ESIPC

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Electranet Transmission Network Revenue Proposal

Dear Mike,

Please find attached the Planning Council's submission to ElectraNet's revenue proposal for the regulatory control period from 1 July 2008 to 30 June 2013.

The Planning Council is happy to assist the AER in its work. Please feel free to contact me if we can provide any additional information.

Yours sincerely,

David Swift

CHIEF EXECUTIVE

PLANNING COUNCIL SUBMISSION TO THE AUSTRALIAN ENERGY REGULATOR IN RELATION TO THE ELECTRANET REVENUE PROPOSAL

1 SUMMARY

On 31 May 2007, ElectraNet submitted its revenue proposal to the AER. Following a preliminary examination, the AER found that it satisfied the requirements of the AER's Submission Guidelines and the National Electricity Rules (NER). Public consultation commenced and this report is submitted in response to that call for submissions.

In considering ElectraNet's revenue proposal, the Electricity Supply Industry Planning Council (the Planning Council) acknowledges that it has had a series of engagements with ElectraNet leading up to the formal submission that have greatly assisted the Planning Council in forming its view of the capital program proposed by ElectraNet for the next Revenue Reset period.

The following sections contain the detail of the Planning Council's submissions as follows:

Section 2: The Industry Arrangements in South Australia
Outlines some of the South Australian specific arrangements that are relevant to the development of transmission projects.

Section 3: The South Australian Electricity Transmission Code
Describes the reliability-based standards that ElectraNet is required to meet.

Section 4: Demand Forecasts
Sets out the current demand forecasts and the Planning Council's independent role in setting those forecasts for South Australia.

Section 5: Scenario Planning
Discusses the role of scenarios in assessing capital requirements.

Section 6: Planning Council's Assessment of the Proposed Network Development
Describes the analysis undertaken by the Planning Council to identify where network development is likely to be required over the Revenue Reset period.

Section 7: Projects to Address Network Constraints
Discusses some of the key strategic projects in the forward capital program.

Section 8: Contingent Projects
Provides commentary of the proposed contingent projects.

Section 9: Limitations on the Planning Council's Review
Identifies areas that the Planning Council has not assessed.

Section 10:Escalation Provisions

Brief commentary on some of the escalation provisions.

Key Conclusion

However the key conclusion reached by the Planning Council in its assessment of ElectraNet's proposed capital program is that our analysis confirms that the projects proposed by ElectraNet match the emerging network limitations identified by the Planning Council.

The Planning Council is satisfied that the projects, taken together, constitute a reasonable development program to meet the emerging network limitations over the regulatory period.

2 THE INDUSTRY ARRANGEMENTS IN SOUTH AUSTRALIA

ElectraNet is a privately owned corporation that holds effective ownership of South Australia's main high voltage electricity transmission network and is responsible for its management and development. Its responsibilities in regard to the development of the transmission network include obligations with respect to network planning and investment decision making as well as obligations to provide third party access in accordance with the NER.

The Planning Council is a statutory corporation formed under the Electricity Act as part of the restructuring of the electricity industry in South Australia. The Planning Council operates under the control of a Board which includes three members from different industry sectors, an independent chair and an independent member. The Electricity Act and a Charter set out the functions and obligations of the Planning Council. The Planning Council was established to:

- review the development plans of the private industry participants against the forecast needs of customers;
- provide independent, expert advice to the Government and the Essential Services Commission of South Australia (ESCOSA); and
- fulfill a number of South Australian representative roles in the National Electricity Market.

Specifically in regard to transmission:

- the Planning Council is the nominated Jurisdictional Planning Body under the National Electricity Rules and provides independent oversight of transmission planning in SA in accordance with its role and a derogation to the NER
- the Planning Council is responsible for preparing and publishing the Annual Planning Report (APR) for South Australia.

The Planning Council has a close working relationship with ElectraNet in regard to these roles and ElectraNet provides formal input to the APR through its Annual Planning Review. The Planning Council also liaises with ETSA Utilities and with generators and retailers active in the South Australian market and works to encourage efficient outcomes in the development of the power system. ElectraNet has developed the network development plans in its revenue proposal in consultation with Planning Council.

Under the regulatory regime in South Australia, ElectraNet must meet the obligations in the Electricity Transmission Code. The fulfilment of these obligations underpins the capital investment proposed for system augmentation in ElectraNet's revenue proposal.

3 THE SOUTH AUSTRALIAN ELECTRICITY TRANSMISSION CODE

ElectraNet is licensed by the Essential Services Commission of South Australia to operate the main electricity transmission network in South Australia under Part 3 of the Electricity Act 1996. As a condition of licence, ElectraNet is required to comply with the Electricity Transmission Code which is maintained by ESCOSA under section 28 of the Essential Services Commission Act 2002.

Clause 2.2.2 of the Electricity Transmission Code establishes specific network reliability standards for the ElectraNet transmission system. The clause 2.2.2 reliability standards initially incorporated into the Electricity Transmission Code were equivalent to the actual reliability standards, which prevailed in the 12 months prior to October 1999, and were intended to ensure that transmission customers would not experience a reduction in reliability performance as a result of the long-term lease of the transmission assets.

The service standards established by the Electricity Transmission Code underpin any reliability augmentation assessment under the National Electricity Rules regulatory test. Therefore, connection point reliability standards specified in the Electricity Transmission Code will have a direct impact on the revenue requirements for ElectraNet.

Clause 2.2.2 of the Electricity Transmission Code allocates each exit point (or in some cases, group of exit points) from the ElectraNet network, connecting either to the ETSA Utilities distribution network or to the supply points of a small number of large direct connect customers, to a defined reliability category. For each category, the Electricity Transmission Code requires ElectraNet to maintain the specified level of reliability and supply restoration standards. ElectraNet must plan, develop and maintain its transmission system such that specified standards are met in relation to each connection point or group of connection points.

Because the reliability categories are fixed, ElectraNet is obliged to ensure that reliability standards are met, regardless of the cost of doing so. While ElectraNet is required to choose the least cost option in providing a reliable transmission network under the Regulatory Test, the application of rigid standards could at times lead to uneconomic investment or, in other cases, prevent investment which is economically warranted.

While it is important to retain the simplicity and certainty of the existing structure, the South Australian arrangements also recognise the need to regularly review the reliability standards to ensure they remain relevant

Review of the Electricity Transmission Code

ESCOSA has reviewed the Electricity Transmission Code and refined the reliability standards set out in section 2.2 prior to the development of ElectraNet's revenue proposal for this upcoming regulatory period. The review was commenced in August 2004 when the Commission requested that the Planning Council review the transmission connection point reliability standards and to consider:

- how connection point reliability should be established? ;
- the appropriateness of the existing connection point standards? ;
- whether the reliability standards for any connection point should be improved as a result of changes in load, demographics and/or network developments?; and
- the indicative capital cost to meet any changes to the existing reliability standards.

The Planning Council reported to ESCOSA on these matters in October 2005. ESCOSA prepared a Discussion Paper seeking comment on the Planning Council's findings early in 2006. They subsequently released a draft decision on the transmission connection point reliability standards and sought public comments in June 2006. ESCOSA came to a final decision after taking into consideration the submissions received.

ESCOSA prepared amendments to the Electricity Transmission Code in accordance with their final decision. These amendments will come into effect on 1 July 2008 and will therefore apply to the next regulatory period.

Electricity Transmission Code Reliability Standard requirements

There are 5 categories of reliability within clause 2.2.2 of the Electricity Transmission Code, and individual transmission connection points, or groups of connection points, are each assigned to a category. These reliability standards, except for Category 1, may be delivered through any means, including transmission network capability, distribution network capability, and demand management or generation alternatives.

As the load growth exceeds these standards, the Electricity Transmission Code requires ElectraNet to augment the relevant connection point and, where necessary, the transmission network. ElectraNet is required by the Electricity Transmission Code to use its best endeavours to correct any breach of the agreed maximum demand (AMD) reliability standards in the Electricity Transmission Code within twelve months and, in any event, no later than three years (often referred to as the “grace period” requirement).

In the case of a new connection point, ElectraNet is required by clause 2.2.2 to seek the approval of the Commission for the applicable reliability standards. Those standards must be developed having regard to a range of factors including size of the load, value of lost load, types and numbers of customers supplied through the connection point, and location.

Generally, high reliability equates to high cost. Therefore, it is normal industry practice to design the transmission network to achieve an appropriate balance between cost and reliability.

Updated Reliability Standards

In undertaking a review of the reliability standards, the approach adopted by the Planning Council involved an economic assessment at each connection point, in which the capital cost of moving to the next highest reliability category has been compared to the value of the resultant increased reliability delivered to that connection point.

Specifically, the assessment process used for each connection point involved:

- calculating, using average outage rates per km of line and typical transformer failure rates, the average number of hours that each connection point would, on average, be without power. This calculation also accounted for the base reliability of the supply points and the relative probabilities of series or parallel supply configurations.
- multiplying the number of outage hours by the connection point demand to establish the energy or load (MWh) that, on average, would be unable to be supplied each year.
- assessing the value of that lost customer load (VCL) as being the number of lost MWh multiplied by the cost that such lost load would cause to customers. In this case the cost per MWh used was $20,000.
- for those connection points with a high VCL, comparing the capital cost of upgrading to a higher reliability standard against the benefits, in reduced VCL, that such an upgrade would provide.

The outcomes of this analysis by the Planning Council and the final decision by the Commission in relation to the new reliability standards can be found on ESCOSA's website.

Summary – Electricity Transmission Code Requirements

The Electricity Transmission Code provides clear reliability requirements for each transmission connection point or group of transmission points, in South Australia. ElectraNet is held responsible to meet those requirements on an ongoing basis. While the reliability standards are clear, they are not arbitrary but rather are regularly reviewed in consultation with stakeholders to ensure they represent appropriate and economically sensible requirements.

The Planning Council supports the reliability standards applicable in South Australia and considers that ElectraNet must be allowed to earn revenue commensurate with them achieving these standards on a "lowest cost" basis.

4 DEMAND FORECASTS

The Planning Council is responsible for preparing and publishing the Annual Planning Report (APR) for South Australia and providing the State's input to the national Statement of Opportunities published by NEMMCO. The Planning Council is responsible for the development of the statewide demand and energy forecasts included in these documents and widely used in the industry.

The Planning Council develops its forecasts in collaboration with ElectraNet and ETSA Utilities and consults with a wide range of stakeholders. The approach adopted though is based on conducting an independent "top down" econometric assessment. Predicting the peak demand in South Australia is very difficult as the summer peak is strongly driven by air-conditioning load and therefore very dependent on the timing and detailed profile of a high temperature event in addition to the peak temperature reached. The Planning Council has used the National Institute for Economic and Industrial Research (NIEIR) to assist in developing its demand and energy forecasts for a number of years. More recently, the Planning Council has sponsored research at the University of South Australia and funded work by Monash University to develop better probabilistic forecasts of the peak demand at various probabilities of exceedance.

The Planning Council's forecasts are published in the APR along with more detailed reports from Monash University. These are all available on the Planning Council's website and have been provided to AER staff and consultants. The Planning Council recognises the importance of sound forecasts for the development of the industry, planning of network development and the maintenance of reliable supply to customers. As a result, considerable resources have been expended in developing the peak demand forecasts and the Planning Council would be pleased to provide any further information in respect of these forecasts.

The primary forecasting work of the Planning Council is focussed on the statewide demand. This is forecast is in effect the diversified maximum of the demand at each connection point and will be less than the sum of the aggregate peak demand of all connection points. The peak demand expected at each individual connection point in South Australia is forecast by ETSA Utilities. These forecasts are examined by the Planning Council and reconciled to the 10% probability of exceedance statewide demand forecasts. These reconciliations have been published annually in the APR and a good correlation has traditionally been achieved. This work was extended this year and is reported below.

Forecast Outcomes

ECONOMIC ASSUMPTIONS

The economic assumptions underpinning South Australia's electricity forecasts were prepared by NIEIR. The Planning Council and other Jurisdictional Planning Bodies use these assumptions as a consistent basis for preparing electricity forecasts for each region of the national market.

The base case forecasts assume South Australian real GSP growth in 2007–08 remains near its recent historic average of 2.4%, before declining in the two subsequent years. GSP growth is projected to rebound strongly in later years. Annual growth is around 1% higher under the high case and 1% lower under the low case. None of the GSP projections explicitly allow for major expansion of the Olympic Dam mine, although the projected growth rates are conditional on continuing strong commodity prices and increased mining activity in the State.

A number of new or expanded mining operations have the potential to significantly change the forward forecasts for both peak demand and energy. However, in view of the uncertainties surrounding both the timing and extent of these projects, the impacts are included in the high case projections only. The base case does assume some ongoing expansion of operations at Olympic Dam, as advised by BHP-Billiton, and the new mine at Prominent Hill.

ENERGY FORECASTS

South Australia has seen strong growth in electricity consumption recently with an increase of 9.1% in sales over the past two years. Growth is expected to moderate from these levels and under the base case total customer sales are forecast to average 1.3% annually over the ten years to 2016–17. Growth under the low case economic assumptions averages 0.5% annually, reflecting the slower GSP and population growth and larger retail price increases associated with this scenario. Considerably stronger average annual growth of 4.1% is forecast under the high growth economic assumptions, reflecting the large load increases associated with the major expansion of the Olympic Dam mine as well as the generally more optimistic economic outlook. Native Energy is forecast to have a slightly lower average growth rate than customer sales, reflecting small rises in Non-Scheduled generation.

Forecast customer sales and Native Energy (GWh
Extract from table 2-11 in the 2007 APR

	CUSTOMER SALES			NATIVE ENERGY		
	ACTUAL/ BASE	HIGH	LOW	ACTUAL/ BASE	HIGH	LOW
2003-04	11,557			12,442		
2004-05	11,698			12,527		
2005-06	12,140			13,037		

	Customer Sales			Native Energy		
	Actual/ Base	High	Low	Actual/ Base	High	Low
2006-07 est	12,783			13,737		
2007-08	12,820	12,933	12,725	13,684	13,806	13,581
2008-09	13,220	13,582	12,972	14,117	14,509	13,848
2009-10	13,364	14,226	13,023	14,264	15,198	13,895
2010-11	13,550	14,802	13,090	14,462	15,818	13,963
2011-12	13,760	15,217	13,187	14,680	16,258	14,060
2012-13	13,954	16,853	13,274	14,886	18,026	14,150

STATEWIDE PEAK DEMAND

South Australia's peak demand forecasts for the 2007 *APR* have been prepared on a Native Demand basis. Native Demand, which represents the load to be met by scheduled generators, wind farms and several small Market Non-Scheduled generators is seen as the best indicator of general demand on the system for planning purposes.

During the 2006/07 summer demand peaked at 2,942 MW on 16 January 2007. While the actual maximum peak demand was slightly less than the 2005–06 peak of 2,953 MW recorded on 20 January 2006 the 2006–07 summer saw seven days where Native Demand exceeded 2,800 MW, including one non-working day. The peak demand experienced on 16 January 2007 was determined to be a 51% probability of exceedance event.

The forecast peak demand at different probabilities of exceedance and for the three economic forecast scenarios is as follows:

Summer peak demand - Native Demand (MW)
From table 2-6 in the 2007 APR

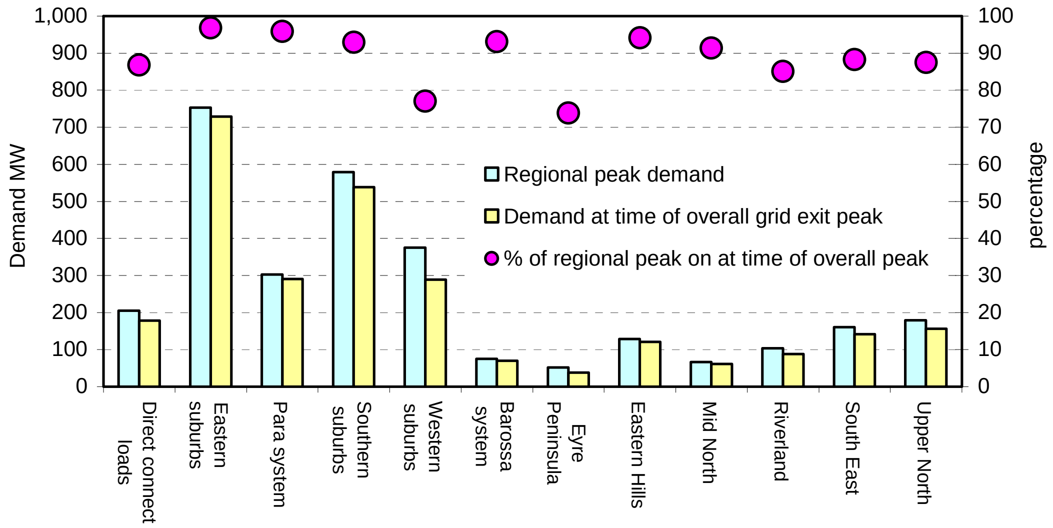
	Actual	Base case forecasts			High case forecasts			Low case forecasts		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2004-05	2,684									
2005-06	2,953									
2006-07	2,942									
2007-08		3,363	3,069	2,821	3,363	3,069	2,821	3,363	3,069	2,821
2008-09		3,473	3,169	2,914	3,544	3,239	2,975	3,434	3,135	2,885
2009-10		3,535	3,225	2,964	3,721	3,398	3,129	3,464	3,162	2,907
2010-11		3,574	3,260	2,996	3,842	3,504	3,224	3,474	3,169	2,918
2011-12		3,644	3,323	3,048	3,991	3,640	3,344	3,496	3,185	2,932
2012-13		3,736	3,408	3,125	4,441	4,077	3,765	3,534	3,222	2,954

CONNECTION POINT DEMAND

The Planning Council endeavours to reconcile its statewide 10% PoE demand forecast with the connection point forecasts developed by ETSA Utilities to ensure that network planning is done on a consistent basis with expected State-wide peak demand levels. The reconciliation process requires adjusting the connection point forecasts to place them on a comparable basis to the State-wide forecasts. This involves scaling up the forecasts to reflect assumed losses and generator house loads, making deductions for new embedded generation and assumed demand management programmes which are included in the State-wide forecasts, and applying a discount to the connection point loads to reflect diversity in the timing of peak demands within different sections of the network.

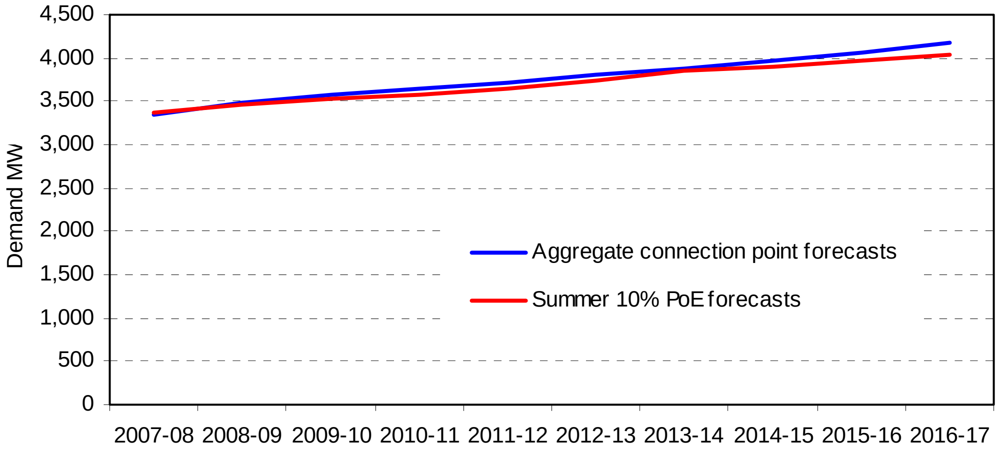
The Planning Council has reviewed the diversity factors used in the past on the basis of experience across the network during the first three quarters of 2006–07. Actual half hourly loads on each connection point were aggregated into regional loads within different areas of the State. The load within each region at the time of the overall grid exit peak was then compared with the peak demand recorded within that region during the nine months to 31 March 2007. The results of this analysis are summarised in the following figure.

Regional demand diversity at time of 2006–07 grid exit peak
Figure 2-11 in the 2007 APR



The results show considerable diversity across regions in the timing of their individual peak demands. The meshed Western suburbs network and loads on the Eyre Peninsula, for example, were at less than 80% of their peak at the time of the overall grid exit peak on 16 February 2007. The difference between regional peaks and loads at the time of the system peak averaged around 10% on a volume weighted basis across the entire network. This discount factor has been applied to forecast connection point loads in reconciling those forecasts with the State-wide 10% PoE forecasts.

Comparison of State-wide and Connection Point demand forecasts
Figure 2-12 in the APR



The above figure compares the adjusted connection point demands with the base case 10% PoE forecasts. The two sets of forecasts show a high level of consistency during the near term, with differences of less than 70 MW or less than 2% during the regulatory control period. These differences are likely to reflect the economic assumptions underlying the State-wide forecasts, in particular the lagged effect of slower GSP growth in 2008–09 and 2009–10 and retail price rises assumed from 2012–13 due to carbon trading. They are considered immaterial within the planning context and the Planning Council therefore supports the connection point forecasts used in their revenue proposal.

The network augmentation projects in the revenue proposal have been premised on using the connection point forecasts which align with the base case economic outlook. The forecast for the low and high case outlook are not symmetrical with respect to the base case with a low case forecast 5% below the base and a high case 25% above at the end of the regulatory control period. This reflects the potential for South Australian demand to grow very strongly as a result of new mining and mineral processing loads. These would be generally seen as significant point loads on the network and would not be expected to be dealt with as part of the general load growth on the network. ElectraNet has made provision for these types of loads occurring in a range of areas across the state as contingent projects. The Planning Council endorses their treatment in this manner.

5 SCENARIO PLANNING

ElectraNet's revenue proposal for capital spending on network investment has been developed on the basis of scenario planning. ElectraNet was assisted in applying the scenario analysis methodology by ROAM Consulting (ROAM). The work examined the potential impact of different development scenarios on the likely need for network augmentation over the regulatory control period. Potential generation development options for South Australia were assessed for three separate 'theme sets' defining the direction of the energy sector in the region. These theme sets addressed looked at scenarios driven by:

- various rates of load growth including consideration of the potential for expanded industrial load of moderate and major size;
- varying trading outcomes between South Australia and the rest of the national electricity market depending on energy policy changes and changes to the relative pricing of energy resources, and;
- varying carbon value, or greenhouse emissions reduction schemes.

The Planning Council participated in the process and contributed to the development of the scenarios. While the Planning Council considers that the scenarios developed and probabilities assigned are not unreasonable, the application of such a process to a potentially wide range of network investment is seen as difficult. The Planning Council has put forward arguments in support of this position to a number of previous consultations on the Rules and the regulatory processes. Our specific concerns in this case are that:

- quantifying the probability of particular scenarios occurring is largely subjective;
- in a dynamic industry environment any subjective assessment could be found considerably off the mark;
- under the NER and South Australian regulatory arrangements, ElectraNet does not have an obligation to invest in augmenting the network as a result of generator investment either in the state or without;
- even if a need to augment the network as a response to a major new load or generator was found to be warranted under the regulatory test, it is impossible to accurately scope and cost that investment without detailed information on the triggering event.

ElectraNet has removed from its revenue proposal any projects which are uncertain in that they would need to be driven by the successful application of the market benefits limb of the regulatory test or by unexpected growth of spot loads. Removing these cases has led the scenario planning to provide a tight band of forecast expenditure across all scenarios. Conversely the approach has left a considerable number of projects to be treated as contingent projects.

The Planning Council strongly supports the approach taken by ElectraNet in this respect. The Planning Council will continue to work with ElectraNet on longer term network planning and planning associated with these potential contingencies as they emerge. We have already undertaken work, for example, on the options and economics for increased interconnection. We recognise though that the assessment of a number of major contingent projects during the regulatory control period may be viewed as a potential burden on the AER and that there will be issues to resolve in some cases to identify genuine additional capital spending arising from the triggering event. As the independent planner in South Australia, we would be pleased to assist the AER with the assessment of any contingent projects that do arise during the regulatory control period.

6 PLANNING COUNCIL'S ASSESSMENT OF THE PROPOSED NETWORK DEVELOPMENT

As outlined above, the ElectraNet revenue proposal only includes capital expenditure on network augmentations required to meet the reliability standards in the South Australian Electricity Transmission Code. The Planning Council has therefore undertaken power system modelling to independently confirm whether all the augmentation projects identified are required to deliver to customers the specified level of reliability. It was further highlighted that the expenditure was very closely aligned on the scenarios presented. As a result, the Planning Council has only analysed outcomes on one forecast case being the base case projections.

ElectraNet's licence requires it to use its best endeavours to correct any potential breach of the reliability standards in the Electricity Transmission Code within twelve months and, in any event, no later than three years. The Planning Council modelling has taken the forecast connection point demand in 2011/12 as an indicator of which investment should be made within the regulatory control period.

The Planning Council established a model of the network as it is expected to exist at the start of the regulatory control period; i.e. 1 July 2008. We then applied to this forecast, loads at each connection point representing the peak demand forecast for 2011/12. We then sought to balance supply and demand on the network both for active and reactive energy.

The active energy required was increased by the modelled losses and was supplied by adding conventional generators located to minimise cost to the shared transmission network. The resulting model included the following additional (notional) generation:

Port Augusta	480 MW
Torrens Island	155 MW
TOTAL	635 MW.

While these locations were specifically applied in the modelling, there are a number of real world opportunities at sites which are electrically in the same area and where generation of a similar size could be connected with similar limited impact on the shared network. It is possible, even likely, that generation is installed at quite different locations over the regulatory control period or that there is an increase in reliance on imports. Any network augmentation required as a result would need to be shown to pass the market benefits limb of the regulatory test before proceeding as a contingent project.

The reactive power requirements of the network in 2011/12 will also need to be met by a combination of the new generators and network investment. For the purposes of this review, the additional reactive required was supplied by new static var capacitors (SVCs). The nominal size required to meet the reactive power requirements in the base case were as follows:

Northern Region	215 MVAR
Para	100 MVAR
South east sub-station	25 MVAR
TOTAL	340 MVAR.

The Planning Council notes that the requirement in the Northern Region is primarily a matter for local mining loads. The remaining amounts have been checked against ElectraNet's revenue proposal and seen to be broadly consistent. ElectraNet proposes significant addition reactive (100 MVAR) at Tungkillo, additional reactive at several sub-station across the network and the new underground cable to the CBD will generate significant reactive meeting the likely requirements. Again requirements would change with different generator locations and characteristics and with new large loads.

The Planning Council undertook a series of loadflow analysis for 2011/12 using PSS/E (the industry standard loadflow analysis program) to identify network limitations on both a system normal and N-1 basis. The work sought to identify all cases where:

- a transmission line was running over its rated capacity;
- a transformer was running over its rated capacity; or
- a sub-station bus was running outside voltage limits.

The outcomes for the case of system normal are summarised in the tables on the following pages.

The tables demonstrate a very close alignment between the constraints identified and the work program proposed by ElectraNet. We acknowledge that ElectraNet has consulted with the Planning Council through the development of the plans and some early concerns have been addressed in the plan now proposed.

The Planning Council has not undertaken detailed modelling to ensure the projects identified actually remove identified problems with the voltage profiles. The impacts of other network developments on voltage profiles some distance away, the potential impacts of lower value projects not individually identified and of work by the customer (usually ETSA Utilities) could assist in many cases. The cost of any additional investment would be minimal given the work identified that the macro reactive balance appears adequate.

CONSTRAINED ELEMENTS IN THE SA TRANSMISSION NETWORK IN 2011/12 - BASE CASE - SYSTEM NORMAL

Transmission Line Over Load (> 100%)					ElectraNet Projects
From	**To**	**kV**	**MVA**	**%**	
Whyalla	Middleback	132	59	159	P8 - Port Lincoln 33kV Cap Banks, Note 1
Middleback	Yadnarie	132	59	125	
Yadnarie	Port Lincoln	132	33	140	
Templers	Dorrien	132	46	104	P4 - Templers 275/132kV Injection, Note 2
Transformer Over Load (> 100%)					
Substation		**kV**	**MVA**	**%**	
Waterloo		132/33	13	139	P18 – Clare North and P16 - Waterloo Rebuild
Kadina East		132/33	28	107	P12 - Kadina East Transformer Reinforcement
Bus Voltage (1.05pu < V < 0.95pu)					
Substation		**kV**	**Vpu**		
Waterloo		33	0.908		P18 – Clare North and P16 - Waterloo Rebuild
Hummocks		33	0.935		P14 - Hummocks Asset Replacement, 132kV Cap Bank

Notes: 1 – use of contracted generation at Port Lincoln will offset overloads

2 – The establishment of the 275 kV section at Templers sub-station and some reconfiguration of the existing lines

LIST OF CONSTRAINED ELEMENTS IN THE SA NETWORK FOR 2011/12 UNDER N-1 CONDITIONS - TRANSMISSION LINES

From	To	kV	MVA	% Load	ElectraNet Projects
Cherry Gardens	Morphett Vale East	275	463	109	P11 - Cherry Gardens-Morphett Vale East 275kV line uprate
Cultana	Whyalla	132	137	106	P2 / P5 - Whyalla terminal rebuild, Cultana 275/132kV Injection
Playford	Whyalla	132	85	136	
Playford	Whyalla	132	91	114	
Robertstown	North West Bend	132	111	168	Note 3
Robertstown	North West Bend	132	144	123	
North West Bend	Monash	132	111	129	
Hummocks	Kadina East	132	33	102	Note 4
Roseworthy	Dorrien	132	46	237	P4 - Templers 275/132kV Injection and Note 2
Templers	Dorrien	132	46	173	
Mobilong	Mannum	132	69	116	P3 - Mount Barker 275/66kV Injection and line upgrades to be completed prior to the regulatory reset period
Mannum	MAP2	132	47	106	
Milbrook Tee	Angas Creek	132	73	121	
Angas Creek	MAP3	132	52	132	
Tailem Bend	Mobilong	132	144	118	P3 - Mount Barker 275/66kV Injection and Note 5

Note: 3. Requirement to undertake work in this respect is dependent on support available from MurrayLink (See Contingent Project No 2 - Riverland Reinforcement)

4 Capacity of the line is well utilised and overload is possible depending upon the detailed modelling assumptions

5 Post contingent loadings on this and other 132 kV lines are in part managed by constraints on interconnector and south-east generation flows

List of Constrained Elements in the SA Network for 2011/12 under N-1 conditions - Transformers

Substation	kV	MVA	% Load	ElectraNet Projects
Cultana	275/132	160	101	P5 - Cultana 275/132kV Injection
Robertstown	275/132	160	116	Note 3
Para	275/132	160	109	P3 - Mount Barker 275/66kV Injection and P4 - Templers 275/132kV Injection
Cherry Gardens	275/132	160	102	P3 - Mount Barker 275/66kV Injection
Para	275/66	120	174	Note 6
Parafield Gardens West	275/66	180	114	
Magill	275/66	225	142	P6 - Southern Suburbs 275/66kV Injection
Happy Valley	275/66	180	125	
Morphett Vale East	275/66	225	169	
Playford	132/33	26.3	139	P20 - 132kV Playford Replacement
Hummocks	132/33	12.6	134	P14 - Hummocks Asset Replacement & Transformer Capacity Increase
Ardrossan West	132/33	13.4	134	P15 - Ardrossan West Asset Replacement & Transformer Capacity Increase
Mt Barker	132/66	71	149	P3 - Mount Barker 275/66kV Injection
Mannum	132/33	20	106	Minor project to add transformer cooling
Keith	132/33	29	104	P19 - Coonalpyn West 132/33kV substation establishment
Kincraig	132/33	27/29	112	P9 - Kincraig 132kV Cap Bank
Mt Gambier	132/33	30	136	P17 - Penola West 132/33kV connection

Note: 6. Electricity Transmission Code requirement is for n-1 on the combined Para and Parafield Gardens West

LIST OF CONSTRAINED ELEMENTS IN THE SA NETWORK FOR 2011/12 UNDER N-1 CONDITIONS - BUS VOLTAGES

Substation	kV	Vpu	ElectraNet Projects
Whyalla	132	0.934	P2 / P5 - WhyallaTerminal Rebuild, Cultana 275/132kV Injection
Middleback	132	0.904	
Iron Duke	132	0.897	
Yadnarie	132	0.922	
Wudinna	132	0.904	P13 / P2 / P5 - Wudinna Transformer Reinforcement , Whyalla Terminal Rebuild
Bungama	132	0.929	P14 - Hummocks Asset Replacement & 132kV Cap Banks
Port Pirie	132	0.925	
Barossa	132	0.924	P4 - Templers 275/132kV Injection
Templers	132	0.926	
Dorrien	132	0.938	
Roseworthy	132	0.843	
Hummocks	132	0.898	P14 / P4 - Hummocks 132kV Cap Banks, Templers 275/132kV Injection
Kadina East	132	0.947	
Ardrossan West	132	0.947	
Dalrymple	132	0.935	
Para	132	0.904	P3 - Mount Barker 275/66kV Injection
Cherry Gardens	132	0.864	
Mt Barker	132	0.861	
Milbrook	132	0.909	
Angas Creek	132	0.942	
Mannum	132	0.946	
Mobilong	132	0.941	
MHP1	132	0.940	
MHP2	132	0.930	
MHP3	132	0.893	
Kanmantoo	132	0.893	
Mt Gambier	132	0.865	Note 7
Blanche	132	0.880	

Note: 7. Follow up work required on voltage issues in these areas. Project P17, Penola West 132/33kV connection will assist by offloading Mt Gambier but further work may be required.

7 PROJECTS TO ADDRESS NETWORK CONSTRAINTS

The aim of the analysis described above was to determine those areas of the network that are likely to require attention over the next regulatory period to ensure that the network continues to meet the requirements of the South Australian Electricity Transmission Code and the National Electricity Rules.

The Planning Council has undertaken a preliminary review of each specific project proposed by ElectraNet to address these deficiencies. A more detailed assessment has been made of a number of the projects that are considered to be strategically important. ElectraNet has responded to issues raised throughout this work and made changes where potential improvements have been identified. The following comments are made to some of the specific projects:

Clare North and Waterloo

The new Clare North substation has the potential, at least in the short term, to completely unload the existing Waterloo substation which currently supplies that area of the mid-North. However, analysis shows that the underlying 33kV network does not have the capability to support the more distant loads from the single Clare North substation past 2012/2013. The Planning Council has pursued the need to rebuild the Waterloo sub-station and the potential for upgrading the underlying 33 kV sub-transmission system as an alternative. The Planning Council has been formally advised by ETSA Utilities that they consider that Waterloo is required as a transmission injection point into the future and that it remains the most cost effective alternative.

CBD Supply

The Planning Council and its consultants PB Power have undertaken a body of work on the major project to supply the Adelaide CBD. The report by PB Power has been separately supplied to the AER and its consultants. The need for the project is unambiguous as it is the subject of a specific requirement in the Electricity Transmission Code. However, the actual design of the project and the capital investment required is the responsibility of ElectraNet. A key determinant of the cost will be the length of cable which needs to be underground to obtain planning permission. An additional cost determinant is the ultimate transfer capability of the cable and the allowance made for the project to be widened in the future.

The establishment of a new 275 kV injection point to the west of the Adelaide CBD opens a range of possibilities for the efficient development of the network into the future. Within the regulatory control period, some of this potential is realised with the southern suburbs injection. The Planning Council notes that this longer term optimisation of the project has not been completed at this stage.

Davenport-Cultana-Whyalla work

A number of projects in the north of the state, namely:

- Project 2 Whyalla terminal rebuild and capacity increase
- Project 5 Cultana 275 kV injection and breakout of the second Davenport to Cultana transmission line
- Project 20 Playford relocation to Davenport

are closely inter-related. The Planning Council has not examined the proposed rebuild works at Davenport and at Whyalla in detail but notes that some services currently supplied at these points will no longer be required when all the work is integrated.

Conclusion

Analysis confirms that the projects proposed by ElectraNet match the emerging network limitations identified by the Planning Council The Planning Council is satisfied that the projects, taken together, constitute a reasonable development program to meet the emerging network limitations over the regulatory period.

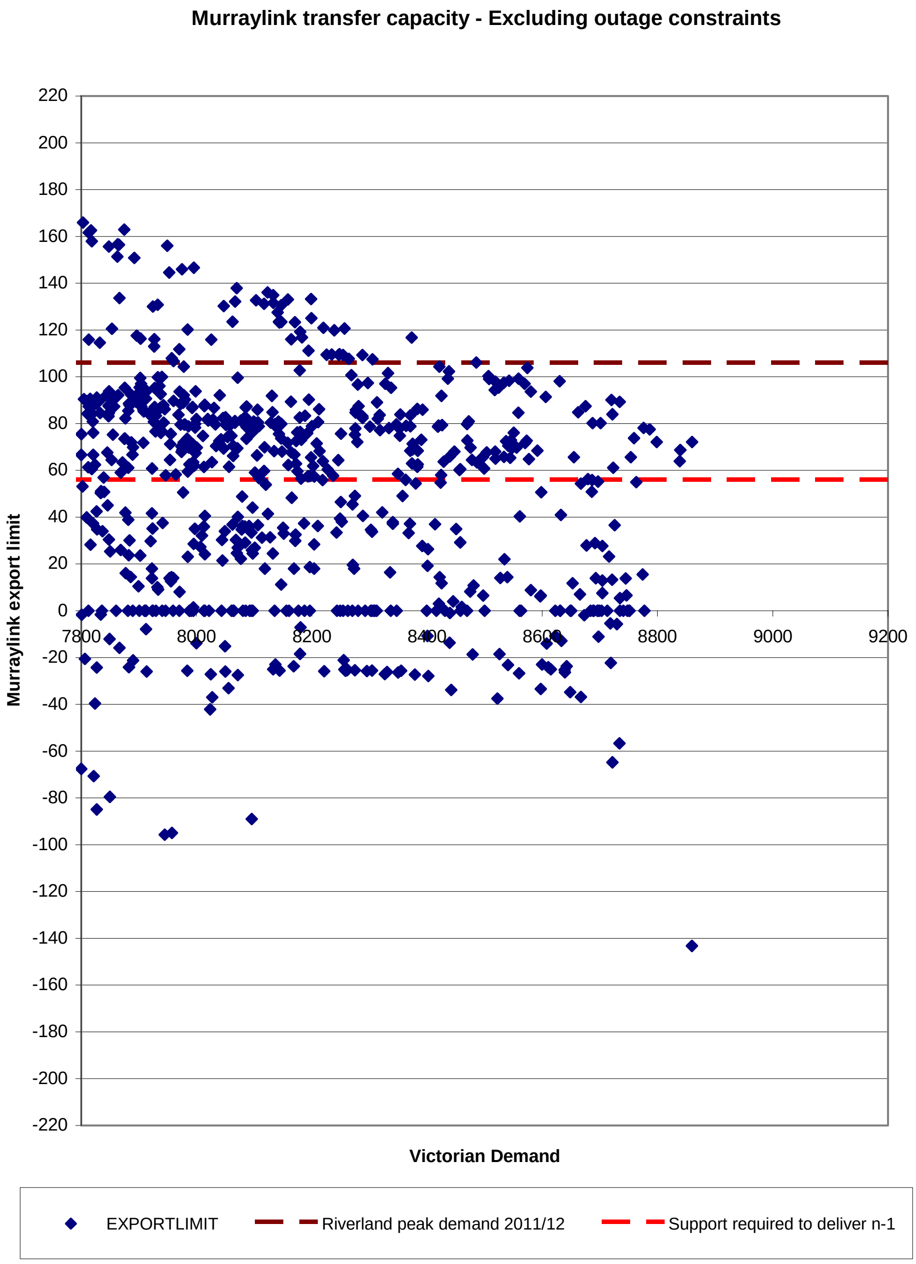
8 CONTINGENT PROJECTS

ElectraNet's submission includes a significant number of contingent projects. The Planning Council assumes that the projects and cost estimates submitted in this category are only intended to represent one of a number of possible solutions and that at the time of the contingency occurring, a more rigorous assessment will be undertaken to determine the precise scope and establish the actual amount to be rolled into the capital program. The Planning Council would be very concerned if this were not the case.

The Planning Council agrees that significant network augmentation would arise from each of the identified trigger events. It does not necessarily agree that the particular projects identified in association with each trigger would be the most efficient response. In fact, it is not possible to determine the most efficient response in many cases as there is no detail available in respect of the actual additional demand or other trigger which may arise. In any event, the Planning Council considers that there is value in undertaking further strategic planning to consider the longer term development options with respect to a number of these areas and is commencing work in collaboration with ElectraNet in these regards. The Planning Council provides the following comments in respect to individual contingent projects.

Riverland

The Planning Council remains concerned about the ability of Murraylink and the north western Victorian network to deliver sufficient support to defer the Riverland Augmentation beyond the next revenue reset period. The Planning Council has undertaken further analysis on the basis of information provided by SPAusNet and examined data from the operation of the NEM. The following graph shows the constraints applied to power transfers across Murraylink during individual dispatch intervals in the last year. Only transfers when the demand in Victoria is high have been shown as relatively high demand can be expected in Victoria when the Riverland is at a peak demand.



Constraints applying under system normal conditions (ie not arising as the result of some other network outage) have been shown. The data suggests that the transfer capacity of Murraylink is often constrained to considerably lower transfer capability levels than that required to support the Riverland at peak demand times if the higher capacity 132 kV line from Robertstown was unavailable.

The Planning Council supports the Riverland Augmentation being listed as a contingent project, but is concerned that the current trigger is not the most appropriate. The Planning Council will also consider the alternative of supporting upgrades to key lines in Victoria to maintain the level of support necessary to defer expensive network development in the Riverland.

Interconnector Upgrades

The Planning Council has completed preliminary work on the potential to upgrade the Heywood interconnector. The report from its consultant, John Thompson Inclusive, has been separately provided to the AER and its consultants. While current analysis does not indicate that any upgrade is likely to provide sufficient market benefits to pass the Regulatory Test, market conditions could change at any time. Large increases in demand in South Australia or investment in low cost generation in Victoria could, for example, trigger such a revaluation. The Planning council therefore supports interconnector upgrades as contingent projects.

Prescribed or Negotiated Services

A regulatory ruling on whether some of the proposed projects should be classified as negotiated or prescribed may result in changes to the capital program. For example, the project cost associated with a possible Penola pulp mill may be seen as a negotiated service while the rebuild of some existing regulated assets, such as the pumping station connection points, may, subject to interpretation, be considered regulated. Where there is some doubt over the definition, the Planning Council supports, subject to the agreement of the AER, the listing of those projects as “Contingent” with one of the triggers being a regulatory ruling as to the whether the project should be considered as part of the prescribed or the negotiated services.

9 LIMITATIONS ON THE PLANNING COUNCIL’S REVIEW

The work of the Planning Council has focussed on only part of the capital investment program in ElectraNet’s revenue proposal. The review has covered the investment in major projects associated with network augmentation to reliably meet future demand. It is important to note that in reviewing the capital program, the Planning Council has not assessed, nor is it in a position to assess, the appropriateness of the quantum of costs associated with each project. The Planning Council understands that the cost estimates used by ElectraNet will be the subject of review by the AER’s consultants.

Additionally, the Planning Council has not undertaken an independent assessment of the condition based replacements proposed by ElectraNet.

10 ESCALATION PROVISIONS

The Planning Council notes that ElectraNet has provided information on the forecast escalation rates that should be applied to its investments and labour costs. The Planning Council is aware that industry costs have increased beyond the rate of CPI and accepts the need to provide such forecasts under the current regulatory arrangements. These forecast are, however, very uncertain. This week has again demonstrated the risks in forecasting economic parameters and particularly exchange rates and sector specific factors.

The Planning Council suggests that the current approach of predicting specific escalators and then converting to a CPI plus equivalent escalator is very risky and could act against the interests of customers and the network service provider. The use of more specific escalators should be considered by the AER as a better approach even if a new capital price index needs to be developed with the assistance of the ABS and industry.