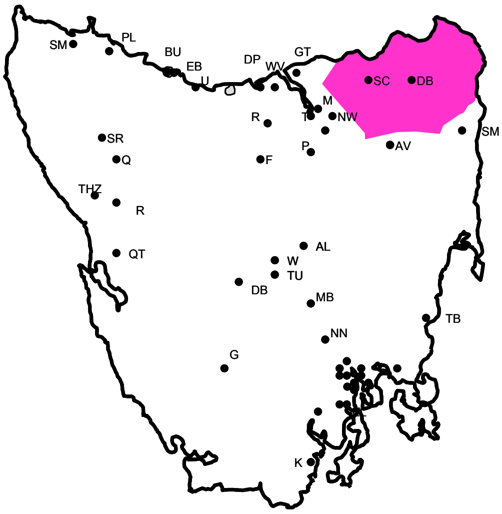
Aurora ENERGY

ABN 85 082 464 622



NORTH EAST

DEVELOPMENT PLAN

REV NO.	DATE	REVISION DESCRIPTION	APPROVALS	
0		Working Draft	Prepared by	
			Reviewed by	
			Approved by	

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1. EXECUTIVE SUMMARY

The North East (NE) covers an area along the north eastern coast of Tasmania with Scottsdale as the major service centre and a number of small communities scattered across the region.

The main industries in the North East are farming, forestry, viticulture and tourism. The area has an urban centre at Scottsdale, high density rural areas in Derby, Winnaleah and Ringarooma and the remaining area is low density rural fed by a number of SWER systems.

To facilitate the current and forecast load, the NE planning area maintains a 22kV distribution network, supplied from Scottsdale and Derby terminal substations. The NE network supplies 6,518 connected customers via 1,124 km of OH and UG 22kV circuit.[1]

The identified or known large constraints are as follows:

•

To address the above constraints the following is being proposed:

•

[1] Data available in NW-#30146137-Feeder Data for Development Plans.

TABLE OF CONTENTS

2. EXISTING SYSTEM

2.1 Substations

The substations supplying this area are listed below.

Note: hyperlinks in the section below will display the power circuit one line diagram from Transend's Operational Diagram System.

Transend owned substations

- Derby (click here to see the 110/22kV single line diagram)
- Scottsdale (110/22kV)

Aurora owned substations

- There are no Aurora owned zone substations in the North East Planning Area.

2.2 Supply Network

Distribution within this planning area is at 22kV, supplied by 110/22kV terminal stations. There are a number of low density rural areas serviced by SWER systems.

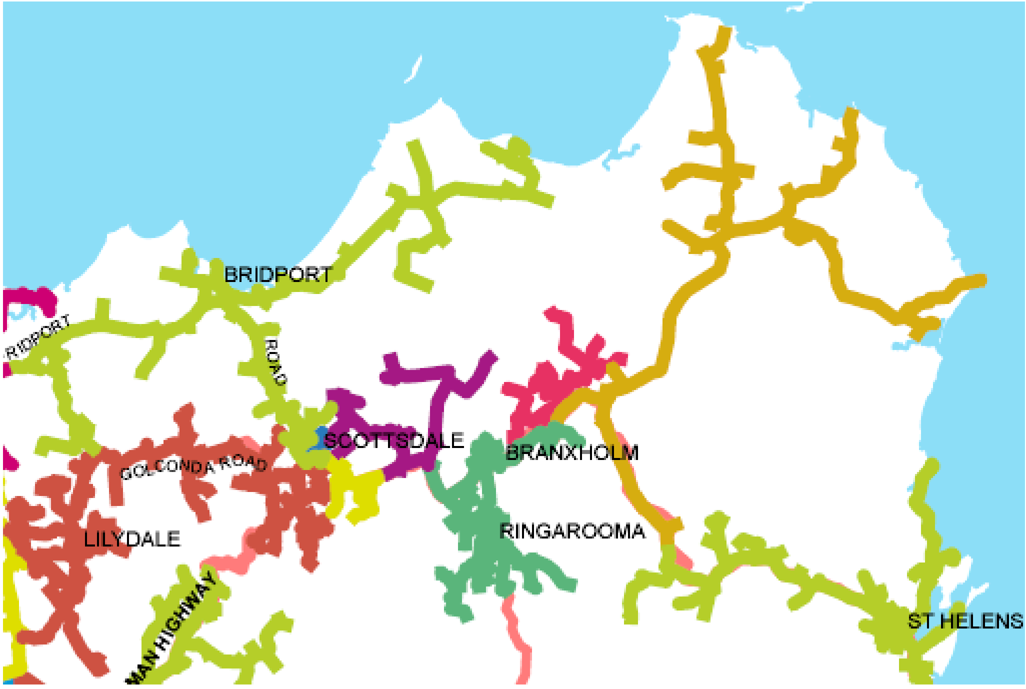
2.3 Network Statistics

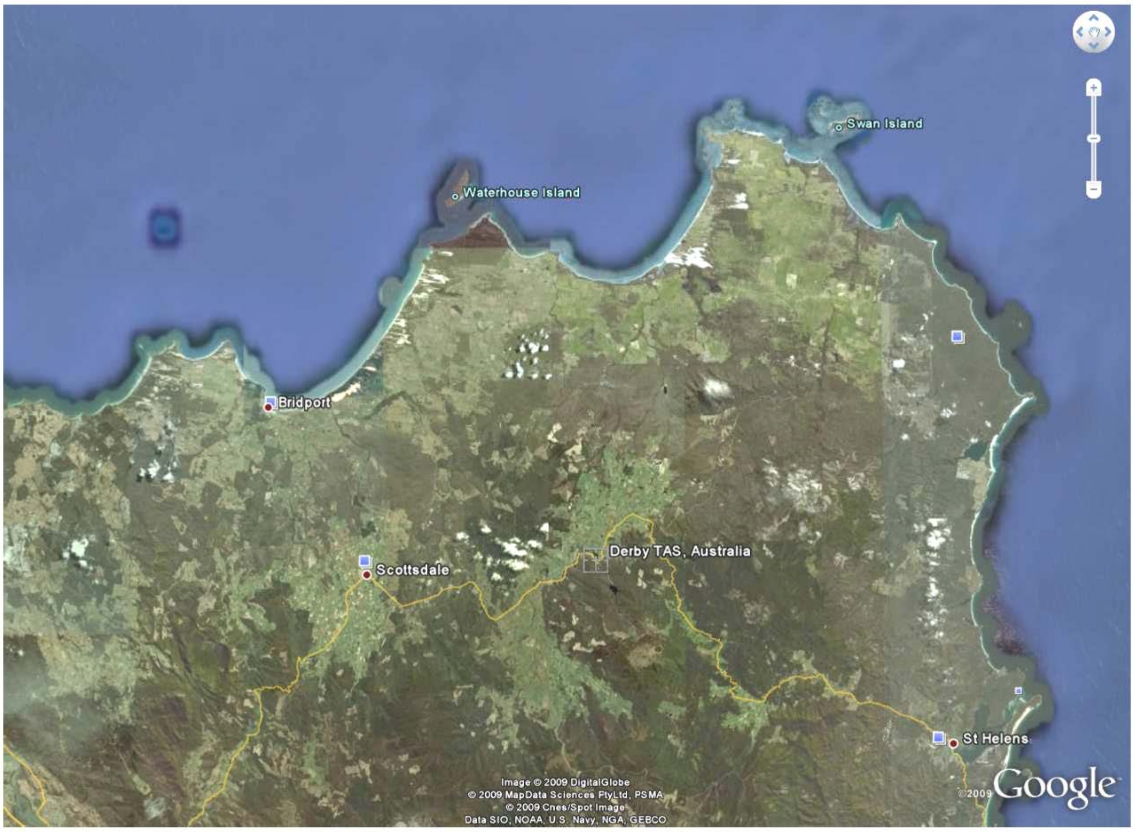
NE area network statistics [2]

22kV circuit length	1,124	km
Connected customers	6,518	
Connected transformer capacity	115,923	kVA
Customer density	5.8	per 22kV circuit km
Transformer capacity density	103	kVA per 22kV circuit km

[2] Data sourced from Gtech, query DISTFDR. See NW-#30146137-Feeder Data for Development Plans.

The maps below show the area referred to as the North East planning area.




Swan Island
Waterhouse Island
Bridport
Scottsdale
Derby TAS, Australia
St Helens
Image © 2009 DigitalGlobe
© 2009 MapData Sciences Pty Ltd, PSMA
© 2009 Cnes/Spot Image
Data SIO, NOAA, U.S. Navy, NGA, GEBCO
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3. LOCAL PLANNING ISSUES

3.1 Long Term System Strategy

NE will continue the development of a radial 22 kV distribution network for the foreseeable future.

In the urban areas, interconnected Low Voltage reticulation will continue to develop at 433V. In rural areas use of low voltage reticulation will be minimised.

Embedded Generation options will be encouraged at the 22 kV and 433V connection points.

Demand Side Management solutions will be encouraged to reduce system peaks and defer large system upgrades where possible.

3.2 Local Government Authorities

For planning purposes, Aurora consults closely with the following local government authorities in the NE planning area:

- Dorset Council.

Other relevant authorities include:

- Department of Infrastructure, Energy and Resources (DIER); and
- Ben Lomond Water.

3.3 Existing Critical Loads

NE planning area has a number of existing critical loads requiring a higher level of supply security or a limit to operational flexibility. Table 1 below details critical loads in the area:

Load Type	Description	Substation(s)	Feeder(s)	Asset Connection Point(s) - if applicable
Commercial / Major Retail				
Medical				

Load Type	Description	Substation(s)	Feeder(s)	Asset Connection Point(s) - if applicable
Rehabilitation Services				
Industrial				
Sewerage Treatment Plants				
Education				

Table 1 –North East Planning Area - Critical Loads

Improvements to supply security for the above connections and supply areas are encouraged.

3.4 Future Developments and Restrictions

- Council planning schemes

The Dorset council has a strategic plan document for 2008-2012. This document outlines corporate objectives, strategies and outcomes including strategies for natural and environmental sustainability, community wellbeing, social and economic development and governance.

3.5 Reliability for the area

The North East Area includes the following Reliability communities:

- Urban – Bridport, Scottsdale
- High Density Rural - Derby – Ringarooma, Scottsdale Rural, Winnaleah
- Low Density Rural - Far North East Rural, North East Rural

Details of actual reliability performance in the 09/10 financial year are available in here. (DM ref# 30061377)

On figures for the 9 months to March 2010 the following communities appear likely to have reliability performance worse than target in 2010:

- Winnaleah (High Density Rural)
- Far North East Rural (Low Density Rural)

The remaining reliability communities in the North East Planning area have shown adequate reliability performance in 2009/10 up to March 2010.

3.6 Asset issues

There are no existing Aurora owned zone substation transformers in the Sorell – Peninsula Area.

Further information is detailed in the following Asset Management Plans relevant to the SP planning area:

NW30084385 - Management Plan 2010: Ground Mounted Substations

NW30070052 - Management Plan 2010: High Voltage Regulators

NW30084411 - Management Plan 2010: Overhead System and Structures

NW30043361 - Management Plan 2010: Underground System

3.7 Links

Only one LAM Area Management Plan is relevant to the North East planning area:

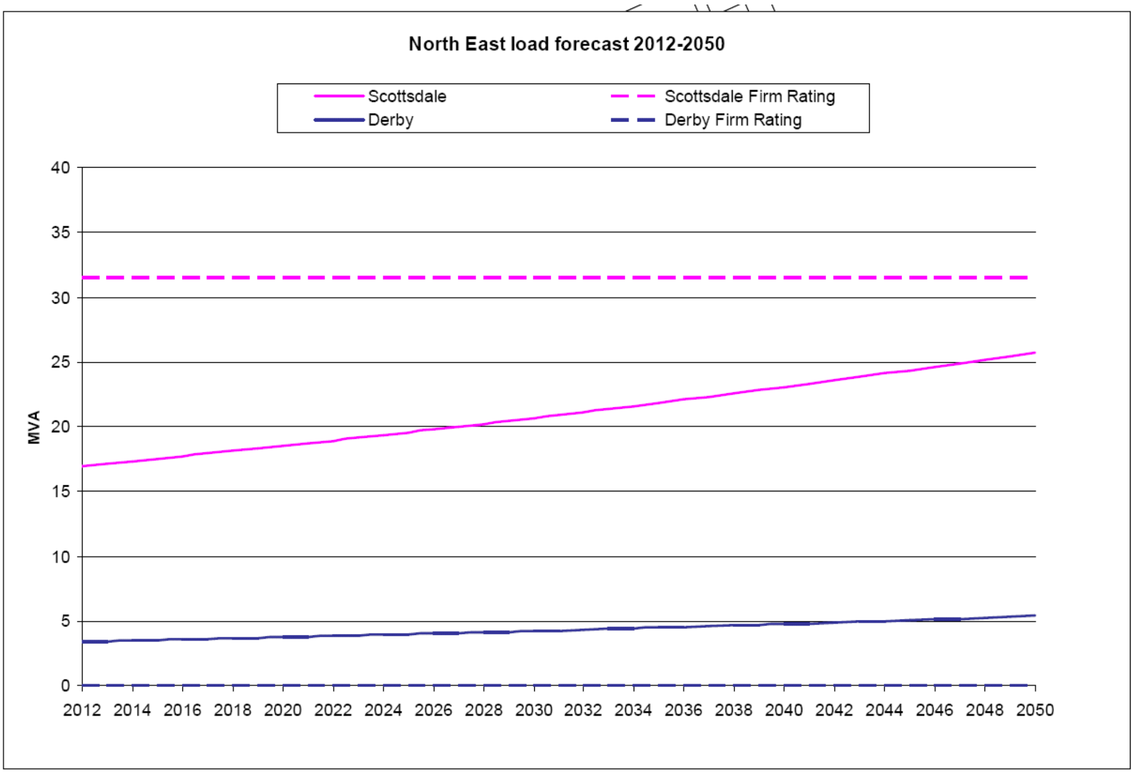
- North – East NW-#215133-Area Management Plan North East

In addition Transend's Annual Planning Report contains relevant information. It can be found on their website www.transend.com.au.

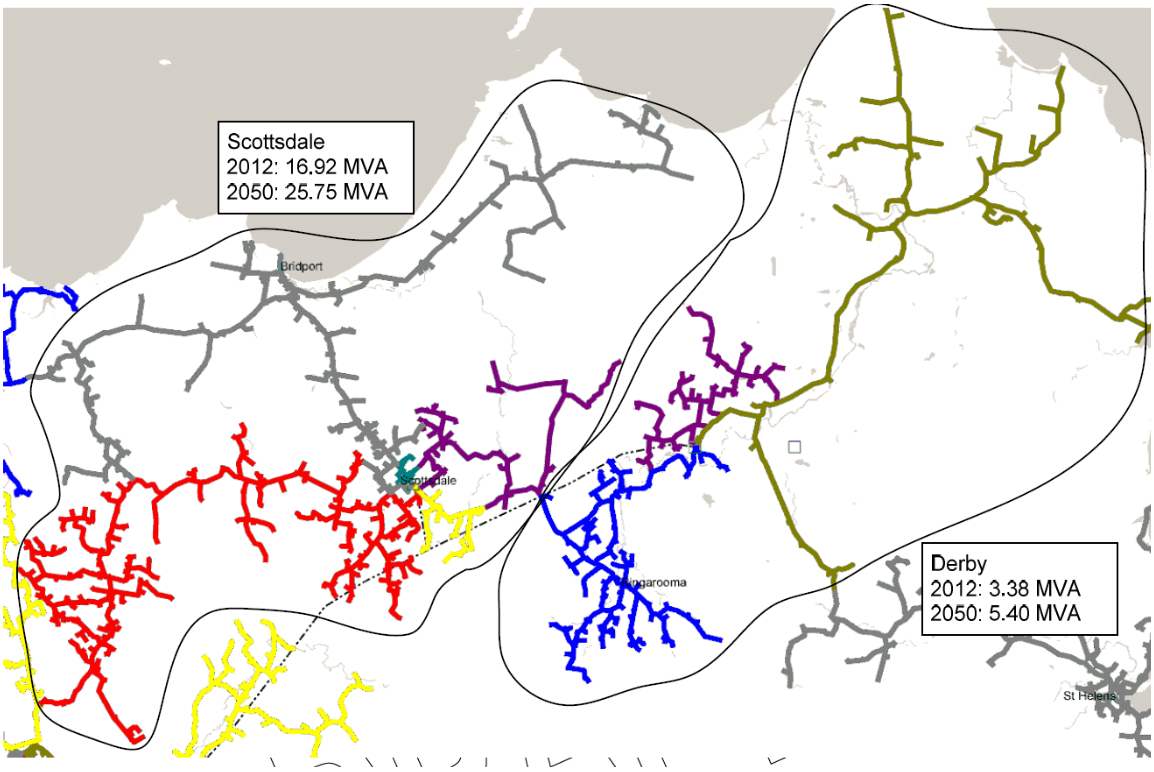
4. LOAD FORECAST

Due to the rural nature of the load in the Scottsdale and Derby supply areas, significant growth above the medium rate is considered unlikely. As a result, for the purposes of the long term strategic study, medium growth has been applied at both Scottsdale and Derby terminal substations

The resulting 38 year load forecast and firm ratings for substations of the East Coast planning area are provided below.



The following figure provides a geographic view of the resulting load distribution in 2012 and 2050.



The 2009 10 year load forecast report by UES is used as the basis for this plan. NW30089965 - Aurora 2009 Maximum Demand & Consumption 10 year Forecast Report

Forecast load growth tables are stored in the spreadsheet NW-#30040697-Zone and Area MD and consumption tables 2009

	Planning Area	Connection Point Substation	Forecast Growth pa
	Northeast	Derby	2.60%
	Northeast	Scottsdale	2.80%

Copy of load profile

4.1 Future committed point loads (> 1 MVA)

- None identified

4.2 Possible point loads (> 1 MVA)

- Major Subdivisions (>200 lots)
  - None identified

4.3 Possible point loads to be removed (> 1 MVA)

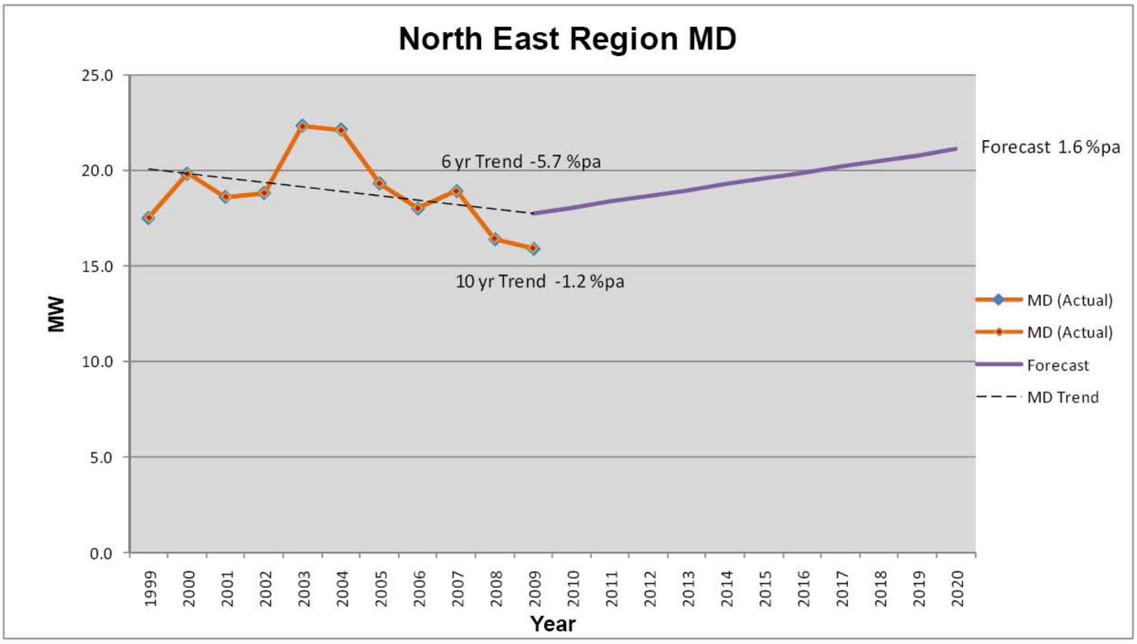
- None identified

4.4 Possible future embedded generation (> 1 MVA)

- None identified

4.5 Analysis of Load Forecast

- Load model hyperlink / reference NW-#30069007-North East area load model (2009)
- Copy of load forecast graph NW-#30083791-(pdf version) Aurora 2009 10year Load forecast - Draft



Modest growth is expected over the next ten years due to commercial and agribusiness growth, particularly irrigation.

5. PLANNING CRITERIA

Aurora's Distribution Network Planning Manual issued in May 1999 is available in DM, ref NW10250570.

More up to date information is included in this document in Appendix B on page 30.

6. CONSTRAINTS (LIMITATIONS)

Constraints in the SP planning area are classified under the following management groups:

Constraint	Description	Definition
Capacity	Substation Firm Capacity	Substation Maximum Demand > Substation Firm Capacity (N-1)
	Feeder Tail Capacity	Feeder Maximum Demand > 5 MVA for 11 kV OR 10 MVA for 22 kV
	Feeder Section Capacity	Load through conductor >conductor continuous rating
	Feeder Tie Capacity	Transfer Capacity limited due to undersized conductor/equipment
Fault Level	Substation Bus Fault Level	Maximum 3-phase fault level > 13.1 kA OR Maximum 1-phase > XX.X kA
	Equipment Rating Fault Level	Maximum 3-phase OR 1-phase fault level > equipment rating
Voltage	Normal load Voltage Drop	Voltage drop exceeds ± 6%
	Emergency load Voltage Drop	Voltage drop exceeds ± 10%
Reliability	SAIDI	Reliability community SAIDI performance has or is likely to exceed target
	SAIFI	Reliability community SAIFI performance has or is likely to exceed target

Table 2 - Constraint Definitions

Constraints are managed at the following levels

- Zone Substation
- Subtransmission Feeder
- Distribution Feeder
- Distribution Substation
- LV Systems

Since the SP planning area does not contain zone substation or subtransmission assets, this document details constraints at Distribution Feeder levels only. Refer to NW-#30141356-Distribution Network Planning Manual DRAFT 2010 for State wide management plans for the Distribution Substation and LV System planning levels.

6.1 Summary of Constraints

6.1.1 Terminal Substation Constraints

Capacity Constraints				
Substation	**Firm Capacity (MVA)**	**Current Load (MVA)**	**Forecast to exceed (year)**	**Comments**
Scottsdale			2033	Aged asset: Firm capacity not exceeded until well beyond 2050. Transformers recommended for replacement in 2033.
Derby			2015	Capacity/Aged Asset: Substation equipped with one transformer only, resulting in no firm capacity. Transformer recommended for replacement in 2015.

Fault Level Constraints			
Substation	**Fault Level Description**	**Forecast replacement (year)**	**Comments**
			None identified

6.1.2 Zone Substation Constraints

The NE planning area does not include any zone substation assets.

6.1.3 Subtransmission Constraints

The NE planning area does not include any subtransmission assets.

6.1.4 Distribution Feeder Constraints

Capacity Constraints				
Substation	**Feeder**	**Capacity constraint type**	**Forecast to exceed (year)**	**Comments**
		Feeder Tail		
		Feeder Section		
		Feeder Tie		

Voltage Constraints			
Substation	**Feeder**	**Forecast to exceed (year)**	**Comments**
			None identified

Reliability Constraints			
Substation	**Feeder**	**Forecast to exceed (year)**	**Comments**
			None identified

6.2 Security

Aurora’s zone substations are typically run in N-1 secure mode. This means that in the event of any single outage of a network element all load can still be supplied.

Since there are no Aurora zone substations in the NE area this level of security is not considered. Transend’s Derby substation has only one transformer, so does not provide N-1 security.

6.3 Transfer and Operational Capability

The table below shows the rating, peak load and transfer capacity. The peak load figures are those forecast for winter 2010. Since Aurora’s substations are subject to winter peaks, these are the most onerous.

	MVA				
Substation	**Rating**	**N-1 Rating**	**Peak Load**	**Transfer Capacity (2010)**	**Transfer Substation**
Scottsdale					
Derby					

The table shows that ….

Details of the analysis carried out on load transfers in the NE area are available in

6.4 Power Factor

- Customer power factor correction
- Network power factor correction

6.5 LV issues

There are no locations in the NE Planning area where widespread LV network issues have been identified.

The table below shows the count of transformers in the planning area and the count of those that are at risk of overloading. This is determined by the count of connected customers indicated a load greater than 130% of nameplate rating. It should be noted that the actual load on a transformer may be much different to its value calculated in this way.

	Total		>130% of rating[3]	
Tx size	**Count**	**Customer Count**	**Count**	**Customer Count**
< 50 kVA	981	1,937	34	242
>= 50 kVA	698	4,502	21	878

7. SHORT TERM PLAN (<5YR)

The North East Area Strategic Plan provides the background to much of the planning information in this document. It can be found at: NW-#30141802-North East area strategic plan Rev_5_2010 final report.

A summary of the proposed works from 2010 to 2015 in the North East planning area is outlined in the following table.

Year	Proposed Project	Proposed Outcomes
2015	Derby second transformer installation	Provides firm capacity at Derby

Details of the constraints, options and possible solutions analysed to arrive at these proposed projects are included in Appendix A on page 23.

8. MEDIUM TERM PLAN (5 TO 10YR)

The North East Area Strategic Plan provides the background to much of the planning information in this document. It can be found at: NW-#30141802-North East area strategic plan Rev_5_2010 final report.

A summary of the proposed works from 2016 to 2020 in the North East planning area is outlined in the following table.

Year	Proposed Project	Proposed Outcomes
2016	Derby transformer replacement	Addresses age limitation on existing transformer

Details of the constraints, options and possible solutions analysed to arrive at these proposed projects are included in Appendix B on page 25.

[3] Data sourced from NW-#30075639-Statewide Distribution Transformers Customer Count Nov 09. Transformer data extracted from Gtech in November 2009.

9. LONG TERM PLAN (10YR+)

The North East Area Strategic Plan provides the background to much of the planning information in this document. It can be found at: NW-#30141802-North East area strategic plan Rev_5_2010 final report.

A summary of the proposed works from 2021 to 2050 in the North East planning area is outlined in the following table.

Year	Proposed Project	Proposed Outcomes
2033	Scottsdale transformer replacement	Addresses age limitations on the existing transformers

Details of the constraints, options and possible solutions analysed to arrive at these proposed projects are included in Appendix C on page 26.

10. PROGRAM OF WORK DRAFT

Project	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Install UG HV - 6 feeder tails New Norfolk Zone		$ 173,000				
(Project BW 006] Install 0.2 km HV UG Huntingtier Rd PID 221007 to Hardwicks Rd Bagdad PID 390836	$ 80,000					
Augment OH HV - 14 Mile Rd, Tarraleah					$ 210,000	
Augment OH HV - Fdr 37002 stage 1 Gretna Zone associated with Zone replacement					$ 411,000	
Augment OH HV - Fdr 37002 stage 2 Gretna Zone associated with Zone replacement					$ 411,000	
Augment OH HV - Fdr 37002 stage 3 Gretna Zone associated with Zone replacement					$ 206,000	
Derwent Bridge - Install 3rd wire Lyell Hwy (generator stability) 2 kms	$ 40,000					
Derwent Bridge - Install permanent connection point generator	$ 25,000					
Install 1 x 6.6/ 22 kV step up stations at todds corner						$ -
Install 19/3.25 AA OH link Hamilton - F45003 2 kms	$ 130,000					
Install OH HV - Auburn Rd to Macquarie Rd						
Install OH HV - Derwent Bridge to Bronte Link					$ 630,000	
Install OH HV - link Meadowbank 45003 to Wayatinah 49412 to Tunagtinah 49305						$ 420,000
Install OH HV - link to Lake Cresent 3 ph (to assist in removal of SWER)				$ 630,000		
Install OH HV - link Victoria Valley SWER to Tungatinah fdr 49303, Dee Lagoon					$ 124,000	
Install OH HV - new Feeder, Elderside						$ -
Install OH HV - Upgrade SWER, Dee Lagoon Link, Victoria Valley Rd				$ 294,000		
Project BW 004 Reinsulate7.6 k & 8 tx Bridgewater F48 190 to 22 kV and supply from Meadowbank TS	$ 300,000					
Project BW 005 Reinsulate 10.0 k &11 tx Bridgewater F 48 190 to 22 kV and supply from Meadowbank TS		$ 352,000				
Project MB 001 - Westerway 38002 OH conversion to 22 kV (10 km OH and 15 tx's)		$ 400,000				
Project MB 002 - Westerway 38002 OH conversion to 22 kV (12 km OH and 22 tx's)			$ 460,000			
Project MB 003 - Westerway 38002 OH conversion to 22 kV (11 km OH and 15 tx's)					$ 360,000	
Tods corner - Convert 6.6 kv line to 22 kv						$ -
Augment pole sub 300 kVA First Avenue New Norfolk	$ 40,000					
Augment pole sub Fairfax Terrace New Norfolk	$ 40,000					
Install new pole sub George Street New Norfolk	$ 40,000					
Install Substation - new or augment pole type 300 kVA				$ 30,000	$ 30,000	$ 30,000
Augment OH LV - overloaded LV ccts Highlands stage 2		$ 14,000				
Augment OH LV - overloaded LV ccts Midlands South stage 2		$ 14,000				
Augment OH LV - overloaded LV ccts Midlands South stage 3		$ 14,000				
Augment OH LV - overloaded LV ccts Midlands South stage 4				$ 14,000		
	$ 695,000	$ 967,000	$ 460,000	$ 968,000	$ 2,382,000	$ 450,000

11. OPERATIONAL PLANS

- Contingency plans (not at operational level)

12. REFERENCE DOCUMENTS

Self explanatory but listed documents for system studies, council plans etc

- Listing of DINIS personal files
- Links to other work documents

13. NOTES

- System development plans identified for the area should link to other plans. Consultation with other work groups, in particular System Performance, Distribution Operations, Area Managers and key external stakeholders e.g. Councils and Government Departments, is essential to ensure optimum outcomes.
- It would be useful to include any details of reference documents and schematic diagrams indicating current substation layout and HV feeder arrangements.

Appendix A. Short Term Plan (<5 years) – Constraints Options and Solutions

A.1 Derby second transformer installation

A.1.1. Constraints

Derby terminal substation supplies high density rural areas in Derby, Winnaleah and Ringarooma and the remaining area is low density rural fed by a number of SWER systems.

Derby substation has one 10 MVA 110-88/22-11 kV transformer which was installed in 1966 and refurbished in 1983. The forecast summer peak load in 2012 is 6.76 MVA and it is expected to grow to 7.66 MVA in 2022. As there is only one transformer, the firm capacity of the substation has been exceeded. The loss of the transformer will interrupt more than 300 MWh of energy, which breaches clause 5.(1)(a)(iv) of the ESI Network Performance Requirements.

There are three distribution feeders which are well within their nominal ratings of 10 MVA. The feeders are long and there is limited transfer capability between feeders. Backup supply for part of the load is available from Scottsdale and St. Mary's.

A.1.2. Options considered

1. Install a second transformer at Derby
2. Upgrade the distribution network to provide backup supply from Scottsdale
3. Install backup generation (non-network solution)
4. Do nothing option

Option 1 – Install a second transformer at Derby

The first option is to install a second transformer at Derby substation in 2015. This will provide firm capacity at the substation and ensure compliance with the ESI Network Performance Requirements.

Option 2 – Upgrade the distribution network to provide backup supply from Scottsdale

The second option is to install a new 22 kV feeder from the Scottsdale substation to a spare breaker at the Derby substation. This will provide backup supply for the loss of the existing transformer or the loss of the single circuit 110 kV line from Scottsdale to Derby.

Option 3 – Install backup generation (non-network solution)

The third option is to install backup generation at the Derby substation. This will provide backup supply for the loss of the existing transformer or the loss of the single circuit 110 kV line from Scottsdale to Derby.

Option 4 – Do nothing option

The do nothing option is not considered a feasible option as the load is above firm capacity at Derby substation.

Technical comparison

Option	Description	Advantages	Disadvantages
1	Install a second transformer at Derby	• Addresses transformer firm capacity limitation at Derby substation • Ensures compliance of ESI Network Performance Requirements for the loss of a transformer • Land available at site for expansion • Consistent with network development plan	• Does not comply with ESI Network Performance Requirements for the loss of the single circuit 110 kV transmission line to Derby
2	Upgrade the distribution network to provide backup supply from Scottsdale	• Ensures compliance of ESI Network Performance Requirements for the loss of a transformer or single circuit 110 kV transmission line • Addresses transformer firm capacity limitation at Derby substation	

Cost comparison

Option	Initial Capital Cost ($M)	Total Capital Cost ($M)	Net Present Value ($M)
1	4.5	6.5	4.6
2	3.2	9.7	4.7

The above cost comparison of options indicates that option 1 provides the lowest cost solution. Details of the NPV analysis are given in appendix B of NW-#30141802-North East area strategic plan Rev_5_2010 final report.

A.1.3. Possible Solution

Based on the technical and cost comparison, option 1 is considered the preferred option to address the forecast limitations.

Therefore it is recommended to install a second transformer at Derby Terminal station in 2015.

Appendix B. Medium Term Plan (5 to 10 years) – Constraints Options and Solutions

B.1 Derby transformer replacement

B.1.1. Constraints

A new transformer will be installed at Derby in 2015 to address the firm capacity limitation at the substation. The existing 10 MVA 110-88/22-11 kV transformer was installed in 1966 and refurbished in 1983. Assuming an asset life of 50 years, it is predicted that the transformer will need replacement in 2016.

B.1.2. Options considered

1. Replace the ageing transformer at Derby substation
2. Non-network option
3. Do nothing option

Option 1– Replace the ageing transformer at Derby substation

The first option is to replace the existing 110/22 kV 10 MVA transformer with a new 110/22 kV 10 MVA transformers in 2016. This will address the age limitation of the existing transformer.

Option 2 – Non-network option

No non-network alternatives have been considered.

Option 3 – Do nothing option

The do nothing option is not considered a feasible option as the Derby transformer has been deemed to be end of life by 2016, and therefore must be removed from service by this time.

B.1.3. Possible Solution

Based on the technical and cost comparison, option 1 is considered the preferred option to address the forecast limitations.

Therefore it is recommended to replace the existing transformer with a 110/22kV 10MVA transformer. The estimated cost of the upgrade is $2 million.

Appendix C. Long Term Plan (>10 years) – Constraints Options and Solutions

C.1 Scottsdale transformer replacement

The transformers at Scottsdale terminal substation were installed in 1983. Assuming an asset life of 50 years, it is predicted that the transformers will need replacement in 2033. If the load trend is closer to the high growth forecast than the medium growth forecast, age replacement will coincide with the terminal substation load reaching firm capacity. The timing can be refined further by completing regular testing on the transformer as it approaches the 50 year mark.

Appendix D. Technical Data

D.1 Substation loading

Gretna			Capacity with all elements in service (N)		Capacity with one element out of service (N-1)		Maxium Demand 2008		Maxium Demand predicted summer 2009		Maximum Demand predicted for winter 2009	
Elements	No	Emergency Rating MVA	Summer MVA	Winter MVA	Summer MVA	Winter MVA	Summer MVA	Winter MVA	Summer MVA	N-1 Load at Risk	Summer MVA	N-1 Load at Risk
Transfomers	2	1	45	45	22.5	22.5			0	0	0	0
Distributed Subtransmission Feeder NNxxx	1	N/a										

Reference master document # 30006462

D.2 Aurora Zone Substation data sheet

None in the North East planning area

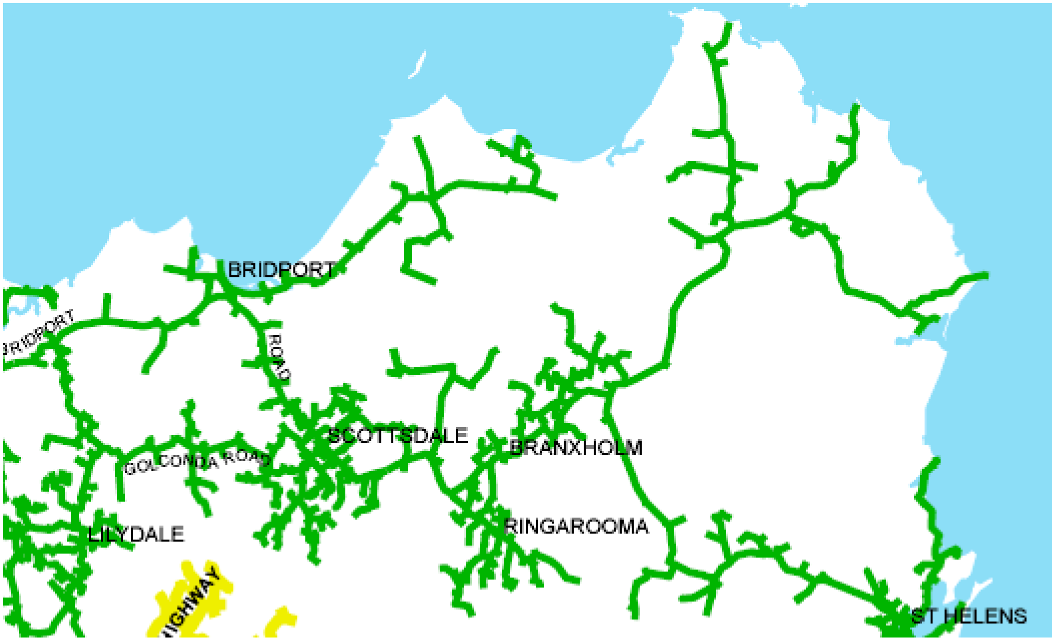
D.3 Transend Station data sheet

Planning Area	Connect Point Substation	Connection Company	Connection Voltage kV	No. Of Connection Points	Type
Northeast	Derby	Transend Netwc	22	3	Distribution
Northeast	Scottsdale	Transend Netwc	22	5	Distribution

Reference master document #30040697

D.4 High Voltage feeder loading

2008/09



Planning Area	Station	Feeder Number	Voltage	Sum of MD (MVA)	Planning Std (MVA)	Load in 5 years (MVA)
Central	Fisher	3 (C252)	11	0.9	5	1.0
		4 (D252)	11	0.0	5	0.1
	Meadowbank	45001	22	1.6	10	1.9
		45002	22	2.1	10	2.4
		45003	22	3.2	10	3.6
	New Norfolk (Terminal)	39563	22	7.5	10	8.3
		39565	22	6.2	10	6.9
		39568	22	2.3	10	2.6
		39569	22	0.1	10	0.2
		39570	22	6.1	10	6.8
		39571	22	3.6	10	4.0
	New Norfolk (Zone)	35010	11	2.9	5	3.2
		35011	11	2.3	5	2.7
		35012	11	2.3	5	2.6
	Tungatinah	T8&T9	22	1.4	10	1.6
	Waddamana	202	22	0.6	10	0.7
	Wayatinah	1	0	0.0	0	0.1
		2	0	0.0	0	0.1
		3	0	0.0	0	0.1

Reference master document #30040697

D.5 Transfer Capacity

- MD transfer capacity with other stations (order of)
-
-
- Brief outline of transmission and subtransmission feeder arrangements, ratings and capabilities

Note it would be useful to include any details of reference documents and schematic diagrams

- HV feeder ratings, current summer and winter loads. MD’s
- Provide high and low load forecasts i.e. +/- 10% of base load as above for each HV feeder for the next 10 years
- Indicate anticipated summer and winter load growths for each of the existing HV feeders in the area including ratings of the feeder.
- As above for major zones
- Reference Transend Annual Planning Report.

-

Appendix E. Planning Criteria and Guidelines

E.1 Transmission Planning Criteria

Transend's planning criteria are fundamentally based on:

- the National Electricity Rules (NER);
- the Electricity Supply Industry (Network Performance Requirements) Regulations 2007; and
- good electricity industry practice

The following criteria are used when planning for the transmission system.

Transmission and transformer loading

- Transmission lines and autotransformer loadings for an intact system or for a contingency (N–1) should not exceed their continuous ratings in planning studies. For supply transformers four-hour emergency ratings can be used to defer augmentations depending on the peak duration of the load duration curve.
- Transmission line loading on circuits covered by NCSPS should not exceed 95 per cent of their rating for an intact system when Basslink is exporting. When Basslink is not in service or importing, standard N–1 criteria applies.

Load interruptions

For an intact system, i.e. where no elements are out of service for maintenance the following should apply as per Network Performance Requirements:

- no credible single contingency event will interrupt more than 25 MW load;
- no single asset failure will interrupt more than 850 MW or, in any event cause a system black;
- the unserved energy to loads interrupted as a result of damage to a network element related to a credible contingency event must not exceed 300 MWh; and
- the unserved energy to loads interrupted as a result of a single asset failure must not exceed 3,000 MWh

Single asset failure that would cause large load interruptions is the loss of a double circuit line, a bus section fault or a bus coupler fault. In calculating unserved energy, the ability to transfer load and the time required for load restoration should be taken into account.

Exposure due to maintenance outage

- Where a network element has been withdrawn from service for maintenance, replacement or repair, the energy exposed to interruption by a credible contingency event must not exceed 18,000 MWh.

In calculating unserved energy, the ability to transfer load should be taken into account.

Maximum repair / replacement time

Minimum Performance Requirements state that for the purpose of calculating unserved energy, any replacements or repairs undertaken, should not exceed the following:

- Transmission line repair – 48 hours
- Transformer replacement – 8 days
- Auto transformer replacement – 18 days

E.2 Distribution Planning Criteria

Key planning standards include: -

System Performance

- Voltage regulation range of + 6% and – 6% of the nominal HV voltage and a LV voltage range of 230/400 V +10% and –2%;
- Power quality standards are recognised in accordance with the TEC, NER and applicable Australian Standards; and
- Tasmanian Reliability Performance Standards

Table Appendix B -1 Tasmanian Reliability Performance Standards

Community category	Frequency standard (Maximum average number of supply interruptions per year)		Duration standard (Maximum total time without electricity in a year measured in minutes)	
	For the category	For each community	For the category	For each community
Critical infrastructure	0.2	0.2	30	30
High density commercial	1	2	60	120
Urban and regional centres	2	4	120	240
Higher density rural	4	6	480	600
Lower density rural	6	8	600	720

Source: Tasmanian Electricity Code

Capacity

Maximum average loading considerations for distribution feeders facilitating HV feeder interconnectivity;

- 22 kV – 10 MVA continuous and 15 MVA (typically one hour) emergency;
- 11 kV - 5 MVA continuous and 7.5 MVA (typically one hour) emergency.

Security of supply

Group firm philosophy or a deterministic planning standard, e.g. “N-1”, dependent on elements of security, load and exposure to risk

Schedule 5.1.2.2 (a) of the NER states:

> *“In the* satisfactory operating state*, the* power system *must be capable of providing the highest reasonably expected requirement for* power transfer *(with appropriate recognition of diversity between individual peak requirements and the necessity to withstand* credible contingency events*) at any time.”*