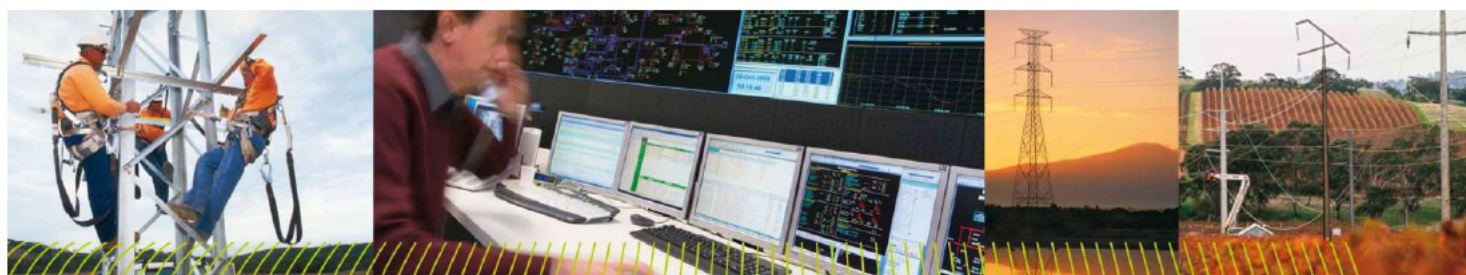




# Managing voltages on the Mid North transmission system

RIT-T: Project Specification Consultation  
Report

August 2012



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## **1. Introduction**

### **1.1 Background**

This Project Specification Consultation Report (PSCR) addresses forecast voltage limitations and inadequate reactive power margins in the Mid North region of South Australia.

The PSCR has been prepared by ElectraNet as part of the prescribed National Electricity Rules (NER)<sup>1</sup> process for the approval of proposed shared network augmentations. It represents the first stage of the consultation process in relation to the application of the Regulatory Investment Test – Transmission (RIT-T) to the management of voltages on the Mid North transmission system.

This report:

- Describes the identified need which ElectraNet is seeking to address, together with the assumptions used in identifying this need;
- Sets out the technical characteristics that a non-network option would be required to deliver in order to address this identified need;
- Describes the credible options that ElectraNet currently considers may address the identified need; and
- Discusses specific categories of market benefit which in the case of this specific RIT-T assessment are unlikely to be material, in line with the requirement of NER 5.6.6(c)(6)(iii).

### **1.2 Submissions**

ElectraNet welcomes written submissions on this PSCR. Submissions are particularly sought on the credible options presented and from potential proponents of non-network options.

Submissions are due on or before 7 November 2012.

Submissions should be emailed to [consultation@electranet.com.au](mailto:consultation@electranet.com.au). Submissions will be published on the ElectraNet website. If you do not wish for your submission to be made publicly available please clearly stipulate this at the time of lodging your submission.

Further details in relation to this project can be obtained from:

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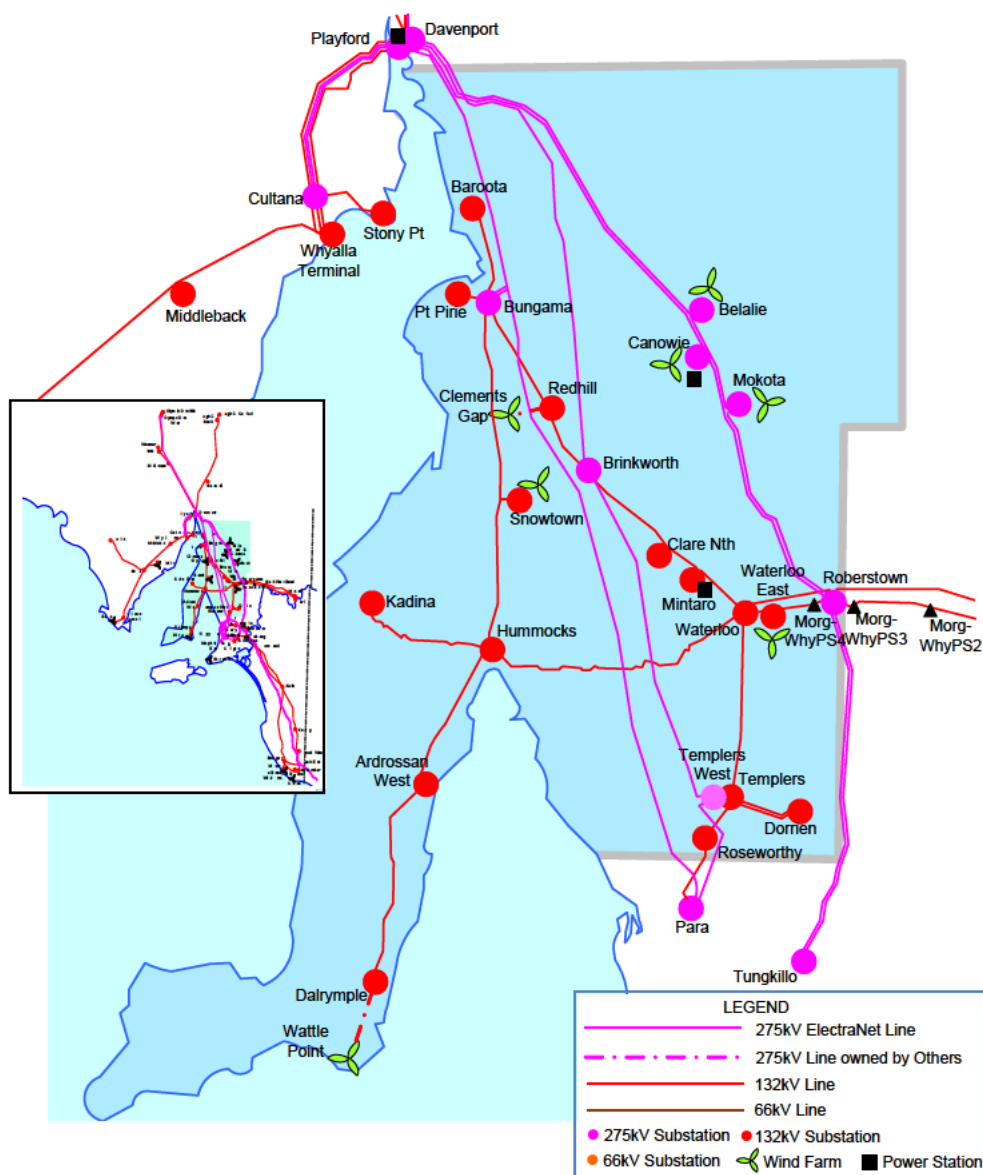
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<sup>1</sup> National Electricity Rules, clause 5.6.6.

## 2. Background

### 2.1 Existing Mid North network

The Mid North 132 kV transmission system comprises a network that supplies major load centres at Ardrossan, Brinkworth, Clare, Kadina and Port Pirie, as well as other loads in the Barossa Valley and Yorke Peninsula regions. It derives its supply from the Main Grid 275 kV system via 275/132 kV substations located at Para (near Elizabeth), Templers West, Robertstown, Brinkworth and Bungama (near Port Pirie). Figure 1 is a geographical diagram of the region.



**Figure 1: Geographical diagram of the Mid North region**

The Mid North 132 kV system operates in parallel with the 275 kV Main Grid system that connects the major sources of generation at Port Augusta with

the Adelaide metropolitan load centre. As a consequence, power flows in the Mid North 132 kV system are not only determined by the loads that must be supplied within the region but also by flows on the Port Augusta to Adelaide 275 kV system<sup>2</sup>.

## 2.2 Committed and anticipated network developments

ElectraNet has a program of committed projects to address supply reliability requirements in the Mid North. These projects are summarised in Table 1 below.

**Table 1: Committed projects in the Mid North region**

Connection Point	Scope of Work	Timing
Ardrossan West	Install 2x25 MVA 132/33 kV transformers and 15 Mvar 132 kV switched capacitor bank	2012
Dorrien	Install a third 60 MVA 132/33 kV transformer	2012
Hummocks	Install 2x25 MVA 132/33 kV transformers and upgrade a section of the 132 kV bus	2013
Waterloo	Rebuild Waterloo substation on an adjacent site with 2x25 MVA 132/33 kV transformers	2013

In addition, there are a number of anticipated network projects in the Mid North region. Specifically, ElectraNet anticipates that installation of a 15 Mvar 132 kV switched capacitor bank at Kadina East will be required in 2013. ElectraNet has also identified network reinforcement of the Yorke Peninsula as a proposed augmentation project. This network reinforcement is driven by the need to address post-contingent thermal overload of 132 kV lines supplying the Yorke Peninsula, and to accommodate potential new mining loads<sup>3</sup>.

These anticipated network developments (including a number of other developments in the Mid North region which do not affect the forecast network limitations that are the subject of this RIT-T assessment) are discussed in more detail in ElectraNet's 2012 Annual Planning Report (APR)<sup>4</sup>.

## 2.3 Existing and committed generation

Existing generation on the Mid North 132 kV network includes a mixture of gas turbine plant and wind farms.

<sup>2</sup> Further information on the Mid North region can be sourced from Chapter 9 of ElectraNet's 2012 Annual Planning Report.

<sup>3</sup> This augmentation will be subject to a separate RIT-T consultation process.

<sup>4</sup> 2012 ElectraNet Annual Planning Report, available at: <http://www.electranet.com.au/assets/Uploads/2012APR.pdf>. For more information regarding future augmentation projects see section 9.4.

The 90 MW Mintaro open cycle gas turbine (OCGT) is connected to the 132 kV system while the OCGTs at Hallett power station (192 MW) are connected to the 275 kV Main Grid. There is also a 50 MW distillate fired generator embedded in the ETSA Utilities 33 kV distribution network at Angaston.

There are eight existing wind farms operating in the Mid North, which are more widely scattered throughout the region. The wind farms connected to the 132 kV system are Wattle Point (90.8 MW, near Edithburgh on the Yorke Peninsula), Snowtown (98.7 MW),<sup>5</sup> Clements Gap (56.7 MW, south of Port Pirie) and Waterloo (111.0 MW, east of the Waterloo area). The wind farms connected to the 275 kV Main Grid are Brown Hill (94.5 MW), Hallett Hill (71.4 MW), North Brown Hill (132.3 MW) and The Bluff (52.5 MW), all located in the vicinity of Canowie, Mokota and Belalie.

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<sup>5</sup> ElectraNet notes that there are plans to expand the Snowtown wind farm by a further 270 MW, to be completed by 2014. (See media release by TrustPower Limited, 26 July 2012, at <http://www.trustpower.co.nz/index.php?section=360>). An application for an electricity generation licence has also been approved by the Essential Services Commission of South Australia (ESCOSA) in respect of 144 MW at Snowtown connecting to the 275 kV transmission system (see <http://www.escosa.sa.gov.au/electricity-overview/licensing/generation-wind-generation-licences.aspx>).



### 3. Identified need

#### 3.1 Description of the identified need

ElectraNet's 2012 Annual Planning Report identifies the likelihood of future voltage limitations at Bungama, Port Pirie and Baroota connection points following an outage of the existing 200 MVA 275/132 kV transformer at Bungama. In addition to these forecast voltage limitations, network studies have identified the likelihood of post-contingent inadequate reactive power margins at Bungama and Port Pirie connection points.

Specifically, from summer 2015/16, loss of the Bungama transformer would result in both:

- voltages at Bungama, Port Pirie and Baroota connection points falling below the minimum requirement specified in ElectraNet's Transmission Connection Agreement (TCA) with ETSA Utilities, as agreed in accordance with clause S5.1.4 of the NER; and
- inadequate reactive power margins at the Bungama and Port Pirie connection points to satisfy the minimum standard specified in clause S5.1.8 of the NER.

Reliability corrective action<sup>6</sup> is therefore required in order to ensure that the network continues to satisfy NER requirements and avoid the potential for a loss of load in the distribution network.

#### 3.2 NER requirements

The NER require ElectraNet to comply with the power system performance and quality of supply standards contained in schedule 5.1. This schedule includes requirements and limits for voltage levels, frequency variation, harmonics, flicker and voltage unbalance in the network.

Clause S5.1.4 of the NER requires ElectraNet to plan and design its transmission system for control of voltage such that the minimum steady state voltage magnitude is consistent with the levels provided by clause S5.1a.4. In the event of a contingency event,<sup>7</sup> such as loss of the Bungama transformer, clause S5.1a.4 does not specify a minimum voltage requirement for any connection point.

Instead, clause S5.1.4(c) allows Network Service Providers and Network Users to jointly determine target voltages or a target range of voltage magnitude for connection points connected to a transmission line through a transformer. Clause S5.1.4 also states that any agreement to a target range of voltage magnitude must be specified in the relevant connection

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<sup>6</sup> Defined in NER Chapter 10 as "Investment by a Transmission Network Service Provider in respect of its transmission network for the purpose of meeting the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network or non-network options".

<sup>7</sup> 'Contingency event' is a defined term in the NER.

agreement, which may include a different target range in a satisfactory operating state<sup>8</sup> and after a credible contingency event.

Consistent with clause S5.1.4 of the NER, ElectraNet's TCA with ETSA Utilities requires that voltage levels at connection points must be kept above 90% of the nominal voltage level following any single contingency in the network supplying that connection point.

ElectraNet has identified that from summer 2015/16 an outage of the existing Bungama transformer would result in voltages at Bungama, Port Pirie and Baroota connection points that fall below the minimum requirement specified in the ElectraNet/ETSA Utilities TCA as agreed in accordance with clause S5.1.4 of the NER.

Clause S5.1.8 of the NER states the reactive power reserve margin that must be maintained at each connection point to ensure sufficient voltage support in the event of a severe network disturbance. This clause allows ElectraNet the discretion to select the appropriate margin at each connection point, provided that the margin (expressed in capacitive reactive power (Mvar)) is at least 1% of the maximum fault level (in MVA) at the connection point.

ElectraNet has identified that from summer 2015/16 an outage of the existing Bungama transformer results in a reactive power margin that is less than 1% of the maximum fault level at both the Bungama and Port Pirie connections points.

### **3.3 Assumptions made in relation to the identified need**

The following sections describe the assumptions underpinning ElectraNet's assessment of the identified need. As part of the network studies undertaken to identify the forecast voltage limitations and inadequate reactive power margins in the Mid North, assumptions were made regarding:

- the committed and anticipated Mid North network augmentation projects, as set out in section 2.2;
- characteristics of the load profile in the Mid North region;
- forecast load growth for the region; and
- the likely operation of generation in the region at peak load times.

#### **3.3.1 Characteristics of the load profile**

The Mid North of South Australia contains a mixture of electrical loads including agriculture, grazing, aquaculture and viticulture loads. Commercial loads also comprise a significant portion of total load at the major centres of Port Pirie, Kadina, Port Wakefield, Clare and on the Yorke Peninsula and in the Barossa Valley.

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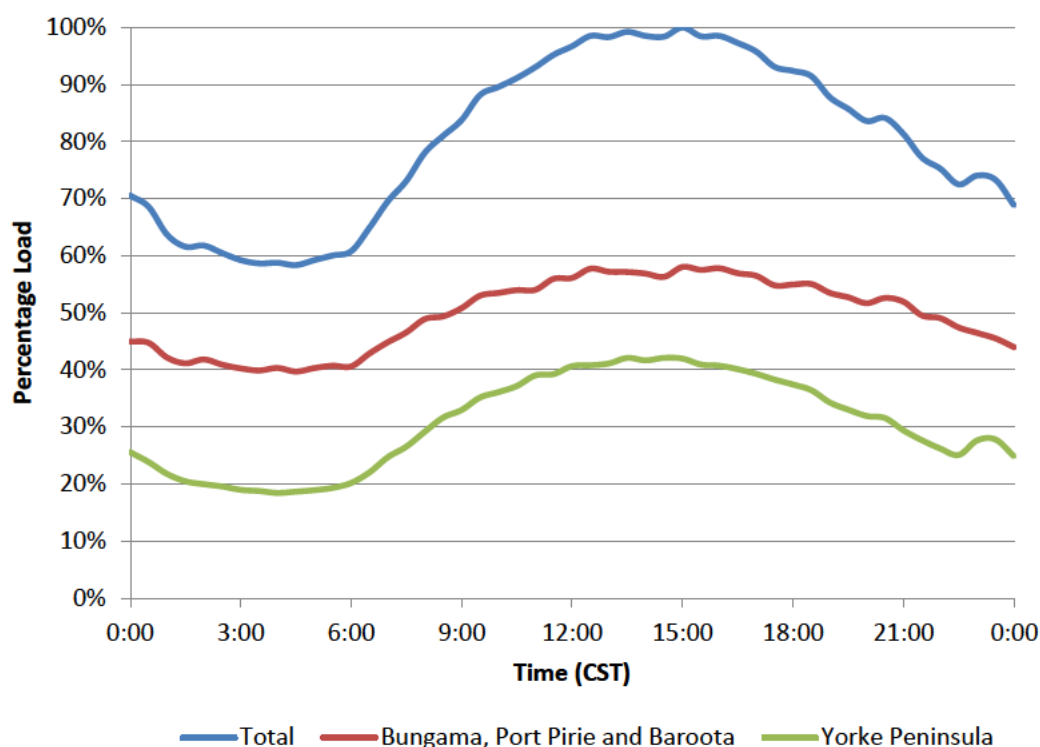
<sup>8</sup> 'Satisfactory operating state' is a defined term in the NER.

Figure 2 shows the typical daily load profile on the day of peak demand for relevant connection points that impact the forecast voltage limitations and inadequate reactive power margins in the Mid North.

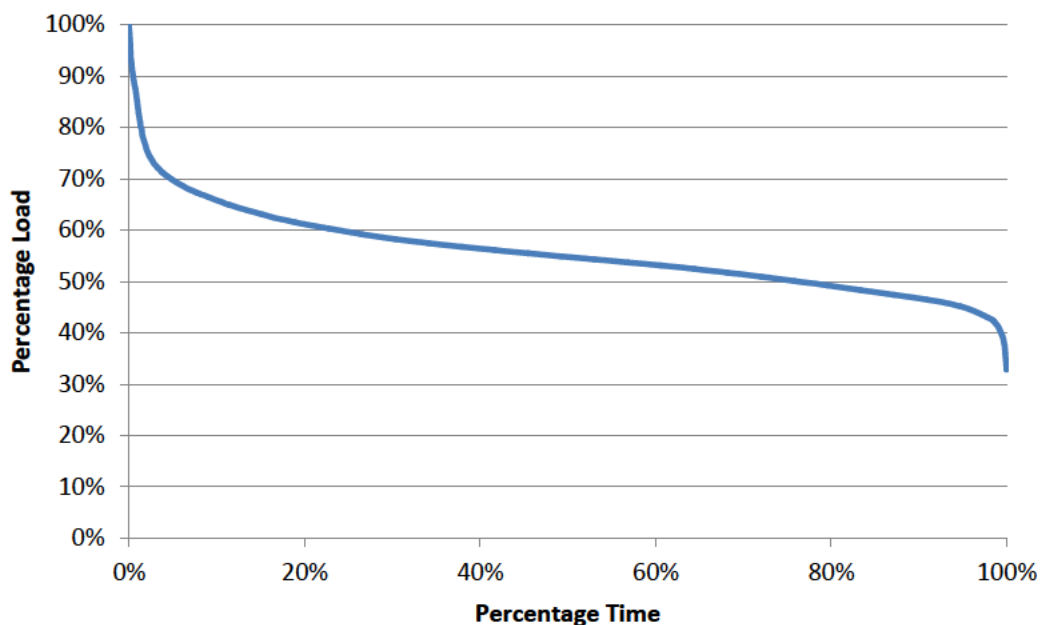
Figure 3 shows the load duration curve for the same Mid North connection points for the 2008/09 peak load year.

The size of loads and the dispatch and operation of generation connected to the Mid North 132 kV transmission network at connection points as far north as Baroota and as far south as Dalrymple can significantly affect post-contingent voltage levels and reactive power margins at Bungama, Baroota and Port Pirie. For this reason, in addition to loads at connection points forecast to breach voltage limitations and/or reactive power margins (Bungama, Baroota and Port Pirie), loads connected to Yorke Peninsula connection points (Kadina East, Hummocks, Ardrossan West and Dalrymple) must also be considered.

**Figure 2: Daily peak load profile for Bungama, Port Pirie, Baroota and Yorke Peninsula (30 January 2009)**



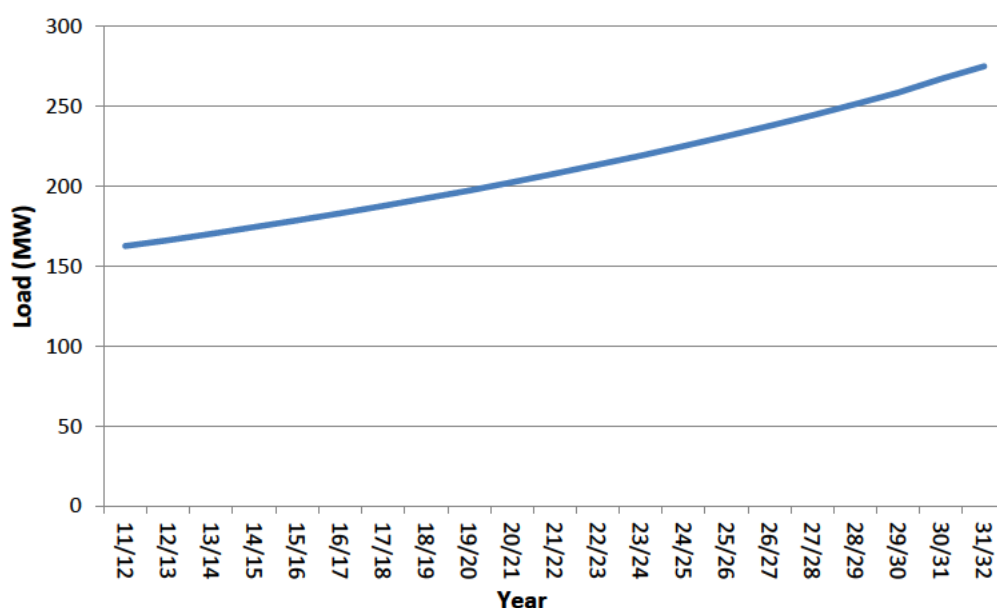
**Figure 3: Load duration curve for Bungama, Port Pirie, Baroota and Yorke Peninsula (2008/09)**



### 3.3.2 Forecast load growth

Figure 4 shows the combined 2012 ETSA Utilities' medium load forecast for underlying load growth for the Mid North connection points relevant to the identified need. The load forecasts for the individual connection points are provided in Appendix C. There are no directly connected customers at these connection points.

**Figure 4: Forecast medium load growth for Bungama, Port Pirie, Baroota and Yorke Peninsula**



According to the ETSA Utilities' medium demand forecast, the combined average load growth rate across the Bungama, Port Pirie, Baroota and connection points on the Yorke Peninsula over the next 20 years is 2.7% per year.

As highlighted within ElectraNet's 2012 Annual Planning Report, ElectraNet is also aware of a potential new mining load connection on the Yorke Peninsula, the indicative size of which is 67 MW<sup>9</sup>. Given that this mining development is in a pre-feasibility stage, ElectraNet has not included this potential new mining load in its network studies for the purposes of this PSCR. However, a firm commitment by this mining load may affect both the timing of forecast network limitations and the required technical characteristics of non-network solutions discussed in section 3.4. If required, ElectraNet may revise information, including forecast load growth, forecast network limitations and non-network requirements, to reflect the commitment of a new mining load in the period prior to the publication of the Project Assessment Draft Report (PADR).

### 3.3.3 Assumptions on generation operation

In relation to the availability of local generation, the network studies were based on the following assumptions:

- Local generation in the Mid North region connected at 132 kV or lower is unavailable and, therefore, reactive power support from these generators is also unavailable.
- Given that network performance at times of peak demand typically relies on the dispatch of conventional, fossil fuel driven generation with coincident low contribution by wind generation, wind farms connected to the 275 kV Main Grid are assumed to generate at 5%<sup>10</sup> of installed capacity (at summer peak) and reactive power support from these generators is available.

## 3.4 Required technical characteristics of non-network options

This section describes the technical characteristics that a non-network option would be required to deliver in order to address the identified need<sup>11</sup>.

As outlined in section 3.1, the identified need is for reliability corrective action from summer 2015/16, in order to prevent loss of the Bungama transformer resulting in voltages at the Bungama, Port Pirie and Baroota connection points falling below the minimum requirement specified in ElectraNet's TCA with ETSA Utilities and reactive power margins at Bungama and Port Pirie connection points falling below the minimum requirement specified in the NER. To meet the identified need and satisfy NER requirements, non-network options, either individually or collectively, must be capable of maintaining adequate voltages at Bungama, Port Pirie and Baroota connection points and adequate reactive power margins at

<sup>9</sup> 2012 ElectraNet Annual Planning Report, section 2.2.

<sup>10</sup> Sourced from AEMO, 2011 South Australian Supply and Demand Outlook.

<sup>11</sup> In accordance with NER clause 5.6.6(c)(3).

Bungama and Port Pirie connection points following an outage of the Bungama transformer from summer 2015/16.

### 3.4.1 Size of required load reduction or additional supply

Table 2 provides an indication of the pre-contingent non-network requirement (in MW) to be supplied in each year by new generation or to be reduced by demand side management (DSM) at either the Bungama, Baroota or Port Pirie connection points in order to meet the identified need discussed in section 3.1.

The optimal location for additional supply or load reduction is Port Pirie. In addition to being the major load centre in the area, Port Pirie is the optimal location since load reduction or additional supply at this connection point will reduce transmission and distribution losses between Bungama and Port Pirie<sup>12</sup>. The MW quantity required at Port Pirie by summer 2015/16 (the time at which the forecast voltage limitations and inadequate reactive power margins emerge) is 8 MW. The MW amounts required at either Bungama or Baroota would be greater than this, as shown in Table 2.

**Table 2 Forecast non-network requirements (MW)**

Year	Port Pirie	Bungama	Baroota
2015/16	8	11	11
2016/17	9	11	12
2017/18	13	17	28
2018/19	17	22	n/a*
2019/20	26	34	n/a*
2020/21	0	0	0
2021/22	0	0	0
2022/23	0	0	0

\* A non-network solution at Baroota is unable to resolve forecast inadequate reactive power margins in 2018/19 and 2019/2010.

In order to meet the identified need, this MW quantity would need to be provided by local generators or DSM or a combination of both. When the MW quantities in Table 2 are compared with the medium load forecasts for individual connection points in Appendix C, ElectraNet notes that in some cases the required MW quantity exceeds the forecast load at that connection point.

The forecast annual non-network requirements provided in Table 2 assume load growth consistent with ETSA Utilities' medium load forecast for Mid North connection points and the committed and anticipated network projects

<sup>12</sup> The reduction in losses is a market benefit which ElectraNet would take into account as part of the RIT-T analysis of any proposed non-network option.

discussed in section 2.2<sup>13</sup>. Table 2 also assumes completion of the proposed network reinforcement of the Yorke Peninsula by summer 2020/21<sup>14</sup>. Whilst this network reinforcement is being driven by a different need, it will also resolve forecast voltage limitations and inadequate reactive power margins at Bungama, Baroota and Port Pirie connection points, once completed.

### 3.4.2 Location of required load reduction or additional supply

The MW quantities shown in Table 2 provide an indication of the extent of the non-network requirements at any of the three connection points with forecast voltage limitations and/or inadequate reactive power margins. The table highlights the quantity that would be required at any one of those locations. In addition, it would be possible for a non-network option to be spread over more than one of these locations.

Load reduction or additional supply at any of the connection points on the Yorke Peninsula (ie Hummocks, Kadina East, Ardrossan West and Dalrymple) could also resolve the forecast voltage limitations and inadequate reactive power margins in the Mid North.

To provide an indication of the non-network requirement elsewhere in the Mid North, Table 3 shows the MW quantity that would be required at one of the connection points in the Yorke Peninsula, relative to 1 MW provided at Port Pirie.

**Table 3 Non-network requirement relative to 1 MW at Port Pirie**

Connection Point	Relative requirement (MW)
Kadina East	1.9
Hummocks	2
Ardrossan West	1.9
Dalrymple	1.8

### 3.4.3 Required support from existing generation

As stated within section 3.3.3, network studies performed by ElectraNet have assumed that local generation in the Mid North region connected at 132 kV or lower is unavailable and, therefore, reactive power support from these generators is also unavailable. However, the provision of reactive power support by one or more existing generators may resolve the post-contingent voltage limitations and inadequate reactive power margins forecast in the Mid North.

Network studies have also shown that although generation support from Angaston power station will not resolve the forecast network limitations, generation support from the Mintaro OCGT can resolve the forecast network limitations in certain years.

<sup>13</sup> For a summary of proposed Mid North network augmentation projects, see Table 9.6 of ElectraNet's 2012 Annual Planning Report.

<sup>14</sup> This augmentation will be subject to a separate RIT-T consultation process.



The provision of reactive support by wind generators and/or generation support by the Mintaro OCGT is an alternative solution to the potential additional supply and DSM solutions described in sections 3.4.1 and 3.4.2. However, it is also possible for a combination of reactive power support, generation support, additional supply and DSM to resolve the forecast limitations.

Table 4 indicates which of the existing generators connected to the 132 kV network are able to resolve the forecast network limitations and the quantity of reactive power support (in Mvar) or generator support (in MW) required by each generator. The table assumes that if reactive power support is provided by a wind farm, all dynamic reactive plant is in service with full range available. For wind farms capable of resolving the forecast network limitations, the quantity of reactive power support provided in the table is the minimum Mvar quantity of switched capacitance required. If generator support is provided by the Mintaro OCGT, the MW quantity provided in the table is the minimum quantity of pre-contingent generation required.

**Table 4 Required reactive power support (in Mvar) or generation support (in MW) from existing generation**

Year	Generators capable of resolving forecast network limitations
2015/16	Snowtown (0 Mvar) or Clements Gap (8 Mvar) or Waterloo (48 Mvar) or Mintaro (25 MW)
2016/17	Snowtown (18 Mvar) or Mintaro (70 MW)
2017/18	Snowtown (18 Mvar)
2018/19	Snowtown (27 Mvar)
2019/20	Snowtown (45 Mvar)

For example, Table 4 shows that in order to resolve the network limitations forecast by 2015/16, one of the following is required:

- the dynamic plant of the Snowtown Wind Farm is in service;
- the dynamic plant of the Clements Gap Wind Farm is in service and a minimum of 8 Mvar of switched capacitance provided;
- the dynamic plant of the Waterloo Wind Farm is in service and a minimum of 48 Mvar of switched capacitance provided; or
- minimum pre-contingent generation at Mintaro OCGT is 25 MW.

Wattle Point Wind Farm is unable to individually resolve the forecast network limitations in any year. It is possible that support from a combination of generators may also resolve the forecast network limitations but Table 4 does not identify every possible combination. As discussed in section 3.4.1, Table 4 assumes completion of the proposed network



reinforcement of the Yorke Peninsula by summer 2020/21, which would resolve the forecast network limitations.

#### 3.4.4 Required operating profile of non-network options

Table 5 sets out the operating profile<sup>15</sup> that non-network options would be expected to meet. The table indicates the maximum number of days per year, hours per day and times of day that the MW quantities provided in Table 2 and the Mvar and MW quantities provided in Table 4 are forecast to be required during peak load conditions. As with previous tables, Table 5 assumes completion of the proposed network reinforcement of the Yorke Peninsula by summer 2020/21, which would resolve the forecast network limitations.

**Table 5 Required operating profile for non-network options**

Year	Maximum number of days per year	Maximum number of continuous hours per day	Times of day network support services must be available (CST)
2015/16	3	4	11am to 5pm
2016/17	3	4	11am to 5pm
2017/18	4	6	10.30am to 6pm
2018/19	5	6	10am to 6pm
2019/20	7	9	9am to 7pm

The typical calendar period during which network support services must be available is 1 November to 1 April.

Generation and DSM solutions must reduce power flows on the constrained network to prevent widespread supply interruptions following a critical network outage. Depending on the situation and the operating characteristics of the local generator, this is likely to require pre-contingent operation. DSM solutions must either reduce load pre-contingent or disconnect sufficient customer demand within an acceptable time frame following a contingency.

ElectraNet notes that proposed non-network services must be capable of reliably meeting electricity demand under a range of conditions and, if a generator, must meet all relevant NER requirements related to grid connection.

ElectraNet has obligations under the National Electricity Rules, South Australian Electricity Transmission Code (ETC)<sup>16</sup> and connection agreements to ensure supply reliability is maintained to its customers. Failure to meet these obligations may give rise to liability.

<sup>15</sup> NER 5.6.6(c)(3)(iii).

<sup>16</sup> The Electricity Transmission Code is available at: <http://www.escosa.sa.gov.au/electricity-overview/codes-guidelines-rules/electricity-codes.aspx#T45>.

If the proponent of a proposed non-network service wishes to provide network support services to ElectraNet as part of meeting ElectraNet's reliability obligations, it must also be willing to accept any liability that may arise from its contribution to a reliability of supply failure.

### **3.5 Requirement to apply the RIT-T**

ElectraNet is required to apply the RIT-T to this investment, as none of the exemptions listed in NER clause 5.6.5C(a) apply.

ElectraNet has classified this project as a reliability corrective action because the existing network will not be able to provide the required level of reliability under schedule 5.1 of the NER at Bungama, Port Pirie and Baroota connection points by summer 2015/16.

The network options discussed in section 4.1 have not been foreshadowed in AEMO's 2011 National Transmission Network Development Plan as these options do not play a part in the main transmission flow paths between the NEM regions.

## 4. Potential credible options to address the identified need

This section sets out the credible options currently considered to be capable of addressing the identified need described in section 3.1<sup>17</sup>. All of the credible options are expected to be both technically and commercially feasible. Further, all options are able to be implemented in sufficient time to meet the identified need<sup>18</sup>.

### 4.1 Network options

The two credible network options discussed below relate to the maintenance of adequate voltages and reactive power margins at Bungama, Port Pirie and/or Baroota connection points. Both options address the forecast low short-term post-contingent connection point voltage levels and inadequate reactive power margins due to the loss of the existing 275/132 kV Bungama transformer.

#### 4.1.1 Option 1: Install a 30 Mvar 132 kV capacitor bank at Bungama

The proposed scope of work at Bungama substation under option 1 includes:

- installation of a 30 Mvar 132 kV capacitor bank directly connected to a short extension of the East 132 kV bus; and
- extension of the existing bench to accommodate the capacitor bank.

Figure 5 presents an electrical representation of the Bungama substation after installation of a 132 kV capacitor bank. Augmented network assets included within the scope of option 1 are shown using solid red lines and the potential ultimate substation arrangement is shown using dashed red lines. The positioning of the capacitor bank is indicative only and should allow for the future connection of a second 275/132 kV transformer and two additional 132 kV line exits to Port Pirie and Baroota (shown in dashed red lines).

The total indicative capital cost (in 2015/16 dollars) of option 1 is \$4.8 million. Annual operating and maintenance costs are estimated to be around 1.5% of the capital cost.

The estimated construction timetable is around 6 months, with commissioning prior to summer 2015/16.

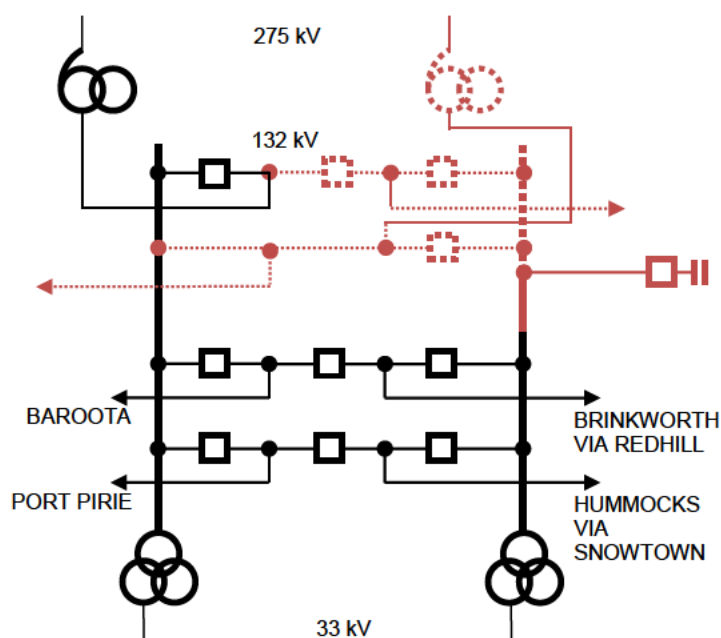
Option 1 will address the identified need in the short-term, from 2015/16. However, it is likely that further reliability corrective action, such as the installation of a second 275/132 kV transformer at Bungama, will be required in order to address forecast voltage limitations and inadequate reactive power margins in the longer term. The requirement for a second

<sup>17</sup> As required by NER clause 5.6.6(c)(5).

<sup>18</sup> In accordance with the requirements of NER clause 5.6.5D(a).

transformer will depend on, among other things, the timing and extent of the proposed network reinforcement of the Yorke Peninsula<sup>19</sup>.

**Figure 5: Bungama substation configuration under option 1**



#### 4.1.2 Option 2: Install a second 275/132 kV transformer at Bungama

The proposed scope of work at Bungama substation under option 2 includes:

- installation of a second 275/132 kV transformer directly connected to a short extension (over a future roadway) of the East 132 kV bus; and
- installation of 275 kV and 132 kV circuit breakers.

Figure 6 presents an electrical representation of the 275/132 kV substation configuration at Bungama after installation of a second 275/132 kV transformer. The augmented network assets are again shown in solid red lines. The positioning of these assets is indicative only and may be adjusted if required.

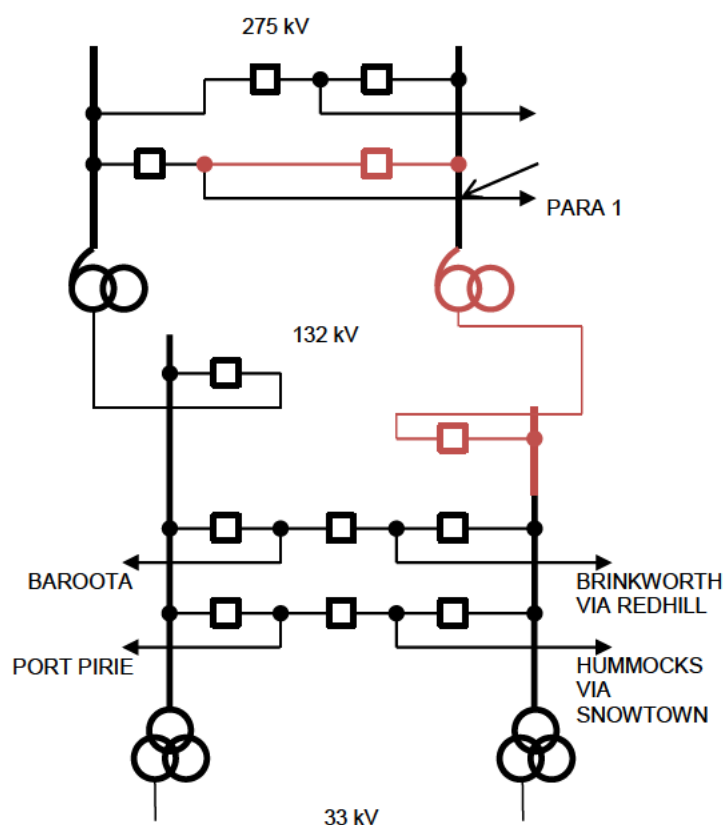
The total indicative capital cost (in 2015/16 dollars) of option 2 is \$9.4 million. Annual operating and maintenance costs are estimated to be around 1.5% of the capital cost.

The estimated construction timetable is around 12 months, with commissioning prior to summer 2015/16.

<sup>19</sup> Network reinforcement of the Yorke Peninsula was identified as a proposed Mid North augmentation project within Table 9.6 of ElectraNet's 2012 Annual Planning Report.

Option 2 will address the identified need in the longer term, irrespective of the timing and extent of the proposed network reinforcement of the Yorke Peninsula.

**Figure 6: Bungama substation configuration under option 2**



#### 4.1.3 Options considered but not progressed

This section discusses additional options which ElectraNet has considered but does not consider are technically and/or commercially feasible, and therefore which are not currently considered to be credible options.

Installation of a second 132/33 kV transformer at Port Pirie substation was investigated as a potential solution to the forecast voltage limitations and inadequate reactive power margins at Bungama, Port Pirie and/or Baroota connection points. Network studies showed that although a second Port Pirie transformer did resolve inadequate voltages at Port Pirie connection point, voltages at Bungama and Baroota connection points remained inadequate from summer 2015/16. This option is therefore not technically feasible.

As noted earlier, ElectraNet has proposed network reinforcement of the Yorke Peninsula by summer 2020/21. This reinforcement is driven by the need to address post-contingent thermal overload of 132 kV lines supplying the Yorke Peninsula, and to accommodate potential new mining loads. However, this augmentation will also resolve forecast voltage limitations and inadequate reactive power margins at Bungama, Baroota and Port Pirie connection points, once it is in place. One option would therefore be to bring

forward the timing of this augmentation to summer 2015/16 in order to resolve the forecast network limitations. However, the likely cost of this augmentation means that the cost of bringing the timing forward would be substantially above the cost of the two credible network options discussed above. ElectraNet does not therefore consider this option commercially feasible.

Table 9.3 of ElectraNet's 2012 APR<sup>20</sup> also identified an option to install multiple capacitors at Bungama and Port Pirie substations in order to resolve post-contingent voltage limitations forecast at Bungama, Port Pirie and Baroota connection points. However, recent network studies subsequent to the publication of the APR have shown that a single capacitor at Bungama (ie network option 1 presented in section 4.1.1) is sufficient to resolve the forecast network limitations.

ElectraNet also considered a distribution network solution to the forecast network limitations. However, network studies show that installation of a total of 30 Mvar of capacitor banks on ETSA Utilities' 33 kV distribution network would over-compensate the power factor of the Bungama – Port Pirie meshed connection point resulting in a leading power factor, even at peak load times. In addition, switching studies indicate that the amount of capacitance required would not be able to be switched in a single step, and as a result, this option is not technically feasible.

## **4.2 Non-network options**

Section 3.4 sets out the required technical characteristics that a non-network option would be required to deliver in order to meet the identified need described in section 3.1

No specific non-network options have been identified by ElectraNet at this stage. ElectraNet is seeking responses from potential proponents of non-network options to this PSCR.

Non-network solutions must meet an equivalent reliability standard to that required of ElectraNet under the NER, ETC and connection agreements. Consequently, non-network proponents must be willing to accept any liability that may arise from its contribution to a reliability supply failure.

## **4.3 Material inter-regional impact**

In accordance with NER clause 5.6.6(c)(6)(ii), ElectraNet has considered whether any of the credible options above are expected to have a material interregional impact. ElectraNet considers this to be the same as a material inter-network impact, which is defined in the NER as:

“A material impact on another Transmission Network Service Provider's network, which may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network.”

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<sup>20</sup> 2012 ElectraNet Annual Planning Report, Table 9.3, option 2.

AEMO currently defines the criteria for material inter-network impact. AEMO's suggested screening test for whether or not a transmission augmentation has a material inter-network impact is that it satisfies the following:<sup>21</sup>

- A decrease in power transfer capability between the transmission networks or in another TNSP's network of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW;
- An increase in power transfer capability between transmission networks of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW;
- An increase in fault level by less than 10 MVA at any substation in another TNSP's network; and
- The investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

ElectraNet notes that none of the credible options set out in this PSCR involve either a series capacitor or modification in the vicinity of an existing series capacitor. Neither are any of the credible options discussed above expected to result in change in power transfer capability between South Australia and neighbouring transmission networks. In addition fault levels are not expected to increase by more than 10 MVA at any substation in another TNSP's network.

As a consequence, by reference to AEMO's screening criteria, there are no material inter-network impacts associated with any of the credible options.

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<sup>21</sup> The screening test is set out in Appendix 3 of the *IRPC's Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentations, Version 1.3*, October 2004.



## 5. Materiality of market benefits for this RIT-T assessment

The NER require that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option<sup>22</sup>.

Under NER clause 5.6.6(c)(6)(iii), the PSCR should set out the classes of market benefit that the TNSP considers are not likely to be material for a particular RIT-T assessment.

### 5.1 Market benefits relating to the wholesale market

The AER has recognised that if the proposed investment will not have an impact on the wholesale market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated<sup>23</sup>.

The credible network options described in section 4.1 do not address network constraints between competing generating centres and are therefore not considered to result in any change in dispatch outcomes and wholesale market prices.

Therefore, ElectraNet considers that the following classes of market benefits are not material for this RIT-T assessment for any of the credible network options:

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);
- changes in costs for parties, other than for ElectraNet (since there will be no deferral of generation investment);
- changes in ancillary services costs;
- competition benefits; and
- Renewable Energy Target (RET) penalties.

ElectraNet notes that credible non-network solutions proposed to meet the identified need may potentially impact the wholesale market. If ElectraNet considers that a proposed non-network solution identified during the consultation period will impact the wholesale market, the materiality of all of the above classes of market benefits associated with that option will be assessed. As a result of that assessment, where any of these classes of market benefit are considered to be material, they will be quantified as part of the RIT-T assessment.

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<sup>22</sup> NER clause 5.6.5B(c)(6).

<sup>23</sup> AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, June 2010, version 1, page 15.



## 5.2 Other classes of market benefits

In addition to the classes of market benefits listed above, NER clause 5.6.5B(c)(4) requires ElectraNet to consider the following classes of market benefits in relation to each credible option:

- differences in the timing of transmission investment;
- option value;
- changes in network losses; and
- changes in involuntary load shedding.

Of these four classes of market benefits, ElectraNet considers that differences in the timing of transmission investment and option value are not material classes of market benefits for this RIT-T assessment, for the reasons set out below. ElectraNet does currently anticipate quantifying the change in network losses and changes in involuntary load shedding as part of this RIT-T. ElectraNet does not consider that there are any other classes of market benefits which would be material for the purposes of this RIT-T assessment.

ElectraNet notes that since this investment is a reliability corrective action, quantification of the market benefit associated with changes in involuntary load shedding will only apply in so far as the market benefit delivered exceeds the minimum standard required for reliability corrective action<sup>24</sup>.

### 5.2.1 Differences in the timing of transmission investment

ElectraNet considers that none of the credible options discussed in section 4.1 will affect the timing of other unrelated transmission investments (ie transmission investments based on a need that falls outside the scope of that described in section 3.1.) Consequently, ElectraNet considers that market benefits associated with differences in the timing of unrelated transmission investment are not material to the credible options subject to this RIT-T assessment.

### 5.2.2 Option value

ElectraNet notes the AER's view that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered by the TNSP are sufficiently flexible to respond to that change.<sup>25</sup>

ElectraNet also notes the AER's view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T.

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<sup>24</sup> AER, Regulatory Investment Test for Transmission, June 2010, clause (9).

<sup>25</sup> AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, June 2010, version 1, pages 39 and 75.

For this RIT-T assessment, the estimation of any option value benefit over and above that already captured via the scenario analysis in the RIT-T would require a significant modelling assessment, which would be disproportionate to any additional option value benefit that may be identified for this specific RIT-T assessment. ElectraNet does not therefore propose to estimate any additional option value market benefit for this RIT-T assessment.



# Managing voltages on the Mid North transmission system

Appendices

August 2012



## Appendix A Definitions

Applicable regulatory instruments	All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the Rules) which apply to Registered Participants from time to time, including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms and conditions relating to access to a network, connection to a network, the provision of network services, network service price or augmentation of a network.
AEMO	Australian Energy Market Operator
Base case	A situation in which no option is implemented by, on behalf of the transmission network service provider.
Commercially feasible	<p>An option is commercially feasible under clause 5.6.5D(a)(2) of the Electricity Rules if a reasonable and objective operator, acting rationally in accordance with the requirements of the RIT-T, would be prepared to develop or provide the option in isolation of any substitute options<sup>26</sup>.</p> <p>This is taken to be synonymous with ‘economically feasible’.</p>
Costs	Costs are the present value of the direct costs of a credible option.
Credible option	<p>A credible option is an option (or group of options) that:<sup>27</sup></p> <ul style="list-style-type: none"><li>(1) address the identified need;</li><li>(2) is (or are) commercially and technically feasible; and</li><li>(3) can be implemented in sufficient time to meet the identified need.</li></ul>
Economically feasible	<p>An option is likely to be economically feasible where its estimated costs are comparable to other credible options which address the identified need. One important exception to this general guidance applies where it is expected that a credible option or options are likely to deliver materially higher market benefits. In these circumstances the option may be “economically feasible” despite the higher expected cost.<sup>28</sup></p> <p>This is taken to be synonymous with ‘commercially feasible’.</p>
Identified need	The reason why the Transmission Network Service Provider proposes that a particular investment be undertaken in respect of its transmission network. <sup>29</sup>

<sup>26</sup> AER, *Final Regulatory Investment Test for Transmission Guidelines*, June 2010, version 1, page 10.

<sup>27</sup> NER clause 5.6.5D(a).

<sup>28</sup> AER, *Final Regulatory Investment Test for Transmission Guidelines*, June 2010, version 1, page 6.

<sup>29</sup> NER, Glossary.

Market benefit	<p>Market benefit must be:<sup>30</sup></p> <p>(a) the present value of the benefits of a credible option calculated by:</p> <p>(ii) comparing, for each relevant reasonable scenario:</p> <p>(A) the state of the world with the credible option in place to</p> <p>(B) the state of the world in the base case,</p> <p>And</p> <p>(ii) weighting the benefits derived in sub-paragraph (i) by the probability of each relevant reasonable scenario occurring.</p> <p>(b) a benefit to those who consume, produce and transport electricity in the market, that is, the change in producer plus consumer surplus.</p>
Net economic benefit	Net economic benefit equals the market benefit less costs. <sup>31</sup>
Preferred option	The preferred option is the credible option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market compared to all other credible options. Where the identified need is for reliability corrective action, a preferred option may have a negative net economic benefit (that is, a net economic cost). <sup>32</sup>
Reasonable scenario	Reasonable scenario means a set of variables or parameters that are not expected to change across each of the credible options or the base case. <sup>33</sup>
Reliability corrective action	Investment by a Transmission Network Service Provider in respect of its transmission network for the purpose of meeting the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network or non-network options. <sup>34</sup>
State of the world	State of the world means a reasonable and mutually consistent description of all of the relevant market supply and demand characteristics and conditions that may affect the calculation of <i>market benefits</i> over the period of the assessments. <sup>35</sup>

<sup>30</sup> AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph (4), page 3.

<sup>31</sup> AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph (1), page 1.

<sup>32</sup> NER 5.6.5B(b); and AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph (1), page 1.

<sup>33</sup> AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 15, page 6.

<sup>34</sup> NER, Glossary.

<sup>35</sup> AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 17, page 7.

## Appendix B Checklist of Compliance Clauses

This section sets out a compliance checklist which demonstrates the compliance of the RIT-T with the requirements of clauses 5.6.6(c) of the NER version 51.

NER clause	Summary of Requirements	Section
5.6.6(c)	A <i>Transmission Network Service Provider</i> must prepare a report (the <i>project specification consultation report</i> ), which must include:	Section 3.1
	1. a description of the <i>identified need</i> ;	
	2. the assumptions used in identifying the <i>identified need</i> (including, in the case of proposed <i>reliability corrective action</i> , why the <i>Transmission Network Service Provider</i> considers <i>reliability corrective action</i> is necessary);	Section 3.3
	3. the technical characteristics of the <i>identified need</i> that a non- <i>network</i> option would be required to deliver, such as:	
	(i) the size of <i>load</i> reduction of additional supply;	Section 3.4.1
	(ii) location; and	Section 3.4.2
	(iii) operating profile.	Section 3.4.4
	4. If applicable, reference to any discussion on the description of the <i>identified need</i> or the <i>credible options</i> in respect of that <i>identified need</i> in the most recent <i>National Transmission Network Development Plan</i> ;	N/A
	5. a description of all <i>credible options</i> of which the <i>Transmission Network Service Provider</i> is aware that address the <i>identified need</i> , which may include, without limitation, alternative <i>transmission</i> options, <i>interconnectors</i> , <i>generation</i> , demand side management, <i>market network services</i> or other <i>network</i> options;	Section 4.1 Section 4.2
	6. for each <i>credible option</i> identified in accordance with subparagraph (5), information about:	
	(i) the technical characteristics of the <i>credible option</i> ;	Section 4.1
	(ii) whether the <i>credible option</i> is reasonably likely to have a material <i>inter-regional</i> impact;	Section 4.3
	(iii) the classes of market benefits that the <i>Transmission Network Service Provider</i> considers are likely not to be material in accordance with clause 5.6.5B(c)(6), together with reasons of why the <i>Transmission Network Service Provider</i> considers that these classes of market benefit are not likely to be material;	Section 5.1 Section 5.2
	(iv) the estimated construction timetable and commissioning date; and	Section 4.1
	(v) to the extent practicable, the total indicative capital and operating and maintenance costs.	Section 4.1

## **Appendix C Mid North connection point medium load forecasts (MW)**

<b>Connection Point</b>	<b>2015/16</b>	<b>2016/17</b>	<b>2017/18</b>	<b>2018/19</b>	<b>2019/20</b>	<b>2020/21</b>
Ardrossan West	16.7	17.3	17.8	18.4	19.0	19.7
Baroota	9.7	9.8	10.0	10.2	10.4	10.5
Dalrymple	11.2	11.5	11.9	12.2	12.6	13.0
Hummocks	17.4	18.2	19.1	19.9	20.8	21.8
Kadina East	32.9	34.4	35.9	37.5	39.1	40.9
Port Pirie System*	90.8	91.9	93.1	94.3	95.5	96.8

\* ETSA Utilities' medium load forecast for the Port Pirie System includes Port Pirie and Bungama connection points.