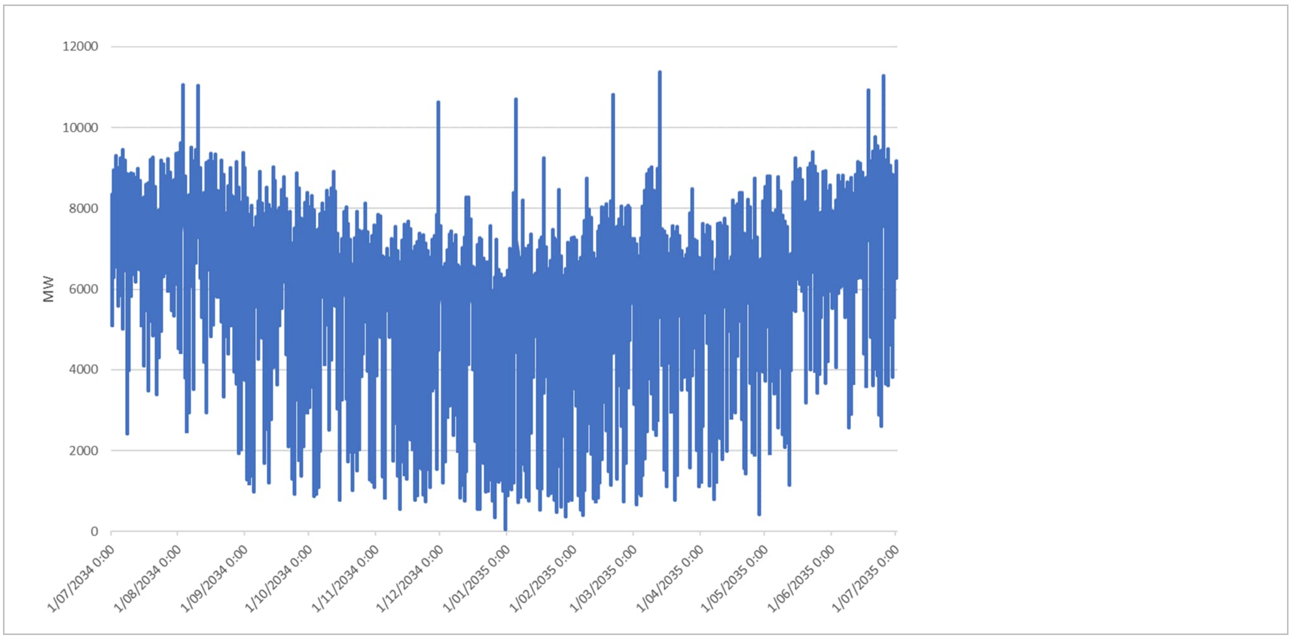
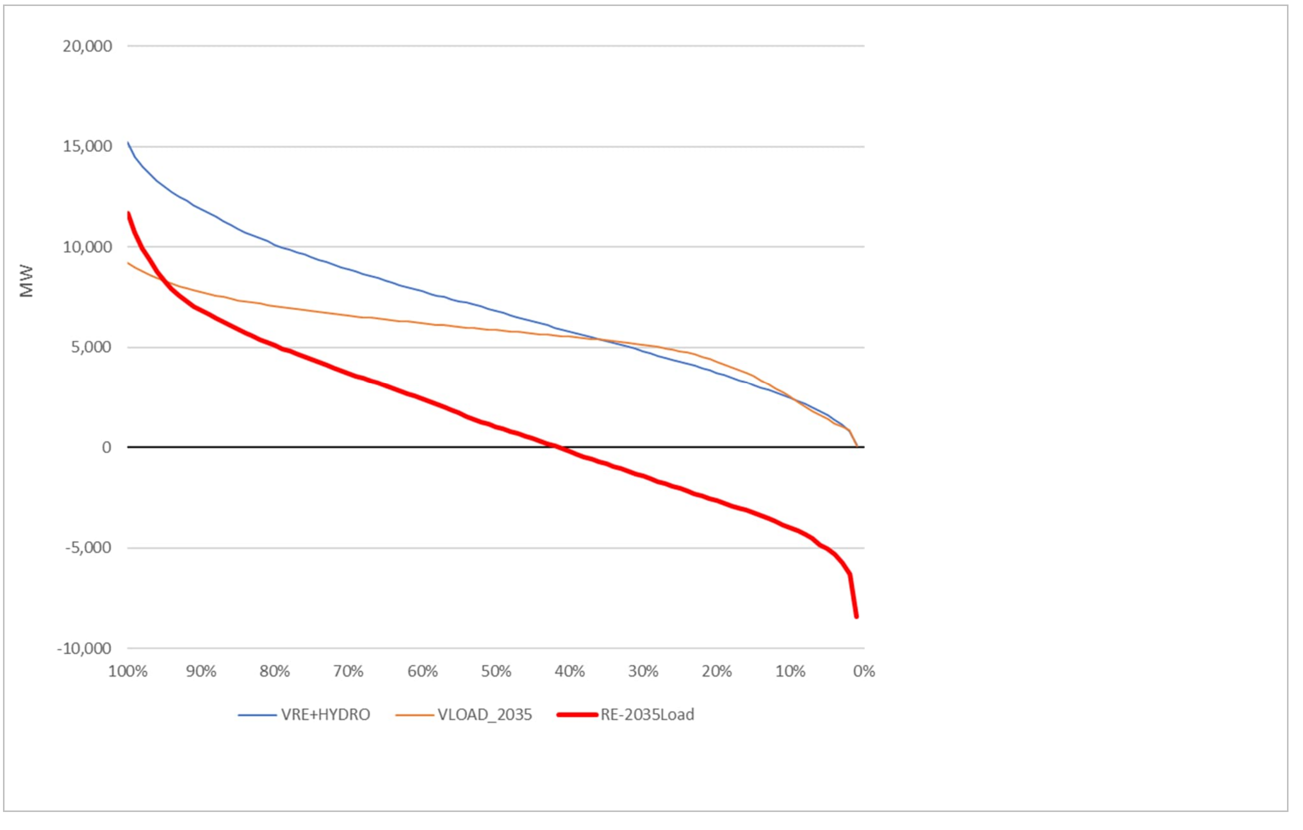


Figure 67. Illustrative 2035 Plan B VRE+hydro – load duration curve for Victoria[76]



[75] AEMO ISP2022, Step change, operational load, sent out for Victoria. OPSO load does not include EV charging, storage charging/pumping, and has not deducted interconnector losses

[76] For the illustration V2 and V6 are assumed solar dominated and the other REZs are assumed to be wind dominated.

Overall, there is a net 12,900 GWh surplus for this mix of renewables. The right-hand side of the curve that is less than zero indicates that 9,500 GWh needs to come from storage, interconnectors, gas peakers or demand side response, at up to 5000MW. Gas fired peakers would have limited operation (due to the VRET requirement). Existing interconnectors would only be able to provide a modest fraction. Storage or load shedding (demand response) would be needed for the bulk of the duty.

At the left-hand side, there is excess energy (22,300 GWh) some of which could be stored if storage was provided, some could flow interstate (subject to the interconnector sizing), or be curtailed. For approximately 20% of hours the "surplus" is over 5000MW.

Jacobs has constructed a simulation model to gain insight into how the Plan B generation across Victoria would work with the Victorian load forecast in 2034/35 at 30-minute granularity (Step Change, as shown in **Figure 66**) given the correlation/non-correlation between them. The simple analysis applied used the AEMO ISP2022 representative output "traces" for wind and solar generation by REZ, the FY2023 Victorian hydro dispatch profile[77], the current interconnector limits into and out of Victoria, and the ISP Victorian gas generation capacity. An amount of storage is allowed (an independent variable the user can change). There are no network losses or storage losses in the model.

The model steps through each 30 minute period in the year and calculates how much RE could be produced (available RE) and subtracts the load in the half hour. If there is excess energy the model tries to put it in storage (if the storage is not full), export it to another region (assuming the other regions can always give/take energy at the interconnection limit), or spill/curtail the excess. If there is a shortfall of energy the model tries to import from another region, use gas fired generation subject to its capacity, or take the energy from storage (if the storage is not empty). RE capacity can be built up to the hosting capacity in the model – an optimiser attempts to minimise spill (ie get the best mix) without having an annual shortfall (curtailed load) and attempting to have the storage end the year at the same inventory level as the starting inventory (ie not borrowing/lending energy to an adjoining year). The model shown incorporated 16GW of Victorian solar[78] + wind renewable energy (+ hydro).

Running this model with 0.2% of Victoria's annual consumption, or 100,000 MWh, of storage available the model will not successfully meet all the criteria even with all hosting capacity of Plan B built-out with renewable generation. The model in that case had nearly 10% of load served by gas, 0.2% load shortfall, 13% spill and was not able to end the year with the same storage inventory as at the start of the year. Flow duration curves for key parameters are shown in Figure 68. Visualisations are shown in Figure 69: The winter period is the most difficult to manage however for the rest of the year the storage is only partially utilised. This storage duty would be expensive due to the low number of cycles per year. If no greenhouse gas limitations were applied a peaking power station would be lower cost. Extra interconnection capacity (such as VNIW) would also assist cover this period.

[77] In practice the hydro would dispatch somewhat differently under the changed conditions of 2034-35. There is no "look ahead" optimisation done for hydro or storage dispatch. Market modelling would be required to determine how it would dispatch. The FY23 data for Victorian hydro totalled 4,366 GWh however and this was a relatively high (wet) dispatch year. Compare with Table 25 and **Figure 61**.

[78] Excluding rooftop PV which is included in the load

Figure 68. Flow-duration curves for simulation of Plan B with 100,000 MWh storage

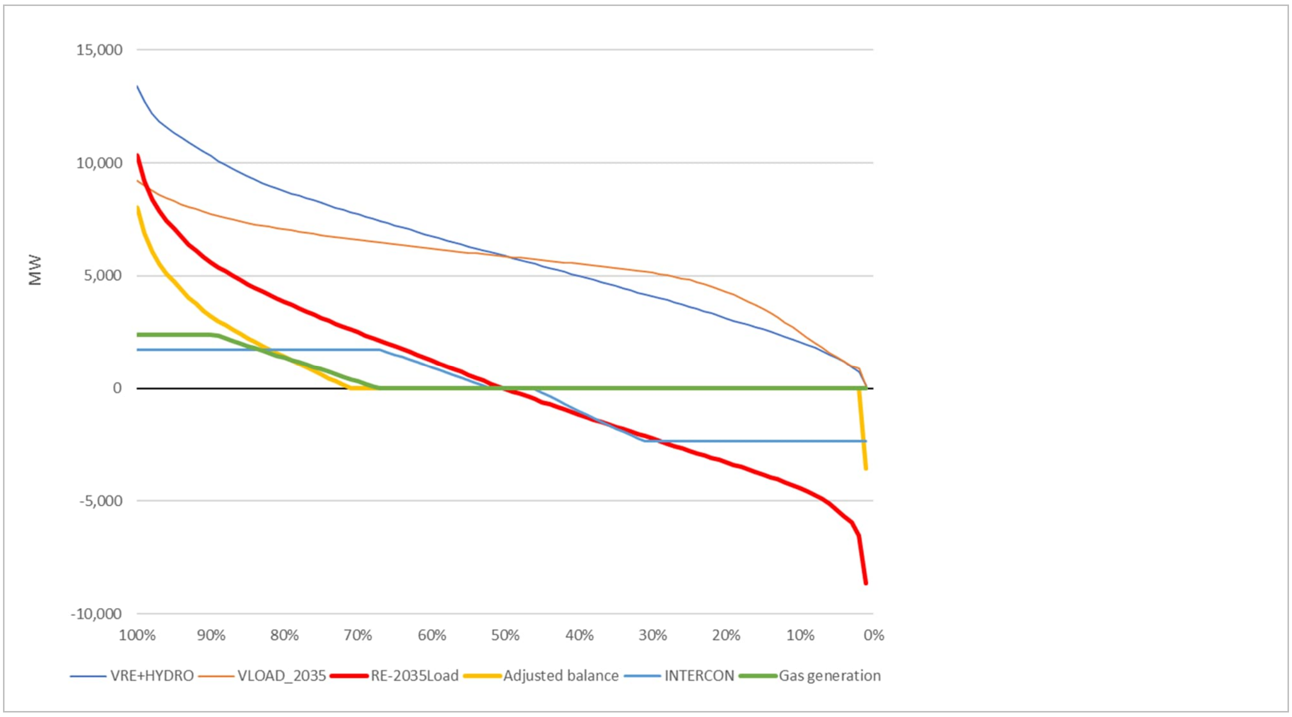
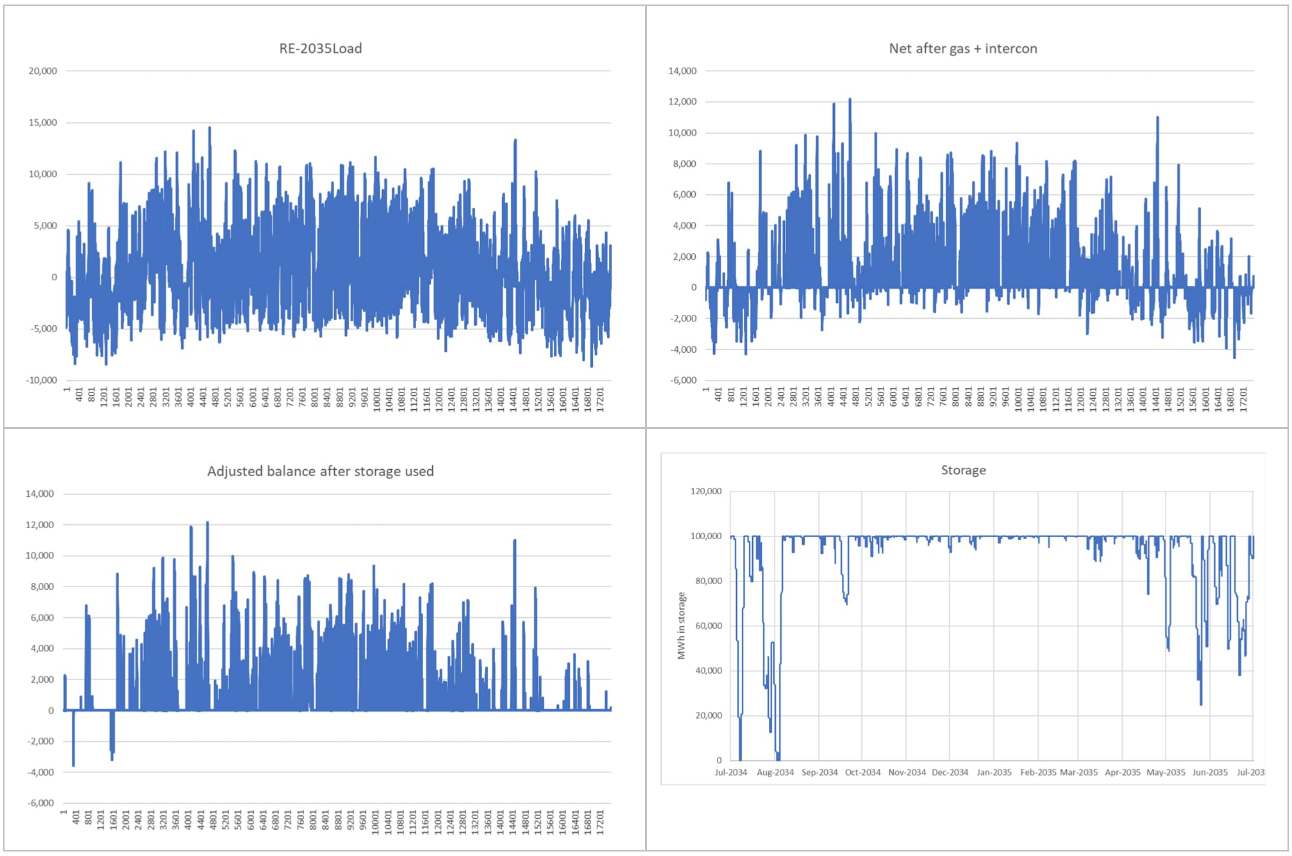
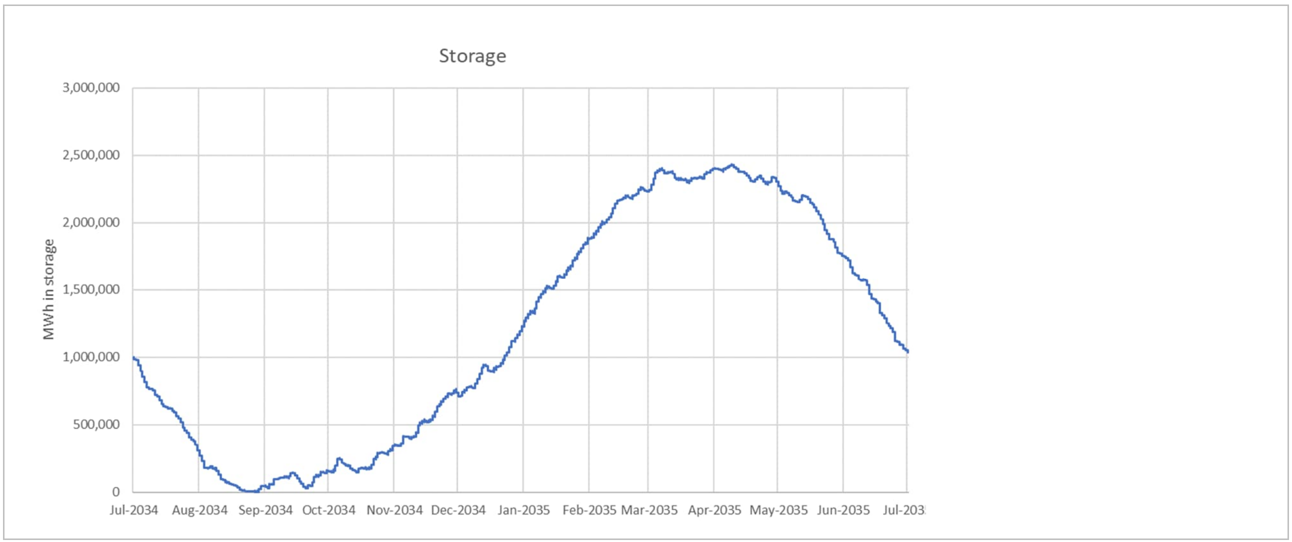


Figure 69. Visualisations from simulation of Plan B with 100,000 MWh storage



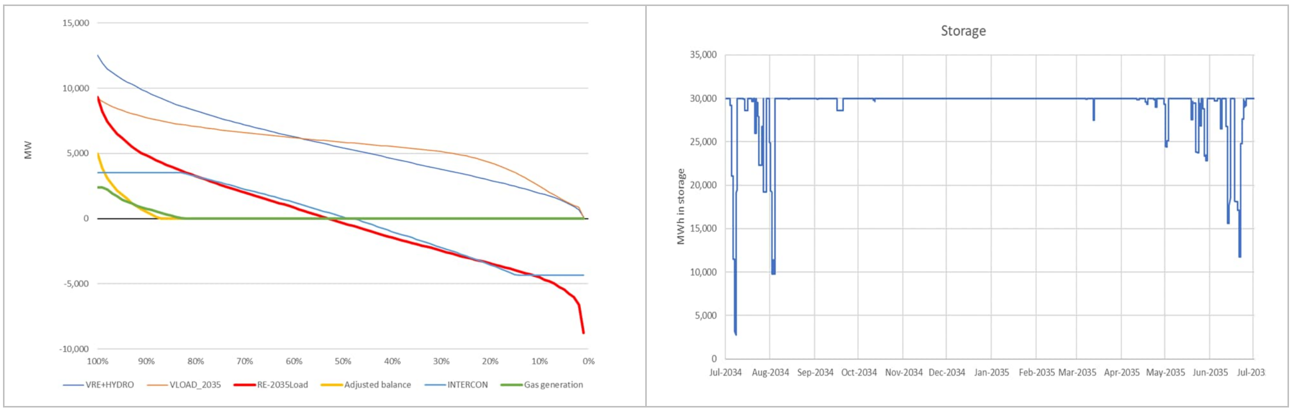
For comparison, if the model is run with sufficient (effectively unlimited) storage to provide an energy balance over the year (other than existing interconnection capacity import/export and gas generation), the energy-in-storage inventory is shown in **Figure 70**. This shows the impact of the seasonality of the RE-load balance with August in this year being the critical period. This simulation run has reduced RE requirements (7.7GW + hydro) and no spill or shortfall however this amount of storage is not credible.

Figure 70. Energy in-storage visualisation for effectively unlimited storage capacity simulation (Plan B case)



The same simulation model run with the expanded VNIW interconnection capacity included 14.6 GW of wind+solar capacity (excluding rooftop PV) and 30,000 MWh of storage capacity is shown in Figure 71. In this simulation there was 4.7% spill[79] and 4% of the load was served by gas.

Figure 71. Simulation model with VNIW interconnection capacity

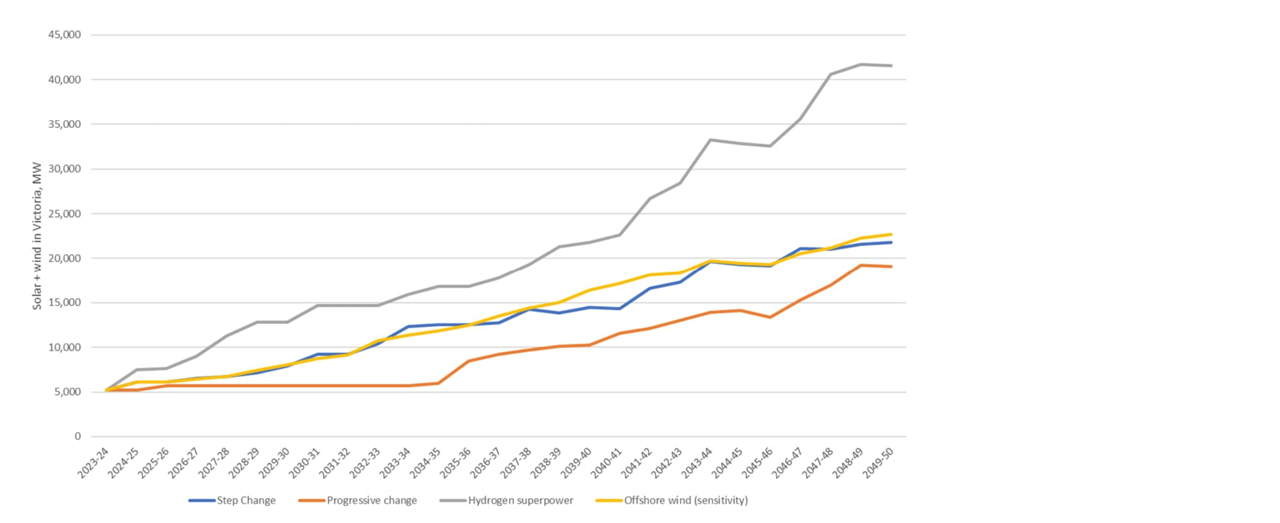


The quantity of Victorian wind+solar generation and Victorian storage in 2034-35 shown in the PACR modelling by EY for Step Change scenario (Case 5A) was 12.5 GW (refer Figure 72) and 16,000 MWh (refer **Figure 75**[80]) respectively are lower than the simulation produced for the VNIW case but of similar magnitude. This suggests that the simplified simulation may be conservative however the relative outcomes for Plan B versus VNIW are expected to be valid.

[79] This model does not include network losses or intraregional constraint and hence the curtailment of existing wind and solar in the western side of V2 and V3 due to network constraints would be additional

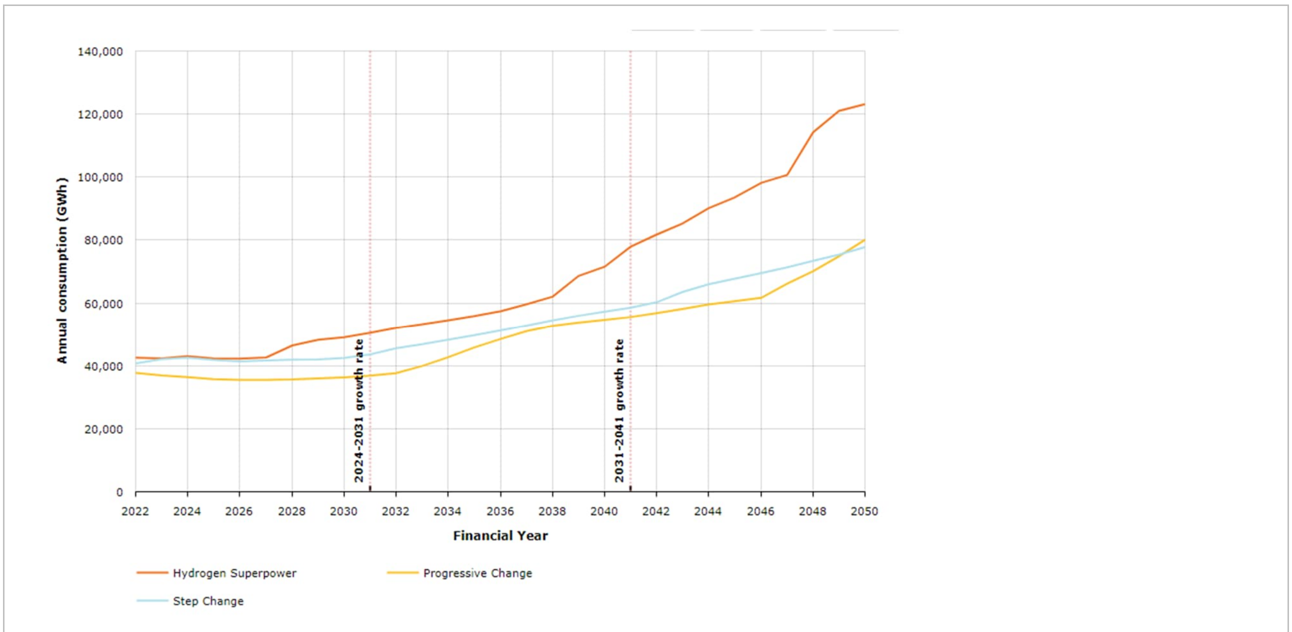
[80] This value is from the ISP2022 CDP2 scenario outputs as this parameter is not shown in the PACR outputs.

Figure 72. Wind + (grid) solar capacity in Victoria with VNI West (PACR case 5A)



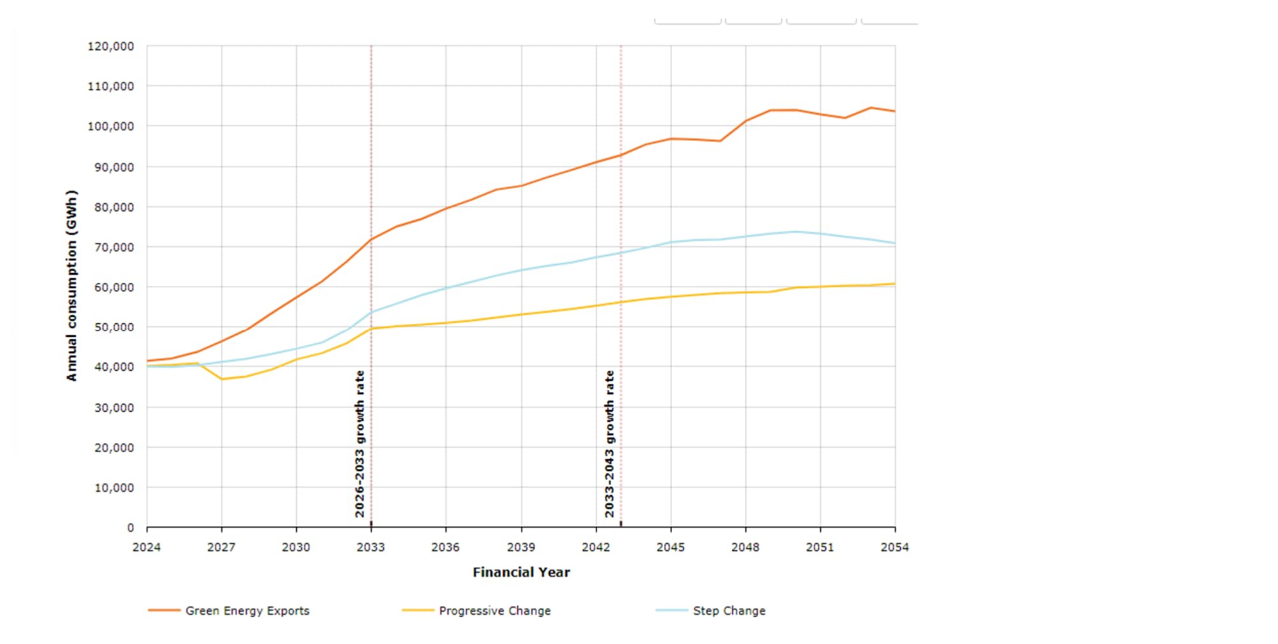
The forecast load differs according to which scenario is applied. This is shown in **Figure 73** for the ISP2022 forecasts. Forecasts are regularly updated and change in particular where new policies (such as greenhouse gas reductions) are announced. The forecasts in the current draft of the ISP2022 set are shown in **Figure 74**. Generally, there is further load growth expected beyond 2035.

Figure 73. Victorian annual electricity consumption (Operational, sent-out) – ISP2022[81]



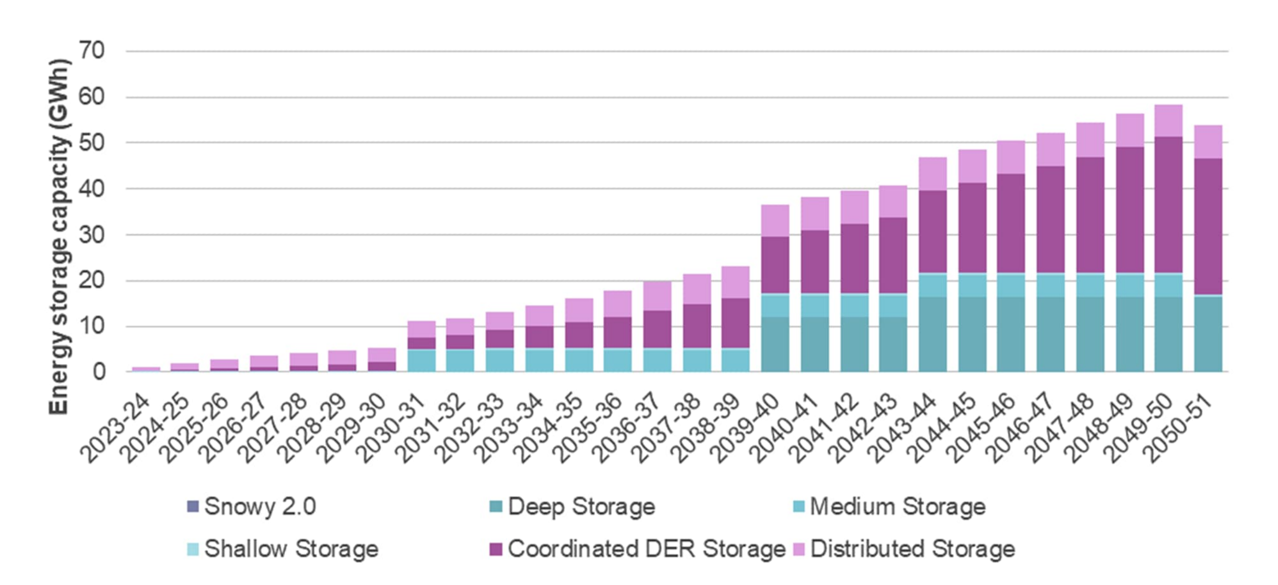
[81]Data/chart is from https://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational

Figure 74. Victorian annual electricity consumption (Operational, sent-out) – ISP2024 (draft)[81]



For comparison, the amount of storage expected in Victoria under the Step Change Scenario (ISP2022) is shown in **Figure 75**. This does not include any Snowy 2.0 storage capacity (located in NSW and accessed via the interconnector):

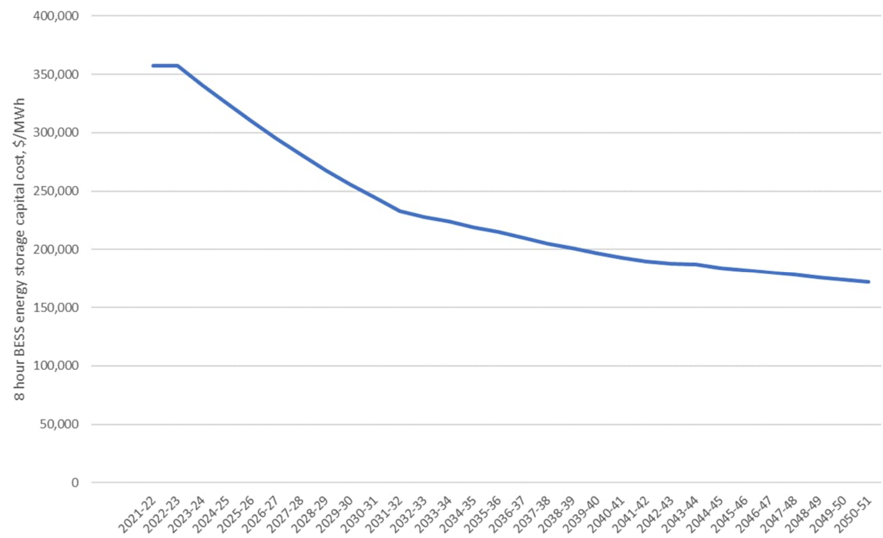
Figure 75. Energy storage capacity in Victoria, ISP2022[82]



The cost (per unit of storage) of BESS from ISP2022 are anticipated to reduce over time (due to Learning Rate) as shown in **Figure 75**:

[82] Data is from AEMO "2022 Final ISP results workbook - Step Change - Updated Inputs", CDP2 for Victoria

Figure 76. Energy storage costs, ISP2022[83]



In the event that (say) 50,000 MWh of additional storage was required for an option, the order of magnitude of additional capital cost would be $10B.

3.1.2 Hosting capacity in V2 and V3 REZs

The Plan B report's additional hosting capacities in the Victorian REZs are shown in Table 24:

Table 24. Plan B additional renewable generation hosting capacity[84]

	V1 (Ovens Murray)	V2 (Murray River)	V3 (Western Victoria)	V4 (South West Victoria)	V5 (Gippsland)	V6 (Central North)	TOTAL
Open-circuit Buronga – Red Cliffs 220 kV line							
Increase maximum conductor temperature on some 220 kV lines		160	160				320
On-line dynamic rating Red Cliffs-Ballarat-Moorabool-Sydenham							
V3-220 kV Elaine to Moorabool			1,914				
Gippsland REZ - 500kV Loy Yang to near Basslink transition point					3,000		3,000
V2 220kV network upgrade: Red Cliffs to Murra-Warra		957					957
V3 220 kV network upgrade: Murra-Warra to Ballarat							-
V3-V4 220 kV network upgrade Ballarat – Moorabool (line 1)							

83 20 March 2023 version, Step Change. Real$2021 excluding connection costs. Values are $/kW for 8 hour BESS x1000/8

84 At Table 5 in the Plan B report

	V1 (Ovens Murray)	V2 (Murray River)	V3 (Western Victoria)	V4 (South West Victoria)	V5 (Gippsland)	V6 (Central North)	TOTAL
Total Phase 1 additional hosting capacity (completed by mid 2027)	-	957	1,914	-	3,000	-	5,871
Minor works at Loy Yang and Hazelwood 500 kV substations							
V2 220 kV network upgrade : Red Cliffs to Kerang		1,514					1,514
V2-V3 220 kV network upgrade Kerang-Bendigo-Ballarat lines							
V3-V4 220 kV network upgrade Ballarat-Moorabool (line 2)							-
V4 500 kV S/C Sydenham to Moorabool				3,000			
Total Phase 2 additional hosting capacity (completed by mid 2031)	-	1,514	-	3,000	-	-	4,514
V6-V1 220kv line Shepparton-Glenrowan-Dedarang						1,100	1,100
Total Phase 3 additional hosting capacity (completed by mid 2035)	-	-	-	-	-	1,100	1,100
Total Plan B additional hosting capacity by mid 2035	-	2,471	1,914	3,000	6,000	1,100	14,485

Jacobs Sample Calculations for Plan B Hosting Capacity

Item: V2 220kV network upgrade: Red Cliffs to Murra-Warra:

Claimed Hosting Capacity = 957MW

- Assume the upgrade consists of a new double circuit 220kV line using Twin Peach conductor. The catalogue rating of 220kV Twin Peach = 1059MVA (Summer, 1m/sec). Total new capacity quoted by Plan B = 1914MVA. The difference is explained by the use of St Clair curve ratings. Jacobs accepts the differences as being negligible.
- Assume existing generation will be connected to the new 220kV circuits with a total capacity of 925MVA.
- Hosting capacity for additional generation = 1914 – 925 MVA = 989 MVA. Plan B states 957 MVA. Jacobs accepts that these estimates are functionally equivalent.
- Jacobs notes that the augmentation should include 220kV circuits from Murra Warra-Bulgana-Ballarat

Item: V2 220kV network upgrade: Red Cliffs to Kerang (via Wemen):

Claimed Hosting Capacity = 1514 MVA

- Assume the upgrade consists of a new double circuit 220kV line using Twin Peach conductor. The catalogue rating of 220kV Twin Peach = 1059MVA (Summer, 1m/sec). Total new capacity quoted by Plan B = 1914MVA. The difference is explained by the use of St Clair curve ratings. Jacobs accepts the differences as being negligible.
- Assume existing generation will be connected to the new 220kV circuits with a total capacity of 383MVA.
- Hosting capacity for additional generation = 1914 – 383 MVA = 1531 MVA. Plan B states 1514 MVA. Jacobs accepts that these estimates are functionally equivalent.
- Jacobs notes that the augmentation should include 220kV circuits from Kerang-Bendigo-Ballarat.

Findings

- Based on the assumptions listed above, Jacobs' sample calculations regarding hosting capacity for the "Rhombus of Regret" agree with the Plan B assessments
- The hosting capacities shown in Table 24, include 2 x 160MVA increments (for increasing maximum temperature on some 220kV lines). Jacobs does not support including these increments as the 220kV lines are proposed to be replaced under Plan B and/or AEMO advise that these upgrades have been previously undertaken
- Jacobs expects that the Plan B Project 1.4 (Elaine to Moorabool) that Plan B says "could extend to Ballarat" will likely need such an extension (a low capacity line in parallel with high capacity lines with similar impedance will result in a limitation)
- Similarly, it would be expected that the capacity of the first upgraded circuits from Ballarat to Moorabool in Phase 1 at Project 1.8 will be limited in capacity until such time as the other circuit is upgraded in Phase 2 under Project 2.3.

3.1.3 Hosting capacity in Gippsland V5 REZ

Refer to Section 3.8

3.2 Need for easements

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area A -11	**Easements** Discuss easement risks and processes. What is the risk profile of 500kV and 220kV regarding easements, and the risk issues of new easements versus extensions or shifts of existing easements.
Area B -2	**Need for easements** Plan B: "Plan B's total line length is 1,451 km. With the exception of AusNet's proposed G-REZ projects in Gippsland, all Plan B projects use existing or spare easements, thus greatly reducing impacts on landholders. By comparison only 2 of Extended VNI-West's 7 projects (386 km out of total length of 1,659 km) use existing easements. "

3.2.1 Easement widths

Expected easement requirements for 220kV and 500kV lines across NEM along with spacings between two towers in same easement is shown below.

Easement widths

Nominal Voltage (kV)	Circuit / Tower type	NSW width (m)[1]	Victoria width (m)[2]	Queensland width (m)[3]	Tasmania width (m)[4]
220	Single circuit	50	40	60	60
220	Double circuit	50	40	60	60
220	2 x single circuit	*	60	90	90
	Distance between towers	*	20	30	30
500	Single circuit	70	65+	80	N/A
500	Double circuit	70	60	80	N/A

Nominal Voltage (kV)	Circuit / Tower type	NSW width (m)[1]	Victoria width (m)[2]	Queensland width (m)[3]	Tasmania width (m)[4]
500	2 x single circuit	*	90	120	N/A
	Distance between towers	*	30	40	N/A

* No information available
+ Based on delta type structure that is shorter

1 https://www.transgrid.com.au/media/3tkdd5lr/easement-guidelines.pdf and https://www.transgrid.com.au/media/2wfirnkf/1-3-transmission-line-design-standard-rev-2.pdf
These easement widths are standard widths to ensure standard safety clearances under high wind conditions and provide an area where vegetation heights and third party developments can be controlled and provide ease of access for ongoing maintenance and repairs.
There is an allowance for reduction is easement widths for reduced spans

2 https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/safety/a-guide-to-living-with-transmission-line-easements.pdf
These values are standard design values. Long spans are to be checked for specified horizontal clearance requirements under blowout conditions (T500C + 375Pa) to edge of easement boundary 220kV – 4.6m

3 https://www.powerlink.com.au/sites/default/files/2018-06/Site%20Selection%2C%20Easements%20and%20Sites%20-%20Guideline_2.pdf

4 https://www.tasnetworks.com.au/config/getattachment/9d7f2f65-209d-4478-9074-94eb35689429/transmissionlineeasementsa5_v4.pdf and https://www.tasnetworks.com.au/config/getattachment/39f8ac75-dc9f-4dbb-8012-238d9ed75cbc/Transmission-Line-Normative-to-the-Design-Standard.pdf

The above information is from published documents. It is noted that actual easement widths may vary depending on specific circumstances including the structure hardware arrangements, separation for other circuits, management of earthing and EMF potential, and line layout and maintenance requirements.

According to AS/NZS 7000: 2016 an easement is legally described as an encumbrance on the title of land limited in width and height above or below the land conferring a right to construct, operate and maintain an electricity power line, cable, or apparatus.

Typical informative easement widths are specified in AS/NZS 7000: 2016 Appendix CC and are shown in Table 25.

Table 25: Typical Easement Widths Specified in AS/NZS 7000: 2016[85]

Nominal Voltage	Easement building restriction widths generally used (measured from the centre line of the overhead line)	Typical Width of Easement – Informative
Up to 33 kV	5-10m	10-20m
66 kV	10-15m	20-30m
110 kV/132 kV	15-20m	20-40m
220 kV	15-25m	30-50m
275 kV conventional	25-30m	50-60m
275 kV guyed	30m	70m
330 kV	30m	60m
400 kV	30m	65m
500 kV	35m	70m

85 AS/NZS 7000-2016 " Overhead line design" at Appendix CC

3.2.2 Effect of Span Lengths on Easement Widths

AS/NZS 7000: 2016 has a prescribed method for determining easement corridor widths based on physical line mechanics and a screenshot of Figure 3.11 from AS/NZS 7000: 2016 is in Figure 77. (Insulator and conductor blowout effect the easement corridor).

Line spans of varying length have varying blowout off-sets from the easement centreline. Consequently, when determining easement widths span lengths should be considered. A number of TSNPs have adopted this approach when determining minimum easement widths.

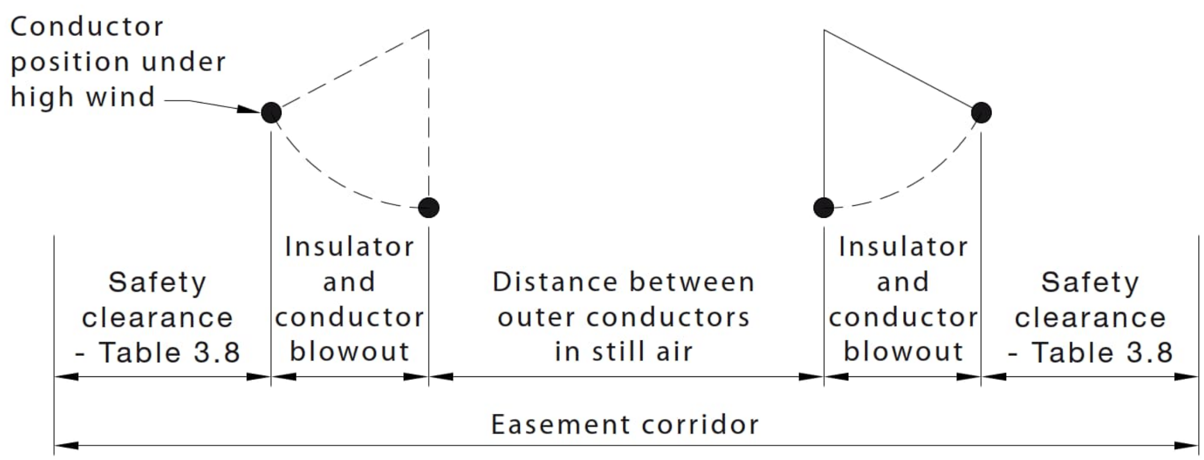


Figure 77: Easement Corridor from AS/NZS 7000: 2016.

Jacobs carried out a study for minimum easement widths considering blowout for varying span lengths. The study was carried out in PLS-CADD using the following parameters:

- Blowout weather condition – T50^{0}C + 375Pa.
- Span lengths used were from 250-900m.
- Conductor
  - Sulphur conductor strung at 20% UTS at T15^{0}C
  - Lemon conductor strung at 20% UTS at T15^{0}C
- Terrain is flat.
- The safe clearance from the conductor position at blowout is 4.5m (in accordance with clearance C in Table 3.7 of AS/NZS 7000: 2016).

Outputs from the study are in

Table 26 and the following is noted:

Table 26: Easement Widths Considering Span Lengths

Span Length	Safety Clearance (m)	Typical Blowout for Sulphur Conductors From Centreline (m)	Typical Minimum Easements Widths (m)
250	4.50	8	25
300	4.50	10	29
350	4.50	12	33
400	4.50	14	37
450	4.50	16	41
500	4.50	18	45
550	4.50	21	51
600	4.50	23	55
650	4.50	26	61
700	4.50	30	69
750	4.50	33	75
800	4.50	37	83
850	4.50	41	91
900	4.50	45	99

3.2.3 Physical Separation of Adjacent Transmission Lines

Refer to Table 27 for analysis of physical separation of adjacent transmission lines.

Table 27: Physical Separation of Adjacent Transmission Lines

Item	Comment
Electrical clearances between the lines considering conductor blowout	AS/NSZ 7000: 2016 does not have specific requirements. However, the value is expected to be approximately 2.3m. Jacobs carried out conceptual blowout clearance calculations for adjacent lines with matching span lengths and the following is noted: - Spans lengths 250-300m – 15m structure centreline spacing is OK - Spans lengths 400-450m – 20m structure centreline spacing is OK - Spans lengths up to 550m – 25m structure centreline spacing is OK - Spans lengths up to 800m – 30m structure centreline spacing is OK - Spans lengths up to 850m – 40m structure centreline spacing is OK For the 350m span shown in Figure 79 (refer to section 3.2.4) the structure centreline spacing would need to be approximately 20m if the existing spans are maintained and matched with an adjacent temporary line. Please note these values are preliminary and refer to section 3.2.4 for further details of the calculation assumptions.
Structure fall distances	Where structure heights are greater than the line separations there is a risk when a structure failure event occurs, the adjacent line can be damaged. However, Jacobs notes that this item is generally not considered when designing adjacent lines.
Maintenance and Construction Access	For mobile plant operated in the vicinity of 220kV OHLs the following clearance requirements are noted - Energy Safe Victoria 'The Blue Book' Table 4 ▪ Mobile Plant Instructed Persons: 2400mm ▪ Mobile Plant Ordinary Persons: 4600mm - ENS NES 04 Table 3/4 ▪ Mobile Plant Instructed Persons: 2400mm ▪ Mobile Plant Ordinary Persons: 6000mm Refer to the section 3.2.4 for a worked example diagram for construction and maintenance clearances produced by Jacobs and the following is noted: - Using a clearance requirement of 4600mm and a construction corridor of 2000mm from the outer wires, the minimum clearance for adjacent structures is 15.6m. - This distance would need to be increased based on blowout distances should the structures be located midspan to the adjacent line. For the 350m span shown in Figure 79 (Brown Hill, Ballarat) the maximum blowout under maintenance conditions is 2.5m. - The 15.6m distance may be reduced should the plant be operated by Instructed Persons.
Induction effects	Outcomes from previous studies carried out by Jacobs determined that induction was not the critical factor in determining the physical separation and it is expected that electrical clearances and maintenance clearances between the two lines governs.

As an example see the separation distance between two 220 kV towers

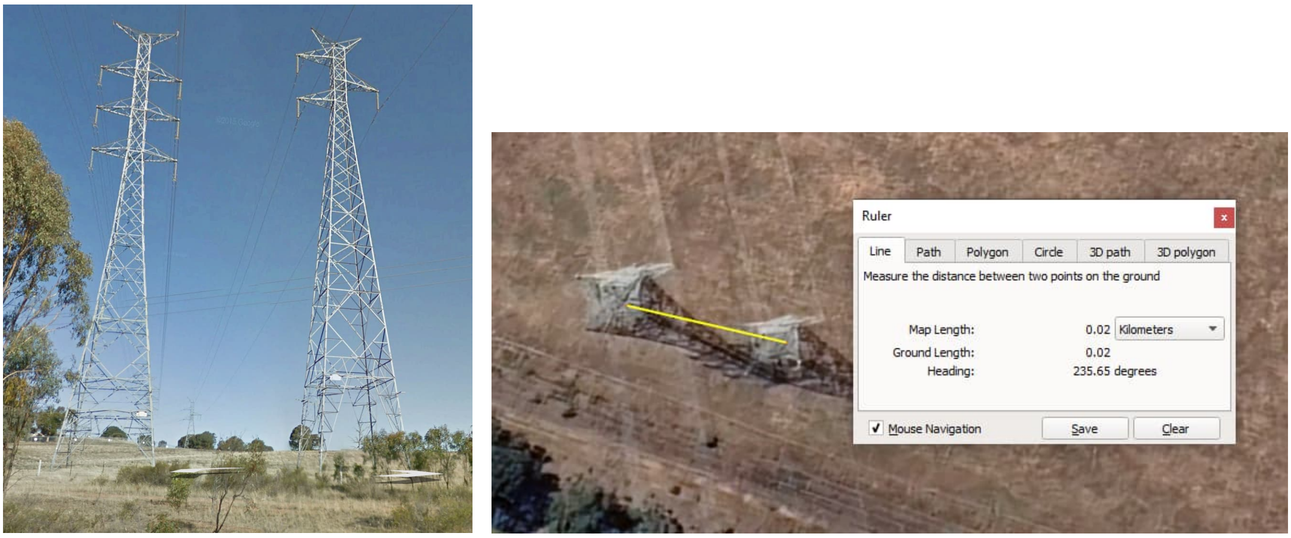


Figure 78: Google Earth Data – 220kV Tower Spacing near Glenrowan Terminal Station (Structure heights are greater than separation).

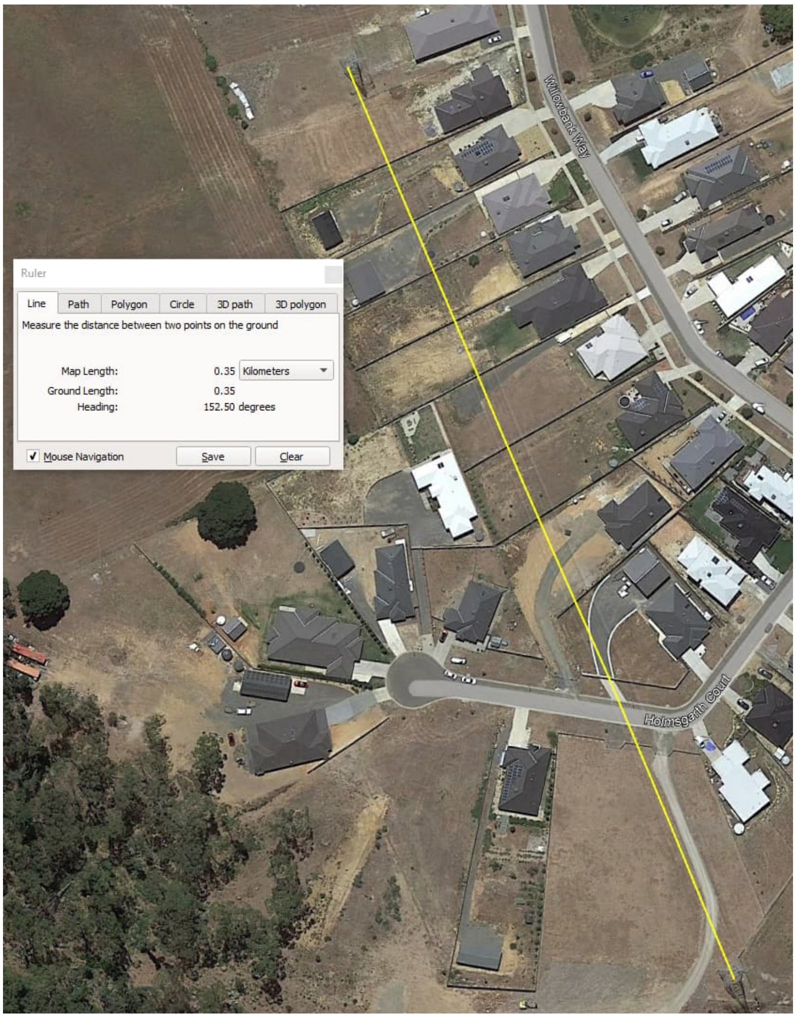


Figure 79: 350m span in Brown Hill, Ballarat

3.2.4 Construction and Maintenance Clearance worked example

Blowout Clearances for Adjacent OHLs

Span Length	Standard Crossarm Lengths for Structure Centreline (m)	Leeward Span Blowout at T50C+375Pa (m)	Windward Span Blowout at T50C+100Pa (m)	15m Off-set		20m Off-set		25m Off-set		30m Off-set		40m Off-set	
				Phase to Phase Clearance at EDT	Phase to Phase Clearance with Wind	Phase to Phase Clearance at EDT	Phase to Phase Clearance with Wind	Phase to Phase Clearance at EDT	Phase to Phase Clearance with Wind	Phase to Phase Clearance at EDT	Phase to Phase Clearance with Wind	Phase to Phase Clearance at EDT	Phase to Phase Clearance with Wind
				15		20		25		35		40	
250	5	3.5	1.5	5	3	10	8	15	13	25	23	30	28
300	5	5.5	2	5	1.5	10	6.5	15	11.5	25	21.5	30	26.5
350	5	7.5	2.5	5	0	10	5	15	10	25	20	30	25
400	5	9.5	3	5	0	10	3.5	15	8.5	25	18.5	30	23.5
450	5	11.5	3.5	5	0	10	2	15	7	25	17	30	22
500	5	13.5	4.5	5	0	10	1	15	6	25	16	30	21
550	5	16.5	5.5	5	0	10	0	15	4	25	14	30	19
600	5	18.5	6.5	5	0	10	0	15	3	25	13	30	18
650	5	21.5	7.5	5	0	10	0	15	1	25	11	30	16
700	5	25.5	8.5	5	0	10	0	15	0	25	8	30	13
750	5	28.5	9.5	5	0	10	0	15	0	25	6	30	11
800	5	32.5	10.5	5	0	10	0	15	0	25	3	30	8
850	5	36.5	11.5	5	0	10	0	15	0	25	0	30	5
900	5	40.5	12.5	5	0	10	0	15	0	25	0	30	2

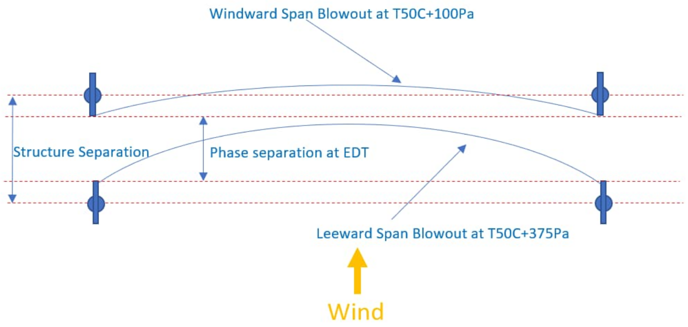


Figure 80: Windward Span and Leeward Span Blowout

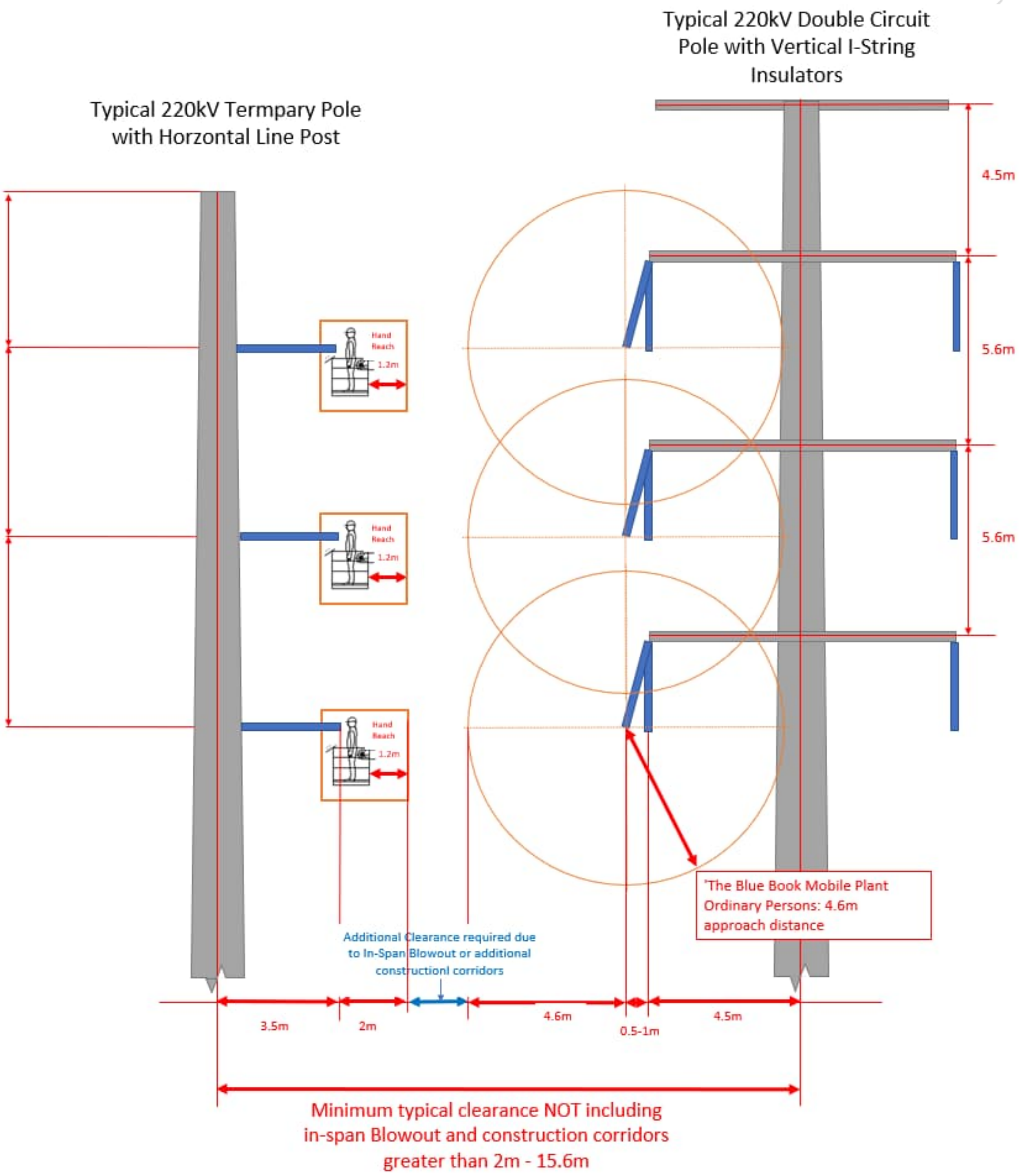


Figure 81: Construction and Clearance worked example for 350m span

In Appendix C.3 Plan B provide an alternative construction technique that involves the use of temporary single circuit 220 kV lines with the new 220 kV pole installed at least 12m from the temporary single circuit 220kV line. The construction technique approach is viable however as detailed in Table 27 the minimum clearance requirement between structures is greater than the distances quoted by Plan B and for spans greater than 400m it will become challenging to stay within the existing easement.

Plan B have proposed to shift existing easements 10 – 15m and then relinquishing the equivalent portion of easement, not required upon project completion, and rehabilitating the easement. There are instances where this proposed approach would need to be re-considered. For Plan B project B1.8 Ballarat – Moorabool (1) and B2.3 Ballarat – Moorabool (2) the approach is based on rebuilding of existing 220 kV S/C line with a 220 kV double D/C in its existing easement followed by the demolition of the existing line and the restoration of the 10m of easement width for relinquishment of the easement no longer required to the landowner. However the existing lines from Ballarat to Moorabool are installed on a combination of a double circuit tower and single circuit tower. Installed on the double circuit tower and is the Ballarat to Elaine to Moorabool 220 kV line and the Ballarat to Moorabool No.2 220 kV line, and the single circuit tower carries the Ballarat to Moorabool No.1 220 kV line. Furthermore, on the approach to the Elaine terminal station there is a wind farm transmission line installed adjacent to the double circuit line as shown in Figure 82. This would impact on both project B1.8 and project B1.4. In these instances, an alternative approach to that proposed would be required and the overall easement width may need to increase or greater easement adjustments that those suggested.

Figure 82: MLTS-BATS No.1 and 2 220 kV lines, MLTS-ELTS 220 kV line and Wind farm line on approach to Elaine Terminal station

Plan B project B1.4 and project B3.1 are proposed to be installed in spare easements. Jacobs have been unable to find any details indicating that there is a spare easement from Elaine to Moorabool or Shepparton to Glenrowan to Ballarat, https://vic.digitaltwin.terria.io/ shows only the easement to accommodate the existing towers.

In Appendix C.3 below, the Plan B report states that where there are any requirements to undertake further studies to obtain any necessary approvals that there will be provision for truncated processes compared with VNI West, that biodiversity and EPBC studies and approvals are unlikely to be required and that cultural heritage studies are unlikely to be required.

Jacobs Environmental Approvals team provided the following advice in relation to the proposed Plan B projects. Approvals are required under respective legislation due to an impact occurring through the actions of a proponent i.e. The Project. The following approvals are likely required along with additional secondary approvals. At least 2 years should be allowed for the approval of both the EES and CHMP.

Compared with VNI West, the approvals are assumed to be the same due to the level of public interest in the project and the likely impacts to environment, heritage and social values. Timeframes for approvals may however be reduced given the proposed works area for Plan B is less than the former two projects, the period for undertaking the impact assessment will be less and subsequently saving time in preparing inputs to the approvals.

For Plan B projects B1.6, B1.7, B2.1 and B2.3 the costs were adjusted to provide only a 1% cultural heritage allowance as Plan B stated that the 6% cultural heritage allowance applies to civil and structural works. The construction of footings regardless of whether in a existing easement or new easment does require cultural heritage investigations wherever there will be ground distrubance in order to determine areas of cultural sensitivity.

Legislation/Policy	Approval Required	Approver
Environment Protection and Biodiversity Conservation Act 1999 (EPBC Act)	EPBC Referral A referral is likely required as the project will or is likely to have a significant impact on a matter of national environmental significance.	DCCEEW
Environment Effects Act 1978 (EE Act)	Environment Effects Statement (EES) An EES Referral must be submitted to DTP if the project has or is likely to trigger criteria under the Ministerial guidelines for environmental assessment. A combination of criteria are likely to be triggered under the Ministerial guidelines for environmental assessment leading to the requirement for an EES. Based on the information presented, the criteria would likely be triggered due to impacts resulting from vegetation clearance, impacts to species, communities, and habitat, impacts to landuse, social impacts as well as impacts to historic and Aboriginal cultural heritage.	Department of Transport and Planning, Minister for Planning
Planning and Environment Act 1987	Planning Scheme Amendment (PSA) The project is likely to trigger the requirement for a Planning Scheme Amendment to change the planning scheme map, a written part of the scheme to incorporate information about the transmission line and associated infrastructure .	Local Government Council

Legislation/Policy	Approval Required	Approver
Aboriginal Heritage Act 2006 (AH Act) *and* Aboriginal Heritage Regulations 2018	Cultural Heritage Management Plan (CHMP) If the project includes works within an area of cultural heritage sensitivity, and if impacts cannot be avoided, a CHMP will be required. Given the length of the project and the likely ground disturbance required, one or more CHMPs are likely required.	Registered Aboriginal Party (RAP)
Heritage Act 2017	Consent/Permit from Heritage Victoria A Heritage Permit is required for any activity that alters a place or object listed on the VHR Consent from Heritage Victoria is required to disturb any archaeological site in Victoria listed on the VHI. Types of consent: • A consent to uncover • A consent to excavate • A consent to damage • A consent for other works	Heritage Victoria

3.3 Visual impact

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area B -3	**Visual impact** Plan B: "Most of Plan B's projects are 220 kV with 41 metre towers, with a small length of single circuit 500 kV towers up to 48 meters high. By comparison 466 km of Extended VNI-West's projects are double-circuit 500 kV, with 70 to 80 metre high towers. Since visual impacts rise as the square of height, shorter towers have substantially smaller visual impact"

Jacobs have reviewed a number of landscape and visual impact assessments undertaken for new and existing transmission lines. These include:

- UPC Renewables Robbins Island Transmission Lines Landscape and Visual Impact Analysis
- Australia-Asia Powerlink Project Landscape and Visual Impact Assessment
- Landscape and Visual Impact Assessment of Existing Electricity Transmission Infrastructure in Nationally Protected Landscapes in England and Wales
- Wambo Wind Farm Connection Project Visual Impact Assessment
- Project Energy Connect Visual Amenity Chapter of EIS

All of these assess visual impact based on some or all of the following:

- Landscape character
- Sensitivity of visual receptors (residents, visitors to the area)
- Frequency of change in view (depends on viewpoint)
- Magnitude of change in view (depends on viewpoint)

As per "The Guidance for Landscape and Visual Impact Assessment (GLVIA)" these factors are all interrelated and need to be considered in an integrated way rather than as a series of separate steps.

Jacobs have found no information that visual impacts rise as the square of height. What is apparent from the landscape and visual impact assessments is that as part of the route selection and alignment there are mitigation measures than can be adopted to help minimise visual impact. It is recommended that VNI West consider these mitigation measures as part of developing the project.

Most of Plan B's projects are 220 kV with 41 metre towers, with a small length of single circuit 500 kV towers up to 48 meters high. This would imply steel pole type designs which aligns also with the information provided in Appendix C.3. Heights for tubular steel pole are up to 45 m but can be higher based on specific design requirements. Foundation sizes for poles with voltages 330 kV and above can be relatively large. A typical foundation is a pad and pedestal 11m x 11m wide pad area, 4 piles 6m deep with tie-pad of another 10m width. This can mean foundation costs for poles are more expensive than that of lattice towers. Plan B have stated that estimated capital cost of each project has been derived from relevant project in the AEMO's Draft Transmission Cost Estimates Report, amended where appropriate for changes in the scope of the project relative to the scope of the project from that Report. The AEMO Draft Transmission Cost Estimates Report makes use of building blocks overhead line costs that assumes Strain + Structural tower associated costs (steel tower with single earth peak, structural foundation steel, foundation leg steel, climbing barrier, fittings, insulators) and insulator and conductor. 85% suspension, 15% strain and 400m span. Plan B have not indicated whether their costs were amended based on a different tower design type or spans of less than 400 m as would be required to construct a number of the projects using the methodology outlined in Appendix C.3.

3.4 Capex

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area B -4	**Capex** Plan B: "Plan B is projected to cost $6 billion whereas Extended VNI-West is expected to cost $11 billion (about three times the value of Victoria's existing transmission network). "

An extract from the PACR is shown at Figure 83.

Figure 83. Status of capex for VNI-W in the PACR[86]

2.6 Victorian costs have been revised

Submissions to the PADR and Additional Consultation Report raised a number of concerns regarding the completeness and accuracy of the costs included in the cost benefit analysis and requested further information on the methodologies adopted (see PACR Volume 2 for a summary of points raised).

Based on this consultation feedback, updated costing input information received since the Additional Consultation Report, and also the recently updated 2023 Transmission Cost Database (TCD), the cost estimate for the Victorian Option 5 has further been revised for this PACR. The same updated input information has been used to estimate Option 5A costs.

The revisions to the Victorian estimates for the PACR include:

- **Revision of the Victorian 500 kV transmission line costs to reflect new market costing information**. As pointed out in the feedback, Victorian line costs appeared lower than New South Wales costs. While this is partially due to differences in allocations to the cost categories, some costs were identified as requiring escalation due to recent changes in market factors such as material and labour price inflation. The Victorian line costs have been updated with reference to analysis undertaken as part of a concurrent update to the AEMO TCD, as well as recent transmission network service provider (TNSP) per kilometre rates for similar lines. Specifically, the Victorian line bottom-up cost estimates have been escalated based on the trends identified in AEMO's 2023 TCD update for the current market line capital costs, with the costs for easement compensation and biodiversity offsets estimated separately (all discounted back to June 2021 real dollars[70]). This update only applies to the VNI West lines component, because the WRL line estimates are based on TNSP estimates.

[70] All costs in this PACR are reported in June 2021 real dollars.

- **Changes to known and unknown risk allowances** based on the levers available in the 2023 TCD, replacing the earlier $300 million overall contingency allowance that was previously included in the PACR and Additional Consultation Report on a percentage of total cost basis. The TCD contingency allowances for known and unknown risk (as described in Section 3.3.1) are able to better reflect the level of project complexity and risk identified from the MCA and consultation process.
- **Additional allowances for accessing land for survey purposes have been included** in response to recent changes in the payment structure for access agreements used by other organisations (such as AusNet).
- **Biodiversity offset allowances have been re-estimated** based on the areas of interest for each option identified through the MCA process.
- **The Victorian landholder payments have been reflected** (as outlined in Section 2.5) in the operating expenses.
- **Operating expenses have been updated to reflect latest advice on easement tax.** In response to submissions received on the Additional Consultation Report, further advice was obtained on the approach to calculating total taxable value of easements within Victoria with the estimated easement tax updated to reflect the advice.

3.4.1 Transmission cost escalation

AEMO publish a Transmission Cost Database as the reference document for projects considered in the ISP process. The version of the database applied in ISP2022 and in the earlier part of the VNIW RIT-T process was the 2020 Transmission Cost Database. Preparatory to the ISP 2024, an updated transmission cost database has now been published[87].

[86] At pages 38-39

[87] Refer to https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

Mott Macdonald has undertaken the update work. They note "*Mott MacDonald developed a method to update the costs for equipment, materials, and services for each building block from the original estimates used for the 2020 Transmission Cost Database (31 December 2020) to the new reference day (30 June 2022 Australian dollar terms*)." An extract of escalation factors noted is in Figure 84:

Figure 84. Transmission cost escalation[88]

Table 2.7: Escalation factors per cost components

Cost Components	Building Blocks				
	Switch bay Property site work and building Secondary system building	Underground cables	CB (circuit breaker) CVT (current-voltage transformer) SA (surge arrestor) CT (current transformer) ES (earth switch) ROI (outdoor insulator) HVDC converters Modular power flow controller	Phase shifting transformer SVC (Static Var Compensators) Reactor Capacitor Statcom (Static synchronous compensator) Synchronous condenser Transformer	Overhead lines
Plant	1.2826	1.2860	1.0879	1.2376	1.2802
Civil	1.1138	1.1138	1.1138	1.1138	1.1138
Electrical	1.1138	1.1138	1.1138	1.1138	1.1138
Secondary systems	1.0427	1.0427	1.0427	1.0427	1.0427
Design	1.0983	1.0983	1.0983	1.0983	1.0983
Testing	1.1138	1.1138	1.1138	1.1138	1.1138
Project management	1.0983	1.0983	1.0983	1.0983	1.0983
Easement	1.1383	1.1383	1.1383	1.1383	1.1383

3.4.2 Escalation of solar, wind and storage:

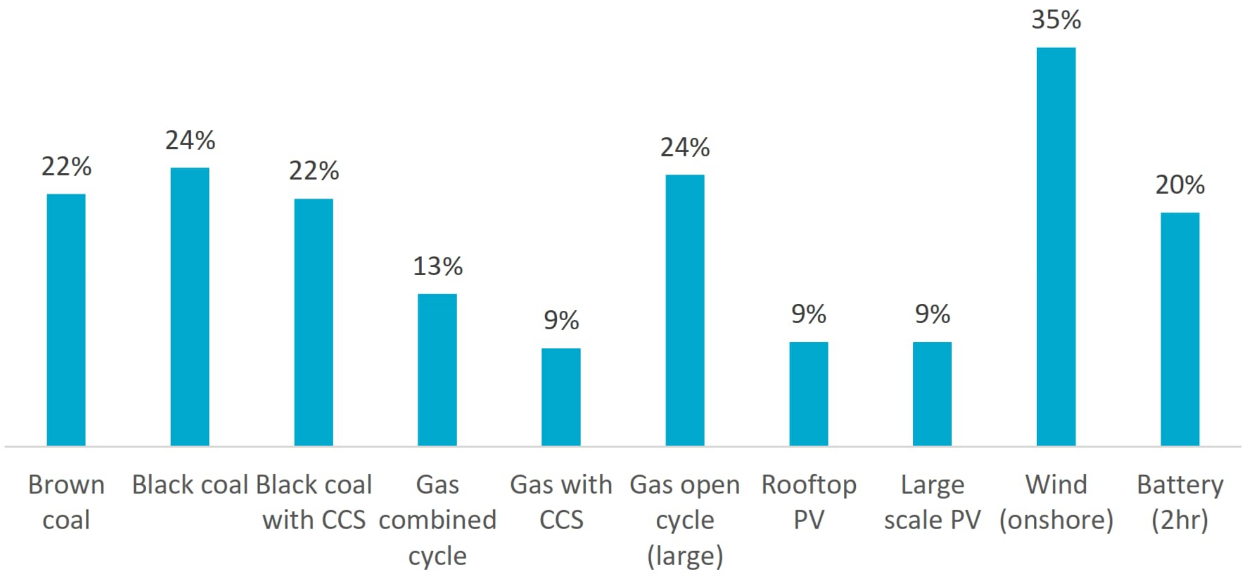
The version of the IASR "Forecasting Assumptions Update workbook full" 20 March 2023 (and the "draft 2023 Inputs, Assumptions and Scenarios Report, December 2022 " described in the PACR) included costs of new build power generation using CSIRO's 2021-22 GenCost report. A more recent GenCost report has recently been published[89] (after the PACR was published).

The updated report notes that the costs of generation and storage related technologies have increased significantly from the previous version, as shown in Figure 85:

[88] Mott Macdonald "AEMO Transmission Cost Database, Building Blocks Costs and Risks Factors Update Final Report", 24 July 2023

[89] https://www.csiro.au/en/research/technology-space/energy/Energy-data-modelling/GenCost

Figure 85. Increase in current costs of selected technologies in GenCost 2022-23 relative to 2021-22[90]



The reference date of the GenCost 2022-23 data is middle of CY2022 and the stated uncertainty range is ±30%. The previous GenCost report (ISP2022) had a reference date of "end of 2021"[91]

3.4.3 Nominal escalation

Nominal inflation (Consumer Price Index, CPI) has increased significantly across the relevant timeframe as shown in Table 28:

Table 28. Australian CPI index (weighted average eight capital cities)[92]

	31 March	30 June	30 September	31 December
2020	116.6	114.4	116.2	117.2
2021	117.9	118.8	119.7	121.3
2022	123.9	126.1	128.4	130.8
2023	132.6	133.7		

Between the end of 2021 and recent (June 2023) times CPI has increased by over 10%. All financial models (including Cost-Benefit-Analyses) expressed in real terms will have both the cost side and benefit side escalated by CPI if they were re-expressed today, and hence the net benefit will likewise have increased if re-expressed in current dollars.

[90] Graham, P., Hayward, J., Foster J. and Havas, L. 2023, GenCost 2022-23: Final report, CSIRO, Australia, 27 June 2023, at Figure 0-1

[91] Graham, P., Hayward, J., Foster J. and Havas, L. 2022, GenCost 2021-22: Final report, CSIRO, Australia.

[92] Australian Bureau of Statistics, Consumer Price Index, Australia June Quarter 2023

3.5 Single Points of Failure

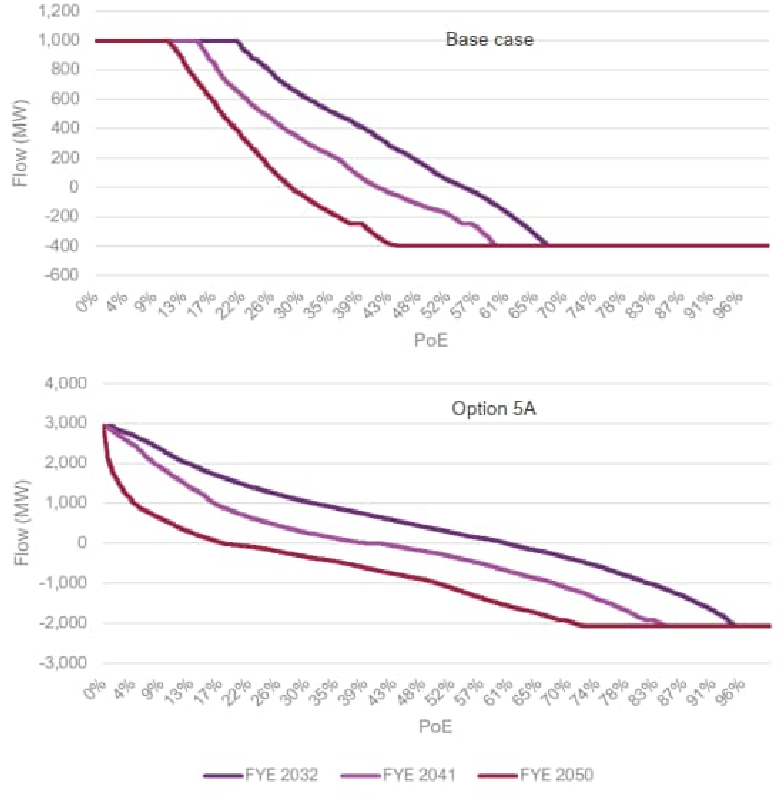
The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area B -5	**Single Points of Failure** Plan B: "Extended VNI-West has more than 1,000 "single points of failure" on transmission lines that are likely to be defined as a System of National Significance under the Security Legislation Amendment (Critical Infrastructure Protection) Act 2022 (SLACIP Act). Plan B eliminates the risk of cascading collapse of the Victorian grid by avoiding double circuit 500 kV single tower lines and by making the most of Victoria's deeply meshed, dual redundant and resilient 220 kV network."

3.5.1 Load flow

Jacobs has undertaken a basic load flow analysis to evaluate the flows indicated on the Vic↔NSW interconnector indicated in the PACR (Figure 86). This indicates the expected level of constraint in the Base Case (no VNI West) versus with VNI West (Option 5A). It also indicates that the normal operating flow limits would be 3000MW to NSW and 2300MW from NSW to Victoria.

Figure 86. Flow-duration curves, Vic to NSW from PACR[93]



[93] PACR Volume 1 Fig 12 at Page 67

Jacobs has undertaken a flow analysis of the interconnector at 50% and 100% reactance. A summary for the case of import to Victoria is shown in Figure 87. Selected modelling outputs for key circuits are shown in Figure 88.

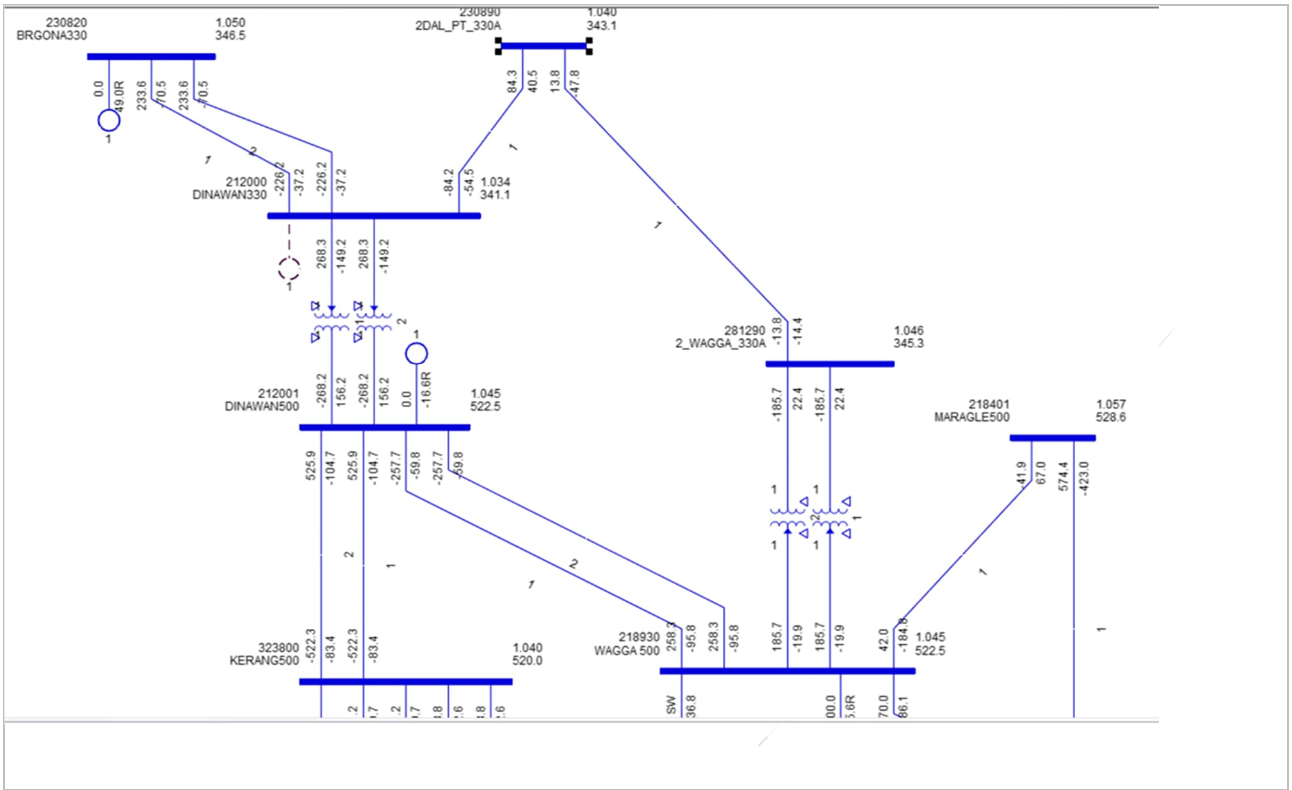
Jacobs noted:

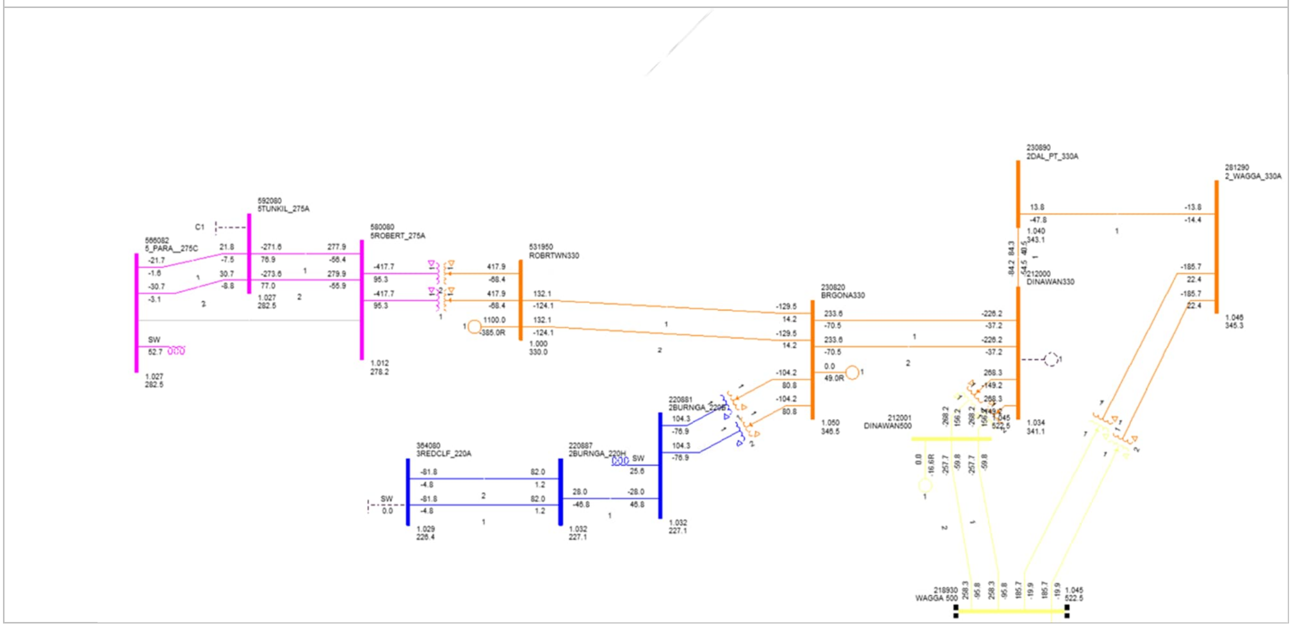
- The 330kV flows (into Dederang) are about the same as the 500kV flows (into Kerang). The 330kV flows will limit the import capacity as they are close to the thermal limits.
- The 500kV series compensation between Kerang and Bulgana acts to shift flow from the 330kV route onto the 500kV route – but only by a small amount.
- The import results are consistent with figures from AEMO (2,200MW)
- The calculations provide an indication of the flow balance between the three elements of the Vic-NSW interconnector and how much of the flow is likely to be carried by the 2x500kV D/C VNI-W.

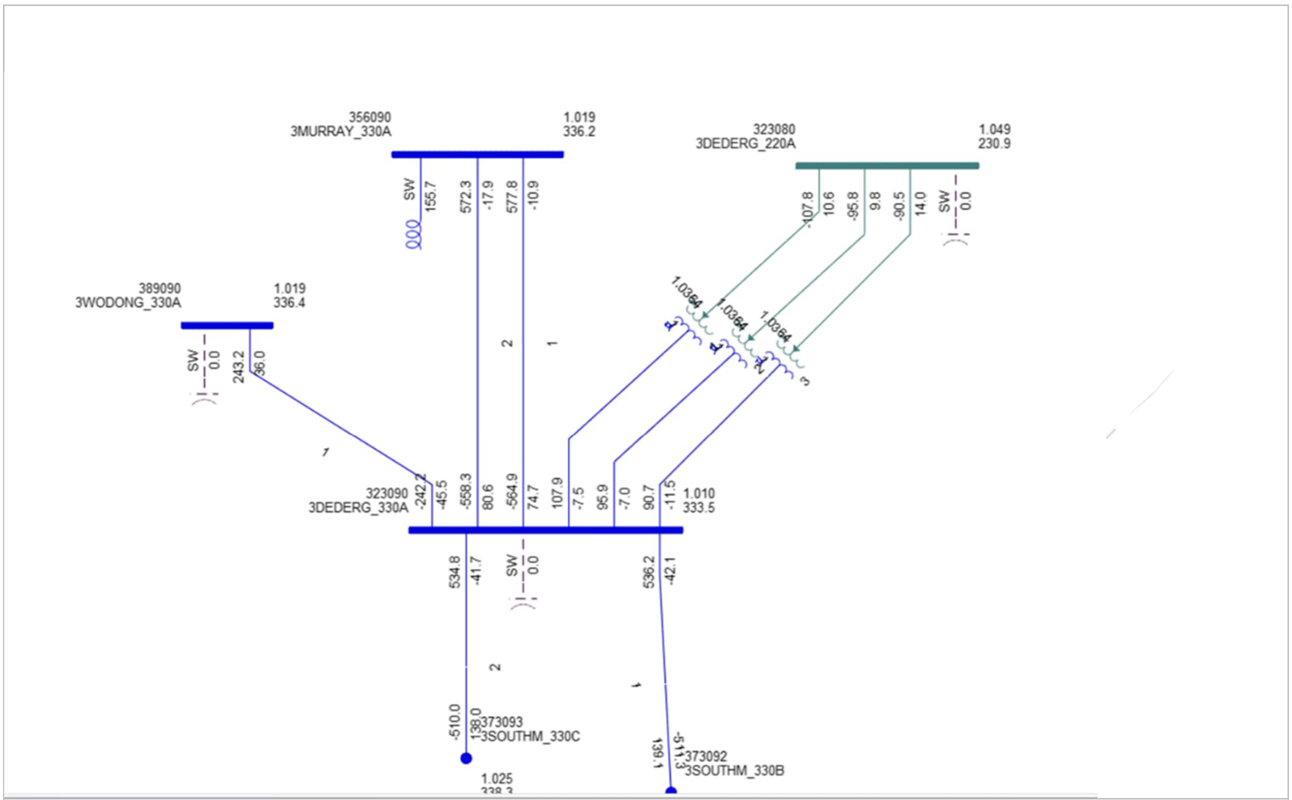
Figure 87. Summary import at 100% reactance

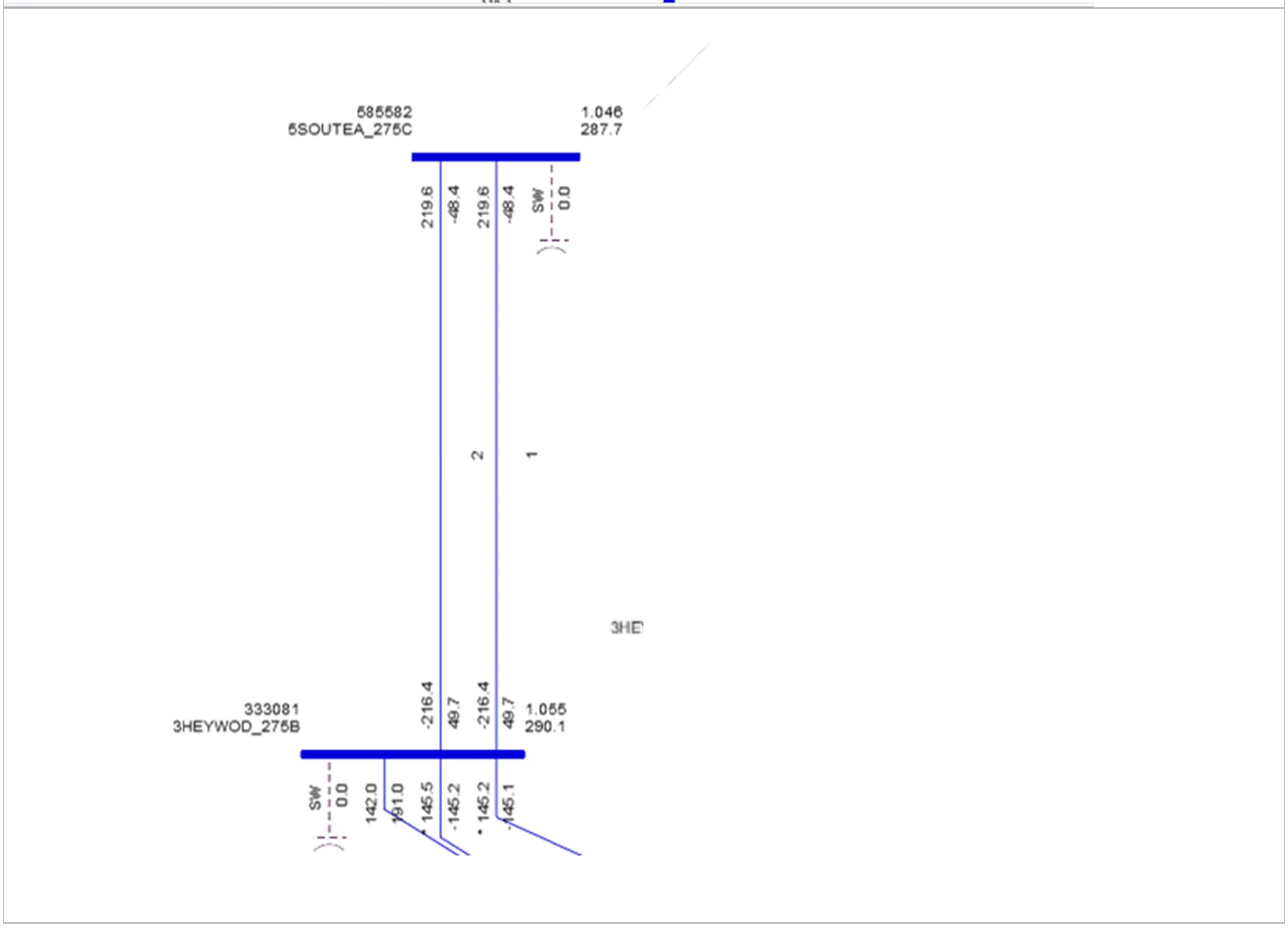
To			From		
323800	**MW**	Mvar	212001	MW	Mvar
Kerang 500	**-1044.6**	-166.8	Dinawan	1051.8	-209.4
364080			220887		
Red Cliffs 220	**-163.6**	-9.6	Buronga	164	2.4
323090			356090		
Dederang 330	**-1123.2**	155.3	Murray	1150.1	-28.8
333081			585582		
Heywood 275	**-432.8**	99.4	South East	439.2	-96.8
Total VIC import	**-2764.2**				
VIC import from NSW	-2331.4				

Figure 88. Selected calculated flows, 100% reactance






356090
3MURRAY_330A
1.019
336.2
323080
3DEDERG_220A
1.049
230.9
389090
3WODONG_330A
1.019
336.4
323090
3DEDERG_330A
1.010
333.5
373093
3SOUTHM_330C
1.025
373092
3SOUTHM_330B


585582
5SOUTEA_275C
1.046
287.7
333081
3HEYWOD_275B
1.055
290.1

3.5.2 Stability

There are a number of points to consider when addressing this very important issue.

The first point to consider is that, in the NEM, there are numerous special control schemes designed to prevent cascading system black events, including:

- System splitting scheme to limit impact of a major contingency to one region e.g., split the Vic-NSW 330kV interconnector at Murray Power Station for a blackout in Victoria (or NSW).
- Special control schemes in use today e.g., Emergency Generation Reduction Scheme for loss of both 500kV circuits into Heywood and consequential loss of both South Australia and the Portland smelter. The EGRS is designed to be high speed.
- Under-frequency tripping of smelters (Under Frequency Load Shedding, or UFLS)
- Special Protection Schemes in Tasmania to protect against loss of the HVDC connection to Victoria.
- Special Protection Schemes in NSW for loss of Line 63 (Wagga-Darlington Point 330kV)

These examples are not exhaustive but do show that considerable attention is paid to keep the network as intact as possible even in the event of extreme (i.e., non-credible) contingencies.

The next point is whether or not a 500kV double circuit outage will actually result in system collapse. Plan B report and submissions[94] has stated that any 500kV double circuit outage will definitely result in system collapse.

Jacobs has considered what would likely happen in the event of a 500kV double circuit outage at times of maximum transfer. Jacobs has studied this outage scenario and has shown that the network is actually reasnably resilient and can withstand this non-credible 500kV contingency. Similarly, Jacobs has analysed an additional transient stability case for tripping of 500kV double circuit lines between Kerang and Dinawan These transient stability analyses were consucted with an additional load flow assessment at maximum Vic Import from NSW (2,600MW). This is beyond AEMO's published expected transfer limit of 2,200MW.

The additional load flow results are presented in the table below. Of relevance to the discussion is that the Vic Import flows are spread almost evenly between the 500kV Kerang-Dinawan link and the existing 330kV VNI into Dederang. This means that the existing 330kV VNI link into Dederang is operating at around 50% of its nominal capacity.

Study Conditions: Vic Import from NSW = 2,600MW

Studies:

- Load Flow (steady-state) before and after 500kV double circuit outage
- Transient Stability for tripping of 500kV double circuit lines between Kerang and Dinawan.
- Transient Stability for fault + double circuit 500kV line trip

[94] Plan B report Page 55, submission by Prof Bartlett and Mountain 5 April 2023 on the VNI West Consultation – Options Assessment, at Page 29

Load Flow results

Table 1 Load flow results before and after double circuit outage

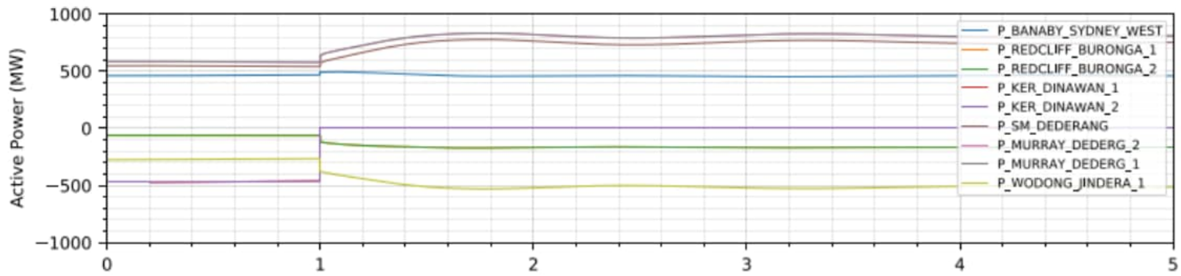
To	From	Before	After
323800	212001	MW	MW
Kerang 500	Dinawan	-1056	0
364080	220887		
Red Cliffs 220	Buronga	-156.8	-423
323090	356090		
Dederang 330	Murray	-1179	-1690
389090	242490		
Wodonga 330	Jindera	-232.9	-556.9
333081	585582		
Heywood 275	South East	-418	-524

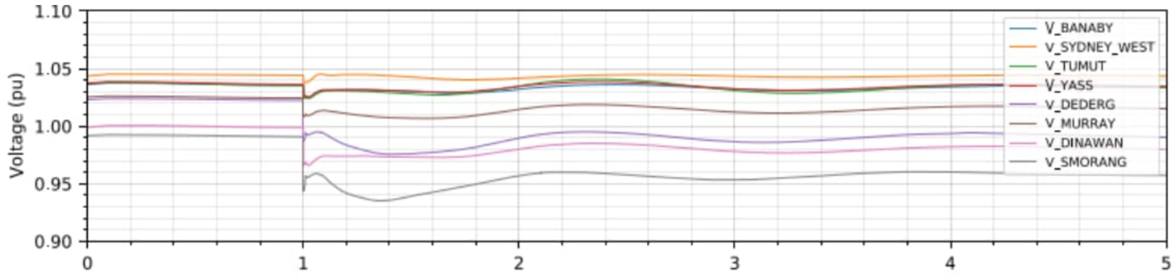
The total Victorian import from NSW is around 2,600MW – significantly in excess of AEMO's published limit of 2,200MW.

Transient Stability Results - Trip

Study: Open both Kerang-Dinawan 500kV circuits at T=1.0sec with Vic importing 2,600MW from NSW. The MW Flow results are shown below. Jacobs note:

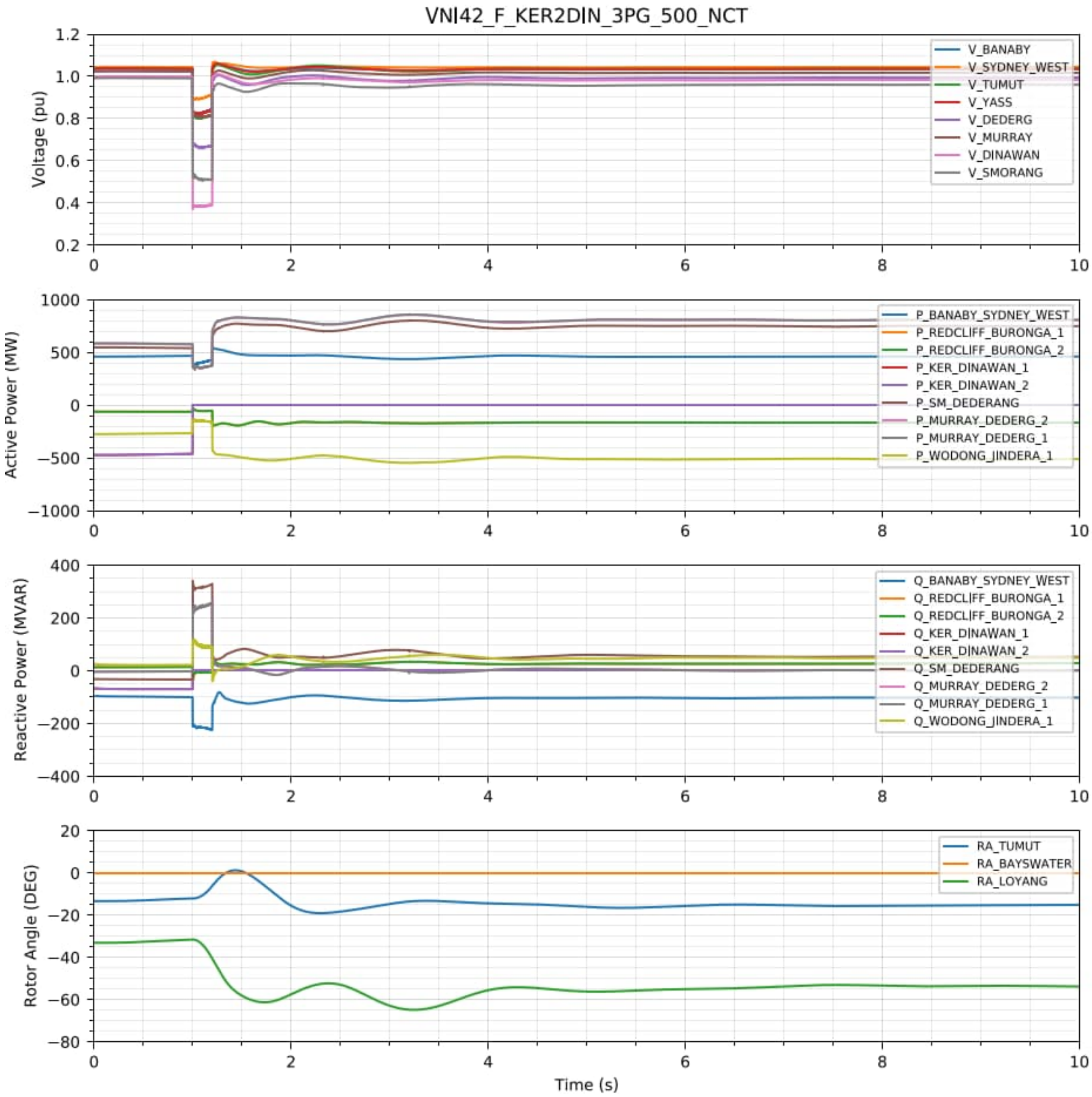
- At T=1.0 sec, the Kerang-Dinawan 500kV flows go to zero
- The Dederang-Murray 330kV flows increase by around 300MW per circuit (600MW in total)
- Network voltages are above 0.95 pu – indicating a viable post-contingency result
- The results show excellent damping





Transcient Stability Results – Fault followed by trip

Results for a 3PG fault between Kerang-Dinawan lines cleared within 100ms and followed by line trips



The network is stable followpwing on from the disturbance.

Jacobs believes these results demonstrate important findings:

- The propositions made in the Plan B report regarding the impact of double circuit 500kV lines on power system security are **not** correct.
- VNIW is estimated to **improve** power system security of the NEM with respect to Victorian Import limits

Study Limitations

It is important to note that the studies above do **NOT** demonstrate that there will never be any circumstance when a 500kV double circuit outage will not result in major impact on power system security. These study results should be taken as indicative only. Jacobs would expect that there would be hundreds (if not thousands) of detailed studies to properly examine a major new interconnector as the design progresses. For example the following studies would be expected:

- The outage of the Kerang-Bulgana 500kV double circuit lines
- The outage of the Bulgana-Sydenham 500kV double circuit lines
- Outages under Victorian export conditions
- Jacobs' assessment has not considered prior outages (e.g., planned outage of a Murray-Dederang 330kV line). Jacobs would expect this aspect would be the subject of operational limits being applied (such as constraint equations witin the NEM Dispatch Engine[95].
- The impact of different generation scenarios
- The impact of different demand scenarios

For these reasons, Jacobs would expect AEMO would, in due course, give consideration to the installation of Special Protection Schemes to trip load (e.g., smelter) or generation, as the case may be.

Jacobs evaluates that if the two 500kV circuits are lost together at these flows into Victoria that the system will be manageable with normal system security arrangements without a cascading collapse to system-black in Victoria.

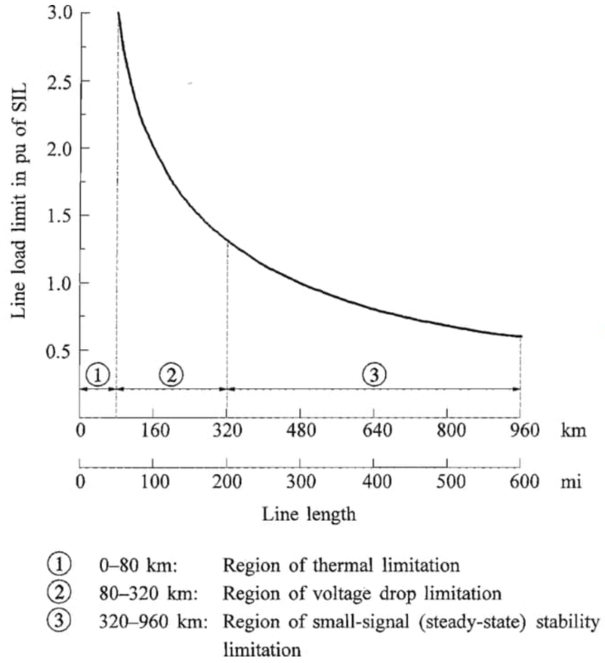
There are numerous means that can be employed to manage and mitigate the consequences of a failure of a double circuit tower or a double circuit fault event. This includes market constraints, re-classification of certain events as credible during particular weather conditions and operational systems such as special control schemes.

3.5.3 St Clair Curve

Professor Bartlett has used the St Clair curve approach to estimate the capability of transmission lines. The concept of a St Clair curve is that it can provide a generalised assessment of transmission line capability as a function of line length alone. Jacobs' view is that this is a tool for preliminary analysis. However, the results become problematic when assessing a line connecting into an actual network with significant reactive compensation. Thus, use of the St Clair curve can under-estimate the transmission capability by ignoring the impact of reactive support.

[95] The NEM Dispatch Engine (NEMDE) is the software that calculates the optimum mix of dispatchable generation and dispatchable load, and the consequent price, in each dispatch interval (presently 5 minutes) subject to a large list of constraints that must be met

Figure 89. St Clair curve[96]



The St. Clair curve as based on the results of [14] retrieved from [15] is used to estimate the maximum loadability of a transmission line. It combines three major causes for transmission limitations (thermal limitations, voltage drop limitations and steady-state stability limitations) in a single, simple relationship. This relationship allows a transmission line's maximum capacity to be estimated as a function of the line's length alone.

Victorian example:
Based on actual circuit (HWTS-SMTS 500kV and SMTS-DDTS 330kV):

500kV SIL Calculations					
	HWTS-SMTS 500kV				
	distance=	154.2			
	r=	0.0011			
	x=	0.01595			
	b=	169.1	MVAr charging		
I =	1030	MVA	=SIL of 500kV line with		
	10.30	pu	thermal rating of 3200MVA		
I^2.X =	1.69115	pu			
	169.1	MVAr	Line Q loss		

330kV SIL Caclulations					
	SMTS-DDTS 330kV				
	distance=	225.3			
	r=	0.0088			
	x=	0.0674			
	b=	89.55	MVAr charging		
I =	365	MVA	=SIL of 330kV line with		
	3.65	pu	thermal rating of 976MVA		
I^2.X=	0.895576	pu			
	89.56	MVAr	Line Q loss		

From these calculations:

500kV SIL[97] = 1030 MVA (when Line charging = Line Q loss). Thermal limit ~3,200MVA

330kV SIL = 365 MVA (when Line charging = Line Q loss). Thermal Limit ~ 1,000MVA

The St Clair curve puts the load limit as follows:

- 154km 500kV example – line capability ~2 times SIL (2060MVA) but it can reach thermal loading limit of 3200MVA. (~ 3 times SIL). The reason for this difference is due to the large amount of reactive support

[96] Cited in a submission provided by Plan B proponents "Verification of hosting capacity of Plan B", referenced to **IEEE** https://ieeexplore.ieee.org/document/4113522

[97] Surge Impedance Loading

provided at the receiving end (Melbourne). This support consists of >400MVAr of shunt capacitors and 2 x 100MVAr SVCs.

- 225km 330kV example – line capability ~1.6 times SIL (586MVA) but can be operated to over 1,000MVA. The reason for this difference is due to the presence of 330kV series capacitors at South Morang and the large amount of reactive support provided at the receiving end (Melbourne). This support consists of >400MVAr of shunt capacitors and 2 x 100MVAr SVCs.

3.5.4 Series Compensation

Prof. Bartlett stated that the proposed 500kV series compensation between Kerang and Bulgana is "*unlikely to be successfully implemented for a range of reasons*"[98]. He has stated that the issue of sub-synchronous resonance (SSR) will be the main cause – specifically Sub-Synchronous Control Instability (SSCI) with renewable generation.

Jacobs notes that there is existing 50% Series Compensation on the Dederang-South Morang 330kV lines, and that this has been in service for nearly 30 years without any SSR/SSCI issues. Jacobs does accept that this may be due to the absence of nearby renewable generation.

In addition, SSR protection relays can be installed on series compensation facilities. These relays are designed to detect SSR and switch out the series compensation. A CIGRE/American Electric Power paper[99] describes such devices.

3.5.5 Victorian tower failures – January 2020

In Victoria there was an extreme localised storm even on Friday, 31 January 2020 that caused six 500kV double circuit overhead line towers to fall over with one severely damaged near the town of Cressy in South-West Victoria (illustrated in Figure 90). As detailed in AEMO Final Report VIC-SA separation 31 Jan 2020 the outage of the MLTS-MOPS and MLTS-HGTS lines resulted in the separation of South Australia from Victoria, but left generation at Mortlake Power Station, Macarthur wind farm and Portland wind farm connected to the South Australia network. The APD aluminium smelter was also left connected to South Australia, but both potlines tripped co-incident with the faults on the MLTS-MOPS and MLTS-HGTS lines.

Figure 90. Fallen Victorian 500kV tower

[98] Note dated 9 October 2023

[99] "A New Subsynchronous Oscillation Relay for Renewable Generation and Series Compensated Transmission Systems" by Yanfeng Gong, Yiyan Xue and Ben Mehraban 2015

In response to the unavailability of the MLTS-MOPS and MLTS-HGTS lines, AEMO worked with market participants to develop and implement a plan to supply the APD load from the Mortlake Power Station and maintain a secure operating state in South Australia (see Section 10 of this report for further details). This plan remained in place until the MLTS-HGTS line was returned to service on 17 February 2020. This was the longest separation of the Victoria and South Australia networks and the first time APD has been connected to the South Australia network without a connection to Victoria.

The MLTS-MOPS line was returned to service on 3 March 2020. It should be noted that both lines were returned to service via temporary towers. Permanent replacement of the damaged towers were completed in March 2021.

This incident had several impacts on the power system including:

- High frequency in South Australia and the response of generating units to this high frequency.
- Reserve levels in Victoria.
- The trip of the APD load.

This incident did not result in cascading collapse of the Victorian grid. This has been the only failure of 500kV towers in Victoria. Up to Jun 2020 there had been 11 events with 45 tower failures in 61 years in Victoria (Figure 91). They are an event that can happen, at low annual probability.

Figure 91. Extract from AusNet Asset Management System (AMS) Jul 2020[100]

Figure 14 – Structure functional failure history

Eleven separate events have led to the collapse or failure of 45 structures in 61 years. In most cases the collapse of one structure caused several other structures to fail with the worst multiple-failure event taking place in 1959 on the Geelong - Colac 220 kV line when a total of eight structures failed. The Bendigo to Kerang 220 kV line has experienced four tower collapse incidents due to the tower design structural inadequacy for high intensity winds since it was constructed in 1961. A total of 18 towers have failed from four separate events in 1979, 1993, 2010 and 2014.

On the 31st of January 2020, at around 2:46pm, an extreme weather event called a severe convective downburst went across the transmission line near Cressy which is located a few kilometres from Geelong. The intensity of the wind was so strong that it brought down six-500kV towers and damaged a seventh tower. The six towers fell almost perfectly transverse to the line's alignment while the seventh tower was twisted along its superstructure. This tower fortunately did not collapse as it was only a few metres from an arterial road and the event occurred just as a road user was travelling underneath the circuits.

Table 4 – Structure collapse incidents

Year	Number of towers	Cause	Tower Type	Voltage	Location
1959	1	Extremely high winds	Suspension tower	220 kV	Yallourn-Melbourne
1959	8	Extremely high winds	Suspension towers	220 kV	Geelong-Colac
1962	6	Tornado	Suspension towers	220 kV	Geelong-Colac
1979	4	Severe Thunderstorm	Suspension towers	220 kV	Bendigo-Kerang
1981	1	Windstorm	Suspension tower	330 kV	Murray - Dederang No.2
1993	3	Severe Thunderstorm	Suspension towers	220 kV	Bendigo-Kerang
1999	3	High intensity wind gusts	Suspension towers	330 kV	Dederang- South Morang No.2
2009	1	North-westerly winds plus convection effect of bushfires	Suspension tower	330 kV	Dederang- South Morang No.1
2010	5	Microburst wind during severe Thunderstorm	Suspension towers	220 kV	Bendigo-Kerang
2014	6	Severe Thunderstorm	Suspension towers	220 kV	Bendigo-Kerang
2020	7	Downdraft wind during severe Thunderstorm	Suspension towers	500 kV	Moorabool-Heywood

The mean time between failures (MTBF) of transmission line structures has declined since 1992 due to failures of low strength towers in extreme winds. The initial improvement since 1959 was due to an increasing population

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Transmission Line Structures

size of higher strength structures, in acknowledgement of the inadequacies in early design standards. The improvement in the MTBF which was achieved since 2015, upon completion of the tower strengthening works along Bendigo to Kerang 220 kV line, the Dederang to South Morang No.1 and No.2 330 kV lines was impacted by the latest incident along the Moorabool to Heywood 500 kV line. With this latest event, the MTBF was downgraded to 6.4 years as shown in Figure 15.

[100] AusNet AMS 10-77 Transmission Line Structures 2023-27 Transmission Revenue Reset, https://www.aer.gov.au/system/files/AusNet%20Services%20-%20Technical%20AMS%2010-77%20Transmission%20Line%20Structures%20-%2029%20October%202020.pdf

3.5.6 WRL double circuit failure analysis

In the Plan B proponents' comments on Jacobs' draft report (refer to Appendix C.13[101]), they noted an additional case that they suggested should be modelled, that of a double-circuit outage of the WRL 500kV that connects VNIW to Melbourne/Geelong load centre. Jacobs has undertaken additional modelling of this pathway.

In Professor Bartlett's email of 20 November 2023, Professor Bartlett posed the following question:

> "*Why did Jacobs not undertake the N-2 study on WRL as described in plan B, on a windy day during the daytime in summer when WRL and the parallel 220 kv lines are bound to be at full load. My analysis, which was provided to Jacobs show that is certain to result in the complete blackout of Southern Victoria including Melbourne and the Smelter*."

Study details

Base case

1. System intact – VNI West and WRL 500kV in service
2. Vic Demand 5000-6000MW, NSW Demand 7000-8000MW
3. Neutral interconnector flows
4. Loy Yang generation ~ 2000MW, Snowy generation ~0MW (Murray, Lower Tumut and Upper Tumut), ~1500MW WF in south west Vic (Macarthur, Stockyard Hill and Golden Plains). This generation is a proxy in the analysis for the Victorian supply that is not using WRL at the time of the outage – vis flow that is not coming from NSW or V2+V3 REZs. After brown coal (Loy Yang) leaves the market, this would be supplied in this case by other generation and storage in Victoria (not in V2+V3) and/or from South Australia or Tasmania as applicable at the time of the outage.
5. **1600MW wind at Bulgana** (connected by 2 x 1000MW 500/220kV transformers). This should be the total of new + existing wind and should be modelled as a new 600MW generator at Bulgana 220kV bus along with all existing WF (including Murra Warra at 400MW, Ararat WF at 240MW, Bulgana at 120MW, Crowlands at 80MW, Waubra at 192MW).
6. **1600MW Solar at Kerang** (connected by 2 x 1000MW 500/220kV transformers).

This should be the total of new + existing Solar PV and should be modelled as new 2 x 500MW Solar PV generator at New Kerang 220kV bus along with all existing SF (including Kiamal SF at 200MW, Karadoc at 90MW, Wemen SF at 88MW, Bannerton SF at 88MW, Gannawarra SF at 60MW)

Outage Scenarios

Scenario 1:

Double circuit outage of Bulgana-Sydenham 500kV (leaving Bulgana 500/220kV transformers in service along with 500kV circuits from Bulgana-Kerang and Kerang-Dinawan).

[101] And a separate Professor Bartlett's email of 20 November 2023

Scenario 2:

Double circuit outage of Bulgana-Sydenham 500kV followed by trip (due to overload) of Bulgana-Waubra 220kV line.

Table 29. Generation assumptions

Detail	Generations	Existing case	Modified Case
		P (MW)	New P(MW)
	Loy Yang	2831.1	2000
Snowy 0MW approx..	Murray	1166.0	116.6
	Lower Tumut	1019.5	101.9
	Upper Tumut	458.6	45.9
South West Vic	Macarthur	29.7	93.4
	Stockyard Hill	128.8	406.5
	Golden Plains	-	1000
Bulgana existing + New	Bulgana New 220kV	-	600
	Murra Warra	118.1	400
	Ararat WF	51.9	240
	Bulgana	67.3	120
	Crowlands	39.5	80
	Waubra	62.7	192
Kerang Existing + New	Kerang New 220kV	-	1000
	Kiamal SF	0	200
	Karadoc	0	90
	Wemen SF	0	88
	Bannerton SF	0	88
	Gannawarra SF	0	60

Results – Outage of 500kV D/C lines between Bulgana and Sydenham

Results of the voltage assessment are shown in Table 30:

Table 30. Voltage assessment

Bus Number	Bus Name	VNI-West_N-0 V(p.u)	VNI-West_N-2 V(p.u)	% Change
376090	Sydenham_500	1.027	1.029	0.2
316590	Bulgana_500	1.019	1.01	-1.0
323800	Kerang_500	1.000	1.000	0.0
323090	Dedarang_330	1.019	1.018	-0.1
373091	South_Morang_330	1.016	1.009	-0.7
316580	Bulgana_220	1.012	1.012	0.0
342081	Kerang_220	1.000	1.000	0.0
309080	Ballarat_220	1.003	0.975	-2.9
351080	Moorabool_220	1.000	0.987	-1.3

These voltage results show that the 500kV and 330kV voltages across the network are not significantly affected by the double circuit 500kV outage.

Results of the thermal assessment are shown in Table 31:

Table 31. Thermal assessment

				VNI-West_N0				VNI-West_N-2			
n	To Bus	Thermal Rating	Line Name	MW	MVAr	MVA	% Loading	MW	MVAr	MVA	% Loading
316590	376090	3000	Bulgana_Sydhm_1	590.2	-170.0	614.2	20.5	0.0	0.0	0.0	0
316590	376090	3000	Bulgana_Sydhm_2	590.2	-170.0	614.2	20.5	0.0	0.0	0.0	0
316590	323800	3000	Bulgana_Kerang_1	-17.0	95.2	96.7	3.2	368.2	-1.8	368.2	12.3
316590	323800	3000	Bulgana_Kerang_2	-17.0	95.2	96.7	3.2	368.2	-1.8	368.2	12.3
323090	373092	1174.2	Dedarang_SouthMorang_1	-32.9	18.8	37.9	3.2	229.9	-24.8	231.2	19.7
323090	373093	1174.2	Dedarang_SouthMorang_2	-32.8	18.6	37.7	3.2	229.2	-24.7	230.5	19.6
309080	384080	698.9	Ballarat_Waubra_1	-348.8	81.3	358.2	51.3	-670.4	236.2	710.8	101.7
309080	351080	521.5	Ballarat_Moorabool_1	73.2	-9.2	73.8	14.2	188.3	-48.4	194.5	37.3
309080	351080	521.5	Ballarat_Moorabool_2	95.3	-18.5	97.1	18.6	242.3	-80.2	255.3	48.9
310781	378080	706.1	Ballarat-Terang_1	90.2	-15.6	91.5	13.0	123.7	-28.3	126.9	18
311080	327080	500.6	Bendigi_Shepparton_1	111.3	-47.8	121.1	24.2	156.8	-65.6	170.0	34
333081	585582	762	Heywood_South_1	85.5	-23.2	88.6	11.6	15.6	-16.9	23.0	3
333081	585582	762	Heywood_South_2	85.5	-23.2	88.6	11.6	15.6	-16.9	23.0	3

These results show that the 500kV, 330kV and 220kV line flows across the network are not significantly affected by the double circuit 500kV outage. Essentially, a large part of the generation around Bulgana changes direction and flows north into Kerang and enters into Victoria via the 330kV network, as follows:

- The flow from Bulgana to Kerang increases by 770MW.
- The Dederang-South Morang 330kV flow then increases by approximately 530 MW.
- The Waubra-Ballarat 220kV increases by 320MW.
- Table 31 shows the Bulgana-Sydenham 500kV flows going to 0MW after the contingency.

Table 31 does show that the 220kV line from Waubra-Ballarat is loaded to 101.7% after the contingency. Jacobs notes that this is based on a circuit rating of 698.9MVA – as provided in AEMO's OPDMS snapshot.

Jacobs has not been able to verify this rating and suggests that this rating should be confirmed (in due course). If the rating is less than 698MVA, then the prospective overloading could be much greater than indicated – requiring overload tripping of the 220kV line. The next section considers the impact of such overload tripping.

Results – subsequent outage of Waubra-Ballarat 220kV line

– Outage of 500kV D/C between Bulgana and Sydenham together with overload tripping of the Waubra-Ballarat 220kV line.

Table 32. Voltage assessment (subsequent outage case)

Bus Number	Bus Name	VNI-West_N-0 V(p.u)	VNI-West_N-3 V(p.u)	% Change
376090	Sydenham_500	1.027	1.029	0.2
316590	Bulgana_500	1.019	1.007	-1.2
323800	Kerang_500	1	1	0.0
323090	Dedarang_330	1.019	1.01	-0.9
373091	South_Morang_330	1.016	0.999	-1.7
316580	Bulgana_220	1.012	1.012	0.0
342081	Kerang_220	1	1	0.0
309080	Ballarat_220	1.003	0.988	-1.5
351080	Moorabool_220	1	0.996	-0.4

These voltage results show that the 500kV and 330kV voltages across the network are not significantly affected by the double circuit 500kV outage along with the associated outage of the Waubra-Ballarat 220kV line. The worst impact is at South Morang 330kV bus with a voltage change of 1.7%. This relatively low voltage impact is believed to be associated with the series compensation on the Dederang-South Morang 330kV circuits.

Table 33. Thermal assessment (subsequent outage case)

				VNI-West_N-0				VNI-West_N-3			
From Bus	To Bus	Thermal Rating	Line Name	MW	MVAr	MVA	% Loading	MW	MVAr	MVA	% Loading
316590	376090	3000	Bulgana_Sydhm_1	590.24	-170.04	614.24	20.5%	0	0	0	0%
316590	376090	3000	Bulgana_Sydhm_2	590.24	-170.04	614.24	20.5%	0	0	0	0%
316590	323800	3000	Bulgana_Kerang_1	-16.99	95.22	96.72	3.2%	683.98	-20.99	684.3	23%
316590	323800	3000	Bulgana_Kerang_2	-16.99	95.22	96.72	3.2%	683.98	-20.99	684.3	23%
323090	373092	1174.2	Dedarang_SouthMorang_1	-32.89	18.78	37.87	3.2%	390.75	-43.41	393.15	33%
323090	373093	1174.2	Dedarang_SouthMorang_2	-32.84	18.58	37.73	3.2%	389.68	-43.14	392.06	33%
309080	384080	698.9	Ballarat_Waubra_1	-348.82	81.32	358.17	51.2%	0	0	0	0%
309080	351080	521.5	Ballarat_Moorabool_1	73.2	-9.16	73.77	14.1%	63.9	-28.44	69.94	12%
309080	351080	521.5	Ballarat_Moorabool_2	95.31	-18.53	97.1	18.6%	81.4	-42.91	92.02	16%
310781	378080	706.1	Ballarat-Terang_1	90.18	-15.64	91.53	13.0%	87.46	-18.61	89.42	12%
311080	327080	500.6	Bendigi_Shepparton_1	111.25	-47.81	121.09	24.2%	136.33	-78.32	157.22	27%
333081	585582	762	Heywood_South_1	85.5	-23.22	88.6	11.6%	-34.42	-2.16	34.49	-5%
333081	585582	762	Heywood_South_2	85.5	-23.22	88.6	11.6%	-34.42	-2.16	34.49	-5%

These results show that the 500kV, 330kV and 220kV line flows across the network are not significantly affected by the double circuit 500kV outage and associated tripping of the Waubra-Ballarat 220kV line. Essentially, a large part of the generation around Bulgana changes direction and flows north into Kerang and then enters into Victoria via the 330kV network, as follows:

- The flow from Bulgana to Kerang increases by 1,400MW.
- The Dederang-South Morang 330kV flow then increases by approximately 850 MW.
- The import from Heywood increases by 240MW.
- Due to the outages, Table 5 shows the Bulgana-Sydenham 500kV flows and the Waubra-Ballarat 220kV flow reducing to 0MW.

Conclusions

- This study was carried out using the north-west Victorian generation scenario and double circuit 500kV outage scenario suggested by Professor Bartlett.
- The study results show:
  - With a double circuit outage on the Bulgana-Sydenham 500kV lines there is no significant impact on either voltages across the system or on network loading – with the possible exception of the Waubra-Ballarat 220 line.
  - If it assumed that the Waubra-Ballarat 220kV line is tripped (by an overload relay), the network voltages and line loadings are satisfactory.
  - The power flows are re-directed primarily onto Bulgana-Kerang 500kV circuits and then onto the Dederang-South Morang 330kV circuits, (together with an increase in import from South Australia via Heywood).
- Notwithstanding the above, it is expected that with this level of overload there would be a redispatch to bring the loading back to 100% over the next couple of dispatch periods, and for higher levels of wind and solar generation a runback scheme may need to be employed as is standard for N-2 contingencies to prevent cascade outages.

Summary

In summary, the proposed N-3 contingency does not result in cascading collapse of the system nor in blackouts in southern Victoria. This in contrast with Professor Bartlett's expectations - "…. that is certain to result in the complete blackout of Southern Victoria including Melbourne and the Smelter".

3.6 Project delivery risk

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area B -6	**Project delivery risk** Plan B: "Extended VNI-West has much greater risks of project delivery delays and cost blow-outs associated with supply chain constraints, skilled labour shortages, insufficient competent contractors, social licence challenges, inadequate competition, and conflicts with other Victorian critical infrastructure provision"

No specific additional public domain materials referenced.

3.7 MCA

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area B -7	**MCA** Plan B: "Our "multi-criteria assessment" (gives Plan B a score of 23 and Extended VNI-West 79 (the lower the score the better). The biggest differences between Plan B and Extended VNI-West are in the areas of socio-economic & environmental, visual and culture & heritage. At the route of this difference is that Extended VNI-West consumes so much more land than Plan B."

No specific additional public domain materials referenced, however the following is noted:

- PACR
- Plan B

- Infrastructure Australia MCA Guidelines[102]
- Relevant objectives (NER, Environmental and planning consent frameworks, Victorian Government policy)

3.8 Hosting capacity in Gippsland

The following materials have been gathered to support Jacobs' assessment of the following proposition:

Area B -8	**Hosting capacity in Gippsland** Plan B "Appendix C: AEMO has unreasonably constrained the development of renewables in Gippsland "

The following figures (Figure 92, Figure 93 and Figure 94) are from a study Jacobs (then SKM) did for the Victorian Government (circa 2010) on Victoria's Renewable Energy Resources. The figures illustrate the relative issues of existing land use versus wind and solar resources[103].

Comparing the REZ areas with Local Government Areas, and identified land use (as at 2010), a set of LGA's considered as representative of the REZ shapes, and the areas of different land use, is shown in Table 34

Table 34. Indicative land use in REZs

						Proxy LGA landuse, km^2										
REZ	REZ area, km2	Proxy LGAs (approx)	Population (approx)	Pop.. Density (per km2)	Proxy Area, km^2	No data	Not indicated	Nature conservation	Other protected areas (incl indigenous areas)	Minimal use	Livestock grazing	Forestry	Dryland agriculture	Irrigated agriculture	Built environment	Waterbodies (not elsewhere classified)
V1	14,800	Towong, Alpine	19,000	1.3	11,460	5	0	2,959	0	602	1,722	5,574	548	33	13	4
V2	22,700	Greater Bendigo (but excl Bendigo itself), Campaspe, Gannawarra, Swan Hill, Mildura, Boloke, Loddon, Yarriambiak	140,000	6.2	39,390	53	0	1,343	292	635	14,210	1,299	17,768	3,451	266	72
V3	21,600	West Wimmera, Horsham, Northern Grampians, Ararat, Pyrenees	55,000	2.5	26,748	14	0	3,131	82	476	8,642	1,623	12,591	44	65	81
V4	14,500	Glenelg, Moyne, Corangamite	54,000	3.7	16,109	29	44	1,015	79	255	6,342	1,546	6,654	56	49	39
V5	4,900	Wellington (S half), Latrobe	69,000	14.1	12,434	22	227	2,450	223	838	2,331	3,988	1,371	359	357	268
V6	6,000	Strathbogie, Greater Shepparton	120,000	20.0	5,726	1	0	47	20	238	2,453	270	1,869	778	42	8

This is relevant to the issues of:

- Whether significant expansion of onshore wind or solar in Gippsland has merit, and
- That there may be merit from a competing land-use perspective in VRE development in V2 and V3 being more to the West of those zones rather than VNI-W acting as a "magnet' for development along its alignment

[102] https://www.infrastructureaustralia.gov.au/guide-multi-criteria-analysis

[103] Data is from circa 2010, boundaries shown are LGA boundaries at the time

Figure 92. Land use over Victorian Local Government Areas (LGAs) circa 2010

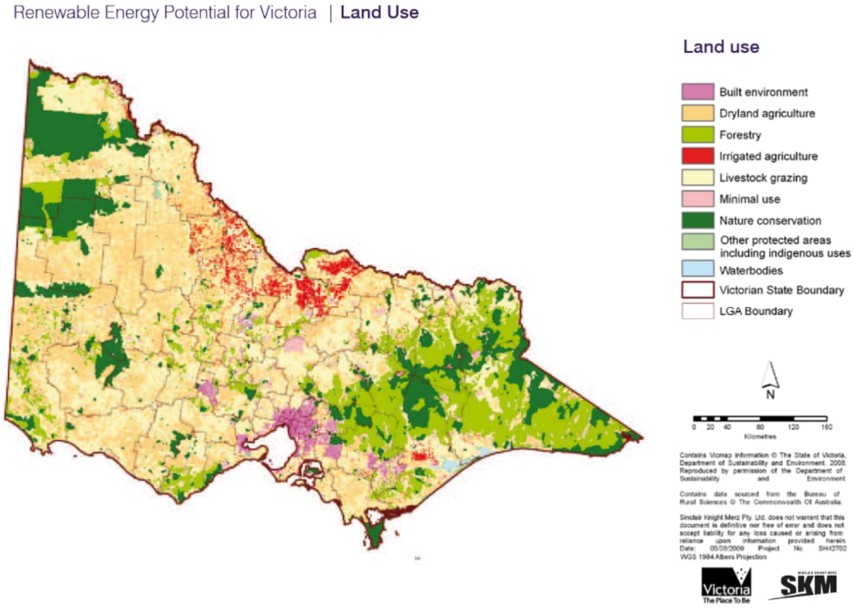


Figure 93. Indicative wind resource in Victoria

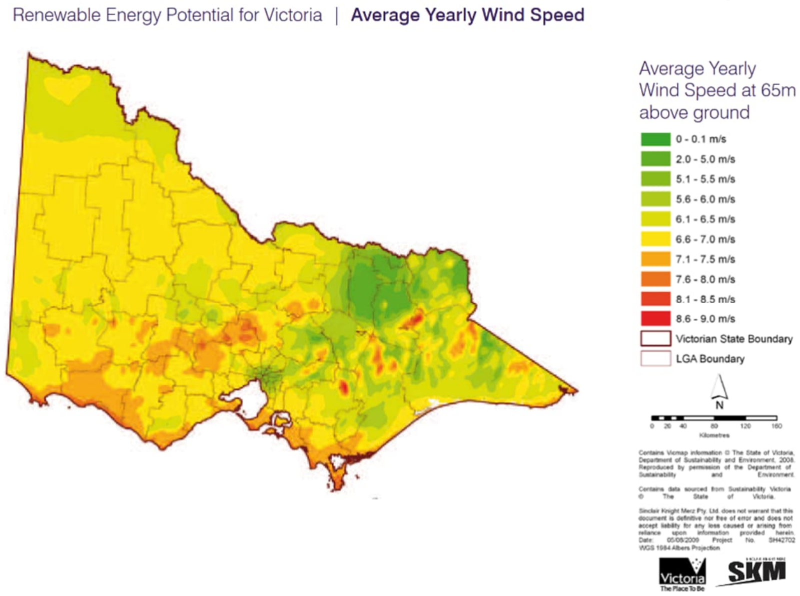
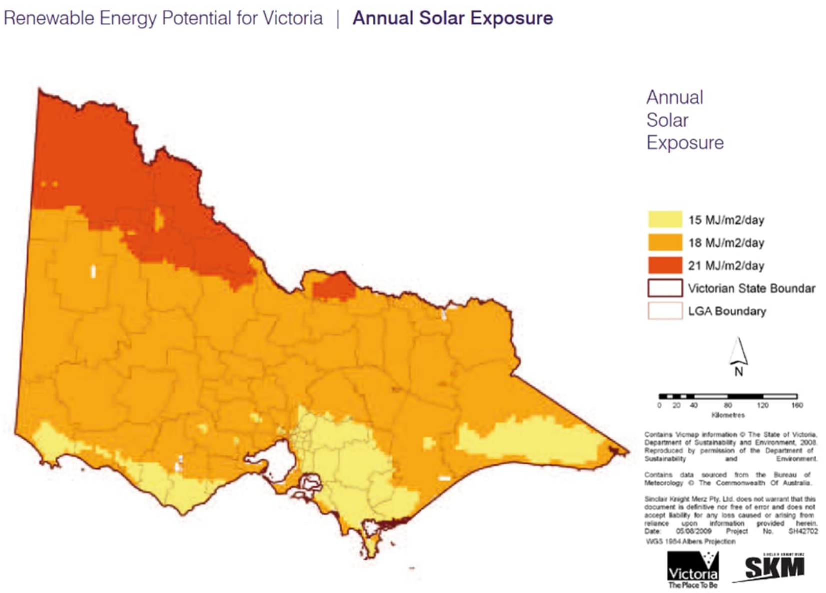
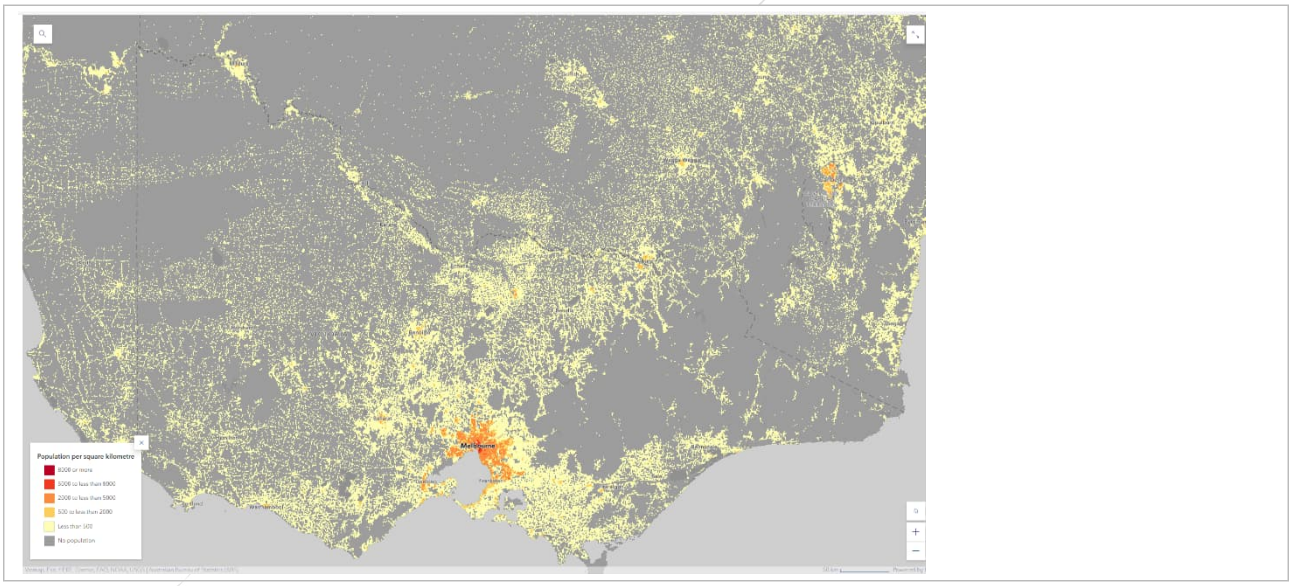


Figure 94. Indicative Victorian solar resource



The population density across Victoria can be seen in Figure 95:

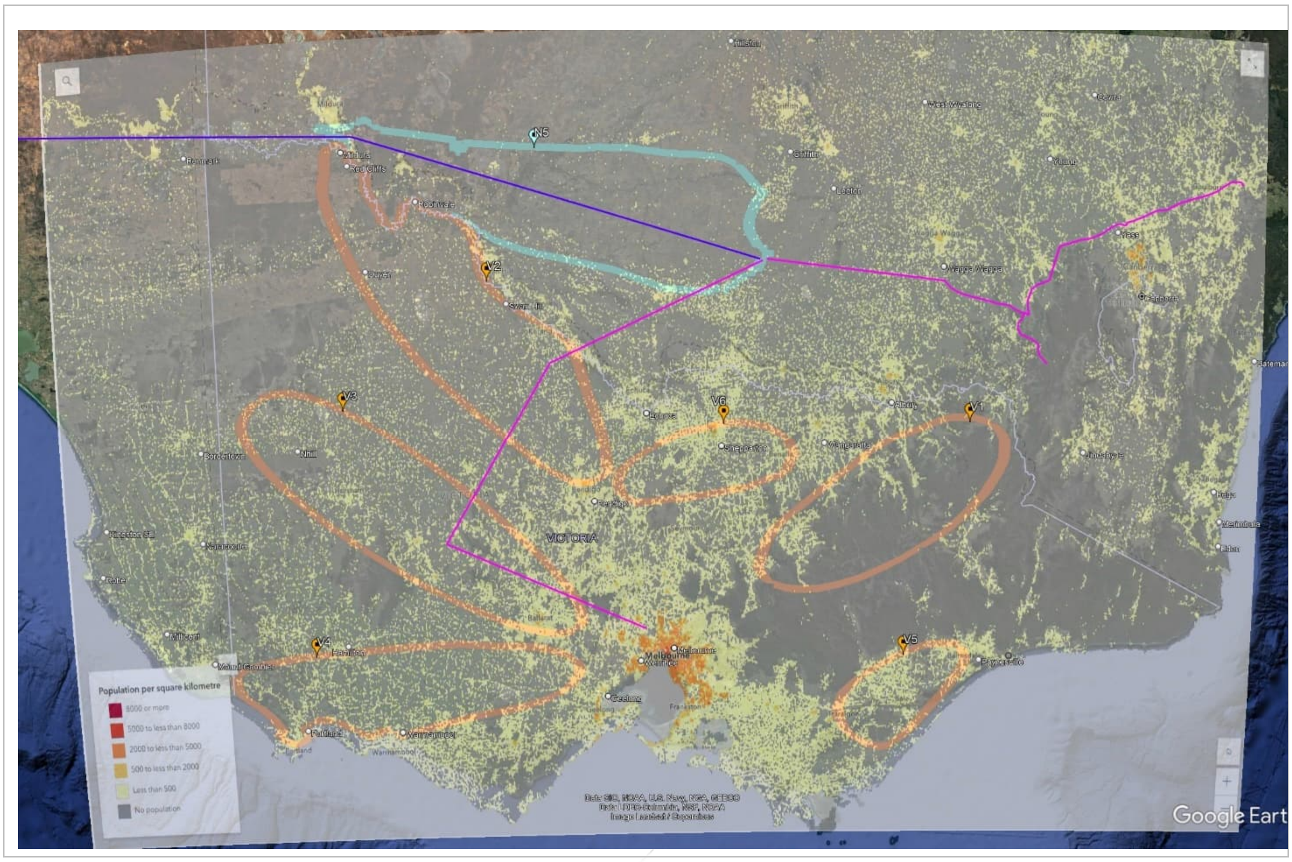
Figure 95. Regional population 2021-22[104]



For comparison, the overlay of the population density with the REZs and major relevant interconnectors is shown in **Figure 96**:

[104] Australian Bureau of Statistics "Regional Population 2021-22: Population Grid accessed at https://storymaps.arcgis.com/stories/e2eac66d11984d0e86e6d795b0ca0eec

Figure 96. Overlay of population density, REZs and major interconnectors



With respect to hosting capacity in Gippsland V5, the current REZ Initial Build Limits for Gippsland (onshore V5) are 500MW wind-high, 1500MW wind-med. And 500MW of solar[105]. A transmission limit is noted for the SEVIC1 limit. AEMO notes that land use limits of 1,031MW of wind and 2,474MW of solar are applied[106]

[105] 2023 IASR Assumptions Workbook (8 Sept 2023 version)

[106] Larger amounts 5,153MW of wind and 12,368MW of solar, are identified for the Green Energy Exports scenario

Figure 97. Extracts from the 2023 Transmission Expansion Options Report (relevant to Gippsland)

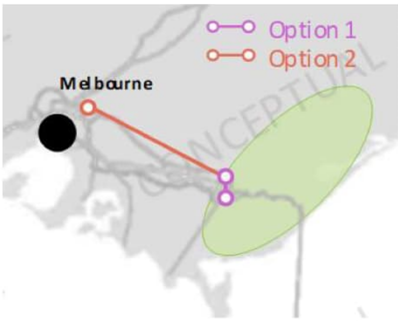
4.6.5 Gippsland (V5)

Summary

The Gippsland REZ has moderate quality wind resources, in proximity to the 500 kV networks.

The Victorian Government has outlined its vision for offshore wind and has set targets for 2 GW of offshore wind capacity by 2032, 4 GW by 2035 and 9 GW by 2040. The government has announced that VicGrid will provide a coordinated transmission connection point near the Gippsland Coast[116].

VicGrid is currently undertaking consultation on the development of this infrastructure and AEMO will continue to co-ordinate with VicGrid on this matter.



Existing network capability

Due to the strong network in this REZ (with multiple 500 kV and 220 kV lines from Latrobe Valley to Melbourne designed to transport energy from major Victorian brown coal power station), significant generation can be accommodated.

However, transfer capacity from Gippsland, through the Latrobe Valley to major load centres is restricted by the SEVIC1 transmission limit and group constraint.

See Section 4.6.9 (SEVIC1 group constraint augmentations).

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
See Section 4.6.9 (SEVIC1 group constraint augmentations)				

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
See Section 4.6.9 (SEVIC1 group constraint augmentations)		

4.6.7 Gippsland Coast (V7)

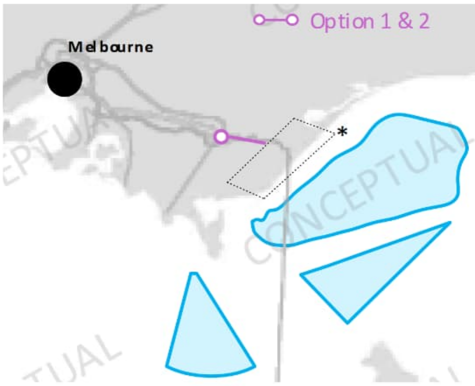
Summary

The Gippsland Coast REZ has been identified for offshore wind resource potential in relatively shallow waters close to shore, with a connection point close to existing 500 kV networks at Loy Yang/Hazelwood. There is currently significant interest in this area from a number of offshore wind farms, but projects have not developed sufficiently at this stage to be considered anticipated. Augmentation options below will provide capacity for onshore and offshore connection.

The Victorian Government has outlined its vision for offshore wind and has set targets for 2 GW of offshore wind capacity by 2032, 4 GW by 2035 and 9 GW by 2040. The government has announced that VicGrid will provide a coordinated transmission connection point near the Gippsland Coast. New transmission lines will also be developed where needed to link the common connection points with the existing energy grid.

AEMO understands from the Victorian Government and VicGrid that transmission augmentation projects for Gippsland REZ are likely to be delivered as a dedicated asset of some kind. This may need to be treated similar to a generation connection asset in the ISP model, rather than like a network augmentation.

VicGrid is currently undertaking consultation on the development of this infrastructure and AEMO will continue to co-ordinate with VicGrid on this matter. This document does not pre-empt the outcome of the VicGrid consultation. The options in this section are for ISP modelling purposes.



*Coastal location of Option 1 & 2 is expected to be within the dotted box, as per the Victorian offshore wind transmission development & engagement roadmap[117].

Existing network capability

Gippsland offshore REZ connects to the 500 kV network in the Gippsland REZ. See Section 4.6.5 for a description of existing network capability.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1: • New 500 kV double-circuit line from Hazelwood to vicinity of Gippsland coast. • 2 x 500/220 kV transformers.	2,000[118]	684 Class 5b (± 50%)	16	Long
Option 2: • New 500 kV double-circuit line from Hazelwood to vicinity of Gippsland coast. • 2 x 500/220 kV transformers. *Pre-requisite: Option 1*	6,000	684 Class 5b (± 50%)	16	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land use: Grazing • Project network element size: 10 to 100 km, no. of bays 6-10 • Proportion of environmentally sensitive areas: 50% • Location (regional/distance factors): Regional • Delivery Timetable: Long	Known risks: • Project complexity – Highly complex • Environmental offset risks – High • Cultural heritage – High • Outage restrictions – High • Compulsory acquisition – High • Others – BAU Unknown risks: Class 5b
Option 2	As per Option 1.	As per Option 1.

SEVIC1

Summary

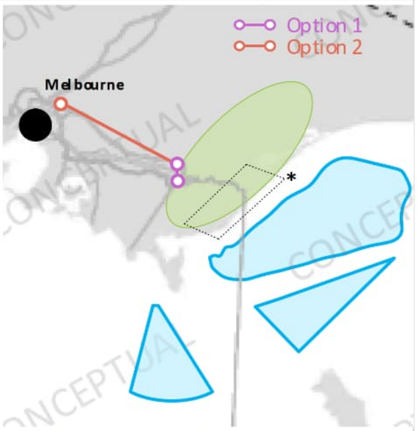
The group constraint SEVIC1 represents the generation build limit applied to V5, V7 REZs and the Tasmania – Victoria Basslink interconnector. Upgrade options associated with this group constraint may be built to improve the generation capacity in South-East Victoria. These augmentations will facilitate generation transmission to Melbourne load centre.

Existing network capability

The network capacity available for SEVIC1 is the same for V5 Gippsland and V7 Gippsland Coast.

Approximately 6,000 MW of VRE, interconnector flow and output from other generation can be accommodated at the Hazelwood and Loy Yang 500 kV substations. This includes supply from existing generation, V5, V7 and Tasmania – Victoria. This limit does not include the potential for connection of new generation at the Yallourn 220 kV substation. This limit is represented in the SEVIC1 REZ transmission limit equation.

AEMO Victorian Transmission Planning is exploring options for increasing this limit, for example through reconfiguring the arrangement of the 220 kV and 500 kV stations to ensure the existing Transmission lines are fully utilised and to support additional capacity.



* Coastal location for Gippsland Offshore connection is expected to be within the dotted box, as per the Victorian offshore wind transmission development & engagement roadmap.

Augmentation options

Description	Additional network capacity (MW)	Expected cost ($ million) & cost classification.	New transmission line easement length (km)	Lead time
Option 1: • New 220 kV double-circuit from Hazelwood – Yallourn. • 4 x 600 MVA power flow controllers (control power flowing through the Hazelwood TS 500/220kV transformers). • Substation works to accommodate new Hazelwood – Yallourn transmission lines & power flow controllers.	1,500	254 Class 5b (± 50%)	14	Medium
Option 2: • New 500 kV single circuit from Loy Yang – South Morang within the existing easement corridor. • 250 MVAr dynamic reactive compensation *Pre requisite: Option 1*	1700	947[122] Class 5b (± 50%)	-	Long

Adjustment factors and risk

Option	Adjustment factors applied	Known and unknown risks applied
Option 1	• Land Use: Grazing • Jurisdiction: VIC • Project network element size: 10 to 100 km/# of total Bays 1 - 5 • Location (regional/distance factors): Regional • Delivery timetable: Long	Known Risks: • Outage restriction : High • Project complexity: Partly complex • Environmental offset risks: Low • Macroeconomic influence: Heightened uncertainty • Others: BAU Unknown risks: Class 5b
Option 2	• Land Use: Grazing • Jurisdiction: VIC • Project network element size: 100 to 200 km/# of total Bays 1 - 5 • Location (regional/distance factors): Regional • Terrain: Mountainous Delivery timetable: Long	As per Option 1 except: • Removal of easement/property costs associated with the transmission line scope of works (existing 500 kV easement space utilised).

[122] This cost estimate assumes zero costs for acquiring property and for environmental offsets for the transmission line components, because it is assumed that an existing easement corridor can be used.

3.9 Low hanging fruit

Area B -9	**Low Hanging Fruit** Consider if Plan B elements point to "low hanging fruit" and/or "low regret" options to upgrade Vic intraregional transmission that warrant future consideration

Plan B project B1.2 proposed to install weather monitors and telecommunications on the Red Cliffs-Ballarat-Moorabool-Sydenham line. As per AEMO Victorian Annual Planning Report October 2021 the following NCIPAP projects have already been completed to increase the thermal ratings on these existing lines.

- AusNet NCIPAP project to upgrade the Ballarat – Berrybank – Terang - Moorabool 220 kV line to increase its thermal rating, including the ability for wind monitoring to input into dynamic ratings, was completed in November 2020.
- AusNet NCIPAP project to upgrade the Red Cliffs – Wemen – Kerang - Bendigo 220 kV line to increase its thermal rating, including the ability for wind monitoring to input into dynamic ratings, was completed in August 2021.

4. Area C - Consequential actions/considerations for VicGrid

- Refer to Volume 1 of the report.

Appendix A. Contextual and framework materials

A.1 National Electricity Objectives[107]

7—National electricity objective

The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system; and

(c) the achievement of targets set by a participating jurisdiction—

(i) for reducing Australia's greenhouse gas emissions; or

(ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

Note—

The AEMC must publish targets in a targets statement: see section 32A.

7AA—Regulations may prescribe matters for national electricity objective

Without limiting Part 4 of the National Electricity (South Australia) Act 1996 of South Australia, the Regulations may make provision about a matter relating to the achievement of targets mentioned in section 7(c) of this Law.

7A—Revenue and pricing principles

(1) The revenue and pricing principles are the principles set out in subsections (2) to (7).

(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—

(a) providing direct control network services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—

(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

[107] National Electricity Law as at 12/10/2023 under the "National Electricity (South Australia) Act" at NATIONAL ELECTRICITY (SOUTH AUSTRALIA) ACT 1996 - SCHEDULE (austlii.edu.au)

(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

(4) [Not shown]

(5) [Not shown]

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

A.2 Selected National Electricity Rule provisions surrounding transmission investments

5.15 Regulatory investment tests generally

5.15.1 Interested parties

[Not shown]

5.15.2 Identification of a credible option

(a) A *credible option* is an option (or group of options) that:

(1) addresses the *identified need*;

(2) is (or are) commercially and technically feasible; and

(3) can be implemented in sufficient time to meet the *identified need*, and is (or are) identified as a *credible option* in accordance with this clause.

(b) Subject to paragraph (b1), in applying the *regulatory investment test for transmission*, the *RIT-T proponent* must consider, in relation to a *RIT-T project* other than those described in clauses 5.16.3(a)(1)-(8) or 5.16A.3(a), all options that could reasonably be classified as *credible options* taking into account:

(1) energy source;

(2) technology;

(3) ownership;

(4) the extent to which the *credible option* enables *intra-regional* or *interregional* trading of electricity;

(5) whether it is a *network option* or a *non-network option*;

(6) whether the *credible option* is intended to be regulated;

(7) whether the *credible option* has a proponent; and

(8) any other factor which the *RIT-T proponent* reasonably considers should be taken into account.

(b1) Paragraph (b) only applies to the application of the *regulatory investment test for transmission* to a *RIT-T project* that is an *actionable ISP project* where a *RIT-T proponent* is considering new *credible options* under clause 5.15A.3(b)(7)(iii)(C).

(c) [Not shown]

(d) The absence of a proponent does not exclude an option from being considered a *credible option*.

5.15.3 Review of costs thresholds

Regulatory investment test for transmission thresholds

[Not shown].

Regulatory investment test for distribution costs thresholds

[Not shown]

5.15.4 Costs determinations

[Not shown]

5.15A Regulatory investment test for transmission

5.15A.1 General principles and application

(a) The *AER* must develop and *publish* the *regulatory investment test for transmission* in accordance with the *transmission consultation procedures* and this rule 5.15A.

(b) The *regulatory investment test for transmission* will apply to *RIT-T projects* which are not *actionable ISP* projects (in accordance with rule 5.16) and to *RIT-T projects* which are *actionable ISP projects* (in accordance with rule 5.16A) but will differ in its application to each of those types of projects.

(c) The purpose of the *regulatory investment test for transmission* in respect of its application to both types of projects is to identify the *credible option* that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the *market* (the *preferred option*). For the avoidance of doubt, a *preferred option* may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) to the extent the *identified need* is for *reliability corrective action* or the provision of *inertia network services* required under clause 5.20B.4.

(d) The *regulatory investment test for transmission application guidelines* under clause 5.16.2 apply to *RIT-T projects* which are not *actionable ISP projects*. (e) The *Cost Benefit Analysis Guidelines* under clause 5.22.5 apply to *RIT-T projects* which are *actionable ISP projects.*

5.15A.2 Principles for RIT-T projects which are not actionable ISP projects

[Not shown]

5.15A.3 Principles for actionable ISP projects

(a) This clause 5.15A.3 only applies in respect of the application of the *regulatory investment test for transmission* to *RIT-T projects* that are *actionable ISP projects*.

(b) The *regulatory investment test for transmission* must:

(1) assess the costs and benefits of future supply and demand if each *credible option* were implemented compared to the case where that option is not implemented;

(2) not require a level of analysis that is disproportionate to the scale and likely impact of each of the *credible options* being considered;

(3) be capable of being applied in a predictable, transparent and consistent manner;

(4) require a *RIT-T proponent* to include a quantification of all classes of market benefits identified in the relevant *Integrated System Plan,* and may include consideration of other classes of market benefits, in accordance with the *Cost Benefit Analysis Guidelines*;

(5) with respect to the classes of market benefits set out in subparagraph (4), ensure that, if the *credible option* is for *reliability corrective action,* the quantification assessment required by subparagraph (4) will only apply insofar as the market benefit delivered by the *credible option* exceeds the minimum standard required for *reliability corrective action*;

(6) require the *RIT-T proponent* to quantify the following classes of costs:

(i) costs incurred in constructing or providing each *credible option*;
(ii) operating and maintenance costs in respect of each *credible option*;
(iii) the cost of complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of each *credible option*; and
(iv) any other class of costs that are:
(A) determined to be relevant by the *RIT-T proponent* and agreed to by the *AER* in writing before the date the relevant *project assessment draft report* is made available to other parties under clause 5.16A.4; or (B) specified as a class of cost in the *regulatory investment test for transmission*;
(7) specify that the *RIT-T proponent* must:
(i) comply with the *Cost Benefit Analysis Guidelines*;
(ii) adopt the *identified need* set out in the *Integrated System Plan* relevant to the *actionable ISP project*;
(iii) consider the following *credible options*:
(A) the *ISP candidate option* or *ISP candidate options*, which may include refinements of an *ISP candidate option*;
(B) *non-network options* identified in the *Integrated System Plan* as being reasonably likely to meet the relevant *identified need*, in accordance with clause 5.22.12(e)(1); and
(C) any new *credible options* that were not previously considered in the *Integrated System Plan* that meet the *identified need* (including any *non-network options* submitted to *AEMO* in accordance with clause 5.22.14(c)(1));
(iv) adopt the most recent *ISP parameters*, or if the *RIT-T proponent* decides to vary or omit an *ISP parameter*, or add a new parameter, then the *RIT-T proponent* must specify the *ISP parameter* which is new, omitted or has been varied and provide demonstrable reasons why the addition or variation is necessary;
(v) assess the market benefits with and without each *credible option*; and
(vi) in so far as practicable, adopt the market modelling from the *Integrated System Plan*;
(8) specify that the *RIT-T proponent* is not required to:
(i) consider any *credible option* that was previously considered in the *Integrated System Plan*, but does not form part of the *optimal development path*;
(ii) consider any *non-network options* identified in the *Integrated System Plan* as not meeting the relevant *identified need*, in accordance with clause 5.22.12(e)(2); or
(iii) request submissions for *non-network options*, or otherwise seek to identify *non-network options* in addition to those assessed in the *Integrated System Plan* under clause 5.22.12(d) or submitted to *AEMO* in accordance with clause 5.22.14(c)(1); and
(9) specify the *RIT-T proponent* may, but is not required to, consider *credible options* already considered and not included in the *optimal development path* in the *Integrated System Plan*.

A.3 National Electricity (Victoria) Amendment Act

The National Electricity (Victoria) Amendment Act (NEVA), No 14 of 2020, amends the National Electricity Law (NEL) and the National Electricity Rules (NER) as they apply in Victoria

The provisions include:

1 Purposes

The purposes of this Act are—

(a) to amend the National Electricity (Victoria) Act 2005 to enable the Minister, by Order, to modify or disapply certain regulatory requirements that apply under the National Electricity (Victoria) Law and National Electricity Rules to—

(i) specified augmentations of the Victorian declared transmission system; or

(ii) services provided, or to be provided, in relation to or by means of specified augmentations; or

(iii) specified services provided, or to be provided, to a declared transmission system operator or AEMO for or with respect to the declared transmission system; and

[…]

Subject to the NEVA, the Act allows the Minister to disallow or modify certain aspects of the NEL and to pronounce that parts of the NER do not apply or are modified in Victoria as the apply to a specified augmentation or specified augmentation service and other matters.

Of relevance to VNI West, the Minister has gazetted two orders:

▪ GG2023S060 of 20 Feb 2023	Amending the NEL and NER as they apply in Victoria and making VNI-W and WRL (as varied) similar to the Gazettal below and requiring AEMO/Transgrid to publish a PACR for VNI-W
▪ GG2023S267 of 27 May 2023	[at 3.1]The carrying out of all works to construct a new high-capacity transmission line between Victoria and New South Wales connecting the Western Renewables Link with Project Energy Connect to meet the identified need described in the VNI West PADR and all associated works, insofar as such works are an augmentation of the declared transmission system, is a specified augmentation for the purposes of Division 7 of Part 3 of the Act (VNI West) [at 3.4] The carrying out of all works to meet the identified need described by AEMO in the WRL PACR, including but not limited to: (a) proposed high voltage transmission lines; (b) new terminal stations; and (c) all associated works, insofar as such works relate to the declared transmission system, is a specified augmentation for the purposes of Division 7 of Part 3 of the Act. [at 3.5] Without limiting clause 3.4, the carrying out of all works specified in Schedule 2, insofar as such works relate to the declared transmission system, is a specified augmentation for the purposes of Division 7 of Part 3 of the Act. [at 5.2] The following provisions do not apply in respect of the augmentations specified under this Order or to any of AEMO's functions conferred under this Order: (a) sections 50F(2), 50F(3) and 50H of the Law;

	(b) clauses 5.15A, 5.16, 5.16A and 5.16B of the Rules; (c) clauses 8.11.4, 8.11.6, 8.11.7, 8.11.8, 8.11.9 and Schedule 8.11 of the Rules; and (d) AEMO's planning criteria published in accordance with clause 8.11.4 of the Rules. [At Schedule 1] PREFERRED OPTION – VNI WEST Construction of a new 500 kV double-circuit overhead line from a new terminal station near Kerang to Dinawan crossing the Murray river north of Kerang to Bulgana Terminal Station (BGTS), including series compensation on the line near Kerang and 500 kV line shunt reactors at both ends of each 500 kV line segment. Construction of a new terminal station near Kerang, with two 500/220 kV 1,000 MVA transformers and up to ± 400 MVAr dynamic reactive compensation on the 220 kV network. Construction of 220 kV connections from the new terminal station near Kerang to the existing 220 kV lines near Kerang. Construction of two new 500 kV bays and line exits with a total of two 500 kV line shunt reactors at the BGTS. Modular power flow controllers or other equipment to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang and 220 kV lines between Dederang and Thomastown. Minor augmentations at existing terminal stations impacted by the above works. Refinement to the works specified above required as a result of further investigation, design and planning. Any works consequential, or related, to those specified above. [at Schedule 2] SPECIFIED AUGMENTATION – WRL UPRATE Extension of the 500 kV Sydenham Terminal Station (SYTS) by two breaker and a half switched bays. Additional 500 kV switched bus connected reactor sized approximately 100 MVar. Rerouting of the existing No. 1 Sydenham to South Morang and Sydenham to Keilor 500 kV Transmission Lines to terminate into new bays. Construction of new 220kV circuit breakers and a second 220kV bus at BGTS. Construction of a new 500 kV double circuit transmission line from SYTS to BGTS with switched estimated 70 MVAr shunt line reactors at the end of each circuit. Extension of the existing 220kV BGTS to construct an adjacent 500kV switchyard, including two 500/220 kV 1000 MVA transformers, transmission line realignment, site provisioning and line cut in works for the existing Bulgana

	to Horsham 220kV transmission line and Crowlands to Bulgana 220kV transmission line. Installation of new 220kV circuit breakers at Ballarat Terminal Station (BATS) to establish double switching on the existing 220kV bays. Cut-in, termination and switching of the existing Ballarat to Moorabool No.2 220kV transmission line at Elaine Terminal Station (ELTS), forming Ballarat to Elaine No.2 line and Elaine to Moorabool No.2 line. Re-alignment and switching of the existing Ballarat to Elaine transmission line and Elaine to Moorabool transmission lines at ELTS and renaming them to Ballarat to Elaine No.3 line and Elaine to Moorabool No.3 line. Interface activities at various terminal stations including, but not limited to: a) special control scheme requirements; b) overhead earth wire (OHEW) and optical ground wired (OPGW) requirements; c) secondary settings and physical requirements. Minor augmentations at existing terminal stations impacted by the above works. Refinement to the works specified above required as a result of further investigation, design and planning. Any works consequential, or related, to those specified above.

A.4 Victorian renewable energy and storage targets

The targets ("VRET") are described as[108]:

> Victoria's current renewable energy targets legislated in the *Renewable Energy (Jobs and Investment) Act 2017 (Vic)* are:
>
> - 25% by 2020 (achieved)
> - 40% by 2025
> - 50% by 2030.
>
> Meeting our targets will:
>
> - create investment in new renewable energy projects in Victoria
> - support the reliability of Victoria's electricity supply
> - create thousands of jobs
> - put downward pressure on electricity prices

[108] https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets

- reduce emissions from electricity generation.

We have recently announced an intention to legislate updated targets of:

- 65% by 2030
- 95% by 2035.

These targets were based on energy market modelling undertaken for DEECA by Jacobs and economic impacts modelling carried out by PwC.

The objects of the Act (at Clause 5) are:

> The objects of this Act are—
>
> (a) to increase the proportion of Victoria's electricity generated by means of large-scale facilities that utilise renewable energy sources or convert renewable energy sources into electricity; and
>
> (b) to contribute to achieving the renewable energy targets; and
>
> (c) to support the development of projects and initiatives to encourage investment, employment and technology development in Victoria in relation to renewable electricity generation; and
>
> (d) to contribute to the reduction of greenhouse gas emissions in Victoria and to achieve associated environmental and social benefits; and
>
> (e) to promote the transition of Victoria to a clean energy economy; and
>
> (f) to contribute to the security of electricity supply in Victoria.

The Act specifies that the percentages relate to generation amounts within Victoria (using 2030 as an example at Clause 7c): "*by 2030, for 50% of electricity generated in Victoria to be generated by means of facilities that generate electricity by utilising renewable energy sources or converting renewable energy sources into electricity*."

Jacobs understands that the generation amounts include rooftop PV (ie behind the meter solar) in addition to larger scale generation facility generation.

A.5 Cost Benefit Analysis Guidelines

The Cost Benefit Analysis process is undertaken by AEMO in developing the Optimal Development Path in the ISP and by the RIT-T proponent in justifying the resulting Actionable Projects (or stages for a staged RIT-T).

The comparison is against a counterfactual which is different between each type of CBA. The ISP operates on a portfolio of (related or integrated) projects and the RIT-T CBA operates on the incremental project being considered.

For the ISP formation CBA:

> *The counterfactual development path is the status quo or base case that AEMO uses to compare development paths in the ISP CBA. Specifically, AEMO estimates the market benefits*

of each development path by comparing it to the counterfactual development path, in each scenario. This is because only costs and benefits that would not have occurred in the base case should be included in a CBA. Under clause 5.22.5(d)(4)(i) of the NER, the CBA guidelines must describe the objective AEMO should seek to achieve when developing the counterfactual development path. The counterfactual development path should result in the least cost set of investments to meet power system needs in each scenario, where no ISP projects in AEMO's selected development paths are built. The guidance in this section promotes this objective.

AEMO is required to:

• develop a single counterfactual development path; and

• not include in the counterfactual development path, any ISP projects in its selected development paths (see section 3.3.1) or any projects that may become future ISP projects.

For the RIT-T CBA Guidelines of 6 October 2023[109] which is after the RIT-T for VNI West PSCR, but Take-Out-One-at-A-Time (TOOT) philosophy in assessing costs and benefits an Actionable project:

[109] The 25 August 2020 CBA Guidelines has the same guidance

Figure 98. Extract from October 2023 CBA Guidelines

Under the RIT–T instrument, all RIT–T applications to actionable ISP projects must explore an ISP candidate option as a credible option.[101] Since the ISP candidate option will form part of the optimal development path, the RIT–T proponent must remove that candidate option from all states of the world in the base case or where a different credible option is in place.[102] This is a 'take one out at a time' approach, and allows the RIT–T proponent to estimate an individual project's incremental market benefit.

Example 12 illustrates how to apply the 'take one out at a time' approach to calculate the market benefits of an ISP candidate option.

Example 12: Take one out at a time approach to ISP candidate options

The ISP has identified a transmission extension to a renewable energy zone (REZ1) as an ISP candidate option (Project B). Project B is an actionable ISP project that forms part of the optimal development path.
The RIT–T proponent will estimate the market benefits of the generation expansion path from building Project B, which results in extending the network to REZ1, by doing the following:

- Including all actionable ISP projects (including Project B) in each scenario that the ISP identifies as relevant (which may only be one of the ISP scenarios). These results will reflect states of the world with Project B in place.
- Including all future ISP projects and modelled transmission projects where scenario appropriate.
- Obtaining or deriving the base case state or other states of the world (such as where a different credible option is being tested) without Project B present. Where the ISP has not reported this information, the RIT–T proponent might request results of relevant states of the world without Project B from AEMO (if available) or work with AEMO to re-run the ISP modelling to generate the required results. Alternatively, the RIT–T proponent could independently undertake market modelling for each relevant scenario to identify the generation expansion path without the extension to REZ1.
- For each relevant scenario, calculating the difference in generation investment and dispatch costs between the expansion path in each base case and the expansion path with the extension to REZ1 in place. This will reflect changes in the location and/or type of generation plant compared with the base case.

Appendix B. Plan B submission to the PADR[110]

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8 September 2022

AEMO (Victorian Planning) and TransGrid

By email: VNIWestRITT@aemo.com.au.

Dear Madam/Sir

SUBMISSION ON VNI-WEST PROJECT ASSESSMENT DRAFT REPORT (PADR)

We appreciate the opportunity to make this submission on your VNI West PADR. This submission should be seen in the context of our prior work on transmission augmentations that AEMO has advocated for through its Integrated System Plan (ISP). This includes our submission on AEMO's Draft 2022 ISP; two reports on Marinus Link (here and here); and a submission on TransGrid's HumeLink Project Assessment Conclusions Report.

VNI West together with the "VNI West share" of the Western Renewables Link (i.e. the new North Ballarat substation and the 500 kV upgrade to the lines to the Sydenham substation) will be the biggest transmission augmentation in the history of the NEM[1]. It will increase the regulated asset value of transmission assets in Victoria by about 75%, and so is likely to proportionally increase the average transmission charges in Victoria.

The relative effect of VNI West on transmission asset values will be smaller in NSW, but it will contribute to roughly a doubling of the regulated asset value of transmission assets in NSW that will arise (before counting REZ zone investments) as a result of NSW's share of Project Energy Connect, VNI West, HumeLink and the Sydney Ring augmentation (which is driven by HumeLink).

[1] When properly counting the cost including the North Ballarat substation and upgrade of North Ballarat to Sydenham transmission line, as discussed later.

[110] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/non-confidential-submissions/victoria-energy-policy-centre---submission-to-vni-west-padr.pdf?la=en

The VNI West PADR concludes that the benefits of VNI West exceeds its costs (in the ratio of about 1.2 to 1) and so, AEMO/TransGrid argue, it should be developed and consumers in NSW and VIC should pay for. The claimed benefits are that it will defer (mainly) renewable generation and storage for about a decade while under construction and it will avoid some gas-fired generation before, but mainly after, VNI West is built.

AEMO/TransGrid's modelling results show that VNI West will make almost no perceptible difference to renewable electricity production or greenhouse gas emissions over the period that has been modelled (from 2024 to 2048) relative to the Counter-Factual that VNI West is not built. In particular, the modelling ouput spreadsheets reveal that as a percentage of total NEM generation, relative to the Counter-Factual VNI West will:

- reduce generation from gas and diesel generators by 0.5%;
- increase generation from renewable sources by 0.3%;
- increase generation from coal-fired sources by 0.3%;
- reduce greenhouse gas emissions by 0.3%.

The inconsequential impact of VNI West relative to the Counter-Factual can also be seen in the quantity of renewable generation capacity. Over the modelled period, building VNI West is associated with 3,180 MW of additional solar generation but this is more than offset by 3,722 MW less wind generation, for the Step Change scenario.

It bears particular observation that relative to the Counter-Factual, VNI West will *increase* greenhouse gas emissions by 14 $mtCO_2$ (2%) between 2024 and 2033 (Step Change). It does this by increasing electricity generation from coal and decreasing it from renewables in the period to 2034 relative to the Counter-Factual. VNI West therefore undermines the Australian Government's and State Governments' 2030 emission reduction policies, relative to the Counter-Factual.

I do not think that AEMO/TransGrid have made a persuasive argument for the construction of VNI West. To the contrary, the evidence from the modelling seems to substantiate exactly the opposite conclusion. I substantiate this view through four arguments:

1. The Counter-Factual against which VNI West's benefits are established is not consistent with governments' emission reduction policy.
2. AEMO/TransGrid has failed to account for the time value of emissions.
3. Benefits with a present value of $536m that arise after 2048 have been included but the power system is assumed to be full decarbonised by then. Such benefits will not arise.

4. AEMO/TransGrid has defined VNI West in a way that excludes a large amount of its costs and these costs are not assessed elsewhere.

Point 1: The Counter-Factual against which VNI West's benefits are established is not consistent with governments' emission reduction policy

The PADR, as with other regulatory investment tests, is a counter-factual assessment. Benefits are established by comparing the preferred case relative to a hypothetical Counter-Factual. The Counter-Factual (also known as the Base Case) is not objectively known, it is a subjective hypothesis that AEMO/TransGrid have asserted. The construction of the Counter-Factual affects the estimate of the benefits. So, it is possible to pump up the benefits not through any intrinsic property of the preferred project, but by asserting an unrealistic Counter-Factual. I argue that this is what AEMO/TransGrid has done in this PADR and I note that it is consistent, in principle even if not precisely in detail, with what TransGrid has done in the ISP.

Specifically, in the Counter-Factual AEMO/TransGrid assumes less coal generation if VNI West is not built than if it is built (755 TWh for Counter-Factual versus 772 TWh if VNI is built). The 17.3 TWh difference results in roughly 16.4 million tonnes less CO_2 from coal-fired generation in the Counter-Factual. This creates "headroom" for additional gas-fired generation in the Counter-Factual compared to with-VNI (254 TWh in the Counter-Factual versus 223 TWh with-VNI). The additional gas generation in the Counter-Factual soaks up the CO_2 headroom that arises as a result of the lower coal generation in the Counter-Factual, so that the Counter-Factual and VNI cases have similar aggregate emissions over the modelling period.

This arrangement of fossil fuel generation in the Counter-Factual is essential to the calculation of VNI West's benefits. These benefits arise firstly by having more coal-fired generation in VNI West which, in AEMO/TransGrid's calculation, creates a benefit by deferring capital expenditure on storage, wind and solar generation for about a decade. This accounts for about half the benefit of VNI West. Then, when VNI West is commissioned, it is shown to create fuel benefits by displacing the gas-fired generation that is assumed to occur in the Counter-Factual. This accounts for the other half of the benefit of VNI West.

In this way, VNI West is portrayed to be a development that is in the public interest. Exactly the same approach is adopted in the ISP to argue that the "actionable" projects are in the public interest.

But the plausibility of this approach (i.e. the way that AEMO/TransGrid has constructed the Counter-Factual) relies on the assumption that governments' emission reduction policy does not seek to continually reduce emissions. Instead AEMO/TransGrid assumes that governments are content that any early outperformance would be met with a policy response that then relaxes emission constraints so that the outperformance is then "consumed" by higher emissions (i.e. the gains from early coal generation reductions are later used up with higher gas generation).

This assumption is not consistent with any of the State government emission reduction policies and neither is it consistent with this or the previous Australian Government's emission reduction policies. In all cases, governments have set net zero targets by 2050 at the latest (or "as soon as possible" in the case of the last Australian Government which then changed its policy to "by 2050 at the latest" shortly before the Glasgow Conference of the Parties). In the case of the State governments it was, in all cases, net zero by 2050 at the latest and also with non-trivial 2030 reduction targets.

By adopting the carbon budget approach that it has, AEMO/TransGrid has established a Counter-Factual that inflates the purported benefits of its preferred option, while still being able to claim comparable aggregate emissions for the Counter-Factual and its preferred option over the modelling period. But these purported benefits are based on a bogus Counter-Factual that is inconsistent with governments' policies.

Point 2: AEMO/TransGrid has failed to account for the time value of emissions

In its analysis AEMO/TransGrid has not accounted for the time value of emissions. Emissions are a cost recognised by State and Australian Government emission reduction and renewable electricity policy. Just like the cost of fossil fuels and capital, emission costs must be brought into the analysis and valued to the present for the purpose of establishing the relative balance of costs and benefits.

I address this by calculating the greenhouse gas costs that VNI West will give rise to, compared to the Counter-Factual. These calculations use values of the Social Cost of Carbon (SCC) that range between \$100 and \$500 per tonne $CO_{2\text{-}e}$[2]. I calculate the emission

[2] For example, Ricke, K., L. Drouet, K. Caldeira, M. Tavoni. "Country level social cost of carbon." Nature (2020) https://doi.org/10.1038/s41558-018-0282-y provide a 66% confidence level estimate of SCC of US\$177–805 per tCO_2. In more recent research, Rennert, K., Errickson, F., Prest, B.C. et al. "Comprehensive Evidence Implies a Higher Social Cost of CO2". Nature (2022). https://doi.org/10.1038/s41586-022-05224-9 conclude their preferred mean SCC is USD185 per tCO_2(2020 dollars). For the avoidance of doubt, SCC is a measure in policy evaluation. It does not imply that this is the emission price that policy makers would be willing to include in electricity prices. Indeed in electricity none of the State governments or the Federal Government have agreed

cost using your data on generation dispatch by fuel type, for the Step Change and Progressive Change scenarios. In all cases there is a net emission cost (i.e. detriment). This is because, relative to the Counter-Factual, VNI West *increases* greenhouse gas emissions for the first 12 years and only starts to reduce them after that. Accounting for time preference by discounting future emission costs, correctly establishes the present value of those costs.

The table below presents the outcome of this analysis. It shows a net present emission cost (i.e. detriment or disbenefit) that ranges between $186m and $1,975m for the three estimates of SCC and for the Step Change and Progressive Change scenarios.

SCC ($ / tCO_2) / Modelled scenario	**$100**	**$250**	**$500**
Step Change	$395m	$987m	$1,975m
Progressive Change	$186m	$466m	$932m

Point 3: Benefits with a present value of about $536m that arise after 2049 have been included but the power system is assumed to be fully decarbonised by then. Such benefits will not, by definition, arise.

The emission reduction policy of all the Australian Governments demand full decarbonisation of electricity supply by 2050 at the latest. By definition, from this date, VNI can not deliver any fuel substitution benefit (there is no fossil fuel to substitute). Likewise any claim to capital deferral after 2049 is not realistic for a transmission line that by then will have been in service for 20 years, and in a fully decarbonised power system. Indeed this what AEMO/TransGrid's modelling shows for the last five years of the modelling period. Yet AEMO/TransGrid still assume around $536m[3] of benefits (present value, Step Change) arise after 2049 when the power system is assumed to be full decarbonised. This is not plausible, the number should be zero.

to explicitly include emission prices in electricity prices. This does not affect the calculation of the SCC, a measured used in regulatory and policy analysis.

[3] This is the present value of the $2.044bn residual value in 2048.

Point 4: AEMO/TransGrid has defined VNI West in a way that excludes a large amount of its cost and these costs are not assessed elsewhere

AEMO/TransGrid has excluded the cost of the North Ballarat substation and the North Ballarat to Sydenham 500 kV upgrade from the Western Rnewable Link, from the time that VNI West is commissioned. This cost must therefore be brought into the VNI West assessment from the time that VNI West has been commissioned. This means AEMO/TransGrid has understated the present cost of VNI West by around $300m.

Summary of the main points

Relative to the Counter-Factual VNI West will result in substantial increases in electricity transmission charges; will increase coal generation; makes almost no difference to aggregate renewable electricity generation expansion or greenhouse gas emissions and has a substantial emission cost because it defers emission reductions.

AEMO has advocated for VNI West (or "Snowy Link South" as it was originally known) since Snowy 2.0 was announced. Indeed AEMO's assumption that VNI West would proceed, determined the outcome of AEMO's assessment of the Western Renewables Link. By virtue of these historic pronouncements, AEMO has powerful incentives to deliver an assessment of VNI West that is favourable to it. But taking into account the bogus Counter-Factual, the failure to recognise the time value of emissions, the implausible claims of benefits even after the NEM's electricity supply has fully decarbonised and the under-statement of VNI's costs leads me to the conclusion that VNI should not be built.

From first principles it is not hard to see why VNI West does not stack up. From Sydenham to Wagga Wagga via Ballarat, Bendigo and Kerang is about the distance from Paris to Munich, to put it in geographic markers that are probably more familiar to most Australians. At around $9million per km of 500 kV line, and with three new 500 kV substations (North Ballarat, Bendigo, Dinawan) this is an enormous transmission project.

The supposed benefits of load and generation diversification between NSW and VIC, including stronger access to the generators in the Snowy Mountains, is evidently not nearly valuable enough to cover the cost of this massive transmission project.

This can be no surprise: the cost of producing electricity from the wind and sun (our future) and storying it in batteries of various forms is likely to be much the same in NSW and VIC. Just where, then, can be the value to justify such massive interconnection? It can not be found because, evidently, it does not exist.

Has the decision to build VNI West already been made?

As noted earlier, three years ago AEMO selected the more expensive option for the Western Renewables Project on the basis that much of the cost of that more expensive option need not be counted because VNI West, covering the same route in part, would be built anyway. Similarly in this PADR AEMO included $921m of benefits that it calculates will arise ***before*** the decision to build VNI West is formally made. Evidently AEMO/TransGrid assumes that VNI West will be built and also that investors are already convinced of this and so are altering their investment decisions now[4]. If so, what then is really under consideration here?

Why is an investment contrary to governments' emission reduction policy being advanced?

If the arguments and evidence in this submission withstand scrutiny, it begs the question of why an investment that is contrary to governments' emission reduction policy is being advanced. Might it be that, actually, AEMO/TransGrid do not really believe what they say will happen with and without VNI West; and that what AEMO/TransGrid really believe is that building VNI West will actually facilitate the development of renewables and so will advance, not retard, the decarbonisation of electricity supply?

If this is the case, then why does AEMO/TransGrid's not report this truth as they really believe it to be? One answer might be that the truth of the matter will not satisfy the regulatory investment test i.e. that an outcome that is consistent with emission reduction policy will not satisfy the test. If this is indeed the case – and our critique suggests it is for the project proposed – then AEMO/TransGrid is in the invidious position of choosing the truth it really believes and failing the test, or choosing a falsehood that depends on the use of a bogus Counter Factual, ignoring the time value of emissions and understating costs and so, purportedly although not in actuality, passing the test.

It would seem to me that AEMO/TransGrid has chosen the latter (pursuit of a falsehood the promises, vainly when scrutinised, to pass muster). How can this be convincing to the communities being asked to supply the "social licence" that VNI West and Western Renewables Link so desperately need? Would it not be better to tell the truth and if that fails the regulatory test as it obviously will, that difficulty that should be referred to

[4] As an aside this raises yet another conundrum intrinsic to counter-factual assessments: if investors already anticipate VNI West, then deciding on VNI-West in some future period does not give rise to the benefits that pre-date that decision – if the outcome has already been anticipated it matters not a jot what that outcome utilimately turns out to be and benefits derived in anticipation of that outcome should not be booked to the outcome.

governments to resolve. In EnergyCo and VicGrid, the NSW and VIC Governments are showing great appetite to address these challenges.

Unpriced detriments and other concerns

I draw attention to unpriced detriments including the sterilisation of large tracts of land, the loss of amenity and detrimental social and environmental impacts by communities affected by VNI West. Such detriments should be explicitly included in the evaluation.

Finally I understand that there are now shortages of skilled workers across the economy. Grandiose projects like VNI West that have adverse emission impacts and make no appreciable difference to renewable electricity generation relative to the Counter-Factual, should make way for transmission augmentations that will quickly deliver more renewable electricity generation and that will quickly reduce emissions.

Acknowledgements

I acknowledge, with thanks, helpful comments from Ted Woodley, Simon Bartlett, Hugh Outhred and also AEMO staff in their preliminary responses to questions that arose during the preparation of this submission.

Yours faithfully,

Professor Bruce Mountain
Director

Appendix C. Subsequent Plan B submissions and information

C.1 Plan B proponents' submission 5 April 2023

Simon Bartlett and Bruce Mountain made a submission on the "VNI West Consultation Report – Options Assessment". The submission is dated 5 April 2023[111]

The submission is 118pp and is not reproduced in full here. The Executive Summary is reproduced below.

> Executive Summary
>
> This document has been prepared by Simon Bartlett and Bruce Mountain and is submitted to the AEMO Victorian Planner (AVP) and TransGrid, pursuant to their invitation for submissions on the VNI West Consultation Report Options Assessment ("Consultation Report").
>
> AVP's recommendation in the Consultation Report for the development of the Western Renewables Link and VNI West ("WRL-VNI") will, if accepted by the Government of Victoria, be the most significant development in the Victorian transmission system in more than 50 years. It will open up a new 500 kV corridor cutting through the heart of western and northern Victoria and then deep into New South Wales.
>
> We have been active in the consultation on this project and on the separate predecessor project assessment reports for the Western Victoria Transmission Project (since renamed the Western Renewables Link) and VNI-West. We acknowledge AVP's efforts in responding to our questions in the short period between the publication of the Consultation Report and the closing date for submissions. We also acknowledge with gratitude the excellent debate and information provided by numerous interested parties and colleagues, in the preparation of this submission.
>
> In this submission we conclude that the development of WRL-VNI will be a monumental mistake. Specifically:
>
> 1. WRL-VNI will drastically increase the exposure of Victoria's power system to natural disasters and terrorism risk.
>
> 2. Recovering the capital outlay in WRL-VNI will increase transmission charges in Victoria by at least 70%. The ongoing operation and maintenance charge will increase transmission charges by a further 25%. In round numbers WRL-VNI will therefore double transmission charges in Victoria.
>
> 3. WRL-VNI will also detrimentally affect the efficiency of the Victorian power system by wasting existing transmission capacity (the extensive 500 kV and 220 kV network from the Latrobe Valley to Melbourne) and forcing the development of renewable electricity in locations that are further away from Victoria's main load centre and will have a large part of their renewable energy wasted by spillage due to severe congestion on VNI West. This too will push prices up relative to what they otherwise would be.

[111] At https://www.vepc.org.au/_files/ugd/92a2aa_18d15bdcf9034cc68684754e0c14d526.pdf

4. The development of WRL-VNI will delay the transition to renewable electricity in Victoria. It will do this by forcing new renewable entry to wait on the completion of this massive transmission augmentation (which is likely to take eight years to complete). It also undermines the development of onshorerenewable generation in Gippsland and adjacent areas and thus wastes the capacity of Victoria's most valuable electrical transmission infrastructure connecting the Latrobe Valley to Melbourne.

5. WRL-VNI lays the foundations for massive additional 500 kV transmission developments in west, central and northern Victoria. This is likely to involve additional expenditure at least as big as WRL-VNI to follow in the decade after WRL-VNI is completed.

6. Finally, when it was first proposed, VNI-W was christened "Snowylink South" and its rationale was claimed to be making the capacity of the promised Snowy 2.0 pumped hydro station available to Victoria. But WRL-VNI, according to AVP, makes no perceptible difference to the dispatch of Snowy 2.0 and in reality Snowy 2.0 will become choked by the congestion on VNI West and Humelink. Instead. of any gain from Snowy 2.0, AVP's analysis contends that the bulk (75%) of the benefit of WRL-VNI lies in the substitution of pumped hydro generation in Victoria by batteries in NSW.

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

Costs have been under-estimated

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

In summary:

• We estimate AVP have understated the build cost of its preferred option by $1,220m (38%) and understated the operating cost of its preferred option by $5.1bn over 50 years, or $1,012m stated as a present value (PV) in 2020/21.

• We estimate AVP's calculation of gross benefits of its preferred option of $3,921m PV is not plausible, and has been overstated by $5,185m PV, giving a (gross) detriment of $3,921m - $5,185m = - $1,264m PV. For the avoidance of doubt this disbenefit is before deducting the cost of WRL-VNI. The additional detriment (separate to the cost of WRL-VNI) will be expressed in electricity markets in the form of electricity prices that will be higher than they otherwise would be.

• After accounting for the Victorian share of the cost of WRL-VNI, we estimate a total net detriment of WRL-VNI of $6,778m stated as a PV in 2020/21. Benefit estimates are not plausible

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

• AVP have intentionally hobbled the on-shore development of renewable electricity to the east and south of the Latrobe Valley by setting hard limits on wind and soft limits on PV capacity (plus penalties for any PV above 500 MW) that bear no relation to the development potential in Gippsland. AVP have also adopted a Gippsland transmission limit of 2,000 MW, beyond which steep penalties apply. The actual transfer limit from Gippsland to Melbourne is at least 9,450 MW at 40 degrees celsius[112] and 12,500 MW at 10 degrees celsius1. VENCorp's 2005 Vision 2030 report[113] showed that the transfer capacity (which it said was 9450 MW, consistent with the 40 C rating) can be almost doubled at no great expense using existing 500kV easements, and can be increased by 30% for an inconsequentially small outlay. AEMO's transfer limit is about 3000 MW less than the "spare" capacity (assuming that coal generators have a firm transfer right as AVP assumes, contrary to the National Electricity Law) and 7,450 MW below the actual transfer limit.

• AVP have also assumed transmission expansion costs from Gippsland to its nearest load centre ($0.57m/MW) that apply for transfers above its 2,000 MW limit. But we know from the existing transfer limit that no expenditure is required up to its existing 9,450MW. And even above this amount, VENCorp's analysis provides a marginal cost (albeit in 2005$) of $0.05m/MW. Even if we increased this by 75% to state it in 2023$, that is still less than one-fifth of the amount that AEMO assumes.

• AVP's modelling assumes perfect foresight on behalf of investors but then it ignores the enormous level of spilled production from wind generation and even more so solar generation located along the WRL-VNI 500 kV corridor. Such renewable expansion would obviously not occur in the places AVP forecast if developers with the perfect foresight AVP assumes, know of the huge spilled production AVP forecast they will experience. AVP's modellers, EY, have described such spills as "economic" (i.e. that they reflect efficient overbuilding of solar and wind). This is not correct: they arise as a consequence of a modelling approach that, completely absurdly, is unaware of the spillage of the generation entry that it predicts.

The consequence of these flaws results in AVP's modelling driving renewable generation entry (particularly solar) to the far inland parts of the Victorian network that consequently experience severe network congestion. In AVP's Base Case this then drives the development and extreme running of gas-fired generation and expensive pumped hydro storage in Victoria. AVP's solution to this assumed Base Case is the construction of WRL-VNI, whose main benefit is claimed to be that it allows batteries in NSW to replace the hugely expensive pumped hydro storage in Victoria. This is explained in detail in Section 2 with further relevant detail in Appendices B, C and D.

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

We note in addition that this is a completely different rationale for the justification of VNI-West that AVP claimed in the draft assessment of VNI-West and in the final assessment and then updated final assessment of WRL. We also note that the reason for the bizarre

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

[113] Specifically it concluded that an 85% capacity increase could be achieved for $420m. Reference: VENCorp 2005, "25 Year vision for Victoria's energy transmission networks". Page 58. Available from https://www.vgls.vic.gov.au/client/en_AU/vgls/search/detailnonmodal?qu=Energy+consu mption.&d=ent%3A%2F%2FSD_ILS%2F0%2FSD_ILS%3A169664%7E%7E0&ps=300&h=8. Even if we double VENCorp's estimate, this is by far the cheapest large capacity augmentation option of all possibilities in Victoria.

generation/storage development program is because it is developed by the Plexos simulation program that locates all of Victoria's load and generation at Melbourne with no knowledge of the VNI congestion and REZ renewable spillages that occur in the subsequent phase of the process.

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

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

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

VNI presents huge reliability risk

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

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

The likelihood of severe lightning, destructive winds, fierce bushfires, widespread flooding, terrorism or even military attacks on Australia's critical infrastructure, will increase further as the climate changes. AEMO forecasts VNI will operate for up to 2,900 hours a year by 2050 at its maximum import to Victoria. An instantaneous and/or pronged outage of both 500kV circuits on this transmission line would immediately interrupt Victoria's largest electricity supply, causing a state-wide blackout to Victoria with extensive electricity rationing until the damage is rectified.

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

1. System restart requirements for each state may also have been overlooked in developing the ODP. These are essential facilities to restart their power systems following a complete state-wide blackout which is certain to occur by following the ODP.

2. The Consultation Report recommends routing VNI West even further west which increases VNI West/WRL's length by 146kms costing ~$600m and reducing its interconnector transmission limit to Victoria even further to below 1,475MW, except for the risky assumption of series compensation for only option 5.

3. Option 5 omits the new 500kV/220kV substations at Ballarat and Bendigo which will increase the constraints on the existing 220kV networks requiring the installation of 400MVAr of FACT's devices at the existing Kerang 220kV substation as well as new 220kV transmission lines to Bendigo only seven years after VNI West to "keep the lights on" in Bendigo.

4. No Sub-synchronous Resonance Studies (SSR) appear to have been undertaken by AEMO to prove the practicality of their proposed series compensation of option 5, despite this being an obvious threat to power system security and a mandatory requirement in parts of the United States. AEMO's last recommendation to install series compensation on the Heyward interconnection in 2013 has only delivered 90MW of the 190MW increased interconnector limit from South Australia to Victoria, yet AEMO is now assuming the Heyward interconnector limit will increase another 200MW as soon as Project Energy Connect is completed. This has serious ramifications for the reliability of electricity supply for Victorians. Progressing VNI West option 5 will significantly increase the risks of state-wide blackouts and extended electricity rationing in Victoria.

Conclusion

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

C.2 Plan B note on materials regarding hosting capacity issue

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Verification of Hosting Capacity of Plan B

Background

AEMO has made unsubstantiated assertions that the hosting capacity of Plan B is approximately half the levels in the Plan B report. No factual evidence has been provided by AEMO of their assertion. The purpose of this report is to verify that the hosting capacities in Plan B are technically valid. It does this thought the following steps:

(a) Recapping the claimed renewables hosting capacity for plan B and the Extended VNI West plan
(b) Clarification of the individual REZ hosting capacities
(c) Assumed geographical location of energy storage batteries incorporated in the VRET target of 2.6 GW by 2035

(d) Geographical location of existing and new renewable energy generation based on the latest queueing map provided by AEMO
(e) Application of Kundur's St Clair curve to estimate transmission capacity for various locations for Plan B
(f) Use of battery storage to shift peak solar power generation, in particular from sunny daytimes to the morning as evening peak load periods, and its impact of Plan B transmission requirements
(g) Consideration of N-1 and N-2 transmission outages
(h) Overall verification of renewable hosting capacities of Plan B, REZ by REZ

The same methodology has been applied to the Extended VNI West Plan to verify the claimed renewable hosting capacities for each REZ in that Plan, as well as the assumed scope of that plan. In, particular the requirement for WRL-VNI West to also include substantial amounts of new 220 kV transmission line in V2 (Murray River) REZ and V3 (Western Victoria) REZ.

VicGrid has advised they have engaged Jacobs Engineering to verify the claims made for Plan B, and presumably the Extended VNI West plan. The technical brief for Jacobs to undertake that work should include this report.

Recapping the claimed renewables hosting capacity for plan B and the Extended VNI West plan

Table 35. Plan B additional renewable generation hosting capacity

	V1 (Ovens Murray)	V2 (Murray River)	V3 (Western Victoria)	V4 (South West Victoria)	V5 (Gippsland)	V6 (Central North)	TOTAL
Open-circuit Buronga – Red Cliffs 220 kV line							
Increase maximum conductor temperature on some 220 kV lines		160	160				320
On-line dynamic rating Red Cliffs-Ballarat-Moorabool-Sydenham							
V3-220 kV Elaine to Moorabool			1,914				
Gippsland REZ - 500kV Loy Yang to near Basslink transition point					3,000		3,000
V2 220kV network upgrade: Red Cliffs to Murra-Warra		957					957
V3 220 kV network upgrade: Murra-Warra to Ballarat							-
V3-V4 220 kV network upgrade Ballarat – Moorabool (line 1)							
Total Phase 1 additional hosting capacity (completed by mid 2027)	-	957	1,914	-	3,000	-	5,871
Minor works at Loy Yang and Hazelwood 500 kV substations							
V2 220 kV network upgrade : Red Cliffs to Kerang		1,514					1,514
V2-V3 220 kV network upgrade Kerang-Bendigo-Ballarat lines							
V3-V4 220 kV network upgrade Ballarat-Moorabool (line 2)							-

	V1 (Ovens Murray)	V2 (Murray River)	V3 (Western Victoria)	V4 (South West Victoria)	V5 (Gippsland)	V6 (Central North)	TOTAL
V4 500 kV S/C Sydenham to Moorabool				3,000			
Total Phase 2 additional hosting capacity (completed by mid 2031)	-	1,514	-	3,000	-	-	4,514
V6-V1 220kv line Shepparton-Glenrowan-Dedarang						1,100	1,100
Total Phase 3 additional hosting capacity (completed by mid 2035)	-	-	-	-	-	1,100	1,100
Total Plan B additional hosting capacity by mid 2035	-	2,471	1,914	3,000	6,000	1,100	14,485

Table 9. Extended VNI-West additional renewable generation hosting capacity in each REZ by 2035

Extended VNI-W Plan	V1 (Ovens Murray)	V2 (Murray River)	V3 (Western Victoria)	V4 (South West Victoria)	V5 (Gippsland)	V6 (Central North)	TOTAL
WRL 500kV Sydenham to Bulgana			1,460				1,460
500kV D/C Loy Yang to Basslink Transition					3,000		3,000
220kV S/C Shepparton to Dedarang via Glenrowan						400	400
VNI West option 5A 500kV Bulgana to NSW border		1,580	200				1,780
500kV S/C Sydenham to Mortlake				3,000			3,000
220kV network for V3 (Western Vic REZ) - for WRL							-
220kV network for V2 (Murray River REZ) - for VNI West							-
Total additional Hosting capacity by 2035		1,580	1,660	3,000	3,000	400	9,640

VNI west PACR claimed renewables hosting capacity (N5 hosting capacity is not in Victoria and should be excluded)
Leaving 1,580MW in V2 and 1,660MW in V3, comprising 1,780MW attributable to VNI West and 1,460MW attributable to WRL

Table 1 Summary of the credible options assessed

Option	Indicative impact on transfer capability		Indicative impact on REZ transmission limit	
	VIC to NSW	NSW to VIC	Individually	Total
Option 5 (near Echuca)	+1,960 megawatts (MW)	+1,710 MW	V2 – Murray River: +1,075 MW** V3 – Western Vic (WRL timing): +1,460 MW*** V3 – Western Vic (VNI West timing): +200 MW N5 – South West NSW: +900 MW	+3,635 MW
Option 5A (north of Kerang)	+1,935 MW	+1,669 MW	V2 – Murray River: +1,580 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +200 MW N5 – South West NSW: +900 MW	+4,140 MW
Sensitivities				
Option 5A (westerly sensitivity)	+1,910 MW	+1,650 MW	V2 – Murray River: +1,460 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +0 MW N5 – South West NSW: +900 MW	+3,820 MW
Option 5 (without series compensation)	+1,750 MW	+1,500 MW	V2 – Murray River: +800 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +0 MW N5 – South West NSW: +900 MW	+3,160 MW

Clarification of the individual REZ hosting capacities

Plan B demonstrated that the total Victorian renewables hosting capacity required to achieve the VRET targets are as follows, based on interpreting VRET as the percentages of Victoria's electricity usage to be supplied by renewable generation located in Victoria.

Table 36. Large scale renewable energy generation shortfall (GWh)

Row	Source	2023/24	2024/25	2029/30	2034/35
1	Hydro	2,748	3,336	3,418	3,405
2	Wind (after curtailment)	10,177	12,813	20,737	29,132
3	Large-scale PV (after curtailment)	2,205	1,888	1,850	5,154
4	Rooftop PV (after curtailment)	3,872	4,128	5,100	5,460
5	Total Victorian renewables (after curtailment)	19,002	22,165	31,105	42,691
6	VRET target	37%	40%	65%	95%
7	Required renewable generation	15,578	17,040	27,706	47,832

6	Total electricity consumed in Victoria (see [referenced elsewhere])	42,103	42,601	42,625	50,439
9	Shortfall in renewable generation compliance (GWh) (negative is shortfall)	0	0	0	5,141
10	Shortfall in renewable capacity (MW)	0	0	0	2,130 MW

Table 37. Required minimum VRE hosting capacity for Plan B to comply with VRET

	2023/24	2029/30	2034/35
Option 5A: wind	4,122 MW	8,141 MW	9,881 MW
Option 5A: large scale PV	1,082 MW	1,082 MW	2,892 MW
Option 5A: Total VRE	5,204 MW	9,223 MW	12,773 MW
Shortfall (row 10 of Table 36)	0	0	2,130 MW
Plan B required minimum hosting capacity	5,204 MW	9,223 MW	14,903 MW

The objectives of Plan B are to support VRET, not to exceed VRET (as that makes no sense) as well as providing additional hosting capacity to

- Slash wastage of existing renewables at Murray River V2 and Western Victoria V3 REZ by cutting spills from 40% to 13% and increasing m.l.f.'s from 0.87 to 0.93
- diversify large scale supply around the state

It also supports a much earlier development of solar farms and increased flexibility to accommodate the uncertainty in exactly where and when new renewable generation will be developed.

Assumed geographical location of energy storage batteries incorporated in the VRET target of 2.6 GW by 2035

VRET includes the installation of at least 2.6 GW of energy storage in Victoria by 2035. The obvious locations for that energy storage are alongside solar farms in Murray River V2 REZ, as it simultaneously

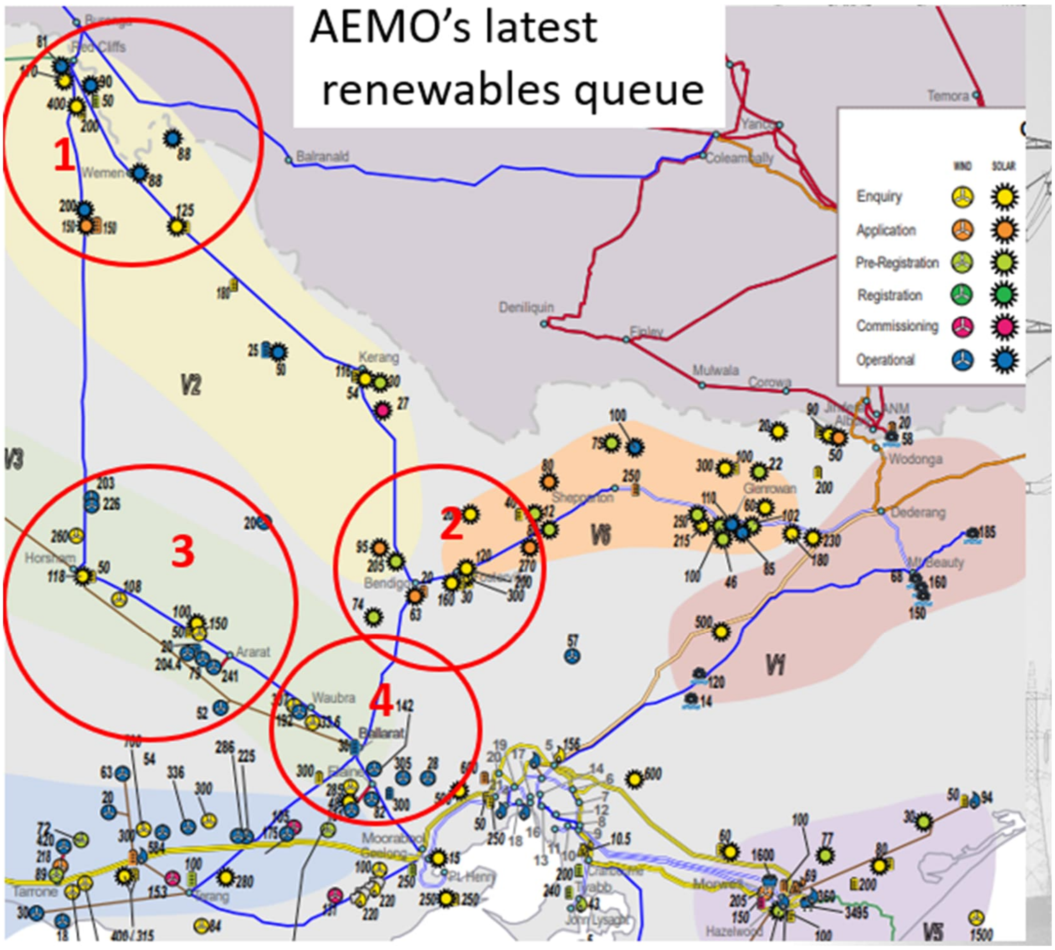
(a) shifts a proportion of the solar generation from sunny daytimes, when it is surplus to requirements and much is already being curtailed to the early morning, early evening peak load periods where it has much higher value

(b) significantly reduces the need for transmission from V2, particularly in the Rhombus of Regret around Red Cliffs.

For the purpose of Plan B, it is assumed that around 1.5 GW (around 60% of the 2.6 GW) would be located in V2, with ~1.0 GW located in the north-west (sub-location 1 in the map below) and the remaining 0.5 GW located near large solar farms elsewhere in V2 including in the vicinity of Bendigo (sub-location 2 in the map below). It is also assumed that the storage capacity of these batteries would be up to 8 hours similar to the lithium storage battery that won the NSW energy storage bidding process, but would be 8-hour Vanadium Flow batteries (similar to the Sichuan 100MW Vanadium flow battery commissioned last year, once they become commercially available due to their lower cost, indefinite number of charging cycles, low maintenance and non-flammability.

Geographical location of existing and new renewable energy generation based on the latest queueing map provided by AEMO

Whilst there is uncertainty on the locations for new renewable generation, the most likely locations in the next decade are considered to be those locations and relative capacities disclosed by AEMO in their latest renewables queue map illustrated below for V2, V3 and locations near Bendigo and able to be services by the proposed 220kV network passing through and close to those location. This map includes existing renewables and their installed capacities as well as new renewables at various stages of their planning and development process. V2 has been divided into 2 sub-locations 1 and 2. V3 has been divided into sublocation 3 and 4. There is also an inconsequential 176MW in the vicinity of Kerang, mostly just inquiries, but easily accommodated by both PlanB and VNI West, but much later. The total installed and committed renewables, and the total under consideration for each of sub-locations 1, 2, 3 and 4 are summarised in the table below:



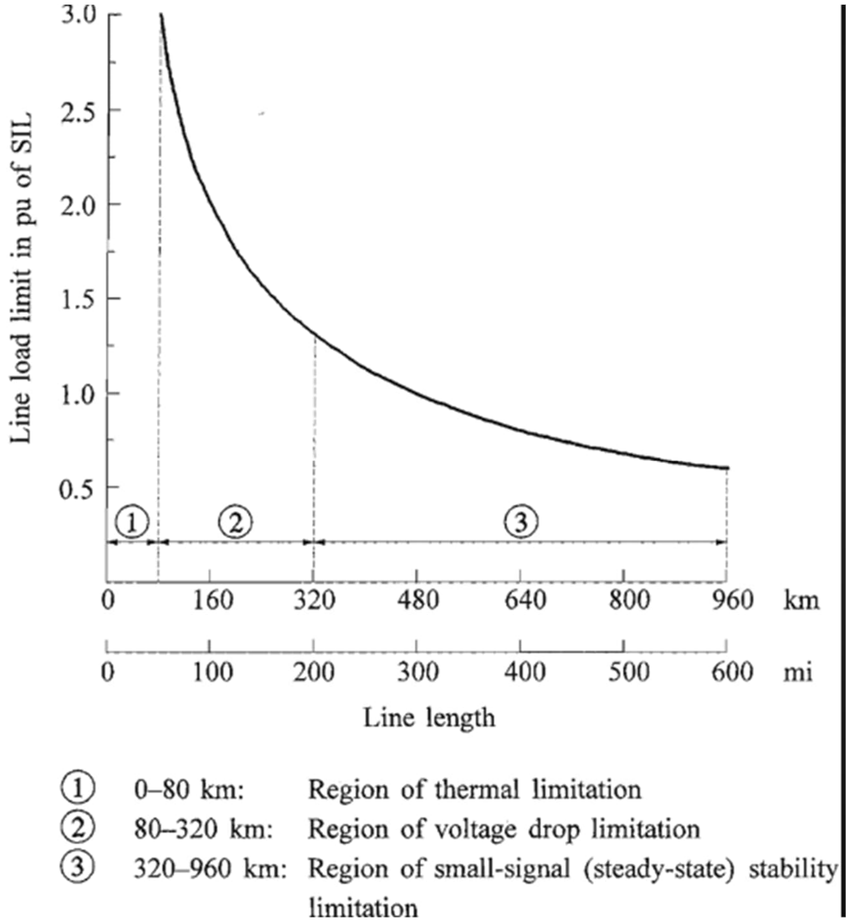
Sub-location	operating and committed	under consideration	Operating /committed plus 50% of those under consideration
1	804 MW (vs 1,087MW)	995 MW	1,585 MW (60% of V2 capacity)
2	0 MW	2,000 MW	1,000 MW (40 % of V2 capacity)
3	780 MW	719 MW	1,140 MW (45% of V3 capacity)
4	1,072 MW	808 MW	1,480 MW (55% of V3 capacity)

Notes 1 Reneweconomy states 1,087MW in sub-location 1 including Carwarp SF
2 VNI West PACR states 679MW existing V2 capacity (compared with 804MW and 1,087 MW) and 1,935MW existing V3 capacity (compared with 1,852MW)

Based on these relative allocations of renewables capacity within each of V2 and V3, and using the PACR stated existing renewables of 679 MW in V2 REZ and 1,935MW in 2023/24, and adding the claimed hosting capacities foe each of V2 an V3 gives the following maximum hosting capacities for each sub-location

Sub-location	Capacity 2023/24	Additional hosting capacity Plan B	Total max hosting capacity by 2035
1	679 MW	1,480MW	2,160 MW
2	0 MW	990 MW	990 MW
3	815MW	860 MW	1,675 MW
4	1,121MW	1,050 MW	2,170 MW

Application of Kundur's St Clair curve to estimate transmission capacity for various locations for Plan B

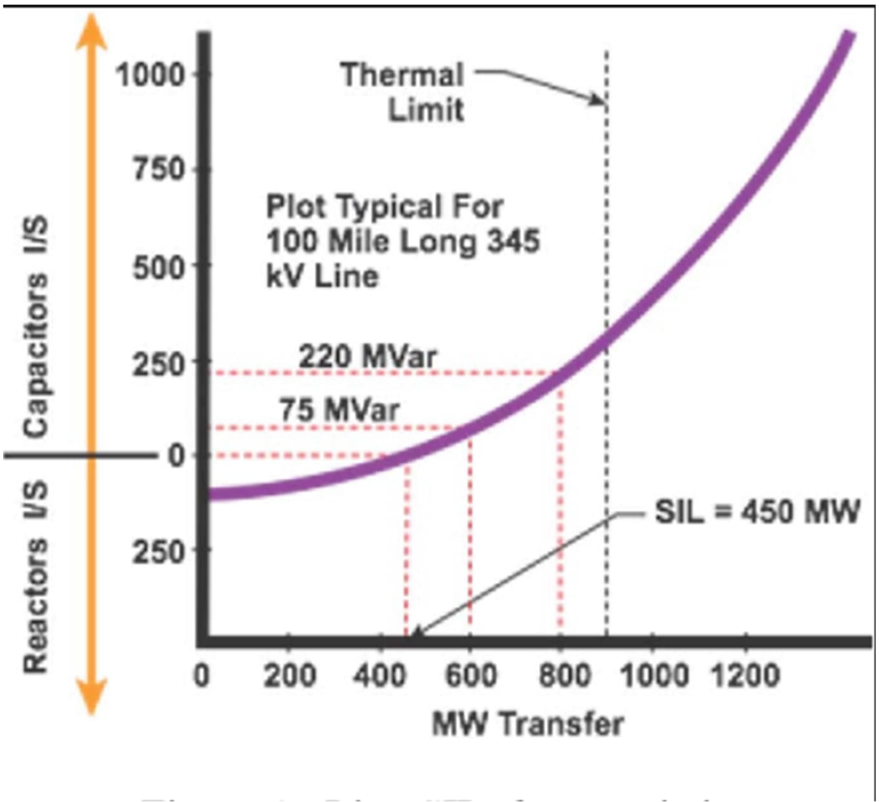


Ref IEEE https://ieeexplore.ieee.org/document/4113522

The transmission distances from each of sub-locations 1, 2, 3 and 4 to Moorabool 220/500 kV substation are approximately as follows

Sub-location 1	450km	steady state stability	1.0 x SIL
Sublocation 2	180 km	voltage drop limitation	1.7 x SIL
Sublocation 3	170 km	voltage drop limitation	1.7 x SIL
Sublocation 4	80 km	thermal limitation	3 x SIL or more

SIL of 220 kV line at 50 HZ



Must correct for voltage (prop V x V) and frequency (x 60/50)

SIL for 220 kV = 450 x 220/345 x 220/345 x 60 / 50 = 220 MW per circuit

SIL for 500 kV = 450 x 500/345 x 500/345 x 60/50 = 1,130 MW per circuit

Can increase with shunt capacitors – typically adds +2MW for every MVar

Table 6.1 Typical overhead transmission line parameters

Nominal Voltage	230 kV	345 kV	500 kV	765 kV	1,100 kV
R (Ω/km) $x_L = \omega L$ (Ω/km) $b_C = \omega C$ (µs/km)	0.050 0.488 3.371	0.037 0.367 4.518	0.028 0.325 5.200	0.012 0.329 4.978	0.005 0.292 5.544
α (nepers/km) β (rad/km)	0.000067 0.00128	0.000066 0.00129	0.000057 0.00130	0.000025 0.00128	0.000012 0.00127
Z_C (Ω) SIL (MW)	380 140	285 420	250 1000	257 2280	230 5260
Charging MVA/km $= V_0^2 b_C$	0.18	0.54	1.30	2.92	6.71

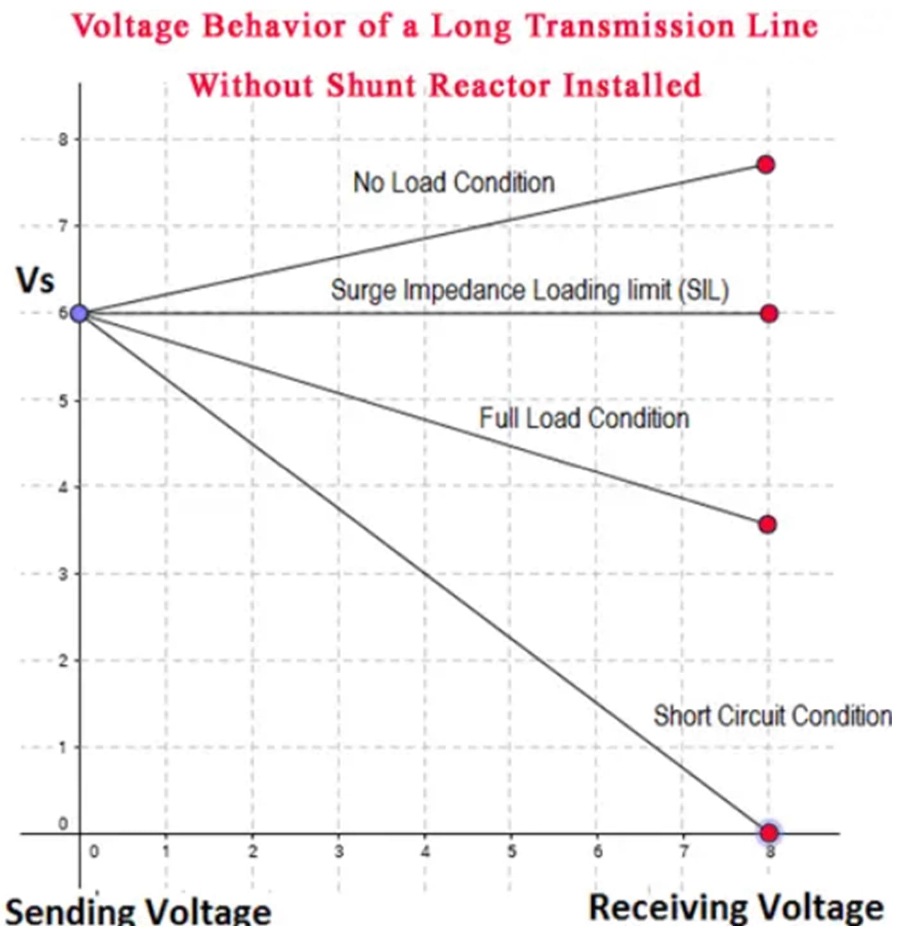
Notes: 1. Rated frequency is assumed to be 60 Hz.
2. Bundled conductors used for all lines listed, except for the 230 kV line.

Correct for voltage, bundled conductors and frequency

140 MW x 220/230 x 220/230 x 60/50 x 380/285 = 205 MW for 220 kv

1,000 MW x 60/50 = 1,200 MW for 500 kV

Tweaking the spacer and tower design could probably increase SIL by another 10%



Use of battery storage to shift peak solar power generation, in particular from sunny daytimes to the morning as evening peak load periods, and its impact of Plan B transmission requirements

Plan B assumes there would be 1.0 GW of 8-hour batteries located in location 1 and 0.5GW in location 2. By charging these batteries on sunny days, the 2,160 MW of PV in location 1 can be hosted, without curtailment, provided it is serviced by at least 1,160MW of transmission capacity. Under Plan B, location 1 is supported by four 220 kV circuits, comprising a double circuit line via Kerang and another via Horsham. Each circuit has a SIL of 220MW and a thermal rating of 957MW. The 220MW SIL could be enhanced by the installation of shunt capacitors, if and when required. For example, installing 100 MVar of shunt capacitors at Kerang and Horsham would help to manage voltages during power flows exceeding the SIL including during outages of any of the 220 kV circuits. Given that every 1 MVar of shunt capacitors would increase the transmission capacity by around 2 MW, this would increase the combined SIL transmission support for location 1 from 880MW (being 4 x SIL of 220 MW/circuit) to around 1,280MVA equivalent to the required peak of 1,160MW at 0.9 power factor. That would also provide adequate transmission capacity when the 1,000MW of storage batteries are discharging during early evening and early morning peak load periods. During outages any of the four 220 kV circuits (for maintenance, forced outages or project outages), the N-1 transmission capacity would be around 940MW (i.e. 1,160MW – 220MW noting the shunt capacitors would still be available when required). This may result in some curtailment of solar PV, at times when it is loaded above some 80% of its installed capacity by 2035. However, it is likely that on those days, there would still be storage capacity available in the batteries. Overall, the amount of curtailment would be well below the 13% pa average targeted by Plan B.

In the case of location 2, being only 180 km from Moorabool 500kV/220kV substation, the transmission capacity of the two 220 kV lines between location 2 and Ballarat, is 1.7 x SIL according to the St Clair curve, total 2 x 220MW x 1.7 = 750MW considering voltage management and 2 x 957MW = 1,914MW considering thermal limits. Plan B assumes that there would be 500MW of grid scale storage batteries located new PV farms in the area, which would mean that the 990MW of solar farms in location 2 to be supported would only require a transmission capacity of 490MW. The two 220 kV circuits passing through location 2 would also be transmitting a proportion of the power from location 1. As explained above, the maximum power transmitted from location 1 would be 1,160MW, shared between the four 220 kV transmission circuits supporting location 1. For the purpose of this analysis, it is assumed that could amount to a peak transmission flow of 290MW a circuit. In reality it is likely that the power flow via location 2 may be lower than via location 3. Adding the peak flow of 290 MW x 2 circuits to the 490MW peak flow to support location 2, gives a peak flow of 1,070MW between location 2 and Ballarat, a distance of some 80 km. This is 320MW (or 42%) above the 750MW based on SIL's and 56% of the 1,914MW thermal limit. Increasing the voltage management limit of these short sections of transmission line may require the installation of some 160 MVar of shunt capacitors at Ballarat or Elaine substations during first half of the 2030's. Outages of one of the two 220kV circuits would result in more power flowing from location 1 via Horsham, thereby reducing the flow via location 2. There is likely to be some transmission constraints during maintenance outages, resulting in additional storage of solar power in the grid batteries in locations 1 and 2, and probably curtailment during days of very high solar generation. Again, this would be well withing the 13% annual target. Unexpected forced outages of the 220 kV circuits between location 2 and Ballarat, may cause transient voltage swings needing to be managed in the 2030's by the installation on an SVC (Static VAR Compensator at Ballarat or Elaine). The cost of the SVC is immaterial compared with the overall $bn6 cost of Plan B and the $bn12 cost of extended VNI West.

In the case of location 3, being only 170 km from Moorabool 500kV/220kV substation, the transmission capacity of the two 220 kV lines between location 3 and Ballarat, is 1.7 x SIL according to the St Clair curve, total 2 x 220MW x 1.7 = 750MW considering voltage management and 2 x 957MW = 1,914MW considering thermal limits. Plan B assumes aims to provide sufficient 220 kV transmission capacity to support up to 1,675MW of mostly wind-farm capacity at location 3 which is well in excess of VRET and that claimed by VNI West. Based on a 36% annual capacity factor, the average generation of 1,675MW of wind farms would be 600MW with no curtailment. The two 220 kV circuits passing through location 3 would also be transmitting a proportion of the power from location 1. As explained above, that could peak at 290MW a circuit, totalling a peak of 580 MW, but only on sunny, cloud-free summer days. There may also be up to 500MW of battery discharge from location 1 during early evening periods, flowing through location 3, but otherwise, there will be little power from location 1 flowing through location 3. The combined 750MW voltage stability limit of the two 220 kV lines would be increased by 320MW from the 160MVar of shunt capacitors installed at Ballarat or Elaine, or additional shunt capacitors could be installed if additional capacity is required at location 3 on sunny days or evening peak load times. This would increase the

750MW to 1,070MW. In addition, Murraylink could be used to export up to 220MW from Western Victoria to South Australia, taking the total transmission capacity to a peak of 1,290MW. It is considered this would be sufficient transmission capacity to support up to 1,675MW of wind farms in location 3, on top of the power flows from location 1 and limit curtailments to below the 13% target for Plan B for Western Victoria REZ. Even during sunny daytime periods, this would be sufficient to transmit 580 MW from location 1 via location 3, leaving 710MW to transmit wind power from location 3, being 18 % greater than the average 600 MW of its wind-farm generation by 2035. There is likely to be some transmission constraints during maintenance outages. Surplus wind power generated after the Murray River REZ batteries have been discharged, can be back-fed to those storage batteries via the lightly loaded 220 kV transmission lines between location 1 and 3 and 2, and stored until early morning to help supply peak loads. There are likely to be some curtailment of location 3 wind farms during windy periods co-inciding with maintenance outages of the 220 kV transmission lines between location 3 and Ballarat, however these infrequent events would be well within the 13% annual target. Unexpected forced outages of the 220 kV circuits between location 3 and Ballarat, may cause transient voltage swings needing to be managed in the 2030's by the installation on the same SVC.

In the case of location 4, being only 80 km from Moorabool 500kV/220kV substation, the transmission capacity of the six 220 kV lines between location 4 and Moorabool, is 3.0 x SIL according to the St Clair curve, total 6 x 220MW x 3 = 4,000MW and 6 x 957MW = 5,740MW considering thermal limits. Plan B assumes aims to provide sufficient 220 kV transmission capacity to support up to 2,170 MW of mostly wind-farm capacity at location 4 which is well in excess of VRET and that claimed by VNI West. Based on a 36% annual capacity factor, the average generation of 2,170MW of wind farms would be 780MW with no curtailment. The six 220 kV circuits passing through location 4 would also be transmitting the power from locations 1, 2 and 3 all via locations 2 and 3. As explained above, that could peak at 1,070MW via location 3 and 1,070 MW via location 2 totalling 2,140 MW. That would leave a minimum of 1,860 MW available for location 4, being 85% of its maximum installed wind farm capacity by 2035. This is considered to me more than adequate for location 4. There is unlikely to be any curtailment at that location. Even during outages of one of the six 220 kV circuits, the remaining five circuits would have a combined transmission capacity exceeding 3,300 MW, sufficient for the maximum power flow from locations 1, 2 and 3 and leaving at least 1,160 MW for location 4 being 150% the average wind farm generation by 2035, and an infrequent curtailment would be well under the 13% Plan B target.

Consideration of N-1 and N-2 transmission outages

N-1 transmission contingencies have been considered above. N-2 contingencies would still leave 2 remaining 220 kV transmission circuits available for locations 1, 2 and 3 and 4 transmission circuits for location 4 plus Murraylink. Thus, the remaining transmission capacity would 2/3rds of the N-1 transmission capacity for locations 1, 2 and 3 and 80% of the N-1 capacity for location 4. There would be additional curtailment, but still under 20% at those times, with no threats to the security and continuity of electricity supply to Victoria.

The extended VNI Plan, has virtually zero transmission capacity under both N-1 and N-2 transmission outages of the 500 kV lines. Even under a single planned outage of just one 500 kV circuit, AEMO must operate the power system anticipated an unexpected outage of the parallel 500 kV circuit – resulting in the entire 500 kV line being out of service. This would render WRL-VNI West virtually useless, resulting in widescale electricity shortages and power rationing across Victoria. An unexpected N-2 outage will almost certainly black out southern Victoria including Greater Melbourne and the Portland Smelter.

C.3 Plan B note regarding easement and design

Note from Simon Bartlett dated 20 September 2023

This is reproduced below:

Construction of Plan B – Bendigo to Ballarat line near Brown Hill, Ballarat

At the Steering Committee meeting held on 19th September, attention was drawn to easement issues for both WRL-VNI West and the Plan B 220 kV lines. The suburb of Brown Hill, to the east of Ballarat was highlighted as a location where residential development alongside the existing transmission line easement is a key consideration in the construction of that section of 220 kV line. The aerial photograph below shows the residential development in Holmgarth Cresent and Willowbank Way in Brown Hill, which has existing houses built on either side of the existing easement, but no dwellings built on the easement.

This is a good example of where the alternative construction technique, described at yesterday's meeting, is likely to be the best solution for this small part of the route of the line. It is described below for Jacobs to consider the engineering, construction and aesthetical issues.

Type of line construction (when close to urban development)
Steel pole, compact double circuit 220 kV line, (see photo below) – could also consider using 220 kV insulated crossarms

Use of existing easement and temporary 220 kV line, when it's not possible to shift existing easement sideways up to 15m

Erect a temporary single circuit 220 kV line, along the edge of the easement (at least 6.4m from any adjacent structures and preferably 8m – i.e., 6.4m no-go zone without spotter) Use a steel pole, with porcelain long rods in vertical configuration, single conductor, or Lindsay structures or equivalent. Cut-over from existing line to temporary line. The cut-in will require a short outage, however there are alternative 220kV lines supplying Bendigo and Ballarat.

De-energise and demolish the existing 220 kV transmission line, using a crane on the existing easement. Any work within 3m – 6.4m of the energised temporary 220 kV conductors will require a spotter.

Build the new foundations and erect the new 220 kV pole (with insulators attached) in the centreline of the easement (close to the location of the existing line. This should be ~20m from one side of the easement and at least 12m from the temporary 220 kV line. Safe working distance 3m to 6.4m with spotter from energised conductors of temporary line. Most construction activities should be possible with the temporary line energised, however if there are short duration activities needing the line to be de-energised (e.g., flying in poles using a helicopter, positioning cranes etc, the line could be de-engaged whilst relying on the other 220 kV feeders to reliably supply Bendigo and Ballarat.

Stringing of conductors to be done using winch located on the easement, located on the opposite side to the temporary 220 kV line. Run trailing earths to eliminate risks from induced voltages on the new conductors during construction

Remove temporary line after new line has been commissioned.

Other locations

In other locations along the route of Plan B, negotiations should be held with the property owners of the existing easements and on the appropriate side of the line, to understand their situation regarding the existing and proposed new line and easement changes. Where feasible, negotiations should be held with the relevant landowners regarding "shifting" the existing easement ap to 15m to the side, and then relinquishing the equivalent portion of easement, not required upon project completion, and rehabilitating the easement. Payment for the landowners' costs and compensation and the $200,000 line hosting payment should all apply in the same manner as for WRL-VNI west but at a much lower level. Where agreement cannot be reached, the above construction techniques should be applied to stay withing the existing easement.

Requirement for Additional Studies prior to. committing to Plan B.

Given the availability of the option to remain withing the existing easement, should negotiations fail, the only additional studies required before committing to Plan B would appear to include:

(a) check the wording of the SECV easement documents for circa 1960/70's to ensure they permit the 220kV line being built, operated and maintained on the easement. This is almost certain to be the case based on the standard easement conditions in Queensland at that time.
(b) Check state planning legislation and environmental legislation to ascertain the extent of environmental (etc) studies and approvals required taking into account any "as-of-right" entitlements for existing transmission lines. It is likely that if there are any requirements to undertake further studies to obtain any necessary approvals, that there will be provision for truncated processes compared with the extensive studies and associated consultation processes required foe WRL and VNI West.
(c) Biodiversity and EPBC studies and approvals are unlikely to be require
(d) Cultural Heritage studies are unlikely to require the assessment of above ground impacts as there are unlikely to be any scar trees, artifacts etc on the existing easements or within 15 m either side. It would be prudent to engage indigenous monitors during construction, for underground activities such as excavating tower foundations and earthing. This will not require additional studies or approvals prior to committing to Plan B.

Further Clarifications

Should Jacobs require any further clarifications on the proposed design, construction, and easement considerations for Plan B, please do not hesitate to ask

Simon Bartlett
20th September 2023

C.4 Plan B materials extracted from Victorian TAPR

Snippet extracts provided by Plan B for support info circa 26 September 2023. Reproduced below

Extracts from AEMO Victorian 2022 Annual Planning Report – of Relevance to WRL - VNI West and Plan B

From Appendix A.2 DSN Limitation detail:

The possible network solutions presented in the sub-sections below should be treated as indicative only, and a RIT-T will be required to determine the full list of network and non-network options as well as the preferred option. The preferred option may include one or a combination of the solutions presented in the sub-sections below

Table 22 Limitations in the Central North REZ

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Dederang – Glenrowan – Shepparton – Bendigo 220 kV and Dederang – Shepparton 220 kV line loading	Monitored	• Install an automatic load shedding and generation runback control scheme to enable the use of five minute line rating. • Install a wind monitoring scheme. • Install a modular flow controller on the Bendigo – Fosterville – Shepparton 220 kV line. • Replace existing Dederang – Shepparton and Shepparton – Bendigo 220 kV line with new double circuit lines.	Increased demand in regional Victoria and/or increased import from New South Wales. Large-scale new generation connected to Western Victoria area, and congestion within Western Victoria relieved to allow the new generation to be sent out of Western Victoria.	Identified limitation as part of Central North Victoria REZ	The new transformer or new transmission lines are likely to be contestable projects.

Plan B includes a new double circuit 220 kV line – Dederang – Shepparton on an existing spare easement (according to VicGrid report), but not from Bendigo to Shepparton.

Extended VNI West includes another single circuit 220kV line from Dederang to Shepparton – exactly as proposed in the AEMO APR

Plan B includes replacing two of the Ballarat to Moorabool 220kv lines with double circuit lines, as proposed in the APR

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Moorabool 220 kV line		• Replace the existing Ballarat – Berrybank – Terang – Moorabool 220 kV line with a new double circuit 220 kV circuit line.			
Inadequate south-west Melbourne 500 kV	Monitored	• A new Moorabool – Mortlake/Tarrone – Heywood 500 kV line.	Significant wind generation and/or gas generation (in addition to the existing generation from Mortlake) is	Identified as a limitation in 2020 ISP South West Victoria REZ Scorecard.	The new line is likely to be a contestable project

Plan B includes two new Moorabool 220kV / 500 kV transformers as proposed in the APR

Extended VNI includes a new 500 kV circuit from Sydenham to Moorabool to Mortlake – as proposed in the APR

Table 28 Limitations in Western Victoria REZ

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Red Cliffs – Kiamal – Murra Warra - Horsham-Bulgana 220 kV line	Monitored	• Install an automatic generation runback control scheme. • Install a new double circuit Bulgana to Murra Warra 220kV line via a new terminal station at Horsham.	Increased generation in Western Victoria and Murray River REZ.	Not identified.	These are unlikely to be contestable projects.

Plan B includes replacing the existing Red Cliffs to Ballarat line with a double circuit 220 kV line

Extended VNI West includes a new double circuit 220 kV line from Murra Warra to Bulgana exactly as proposed in the APR

Red Cliffs – Wemen – Kerang – Bendigo 220 kV line (high generation)	Monitored	• Replace the existing Bendigo – Kerang – Wemen – Red Cliffs 220 kV line with a new double circuit 220 kV circuit line and establish associated new terminal stations or existing station augmentations.	Increased generation in Regional Victoria	Identified as limitation as part of Murray River REZ	These are likely to be contestable projects.

Plan B includes replacing the Red Cliffs – Kerang – Bendigo line with a double circuit 220 kV line

Extended VBNI West includes a new 220 kV double circuit line from Red Cliffs – Nerang – Bendigo exactly as proposed in the APR

• Install a wind monitoring scheme.	Large-scale new generation	**x 3 in the APR**

Three wind monitoring stations are proposed in the APR, exactly as included in Plan B

The APR also uprates the operating temperature of various 220 kv lines, exactly as proposed in Plan B

C.5 Security and Resilience of Australia's Electricity Transmission Network and its Relevance to Australia's National Security

Note from Simon Bartlett dated 19 September 2023 which:

- Describes Security of Critical Infrastructure Act 2018 (the SOCI Act)
- Describes Security Legislation Amendment (Critical Infrastructure Protection) Act 2022 (SLACIP Act)
- Describes Transmission of National Significance
- Discusses single-point of failure
- Describes "supergrid" from Melbourne to Townsville as a proposal of Australian Electricity Market Operator (AEMO), together with TransGrid and Powerlink Qld
- Suggests should be underground HVDC on socio-environmental-economic-security grounds

C.6 Length and capacity of VNI West

Note from Simon Bartlett 9 October 2023

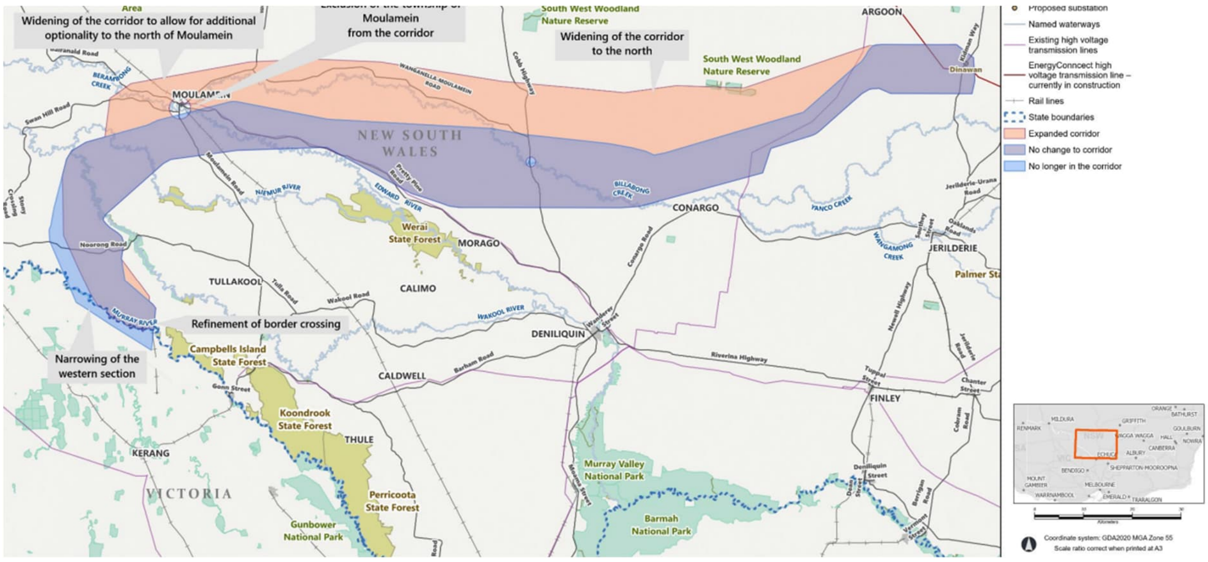
In early October, 2023, both TCV and TransGrid announced changes to their respective study corridors for VNI West that have increased the length of VNI West by 50km. There remains uncertainty about the final route and its length other than it must be longer still, as the alignment must vary from the centreline of the study corridor, thereby increasing it length further – possibly by 5% which would result in another 25 km route length

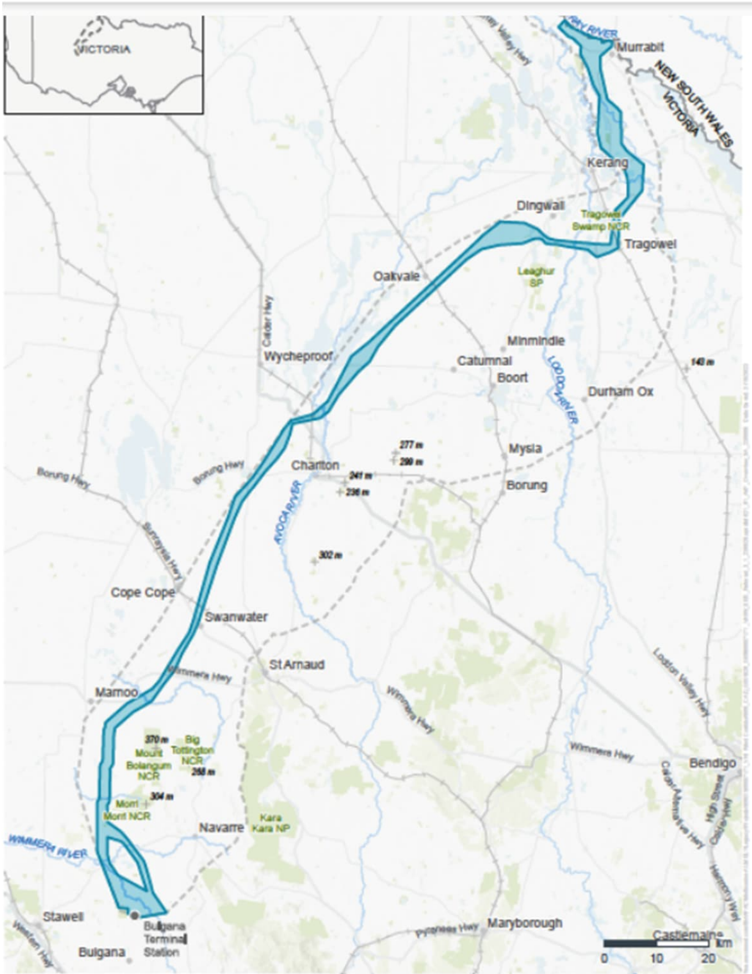
The relationship between the route length of VNI West and it import capacity to Victoria, can be determined from the results in the Consultation report and the PACR for options 1, 3, 4, 5, and 5A – and in the case of options 5 and 5A omitting the series compensation (which is unlikely to be successfully implemented for a range of reasons). These results show that every addition 1 km of route length corresponds to approx. a 2MW reduction in the import capacity for VNI. This aligns with electrical engineering theory (see at the end of this report)

As the import capacity of option 5A was 1,350MW in the PACR (without compensation), then an increase of 50 km would reduce its import capacity be 100MW (2MW * 2MW/km) there my reducing its import capacity by 1900MW, to 1,250MW.   This is 400MW (i.e., 25%) lower than the 1,650MW import capability used in the PACR

Jacob's needs to independently evaluate what a 25% reduction in the NSW-to Qld transmission capacity of VNI West. Would do to its benefits to Victoria.

Change to NSW route of VNI West in NSW. The study corridor has been extended approx. 10 km to the north, and 3 km to the west, obviously with the intention of shifting the preferred alignment further away. This means that the minimum length of VNI West in NSW will be 233 km, which is 30 km longer than the 203km length claimed for option 5A in the PACR.





TCV has just announced the study corridor for Newest in Victoria, which has a length of 226km along the centreline, this is 20 km longer than the 206km claimed in AEMO PACR.
Following is Table 6 from the VNI West PACR, in which AEMO claims that the length of VNI West is 206 km in Victoria and 203 km in NSW. Note that the Mountain/Bartlett submission on the VNI West Consultation Report calculated the actual length of VNI West in Victoria as 225km – but that was rebutted by AEMO in the PACR.

TransGrid's claim that the length of option 5A in NSW is only 203km was shown to be wrong by Bartlett as soon as TransGrid released their study area mapping just after the PACR was published – and it was shown that the route length is really 222km. This has now increased to 233km, being 30 km longer than the 203km assumed in the PACR.

Table 6 Summary of the credible options assessed in this report – capital costs, $m in FY2020-21 dollars

Cost component	Option 5 (to Bulgana)		Option 5A (to Bulgana, east of Kerang)	
	NSW	VIC	NSW	VIC
Stage 1 – Early works				
Early works – Property/access/ easements	66	69	72	69
Early works – other	50	60	50	60
EnergyConnect enhanced	182	-	182	-
Stage 2 – Implementation				
Substation/ terminal station works	354	415	354	415
Line works	751	1,034	831	1,034
Power flow controllers / series compensation	183	164	183	164
Biodiversity offset costs	66	12	73	12
Total (by state)	1,651	1,755	1,744	1,755
Total (all states)	3,406		3,499	

Effect of increase length of VNI West on its import capacity into NSW

Jacobs can access the Consultation Report to obtain the following published information on the claimed route lengths (Table 5) and import capacities (Table 1) of VNI West for options 1, 3, 4, and 5. The route lengths for options 1, 3 and 4 must be reduced by 35 km being the additional length included by AEMO for the 35kms of 220 kV transmission line between New Bendigo substation and the existing Bendigo substation as explained in the note under Table 3 in the Consultation report. The 35km is the length of the New Bendigo to Bendigo 220 kV transmission line shown in Figure 55 in the Consultation Report. Only the lengths of the 500 kV part of VNI West are relevant in determining the transmission capacity of VNI between NSW and Victoria. The VNI capacities are given in the Consultation Report for all options – and for both import and export.

The public data is summarised below to assist Jacobs. Note that the VNI West transmission capacities for option 5 are inconsistent with those of options 1, 3 and 4 as option 5 assumes series compensation of VNI West in Victoria, which has increased its capacity by some 210 MW (according to the PACR – i.e., 1,710 MW – 1,500 MW see below).

option	Length stated	Included for Bendigo 220	Length of 500 kV in Victoria	Plus WRL	Plus, VNI west in NSW	Total length WRL-VNI
1	229 km	35 km	194 km	85km	184 km	463 km
3	230 km	35 km	195 km	122 km	184 km	499 km
4	268 km	35 km	233 km	190 km	184 km	607 km
5	205 km	0 km	205 km	190 km	184 km	579 km
5 (PACR)	205 km	0 km	205 km	190 km	184 km	579 km
5A (PACR)	206 km	0 km	206 km	190 km	203 km	599 km
5 (no series compensation)	205 km	0 km	205 km	190 km	184 km	579km
5A - now	226 km	-	226km	190 km	233km	649 km
5A – plus 5%						681 km

option	Length total	Export capacity	Import capacity
1	463 km	1,930 MW	1,800 MW
3	499 km	1,830 MW	1,650 MW
4	607 km	1,700 MW	1,475 MW
5	579 km	1,930 MW	1,650MW *
5 (PACR)	579 km	1,960 MW	1710 MW
5A (PACR)	599 km	1,935 MW	1,669 MW
5 (no series compensation)	579km	1750 MW	1,500 MW
5A - now	649 km		
5A – plus 5%	681 km		

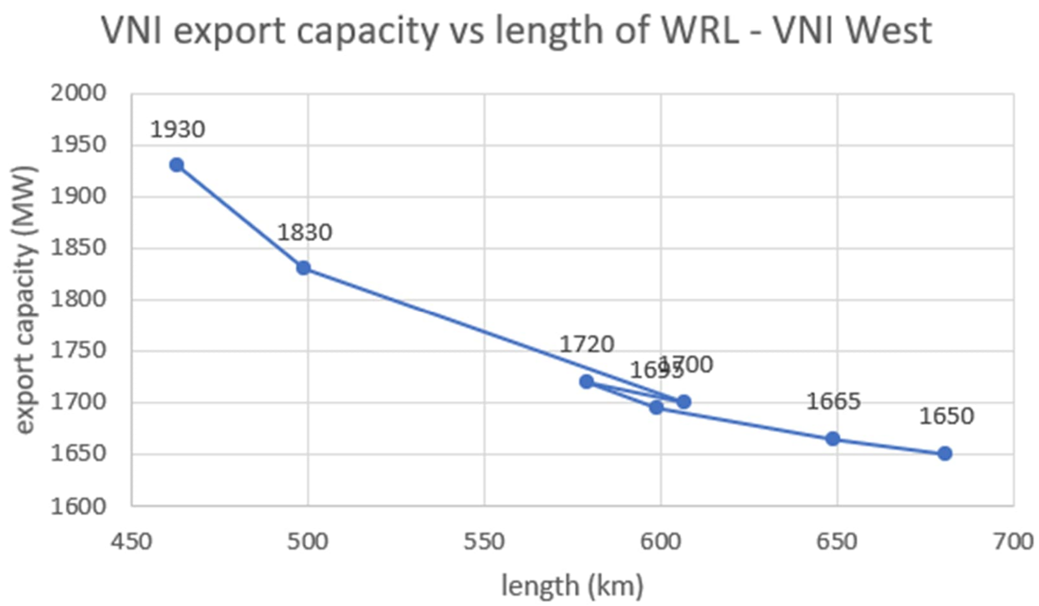
The increase in VNI West import capacity of 60 MW (i.e., 1,710 MW – 1,650MW) and 30 MW (i.e., 1,960 MW – 1,930MW) of export capacity, between the Consultation Report and the PACR) was not explained in the PACR, but creates an inconsistency between the results of the Consultation Report and the results of the PACR. As explained in the Mountain/Bartlett submission to the Consultation report, it is unlikely that the series compensation of VNI west will be implemented or be successful. This can be inferred from the PACR including the option 5 (without series compensation). Had the option 5A (without series compensation been included, it is expected that its VNI transmission capacities would have been equal, or less than

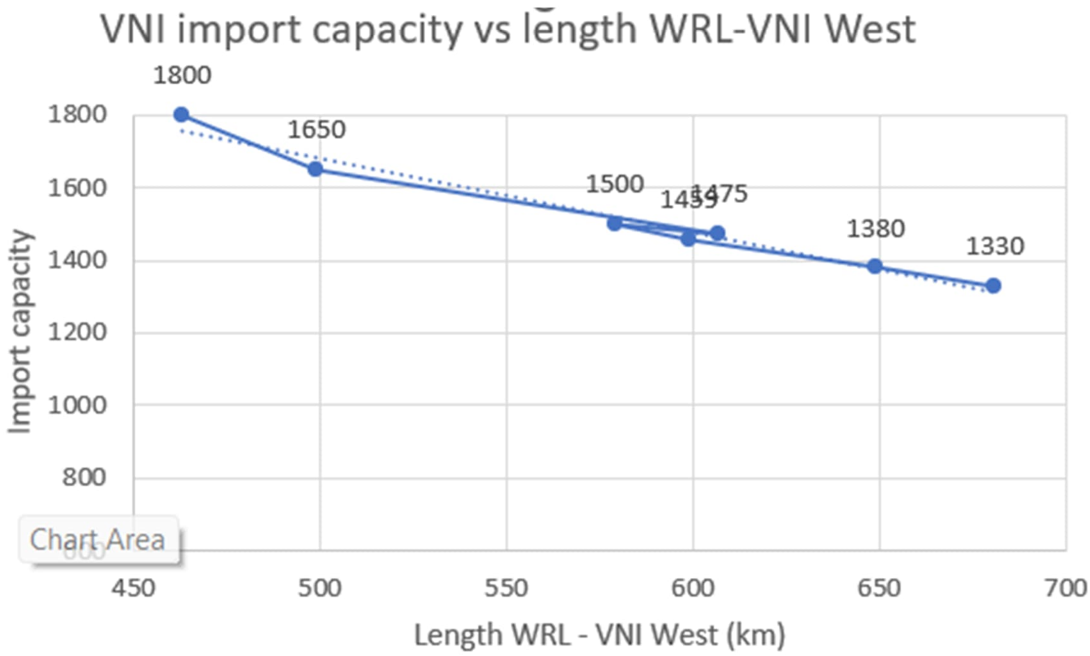
Import capacity = 1,669 MW less (1,710 MW – 1,500 MW) = 1,459 MW
Export capacity = 1,935MW less (1,960 MW – 1,750MW) = 1,725 MW

For the purpose of deriving the relationship between the length of VBNI West and its import and export capacities, the above AEMO results have been used, after removing the additional 35 km of 220 kV line, and adding the length of VNI west in NSW and the length of WRL. The 210 MW of additional VNI west transmission capacity attributed by AEMO for to series compensation of options 5 and 5A has been removed. The additional 60MW of import capacity and 30 MW of export capacity has been left in the transmission capacity of the PACR results for options 5 and 5A, despite the lack of a convincing explanation in the PACR. The resultant data is as follows

Option	Total length WRL-VNI West	VNI import capacity	VNI export capacity
1	463 km	1,800 MW	1,930 MW
3	499 km	1,650 MW	1,830 MW
4	607 km	1,475 MW	1,700 MW
5	579 km	1,500 MW	1,750 MW
5A	599 km	1,459 MW	1,725 MW
5A now	649 km		
5A plus 5%	681 km		

This data is plotted below and used to determine the expected VNI West transmission capacities with the increased lengths, now advised by the latest AEM and TransGrid maps. A future possibility with 5% longer length has been assessed to cover the certainty that additional route diversions will occur as the route is finalised within (or further outside) the latest study corridors





Based on AEMO's results, it is concluded that the capacity of VNI has nor reduced to around 1,380 MW import and 1,665 MW export and that this is likely to reduce further to 1,330 MW as the route of WRL-VNI West is further refined.

Jacob's needs to undertake its own assessment of these factors as well as the impact on the interconnector benefits (if there are any) of VNI West, as this is a significant reduction in the assumed 1,650MW import capacity on the PACR

Theoretical relationship
According to Kirchoff's and Ohm's laws, the electrical power between the existing VNI interconnector and VNI West would be shared in proportion to the reciprocal of their respective electrical impedances. Line impedance is proportional to the length of each interconnector. As the length of VNI West is increased, so is its impedance. This will reduce the amount of power flowing on VNI west, until it reaches the point that the existing VNI is at its limit. If both interconnections are operating at their respective limits, the load sharing would be in proportion to the square of their voltages. Given their respective surge impedance loadings are around 1,200MVA and 500MVA, it is expected that a 1,700MW transfer would be share 1,200 MW on VNI West and 500 MW on the existing VNI. As the length of VNI West increases, the 500 MW would stay the same, but the 1,200MW would reduce in proportion to the reciprocal of its length. Thus, the function is a constant 500MW plus a hyperbola starting at 1,200 MW and reducing in a hyperbolic function as the length increases. For the span length being examined, the hyperbola is in the left side and has a slope of around 2MW/1km for import capacity, that reduced as length increases. These characteristics are observed in AEMO's results.

C.7 Threat to the Security of Electricity Supplies to Victoria and NSW due to the flawed design of WRL, VNI West and Humelink transmission lines

Note from Simon Bartlett 5 October 2023

1. Introduction

This report documents a serious threat to the security of electricity supplies to Victoria due to the flawed design of AEMO's Western Renewables Link (WRL) and AEMO/TransGrid's Victoria-NSW West interconnection (VNI West), collectively called WRL – VNI West. The same flaw is present in the design of TransGrid's Humelink project and the remainder of AEMO's 500 kV Super-grid stretching 3.000 kms from Melbourne to Sydney to Brisbane to Townsville. The lack of resilience of the Super-grid, is certain to result in widespread blackouts and extended electricity rationing in Victoria, NSW and Queensland. This will have major adverse impacts on Australia's economy and society and the vulnerability could be targeted by saboteurs or terrorists.

2. Criticality of Electricity Transmission

Electricity transmission is the essential backbone of the power system enabling society, industry, and public services such as hospitals, transportation, emergency response systems, and communication networks to operate. Avoiding single points of failure (SPoF's) in the grid is essential in preventing wide-scale blackouts due to the failure of a single key part of the grid. Interconnectors can be SPoF's as they transmit large amounts of power over long distances from remote generators and between regions and states. If an interconnector fails due to equipment breakdown, sabotage, or a natural disaster, it can black-out the connected regions, unless it is lightly loaded or adequately duplicated. There can be a cascading collapse of the power system or instantaneous instability that may blackout large parts of the state(s) with widespread and long-lasting power outages. This is increasingly likely to occur in the transition to large, remote sources of renewable generation via the long-distance, high-capacity Super-grid. Investing in the necessary infrastructure to avoid SPoF's in the Super-grid is justified despite adding ~20% to the capital cost as it prevents massive disruptions in the long run. Transmission planners must prioritise security, reliability, resilience, and redundancy in planning Australia's Super-grid.

3. Federal Legislation on Critical Infrastructure Security

The Federal government's Critical Infrastructure Centre was established in January 2017 to safeguard Australia's critical infrastructure from the increasingly complex national security risks of sabotage, espionage and coercion. A disruption to critical infrastructure could have serious implications for business, governments and the community. The Security of Critical Infrastructure Act 2018 (the SOCI Act) places obligations on entities in the electricity sector. *SOCI Act Section 10* states that a critical electricity asset is a network, system, or interconnector, for the transmission or distribution of electricity to ultimately service at least 100,000 customers. The Security Legislation Amendment (Critical Infrastructure Protection) Act 2022 (SLACIP Act) uplifted the security and resilience of Australia's critical infrastructure and introduced new obligations for responsible entities to create and maintain a critical infrastructure risk management program for operators of systems of national significance (Australia's most important critical infrastructure assets – SoNS). It aims to make risk management, preparedness, prevention and resilience, business as usual for the owners and operators of critical infrastructure assets.

On 12 August 2022, Energy Ministers agreed to identify and declare transmission of national significance which included the actionable projects in the Integrated System Plan and specifically identified VNI West (via Kerang) and Humelink. The proponents and designers of these projects, AEMO and TransGrid now have these legal responsibilities. A single point of failure (SPoF) is a flaw in the design, configuration, or implementation of a system, circuit, or component where just one malfunction or fault causes the whole system to stop working. According to the Australian Energy Market Commission (AEMC), increasing the degree of interconnection means that there are fewer SPoF which is important for both system security, resilience and reliability. According to Appendix 8 of AEMO's 2020 Integrated System Plan (ISP) energy systems are normally designed to avoid SPoF's. AEMO claims that transmission lines are separated over multiple, diverse corridors using meshed designs. The AEMC and AEMO requirement to avoid SPoF's in transmission network design has not been applied to Humelink and WRL-VNI West or the remainder of the Super-grid being developed and designed by AEMO in the Integrated System Plan (ISP).

4. Design of WRL – VNI West Project and Humelink

AEMO, together with TransGrid have designed and are implementing the WRL – VNI West project that stretches ~800 km from Melbourne to Wagga Wagga, NSW via Bulgana, New Kerang and Dinawan substations. It then connects to TransGrid's Humelink Project which runs 360km to Bannaby substation (130km from Sydney) via Snowy 2.0 power station. AEMO's ISP predicts that ~11,000MW of existing and new power generation will depend on that Super-grid to reliably transmit their electricity to Melbourne and Sydney just 8 years from now. This will comprise 6,500MW connected to WRL-VNI West and 4,500MW connected to on Humelink.

As illustrated in TransGrid's figure alongside, the design has a single tower on a single easement, with each tower supporting two transmission circuits, on each side of the tower. This is called a double-circuit (D/C) transmission line. Each circuit is rated at ~ 3,000MW of electricity which is ~60% of the total average electricity demand of Victoria and 40% of NSW. There will be approximately 1,750 D/C transmission towers supporting the 800 km of WRL-VNI West, and 800 supporting Humelink, each tower being a SPoF should that tower fail. Australia's uses an N-1 security criteria for planning and operating its power system so that the failure of any single part of the grid will not cause load-shedding, however this does not include the failure of a single tower causing both D/C transmission circuits to fail. Other counties invariably consider a D/C transmission line failure as N-1. Should both circuits fail (as occurs from time to time with a D/C line), there will be no transmission capacity across that part of WRL-VNI West or Humelink. The power will immediately transfer to the parallel 220 kV or 330 kV transmission network, causing it to overload and trip resulting in a cascading collapse of the southern Victorian or southern NSW power systems. Given the large power flow on WRL-VNI West, the cascading collapse is likely to black-out greater Melbourne and the Portland smelter and the rest of southern Victoria. In the case of NSW, Humelink is rated at 2,200MW, the loss of which will immediately cause the Queensland – NSW interconnection to overload and trip, which combined with the loss of Humelink, is almost certain to result most of NSW being blacked-out including greater Sydney and the Hunter Valley aluminium smelters. If aluminium smelters are without electricity for more than about 8 hours, they are abandoned.

5. AEMO, and TransGrid were formally advised of the severe risk to power system security

AEMO, TransGrid and the AEMC Reliability Panel have been formally advised of this severe risk to Victoria's electricity supply in the Mountain/Bartlett submission to the VNI West Consultation report in April 2023; and in the Mountain/Bartlett Plan B submission in August 023, and in two emails to the Chairman of the AEMC Reliability Panel in March and April 2023. The later were not even acknowledged and the responses from AEMO/TransGrid were technically incorrect and included:

(a) towers will not fail, despite actual failures proving otherwise, the increasing intensity of natural disasters (e.g., severe lightning, wildfires, extreme winds, floods, sabotage). AEMO publicly accused Mountain/Bartlett of being "reckless" in mentioning this serious risk in a public submission, in an apparent attempt to discredit their reputation and their submission

(b) "Special control schemes" will prevent this from happening, however protection schemes will instantaneously switch-out both circuits to protect life and property well before any control scheme can possibly operate. AEMO/TransGrid's response demonstrates ignorance of the difference between protection and control of the power system, and flippantly rejects the certainty that the Victorian power system will collapse

.

(c) Stating that the parallel 220kv and 330 kV lines would be able to carry the power transferred from both tripped 500 kV lines. This ignores the certainty that the parallel lines would overload and be automatically switched out or that voltage and transient instability of the power systems would occur even before the protection schemes can operate.

(d) The power will instead be carried by the existing Victoria NSW Interconnection (VNI), which is incorrect as that line does not connect to any of the 6,500MW of generation to be serviced by WRL-VNI West

(e) TransGrid's Humelink proposal to eliminate severe lightning failures using surge arrestors and improved tower footing resistance is invalid for severe, "steep-fronted" lightning strikes that will result in simultaneous "double back flashovers" occurring on both 500 kV circuits regardless

(f) TransGrid's proposal to de-load Humelink whenever bush-fires approach the power line will still mean that both 500 kV circuits will be held to low power transfers whereas locating the 500 kV circuits on geographically separate easements will avoid this happening.

AEMO and TransGrid have consistently failed to acknowledge the outcome is almost certainly to be the collapse of the Southern Victorian power system, followed by a lengthy manual system-restart taking days, noting that AEMO has no plan or experience in restarting a primarily renewable power system.

5. What could bring down any of the 2,550 D/C transmission towers?

Severe lightning: AEMO issues market notices, sometimes, many times a day for severe lightning tripping both circuits of a D/C transmission lines A positive-voltage lightning strike often occurs with no prior storm warning, so it is impractical to take prior precautions

Wildfires: have caused multiple transmission lines on the same easement to trip, one resulting in ~ 250,000 Victorian electricity users having their electricity supply automatically interrupted without warning. Transmission lines must be switched off when fire-fighters are near transmission lines, yet AEMO and TransGrid have not considered this in locating the D/C line on a single easement in fire-prone areas.

Flood damage: has and will undermine the foundations of transmission towers causing them to collapse or flood debris can bring down transmission towers. VNI West is being routed through flood-land in many places, yet this risk does not appear to have been considered in planning the route for VNI-West.

Sabotage: has and will occur, as recently as May 2023 when bolts were removed from a tower base causing it to collapse near Perth. There have been similar instances in the past in other states, including using high explosives to blow the legs off transmission towers. The UK Government Register now rates the likelihood of an attack on its energy network 5% to 25% likely during the next two years.

Destructive Winds: have collapse 233 transmission towers in Australia and NZ in the last 65 years, including seven 500kV D/C towers in Victoria in 2020 that nearly resulted in permanent damage and closure of the Portland aluminium smelter. Transmission towers are not built to withstand extreme winds and the intensity of destructive winds are increasing with climate change.

These risks are real and cannot be ignored, as being done at present by AEMO and TransGrid in planning WRL – VNI West and Humelink. This appears to be reckless disregard for known risks with extreme consequences.

6. AEMO and TransGrid acknowledge this power system security risk

Section 4.1 of TransGrid's 2023 Annual Planning Report acknowledges thatTransGrid is planning the NSW Super-grid for "cascading outages with system-wide impacts", potentially resulting in a state-wide blackout, and foreshadows adopting a new "N-1 Secure planning criteria". This will be too-little, too late, as the D/C design will be locked-in. No amount of N-1 secure planning/operation can change the certainty of state-wide, blackouts, unless the Super-grid is then duplicated which is impractical. AEMO's July 2022 Power System Frequency Risk Review acknowledges in Recommendation 10 that a non-credible outage of the Western Renewables Link would cause a cascading collapse of the transmission network supplying Southern Victoria including greater Melbourne and the Portland aluminium smelter. Despite undertaking to consider that serious risk in the planning process, AEMO has since committed to VNI West which will vastly increase the amount of electricity to be transmitted across WRL and virtually ensure that a D/C fault on WRL must result in blacking out southern Victoria.

7. Learning from the past

A review of the historical development of the Victorian, NSW and other state's transmission networks shows that never before, has a higher voltage, higher capacity super-grid, been built using D/C transmission lines located on a single transmission easement. All have adopted secure and resilient transmission network designs by building single circuit transmission lines (not double circuit lines) located on geographically separated easements (not a single easement) to avoid these unacceptably high power system security risks. Only when the network had developed to the stage it had sufficient resilience and redundancy, were lower-cost D/C lines used along lower risk routes. D/C lines are ~ 20% lower-cost but have been rejected by the planners of Australia's transmission networks in the past, and this is even more justified with the increased climate risks and Australia's growing dependency on long distance transmission. TransGrid adopted D/C lines for Humelink in their July 2021 PACR, even though the saving was only 5% to build the highest-risk 228kms of the route as D/C and only 22% savings for the entire route. TransGrid only considered lightning and bushfire risks and even then, their justification for adopting D/C lines was invalid as demonstrated in (e) and (f) above. TransGrid did not consider the risks of extreme winds, flooding or sabotage and gave no benefit for the much higher security of single-circuit 500kV transmission lines located on separated transmission easements.

8. **Conclusion**

Through its ongoing development and defence of both the WRL and VNI West projects, AEMO appears to have blatantly neglected its responsibilities under the SOCI Act, the SLACIP Act and its own Resilience and Climate Change report. A loss of the WRL – VNI West interconnector would result in the majority of generation in western Victoria and imports from NSW being instantly separated from southern Victoria resulting is a cascading collapse of the southern Victorian power system, blacking out greater Melbourne and the Portland smelter. A similar risk to electricity supplies to most of NSW including greater Sydney and the Hunter Valley smelters is created by the design of Humelink. Is this not 'reckless' by design?

Investing in the necessary infrastructure and technology to avoid single points of failure in electricity transmission can cost an additional 20% in the short term but can save a significant amount of money and prevent massive disruptions in the long run. It is, therefore, essential for transmission planners to prioritise security, reliability, resilience, and redundancy in their electricity transmission systems. This is something that has not occurred in planning and developing WRL – VNI West, Humelink and the rest of the 500 kV Super-grid for eastern Australia.

C.8 VEPC Our response to AEMO media release on "Lost in transmission"

This note puts onto the public record our response to AEMO's media release[1] responding to our Report. This media release was made at the same time that our Report was released on 2 August 2023.

7 August 2023

AEMO comment	Our response
PLAN B report shows it would result in lower levels of renewable generation entering the grid.	Lower? Than what?
PLAN B will require the acquisition and demolition of people's homes on the outskirts of Ballarat and Bendigo.	Assertion. We are aware of 14 homes in the outer Ballarat suburb of Mount Helen that have been built within 5 meters of the southern side of the easement for a distance of 400m with the closest house 10 metres from the existing Wemen to Ballarat line. There is sufficient room on the northern side of the easement to widen the easement on that side. Alternatively, a temporary line could be installed on the northern edge and the new line built a few metres further away, improving the current situation

[1] https://aemo.com.au/newsroom/media-release/aemo-responds-to-vni-west-alternative-plan

	for these 14 homes. The position of these homes would be enhanced by relinquishing the easement that currently devalues their property and moving the line further away from their houses.
PLAN B would result in long periods of power system disruption in towns and rural communities.	Assertion. There will not be long periods of power disruptions as the existing lines will not be switched off and pulled down until the new Plan B lines are commissioned.
PLAN B would not sufficiently support renewable generation development in north-west Victoria.	Assertion. Our report provides the detail to support our conclusions to the contrary.
Generation from the sunniest and some of the windiest parts of the state would not be serviced by enough transmission. Renewable energy in the area would find it hard to reach concentrations of homes and businesses.	Assertion. Our report provides the detail to support our conclusions to the contrary.
PLAN B fails to deliver the improved access to the Snowy Mountains Scheme – including the upgraded capacity from Snowy 2.0.	AEMO's modelling shows that VNI-West has an inconsequentially small impact on Snowy 2.0's dispatch, yet AEMO continues to repeatedly insist on these lines. Why? Is AEMO not aware of its own analysis or does it not believe it?
PLAN B strikes a blow to the investment case for renewable	Is there any evidence that renewable projects in Victoria are targeting export to other states? Do any have off-take agreements with inter-state governments or customers? Surely not.

projects in Victoria as they can't export energy to other states.	In addition, AEMO's modelling shows that it expects that with VNI-West Victoria can be expected to relinquish its current strong export position and will be importing 26% of its electricity by 2035. Our report finds – based on AEMO's and CSIRO's data – that relative cost differences in wind or solar between NSW and Victoria are much too small to justify the cost of interconnection. In addition as we set out using AEMO's data, the inter-state variability in wind for neighbouring REZs is smaller than intra-state variability. So where is the case for interconnection to diversify supply variability?
The *PLAN B* assumption that only an extra 10m of easement will be required to construct 1,040km of 220 kV double-circuit line in western and north-western Victoria, is overly optimistic. The consequences to both the supply reliability to regional communities during construction, and the outage impacts on the existing renewable generators would be significant.	The extra easement width is only required during construction. After the new line is completed and the old line is pulled down, the surplus easement width will be returned to the land-owner after it is rehabilitated. Plan B includes payment to the landowner for the land used by the shift, and the easement is given back for free. Should the landowner incur any additional costs they will be paid. If they object to the easement shift, there are ways to rebuild in-situ by using temporary structures on the edge of the easement. Only 6 - 8m separation is required between the conductors of Plan B lines and existing lines. After allowing for the width of both towers, the maximum shift would be less than 15m.
Reliability of supply to major regions will be compromised, existing renewable generators in western and north-western Victoria will lose their route to market, leading to	The existing line will remain in service until the new line is operating, then removed. There will be no compromise to reliability of major regions, or impacts on existing generators.

significant reductions in earning opportunities.	
Many of the renewable generation hosting capacity figures are unsubstantiated and well in excess of the detailed power system analysis and modelling undertaken by AEMO. Based on AEMO's initial assessment, *PLAN B* will only harness half the renewable generation claimed.	Assertion. Our report provides the detail to support our conclusions.
All *PLAN B* developments not involving new lines has already been investigated.	Is this true? If so, surely evidence of it can be quickly produced. Why has it not?
We agree our plan does not provide a way for generators to connected at 220 kV but they will connect at 500 kV.	There are no renewable generators in the NEM connecting to the 500 kV grid. In Victoria all use 220 kV lines because of the much lower cost. Even the MacArthur Stockyard Hill and Dundonnell use 220 kV or 132 kV lines until they reach the 500 kV substation. Whether its 500 kV or 220 kV lines, they have to be built between New Kerang and Red Cliffs and across to Bendigo before VNI West will work (other than as an interconnector). A 500kV connection is far more costly then 220 kV
The 1,000 single points of failure (SPoF) on VNI West causing a black out of Melbourne and southern Victoria can be ignored because Victoria already has more than 6,000 kilometres of existing transmission line, including double circuit lines with one set of towers supporting two transmission circuits and because there are systems to immediately protect the grid by making automatic adjustments following an extreme event to maintain secure operation. There is no evidence VNI West would increase risks.	There are no SPoF's in Victoria's critical transmission network other than the double circuit 500kV line in western Victoria. In 2020, extreme winds collapsed 7 towers on that line near Cressey nearly blacking out the Portland smelter which would have then been permanently closed. Other than that section, none of Victoria's 6,000 km of transmission lines are high capacity 500 kV double circuit 500 kV lines having SPoF's at every tower. Recommendation 10 of AEMO's Power System Frequency Risk Review dated July 2022 states that a double circuit trip of WRL will cause a cascading collapse of the five circuits supplying southern Victoria. That is likely to be immediately followed by the overloading and tripping of Heyward and existing VNI interconnectors, blacking out Southern Victoria including Greater Melbourne. 22 towers have collapsed in Victoria since 1999, a major incident every 4 years, wildfires tripping the existing VNI blacking out hundreds of thousands of Victorians, sabotage of a critical tower in Perth in April 2023, severe lightning frequently tripping both circuits on double circuit towers across the NEM, severe flooding destroying towers in NZ. What more proof does AEMO need? AEMO is being reckless ignoring these certain risks.
Cost of VNI West in Victoria will be \$1,755m including \$315m to uprate WRL from its cost estimate of \$737m, totalling \$2.5bn.	In addition to the detailed analysis in our report we note that based on AEMO's claimed lengths of 190km for WRL and 205 km for VNI-West, the average cost/km, for the combined projects is \$6.3 million/km. Transgrid announced last week at the NSW Undergrounding inquiry that Humelink's (latest estimate) cost is nearly \$5 billion which averages \$13.9 million/km. Using comparable per kilometre costing suggest that the Victorian section of VNI-West may cost \$5.5 billion (even before counting interest during construction). And this does not include the \$3.2 billion for the essential 850 kms of 220 kV lines to make VNI-West useful in Victoria.
AEMO also strongly refutes the claim in the report that *"VNI West will more than double transmission charges, not increase them by 25% as AEMO says"*.	AEMO has now doubled its assessment of the impact of VNI-West on Victoria's transmission charges (which of course is only one development in two sections) to "as much as" 50%, from the 25% it claimed in response to our Consultation Report Submission. Though AEMO now portrays the 50% as "accounting for both the cost of

All up, accounting for both the cost of Western Renewables Link and VNI West, transmission charges in Victoria are estimated to increase by as much as 50%.	Western Renewables Link and VNI West" it's early estimate of 25% accounted for both. While AEMO is starting to demonstrate a (slightly) better understanding of the impact of its proposals on prices, AEMO evidently persists in under-estimating the likely capital and operating costs, ignores interest during construction and the extensive augmentation of the 220 kV network in Victoria that will be needed to make VNI-West useful in Victoria. AEMO also fails to account for the effect on electricity prices of the renewables subsidies that will be needed to compensate for the curtailment that its plans deliver. It is not clear why AEMO fails to account for this, because AEMO does recognise that such subsidies will be needed to compensate renewable generators for the curtailment that its plan delivers.
Compared to the projects proposed in AEMO's Integrated System Plan, *PLAN B* would have detrimental outcomes for more landholders, regional and rural communities and the renewable generation investment required to give consumers reliable and affordable power supply.	Assertion. Our report provides the detail to support our conclusions that Plan B would have significantly lower impact on landholders, regional and rural communities and the renewable generation investment required to give consumers reliable and affordable power supply, than VNI-West.

C.9 "Is there a case for building new grid interconnectors? AEMO's own data suggests not"

Article by Bruce Mountain in RenewEconomy[114] brought to Jacobs' attention for this review

Support materials for this article were provided to Jacobs by Prof. Mountain (10.10.2023). This included a spreadsheet calculation that produced the results used in the article.

The transcript received by Jacobs was:

> What is the case for building a bridge, or its electrical equivalent, an interconnector? Three possible answers arise. First, it allows you to get a resource that you otherwise could not get; second it allows you to import cheaper production to replace your own more expensive production; or third it allows you to diversify the risk of supply constraints.
>
> The first of these is not a benefit in any part of the National Electricity Market – we can make electricity easily in all NEM States and so don't need interconnectors to ensure supply. The second of these has been a rationale for interconnection in the past: coal and gas resources differ across our States and so there has been some benefit from trade. Victoria has long been an electricity exporter for this reason. But this is not a rationale for interconnection in our decarbonised future. CSIRO says and we all seem to agree that the cost of wind generation, solar generation and battery storage does not vary meaningfully across the NEM. Indeed the

[114] https://urldefense.com/v3/__https://reneweconomy.com.au/is-there-a-case-for-building-new-grid-interconnectors-aemos-own-data-suggests-not/*disqus_thread__;Iw!!B5cixuoO7ltTeg!GbBwD3GUUXTjMmzKr0y2h_ICtpcjP6tGf3x2Un8bnKdYE1q_bTHFZsh-tNul4sC5eEBmBxD_DjedLoWL-e8SxjlKG8toCw$

combination of small inter-State differences on technology cost and resource productivity of wind and solar means there is inconsequential value in relation to the enormous cost of interconnection.

So this leaves the third possibility: diversification of supply variability by connecting areas where the wind blows or sun shines in some places but not others, at the same time. Is there value in this that justifies interconnection? AEMO, and network asset owners, insist that there is, but they have failed to provide a body of evidence or analysis to support its claim.

In this note I test AEMO's claim using the evidence of what we can see in the NEM now from the production of electricity powered by the wind and sun in NSW, VIC and SA. There are 16 wind farms in NSW, 38 in Victoria and 23 in South Australia with their own despatch unit IDs and they produce data every five minutes on their production. In the quarter just finished they provided 7%, 26% and 42% respectively of end-use electrical consumption in these States.

In addition, each of these States has good rooftop solar data. In the quarter just finished, from AEMO's data estimates of rooftop solar production we find that that rooftop solar supplied 9%, 8% and 16% respectively of end-user demand in NSW, VIC and SA. Finally there are 36 solar farms in NSW, 10 in Vic and 16 in SA that produced 8%, 3% and 5% respectively of the electricity consumed in each State in the last quarter.

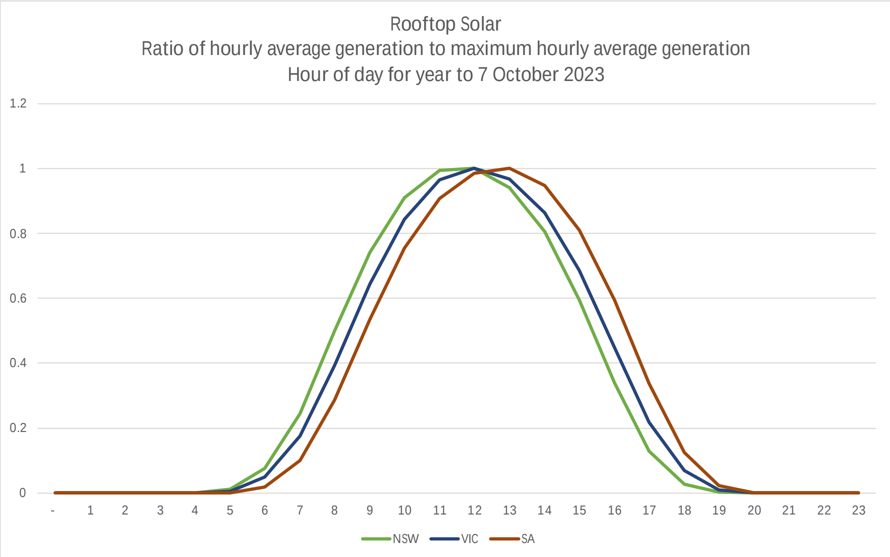
I have left Queensland and Tasmania out of the analysis. Queensland is left out because it is weakly connected with NSW and has very little wind generation (just 4% of end user demand year-to-date) and because variability in QLD to VIC or SA is a much more problematic thing to consider since it is one step (i.e. NSW) removed, so diversity between QLD and NSW is likely to be soaked up in NSW and little or no residual left for SA or VIC.

TAS is left out because I am interested here in focussing specifically on the mainland interconnectors. The coming (hopefully avoided!) train smash that is Marinus merits their own article(s) and I will get to those later.

I obtained the five-minute production data (from AEMO) on the electricity from these sources by type (wind, large scale solar and rooftop solar) for each state, for the year to 7 October 2023 (nothing particular about this, its just the day that I did these sums). Then I compared the average production, by type, for each hour of a 24 hour day, across the year. Specifically, I worked out the average in each hour (so, the average of the production for the 12 five minutes in each hour, e.g. 1am to 2am, that recurs on the 365 days in the year. This means the average of 4,380 data points in each hour for each type. In the charts that follow I show these average values, normalised by the highest average in all the 24 hours.

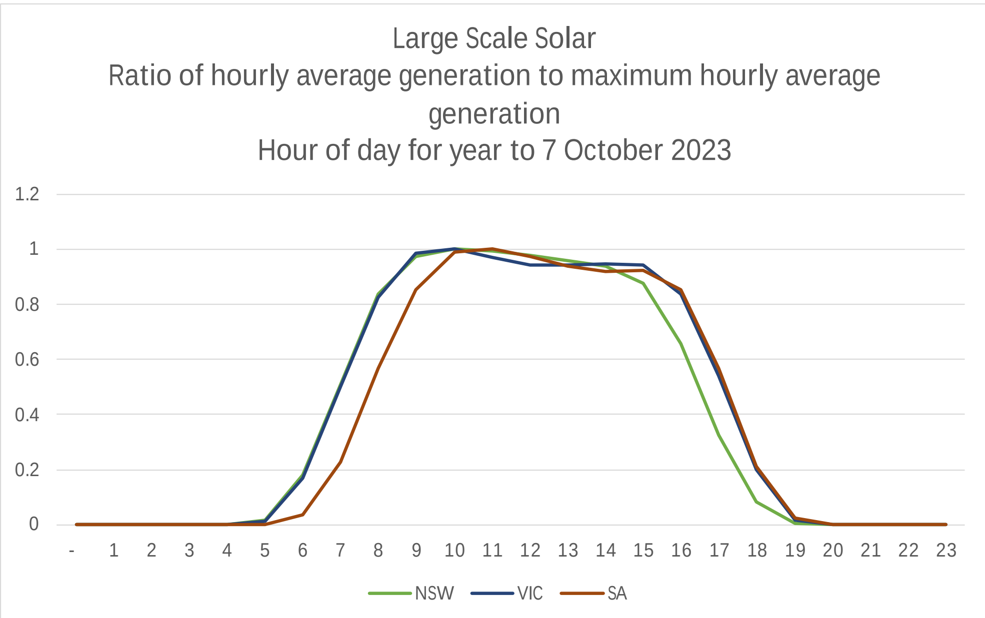
I also inspected the upper lower reaches of the data (so the 1st,5th, 95th and 99th percentiles) to see if the conclusions we can draw from observing the average values are still relevant at those points in the distribution.

Let's start with rooftop solar. What do you expect? Well Australia is a sunny country, a sunny day is the default. Is this what the data shows? Indeed it is, the chart below shows a very tight correlation of rooftop solar production in NSW, VIC and SA. The Pearson Product Moment is 89% between VIC and NSW and 92.2% between SA and VIC The small variation in the chat below is likely to be explained by longitude, mainly.

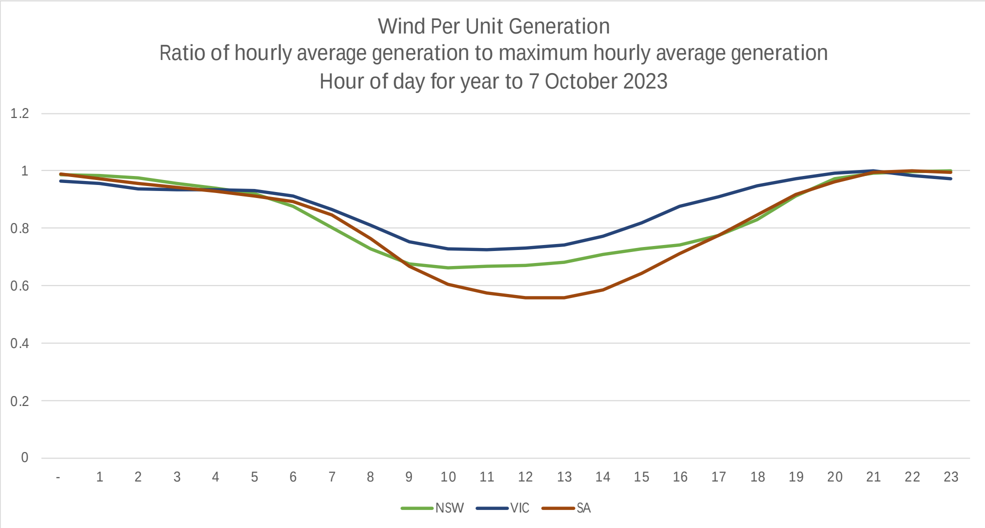


So, clearly, you can't justify building an interconnector to export rooftop solar from one state to another on the basis of the diversity of rooftop solar production. It is perplexing that AEMO has justified VNI-West on the basis of the benefit of exporting rooftop solar from Victoria to NSW.

Let's turn next to large scale solar. What do you expect? Surely much the same as rooftop solar: high correlation? Indeed this is what we see in the chart below. PPMs are 86.9% between VIC and NSW and 85.4% between VIC and SA The flatter production profile relative to rooftop solar is explained by axis tracking and usually substantial oversizing of production capacity relative to inverter size in most solar farms. So, clearly, you can't justify building an interconnector to export farmed solar from one State to another on the basis of the diversity of farmed solar production.



Next, let's turn to wind. What do you expect? I expect high correlation. PPMs are still high in statistical terms 45.7% NSW-VIC and 52.3% SA-VIC, but lower than solar, as expected where correlation is extremely high. But how does wind correlation vary by time of day?



Across the day, as the chart shows, wind in NSW and VIC on average is very correlated from 7pm to 7am. Even during much of the day, from 7am to 3pm, there is little difference on average. It is only from 3pm to 7pm that there is a little bit of a gap.

Let's estimate the value this. The chart shows that on average in this window, VIC windfarms can be expect to produce at about 90% of their maximum hourly average production. In NSW that number falls to about 80%. So, about 10 percentage points difference. Now, the maximum hourly average production in both NSW and VIC is around 40% of installed capacity. So, per MW of wind capacity installed in VIC rather than in NSW, NSW can expect that, on average, it would get 10%*40% = 4% more production on average from a windfarm in Vic from 3pm to 7pm than from a wind farm in NSW.

But wait, it gets worse. What value does that 4% increase in average productivity of wind really offer? In capacity markets in Europe and Britain, the firmness factor that is applied to determine the firm (reliable) value of wind is around 15%. This gives an estimate of the production that can be relied upon with some reasonable level of certainty. So, to a rational transmission planner (or a Minister considering the advice of a transmission planner) they need to weigh the certain cost of an interconnector against the certain benefit of interconnection. If that transmission planner (or Minister) was to ask "what firm supply do we get from incurring this cost" the answer would be 15% of 4% = 0.6%, So from NSW's perspective, putting an interconnector in to import wind generation from Victoria results in a firm supply benefit worth 0.6% of each MW of wind supply built in VIC rather NSW. If you were the Minister in Sydney or Melbourne, how could you possibly justify imposing the costs of an interconnector if you knew this?

I mentioned that I also looked at the top and the bottom of the distributions, what did I see? At the bottom when hourly wind production is low we get a very tight correlation of wind in NSW and VIC. All that is left on very still days is a bit of morning and evening land-sea temperature differential driven breezes. What about very wind days: again very high correlation – when it is windy it blows throughout the day in NSW and VIC.

The critical thinker might suggest that the issue is not resource diversity looking separately at wind and solar but rather looking at the coincident portfolio of wind and solar in each State. What then do we see when we look at the portfolio ? You guessed: very high correlation. Specifically, Person Product Moment scores of 67.7% for NSW-VIC and 68.1% for SA-VIC.

Of course none of this is to say that when you look at individual wind farms, you do not see diversity in production relative to other wind farm in the State it is located in or in neighbouring States. But this does not justify interconnection. Indeed, as we have previously pointed out, even the unidentified wind “resource” data that AEMO has used to support interconnection finds greater potential for intra-state diversification than inter-state diversification.

At the AFR’s Energy and Climate Summit this week, AEMO made the case for interconnection, firstly by alluding to our fossil fuel past (when interconnection had some value) and then, by anecdote, alluding to renewable resource diversification in our renewable future: “*just this past week we’ve seen that it can be cold and windy in Victoria, but sunny and warm in NSW*.”

But the plural of anecdote is not data. The data is plentiful and easily accessible, indeed its data that AEMO publishes that I have used here. Analysis of them seems to lead to a clear conclusion that invalidates the (ambiguous) anecdote. (As an aside the anecdote seems to crumble under its own weight: over the last week the wind and sun in “cold and windy” Victoria met 36% of Victoria’s end use demand, and in “sunny and warm” NSW it was 30% of end user demand, pretty much bang-on the quarterly averages.)

In his AFR speech, AEMO’s CEO suggested, reasonably, that social licence depends on “quality decisions”. In this pursuit of quality decisions, perhaps AEMO might critically (and publicly) assess the evidence presented in this note. If it fails to find substantive flaw, AEMO might then explain how it will be responding to this evidence in revising its assessment of transmission expansions. Indeed, the inevitable conclusion of this analysis is not just that interconnectors like VNI-West are unlikely to have a *net* benefit, but that they are unlikely to have *any* consequential benefit at all in a future NEM that relies on the wind and sun.

Bruce Mountain, 10 October 2023

Professor Bruce Mountain is Director of the Victoria Energy Policy Centre at Victoria University

C.10 “TOOT Methodology will guarantee that cost understatements are passed through”

Note received from Simon Bartlett 12 October 2023

Table 6 of the VNI West PACR, estimated that the cost of VNI West in Victoria would be $m1,440 (i.e., $m1,755 less the $m315 WRL costs). The 206 km line length was incorrect and the latest study corridor is 226 km long and the final length will be longer. The average cost/km is claimed to be $m5.4/km.

Table 6 Summary of the credible options assessed in this report – capital costs, $m in FY2020-21 dollars

Cost component	Option 5 (to Bulgana)		Option 5A (to Bulgana, east of Kerang)	
	NSW	VIC	NSW	VIC
Stage 1 – Early works				
Early works – Property/access/ easements	66	69	72	69
Early works – other	50	60	50	60
EnergyConnect enhanced	182	-	182	-
Stage 2 – Implementation				
Substation/ terminal station works	354	415	354	415
Line works	751	1,034	831	1,034
Power flow controllers / series compensation	183	164	183	164
Biodiversity offset costs	66	12	73	12
Total (by state)	1,651	1,755	1,744	1,755
Total (all states)	3,406		3,499	
WRL – Incremental costs for alternate options (included in the totals above but separately itemised here as well for transparency)				
Included cost		315		315
WRL uprate length		104 km		104 km
Other relevant assumptions				
Approximate line length [A]	184 km	205 km	203 km	206 km
Project EnergyConnect uprate length	174 km	-	174 km	-
Quantity substations/ terminal stations [B]	-	1	-	1

A. Approximate line length is the indicative total length (in kilometres) of lines between EnergyConnect (at Dinawan) and the connection point to WRL. As a route has not yet been determined, line length has been taken as the centre of the area of interest.
B. Quantity substations/ terminal stations is the quantity of terminal stations along the VNI West project and excludes the Dinawan and WRL connection point terminal stations.
C. WRL included uprate costs include costs across all cost components, not just line works. Refer to the single line diagrams in Appendix A2 for scope details.

In comparison, the estimated cost of Humelink is $m13.6/km (i.e., $bn 4.9/360 km) yet VNI West includes series compensation and flow controllers. Based on the Humelink $13.6/km, VNI West would cost $m3,070 being 213% of the PACR cost estimate. There is certain to be further cost increases by the time VNI West is completed.

Irrespective of the cost estimate in the PACR, the owner of VNI west in Victoria, is guaranteed to i.e., include every dollar spend (and more) because the National Electric Rules include the following provisions:

(a) Contingent Project Application Process (CPAP) that requires AEMO to run a TOOT process meaning "Take One project Out at a Time." to establish the maximum asset valuer that the AER may approve. This methodology is deeply flawed as explained below
(b) Asset actual expenditure "roll-in" that ensures that all actual expenditure during construction is rolled into the regulated asset base, regardless of approved amounts.

Under the TOOT methodology, AEMO removes VNI West from their ISP economic analysis and observes the reduction in net benefits and uses that to derive the maximum allowable asset value.

This is exactly like removing one link from a bicycle chain and observing what that does to the value of the bicycle. Of course, the whole chain falls off and the bicycle won't work. So, the value of that one link is calculated to be the value of the whole bicycle.

There are six links in the Sydney to Melbourne interconnector chain – Southern Sydney Loop, Humelink, PEC, VNI West (NSW), VNI West (Victoria) and WRL. Removing any one of those six links in the interconnector chain is like removing one link in the bicycle chain. The reduction in benefits will be the loss in value of the entire Melbourne to Sydney interconnection. Every one of the six links in the interconnection chain, will be credited with a substantial part of the whole interconnection. Even the absurd 130% cost increase is likely to be justified using the TOOT method, which has been enshrined in the National Electricity Rules by the AEMC, the ESB and AER.

If the certain cost blow-outs are not approved by the CPAP/TOOT process, all actual expenditure will be rolled into the regulated asset base at the start of the next revenue reset process. Every dollar spent on WRL-VNI west in Victoria will be charged to Victorian customers plus inflation plus regulated return over the next 50 years.

This cannot comply with the AER's guiding principle of protecting electricity users from un-justified increases in electricity prices caused by monopoly network services providers.

C.11 Power system security guidelines

Materials received from Prof. Bartlett (12.11.2023) on AEMO's Power System Security Guidelines[115]:

> Please find attached public information that is relevant to Jacobs investigating the risk of WRL-VNI West double circuit tower design, on a single easement to the security of electricity supply in Victoria, and the associated implications whenever AEMO, in operating the power system, considers that a double circuit outage is a credible contingency.
>
> Your attention is drawn to the following appendices, tables and figures
>
>> Appendix K - Large Social interference, and in particular (b) vandalism and sabotage that AEMO claimed the Plan B authors were Reckless in including as a risk

Appendix K. Reclassification Criteria – Large scale social unrest

K.1 Risk to the power system

Risks to the power system include:

(a) major industrial action impacting operations of the *market* or power system

(b) vandalism or sabotage of significant power system assets

(c) humanitarian crisis impacting operations etc.

[115] The latest version of the guidelines are available at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf?la=en

Appendix A Bushfires, paragraphs 33 that weights double circuit lines as having twice the risk of single circuit lines on the same easement. See also A 2.2 .1 (f) where double circuit bushfire trips become credible contingencies

(f) If there are multiple transmission circuits in an easement, the intent of the process is to identify and manage the double circuit or two adjacent single circuits most exposed to the bushfire front. These are deemed to be the critical elements requiring an assessment.

Appendix B - Lightning section B.2 and Figure 4 include the specific provisions for simultaneous double-circuit lightning faults where double circuit lines are classiffied as possible, probable and proven. Please refer to the link to the current NEM classifications which include two double circuit 500 kV lines as proven (Bayswater to Mount Piper twice recently and probable - Barnaby to Mount Piper - once recently. Note that positive lightning strikes are seldom anticipated.

Appendix D - Severe Winds states that the greatest risk comes from wind borne debris and Table 7 indicates that risks arise even for wind speeds as low as 63 km/hr. The wind vulnerable transmission lines include the 500 kV transmission lines between Heyward and Moorabool in Victoria - meaning that the failure of the double circuit section of that Victorian 500 kV line is classified as a credible contingency for forecast wind speeds above the threshold. Note that the Cressey tower collapses were unanticipated by the control room operators at the time.

Appendix F - Floods include the risk of double circuit towers collapsing from their foundations being undermined, a common occurrence in the NEM

Appendix G - Widespread Pollution on easements is another common occurrence particularly where transmission lines cross cultivated land and the build-up of dust on the insulators becomes a conductive slurry in the early morning heavy dew creating faults on the circuits on that easement

Appendix H - Landslides collapse the towers on the affected easement

In assessing the implications of AEMO declaring that both circuits of WRL-VNI West are going to be frequently declared as a credible contingency, Jacobs needs to consider that there is only a single 220 kV transmission line running parallel to the 500 kV VNI West between New Kerang and Wagga-Wagga, and that is likely to be open circuited anyway due to the loop flows between the 500 kV network and its parallel 2290 kv single line. Especially given the changes in the power flow on the 500 kV network every time the sun intensity changes as clouds pass overhead and at nightfall.

In the case of the southern part of VNI West between New Kerang and Bulgana and Sydenham, there are only two 220 kV lines running parallel to the 500 kV network, and in the case of WRL, one of those 220 kV lines runs 900kms via Red Cliffs and Bendigo so will hardly carry any power should AEMO be anticipating the outage of both 500 kV circuits. The unexpected outage of both 500 kV circuit is virtually certain to result in the tripping of both 220 kV lines that run in parallel to the 500 kV section that has tripped, as those 220 kV line4s would already be heavily loaded and unable to carry the addition power that was being carried by the 500 kV network

C.12 Voltage management benefits of Plan B

Received 13.11.2023

Voltage Management of the Victorian Network and the Benefits of Plan B

According to figure 35 of the Victorian Annual Planning Report 2023 I (see below), there are already high voltages being experienced on the 500 kV network around Melbourne, for the loss of a single Loy Yang Unit at time of minimum demand.

Figure 35 shows a heat map of post-contingent voltages across Victorian 500 kV terminal stations for a critical contingency. The post-contingent voltages across the 500 kV network are higher than or equal to those of the annual minimum demand snapshot.

Figure 35 Heat map of post-contingent voltages at 500 kV terminal stations for the loss of a Loy Yang unit during night-time minimum demand

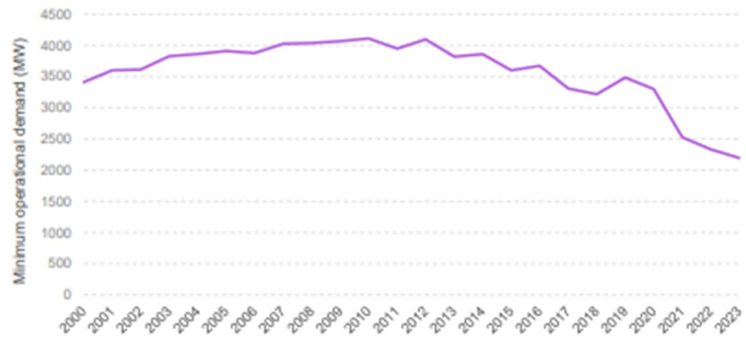
This is because the lightly loaded 500 kV transmission lines generates around 1 MVAR/km/circuit which totals up to 1,300 MVAR's for the approx. 1,300 km of 500 kV transmission circuits in Victoria. The approx. 4,700 kms of 220kv transmission circuits generate only 0.2 MVAR's /km/circuit totalling a maximum of 940 MVAR's for no-load. However, the 220 kV lines are generally more heavily loaded compared with their surge impedance loading of around 220 MVA/circuit (vs 1,200 MVAR/circuit for 500 kV circuits, so the 220 kV network's contribution is low compared with the 500 kV network.

Some of the surplus reactive power has traditionally been adsorbed by the distribution network, however, this is rapidly reducing as rooftop PV is causing the power factor at the transmission/distribution connection points to become leading instead of the traditional lagging power factor. Grid connected renewables are not adsorbing the surplus reactive power, leaving only the existing synchronous generators and a few shunt reactors available to perform this essential voltage management task. It is typical that each of the Loy Yang units can adsorb up to 75MVAR's and the Yallourn units up to 50 MVAR's totalling around 650 MVAR in total. Figure 35 of the 2023 VAPR indicates that the management of high voltages under a credible contingency at minimum load is already a critical consideration.

This situation will rapidly deteriorate with

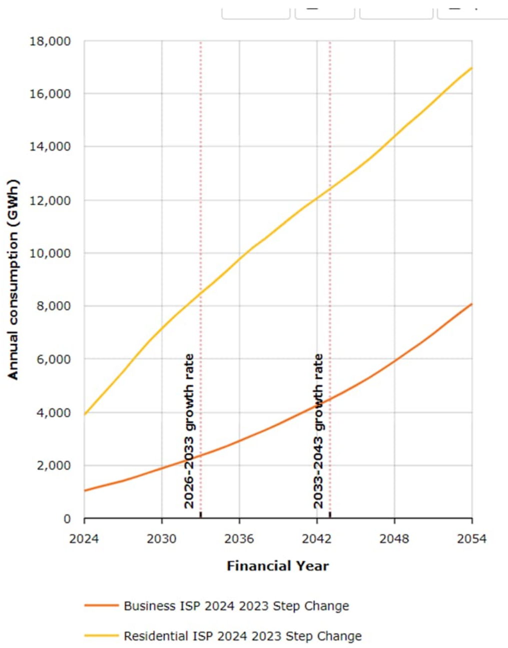
(a) The rapid reduction in system minimum load of around 10 % pa (see figure 13 below from VAPR

Figure 13 Actual minimum Victorian operational demand, 2000 to 2023



More than 500 MW of distributed PV was installed in Victoria over the 2022-23 financial year. As the installed capacity and maximum generation from distributed PV have continued to grow, daily minimum demand is

(b) The rapid increase in rooftop PV, which AEMO forecasts to triple by 2035 comparted with 2022 levels



Both (a) and (b) above will increase the surplus reactive power on the Victorian transmission network as the substantial reverse power frows from the distribution networks significantly elevate the voltage of the low voltage and medium voltage networks forcing up the voltage on the transmission network. The additional amount of reactive power being injected into the transmission network whenever the rooftop solar is generating will depend on rectifying the existing 70% rooftop solar inverters that are currently non-compliant with the mandated volt/var control obligation, but could exceed thousands of MVAR's.

(c) the closure of all existing synchronous generators by 2032 being AEMO's forecast date in the VNI West PACR, reducing the current reactive power adsorption capacity by an estimated 650 MVAR's

(d) the commissioning of another 1,600 kms of 500 kV circuits being 800km of double circuit 500 kV lines between Sydenham and Wagga Wagga generating another 1,600 MVAR when lightly loaded

Collectively, the amount of surplus reactive power on the Victorian transmission grid could reach 2,000 (?) + 650 + 1,600 = 4250 MVAR's by the mid 2030's

AEMO undertook a RIT-T assessment in May 2018 to December 2019 on Victoria Reactive Power Support that address the very beginning of these voltage management issues

https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victorian-reactive-power-support-RIT-T-PSCR.pdf

https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/Reactive-Power-RIT-T/Victorian-Reactive-Power-Support-PACR.pdf

The outcome was to install three 100 MVAR bus connected shunt reactors by 2022 to 2025, This 300 MVAR program is yet to be implemented but is immaterial compared with the possible shortfall of around 4,250 MVAR. The scope of WRL includes four 50 MVAR 500 kV line shunt reactors and the scope of VNI West includes six 100 MVAR line shunt reactors, together totalling 800 MVAR's of shunt reactors. When added to the 300 MVAR's of shunt reactors from the 2019 RIT-T, the total is 1,100 MVAR of shunt reactors well below the estimated need for just category (d) above being the reactive power generation for the additional 1,600 kms of 500 kV circuits for WRL-VNI West.

The used of switched shunt reactors is not a viable solution from the viewpoint of the practical life of the 500 kV circuit breakers and shunt reactors based on the experience with the 275 kV circuit breakers at Mount England substation that have to switch daily to energise/reenergise the Wivenhoe pumped storage units that were originally built without generator circuit breakers. The design life of SF6 EHV circuit breakers is typically 6,000 operations, which at two switching operations each day would be reached in just eight years. This was the experience with those circuit breakers.

Even more frequent switching is likely to be required for the 500 kV line shunt reactor circuit breakers given the daily cycle of the solar power being transmitted across WRL- VNI West. Further switching will be required when large areas of cloud pass over the Murray River REZ and SW NSW REZ. Depending on the frequency of those events, the design life of the 500 kV circuit breakers could be reached in just a few years. Likewise, the frequent energisation and de-energisation of the shunt reactors is likely to cause premature failures of those reactors, which would normally have a service life of around 25 years

Advantages of Plan B

Plan B assumes 4 to 6 220 kV circuits in much shorter single line sections in place of the two 500 kV ~200km line sections. The reactive generation for a 220 kV line is only approx. 0.2 MVAR/km/circuit, being 1/5th of that of a 500 kV circuit. In addition, Plan B replaces the existing 220 kV lines, so is only adding approximately 1050 km of additional 220 kV transmission line, adding only 210 MVAR maximum of additional reactive power generation compared with 1,600 MVAR for WRL-VNI West.

Further, it is impractical to switch out any of the eight 500 kV circuits of WRL-VNI West due to the security implications and the N-1 credible contingency would then be the loss of the entire double circuit line. Plan B has four to six 220 kV lines, any two of which can be readily switched out at times of lower power flow, to reduce reactive power generation without creating security risks.

These are very substantial benefits of Plan B, especially given the lines, very large amounts of surplus reactive power to be generated across the Victorian transmission network

Jacobs needs to consider the above facts in their review of the benefits of Plan B over WRL-VNI West

Simon Bartlett

13th November, 2023

C.13 Information on curtailment

Information received 1 October 2023

Sources of information for Tasks A.5 and A.6 - Curtailment

Task A.5 states

VNI West doesn't address curtailment
Plan B:"Leaving to one side our critique of the merits of interconnection, our analysis of the results of AEMO's modelling analysis of VNI-West finds that it is not successful in meaningfully addressing the pressing problem of renewables curtailment in Victoria. AEMO's results show a slight reduction in renewable curtailment in those REZs affected by VNI-West in the decade after VNI-West is commissioned. But this is followed by a return to the pre- VNI-West levels of curtailment a decade after commissioning

Jacobs will need to access public information on AEMO's forecast of curtailment of renewable generation at Victorian REZ's and especially SW NSW, Murray River and Western Victoria REZ's, and independently verify the legitimacy of those forecasts.

Note that the definition of curtailment is the proportion of renewable generation at each REZ, that cannot be exported to the transmission network because of transmission congestion on the network between the renewable generation site and the reference node. There may be additional curtailment because the renewable generation cannot be dispatched due to an oversupply of renewable generation compared with the load. Jacobs will need to establish whether this second category of curtailment is material in the period up to 2035.

The publicly available information for calculating AEMO's forecast curtailment is contained in the spreadsheets in the E&Y market modelling results for the VNI West PACR. This can be accessed via the link

https://aemo.com.au/initiatives/major-programs/vni-west/reports-and-project-updates

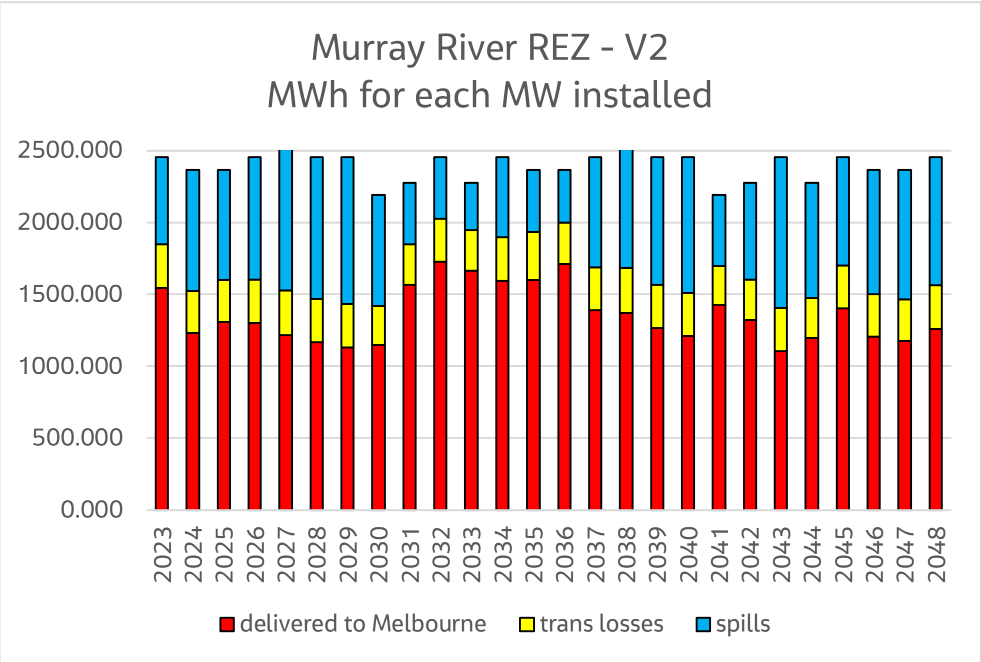
tag option 5A – REZ capacity and REZ energy, for each REZ and each year for both solar farm generation and wind-farm generation. This data can be used to calculate the annual capacity factor for the solar farms or windfarms in each REZ for each year.

The next source of required public information is the capacity factors for each REZ, year, and for solar farms and wind farms (high wind and medium wind) that the renewable generation would operate at with zero curtailment. These capacity factors are found in the Data and Assumptions workbook for the 2022 ISP – tag "capacity factors"

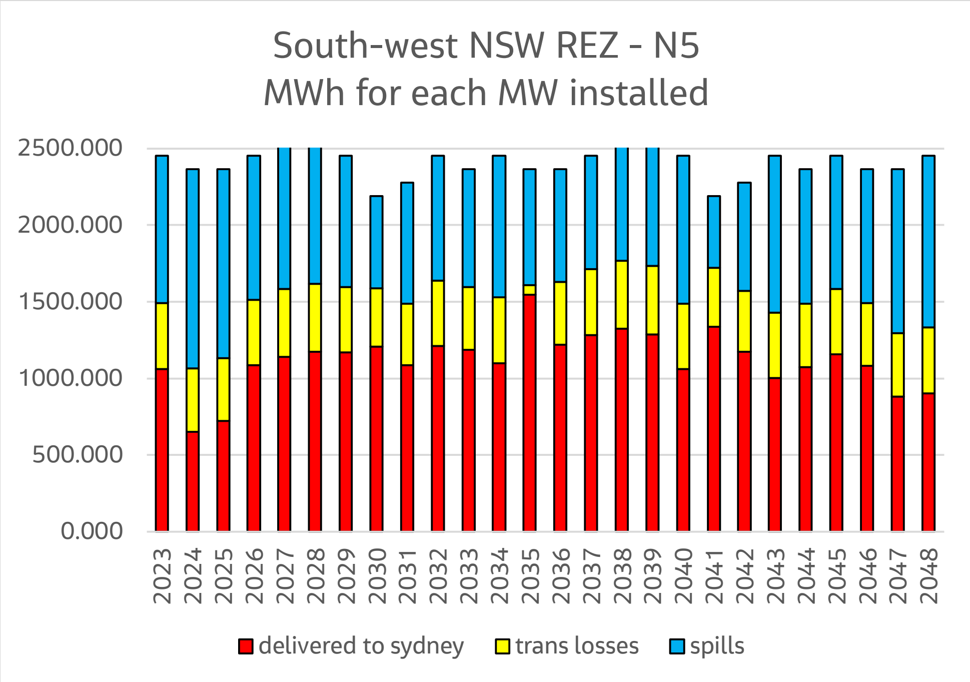
The difference between these two numbers is the reduction in capacity factor due to curtailment. This can be divided by the maximum capacity factor to determine the percentage of curtailment.

To assist Jacobs to undertake these calculations, below are figures that illustrate, for each REZ and each year, the amount of energy generation pa for each MW of renewables, broken down into total generation, curtailed, transmission losses, and the residual energy delivered to the reference node at Melbourne or Sydney (for SW NSW REZ).

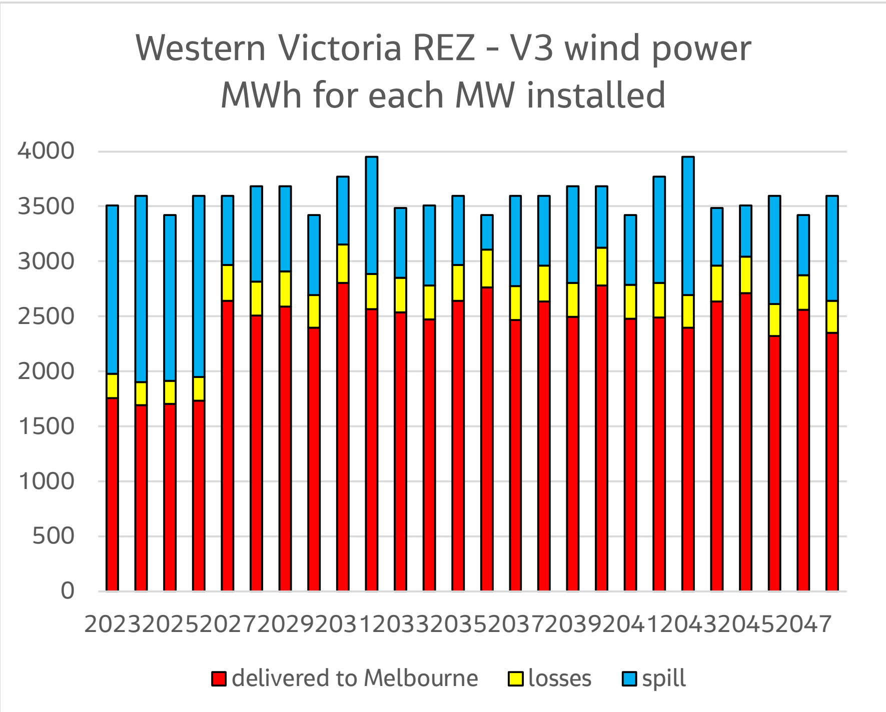
If required by Jacobs, the master spreadsheet that calculates and plots these figures can be provided



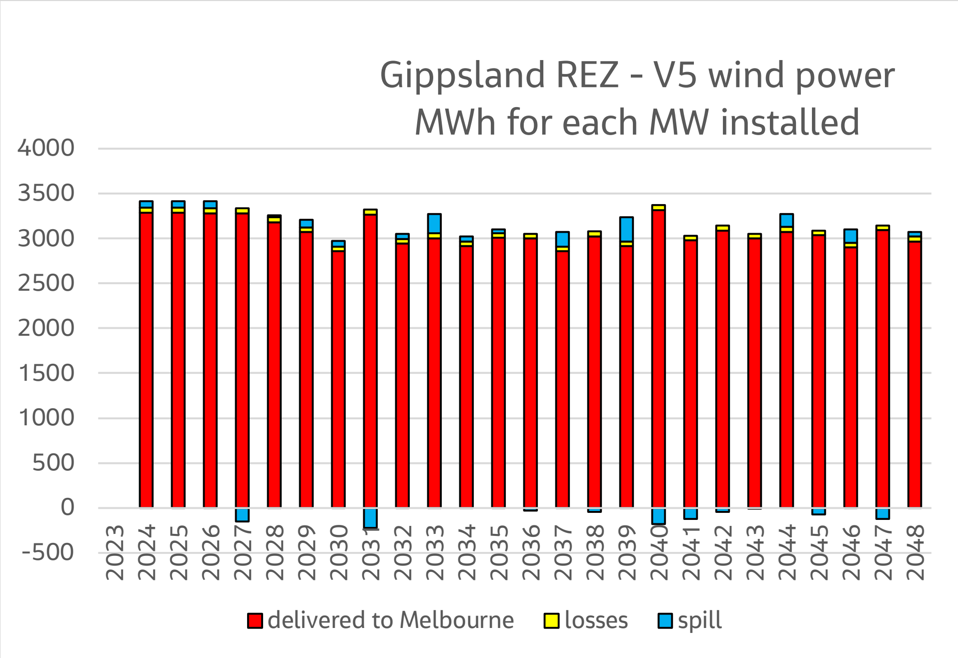
The curtailment for Murray River REZ confirms the statement made in the Plan B report that AEMO's forecast of Murray River REZ curtailment does reduce from approx. 40%, once VNI West is commissioned in 2031. However, they are still at high levels of around 20% and return to their former very high levels from 2037 onwards (only6 years after VNI West is commissioned



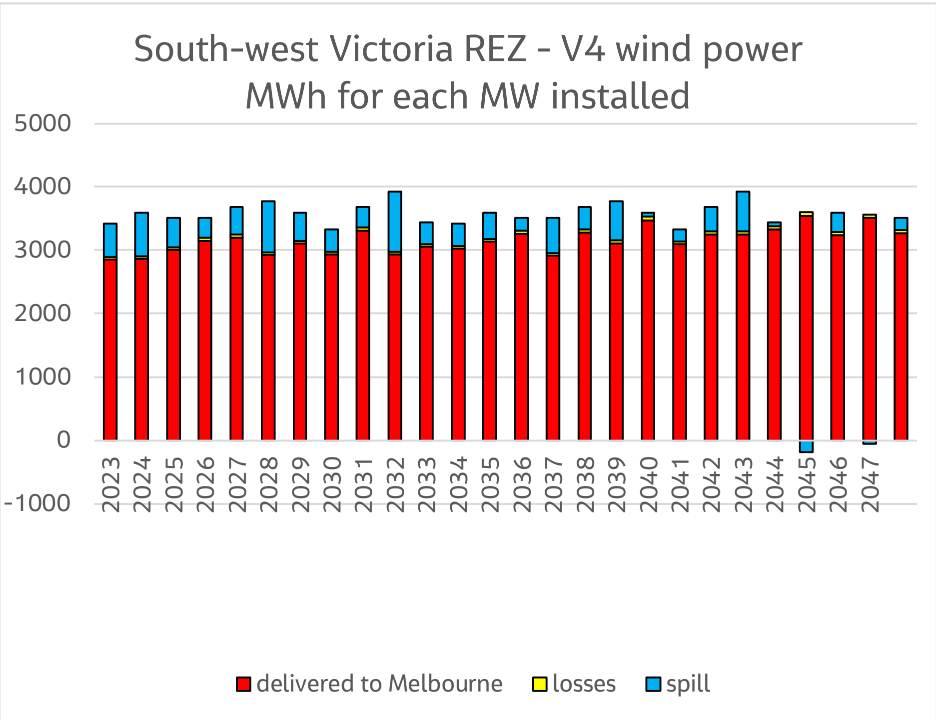
The curtailment at SW NSW REZ is even higher at ~50% until PEC is commissioned in 2026, but continue at around 40%, except for two years after VNI West is commissioned.



Curtailment in Western Victoria REZ are around 40% until WRL is commissioned in 2027. They then continue at around 20% with some years being even higher.



The very low curtailment in Gippsland REZ demonstrates that the curtailment due to an over-supply of renewables compared with total load is immaterial compared with the curtailment due to transmission congestion, particularly at the REZs serviced by WRL – VNI West



Curtailment in South-western Victoria REZ are around 15% until 2044 when AEMO's market modelling assumes another 500 kV line is commissioned.

In investigating whether the AEMO forecasts of curtailment are reasonable, Jacobs need to reflect on the fact that AEMO's transmission model for western and north-west Victoria is unrealistic as it

(a) assumes that all new V2 renewables are located within 5 km of New Kerang substation, and does not allow for the congestion that will occur when those new renewables connect to the existing 220 kV network.

(b) Likewise for new V3 renewables, which are assumed to be located within 5 km of Bulgana substation with no congestion on the existing 220 kV network

(c) Ignores the effect of N-1 planned outages on any of the 500 kV circuits on VNI West and WRL. During these outages, AEMO would drastically reduce the 500 kV transmission limit as a precaution against the other 500 kV circuit tripping unexpectedly. This would create very high congestion on the transmission network resulting in even higher curtailment of the V2 and V3 renewable generation, both the existing renewables and the new renewables.

Jacobs needs to consider whether the effect of these factors would be much higher levels of curtailment than forecast by AEMO for WRL- VNI West.

One of Plan B's objectives and achievements is to keep V2 and V3 curtailment to below 13% though-out the study period. Jacob's independent review of Plan B may need to consider the report that verifies Plan B's Hosting Capacities. That report demonstrates that, even with these high levels of hosting at V2 and V3, Plan B provides sufficient transmission capacity which means there would be no curtailment of V2 and V3 renewable generation when all 220 kV circuits are in service. That report also demonstrated, that under N-1 outages, the remaining 220 kV network is likely to be constrained when the maximum number of hosted renewables is operating at full load, however the surplus generation could be stored in grid scale Batteries located in V2 rather than being wasted by curtailment. Ther stored energy could be discharged over the peak load periods using the available N-1 transmission capacity. The report also demonstrated, that under N-2 outrage conditions, the Plan B network would not result in a cascading collapse of the Victorian grid as likely to occur for WRL - VNI West. There will be some curtailment of generation at V2 and V3, however this will be much lower than the targeted 13% curtailment cap targeted for Plan B.

Should Jacob's need access to further information to undertake its independent review of curtailment for WRL-VNI West or Plan B, we would be pleased to assist where we are able.

C.14 Information for Task B2

Information received 1 October 2023

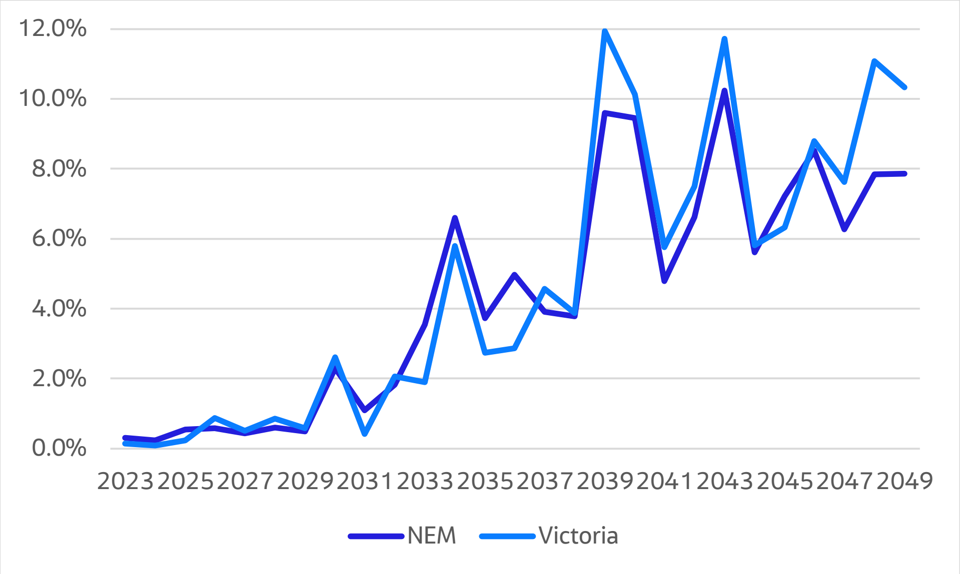
Public Sources of Information for Jacobs to access for undertaking Tas B.2 Visibility

Introduction

For Jacobs to undertake tasks B.2 Visibility

For the OCGT/Diesel generation, the above energy productions and installed capacities have been converted in annual capacity factors to provide an indicator for how tight the supply/demand balance is in each year, as illustrated below

Annual Capacity Factor of peaking Gas Turbines (in %) – as measure of supply tightness



It can be seen that the annual capacity factors increase to very high levels, after the coal-fired stations are closed down, and that they reach progressively higher peaks in both the NEM and in Victoria, in the years that have been modelled using weather data from 2011/12 (moderate La Nina year) and 2017/18 (moderate La Nina year)

Simulated year	Weather year	a.m. (%)
2030	2013	2.6%
2034	2017	5.8%
2037	2011	4.6%
2039	2013	11.9%
2043	2017	11.7%
2046	2011	8.8%
2048	2013	11.1%

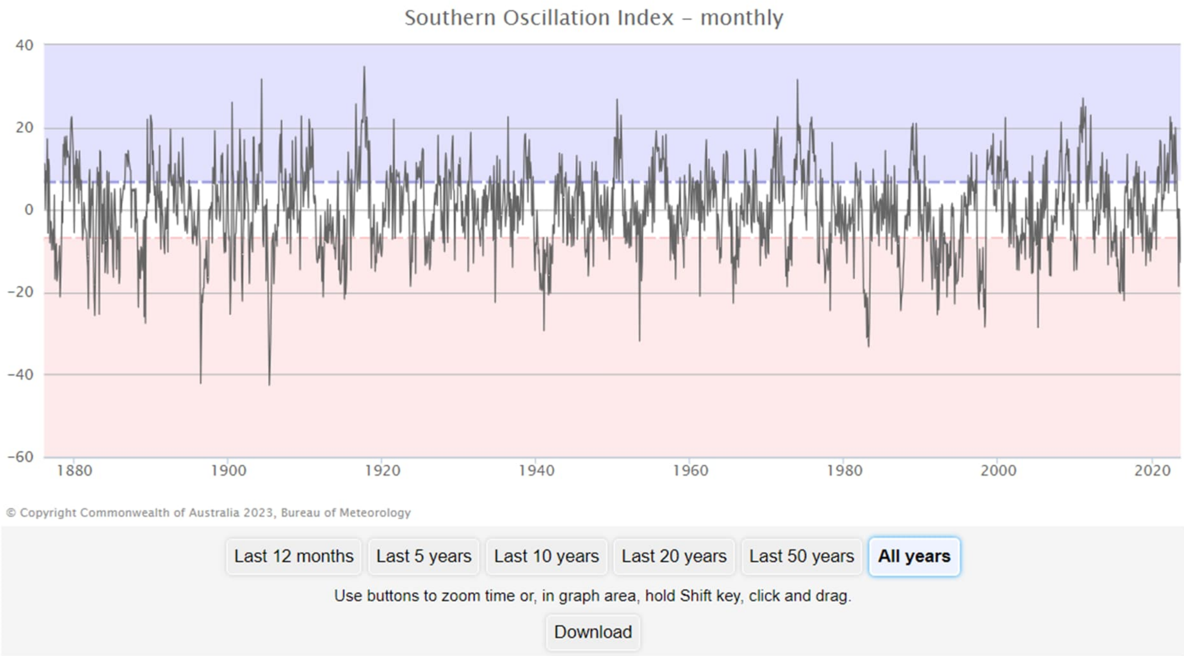
This confirms that, once the coal-fired stations have mostly closed, the outcomes of the ISP simulated studies are being primarily driven by the lack weather model, reducing the renewable energy generation in those years modelled by moderate and weak La Nina years.

It is noted that the restricted 8 years of weather data did not include any of the four strong La Nina years or the other three moderate La Nina years that occurred in the last or st25 years. Had the ISP be based on a more representative series of weather patterns, there would have been many more, and more severe La Nina events. This would have had a significant impact on the ISP results as it would have highlighted for every state, and the NEM, the absence of diversity of weather and the uselessness of constructing major new interconnections between the states.

Further public information on the absence of diversity between all REZ's in the NEM states

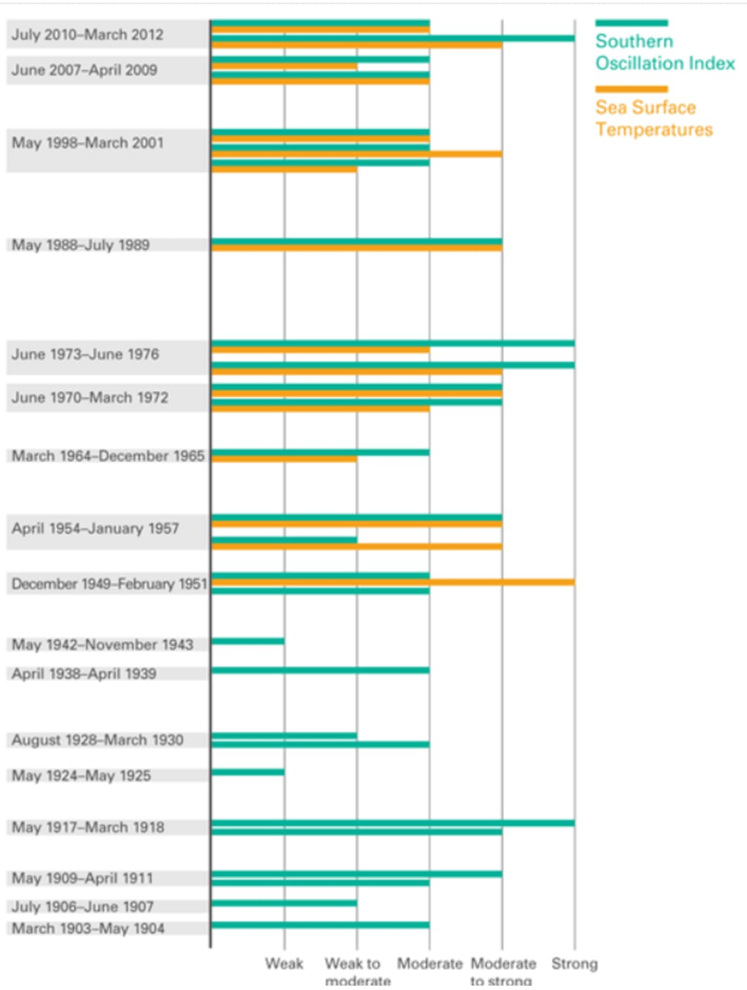
The BOM website contains monthly data since 1876 (the last 146 years) – that can be readily accessed and analysed by Jacobs to investigate whether the 8 years of weather data used for the ISP is representative, and whether there have been years and sequences of years, with far more onerous weather conditions that the sequences studied in the ISP. See links to BOM website as follows

http://www.bom.gov.au/climate/enso/soi/



Southern Oscillation Index monthly data												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	+11.8	+10.5	−2.0	+0.3	−18.5	+0.2	−4.3	−12.7	-	-	-	-
2022	+4.1	+8.2	+13.8	+22.6	+17.1	+21.2	+8.7	+9.1	+18.3	+17.7	+4.6	+20.0
2021	+16.5	+11.5	−0.3	+2.0	+3.6	+2.6	+15.9	+4.6	+9.3	+6.7	+12.5	+13.8
2020	+1.3	−2.2	−5.2	−0.5	+2.8	−9.6	+4.2	+9.8	+10.5	+4.2	+9.2	+16.9
2019	−0.6	−13.5	−6.8	−1.3	−9.0	−10.4	−5.6	−4.4	−12.4	−5.6	−9.3	−5.5
2018	+8.9	−6.0	+10.5	+4.5	+2.1	−5.5	+1.6	−6.9	−10.0	+3.0	−0.1	+9.3
2017	+1.3	−2.2	+5.1	−6.3	+0.5	−10.4	+8.1	+3.3	+6.9	+9.1	+11.8	−1.4
2016	−19.7	−19.7	−4.7	−22.0	+2.8	+5.8	+4.2	+5.3	+13.5	−4.3	−0.7	+2.6
2015	−7.8	+0.6	−11.2	−3.8	−13.7	−12.0	−14.7	−19.8	−17.8	−20.2	−5.3	−9.1
2014	+12.2	−1.3	−13.3	+8.6	+4.4	−1.5	−3.0	−11.4	−7.6	−8.0	−10.0	−5.5
2013	−1.1	−3.6	+10.5	+0.3	+8.4	+13.9	+8.1	−0.5	+3.9	−1.9	+9.2	+0.6
2012	+9.4	+2.5	+2.9	−7.1	−2.7	−10.4	−1.7	−5.0	+2.6	+2.4	+3.9	−6.0
2011	+19.9	+22.3	+21.4	+25.1	+2.1	+0.2	+10.7	+2.1	+11.7	+7.3	+13.8	+23.0
2010	−10.1	−14.5	−10.6	+15.2	+10.0	+1.8	+20.5	+18.8	+24.9	+18.3	+16.4	+27.1
2009	+9.4	+14.8	+0.2	+8.6	−7.4	−2.3	+1.6	−5.0	+3.9	−14.7	−6.0	−7.0
2008	+14.1	+21.3	+12.2	+4.5	−3.5	+4.2	+2.2	+9.1	+13.5	+13.4	+17.1	+13.3
2007	−7.8	−2.7	−1.4	−3.0	−2.7	+5.0	−5.0	+2.7	+1.4	+5.4	+9.2	+14.4
2006	+12.7	+0.1	+13.8	+14.4	−9.8	−6.3	−7.6	−15.9	−5.8	−16.0	−1.4	−3.5
2005	+1.8	−28.6	+0.2	−11.2	−14.5	+2.6	+0.9	−6.9	+3.9	+10.9	−2.0	+0.1
2004	−11.6	+9.1	+0.2	−15.4	+13.1	−15.2	−6.9	−7.6	−2.8	−3.7	−8.6	−8.0
2003	−2.0	−7.4	−6.8	−5.5	−7.4	−12.0	+2.9	−1.8	−2.2	−1.9	−3.4	+9.3
2002	+2.7	+7.7	−5.2	−3.8	−14.5	−6.3	−7.6	−14.6	−8.2	−7.4	−6.0	−10.6
2001	+8.4	+11.9	+6.7	+0.3	−9.0	+1.8	−3.7	−8.2	+1.4	−1.9	+7.2	−9.1
2000	+5.1	+12.9	+9.4	+16.8	+3.6	−5.5	−3.7	+5.3	+9.9	+9.7	+22.4	+7.7

Sequences of months/years that have been much worse than those investigated by AEMO’s ISP include



Jacobs can also access recent UNSW research that has analysed and mapped BOM weather data over the 147 years across the NEM REZ's for every state, and concluded there is a high likelihood of simultaneous wind droughts and solar droughts occurring across all REZ's in Victoria, NSW, Southern Qld, South Australia and Tasmania.

Climate controls on compound solar and wind droughts in Australia

D. Richardson[1,*], **A. J. Pitman**[1], **and N. N. Ridder**[2]

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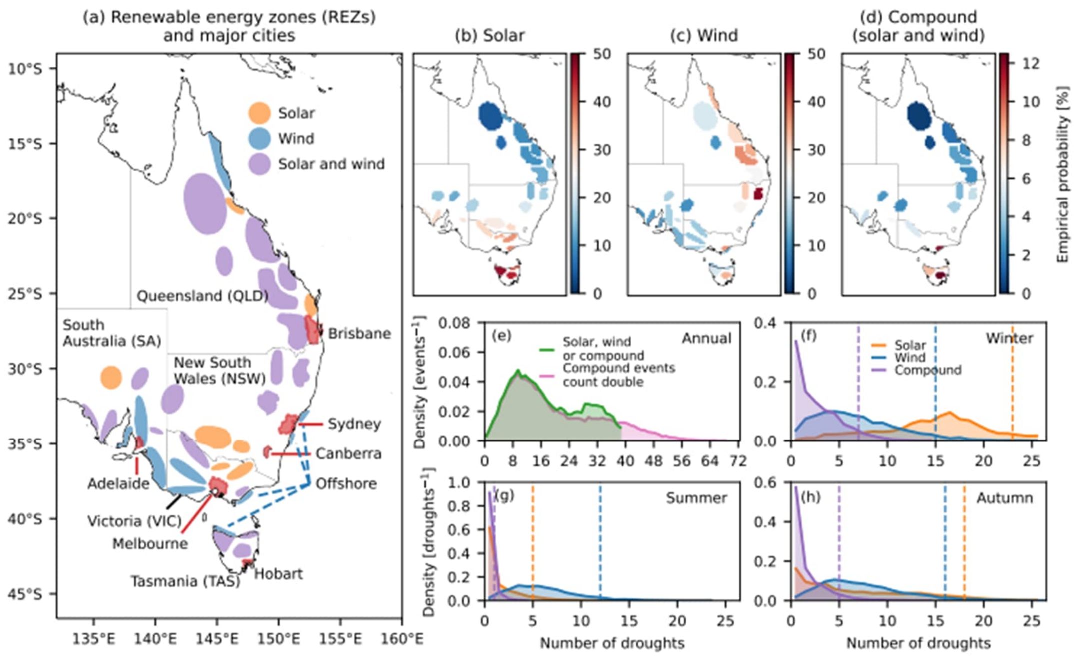
[2]Suncorp Group Limited, Brisbane, Queensland 4000, Australia
[*]doug.richardson@unsw.edu.au

ABSTRACT

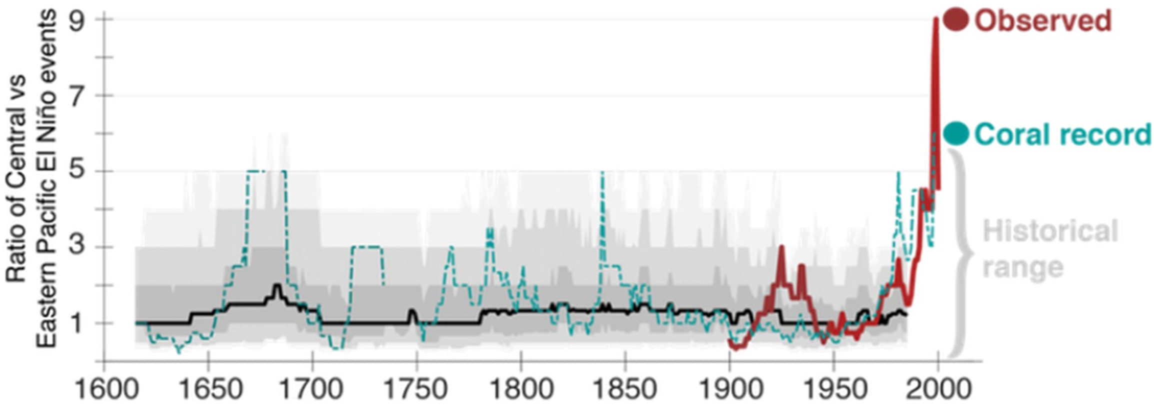
Solar and wind power are central to Australia's renewable energy future, which implies an energy sector vulnerable to weather and climate variability. Alignment of weather systems and the influence of large-scale climate modes of variability risks widespread reductions in solar and wind resources, and could induce grid-wide impacts. We therefore systematically analyse the relationship between compound solar and wind droughts with weather systems and large-scale climate modes of variability over multiple time scales. We find that compound solar and wind droughts occur most frequently in winter, affecting at least five significant energy producing regions simultaneously on 10% of days. The associated weather systems vary by season and by drought type, although widespread cloud cover and anticyclonic circulation patterns are common features. Indices of major climate modes are not strong predictors of grid-wide droughts, and are typically within one standard deviation of the mean during seasons with the most widespread events. However, the spatial imprints of the teleconnections display strong regional variations, with drought frequencies varying by more than ten days per season between positive and negative phases of climate modes in some regions. The spatial variability of these teleconnection patterns suggests that droughts in one region may be offset by increased resource in another. Our work highlights the opportunity for minimising the impact of energy production variability by utilising weather and climate intelligence. Exploiting the spatial variability associated with daily weather systems and the seasonal influence of climate modes could help build a more climate-resilient renewables-dominated energy system.



Jacobs should also access publicly available research papers that prove that the severity of El Nino events in Australia have and will become much worse. An ex

https://www.sciencealert.com/coral-records-show-that-brutal-el-ninos-haven-t-always-been-this-way

Our paper, published in *Nature Geoscience* today, fills this gap using coral records to reconstruct El Niño event types for the past 400 years.



Central Pacific El Niño frequency relative to Eastern Pacific El Niño frequency. (Author Provided)

Implications for Jacobs to consider based on this public information

(a) The ISP is based on an inadequate sample of weather data, which means that its conclusions are invalid and cannot be relied upon for the purpose of Jacob's review of Plan B

(b) The appears to be no justification in AEMO statements that interconnection can be justified from the diversity of wind-power and solar-power across the NEM

C.15 Rooftop PV penetration

Information received 30 October 2023

<u>Public Information for Jacobs to consider in its independent assessment of rooftop PV energy generation for Plan B and extended WRL-VNI West</u>

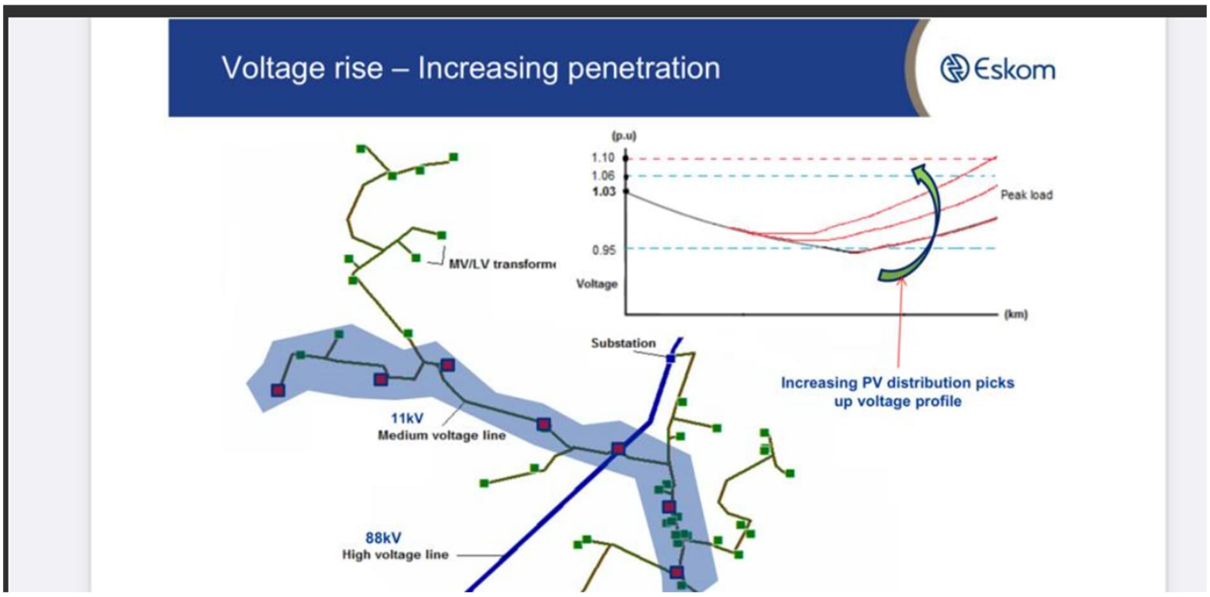
Please find below links to publicly available information that can be used by Jacobs to determine that the maximum practical penetration of rooftop PV on the overhead low voltage distribution networks (i.e., the 230 Volt wires along footpaths) cannot exceed approx. 30% due to the voltage towards the ends of those lines being outside the statutory voltage range of 216V to 253V (i.e., 230V + 10% to 230 V -6%)

This includes the papers from a SAIEEE seminar on renewable generation which includes the following ESKOM figure illustrating that the voltage profile along a sample ESKOM 11 kV line exceeds their allowable voltage range of +10% to - 5% towards the ends of the line for modest increases in PV penetration. ESKOMs policy is that the total rooftop PV exports from all customers along an LV/MV overhead feeder cannot exceed 33% of their combined demand.

The allowable voltage range for Victoria used to be 240V +-6% (with a 28V (12%) range below 254V). The new Victorian standard is 230 V + 10% - 6% (with a 37 V range below 253V). The South African range is 230 V +10%-5% (i.e., a 35V range below 253V). Thus, the latest Victorian voltage standard, progressively introduced from August 2022 required a similar maximum voltage but increased the allowable range from 28V to 37V, almost identical to the 35 V range in South Africa. The allowable range is the key factor in determining the allowable penetration of rooftop PV as the highest voltage occurs in the middle of a summer day whilst the lowest voltage occurs at time of peak load after the sun has set. The Victoria LV/MV networks were designed and built for one way flow of power with an allowable voltage range of 28 V. The additional 9V of the new range has now been used to allow rooftop OPV to feed into the network, reversing the power flow and increasing the voltage towards the end of the line. The new Victorian Voltage standard is almost identical to the South African standard, but with an extra 2V that should allow slightly more 6%/5% = 1.2 times as much rooftop PV to be accommodated.

This aligns with Plan B model which also includes the effect of domestic batteries as forecast by AEMO as well as AEMO's forecast of reducing electricity usage by residential electricity users.

Converting the ESKOM policy to the Victorian situation, their 33% export limitation needs to be adjusted for the extra 1.2 times increase in voltage range plus the fact that Victoria allows PV exports of 5 kW and 10 kV depending on the distributor. Just using a 5-kW export limit, the equivalent limitation for Victoria would be 33% x 1.2 = 40% of the combined load on a feeder. Given that the distribution networks are traditionally designed for an average 3 kW diversified peak customer demand, the average allowable PV export per customer would be 40% of 3 Kw = 1.2 kW. The is equivalent to an equivalent to a 24% penetration of rooftop PV capped to a 5 kV export, and 12 % penetration for PV customers. The average penetration of rooftop PV in Victoria is currently 25% and AEMO is forecasting the penetration to increase to 75% in the 2022 ISP and top 80% in the 2024 ISP. The AEMO forecasts are more than 3 times the equivalent penetrations allowed by ESKOM which indicates that AEMO's rooftop PV generation forecasts appear to be technically impractical due to the allowable statutory voltage limits for Victoria.



Link to SAIEE Seminar on the integration of renewables in 20290

https://youtu.be/TwwawX4bDuY?si=60tSJqMMy29ALkK6
The electrical engineering explanation of the increased voltages caused by increasing penetrations of rooftop PVF on LV feeders is explained in the attached technical paper from Research gate based on actual voltage measurements in Sri Lanka

https://www.researchgate.net/publication/362657653_Voltage_Impact_of_Roof-Top_Solar_Photovoltaic_Systems_on_Low_Voltage_Distribution_Network

Figure 9, repeated below shows that field measured voltage at the mid-points of two feeders can reach 257 volts in the daytime when PV is operating, and fall to 215V over the peak load period. These voltages are at the limits of the permissible voltage range in Victoria. These feeders had rooftop PV penetrations of 18% and 20% respectively.

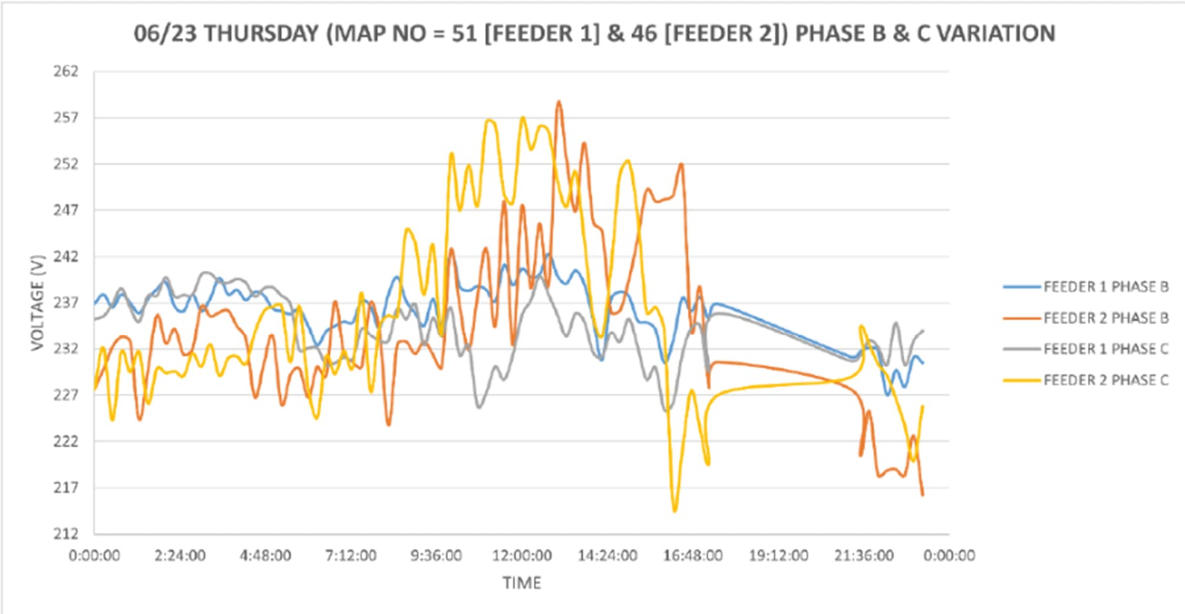


Figure 09: Comparison of Feeder 1 & Feeder 2 Phase B & C

Close to the ends of the feeders, the measured voltages are well outside of permitted voltage ranges. these feeders had rooftop PV penetrations of 18% and 20% respectively.

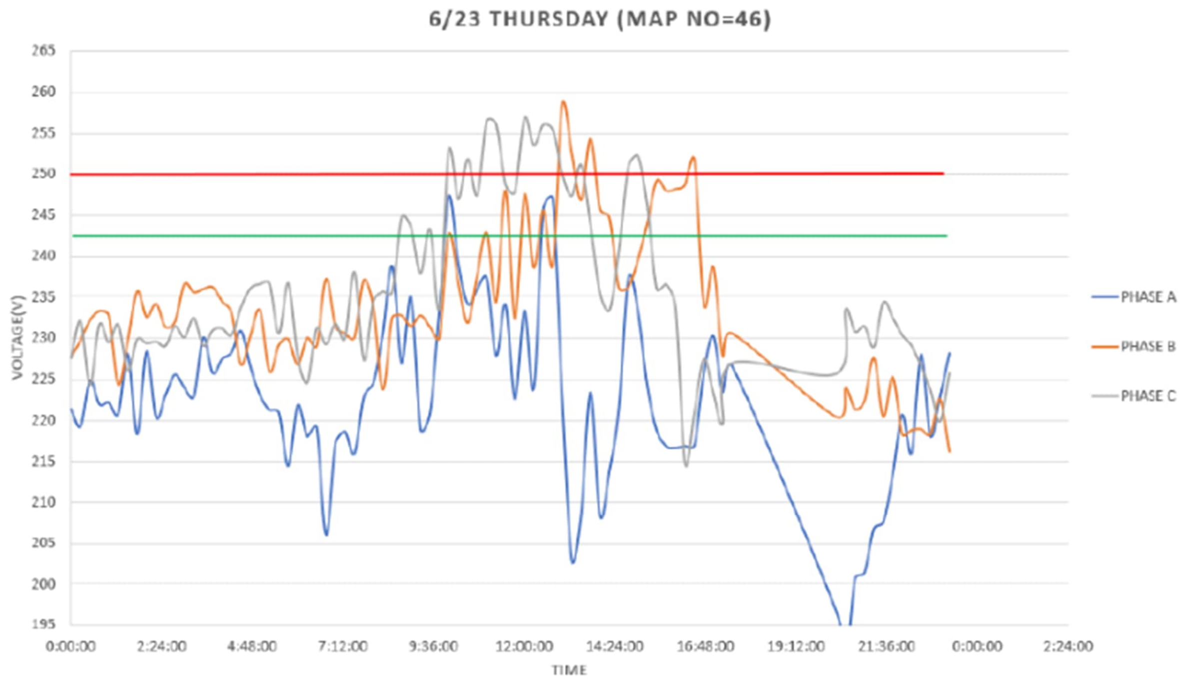


Figure 04: Voltage profile of Solar Customer Map number 46

There are surveys of voltages on Victorian distribution feeders, however their results are meaningless as

(a) they are average voltages with respect to long time periods, entire feeders regardless of location along the line

(b) the 10-volt reduction in the standard voltage from 240 volts to 230 volts overwhelms the increases in voltages at the feeder ends due to the increased penetration of PV in just a few years

Solar Enablement Research Project, UQ 2016 to 2020

The author directed an ARENA/industry funded research project into the state estimation of LV voltages and currents along each phase of actual low voltage feeders in Queensland and Tasmania that verifies the findings of the above research paper for Australian LV networks. That project involves active participation from Energy Queensland, Essential Energy, United Energy and TasNetworks.

The findings have since been commercialized and are now being implemented on the Energy Queensland network

Rooftop PV model used to forecast rooftop PV energy production for Plan B

Based on the knowledge and experience gained though that project, the author has developed a model to estimate the forecast rooftop PV energy production for each year of Plan B up to 2034/35.

Unfortunately, the detail of that model is commercial-in confidence, due to its commercial value, however some aspects include the following:

(a) Potential maximum rooftop PV generation – as forecast in AEMO ISP 2022 – see load forecasting report in 2021 IASR

(b) Model residential rooftop PV separate from commercial rooftop PV, as they generally connect to different LV/MV feeders

(c) AEMO's forecasts of non-scheduled PV and small-scale distributed PV are modelled separately

(d) PV generation is assumed to generate 2,000 hours pa equivalent to convert annual energy generation into equivalent MW of rooftop PV being generated

(e) Residential load consumption is derived from AEMO's forecast residential energy consumption (which reduces by 40 % over the study period.

(f) Residential power consumption during summer daytime is calculated from € and current residential daily load curves

(g) Domestic battery storage charging is taken from the AEMO results for option 5A in the VNI West PACR market modelling results

(h) Battery storage charging is profiled in proportion rooftop solar generation to maximise its benefits

(i) Typical LV feeder load is calculated from total residential load – roof top PV generation + battery charging, each estimated from the above model for a representative LV feeder for both midday summer and peak load conditions.

(j) Assumed that pole-top transformer fixed taps will be adjusted every few years to optimise feeder voltages at the feeder ends to keep withing the statutory voltage range

(k) Voltage drop along a typical LV feeder for peak load conditions in 2022/23 (with no PV generation) is assumed to be between 22V and 28V (being 9% to 11.5% of 240V) of the available 37 V range with the remaining 9 Volts to 15 volts available for the export of excess PV (after supplying load and charging batteries)

(l) AEMO rooftop PV forecast accepted for voltage drops up to 9 V, capped for voltage drops exceeding 15 Volts and prorated using quadratic interpolation for voltage drops between 9 and 15 volts.

Other AEMO assumptions

1. AEMO's input data for the 2022 ISP includes generation from non-renewable distributed generation that has not been included in the Jacobs data

2. AEMO's forecasts of small-scale PV farms and non-scheduled renewables appear unjustified given there are almost none of these categories of renewables in Victoria, they are not mentioned in the AEMO 2023 APR and because their capacity appears to beyond the transmission capacity of the 66 kV feeders supplying the Distribution

networks of Victoria, Plan B has therefore removed these assumed renewable generation sources for Plan B and extended VNI West

3. AEMO's assumed schedule for the early retirement of Victoria's coal fired power station assumed much earlier dates than advised by the owners of those power stations. The assumed date for Loy Yang A power station do not reflect the formal agreement reached between n the Victorian government and the owner of Loy Yang A. These are crucial assumption in determining compliance with VRET

4. Based on calculating the percentage of renewable generation using total generation rather than total consumption, VRET targets of 95% can be achieves as soon as the Victorian coal fired stations are retired irrespective of the increased risks to the security of electricity supply in Victoria or the objects of the Victorian VRET legislation

C.16 Information on capital and operating costs

Information received 1 October 2023

Public Information for Jacobs to Consider in undertaking task A.8 - Operating Costs

Task A8 is described as

Impact on prices (capex, WACC, IDC, opex)
Plan B "Moving onto the impact on prices as a result of its proposals, AEMO says that VNI-West will only raise transmission charges by 25% in Victoria. But AEMO uses 2021 prices, a cost of capital that does not reflect the re-pricing of risk that AEMO is adopting in its forthcoming ISP, ignores interest during construction and understates capital costs and greatly understates operating costs"

Public information relevant to the understatement of capital cost can be found in the transcripts of the NSW Senate Inquiry into Undergrounding, where the TransGrid CEO advised, under oath, that Humelink is now expected to cost $m4,900. This is confirmed in AEMO's September 2023 Transmission Expansion Options Report, extract below.

Description	Additional network capacity (MW)	Expected cost ($ million)	New easement length (km)	Lead time
Option 1 (HumeLink): • New Wagga Wagga 500/330 kV substation and 330 kV double-circuit connection to the existing Wagga Wagga 330 kV substation. • Three new 500 kV transmission lines: - Between Maragle and Bannaby 500 kV substations. - Between Maragle and new Wagga Wagga 500 kV substations. - Between new Wagga Wagga and Bannaby 500 kV substations. • Three 500/330 kV 1,500 MVA transformers at Maragle. • Two 500/330 kV 1,500 MVA transformers at new Wagga Wagga. • 500 kV Line shunt reactors at the ends of Maragle – Bannaby, Maragle – new Wagga Wagga and new Wagga Wagga – Bannaby 500 kV lines. Provided by Transgrid – see Section 1.2	2,200[63] N6+N7: 2,200 (N6: 1,500), N5: 800	4,892[64] (June 2023 dollars) Class 3 (-5% to +12%)	360	Short

This is a 50% increase in the cost estimate just 2 years ago which TransGrid advises is based on actual contracts with an accuracy -5% to + 12%. The average cost of the project is now $ m13.6/km ($m4,892/360km).

In comparison, AEMO's published cost estimate for WRL is $737m (2021 prices) and VNI West (in Victoria) is $m1,755 (2021 prices) totalling $m2,492. For the total claimed length of 396km (i.e., 190km WRL + 206km VNI West (in Victoria)), AEMO's cost estimate average $bn6.3/km. Not only is WRL-VNI West longer than Humelink, but it's scope of works in Victoria include costly series compensation, power flow controllers and pass through more valuable prime agricultural land. Yet AEMO's average cost of Humelink is 219% of the average estimated cost of WRL-VNI West.

Jacob's investigations for Task A.8 needs to examine valid reasons for this huge discrepancy in cost estimates is accessing Plan B's statement that the capital cost of WRLK – VNI West is understated.

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

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

Table 6 Summary of the credible options assessed in this report – capital costs, $m in FY2020-21 dollars

Cost component	Option 5 (to Bulgana)		Option 5A (to Bulgana, east of Kerang)	
	NSW	VIC	NSW	VIC
Stage 1 – Early works				
Early works – Property/access/ easements	66	69	72	69
Early works – other	50	60	50	60
EnergyConnect enhanced	182	-	182	-
Stage 2 – Implementation				
Substation/ terminal station works	354	415	354	415
Line works	751	1,034	831	1,034
Power flow controllers / series compensation	183	164	183	164
Biodiversity offset costs	66	12	73	12
Total (by state)	1,651	1,755	1,744	1,755
Total (all states)	3,406		3,499	
WRL – Incremental costs for alternate options (included in the totals above but separately itemised here as well for transparency)				
Included cost		315		315
WRL uprate length		104 km		104 km
Other relevant assumptions				
Approximate line length [A]	184 km	205 km	203 km	206 km
Project EnergyConnect uprate length	174 km	-	174 km	-
Quantity substations/ terminal stations [B]	-	1	-	1

A. Approximate line length is the indicative total length (in kilometres) of lines between EnergyConnect (at Dinawan) and the connection point to WRL. As a route has not yet been determined, line length has been taken as the centre of the area of interest.
B. Quantity substations/ terminal stations is the quantity of terminal stations along the VNI West project and excludes the Dinawan and WRL connection point terminal stations.
C. WRL included uprate costs include costs across all cost components, not just line works. Refer to the single line diagrams in Appendix A2 for scope details.

Public information relevant to statement that operating costs are understated

AEMO and TransGrid have calculated their operating costs for WRL and VNI West as 1% pa of the capital cost (excluding easement and biodiversity costs), but have not provided any break-down or explanation of the operating costs. Other than stating that the ISP and other recent

RIT-T's have also assumed 1% pa. AEMO also states in its VNI West PADR that "*AEMO reviewed recent revenue determinations, contingent project applications and RIT-Ts, and concluded that 1% was reasonable for ISP purposes as the cost of major projects in the ISP are dominated by transmission lines rather than substations. While the modelling applies operating expenditure (opex) costs consistently throughout the modelling horizon, opex costs are realistically expected to start low and grow as assets age.*". However, the transmission line component of Option 5 is $597m is less than the substation component of $639m including flow controllers, series compensation and early procurement costs). Substation maintenance costs are typically double those of transmission lines and electronic equipment must be replaced several times during the 50-year life of transmission lines funded from additional CAPEX. AEMO's WRL PACR allowed 3.5% for Option C2 only 4 years ago.

Jacob's needs to access a range of published reputable reports in undertaking task A.8. This includes the AER's annual benchmarking of the NEM TNSP's annual costs provides the average annual expenditures, for the last five years, of each TNSP's costs funded from both their operating fund and capital fund. The Mountain-Bartlett submission to the VNI West Consultation Report describes how Table B.2 of the AER's 2022 Benchmarking Report (*AER report*) can be used to demonstrate that the annual expenditure by the four eastern state TNSP's are all close to 3.3% pa of their undepreciated asset bases.

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

TransGrid's current AER Revenue submission also contains public information that is consistent with these figures.

The Mountain – Bartlett submission to the VNI West Consultation Report asserts that a 3.3% pa annual expenditure over the 50-year life of a transmission asset would total 165% of its construction cost and have a PV exceeding 50% of the PV of its construction cost. Assuming only 1% pa would be equivalent to only 16% of the PV of the construction cost. The missing 34% (50% - 16%) could mean that the net benefit of a new transmission project could be over-stated by 34% of the PV of its construction cost.

Should Jacobs require assistance accessing these documents, please advise and appropriate links will be provided

C.17 Transmission in V2 and V3

Information received 1 October 2023

Public Sources of Information for Jacobs to access for undertaking agreed Tasks – A.1, A.5. A.7. A.10, B.1, B.2, B.3 and B.7

Introduction

To undertake all of the above tasks, Jacobs will need to consider the transmission network between existing/future renewable generation sites and the main supply points to Greater Melbourne (eg Sydenham) as these works will be vastly different for Plan B vs VNI West. Jacobs will also need to consider required reinforcement of the existing 220kv networks to New Kerang and Bulgana 500kV/220 kV substations e.g. from Red Cliffs – Kerang – Bendigo and from Murra Warra to Bulgana to Ballarat. Jacob's must not ignore the 220 kv networks in their independent review, as done in the WRL-VNI West network modelling for the PACR. This will require Jacob's accessing the public data on the scope and cost of the connections for new renewables, in the Murray River (V2) REZ, and the Western Victoria (V3) REZ – in the AEMO reports on Transmission cost options as well as the ISP data and assumptions workbook. Jacobs will also need to access the information in the AEMO Annual Planning Report 2022 (or 2023) on the congestion, constraints and augmentation plans for the existing 220 kV networks in V2 and V3.

Data on connections for new renewables in V2 and V3

https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en

https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation

REZ names	Region	REZ network voltage (kV)	Connection capacity (MVA)	Feeder length (km)	Total cost ($M)[2]	$/kW	System Strength connection cost ($/kW)[3]
Far North Queensland	QLD	275.00	300.00	5.00	35.00	116.67	137.00
North Queensland Clean Energy Hub	QLD	275.00	300.00	10.00	48.00	160.00	137.00
Northern Queensland	QLD	275.00	300.00	5.00	35.00	116.67	137.00
Isaac	QLD	275.00	300.00	5.00	34.00	113.33	137.00
Barcaldine	QLD	275.00	300.00	10.00	45.00	150.00	-
Fitzroy	QLD	275.00	300.00	5.00	34.00	113.33	137.00
Wide Bay	QLD	275.00	300.00	5.00	34.00	113.33	-
Darling Downs	QLD	275.00	300.00	5.00	35.00	116.67	-
Banana	QLD	275.00	1,800.00	100.00	414.00	230.00	137.00
North West New South Wales	NSW	330.00	400.00	10.00	54.00	135.00	-
New England	NSW	330.00	400.00	10.00	54.00	135.00	-
Central-West Orana	NSW	330.00	400.00	10.00	54.00	135.00	-
Broken Hill	NSW	220.00	250.00	10.00	44.00	176.00	-
South West New South Wales	NSW	330.00	400.00	10.00	54.00	135.00	-
Wagga Wagga	NSW	330.00	400.00	10.00	54.00	135.00	137.00
Tumut	NSW	330.00	400.00	5.00	40.00	100.00	-
Cooma-Monaro	NSW	330.00	400.00	5.00	40.00	100.00	-
Hunter-Central Coast	NSW	330.00	400.00	10.00	40.00	100.00	-
Hunter Coast	NSW				Note 1		
Illawarra Coast	NSW				Note 1		
Illawarra	NSW	330.00	400.00	5.00	40.00	100.00	-
Ovens Murray	VIC	220.00	250.00	5.00	34.00	136.00	-
Murray River	VIC	220.00	250.00	5.00	33.00	132.00	137.00
Western Victoria	VIC	220.00	250.00	5.00	35.00	140.00	137.00
South West Victoria	VIC	500.00	600.00	10.00	84.00	140.00	137.00
Gippsland	VIC	220.00	250.00	10.00	49.00	196.00	-
Central North Victoria	VIC	220.00	250.00	10.00	46.00	184.00	137.00
Gippsland Coast	VIC			Note 1			137.00
Portland Coast	VIC			Note 1			137.00

Project Name: Murray River (V2) REZ Connection Costs

Project Description: 250 MVA connection to 220 kV network including 1 x 5km 220 kV transmission line.

Project Cost Estimate - View A

Indirect Cost Selection

Total Network Elements Cost Category	Below $50 million
Greenfield or Brownfield	Greenfield
Stakeholder and Community Sensitive Region	Commensurate with land use
Contract Delivery Model	EPC contract

TCD Cost Estimation Tool Version

Tool Version	15-10-2021
Project file	Connection V2 - 4-0 - 15-10-2021.xlsb

View A illustrates the cost breakdown for each network element and the total expected project cost after accounting for the indirect costs. The costs for each network element is adjusted for the respectively chosen project attributes and risks.

The TCD is designed to compile Class 5b project cost estimates (+/- 50%) using the selection of the provided building blocks, attributes and risk factors based on unbiased and objective user judgement. While the TCD allows the selection of other or more mature classes of cost estimates for unknown risk factors, it is expected to be used only in special circumstances where the user has advanced knowledge of project scope and cost resulting in bespoke description and quantities of building blocks and project attributes. For further qualification of this cost estimate output, please refer to the Section 9 of the TCD report and also the messages in description and note field when selecting unknown risk factors. This cost estimate is subject to the full legal disclaimer listed in the TCD user interface.

Cost and Risk Data Version

Release Date	10/03/2023
Version Number	4-0

Network Element Number	Network element	Total Network Element costs	Plant and Materials	Civil and Structural Works	Electrical Works	Secondary Systems	Design & Survey	Testing & Commissioning	Contractor Project Management & Overheads	Easement/ Property Costs	Environmental Offset Costs
1	REZ Feeder	$ 10.78 M	$ 3.27 M	$ 3.64 M	$ 0.76 M	$ 0.00 M	$ 0.43 M	$ 0.00 M	$ 0.64 M	$ 1.24 M	$ 0.80 M
2	REZ Connection Substation	$ 17.48 M	$ 2.62 M	$ 9.60 M	$ 1.12 M	$ 1.67 M	$ 0.66 M	$ 0.32 M	$ 1.45 M	$ 0.02 M	$ 0.01 M
	Total Network Element Cost	$ 28.25 M	$ 5.89 M	$ 13.24 M	$ 1.87 M	$ 1.67 M	$ 1.09 M	$ 0.32 M	$ 2.09 M	$ 1.26 M	$ 0.81 M
	Indirect Costs										
	Project Development	$ 1.81 M									
	Works Delivery	$ 0.72 M									
	Land and Environment	$ 0.77 M									
	Stakeholder and Community Engagement	$ 0.50 M									
	Procurement Costs	$ 0.45 M									
	Insurance	$ 0.27 M									
	Total Indirect Cost	**$ 4.52 M**									
	Total Expected Project Cost	**$ 32.77 M**									

Project Name: Western Victoria (V3) REZ Connection Costs

Project Description: 250 MVA connection to 220 kV network including 1 x 5km 220 kV transmission line.

Project Cost Estimate - View A

Indirect Cost Selection

Total Network Elements Cost Category	Below $50 million
Greenfield or Brownfield	Greenfield
Stakeholder and Community Sensitive Region	Commensurate with land use
Contract Delivery Model	EPC contract

TCD Cost Estimation Tool Version

Tool Version	15-10-2021
Project file	Connection V3 - 4-0 - 15-10-2021.xlsb

View A illustrates the cost breakdown for each network element and the total expected project cost after accounting for the indirect costs. The costs for each network element is adjusted for the respectively chosen project attributes and risks.

The TCD is designed to compile Class 5b project cost estimates (+/- 50%) using the selection of the provided building blocks, attributes and risk factors based on unbiased and objective user judgement. While the TCD allows the selection of other or more mature classes of cost estimates for unknown risk factors, it is expected to be used only in special circumstances where the user has advanced knowledge of project scope and cost resulting in bespoke description and quantities of building blocks and project attributes. For further qualification of this cost estimate output, please refer to the Section 9 of the TCD report and also the messages in description and note field when selecting unknown risk factors. This cost estimate is subject to the full legal disclaimer listed in the TCD user interface.

Cost and Risk Data Version

Release Date	10/03/2023
Version Number	4-0

Network Element Number	Network element	Total Network Element costs	Plant and Materials	Civil and Structural Works	Electrical Works	Secondary Systems	Design & Survey	Testing & Commissioning	Contractor Project Management & Overheads	Easement/ Property Costs	Environmental Offset Costs
1	REZ Feeder	$ 13.08 M	$ 3.27 M	$ 3.64 M	$ 0.76 M	$ 0.00 M	$ 0.43 M	$ 0.00 M	$ 0.64 M	$ 3.55 M	$ 0.80 M
2	REZ Connection Substation	$ 17.51 M	$ 2.62 M	$ 9.60 M	$ 1.12 M	$ 1.67 M	$ 0.66 M	$ 0.32 M	$ 1.45 M	$ 0.06 M	$ 0.01 M
	Total Network Element Cost	$ 30.59 M	$ 5.89 M	$ 13.24 M	$ 1.87 M	$ 1.67 M	$ 1.09 M	$ 0.32 M	$ 2.09 M	$ 3.60 M	$ 0.81 M
	Indirect Costs										
	Project Development	$ 1.96 M									
	Works Delivery	$ 0.78 M									
	Land and Environment	$ 0.83 M									
	Stakeholder and Community Engagem	$ 0.54 M									
	Procurement Costs	$ 0.49 M									
	Insurance	$ 0.29 M									
	Total Indirect Cost	**$ 4.90 M**									
	Total Expected Project Cost	**$ 35.49 M**									

Project Name: Other 500 kV Connection Costs

Project Description: 600 MVA connection to 500 kV network including new connection substation, 500 / 22 kV transformer and 2 x 1 km feeders at 500 kV. Note that the most appropriate item

Project Cost Estimate - View A

View A illustrates the cost breakdown for each network element and the total expected project cost after accounting for the indirect costs. The costs for each network element is adjusted for the respectively chosen project attributes and risks.

The TCD is designed to compile Class 5b project cost estimates (+/- 50%) using the selection of the provided building blocks, attributes and risk factors based on unbiased and objective user judgement. While the TCD allows the selection of other or more mature classes of cost estimates for unknown risk factors, it is expected to be used only in special circumstances where the user has advanced knowledge of project scope and cost resulting in bespoke description and quantities of building blocks and project attributes. For further qualification of this cost estimate output, please refer to the Section 9 of the TCD report and also the messages in description and note field when selecting unknown risk factors. This cost estimate is subject to the full legal disclaimer listed in the TCD user interface.

Indirect Cost Selection

Total Network Elements Cost Category	Below $50 million
Greenfield or Brownfield	Greenfield
Stakeholder and Community Sensitive Region	Commensurate with land use
Contract Delivery Model	EPC contract

TCD Cost Estimation Tool Version

Tool Version	15-10-2021
Project file	Connection Other 500 kV - 4-0 - 15-10-2021.xlsb

Cost and Risk Data Version

Release Date	10/03/2023
Version Number	4-0

Network Element Number	Network element	Total Network Element costs	Plant and Materials	Civil and Structural Works	Electrical Works	Secondary Systems	Design & Survey	Testing & Commissioning	Contractor Project Management & Overheads	Easement/ Property Costs	Environmental Offset Costs
1	REZ Feeder	$ 4.80 M	$ 1.42 M	$ 1.28 M	$ 0.82 M	$ 0.00 M	$ 0.19 M	$ 0.00 M	$ 0.24 M	$ 0.45 M	$ 0.41 M
2	REZ Connection Substation	$ 43.95 M	$ 17.30 M	$ 17.11 M	$ 2.80 M	$ 2.25 M	$ 1.61 M	$ 0.61 M	$ 2.18 M	$ 0.06 M	$ 0.05 M
	Total Network Element Cost	$ 48.76 M	$ 18.71 M	$ 18.39 M	$ 3.63 M	$ 2.25 M	$ 1.79 M	$ 0.61 M	$ 2.42 M	$ 0.51 M	$ 0.46 M
	Indirect Costs										
	Project Development	$ 3.12 M									
	Works Delivery	$ 1.25 M									
	Land and Environment	$ 1.33 M									
	Stakeholder and Community Engager	$ 0.86 M									
	Procurement Costs	$ 0.78 M									
	Insurance	$ 0.47 M									
	Total Indirect Cost	**$ 7.80 M**									
	Total Expected Project Cost	**$ 56.56 M**									

Discussion

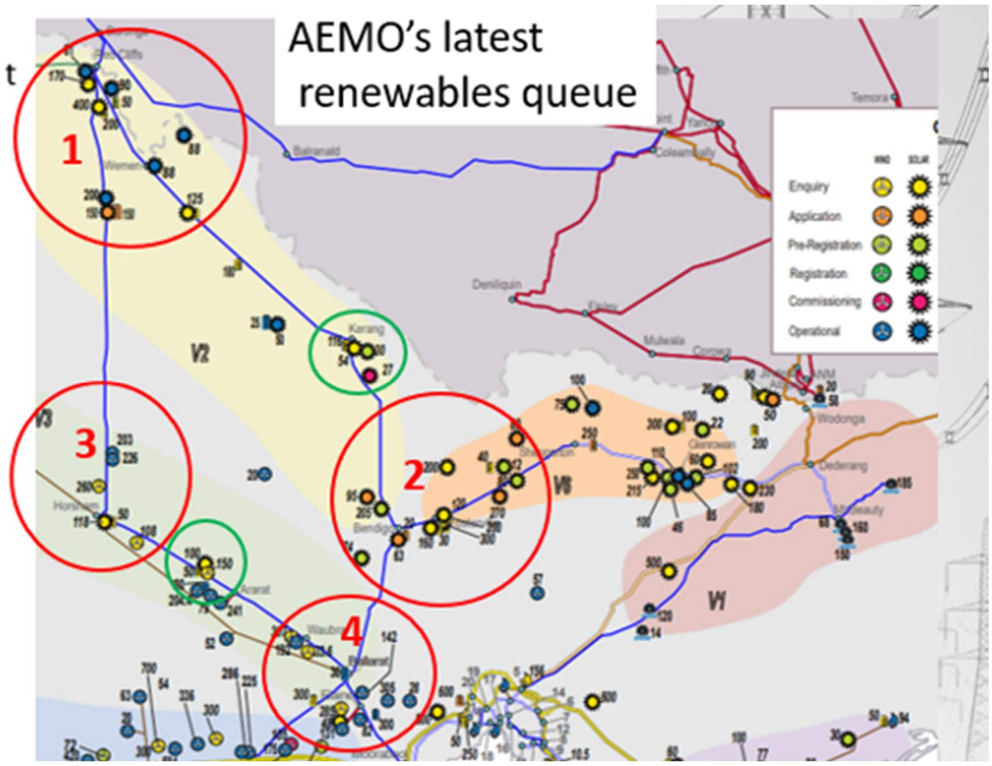
These are the connection cost estimates to be used in the 2024 ISP, which are similar to those used in the VNI West PACR, other than for escalation.

They are all based on very short lengths of transmission line – only 1 km of single circuit 500 kV line between the site and the 500 kV substation, and only 5 km of single circuit 220 kv line.

This grossly understates the cost of connecting new renewables to New Kerang and Buronga 500kV or 220 kV substations. From the map below, this would be insufficient to connect new sites even within the green circles and would need to be 20 to 50 times as long to connect to the sites within the red circles, where the vast majority of new renewables are being planned.

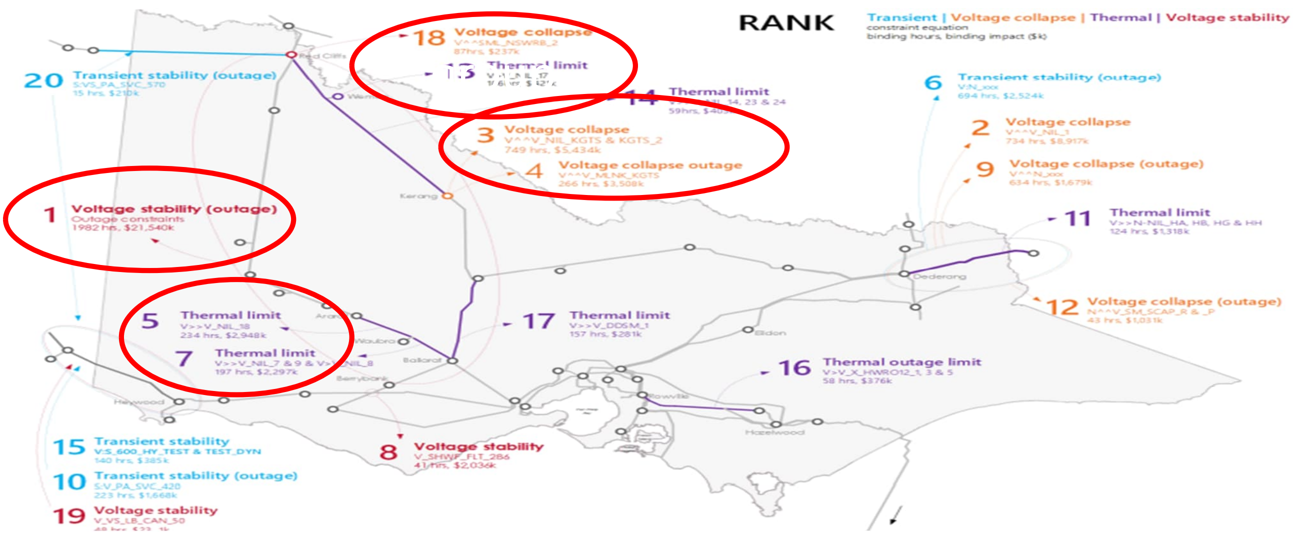
Adjusting these connection costs to include 100 km of transmission line (conservatively required for V2 and V3, on average), the cost of the 220kV, 250 MVA connection would increase by ~$m250 or $m1.0/MVA, and the 500 kV, 600 MVA connection by $m480 or $m0.8/MVA. Applying $m0.9/MVA to the 1,585MW of additional renewables in V2 and the 1,660MW in V3 would add $bn2.9 to the cost of WRL-VNI West. This is similar to the $bn2.5 (excluding IDC) of 220kV V2 and V3 works included in the Extended VNI West cost estimate in the Plan B report.

In the case of Plan B, the locations of the new sites (coloured yellow, orange and green) are all within the 5 km allowance in the connection cost estimate, hence no additional connection costs would be required other than rebuilding approximately 30 kms of the Bendigo to Shepparton 220 kV line at an estimated cost of $m100



An examination of AEMO's 2022 Annual Planning Report shows that in 2021/22 the existing 220 kV network servicing V2 and V3 was congested (i.e. loaded to its transmission limit) for 3,858 hours of the year or 44% of the time. This is the main reason for the existing solar farms and wind farms having ~40% curtailment which has resulted in the no further investments in renewables in Victoria. Unless the existing 220 kV networks are urgently augmented, the existing renewable generation in V2 and V3 will continue to experience these high levels of curtailment due to the congestion on the 220 kV network. The establishment of New Kerang and Bulgana 500kV/220kV substations and VNI west will not alleviate the existing congestion except to a minor extent downstream from Bulgana. This means that in addition to the connections to the new renewable sites, there must also be augmentation of the existing 220 kV networks in V2 and V3 to reduce the curtailment of the existing renewables. It is considered thar Plan B's additional 220 kV shared augmentations are a more efficient way of addressing both the connection of new renewables and alleviation the congestion of the existing 220 kV network. However a far more efficient option is to build Plan B.

https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2022/2022-victorian-annual-planning-report.pdf



location	type of constraint	hours
1	voltage stability, outage	1,982
3	thermal limit	749
4	voltage collapse, outage	266
5	thermal limit	234
7	thermal limit	197
17	thermal limit	137
13	thermal limit	106
18	voltage collapse	87
14	thermal limit	59
8	voltage stability	41
Total		3,858 hr 44% of year

C.18 Plan B proponents' comments on Jacobs' Draft Report

Jacobs issued its Draft Report to the Advisory Group (that includes the Plan B proponents) on 17th November 2023 for comment. The following response was received from the Plan B proponents on 3 December 2023

Victoria Energy Policy Centre

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3 December 2023

Mr Alistair Parker
Chief Executive Officer
VicGrid

By email

Dear Alistair

Thank you for sending us a copy of Jacobs' Draft Report. This letter is a submission in response to that Draft Report. As we had previously indicated, we reserve our right to publicly release this letter when VicGrid releases Jacobs' final report or VicGrid/the Government releases its decision on this review.

We have addressed this letter to you and, by extension, to the Government since the issues now lie with you and the Government not with Jacobs.

VicGrid told us that it commissioned Jacobs to assess "*The Plan B report's assessment of VNI-West*" … and … "*The Plan B strategy outlined in the report*". VicGrid also communicated this publicly in its "holding statement". As you know during the process of this review, we repeatedly sought clarification from VicGrid that this is, in fact, what Jacobs were asked to do. We were repeatedly told by VicGrid that this was what Jacobs were asked to do.

Yet, this is not what Jacobs has done.

Plan B's objectives

As you know, the Plan B Report begins with the objectives that Plan B is designed to meet. These are not the same objectives that AEMO says "VNI-West" is designed to meet (i.e. interconnection between NSW and VIC).

Having established Plan B's objectives we then established Plan B and "Extended-VNI-West" (a suite of projects that includes VNI-West, that meets Plan B's objectives). Our report then presents a pair-wise comparison that covers renewables hosting capacity, cost, curtailment, social and environmental impacts and so on.

One of the objectives for Plan B was that 95% of Victoria's electricity demand should be supplied by renewable electricity produced in Victoria by 2035 (and 65% by 2030). This objective is not one that we invented. Rather, it is consistent with the Government's election promises and the Objects of the existing Renewable Energy (Jobs and Investment) Act 2017 in which these election commitments will be legislated (we understand in 2024).

Specifically, these Objects include "*to support the development of projects and initiatives to encourage investment, employment and technology development in Victoria in relation to renewable electricity generation; and to contribute to the reduction of greenhouse gas emissions in Victoria and to achieve associated environmental and social benefits*".

What Jacobs has done

Jacobs has said that our Plan B objective is not consistent with the specific wording in the Act (Part 2, Clause 7), which defines the targets for renewable electricity as "*a percentage of electricity generated in Victoria*", rather than as a percentage of the load in Victoria. In fact, Jacobs says that the two are "*fundamentally different*".

This could be correct, but not necessarily so. Specifically a "fundamental" difference between a renewable electricity target specified as a proportion of demand or as a proportion of generation in Victoria would only arise if Victoria's coal generators closed (and Victoria's gas generation was constrained) and the consequent electricity shortfall was not almost entirely replaced with renewable electricity produced in Victoria.

In this case, the ratio of renewable electricity produced in Victoria to electricity production in Victoria would be higher than the ratio of renewable electricity produced in Victoria to Victorian demand, because the difference is imported electricity. If this happened, the Government might be able to claim that it had met its renewable electricity target (as defined Clause 7 in the Act). But this would be at the expense of having to import electricity (from NSW mainly). Furthermore there is no guarantee that that that imported electricity would be renewable.

Jacobs insists that "*Unless decision makers adopt the changed VRET formulation ... it is unnecessary to evaluate VNIW as Extended VNIW in the way described in the Plan B report ...*" Jacobs has therefore <u>necessarily</u> assumed that Victoria will become a substantial net importer of electricity from NSW. Victoria must <u>necessarily</u> become a substantial net importer in order to satisfy Jacob's claim of a "fundamental" difference between a target specified as a percentage of demand and a target specified as a percentage of generation.

Since we do not make such an assumption, Jacobs has decided that our objectives are not plausible and so it refuses to assess Plan B against Extended VNI West.

Accordingly, Jacobs does not compare Plan B to Extended VNI-West in all the measures of that comparison (renewable hosting capacity, curtailment, cost, electricity price impact, power system security impact, social and environmental impacts). In fact, in several areas (curtailment, hosting capacity, price impacts, social and environmental impacts) Jacobs either relieves itself altogether of the requirement to perform a comparative assessment, or it chooses a definition of Plan B and VNI-West entirely inconsistent with how we had defined them.

To summarise Jacobs' assessment in its own words: "*If decision makers accept some or all of Plan B's proposed differing objectives and they become required objectives, then VNIW would need to be re-worked and optimised, or a different set of projects conceived for evaluation (one option for which might be Plan B or an extension of Plan B) to make it compatible with the changed objectives.*"

Is the Government's energy policy to turn Victoria into a major electricity importer?

As we noted earlier, we understood the Government's renewable electricity targets to be consistent with the Objects of the Government's legislation, i.e. to expand renewable electricity generation in Victoria. This is consistent with the long history of the Government's communication of its renewable electricity policy "<u>Making Victoria a Renewable Energy Powerhouse</u>" and its election promises "<u>In Victoria, we're not just talking about climate action. We're getting on with it</u>" and with the Energy Minister's statements in the <u>Victorian Parliament</u> and <u>publicly</u>.

It is unclear therefore how AEMO has convinced the Government into accepting VNI-West when AEMO's analysis says VNI-West will drastically reduce the rate of renewable generation expansion in Victoria and turn Victoria into a major net importer of electricity from NSW.

We have covered this in published articles, the <u>first</u> of which explained that VNI-West would drastically reduce the rate of renewable electricity expansion in Victoria. The <u>second</u> article then explained, consistent with the observations in the first article, that AEMO's VNI-West modelling showed Victoria becoming a net importer of 16% of the electricity it consumes in 2030 and of 26% by 2040. Neither VicGrid nor AEMO nor Jacobs (or anyone as far as we know) has disputed these articles.

At the time of those articles we had thought that the Government had misunderstood AEMO's analysis and that after we had pointed out the truth of the matter, drawing on the results of AEMO's analysis, the Government would reject an interconnector recommended by AEMO that AEMO's analysis shows will deliver outcomes that are so clearly at odds with the Government's policy.

Evidently we were wrong in our assumption of how the Government would respond to this evidence. And now we see that a consultant hired by VicGrid dismisses Plan B because it rests on objectives that assume that the Government is not seeking to turn Victoria into a major net importer of electricity from NSW. Since you have told us that VicGrid accepts Jacobs' report, you are also therefore saying that Plan B can be dismissed from the proper comparative assessment you have repeatedly told us would be done, because Plan B assumes that Victoria has a policy not to become a major net importer of electricity from NSW.

Would it not therefore be true to say that the Governmnent's actual energy policy is quite different to the policy it has communicated to the public and Parliament? Specifically how can the Government agree with Jacobs that Plan B's objectives are implausible but then also argue that the Objects of the Government's renewable electricity legislation (and the many public and parliamentary pronouncements that the Government has made on renewable electricity expansion in Victoria) are true?

To put it more plainly: how can the government claim that the objective of its law is "*to encourage investment, employment and technology development in Victoria in relation to renewable electricity generation*" when actually the basis of its dismissal of Plan B must mean that the Government's policy is actually to drastically reduce the rate of renewable electricity expansion in Victoria (relative to the past and present) and consequently to require the importation of large amounts of electricity from NSW?

To get a sense of what this means, over the last 11 years Victoria has, on average, *exported* enough electricity to meet 4% of NSW's demand (and at the most - in 2016 - the last year before Hazelwood's closure, 10%). Yet, as we explained, AEMO's VNI-West modelling says that Victoria will be *importing* 16% of its electricity from NSW by 2030 and 26% by 2040.

This is an enormous shift in energy policy, not a minor detail. Victoria has never imported as much as 16% of the electricity demand in VIC. The highest net import ever – in 2019 the only year that Victoria ever imported electricity from NSW since the NEM was created - was less than 1%.

Importing 16% by 2030 and 26% by 2040 establishes such a high level of dependence that Victoria's electricity security and prices will be substantially in the hands of producers (and the transmission system) in NSW. This begs the question: has the VIC Government discussed this with the NSW Government? Managing the enormous supply (and price) risks associated with such a policy would require the fulsome (and public) agreement of the NSW Government?

Is it not also most important that the Government explains to the people of Victoria – particularly the communities and landholders affected by WRL-VNI - that actually the sacrifice they are being asked to make is so that Victoria can become a large net importer of electricity from NSW?

If the Government's energy policy is not to turn Victoria into a substantial net importer of electricity, why does it support a transmission augmentation intended to deliver that?

Of course the Government might say that the future is uncertain and Victoria might continue to be a net exporter to NSW, not a net importer, as AEMO intends and predicts. Perhaps so. But then if the Government doesn't trust AEMO's analysis - which establishes the benefits of VNI-West based on Victoria becoming a substantial net importer - why is it pursuing VNI-West?

If the Government wishes to dismiss Plan B on the basis of a reasoned, evidence-based critical analysis, Jacobs' report does not provide such basis. To the contrary, Jacobs' report and the Government's acceptance of it, has exposed a very serious and troubling inconsistency in the Government's energy policy.

But what of the Government's own critique of Plan B? The Government (and VicGrid) has also had plenty of time to, itself, present a reasoned assessment of Plan B. But we have yet to hear a single substantive criticism of any aspect of it from the Government or VicGrid. Specifically, during the process of this review VicGrid has not asked us a single question on any aspect of Plan B.

We noted that in the Government's holding statement that the Government has said, referencing a comment in AEMO's Press Release on our Plan B report, "*AEMO's assessment of the report has indicated significant concerns. The Government's review of the Report to date has not provided any reason to date to change direction.*" We have asked VicGrid to tell us what these "significant concerns" are and to tell us what the Government's review of our report has found. We have not had a reply to this request.

Next steps

We believe that the Government of Victoria is sincere in its desire to decarbonise electricity supply in Victoria and it is vexing that the Government persists in supporting an interconnector that – on the AEMO's own evidence – so clearly undermines the Government's policy, and at great cost to communities, consumers, the environment and affected land holders.

In the attachment to this letter (starting on the next page) we have added a few comments on aspects of the detail of Jacobs' report, for completeness only. We consider the technical content of Jacobs' work to be poor quality although this is not its biggest flaw: Jacobs' refusal to do what it was instructed to do (and VicGrid's acceptance of that) renders the Jacobs report irrelevant to the assessment of Plan B.

It is now clear that there is a very serious gap between the Government's apparent energy policy and its actual energy policy. The issues in the development of VNI-West, while germane, are overshadowed by much bigger challenges of energy security and energy independence that arise from turning Victoria into a state that will depend on NSW for so much of its electricity supply.

While we continue to be willing to cooperate with VicGrid and the Government on its assessment of Plan B, the much more pressing issue for the Government seems to be to confirm and properly communicate its actual energy policy to the Parliament and people.

Yours sincerely

Professor Bruce Mountain
Director, Victoria Energy Policy Centre
On behalf of the Plan B Authors

Attachment

Jacobs has failed to provide any evidence for its conclusion that a second interconnector is justified

In our Plan B report we pointed out that neither NSW nor VIC (on AEMO's cost assumptions) has a comparative (cost) advantage in the provision of renewable electricity, dispatchable generation or storage. We also pointed to AEMO's evidence that greater diversity of renewable electricity production can be obtained intra-state than between NSW and VIC.

Since releasing our Plan B report we also wrote and published an article that presented statistical research quantifying the very high correlation – by hour of day - of wind/solar generation in NSW with that in VIC.

A second article, not long after, explicitly quantified the value of the diversity of wind and solar generation in NSW and VIC by calculating the value at which electricity from the wind or sun traded over VNI-West would need to be priced in order to justify the cost of VNI-West. It found that for solar the average price of intra-regionally traded production would need to be $714/MWh and for wind it would need to be $299/MWh. Such high prices reflect the very high correlation of solar production / high correlation of wind production between NSW and VIC, and the enormous cost of VNI-West. The necessary conclusion from this is that the low diversity in wind and very low diversity in solar can't justify the cost of VNI-West.

How did Jacob's respond to this evidence?

1. First on the evidence that neither NSW nor VIC (on AEMO's cost assumptions) has a comparative (cost) advantage in the provision of renewable electricity, Jacobs did not dispute this. But they suggested it was irrelevant since there are many reasons other than cost affecting generation investment (they mention technical performance, siting factors (land availability, existing usage and land cost), population density/neighbours, environmental constraints, grid access and strength, congestion). Of course such factors affect generation expansion and operation but there is no reason to suggest (and Jacobs do not suggest it anyway) that there is a systematic difference between VIC and NSW on these factors. So, the evidence of no comparative cost advantage between NSW and VIC does matter.

2. Second Jacobs claims that there are many benefits of interconnection that are not (or are not fully) valued in AEMO's modelling. They claim in this regard, the sharing of reserves, storage, production, "decarbonisation measures" (whatever that is) and ancillary services. But where is the evidence for this? The "market modelling" that

AEMO performs claims to value *all* of these things except ancillary services, which is a small and increasingly regional, not multi-regional market.

3. Third, contradicting their complaint that AEMO's market modelling undervalues interconnection, Jacobs then insist that our analysis of comparative cost is not credible because it has not been assessed using a "market model". Jacobs do not say what they mean by "market model" but presumably it would be some form of constrained optimisation calculation such as those used in RIT-Ts or in the development of the Integrated System Plan. We have no objection to such models – they can useful learning tools: in academia the development and use of such models in standard fare in masters level studies. But of course if society had any confidence that "market models" could decide how to allocate resources efficiently, we would have no need for markets. This means that in any realistic regulatory system market models are useful learning tools and not more than that. VicGrid has wisely agreed with this and developed a Victoria Transmission Investment Framework that wisely sets "market models" aside. In addition, as any half-decent modeller knows, through the selection of assumptions and the characterisation of the technical and commercial arrangements, market models can give you whatever answer you want, and model results are not replicable in practice. Therefore dismissing critical scrutiny on the basis that it does not originate in a "market model" is trite.
4. Fourth, Jacobs simply ignored the evidence we presented in Plan B and in our articles on the value of diversity. Rather than at least trying to critique this evidence, Jacobs produce their own "analysis". This consists of a bunch of poorly described line charts, scatter charts, bar charts, a couple of tables of weather data in Sydney, Melbourne and Brisbane in February 2023, a few tables of daily average correlation coefficients (of what?) for a few months, and a screenshot of a powerpoint slide from Ofgem on "hard-to-monetise benefits" of interconnection. Jacobs calls these charts "tranches of evidence". But there is no development of any analysis or argument or reasoning linking any of these "tranches of evidence" or telling the reader just what they evidence. They are more like handfuls of mud thrown at a wall hoping that something will stick. Once they have exhausted their stock of charts, Jacobs then concludes with .... nothing. Yes, nothing! For heaven's sake!
5. Finally, elsewhere in its report, Jacobs reports on a "simple simulation model" which uses various assumptions to conclude that the Plan B will require at least 100 GWh of storage in Victoria. This is not surprising. Our research in South Australia finds that an enormous volume of storage is needed to come close to fully decarbonising electricity supply, assuming that only carbon-based alternatives of dispatchable generation are available. But what is the consequence of this for VNI-West? Jacobs does not model what would happen if VNI-West was built. As we noted in our submission on AEMO's Options Report (which Jacobs ignored), AEMO's modelling claims that the main benefit to Victoria for the development of VNI-West is that it substitutes unnamed generic pumped hydro generators in Victoria, for cheaper battery storage in NSW. The

obvious question (which we have asked of AEMO and it has no answer) is why an interconnector is needed to access battery storage in NSW than can be built just as cheaply in Victoria.

Our claim stands.

Jacobs recognises that VNI-West will fail to reduce curtailment but, like AEMO, dismisses this

In our submission on AEMO's Project Assessment Conclusions Report and in our Plan B report, we drew attention to the fact that on AEMO's own analysis, VNI-West makes a very minor improvement to the very high levels of curtailment (of wind) in Western Victoria REZ, briefly improves curtailment of solar in the Murray REZ before reverting back to existing levels and makes curtailment worse of solar in the Central North REZ. In a separate article we drew particular attention to the fact that AEMO's market modelling ignored congestion:

"Their modelling assumes that these generators get income based on prices that are established as if they are not curtailed and there are no network losses. So the solar farms that AEMO claims in its modelling will locate in the SW NSW REZ will be making huge financial losses. A problem? Not for AEMO, "NEM reform activities," it says, will sort this out. In other words, new market arrangements will compensate distant renewable generators for their curtailment."

In our Plan B report we draw attention to the fact that AEMO had failed to calculate the "efficient" level of curtailment:

"This is because in their modelling they do not price renewable generation at the level needed to actually finance that generation, i.e. by taking account of its curtailment. Rather they assume it is not curtailed and neither is it charged for marginal losses. AEMO therefore do not correctly calculate the efficient combination of generation, storage, and demand to meet customers' needs. "

As we noted in the Plan B report, this is no cause for concern for AEMO:

"... AEMO says that its modelling has delivered results that are "not necessarily the outcomes that would emerge from the current regulatory structure" ... But AEMO then says that "NEM reform activities, such as the Post 2025 project, are being looked at separately by the market bodies to ensure the regulatory and market arrangements are fit to best address the needs of power consumers, today and into the future"

What does Jacobs have to say about this? Well, Jacobs do not contest our calculation of curtailment based on AEMO's modelling results. Instead, much like other of our conclusions they don't like, they just blithely wave it away: *"Congestion is a parameter of note"* they patronisingly inform us *"but is not in itself an objective that necessarily achieves the overall NEM objective"*. If that was not enough to make you fall off your seat, Jacobs then repeats AEMO's line that it is someone

9

VICTORIA UNIVERSITY ABN 83776954731 CRICOS Provider No. 00124K else's problem to fix the curtailment of the renewable generation that their transmission proposals cause: "*Given that the Victorian government's policy is to encourage renewable generation and that outcome is faced with a competitiveness barrier, Victoria may need to look for means to stimulate the investment in some other manner*".

We already know that pushing an enormous interconnector with such huge environmental, landholder and consumer impacts and that effectively does nothing to meaningfully reduce the curtailment of renewables in Victoria, posed no concern to AEMO. Evidently Jacobs is similarly unperturbed. Such irresponsible nonchalance leaves us flabbergasted.

Our claim stands.

Jacobs accepted AEMO's false claims that additional transmission expansion beyond WRL-VNI is not required in Victoria

Jacobs said that AEMO did not claim that the only transmission augmentation required in Victoria after WRL-VNI West is a 500kV line to Western Victoria and possibly a 220kV line to Shepparton and no other transmission augmentations in Victoria were included in AEMO's modelling of VNI-West. But Jacobs ignored AEMO's VNI-West PACR and Options Report modelling which shows no other transmissions augmentations in Victoria other than a 500kV line to Western Victoria and possibly a 220kV line to Shepparton. Jacobs also ignores AEMO's response to our submission on the Options Report where AEMO explicitly claim no other transmission augmentations in V2 and V3.

So, there is extensive further additional transmission expansion – which AEMO claims it did not say would not occur - and yet which AEMO did not include in its modelling (and which Jacobs ignores in its assessment of VNI-West). Jacobs, like AEMO ignored VicGrid's Initial REZ Development Plan which contains twelve new transmission lines (much of them in line with what we had proposed in Plan B).

Jacobs' conclusions on power system stability impacts of VNI-West are not plausible

Plan B pointed out that WRL-VNI West have approx. 1,000 single points of failure (SPoF) in Victoria alone, as a failure of any of its double circuit towers (due to severe lightning, destructive winds, wildfires, flooding or sabotage) would take out both 500 kV circuits which will be a crucial supply of electricity to Southern Victoria.

Plan B drew particular attention to WRL as it will be frequently very heavily loaded. But Jacobs only investigated a double circuit outage on the lightest loaded section of VNI West north of New Kerang and even then assumed loading well below that forecast by AEMO. Jacobs completely ignored the severe risk to Victoria from a double circuit outage of WRL. They have not assessed our claim, they ignored it.

Jacobs also say that a total collapse of Southern Victoria could be avoided by inter-tripping and run-back schemes. This is trite. Only the 600MW Portland Smelter is likely to be available for a direct intertrip, there are no other point load in Victoria that comes close to this in size. Furthermore even if an inter-trip scheme could somehow be implemented, it would require blacking out a large proportion of Greater Melbourne and the smelter. Astonishingly Jacobs is evidently not aware of the 2016 black out of South Australian on the loss of less than 500 MW on Heywood. WRL, according to AEMO will be carrying 3,000MW.

Our claim stands.

Jacobs ignores the inability to run all Snowy 2.0 pumps and the implication of this for VNI West's claimed benefits

The Plan B authors advised Jacobs that a fault on the 500 kV network near Loy Yang is certain to cause transient instability of the Victorian Power system when all of the Snowy 2.0 pumps are on-line.

Jacobs undertook a transient stability study but just with the existing Tumut 3 pumps on-line, not the 2000 MW of Snowy 2.0 pumps onlinbe, and claimed that that addressed the concerns raised by the Plan B authors.

This is laughable. Had Jacob's undertaken the correct study with all pumps on-line at Snowy 2.0 and Tumut 3, they would then have had no basis for their claim that VNI West enables access to the benefits of Snowy 2.0. Snowy 2.0 is useless if it cannot pump.

Jacobs were also advised that a fault on the 330 kV transmission lines near Lobe's Hole near Snowy 2.0 when all pumps are on-line is certain to cause all units to "pole-slip" which could destroy them. Jacobs ignored this warning and do not mention this serious risk in their report. Again, this means that it will not be feasible to run all snowy 2.0 pumps at the same time.

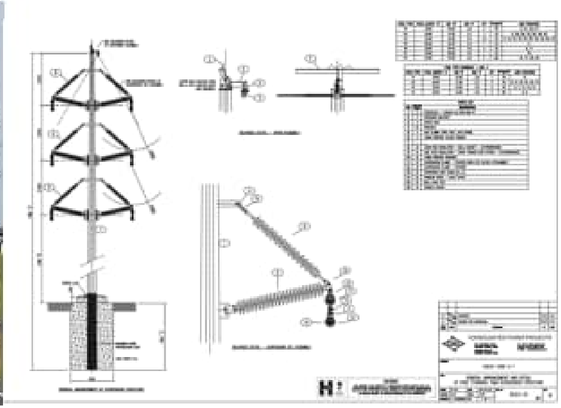
Our claims stand.

Socio-environmental impacts of Plan B vs WRL-VNI West

During the Review of Plan B, the authors realised that the most aesthetically pleasing option for the Plan B 220 kV transmission lines is a pole type of structure instead of traditional lattice steel towers. A pole structure is much less visually intrusive and can even be run along the sides of roads and highways (as shown below). The authors engaged the services of a South African tower design expert who prepared the pole design illustrated below.

The Plan B MCA analysis assumes lattice towers, A pole type tower would score even lower in the measure of visual impact. If Plan B was run alongside roads and highway, socio-economic impact would be even lower, particularly if the existing 220 kV lines are removed and the easements relinquished.

What did Jacobs do with this information? Blithely ignored it.



Jacobs claim that the deliverability of Plan B is similar to WRL-VNI West.

This is sully. WRL-VNI West will need most of the 220 kV upgrades in Plan B in order to connect the 500 kV to the existing and new renewables in Murray River REZ and Western Victoria. But WRL-VNI West also requires 500kV/220kV transformers, reactors, circuit breakers as well as series compensation, and reactive compensation equipment, none of which is required for Plan B. Furthermore very few companies and skilled workers can design and construct 80m high 500 kV lines. However, steel pole 220 kV lines are an off-the-shelf product available in a month from China and India.

Our claims stand.

Jacobs fails to assess comparative capital costs

Jacobs accepted AEMO's costing without explanation, despite the detailed critique of AEMO's costing which we set out in our Consultation Report submission and Plan B report, every single bit of which Jacobs blithely ignored.

Our claims stand.

Jacobs fails to assess comparative price impacts

Jacobs did not compare Plan B to Extended VNI-West. As we noted in the letter, Jacobs explicitly do not compare Plan B to Extended VNI-West. Yet here they purport to draw conclusions on price impacts by comparing Plan B just to AEMO's estimate of the cost only of VNI-West. Pathetic.

Our claims stand.

Appendix D. AEMO public response to Plan B

AEMO responds to VNI West 'alternative plan'[116]

02/08/2023

AEMO's initial review of Victoria Energy Policy Centre *PLAN B* report shows it would result in lower levels of renewable generation entering the grid, will likely require the acquisition of people's homes on the outskirts of Ballarat and Bendigo, and would result in long periods of power system disruption.

PLAN B would not sufficiently support renewable generation development in north-west Victoria – meaning less renewable generation would be built, and that less energy from renewable sources will end up powering Victorian homes and businesses.

PLAN B projects will not deliver the capacity needed in western and north-western Victoria. This means that generation from the sunniest and some of the windiest parts of the state would not be serviced by enough transmission. Renewable energy in the area would find it hard to reach concentrations of homes and businesses.

The *PLAN B* projects also fail to deliver the improved access to the Snowy Mountains Scheme – including the upgraded capacity from Snowy 2.0. This will limit the potential for Victorian electricity customers to access hydroelectricity from the Snowy during periods of low sunshine and wind.

PLAN B's failure to provide stronger connection to the NSW grid also strikes a blow to the investment case for renewable projects in Victoria. This is because a central part of any investment case is the ability to export energy to other states when Victoria is generating more electricity than it needs.

Due to proximity of existing transmission to homes on the outskirts of Ballarat and Bendigo, the implementation of the PLAN B alternative would likely require the demolition of homes, while its construction would threaten power supply to major regional and rural towns.

The *PLAN B* assumption that only an extra 10m of easement will be required to construct 1,040km of 220 kV double-circuit line in western and north-western Victoria, is overly optimistic. The consequences to both the supply reliability to regional communities during construction, and the outage impacts on the existing renewable generators would be significant.

If existing lines need to be taken out of service before new lines are built and commissioned, reliability of supply to major regions will be compromised. Also, existing renewable generators in western and north-western Victoria will lose their route to market – leading to significant reductions in earning opportunities.

Also, *PLAN B* makes the incorrect assumption that spare easements exist next to some existing 220kV lines. This is simply not correct. There are no spare easements for the Ballarat to

[116] https://aemo.com.au/newsroom/media-release/aemo-responds-to-vni-west-alternative-plan

Moorabool transmission line, nor are there spare easements for Shepparton to Glenrowan to Dederang transmission line.

Many of the renewable generation hosting capacity figures claimed by the Victoria Energy Policy Centre are unsubstantiated and well in excess of the detailed power system analysis and modelling undertaken by AEMO. Based on AEMO's initial assessment, *PLAN B* will only harness half the renewable generation claimed.

5. Developments not involving new lines

PLAN B's suggestions of '*developments not involving new lines*' upgrades have all been investigated by AEMO and AusNet in the past – and either implemented or rejected on technical and commercial basis.

This includes the suggestion of weather monitors and telecommunications installed on some easements to allow dynamic ratings. This has already been implemented. In fact, the first of the projects was completed more than a decade ago.

Also, there is a suggestion that maximum conductor temperature be increased on some lines. This has also been implemented where safe to do so, while not breaching the clearance guidelines that were released following the Black Saturday bushfires and the subsequent Royal Commission.

6. Inaccuracies on VNI West

The report also makes a series of inaccurate statements about VNI West.

The first, is that *"VNI West will not increase the renewables hosting capacity of Murray River REZ"*. This is a statement that is based on the false assumption that all new renewable generators in the REZ will connect to the existing 220kV infrastructure. Construction of 500kV through VNI West will open the opportunity of higher capacity connection.

AEMO also strongly refutes the claim that *"VNI West will introduce 1000 single-points-of-failure as it relies on a 500 kV dual-circuit transmission line with single towers supporting both 500 kV transmission circuits. This means that a single event of severe lightening, destructive wind gusts, bushfires, extreme flooding, and sabotage would take out the entire line, causing an instantaneous cascading tripping of any parallel 220 kV lines and the existing VNI and Heyward interconnections, plunging southern Victoria including Melbourne and the Portland smelter into an absolute blackout."*

Victoria already has more than 6,000 kilometres of existing transmission line, including double circuit lines with one set of towers supporting two transmission circuits. This approach is also used throughout Australian and international transmission networks. There are well established operational arrangements which manage the risks described, acting immediately to protect the grid following an extreme event by making automatic adjustments needed to maintain secure operation. There is no evidence the additional transmission lines for VNI West would increase risks.

AEMO also strongly refutes the claim in the report that *"VNI West will more than double transmission charges, not increase them by 25% as AEMO says"*.

This incorrect assertion has already been responded to in the regulatory process.

Recent repricing risk in financial markets has resulted in an increase in the discount rate, as identified in AEMO's latest Inputs Assumptions and Scenarios report (published last Friday). Even applying the higher 7 per cent discount rate now reported by AEMO as its central estimate, VNI West is forecast to increase transmission charges by 29%, not the 75% claimed.

All up, accounting for both the cost of Western Renewables Link and VNI West, transmission charges in Victoria are estimated to increase by as much as 50%, although this will be more than offset by the lower wholesale cost of electricity than would otherwise be charged. To put this in perspective, in 2022, transmission charges accounted for 6.3% of the annual residential bill in Victoria.

7. Why we need VNI West

VNI West will harness clean, low-cost electricity from renewable energy zones in both Victoria and New South Wales and improve the reliability and security of electricity supply.

VNI West is needed, because Australia's ageing coal-fired generators are exiting the market after decades of great service. And more than that, their age and the economics of the electricity market are accelerating these closures.

We know, because of rigorous research and analysis conducted by AEMO and the CSIRO, the lowest cost replacement for this coal generation is renewable energy from the sun and the wind – backed up by batteries, gas and hydro to smooth the bumps in production.

One of the challenges this presents is that we need projects like VNI West to connect these new and diverse sources of electricity with Australian homes and businesses. Existing transmission cannot be relied upon, because the geographic location of generation has changed.

Compared to the projects proposed in AEMO's Integrated System Plan, *PLAN B* would have detrimental outcomes for more landholders, regional and rural communities and the renewable generation investment required to give consumers reliable and affordable power supply.

ENDS

Note: Quotes can be attributed to Merryn York, AEMO Executive General Manager System Design.