EIS Volume 1 Chapter 3

Alternatives to the Project

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3. Alternatives to the Project

3.1. Introduction

Chapter 2 Project Justification describes why the Project is needed and uses expert investigation findings and energy policy directions of key authorities including the Australian Energy Market Operator (AEMO), Australia's Chief Scientist, and Commonwealth and State governments to explain the benefits of the Project and justify its development.

This chapter provides an analysis of alternatives which have been considered by ElectraNet in designing the Project, to achieve the primary objective of delivering a net benefit to consumers and producers of electricity in terms of energy cost and security, and support for energy market transition.

The alternative options considered for an interconnector are discussed in this chapter. Further description of the route selection process through which the proposed route alignment was selected is provided in Chapter 4 Route Selection.

Detail on alternative design and construction techniques are discussed further in Chapter 7 Project Description.

3.2. EIS Guidelines

The EIS Guidelines in relation to the assessment of alternative options and technologies, routes, and design and construction techniques considered for the Project are provided in Table 3-1.

Table 3-1: EIS Guidelines in the Alternatives to the Project chapter

EIS Guidelines and Assessment Requirements	Assessment level
Alternatives *Assessment Requirement 11:* There are a number of alternatives that require exploring	
• 11.1: Provide a brief comparative social, environmental and economic analysis of broader alternatives that could meet the proposed objectives at the State level and in the Riverland region. For example, power supply options and technologies, demand management and upgrades of existing lines.	Medium
• 11.2: Provide a comparative analysis of alternative routes and the short, medium and long term social, environmental and economic advantages and disadvantages of each	Medium
• 11.3 Identify alternative design and construction techniques to meet the proposed objectives (e.g. undergrounding, tower design and placement), with reference to any hazards / risks and the social, environmental and economic advantages and disadvantages of each.	Medium
• 11.4: Assess the 'do nothing' option.	Medium

Aspects of assessment requirements identified in Table 3-1 above which are not addressed in this chapter are listed in Table 3-2 together with the applicable chapter.

Table 3-2: Aspects of assessment requirements addressed in other chapters

Assessment Requirement	Chapter
• 11.3 Identify alternative design and construction techniques to meet the proposed objectives (e.g. undergrounding, tower design and placement), with reference to any hazards / risks and the social, environmental and economic advantages and disadvantages of each.	Chapter 7 Project Description

3.2.1. Alternatives considered

The range of alternatives considered during evaluation of project feasibility which are discussed in this chapter include:

- **'Do nothing'** alternative
- **Strategic alternatives** – including demand / supply management alternatives, network upgrades and additional energy generation / storage capacity
- **Interconnector alternatives** – including potential interconnectors to other states (i.e. NSW, Queensland and Victoria)
- **Design alternatives** – including alternatives for proposed infrastructure design such as towers and their spacing, and transmission and technology alternatives.

3.3. 'Do Nothing' Alternative

The objective of the Project is to improve the affordability, reliability and sustainability of electricity supply in the National Electricity Market (NEM) by improving the transmission network between SA, NSW and Victoria. It is expected that achievement of these objectives will provide a wide range of benefits at a local, state and national level, as discussed in Chapter 2 Project Justification.

The 'Do Nothing' alternative requires an evaluation of whether not proceeding with the proposed Project would have consequences that outweigh the positive and negative impacts of the Project. Under a 'Do Nothing' alternative, the interconnector and its associated infrastructure would not be constructed. The land upon which such construction is proposed to occur (e.g. agricultural land and land reserved or managed for conservation purposes) would remain unaffected (unless developed for some separate purpose). As a consequence, the environmental impacts, identified in this EIS, both positive and negative, would not occur. Similarly the social and economic impacts to the region surrounding the Project, including the benefits of employment and business opportunities, would not eventuate.

However, it has been demonstrated in Chapter 2 that there is a significant need for the Project in order to improve energy security for SA, particularly during periods of high demand. Australia is in the midst of a widely acknowledged energy market transition which will see increased penetration of renewable energy in the NEM, particularly in regional areas, at a time when the network infrastructure available to support this transition is either at, or nearing capacity. The Project will support this transition and deliver net market benefits as described in Chapter 2.

The 'Do Nothing' alternative would have the following negative outcomes:

- Jeopardise the increased uptake of new renewable energy generation, both in SA and NSW, which would otherwise enhance energy trade and in turn lower wholesale energy prices, both of which are desired policy outcomes of the State and Commonwealth governments.
- Forego the economic benefits of the construction and operation of the transmission line that would otherwise flow to a region that is experiencing a reduction in agricultural and other economic activity.
- Compromise the ability of the NEM to accommodate varying energy usage patterns and withstand the problems caused by increased intermittency of renewable energy generation in the NEM.
- Fail to address the primary need for increased system security and reliability that has been identified as a key requirement for the South Australian network to address widespread power outages, such as those which occurred in 2016 (AEMO 2018a).
- Loss of the opportunity to enable supply requirements in NSW to be met at a lower cost.

- Necessitate greater investment in new energy infrastructure, either elsewhere in SA or the NEM more broadly, and at greater cost with lower net market benefits.
- Compromise the opening up of Renewable Energy Zones and uptake of renewable projects which will assist in the transition to lower carbon emissions and meeting national and State carbon emission and renewable energy targets.

The NEM is evolving rapidly with new technologies and varying usage patterns, as discussed in Chapter 2. The needs of the future will be vastly different to the past, and will require a strong network capable of tolerating a range of technologies across wide geographies to enable intermittency in demand and generation to be addressed (AEMO 2020a; ElectraNet 2016).

The 'Do Nothing' alternative is not viable, given the imminent need for improved reliability, affordability and sustainability of electricity supply both in SA and across the NEM.

3.4. Strategic Alternatives

The following strategic alternatives to address South Australia's existing vulnerability under the current NEM arrangements were considered and assessed against the objective of the Project[1]:

1. Increasing demand side management (DSM) measures and distributed energy resources (DER) within the South Australian network
2. Upgrading the existing transmission network
3. Adding generation and storage capacity within the South Australian network, including generation by, and storage of, renewable energy.

These alternatives are discussed in the following sections.

3.4.1. Demand side management and distributed energy resources

Demand side management

Demand side management (DSM) refers to actions taken by electricity supply managers to regulate when and how electricity is used, as an alternative to providing additional power supply to meet demand. During periods of peak electricity demand, electricity supply availability can be lower than that required to meet demand, leading to power outages which are managed by AEMO in consultation with the South Australian government, ElectraNet and SA Power Networks[2].

DSM can be implemented using a range of tools available to the market operator including:

- offering customers incentives to reduce their electricity use during peak times
- developing technology that gives electricity customers the ability to track their electricity use and manage load during peak times
- encouraging electricity customers to self-generate and store energy to relieve local demand pressures; and
- direct load control by turning off appliances or large loads during peak times.

The most widely known DSM measure is 'load shedding' which can affect industrial and residential customers and is considered a last resort during peak demand where other supply and DSM strategies have been exhausted.

[1] Refer Chapter 1 Introduction

[2] South Australia Power Networks (SAPN) is the distribution service provider in South Australia. SAPN are responsible for building, maintaining and operating the distribution network that delivers power to approximately 900,000 homes and businesses.

Distributed energy resources

Distributed energy resources (DER) are small-scale units of local generation connected to the grid at the distribution level. These include rooftop solar PV units, natural gas turbines, microturbines, wind turbines, biomass generators, fuel cells, battery storage, electric vehicles (EV) and EV chargers. Increased use of DERs can help relieve pressure on the power network during peak demand with these separate elements working together to form distributed generation.

South Australian initiatives underway to encourage building and integration of DER include:

- The South Australian government Home Battery Scheme initiative supporting the installation of residential batteries which are capable of enrolling in virtual power plant (VPP) aggregations (refer Figure 3-1).
- The South Australia 's Virtual Power Plant initiative in partnership with major VPP operators for the roll-out of solar and battery storage systems to South Australian homes.

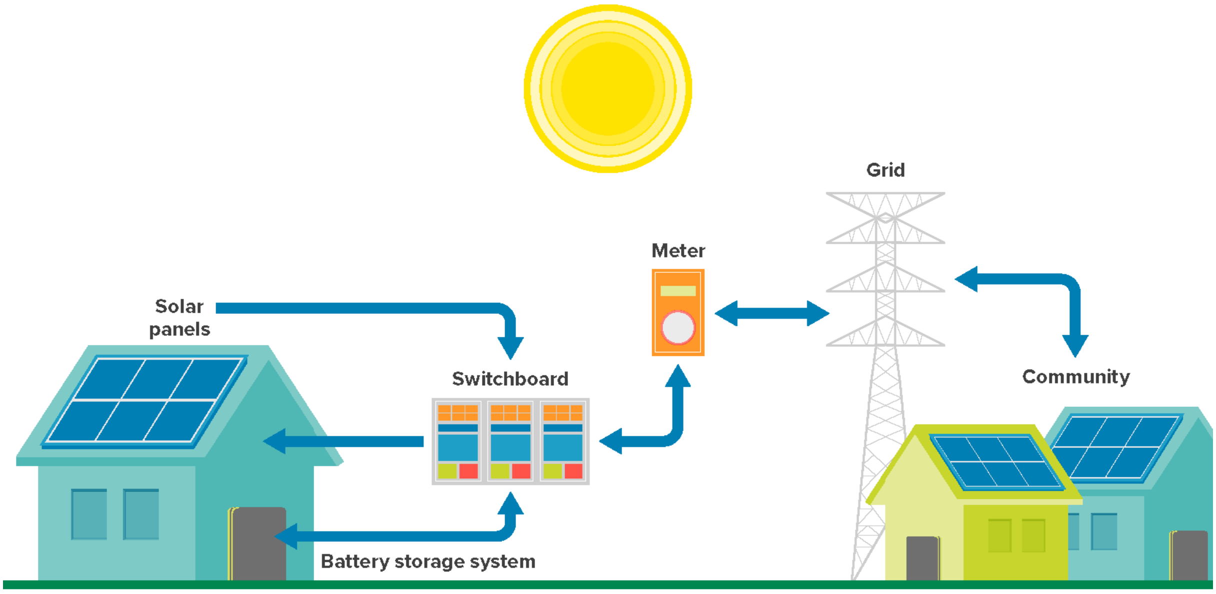


Figure 3-1: Schematic example of a virtual power plant

Interaction of DSM and DER in South Australia

Historically, the trend of wholesale energy consumption in SA has been declining since 2001–2012, as a direct result of DSM, uptake of DER (primarily rooftop PV) and adoption of more energy efficient appliances (AEMO 2018a).

In relation to long term forecast demands, ongoing improvement in energy efficiency of appliances, including air-conditioning, and better insulation of houses is expected to reinforce this trend. Business energy consumption is also forecast to remain relatively flat, as growth in the state economy is offset by the decline in consumption due to commercial rooftop PV installations and business sector energy efficiency programs. Electric vehicle consumption is forecast to rise and largely offset the drop in residential consumption. (AEMO 2020b) (refer Figure 3-2).

Uncertainty in near-term forecast demand has increased substantially due to COVID-19, as the economic and social impact of drivers such as activity and movement restrictions are unprecedented and have dramatically altered the consumption patterns of the population. In 2020–21, the economic effect of COVID-19 is forecast to lower consumption for the business sector. This is partly offset by a forecast increase in residential consumption, partially as a result of increased daytime residential occupancy resulting from increased work-from-home arrangements.

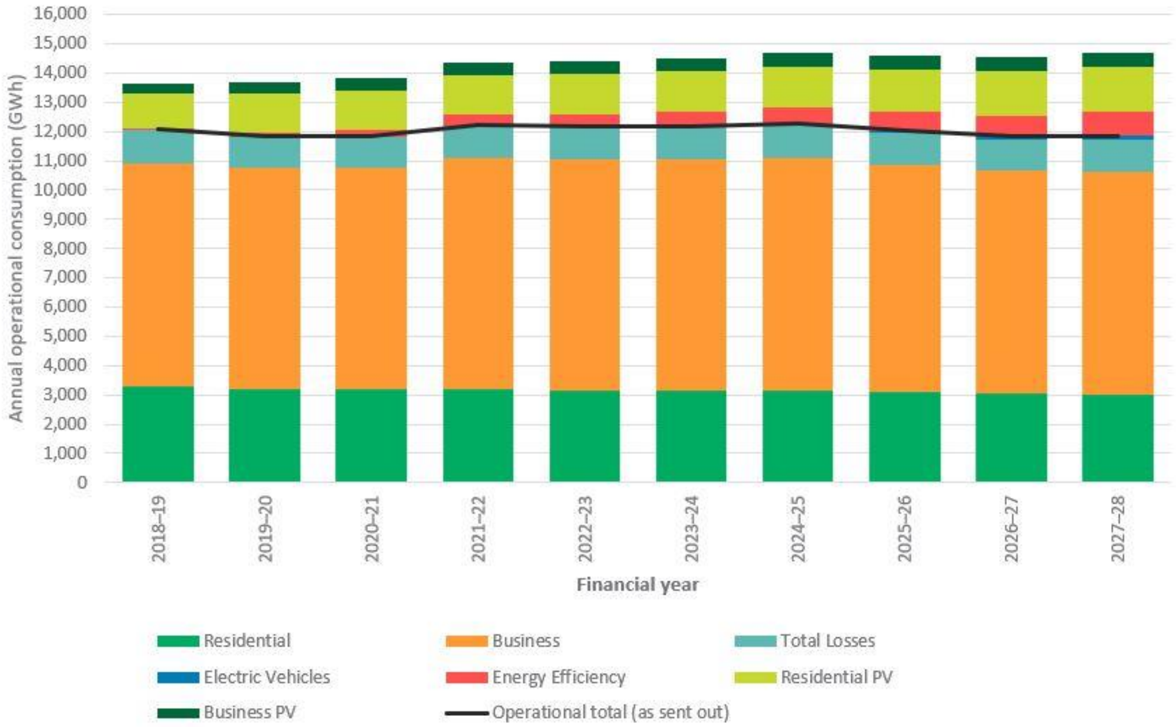


Figure 3-2: Forecast annual operation consumption (sent out) with stacked components (neutral scenario).
Source: AEMO 2020b

DSM in SA is therefore well advanced and is an important contributor to managing periods of high and peak demand to reduce net consumption and minimise risk of energy deficit. DER are also one part of the portfolio for cost-effective replacement of existing thermal energy generation which includes utility-scale renewable generation, energy storage, flexible thermal capacity including gas-powered generation (GPG), and transmission (AEMO 2020a).

Growth of DER is largely consumer driven and until recently unrestricted by policy settings, and to that extent introduces an element of uncertainty to the energy generation mix. AEMO has recently investigated this further which has resulted in recommendations to AEMC in relation to DER performance standards, compliance processes, feed-in management and importantly, the delivery of Project EnergyConnect to address this uncertainty (AEMO 2020c). In December 2020, AEMC released an alternative solution as a draft rule to allow for small DER systems, primarily rooftop PV, to be better managed in the NEM. The rule sets minimum technical standards for newly connected and replacement systems to reduce uncertainty about the performance of DER systems. The current uncertainty undermines the ability of AEMO to manage voltage disturbances and maintain grid stability. AEMC is undertaking stakeholder consultation until early 2021 (AEMC 2020b).

It is considered that increased DER and DSM on their own are not only insufficient to address the need identified in the Integrated Systems Plan (ISP) for SA to have more reliable and secure electricity supply (AEMO 2018a), but are creating weaknesses in the system. DSM strategies alone cannot address the need for increased energy security and affordability, and increased penetration of renewable energy within the NEM, particularly during major system interruption and outages.

3.4.2. Upgrades to the existing transmission network

As discussed in Chapter 2, power in SA is currently imported from, and exported to the rest of the NEM only via the 275 kV Heywood and 150 kV Murraylink interconnectors with Victoria. The Heywood

Interconnector has historically been a significant gross importer of power particularly during peak demand times in SA, whereas Murraylink has 220 MW of capacity which is constrained by the thermal overloads on infrastructure at either end of the transmission line (AEMO 2018b). There is no interconnector between SA and NSW.

Should there be a loss of connection to the Heywood Interconnector, SA can effectively become separated from the rest of the NEM (i.e. 'islanded'). Whilst Murraylink is still capable of power transfers, it does not provide a synchronous connection between South Australia and Victoria. This situation would leave the State's power system vulnerable to system interruption and outages as occurred in September 2016 and the summer of 2020.

Upgrades to the existing transmission network alone, would fail to deliver a key objective of Project EnergyConnect which is to enhance the security of electricity supply in SA by providing a second major interconnector to the rest of the NEM. In contrast, direct interconnection between NSW and SA will provide the opportunity to utilise existing surplus electricity generating capacity in both SA and NSW during peak demand periods in either state (as they tend to have uncorrelated maximum demand conditions), and improve security and reliability of supply in SA.

3.4.3. Additional generation and storage capacity

Additional generation and storage capacity initiatives in SA (predominantly in association with renewable energy) that were committed and publicly announced by mid-November 2020, totalled an increase of more than 10,000 MW from more than 50 projects. Of these, renewable energy sources (wind and solar) comprised the majority of the increase from a capacity perspective. There was also an increase in the amount of new battery, pumped hydro, and gas-fired peaking projects publicly announced compared to the year before (AEMO 2020d).

While it is considered unlikely that all of these projects would proceed to operation, it is anticipated that local supply and storage will continue to increase in SA. However, given the predicted ongoing dominance of renewable energy sources and the resulting issues in relation to system stability caused by the intermittent nature of renewable energy, additional generation and storage capacity would be unlikely to bring the same level of reliability and security to electricity supply when compared to the proposed interconnector. Importantly, it is anticipated that the proposed interconnector will not only support reliability and security, but will also enhance opportunities for new energy projects to be developed and export energy to the rest of the NEM[3].

3.5. Interconnector Alternatives

3.5.1. Economic Cost Benefit Assessment – RIT-T Process

As noted in Chapter 2, the primary examination of alternatives to the Project was undertaken in the SAET RIT-T[4] process by ElectraNet overseen by the Australian Energy Regulator (AER).

The RIT-T is an economic cost benefit test and applies to all major network investments in the NEM. It involves consultation with stakeholders, assessment of the impacts of key variables under a range of future scenarios, consideration of alternatives, and presentation of the findings of the process, the recommended solution and the intended course of action.

The purpose of the RIT-T process is to identify the transmission investment option which will maximise net economic benefits and where applicable, meet the relevant reliability standards. The process

[3] One of the critical factors for selecting the location for the Neoen Goyder South Hybrid Renewable Energy Facility was the site's proximity to the proposed Project EnergyConnect SA-NSW interconnector (GHD 2020)

[4] South Australian Energy Transformation - Regulatory Investment Test for Transmission

ensures that the final recommended solution will have the desired long term economic and social benefits, meet mandated reliability standards and can be scaled with changing electricity demands.

Three future electricity market scenarios were considered in the SAET RIT-T (ElectraNet 2019a). These scenarios reflect different assumptions that affect the relative market benefits of the options being considered, including:

- future market development
- long-term gas prices
- fluctuating electricity demand
- technology uptake and emissions reduction policy targets (at both State and Commonwealth levels).

The assessment was tested to a wide range of sensitivities, including the outcomes of the concurrent Western Victoria RIT-T, the assumed timing of gas generator retirements in SA, differences in assumed future mining load developments in SA and the estimated costs of the various options. (ElectraNet 2019a).

The three future scenarios assessed in the SAET RIT-T are presented in Table 3-3.

Table 3-3: Summary of future electricity market scenarios considered

Low scenario	Central scenario	High scenario
Reflects the state of the world with low gas process, low demand and no emissions reductions targets over and above the existing large-scale renewable energy target (LRET).	Reflects the best estimate of the evolution of the market going forward and is aligned in all material aspects with AEMO's ISP neutral scenario.	Reflects a state of the world with high gas prices ad high demand, alongside aggressive emissions reduction targets.

The SAET RIT-T then considered a range of interconnector alternatives which were evaluated against the scenarios above, consistent with the network planning options identified in the ISP prepared by AEMO in 2018. Four main options were examined:

- network support and non-network options internal to SA (Option A)
- new interconnection with Queensland (Option B)
- new interconnection with NSW (Options C.1, C.2, C.3, C.3ii, C.3iii, C.4 and C.5)
- additional interconnection with Victoria (Option D).

A range of variants to these options were evaluated within the SAET Project Assessment Draft Report (PADR) (ElectraNet 2018) and SAET Project Assessment Conclusions Report (PACR) (ElectraNet 2019a) to assess a range of inputs, address submissions from various stakeholders and test tolerances of assumptions, as discussed below.

The interconnector options discussed in this chapter are shown below in Figure 3-3, Figure 3-4, Figure 3-6 and Figure 3-7.

It should be noted that the RIT-T process operates as a detailed economic assessment of the costs and benefits of alternative interconnector options, undertaken to assess the ability to meet applicable economic benefit and reliability standards objectives. Due to the very high capital cost of this type of infrastructure, these economic and operational aspects are the decisive consideration in whether or not to proceed with a particular option. As a result, social and environmental advantages and disadvantages are explicitly removed from consideration in the RIT-T and have therefore not been analysed in this chapter. These aspects are however, of primary importance in selecting the alignment of the preferred option and are fully explored in the assessment undertaken in this EIS, as detailed in Chapter 4.

3.5.2. Non-interconnector alternative (Option A)

The technical and economic feasibility of non-interconnector solutions was explored by ElectraNet to evaluate whether new generation, storage and DSM could deliver equivalent net market benefits to new transmission interconnection.

Option A was developed as a 'least-cost' option for assessment as part of the PADR, and was designed to prevent a system black event that would likely occur from a loss of the existing Heywood interconnector (ElectraNet 2018). The energy system components in SA that were assumed to be present as part of the assessment of this option included the following:

- pumped storage (Port Augusta)
- Osborne co-generation
- solar thermal at Davenport
- battery energy storage system (BESS) – Tailem Bend
- Murraylink (transfer of Frequency Control Ancillary Services (FCAS))
- an additional BESS (location to be determined)
- minimum load control (to enable control of solar PV installations, which would be directly invested in by ElectraNet).

Although it provided considerable diversity in generation and storage options within SA, the non-interconnector option was estimated to deliver negative to low net market benefits in the scenarios modelled, when compared to the other options considered (refer Table 3-5).

This option also did not materially lower dispatch costs or facilitate the broader market transition to lower carbon emissions compared to the other alternatives considered. It also did not meet the defined minimum system performance levels under all conditions or provide the same system security benefits compared to a new interconnector (ElectraNet 2019a).

3.5.3. Interconnector from South Australia to Queensland (Option B)

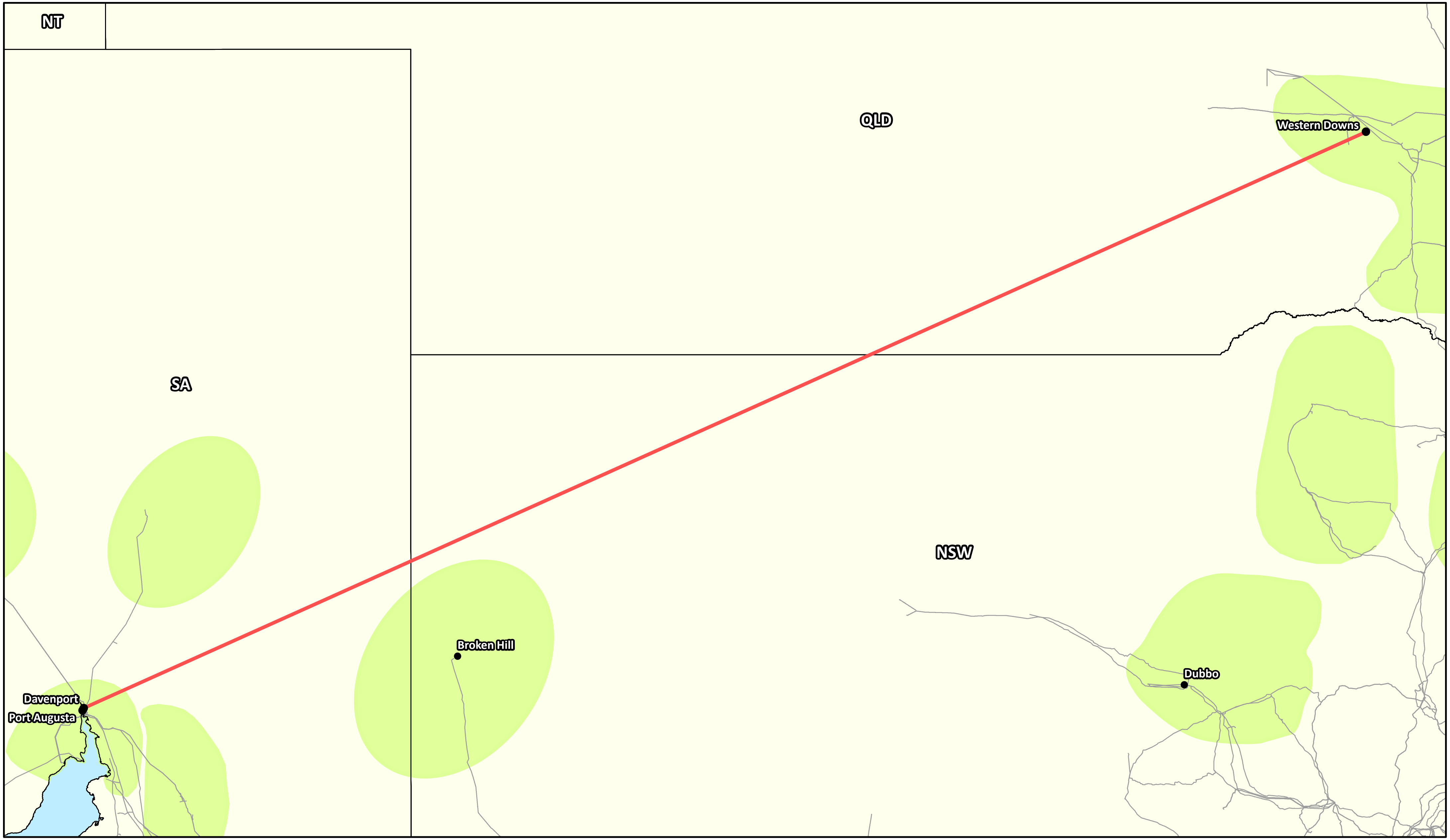
A new interconnector between northern SA and Queensland was assessed as Option B in the SAET PACR (refer Table 3-5 and Figure 3-3).

This proposed alternative comprised a high capacity high-voltage direct current (HVDC) interconnector approximately 1,450 km in length with an assumed capacity of 700 MW and a cost of $1.98 billion. The indicative route assessed for this option was assumed to be between Davenport in SA, traversing the north-west of NSW (linking to the Broken Hill REZ), before connecting into the Queensland network at Western Downs (ElectraNet 2019a).

Transmission costs and losses were forecast to be high due to the length of the line. However strong connection nodes at each end meant that this option had a reduced risk of constraints compared to the NSW interconnector options. Due to its length, this option had the highest forecast capital cost at $1.98 billion, and would traverse significant distances of sparsely populated land with poor infrastructure, low industry penetration and low energy demand (ElectraNet 2018).

A range of assumptions and tolerances were therefore investigated relating to the inclusion of converter stations which would enable renewable generation (wind and solar) within REZs along the route, including Broken Hill. The PACR found that the cost of the converter stations was higher than the benefits expected to be realised by them, and that the net market benefits were negative, but removal of the converter stations did not affect the selection of the preferred option (ElectraNet 2019a).

The net market benefits for Option B were assessed to be lower than the interconnector options between SA and NSW (ElectraNet 2019a).



ElectraNet - Options
Option B indicative HVDC between northern SA and QLD
Existing electrical infrastructure
Renewable Energy Zone (REZ)

Figure 3-3
Option B – HVDC interconnector between northern South Australia and Queensland

0 200
Kilometres
N

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3.5.4. Interconnector with New South Wales (preferred Option C)

The PADR identified new interconnection between SA and NSW via Buronga as the option that best satisfied the RIT-T, which reinforces the findings of AEMO in the 2018 ISP.

Five key options were evaluated in the PADR with a range of minor variants (ElectraNet 2018):

- Option C.1 – New DC link from Riverland SA to NSW ('Murraylink 2')
- Option C.2 – 275 kV link from Mid North SA to Wagga Wagga in NSW, via Buronga
- Options C.3 and C.3i – 330 kV line from Mid North SA to Wagga Wagga in NSW
- Option C.4 – 330 kV line from Mid North SA to Wagga Wagga NSW, via Darlington Point
- Option C.5 – 500 kV line from Northern SA to east NSW.

A full and detailed analysis of each of the options above, including some minor variants, is provided by ElectraNet in the PADR (ElectraNet 2018). The PADR highlighted that there were a number of aspects of the options into NSW that required further investigation to refine the scope, including the compatibility of fixed series compensation[5] with the connection of new renewable generation and the potential benefits of strengthening the link between Buronga in NSW and Red Cliffs in Victoria.

Following extensive consultation and feedback on the PADR, these aspects were evaluated for each of the options and ElectraNet concluded that a number of the options were no longer feasible, as shown in Table 3-4 (ElectraNet 2019a).

The subsequent PACR assessment further considered three option variants relating to new interconnection between SA and NSW, via Buronga. Two of these variants were developed in response to submissions on the PADR (C.3ii and C.3iii). The three route alternatives which were considered in detail in the PACR are discussed further in Section 3.6 and shown in Figure 3-6.

Table 3-4: Options included in the PADR which were excluded from the PACR

Description	Reason for exclusion for PACR assessment
Option C.1 New DC link from Riverland SA to NSW ('Murraylink 2')	PADR assessment showed low or negative net market benefit. This option was proposed in a submission to the PSCR[6], but there were no supporting submissions following the PADR assessment.
Option C.2 275 kV line from Robertstown in SA to Wagga Wagga NSW, via Buronga	PADR assessment showed substantially lower net market benefit than for other options. Refinements to the market modelling in the PACR to better capture benefits associated with avoiding transmission investment associated with REZs would not change this outcome. These benefits would not accrue to the 275 kV option as much as the 330 kV option whilst increasing benefits associated with the 330 kV options.
Option C.3i 330 kV line from Robertstown in SA to Wagga Wagga NSW, via Buronga, plus series compensation (or similar)	Further technical assessment confirmed that addition of series compensation may restrict the connection of renewable generation due to technical consideration, reducing benefits associated with renewable energy development. Specifically, the deployment of fixed series compensation on lines posed the risk of sub-synchronous resonance and sub-synchronous control interactions, if new generators are connected in the proximity to the series capacitors. This assessment also identified that series compensation is no longer needed in order to reduce constraints on the combined operation of the Heywood interconnector and a new interconnector, due to changes in proposed network configuration under this option and with reasonable levels of load shedding.

[5] Series compensation techniques are used to modify the natural electrical characteristics of an electric power system. Series compensation modifies the reactance parameter of the transmission system, in other words it reduces voltage drop over long distances.
[6] Project Specification Consultation Report

Description	Reason for exclusion for PACR assessment
	In effect, this option became redundant,
Option C.4 330 kV line from Robertstown in SA to Wagga Wagga NSW, via Darlington Point	Further technical assessment showed that bypassing Buronga en route to Darlington Point would not capture benefits associated with avoided REZ transmission, and would also have a higher cost associated with the requirement to include an additional switching station to manage system technical performance.
Option C.5 500 kV line from Northern SA to east NSW	PADR assessment showed low or negative net market benefit associated with this option, driven by its substantially higher cost. Refinements to the market modelling in the PACR to better capture benefits associated with avoiding transmission investment associated with REZs were not expected to fundamentally alter this outcome, given the magnitude of the option cost.

3.5.5. New interconnector to Victoria (Option D)

A new 275 kV line interconnector into Victoria from central SA was assessed as Option D (refer Table 3-5 and Figure 3-4).

This option was considered to strengthen South Australia's connection to the east coast by providing an increase in export and import capability. The indicative route investigated was approximately 420 km in length between Tungkillo in SA to Horsham in Victoria, with an additional 90 km between Horsham and Ararat. This option was assessed with a minimum capacity of 650 MW and a capital cost of approximately $1.2 billion.

Option D.i was also considered which included 50% series compensation between Horsham and Tungkillo, to reduce constraints that would otherwise occur on the combined capacity of the existing Heywood interconnector and a new interconnector. This increased the effective capacity across both interconnectors from around 950 MW to 1,100 MW and cost an additional $30 million to Option D (ElectraNet 2018). In the PACR, ElectraNet identified that series compensation was likely to restrict the connection of renewable generation, reducing benefits associated with renewable energy development and that series compensation was no longer needed in order to reduce constraints on the combined operation of the Heywood interconnector and a new interconnector. Option D.i was therefore excluded from further assessment with the benefits being captured directly by Option D (ElectraNet 2019a).

The PACR concluded that Option D was the top ranked non-NSW option under the central scenario (refer Table 3-3) which reflects the best estimate of the evolution of the market going forward (ElectraNet 2019a). However, a material risk of bushfire was associated with this option due to the area traversed and this was also incorporated into the assessment. A severe bushfire could potentially lead to coincident and widespread damage to both the existing Heywood interconnector and a new interconnector, resulting in an extended time period to bring them back into service. Network hardening was also required to be included in the capital costs to ameliorate this bushfire risk, which reduced the net market benefits of this option (ElectraNet 2018).

Although this option is the top ranked non-NSW option considered, all the NSW interconnector alternatives options (Option C.3, C.3ii and C3.iii in Table 3-5) are expected to deliver higher net market benefits than a new interconnector to Victoria, and this finding was found by the RIT-T to be robust across a wide range of future scenarios and sensitivity tests (ElectraNet 2019a).

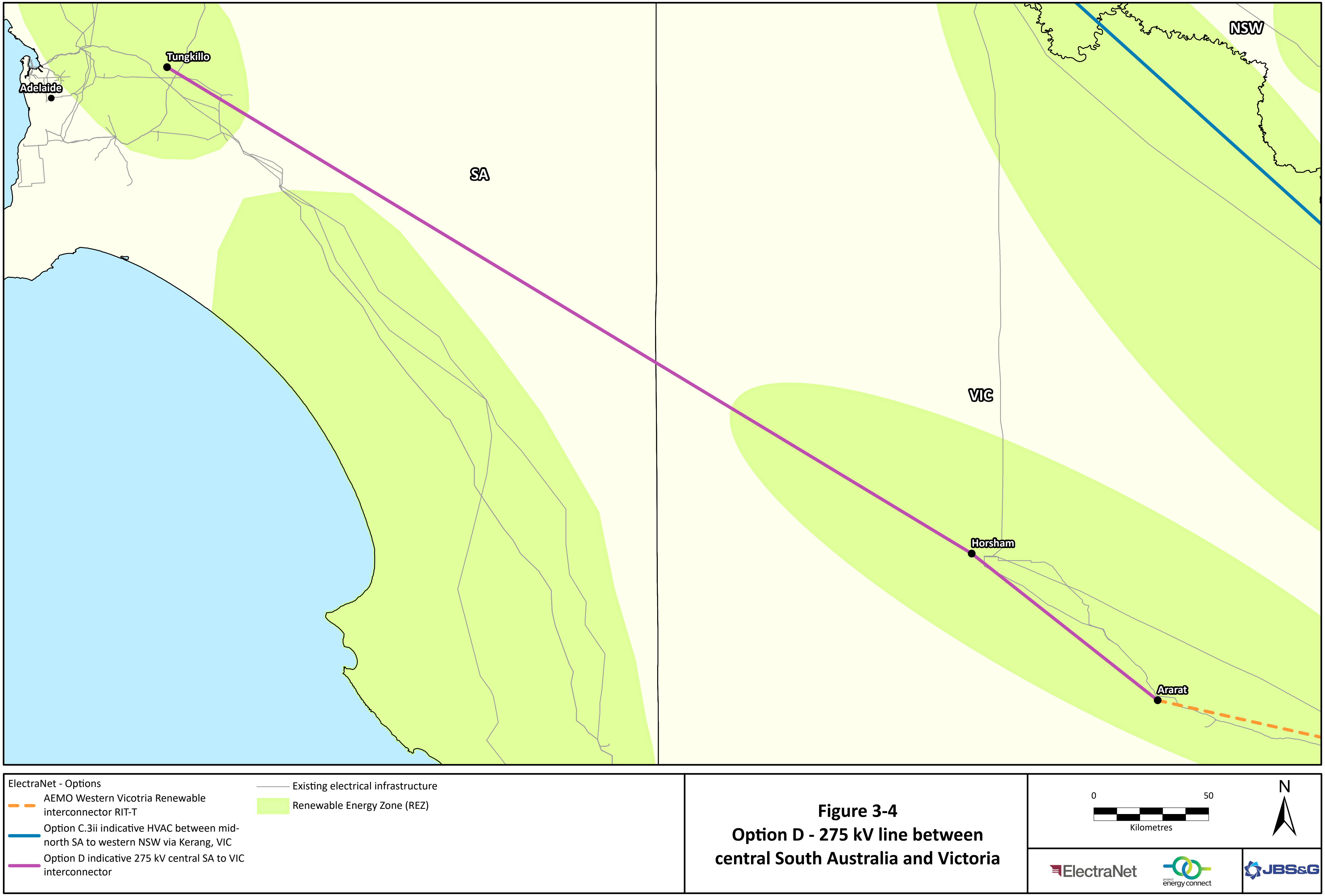

Figure 3-4
Option D - 275 kV line between central South Australia and Victoria

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3.6. Outcomes of the Assessment of Interconnector Alternatives

As described in Section 3.5.4, an interconnector between SA and NSW was considered the preferred option in the SAET PACR.

Three interconnector options between the two states were considered to be viable alternatives for delivering net market benefits within the RIT-T process (refer Figure 3-6):

- Option C.3 – 330 kV line between Robertstown in Mid North SA and Wagga Wagga in NSW, via Buronga, plus Buronga-Red Cliffs 220 kV
- Option C.3ii – 330 kV line between Robertstown in Mid North SA and Wagga Wagga in NSW, via Buronga, Red Cliffs, Kerang and Darlington Point
- Option C.3iii –HVDC transmission between Robertstown in Mid North SA and Darlington Point via Buronga; high-voltage alternating current (HVAC) line between Darlington Point and Wagga Wagga in NSW, plus Buronga-Red Cliffs 220 kV.

Of these interconnector options, Option C.3 (refer Figure 3-7) was found by the RIT-T to deliver the highest net market benefits, and across all reasonable future scenarios and sensitivities. The relative costs and capabilities of the credible options considered are summarised in Table 3-5 and Figure 3-5 (ElectraNet 2019a).

Table 3-5: Summary of the credible options considered in the SAET RIT-T

Overview[7]	Capital cost	Annual contract cost	Notional Maximum Capability (MW)[10]	
			Heywood	New interconnector
'Non-interconnector' option				
Option A – Least cost non-interconnector option in SA	$3 m	$110 m[11]	650	-
An interconnector to Queensland				
Option B – 400 kV HVDC between north SA and Queensland	$1.98 b	-	750	700
NSW interconnector options				
Option C.3 – 330 kV line between Robertstown in Mid North SA and Wagga Wagga in NSW, via Buronga, plus Buronga-Red Cliffs 220 kV	$1.53 b	-	750	800
Option C.3ii – 330 kV line between Robertstown in Mid North SA and Wagga Wagga in NSW, via Buronga, Red Cliffs, Kerang and Darlington Point	$1.73 b	-	750	800
Option C.3iii – HVDC transmission between Robertstown in Mid North SA and Darlington Point via Buronga; HVAC line between Darlington Point and Wagga Wagga in NSW, plus Buronga-Red Cliffs 220 kV.	$1.64 b	-	750	800
A new interconnector to Victoria				
Option D – 275 kV line from Tungkillo in SA to Horsham and Ararat in Victoria	$1.15 b	-	750	650

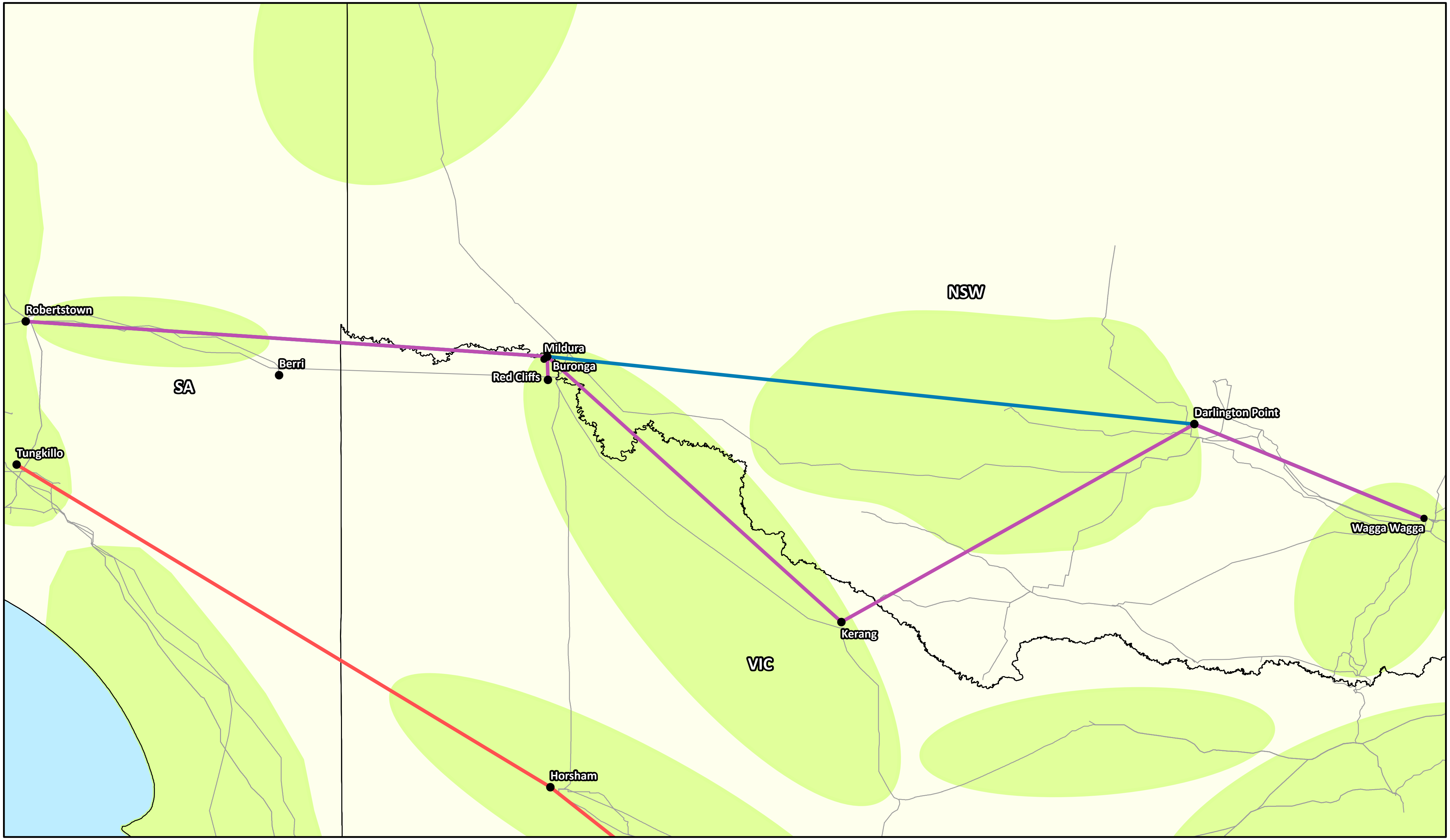
[10] The notional maximum capabilities are not to be treated as additive due to network interactions. For example, the preferred option is modelled to deliver approximately 1,300 MW of combined transfer capacity.
[11] This figure is for the central scenario and is the average over each year of the assessment period

[7] For the purposes of this chapter the assessment of options discussed in Table 3-5 refers to the central scenario described in Table 3-2 which is consistent with the neutral scenario identified in the ISP.

Figure 3-5: Summary of the estimated net market benefits under the central scenario in the SAET RIT-T
(Source: ElectraNet 2019a)

Following the selection of Option C.3 as the preferred option, a rigorous route selection process was undertaken to evaluate a range of route alternatives using a multi-criteria analysis (MCA). The MCA process covers the full ambit of environmental, economic, social and technical issues to identify a preferred corridor which was subsequently refined to include a proposed alignment that minimises impacts. A description of the route selection and route alternatives process leading to the identification of the proposed route alignment for the transmission line is provided in Chapter 4 Route Selection.

The 'Do Nothing' alternative has been excluded for the reasons described in Section 3.3.



ElectraNet - Options

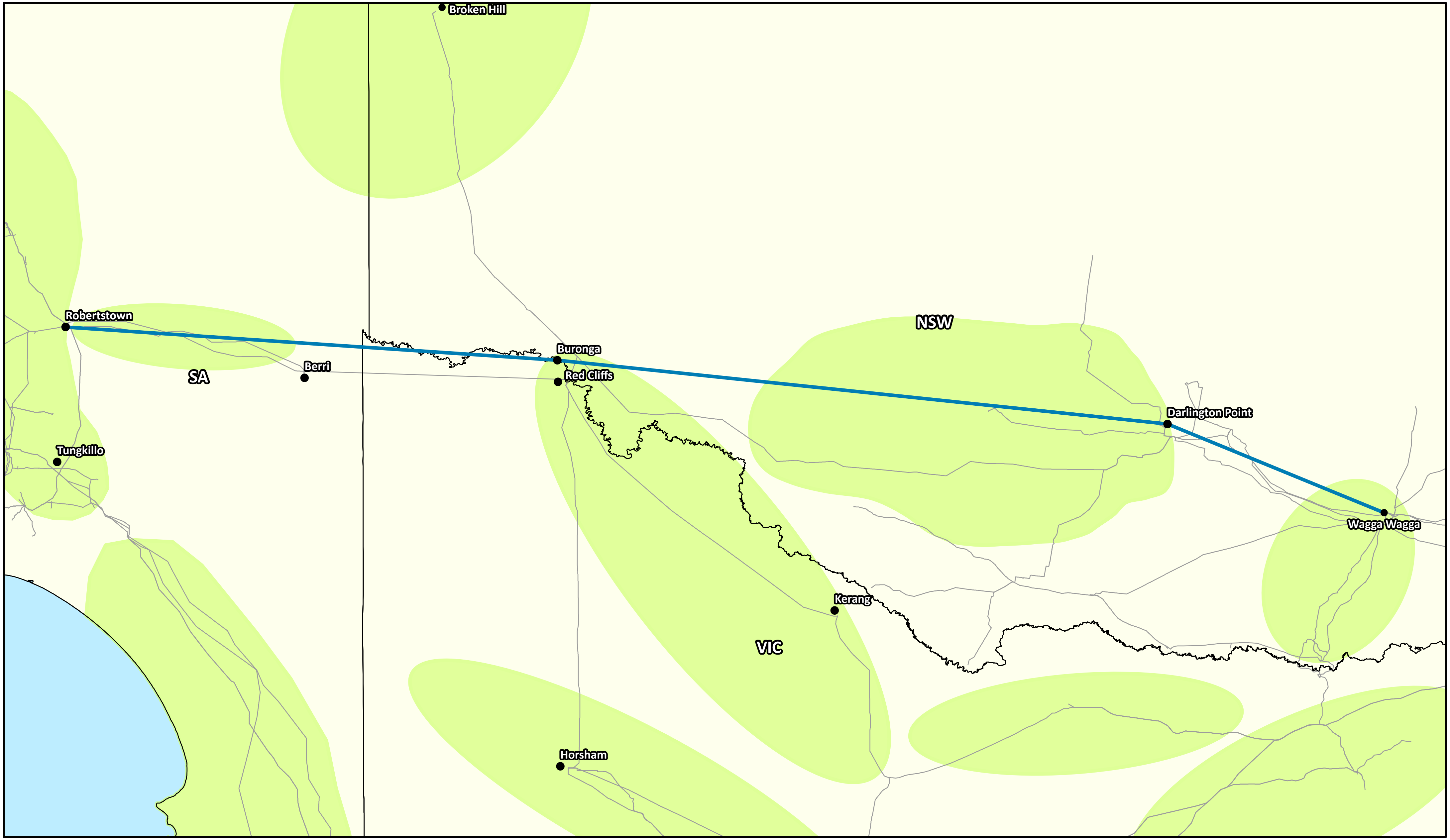
- Option D indicative 275 kV central SA to VIC interconnector
- Option C.3 and C.3iii 330 kV indicative HVAC or 400 kV indicative HVDC between mid-north SA and western NSW
- Option C.3ii indicative HVAC between mid-north SA to western NSW via Kerang, VIC
- Existing electrical infrastructure
- Renewable Energy Zone (REZ)

Figure 3-6
Options C 3 – 330 kV line between South Australia and New South Wales

0 100
Kilometres

N

ElectraNet
project energy connect
JBS&G



ElectraNet - Options

- Option C.3 and C.3iii 330 kV indicative HVAC or 400 kV indicative HVDC between mid-north SA and western NSW
- Existing electrical infrastructure
- Renewable Energy Zone (REZ)

Figure 3-7
Preferred option C.3 – South Australian – New South Wales Interconnector

0 100
Kilometres

N

ElectraNet
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