ElectraNet
electricity transmission

South Australian Annual Planning Report 2011

June 2011

Version 1.0

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Executive Summary

ElectraNet produces a South Australian Annual Planning Report which provides information to market participants and other interested parties on the current capacity and emerging limitations of the South Australian electricity transmission network.

South Australia's electricity transmission network is an integral part of the National Electricity Market (NEM) interconnected network. The transmission network is a strategic asset that underpins South Australia's economic development and the prosperity of the broader community. ElectraNet is responsible for planning, developing, operating and maintaining this network to enable the safe and reliable transfer of electrical power from electricity generators to connection points with the distribution network and customers connected directly to the transmission network.

The South Australian Annual Planning Report covers a twenty-year planning period and includes peak demand projections; emerging network limitations or constraints; and information on completed, committed and potential transmission network developments. This information helps potential loads and generators to identify and assess opportunities in the National Electricity Market (NEM) and also assists in the preparation of the National Transmission Network Development Plan (NTNDP) by the Australian Energy Market Operator (AEMO). The NTNDP provides information on the strategic and long-term development of the national transmission system under a range of market development scenarios.

Key Messages

Peak demand is continuing to grow over the outlook period at the vast majority of connection points. However, there were no material changes in the 2011 demand forecasts prepared by ETSA Utilities and direct connect customers compared to published forecasts in the 2010 South Australian Annual Planning Report. This has resulted in relatively minor changes to the timing of emerging network limitations and associated transmission network development plans.

Despite minimal change to the medium economic growth load forecast, ElectraNet is experiencing growing interest on the Eyre Peninsula due to mining exploration activity. Preparatory work has commenced to investigate a variety of options to supply this potential and existing demand.

There is continuing interest in generation development in South Australia and opportunities for connection are outlined in this report.

ElectraNet and AEMO have progressed work on the incremental upgrade of the Heywood interconnector. This work has indicated that an incremental upgrade is able to deliver positive net market benefits over a wide range of market development scenarios, with optimal timing between 2013 and 2017. ElectraNet and AEMO will jointly commence the Regulatory Investment Test – Transmission (RIT-T) in 2011-12.

Furthermore, ElectraNet has identified additional solutions to alleviate some Heywood interconnector import constraints and firm-up the existing interconnector capability available to the market. ElectraNet intends to progress these solutions over the short to medium term.

Transmission Planning Framework, Context and Process

ElectraNet is the principal Transmission Network Service Provider (TNSP) in South Australia and publishes the South Australian Annual Planning Report by 30 June each year under Clause 5.6.2A (a) of the National Electricity Rules (Rules). ElectraNet is also the Jurisdictional Planning Body (JPB) under the Rules.

The South Australian Annual Planning Report includes the outcomes of a joint planning process with ETSA Utilities, the South Australian Distribution Network Service Provider (DNSP), and sets out:

- Forecast loads submitted by ETSA Utilities and direct connect transmission customers;
- Planning proposals for future transmission network connection points;
- Projected network limitations and potential solutions to address those limitations;
- Notice of any proposed network augmentations; and
- Details of proposed replacement transmission network assets.

AEMO publishes the annual South Australian Supply and Demand Outlook (SASDO) in conjunction with this South Australian Annual Planning Report, which is an independent report prepared as part of the advisory functions AEMO provides to the South Australian jurisdiction.

The South Australian Annual Planning Report is a key source of information on the current capacity and emerging limitations of the South Australian transmission network. Generation and demand side proponents, and customers considering investment opportunities are encouraged to review this information. The South Australian Annual Planning Report also includes information on potential opportunities for connection to the network, including current and future transmission network nodes, which would be of particular interest to generation investors.

The South Australian Annual Planning Report also identifies a range of potential solutions to emerging network limitations and indicative costs, based on the quality, security and reliability requirements of the Rules and the South Australian Electricity Transmission Code (ETC). Potential proponents of non-network solutions are invited to propose alternative solutions to address the identified limitations.

Major Projects under Construction

The following major projects have been reported in previous South Australian Annual Planning Reports and are currently under construction:

- Adelaide Central Reinforcement: Establish a new 275/66 kV City West substation (at Keswick Terminal) supplied from Torrens Island via a new underground 275 kV transmission cable to reinforce Adelaide’s electricity supply;
- Kadina East Transformer Capacity Increase: Expand the capacity of the existing substation by installing two 60 MVA 132/33 kV transformers and associated works;
- Mount Barker South Substation: Establish a new Mount Barker South 275/66 kV substation with a single 225 MVA transformer to be run in parallel with the existing 132/66 kV substation at Mount Barker; and

- Templers West Substation - Stage 1: Install a single 160 MVA 275/132 kV transformer connected to the Para to Brinkworth 275 kV circuit via a short new 275 kV double-circuit transmission line, and run directly into the Templers - Dorrien 132 kV transmission line; reconnect the existing Templers 132 kV bus to the Roseworthy transmission line.

Load Forecast, Emerging Limitations and Demand Side Participation

ETSA Utilities and customers connected directly to the transmission network provide load forecasts for their connection points to the transmission network on an annual basis. These forecasts are a key input to the planning and development of the transmission network. Key points of the 2011 load forecast are as follows:

- Peak demand is continuing to grow over the outlook period for the vast majority of connection points. However, there were no material changes in the 2011 ETSA Utilities load forecast compared to 2010. Due to a mild summer, ETSA Utilities did not record a state wide system peak load during 2010-2011 and the 2011 forecast is still based mainly on the 2008-2009 summer peak;

- ETSA Utilities has included 80 MW of additional load on the Eyre Peninsula in the high economic growth load forecast;

- The 2011 load forecast did not result in any significant shift in the timing of demand driven projects, except for a higher Adelaide CBD forecast which brings forward the need for a second East Terrace 275/66 kV transformer to 2016; and

- Significant load increases are forecast for the Olympic Dam mine expansion. ElectraNet is closely monitoring this development due to its potential significant impact on the transmission network.

The information and analysis presented in this South Australian Annual Planning Report is based on reasonably foreseeable future generation and demand scenarios, including the scenarios presented in the 2010 NTNDP. This analysis is intended to provide a robust development plan for investment purposes.

The South Australian Annual Planning Report identifies a wide variety of emerging limitations and proposes potential solutions. The significant emerging limitations across the state are summarised below:

- ETSA Utilities is foreseeing a distribution network limitation on the Fleurieu Peninsula. The nature of this limitation requires a transmission solution or significant embedded generation in the distribution network. A suitable generation solution could defer the timing of a transmission solution by 5-6 years;

- The Eyre Peninsula may require additional generation network support to cope with the forecast load. Should the high economic growth scenario eventuate, or a step load increase occur, a transmission development is most likely to be the most economical solution;

- The 132 kV transmission system supplying the Yorke Peninsula is forecast to become constrained by transmission line thermal ratings by around 2018;

- The 132 kV transmission system supplying the Riverland is forecast to become constrained by transmission line thermal ratings by as early as 2015. However, while the capacity of the Murraylink interconnector is diminishing as the Victorian demand grows, it is anticipated that network developments on the Victorian side of Murraylink may defer the need to extend the 275 kV from Robertstown to Monash by several years. ElectraNet and AEMO intend to undertake a joint analysis in 2011/12;

- Continued residential development in the Northern Metro area will require a capacity increase at the proposed Munno Para connection point substation and potentially another new connection point substation in the 2020s to supply the expanding Adelaide metropolitan area north of Gawler; and

- Growing load in the Adelaide CBD and Southern Metro area increases the future risk of the transmission network being unable to withstand the loss of the radial 275 kV cable supplying the City West substation. Indications are that an alternate 275 kV supply to the City West substation will be required in the mid-2020s.

The South Australian Annual Planning Report includes estimates of the amount of load reduction required to achieve a twelve month deferral of planned augmentations. This information is intended to provide non-network proponents, including demand side proponents, with a guide to the scale of required solutions that could defer the need for network investment.

ElectraNet welcomes proposals for alternative solutions to address identified limitations from potential proponents of non-network solutions.

Generation Connection Outlook

The South Australian Annual Planning Report has been prepared within the broader context of a continuing increase in renewable energy generator connections to the network, particularly wind generation. As Government climate change policy targets and measures such as the enhanced Renewable Energy Target Scheme are strengthened, there is significant potential for further renewable energy generation in the State. This trend is changing the mix and location of generation and has the potential to have a significant impact on the future development of the transmission network.

Studies show that the existing transmission network has the capacity to enable up to approximately 2300 MW of wind generation in South Australia before generation exceeds regional demand and interconnector export capacity. This means that the currently installed wind generation capacity could roughly be doubled. Beyond this, more extensive development of South Australia’s renewable energy resources would require significant transmission investment.

Network Constraints and Transfer Capability

The 2011 South Australian Annual Planning Report provides new information on the top twenty binding constraints on the South Australian transmission network. This information includes commentary on the constraints identified and potential solutions to alleviate them. Potential network augmentations would be required to demonstrate net market benefits under the RIT-T before they can be implemented. Constraints analysis will be expanded in future South Australian Annual Planning Reports to proactively identify market benefit projects that will maximise the transmission network transfer capability available to the market.

Initiatives

During 2010-11, ElectraNet has been actively engaged in the following important initiatives to support the continued development of significant load connections, as well as renewable and other generation investment in South Australia:

- Finalisation of the South Australian Interconnector Feasibility Study, jointly undertaken by ElectraNet and AEMO, to investigate the technical and economic feasibility of a range of transmission development options to increase the interconnector transfer capability between South Australia and other NEM load centres[1];

- Increase of the upper limit on the combined South Australian Heywood and Murraylink Interconnection export capability from 420 MW to 580 MW[2];

- Heywood Interconnector import capability study to investigate the nature of constraints limiting power transfers below the existing nominal capacity of the interconnector. This work has identified potential solutions to alleviate some of these constraints and firm-up the existing interconnector capability available to the market;

- ElectraNet and AEMO have progressed work on the incremental upgrade of the Heywood interconnector. This work has indicated that an incremental upgrade is able to deliver positive net market benefits over a wide range of market development scenarios, with optimal timing between 2013 and 2017. ElectraNet and AEMO will jointly commence a RIT-T process in 2011-12;

- Lower Eyre Peninsula reinforcement study to explore optimal network development to meet demand growth, taking into account potential future development in the area, including step load increases due to mining developments and new wind farm connections;

- Continued joint work with the Resources and Energy Sector Infrastructure Council (RESIC) and the South Australian Chamber of Mines and Energy (SACOME) to develop a future view of South Australia's resources and renewable energy sectors; and

- Further development of a nodal connection approach to maximise the capacity of the existing transmission network for generator connections in a way that increases access and minimises cost to market participants.

Additional information in relation to a number of these initiatives is included in the South Australian Annual Planning Report.

Conclusion

ElectraNet's South Australian Annual Planning Report provides information to market participants and other interested parties on the outlook for the South Australian transmission network in order to assist potential loads and generators to identify and assess opportunities in the market.

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1 Final report published in February 2011 is available at www.electranet.com.au.
2 The limit was increased on 6 January 2011.

The changing context for transmission network planning and the initiatives referred to above will be the subject of increased focus in future South Australian Annual Planning Reports, which will continue to be informed by AEMO's National Transmission Network Development Plan (NTNDP).

Glossary of Terms

Term	Description
A	Ampere (current)
ac	Alternating current
ACR	Adelaide Central Region
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ALS	Aerial Laser Survey
AMD	Agreed Maximum Demand
ANTS	Annual National Transmission Statement
APR	Annual Planning Report
AS	Australian Standard
BHPB	BHP Billiton
BOC	BOC Australia - a member of The Linde Group
CB	Circuit breaker
CBD	Central Business District
CIGRE	International Council on Large Electric Systems
Committed Project	As defined by AEMO in the 2010 NTNDP
CT	Current Transformer
DNSP	Distribution Network Service Provider
dc	Direct current
ESCOSA	Essential Services Commission of South Australia
ESIPC	Electricity Supply Industry Planning Council
ESAA	Electricity Supply Association of Australia
ESOO	Electricity Statement Of Opportunities
ETC	Electricity Transmission Code (South Australia)
GT	Gas Turbine
HVDC	High Voltage Direct Current
Hz	Hertz (cycles per second)
IEC	International Electrotechnical Commission
JPB	Jurisdictional Planning Body
kA	kiloAmperes
KCA	Kimberly-Clark Australia & New Zealand
km	kilometres
kV	kiloVolts
MNSP	Market Network Service Provider

Term	Description
m/s	Metres per second
MVA	Megavolt-ampere
Mvar	Megavolt-ampere reactive
MW	Megawatt
NEL	National Electricity Law
NEM	National Electricity Market
NEX/R	Neutral Earthing Reactor/Resistor
NGM	National Grid Metering
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
NTS	National Transmission Statement
OHEW	Overhead Earth Wire
PASA	Projected Assessment of System Adequacy
POE	Probability of Exceedance
PoW	Point on Wave
QV	Reactive Power-Voltage (relation between)
RDP	Regional Development Plan
RIT-T	Regulatory Investment Test for Transmission
Rules	National Electricity Rules
SASDO	South Australian Supply/Demand Outlook
SCADA	Supervisory Control and Data Acquisition
SENE	Scale Efficient Network Extensions
SVC	Static Var Compensator
SWER	Single Wire Earth Return
TNSP	Transmission Network Service Provider
V	Volt
WF	Wind Farm

1. Introduction

ElectraNet is the principal Transmission Network Service Provider (TNSP) in the South Australian region of the National Electricity Market (NEM). ElectraNet plans, builds, owns, operates and maintains South Australia's high voltage electricity transmission network. ElectraNet is also the Jurisdictional Planning Body (JPB) for South Australia.

ElectraNet, in conjunction with ETSA Utilities, undertakes a review of the capability of its transmission network and regulated connection points to meet forecast electricity demand under a variety of operating scenarios. The outcome of that review is presented in this South Australian Annual Planning Report and provides market information for Registered Participants and other Interested Parties.

Projected limitations in the capability of the network have been identified for the next 20-year planning period and possible solutions to address those limitations are discussed. Interested parties are encouraged to provide input to facilitate identification of the most appropriate solutions to ensure supply reliability and quality can be maintained to customers in the face of continued growth in electricity demand. To assist with the identification of solutions this report includes information for suppliers of demand side and non-network solutions.

Consistent with Rule 5.6 of the National Electricity Rules (Rules), consideration has been given to AEMO's 2010 National Transmission Network Development Plan (NTNDP) and information related to current or potential national transmission flow paths reported in the NTNDP.

1.1 Purpose of the Annual Planning Report

This South Australian Annual Planning Report provides information to Registered Participants in the NEM and other Interested Parties about the South Australian transmission system and the planning for its development. The content of this South Australian Annual Planning Report includes:

- Performance of the existing transmission network;
- Power transfer capability within the transmission system;
- The demand forecast for the next 20-year period;
- Planning proposals for future connection points to the network;
- Actual and potential network constraints;
- Proposed developments to the transmission network;
- Proposed replacement of transmission network assets; and
- Adequacy of the transmission network to enable the transfer of electrical power from generators to consumers.

The detailed requirements for the South Australian Annual Planning Report are set out in Rule 5.6.2 and Rule 5.6.2A. Relevant extracts from these Rules are included in Appendix D.

While every endeavour is made to make the information provided in this South Australian Annual Planning Report as accurate as possible, the planning of the transmission system is subject to uncertainty, including changes to government policies and future NEM outcomes.

Therefore this South Australian Annual Planning Report does not define a single specific future development plan for the South Australian transmission system, but rather is intended to form part of a consultation process aimed at ensuring that the transmission network is efficiently and economically developed to meet forecast electricity demand requirements over the forecast timeframe.

1.2 Scope

The South Australian Annual Planning Report covers the South Australian transmission system as shown in Figure 1.1.

The period covered by this South Australian Annual Planning Report is from 1 July 2011 to 30 June 2031. The first 10 years are covered in more detail including consideration of various market development scenarios, while a higher level of analysis has been undertaken for years 11 - 20 using only a medium economic growth scenario.

1.3 Estimated Costs

All costs included in this document are indicative only unless otherwise stated, and are presented in 2010/11 dollar values.

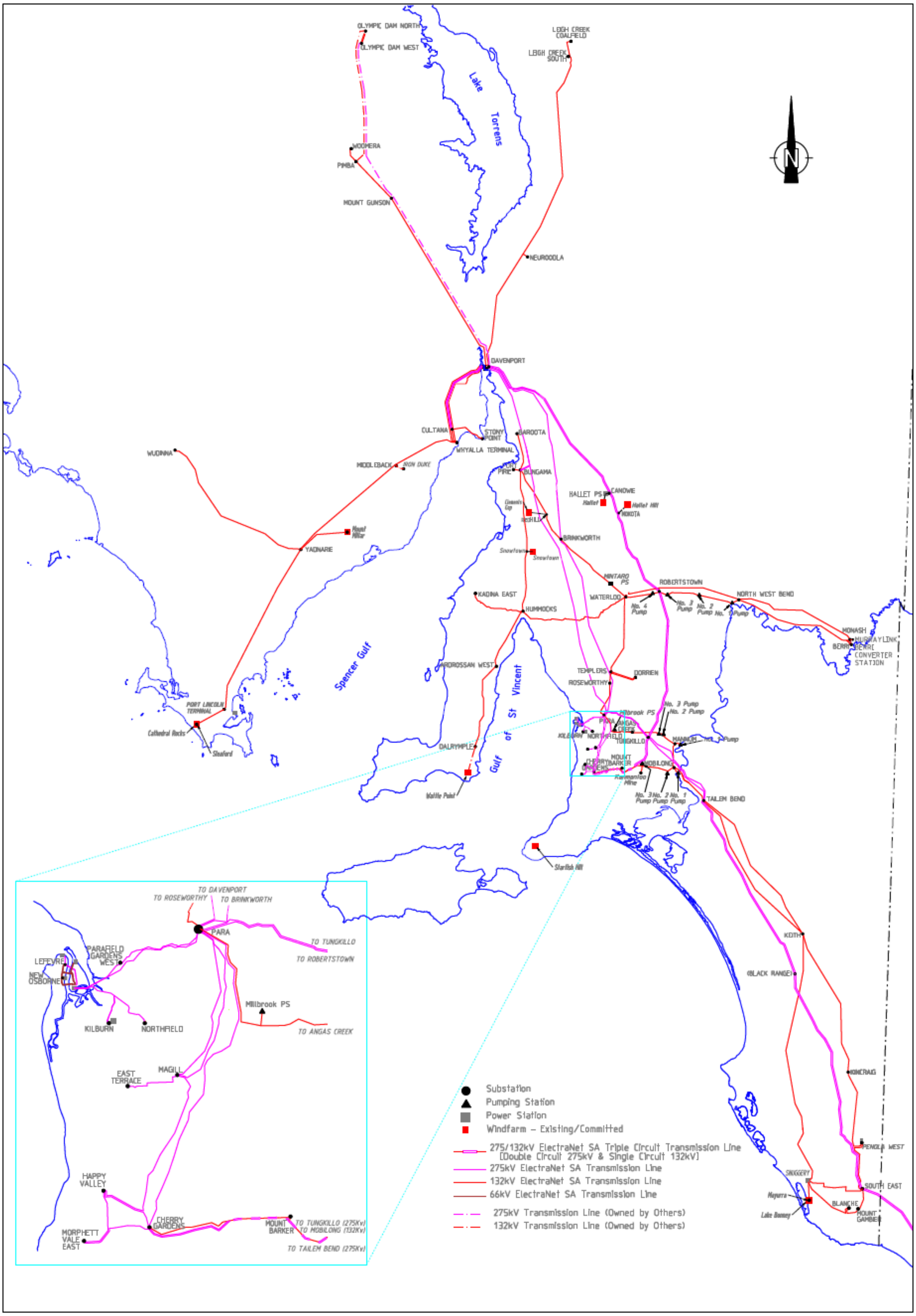


Figure 1.1: Simplified representation of the existing network

1.4 Transmission Planning Framework and Responsibilities

ElectraNet is the principal TNSP in South Australia and is the South Australian JPB under Clause 11.28.2 of the Rules.

Chapter 5 of the Rules deals with a TNSP's obligations with regard to network connection, network planning, and establishing or modifying a connection point, and details the technical obligations that apply to all Registered Participants.

In addition to the Rules, ElectraNet is also required to comply with the South Australian Electricity Transmission Code (ETC), which sets minimum standards for transmission system reliability at each transmission load connection point, in addition to requirements relating to planning, developing and operating the South Australian transmission system. ESCOSA is responsible for the ETC.

ElectraNet's planning and development responsibilities with regard to the South Australian transmission network include:

- Ensuring that the network is planned, designed, constructed, operated and maintained with the safety of the public as the paramount consideration;
- Ensuring that the network is operated with sufficient capability, and augmented if necessary, to provide at a minimum, the stipulated levels of network services to customers;
- Ensuring that its network complies with technical and reliability standards contained in the Rules and jurisdictional instruments such as the ETC;
- Ensure that its network is planned, developed and operated such that there will be no requirements to shed load to achieve the quality and reliability standards imposed by the Rules under normal and foreseeable operating conditions;
- Conducting annual planning reviews with Distribution Network Service Providers (DNSPs) and other TNSPs whose networks are connected to the transmission network; that is, ETSA Utilities, Murraylink, and AEMO;
- Providing information to registered participants and interested parties on projected network limitations and the required timeframes for action; and
- Developing recommendations to address projected network limitations through joint planning with DNSPs and consultation with registered participants and interested parties. Solutions may include network upgrades or non-network options, such as local generation and demand side management initiatives.

ElectraNet also provides advice on network developments which may have material inter-network effects, and participates in inter-regional system tests associated with new or augmented interconnections.

Appendix D provides additional information on the roles of AEMO and ESCOSA and the provisions of the Rules and ETC that are relevant to the development of the South Australian Annual Planning Report.

1.5 Annual Planning Review Context and Assumptions

This section explains the environment within which the annual planning review has been carried out and the drivers that have shaped the outcomes of that planning.

1.5.1 Changing Transmission Planning Environment

Historically, base, intermediate and peaking plant in South Australia was supplemented by import from Victoria via the Heywood and Murraylink interconnectors during peak load periods.

As a result, the South Australian transmission network now consists of a high capacity 275 kV main grid that links base load generation to major load centres (including metropolitan Adelaide), with lower capacity 132 kV regional systems providing supply to small regional loads, as shown in Figure 1.2.

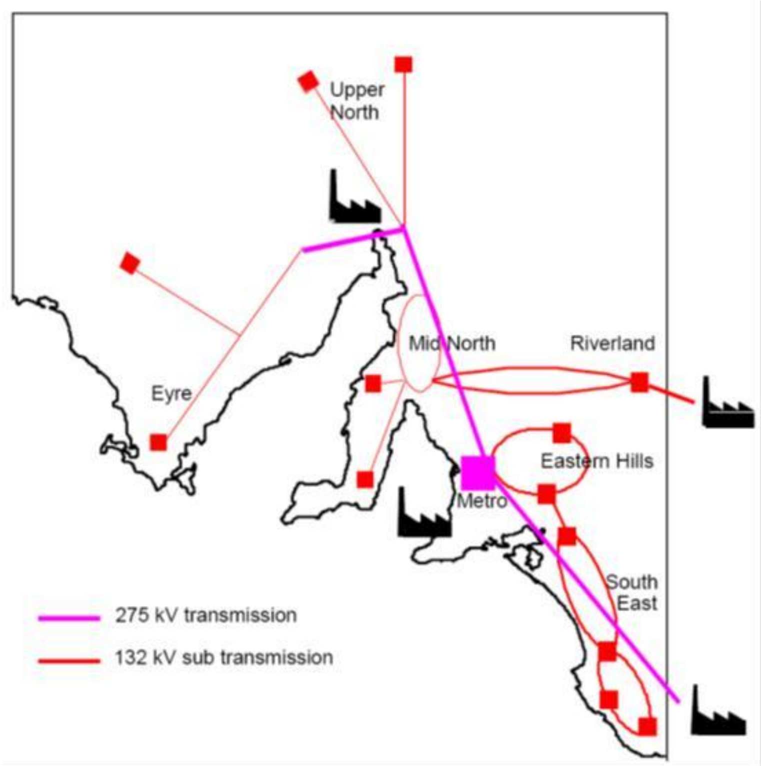


Figure 1.2: Simplified representation of the transmission network

More recently, Government policy responses to climate change have seen an increase in the number of renewable energy generators, particularly wind generators, connecting to the transmission network at various locations throughout South Australia.

As these policy targets are strengthened, there is significant potential for further renewable energy generation expansion, and retirement of existing fossil fuel generation both of which have the potential to have a significant impact on future development of the transmission network.

The key issues relating to the rapid development of significant amounts of renewable generation are that:

- Judicious development of generation network connection nodes is required in order to maximise the existing intra-regional transmission capacity so that new generation connections can be maximised with minimal constraints;
- Inter-regional capacity to export energy from South Australia is limited, potentially restricting flows from existing and additional generation connecting in South Australia. This is particularly noticeable during periods of light load and high wind conditions; and
- Dynamic management of power flows in the transmission network is required due to the variability of some forms of renewable generation (such as wind and solar) and the ability of conventional generation and interconnectors to follow this variability to maintain a reliable supply demand balance.

The retirement of existing fossil fuel generation also has the potential to change the characteristics of the power flows on the transmission system.

1.5.2 ElectraNet's Strategic Network Vision 2035

ElectraNet is currently updating its long-term vision for the transmission network and will again consult with stakeholders during this process. The long-term vision provides direction and guidance for the South Australian Annual Planning Report.

ElectraNet's Network Vision 2035 will set out the objectives and guiding principles for the development of the transmission network based on ElectraNet's understanding of the needs of the South Australian community and the NEM.

ElectraNet undertook an environmental scan in the latter part of 2010 to review and update the alternative futures facing the transmission system.

The key principles of Network Vision 2035 remain the same as those adopted previously. These principles are:

- Managing network development by taking a long-term view;
- Making the best possible use of available technology;
- Using whole of network thinking; and
- Anticipating customer and stakeholder expectations.

ElectraNet will consult with stakeholders on the development of its Network Vision 2035 in the second half of 2011.

ElectraNet welcomes feedback from stakeholders on its approach to planning and development of the transmission network.

1.6 Planning Process

The planning process for developing the 2011 South Australian Annual Planning Report is shown in Figure 1.3. The planning assumptions and criteria used in the annual planning review are set out in Appendix D.

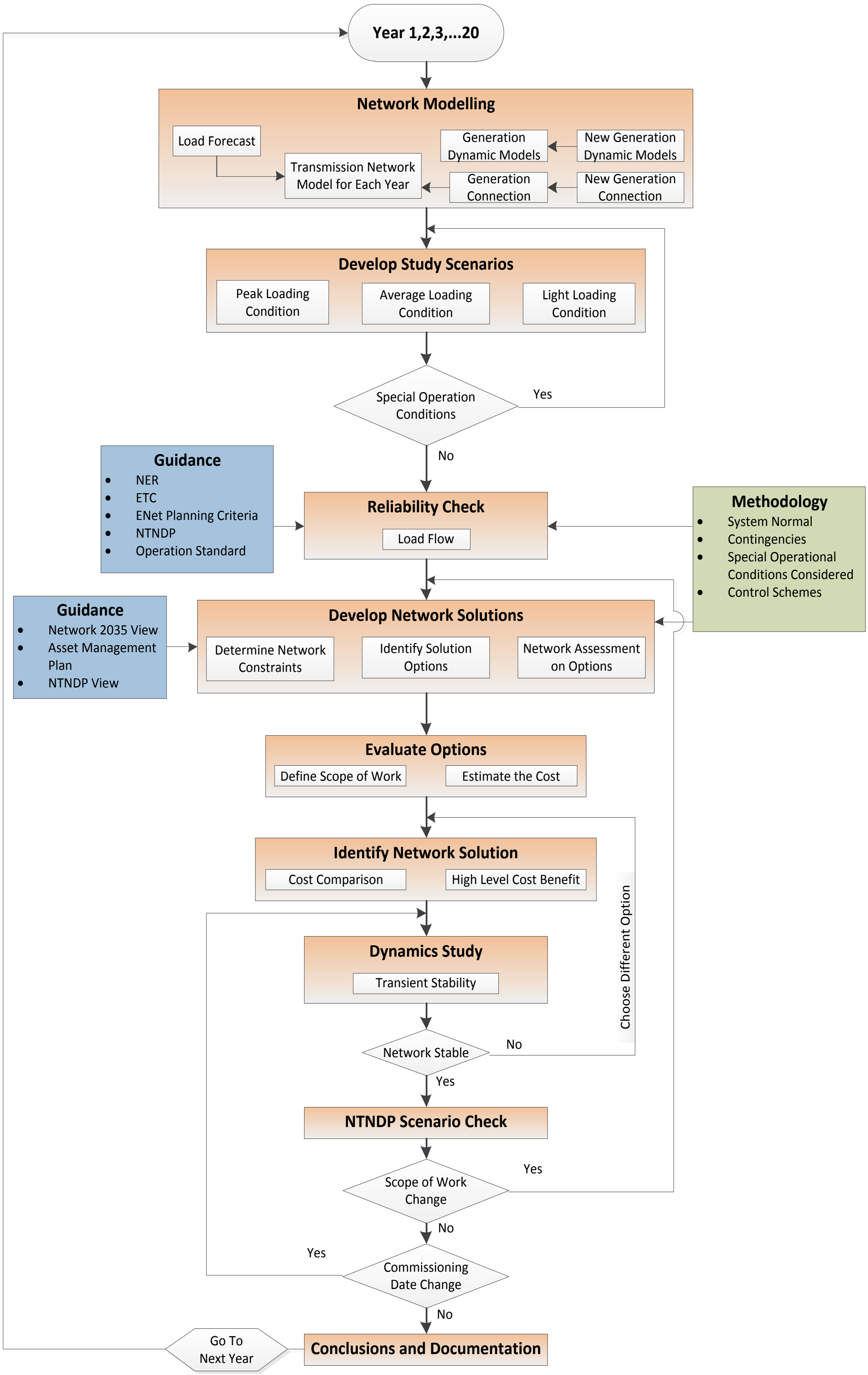


Figure 1.3: Planning process flow chart

2. Load Forecast and Characteristics

Transmission networks are developed to provide transmission capacity to meet electricity demand.

The loading on components of the transmission system are determined primarily by the location and output of generating plant, the system configuration, and the electricity demand.

As electricity demand is dynamic and varies hour-by-hour, the transmission system must be capable of carrying peak demand under all practical generation and forecast load patterns. Due to the length of time between planning and the final commissioning of transmission system projects, it is necessary to forecast electricity demand and loading conditions into the future.

As the need for transmission reinforcement is generally of a localised nature and is based on demand which occurs at the local level or at sub-regional (bulk supply point) levels, it is necessary to construct a demand forecast for every connection point on the system. System load diversity must also be considered when constructing a load forecast for transmission planning purposes and it is often necessary to construct specific load forecasts for each part of the transmission network.

The 10-year peak summer load forecasts have been submitted by ETSA Utilities, in accordance with Clause 5.6.1 of the Rules, and modified in accordance with Clause 5.6.2 (b). These are provided in this South Australian Annual Planning Report as required by Clause 5.6.2A(b) (1).

The total South Australian system load forecast is provided by AEMO and contained in its SASDO report, and is used as a sensibility check against the load forecast derived using customer notifications.

ElectraNet has also included an aggregated 10-year maximum demand forecast for its direct connect customers in Table 2.4.

2.1 ETSA Utilities Load Forecast

This section provides an explanation of the 2010/11 connection point forecasts as provided by ETSA Utilities.

2.1.1 Load Forecast Base

ETSA Utilities did not record a state wide system peak load during the summer 2010/11. However, the 2010/11 connection point forecast was exceeded at several locations on 31 January 2011. These included Hummocks and Brinkworth connection points due to unusually high grain handling customer demand, and Waterloo and Angas Creek connection points due to network abnormalities.

No extended heatwaves occurred during the summer 2010/2011 with the only major heat event being on 30 and 31 January 2011 when the Adelaide maximum recorded temperature reached 42.9°C.

The connection point load forecast has been reviewed and in most cases the existing medium case forecast has been retained. That is, the 10-year forecast will generally remain based on the measured peak demand in the summer 2008/09. Exceptions are Hummocks and Brinkworth Connection Points where forecast values have been reset due to reflect known customer load increases. However, the high and low forecast cases have been modified with information obtained from large customers on their potential increased or decreased maximum demand in the next 10-years.

2.1.2 Load Forecast

ETSA Utilities provided three load forecasts, high, medium and low to allow for changes to the South Australian rate of economic development and major customer plans. The three load forecasts are detailed in Appendix B.

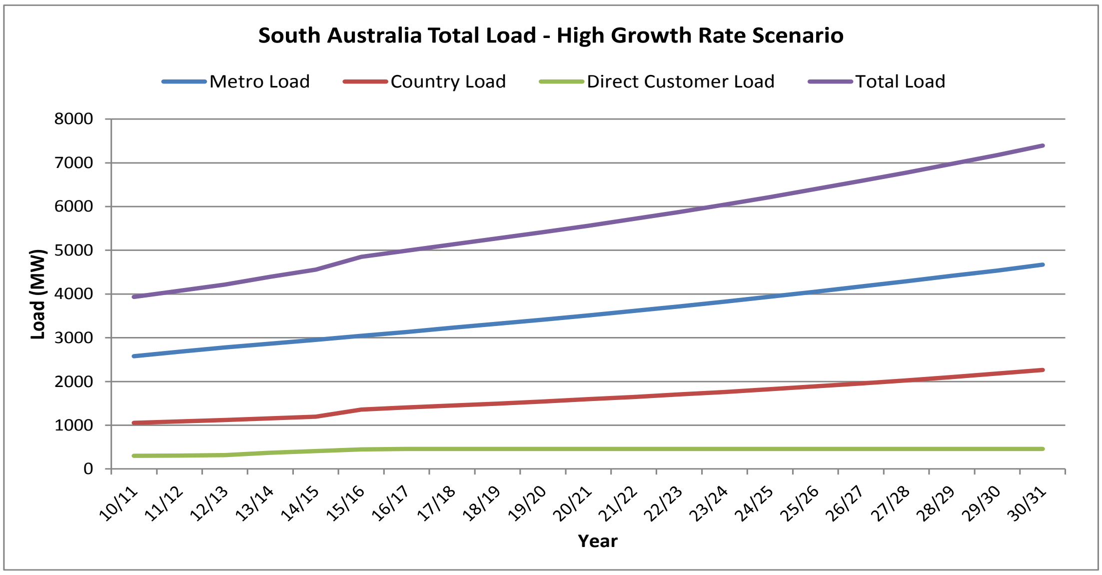


Figure 2.1: South Australian peak load forecast – high growth rate scenario

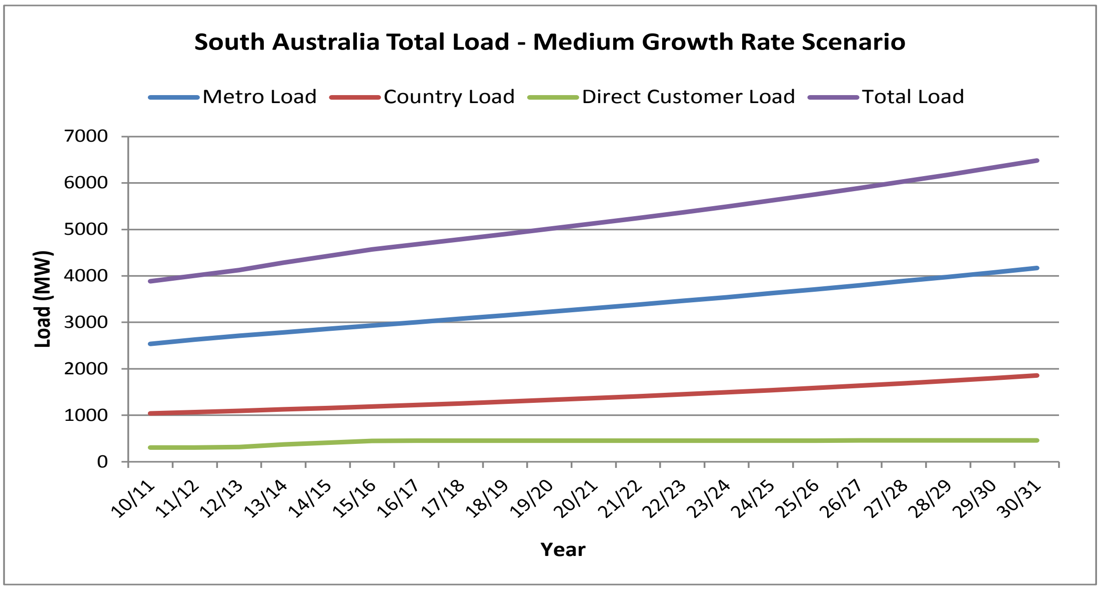


Figure 2.2: South Australian peak load forecast – medium growth rate scenario

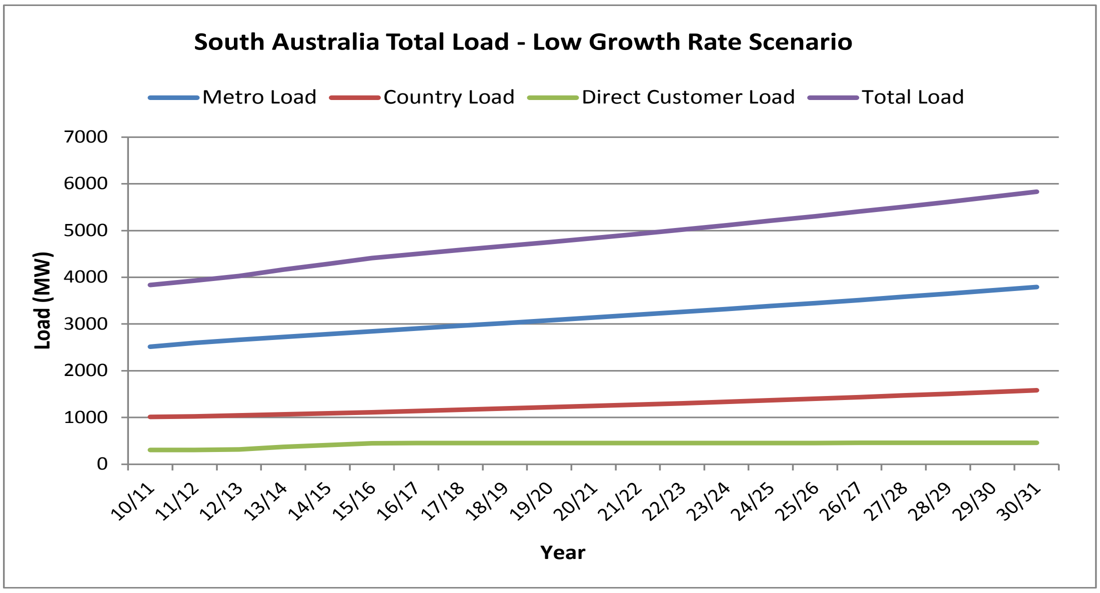


Figure 2.3: South Australian peak load forecast – low growth rate scenario

Figure 2.1, Figure 2.2 and Figure 2.3 show the South Australian load forecast for three scenarios, namely high, medium and low growth rate.

All three load forecasts use as a base the measured 2008/09 demand except for the connection points that were reset in 2010/11. All load forecasts are for a hot summer.

As required by the ETC Table B.2 lists the Adelaide Central [CBD] moderate 10-year load forecast.

The Adelaide CBD region is defined in the ETC and includes all of the customers supplied by ETSA Utilities from CBD substations (East Terrace, Hindley Street, Whitmore Square and Coromandel Place), but does not include the customers supplied from North Adelaide Substation.

The ETSA Utilities forecasts are not to be used as a generation forecast as they do not consider transmission losses, other ElectraNet customers, diversity between connection points or load curtailment programs.

2.1.3 Relationship to Distribution Forecast

For the base year 2010/11, the load forecast data for each connection point is the sum of the summer peak load forecast in MW for all the distribution substations supplied by that connection point multiplied by a diversify factor where applicable.

The distribution load forecast is primarily based on the measured 2008/2009 load at each substation with adjustments made to some individual substations on an as needs basis. The load growth rate for each substation has generally been retained with advice from ETSA Utilities' customers of their plans incorporated into the load forecast.

An allowance is made for co-generators above 1 MW who were operating at the time of peak load measurement in 2008/09. The assumption is that these co-generators may not be available at peak load times. The amount of this allowance is shown in Table 2.1.

Table 2.1: Co-generation allowances

Connection Point	Co-generation (MW)
Eastern Suburbs	8.0[i]
Southern Suburbs	2.6 + 20[ii] + 34[iii]
Western Suburbs	5
Whyalla Terminal	32
Snuggery	46[iv]
Dorrien	50[v]

i 8.0 MW various small generators
ii 20 MW Lonsdale Power Station
iii 34 MW Starfish Hill Wind Farm at Cape Jervis
iv 46 MW Canunda Wind Farm at Snuggery
v 50 MW Angaston Power Station

An allowance is made for the large industrial customers where their measured load during the peak period in 2008/09 was well below their normal summer peak (recorded on other summer days in 2008/09). The assumption is that this load curtailment may not be available at peak load times. The amount of this allowance is shown in Table 2.2.

Table 2.2: Load curtailment allowance

Connection Point	Curtailed load (MW)
Western Suburbs	15
Dorrien	4
Port Pirie System	24
Northern Suburbs	15
Eastern Suburbs	7

2.1.4 Diversity Factor

The diversity factor is the ratio of the peak measured load at the connection point in 2009 and the measured peak distribution substation load in 2009. This diversity factor takes into account the losses within the distribution network and the diversity between the distribution substations, and is normally less than 1.

2.1.5 Growth Rate

The load forecast for each year after 2010/11 is a function of the 2010/11 predicted load and the annual growth rate. For the moderate growth forecast the annual load growth rate has been retained due to the new measured peak loads not being recorded at most locations.

Where load has been permanently transferred between connection points or new connection points have been added, ETSA Utilities have estimated the impact on growth rates and power factors.

For high and low growth forecasts the annual growth rate has been modified to take into account different state economic development factors and major customer plans. However, both the low and high growth forecasts use the 2008/09 load as the base.

In addition to the historically based growth rates ETSA Utilities have included abnormal large step load increases or reductions where firm advice has been received from major customers. Connection points that include medium load forecast firm step loads are Southern Suburbs (desalination and electrification of trains projects), Western Suburbs (ship building and electrification of trains projects), Northern Suburbs (Edinburgh defence precinct and various northern area regional developments) and the CBD (Royal Adelaide Hospital net load increase) (refer Table 2.3).

Where there is uncertainty over the demand increase the step load is reflected in the high growth forecast only. Connection points that include high load forecast speculative loads are Yadnarie, Whyalla Terminal, and Stony Point.

Table 2.3: Customer step load allowances

Connection Point	Customer Step Loads in Medium Forecast MW	Speculative Customer Step Loads in High Forecast MW
Adelaide Central	12	
Western Suburbs	35	
Northern Suburbs	46	
Southern Suburbs	70	
Stony Point		5
Whyalla Terminal		50
Yadnarie		25

2.1.6 Load Transfers

Planned 2011 permanent load transfers between connection points are included in all forecasts.

The temporary load transfer of the Linden Park substation from the Eastern suburbs to the Southern Suburbs has been included in the load forecasts until 2012. This temporary transfer will be restored once the City West substation project is commissioned. As such, Linden Park substation load is intended to be returned to the Eastern suburbs in 2012.

Load transfers to the new connection points of Penola West and Clare North assume final commissioning dates during 2011.

A Kilburn to Cavan 66kV line is planned for 2012 which will permit Cavan substation to be supplied from either the Northern Suburbs or Western Suburbs for sub-transmission contingency purposes.

2.1.7 Major ETSA Utilities Customers

For connection points which supply very large industrial customers, forecasting using an annual incremental growth rate is not appropriate as load growth is determined by the expansion plans of individual customers.

The Whyalla Terminal connection point forecast has been varied between the low to high forecasts to reflect the behaviour of One Steel and BOC. The low forecast considers the peak measured load by One Steel and BOC, and the high forecast considers the agreed maximum demand with One Steel and BOC.

The Snuggery Industrial forecast has been varied between the low to high forecasts to reflect the behaviour of KCA. The low forecast is based on the KCA maximum demand after the scaling back of their operations. The medium forecast considers the peak measured load at KCA, and the high forecast considers the agreed maximum demand with KCA.

2.1.8 Power Factor

The forecast ETSA Utilities power factors at each connection point listed in Appendix B are based on the measured power factor at the time of system peak and the planned levels of reactive compensation proposed to be added into the ETSA Utilities distribution network during the next 10-years.

2.1.9 Sub-transmission Losses

An allowance has been made for an increase in sub-transmission losses (66 kV network) from that determined by loadflow in 2010. The losses in each area have been increased by the local growth rate squared on the assumption that network is not augmented. Actual losses will be reduced by 66 kV line projects completed during the forecast period.

2.2 Direct Connect Customers Aggregated Load Forecast

Large customer loads that connect directly to either the 275 kV or the 132 kV transmission networks have also provided load forecasts for their respective connection points.

These individual load forecasts are combined into the aggregated load forecasts contained in Table 2.4 below.

ElectraNet’s direct connect customers are:

- BHP Billiton (Davenport substation 275 kV connection point and a 132 kV connection point at Pimba).
- DSC Woomera (Woomera substation 132 kV connection point).
- Alinta Energy (Leigh Creek Coalfield 33 kV connection point and Northern Power Station and Playford Power Station 132 kV supplied house supplies).
- OneSteel (Middleback 132 kV and 33 kV connection points).
- Roseworthy AMCOR (Roseworthy substation 11 kV connection point).

- SA Water (3.3 kV connection points at Morgan-Whyalla 1, 2, 3 & 4, Mannum-Adelaide 1, 2 & 3, Millbrook, and 11 kV connection points at Murray Bridge-Hahndorf 1, 2 & 3 water pumping stations).
- SANTOS (Stony Point substation 11 kV connection point).
- AGL (Torrens Island Power Station 66 kV house supplies).

The power factors at the connection points are maintained in accordance with Rules requirements (S5.3.5).

Table 2.4: Combined direct connect customers' connection point load forecast

	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Year From Base		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
COMBINED TOTAL*	MW	303	308	318	374	412	450	456	456	456	456	456

* Excludes the power station house supply loads

2.3 Load Forecast Comparisons

2.3.1 Comparison of NTNDP and South Australian Annual Planning Report Load Forecasts

The following factors need to be taken into account when comparing the NTNDP and South Australian Annual Planning Report demand forecasts:

- The 2011 South Australian Annual Planning Report forecasts are more recent than the 2010 NTNDP forecasts which are based on 2010 and 2009 forecasts; and
- The NTNDP demand forecasts are diversified State-wide forecasts whereas the South Australian Annual Planning Report demand forecasts are the summation of forecast maximum demand at each connection point (i.e. undiversified forecasts).

Making allowance for diversity, broad alignment between the forecasts exists as follows:

- The 2010 South Australian Annual Planning Report high load forecasts correspond to the Scenario 1 and 2 forecasts in the 2010 NTNDP;
- The 2010 South Australian Annual Planning Report medium load forecasts correspond to the Scenario 3 forecasts in the 2010 NTNDP; and
- The 2010 South Australian Annual Planning Report low load forecasts correspond to the Scenarios 4 and 5 forecasts in the 2010 NTNDP.

A more detailed reconciliation of bottom up/ top down load forecasts is included in the 2011 SASDO.

2.3.2 Comparison of 2011 and 2010 South Australian Annual Planning Report Load Forecasts

The main differences between the 2010 and 2011 load forecasts are in relation to the direct connect customer forecasts. Specifically, BHP Billiton has now provided a view of its Olympic Dam expansion plans. This is compared to last year where the load forecast included no specific information on the timing or magnitude of the expanded load.

Additionally, the prospects for mining expansion on the Eyre Peninsula have increased ETSA Utilities and some direct connect customer load forecasts, which would have a major impact on the timing and size of transmission augmentation required on the Eyre Peninsula.

Furthermore, any transmission augmentation of the Eyre Peninsula will also present the opportunity for other loads to connect; i.e. loads that are not actually taken into account in any of these load forecasts. Given their likelihood, these loads need to be taken into account in developing future planning scenarios.

2.4 South Australian Load Characteristics and Related Planning Assumptions

This section provides the characteristics of the load in South Australia and establishes the context of planning assumptions with regard to the dispatch of wind and conventional generation that have been adopted by ElectraNet. It is also important to understand the importance the State's load characteristics play in formulating the assumptions that relate to the proposed augmentation of interstate interconnection capability that ElectraNet is currently investigating with AEMO.

The load duration curve provided in Figure 2.4shows the half-hour metered demand data collected via National Grid Metering (NGM) plotted against time (represented as a percentage of the year). This curve, along with the observed behaviour of generators has given guidance to the planning assumptions applied to different classes of generator when conducting network planning studies.

2.4.1 Demand Characteristics

The South Australian load duration curve, shown in Figure 2.4, indicates that peak load (load in excess of about 2600 MW) only occurs for a small portion of the year (approximately 2%), although the observed trend is that the duration of that peak load period is slowly increasing. In general though, for most of the year the load in South Australia ranges between approximately 1200 MW and 2400 MW. If the peak and very low demand periods are ignored, the load remains in that range for about 90% of the year.

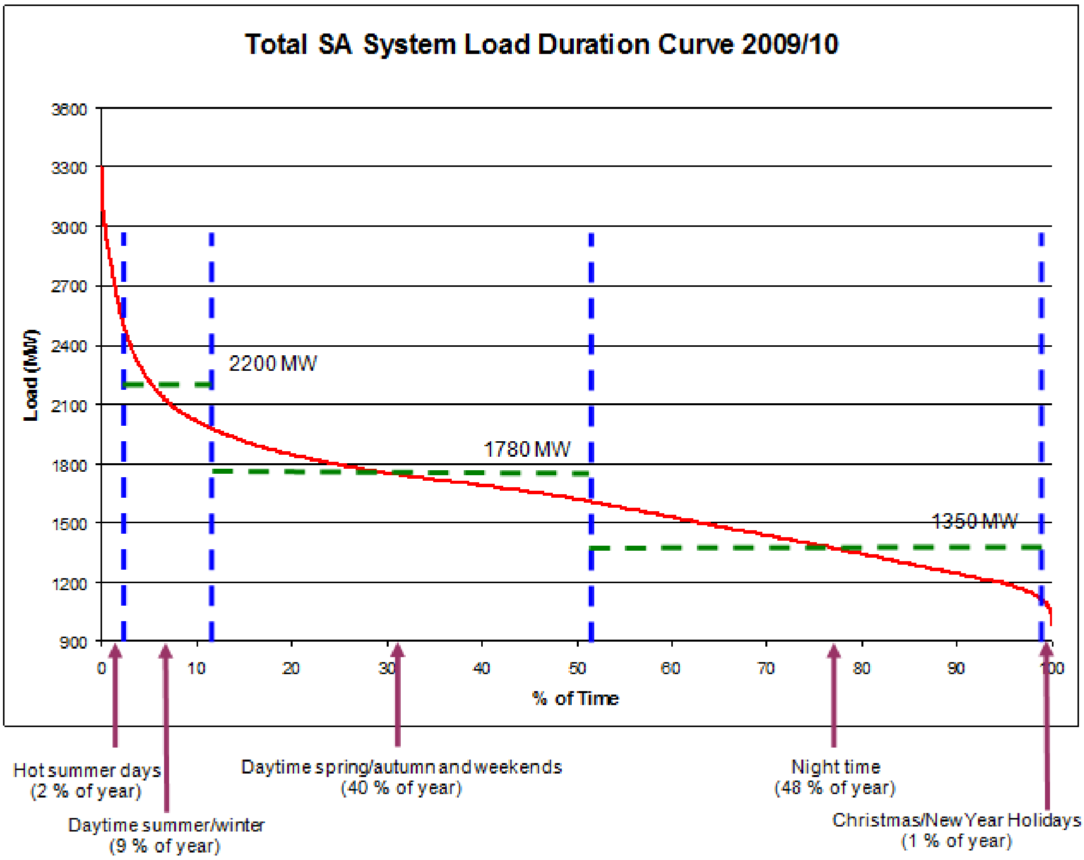


Figure 2.4: South Australian system wide load duration curve

2.4.2 Demand vs Supply Pattern

Peak demand is typically met by conventional, fossil fuel driven generation, as there is an observed coincident the low contribution by wind generation at this time driven by a range of factors. Therefore ElectraNet considers it reasonable to analyse State-wide transmission network performance at peak demand times based on dispatch of predominantly conventional generation, with the contribution from wind generation assumed to be 3% of installed wind farm capacity. However, when focussing on a particular region, zero output is readily observable and therefore taken into planning considerations.

In contrast, a high level of wind generation has been observed regularly during periods of medium and light demand. Therefore ElectraNet considers that it is reasonable to analyse transmission network performance during these periods based on the dispatch of high levels of wind generation. Following the analysis of several years' worth of NGM recorded wind generation data, ElectraNet considers that a coincidental dispatch of 75% of a wind farm's installed capacity is a reasonable basis for planning studies, because State-wide wind penetration above this level is only very rarely observed.

3. Network Constraints and Transfer Capability

This section provides an overview of the existing inter and intra-regional network constraints that impact on the NEM and discusses potential solutions to alleviate the constraints in the short term.

3.1 Top Network Constraints in 2010

This section provides an assessment of the top 20 network constraints that were experienced during the 2010 calendar year.

Table 3.1 provides the name and description of each binding constraint, the number of hours it bound and an estimate of the annual marginal value associated with the constraint. Commentary is also provided, on the need or otherwise for any action to alleviate the constraint.

ElectraNet is actively working to investigate potential solutions to alleviate constraints and maximise the transmission network transfer capability available to the market.

3.1.1 Heywood Interconnector Import Capability Study

This section summarises the outcomes of a study undertaken by ElectraNet to investigate the nature of constraints limiting power transfers on the Heywood Interconnector below the existing nominal capacity of the interconnector.

The relevant constraints are broadly classified as either thermal or voltage stability constraints.

<u>Thermal constraints</u>

Thermal constraints are associated with the lower capacity of the underlying 132 kV system in the South East region of the state. These constraints arise during summer peak demand periods, with high generation levels in the South East region.

<u>Voltage stability constraints</u>

Voltage stability is classed into two types – long-term voltage stability and short-term voltage stability. These are defined as follows:

- Short term voltage stability: voltage at nominated buses should not fall below 0.8 per unit for more than 1 second in duration.
- Long term voltage stability: There are two criteria for the assessment of long term voltage stability, which are described below:

  Change in steady state Voltage: The steady state voltage on the 275 kV and 132 kV network should not drop more than 8% and 10% respectively.

  Generator reactive power limit: This limit arises when generating plant reaches its maximum reactive power capability limit, even after optimal re-dispatch of all reactive plant in the system.

Study Outcomes

The study indicates the following potential solutions to alleviating constraints related to Heywood Interconnector import capability:

- Reduce unnecessarily high AEMO operating margins applied to the outputs of constraint equations;
- Increase the rating of limiting 132 kV lines in the South East region of South Australia;
- Apply certain long-term voltage stability constraint equations on the basis of capacitor ‘availability’ rather than capacitor ‘status’;
- Un-meshing of the 132 kV system in the South East region; and
- Series compensation of the 275 kV lines between Tailem Bend and South East as well as additional dynamic reactive power compensation (SVCs).

ElectraNet is actively investigating these potential solutions.

A number of the potential solutions will be included in options for augmenting the Heywood Interconnector discussed in section 4.3.2. ElectraNet and AEMO intend to assess Heywood Interconnector augmentation options fully through a joint RIT-T process in 2011/12.

Table 3.1: Historical constraint responses

Constraint Equation	∑ Marginal values	2010 Hours	Definition	Network Status	Limitation	Impact of Constraint	Commentary
S_NBH_0	$2,948,721	241.50	Discretionary upper limit for North Brown Hill generation of 0 MW	Outage	-	Generation constrained off	The connection of Porcupine Range Wind Farm to Belalie substation required the complete disconnection of Belalie substation and disconnection of North Brown Hill Wind Farm. The constraint was caused by a one-off construction outage required for customer connection - no action required.
S_PLN_ISL1	$1,716,792	14.30	Whyalla to Yadnarie line, Port Lincoln units 1 and 2 islanded	Outage	-	Generation constrained on	ElectraNet dispatches this contracted generation to supply the Port Lincoln load under islanded conditions.
S>BGPA_BRPA_MNWT	$699,998	12.33	Bungama - Para line; Limit SA generation to avoid overload of Mintaro - Waterloo 132 kV line for trip Brinkworth - Para 275kV line.	System Normal	Thermal	Generation constrained off	Waterloo bus uprating has recently been completed, which is expected to see the impact of this constraint become minimal - no action required.
V^^S_NIL_NPS_xxx & V^^S_TBCP_NPS_xxx & V::S_NIL	$548,852	485.33	Vic to SA long term voltage stability limit for loss of one Northern unit, South East cap bank on/off, Tailem Bend cap bank on / off.	System Normal	Voltage	Regional price separation due to import constraint	The application of this constraint is currently under investigation.
S_PLN_ISL2	$536,970	4.17	Yadnarie to Port Lincoln line, Port Lincoln units 1 and 2 islanded	Outage	-	Generation constrained on	ElectraNet dispatches this contracted generation to supply the Port Lincoln load under islanded conditions.
S>NIL_NIL_MNWT	$460,215	5.08	Limit Mintaro generation to avoid Mintaro - Waterloo line overload (continuous rating).	Outage	-	Generation constrained off	Waterloo bus uprating has recently been completed, which is expected to see the impact of this constraint become minimal - no action required.
S_HALWF_0	$385,657	31.50	Discretionary upper limit for Hallett Wind Farm generation of 0 MW	Outage	-	Generation constrained off	The connection of Porcupine Range Wind Farm to Belalie substation required the complete disconnection of Belalie substation and disconnection of North Brown Hill Wind Farm and affected the Hallett Wind Farm. The constraint was caused by a one-off construction outage required for customer connection - no action required.
NSA_S_POR01_20	$249,433	1.67	Port Lincoln >= 20 MW for Network Support Agreement	System Normal	Voltage	Generation constrained on	ElectraNet dispatches this contracted generation to support the transmission network under system normal operating conditions.
S>>V_NIL_NIL_MNWT	$241,060	8.83	Avoid overload of Mintaro to Waterloo (1) (continuous rating)	System Normal	Thermal	Generation constrained off	Waterloo bus uprating has been completed, which is expected to see the impact of this constraint become minimal - no action required.

Constraint Equation	∑ Marginal values	2010 Hours	Definition	Network Status	Limitation	Impact of Constraint	Commentary
V>>S_NIL_KHTB2_KHTB1	$239,279	7.42	Prevent Keith - Tailem Bend #1 line overload for Keith - Tailem Bend #2 line trip.	System Normal	Thermal	Regional price separation due to import constraint	Application of short-term/ real-time ratings on this line is currently under investigation.
NSA_S_POR01_25	$237,011	1.58	Port Lincoln >= 25 MW for Network Support Agreement	System Normal	Voltage	Generation constrained on	ElectraNet dispatches this contracted generation to support the transmission network under system normal operating conditions.
NSA_S_POR01_15	$162,255	1.08	Port Lincoln >= 15 MW for Network Support Agreement	System Normal	Voltage	Generation constrained on	ElectraNet dispatches this contracted generation to support the transmission network under system normal operating conditions.
S>V_NIL_NIL_RBNW	$142,324	141.00	Avoid overloading North West Bend to Robertstown 132kV line for no contingencies	System Normal	Thermal	Regional price separation due to export constraint	Application of short-term/ real-time ratings on this line is currently under investigation.
S_PF_4_UNITS	$137,535	11.17	4 Playford units. Playford PS output <= 0MW	Outage	-	Generation constrained off	Davenport-Playford 275 kV outage - results in generation disconnected from network - no action required.
S>NIL_NOTI_NOTI	$122,779	5.58	Limit generation to avoid overload Torrens Island to New Osborne 66 kV lines for trip one of the Torrens Island to New Osborne 66 kV line.	System Normal	Thermal	Generation constrained off	Requires unusual generation dispatch pattern; i.e. no OCPL AND Quarantine AND Dry Creek unit at full output - ElectraNet will assess if market benefit of removing constraint is sufficient to advance the need for a third 66 kV circuit between Torrens Island and New Osborne.
S>>V_NIL_SETX_SETX	$117,467	214.00	Avoid overloading a South East 275/132 kV transformer on trip of the remaining South East 275/132 kV transformer	System Normal	Thermal	Export constraint / Generation constrained off	The market benefit of installing a 3rd transformer in the South East region earlier than otherwise would be required is currently being investigated.
V>>S_NIL_NIL_SGKHC	$114,365	5.08	Limit all other generators except LB3 to avoid overload of Snuggery to Keith 132 kV line above the continuous rating	System Normal	Thermal	Import constraint / Generation constrained off	Application of short-term/ real-time ratings on this line is currently under investigation.
S>>V_RBTU_N-2_RBTX1	$113,207	2.58	Avoid overload of Robertstown transformer #1 on trip of Robertstown - Para and Robertstown - Tungkillo 275kV lines with Robertstown No2 Transformer	System Normal	Thermal	Export constraint / Generation constrained off	Currently under further investigation.
S_TA4_TX	$78,388	6.33	Torrens A 4 Transformer O/S; unit=0	Outage	-	Generation constrained off	Related to outage of Generator assets
S_LB2WF_CONF	$75,229	16.08	Limit Lake Bonney 2 & 3 generation based on DVAR availability.	Outage	-	Generation constrained off	Related to outage of Generator assets

3.2 Existing Network Transfer Capability

Transfer between NEM regions and transmission lines and substation plant within a region can, at times, be constrained because of network outages, thermal ratings or power system security margin limits. The actual level of constraint experienced in the market will depend not only on the capacity of network elements, but also on the non-scheduled and market dispatch of generation.

This section provides an overview of the existing South Australia to Victoria Heywood and Murraylink Interconnector capability and associated transfer limits.

The combined upper transfer limit on total export from South Australia to Victoria under system normal operating conditions was increased from 420 MW to 580 MW across the two interconnectors. This increase came into effect on 6 January 2011 following completion of an AEMO due diligence process.

The following limit equations derived by ElectraNet and the supporting descriptions are valid at the time of publication. AEMO's market systems may also contain other thermal limit equations for the South Australian transmission system, which are maintained by AEMO.

It should also be noted that these limit equations are under ongoing review to take into account changing generation, load and network conditions, and further increases in transfer limits are being investigated as outlined below.

3.2.1 Heywood Interconnector

The Heywood Interconnector comprises a double circuit 275 kV transmission line from South East substation in South Australia to Heywood substation in Victoria, where two 275/500 kV transformers make the connection to the Heywood to Melbourne 500 kV transmission system.

The physical and security related constraints on the existing Heywood interconnector which limit transfer capability are principally related to the 460 MW limitation of transformer capacity at Heywood. There are also voltage collapse constraints on the South Australian network following a South Australian generation trip, and thermal limitations on the underlying 132 kV transmission system from South East to Para and Cherry Gardens substations.

The existence of these limitations may result in constrained power flows from time to time.

Import Capability

The import capability is defined by two types of equations (for system normal operating conditions):

A.) Thermal Limited Transfer Capability

This equation is determined by AEMO and is based on plant and equipment rating parameters provided by ElectraNet.

The South East 275 kV and 132 kV networks operate in parallel. Generation installed in the South East 132 kV transmission system has the tendency to displace import on the Heywood interconnector. In accordance with the Rules, Schedule S5.2.5.12, generation is allowed to connect to networks and displace interconnection flows but by no more than on a one-for-one basis.

B.) Voltage Stability Transfer Capability

The import capability of the Heywood interconnector under system normal operating conditions is defined by the following Equation:

Import Transfer Capability [MW] =

$$Sed*C_1 + Lad*C_2 + LB_1*C_3 + Can*C_4 + LB_2*C_5 + LB_3*C_6 + Snug*C_7 + Const$$

Where:

Sed	= Total South-East Region Demand in MW
C_1	= 0.94
Lad	= Ladbroke Grove Power Station output in MW
C_2	= -0.21
LB_1	= Lake Bonney Wind farm Stage 1 output in MW
C_3	= -0.80
Can	= Canunda Wind farm output in MW
C_4	= -0.78
LB_2	= Lake Bonney Wind farm Stage 2 output in MW
C_5	= -0.65
LB_3	= Lake Bonney Wind farm Stage 3 output in MW
C_6	= -0.65
Snug	= Snuggery Power Station output in MW
C_7	= -0.82
Const	= 368.6

The South Australian Heywood import capability remains limited to a 460 MW upper thermal limit under system normal operating conditions. This 460 MW import capability is reduced as wind generation in the South East region increases as per the equation above.

Export Capability

The export capability is defined by two types of equations (for system normal operating conditions):

A.) Thermal Limit Transfer Capability

This equation is determined by AEMO and is based on plant/equipment ratings/parameters provided by ElectraNet.

B.) System Stability Transfer Capability

The South Australia to Victoria export capability on the Heywood interconnector is capped at 460 MW under system normal conditions.

In practice, there are conditions when export will be constrained below 460 MW by thermal limits of the 132 kV transmission network in the South East region and the South East 275/132 kV transformers, generation levels and system demand in the South East region of South Australia.

ElectraNet and AEMO undertook an investigation into the economic feasibility of addressing these thermal limits as part of the South Australian Interconnector Feasibility Study. The results of this study are available at the following link:

http://www.electranet.com.au/network/transmission-planning/interconnection-studies/

3.2.2 Murraylink Interconnector

The Murraylink HVDC interconnection connects the Victorian Red Cliffs 220 kV substation to the ElectraNet 132 kV transmission system at Monash substation near Berri. Two 132 kV circuits on separate structures connect Monash to Robertstown substation via North West Bend substation. Power flows throughout the Mid North 132 kV transmission system are also influenced by Murraylink interconnection transfers.

The following network limit equations relate to the operation of Murraylink when importing and exporting, describing limitations in the Riverland region of South Australia, and assume system normal conditions. The equations also assume the Murraylink “run-back” control is operational to prevent any unacceptable overloading of ElectraNet plant.

Import Capability

The import capability is 200 MW for system normal summer operating conditions. However, it should be noted that the capability of the Murraylink interconnection to inject power into South Australia is also highly influenced by the ability of the Victorian transmission system to supply Murraylink. Under high load conditions in Victoria it is this factor that limits the amount of real power that can be supplied into South Australia by Murraylink.

Generation installed in the Riverland 132 kV transmission system and in the eastern region of the Mid North 132 kV transmission system can potentially displace import on the Murraylink interconnector. In accordance with the Rules Schedule S5.2.5.12, generation is allowed to connect to networks and displace interconnection flows, but by no more than on a one-for-one basis.

Export Capability

The export capability under system normal operating conditions is defined by a thermal limit transfer capability equation. This equation is determined by AEMO and is based on plant/equipment ratings/parameters provided by ElectraNet.

The equation assumes that the Murraylink “run-back” control scheme is operational, to prevent any overloading of ElectraNet plant.

Due to the complex interaction between load and generation in the different electrical sub-regions within South Australia, it is possible for the constraint on export from South Australia to Victoria via Murraylink to be located in the Mid North sub-region.

3.2.3 Combined Inter-regional Export Capability

The combined South Australian Heywood and Murraylink Interconnection export capability is currently limited to a 580 MW upper limit under system normal operating conditions.

AEMO has advised that pending further studies, a number of prior outages (i.e. not under system normal conditions) across South Australian to Victoria, New South Wales and Queensland require the combined South Australian to Victorian capability to be capped at 420 MW.

3.3 Strategies to Increase Utilisation of Existing Network Capacity

3.3.1 Segregation of 275 kV and 132 kV Networks

Where a higher voltage network normally overlays a lower voltage one, as is the case with ElectraNet's 275 kV and 132 kV networks, the reliability benefits originally provided by such an arrangement may over time, be outweighed by other considerations.

Segregation of the networks could be beneficial by:

- Avoiding augmentation of the constraining network;
- Facilitating the retirement of aged assets;
- Reducing intra and inter-regional constraints;
- Increasing intra and inter-regional power transfer capacity;
- Reducing fault levels; or
- Increasing the opportunity for planned outages with less (market) impact.

Some of the key issues in segregating networks that need to be adequately addressed in any assessment include:

- The impact on power transfer capability of lowering transient and voltage stability limits, due to increase in network impedances;
- The advancements required for future network and connection point augmentations;
- The impacts on network reliability and security under a range of operating conditions; and
- The impacts of network operability under conditions of planned plant outages.

Separation of parallel 275 kV and 132 kV networks would also require a net market benefit to be demonstrated. ElectraNet is continuing with studies to determine the viability of this strategy, in particular in relation to the South East 132 kV system.

<u>Assessment of un-meshing the South East Transmission 132 kV System</u>

An assessment was undertaken to consider the option of un-meshing the South East 132 kV system from the parallel 275 kV system to increase thermal transfer capability. The un-meshing option considered is as shown in Figure 3.1.

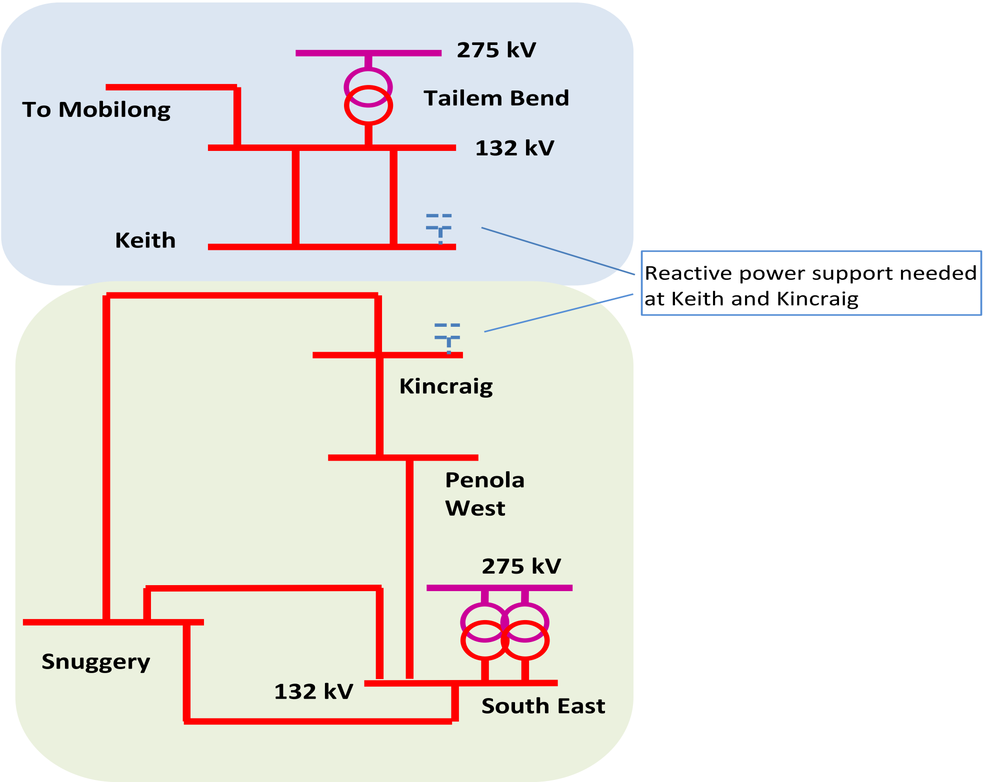


Figure 3.1: South East network un-meshing option

To date, this work indicates that while un-meshing may increase thermal capacity, it reduces the voltage and stability performance of the transmission system, requiring additional reactive support. ElectraNet intends to investigate this option further, including its impact on other potential developments such as augmentation of the Heywood Interconnector capacity.

3.3.2 Optimal Placement of Connection Points

Where a number of generators and/or loads are developed in close proximity, it is important to provide connection in such a way that maximum utilisation of network capacity is achieved. For example, connection of proposed wind farms in the Mid North will be planned to ensure loading on the parallel 275 kV lines between Port Augusta and Adelaide is balanced to reduce the likelihood of generation constraints.

Generators and load customers should note that in response to a connection enquiry, ElectraNet will consider the location and configuration of the connection in relation to the Rules, ETC and optimal placement within the network to efficiently maximise the utilisation of the existing shared network. ElectraNet may direct the connection to a specific network location if it is efficient to do so. ElectraNet will also specify the appropriate configuration for that connection.

This 'nodal' concept is substantially aligned with AEMO's connection initiatives currently under consultation in Victoria.

Figure 3.2 shows the placement of current and possible future nodes in the South Australian transmission network.

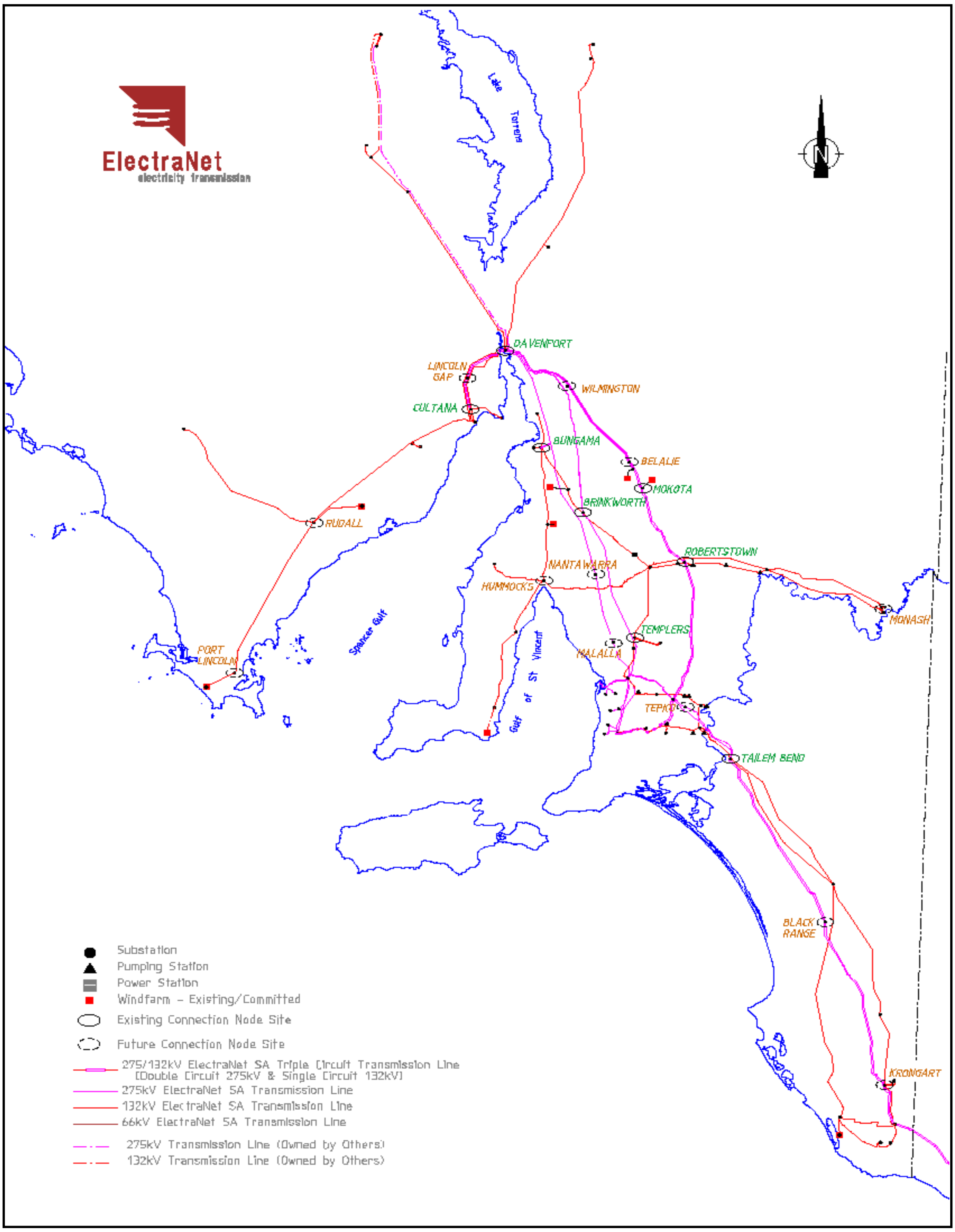


Figure 3.2: Current and possible future transmission network nodes

3.3.3 Transmission Line Real-time Ratings

In order to maximise the utilisation of existing transmission network capacity, ElectraNet has investigated and implemented a number of initiatives, including:

- Assessment of 'as built' ratings and the development of geo-spatial transmission line models (PLS-CADD models);
- Removal of any equipment limitations that prevent achieving the as-built rating of a transmission line;

- Uprating the line beyond its as-built rating, if it is economically justifiable;
- Application of short term ratings, if possible; and
- Application of dynamic line ratings.

ElectraNet has undertaken Aerial Laser Surveys (ALS) on a number of critical transmission lines (such as those in high bush fire risk areas), to confirm their as-built capability. This facilitates the development of a geo-spatial (PLS-CADD) model of the transmission line, which can be used to determine the number of spans requiring treatment to achieve a given transmission rating, while maintaining statutory clearances. This model will also facilitate the application of short term ratings to transmission lines. ElectraNet intends to carry out this survey for all remaining lines to maximise the utilisation of the existing transmission network.

ElectraNet is also systematically reviewing the ratings of existing transmission lines with respect to their design ratings and identifying any lower rated primary and secondary substation plant and equipment. ElectraNet has developed a programme of works to remove these constraints to maximise utilisation of the existing transmission network.

The application of real-time ratings to a transmission system allows the existing system capacity to be utilised more effectively as the system operator then has a far better knowledge of the true limitations on the system. This allows the release of capacity for such things as wind farm generators and increased intra and inter-regional transfers and is generally useful in accommodating these varying demands.

ElectraNet is currently in the process of installing weather stations across the transmission network, with a view to applying real-time thermal ratings on critical transmission lines. This will provide important information on conductor to ground clearances under a realistic assessment of environmental conditions, which is not achieved by the application of static seasonal line ratings. This also facilitates decisions on the application of short term emergency ratings on transmission lines.

The calculation of ratings in real-time is achieved by utilising measured rather than assumed parameters. The real time rating calculation makes use of actual wind speed and direction, ambient temperature, line current and solar radiation calculated from the solar almanac. Measurement of actual solar radiation is not used to avoid issues with cloud interference.

It should be noted that applying real-time ratings is an interim solution in most cases to delay the need to build new transmission lines. Applying real-time ratings to the transmission system may be used as the first step in the development of a major network augmentation to allow time to gain the necessary approvals to build new overhead transmission lines. The use of real-time ratings in the majority of cases will not remove the need to plan and construct new overhead transmission lines.

4. Long Term Network Development Outlook

The long term strategy for network development is driven by generation and demand growth in the State and interconnector capacity. The existing 275 kV transmission system can be simplistically represented as shown in the following single line diagram:

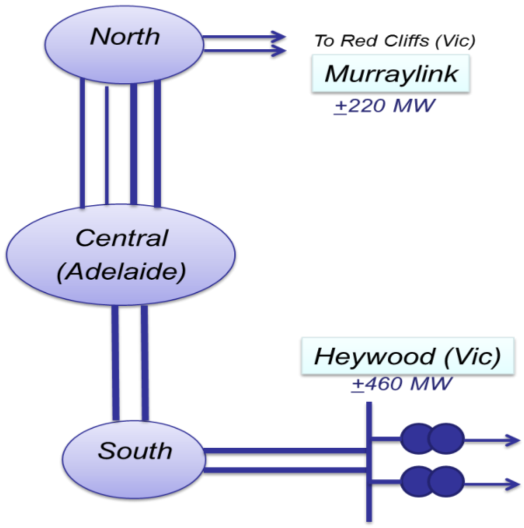


Figure 4.1: 275kV backbone network

There are two interconnectors which connect the South Australian system to the rest of the NEM: a 275 kV AC interconnector which connects South East in South Australia to Heywood in Victoria (existing maximum capacity of +460 MW) and the Murraylink +220 MW HVDC interconnector connecting Monash in South Australia to Red Cliffs in Victoria. While the combined capacity is 680 MW, this is non-firm and there are limits imposed in real time operation which reduce this capability. For example, the current combined export limit is set to 580 MW, due to an oscillatory stability limitation.

Seventy five per cent of the State's demand is in the Adelaide area.

Figure 2.4 indicates the very 'peaky' nature of the demand profile with low 'energy content'. This means that for most of the year, the demand is about 1650 MW (average of the above curve).

South Australia has a very high penetration of wind generation, with 1220 MW of installed wind generation, which is already delivering about 20% of the energy needs of the State. However, there is significantly more potential for wind generation. For this potential to be realised, it will require higher levels of energy consumption in South Australia and additional interconnector capacity to facilitate the export of surplus generation to the other NEM load centres.

As wind is an intermittent energy source which cannot be relied upon to meet demand, demand growth will require more local conventional generation such as gas plants (open or combined cycle) or increased interconnector capacity.

Described below are some specific development outlooks for generation and demand in South Australia.

- **Generation outlook:** Significant potential exists for wind generation in the Mid North, Eyre Peninsula and South East regions of the state. There is also interest in the development of geothermal generation in the Upper North and South East regions. Most of the interest in gas based generation is focussed in the Adelaide area, though there is some interest in both the Northern and Southern parts of the state.
- **Demand outlook:** About 75% of the present state demand is concentrated in the Adelaide region. The mining interest in the more remote parts of the state, including Upper North and Eyre Peninsula, has the potential to be very significant.
- **Network Capacity:** Depending on the transfer requirements in the longer term, additional transmission network capacity may need to be built, either at the existing backbone voltage of 275 kV or higher voltages such as 500 kV. This may also need to be considered in conjunction with the need to rebuild transmission lines that are nearing the end of their useful life.

4.1 Transmission Capacity Assessment

The assessment of the main backbone transmission network was primarily based on the market development scenarios published by AEMO in its 2010 NTNDP. The approach adopted was to identify the transfer required over the major corridors of the network. This requirement was calculated based on three demand profiles – peak, average and low demand with appropriate generation dispatch.

On the basis of the generation and demand scenarios in the 2010 NTNDP, there is no requirement for significant augmentation of the South Australian backbone transmission network over the planning period. There is also little difference between the scenarios from an overall transmission impact perspective. An example of the assessment (for NTNDP Scenario 1) is shown in the following diagrams. They indicate corridor capacities and resultant flows.

Triggers that could require major augmentation of the transmission system to deliver additional capacity include the following:

- A significant step load increase in the north of the state, depending on the location of generation to support the load;
- Retirement of coal based conventional generation;
- Significant step increase in generation in any specific region, with no corresponding retirement of existing generation plant;
- The development of a new high capacity interconnector; or
- A requirement to rebuild aged transmission lines.

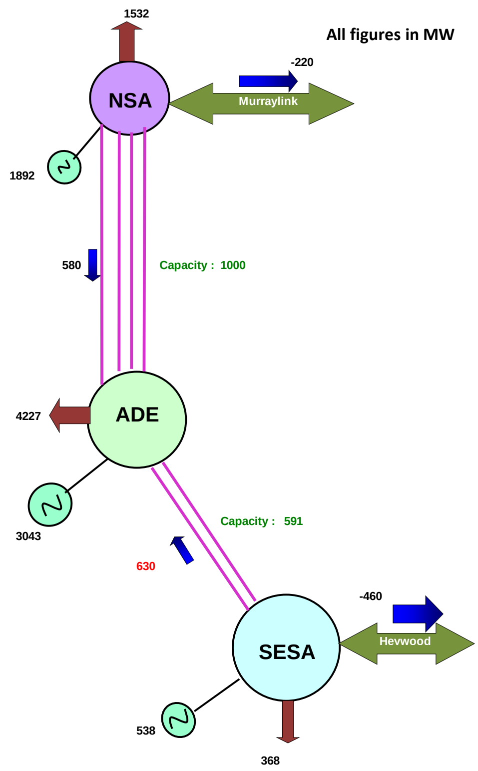


Figure 4.2: NTNDP Scenario 1 peak load transfers in 2030

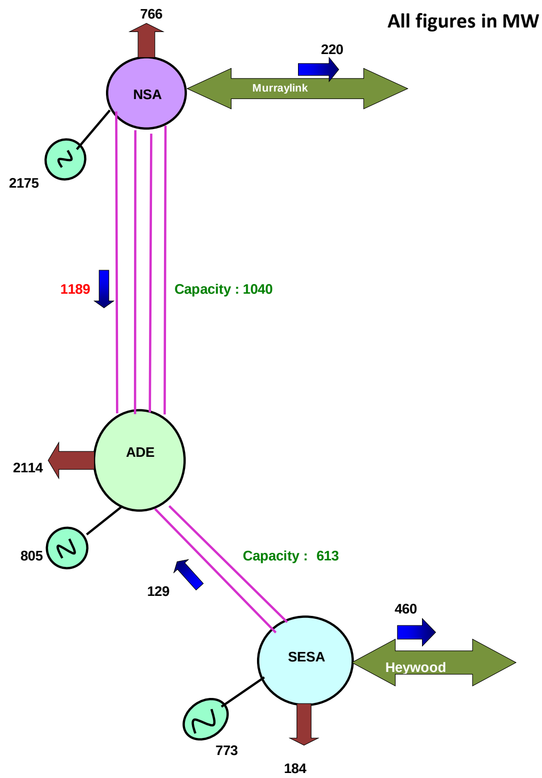


Figure 4.3: NTNDP Scenario 1 average load transfers in 2030

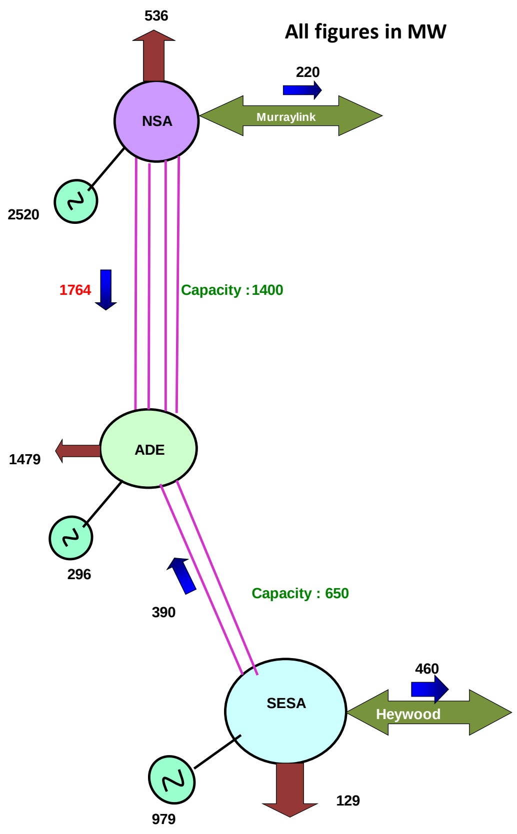


Figure 4.4: NTNDP Scenario 1 low load transfers in 2030

4.2 Augmentation of Interconnectors

This section summarises work done in the last year to explore the possibility of augmenting interconnector capacity.

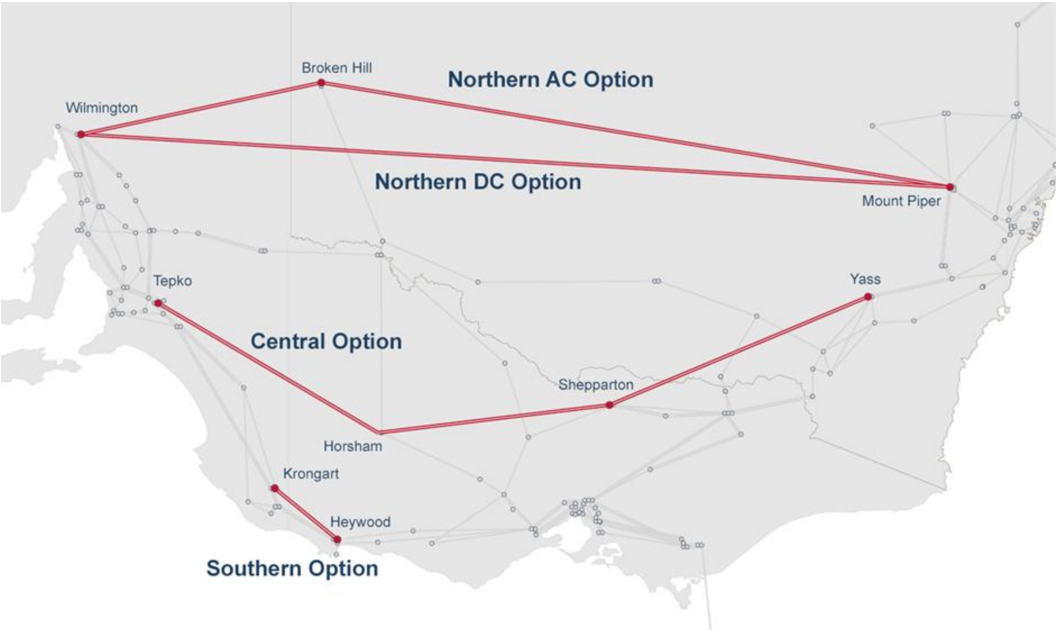
4.2.1 AEMO-ElectraNet Joint Interconnector Feasibility Study

ElectraNet and AEMO undertook a joint feasibility study into transmission development options that would increase the transfer capability between South Australia and other NEM load centres.

The purpose of this feasibility study was to investigate and assess the technical and economic merits of transmission development options that may allow further development of South Australia's renewable resources while also supporting South Australian demand, particularly at peak demand times.

A number of options to enhance transmission capability were considered, ranging from incremental upgrades of existing interconnectors to major new high-capacity interconnectors between South Australia and the eastern states. Figure 4.5 below illustrates the new high-capacity options considered.

The feasibility study compared the total costs to the NEM of meeting demand for a base case with no extra interconnection capacity between South Australia and the rest of the NEM, with a number of options to increase that capacity. This assessment was undertaken under a range of market development scenarios describing possible future conditions of economic growth, technological advancement, fuel scarcity, and external policy settings such as an imposed price on carbon emissions.



Source – ElectraNet-AEMO Joint Feasibility Study Final Report

Figure 4.5: Interconnector options considered in Joint Feasibility Study report

The feasibility study demonstrated that there is potential for augmenting transmission capacity between South Australia and the rest of the NEM, not only to facilitate export of renewable energy out of South Australia, but also to support South Australian peak demand as the level of intermittent generation increases[3].

The study also recommended that AEMO and ElectraNet undertake further work in 2011 that is focussed on clarifying the costs, benefits and timing of the lower cost incremental augmentation option (including a more accurate assessment of the impact of changes in system losses).

The outcomes of this further work are discussed in the following section.

4.2.2 Heywood Interconnector Upgrade Joint Study

As discussed in section 4.2.1, in 2010, ElectraNet and AEMO conducted a joint feasibility study of transmission development options that could economically increase interconnector transfer capability between South Australia and other National Electricity Market (NEM) load centres.[4]

This joint feasibility study arose from ongoing questions about the potential development of South Australia's extensive renewable energy resources and how limits on South Australia's export capability may limit the extent to which these resources can be developed. The study also addressed the need to investigate

[3] ElectraNet-AEMO Joint Feasibility Study Final Report, February 2011 which is available at www.electranet.com.au/network/transmission-planning/interconnection-studies

[4] see http://www.aemo.com.au/planning/saifs.html

future South Australian transmission system congestion identified in AEMO's 2009 National Transmission Statement.

The joint feasibility study indicated that a relatively low cost incremental upgrade option to increase the capability of the Heywood interconnector between Victoria and South Australia, by means of a third 500/275 kV transformer at Heywood and supporting augmentations in South Australia, could deliver net market benefits. The study indicated that this relatively low cost option of upgrading existing facilities could be economically justified as early as 2017–18 depending upon the future scenario considered.

After the completion of the joint feasibility study in February 2011, AEMO and ElectraNet have examined more closely the technical and economic feasibility of a range of relatively low cost incremental upgrades to the Heywood interconnector.

The incremental upgrade options would increase the capacity of the interconnector from the current 460 MW capacity up to the thermal capacity of the existing 275 kV transmission lines between Heywood in Victoria and the South East substation in South Australia, which is approximately 650 MW under favourable operating conditions.

The augmentation would require:

- A third 500/275 kV transformer at the Heywood 500 kV terminal station;
- Additional 275/132 kV transformer capacity in the South East region of South Australia;
- The development of weather stations and real-time dynamic line ratings to be applied to 275 kV and 132 kV lines in South Australia, including the interconnecting South East to Heywood 275 kV lines; and
- Reactive compensation in the South Australian network (options include combinations of series and/ or shunt compensation).

Using the NTNDP dataset and scenarios as a basis, this incremental option has been further refined and studied. Results indicate that this upgrade is able to provide positive net market benefits over a wide range of scenarios, with optimal timing between 2013 and 2017.

This analysis shows greater market benefit and an earlier implementation than the higher-level joint feasibility study. This is partly due to assumptions made in the joint feasibility study that reduced the augmentation benefits observed. For example, the joint feasibility study was a high level study that did not capture certain network limitations, particularly the voltage stability limits currently limiting power transfers, leading to higher than actual base case power transfer capacity, resulting in reduced augmentation benefits. The joint feasibility study also used average wind farm capacity factors, and so did not capture benefits during high wind outputs.

AEMO and ElectraNet intend to assess this incremental upgrade option through a joint RIT-T process in 2011/12.

4.3 Potential outlook for the future of the South Australian Transmission Network

Figure 4.6 indicates the potential for development of generation and demand that could eventuate in South Australia, which would result in the need for strengthening the existing transmission infrastructure. This is based on the information available from various sources such as developers, media reports, AEMO's planning documents etc.

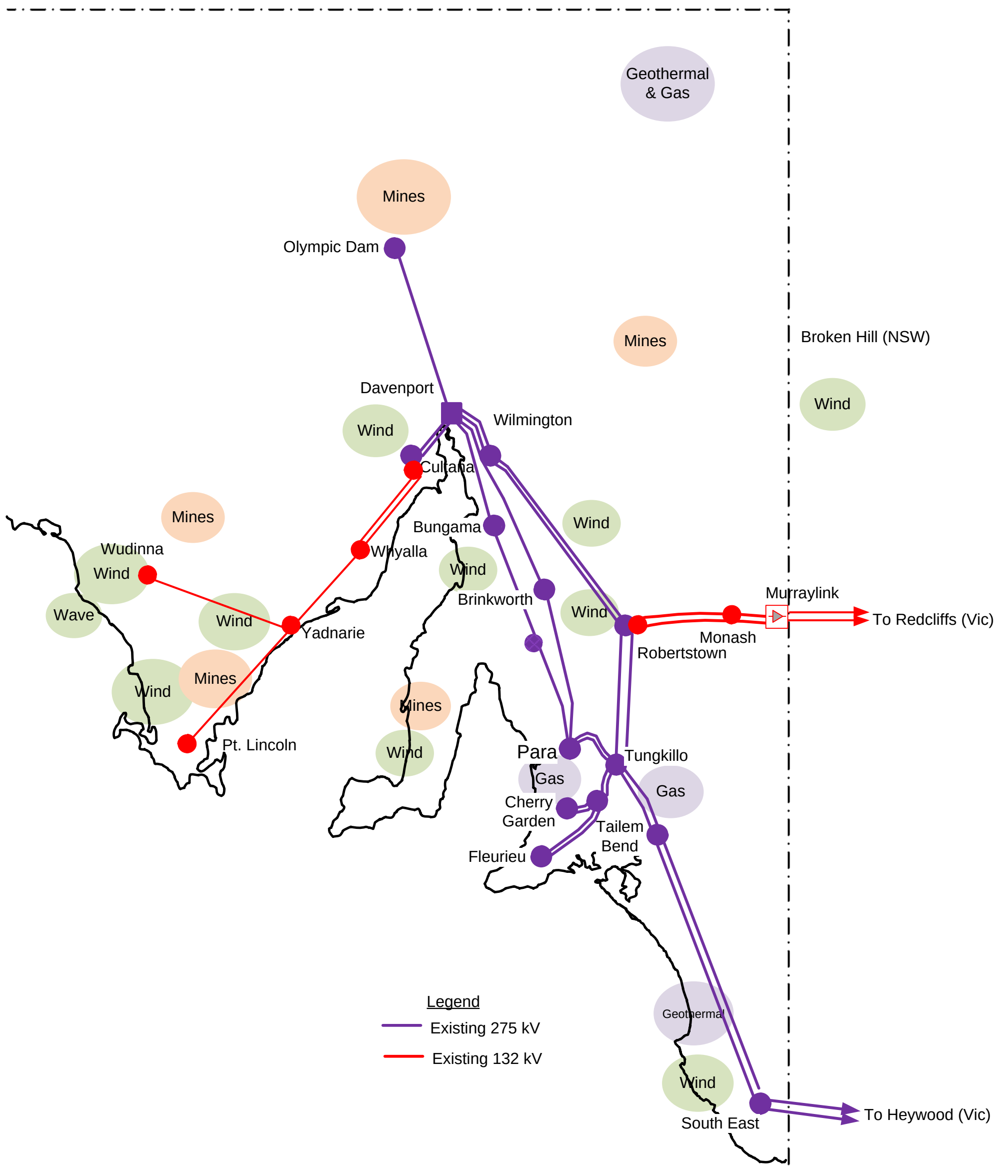


Figure 4.6: Potential for development of demand and generation in South Australia

Figure 4.7 shows a conceptual future network outlook for South Australia that may be needed to support such developments with three alternative interconnection paths (depending on the size of required power transfers across the network).

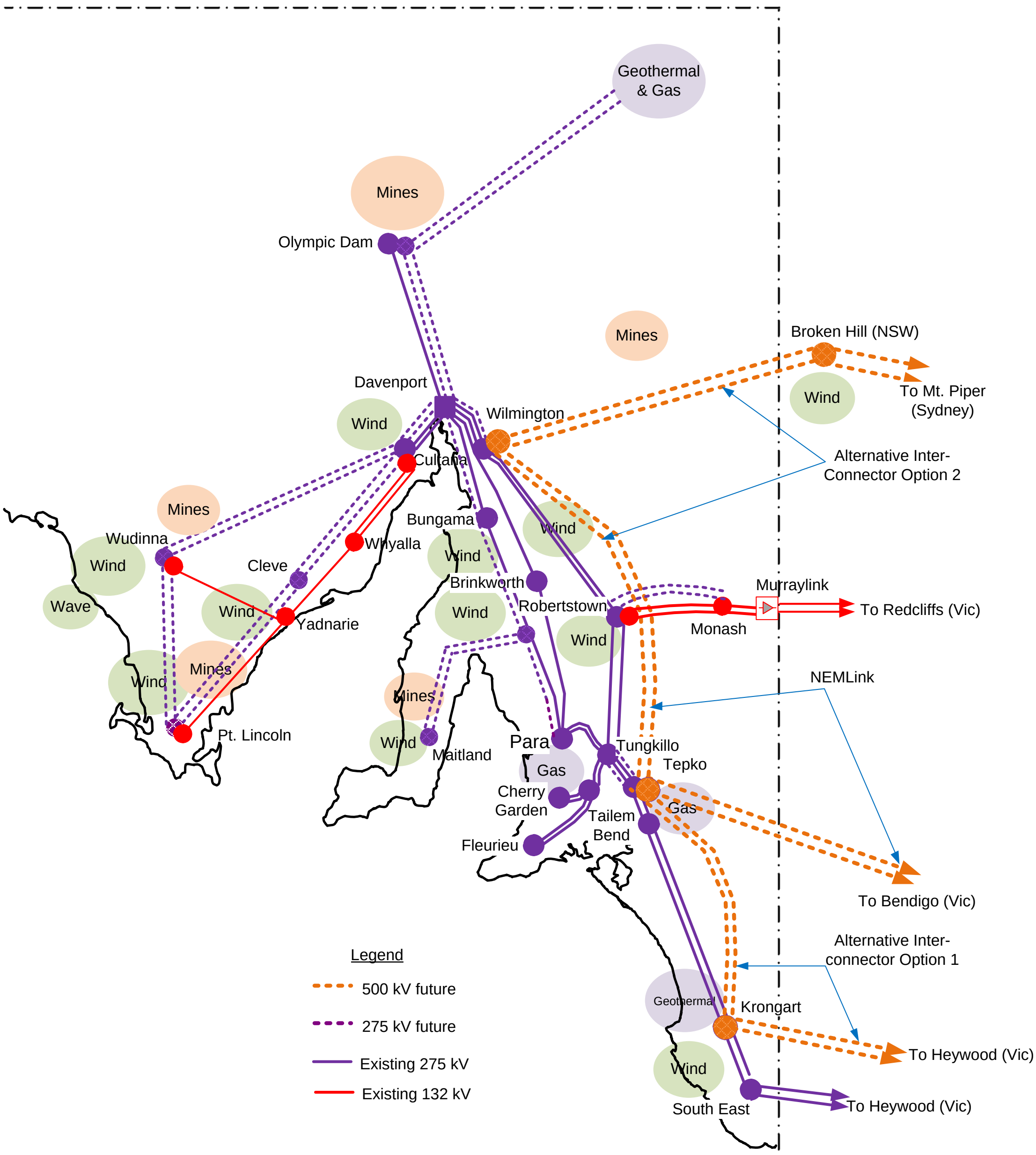


Figure 4.7: Potential future outlook for South Australia Transmission Network

Note: NEMLink is a concept development reported by AEMO in its December 2010 NTNDP.

ElectraNet is investigating various possible future network development scenarios, including those indicated above as part of its planning process.

An example of this is the preliminary study undertaken on the Lower Eyre Peninsula reinforcement – refer to Section 12.4 for more details.

5. Reactive Power Planning

5.1 Introduction

Reactive power planning is required to maintain system and connection point voltages within specified limits throughout the system. Schedule S5.1.8 'Stability' of the Rules requires an adequate reactive margin at all connection points to ensure that stable voltage control can be sustained following the most severe credible contingency event. This required minimum reactive margin is defined as 1% of the maximum fault level (in MVA) at the connection point expressed in Mvar.

The reactive margin at a connection point is calculated using QV analysis under outage conditions. Using this analysis, the required timing for additional reactive capacity, in the form of capacitor banks, reactors, Static Var Compensators (SVCs) and network augmentations such as injection from a higher voltage level, may be assessed. However, this analysis, does not examine thermal limitations on the transmission system; therefore, when determining and scheduling network augmentations both reactive requirements and thermal limitations must be accounted for.

As it is physically difficult to 'transport' reactive power through transmission lines over long distances, reactive power is usually produced near to where it is consumed. At heavy loads transmission lines absorb reactive power, while at light loads, the inherent shunt capacitance of long lines may become dominant, causing the lines to become a source of reactive power. Transformers always absorb reactive power, whereas at transmission voltages, cables are always generators of reactive power due to their relatively high capacitance. Loads generally absorb reactive power while capacitor and reactor banks provide local static reactive supply and absorption capability. Synchronous generators are the main source of supply to the system of both positive and negative reactive power and generally provide the balance of reactive power required to maintain voltages within specified limits throughout the system. Different generators have different reactive power supply and absorption capabilities. The requirement for a generator to produce or absorb reactive power within pre-set capabilities is outlined within the Rules, with the actual (negotiated) requirement incorporated into individual connection agreements.

Assessment of the system's reactive power requirements under peak and light system load conditions is necessary to ensure that generators and other network equipment are adequate to either absorb or generate the level of reactive power necessary. Care must be taken that the reactive demand placed on this equipment does not exceed the Rules requirements, derogated amounts, or levels otherwise agreed between ElectraNet and the generators.

If there is a reactive power shortfall, the system voltage will fall until the reactive power demand matches supply. In cases of severe shortfall of reactive power, the voltage may collapse to very low levels that cause widespread disconnection of power. Conversely, a shortfall in reactive power sinks under light load conditions will result in system voltages rising. Excessively high voltages can result in damage or failure of plant and equipment connected to the power system. Power system studies are therefore undertaken at peak load and at light system load for a range of scenarios to assess reactive power requirements.

5.2 Peak Load

Under peak load conditions, with all customer connections within their power factor requirements as stipulated by S5.3.5 of the Rules and assuming all connected generators meet their registered generator performance standards with regard to reactive power obligations, studies were undertaken to determine if additional capacitive reactive plant is required to address local limitations.

Any subsequent transmission-wide capacitive reactive shortfalls would then be met with 275 kV connected banks, mainly distributed around the Adelaide metropolitan area and along the Main Grid network between Davenport and South East substations.

Peak load reactive planning is carried out on all connection points within each of the transmission regions. Studies are carried out by region, as the reactive margin at a connection point is essentially a measure of the available reactive support within that region.

The reactive margins of connection points within the same transmission region are related by their proximity to injection points or static and dynamic sources of reactive power such as capacitor banks and SVCs. As a result, a single network augmentation may improve the reactive margin of more than one connection point within any given region.

AEMO's 2010 'NEM NSCS Assessment 2009-13' identified reactive deficiencies along the national transmission path. This report found that for the next five years and beyond, the Eastern Hills and Yorke Peninsula regions would each have a reactive deficiency.

ElectraNet has analysed the peak load reactive margins at each of its connection points. The results of this analysis are presented in Table 5.1. Note that crosses indicate that theoretical margin is breached, however, this does not necessarily mean that voltage collapse is imminent. These results align with AEMO's findings and provide additional data for connection points that are not on the national transmission path and therefore were not examined by AEMO. Proposed projects to address the shortfalls identified by this analysis are presented in the respective regional development plan.

Table 5.1: Summary of connection point reactive margin compliance

Location		Year		
Region	**Connection Point**	**2011**	**2015**	**2019**
SOUTH EAST	MOUNT GAMBIER	✗	✗	✗
	BLANCHE	✓	✗	✗
	SNUGGERY	✓	✓	✓
	PENOLA WEST	✓	✓	✓
	KEITH	✗	✗	✗
	KINCRAIG	✗	✓	✓
	TAILEM BEND	✗	✗	✗
Notes: Capacitor bank recommended at Tailem Bend.				
RIVERLAND	NORTH WEST BEND	✓	✓	✓
	MONASH	✓	✓	✓
	BERRI	✓	✓	✓
Notes: Assumes 275 kV injection at Monash in 2018				
EYRE PENINSULA	YADNARIE	✗	✓	✗
	WUDINNA	✗	✓	✗
	MIDDLEBACK	✗	✓	✓
	PORT LINCOLN	✗	✓	✓
	STONY POINT	✗	✓	✓
	WHYALLA	✗	✓	✓
Notes: Assumes 275 kV injection to Pt Lincoln before 2019. Voltage control at Yadnarie and Middleback needs further examination.				
EASTERN HILLS	MOUNT BARKER SOUTH	N/A	✓	✓
	MOUNT BARKER	✗	✓	✓
	ANGAS CREEK	✗	✓	✓
	MANNUM	✓	✓	✓
	MOBILONG	✓	✓	✓
	KANMANTOO MINE	✓	✓	✗
MID NORTH	BAROOTA	✗	✗	✓
	PORT PIRIE	✗	✗	✓
	BRINKWORTH	✗	✓	✓
	WATERLOO	✓	✓	✓
	CLARE NORTH	✓	✓	✓
	TEMPLERS	✗	✓	✓
	DORRIEN	✗	✓	✓
	HUMMOCKS	✗	✗	✓
	ARDROSSAN WEST	✗	✗	✓
	KADINA EAST	✗	✗	✓
	ROSEWORTHY	✗	✓	✓
	DALRYMPLE	✗	✗	✓
Notes: Assumes Brinkworth 2nd TF and Hummocks 275 kV injection by 2019.				

The following observations are specific to the indicated sub-regions and assumptions detailed in the text should be noted:

5.2.1 Metropolitan Subregion

No peak load N-1 reactive margin inadequacies were found in the Metropolitan sub-region over the next 10 years. This is largely due to the highly meshed nature of the system, the high proportion of generation connected within the area, the number of 275/66 kV injection points and the number of capacitor banks connected to the transmission and distribution networks that provide significant levels of reactive support and compensation.

5.2.2 Eastern Hills Subregion

The Mount Barker South 275/66 kV project (commissioning planned for 2011) will address the current reactive reserve shortfall in this area. The installation of the second 275/66 kV transformer at Mount Barker South in approximately 2016 will ensure continuing adequate reactive reserve. Studies performed with and without SA Water pumping loads made minimal difference to the required timing of proposed augmentations with the exception of Angas Creek. Capacitor banks could be installed at Angas Creek as part of the proposed rebuild of the entire substation in about 2023 to address the need for increased 132/33 kV transformer capacity and asset condition.

5.2.3 Mid North Subregion

The planned Templers 275/132 kV injection in 2011 will address the current reactive reserve shortfall in the Barossa Valley area. The future installation of the second 275/132 kV transformer at Templers will ensure continuing adequate reactive reserve.

The planned installation of capacitor banks, initially at Ardrossan West in 2012, followed by additional banks at both Kadina East and Dalrymple in about 2015 will ensure continuing adequate reactive reserve in the Yorke Peninsula region until the thermal capacity of the infeed 132 kV sub-transmission lines supplying this area are exhausted and a new 275/132 kV injection into the area is required in about 2018.

The proposed installation of a second 275/132 kV transformer at Bungama will ensure adequate reactive margins are maintained at Bungama substation and other nearby connection points.

5.2.4 Riverland Subregion

Studies were performed for scenarios with and without SA Water pumping loads. This made minimal difference to the required timing of proposed augmentations with the critical credible contingency being the loss of the Murraylink interconnector.

Planned reactive compensation at Monash will ensure continuing adequate reactive margins until the planned Riverland 275 kV reinforcement project in about 2018.

5.2.5 South East Subregion

For the peak load conditions analysed, the South East interconnector was assumed to be importing into South Australia. The Kincraig capacitor bank planned for 2012 will ensure continuing adequate reactive margin in this region. In addition, when Mount Gambier substation is rebuilt, it will be possible to optimally size the replacement reactive compensation currently located there. Reactive support is required at Tailem Bend in the event of a peak load outage of the Tailem Bend 275/132 kV transformer. An additional capacitor bank at Tailem Bend 132 kV has been proposed to meet this requirement.

5.2.6 Eyre Peninsula Subregion

Two Port Lincoln gas turbines were assumed to be in-service in accordance with the existing network support contract. With this network support contract in place adequate reactive reserves can be maintained until further augmentation of the region occurs. The retirement of Playford Power Station, as discussed in AEMO's NTNDP, results in reduced reactive margins on the Eyre Peninsula 132 kV system. This will require addressing once this scenario eventuates.

5.2.7 Upper North Subregion

Analysis of the Upper North subregion showed no reactive margin deficiencies under N-1 conditions. The retirement of Playford Power Station, as discussed in AEMO's NTNDP, results in reduced reactive margins across the 275 kV Main Grid that will need to be addressed once this scenario eventuates.

5.3 Light Load

Under light load conditions sufficient inductive reactive plant is required to keep system voltages below the maximum level of transmission equipment ratings.

The approach taken in relation to the South Australian transmission system is typically to maintain reactive margins on the South East and Para SVCs, thereby allowing the transmission system enough dynamic reactive reserve to withstand either the trip of the largest generating unit in the state (thus losing its reactive power absorption capability), or the trip of a significant load without resulting in system over-voltage.

System studies performed to assess light load reactive margins within the South Australian transmission system demonstrate that adequate reactive margins exist to ensure voltages are maintained within the acceptable range following credible contingency events involving a trip of a single machine at Northern Power Station or the trip of load at Olympic Dam under light load conditions.

For operating conditions involving Olympic Dam load at 30% of AMD (refer S5.3.5 of the Rules), the trip of a single machine at Northern Power Station results in reactive margins falling just below the acceptable level. The planned replacement of a 30 Mvar 275 kV reactor at Davenport substation (see Upper North Development Plan) with a 50 Mvar unit will resolve this limitation.

As was identified in the peak load reactive planning assessment, the retirement of Playford Power Station results in reduced reactive margins across the 275 kV Main Grid that will need to be addressed once this scenario eventuates.

6. Main Grid Development Plan

6.1 Existing Network Overview

The Main Grid 275 kV transmission system as shown in Figure 6.1 comprises a meshed 275 kV network that connects the Cultana substation, near Whyalla, to South East substation near Mount Gambier and includes two interconnections that connect South Australia to the Victorian region of the NEM. The Main Grid 275 kV transmission system excludes the 275 kV network around the Adelaide metropolitan region which is covered separately.

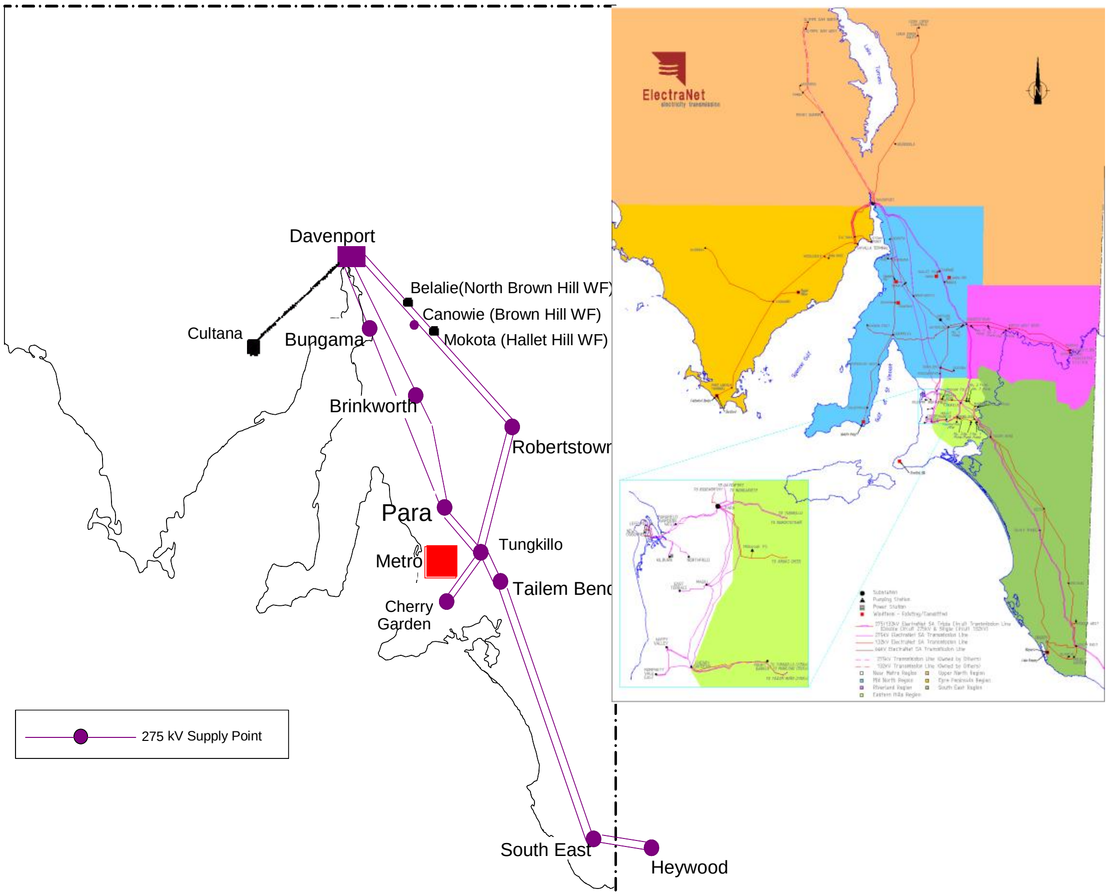


Figure 6.1: Main Grid transmission region

The South Australian Main Grid 275 kV transmission system has been developed progressively over the past 50-years and provides the connection to all significant sources of generation that supply South Australian loads, including those in the eastern states via the interconnections with Victoria. It also provides the main transmission corridor between those generators and the bulk supply substations that in turn supply direct connect customer loads and the distribution system owned by ETSA Utilities.

The nature of the Main Grid 275 kV transmission systems' development has resulted in the injection of power from the high voltage network into the 132 kV regional transmission networks. These regional transmission networks operate in parallel with the Main Grid 275 kV system and are inherently lower rated. Any increase or variation in generation and load is ultimately reflected on the Main Grid 275 kV transmission system, which must be capable of performing adequately within the technical and operational requirements of the Rules, the ETC, and Good Electricity Supply Industry Practice as that term is defined in the Rules.

There is presently one customer load directly connected to the Main Grid 275 kV transmission system which is the BHP Billiton (BHPB) Olympic Dam copper/uranium mine that is located in the upper north of the State. Several projects are presently in the planning phase which will see additional load directly connect to the Main Grid transmission system. These include new mining and industrial consumers in various parts of the State.

In general, the 275/132 kV substations are designed to reinforce the 132 kV regional networks that supply ETSA Utilities and other directly connected 132 kV customers that connect at their bulk supply connection points. A simplified representation of the Main Grid 275 kV transmission system is shown in Figure 6.2.

6.1.1 Existing and Committed Generation

Major points of generation exist on the 275 kV transmission system at Northern Power Station (520 MW), Playford Power Station (240 MW), Torrens Island (1280 MW), Pelican Point (504 MW) and the Hallett gas turbine (GT) Power Station (192 MW). In addition there are a number of other GT driven power stations connected to the 132 kV and 66 kV system at Dry Creek (156 MW installed capacity), Mintaro (90 MW), Osborne Cogeneration (190 MW), Port Lincoln (75 MW), Snuggery (63 MW) and Quarantine (225 MW) that indirectly supply the Main Grid 275 kV system.

At present there are three operational wind farms that are directly connected to the Main Grid transmission system at Canowie (Brown Hill WF), Belalie (North Brown Hill WF) and at Mokota (Hallett Hill WF). The Porcupine Range wind farm is currently under construction and will connect to the Belalie 275 kV substation with a number of other wind farms at various stages in the connection process.

However, it should be noted that all generation in the state (whether connected to ElectraNet or to ETSA Utilities network) will have an impact on flows in the Main Grid transmission system to some degree; particularly those connected to the Eyre Peninsula, Mid North and South East 132 kV transmission regions.

6.1.2 Intra-regional Transfer Capability

At present there are three wind farms connected to the Main Grid 275 kV transmission network; Brown Hill, Hallett Hill and North Brown Hill wind farms. These wind farms experience minimal generation constraints under system normal and many single planned outage network configurations.

In order to meet the system security requirements in the Rules, generation located north of Robertstown, including that connected on the Eyre Peninsula and at Playford and Davenport will need be constrained under certain operating conditions, including during some planned maintenance (e.g. 275 kV circuit breaker maintenance at Robertstown).

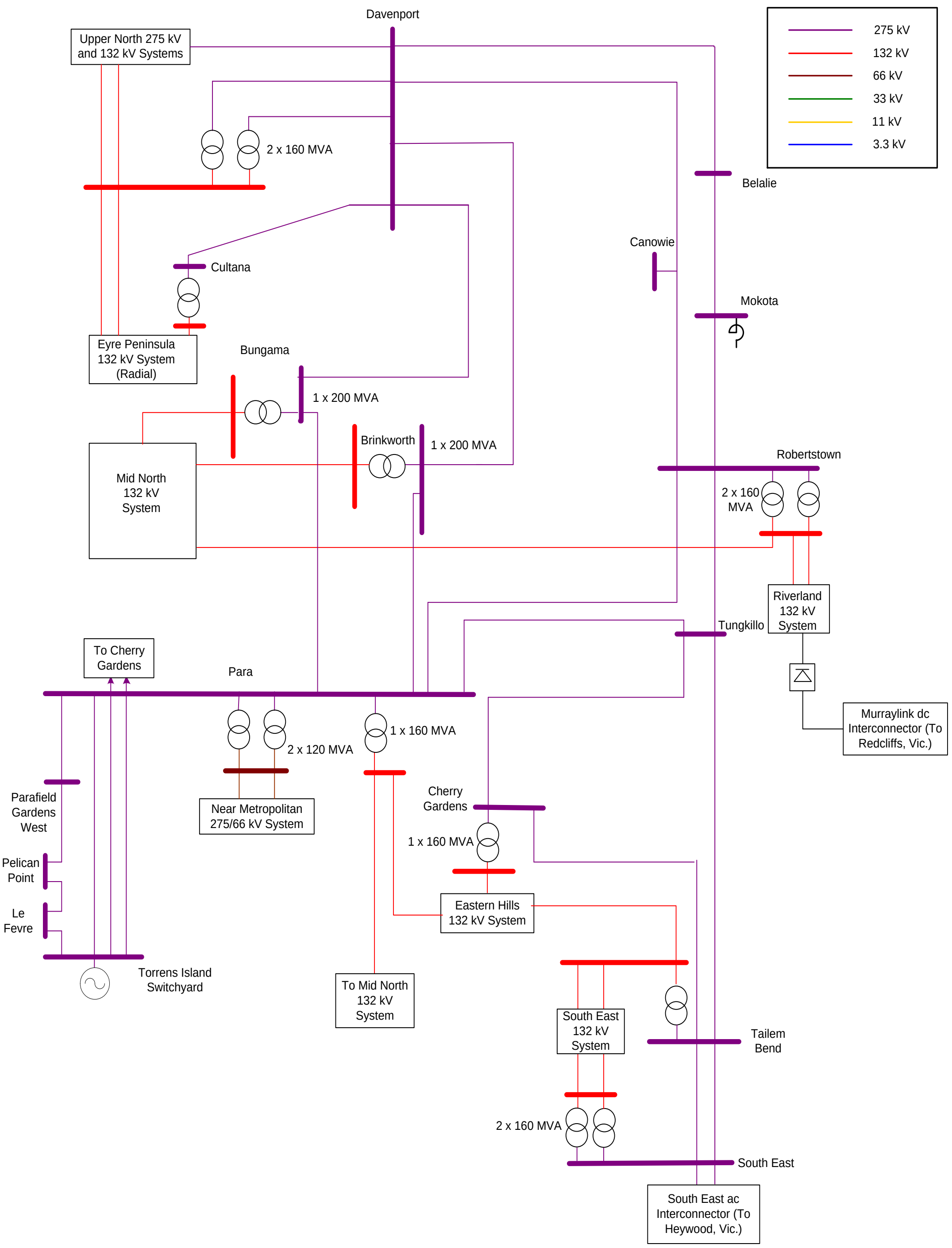


Figure 6.2: Existing Main Grid transmission network single line diagram

6.2 Study Methodology

6.2.1 Planning Criteria and Assumptions

This development plan has been prepared according to the planning framework described in Appendix D.

6.2.2 20 Year Load Forecast

The Main Grid development plan analysis is based on the undiversified load forecasts provided by ETSA Utilities and other direct-connect customers. This analysis assumes that all the connection points experience the forecast Agreed Maximum Demand (AMD) simultaneously. The 20-year SA high, medium and low demand forecasts for the Main Grid are shown in Figure 6.3. Refer to Appendix B for more information in relation to load forecasts.

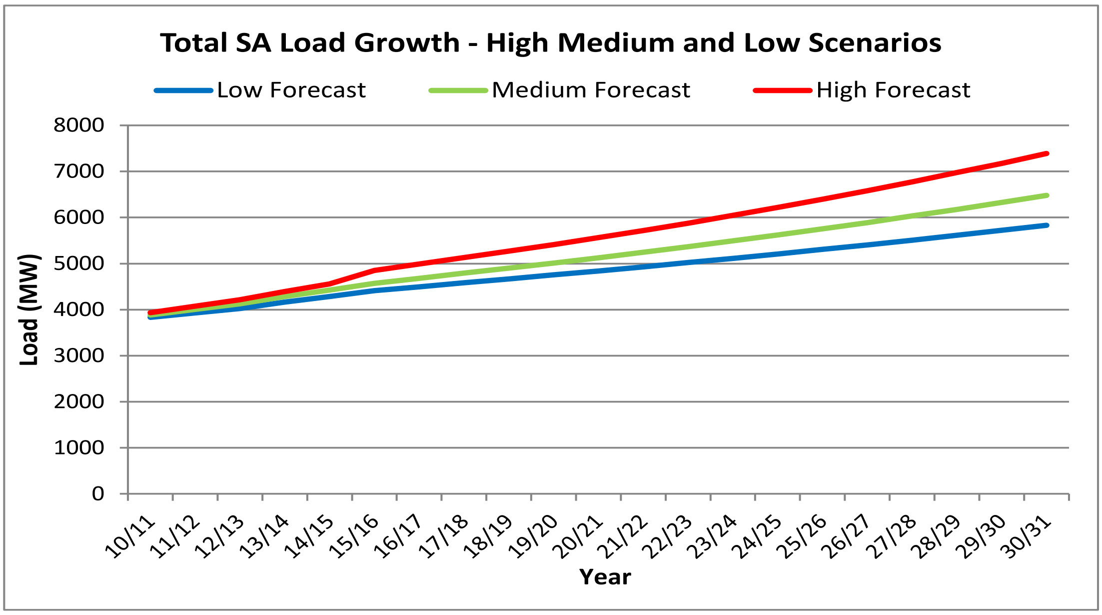


Figure 6.3: Main Grid 20-year peak load forecasts

6.2.3 Special Considerations in the Main Grid

The base case for this development plan uses the future generation assumptions contained within the NTNDP Scenario 3 forecast. This assumes that open cycle gas turbine plant (OCGT) will be connected at both Torrens Island and Tungkillo to balance the demand.

<u>Critical Operating Conditions</u>

A number of critical operating conditions were examined which may result in different investment plans. These operating conditions are:

- The retirement of Playford power station as defined in NTNDP;
- The prior outage of one Northern Power Station unit followed by a single contingency event which could be either a transmission element or another generation unit; and
- The prior outage of one main 275 kV line followed by another major transmission line in the same region.

<u>Low Probability High Risk Events</u>

Certain low probability events may result in high risks to system security should these occur. While not included in the investment plan, these high risk events need to be analysed so that emergency operation plans can be developed and put in place. For the Main Grid, the following low probability/high risk event was analysed:

- Prior outage of a double circuit 275 kV transmission line followed by single contingency outage of another network element.

NTNDP Future Generation Connections

The alternative NTNDP scenarios propose different future generation plans. Where possible this development plan attempts to utilise the existing South Australia transmission network. However, this is not always possible and any project which is triggered by a new generation connection is described as market benefit project.

Main Grid Stability Limit Assessment

An assessment of the long term stability limits of the Main Grid network has been conducted in order to investigate the impact of proposed projects and developments on existing limits and to identify emerging limitations. Studies were performed for the years of 2019 and 2021 under peak load import and light load export conditions. In addition to including proposed network developments, additional generation was assumed within the South Australian transmission network within the metropolitan area and also in the vicinity of Tungkillo substation. The studies applied numerous line and generator contingencies to the Main Grid transmission system in order to determine limits for critical contingencies.

Steady state analysis has identified the requirement for additional reactive support at Davenport. The addition of a capacitor bank at Davenport resolved the identified steady state voltage limits; however dynamic limits were still identified. Therefore, an SVC is likely to be required at Davenport. The exact configuration of the reactive support required at Davenport is subject to further analysis. Dynamic analysis has identified stability limits under import and export conditions post 2019. The solution to these limits will also be the subject of further investigation.

6.2.4 Fault Levels

Substation fault levels are assessed to remain within design and equipment limits. A table listing the 5 year maximum substation fault levels and circuit breaker ratings is provided in Appendix C of this report.

6.3 Connection Opportunities

This section identifies potential opportunities for the connection of additional generation and load to the 275 kV transmission network. Generation and load proponents should take this information into account when considering the location of their projects (especially for larger projects).

6.3.1 Generation Connection Opportunities

Any point in the proximity of the Main Grid 275 kV transmission system should be suitable for a new generator to connect. Specifically, the following represent strategic locations in close proximity to fuel sources:

- Tailem Bend
- Tepko

- Mallala
- Hallett
- Templers

Other electrically favourable sites for connecting generation are:

- Davenport
- Cultana
- Bungama
- Wilmington
- Lincoln Gap
- Belalie
- Brinkworth
- Mokota
- Robertstown
- Black Range
- Krongart

6.3.2 Load Connection Opportunities

Any point in the proximity of the Main Grid 275 kV transmission system should be suitable for a new load to connect. However, any substantial load connections may require deep network augmentation to provide a reliable supply arrangement.

6.4 Constraints and Proposed Augmentation Projects

Projected power system limitations within the Main Grid 275 kV system are highly dependent on load growth and demand from both directly connected customers and on ETSA Utilities distribution system as well as the development of renewable generation throughout the regions of the State. Developments in the seven State regions have been examined individually, and where necessary the combined impact of those individual projected network and connection point limitations has been examined to determine any impacts that result on the Main Grid network.

The network limitations, along with the proposed solutions, timings, estimated capital expenditures, and option analysis for projects that have been identified for the next 5-year period are described in section 6.4.1. Projects identified for the initial 10-year period of this 20 year development plan, including those projects that will improve the performance of existing plant and equipment, rather than physically adding to the asset base (e.g. installing control schemes to maintain network security) and will be triggered by a sudden load increase, the timing of which is not yet known, are summarised in Table 6.1 and Table 6.2. Finally, asset replacements are considered separately, and are listed in Table 6.4.

6.4.1 5-Year Major Augmentation Projects

Tungkillo 100 Mvar Capacitor Bank

Scope of Work: Install 1 x 100 Mvar 275 kV Capacitor Bank at Tungkillo

Estimated Cost: $6 Million

Timing: 2012

Project Status: Passed Regulatory Test

Project Need

The SVCs located at ElectraNet's Para substation were installed to ensure that stable voltage control could be maintained following a significant single contingency event. Two 100 Mvar 275 kV capacitor banks are installed at Para substation in addition to the SVCs located there. One of these capacitor banks was installed to ensure that adequate steady state voltages can be maintained under system normal peak load conditions without the need for the Para SVCs to generate Mvars. This ensures that the full capability of the SVCs is available to respond to severe network disturbances. The second 100 Mvar capacitor bank was installed to increase the range of the Para SVCs and was to be switched only under significant single contingency conditions.

As a result of continued load growth on the South Australian transmission system, under peak load conditions, the second 100 Mvar capacitor bank at Para which was intended to extend SVC dynamic range is now required to maintain adequate operating voltages under system normal conditions.

In order to ensure that the Para SVC has adequate reactive range to respond to critical network disturbances, an additional 100 Mvar capacitor bank is required on the 275 kV transmission system. The ideal location for this 275 kV 100 Mvar capacitor bank is at an existing 275 kV substation in close electrical proximity to the metropolitan area where connection of a capacitor bank would require minimal construction works and capital cost.

ElectraNet is proposing to install a 100 Mvar 275 kV capacitor bank at the Tungkillo substation in the Eastern Hills of South Australia.

The Network Augmentation consultation paper for this project can be found in ElectraNet 2010 Annual Planning Review, Chapter 19.

6.4.2 Future Augmentation Projects

The following tables contain the list of emerging limitations that have been identified during the development plan study. These represent the recommended network solution based on high level cost estimates and professional engineering judgement and are the most likely of several options. These solutions are subject to variation and change as further study and network development occur. Due to the lack of the certainty on the customer connection, the projects are indicative in terms of timing and the scope of work. The proposed network solution for each constraint will be updated as the better information becomes available.

The table below lists all identified augmentation projects in the region over the next 10-years. A range of project implementation dates is provided where the timing has been determined according to the NTNDP 2010 scenarios.

NTNDP Scenarios:

- S1: Fast Rate of Change
- S2: Uncertain World
- S3: Decentralised World
- S4: Oil Shock and Adaptation
- S5: Slow Rate of Change

Table 6.1: Proposed 10-year Main Grid augmentation projects

Project Timing (NTNDP S3)	Project Timing (NTNDP S1 & S2)	Project Timing (NTNDP S4 & S5)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2012			An unplanned outage of 275 kV transmission lines results in inadequate reactive power reserve on the Para SVC.	Install 1 x 100 Mvar 275 kV switchable PoW capacitor bank at Tungkillo switching station	Augmentation	6
2016			High load increase in the Upper North 275 kV network and possible power station retirement identified by NTNDP in Upper North, one of the Northern generator units out of service will cause inadequate reactive support in the area.	Install a SVC at Davenport	Augmentation	23
2018			Step load increase in Upper North request additional reactive power support due to the loss of Northern generation unit	Install 1 x 100 Mvar 275 kV switchable PoW capacitor bank at Davenport substation	Augmentation	6
2013-2018			Lack of an earth wire on the on the Davenport to Bungama to Para 275 kV line circuit poses a significant network security risk and telecommunications limitations adversely impacting on protection effectiveness	Install OPGW earth wire on the Davenport to Bungama to Para 275 kV line (‘West’ circuit) on one earth peak and ordinary aluminized steel earth wire on the other earth peak	Security/ Compliance	38
2013-2018			Continued growth of wind generation in South Australia results in periods of constraint when utilising static line ratings	Install additional weather stations across the state and operate circuits as required in real-time	Augmentation	4.5
2013-2018			Non-compliant NGM CTs and VTs at various connection points	Replace all non-compliant plant	Security/ Compliance	5
2013-2018			Increasing difficulties in securing maintenance outage windows and maintaining adequate quality of supply on radial networks	Implement a range of engineering solutions to improve supply reliability and to expand outage windows available to performance necessary maintenance on the network	Security/ Compliance	5
2013-2018			Increased loading on the 275 kV network has made compliance with Rules Ch. 4 security provisions difficult operationally and has reduced the opportunities to do critical network maintenance and construction work to very restrictive windows	Install an integrated control scheme in the Main Grid region that will ensure compliance to the ‘next contingency’ security requirements of the Rules and allow a higher utilisation of the network under system normal conditions as well as provide the opportunity to do network maintenance as required	Security/ Compliance	3.5

The table below lists all identified augmentation projects in the region in the 10-20 year period. Project timing is indicative and is based on medium economic growth (NTNDP Scenario 3: Decentralised World).

Table 6.2: Proposed 10-20 year Main Grid augmentation projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2028-2033 Market Benefit may advance timing	Unplanned outage of Mid North 275 kV line overloads the Para – Templers West – Brinkworth – Davenport 275 kV circuit	Uprate the 275 kV Para – Templers West - Brinkworth – Davenport circuit from 65^{0}C to 80^{0}C	Augmentation	38

6.4.3 Potential Market Benefit Projects

Constraints analysis identifies market benefit projects that may improve the transmission network transfer capability available to the market. Project costs are indicative.

Table 6.3 Main Grid potential market benefit projects

Strategic value – Trigger for Project	Description of Project	Capacity/Benefit Provided	Cost (AU$ M)
Increased wind generation in Mid North causes increased generation flows on the Davenport-Robertstown-Para line section and increased generation at Tailem Bend or Tepko.	Tie in Robertstown-Para 275 kV line at Tungkillo	Increase in transfer capacity from Mid North to Adelaide	10
Increased wind/renewable generation in South Australia	Develop a new interconnector to Eastern states. New Inter-connector from Wilmington, Tepko or Penola to NSW/Victoria.	1000 to 3000 MW (dependant on Generation, Load development and AEMO's National transmission plans)	Up to 1000 (SA costs)
Supports interconnector development and helps in optimising the intra-regional system	Rebuild Davenport-Brinkworth-Para as a high capacity 275 kV AC double circuit line with twin conductors	1200 MW	250
Generation driven	Tie the double circuit 275 kV line from Davenport to Robertstown in at Belalie or at Mokota	Balance line flows, maximise utilisation of existing network and limit generation constraints post N-1 conditions	40
Increased generation injection at Tailem Bend or Tepko or increased interconnector capacity.	Tailem Bend to Tungkillo Reinforcement -string vacant 275 kV circuit between Tailem Bend and Tungkillo	400 to 600 MW increase in line section	50

6.5 Anticipated Replacement Projects

Asset replacements are planned based on asset condition. Asset condition monitoring is used to determine the actual timing of any asset replacement. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

Table 6.4: Proposed Main Grid replacement projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2008-2013	Unmanageable voltages at Davenport Substation at times of light Upper North load; condition of the existing 30 Mvar reactors requires replacement	Install 1 x 50 Mvar 275 kV PoW switched reactor on the Mokota exit, replacing the existing 30 Mvar reactor	Replacement	4.4
2008-2013	Condition of Westinghouse RTUs putting reliability of the communication network at risk	Replace aged RTUs with modern day equipment	Replacement	2.6
2008-2013	Condition of the existing secondary systems limiting protection effectiveness at the 275 kV TIPS 'A' switchyard	Replace the existing secondary systems with modern day equipment and minor poor condition plant	Replacement	11
2008-2013	Condition of the existing secondary systems limiting protection effectiveness at the 275 kV TIPS 'B' switchyard	Replace the existing secondary systems with modern day equipment and minor poor condition plant	Replacement	10
2013-2018	Condition of the existing Para SVC control system and the lack of spare parts make maintenance impossible and manufacturer support is largely withdrawn; significant business risk that failure will result in one or both SVCs being unavailable for significant periods, with severe impact on the interconnectors transfer capacity	Replace the existing SVC control system with modern day equipment	Replacement	16

6.6 Future Network Single Line Diagram

Figure 6.4 shows the Main Grid transmission network with all of the proposed projects included, illustrating how the 275 kV network in the state may be developed over the next 20 years (where the dashed lines represent proposed developments).

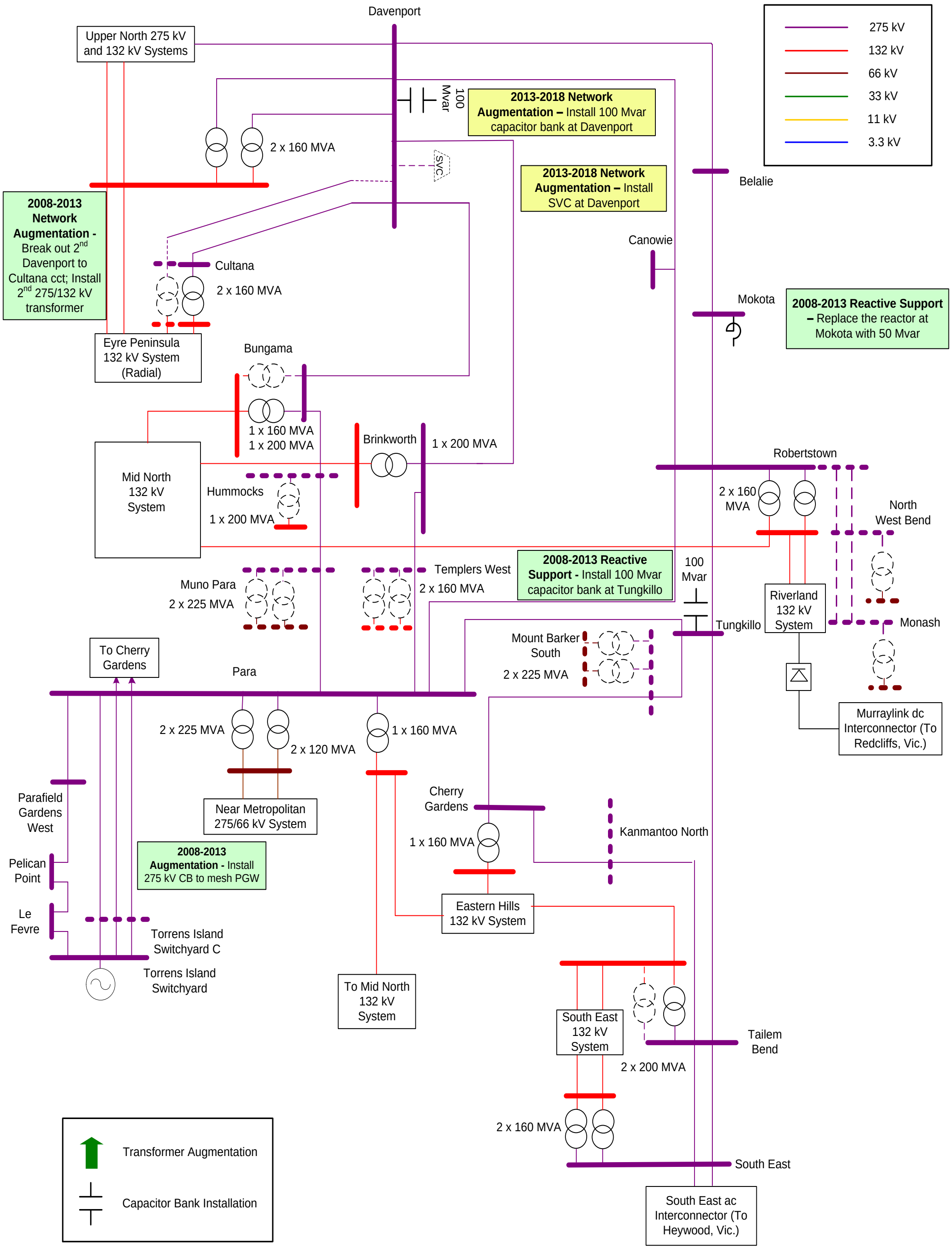


Figure 6.4: Main Grid 20-year development plan single line diagram

7. Metropolitan Region Development Plan

7.1 Existing Network Overview

The city of Adelaide is located about 10 kilometres inland from St. Vincent's Gulf, and is bounded by the Mount Lofty Ranges approximately 10 kilometres to the east. As the city's population increases, growth of the metropolitan area will essentially be restricted to the north and south of the city due to those geographical barriers, with the east and west experiencing an increase in density of housing and commercial and industrial enterprise rather than physical encroachment.

The Metropolitan 275 kV transmission region includes connection points that service the CBD and metropolitan domestic, commercial and industrial loads. Over 80% of the South Australian population is contained within and serviced by the Metropolitan transmission region.

The CBD contains South Australia's major centre of commerce and government, and this has been recognised by creating a separate electricity supply region for the CBD and assigning it the highest level of supply reliability mandated in the legislated ETC. The Eastern Suburbs region, which was previously associated with the CBD in the ETC has retained its previous level of supply reliability (Category 5). The remainder of the Adelaide suburban electricity supply system remains as Category 4 supply areas.

The geographical area representing the metropolitan region is shown in Figure 7.1, with a simplified representation of the metropolitan 275/66 kV transmission network that services the region provided in Figure 7.2 and Figure 7.3.

As the Adelaide metropolitan region has expanded, the 66 kV network has been progressively developed to accommodate the demand for electricity. The development of the interconnected 66 kV network has required increasing sources of 275/66 kV injection to be established at strategic locations in order to meet the growing demand on capacity, and to provide an acceptable level of supply reliability.

Shown in Table 7.1 is a list of the connection points that supply the metropolitan region and the reliability classification presently assigned to each in the ETC. Refer to Appendix D for details in relation to the ETC Connection Point Reliability Standards.

Table 7.1: Metropolitan region connection point ETC categorisation

Connection Point	ETC Category
Adelaide Central	6
Eastern Suburbs	5
Southern Suburbs	4
Western Suburbs	4
Para Area	4

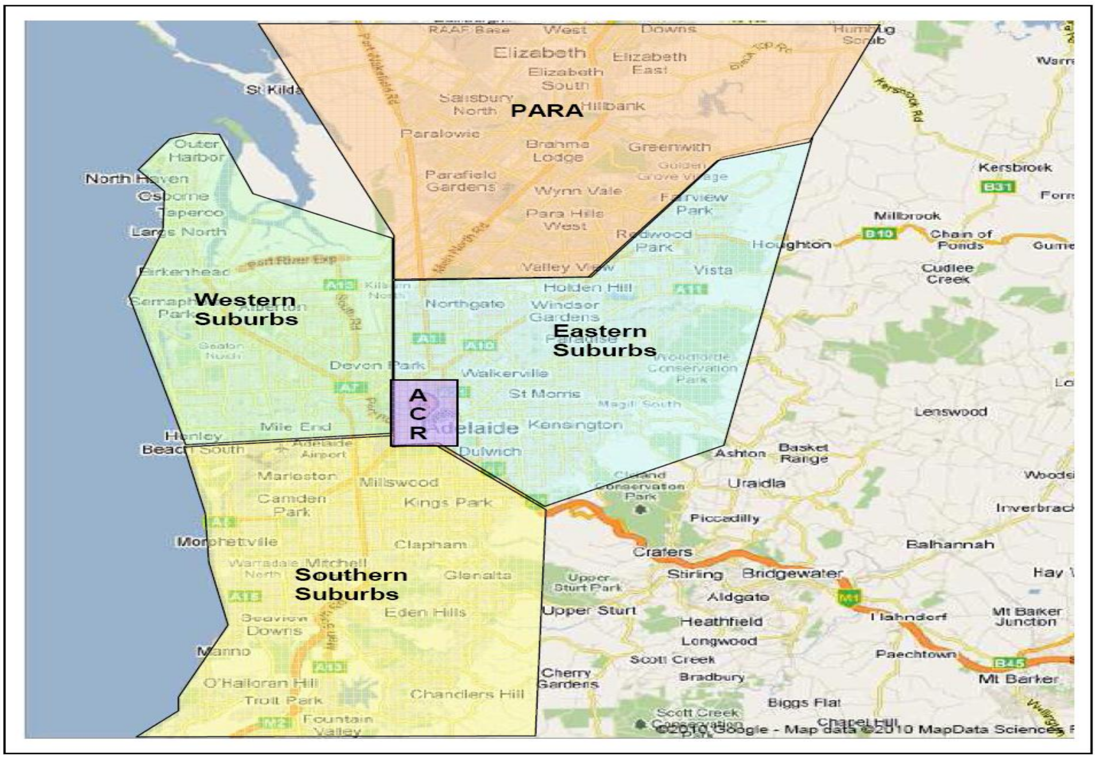


Figure 7.1: Metropolitan supply region

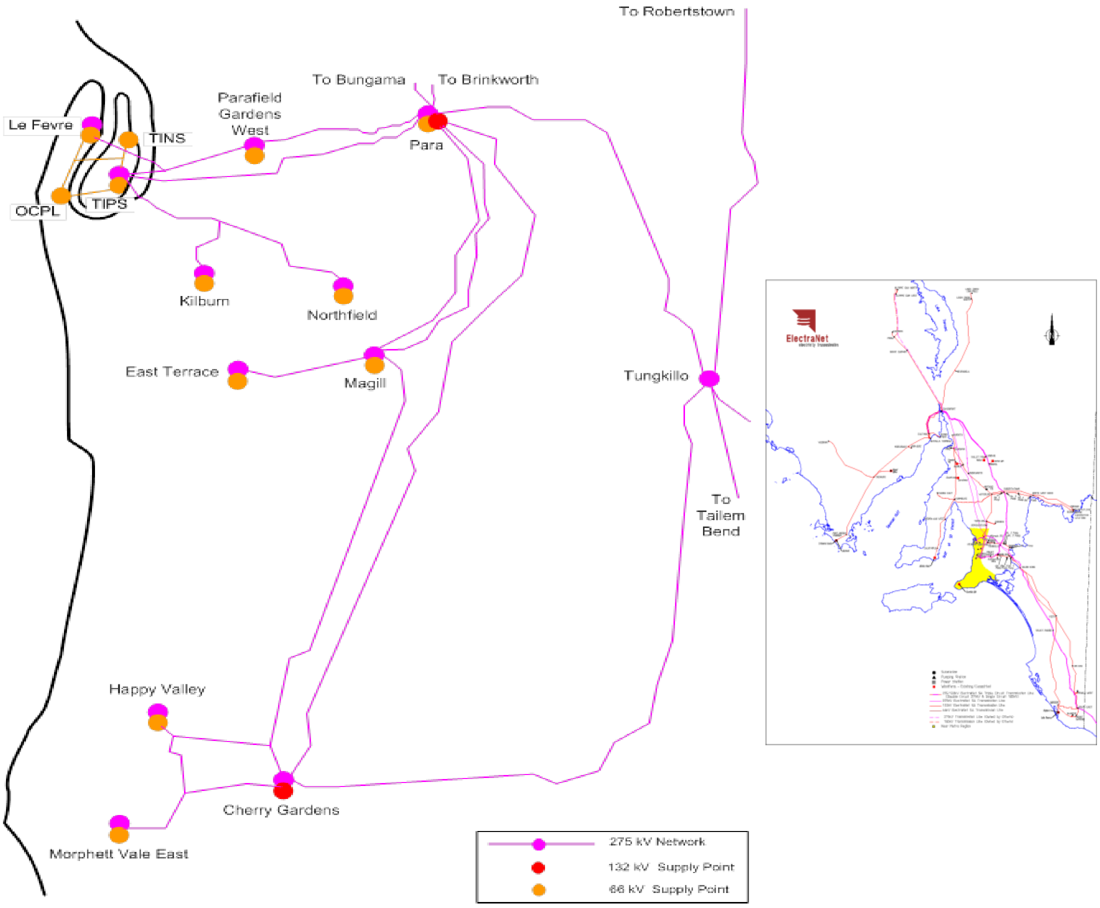


Figure 7.2: Metropolitan transmission region

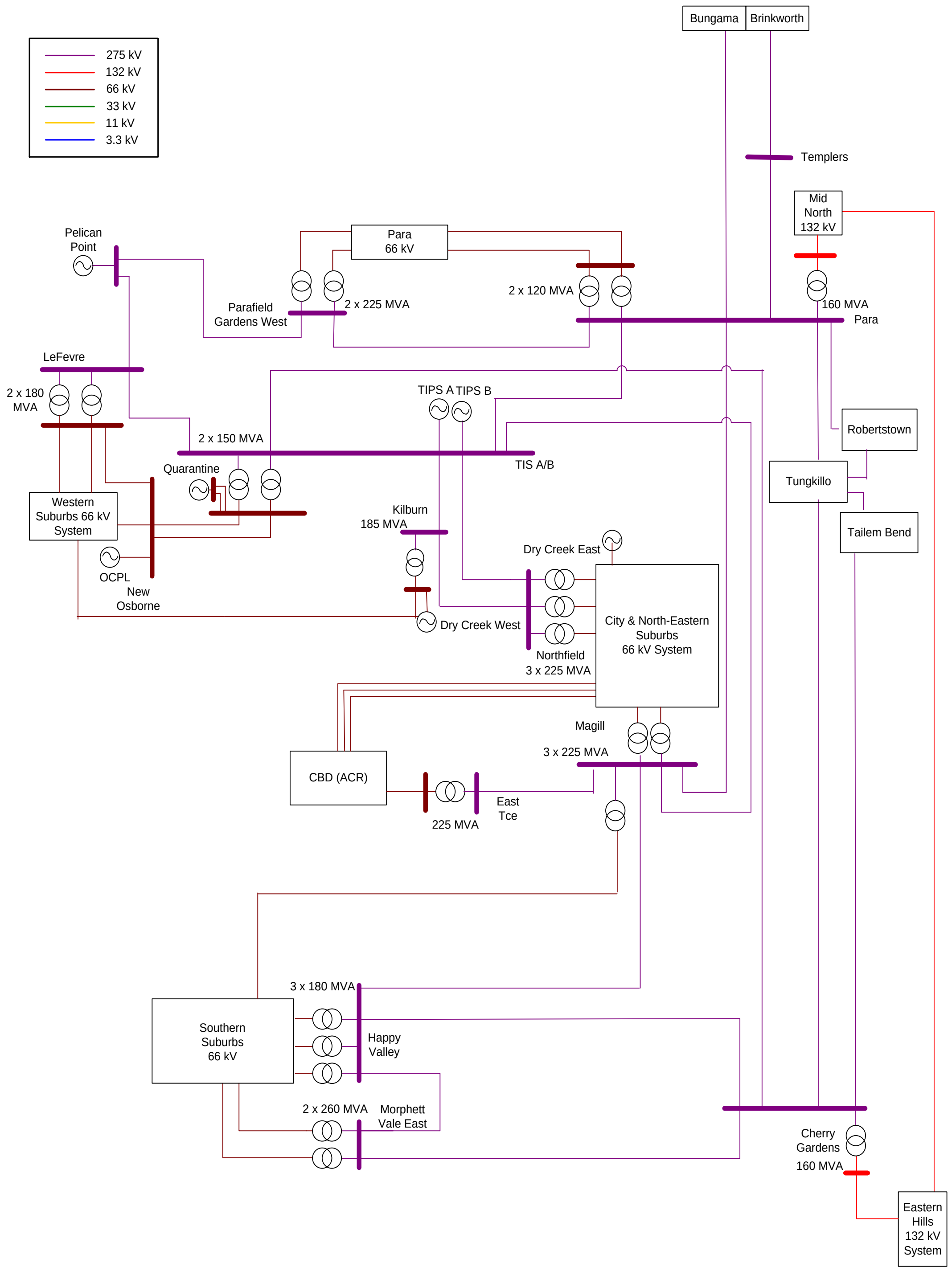


Figure 7.3: Existing Metropolitan transmission network single line diagram

7.1.1 Existing and Committed Generation

Major points of thermal generation exist on the Metropolitan 275/66 kV system. Torrens Island Power Station (1280 MW) and Pelican Point Power Station (487 MW) connect to the 275 kV network. In addition there are a number of generators connected to the 66 kV network at Dry Creek (156 MW), Osborne Cogeneration (190 MW) and Quarantine (225 MW) (all in the Western Suburbs). There are also 'embedded' generators connected to the ETSA Utilities 66 kV power system at Port Stanvac (65 MW), Lonsdale (21 MW), Starfish Hill Wind Farm (35 MW) and various biomass generators (~14 MW).

There are presently no committed wind generation projects proposed for direct connection into the Metropolitan 275/66 kV transmission region and consequently the impacts of wind generation have not been included in this development plan.

A portion of the metropolitan 275/66 kV transmission system forms part of the interconnection between the South Australian and the Victorian regions of the NEM following the commissioning of the Tungkillo switching station as the 275 kV section from Cherry Gardens to Tungkillo is now subjected to interconnector flows. This has resulted in increased oversight of this area by AEMO in performing its role of maintaining system security.

7.1.2 Intra-regional Transfer Capability

Generation in the Adelaide metropolitan area experiences minimal generation constraints under system normal and the majority of single planned outage network configurations. However, Pelican Point Power Station is constrained to 273 MW following the outage of either a Pelican Point – Parafield Gardens West or Pelican Point – Le Fevre 275 kV line to allow for the next contingency event and maintain system security as required by the Rules. Constraints are also applied to Pelican Point for outages of either a Parafield Gardens West – Para or Le Fevre – Torrens Island 275 kV line to prevent 275/66 kV transformer and/or distribution system overloads.

7.2 Study Methodology

7.2.1 Planning Criteria and Assumptions

This development plan has been prepared according to the planning framework described in Appendix D.

7.2.2 20 Year Load Forecast

Electrical demand in the Metropolitan 275 kV transmission system has grown steadily over the years as a result of residential, commercial and industrial development. The Metropolitan transmission system distribution connection points and their associated 10-year economic growth load forecasts are shown in Appendix B. This load forecast has been extrapolated by ETSA Utilities to cover the full 20-year period of interest for the medium load growth scenario. The 20-year high, medium and low demand forecasts for the Metropolitan 275/66 kV system are shown in Figure 7.4.

7.2.3 Special Considerations in the Metropolitan Region

The special considerations given to the Metropolitan development plan studies are:

<u>Critical Operation Conditions</u>

The study has evaluated several critical operating conditions which may result in a different investment plan. These operating conditions were:

- One of the Northern Power station units is out of service while losing one of the Para SVC;
- All Metro West generating units out of service (i.e. OCPL, Quarantine and Dry Creek) while losing the TIPS – City West 275 kV cable; and,
- A prior outage of any of the Northfield – TIPS, TIPS – Kilburn and Northfield – Kilburn 275 kV lines outage followed by the loss of another 275 kV circuit in the region.

<u>Low Probability High Risk Events</u>

Certain low probability events may result in high risks to system security should these occur. While not included in the investment plan, these high risk events need to be analysed so that emergency operation plans can be developed and put in place. For the Metropolitan 275/66 kV system, the low probability but high risk event which was selected for the analysis is:

- Metro West 66 kV generation out service, (i.e. OCPL, Quarantine and Dry Creek) during peak load conditions.

<u>NTNDP Future Generation Connections</u>

The NTNDP scenarios show that future generation in the Metropolitan area will connect to the 275 kV network at Torrens Island. This is consistent with the base case study used for the Metro development plan studies.

As a result of the different load growth assumptions used in the NTNDP scenarios, constraints will manifest themselves in different years. The regional development plan study will identify the changes in project dates as a result of the differing NTNDP scenarios.

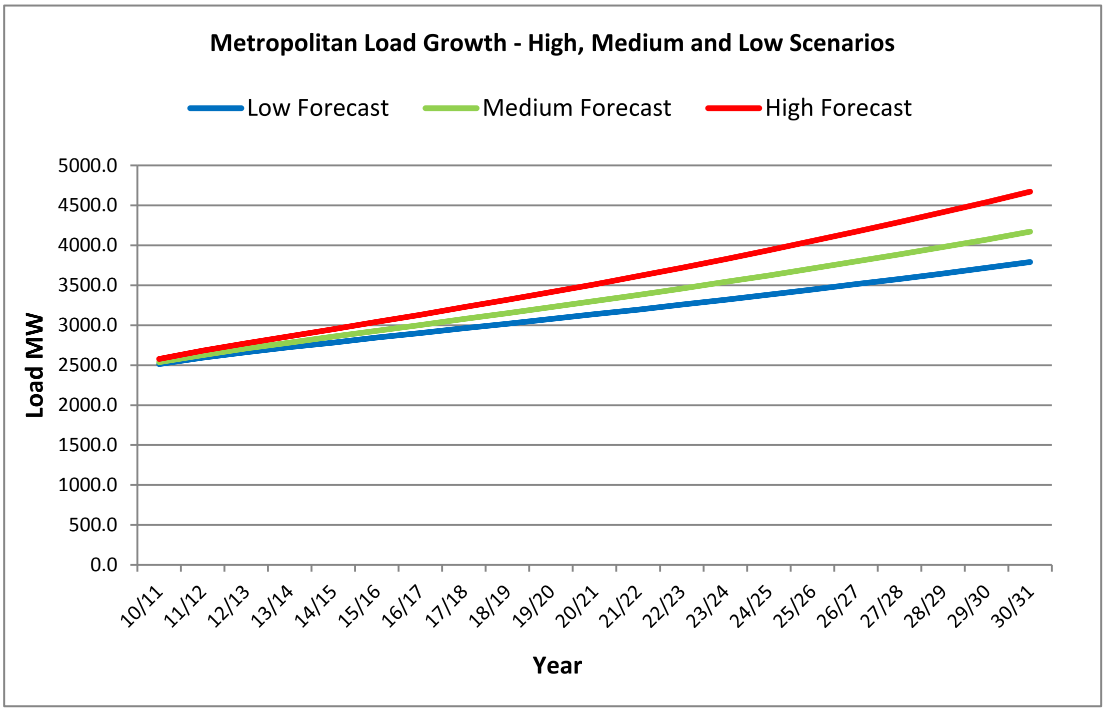


Figure 7.4: Metropolitan region 20-year peak load forecasts

7.2.4 Fault Levels

Substation fault levels are assessed to remain within design and equipment limits. A table listing the 5 year maximum substation fault levels and circuit breaker ratings is provided in Appendix C of this report.

7.3 Connection Opportunities

This section identifies potential opportunities for connection of generation and load to the transmission network. Generation and load proponents should take this information into account when considering the location of their projects (especially larger projects).

7.3.1 Generation Connection Opportunities

Because of the population density within the Metropolitan 275 kV transmission region, development approval for network augmentations and extensions, or new generation, is difficult to obtain in practice. This limits the ability to economically provide new infrastructure to meet growing electricity demands.

Existing fault levels are approaching the plant capability of both ElectraNet's and ETSA Utilities' assets, particularly in the vicinity of Torrens Island, LeFevre, Kilburn, Northfield and Magill. Therefore, while the existing Metropolitan 275/66 kV system may be able to accommodate new generation connections, these may accelerate the need for the major augmentation and/or replacement of existing assets at a number of locations.

7.3.2 Load Connection Opportunities

Electrical demand on the Metropolitan 275 kV transmission system has grown steadily over the years as a result of residential, commercial and industrial development in the Adelaide metropolitan area. All customer loads in this region are ultimately supplied by the Metropolitan 275 kV transmission system. While there are numerous individual customer connection points in the Metropolitan region, with the exception of generators, those connection points service the ETSA Utilities distribution network which in turn supplies individual electricity consumers.

The Metropolitan 275/66 kV system services five sub-regions, namely the Western Suburbs, Northern Suburbs, the Southern Suburbs, the Adelaide Central Region (ACR which includes the CBD), and the Eastern Suburbs (which incorporates the North-Eastern Suburbs).

The existing Metropolitan 275/66 kV system can accommodate new load connections. Depending on size and location these load connections may accelerate the need for the major augmentation and/or replacement of existing assets.

7.4 Constraints and Proposed Augmentation Projects

Projected power system limitations within the Metropolitan 275/66 kV system are highly dependent on load growth and demand on the ETSA Utilities distribution system within the five individual grouped connection points defined in the ETC. Those five sub-regions of the Metropolitan 275/66 kV region have been examined individually within this development plan, and where necessary the combined impact of those individual projected network and connection point limitations has been examined to determine any impacts that result on the overall supply system in the region.

The network limitations, along with the proposed solutions, timings, estimated capital expenditures, and option analysis for projects that have been identified for the next 5-year period are described below. Projects identified for the initial 10-year period of this 20 year development plan, including those projects that will be triggered by a sudden load increase, the timing of which is not yet known, are summarised in Table 7.2 and Table 7.3. Finally, asset replacements are considered separately, and are listed in Table 7.4.

7.4.1 5-Year Major Augmentation Project

<u>Adelaide Centre Reinforcement</u>

Scope of Work: Establish City West substation with 2x300 MVA, 275/66 kV transformers and independent 275 kV supply from Torrens Island

Estimated Cost: $170 Million

Timing: 2011

Project Status: Committed Project

Project Need:

The ACR is a new electrical sub-region defined for the first time in the July 2008 version of the ETC. It is a sub-set of the region that originally encompassed both the Adelaide CBD and the North-Eastern Suburbs of Adelaide. The new sub-region has been geographically defined as the area bordered by the city of Adelaide's South, East and West Terraces, and the River Torrens, to the north. This area is presently supplied by East Terrace 275/66 kV substation, with support from the surrounding suburban 66 kV networks.

From 2011, the ETC mandates the creation of an ACR sub-region and a new load category (Category 6), requiring continuous N-1 transmission line and transformer capacity for at least 100% of the AMD. The ETC also stipulates that ElectraNet establish a new, independent and diverse transmission substation to the west of King William Street to provide an independent source of supply to the ACR, and that the new substation be supplied from an independent and diverse part of the transmission network. In addition to meeting the requirements of the ETC regarding supplies to the ACR, the solution also resolves constraints within the Metro South region. The Southern Suburbs sub-region comprises 275/66 kV connection points at Magill, Happy Valley and Morphett Vale East substations. An unplanned outage of Happy Valley 275/66 kV transformer results in thermal overload of remaining units. In addition, there are several 66 kV distribution network limitations under N-1 conditions.

To meet the ETC service standards in both the ACR and the Southern Suburbs regions ElectraNet is constructing the City West substation which will include two 300 MVA 275/66 kV transformers, one to supply the ACR and the other to service the Southern Suburbs.

A Regulatory Test was completed in 2006 which indicated that this solution was the most efficient to resolve the identified constraints. ElectraNet does not envisage that this project will have any material impact on inter-regional transfers.

Munno Para 275 kV Injection

Scope of Work: Establish a new 275/66 kV injection point at Munno Para comprising a single 225 MVA transformer

Estimated Cost: $42.6 Million

Timing: 2014

Project Status: Passed Regulatory Test

Project Need:

This project is driven primarily by an ETSA Utilities connection request. ETSA Utilities has indicated that load growth in the Northern Suburbs sub-region causes constraints in the underlying 66 kV transmission system. This load growth has also caused 275/66 kV transformer capacity constraint that this project will resolve.

Additional load growth is expected in the northern Metro due to the SA Government 30-year development plan. To consider this additional load growth and due to the marginal cost increase, it may be cost effective to install a 300 MVA 275/66 kV transformer instead of a 225 MVA unit. This will be analysed more closely during the project planning phase.

Public consultation on this project was completed in October 2007; therefore ElectraNet will not be publishing a Project Specification for this project. ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

7.4.2 Future Augmentation Projects

The following tables contain the list of emerging limitations that have been identified during the development plan study. These represent the recommended network solution based on high level cost estimation and professional engineering judgement and are one of several options. These solutions are subject to variation and change as further study and network development occur. Due to uncertainties of the timing and number of customer connections within the Para region, the projects are indicative in terms of timing and the scope of work. The proposed network solution for each constraint will be updated as more information becomes available.

The table below lists all identified augmentation projects in the region over the next 10-years. A range of project implementation dates is provided where the timing has been determined according to the NTNDP 2010 scenarios.

NTNDP Scenarios:

- S1: Fast Rate of Change
- S2: Uncertain World
- S3: Decentralised World
- S4: Oil Shock and Adaptation
- S5: Slow Rate of Change

Table 7.2: Proposed 10-year Metropolitan network augmentation projects

Project Timing (NTNDP S3)	Project Timing (NTNDP S1 & S2)	Project Timing (NTNDP S4 & S5)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2011			ETC category defined Adelaide Centre as Category 6 which requires continuous N-1 transmission line and transformer capacity for at least 100% of the AMD. Outage of one of the 275/66 kV transformer in Metro South will cause the 66 kV line overloading.	Establish City West 275/66 kV substation. Install two x 300 MVA transformers and build one 275 kV cable from Torrens Island to City West substation	Augmentation	170
2012			With New Osborne generation operating and a 66 kV TIPS – New Osborne line contingency the remaining line exceeds its thermal limit	Remove the protection limit and bring the lines to designed rating	Augmentation	1
2012			No Metro West 66 kV generation, outage of TIPS-Kilburn 275 kV overloads the TIPS – Northfield 275 kV line; outage of TIPS – Northfield 275 kV overloads the TIPS – Kilburn 275 kV line	Remove the protection limit and bring the line to its designed rating	Augmentation	2
2012			Substation layout at PGW 275 kV bus constrains the operability at Pelican Point	Install one 275 kV circuit breaker to complete the mesh on the PGW 275 kV bus;	Security/ Compliance	3
2012			Outage of # 1 PGW transformer overloads the # 2 transformer	Cyclically rate the #2 transformer at PGW	Connection	1
2012			Overload of Kilburn #5 transformer under contingency conditions	Cyclically rate the #5 transformer at Kilburn and perform associated works	Connection	2
2014			Load growth in the Metro North overloads the 66 kV network and the 275/66 kV transformer capacity exceeds the ETC requirement	Establish Munno Para substation and install a single 225 MVA 275/66 kV transformer supplying into the Northern Suburbs and install one 100 Mvar capacitor bank. (Increase of transformer size to 300 MVA is being investigated)	Augmentation	43
2016			Under low generation scenario, loss of a major 275 kV line results in inadequate reactive power reserve on the Para SVC.	Install 1 x 100 Mvar 275 kV switchable PoW capacitor bank at Munno Para substation	Augmentation	4
2016	2015	2017	Asset conditions and also under low Metro West 66 kV generation, outage of one of the TIPS 275/66 kV transformers overloads the remaining one.	Replace TIPS transformers with 2x225 MVA (Solution option can be contracting generation in the area)	Augmentation/ Replacement	15

Project Timing (NTNDP S3)	Project Timing (NTNDP S1 & S2)	Project Timing (NTNDP S4 & S5)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2016	2015	2018	Load growth in the CBD area causes the 275/66 kV transformer capacity to exceed the ETC requirement for N-1 TF capacity within the ACR	Install a 2nd 225 MVA 275/66 kV transformer at East Terrace substation; remove the protection limits on the Magill to East Terrace 275 kV cable to 450 MVA Electrically isolate ACR from the Eastern Suburbs	Connection	26
2016			With New Osborne generation operating and a 66 kV TIPS – New Osborne line contingency the remaining circuit exceeds its thermal limit on the river crossing	Construct a 3rd TIPS-New Osborne 66 kV line	Augmentation	19
2016/22 **Actual timing dependent on the outcomes of the Regulatory Test currently being undertaken**			Voltage limitation on ETSA Utilities 66 kV transmission system fed out of Willunga	Establish a 275 kV switching station at Kanmantoo North; construct a double circuit 275 kV line from Kanmantoo North to the Fleurieu Peninsula; establish 275/66 kV transformation	Augmentation	191
2013-2018			Substation layout at Kilburn 275 kV bus constrains the security of Kilburn;	Install one 275 kV circuit breaker to complete the mesh on the Kilburn 275 kV bus;	Security/ Compliance	4
2013-2018			No Metro West 66 kV generation, the 275/66 kV transformation capacity is almost at its limits	Cyclically rate the Kilburn transformer	Connection	1
2013-2018			Increased loading on the 275 kV network has made compliance with the Rules Ch. 4 security provisions difficult operationally and has reduced the opportunities to do critical network maintenance and construction work to very restrictive windows	Install an integrated control scheme in the Metro region that will ensure compliance to the 'next contingency' security requirements of the Rules and allow a higher utilisation of the network under system normal conditions and provide the opportunity to do network maintenance	Security/ Compliance	3.5

The table below lists all identified augmentation projects in the region in the 10-20 year period. Project timing is indicative and is based on medium economic growth (NTNDP Scenario 3: Decentralised World).

Table 7.3: Proposed 10–20 year Metropolitan network augmentation projects

Project Timing (NTNDP S3)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2018-2023	Outage of City West – South transformer or TIPS – City West cable causes inadequate reactive support in the Metro South area	Install SVC in Metro South	Augmentation	23
2018-2023	Outage of TIPS – CW cable or CW_CBD transformer causes inadequate reactive power support in the Metro region	Install SVC in the Metro network	Augmentation	23
2018-2023	Outage of one transformer at Morphett Vale East overloads the remaining transformer	Install a 3rd 225 MVA 275/66 kV transformer at MVE; split the Southern Suburbs distribution network between MVE and Happy Valley	Augmentation/ Connection	20
2018-2023	Munno Para transformer outage overloads the Para transformers	Install a 2nd 225 MVA (possibly 300 MVA) 275/66 kV transformer at Munno Para	Connection	13
2018-2023 Subject to load increase	Loss of either 275/66kV transformers at Magill causes the remaining unit to overload. Similarly, loss of any of the 275/66kV transformers at Northfield results in overloads in the remaining two units. Thermal and voltage limitations in the ETSA Utilities 66 kV network supplying the North Eastern Suburbs	Establish a new 275/66 kV injection point at Yatala Vale North with a 1 x 225 MVA transformer	Augmentation	50
2018-2023 Subject to load increase	Load growth around Freeling and Roseworthy causes thermal overload on the ETSA Utilities distribution network	Establish Kingsford substation; install 2 x 225 MVA 275/66 kV transformers	Augmentation	50
2023-2028	Outage of the cable between TIPS and City West or the City West – South transformer overloads the Happy Valley transformers	Install the 2nd 300 MVA 275/66 kV City West-South transformer Project has to occur in conjunction with the 2nd 275 kV cable	Connection	20
2023-2028	Outage of the TIPS - City West cable causes voltage collapse in the Metro network and thermal overloading in the distribution network between City West and Happy Valley	2nd City West 275 kV cable	Augmentation	150
Subject to ETC change	Reliability requirements for ACR increased to N-2 line and transformer	Install 2nd 300 MVA 275/66 kV transformer supplying into ACR	Connection	22

Project Timing (NTNDP S3)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2028-2033	With the Metro South split between MVE and Happy Valley, loss of the Cherry Gardens to MVE 275 kV line overloads the Happy Valley to MVE 275 kV line	Upgrade the 80^0C section of the Happy Valley to MVE 275 kV line to 120^0C design temperature	Augmentation	10
2028-2033	Outage of one of the transformers at Parafield Gardens West or Para overloads the transformer(s) at PGW	Replace the PGW transformers with 2 x 300 MVA transformers	Augmentation	20

7.5 Anticipated Replacement Projects

Asset replacements are planned based on asset condition. Asset condition monitoring is used to determine the actual timing of any asset replacement. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

Table 7.4: Proposed Metropolitan network replacement projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2008-2013	Condition of the existing secondary systems limiting protection effectiveness in Para substation	Replace the existing secondary systems with modern day equipment and minor poor condition plant	Replacement	30-40
2008-2013	Condition of the existing secondary systems limiting protection effectiveness at the 66 kV TIPS 'A' switchyard	Replace the existing secondary systems with modern day equipment and minor poor condition plant	Replacement	11
2013-2018	Condition of the existing secondary systems at Happy Valley placing limitations on transfer capacity and protection effectiveness	Replace the existing secondary systems with modern day equipment and minor poor condition plant	Replacement	17
2018-2023	Condition of the primary and secondary plant at Dry Creek connection point at the end of its technical life	Replace the existing primary and secondary plant with modern day equipment	Replacement	20

7.6 Future Network Single Line Diagram

Figure 7.5 shows the Metropolitan transmission region with all of the proposed projects included, illustrating how the 275/66 kV network in the region may be developed over the next 20 years (where the dashed lines represent proposed developments).

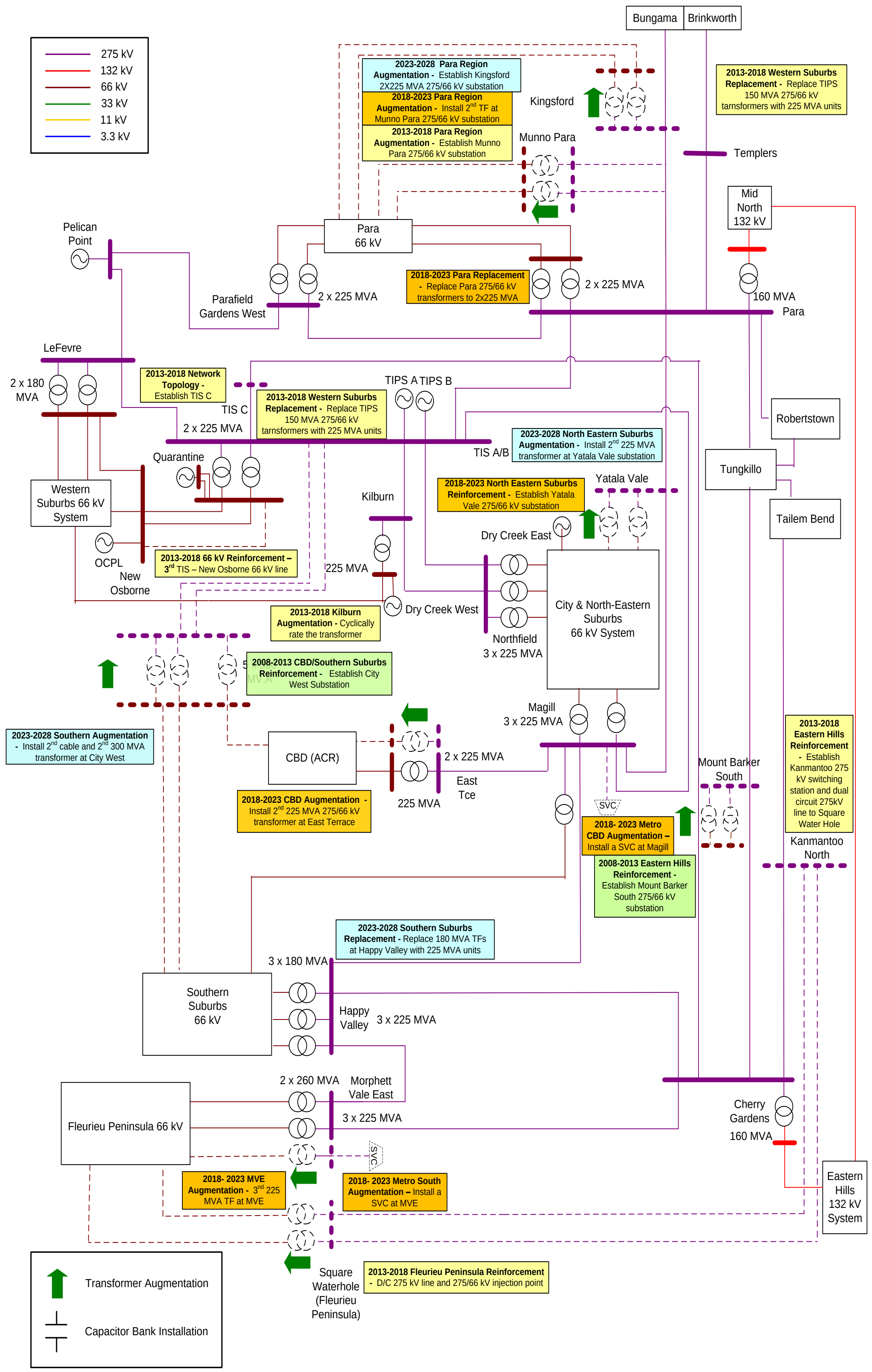


Figure 7.5: Metropolitan network 20-year development plan single line diagram

8. Eastern Hills Development Plan

8.1 Existing Network Overview

The Eastern Hills 132 kV transmission system comprises a network that supplies customer loads to the east and south of the Adelaide metropolitan area. The area is bounded by the Mount Lofty Ranges hills face to the west and the Murray River to the east, and includes major load centres at Angas Creek, Mount Barker, Mannum, Murray Bridge (Mobilong), Kanmantoo, Macclesfield, Strathalbyn as well as supplying a number of SA Water pumping stations on the Mannum – Adelaide and Murray Bridge – Hahndorf water pipelines.

The Eastern Hills transmission system derives its supply from the main 275 kV system via 275/132 kV substations located at Para (near Elizabeth), Cherry Gardens and Tailem Bend, and supplies the electricity requirements to five ETSA Utilities connection point substations as well as to seven SA Water pumping stations in the area. Figure 8.1 shows the geographical region under consideration, and Figure 8.2 provides a simplified representation of the Eastern Hills 132 kV transmission network servicing the area.

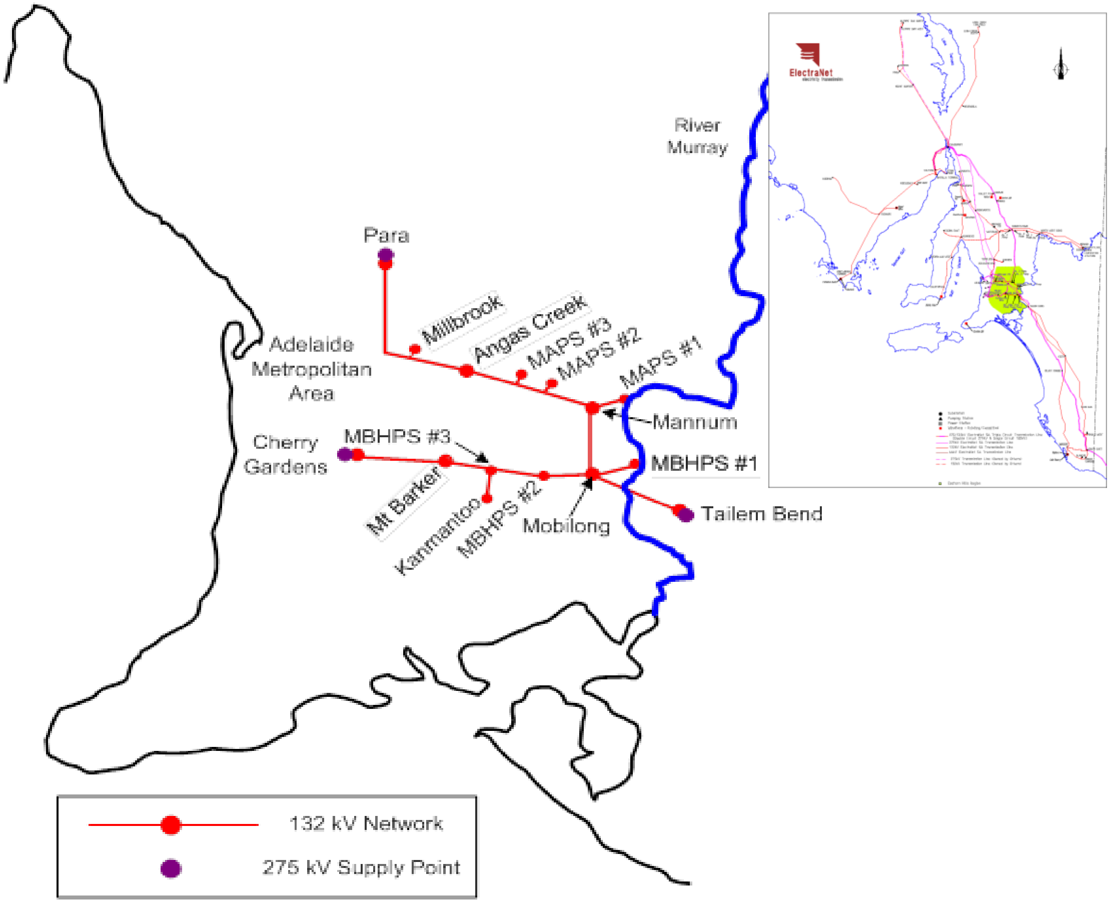


Figure 8.1: Eastern Hills transmission region

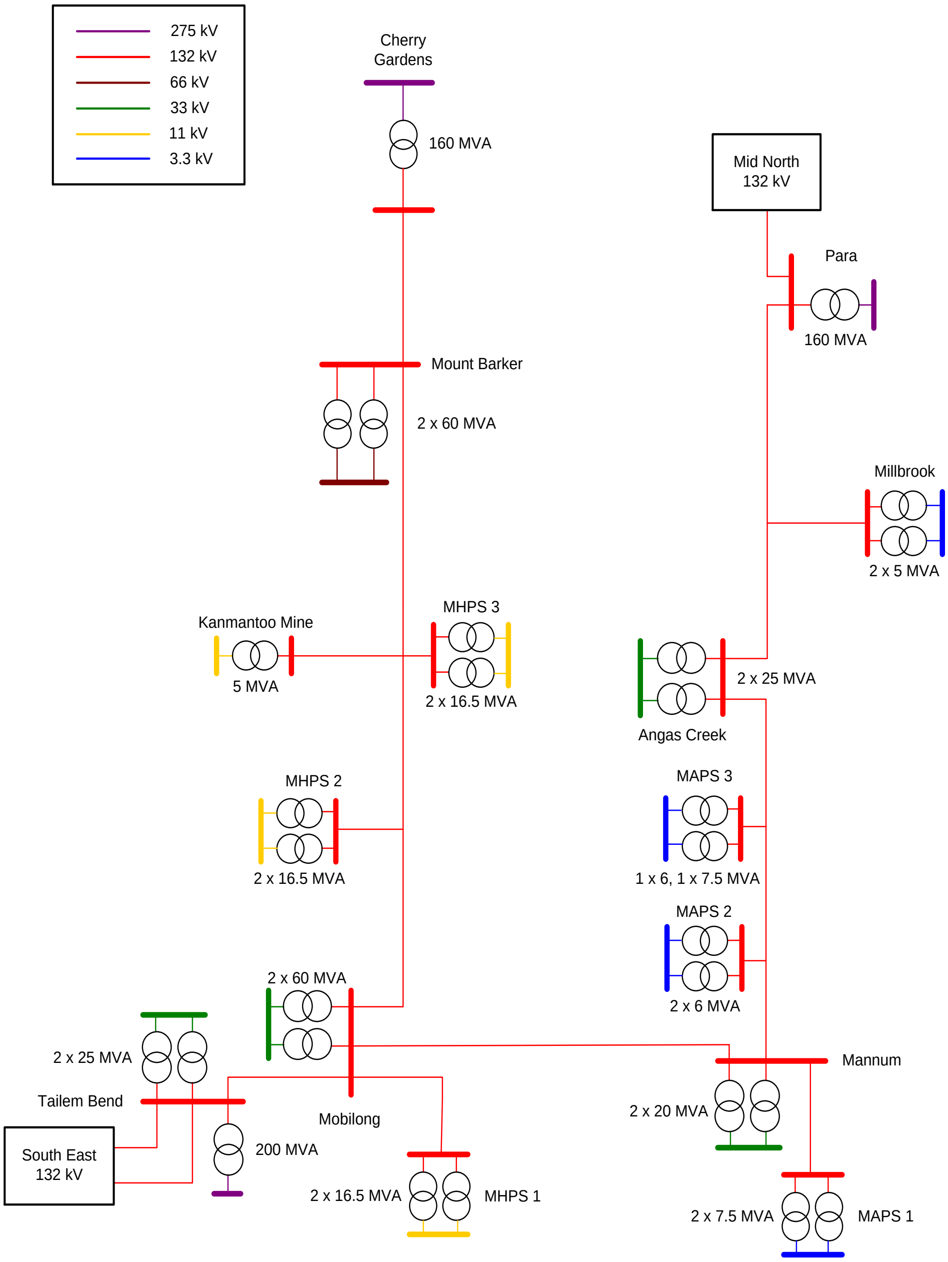


Figure 8.2: Existing Eastern Hills transmission network single line diagram

The Eastern Hills 132 kV system has been developed progressively since 1954 and has subsequently been overlaid by the 275 kV main grid transmission system. 275/132 kV substations were installed as reinforcement became necessary. Due to this method of development, the Eastern Hills 132 kV system now runs in parallel with the main 275 kV system that forms part of the South Australia to Victoria (Heywood) interconnection. As a consequence of this, power flows in the Eastern Hills are not only determined by the loads that must be supplied within the region but by flows on the Heywood interconnector. This 132 kV system has limited capacity to accommodate significant additional electrical demand or generation without augmentation, and consequently has the potential to act as an impediment to continued development in the Eastern Hills region.

The Eastern Hills region of South Australia contains a mixture of electrical loads including light industrial, commercial, agricultural, horticultural, and viticultural. Significant local commercial centres exist at Mount Barker, Mannum, and Murray Bridge. There are presently twelve customer connection points supplied by the Eastern Hills transmission system. The Angas Creek, Kanmantoo, Mannum, Mobilong, and Mount Barker connection points supply the ETSA Utilities distribution system, which in turn reticulates to electricity users in the region. The remaining seven connection points provide electricity supply to the Mannum – Adelaide Pumping Stations No. 1, No. 2 and No. 3, the Murray Bridge – Hahndorf Pumping Stations No. 1, No. 2, and No. 3, and the Millbrook Pumping Station, all of which are owned by SA Water. The mandatory level of reliability that must be provided to a connection point is defined in the ETC. Within the Eastern Hills region, emergency demand side management schemes are in place in the form of under-voltage load-shedding at various connection points. Under-voltage load-shedding schemes are used to selectively trip loads under severe post contingency conditions to prevent voltage collapse from occurring. The controlled load shedding scheme limits the number of customers affected when compared to the much larger number that would be affected in a voltage collapse situation.

Shown in Table 8.1 is a list of the connection points that supply the Eastern Hill region and the reliability classification presently assigned to each in the ETC. Refer to Appendix D for details in relation to the ETC Connection Point Reliability Standards.

Table 8.1: Eastern Hills region connection point ETC categorisation

Connection Point	ETC Category
Angas Creek	4
Kanmantoo Mine	1
Mannum	4
Mannum – Adelaide PS No. 1	1
Mannum – Adelaide PS No. 2	1
Mannum – Adelaide PS No. 3	1
Millbrook PS	1
Mobilong	4
Mount Barker	4
Murray Bridge to Hahndorf PS No. 1	1
Murray Bridge to Hahndorf PS No. 2	1
Murray Bridge to Hahndorf PS No. 3	1

8.1.1 Existing and Committed Generation

There is no significant generation presently connected to the Eastern Hills 132 kV system nor are there any committed plans for generation to connect at this time. There is, however, the potential for generation connections occur within the period covered by this plan due to the presence of the SEAGas pipeline which traverses the region.

8.1.2 Intra-regional Transfer Capability

Power flows in the Eastern Hills are dependent on both regional load and prevailing flows on the Heywood interconnector.

Planned outages of 275/132 kV transformers at Tailem Bend, Para and Cherry Gardens (and their associated 132 kV lines) may require this sub-region to be radialised to maintain system security as required by the Rules. Additionally, some constraints on SA Water pumping stations may be applied from time to time.

8.2 Study Methodology

8.2.1 Planning Criteria and Assumptions

This development plan has been prepared according to the planning framework described in Appendix D.

8.2.2 20 Year Load Forecast

The future system demand considered in the analysis contained in this regional development plan is based on forecasts produced by ETSA Utilities and other direct connect customers and typical summer SA Water pumping loads. ElectraNet believes that the most likely load growth scenario for the Eastern Hills region is the medium load growth forecast based on past experience and known developments in the next 5 to 10-years.

The 20-year high, medium and low demand forecasts for the Eastern Hills 132 kV transmission system are shown on Figure 8.3, and the projected performance limitations have been analysed based on those load forecasts. Refer to Appendix B for more information in relation to load forecasts.

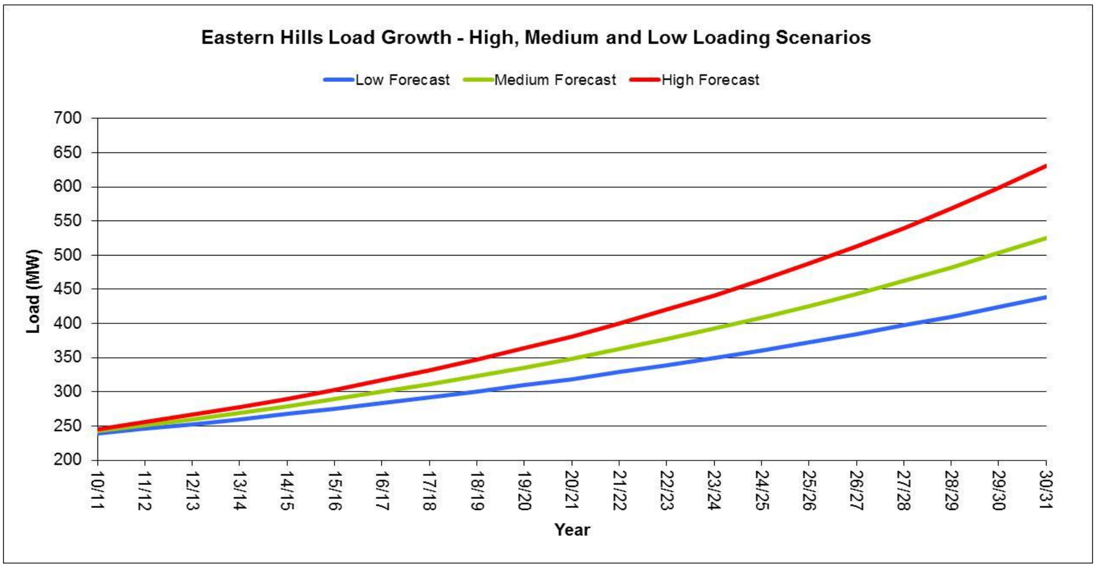


Figure 8.3: Eastern Hills region 20-year peak load forecasts

8.2.3 Special Considerations in the Eastern Hills region

Interconnections

The Eastern Hills region is not adjacent to a separate NEM region, however the Heywood interconnector feeds into the region via 275/132 kV substations at Tailem Bend and Para. As a result of this, power flows in the Eastern Hills 132 kV transmission system are dependent on both, loads within the region and the prevailing flows on the Heywood interconnector. This means that the Heywood interconnector is constrained under some network operating conditions due to thermal capacity limitations within the Eastern Hills 132 kV transmission system.

SA Water Pumping Loads

For the purposes of peak load system planning in the Eastern Hills region, pumping loads at the SA Water owned Millbrook, Mannum – Adelaide and Murray Bridge – Hanhdorf Pumping Stations are assumed to be offline. Under light and average load conditions, pumping loads at these sites are assumed to be online.

Assumed Wind Generation

While there is no wind generation connected within the Eastern Hills transmission system, significant wind generation is present in the neighbouring Mid-North and South East transmission regions. Historical records indicate that at times of peak load the average wind generation across South Australia is generally of the order of 3% of installed capacity. At times of average and light load conditions, higher levels of wind generation (up to 85%) have been observed within South Australia.

For the purposes of peak load system planning for the Eastern Hills region, wind generation within South Australia was assumed to be at 3%. Conversely, for light load analysis, wind generation within South Australia was assumed to be at 85%.

8.2.4 Fault Levels

Substation fault levels are assessed to remain within design and equipment limits. A table listing the 5 year maximum substation fault levels and circuit breaker ratings is provided in Appendix C of this report.

8.3 Connection Opportunities

This section identifies potential opportunities for connection of generation and load to the transmission network. Generation and load proponents should take this information into account when considering the location of their projects (especially larger projects).

8.3.1 Generation Connection Opportunities

The capacity of the existing 132 kV transmission network is well utilised and therefore there is little scope for connecting large scale generation into the existing 132 kV sub-network.

Locations on the 132 kV sub-network in close proximity to the Para – Tungkillo , Tungkillo – Tailem Bend, Tungkillo – Robertstown and Tungkillo – Cherry Gardens

275 kV transmission lines or associated substations may facilitate the connection of such generation.

Lower output generation (<100 MW) may be absorbed at points such as Mannum and Mobilong (Murray Bridge).

8.3.2 Load Connection Opportunities

Electrical demand on the Eastern Hills 132 kV transmission system has grown steadily over the years as a result of residential, commercial and light industrial development within this region. While there are several individual customer connection points in the Eastern Hills region, with the exception of the SA Water pumping stations, those connection points service the ETSA Utilities distribution network which in turn supplies individual electricity consumers.

The capacity of the existing 132 kV transmission network is well utilised and therefore there is little scope for connecting large scale loads to the existing 132 kV transmission network without augmentation.

Locations on the 132 kV transmission network in close proximity to the Para - Tungkillo , Tungkillo - Tailem Bend, Tungkillo - Robertstown and Tungkillo - Cherry Gardens 275 kV transmission lines or associated substations may facilitate the connection of larger loads.

Load less than 5 MW may be absorbed at points such as Mannum and Mobilong (Murray Bridge).

8.4 Constraints and Proposed Augmentation Projects

Projected power system limitations within the Eastern Hills 132 kV transmission system are highly dependent on load growth and demand from ETSA Utilities distribution system and SA Water pumping stations within the region. Each connection point has been examined individually within this development plan, and where necessary the combined impact of multiple network and connection point limitations is examined to determine the overall impact on the region.

The network limitations, along with the proposed solutions, timings, estimated capital expenditures, and option analysis for projects that have been identified for the next 5-year period are described below. Projects identified for the initial 10-year period of this 20 year development plan, including those projects that will improve the performance of existing plant and equipment, rather than physically adding to the asset base (e.g. installing control schemes to maintain network security) and will be triggered by a sudden load increase, the timing of which is not yet known, are summarised in Table 8.3 and Table 8.3. Finally, asset replacements are considered separately, and are listed in Table 8.4.

The following section provides description of the projects that are proposed to alleviate the projected performance limitations identified.

8.4.1 5-Year Major Augmentation Projects

Construct a new 275/66 kV substation at Mount Barker South

Scope of Work: Establish a 275/66 kV substation with 1 x 225 MVA transformer at Mount Barker South

Estimated Cost: $38 Million

Timing: 2011

Project Status: Committed Project

Project Need

An unplanned outage of either the Cherry Gardens 275/132 kV transformer or the Cherry Gardens to Mount Barker 132 kV line under peak load conditions results in unacceptable voltages at Mount Barker and thermal overload of the Tailem Bend to Mobilong 132 kV line.

In addition, the loss of one of the 60 MVA 132/66 kV transformers at Mount Barker under peak load conditions will result in the thermal overloading of the remaining unit beyond its emergency capability.

The proposed Mount Barker South project is the least cost option of those identified that eliminate the impact of the identified constraint. This option has passed the Regulatory Test for Reliability Augmentations and development of the site commenced in February 2010.

8.4.2 Future Augmentation Projects

The following tables contain the list of emerging limitations that have been identified during the development plan study. These represent the recommended network solution based on high level cost estimation and professional engineering judgement and are one of a number of options available. These solutions are subject to variation and change as further study and network development occur. Due to the lack of certainty on the customer connections, the projects are indicative in terms of timing and the scope of work. The proposed network solution for each constraint will be updated as better information becomes available.

The table below lists all identified augmentation projects in the region over the next 10-years. A range of project implementation dates is provided where the timing has been determined according to the NTNDP 2010 scenarios.

NTNDP Scenarios:

- S1: Fast Rate of Change
- S2: Uncertain World
- S3: Decentralised World
- S4: Oil Shock and Adaptation
- S5: Slow Rate of Change

Table 8.2: Proposed 10-year Eastern Hills network augmentation projects

Project Timing (NTNDP S3)	Project Timing (NTNDP S1 & S2)	Project Timing (NTNDP S4 & S5)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2011			An outage of either the Cherry Gardens 275/132 kV transformer or the Cherry Gardens to Mount Barker 132 kV line under peak load conditions results in unacceptable voltages at Mount Barker and the thermal overload of the Tailem Bend to Mobilong 132 kV line; Loss of a 60 MVA 132/66 kV transformer at Mount Barker under peak load conditions overloads the remaining unit.	Establish a 275/66 kV substation with 1 x 225 MVA transformer at Mount Barker South.	Augmentation	38
2013-18			Substation layout of Mobilong 132 kV bus constrains the operability of the 132 kV network; secondary system condition	Install 1 x 132 kV circuit breaker to complete the mesh on the Mobilong 132 kV bus and replace secondary systems	Security/ Compliance, Replacement	15
2013-18			Increased loading on the 132 kV network has made compliance with Rules Ch.4 security provisions difficult operationally and has reduced the opportunities to do critical network maintenance and construction work to very restrictive windows.	Install an integrated control scheme in the Eastern Hills region that will ensure compliance to the 'next contingency' security requirements of the Rules and allow a higher utilisation of the network under system normal conditions as well as provide the opportunity to undertake network maintenance as required.	Security/ Compliance	3.5
2016	2015	2018	Mount Barker 132/66 kV transformers unable to meet ETC service standards under the peak load outage of the Mount Barker South 275/66 kV transformer.	Install a 2nd 225 MVA 275/66 kV transformer at Mount Barker South; retire aged 132 kV assets at Mount Barker from service.	Connection	12

The table below lists all identified augmentation projects in the region in the 10-20 year period. Project timing is indicative and is based on medium economic growth (NTNDP Scenario 3: Decentralised World).

Table 8.3: Proposed 10-20 year Eastern Hills network augmentation projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2018-2023	Forecast peak load at Kanmantoo exceeds 132/11 kV transformer capacity	Rebuild Kanmantoo substation with 2 x 10 MVA 132/33 kV transformers (Subject to ETC category change)	Connection/ Replacement	13
2023-2028	An outage of a 132/33 kV transformer at Mobilong overloads the remaining unit; Mobilong substation at end of technical life	Rebuild Mobilong with 2 x 120 MVA 132/33 kV transformers	Connection	24
2028-2033	An outage of a 275/66 kV transformer at Mount Barker South under peak load conditions overloads the remaining unit; thermal limitations on the distribution system fed from Mount Barker South Substation.	Establish 275/66 kV transformation at Kanmantoo North; extend the 66 kV distribution network to Kanmantoo North via Nairne	Augmentation	40

8.5 Anticipated Replacement Projects

Asset replacements are planned based on asset condition. Asset condition monitoring is used to determine the actual timing of any asset replacement. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

Table 8.4: Proposed Eastern Hills network replacement projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2013-2018	Mannum to Adelaide pumping station #1 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the substation to current day standards and replace the 132/3.3 kV transformers	Replacement	9
2013-2018	Mannum to Adelaide pumping station #2 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the substation to current day standards and replace the 132/3.3 kV transformers	Replacement	11
2013-2018	Mannum to Adelaide pumping station #3 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the substation to current day standards and replace the 132/3.3 kV transformers	Replacement	9
2013-2018	Millbrook pumping station primary plant at end of technical life; site not aligned with current environmental practices and company policy	Rebuild the substation to current day standards and replace the 132/3.3 kV transformers	Replacement	10

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2018-2023	Murray Bridge to Hahndorf pumping station #1 primary plant at end of technical life; site not aligned with current environmental practices and company policy	Rebuild the substation to current day standards and replace the 132/11 kV transformers	Replacement	10
2018-2023	Murray Bridge to Hahndorf pumping station #2 primary plant at end of technical life; site not aligned with current environmental practices and company policy	Rebuild the substation to current day standards and replace the 132/11 kV transformers	Replacement	9
2018-2023	Murray Bridge to Hahndorf pumping station #3 primary plant at end of technical life; site not aligned with current environmental practices and company policy	Rebuild the substation to current day standards and replace the 132/11 kV transformers	Replacement	12
2018-2023	An outage of an Angas Creek transformer under peak load conditions overloads the remaining unit; Unsatisfactory reactive margins at Angas Creek.	Rebuild Angas Creek substation with 2x60 MVA transformers; Install 2 x 15 Mvar 132 kV PoW switched capacitor banks.	Replacement	25

8.6 Future Network Single Line Diagram

Figure 8.4 shows the Eastern Hills transmission network with all of the proposed projects included, illustrating how the 132 kV network in the region may be developed over the next 20 years (where the dashed lines represent proposed developments).

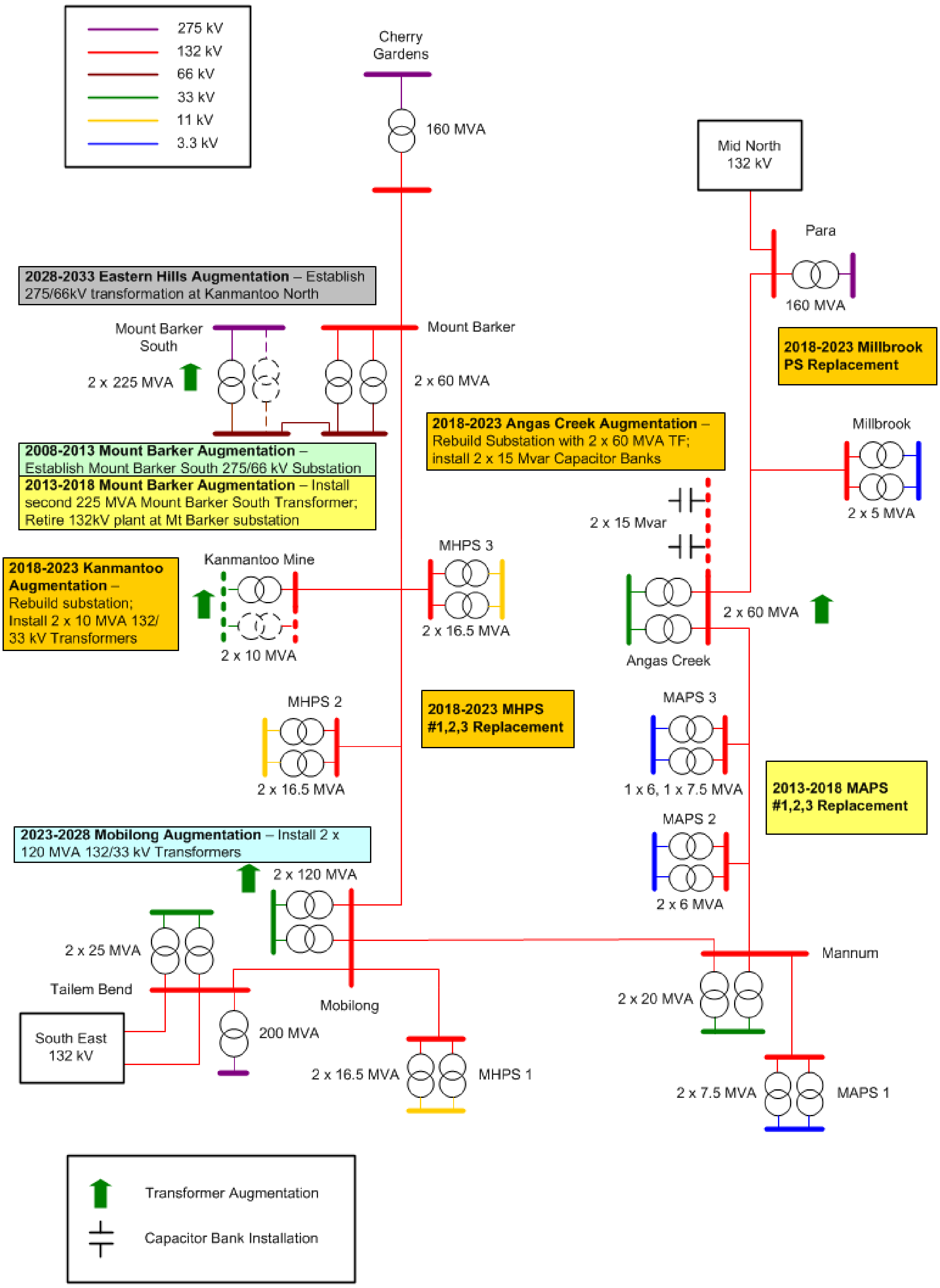


Figure 8.4: Eastern Hills network 20-year development plan single line diagram

9. Mid North Development Plan

9.1 Existing Network Overview

The Mid North 132 kV transmission system derives its supply from the Main Grid 275 kV system via 275/132 kV substations located at Para (near Elizabeth), Robertstown, Brinkworth and Bungama (near Port Pirie). The Mid North supply area includes major load centres at Ardrossan, Brinkworth, Clare, Kadina, Port Pirie, as well as supplying the Barossa Valley and Yorke Peninsula regions. Figure 9.1 shows the geographical region under consideration, and Figure 9.2 provides a simplified representation of the Mid North 132 kV transmission network servicing the area.

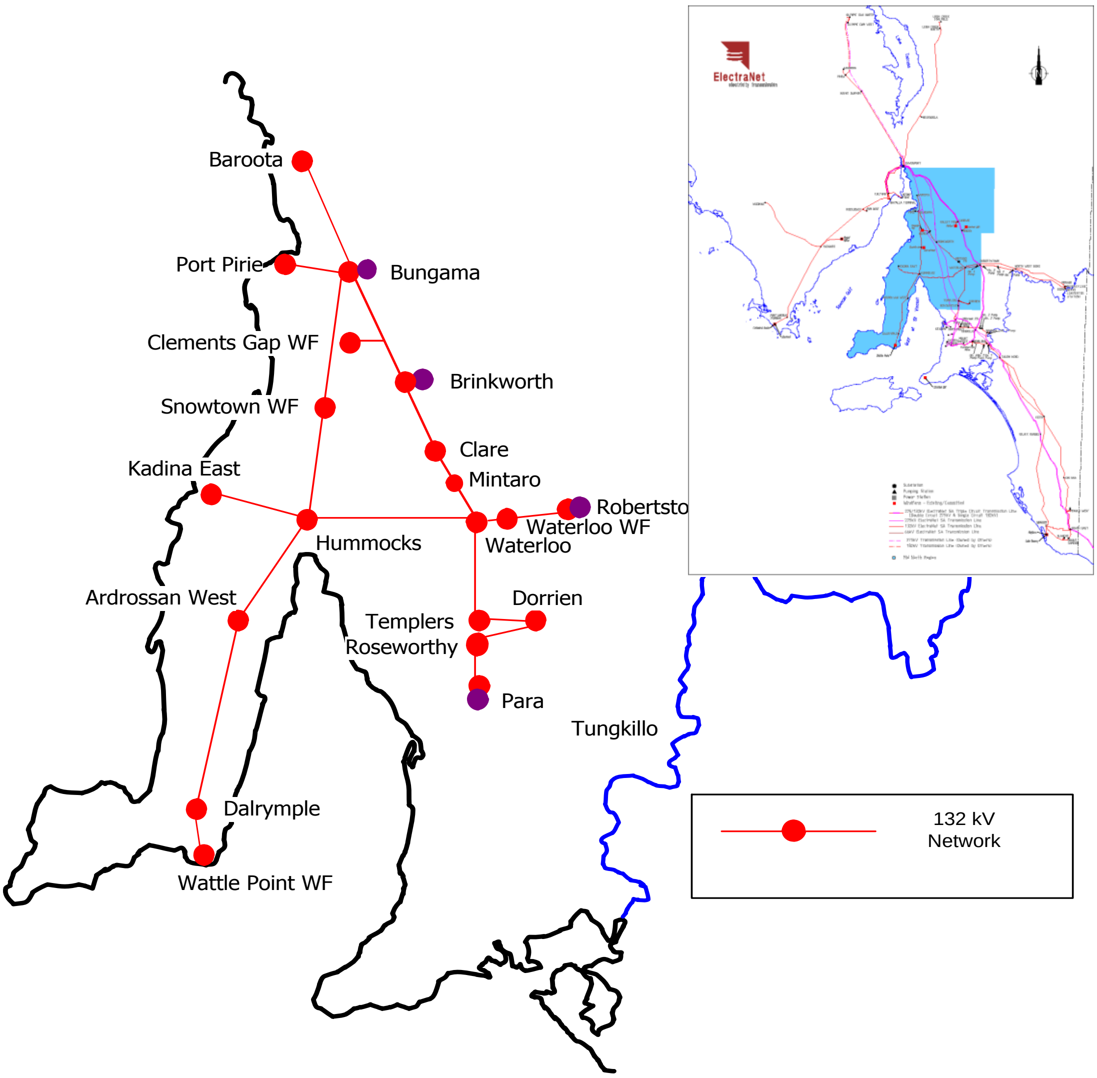


Figure 9.1: Mid North transmission region

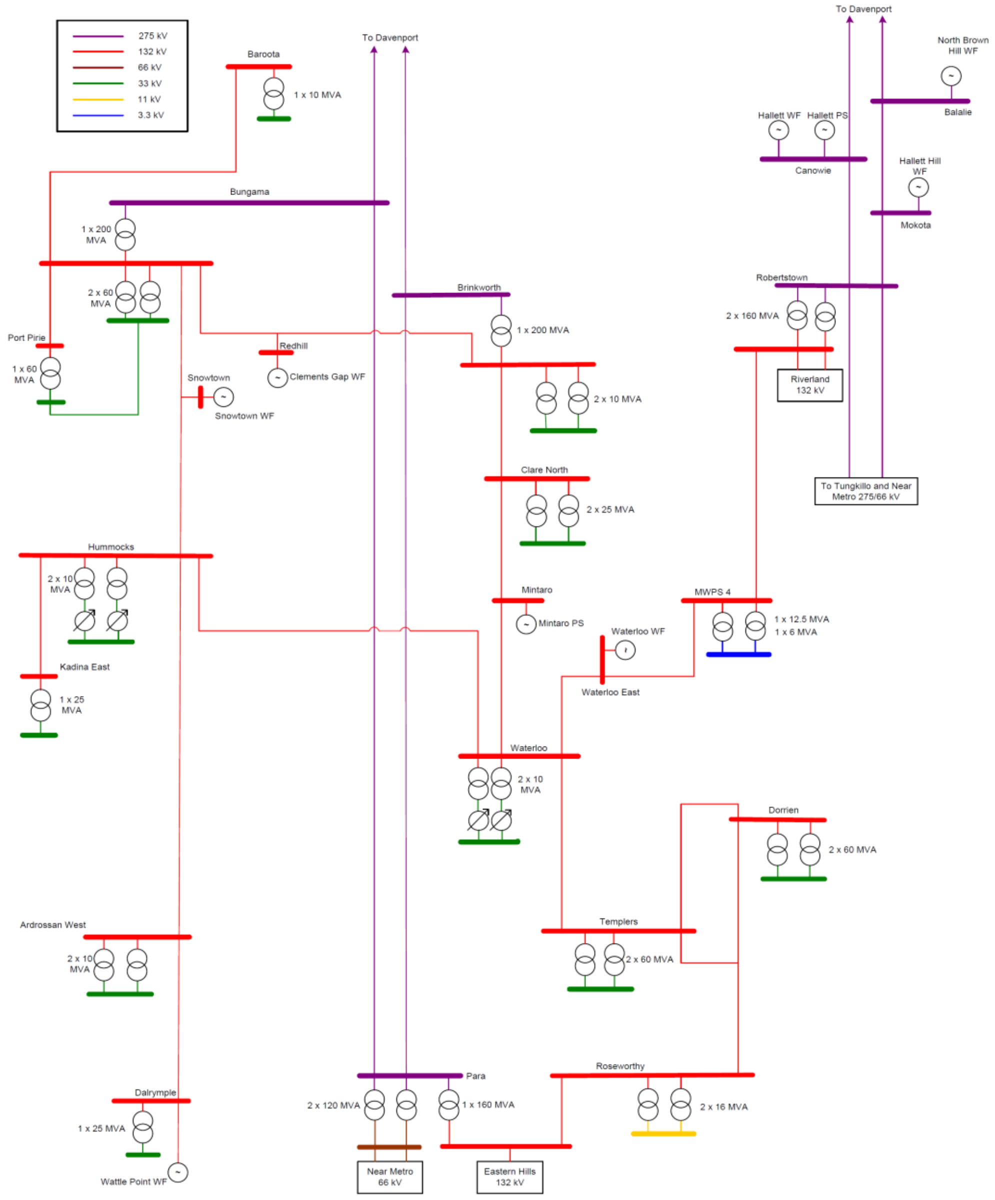


Figure 9.2: Existing Mid North transmission network single line diagram

The Mid North 132 kV transmission region has been developed progressively since 1952 and has subsequently been overlaid by the 275 kV Main Grid network as reinforcement became necessary. Due to this method of augmentation, 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 by flows on the Port Augusta to Adelaide 275 kV system. The Mid North 132 kV system has limited capacity to accommodate significant additional electrical demand or generation without augmentation, and consequently has the potential to act as an impediment to continued development in the Mid North region.

There are presently thirteen customer connection points supplied by the Mid North transmission system. The Ardrossan West, Baroota, Brinkworth, Clare North, Dalrymple, Dorrien, Hummocks, Kadina East, Port Pirie, Templers and Waterloo connection points supply the ETSA Utilities distribution system, which in turn reticulates to electricity users in the region. The remaining two connection points provide electricity supply to the Morgan to Whyalla Pumping Station No. 4 owned by SA Water and the Roseworthy bottling plant owned by AMCOR.

Shown in Table 9.1 is a list of the connection points that supply the Mid North region and the reliability classification presently assigned to each in the ETC. Refer to Appendix D for details in relation to the ETC Connection Point Reliability Standards.

Table 9.1: Mid North region connection point ETC categorisation

Connection Point	ETC Category
Ardrossan West	2
Baroota	1
Clare North	4
Dalrymple	1
Kadina East	2
Morgan to Whyalla PS No.4	1
Roseworthy	1
Waterloo	4
Brinkworth	4
Dorrien	4
Hummocks	4
Port Pirie/Bungama	4
Templers	4

9.1.1 Existing and Committed Generation

Existing generation on the Mid North 132 kV system includes a mixture of gas turbine (GT) plant and wind farms. Gas turbine plant is located at Mintaro (90 MW) and Hallett (192 MW), with wind generation more widely scattered.

Seven wind farms are now operational in the Mid North region. These are, Wattle Point (near Edithburgh on the Yorke Peninsula – 90.75 MW), Snowtown (98 MW), Clements Gap (south of Port Pirie – 56.7 MW), and Waterloo Wind Farm (east of Waterloo – 129 MW) that connect to the 132 kV system. The remaining wind farms at Hallett (94.5 MW), Hallett Hill (71.4 MW) and North Brown Hill (132.3 MW), all connect to the 275 kV system north of Robertstown at Canowie, Mokota and Balalie respectively. Porcupine Range Wind Farm has committed status and will connect at Balalie in the near future. There is also a 50 MW distillate fired market generator embedded in the ETSA Utilities 33 kV distribution network at Angaston in the Barossa Valley.

9.1.2 Intra-regional Transfer Capability

Wind generation on Yorke Peninsula and elsewhere in the Mid North region, (at Wattle Point, Snowtown), is limited by the thermal capacity of the 132 kV line between Hummocks and Waterloo and the 132 kV line section between Bungama and Hummocks.

An automatic tripping scheme has been installed at Wattle Point wind farm to maintain voltage stability in the Mid North region following critical 132 kV contingencies.

The Clements Gap wind farm is connected to the Brinkworth – Bungama 132 kV line. Under some operating conditions this wind farm will potentially be limited by thermal capacity associated with the Mintaro – Waterloo and Waterloo – Templers 132 kV lines.

The Waterloo wind farm is connected to the Waterloo – Robertstown 132 kV line. An automatic run-back control scheme has been installed at the wind farm to limit Waterloo wind farm generation such that any displacement of Murraylink interconnection flows is no more than a 1 MW reduction in flow capacity for 1 MW of Waterloo generation basis.

9.2 Study Methodology

9.2.1 Planning Criteria and Assumptions

This development plan has been prepared according to the planning framework described in Appendix D.

9.2.2 20 Year Load Forecast

The Mid North of South Australia contains a mixture of electrical loads including industrial, 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, the Yorke Peninsula, and in the Barossa Valley. The future system demand considered in the analysis in this Development plan is based on the forecasts produced by ETSA Utilities and other direct connect customers.

The 20-year high, medium and low demand forecasts for the Mid North 132 kV transmission system are shown on Figure 9.3 and the projected performance limitations have been analysed based on those load forecasts. Refer to Appendix B for more information in relation to load forecasts.

9.2.3 Special Considerations in the Mid-North

<u>Interconnections</u>

The Mid North region is not adjacent to a separate NEM region and there are no interconnections that connect to the Mid-North transmission region. However, power flows in the Mid-North region may be influenced by flows on the Murraylink interconnector that terminates at Monash 132/66 kV substation located in the neighbouring Riverland region. The Riverland 132 kV transmission system connects to the Robertstown 132 kV bus where the Robertstown – Waterloo East 132 kV line is also connected (refer to Figure 9.2).

Assumed Wind Generation

Significant wind generation is connected to the Mid North region at both 132 kV and 275 kV voltage levels. Historical records indicate that at times of peak load the average wind generation across South Australia is generally of the order of 3% of installed capacity. At times of average and light load conditions higher levels of wind generation (up to 85%) have been observed within South Australia.

For the purposes of peak load system planning in the Mid North region, wind generation of 3% within South Australia was assumed. However, critical wind farms within the Mid North region were assumed off for analysis in their close proximity. For light load analysis wind generation within South Australia was assumed to be at 85% of installed capacity.

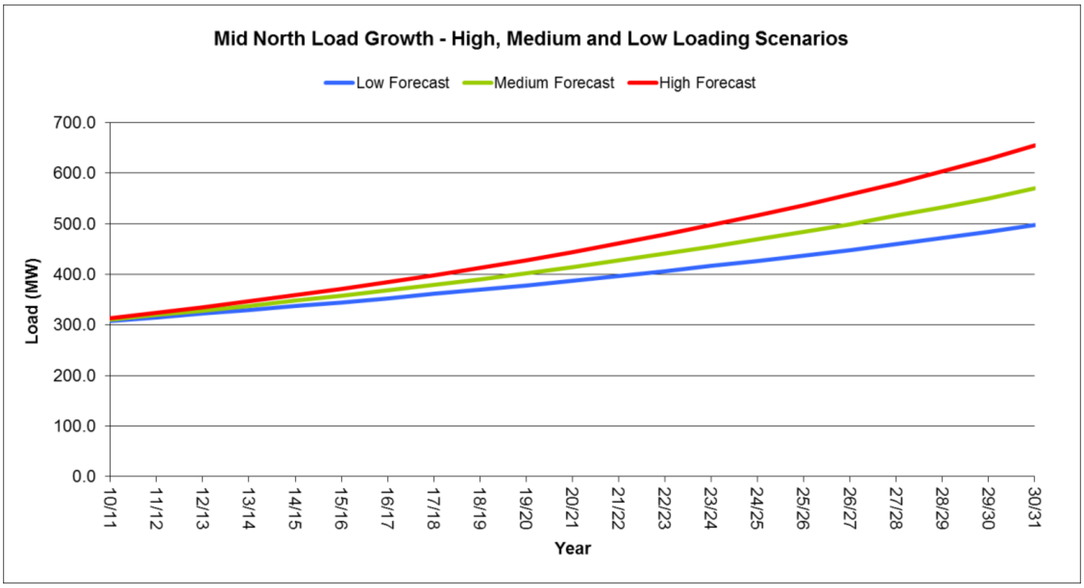


Figure 9.3: Mid North region 20-year peak load forecasts

9.2.4 Fault Levels

Substation fault levels are assessed to remain within design and equipment limits. A table listing the 5 year maximum substation fault levels and circuit breaker ratings is provided in Appendix C of this report.

9.3 Connection Opportunities

This section identifies potential opportunities for connection of generation and load to the transmission network. Generation and load proponents should take this information into account when considering the location of their projects (especially for larger projects).

9.3.1 Generation Connection Opportunities

The SEAGas pipeline crosses under both the Bungama – Para and the Brinkworth – Para 275 kV circuits in the vicinity of Gawler providing an opportunity for gas fired generation to connect at these locations.

The Adelaide – Moomba gas pipeline passes below the Davenport – Robertstown 275 kV circuits at Canowie, and the Waterloo - Brinkworth 132 kV circuit at Mintaro. Both locations have existing generation. The pipeline also traverses in close proximity to ElectraNet infrastructure east of Balaklava (Brinkworth – Para 275 kV and Waterloo – Hummocks 132 kV lines) and crosses the Brinkworth – Para 275 kV line near Owen at a point where the Brinkworth - Para and Bungama – Para 275 kV lines are within approximately 10 km of each other. The Adelaide – Moomba gas pipeline also crosses the Bungama – Para 275 kV line near Wasleys and Mallala. These sites all provide opportunity for gas fired generation to establish and connect.

The 132 kV transmission system in the Mid North region has very limited capacity to connect any large scale generation (>100 MW), although smaller generators may be accommodated, depending on the location in the network and level of generation proposed.

The Yorke Peninsula 132 kV transmission system has very limited capacity to accommodate significant additional generation without augmentation. Depending on magnitude and location, significant augmentation may be needed to connect new generation.

9.3.2 Load Connection Opportunities

Electrical demand on the Mid North 132 kV transmission system has grown steadily over the years as a result of residential, commercial and industrial development. While there are several individual customer connection points in the Mid North region, the majority of those connection points service the ETSA Utilities distribution network which in turn supplies individual electricity consumers.

- Significant loads (>30 MW) could be accommodated in close proximity to the 275 kV substations at Bungama and Brinkworth.
- Load of this magnitude could also be accommodated anywhere along the 275 kV line routes, subject to development approval and depending on the nature of the connection required.
- The 132 kV transmission system in the Mid North area has very limited capacity to connect new demand, though locations adjacent to existing substations, particularly where there is a nearby 275 kV injection or generation source may be suitable for some connection applications.
- Yorke Peninsula 132 kV transmission system has very limited capacity to accommodate significant additional demand without augmentation. Depending on the magnitude and location of the proposed loads significant augmentation may be required.

9.4 Constraints and Proposed Augmentation Projects

Projected power system limitations within the Mid North 132 kV transmission system are highly dependent on load growth and demand on the connection points with ETSA Utilities distribution system. Each connection point has been examined individually within this development plan and, where necessary, the combined impact of multiple network and connection point limitations is examined to determine the overall impact on the region.

The network limitations, along with the proposed solutions, timings, estimated capital expenditures, and option analysis for projects that have been identified for the next 5-year period are described in section 9.4.1. Projects identified for the initial 10-year period of this 20 year development plan, including those projects that will improve the performance of existing plant and equipment, rather than physically adding to the asset base (e.g. installing control schemes to maintain network security) and will be triggered by a sudden load increase, the timing of which is not yet known, are summarised in Table 9.6 and Table 9.7. Finally, asset replacements are considered separately, and are listed in Table 9.9.

The following section provides description of the projects that are proposed to alleviate the projected performance limitations identified.

9.4.1 5-Year Major Augmentation Projects

Kadina East Connection Point Augmentation

Scope of Work: Rebuild Kadina East substation with 2 x 60 MVA transformers

Estimated Cost: $20 Million

Timing: 2011

Project Status: Committed Project

Project Need:

The Kadina East 132/33 kV connection point was reclassified by the July 2008 ETC from Category 1 to Category 2. Kadina East is presently serviced by a single 25 MVA (nominal) 132/33 kV transformer; however, as a result of this change in category, N-1 transformer capability is required at Kadina East no later than July 2011. In addition to this requirement, transformer capacity studies indicate that the existing 25 MVA transformer at Kadina East will no longer be adequate to meet the forecast AMD under system normal conditions beyond 2011.

This option is the least cost option of those that eliminate the impact of the identified constraint. Public consultation on this project was completed in December 2009 and development of this site is underway.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

Templers West 275/132 kV Substation

Scope of Work: Establish Templers West substation with a single 160 MVA 275/132 kV transformer. Create an express feeder to Dorrien 132 kV substation and restore Templers to its original configuration.

Estimated Cost: $36 Million

Timing: 2011

Project Status: Committed Project

Project Need

An unplanned outage of the Para to Roseworthy 132 kV transmission line or the Para 275/132 kV transformer under peak load conditions results in inadequate voltages in the Barossa area. This option addresses the limitation by providing a 275 kV injection into the existing 132 kV transmission system. The proposed scope of work is to establish 275/132 kV transformation at Templers West; create an express feeder to Dorrien; restore Templers to its original configuration. This negates the impact of an outage of either of the 132 kV infeeds to the existing network.

Public consultation on this project was completed in March 2010 and development of this site is underway.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

<u>Ardrossan West Connection Point Augmentation</u>

Scope of Work: Shift load from Ardrossan West for one year. In 2012, install 2x25 MVA 132/33 kV transformers at Ardrossan West. Mesh the 132 kV bus and install 1 x 15 Mvar POW switched capacitor bank.

Estimated Cost: $23 Million

Timing: 2012

Project Status: Committed Project

Project Need

The Ardrossan West 132/33 kV connection point was reclassified by the July 2008 ETC from Category 1 to Category 2. As a result of this change, ElectraNet is required to provide N-1 transformer capacity for 100% of the contracted AMD at the Ardrossan West connection point by no later than July 2011.

Ardrossan West is presently serviced by two 10 MVA (nominal) 132/33 kV transformers. Transformer capacity studies indicate that after load shifting has taken place, these transformers will no longer be adequate to meet the forecast AMD beyond 2012 to the mandated N-1 reliability standard. In addition to this, studies show that beyond this time, voltages at Ardrossan West and Dalrymple will not be NER compliant under N-1 contingency conditions.

This proposed option is the least cost option of those that eliminate the impact of the identified constraint. Public consultation on this project was completed in August 2010 and development of this site is underway.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

Hummocks Connection Point Augmentation

Scope of Work: Install 2x25 MVA 132/33 kV transformers at Hummocks and replace aged plant.

Estimated Cost: $11 Million

Timing: 2013

Project Status: Network Study

Project Need

The Hummocks 132/33 kV connection point is classified as Category 4 under the ETC and is presently serviced by two 10 MVA (nominal) 132/33 kV transformers. Transformer capacity studies indicate that these transformers will no longer be adequate to meet the forecast AMD beyond 2010/11 to the required N-1 reliability level. In accordance with the requirements of the ETC, ElectraNet is required to upgrade the installed transformer capacity at the Hummocks connection point by no later than 2013/14. In addition to installing larger transformers, replacement of poor conditioned assets will be included as part of this project.

Table 9.2: Hummocks connection point augmentation: options considered

Option	Description	Comments	Estimated Cost ($M)
1	Install 2x25 MVA 132/33 kV transformers (refurbished) at Hummocks and replace poor conditioned plant.	This option is the least cost option of those that eliminate the impact of the identified constraint.	11
2	Install 2x25 MVA 132/33 kV transformers at Hummocks and replace poor conditioned plant.	This option is viable but not the least cost option of those that eliminate the impact of the identified constraint.	12
3	Install 2x60 MVA 132/33 kV transformers at Hummocks and replace poor conditioned plant.	This option is viable but not the least cost option of those that eliminate the impact of the identified constraint.	14
4	Permanent or rapid automatic Distribution load shift	There are currently no existing or planned distribution networks of sufficient capacity available to offload the 33 kV distribution network to the extent required and therefore this option was not considered further as a viable alternative.	N/A
5	Demand Side Management	ElectraNet does not consider that DSM would provide an appropriate solution to the limitations at Hummocks because of the asset condition.	N/A
6	Load side Power Factor improvement	The load power factors are already compliant with the connection point agreement and the Rules thresholds. Therefore this option was not considered further as a viable solution.	N/A
7	Generation	Not currently considered viable in the Hummocks area. There are currently no adequate fuel sources available (e.g. gas supply) and generation would have to run system normal at times of high load to achieve the service standards. Furthermore, the existing Hummocks substation would require rebuilding to allow for the connection of generation at this site.	N/A

12 month load deferral requirement

Amount of load reduction required to achieve 12-month deferral of augmentation	Load reduction does not address the asset condition issue.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

Waterloo Connection Point Replacement

Scope of Work: Rebuild Waterloo substation on an adjacent site with 2x25 MVA 132/33 kV transformers.

Estimated Cost: $42 Million

Timing: 2013

Project Status: Network Study

Project Need

Major transmission plant within Waterloo substation was installed in 1953 and is well beyond its nominal service life of 45 years. Additionally, transformer capacity studies indicate that the installed capacity at Waterloo connection point will no longer be adequate to meet the forecast AMD beyond 2011/12 to the required N-1 reliability level. In accordance with the requirements of the ETC, ElectraNet is required to upgrade the installed transformer capacity at the Waterloo connection point by no later than 2014/15.

Table 9.3: Waterloo connection point replacement: options considered

Option	Description	Comments	Estimated Cost ($M)
1	Rebuild Waterloo substation on an adjacent site with 2x25 MVA 132/33 kV transformers.	This option is the least cost option of those that eliminate the impact of the identified constraint and condition related issues at Waterloo substation.	42
2	Permanent or rapid automatic Distribution load shift	Does not address the asset condition issues.	N/A
3	Demand Side Management	Does not address the asset condition issues.	N/A
4	Load side Power Factor improvement	Does not address the asset condition issues.	N/A
5	Generation	Does not address the asset condition issues.	N/A

12 Month Load Deferral Requirement

Amount of load reduction required to achieve 12-month deferral of augmentation	Load reduction does not address the asset condition issue.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

Install a Third Transformer at Dorrien

Scope of Work: Install a third 60 MVA transformer at Dorrien substation.

Estimated Cost: $7.3 Million

Timing: 2012

Project Status: Passed Regulatory Test

Project Need

The Dorrien 132/33 kV connection point is classified as Category 4 under the ETC and presently has two 60 MVA (nominal) 132/33 kV transformers installed. Based upon the present AMD forecast the transformers will not be adequate to meet the ETC N-1 service standards beyond summer 2013/14.

Public consultation on this project was carried out in the form of a Small Network Paper published in ElectraNet's 2010 South Australian Annual Planning Report. That Small Network Paper nominated proposed solution option as the least cost solution. No comments were received in response to that submission and so ElectraNet is progressing with the proposed solution option.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

Install a 15 Mvar Capacitor Bank at Kadina East

Scope of Work: Install 1 x 15 Mvar PoW switched capacitor bank at Kadina East.

Estimated Cost: $4.6 Million

Timing: 2014

Project Status: Network Study

Project Need

Network analysis has identified inadequate reactive margins at the Ardrossan West, Dalrymple and Kadina East connection points beyond 2014. If left unresolved, this will lead to insufficient voltages on the Yorke Peninsula under peak load contingent conditions and may lead to an area wide voltage collapse.

Table 9.4: 15 Mvar capacitor bank Kadina East: options considered

Option	Description	Comments	Estimated Cost ($M)
1	Install 1 x 15 Mvar PoW switched capacitor bank at Kadina East	This option is the least cost option of those that eliminate the impact of the identified constraint.	4.6
2	Establish a 275/132 kV injection point at Hummocks	Higher cost solution	103

Option	Description	Comments	Estimated Cost ($M)
3	Permanent or rapid automatic Distribution load shift	No alternative distribution supply is available capable of meeting the requirements of the ETC	N/A
4	Demand Side Management	ElectraNet does not consider that DSM would provide an appropriate solution to this limitation, as this is reactive power reserve margin requirement from NER.	N/A
5	Load side Power Factor improvement	The load power factors are already compliant with the connection point agreement and the Rules thresholds. Therefore this option was not considered further as a viable solution.	N/A
6	Generation	Not considered a viable solution. There are currently no adequate fuel sources available (e.g. gas supply) and generation would have to run system normal at times of high load to achieve the NER requirements.	N/A

12 Month Load Deferral Requirement

Amount of load reduction required to achieve 12-month deferral of augmentation	2.2 MW total load reduction required at the Kadina East, Ardrossan West and Dalrymple connections points to defer this augmentation by 12 months.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

Install a 160 MVA 275/132 kV transformer at Bungama

Scope of Work: Install a second 275/132 kV transformer at Bungama

Estimated Cost: $11 Million

Timing: 2015

Project Status: Network Study

Project Need

An unplanned outage of the existing Bungama 275/132 kV transformer results in inadequate reactive margins in the vicinity of Bungama, Port Pirie and at Baroota substation.

Table 9.5: Second Bungama transformer: options considered

Option	Description	Comments	Estimated Cost ($M)
1	Install a 160 MVA 275/132 kV transformer at Bungama		11
2	Install 2 x 15 Mvar 132 kV PoW switched capacitor banks at Bungama substation	Studies indicate that a further 15 Mvar 132 kV capacitor bank will be required in 2017 to ensure adequate reactive margins are maintained.	12
3	Permanent or rapid automatic Distribution load shift	ElectraNet does not consider that load shifting would provide an appropriate solution to this limitation	N/A

Option	Description	Comments	Estimated Cost ($M)
4	Demand Side Management	ElectraNet does not consider that DSM would provide an appropriate solution to this limitation	N/A
5	Load side Power Factor improvement	The load power factors are already compliant with the connection point agreement and the Rules thresholds. Therefore this option was not considered further as a viable solution.	N/A
6	Generation	Not considered a viable solution. There are currently no adequate fuel sources available (e.g. gas supply) and generation would have to run system normal at times of high load to achieve the NER requirements.	N/A

12 month load deferral requirement

Amount of load reduction required to achieve 12-month deferral of augmentation	5.8 MW total load reduction is required in the Port Pirie and Baroota load areas to defer this augmentation by 12 months.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

9.4.2 Future Augmentation Projects

The following tables contain the list of emerging limitations that have been identified during the development plan study. These represent the recommended network solution based on high level cost estimation and professional engineering judgement and are one of several options. These solutions are subject to variation and change as further study and network development occur. Due to the lack of the certainties on the customer connection, the projects are indicative in terms of timing and the scope of work. The proposed network solution for each constraint will be updated as the better information become available.

The table below lists all identified augmentation projects in the region over the next 10-years. A range of project implementation dates is provided where the timing has been determined according to the NTNDP 2010 scenarios.

NTNDP Scenarios:

- S1: Fast Rate of Change
- S2: Uncertain World
- S3: Decentralised World
- S4: Oil Shock and Adaptation
- S5: Slow Rate of Change

Table 9.6: Proposed 10-year Mid North network augmentation projects

Project Timing (NTNDP S3)	Project Timing (NTNDP S1 & S2)	Project Timing (NTNDP S4 & S5)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2011			Inadequate voltage in the Barossa area for the loss of the Para to Roseworthy 132 kV transmission line under peak load conditions	Establish Templers West with 1 x 160 MVA 275/132 kV transformer; Create express 132 kV feeder to Dorrien. Restore Templers to its original configuration	Augmentation	36
2011			ETC change requiring N-1 transformer redundancy at Kadina East	Rebuild Kadina East substation with 2 x 60 MVA transformers	Connection	20
2012			Thermal overload of the remaining transformer at Ardrossan West under N-1 conditions; Inadequate voltage on the Yorke Peninsula under peak load contingent conditions	Install 2 x 25 MVA 132/33 kV transformers at Ardrossan West; Install 1 x 15 Mvar PoW switched capacitor bank	Augmentation/ Connection	23
2012			Thermal overload of the remaining transformer at Dorrien under N-1 conditions	Install a third 60 MVA 132/33 kV transformer at Dorrien Substation	Connection	7
2013			Thermal overload of the remaining transformer at Hummocks under N-1 conditions	Install 2 x 25 MVA 132/33 kV transformers and replace selected assets at Hummocks Substation	Connection/ Replacement	11
2014			Inadequate reactive margins on the Yorke Peninsula under peak load contingent conditions	Install 1 x 15 Mvar PoW switched capacitor bank at Kadina East Substation	Augmentation	4.6
2015			Inadequate reactive margins at Bungama, Baroota and Pt Pirie connection points for the loss of the Bungama 275/132 kV transformer	Install a 160 MVA 275/132 kV transformer at Bungama Substation	Augmentation	10
2016			Inadequate reactive margin at Dalrymple substation;	Install 1 x 8 Mvar PoW switched capacitor bank at Dalrymple substation and reconfigure 132 kV bus	Augmentation/ Replacement	23
2016			Subject to proposed ETC change, N-1 transformer redundancy required at Dalrymple	Install a second 25 MVA 132/33 kV transformer at Dalrymple substation	Connection	7
2017			Subject to proposed ETC change, , N-1 transformer redundancy required at Baroota	Replace Baroota substation; install 2 x 25 MVA 132/33 kV transformers at Baroota substation (ETC category change)	Connection/ Replacement	18

Project Timing (NTNDP S3)	Project Timing (NTNDP S1 & S2)	Project Timing (NTNDP S4 & S5)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2013-2018			Increased loading on the 132 kV network has made compliance with Rules Ch. 4 security provisions difficult operationally and has reduced the opportunities to do critical network maintenance and construction work to very restrictive windows	Install an integrated control scheme in the Mid North region that will ensure compliance to the 'next contingency' security requirements of the Rules and allow a higher utilisation of the network under system normal conditions as well as provide the opportunity to do network maintenance as required	Security/ Compliance	3.5
2018	2016	2021	Thermal overload of the Waterloo to Hummocks 132 kV line for the loss of the Bungama to Hummocks 132 kV line. Inadequate voltages at Ardrossan, Kadina East and Dalrymple for the loss of the Bungama – Hummocks line.	Establish a 275/132 kV injection point in the vicinity of Hummocks with 1 x 200 MVA transformer; construct a double circuit 275 kV line from the existing west circuit to the substation location	Augmentation	158
2020	2019	2022	Inadequate reactive margins at Dorrien and Roseworthy connection points after the loss of the Templers West 275/132 kV transformer	Install 1x12 Mvar, PoW switched capacitor bank at Roseworthy substation	Augmentation	5

The table below lists all identified augmentation projects in the region in the 10-20 year period. Project timing is indicative and is based on medium economic growth (NTNDP Scenario 3: Decentralised World).

Table 9.7: Proposed 10-20 year Mid North network augmentation projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2018-2023 Subject to ETSA Utilities Request	Overload of the meshed 33 kV distribution system between Port Pirie and Bungama for the loss of the Port Pirie 132/33 kV transformer	Rebuild the existing 132 kV line from Bungama to Port Pirie as double circuit; install a 2nd 60 MVA 132/33 kV transformer at Port Pirie	Augmentation	44
2018-2023 Subject to ETSA Utilities Request	An increase in demand at or in the Peterborough area will cause under voltage in the distribution network and successful completion of the RIT-T demonstrating a transmission solution as preferred option	Establish new Jamestown 275/66 kV connection point with 2x60 MVA transformers	Augmentation	45
2028-2033	Overload of the 132 kV Templers to Dorrien line for the loss of the 160 MVA 275/132 kV Templars West transformer under peak load conditions	Install a second 160 MVA 275/132 kV transformer at Templers West; rebuild Templers 132 kV section at Templers West	Augmentation	38
2028-2033	Loss of the Templers-Para 275 kV transmission line results in inadequate voltages on the Templers West 275 kV bus	Install a 100 Mvar 275 kV PoW switched capacitor bank at Templers West	Augmentation	5

9.4.3 Potential Market Benefit Projects

Constraints analysis identifies market benefit project that may improve the transmission network transfer capability available to the market. Project cost is indicative.

Table 9.8: Mid North network potential market benefit projects

Strategic value – Trigger for Project	Description of Project	Capacity/Benefit Provided	Cost (AU$ M)
Increased wind generation in Mid North (including 132 kV connected Generation). Limitations may appear during high Murraylink export and light load scenarios.	Rebuild existing Waterloo-Robertstown circuit with high capacity line from Waterloo WF to Robertstown	50 to 150 MW increase in transfer capacity in this line section (depending on the scope of the option).	30-50

9.5 Anticipated Replacement Projects

Asset replacements are planned based on asset condition. Asset condition monitoring is used to determine the actual timing of any asset replacement. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

Table 9.9: Proposed Mid North network replacement projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2008-2013	Critical infrastructure at Waterloo substation at end of technical life; thermal rating of the transformers under N conditions	Rebuild Waterloo and install 2 x 25 MVA 132/33 kV transformers	Replacement	42
2013-2018	Morgan to Whyalla pumping station #4 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the substation to current day standards and replace the 132/3.3 kV transformers	Replacement	10
2018-2023	Brinkworth substation infrastructure is at the end of its technical life	Replace Brinkworth substation to modern standards	Replacement	50

9.6 Future Network Single Line Diagram

Figure 9.4 shows the Mid North 132 kV transmission network with all of the proposed projects included, illustrating how the 132 kV network in the region may be developed over the next 20 years (where the dashed line represents proposed developments.

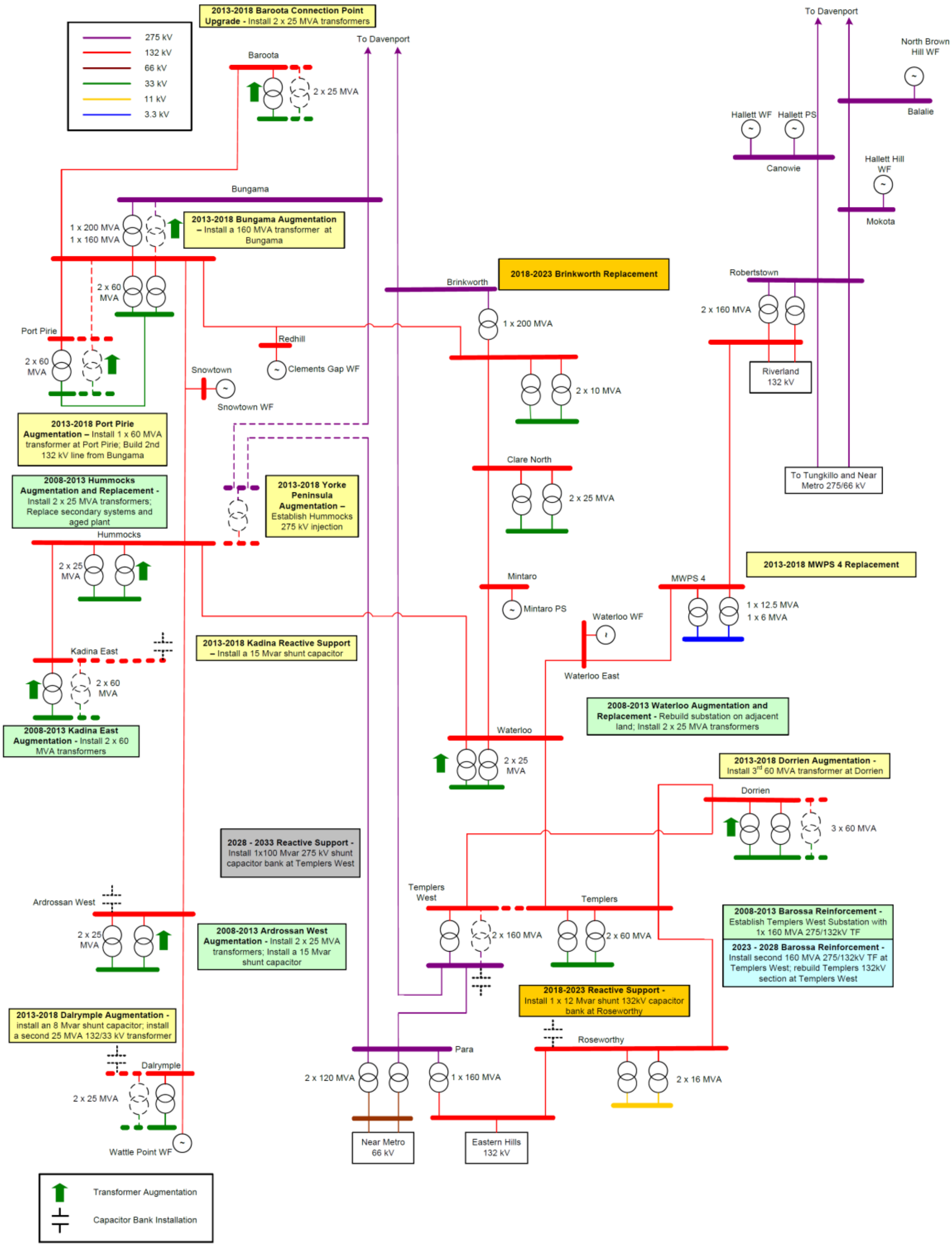


Figure 9.4: Mid North network 20-year development plan single line diagram

10. Riverland Development Plan

10.1 Existing Network Overview

The Riverland 132 kV transmission system comprises a 132 kV network that supplies customer loads in the Riverland region of South Australia which contains the major towns of Barmera, Berri, Blanchetown, Loxton, Renmark, and Waikerie. The area is bounded by Robertstown to the west and the South Australia - New South Wales/Victoria border to the east and includes major load centres along the Murray River as far south as Swan Reach.

The Riverland transmission system derives its electricity supply from the main 275 kV system via two 275/132 kV transformers located at Robertstown substation and also from the Murraylink interconnector. This system provides the power requirements of numerous SA Water pumping stations in addition to several ETSA Utilities connection point substations in the area.

Figure 10.1 shows the geographical region under consideration, and provides a simplified representation of the Riverland 132 kV transmission network servicing the area. Figure 10.2 provides a simplified single line diagram of that transmission network.

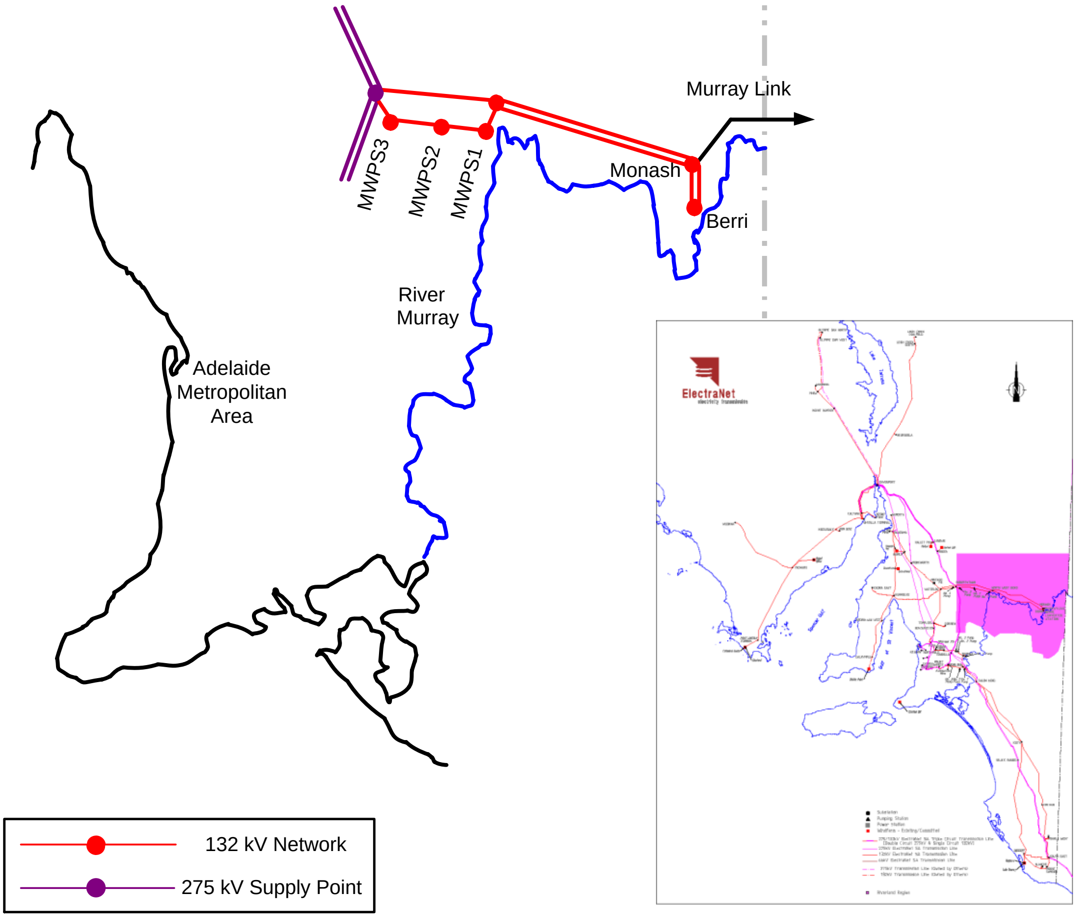


Figure 10.1: Riverland transmission region

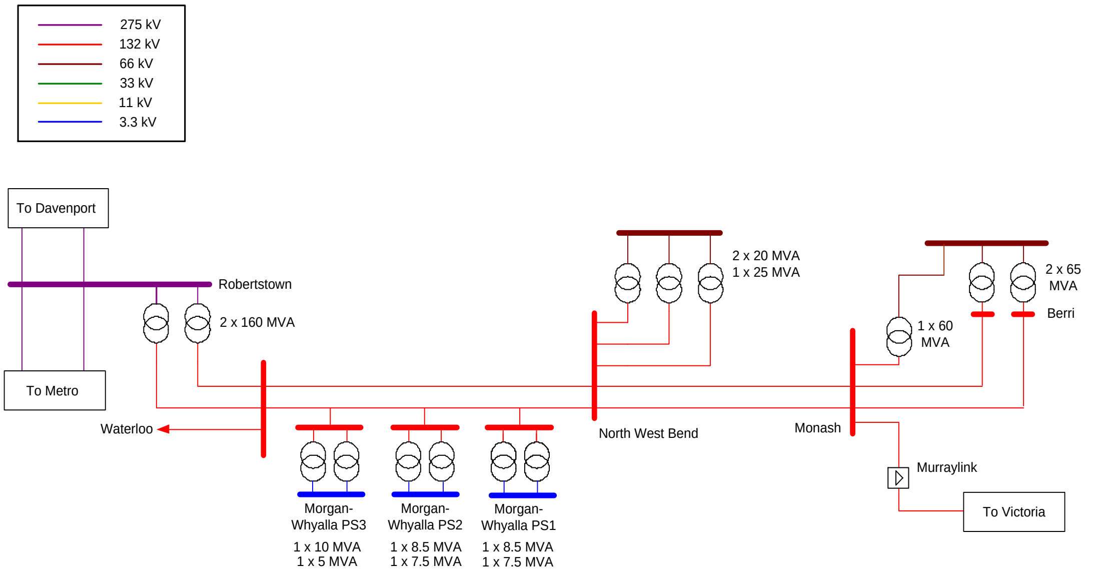


Figure 10.2: Existing Riverland transmission network single line diagram

The Riverland 132 kV system has been developed progressively since 1953 and comprises two 132 kV circuits that essentially connect Robertstown 275/132 kV substation to Berri 132/66 kV substation via a number of intermediate connection points. The Riverland 132 kV system also provides a connection for the Murraylink interconnector that connects South Australia to Victoria. As a consequence, power flows in the Riverland transmission system are determined by both the loads supplied within the region and flows on this interconnector.

The Riverland 132 kV system has limited capacity to accommodate significant additional electrical demand or generation without augmentation, and consequently has the potential to act as an impediment to continued development in the Riverland region.

The Riverland region of South Australia contains a mixture of electrical loads including industrial, agriculture and horticulture, grazing, and viticulture loads. Commercial loads also comprise a significant portion of total load at the major centres of Berri, Loxton, Renmark and Waikerie.

There are presently five customer connection points supplied by the Riverland transmission system. The Berri/Monash combined connection point and the North West Bend connection point supply the ETSA Utilities distribution system which in turn reticulates supply to electricity users in the region. The remaining three connection points provide electricity supply to the Morgan to Whyalla Pumping Stations No. 1, No. 2 and No. 3 owned by SA Water.

Shown in Table 10.1 is a list of the connection points that supply the Riverland region and the reliability classification presently assigned to each in the ETC. Refer to Appendix D for details in relation to the ETC Connection Point Reliability Standards.

Table 10.1: Riverland region connection point ETC categorisation

Connection Point	ETC Category
Morgan to Whyalla Pump Station #1	1
Morgan to Whyalla Pump Station #2	1
Morgan to Whyalla Pump Station #3	1
North West Bend	4
Berri/Monash (combined)	4

10.1.1 Existing and Committed Generation

There is no significant generation presently connected to the Riverland 132 kV system nor are there any committed plans for generation to connect at this time. However, there is the potential for the connection of generation to occur within the period covered by this plan as there are a number of renewable energy generation opportunities available in the Riverland.

10.1.2 Intra-regional Transfer Capability

The Murraylink interconnector connects to the Riverland 132 kV system at Monash and has a major influence on power flows through this sub-region. Power flows in the Riverland are therefore dependent on both regional load and the prevailing flows on the Murraylink interconnector.

Network constraints within the Riverland sub-region are managed via the Murraylink run-back control system. This control system excludes the Robertstown transformers which are managed by constraint equations.

AEMO reported in The Constraint Report 2010, that the North West Bend to Robertstown 132 kV ‘transmission line thermal limit’ constraint bound for 136.9 hours in 2010. ElectraNet has commenced installing weather stations within the Riverland region and plans to implement real time ratings to alleviate this constraint.

10.2 Study Methodology

10.2.1 Planning Criteria and Assumptions

This development plan has been prepared according to the planning framework described in Appendix D.

10.2.2 20 Year Load Forecast

The future system demand considered in the analysis contained in this development plan is based on forecasts produced by ETSA Utilities and other direct connect customers and SA Water pumping loads on a typical summer day. The 20-year high, medium and low demand forecasts for the Riverland 132 kV transmission system are shown in Figure 10.3 and the projected performance limitations have been analysed based on those load forecasts. See Appendix B for more detail.

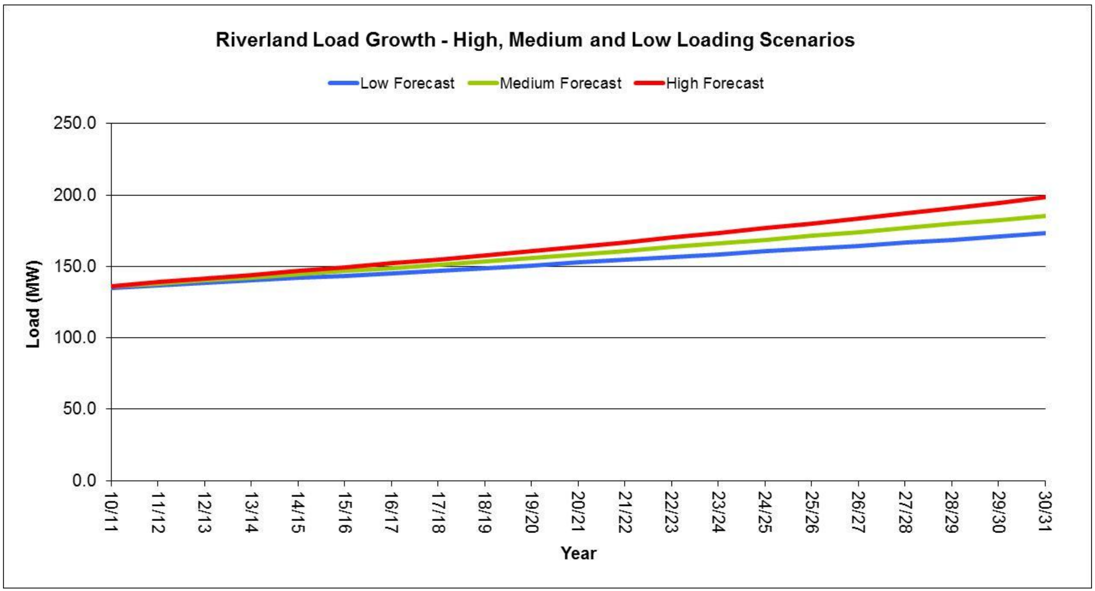


Figure 10.3: Riverland region 20-year peak load forecasts

10.2.3 Special Considerations in the Riverland

Interconnections

The Murraylink interconnector connects to the Monash 132/66 kV substation and influences the power flows through the Riverland region. The capability of Murraylink to support both load and voltages in the region has been taken into account when considering the timing of developments in the Riverland region.

Due to the technology used in Murraylink it has the capability to provide voltage support independently of the real power transferred over the link.

Murraylink's ability to deliver real power into the Riverland region is limited by the following factors:

- The rating of Murraylink is 220 MW of sent out power, which equates to approximately 200 MW delivered power at the receiving end due to electrical losses;
- The capability of the supply networks in South Australia and Victoria, which vary with network loading and outage conditions;
- The availability of surplus generation capacity in the exporting state;
- The status of various run-back control schemes; and
- The operation of the NEM and the ability to constrain Murraylink into service under contingency operating conditions.

The principal influence on the capability of Murraylink to deliver real power into the Riverland region is the capacity of the Victorian transmission network to deliver power to Red Cliffs Terminal Station, the Murraylink connection point in Victoria. AEMO has recently advised that Murraylink's capability to deliver real power to South Australia at the time of 10% POE 2011/12 summer maximum demand in

Victoria is up to 50 MW and is diminishing by approximately 5 MW for every year beyond 2011/12.

Based on this trend and without further augmentation of the Victorian transmission system supplying Red Cliffs, Murraylink's maximum capability to deliver real power to the Riverland region in about 2015/16 will be insufficient to prevent the overloading of the Robertstown–North West Bend 132 kV transmission line under contingency conditions.

Table 10.2 shows the forecast peak load import capability of the Murraylink Interconnector and the resulting load on the Riverland 132 kV transmission system under contingency conditions with SA Water pumping loads switched off in the Riverland.

Table 10.2: Murraylink peak load capability

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Riverland Load (excluding pumping loads)	126.9	129	131.2	133.4	135.6	137.8	140.1	142.5	144.9	147.3
Forecast Murraylink Capability at Peak Load	50	45	40	35	30	25	20	15	10	5
Murraylink Transfer required into SA	27	29	31	34	36	38	40	43	45	48
Net Vic SA Transfer Balance	23	16	9	1	-6	-13	-20	-28	-35	-43

* All figures in MW

Due to this emerging capacity shortfall, ElectraNet and AEMO intend to proceed with joint planning to develop augmentation options and undertake preliminary market simulation studies, in consultation with TransGrid, during 2011/12. However, it is expected that transmission network augmentation in Victoria may be able to defer this capacity shortfall by a few years.

SA Water Pumping Loads

For the purposes of peak load system planning in the Riverland region, pumping loads at the SA Water owned Morgan–Whyalla Pumping Stations are assumed to be offline. Under light and average load conditions, pumping loads at these sites are assumed to be online.

Assumed Wind Generation

While there is no wind generation connected within the Riverland transmission system, significant wind generation is present in the neighbouring Mid-North transmission region at both 275 kV and 132 kV voltage levels. Historical records indicate that at times of peak load the average wind generation across South Australia is generally of the order of 3% of installed capacity. At times of average and light load conditions, higher levels of wind generation (up to 85%) have been observed within South Australia.

For the purposes of peak load system planning for the Riverland region, wind generation within South Australia was assumed to be at 3%. Under these conditions, the Murraylink interconnector was assumed to be importing into South Australia. Conversely, for light load analysis, wind generation within South Australia was assumed to be at 85% and Murraylink was assumed to be exporting into Victoria.

10.2.4 Fault Levels

Substation fault levels are assessed to remain within design and equipment limits. A table listing the 5 year maximum substation fault levels and circuit breaker ratings is provided in Appendix C of this report.

10.3 Connection Opportunities

This section identifies potential opportunities for connection of generation and load to the transmission network. Generation and load proponents should take this information into account when considering the location of their projects (especially larger projects).

10.3.1 Generation Connection Opportunities

There is some transmission network capacity available to connect generation in this system, particularly at Robertstown.

Small scale generation (<100 MW) may be accommodated at Monash, but would compete with Murraylink import for dispatch.

10.3.2 Load Connection Opportunities

Electrical demand on the Riverland 132 kV transmission system has grown steadily over the years as a result of agricultural, horticultural, residential, commercial and light industrial development. While there are several individual customer connection points in the Riverland region, with the exception of the SA Water pumping stations, those connection points service the ETSA Utilities distribution network which in turn supplies individual electricity consumers.

- Without any network support via Murraylink, the Riverland 132 kV transmission network is presently operating beyond its firm capacity. With support from Murraylink, there is limited capacity available to supply new or increased customer loads.
- Customers with large loads could be accommodated at Robertstown on the 275 kV level, while large loads at 132 kV level may require augmentation of transformer and line capacity.

10.4 Constraints and Proposed Augmentation Projects

Projected power system limitations within the Riverland 132 kV transmission system are highly dependent on load growth and demand on the ETSA Utilities distribution system and SA Water pumping stations loads. All five connection points within the region have been examined individually within this development plan and where necessary the combined impact of those individual projected network and connection point limitations is examined to determine any impacts that result on the overall supply system in the region.

The network limitations, along with the proposed solutions, timings, estimated capital expenditures, and option analysis for projects that have been identified for the next 5-year period are described below. Projects identified for the initial 10-year period of this 20 year development plan, including those projects that will improve the performance of existing plant and equipment, rather than physically adding to the asset base (e.g. installing control schemes to maintain network security) and will be triggered by a sudden load increase, the timing of which is not yet known, are summarised in Table 10.4. Finally, asset replacements are considered separately, and are listed in Table 10.7.

The following section provides description of the projects that are proposed to alleviate the projected performance limitations identified.

10.4.1 5-Year Major Augmentation Projects

15 Mvar 132 kV Capacitor Bank at Monash

Scope of Work: Install one 15 Mvar 132 kV Capacitor Bank at Monash

Estimated Cost: $4.9 Million

Timing: 2014

Project Status: Network Study

Project Need

An unplanned outage of the Murraylink interconnector at peak load results in a shortfall in reserve reactive margin at the Monash and Berri substations. If this condition is not addressed, loss of the Murraylink interconnector under peak load conditions will lead to inadequate 132 kV voltages and the possibility of a Riverland wide voltage collapse.

Table 10.3: Monash capacitor bank: options considered

Option	Description	Comments	Estimated Cost ($M)
1	Install 1 x 15 Mvar PoW switched capacitor bank at Monash substation	This option is the least cost option of those that eliminate the impact of the identified constraint.	4.9
2	Permanent or rapid automatic Distribution load shift	There are currently no existing or planned distribution networks of sufficient capacity available to off-load the 66 kV distribution network to the extent required and therefore this option was not considered further as a viable alternative.	N/A
3	Demand Side Management	ElectraNet does not consider that DSM would provide an appropriate solution to this problem.	N/A
4	Load side Power Factor improvement	The load power factors are already compliant with the connection point agreement and the Rules thresholds. Therefore this option was not considered further as a viable option.	N/A
5	Generation	Generation solutions were not considered to be viable due to the nature of the constraint.	N/A

12 month load deferral requirement

Amount of load reduction required to achieve 12-month deferral of augmentation	2.1 MW of load reduction is required at Berri connection point to defer this augmentation by 12 months.

In addition to ensuring adequate reactive margins are maintained at the Monash and Berri substations, this project is likely to provide market benefits in the form of improved Murraylink export limits from South Australia to Victoria. These market benefits are yet to be quantified.

10.4.2 Future Augmentation Projects

The following tables contain the list of emerging limitations that have been identified during the development plan study. These represent the recommended network solution based on high level cost estimation and professional engineering judgement and are one of several options. These solutions are subject to variation and change as further study and network development occur. Due to the lack of the certainties on the customer connection, the projects are indicative in terms of timing and the scope of work. The proposed network solution for each constraint will be updated as the better information become available.

The table below lists all identified augmentation projects in the region over the next 10-years. A range of project implementation dates is provided where the timing has been determined according to the NTNDP 2010 scenarios.

NTNDP Scenarios:

- S1: Fast Rate of Change
- S2: Uncertain World
- S3: Decentralised World
- S4: Oil Shock and Adaptation
- S5: Slow Rate of Change

Table 10.4: Proposed 10-year Riverland network augmentation projects

Project Timing (NTNDP S3)	Project Timing (NTNDP S1 & S2)	Project Timing (NTNDP S4 & S5)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2014			Inadequate reactive margins at the Monash and Berri substations.	Install a 15 Mvar 132 kV POW switched capacitor bank at Monash substation.	Augmentation	4.9
2018 (This date is dependent upon Murraylink's capacity coincident with Victorian peak demand)	2016 (This date is dependent upon Murraylink's capacity coincident with Victorian peak demand)	2020 (This date is dependent upon Murraylink's capacity coincident with Victorian peak demand)	Outage of Robertstown to North West Bend 132 kV #2 line overloads Robertstown-North West Bend #1 line (dependent on Murraylink import performance); voltages sag at Berri under contingency of Murraylink.	Construct a 275 kV double circuit transmission line from Robertstown to Monash; establish a 275/66 kV substation at Monash with 1 x 50 Mvar 275 kV reactor, 2 x 225 MVA 275/66 kV transformers and 1 x 240 MVA 275/132 kV transformer; construct a high capacity double circuit 66 kV line from Monash to Berri; remove all significant transmission infrastructure from Berri.	Augmentation	366
2013-2018			Increased loading on the 132 kV network has made compliance with the Rules Ch. 4 security provisions difficult operationally and has reduced the opportunities to do critical network maintenance and construction work to very restrictive windows.	Install an integrated control scheme in the Riverland region that will ensure compliance to the 'next contingency' security requirements of the Rules and allow a higher utilisation of the network under system normal conditions as well as provide the opportunity to do network maintenance as required.	Security/ Compliance	3.5

Table 10.5 lists all identified augmentation projects in the region in the 10-20 year period. Project timing is indicative and is based on medium economic growth (NTNDP Scenario 3: Decentralised World).

Table 10.5: Proposed 10-20 year Riverland network augmentation project

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2023-2028	North West Bend substation at end of technical life; Emerging 132/66 kV transformer capacity limitation post 2031;	Tie the Robertstown to Monash 275 kV circuits into North West Bend substation; rebuild North West Bend as a 275/66 kV substation	Augmentation/ Replacement	65

10.4.3 Potential Market Benefit Projects

Constraints analysis identifies market benefit projects that may improve the transmission network transfer capability available to the market. Project costs are indicative.

Table 10.6: Riverland network potential market benefit project

Strategic value – Trigger for Project	Description of Project	Capacity/Benefit Provided	Cost (AU$ M)
Murraylink export from South Australia to Victoria is currently limited by the reactive support in the Riverland region. To increase Murraylink transfer capacity	Install two 15 Mvar 132 kV capacitor banks in Riverland. One is at Monash and the other is at North West Bend.	Improve voltage and give reactive support.	10

10.5 Anticipated Replacement Projects

Asset replacements are planned based on asset condition. Asset condition monitoring is used to determine the actual timing of any asset replacement. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

Table 10.7: Proposed Riverland network replacement projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2013-2018	Morgan to Whyalla pumping station #1 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the substation to current day standards and replace the 132/3.3 kV transformers	Replacement	10
2013-2018	Morgan to Whyalla pumping station #2 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the substation to current day standards and replace the 132/3.3 kV transformers	Replacement	12
2013-2018	Morgan to Whyalla pumping station #3 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the substation to current day standards and replace the 132/3.3 kV transformers	Replacement	10

10.6 Future Network Single Line Diagram

Figure 10.4 shows the Riverland 132 kV transmission region with all of the proposed projects included, illustrating how the 132 kV network in the region may be developed over the next 20-years (where the dashed lines represent proposed developments).

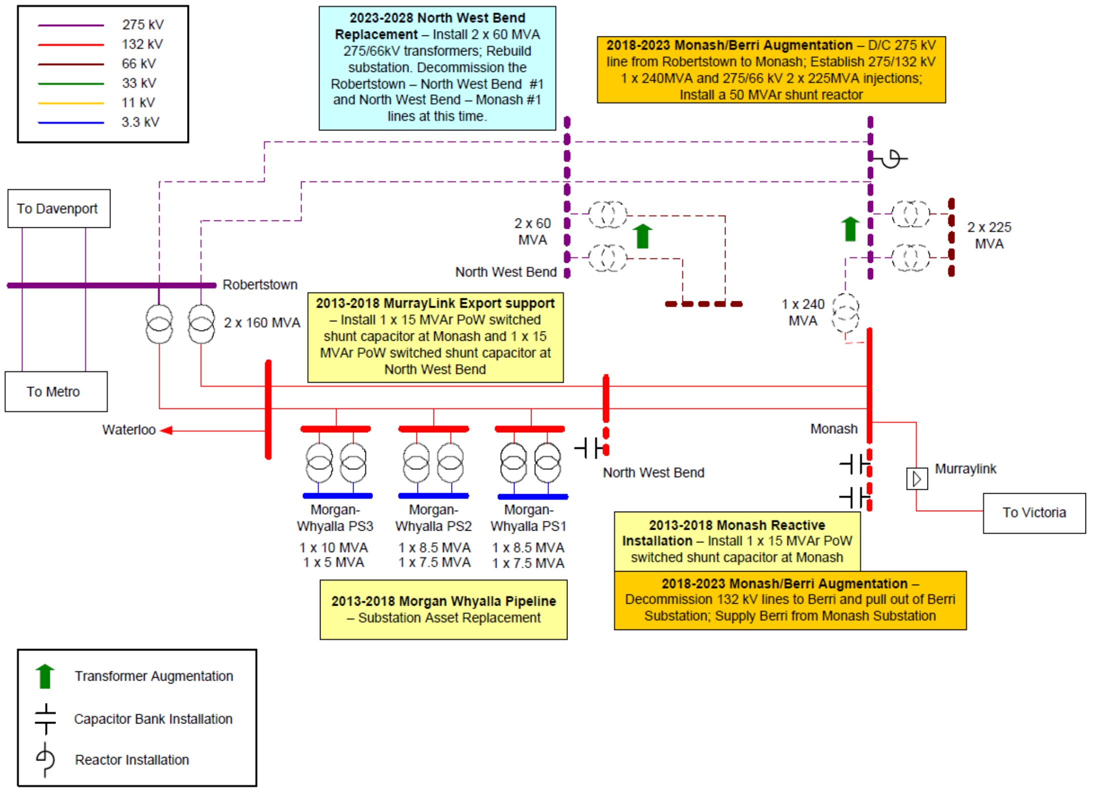


Figure 10.4: Riverland network 20-year development plan single line diagram

11. South East Development Plan

11.1 Existing Network Overview

The South East 132 kV transmission system comprises a network that supplies customer loads in the South East region of South Australia which contains the major towns of Beachport, Keith, Kingston, Millicent, Mount Gambier, Naracoorte, Penola, Robe and Tailem Bend. The area is bounded by the South Australia/Victoria border on the East, the Riverland region to the north, the Eastern Hills region to the North West and the Southern Ocean to the west.

The South East 132 kV region derives its supply from the Main Grid 275 kV network via 275/132 kV substations located at Tailem Bend and South East (approximately 15 km north of Mount Gambier), and supplies the area generally shown on Figure 11.1. A simplified representation of the South East 132 kV transmission region is shown on Figure 11.2.

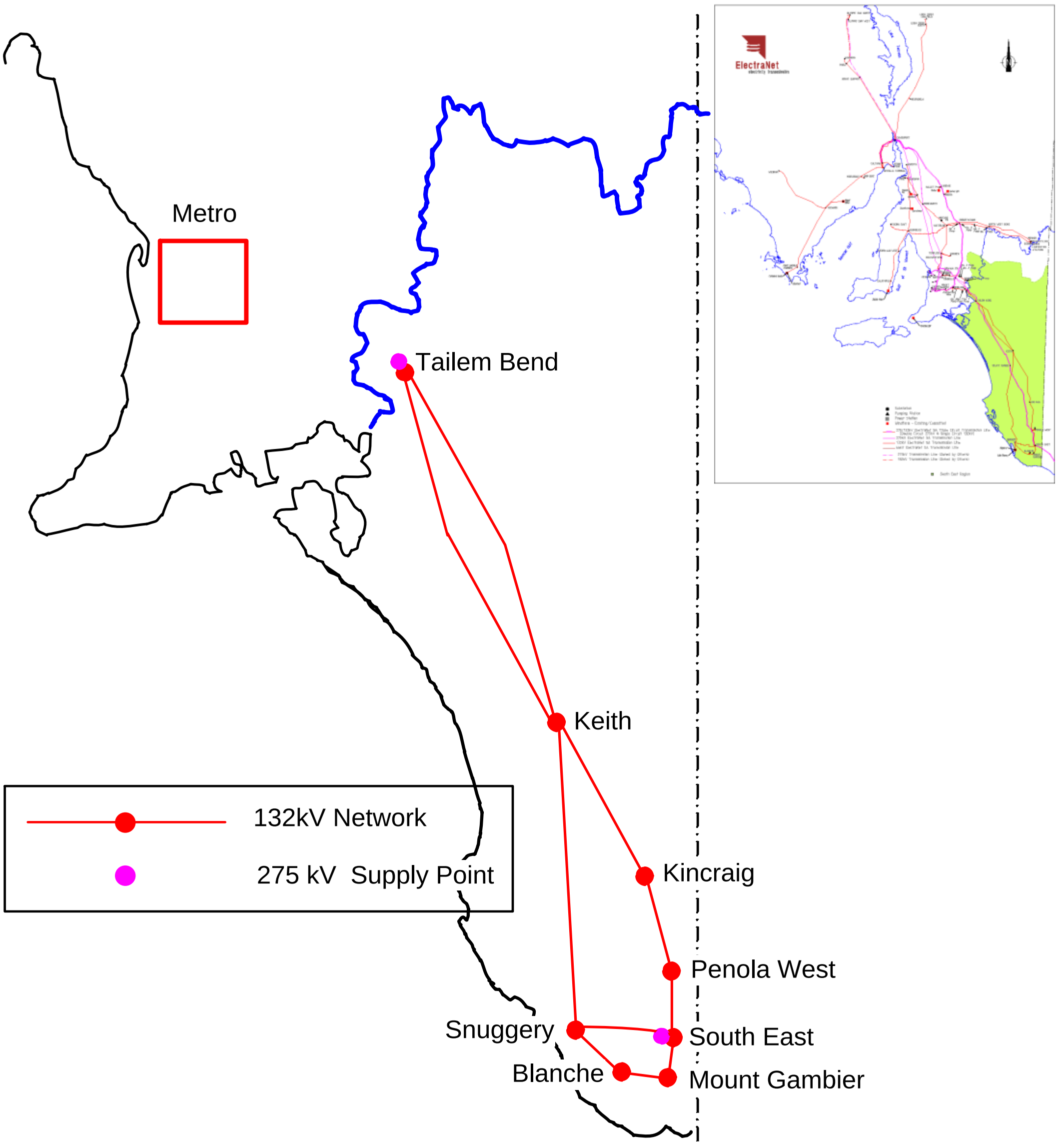


Figure 11.1: South East transmission region

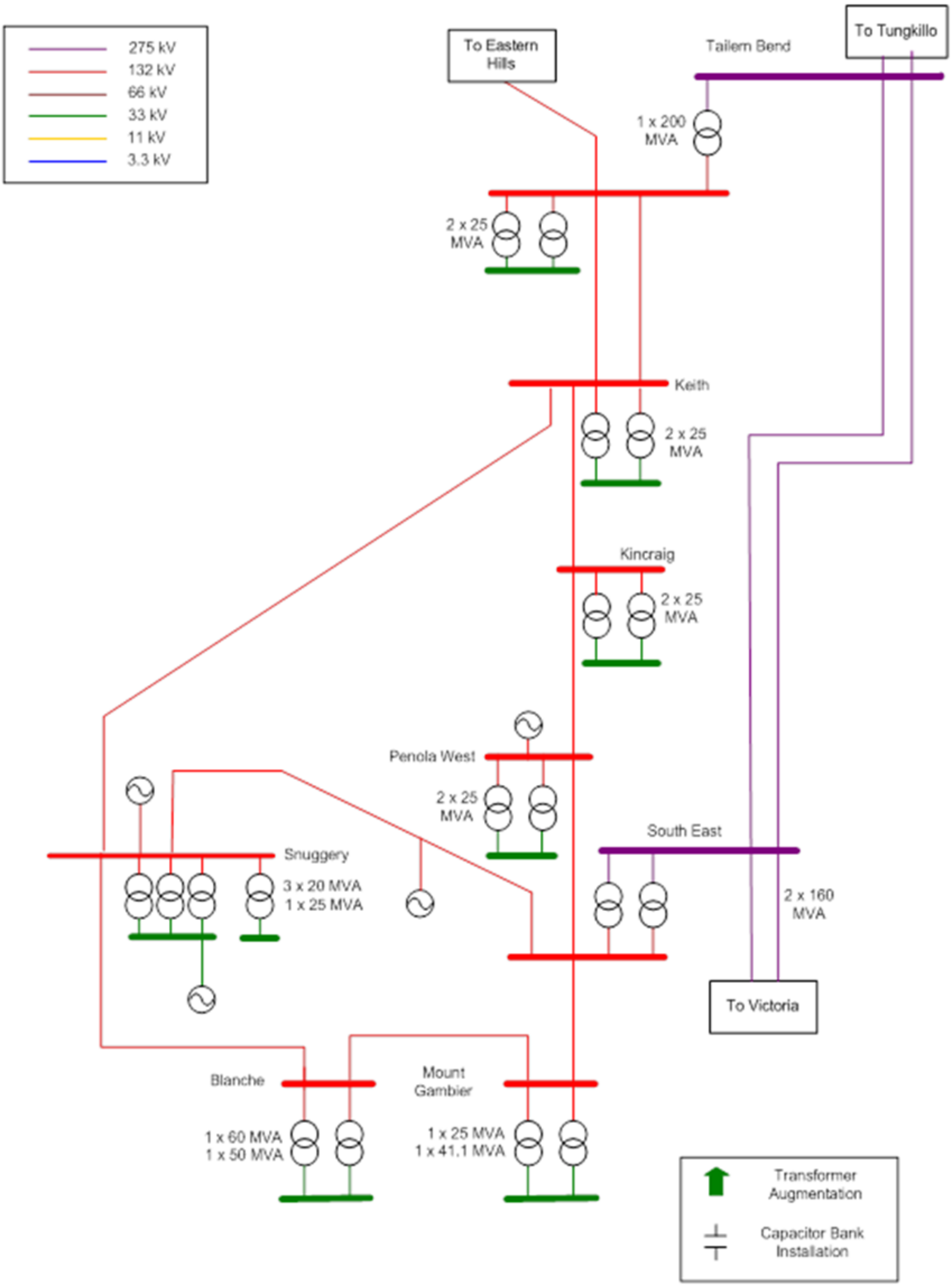


Figure 11.2: Existing South East transmission network single line diagram

The South East region has two 275 kV injecting points, one is at South East and the other in at Tailem Bend. South east region transmission voltage is 132 kV. The 275 kV system was extended to Tailem Bend in 1976 and a 275/132 kV substation established at that location to feed into the South East 132 kV system. Gas turbine generating plant was installed at Snuggery in 1980 and a 132/33 kV substation constructed at Blanche (about 15 km south west of Mount Gambier) in 1981.The

South East system was further augmented as part of the South Australia to Victoria (Heywood) interconnector project in 1989 when the 275/132 kV South East substation was established just north of Mount Gambier and connected to the Kincraig to Mount Gambier 132 kV line. The South East substation was connected to the Victorian transmission system at Heywood 500/275 kV Terminal Station via 90 km of double circuit 275 kV line, and to Tailem Bend by approximately 310 km of double circuit 275 kV line.

A gas turbine generating plant at Ladbroke Grove was connected to the South East to Kincraig 132 kV line at Penola West in 2001. The Lake Bonney wind farm was connected to Snuggery substation in 2005. A second wind farm, Canunda, was also connected to the ETSA Utilities 33 kV bus at Snuggery in 2005. Lake Bonney stage 3 was commissioned in year 2010.

There are presently eight customer connection points supplied by the South East transmission system. The Tailem Bend, Keith, Kincraig (Naracoorte), Snuggery Rural (near Millicent), Blanche, Mount Gambier and Penola West connection points supply the ETSA Utilities distribution system, which in turn reticulates to electricity users in the region. The remaining connection point provides electricity supply to Kimberly-Clark Australia (KCA) (at Snuggery Industry).

There are three generation connection points in the South East region that connect International Power (gas turbines) at Snuggery, Infigen Energy (Lake Bonney wind farm) at Mayurra and Origin Energy (Ladbroke Grove gas turbines) at Penola West. Canunda wind farm is an embedded generator that connects to the ETSA Utilities 33 kV network, at Snuggery substation.

Shown in Table 11.1 is a list of the connection points that supply the South East region and the reliability classification presently assigned to each in the ETC. Refer to Appendix D for details in relation to the ETC Connection Point Reliability Standards.

Table 11.1: South East region connection point ETC categorisation

Connection Point	ETC Category
Blanche	4
Keith	4
Kincraig	4
Mount Gambier	4
Snuggery Rural	3
Snuggery Industrial	4
Tailem Bend	4
Penola West	4

11.1.1 Existing and Committed Generation

Existing generation on the South East 132 kV system is comprised of back-up gas turbine driven plant and wind farms. Gas turbine plant is located at Snuggery (3 x 26 MW) and Ladbroke Grove (2 x 43 MW). In addition to the gas turbine driven generation, four wind farms are operational in the South East region, Canunda (46 MW-via ETSA Utilities network), Lake Bonney Stage 1 (80.5 MW), Lake Bonney

Stage 2 (159 MW), and Lake Bonney Stage 3 (39 MW). These wind farms are located north west, south and south east of Snuggery respectively.

11.1.2 Intra-regional Transfer Capability

The South East 275 kV and 132 kV networks operate in parallel. Generation installed in the South East 132 kV transmission system has the tendency to displace import on the Heywood Interconnector when operating.

Under system normal operating conditions when the Heywood interconnector is importing power from Victoria, the levels of import and generation in the South East 132 kV transmission network are limited to ensure operation within both voltage stability limits, and within thermal limits on the Tailem Bend – Keith and Keith – Snuggery 132 kV line sections. AEMO reported that the Tailem Bend to Keith constraint bound for 18 hours in The Constraint Report 2010.

Additionally, under system normal operating conditions when the Heywood interconnector is importing power from Victoria, the overloading of a South East 275/132 kV transformer occurs on the loss of the second transformer under conditions of high import, high load and low 132 kV connected generation. This situation is currently managed by a control system that simultaneously opens the South East to Penola West 132 kV transmission line on the loss of the second transformer. This allows higher interconnector import to SA, while managing the next credible contingency than otherwise would have been the case.

Conversely, under system normal operating conditions when the Heywood interconnector is exporting power to Victoria, the level of generation in the South East 132 kV sub-network is occasionally constrained at times of low load and high wind to ensure operation within thermal limits of South East 275/132 kV transformers. AEMO reported that this constraint bound in 2010 for 214 hours in The Constraint Report 2010. ElectraNet is currently investigating whether sufficient market benefits exist to advance the planned installation of the third 275/132 kV transformer at South East substation to alleviate constraints under this operating condition. In the 2009 NTS, AEMO also reported that if additional generation were connected to the 132 kV transmission network, the number of hours that this constraint would bind would increase significantly.

An automatic tripping scheme is installed on the Canunda wind farm to preserve voltage stability in the South East sub-region under critical 132 kV fault conditions.

The Lake Bonney Wind Farm Stage 3 has an automatic run back control scheme to limit its generation such that any displacement on Heywood interconnection import is not more than on a one MW per MW of generation basis.

11.2 Study Methodology

11.2.1 Planning Criteria and Assumptions

This development plan has been prepared according to the planning framework described in Appendix D.

11.2.2 20 Year Load Forecast

Electrical demand in the South East 132 kV transmission system has grown steadily over the years as a result of residential, agricultural, commercial and industrial development. The South East transmission system distribution connection points and their associated 10-year economic growth load forecasts are shown in Appendix B. This load forecast has been extrapolated to cover the full 20-year period of interest for the medium load growth scenario provided by ETSA Utilities.

The future system demand considered in the analysis contained in this development plan is based on forecasts produced by ETSA Utilities and other direct connect customers and on typical summer peak loads. The 20-year high, medium and low demand forecasts for the South East 132 kV system are shown on Figure 11.2 and the projected performance limitations have been analysed based on those load forecasts.

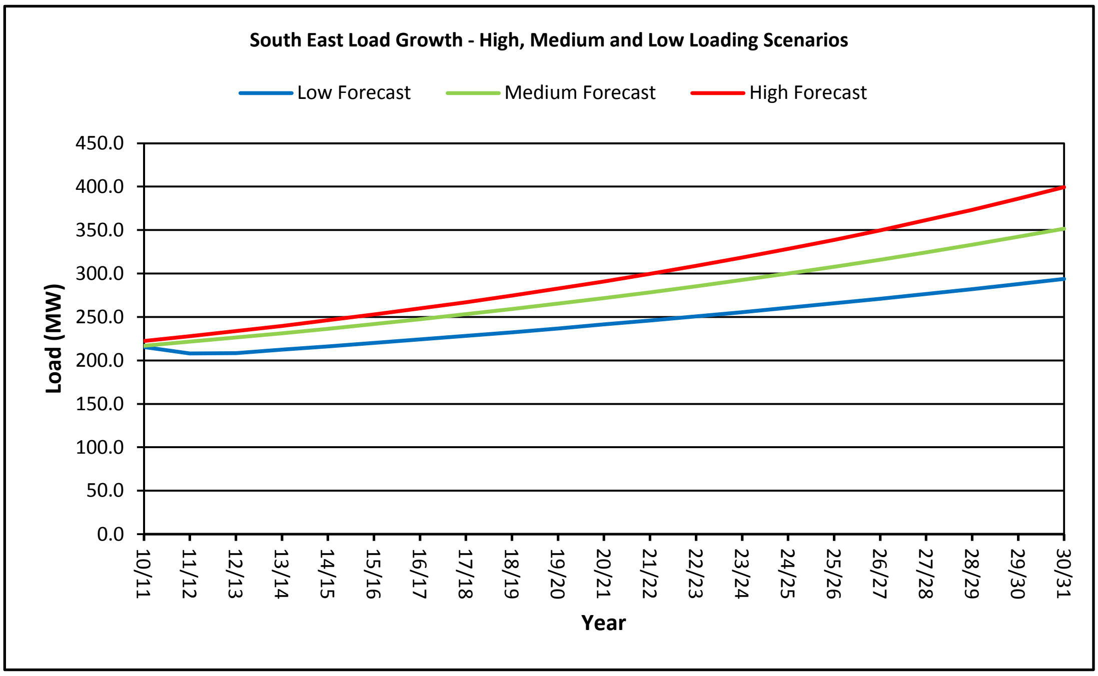


Figure 11.3: South East region 20-year peak load forecasts

11.2.3 Special Considerations in the South East Region

The South East region development plan has also investigated the following scenarios:

Assumed Wind Generation

Historical records indicate that at times of peak load the average wind generation across South Australia is generally of the order of 3% of installed capacity. At times of average and light load conditions, higher levels of wind generation (up to 85%) have been observed within South Australia.

For the purposes of peak load system planning for the South East region, local wind farms are assumed to be out of service while wind generation within South Australia was assumed to be at 3%. Conversely, for light load analysis, wind generation within South East was assumed to be at 85% while wind generation within South Australia was assumed to be at 3%.

Assumed Gas Turbine Generation

Local gas turbine generations are assumed to be out of service for both peak and light loading conditions.

11.2.4 Fault Levels

Substation fault levels are assessed to remain within design and equipment limits. A table listing the 5 year maximum substation fault levels and circuit breaker ratings is provided in Appendix C of this report.

11.3 Connection Opportunities

This section identifies potential opportunities for connection of generation and load to the South East transmission network. Generation and load proponents should take this information into account when considering the location of their projects (especially larger projects).

11.3.1 Generation Connection Opportunities

Tailem Bend would provide a suitable location in the system for generation to connect.

Black Range (approximately 30 km north-west of Padthaway) is also well positioned in the network for generation development. ElectraNet owns property in the area which is suitably located to establish a substation as the site is in close proximity to existing 275 kV and 132 kV transmission lines.

Generation development in close proximity to the Tailem Bend to South East 275 kV transmission lines would provide a viable connection location.

The capacity of the existing 132 kV transmission network is almost fully utilised and there is minimal scope to connect generation into the existing 132 kV network.

11.3.2 Load Connection Opportunities

Electrical demand on the South East 132 kV transmission system has grown steadily over the years as a result of agricultural, commercial, residential and industrial development. While there are several individual customer connection points in the South East region, the majority of those connection points service the ETSA Utilities distribution network which in turn supplies individual electricity consumers.

- Tailem Bend or South East 275/132 kV substations provide good locations at which to connect new load.
- The Black Range substation site is a good location for new electrical loads to connect.

- Connection of new load at any point along the Tailem Bend to South East 275 kV transmission lines would be acceptable especially in the case of large loads (>30 MW).
- The existing South East 132 kV transmission network is operating at close to capacity and there is minimal scope remaining to connect additional load.

11.4 Constraints and Proposed Augmentation Projects

Projected power system limitations within the South East 132 kV transmission system are highly dependent on load growth and demand on the ETSA Utilities distribution system and that of the direct connect customers. All eight customer connection points on the South East 132 kV system have been examined individually within this development plan. Where necessary, the combined impact of individual projected network and connection point limitations have been examined to determine any impacts that result on the overall supply system in the region.

The network limitations, along with the proposed solutions, timings, estimated capital expenditures, and option analysis for projects that have been identified for the next 5-year period are described below. Projects identified for the initial 10-year period of this 20 year development plan, including those projects that will improve the performance of existing plant and equipment, rather than physically adding to the asset base (e.g. installing control schemes to maintain network security) and will be triggered by a sudden load increase, the timing of which is not yet known, are summarised in Table 11.4 and Table 11.5. Finally, asset replacements are considered separately, and are listed in Table 11.7.

The following section provides description of the projects that are proposed to alleviate the projected performance limitations identified.

11.4.1 5-Year Major Augmentation Projects

1 x 15 Mvar Reactive Support at Kincraig

Scope of Work: Install 1 x 15 Mvar 132 kV Capacitor Bank at Kincraig

Estimated Cost: $4 Million

Timing: 2012

Project Status: Network Study

Project Need

Kincraig is located near Naracoorte in the South East and supplies loads as far away as Kingston via the ETSA Utilities 33 kV and SWER distribution systems. Analysis indicates that voltages at Kincraig will fall to unacceptable levels following the loss of the Penola West to Kincraig 132 kV line or the South East to Penola West 132 kV line (assuming no generation at Penola West). ElectraNet is proposing to install a 15 Mvar 132 kV capacitor bank at the Kincraig substation in the South East of South Australia.

Table 11.2: Kincraig capacitor bank: options considered

Option	Description	Comments	Estimated Cost ($M)
1	Install 1 x 15 Mvar PoW switchable capacitor bank	Low cost option; sufficient for the planning period considered	4
2	Install an SVC	Cost is prohibitive	23
3	Permanent or rapid automatic Distribution load shift	No alternative distribution supply is available.	
4	Customer	The customer power factors are maintained as per the connection agreements (as per NER)	N/A
5	Generation	Generation cannot be contracted at Ladbroke Grove as the generator will not help the voltages on a Kincraig to Penola West contingency	N/A
6	DSM	Is already allowed for in the ETSA Utilities load forecasts and in the contracted AMD. ElectraNet is currently unaware of any suitably sized loads that could viably provide additional DSM	N/A

12 month load deferral requirement

Amount of load reduction required to achieve 12-month deferral of augmentation	2 MW of load reduction is required at Kincraig connection point to defer this augmentation by 12 months.

1 x 15 Mvar Reactive Support at Tailem Bend

Scope of Work: Install 1 x 15 Mvar 132 kV Capacitor Bank at Tailem Bend

Estimated Cost: $4 Million

Timing: 2013

Project Status: Network Study

Project Need

Tailem Bend connection point supplies loads as far away as Pinnaroo, Coonalpyn and Narrung via the ETSA Utilities 33 kV and SWER distribution systems. Analysis indicates that voltages at Tailem Bend will fall to unacceptable levels following the loss of the Tailem Bend 275/132 kV transformer. ElectraNet is proposing to install a 15 Mvar 132 kV capacitor bank at the Tailem Bend substation to ensure acceptable voltage levels at the 33 kV connection point.

Table 11.3: Tailem Bend capacitor bank: options considered

Option	Description	Comments	Estimated Cost ($M)
1	Install 1 x 15 Mvar PoW switchable capacitor bank	Low cost option; sufficient for the planning period considered	4
2	Install an SVC	Cost is prohibitive	23
3	Permanent or rapid automatic Distribution load shift	No alternative distribution supply is available.	
4	Customer	The customer power factors are maintained as per the connection agreements (as per NER)	N/A
5	Generation	Contracting generation at Ladbroke Grove is not a viable alternative because it is too far removed to provide the required voltage support	N/A
6	DSM	Is already allowed for in the ETSA Utilities load forecasts and in the contracted AMD. ElectraNet is currently unaware of any suitably sized loads that could viably provide additional DSM	N/A

12 month load deferral requirement

Amount of load reduction required to achieve 12-month deferral of augmentation	1.5 MW of load reduction is required at Tailem Bend and Keith connection points to defer this augmentation by 12 months.

11.4.2 Future Augmentation Projects

The following tables contain the list of emerging limitations that have been identified during the development plan study. These represent the recommended network solution based on high level cost estimation and professional engineering judgement and are one of a number of options available. These solutions are subject to variation and change as further study and network development occur. Due to the lack of the certainties on the customer connection, the projects are indicative in terms of timing and the scope of work. The proposed network solution for each constraint will be updated as the better information become available.

The table below lists all identified augmentation projects in the region over the next 10-years. A range of project implementation dates is provided where the timing has been determined according to the NTNDP 2010 scenarios.

NTNDP Scenarios:

- S1: Fast Rate of Change
- S2: Uncertain World
- S3: Decentralised World
- S4: Oil Shock and Adaptation
- S5: Slow Rate of Change

Table 11.4: Proposed 10-year South East network augmentation projects

Project Timing (NTNDP S3)	Project Timing (NTNDP S1 & S2)	Project Timing (NTNDP S4 & S5)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
	2012		Low voltages at Kincraig under loss of Kincraig-Penola West 132 kV line	Install a 15 Mvar Capacitor bank at Kincraig substation	Augmentation	4
	2013		Low voltage at Keith and Tailem Bend under loss of Tailem Bend 275/132 kV transformer	Install a 15 Mvar capacitor bank at Tailem Bend substation	Augmentation	4
	2016 Actual timing dependent on the outcomes of the Regulatory Investment Test		Inadequate Keith 132/33 kV transformer capacity and asset condition	Rebuild Keith substation at an adjacent site; install 2 x 60 MVA transformers (substation upgrade proposed to be deferred by Demand Management).	Connection/ Replacement	34
2017	2016	2019	Kincraig 132/33 kV transformer capacity limitation; asset condition	Rebuild Kincraig substation on new site and install 2 x 60MVA 132/33 kV transformers at this site.	Connection/ Replacement	34
2018	2017	2019	Loss of Tailem Bend 275/ 132 kV transformer causes low voltage in the area	Complete Tailem Bend 275/132 kV to ultimate layout; install 2nd 275/132 kV transformer, update the existing secondary systems	Augmentation	36
	2013-2018 (Timing to be refined in conjunction with the RIT-T analysis to be undertaken for the Heywood Interconnector incremental upgrade)		Inadequate 275/132 kV transformer capacity and voltage issues on the loss of one 275/132 kV transformer at South East substation	Install additional 275/132 kV transformer capacity in South East region and associated 275 kV and 132 kV line works. The optimal location of this additional capacity to support this emerging limitation is currently under investigation.	Augmentation	60-70
	2013-2018		Increased loading on the 132 kV network has made compliance with Rules Ch. 4 security provisions difficult operationally and has reduced the opportunities to do critical network maintenance and construction work to very restrictive windows	Install an integrated control scheme in the South East region that will ensure compliance to the 'next contingency' security requirements of the Rules and allow a higher utilisation of the network under system normal conditions as well as provide the opportunity to do network maintenance as required	Security/ Compliance	3.5
2017	2016	2018	Snuggery Rural connection point unable to meet the ETC requirements	Replace 25 MVA transformer with 60 MVA transformer or alternatively, with proposed KCA load changes, rearrange substation configuration so that two transformers supply the Snuggery Rural connection point	Connection	7
2020	2018	2023	Loss of South East-Snuggery line results in overload of Mount Gambier-Blanche line and the loss of transformer at SE overloads the other transformer	Upgrade Mt Gambier – Blanche 132 kV line to higher capacity	Augmentation	15

Table 11.5 lists all identified augmentation projects in the region in the 10-20 year period. Project timing is indicative and is based on medium economic growth (NTNDP Scenario 3: Decentralised World).

Table 11.5: Proposed 10-20 year South East network augmentation projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2018-2023 Subject to ETSA Utilities Request	Increase of load in the area cause under voltage in the distribution network and inadequate 132/33 kV transformation	Establish new Mt Benson 132/33 kV connection point and install 2x25 MVA transformers	Augmentation	50-100
2018-2023 Subject to ETSA Utilities Request	Increase of load in the area cause under voltage in the distribution network and inadequate 132/33 kV transformation	Establish new Geranium 132/33 kV connection point and install 2x25 MVA transformers	Augmentation	70
2022 Subject to ETSA Utilities Request	Increase of load in the area cause under voltage in the distribution network and inadequate 132/33 kV transformation	Establish new Coonalpyn West 132/33 kV connection point and install 2x25 MVA transformers	Augmentation	30
2023-2028	Loss of transformer at South East overloads the other transformer	Install a third 160 MVA transformer at South East	Augmentation	15
2023-2028	Loss of South East-Snuggery line results in overload of Mt Gambier-Blanche line and loss of Mt Gambier-South East line results in overload of Snuggery-Blanche line	Build 2nd Snuggery-Blanche-Mount Gambier Lines	Augmentation	60

11.4.3 Potential Market Benefit Projects

Constraints analysis identifies market benefit projects that may improve the transmission network transfer capability available to the market. Project costs are indicative.

Table 11.6: South East network potential market benefit projects

Strategic Value – Trigger for Project	Description of Project	Capacity/Benefit Provided	Cost (AU$ M)
Increase in renewable generation in SA. Lack of base load at times of peak load and installed wind generation exceeds 2300 MW.	Install 3rd Heywood transformer and associated work; such as • SVC • Series compensation • Reconfiguration of the South East 132 kV network	150 MW to 250 MW (over and above 460 MW existing limit) of interconnector transfer capacity (upper limit determined by thermal rating of South East to Heywood 275 kV lines; this may be enhanced further by real time rating the lines).	Currently under investigation

11.5 Anticipated Replacement Projects

Asset replacements are planned based on asset condition. Asset condition monitoring is used to determine the actual timing of any asset replacement. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

Table 11.7: Proposed South East network replacement projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2013-2018	Condition of the existing secondary systems at South East substation placing limitations on interconnector stability; substandard circuit breaker arrangement makes it difficult to obtain outages for maintenance and places network security at risk	Replace the existing secondary systems with modern day equipment and install extra circuit breaker in a third diameter to correct the layout	Replacement	38
2018-2023	Mount Gambier substation at end of technical life; 132/33 kV transformer capacity limitation; unsatisfactory voltages under contingency	Rebuild existing substation at a nearby site; install 2 x 60 MVA 132/33 kV transformers and 2 x 15 Mvar capacitor banks (capacitor bank sizing and timing to be confirmed)	Replacement	35

11.6 Future Network Single Line Diagram

Figure 11.4 shows the South East transmission network with all of the proposed projects included, illustrating how the 132 kV network in the region may be developed over the next 20 years (where the dashed lines represent proposed developments).

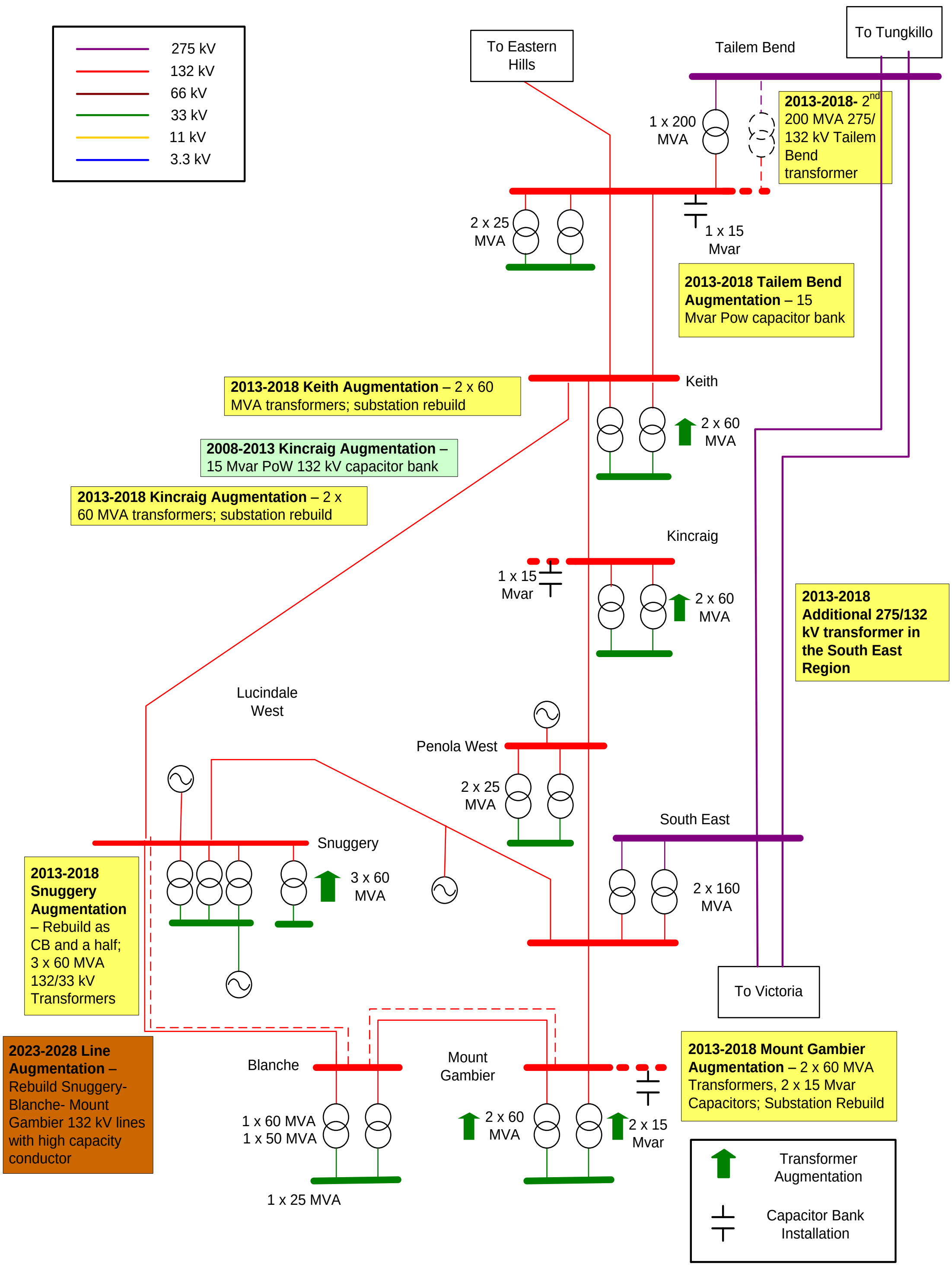


Figure 11.4: South East network 20-year development plan single line diagram

12. Eyre Peninsula Development Plan

12.1 Existing Network Overview

The Eyre Peninsula 132 kV transmission system is characterised by long radial lines and is supplied from the Main Grid 275 kV transmission network via 275/132 kV substations located at Port Augusta (Davenport) and at Cultana, approximately 15 km north west of Whyalla. The Davenport 132 kV system is interconnected to the Cultana 132 kV system via two 132 kV lines that connect to the Whyalla Terminal 132/33 kV substation. A single 132 kV line also connects the Cultana 132 kV bus to Whyalla Terminal substation. The geographical area that is supplied by this system is shown on Figure 12.1. A simplified representation of the Eyre Peninsula 132 kV transmission network is shown in Figure 12.2.

The 275 kV network in Eyre Peninsula was extended from Port Augusta to Cultana (near Whyalla) in 1993 resulting in the paralleling of the existing 132 kV system between Port Augusta and Whyalla with the 275 kV network in the region. As a consequence of this paralleling the capacity of the underlying 132 kV transmission network has become a critical factor in network operation.

The Eyre Peninsula 132 kV system has limited capacity to accommodate significant additional electrical demand or generation without augmentation, and consequently has the potential to act as an impediment to continued development in the Eyre Peninsula region.

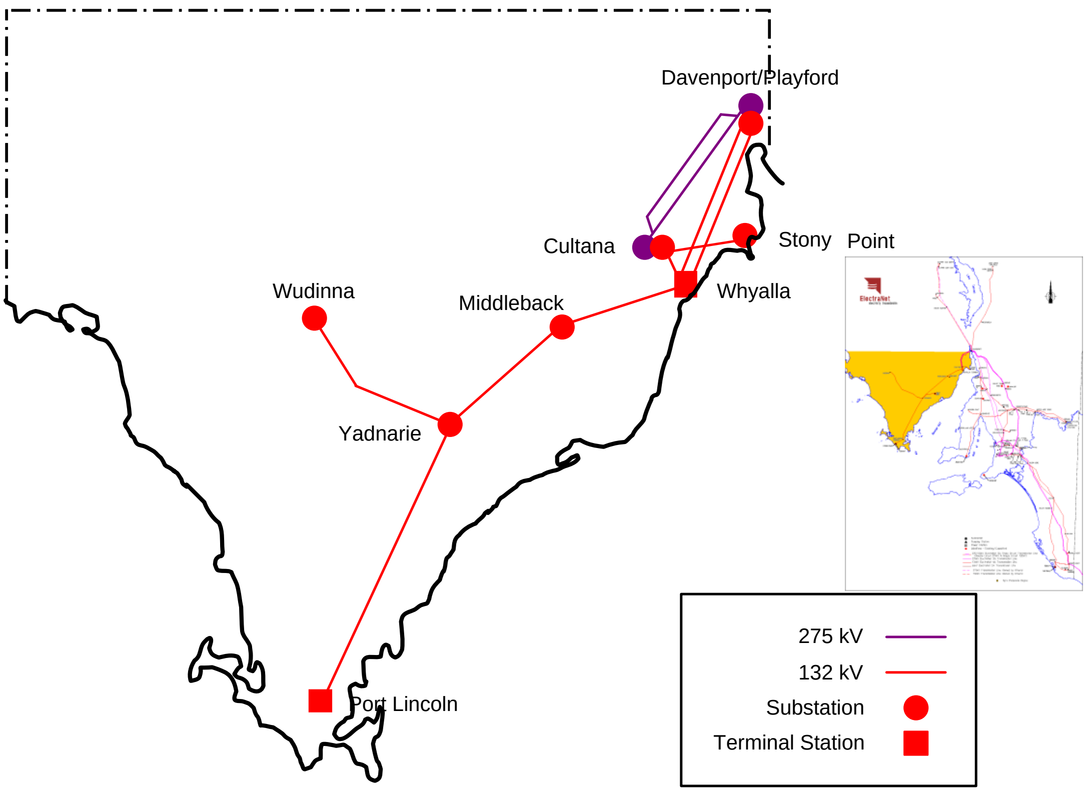


Figure 12.1: Eyre Peninsula transmission region

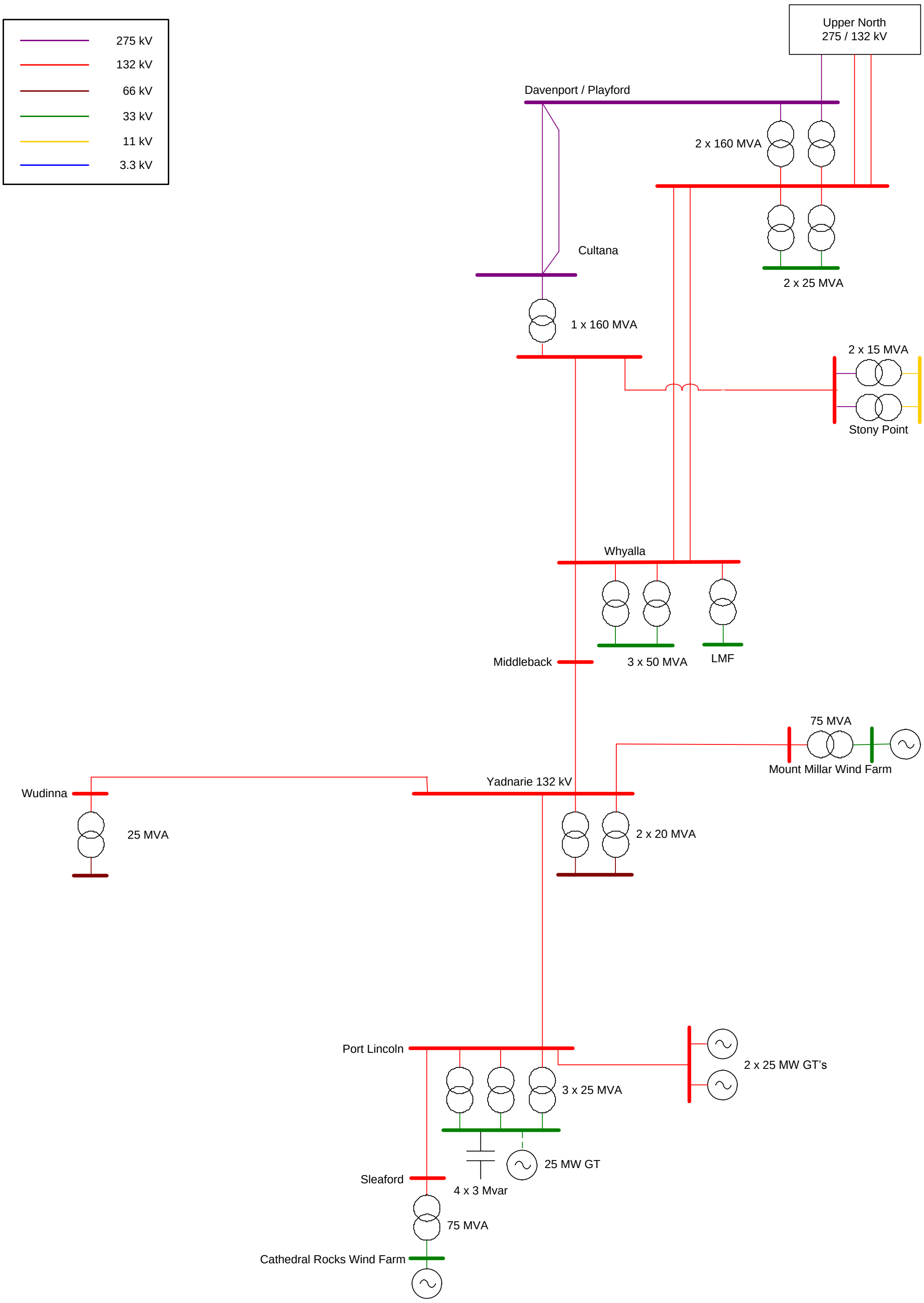


Figure 12.2: Existing Eyre Peninsula transmission network single line diagram

There are presently eight customer connection points supplied by the Eyre Peninsula transmission system. These are Middleback, Yadnarie, Wudinna, Whyalla, Mount Millar, Sleaford and Port Lincoln and Stony Point. With the exception of the Stony Point, Mount Millar, Sleaford and Middleback connections, all of these substations supply the ETSA Utilities transmission and distribution system, which in turn supplies various 132/11 kV, 66/11 kV and 33/11 kV substations throughout the Eyre Peninsula region.

Shown in Table 12.1 is a list of the connection points that supply the Eyre Peninsula region and the reliability classification presently assigned to each in the ETC. Refer to Appendix D for details in relation to the ETC Connection Point Reliability Standards.

Table 12.1: Eyre Peninsula region connection point ETC categorisation

Connection Point	ETC Category
Middleback	1
Port Lincoln Terminal	3
Stony Point	1
Whyalla LMF	1
Whyalla Terminal	4
Wudinna	2
Yadnarie	2

12.1.1 Existing and Committed Generation

Three generating stations presently connect to the Eyre Peninsula 132 kV system. Two of these are wind farms, while the third is a distillate fired gas turbine (GT) power station. Additionally, One Steel has a non-market, embedded generating system connected to its Whyalla Steel Works distribution system. The One Steel generation is used solely to supply the Whyalla steel works and does not participate at all in the NEM.

The two wind farms in the Lower Eyre Peninsula region are located at Cathedral Rocks, south of Port Lincoln, and at Mount Millar, west of Cowell respectively. The Cathedral Rocks Wind Farm comprises a total of 66 MW of wind driven generation that connects to Port Lincoln 132 kV connection point. The Mount Millar wind farm comprises 70 MW of installed generation that connects to the Yadnarie 132 kV connection point. Both of these wind farms are able to generate into the market at any time there is sufficient wind available.

3 x 25 MW diesel fuelled GTs owned by International Power/Synergen are presently connected to the Port Lincoln 132 kV terminal station and are contracted to ElectraNet to provide back-up electricity supply capacity to the Port Lincoln area. This power station is also able to operate as a market generator at times that ElectraNet is not making use of its contracted services.

12.1.2 Intra-regional Transfer Capability

Wind generation on the Eyre Peninsula at Cathedral Rocks and Mount Millar is presently constrained by both the thermal capacity of the 132 kV line section between Yadnarie and Middleback substations and voltage stability limitations in the Lower Eyre Peninsula 132 kV transmission network. These voltage stability limitations are associated with large scale single contingency generation loss in South Australia and multi-phase fault conditions on the Eyre Peninsula 132 kV transmission network.

Under high load operating conditions with low wind based generation on the Eyre Peninsula, contracted generation support at Port Lincoln is required to provide thermal and voltage support to cover the contingency outage of the single Cultana 275/132 kV transformer.

12.2 Study Methodology

12.2.1 Planning Criteria and Assumptions

This development plan has been prepared according to the planning framework described in Appendix D.

12.2.2 20 Year Load Forecast

Electrical demand on the Eyre Peninsula 132 kV transmission system has grown steadily over the years as a result of agricultural, residential, commercial and light-industrial development. The Eyre Peninsula transmission system distribution connection points and their associated 10-year economic growth load forecasts are shown in Appendix B. This load forecast has been extrapolated to cover the full 20-year period of interest for the medium load growth scenario by ETSA Utilities.

The 20-year high, medium and low demand forecasts for the Eyre Peninsula 132 kV system are plotted on Figure 12.3 and the projected performance limitations have been analysed based on those load forecasts.

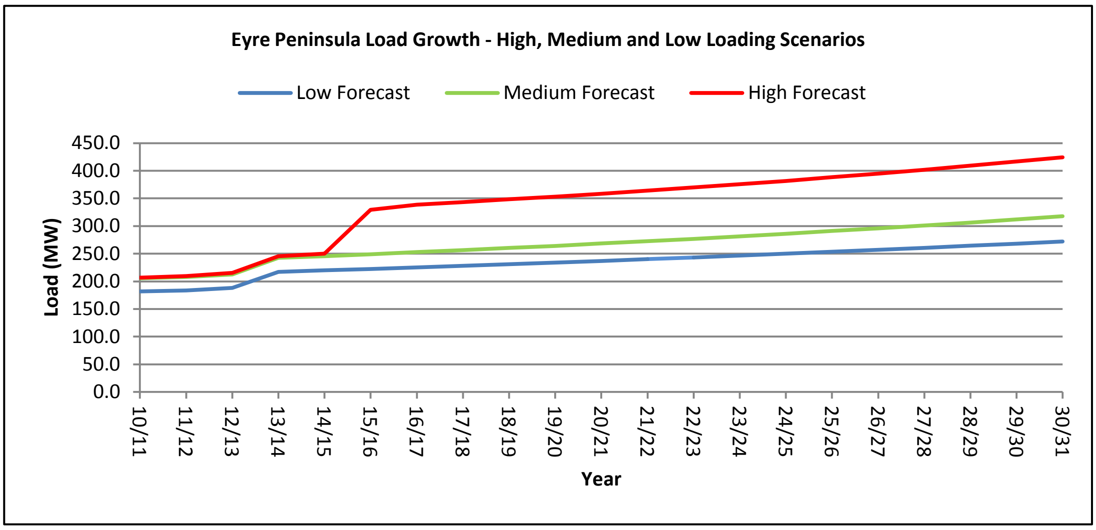


Figure 12.3: Eyre Peninsula region 20-year peak load forecasts

12.2.3 Special Considerations in the Eyre Peninsula Region

The special considerations given to the Eyre Peninsula development plan studies are:

Local Generation Operation Conditions

- The Gas Turbines at Port Lincoln are assumed to be on, providing network support to the Eyre Peninsula Region; and
- At peak loading condition, local wind farms are out of service to ensure the most onerous scenario.

Potential Step Loading Conditions

- The study looked at potential step loading increase in the lower Eyre Peninsula.

12.2.4 Fault Levels

Substation fault levels are assessed to remain within design and equipment limits. A table listing the 5 year maximum substation fault levels and circuit breaker ratings is provided in Appendix C of this report.

12.3 Connection Opportunities

This section identifies potential opportunities for connection of generation and load to the transmission network. Generation and load proponents should take this information into account when considering the location of their projects (especially larger projects).

12.3.1 Generation Connection Opportunities

The Lower Eyre Peninsula 132 kV transmission system has limited capacity to accommodate additional generation without augmentation of the network.

The Upper Eyre Peninsula 132 kV transmission system in the vicinity of Whyalla and Cultana has the capacity to accommodate about 100 MW of generation once the Cultana augmentation and the Whyalla Terminal rebuild are completed. The two projects are due for completion by the end of 2013.

12.3.2 Load Connection Opportunities

Electrical demand on the Eyre Peninsula transmission system varies with location. Load growth in the northern part of the region centred on Whyalla is relatively low apart from infrequent step increases in demand as a consequence of increased mining activity. Load growth on the lower part of the Peninsula varies between 3.3% and 4.9% per annum as a result of general background growth and increased commercial and agricultural activity.

The Eyre Peninsula system has limited capacity to accommodate significant additional demand without augmentation. This is particularly the case at the extremities of the existing 132 kV transmission system, which would not be able to accommodate load increases of any significant magnitude (>5 MW) without some form of major augmentation.

12.4 Lower Eyre Peninsula Reinforcement Study

The Eyre Peninsula Region has significant renewable energy and mineral resources, but limited electricity transmission infrastructure to support the development of these resources.

Network reinforcement of the Eyre Peninsula is anticipated towards the end of the 2013-2018 regulatory period to meet the ETC reliability standards based on normal load growth (i.e. with no material step load increases). Alternatively a non-network solution (e.g. additional generation support) could meet the projected need.

However, recent developments and interest shown in the Eyre Peninsula include:

- The Green Grid study published in July 2010 which proposes the development of 2,000 MW of wind generation and associated transmission development and the subsequent creation of the Green Grid Forum to promote this development;
- The Eyre Peninsula Mining Alliance (EPMA) was formed in September 2010 to take a collaborative approach to community engagement and infrastructure provision for the mining sector on the Eyre Peninsula; and
- AEMO's December 2010 report on its review (for ESCOSA) of the ETC connection point reliability standards. AEMO's analysis provides an indication of the additional load that would be required for reinforcement of the transmission network to Port Lincoln to be economic earlier than otherwise would be the case.

Figure 12.4 below shows a geographic representation of the Eyre Peninsula transmission network as well as locations of possible future loads and generation.

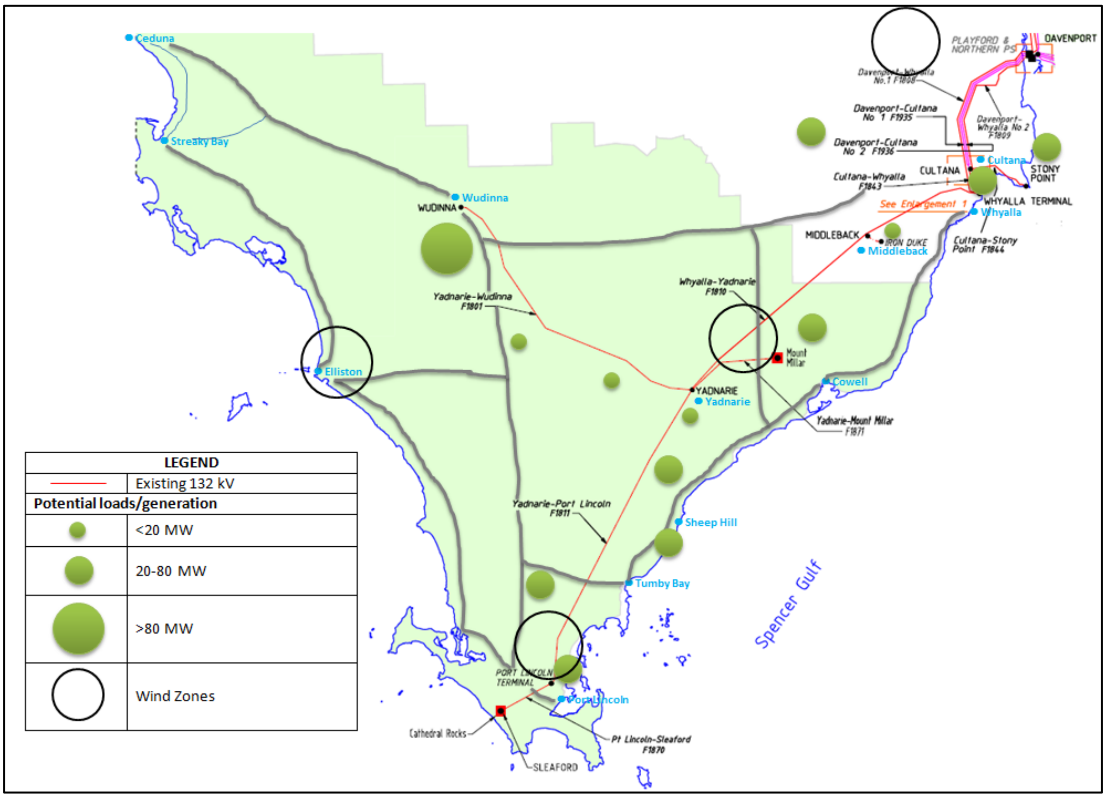


Figure 12.4: Geographic representation of the Eyre Peninsula transmission network

ElectraNet has performed a preliminary study to investigate network development options on the Eyre Peninsula that would cater for additional load and generation connections to the transmission network.

Three planning scenarios were used to consider the possible future development of the Eyre Peninsula:

- Scenario 1: The load forecast in this scenario matches the medium growth rate forecast used in the South Australian Annual Planning Report 2011. This scenario is set as the base case and was also the base case for the Eyre Peninsula RDP 2011 study.

- Scenario 2: This scenario assumed that new mining loads are connected, but no new generation (wind farms) is connected on Eyre Peninsula.
- Scenario 3: This scenario assumed that new mining loads and new generation (wind farms) are connected on the Eyre Peninsula.

A total of eight network development options were identified and studied. These options can be broadly categorised as follows:

- 132 kV radial solution with generator support;
- Double circuit solutions (132 kV and 275 kV); and
- Diverse single circuits solutions (132 kV and 275 kV).

The 275 kV options were treated as staged developments where new 275 kV transmission lines are initially operated at 132 kV.

Based on high level cost estimates and economic analysis the following high level conclusions can be drawn:

- Under medium growth rate conditions the Lower Eyre Peninsula load can be serviced in the short to medium term by increasing the generation support at Port Lincoln or the implementation of a demand side management solution;
- Significant parts of the radial 132 kV line between Cultana and Port Lincoln substations are in poor condition and may require significant renewal investment within 10 years;
- Based on high level economic analysis the 275 kV double circuit solution (initially operated at 132 kV) ranked highest for the vast majority of cases as the next development option once generation support becomes uneconomic; and
- The timing of the 275 kV double circuit solution will depend on load growth, renewable generation developments and further investigation of the condition of existing transmission assets.

ElectraNet intends to progress the Lower Eyre Peninsula reinforcement study to prepare for a market benefits assessment (RIT-T) of the potential future developments, including the assessment of option value.

12.5 Constraints and Proposed Augmentation Projects

Projected power system limitations within the Eyre Peninsula 132 kV transmission system are highly dependent on load growth and demand on the ETSA Utilities distribution system and that of the direct connect customers. All seven customer connection points on the Eyre Peninsula 132 kV system have been examined individually within this development plan. Where necessary, the combined impact of individual projected network and connection point limitations have been examined to determine any impacts that result on the overall supply system in the region.

The network limitations, along with the proposed solutions, timings, estimated capital expenditures, and option analysis for projects that have been identified for the next 5-year period are described below. Projects identified for the initial 10-year period of this 20 year development plan, including those projects that will improve the performance of existing plant and equipment, rather than physically adding to the asset base (e.g. installing control schemes to maintain network security) and will be triggered by a sudden load increase, the timing of which is not yet known, are summarised in Table 12.2. Finally, asset replacements are considered separately, and are listed in Table 12.4.

The following section provides description of the projects that are proposed to alleviate the projected performance limitations identified.

12.5.1 5-Year Major Augmentation Projects

Transformer capacity augmentation at Wudinna

Scope of Work: Install 2nd 25 MVA 132/66 kV transformer at Wudinna

Estimated Cost: $13.8 Million

Timing: 2012

Project Status: Committed Project

Project Need

New ETC Category 2 classification for Wudinna requires firm N-1 transformer capacity to meet the AMD.

Currently, only one transformer is installed at Wudinna. Install a 2nd 25 MVA 132/66 kV transformer at Wudinna; utilise this opportunity to install SCADA remote supervisory and protection upgrades for improved reliability; has been proved to be the lowest cost option, which is sufficient for the planning period considered.

Public consultation on this project was carried out in the form of a Small Network Paper published in ElectraNet's 2010 South Australian Annual Planning Report. That Small Network Paper nominated the proposed solution option as the least cost solution. No comments were received in response to that submission. ElectraNet is progressing with the proposed solution option.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

Reconfiguration and Installation of 2x200 MVA 275/132 kV Transformer at Cultana

Scope of Work: Break out 2nd Davenport to Cultana 275 kV circuit; install two 200 MVA 275/132 kV transformers at Cultana and reconfigure 132 kV Davenport to Whyalla lines

Estimated Cost: $66 Million

Timing: 2013

Project Status: Passed Regulatory Test

Project Need

This project is required for a number of reasons as follows:

- The outage of Cultana 275/132 kV transformer or Davenport to Cultana 275 kV line leads to inadequate 132 kV voltages on the Eyre Peninsula system and thermal overloads on the 132 kV transmission lines connecting Davenport to Whyalla Terminal substation.
- Outage of Cultana to Whyalla 132 kV circuit leads to inadequate 132 kV voltages on the Eyre Peninsula system.

The proposed solution option scope of work is:

- Break out 2nd Davenport to Cultana 275 kV circuit and install 2 x 200 MVA, 275/132 kV transformers at Cultana; and
- Turn both Davenport to Whyalla 132 kV lines into Cultana, only connect the south side at Cultana to Whyalla and supply Yadnarie and lower Eyre Peninsula directly from Cultana.

The network study analysis shows that the proposed option is the lowest cost option; which provides adequate voltage support to the lower Eyre Peninsula. This facilitates the Whyalla rebuilding works and improves supply to the Lower Eyre Peninsula.

The project has passed the regulatory test. The proposed commissioning date is 2013.

12.5.2 Future Augmentation Projects

The following table contains the list of emerging limitations that have been identified during the development plan study. These represent the recommended network solution based on high level cost estimation and professional engineering judgement and are one of several options. These solutions are subject to variation and change as further study and network development occur. Due to the lack of a firm future ETSA Utilities network development plan and the uncertainties surrounding customer connection, the projects are indicative in terms of timing and the scope of work. The proposed network solution for each constraint will be updated as the better information become available.

The table below lists all identified augmentation projects in the region over the next 10-years. A range of project implementation dates is provided where the timing has been determined according to the NTNDP 2010 scenarios.

NTNDP Scenarios:

- S1: Fast Rate of Change
- S2: Uncertain World
- S3: Decentralised World
- S4: Oil Shock and Adaptation
- S5: Slow Rate of Change

Table 12.2: Proposed 10-year Eyre Peninsula network augmentation projects

Project Timing (NTNDP S3)	Project Timing (NTNDP S1 & S2)	Project Timing (NTNDP S4 & S5)	Limitation	Recommended Solution	Category	Estimated Cost ($M)
2012			New ETC Category 2 classification for Wudinna requires N-1 transformer capacity to meet the AMD.	Install 2nd 25 MVA 132/66 kV transformer at Wudinna substation	Connection	14
2013			The outage of Cultana 275/132 kV transformer, Davenport to Cultana 275 kV line or Cultana to Whyalla 132 kV circuit leads to inadequate 132 kV voltages and thermal overloads the 132 kV lines.	Break out 2nd Davenport to Cultana 275 kV circuit; install 2x200 MVA 275/132 kV transformers at Cultana and reconfigure 132 kV Davenport to Whyalla lines	Augmentation	66
2013 Subject to ETSA Utilities Request			Potential customer load increase near Stony Point causing inadequate transmission capacity in the area.	Establish new 132/33 kV substation and associated line work	Augmentation/ Connection	25-40
2014 Subject to ETSA Utilities Request			Potential significant customer load increases near Whyalla causing inadequate transmission capacity in the area	Establish new 132/33 kV substation and associated line work	Augmentation/ Connection	TBD
2014 Subject to ETSA Utilities Request			Potential significant customer load increase near Middleback causing inadequate transmission capacity in the area	Establish new connection point and associated transmission network reinforcement	Augmentation/ Connection	TBD
2015 Subject to ETSA Utilities Request			Potential significant customer load increase near Sheep Hill to supply a step load increase	Establish new connection point and associated transmission network reinforcement	Augmentation/ Connection	TBD
2013	2012	2014	Contracted generation to support the Port Lincoln load during an outage of the radial 132 kV transmission line is exceeded	Work has been initiated to explore either an increase in the amount of contracted generation or a demand side solution to cover the balance of load	Augmentation	TBD
2018	2016	2020	Thermal overload of the Middleback-Yadnarie 132 kV transmission line under system normal conditions; line condition prevents further line uprating from being a viable option. No new load can be connected in the South of Middleback without having to add more generation to the South of Middleback. Condition on the 132 kV radial line between Whyalla and Port Lincoln indicates line replacement.	Reinforce the lower Eyre Peninsula by constructing a double circuit 275 kV line from Cultana-Yadnarie- Port Lincoln in a staged approach. Establishing 275/132 kV substations at Yadnarie and Port Lincoln. Install 100 Mvar cap bank at Yadnarie and SVC at Port Lincoln. In future convert the Port Lincoln to Yadnarie 132 kV line for sub-transmission purposes	Augmentation	200-500
2018	2017	2020	Thermal overload of Port Lincoln transformers after loss of one Port Lincoln transformer	Rebuild Port Lincoln connection point and install 2x120 MVA 132/33 kV transformers	Augmentation	35
2013-2018			Increased loading on the 132 kV network has made compliance with the Rules Ch. 4 security provisions difficult operationally and has reduced the opportunities to do critical network maintenance and construction work to very restrictive windows	Install an integrated control scheme in the Eyre Peninsula to ensure compliance to the 'next contingency' security requirements of the Rules and allow a higher utilisation of the network and provide the opportunity to do network maintenance as required	Security/ Compliance	3.5

12.5.3 Potential Market Benefit Projects

Constraints analysis identifies market benefit projects that may improve the transmission network transfer capability available to the market. Project costs are indicative.

Table 12.3 Eyre Peninsula network potential market benefit projects

Strategic Value – Trigger for Project	Description of Project	Potential Capacity/Benefit Provided	Cost (AU$ M)
Support voltages and strengthen stability conditions in lower Eyre peninsula	Install SVC at a new site adjacent to existing Port Lincoln Terminal substation - will require the first stage of a new 132 kV section to be constructed and turning in and out the line to Yadnarie - will ultimately allow the retirement of the existing substation based on condition.	Improved voltage stability and allow less constraint on Cathedral Rocks and Mount Millar wind farms.	30
Increase in renewable generation and additional non-regulated loads on the Eyre Peninsula	275 kV developments ex Cultana. Target area depends on load generation location. May involve reinforcement of Davenport to Cultana.	600 to 1000 MW increase in transfer capacity in the Eyre Peninsula	200

12.6 Anticipated Replacement Projects

Asset replacements are planned based on asset condition. Asset condition monitoring is used to determine the actual timing of any asset replacement. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

Table 12.4: Proposed Eyre Peninsula network replacement projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2008-2013	Critical infrastructure at Whyalla terminal substation at end of technical life; change in ETC categorisation of Whyalla from Category 3 to 4; firm N-1 transformer capacity for AMD is required.	Rebuild Whyalla Terminal substation on a new site with 2 x 120 MVA 132/33 kV transformers; install 2 x 15 Mvar 132 kV capacitors banks (replacing the existing tertiary connected banks) (also turn in both the Davenport to Whyalla 132 kV lines into Cultana and only connect the south part of the lines to Cultana;	Replacement/ Augmentation/ Connection	54
2018-2023	Condition of the existing assets requires replacement at Yadnarie substation.	Rebuild Yadnarie substation and install 2x25 MVA 132/66 kV substation	Replacement	29

12.7 Future Network Single Line Diagram

Figure 12.5 shows the Eyre Peninsula transmission network with all of the proposed projects included, illustrating how the 132 kV network in the region may be developed over the next 20 years (where the dashed lines represent proposed developments).

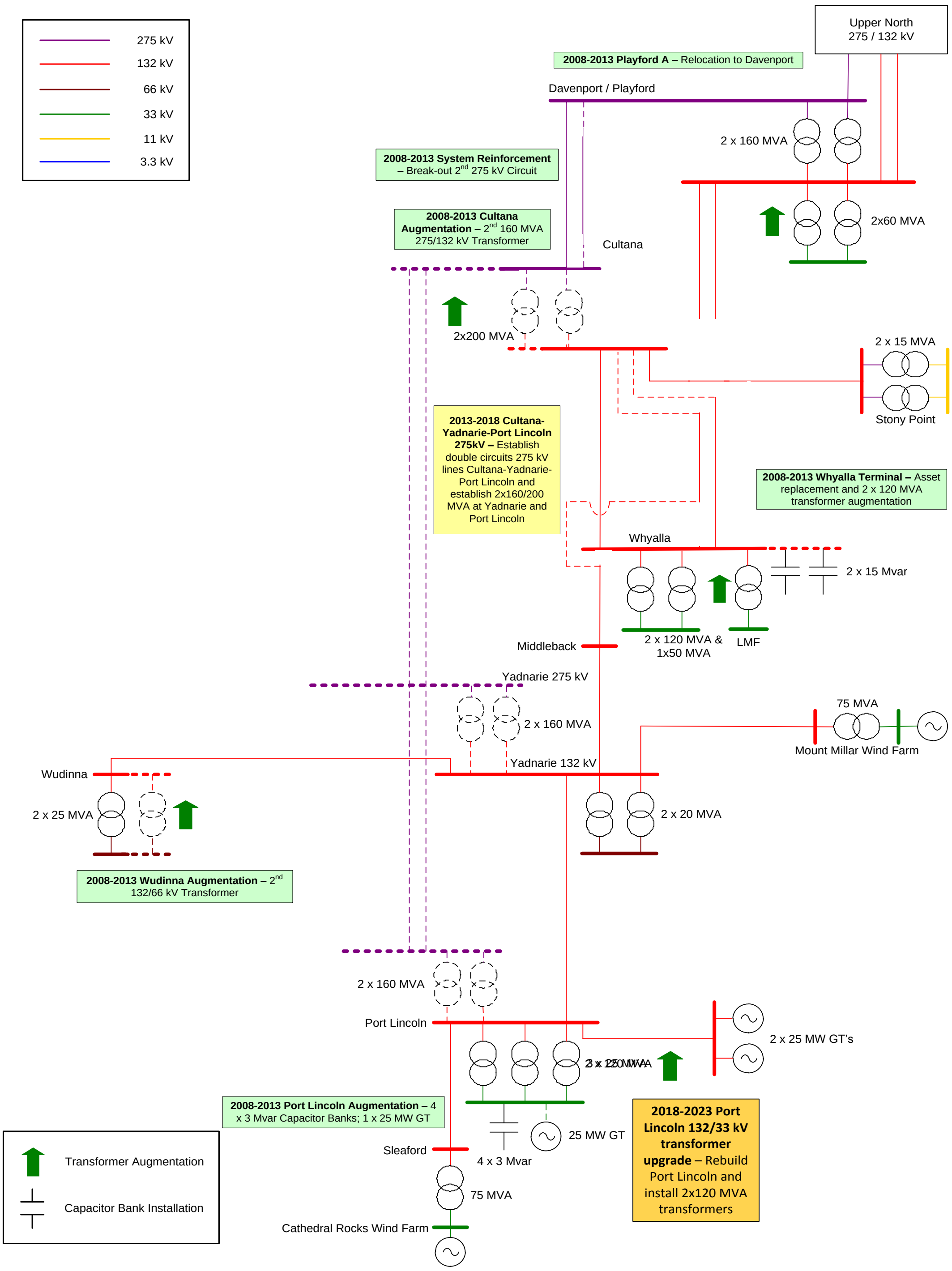


Figure 12.5: Eyre Peninsula network 20-year development plan single line diagram

13. Upper North Development Plan

13.1 Existing Network Overview

The Upper North supply area is bounded by the Eyre Peninsula, Mid North and the Riverland to the south, and the state borders to the north, east and west. The region includes major load centres at Leigh Creek, Olympic Dam, Port Augusta and Woomera, and is shown in Figure 13.1.

The Upper North region of South Australia contains a mixture of electrical loads including agricultural, light and heavy industrial, rural, urban and commercial. The load in the region is dominated by mining activity at Olympic Dam and Prominent Hill, and to a much lesser extent Leigh Creek. The major commercial centre in the region is at Port Augusta, which is serviced by the Davenport 132/33 kV connection point.

The Upper North 132 kV transmission system is characterised by long radial lines that supply loads to the north of Port Augusta. The Upper North 132 kV system is supplied by the Main Grid 275 kV transmission system via a 275/132 kV Davenport substation (near Port Augusta).

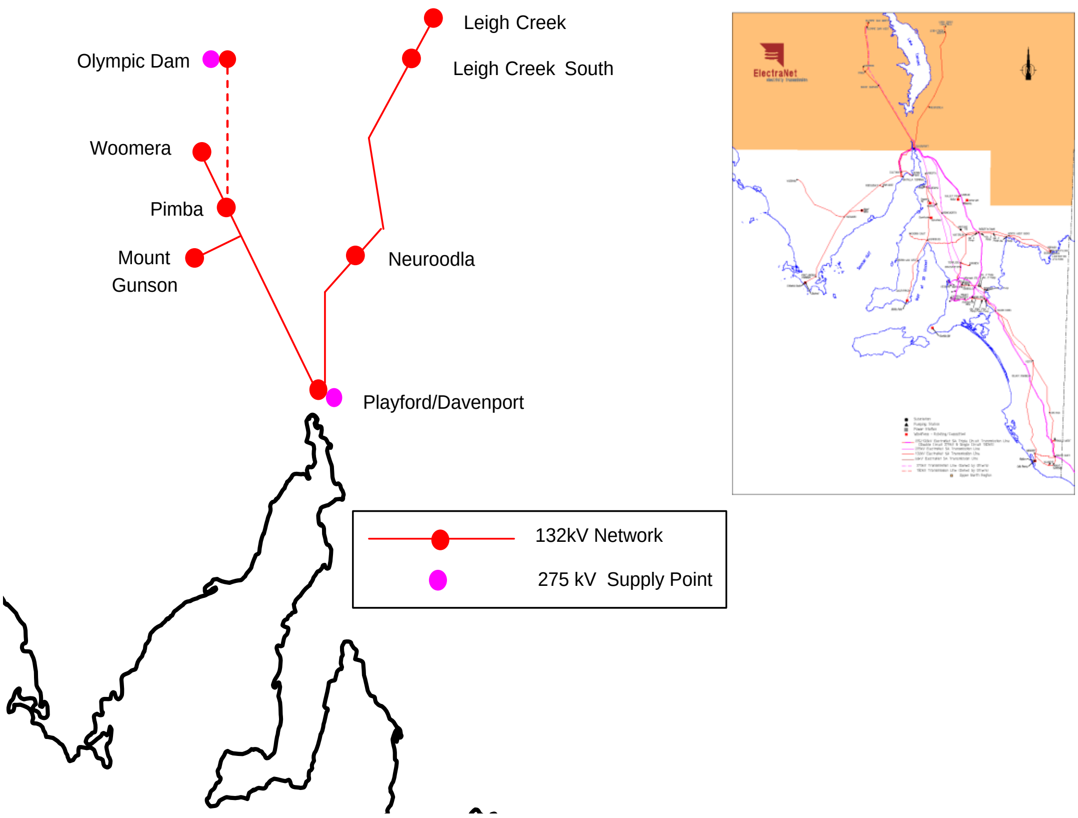


Figure 13.1: Upper North transmission region

The Upper North 132 kV system comprises two radial 132 kV lines that run from Davenport to Leigh Creek and Woomera respectively. These lines supply a number of intermediate sites along their routes and provide connection to several regional communities.

The Upper North 132 kV system supplies power to four ETSA Utilities connection point substations at Davenport, Mt Gunson, Neuroodla and Leigh Creek South, and four direct connect customers in the region. In addition to the two 132 kV radial lines mentioned, there is a privately owned 132 kV line between Pimba and Olympic Dam and a privately owned 275 kV transmission line running from Davenport to Olympic Dam. These privately owned lines supply power to the mining operations in the north of South Australia. A simplified representation of the Upper North 132 kV transmission region is shown in Figure 13.2.

In 1998, a 275 kV connection point was provided at Davenport switching station for Western Mining Corporation, the successor of Roxby Management Services, to facilitate further expansion of mining operations at Olympic Dam. Western Mining Corporation constructed a privately owned 275 kV transmission line and 275/132 kV substation at Olympic Dam as part of this expansion. The exploitation of this ore body is under further consideration by its present owner, BHP Billiton (BHPB) and may in the future involve further 275 kV supply being drawn from the Davenport connection point.

Shown in Table 13.1 is a list of the connection points that supply the Upper North region and the reliability classification presently assigned to each in the ETC. Refer to Appendix D for details in relation to the ETC Connection Point Reliability Standards.

Table 13.1: Upper North region connection point ETC categorisation

Connection Point	ETC Category
Leigh Creek Coal	1
Leigh Creek South	1
Mt Gunson	1
Neuroodla	1
WMC Davenport (275 kV)	1
WMC Pimba (132 kV)	1
Woomera	1
Davenport	4

13.1.1 Existing and Committed Generation

Coal fired steam turbine driven generating plant is located at Port Augusta comprising Northern Power Station (2 x 260 MW units), and Playford Power Station (4 x 60 MW generators).

13.1.2 Intra-regional Transfer Capability

The Northern and Playford Power Stations connected to the Davenport 275 kV substation near Port Augusta currently experience minimal generation constraints under system normal and the majority of single planned outage network configurations. Currently no generation is connected to the Upper North 132 kV transmission system. Due to the length, relatively high impedance, low thermal capability and radial nature of this 132 kV system, there is limited capability to accept generation in the area.

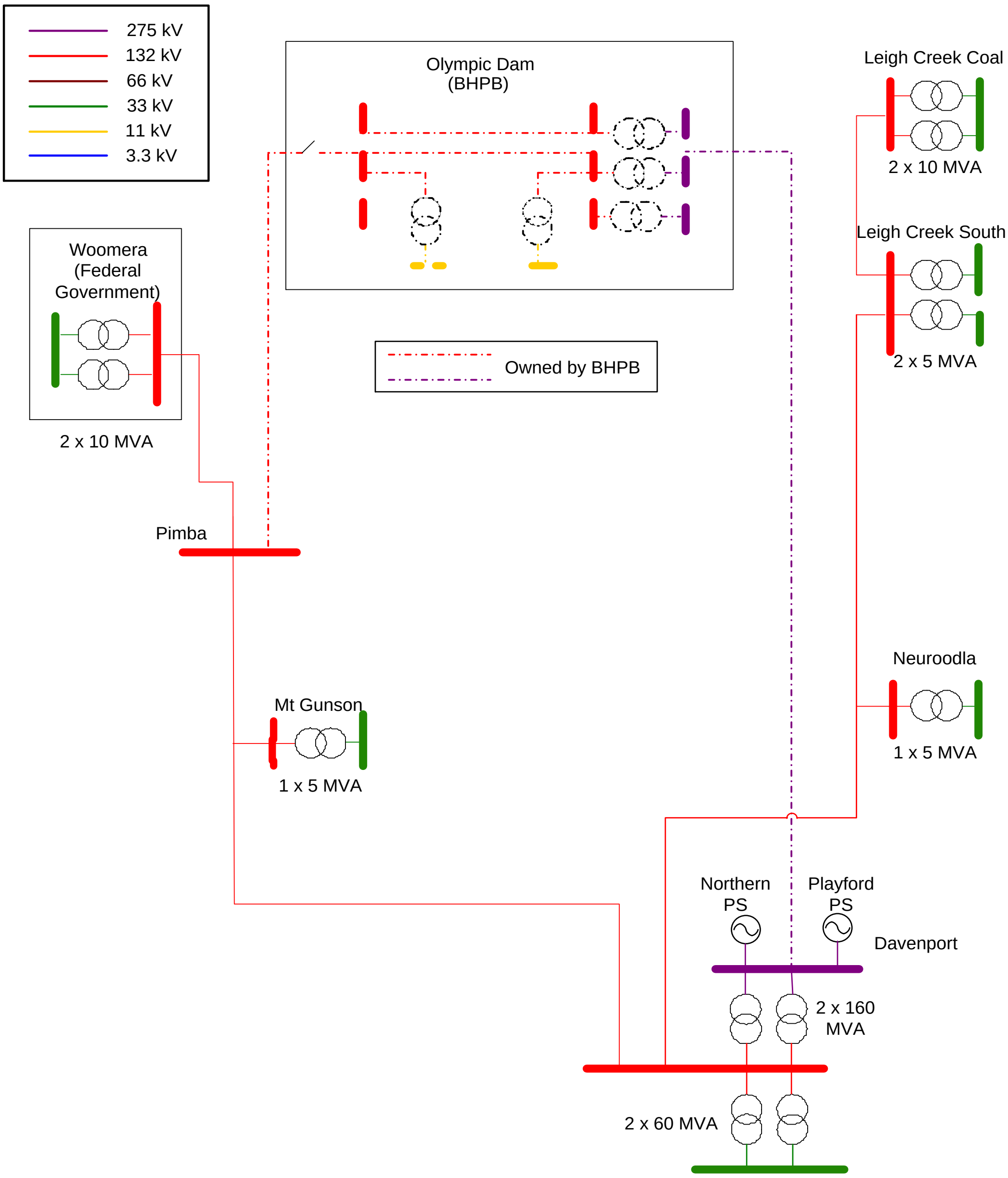


Figure 13.2: Existing Upper North transmission network single line diagram

13.2 Study Methodology

13.2.1 Planning Criteria and Assumptions

This development plan has been prepared according to the planning framework described in Appendix D.

13.2.2 20 Year Load Forecast

Electrical demand on the Upper North 132 kV transmission network has grown steadily over the years. The Upper North transmission system distribution connection points and their associated 10-year economic growth load forecasts are shown in Appendix B. This load forecast has been extrapolated to cover the full 20-year period of interest for the medium load growth scenario provided by ETSA Utilities. The 20-year high, medium and low demand forecasts for the Upper North 132 kV system are shown in Figure 13.3.

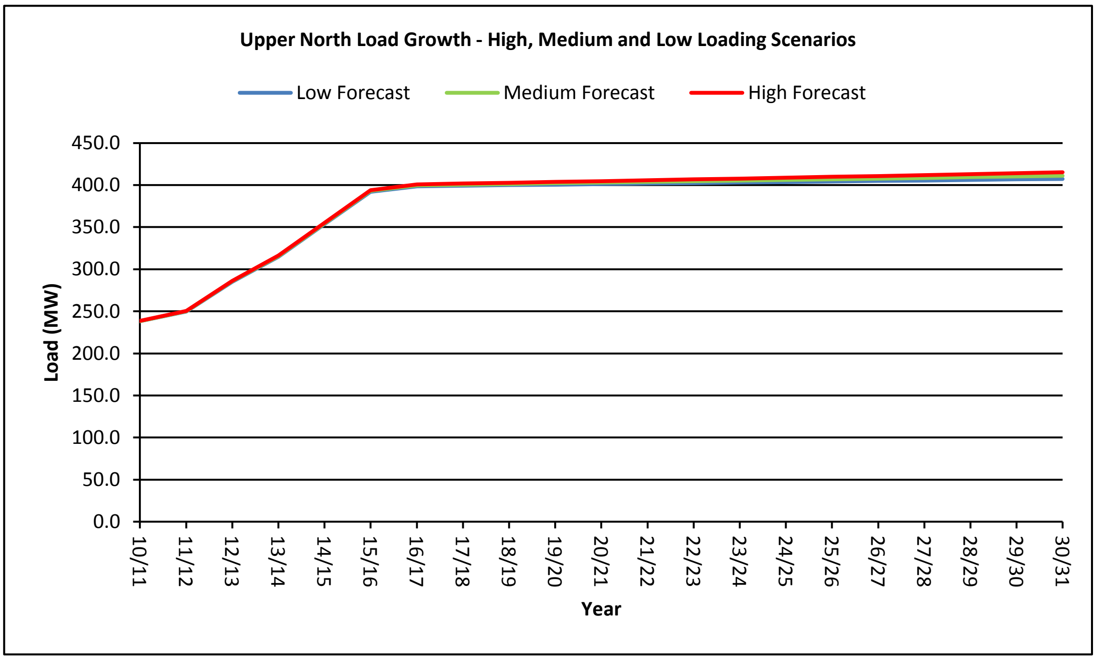


Figure 13.3: Upper North region 20-year peak load forecasts

13.2.3 Special Considerations in the Upper North Region

The future generation assumptions used for the Upper North RDP are based on the NTNDP S3 plan. Additional considerations were given to the Upper North development plan study as follows.

<u>Future Operating Conditions</u>

The following future operating condition has been examined to determine its impact on the investment program.

- Playford power station retirement as defined in NTNDP was studied; and
- High load growth rate for Olympic Dam area.

<u>NTNDP Future Generation and Load Connections</u>

Different NTNDP scenarios propose different future generation plans and load growth rates. The major difference among the NTNDP scenarios in the Upper North region is the possible step load increase due to the Olympic Dam Expansion Plan. These studies have excluded these plans from the development plan study, due to the lack of necessary input information. The ElectraNet direct connected customer load forecast does not include this step load and it has not been modelled in the base case for the study.

13.2.4 Fault Levels

Substation fault levels are assessed to remain within design and equipment limits. A table listing the 5 year maximum substation fault levels and circuit breaker ratings is provided in Appendix C of this report.

13.3 Connection Opportunities

This section identifies potential opportunities for connection of generation and load to the Upper North transmission network. Generation and load proponents should take this information into account when considering the location of their projects (especially larger projects).

13.3.1 Generation Connection Opportunities

Because of limited capacity of the existing Upper North 132 kV transmission system and the length of network involved, the Upper North transmission system has a limited capability to accept any significant generation in the area without augmentation. However, additional generation could be accommodated in the vicinity of Davenport.

13.3.2 Load Connection Opportunities

Electrical demand on the Upper North 132 kV transmission system is relatively static apart from infrequent step increases in load as a consequence of increased mining activity. In contrast to most of the other regions within South Australia, relatively little of the total load supplied in the Upper North of South Australia is connected to a connection point via the ETSA Utilities distribution network.

The Upper North transmission region has substantial mining prospects within it and the development of new mines, or expansion of an existing mine (though not committed at present), represents a real possibility within the 20-year planning period covered. Should such a development occur, it is likely that a major augmentation of the Upper North transmission system and a number of deeper network reinforcements, including reactive support and transmission capacity augmentations, may also be required to permit a sizeable new connection.

As a result of limited capacity within the existing Upper North transmission system and the length of network involved, the Upper North transmission system has a limited capability to accept any significant step change in load (e.g. a mining project) in the area, without augmentation of the transmission network.

13.4 Constraints and Proposed Augmentation Projects

Projected power system limitations in the Upper North region are highly dependent on load growth, particularly from the directly connected mining loads and to a lesser extent the increasing demand on the ETSA Utilities distribution system. The Upper North connection points have been examined individually in this development plan, and due to only moderate load increase, there have been no augmentation projects identified in the 20-year study period.

13.5 Anticipated Replacement Projects

Asset replacements are planned based on asset condition. Asset condition monitoring is used to determine the actual timing of any asset replacement. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

Table 13.2: Proposed Upper North network replacement projects

Project Timing	Limitation	Recommended Solution	Category	Estimated Cost ($ Million)
2013-2018	Neuroodla substation at end of technical life; 132/33 kV transformer condition assessment indicates urgent replacement is required	Rebuild Neuroodla substation at an adjacent site; install 1 x 10 MVA transformer	Replacement	11
2013-2018	Mount Gunson substation at end of technical life; 132/33 kV transformer condition assessment indicates urgent replacement is required	Rebuild Mount Gunson substation at an adjacent site; install 1 x 10 MVA transformer	Replacement	12

13.6 Future Network Single Line Diagram

Figure 13.4 shows the Upper North transmission network with all of the proposed projects included, illustrating how the 132 kV network in the region may be developed over the next 20 years (where the dashed lines represent proposed developments).

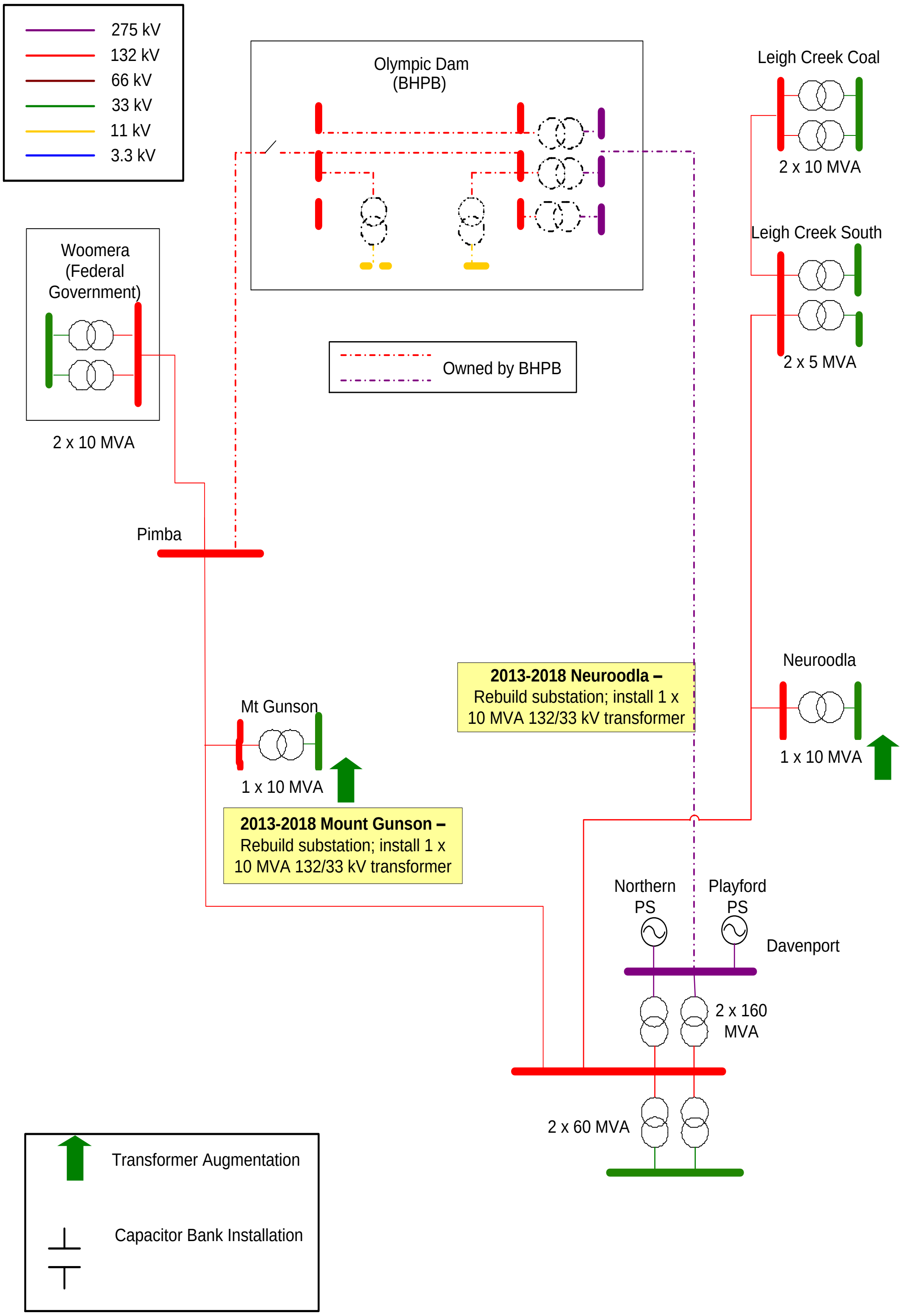


Figure 13.4: Upper North network 20-year development plan single line diagram

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South Australian Annual Planning Report 2011

Appendices

June 2011

Version 1.0

Appendix A South Australian Projects in the NTNDP 2010

This appendix cross-references the results from Chapter 6-13 with the network development projects for South Australia outlined in the 2010 National Transmission Network Development Plan (NTNDP).

In the 2010 NTNDP transmission development 10-year summary, AEMO:

- Summarised the developments occurring in the first 10 years under at least one scenario; and
- Categorised the developments on the basis of the timeframe over which the triggers were identified, how sensitive the triggers are to future conditions, and the risks and consequences of not doing preparatory work.

Table A1 lists the categories used in the 2010 NTNPD and their guiding criteria; and Table A.2 lists the South Australian network development projects in NTNDP 2010.

Table A.1 NTNDP development categories

Category	Timing Trigger	Opportunity Cost
Early attention	Development is triggered in the first five-year period under most scenarios and in the second five-year period in most of the remaining scenarios	High opportunity cost if not done (or has limited or expensive workarounds).
Preparatory work	Development is generally triggered in the second five-year period in most scenarios, but possibly later in others.	High opportunity cost if a need is established and it requires some long lead-time works (for example, easement acquisition).
Monitoring	Development is triggered in the first or second five-year period in some scenarios.	Likely to have workarounds if the triggering conditions unfold (in other words, a relatively low opportunity cost if the development is late).

Table A.2 South Australia network development projects in NTNDP 2010

Transmission Development	2010 NTNDP Rating	Project Context in ElectraNet APR	2011 APR Reference
S1 - Increase the ratings of both 275 kV Torrens Island B to Kilburn and Torrens Island B to Northfield circuits to line design ratings by relevant protection and selected plant modifications	N/A	This project involves changing protection equipment/settings and does not affect major flow paths	Chapter 7
S2 - Increase the ratings of the 275 kV Northfield to Kilburn circuit to line design rating by relevant protection and selected plant modifications	N/A	This project involves changing protection equipment/settings and does not affect major flow paths	Chapter 7
S3 - Cut in the 275 kV Torrens Island B to Cherry Gardens circuit at Para. Increase the rating of the 275 kV Torrens Island B to Para circuit to line design rating by relevant protection and selected plant modifications	N/A	The timing of this project is driven by connection of additional generation in the vicinity of Torrens Island and will be investigated as required. It may also involve other work such as turning in Torrens Island to Cherry Gardens into Parafield Gardens West and Torrens Island to Magill into Para and the establishment of a new Torrens Island C switchyard to allow reconfiguration of the 275 kV network to reduce fault levels	N/A
S4 - Establish the second 275 kV Davenport-Cultana line and reinforcement of 275/132 kV transformation capacity at Cultana and rearrange the 132 kV Davenport - Whyalla and Whyalla to Middleback -Yadnarie lines	Early attention	The work related to this project is currently in progress	Chapter 12

Transmission Development	2010 NTNDP Rating	Project Context in ElectraNet APR	2011 APR Reference
S5 - Establish a 275/132 kV injection point in the vicinity of Hummocks with 1X200 MV.A transformer and construct a 275 kV double circuit line from the existing West circuit to the substation location	Preparatory work	The timing of this project is driven by regional undiversified peak demand with no contribution from wind generation. Depending on the actual load that eventuates, this project will be required as early as 2016 and no later than 2021. Based on the medium demand forecast, this project will be required in 2018.	Chapter 9
S6 - Uprate the 275 kV Para-Brinkworth-Davenport lines to 80^0C	N/A	The timing of this project could be advanced from the 2028-33 period by connection of additional load or generation in the Eyre Peninsula, Mid North, Upper North regions and will be investigated as required.	Chapter 6
S7 - Install the second 275/132 kV Templers transformer in conjunction with 132 kV network re-configuration	N/A	The timing of this project is driven by regional undiversified peak demand with no contribution from wind generation. Based on the medium load forecast, this project will be required in 2023-28 period	Chapter 9
S8/VS1/VS2 - Projects associated with incremental augmentation of the Heywood Interconnector	Monitoring	This project is associated with the Heywood Incremental Augmentation and will be considered as part of the RIT-T assessment which will be undertaken jointly between AEMO and ElectraNet in 2011/12	Chapters 3, 4 & 6
S9 - Install 3rd South East Transformer (now South East 275/132 kV transformer capacity)	N/A	The timing of this project is driven by regional undiversified peak demand with no contribution from wind generation. Based on the medium load forecast, this project will be required in 2015. At the time of publishing the APR, KCA have announced a reduction in their load which will defer the need for this project. However, this project need may also have market benefits and will be investigated as part of the RIT-T assessment for the incremental augmentation of the Heywood Interconnector	Chapter 11
S10 - Rebuild existing 132 kV Mt Gambier - Blanche circuit into high capacity circuit	N/A	The timing of this project is driven by regional demand which at peak times will be the undiversified sum of all South East connection points, with no contribution from wind generation. Based on the medium load forecast, this project will be required in 2023-28. At the time of publishing the APR, KCA have announced a reduction in their load which will defer the need for this project.	Chapter 11
S11 - Rebuild 132 kV South East - Mt Gambier as a double circuit	N/A	The timing of this project is driven by regional demand which at peak times will be the undiversified sum of all South East connection points, with no contribution from wind generation. Based on the medium load forecast, this project will be required in 2023-28. At the time of publishing the APR, KCA have announced a reduction in their load which will defer the need for this project.	Chapter 11
NV1 – A new 220 kV, 250 MVA phase angle regulator on the 220 kV Buronga-Red Cliffs interconnection	Early attention	AEMO and ElectraNet are intending to investigate the ongoing requirements for South Australian imports over Murraylink, and options to support load growth in the Riverland and other areas. AEMO and TransGrid are intending to investigate the impacts for the New South Wales system from high Murraylink transfers at time of peak demand	Chapter 10

Appendix B Load Forecast and Connection Point Constraint Timing

The ETSA Utilities load forecast covers three scenarios, namely high load growth, medium load growth and low load growth rate scenarios. The tables below give the load forecast for all three scenarios at each connection point.

Table B.1: ETSA Utilities medium growth metropolitan and country meshed connection point forecasts

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
Year from Base		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
EASTERN SUBURBS	MW	781	798	858	877	896	916	936	956	977	999	1021	1043	1066	1090	1114	1138	1163	1189	1215	1242	1269
	PF	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.95	0.95	0.95
ADELAIDE CENTRAL REGION	MW	228	233	242	247	256	266	271	277	283	289	295	301	308	314	321	328	335	342	349	356	364
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.99	0.99	0.99	0.99
SOUTHERN SUBURBS	MW	812	861	844	865	886	907	929	952	974	996	1019	1043	1068	1092	1118	1144	1171	1199	1227	1256	1285
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98
WESTERN SUBURBS	MW	479	490	507	521	535	549	559	568	576	585	594	603	612	621	631	640	650	660	670	680	690
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.97	0.97
NORTHERN SUBURBS	MW	380	392	412	433	451	469	488	511	531	551	572	593	615	637	660	684	709	734	759	786	813
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96
PORT PIRIE SYSTEM	MW	86	87	88	89	90	91	92	93	94	96	97	98	99	101	102	104	105	107	109	110	113
	PF	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.94	0.94	0.94	0.94	0.94

Notes

1. In Table B.1and Table B.2, the connection point capacity assessment:
   - Assessed timing is based solely on the capacity of ElectraNet equipment
   - Red indicates the required timing to address the substation limitation
   - Blue indicates emerging transmission network limitation
   - Eastern Suburbs limitation is intended to indicate the required timing of Adelaide Central reinforcement
   - Adelaide Central Region limitation is intended to indicate the required timing of East Terrace transformer reinforcement
2. In Table B.1, the Eastern Suburbs load forecast incorporates the Adelaide Central Region.

Table B.2: ETSA Utilities medium growth country connection point forecasts

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
Year from Base		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
ANGAS CREEK	MW	20.8	21.4	22.0	22.6	23.3	23.9	24.6	25.3	26.0	26.7	27.4	28.2	29.0	29.8	30.6	31.5	32.4	33.3	34.2	35.2	36.2
	PF	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90
ARDROSSAN WEST	MW	14.6	15.1	17.7	18.3	18.9	19.5	20.2	20.9	21.6	22.3	23.1	24.0	24.9	25.7	26.6	27.5	28.4	29.2	30.1	30.9	31.8
	PF	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
BAROOTA	MW	8.9	9.0	9.2	9.4	9.5	9.7	9.8	10.0	10.2	10.4	10.5	10.7	10.9	11.1	11.3	11.5	11.6	11.8	12.0	12.3	12.5
	PF	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.94	0.94	0.94
BERRI	MW	95.9	97.8	99.7	101.7	103.8	105.9	108.0	110.1	112.3	114.6	116.9	119.2	121.6	124.0	126.5	129.0	131.6	134.2	136.9	139.7	142.5
	PF	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
BLANCHE	MW	36.7	37.5	38.4	39.2	45.1	46.1	47.1	48.1	49.2	50.2	51.3	52.5	53.6	54.8	56.0	57.3	58.5	59.8	61.1	62.5	63.8
	PF	0.92	0.92	0.92	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.89	0.89	0.89	0.89	0.89
BRINKWORTH	MW	5.2	5.7	5.8	5.8	5.8	5.8	5.9	5.9	5.9	6.0	6.0	6.0	6.1	6.1	6.1	6.2	6.2	6.2	6.3	6.3	6.3
	PF	0.97	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
CLARE NORTH	MW	13.4	14.0	14.6	15.3	16.0	16.7	17.5	18.2	19.1	19.9	20.8	21.7	22.7	23.7	24.8	25.9	27.1	28.3	29.6	30.9	32.3
	PF	0.93	0.93	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90
DALRYMPLE	MW	10.0	10.3	10.6	11.0	11.3	11.7	12.1	12.4	12.8	13.2	13.7	14.1	14.5	15.0	15.5	16.0	16.5	17.0	17.5	18.1	18.6
	PF	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.90
DAVENPORT WEST	MW	32.9	33.6	34.2	34.8	35.5	36.2	36.9	37.6	38.3	39.0	39.7	40.5	41.3	42.1	42.9	43.7	44.5	45.3	46.2	47.1	48.0
	PF	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96	0.95	0.95	0.95	0.95	0.95	0.95	0.95
DORRIEN	MW	68.3	70.4	72.5	74.7	76.9	79.2	81.6	84.0	86.5	89.1	91.8	94.6	97.4	100.3	103.3	106.4	109.6	112.9	116.3	119.8	123.4
	PF	0.90	0.91	0.91	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90
HUMMOCKS	MW	14.7	14.9	13.5	14.1	14.7	15.4	16.1	16.9	17.6	18.4	19.3	20.1	21.1	22	23	24.1	25.2	26.4	27.6	28.9	30.2
	PF	0.93	0.93	0.94	0.93	0.93	0.93	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
KADINA EAST	MW	27.6	28.9	30.2	31.5	32.9	34.4	36.0	37.6	39.3	41.1	42.9	44.8	46.9	49.0	51.2	53.5	55.9	58.4	61.0	63.8	66.6
	PF	0.93	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.91	0.90	0.90	0.90	0.90	0.90	0.89

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
Year from Base		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
KANMANTOO	MW	1.9	2.0	2.2	2.4	2.5	2.7	3.0	3.2	3.5	3.7	4.0	4.4	4.7	5.1	5.5	5.9	6.4	6.9	7.5	8.1	8.8
	PF	0.93	0.92	0.92	0.91	0.91	0.90	0.90	0.90	0.94	0.94	0.93	0.92	0.92	0.91	0.91	0.91	0.90	0.92	0.92	0.91	0.91
KEITH	MW	30.4	31.7	33.0	34.4	35.8	37.3	38.8	40.4	42.1	43.9	45.7	47.6	49.5	51.6	53.7	56.0	58.3	60.7	63.2	65.9	68.6
	PF	0.89	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90
KINCRAIG	MW	23.0	23.7	24.4	25.2	25.9	26.7	27.6	28.4	29.3	30.2	31.2	32.1	33.1	34.1	35.2	36.3	37.4	38.6	39.8	41.0	42.3
	PF	0.94	0.93	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90
LEIGH CREEK SOUTH	MW	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
MANNUM	MW	14.3	14.4	14.5	14.6	14.6	14.7	14.8	14.9	14.9	15.0	15.1	15.2	15.2	15.3	15.4	15.5	15.5	15.6	15.7	15.8	15.8
	PF	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
MOBILONG	MW	42.5	44.2	45.8	47.6	49.4	51.3	53.2	55.2	57.3	59.5	61.8	64.1	66.6	69.1	71.7	74.4	77.3	80.2	83.3	86.4	89.7
	PF	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.89
MT BARKER	MW	107.2	113.2	119.6	126.3	133.4	140.8	148.7	157.0	165.8	175.1	184.9	195.3	206.2	217.8	230.0	242.8	256.4	270.8	286.0	302.0	318.9
	PF	0.94	0.99	0.99	0.98	0.98	0.98	0.97	0.99	0.99	0.98	0.98	0.97	0.97	0.97	0.98	0.97	0.97	0.96	0.96	0.96	0.96
MT GAMBIER	MW	27.9	28.3	28.8	29.2	24.6	25.0	25.4	25.8	26.1	26.5	26.9	27.3	27.7	28.2	28.6	29.0	29.5	29.9	30.3	30.8	31.3
	PF	0.92	0.92	0.92	0.92	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91
MT GUNSON	MW	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
NEUROODLA	MW	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	PF	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
NORTH WEST BEND	MW	29.0	29.1	29.3	29.4	29.6	29.7	29.9	30.0	30.2	30.3	30.5	30.6	30.8	30.9	31.1	31.2	31.4	31.6	31.7	31.9	32.0
	PF	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
PENOLA WEST	MW	13.7	14.0	14.2	14.5	14.8	15.1	15.4	15.6	15.9	16.2	16.6	16.9	17.2	17.5	17.8	18.2	18.5	18.9	19.2	19.6	20.0
	PF	0.90	0.90	0.90	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
Year from Base		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
PORT LINCOLN TERMINAL	MW	44.7	46.5	48.4	50.4	52.5	54.6	56.9	59.2	61.7	64.2	66.9	69.6	72.5	75.5	78.6	81.8	85.2	88.7	92.4	96.2	100.1
	PF	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.89
SNUGGERY INDUSTRIAL	MW	41.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
	PF	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
SNUGGERY RURAL	MW	17.1	18.1	19.2	20.3	21.5	22.8	24.2	25.7	27.2	28.8	30.6	32.4	34.3	36.4	38.6	40.9	43.4	46.0	48.7	51.6	54.7
	PF	0.92	0.92	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.89	0.89	0.92	0.91	0.91	0.91	0.90	0.90	0.90	0.90
STONY POINT	MW	0.6	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
	PF	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
TAILEM BEND	MW	27.1	27.3	27.4	27.6	27.7	27.8	28.0	28.1	28.2	28.4	28.5	28.7	28.8	29.0	29.1	29.3	29.4	29.5	29.7	29.8	30.0
	PF	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.92	0.92	0.92
TEMPLERS	MW	32.5	34.1	35.8	37.6	39.5	41.4	43.5	45.7	48.0	50.4	52.9	55.5	58.3	61.2	64.3	67.5	70.9	74.4	78.1	82.0	86.1
	PF	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.89	0.89	0.89	0.89	0.89	0.88	0.89	0.88	0.88	0.88	0.88	0.88	0.88
WATERLOO	MW	11.8	12.3	12.9	13.5	14.1	14.7	15.4	16.1	16.8	17.5	18.3	19.1	20.0	20.9	21.9	22.8	23.9	24.9	26.1	27.2	28.5
	PF	0.93	0.93	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.90
WHYALLA TERMINAL	MW	91.9	92.6	93.3	94.0	94.7	95.4	96.2	96.9	97.7	98.4	99.2	100.0	100.8	101.6	102.5	103.3	104.2	105.1	106.0	106.9	107.8
	PF	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
WHYALLA LMF	MW	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
	PF	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
WUDINNA	MW	15.7	15.9	16.1	16.4	16.6	16.9	17.1	17.4	17.7	17.9	18.2	18.5	18.7	19.0	19.3	19.6	19.9	20.2	20.5	20.8	21.1
	PF	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97
YADNARIE	MW	11.8	12.1	12.4	12.7	13.1	13.4	13.8	14.1	14.5	14.9	15.3	15.7	16.1	16.5	16.9	17.3	17.8	18.3	18.7	19.2	19.7
	PF	1.00	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96

Table B.3: ETSA Utilities high growth country connection point forecasts

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Year from Base		0	1	2	3	4	5	6	7	8	9	10
ANGAS CREEK	MW	21.0	21.8	22.5	23.2	24.0	24.8	25.7	26.5	27.4	28.3	29.3
	PF	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91
ARDROSSAN WEST	MW	14.7	15.3	18.0	18.7	19.5	20.3	21.1	22.0	22.8	23.8	24.8
	PF	0.91	0.91	0.90	0.90	0.90	0.90	0.89	0.89	0.89	0.90	0.90
BAROOTA	MW	9.0	9.1	9.3	9.5	9.7	9.9	10.1	10.3	10.5	10.7	11.0
	PF	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96	0.95	0.95
BERRI	MW	96.3	98.6	100.9	103.3	105.8	108.4	111.0	113.6	116.4	119.2	122.0
	PF	0.98	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96
BLANCHE	MW	37.0	38.0	39.0	40.1	46.1	47.3	48.6	49.9	51.2	52.5	53.9
	PF	0.92	0.92	0.92	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90
BRINKWORTH	MW	5.2	5.7	5.8	5.8	5.8	5.9	5.9	5.9	6.0	6.0	6.0
	PF	0.97	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
CLARE NORTH	MW	13.4	14.1	14.9	15.7	16.5	17.4	18.4	19.4	20.4	21.5	22.7
	PF	0.93	0.93	0.92	0.92	0.92	0.91	0.91	0.91	0.90	0.91	0.91
DALRYMPLE	MW	10.1	10.5	10.9	11.3	11.8	12.2	12.7	13.1	13.6	14.2	14.7
	PF	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91
DAVENPORT WEST	MW	33.2	33.9	34.7	35.5	36.3	37.1	38.0	38.8	39.7	40.6	41.6
	PF	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96
DORRIEN	MW	69.1	71.6	74.2	76.9	79.6	82.5	85.5	88.5	91.7	95.0	98.4
	PF	0.90	0.91	0.91	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91
HUMMOCKS	MW	14.7	15.0	13.7	14.5	15.3	16.1	17.0	18.0	19.0	20.0	21.1
	PF	0.93	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.91	0.91	0.91
KADINA EAST	MW	28.1	29.6	31.2	32.9	34.7	36.6	38.5	40.6	42.8	45.1	47.6
	PF	0.93	0.92	0.92	0.92	0.91	0.91	0.91	0.90	0.90	0.90	0.90
KANMANTOO	MW	1.9	2.1	2.3	2.5	2.8	3.0	3.3	3.7	4.0	4.4	4.8
	PF	0.92	0.92	0.91	0.91	0.90	0.90	0.89	0.89	0.93	0.92	0.92
KEITH	MW	30.7	32.2	33.8	35.5	37.2	39.1	41.0	43.1	45.2	47.5	49.8
	PF	0.89	0.92	0.92	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90
KINCRAIG	MW	23.2	24.1	25.0	25.9	26.9	27.9	28.9	30.0	31.1	32.3	33.5
	PF	0.94	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.91	0.91
LEIGH CREEK SOUTH	MW	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
MANNUM	MW	14.4	14.5	14.5	14.6	14.7	14.8	14.9	15.0	15.1	15.2	15.3
	PF	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90
MOBILONG	MW	42.5	44.5	46.5	48.6	50.9	53.2	55.6	58.1	60.8	63.6	66.5
	PF	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.89	0.89
MT BARKER	MW	109.5	116.9	124.7	133.1	142.1	151.6	161.8	172.7	184.3	196.7	209.9
	PF	0.93	0.99	0.99	0.98	0.98	0.97	0.96	0.99	0.98	0.98	0.97
MT GAMBIER	MW	28.1	28.6	29.1	29.6	25.2	25.6	26.1	26.5	27.0	27.5	28.0
	PF	0.92	0.92	0.92	0.91	0.93	0.92	0.92	0.92	0.92	0.92	0.92

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Year from Base		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
MT GUNSON	MW	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
NEUROODLA	MW	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	PF	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
NORTH WEST BEND	MW	29.0	29.2	29.4	29.6	29.7	29.9	30.1	30.3	30.5	30.7	30.8
	PF	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.97	0.97
PENOLA WEST	MW	13.8	14.1	14.5	14.8	15.1	15.5	15.8	16.2	16.5	16.9	17.3
	PF	0.90	0.90	0.89	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.91
PORT LINCOLN TERMINAL	MW	45.4	47.6	50.0	52.4	55.0	57.7	60.6	63.6	66.7	70.0	73.5
	PF	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90
SNUGGERY INDUSTRIAL	MW	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
	PF	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
SNUGGERY RURAL	MW	17.3	18.5	19.8	21.3	22.8	24.4	26.2	28.1	30.1	32.3	34.6
	PF	0.92	0.92	0.91	0.91	0.90	0.90	0.90	0.89	0.89	0.89	0.89
STONY POINT	MW	0.6	0.6	0.6	0.6	0.6	0.6	5.6	5.6	5.6	5.6	5.6
	PF	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
TAILEM BEND	MW	27.2	27.3	27.5	27.7	27.8	28.0	28.2	28.3	28.5	28.7	28.8
	PF	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
TEMPLERS	MW	33.1	35.1	37.2	39.4	41.8	44.3	46.9	49.7	52.7	55.9	59.2
	PF	0.91	0.91	0.91	0.90	0.90	0.90	0.89	0.89	0.89	0.89	0.89
WATERLOO	MW	11.8	12.4	13.1	13.8	14.6	15.3	16.2	17.1	18.0	18.9	20.0
	PF	0.93	0.93	0.92	0.92	0.92	0.91	0.91	0.91	0.90	0.90	0.90
WHYALLA TERMINAL	MW	92.2	93.0	93.8	94.7	95.6	146.5	147.4	148.3	149.2	150.2	151.1
	PF	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
WHYALLA LMF	MW	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
	PF	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
WUDINNA	MW	15.8	16.0	16.3	16.6	16.9	17.2	17.5	17.9	18.2	18.5	18.8
	PF	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.98	0.98
YADNARIE	MW	11.9	12.3	12.7	13.1	13.5	38.9	39.3	39.8	40.2	40.7	41.2
	PF	1.00	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.97

Table B.4: ETSA Utilities high growth metropolitan and country meshed connection point forecasts

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Year from Base		0	1	2	3	4	5	6	7	8	9	10
EASTERN SUBURBS	MW	788	809	872	895	918	942	967	992	1018	1045	1072
	PF	0.99	0.99	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97
ADELAIDE CENTRAL REGION	MW	230	236	246	252	263	274	281	288	295	302	310
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
SOUTHERN SUBURBS	MW	839	892	880	904	930	956	983	1011	1039	1067	1097
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99	0.99
WESTERN SUBURBS	MW	482	494	514	529	545	561	572	583	594	605	615
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98
NORTHERN SUBURBS	MW	385	400	423	446	467	491	515	545	571	599	628
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98
PORT PIRIE SYSTEM	MW	86	87	89	90	91	92	94	95	97	98	100
	PF	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95

Note: The Eastern Suburbs load forecast incorporates the Adelaide Central Region

Table B.5 ETSA Utilities low growth metropolitan and country meshed connection point forecasts

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Year from Base		0	1	2	3	4	5	6	7	8	9	10
EASTERN SUBURBS	MW	775	788	844	859	874	890	906	922	938	955	972
	PF	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.97
ADELAIDE CENTRAL REGION	MW	226	230	238	242	250	258	263	267	272	276	281
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
SOUTHERN SUBURBS	MW	804	850	829	845	862	879	896	914	931	948	965
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
WESTERN SUBURBS	MW	476	485	501	513	526	538	545	553	560	566	573
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
NORTHERN SUBURBS	MW	375	385	402	420	434	449	465	484	500	516	533
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98
PORT PIRIE SYSTEM	MW	85	86	87	88	89	89	90	91	92	93	94
	PF	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95

Note: The Eastern Suburbs load forecast incorporates the Adelaide Central Region

Table B.6: ETSA Utilities low growth country connection point forecasts

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Year from Base		0	1	2	3	4	5	6	7	8	9	10
ANGAS CREEK	MW	20.6	21.1	21.5	22.0	22.5	23.0	23.5	24.0	24.6	25.1	25.7
	PF	0.93	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.92
ARDROSSAN WEST	MW	14.5	14.9	17.4	17.9	18.3	18.8	19.4	19.9	20.2	21.0	21.5
	PF	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.89	0.89
BAROOTA	MW	8.8	9.0	9.1	9.2	9.3	9.5	9.6	9.7	9.8	10.0	10.1
	PF	0.97	0.97	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.96	0.96
BERRI	MW	95.1	96.6	98.2	99.8	101.4	103.0	104.6	106.3	108.0	109.7	111.5
	PF	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.96
BLANCHE	MW	36.4	37.0	37.7	38.4	44.0	44.8	45.6	46.4	47.2	48.1	48.9
	PF	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.90	0.90	0.90
BRINKWORTH	MW	5.2	5.7	5.7	5.8	5.8	5.8	5.8	5.9	5.9	5.9	5.9
	PF	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
CLARE NORTH	MW	13.4	13.9	14.4	14.9	15.4	16.0	16.6	17.2	17.8	18.4	19.1
	PF	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.92	0.92
DALRYMPLE	MW	9.9	10.1	10.4	10.6	10.9	11.2	11.5	11.8	12.1	12.4	12.7
	PF	0.93	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.92
DAVENPORT WEST	MW	32.7	33.2	33.7	34.2	34.7	35.2	35.8	36.3	36.9	37.4	38.0
	PF	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.96
DORRIEN	MW	67.5	69.1	70.8	72.5	74.2	76.0	77.9	79.7	81.6	83.6	85.6
	PF	0.90	0.91	0.91	0.92	0.92	0.92	0.92	0.92	0.92	0.91	0.91
HUMMOCKS	MW	14.7	14.7	13.2	13.7	14.2	14.7	15.2	15.8	16.4	17.0	17.6
	PF	0.93	0.93	0.94	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.92
KADINA EAST	MW	27.2	28.1	29.1	30.2	31.3	32.4	33.6	34.8	36.0	37.3	38.7
	PF	0.93	0.93	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91
KANMANTOO	MW	1.8	1.9	2.1	2.2	2.3	2.5	2.6	2.8	3.0	3.2	3.4
	PF	0.93	0.92	0.92	0.92	0.91	0.91	0.91	0.90	0.95	0.95	0.94
KEITH	MW	30.2	31.2	29.2	30.3	31.4	32.5	33.7	34.9	36.2	37.5	38.8
	PF	0.89	0.92	0.93	0.93	0.92	0.92	0.92	0.92	0.91	0.91	0.91
KINCRAIG	MW	22.7	23.2	23.8	24.4	25.0	25.6	26.3	26.9	27.6	28.3	29.0
	PF	0.94	0.94	0.93	0.93	0.93	0.93	0.93	0.93	0.92	0.92	0.92
LEIGH CREEK SOUTH	MW	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	PF	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
MANNUM	MW	14.3	14.4	14.4	14.5	14.5	14.6	14.7	14.7	14.8	14.8	14.9
	PF	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90
MOBILONG	MW	41.9	43.2	44.5	45.9	47.3	48.7	50.2	51.7	53.3	54.9	56.6
	PF	0.92	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90
MT BARKER	MW	105.0	109.7	114.6	119.7	125.1	130.7	136.6	142.7	149.1	155.7	162.7
	PF	0.94	0.99	0.99	0.99	0.99	0.98	0.98	1.00	0.99	0.99	0.99
MT GAMBIER	MW	27.8	28.1	28.4	28.8	24.1	24.4	24.7	25.0	25.3	25.6	25.9
	PF	0.92	0.92	0.92	0.92	0.93	0.93	0.93	0.93	0.93	0.92	0.92

Connection Point	Units	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Year from Base		0	1	2	3	4	5	6	7	8	9	10
MT GUNSON	MW	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
NEUROODLA	MW	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	PF	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
NORTH WEST BEND	MW	28.9	29.0	29.2	29.3	29.4	29.5	29.6	29.7	29.9	30.0	30.1
	PF	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
PENOLA WEST	MW	13.6	13.8	14.0	14.2	14.4	14.6	14.8	15.1	15.3	15.5	15.8
	PF	0.90	0.90	0.90	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91
PORT LINCOLN TERMINAL	MW	43.9	45.4	46.9	48.4	50.0	51.7	53.4	55.1	57.0	58.8	60.8
	PF	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.90
SNUGGERY INDUSTRIAL	MW	41.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
	PF	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
SNUGGERY RURAL	MW	16.7	17.4	18.1	18.8	19.6	20.4	21.2	22.0	22.9	23.8	24.8
	PF	0.92	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.90	0.91	0.91
STONY POINT	MW	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
	PF	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
TAILEM BEND	MW	27.1	27.2	27.3	27.4	27.5	27.6	27.8	27.9	28.0	28.1	28.2
	PF	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
TEMPLERS	MW	31.8	33.1	34.4	35.8	37.3	38.7	40.3	41.9	43.6	45.3	47.1
	PF	0.91	0.91	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.89
WATERLOO	MW	11.8	12.2	12.7	13.1	13.6	14.1	14.6	15.1	15.7	16.2	16.8
	PF	0.93	0.93	0.92	0.92	0.92	0.92	0.92	0.91	0.91	0.91	0.91
WHYALLA TERMINAL	MW	82.3	83.4	83.9	84.5	85.1	85.6	86.2	86.8	87.4	88.0	88.6
	PF	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
WHYALLA LMF	MW	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
	PF	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
WUDINNA	MW	15.6	15.8	16.0	16.1	16.3	16.5	16.7	16.9	17.1	17.3	17.6
	PF	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98
YADNARIE	MW	11.7	11.9	12.2	12.4	12.7	12.9	13.2	13.5	13.8	14.1	14.4
	PF	1.00	1.00	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98

Appendix C Substation Fault Levels and Circuit Breaker Ratings

The 5 year estimated three-phase and single phase-to-ground fault levels under the peak loading conditions in South Australian system are shown in the table below. The table also shows the fault level interruption capacity of the lowest rated circuit breaker(s) at each location.

The provided fault level information should be taken only as an approximate guide to the conditions at each location. Predominantly due to the impact of embedded generation, fault levels may be higher at some locations than shown. Interested parties needing to consider the impacts of their proposals on fault levels should consult ElectraNet and the Distribution Network Service Provider, ETSA Utilities, for more detailed information.

The following network augmentations were modelled for the future fault level calculations:

Year	Scope of Work
2011	Establish a 275/66 kV substation with 1 x 225 MVA transformer at Mount Barker South and related ETSA Utilities network reconfigurations.
2011	Build Torrens Island - City West 275 kV cable; install 2 x 300 MVA 275/66 kV transformers at City West substation and related ETSA Utilities network reconfigurations.
2012	Install 1 x 100 Mvar 275 kV switchable PoW capacitor bank at Tungkillo switching station
2012	2nd Wudinna 132/33 kV transformer and related ETSA Utilities network reconfigurations.
2012	Install 1x15 Mvar capacitor bank at Kincraig.
2012	Replace Ardrossan West transformers with 2x25 MVA 132/33 kV transformers; install 1x15MvarMvar capacitor bank at 132 kV busbar and related ETSA Utilities network reconfigurations.
2013	Replace 160 MVA by installing 2x200 MVA Cultana 275/132 kV transformers; Whyalla replacement with 2x120 MVA 132/33 kV transformers and related ETSA Utilities network reconfigurations.
2013	Replace Hummocks transformer with 2x25MVA 132/33 kV transformers and related ETSA Utilities network reconfigurations.
2013	Replace Waterloo with 2x25 MVA, 132/33 kV transformers and related ETSA Utilities network reconfigurations.
2013	Install the 3rd Dorrien 132/33 kV transformer.
2014	Establish Munno Para 275/66 kV substation, install one 225 MVA 275/66 kV transformer, install one 100 Mvar Capacitor bank at 275 kV busbar and related ETSA Utilities network reconfigurations.
2014	Install 15 Mvar capacitor bank at Kadina East 132 kV busbar.

The following assumptions were made when calculating these fault levels:

- Solid fault condition, (i.e. no fault impedance modelled);
- 2 ohm NEX installed on Northfield 275/66 kV transformer #9;

- 2 ohm NEX installed on Quarantine Power Station unit #5 step-up transformer;
- 2 x 2.5 ohm NEX installed on Mannum 132/33 kV transformers;
- 2 x Dry Creek Power Station units dispatched into the Eastern Suburbs;
- Generation at North Brown Hill, Waterloo and Lake Bonney Stage 3 wind farms is online;
- Port Lincoln 3rd gas turbine is online;
- Temporary reconfiguration of Dorrien – Roseworthy 132 kV line as part of establishing 275/132 kV transformation at Templers;
- Embedded generation at Starfish Hill, Angaston, Lonsdale, Port Stanvac and Whyalla is online;
- System normal network configuration: all network elements are in service; and
- Snuggery 33 kV busbar is closed, but with three transformers connected only.

Table C.1: Circuit breaker fault rating and 5-year system fault levels

Location	Bus Voltage (kV)	Circuit Breaker	2011 Fault Level (kA)		2012 Fault Level (kA)		2013 Fault Level (kA)		2014 Fault Level (kA)		2015 Fault Level (kA)	
		Lowest Fault Rating (kA)	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground
ANGAS CREEK	132	31.5	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	5.0	5.0
ANGAS CREEK	33	31.5	5.3	6.6	5.3	6.7	5.3	6.7	5.3	6.7	5.3	6.7
ARDROSSAN WEST	132	31.5	2.7	2.4	2.7	2.5	2.7	2.7	2.7	2.7	2.7	2.7
ARDROSSAN WEST	33	17.5	2.8	3.8	2.8	3.8	4.5	4.4	4.5	4.3	4.5	4.3
BELALIE	275	50.0	5.9	3.9	5.9	3.9	6.2	4.0	6.2	4.0	6.2	4.0
BAROOTA	132	-	3.4	3.1	3.4	3.1	3.4	3.1	3.4	3.1	3.4	3.1
BAROOTA	33	17.5	1.6	1.7	1.6	1.7	1.6	1.7	1.6	1.7	1.6	1.7
BERRI	132	10.9	2.4	2.7	2.4	2.8	2.4	2.8	2.4	2.8	2.4	2.8
BERRI	66	31.5	3.8	4.8	3.8	4.8	3.8	4.8	3.8	4.9	3.8	4.9
BERRI	11	-	10.1	8.7	10.2	8.7	10.2	8.7	10.2	8.7	10.2	8.7
BLANCHE	132	25	5.4	5.6	5.4	5.6	5.4	5.6	5.4	5.6	5.4	5.6
BLANCHE	33	17.5	8.4	11.3	8.4	11.3	8.4	11.4	8.4	11.4	8.4	11.4
BRINKWORTH	275	36.0	5.3	4.1	5.3	4.1	5.3	4.1	5.4	4.1	5.4	4.2
BRINKWORTH	132	15.3	8.0	8.9	8.0	8.9	8.0	8.9	8.0	8.9	8.1	8.9
BRINKWORTH	33	31.5	3.0	3.7	3.0	3.7	3.0	3.7	3.0	3.7	3.0	3.7
BUNGAMA	275	31.5	5.7	4.6	5.7	4.6	5.8	4.6	5.8	4.6	5.8	4.6
BUNGAMA	132	31.5	7.0	8.0	7.0	8.0	7.0	8.0	7.1	8.1	7.1	8.1
BUNGAMA	33	31.5	10.7	6.5	10.7	6.5	10.7	6.5	10.7	6.5	10.8	6.5
CANOWIE	275	31.5	7.1	4.2	7.2	4.2	7.2	4.3	7.3	4.3	7.3	4.3
CHERRY GARDENS	275	40	12.8	13.0	12.9	13.3	13.3	13.7	13.8	14.0	14.2	14.3
CHERRY GARDENS	132	40	6.3	6.8	7.2	7.6	7.3	7.7	7.3	7.7	7.3	7.7
CITY WEST	275	40	-	-	14.9	18.4	15.2	18.8	15.5	19.1	16.2	20.0
CITY WEST_CBD	66	40	-	-	22.2	21.6	22.4	21.7	22.6	21.8	22.9	21.9

Location	Bus Voltage (kV)	Circuit Breaker	2011 Fault Level (kA)		2012 Fault Level (kA)		2013 Fault Level (kA)		2014 Fault Level (kA)		2015 Fault Level (kA)	
		Lowest Fault Rating (kA)	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground
CITY WEST_STH	66	40	-	-	18.6	13.4	18.6	13.3	18.7	13.3	18.9	13.4
CLARE NORTH	132	40	6.8	6.8	6.8	6.8	6.9	6.8	6.9	6.8	6.9	6.8
CLARE NORTH	33	31.5	9.4	6.9	9.4	6.9	9.4	6.9	9.4	6.9	9.4	6.9
CULTANA	275	31.5	6.2	5.7	6.3	5.7	6.3	5.7	6.4	6.0	6.4	6.0
CULTANA	132	31.5	6.9	7.3	6.9	7.3	6.9	7.3	7.5	9.4	7.5	9.4
DALRYMPLE	132	40	2.2	1.8	2.2	1.8	2.2	1.9	2.2	1.9	2.2	1.9
DALRYMPLE	33	8.0	2.6	3.4	2.6	3.4	2.6	3.4	2.6	3.4	2.6	3.4
DAVENPORT	275	31.5	11.1	12.9	11.1	12.9	11.2	13.0	11.3	13.1	11.3	13.1
DAVENPORT	132	40.0	9.6	11.4	9.6	11.4	9.6	11.4	8.3	10.0	8.3	10.0
DAVENPORT	33	31.5	10.2	10.3	10.2	10.3	10.2	10.3	9.8	10.0	9.8	10.0
DORRIEN	132	21.9	5.0	5.2	6.8	6.8	6.9	6.8	6.9	7.2	6.9	7.2
DORRIEN	33	31.5	11.6	14.8	12.9	7.8	12.9	7.8	15.2	10.6	15.2	10.6
DRY CREEK_WEST	66	21.9	20.4	17.8	20.5	17.8	20.7	17.8	20.7	17.8	20.9	17.9
DRY CREEK_EAST	66	21.9	18.6	18.3	19.4	18.4	19.5	18.4	19.6	18.5	19.8	18.6
EAST TERRACE	275	-	12.5	13.4	12.6	13.6	13.0	13.8	13.3	14.0	13.7	14.3
EAST TERRACE	66	31.5	19.8	19.7	23.6	22.9	23.8	23.0	24.0	23.1	24.3	23.3
HAPPY VALLEY	275	50	12.4	12.9	12.5	13.2	12.9	13.5	13.3	13.8	13.7	14.0
HAPPY VALLEY	66	21.9	22.6	20.6	25.6	22.4	26.0	22.4	26.2	22.5	26.6	22.7
HUMMOCKS	132	10.9	4.2	3.7	4.2	3.9	4.2	4.0	4.2	4.2	4.2	4.2
HUMMOCKS	33	17.5	2.4	3.1	2.4	3.2	2.4	3.2	5.2	4.9	5.3	4.9
KADINA EAST	132	-	2.3	2.1	2.3	2.6	2.3	2.6	2.3	2.6	2.3	2.6
KADINA EAST	33	17.5	2.8	3.6	5.7	4.3	5.7	4.3	5.7	4.3	5.7	4.4
KANMANTOO	132	10.9	4.3	4.2	4.9	4.6	4.9	4.6	4.9	4.6	4.9	4.6
KANMANTOO	11	13.1	2.2	2.2	2.2	2.3	2.2	2.2	2.2	2.2	2.1	2.2
KEITH	132	19.7	3.6	3.3	3.6	3.3	3.6	3.3	3.7	3.4	3.7	3.4

Location	Bus Voltage (kV)	Circuit Breaker	2011 Fault Level (kA)		2012 Fault Level (kA)		2013 Fault Level (kA)		2014 Fault Level (kA)		2015 Fault Level (kA)	
		Lowest Fault Rating (kA)	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground
KEITH	33	31.5	4.9	6.2	4.9	6.2	4.9	6.2	4.9	6.3	4.9	6.3
KILBURN	275	31.5	15.4	16.2	15.5	16.3	15.9	16.6	16.2	16.8	17.0	17.4
KILBURN	66	21.9	20.4	17.8	20.5	17.8	20.7	17.8	20.7	17.8	20.9	17.9
KINGRAIG	132	15.3	2.9	2.8	2.9	2.8	2.9	2.8	2.9	2.8	2.9	2.8
KINGRAIG	33	25	4.5	6.2	4.5	6.2	4.5	6.2	4.5	6.2	4.5	6.2
LE FEVRE	275	50	19.4	22.9	19.4	23.1	20.0	23.7	20.6	24.2	21.7	25.4
LE FEVRE	66	25.0	29.5	27.6	29.6	27.6	29.8	27.6	29.9	27.6	30.3	27.8
LEIGH CREEK COALFIELD	132	-	0.6	0.8	0.6	0.8	0.6	0.8	0.6	0.8	0.6	0.8
LEIGH CREEK COALFIELD	33	8.7	1.5	2.1	1.5	2.1	1.5	2.1	1.5	2.1	1.5	2.1
LEIGH CREEK SOUTH	132	-	0.6	0.8	0.6	0.8	0.6	0.8	0.6	0.8	0.6	0.8
LEIGH CREEK SOUTH	33	-	0.9	1.3	0.9	1.3	0.9	1.3	0.9	1.3	0.9	1.3
MAGILL	275	31.5	13.9	14.6	14.0	14.8	14.4	15.1	14.8	15.4	15.3	15.7
MAGILL	66 (1)	31.5	23.3	27.7	23.6	27.9	23.9	28.1	24.1	28.3	24.4	28.5
MAGILL	66 (2)	31.5	11.9	8.3	12.1	8.3	12.1	8.3	12.1	8.3	12.1	8.3
MANNUM	132	40.0	4.9	5.3	5.1	5.4	5.1	5.4	5.1	5.5	5.1	5.5
MANNUM	33	31.5	5.2	4.9	5.3	5.0	5.2	5.0	5.2	5.0	5.2	4.9
MANNUM – ADELAIDE PUMP 1	132	-	4.3	4.5	4.5	4.6	4.5	4.6	4.5	4.6	4.5	4.6
MANNUM – ADELAIDE PUMP 1	3.3	-	27.3	31.7	27.5	31.9	27.4	31.7	27.3	31.6	27.3	31.5
MANNUM – ADELAIDE PUMP 2	132	-	4.6	4.8	4.7	4.9	4.7	4.9	4.7	4.9	4.8	4.9
MANNUM – ADELAIDE PUMP 2	3.3	-	20.1	23.5	20.2	23.6	20.1	23.5	20.1	23.5	20.0	23.4
MANNUM – ADELAIDE PUMP 3	132	-	4.5	4.7	4.7	4.8	4.7	4.8	4.7	4.8	4.7	4.8

Location	Bus Voltage (kV)	Circuit Breaker	2011 Fault Level (kA)		2012 Fault Level (kA)		2013 Fault Level (kA)		2014 Fault Level (kA)		2015 Fault Level (kA)	
		Lowest Fault Rating (kA)	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground
MANNUM – ADELAIDE PUMP 3	3.3	-	24.0	28.4	24.1	28.5	24.0	28.3	24.0	28.3	23.9	28.2
MAYURRA	132	40.0	7.5	5.7	7.5	5.7	7.5	5.7	7.5	5.7	7.5	5.7
MAYURRA#1	33	31.5	20.0	12.7	20.0	12.7	20.0	12.7	20.0	12.7	20.0	12.7
MAYURRA#2	33	31.5	16.9	11.9	16.9	11.9	16.9	11.9	16.9	12.0	16.9	12.0
MIDDLEBACK	132	40.0	3.2	2.7	3.2	2.7	3.1	2.7	2.9	2.6	2.9	2.6
MIDDLEBACK	33	-	1.6	2.1	1.6	2.1	1.5	2.1	1.5	2.1	1.5	2.1
MILLBROOK	132	10.9	5.1	5.1	5.3	5.2	5.3	5.2	5.3	5.2	5.3	5.2
MILLBROOK	3.3	-	20.4	24.7	20.5	24.7	20.4	24.6	20.4	24.6	20.3	24.5
MINTARO	132	20.0	8.0	8.2	8.0	8.3	8.0	8.3	8.1	8.3	8.1	8.3
MOBILONG	132	15.3	5.9	6.3	6.2	6.6	6.3	6.6	6.3	6.6	6.3	6.6
MOBILONG	33	31.5	9.1	7.0	9.4	7.0	9.4	7.0	9.4	7.0	9.4	7.0
MOKOTA	275	50.0	6.3	4.2	6.3	4.2	6.5	4.3	6.6	4.3	6.6	4.3
MONASH	132	31.5	2.5	2.9	2.5	2.9	2.5	2.9	2.5	2.9	2.5	2.9
MONASH	66	-	3.7	4.8	3.7	4.8	3.7	4.9	3.7	4.9	3.7	4.9
MORGAN – WHYALLA PUMP1	132	15.3	4.2	4.3	4.2	4.4	4.2	4.4	4.2	4.4	4.2	4.4
MORGAN – WHYALLA PUMP1	3.3	-	27.0	35.1	27.0	35.2	27.0	35.2	27.0	35.1	27.2	35.4
MORGAN – WHYALLA PUMP2	132	15.3	4.9	4.5	4.9	4.5	4.9	4.5	4.9	4.5	4.9	4.5
MORGAN – WHYALLA PUMP2	3.3	-	27.9	36.4	28.0	36.5	28.0	36.4	27.9	36.4	28.1	36.7
MORGAN – WHYALLA PUMP3	132	15.3	7.9	7.4	7.9	7.4	7.9	7.5	8.0	7.5	8.0	7.5
MORGAN – WHYALLA PUMP3	3.3	-	30.9	2.0	31.0	2.0	31.0	2.0	30.9	2.0	31.1	2.0
MORGAN – WHYALLA PUMP4	132	15.3	9.7	8.8	9.7	8.9	9.8	8.9	9.8	9.0	9.9	9.0

Location	Bus Voltage (kV)	Circuit Breaker	2011 Fault Level (kA)		2012 Fault Level (kA)		2013 Fault Level (kA)		2014 Fault Level (kA)		2015 Fault Level (kA)	
		Lowest Fault Rating (kA)	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground
MORGAN – WHYALLA PUMP4	3.3	-	31.2	2.0	31.3	2.0	31.2	2.0	31.2	2.0	31.3	2.0
MORPHETT VALE EAST	275	31.5	11.4	11.6	11.6	11.8	11.9	12.0	12.2	12.3	12.5	12.5
MORPHETT VALE EAST	66	25.0	21.2	17.6	21.7	17.3	21.8	17.2	22.1	17.3	22.3	17.4
MOUNT BARKER	132	31.5	5.2	5.6	6.7	6.8	6.8	6.8	6.8	6.8	6.9	6.8
MOUNT BARKER	66	31.5	5.0	6.1	11.3	12.0	11.3	12.0	11.4	12.1	11.5	12.1
MOUNT BARKER SOUTH	275	40	-	-	11.0	10.3	11.5	10.7	11.9	11.0	12.1	11.2
MOUNT BARKER SOUTH	66	31.5	-	-	11.5	11.4	11.6	11.5	11.7	11.5	11.8	11.6
MOUNT GAMBIER	132	31.5	6.6	6.5	6.6	6.5	6.6	6.5	6.6	6.5	6.6	6.5
MOUNT GAMBIER	33	17.5	7.1	5.9	7.1	5.9	7.1	5.9	7.1	5.9	7.1	5.9
MOUNT GAMBIER	11	13.1	10.2	9.0	10.2	9.0	10.2	9.0	10.2	9.0	10.2	9.0
MOUNT GUNSON	132	15.3	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
MOUNT GUNSON	33	-	1.0	1.3	1.0	1.3	1.0	1.3	1.0	1.3	1.0	1.3
MOUNT MILLAR	132	40.0	2.3	1.7	2.3	1.7	2.3	1.7	2.3	1.7	2.3	1.7
MOUNT MILLAR	33	31.5	10.5	1.4	10.6	1.4	10.7	1.4	10.5	1.4	10.5	1.4
MUNNO PARA	275	40	-	-	-	-	-	-	-	-	13.3	12.1
MUNNO PARA	66	40	-	-	-	-	-	-	-	-	14.5	11.1
MURRAY – HAHNDORF PUMP1	132	15.3	5.1	5.2	5.4	5.4	5.4	5.4	5.5	5.4	5.5	5.4
MURRAY – HAHNDORF PUMP1	11	-	12.5	13.1	12.7	13.2	12.6	13.1	12.6	13.1	12.6	13.1
MURRAY – HAHNDORF PUMP2	132	15.3	5.5	5.5	6.0	5.8	6.0	5.8	6.0	5.8	6.0	5.8
MURRAY – HAHNDORF PUMP2	11	-	12.7	13.2	12.9	13.4	12.9	13.3	12.9	13.3	12.8	13.3
MURRAY – HAHNDORF PUMP3	132	15.3	5.0	5.0	5.7	5.5	5.7	5.5	5.8	5.5	5.8	5.5

Location	Bus Voltage (kV)	Circuit Breaker	2011 Fault Level (kA)		2012 Fault Level (kA)		2013 Fault Level (kA)		2014 Fault Level (kA)		2015 Fault Level (kA)	
		Lowest Fault Rating (kA)	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground
MURRAY – HAHNDORF PUMP3	11	-	12.6	13.1	13.0	13.4	13.0	13.4	13.0	13.3	12.9	13.3
NEUROODLA	132	-	1.5	1.4	1.5	1.4	1.5	1.4	1.5	1.4	1.5	1.4
NEUROODLA	33	8.7	1.0	1.4	1.0	1.4	1.0	1.4	1.0	1.4	1.0	1.4
NEW OSBORNE	66	40.0	31.7	31.0	31.8	31.1	32.0	31.1	32.1	31.1	32.5	31.3
NORTH WEST BEND	132	10.9	4.2	4.5	4.2	4.5	4.2	4.6	4.3	4.6	4.2	4.5
NORTH WEST BEND	66	13.1	4.3	4.9	4.3	5.0	4.3	5.0	4.3	5.0	4.4	5.0
NORTHFIELD	275	31.5	15.3	15.7	15.4	15.7	15.7	15.9	16.1	16.2	16.8	16.7
NORTHFIELD	66	31.5	26.9	30.3	27.5	24.8	27.7	24.9	28.0	25.0	28.4	25.2
PARA	275	31.5	18.0	20.0	18.0	20.2	18.7	20.9	19.4	21.5	20.1	22.4
PARA	132	21.9	8.1	8.7	8.5	9.1	8.5	9.1	8.6	9.2	8.6	9.2
PARA	66	21.9	16.0	18.2	16.1	18.3	16.2	18.4	16.2	18.4	18.9	21.1
PARAFIELD GARDENS WEST	275	31.5	16.4	17.8	16.4	17.9	16.9	18.3	17.4	18.7	18.0	19.3
PARAFIELD GARDENS WEST	66	31.5	17.3	20.1	17.3	20.1	17.3	20.1	17.5	20.3	18.8	21.4
PELICAN POINT	275	40.0	19.1	22.4	19.2	22.6	19.8	23.1	20.3	23.5	21.3	24.6
PENOLA WEST	132	31.5	5.2	5.9	5.2	5.9	5.2	5.9	5.2	5.9	5.2	5.9
PENOLA WEST	33	31.5	5.4	5.0	5.4	5.0	5.3	5.0	5.4	5.0	5.4	5.0
PIMBA	132	31.5	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
PLAYFORD	275	31.5	10.6	12.3	10.7	12.3	10.7	12.4	10.8	12.5	10.8	12.5
PLAYFORD	132	10.9	4.9	5.4	4.9	5.4	4.9	5.4	4.9	5.4	4.9	5.5
PORT LINCOLN TERMINAL	132	31.5	2.7	3.0	2.7	3.0	2.7	3.0	2.7	3.0	2.7	3.0
PORT LINCOLN TERMINAL	33	17.5	6.6	5.0	6.6	5.0	6.6	5.0	6.6	4.9	6.7	4.9
PORT LINCOLN TERMINAL	11	13.1	9.1	7.9	9.1	7.9	9.1	7.9	9.1	7.9	9.1	7.9

Location	Bus Voltage (kV)	Circuit Breaker	2011 Fault Level (kA)		2012 Fault Level (kA)		2013 Fault Level (kA)		2014 Fault Level (kA)		2015 Fault Level (kA)	
		Lowest Fault Rating (kA)	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground
PORT PIRIE	132	40.0	5.7	5.9	5.7	5.9	5.7	5.9	5.7	5.9	5.7	6.0
PORT PIRIE	33	31.5	9.1	5.3	9.1	5.3	9.1	5.3	9.1	5.3	9.2	5.3
REDHILL	132	40.0	6.7	5.5	6.7	5.4	6.7	5.5	6.7	5.4	6.7	5.5
ROBERTSTOWN	275	31.5	9.3	7.2	9.4	7.3	9.6	7.4	9.7	7.4	9.8	7.5
ROBERTSTOWN	132	31.5	10.7	11.1	10.7	11.1	10.8	11.2	10.9	11.3	10.9	11.3
ROSEWORTHY	132	31.5	6.2	5.6	7.2	6.1	7.2	6.1	7.3	6.2	7.3	6.2
ROSEWORTHY	11	25.0	8.9	12.2	9.0	12.4	8.9	12.3	8.9	12.3	8.9	12.3
SLEAFORD	132	40.0	2.4	1.8	2.4	1.8	2.4	1.8	2.4	1.8	2.4	1.8
SLEAFORD	33	31.5	12.6	11.7	12.6	11.7	12.6	11.7	12.6	11.7	12.6	11.7
SNOWTOWN	132	40.0	4.3	2.9	4.3	3.0	4.3	3.0	4.3	3.1	4.3	3.1
SNOWTOWN	33	31.5	13.9	1.1	13.9	1.1	13.9	1.1	13.9	1.1	13.9	1.1
SNUGGERY	132	40	8.5	8.8	8.5	8.8	8.5	8.8	8.5	8.9	8.5	8.9
SNUGGERY (Industrial)	33	31.5	11.1	14.4	11.1	14.4	11.2	14.5	11.5	14.9	11.5	14.9
SNUGGERY (Industrial)	11	13.1	12.9	11.0	12.9	11.0	13.0	11.0	13.3	11.2	13.3	11.2
SNUGGERY (Rural)	33	31.5	11.1	14.4	11.1	14.4	11.2	14.5	11.5	14.9	11.5	14.9
SNUGGERY (Rural)	11	13.1	11.5	10.8	11.5	10.8	11.5	10.8	11.8	10.9	11.8	10.9
SOUTH EAST	275	31.5	7.5	7.7	7.3	7.6	7.3	7.6	7.3	7.6	7.3	7.6
SOUTH EAST	132	20.0	10.2	11.3	10.2	11.3	10.2	11.3	10.2	11.3	10.2	11.3
STONY POINT	132	31.5	3.7	2.8	3.7	2.8	3.7	2.8	3.9	3.0	3.9	3.0
STONY POINT	11	-	9.7	0.3	9.7	0.3	9.6	0.3	9.8	0.3	9.8	0.3
TAILEM BEND	275	25.2	7.9	5.8	7.9	5.8	8.0	6.0	8.2	6.1	8.3	6.1
TAILEM BEND	132	21.9	6.9	7.9	7.1	8.0	7.1	8.1	7.2	8.1	7.2	8.1
TAILEM BEND	33	25.0	6.0	7.7	6.1	7.7	6.1	7.7	6.1	7.7	6.1	7.7
TEMPLERS	132	40	6.1	6.3	7.7	7.2	7.7	7.2	7.7	7.3	7.8	7.3
TEMPLERS	33	10.9	9.3	12.7	10.1	7.3	10.0	7.3	10.1	7.3	10.1	7.2

Location	Bus Voltage (kV)	Circuit Breaker	2011 Fault Level (kA)		2012 Fault Level (kA)		2013 Fault Level (kA)		2014 Fault Level (kA)		2015 Fault Level (kA)	
		Lowest Fault Rating (kA)	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground	3-phase	phase-to-ground
TEMPLERS WEST	275	31.5	-	-	8.9	7.4	9.0	7.4	9.1	7.5	9.3	7.6
TORRENS ISLAND NORTH	66	-	14.4	14.1	14.5	14.1	14.5	14.1	14.5	14.1	14.6	14.1
TORRENS ISLAND	275	31.5	20.3	24.9	20.3	25.2	21.0	25.9	21.6	26.5	23.0	28.3
TORRENS ISLAND*	66	40	31.8	30.7	31.9	30.7	32.1	30.8	32.3	30.9	32.7	31.1
TUNGKILLO	275	50.0	12.4	10.7	12.4	11.0	13.5	12.4	14.4	13.4	14.7	13.6
WATERLOO	132	10.9	9.8	8.5	10.0	8.7	10.1	8.7	10.1	8.9	10.1	9.0
WATERLOO	33	13.1	2.5	3.7	2.5	3.8	2.5	3.7	6.3	8.0	6.3	8.0
WATERLOO EAST	132	31.5	9.8	8.0	9.9	8.1	10.0	8.2	10.0	8.3	10.0	8.3
WHYALLA TERMINAL	132	10.9	7.1	7.5	7.1	7.5	7.1	7.4	6.6	7.7	6.6	7.7
WHYALLA TERMINAL	33	17.5	13.2	16.3	13.2	16.3	12.6	15.7	15.3	13.1	15.3	13.1
WHYALLA TERMINAL LMF	33	-	4.9	4.9	4.9	4.9	4.9	4.9	4.8	4.9	4.9	4.9
WHYALLA TERMINAL	11	20.0	16.6	14.5	16.6	14.5	16.2	14.4	22.7	20.0	22.7	20.0
WUDINNA	132	31.5	1.0	1.0	1.0	1.0	1.0	1.1	1.0	1.1	1.0	1.1
WUDINNA	66	21.9	1.3	1.5	1.3	1.5	1.6	1.9	1.6	1.9	1.6	1.9
YADNARIE	132	31.5	2.6	2.5	2.6	2.5	2.6	2.6	2.6	2.5	2.6	2.5
YADNARIE	66	40	2.8	3.3	2.8	3.3	2.8	3.3	2.7	3.2	2.7	3.2
YADNARIE	11	18.4	6.3	5.5	6.3	5.5	6.3	5.5	6.3	5.5	6.3	5.5

* Fault level operational measures are in place to manage mechanical bus structures limit at Torrens Island

Appendix D Additional Transmission Planning Information

D.1 Rule Requirements for the Annual Planning Report

Rule 5.6.2 requires ElectraNet to conduct an Annual Planning Review. Clause b of that Rule requires that review to:

(1) incorporate the forecast loads as submitted or modified in accordance with clause 5.6.1;

(2) include a review of the adequacy of existing connection points and relevant parts of the transmission system and planning proposals for future connection points;

(3) take into account the most recent NTNDP; and

(4) consider the potential for augmentations, or non-network alternatives to augmentations, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the market.

The purpose of the APR is to provide the results of that review. More specifically Rule 5.6.2A requires ElectraNet to provide:

(1) the forecast loads submitted by a *Distribution Network Service Provider* in accordance with clause 5.6.1 or as modified in accordance with clause 5.6.1(d);

(2) planning proposals for future *connection points*;

(3) a forecast of *constraints* and inability to meet the *network* performance requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction* over 1, 3 and 5 years;

(3a) in respect of information required by subparagraph (3), where an estimated reduction in forecast *load* would defer a forecast *constraint* for a period of 12 months, include:

(i) the year and months in which a *constraint* is forecast to occur;

(ii) the relevant *connection points* at which the estimated reduction in forecast load may occur;

(iii) the estimated reduction in forecast *load* in MW needed; and

(iv) a statement of whether the *Transmission Network Service Provider* plans to issue a request for proposals for *augmentation* or a non-network alternative identified by the annual planning review conducted under clause 5.6.2(b) and if so, the expected date the request will be issued;

(4) for all proposed *augmentations* to the network the following information, in sufficient detail relative to the size or significance of the project and the proposed operational date of the project:

(i) project/asset name and the month and year in which it is proposed that the asset will become operational;

(ii) the reason for the actual or potential *constraint*, if any, or inability, if any, to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction*, including load forecasts and all assumptions used;

(iii) the proposed solution to the *constraint* or inability to meet the network performance requirements identified in clause 5.6.2A(b)(4)(ii), if any;

(iv) total cost of the proposed solution;

(v) whether the proposed solution will have a material internetwork impact. In assessing whether an *augmentation* to the network will have a *material inter-network impact* a *Transmission Network Service Provider* must have regard to the objective set of criteria *published* by *AEMO* in accordance with clause 5.6.3(b) (if any such criteria have been *published* by *AEMO*); and

(vi) other reasonable *network* and non-*network* options considered to address the actual or potential *constraint* or inability to meet the *network* performance requirements identified in clause 5.6.2A(b)(4)(ii), if any. Other reasonable *network* and non-*network* options include, but are not limited to, *interconnectors*, *generation* options, demand side options, *market network service* options and options involving other *transmission* and *distribution networks*;

(5) the manner in which the proposed *augmentations* relate to the most recent *NTNDP* and the development strategies for current or potential *national transmission flow paths* that are specified in that *NTNDP*.

(6) for all proposed *replacement transmission network* assets:

(i) a brief description of the new *replacement transmission network asset* project, including location;

(ii) the date from which the *Transmission Network Service Provider* proposes that the proposed new rep*lacement transmission network asset* will become operational;

(iii) the purpose of the proposed *new replacement transmission network asset*;

(iv) a list of any reasonable *network* or non-*network* alternatives to the proposed *new replacement transmission network asset* which are being, or have been, considered by the Transmission Network Service Provider (if any). Those alternatives include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission or distribution networks; and

(v) the Transmission Network Service Provider's estimated total capitalised expenditure on the proposed new replacement transmission network asset; and

(7) any information required to be included in an Annual Planning Report under clause 5.6.5C(c) in relation to a transmission investment which is determined to be required to address an urgent and unforeseen network issue.

D.2 South Australian Electricity Market Framework

D.2.1 Australian Energy Market Operator

AEMO has the responsibility of National Transmission Planner (NTP) conferred on it, under the National Electricity Law (NEL). In addition, the South Australian Energy Minister has also requested AEMO perform certain functions in the South Australian jurisdiction.

Among other things, AEMO is required to provide annual reports covering the South Australian power system that include:

- Assessments of the performance of connection point between transmission and distribution systems;

- Any areas of current or future congestion on the transmission network;
- Generation dispatch scenarios;
- Historical fuel use for electricity generation and an assessment of fuel availability to support future electricity production;
- Estimated greenhouse gas emissions associated with electricity supply options;
- Existing and potential future electricity supply options;
- The forecast balance between supply and demand and whether that balance falls within the national guidelines for reliability; and
- The historical and forecast future demand for electricity based on both seasonal peak usage and aggregate energy usage.

The above information is either covered in AEMO's South Australian Supply and Demand Outlook (SASDO) that is published in conjunction with the APR, the Electricity Statement of Opportunities (ESOO), and NTNDP which is published annually in December or in separate reports.

D.2.2 Essential Services Commission of South Australia

The Essential Services Commission of South Australia (ESCOSA) was established under the Essential Services Commission Act 2002 with the objective of "*protection of the long term interests of South Australian consumers with respect to the price, quality and reliability of essential services*". ESCOSA is required to have regard to:

- The promotion of competitive and fair market conduct;
- The prevention of misuse of monopoly or market power;
- The facilitation of entry into relevant markets;
- The promotion of economic efficiency;
- The benefit consumers gain from competition and efficiency;
- The financial viability of regulated industries and the incentive for long term investment; and
- The promotion of consistency in regulation with other jurisdictions[5].

ESCOSA's principal functions and powers in relation to the electricity supply industry include:

- Making determinations for standing contract prices;
- Administering the licensing regime for electricity entities (generation, transmission, distribution, retail and system control);
- Monitoring the performance of licensed entities and promote improvement in standards and conditions of service and supply;
- Formulating and review from time to time the industry codes (such as the ETC);

[5] Essential Services Commission Act 2002 – Part 2 6(a) and (b)

- Enforcing compliance with Licensees' Regulatory obligations, including undertaking enforcement action as appropriate; and
- Providing advice to the SA Energy Minister on matters relating to the economic regulation of regulated industries, including reliability issues and service standards; these functions include setting reliability standards for South Australian transmission system and connection points, as set out in the ETC.

D.2.3 National Electricity Rules

The Rules prescribe a TNSP's obligations with regard to network connection, network planning, network pricing and establishing or making modifications to connection points. In addition, the Rules detail the technical obligations that apply to all Registered Participants.

ElectraNet must plan and operate its transmission network in accordance with the mandated reliability and security standards set out in the Rules.

Schedule S5.1.2.1, 'Credible contingency events', of the Rules sets out the following mandatory requirements on TNSPs:

"Network Service Providers must plan, maintain and operate their transmission and distribution networks to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service and may be required by a Registered Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called "credible contingency events")."

In practical terms, this obligation requires the non-radial portions of the power system to be planned with a system normal network (N) being able to withstand a single credible contingency (N-1) without compromising the integrity of the network.

Chapter 4 of the Rules outlines system security requirements. That chapter requires that even during planned outages, the transmission system must have sufficient redundancy or, if this is not inherent in the network, automatic control systems in place to return the network to a secure operating state following a credible contingency event.

The Rules are available at the following link:

http://www.aemc.gov.au/rules.php

At the time of publication the current version of the Rules was Version 43.

D.3 ElectraNet Planning Framework

D.3.1 Planning Assumptions

Load increase, new loads and new generation connections together with the technical requirements from NER and ETC form the base assumptions needed for transmission planning. Transmission planning criteria measure whether or not, based on a set of assumptions, the network will meet the future demand requirement while maintaining compliance with the NER, the ETC and Good Industry Practice.

The projects together with their proposed commissioning date indicated in this document are based on the assumptions described in the subsection below. Any change in the assumption may result in different development plan.

The assumptions described below are applied to all seven regional and the main grid development plans.

D.3.2 Base Case

The base study case is generated using the current ElectraNet network topology. Any committed projects (as defined in the Glossary) from the 2010 APR are included in their scheduled commissioning year.

The peak loading base case uses the undiversified connection point AMD as this provides the most onerous operating condition possible for assessing network reliability. The average and light loading base cases are studied to assess market benefit.

The future supply – demand balance is based on the NTNDP scenario 3: Decentralised World, Medium Carbon Price forecast which provides the new power plant commissioning and forecast power plant retirement schedule to be studied.

D.3.3 Existing Wind Farms

The regional development plan studies assume that at peak load conditions within the region the local wind farms are at zero output, but the remainder of the wind farms on the power system generate at 3% of their installed capacity. The Main Grid study assumes that all wind farms generate 3% of their installed capacity.

This assumption matches the NTNDP scenario 3 study assumption.

D.3.4 Load Growth Rate Scenarios

The regional development plan studies are based on the medium growth rate load forecast provided by ETSA Utilities and other direct connect transmission customers. All dates that occur in the body of the report refer to this medium forecast. Sensitivity analysis using the ETSA Utilities high and low load forecasts and other NTNDP scenarios has been undertaken to determine the impact that different load growth may make to the capital works programme.

The SA medium load growth rate forecast provided by ETSA Utilities and the NTNDP scenario 3 forecast; are based on the same economic development pattern. However; the forecasts obtained use different approaches. ETSA Utilities uses the “bottom up” approach that focuses on the individual connection point load forecasts while the NTNDP uses the “top-down” approach and focuses on the NEM and SA state economic growth patterns and simultaneous state-wide peak demand. The same principal applies to the high and low load growth rate scenarios which are based on identical economic development patterns.

D.3.5 Planning Criteria

The transmission system planning study requires detailed analysis of the steady state and dynamic interactions of the generation and transmission systems. The system augmentation options that are developed must satisfy all aspects of the planning criteria.

Transmission system augmentation options are assessed against viable non-network options proposed by other NEM participants or interested parties that can equally meet the planning criteria, and Rules and ETC requirements before any investment decision is taken.

D.3.6 Technical Criteria

Overhead Line Ratings

For the long term development planning purposes, under peak loading condition, the line static summer rating is chosen to be the limitation for system normal and contingency condition.

The spring/autumn static rating is chosen to be the limitation for system normal and contingency under average loading condition; while the static winter rating is chosen for light loading condition.

Dynamic line ratings are not considered for the planning purposes but mainly for the operational reserve margin and project timing optimisation purposes.

Transformer Ratings

For this development plan study purposes, the following criteria are adopted:

- The normal cyclic rating is used to determine the maximum allowable loading under system normal and on an ETC Category 1 substation.
- The emergency cyclic rating is used to determine the maximum allowable loading under contingencies and on an ETC Category 2 or higher, substation or on a group of meshed substations.

Cable Ratings

Continuous cyclic rating implies that the cable can be loaded to that rating on a daily basis provided the load curve is of cyclic nature and provides sufficient cooling period for the cable over a set period of time. The emergency cyclic rating is similar to the continuous cyclic rating, except that the cable can only be loaded to this level for a maximum of three consecutive days. The emergency rating is an eight hour cable rating.

Managing Fault Levels

For safety reasons, transmission system fault levels should not encroach on the fault rating of the bus or any equipment in that part of the system at any time for any plausible network configuration. It is also important that the fault level at a substation does not exceed the fault rating of the earth grid to prevent excessive earth potential rise.

In some situations, ElectraNet installs neutral earthing resistors or reactors on connection point transformers to limit unbalanced phase to ground fault currents.

A table listing the 5 year maximum substation fault levels and circuit breaker ratings for the present network is provided in Appendix C of this report.

Stability Criteria

The following stability criteria are applied to ensure stable power system performance during and immediately after a system disturbance and before equilibrium conditions are achieved.

Following the application of a single credible contingency (as defined in NER S5.1a.3):

- The transmission system will remain in synchronism (transient stability);
- Damping of the system oscillations will be adequate (small signal stability);
- Network voltage criteria will be satisfied (voltage stability); and
- System frequency will remain within defined operating limits (frequency stability).

When one of these stability criteria is forecast to be violated, some form of planning action is initiated – either system augmentation works, load management measures, control schemes (e.g. under-frequency, under-voltage load shedding, revised constraint equations or other power flow limiting strategies) or plant control system modifications.

For lines at any voltage above 66 kV which are not adequately protected by an overhead earth wire (OHEW) and/or lines with footing resistances in excess of 10 Ohms, the credible contingency may be extended to include a single circuit three-phase solid fault to cover the increased risk of such a fault occurring.

Shunt Reactive Devices Switching

The size of shunt capacitor and reactor banks is limited by the voltage change caused by switching a bank. As a first approximation the per unit voltage change can be determined by dividing the capacitor bank size (Mvar) by the three phase fault level in MVA.

This voltage change when switching shunt devices should not exceed:

- three percent (3%) with the system healthy or
- five percent (5%) under contingency conditions.

Voltage Limits

For steady state studies, the following voltage levels are to be maintained:

- Maximum Voltages under system normal: 1.05 p.u.(5% above nominal level)
- Minimum Voltages under system normal: 0.95 p.u.(5% below nominal level)
- Maximum Voltages under N-1 contingency: 1.10 p.u.(10% above nominal level)

- Minimum Voltages under N-1 contingency: 0.90 p.u. (10% below nominal level)

Frequency Limits

The role of the TNSP in maintaining system frequency is limited to including in customer connection agreements the requirement for under-frequency load shedding facilities to provide the mechanism for effective and efficient load shedding as required by the Rules. This requirement is for 60% of any Market Customer load greater than 10 MW to be available for automatic load shedding.

The frequency standards for operation of the transmission network in South Australia are in accordance with the Australian Energy Market Commission (AEMC) Reliability Panel requirements.

Harmonic Distortion

The transmission system is planned to ensure that the harmonic voltage distortion to any connection point is limited to the levels defined in AS 61000-2001 Part 3.6 and as set down in the Rules and connection agreements. The levels exclude voltage harmonic distortion produced for a few seconds by events such as switching and fault clearing. The aim of limits is to restrict additional losses, interference and damage to plant and other customer facilities.

At non-integral harmonic frequencies, the inter-harmonic voltage attributable to the transmission network or a market participant will be limited so that it does not exceed 0.15% of the voltage at the fundamental frequency.

Voltage Flicker

The transmission system is planned so that the power-frequency voltage fluctuations that occur on the system as a result of load variations are less than the limits set down within Australian Standard AS 61000 Part 3.7 and as specified within the Rules (refer to Table D.1) This typically relates to the switching of reactive plant, the effect of which is limited to3% on High Voltage busses (132 kV and above) and 4% on Medium Voltage busses (where switching occurs less than once per hour).

Table D.1: Emission limits for voltage changes as a function of the number of changes

r/hour	∆Udyn/UN (%)	
	MV	HV
r≤1	4	3
1<r≤10	3	2.5
10<r≤100	2	1.5
100<r≤1000	1.25	1

Voltage Unbalance

The transmission system is planned and designed in such a manner as to balance the phases of the system in order to achieve the levels of negative sequence voltage (for a 30 minute average) as defined below:

Table D.2: Allowable voltage unbalance

MW	Maximum negative sequence voltage (% of nominal voltage)			
	No contingency event	Credible contingency event	General	Once per hour
	30 minute average	30 minute average	10 minute average	1 minute average
More than 100	0.5	0.7	1.0	2.0
More than 10 but not more than 100	1.3	1.3	2.0	2.5

Larger negative sequence voltages may occur for a short period resulting from a fault, single pole interruption, line switching, transformer, shunt capacitor bank or shunt reactor energisation within the power system.

To achieve the total unbalance defined in the table above, it may be necessary to impose lower limits at some locations. However, this would be subject to more detailed analysis for each individual case.

D.3.7 Electricity Transmission Code

ESCOSA is responsible for the ETC which focuses primarily on standards of transmission system supply reliability at individual load connection points. Together with the Rules, these standards provide planning and service obligations that ElectraNet is required to meet.

The ETC assigns reliability standards to each regulated connection point or group of connection points within the transmission network and thereby imposes specific requirements on ElectraNet for planning and developing its transmission network.

The ETC requires ElectraNet to consider non-network solutions and support arrangements as part of its analysis and to compare these to the preferred network solution. Those non-network solutions are defined as:

- Distribution system capability;
- Generating unit capability;
- Load interruptibility; or
- Any combination of those means.

The ETC also includes additional obligations with regard to response times, spares holdings, and reporting requirements.

Some of the relevant clauses for the purpose of preparation of this report are given below:

Clause 2.3.1 of the ETC states that:

> *A transmission entity must plan and develop its transmission system such that each connection point or group of connection points allocated to a category in accordance with clause 2.4 meets the relevant standards for that category as set out in clauses 2.5 to 2.10.*

Clauses 2.1.1 and 2.1.2 of the ETC impose specific additional obligations on ElectraNet in relation to planning, developing and operating the network. Clauses 2.1.1 and 2.1.2 respectively are quoted as follows:

> *A transmission entity must use its best endeavours to plan, develop and operate the transmission network to meet the standards imposed by the National Electricity Rules in relation to the quality of transmission services such that there will be no requirement to shed load to achieve these standards under normal and reasonably foreseeable operating conditions.*

> *A transmission entity must use its best endeavours to plan, develop and operate the transmission system so as to meet the standards imposed by the National Electricity Rules in relation to the transmission network reliability such that there will be minimal requirement to shed load under normal and reasonably foreseeable operating conditions.*

As a consequence, ElectraNet plans its network on the basis that load shedding is not a feasible option to manage N-1 conditions in the meshed transmission network.

The ETC is available at the following link:

http://www.escosa.sa.gov.au/library/080313-ElecricityTransmissionCode-ETC05.2.pdf

At the time of publication the current version of the ETC is ET/05 (V.2).

ESCOSA engaged AEMO to undertake a review of the reliability standards contained in the ETC in the second half of 2010. ESCOSA is consulting publicly on any proposed changes to the ETC during 2011 to ensure that any changes can be taken into account in ElectraNet's 2013-18 regulatory control period.

D.3.8 Extract from ETC Chapter 2

The extract below provides details of the reliability standards that apply to the different connection points with in South Australia. Heading numbers are those that appear in the ETC document itself.

Note: The extract is provided for ease of reference only. For further details please refer to the full ETC which is available at the following link:

http://www.escosa.sa.gov.au/library/080313-ElecricityTransmissionCode-ETC05.2.pdf

2.4 Allocation of connection points to categories

2.4.1 The allocation of exit ***connection points*** to categories is set out in the table below (***connection points*** in square brackets refer to a group of ***connection points***):

CATEGORY NAME	CONNECTION POINT
Category 1	Baroota Dalrymple Florieton SWER Kanmantoo Mine Leigh Creek Coal * Leigh Creek South Mannum/Adelaide 1 * Mannum/Adelaide 2 * Mannum/Adelaide 3 * Middleback* Millbrook * Morgan/Whyalla 1 * Morgan/Whyalla 2 * Morgan/Whyalla 3 * Morgan/Whyalla 4 * Mt Gunson Murray/Hahndorf 1 * Murray/Hahndorf 2 * Murray/Hahndorf 3 * Neuroodla Roseworthy* Stony Point (Whyalla Refiners) - distribution Stony Point* Waterloo- until 31 December 2009 Whyalla LMF Davenport * Pimba * Woomera* Wudinna (until 30 June 2009) ** denotes a customer but does not include a distributor*
Category 2	Ardrossan West Kadina East Wudinna (on and from 1 July 2009) Yadnarie
Category 3	Port Lincoln Snuggery Rural Whyalla Terminal – Main Bus (until 30 June 2010)

CATEGORY NAME	CONNECTION POINT
Category 4	Angas Creek Berri/Monash Blanche Brinkworth [Bungama and Pt Pirie] Clare North Coonalpyn West Dorrien Templers Hummocks Keith Kincraig Mannum Mobilong Mt Barker Mt Gambier North West Bend Playford Snuggery Industrial Tailem Bend Waterloo – from 1 January 2010 Whyalla Terminal – Main Bus (on and from 1 July 2010) Penola West [Dry Creek West, Kilburn, Le Fevre, New Osborne and Torrens Island 66kV] [Happy Valley , Magill and Morphett Vale East] [Para and Parafield Gardens West]
Category 5	[Dry Creek East, Magill and Northfield]
Category 6	Adelaide Central [East Tce, new City West substation]

2.5 Category 1 loads

2.5.1 For transmission line capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than:

(i) 100% of installed transmission line capacity; or

(ii) where the transmission entity has appropriate network support arrangements in place, 120% of installed transmission line capacity;

(b) provide equivalent line capacity for at least 100% of contracted agreed maximum demand;

(c) in the event of an interruption:

(i) use its best endeavours to restore the line capacity required by this clause so as to minimise the duration of the interruption; and

(ii) in any event, restore the equivalent line capacity required by this clause within 2 days of the interruption.

2.5.2 For transformer capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than:

(i) 100% of installed transformer capacity; or

(ii) where the transmission entity has appropriate network support arrangements in place, 120% of installed transformer capacity;

(b) provide equivalent transformer capacity for at least 100% of contracted agreed maximum demand;

(c) in the event of a transformer failure:

(i) use its best endeavours to so as to minimise the duration of the interruption; and

(ii) in any event, restore the equivalent transformer capacity required by this clause within 8 days.

2.6 Category 2 loads

2.6.1 For transmission line capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than:

(i) 100% of installed transmission line capacity; or

(ii) where the transmission entity has appropriate network support arrangements in place, 120% of installed transmission line capacity;

(b) provide equivalent line capacity for at least 100% of contracted agreed maximum demand;

(c) in the event of an interruption:

(i) use its best endeavours to restore the equivalent line capacity required by this clause so as to minimise the duration of the interruption; and

(ii) in any event, restore the equivalent line capacity required by this clause within 2 days of the interruption.

2.6.2 For transformer capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than:

(i) 100% of installed transformer capacity; or

(ii) where the transmission entity has appropriate network support arrangements in place, 120% of installed transformer capacity;

(b) provide N-1 equivalent transformer capacity for at least 100% of agreed maximum demand;

(c) in the event of a transformer failure, use its best endeavours to repair the installed transformer or install a replacement transformer as soon as possible so as to minimise the likelihood of an interruption as a result of the failure of any other transformer installed at the relevant connection point.

2.6.3 In the event that agreed maximum demand at a connection point or group of connection points exceeds the equivalent transformer capacity standard required by this clause 2.6, a transmission entity must:

(a) use its best endeavours to ensure that the equivalent transformer capacity at the connection point or group of connection points meets the required standard within 12 months; and

(b) ensure that the equivalent transformer capacity at the connection point or group of connection points meets the required standard within 3 years.

2.7 Category 3 loads

2.7.1 For transmission line capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than:

(i) 100% of installed transmission line capacity; or

(ii) where the transmission entity has appropriate network support arrangements in place, 120% of installed transmission line capacity;

(b) provide equivalent line capacity such that at least 100% of agreed maximum demand can be met following the failure of any relevant transmission line or network support arrangement;

(c) in the event of an interruption, use its best endeavours to:

(i) within one hour of the interruption, restore equivalent line capacity to meet 100% of agreed maximum demand; and

(ii) restore the equivalent line capacity required by clause 2.7.1(b) within 2 days of the interruption.

2.7.2 For transformer capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than:

(i) 100% of installed transformer capacity; or

(ii) where the transmission entity has appropriate network support arrangements in place, 120% of installed transformer capacity;

(b) provide equivalent transformer capacity such that at least 100% of agreed maximum demand can be met following the failure of any installed transformer or network support arrangement;

(c) in the event of an interruption use its best endeavours to restore the equivalent transformer capacity required by clause 2.7.2(b) within one hour of the interruption;

(d) in the event of a transformer failure, use its best endeavours to repair the installed transformer or install a replacement transformer as soon as possible so as to minimise the likelihood of an interruption as a result of the failure of any other transformer installed at the relevant connection point.

2.7.3 In the event that agreed maximum demand at a connection point or group of connection points exceeds the equivalent line capacity or equivalent transformer capacity standard required by this clause 2.7, a transmission entity must:

(a) use its best endeavours to ensure that the equivalent line capacity or equivalent transformer capacity at the connection point or group of connection points meets the required standard within 12 months; and

(b) ensure that the equivalent line capacity or equivalent transformer capacity at the connection point or group of connection points meets the required standard within 3 years.

2.8 Category 4 loads

2.8.1 For transmission line capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than 100% of installed transmission line capacity;

(b) provide N-1 equivalent line capacity for at least 100% of agreed maximum demand; and

(c) use its best endeavours to restore equivalent line capacity within 12 hours of an interruption.

2.8.2 For transformer capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than 100% of installed transformer capacity;

(b) provide N-1 equivalent transformer capacity for at least 100% of agreed maximum demand; and

(c) in the event of a transformer failure, use its best endeavours to repair the installed transformer or install a replacement transformer as soon as possible so as to minimise the likelihood of an interruption as a result of the failure of any other transformer installed at the relevant connection point.

2.8.3 In the event that agreed maximum demand at a connection point or group of connection points exceeds the equivalent line capacity or equivalent transformer capacity standards required by this clause 2.8, a transmission entity must:

(a) use its best endeavours to ensure that the equivalent line capacity or equivalent transformer capacity at the connection point or group of connection points meets the required standard within 12 months; and

(b) ensure that the equivalent line capacity or equivalent transformer capacity at the connection point or group of connection points meets the required standard within 3 years.

2.9 Category 5 loads

2.9.1 For transmission line capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than 100% of installed transmission line capacity;

(b) provide N-1 equivalent line capacity for at least 100% of agreed maximum demand;

(c) provide N-2 equivalent line capacity for at least X% of Z, where:6

(i) Z = the sum of the agreed maximum demand for all connection points within Category 5 and Category 6;

(ii) X% = Y% + (100% - Y%) / 2;

(iii) Y% = (AMDCBD / Z) x 100; and

(iv) AMDCBD = the agreed maximum demand for Adelaide Central;

(d) use its best endeavours to restore equivalent line capacity within 4 hours of an interruption.

2.9.2 For transformer capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than 100% of installed transformer capacity;

(b) provide N-1 equivalent transformer capacity for at least 100% of agreed maximum demand;

(c) provide N-2 equivalent transformer capacity for at least X% of Z, where the terms X% and Z have the meanings given in clause 2.9.1(c);

(d) in the event of a transformer failure, use its best endeavours to repair the installed transformer or install a replacement transformer as soon as possible so as to minimise the likelihood of an interruption as a result of the failure of any other transformer installed at the relevant connection point.

2.9.3 In the event that agreed maximum demand at a connection point or group of connection points exceeds the equivalent line capacity or equivalent transformer capacity standards required by this clause 2.9, a transmission entity must:

(a) use its best endeavours to ensure that the equivalent line capacity or equivalent transformer capacity at the connection point or group of connection points meets the required standard within 12 months; and

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6 A worked example of the requirements of clause 2.9.1(c) in relation to equivalent line capacity is set out below. This example is provided for information only and does not affect the operation of this industry code – see clause 10.2.1(a).
If the agreed maximum demand for Adelaide Central (Category 6) is 250MW and the agreed maximum demand for Dry Creek East, Magill and Northfield (Category 5) and Category 6 (excluding the Adelaide Central area) is 500MW, then:
Z = 250MW + 500MW = 750MW
Y% = (250/750) x 100 = 33.3%
X% = 33.3% + (100% - 33.3%) / 2 = 66.6%
Therefore, the N-2 equivalent line capacity required in this case would be 66.6% of 750MW = 500MW.

(b) ensure that the equivalent line capacity or equivalent transformer capacity at the connection point or group of connection points meets the required standard within 3 years.

2.10 Category 6 loads

2.10.1 For transmission line capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than 100% of installed transmission line capacity;

(b) until 31 December 2011, provide transmission line capacity for at least 100% of agreed maximum demand;

(c) after 31 December 2011:

(i) provide N-1 transmission line capacity into Adelaide Central for at least 100% of agreed maximum demand; and

(ii) provide the transmission line capacity referred to in clause 2.10.1(c) (i) on a continuous basis by means of independent and diverse transmission substations (which must be commissioned and commercially available), one of which must be located west of King William Street;

(d) use its best endeavours to restore contracted transmission line capacity within 4 hours of an interruption.

2.10.2 For transformer capacity, a transmission entity must:

(a) not contract for an amount of agreed maximum demand greater than 100% of equivalent transformer capacity;

(b) until 31 December 2011, provide equivalent transformer capacity for at least 100% of agreed maximum demand;

(c) after 31 December 2011:

(i) provide N-1 transformer capacity into Adelaide Central for at least 100% of agreed maximum demand;

(ii) provide the transformer capacity referred to in clause 2.10.2(c) (i) on a continuous basis by means of independent and diverse transmission substations (which must be commissioned and commercially available), one of which must be located west of King William Street

(d) in the event of a transformer failure, use its best endeavours to repair the installed transformer or install a replacement transformer as soon as possible so as to minimise the likelihood of an interruption as a result of the failure of any other transformer installed at the relevant connection point.

2.10.3 After 1 January 2012, in the event that agreed maximum demand at a connection point or group of connection points exceeds the line capacity or transformer capacity standards required by this clause 2.10, a transmission entity must:

(a) use its best endeavours to ensure that the line capacity or transformer capacity at the connection point or group of connection points meets the required standard within 12 months; and

(b) ensure that the line capacity or transformer capacity at the connection point or group of connection points meets the required standard within 3 years.