FINAL REPORT

Prepared For:

Aurora Energy

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Identification of Non-network Initiatives for the 2012-17 EDPR

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1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

Futura Consulting (Futura) was retained by Aurora Energy to provide expert advice on matters relating to the forthcoming EDPR, and to the national framework for network planning and expansion. This report sets out Futura's findings and recommendations in relation to an *identification of non-network initiatives for Aurora's 2012-17 EDPR.*

The scope of work comprised:

- development of a realistically achievable suite of non-network DM and EG programs for inclusion in the business' 2012 to 2017 EDPR; and
- assessment of associated capex and opex requirements for inclusion in the business' 2012 to 2017 EDPR.

1.2. DRIVERS OF PEAK DEMAND

Aurora's network is a winter peaking system, with the winter load profile characterised by a primary and secondary peak. The top 10% or 100 MW of Aurora Energy's network capacity is utilised for just 15 hours over the colder months, or less than 0.5% of the time. The network infrastructure required to serve the top end load represents some $140 million[1] in asset value, but generates only 0.02 % of Aurora's annual revenue requirement.

Traditional network augmentation is a very expensive and sub-optimal strategy for dealing with short duration peaks. Non-network approaches, such as demand-side management (DSM) and distributed generation (DG) options, integrated as part of Aurora Energy's overall network planning process, offer a far more cost effective strategy than continuing to allocate scarce capital to serve short duration peak loads.

The residential sector, and particular uncontrolled water and space heating load, is the main contributor to the winter maximum demand. Uncontrolled loads on the N05 tariff are estimated to account for 29% of the total system peak, while customers on the PAYG tariff contribute 11%. The small to medium business sector is also a major contributor to the peak, accounting for a further 29% to the system peak. The large commercial and industrial sector is estimated to account for approximately 16%.

1 Based on an estimated Regulated Asset Base (RAB) for Aurora Energy of $1.4 billion.

1.3. PROPOSED BROAD BASED NON-NETWORK PROGRAMS AND TRIALS

The AER has stated that the DMIA is a modest sum aimed at assisting DNSPs to engage in non-network solutions, and that the primary source of funding for DSM programs in a regulatory control period should be the forecast operating expenditure (opex) and capital expenditure (capex) approved in the distribution determination. Therefore it is recommended that Aurora Energy include an amount in its opex forecast to cover 'learning-by-doing' activities, and to support broader based trials where the outcomes of demand-side activities may not be known with certainty.

The uncontrolled water heating load is a particularly important end-use that Aurora needs to target. Given the significant quantum of uncontrolled water heating on at peak times and the slow turn over of water heating equipment (at least 15 years) a policy to discourage electric water heating at peak times should be investigated and implemented immediately by Aurora Energy.

Table 1 summarises the proposed broad based programs and trials and forecast budget requirements associated with each of these projects. The total budget for Aurora's broad based programs and trials has been estimated approximately $4.1 million, with opex and capex requirements estimated at $2.55 million and $1.55 million, respectively

Table 1: Proposed Opex/Capex for the 2012-2017 PD for broad based non-network initiatives

Budget Item	Opex $ (m)	Capex $ (m)
Residential and small business load response project	$1.25	$0.75
Residential and small business water heater study	$0.25	n/a
Customer power factor correction program	$0.15	n/a
Energy storage with integrated renewable distributed generation trial	$0.30	$0.70
Institutional partnership trial	$0.25	n/a
Curtailable / DG program with large C&I customers	$0.20	n/a
LED streetlighting trial	$0.15	$0.10
Grand Total	**$2.55**	**$1.55**

1.4. PROPOSED LOCATION-SPECIFIC NON-NETWORK PROJECTS

An assessment of non-network opportunities (demand-side management and distributed generation) was carried out in several Aurora Energy planning areas.

Projects with good prospects for non-network solutions were initially identified by conducting a judgemental screening of all proposed capex projects planned by Aurora Energy for 2012 – 2017 regulatory control period. The following capex projects where identified from the screening analysis as having good potential for deferral by the application of non-network strategies:

- Blackmans Bay Zone Substation;
- Bruny Island Feeders;
- Sandford Zone Substation;
- Wynyard Terminal Substation; and
- Bridgewater 33 kV Injection Point & Austins Ferry Zone Substation

Table 2 provides a summary of the findings in each of the five locations including Aurora's planned augmentation capex, DSM & DG potential available in these locations, years of deferral required to shift the capex into the next PD period, load reduction targets to achieve the necessary deferral period, deferral benefits and budget DSM project implementation costs.

The estimated benefit of deferring the planned capex is $5.8 million, while the cost of implementing the DSM strategy to achieve these deferrals is estimated at $4.7 million.

Table 2: Summary of Estimated Costs and Benefits of Location-Specific DSM Initiatives

Aurora Network Project	Planned Network Augment. Capex $k	Years of Deferral Required to shift capex to next PD	Estimated Available DSM & DG (MVA)	DSM/DG Costs & Benefits		
				DSM/DG Target (MVA)	Deferral Benefit $k	DSM Costs $k (Note 2)
Blackman's Bay ZS	$16,600	2	4.6	2.0	$1,322	$1,060
Bruny Island Feeders (1)	$4,000	5	0.5	0.5	$1,500	$1,055
Sandford ZS	$11,900	2	4.5	1.6	$975	$890
Wynyard TS	$4,400	4	8.3	1.9	$771	$770
Bridgewater 33 kV & Austins Ferry ZS	$15,050	2	6.3	1.7	$1,234	$970
TOTALS	**$51,950**		**24.2**	**7.7**	**$5,802**	**$4,745**

Notes

(1): Benefits at Bruny Island relate to DSM & DG being deployed for contingency support and to reduce load at risk. The target includes the first year target plus an allowance for load growth over the 5 years of the next PD.

(2): Total DSM costs are budget estimates only and include capex and opex related cost items. More detailed business cases are required to refine costs.

1.5. SUMMARY OF FUNDING REQUIREMENTS TO IMPLEMENT PROPOSED NON-NETWORK INITIATIVES

Table 3 summarises the forecast budget requirements associated with the proposed work program of non-network initiatives for the forthcoming 2012 – 2017 PD. The total budget requirement is $8.9 million, with opex and capex requirements estimated at $5.1 million and $3.8 million, respectively. Of this total budget, it is expected that $2 million would be covered by the AER's Demand Management Incentive Allowance (DMIA).

Table 3: Summary of Funding for Non-Network Projects for the 2012 - 2017 PD period

Budget Item	Opex $ (m)	Capex $ (m)
Broad based programs and trials		
Residential and small business load response project	$1.25	$0.75
Residential and small business water heater study	$0.25	n/a
Customer power factor correction program	$0.15	n/a
Energy storage with integrated renewable distributed generation trial	$0.30	$0.70
Institutional partnership trial	$0.25	n/a
Curtailable / DG program with large C&I customers	$0.20	n/a
LED streetlighting trial	$0.15	$0.10
Sub-total – Broad based programs and trials	**$2.55**	**$1.55**
Location-specific non-network programs		
Blackman's Bay ZS	$0.53	$0.53
Bruny Island Feeders	$0.30	$0.75
Sandford ZS	$0.47	$0.42
Wynyard TS	$0.77	n/a
Bridgewater 33 kV & Austins Ferry ZS	$0.45	$0.52
Sub-total – Location-specific non-network programs	**$2.52**	**$2.22**
Grand Total	**$5.07**	**$3.76**

2. INTRODUCTION

Aurora Energy Pty Ltd (Aurora) is a Tasmanian state-owned energy corporation, licensed under the *Electricity Supply Industry Act 1995 (Tas)* (ESI Act) as a provider of electricity distribution and retail services to over 260,000 customers across an area of 68,400 square kilometres on mainland Tasmania. Since May 2005, Aurora has participated in the National Energy Market (NEM) and is, accordingly, subject to the requirements of the National Electricity Law (NEL) and National Electricity Rules (NER).

Aurora, in its capacity as a regulated distribution network service provider (DNSP), is currently operating under the Determination handed down by the Regulator in October 2007. The Determination, which covers the period from 1 January 2008 to 30 June 2012, is administered by The Office of the Tasmanian Economic Regulator (OTTER). A key component of the OTTER's jurisdictional regulation is the review and monitoring of the economic framework that will apply to Aurora.

Responsibility for the regulation of economic aspects of Aurora's provision of electricity distribution services will be moved to the Australian Energy Regulator (AER) for the purposes of making the distribution determination for the next control period. As such, Aurora Energy's electricity distribution pricing review (EDPR) for the period 1 July 2012 to 30 June 2017 will be subject to the requirements of Chapter 6 of the NER. Aurora will also be required to meet the proposed draft rule changes to Chapter 5 of the NER in support of a national framework for network planning and expansion.[2]

2.1. PURPOSE OF THIS REPORT

Background

The operating and capital expenditure objectives for a DNSP are set out in Clauses 6.5.6 and 6.5.7 respectively of the NER.

Clauses 6.5.6(e) and 6.5.7(e) of the NER require that, in determining whether it is satisfied with a DNSP's forecasts of capex and opex, the AER must have regard to the extent to which the DNSP has considered and made provision for non-network alternatives, including demand management (DM) and embedded generation (EG). While these two clauses may not expressly place obligations on the DNSPs to demonstrate that they have had specific regard to demand management alternatives to capex and opex projects, this information is necessary to inform the AER's assessment (and approval) of DNSPs' expenditure forecasts. Compliance with these clauses will require Aurora Energy to put forward details of their consideration of efficient non-network alternatives as part of their regulatory proposal for the 2012 to 2017 control period.

2 AEMC. (2009). Distribution Annual Planning and Reporting Requirements and the Regulatory Investment Test for Distribution Draft Rule Change Request (including draft Rules)

Objective

As specified in Aurora's RFP, the objective is:

> "That Aurora can substantiate the merit of initiatives put forward in its pricing submission and provide justification for the associated costs."

Scope of Work

The scope of work comprises:

- development of a realistically achievable suite of non-network DM and EG programs for inclusion in the business' 2012 to 2017 EDPR; and
- assessment of associated capex and opex requirements for inclusion in the business' 2012 to 2017 EDPR.

2.2. STRUCTURE OF THIS REPORT

The remaining sections of this report are set out as follows.

Section 3 provides a review of the regulatory framework that underpins Aurora Energy's non-network activities;

Section 4 examines the drivers of peak demand on Aurora's distribution network;

Section 5 reviews non-network solutions and activities implemented by other DNSPs in Australia;

Section 6 reviews non-network solutions and initiatives implemented by overseas network businesses with a focus on non-network options aimed at managing winter maximum demands;

Section 7 presents details of proposed broad based non-network programs and trials to be implemented over the 2012-17 EDPR for Aurora Energy's distribution network;

Section 8 provides a detailed assessment of proposed location-specific non-network projects for the 2012-17 EPDR; and

Section 9 provides an overall summary of the funding requirements for inclusion in the 2012-17 EDPR to support the non-network initiatives proposed in Section 7 and 8.

3. REGULATORY FRAMEWORK FOR NON-NETWORK ACTIVITIES

3.1. NEL AND NER

From July 2012, the economic regulation of Aurora will be undertaken by the AER, taking over this role from the state-based jurisdictional regulator, the OTTER. The *AER's* regulatory functions and powers are conferred upon it by the *National Electricity Law* (NEL) and the National Electricity Rules (NER). In undertaking the economic regulation of Aurora Energy, the AER must do so in a manner that will or is likely to contribute to the achievement of section 7 of the NEL:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> *a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *b) the reliability, safety and security of the national electricity system.'*

Further, Clause 5.6.2 of the Rules sets out the procedures to be followed by a DNSP in developing the network and includes the consideration of non-network alternatives to system augmentation.

3.1.1. Capital and Operating Expenditure

The operating and capital expenditure objectives are set out in clauses 6.5.6 and 6.5.7 respectively of the NER. They require a DNSP to 'meet or manage' the expected demand for standard control services.

Forecast Capital Expenditure

Section 6.5.7(a) of the Rules requires that Aurora Energy submit a forecast of capital expenditure to meet the capital expenditure objectives over the relevant regulatory period. These objectives are that Aurora Energy:

> *(1) Meet or manage the expected demand for standard control services over that period;*
>
> *(2) Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
>
> *(3) Maintain the quality, reliability and security of supply of standard control services; and*

(4) Maintain the reliability, safety and security of the distribution system through the supply of standard control services.

Section 6.5.7(c) of the Rules requires the AER to accept Aurora Energy's proposed capital expenditure if it reasonably reflects the following criteria:

1. The efficient costs of achieving the capital expenditure objectives;
2. The costs that a prudent operator in Aurora Energy's circumstances would require to achieve the capital expenditure objectives; and
3. A realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

In deciding whether or not to accept Aurora Energy's proposed capital expenditure the *AER* is must have regard to the capital expenditure factors. Clause 6.5.7 (e) (10) stipulates that one of these factors is the extent Aurora Energy has considered, and made provision for, efficient non-network alternatives.

Forecast Operating Expenditure

Under clause 6.5.6 of the Rules, the AER is required to accept Aurora's forecast operating expenditure if it is satisfied that the forecast operating expenditure for the regulatory control period meets the *operating expenditure criteria*. These criteria are that the forecast operating expenditure reasonably reflects:

1. The efficient costs of achieving the operating expenditure objectives;
2. The costs that a prudent operator in the circumstances of Aurora Energy would require to achieve the operating expenditure objectives; and
3. A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

The *operating expenditure objectives* specified within clause 6.5.6 of the Rules are that Aurora:

1. Meet or manage the expected demand for standard control services over the regulatory control period;
2. Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
3. Maintain the quality, reliability and security of supply of standard control services; and
4. Maintain the reliability, safety and security of the distribution system through the supply of standard control services.

In deciding whether or not the *AER* is satisfied as referred to in paragraph, the *AER* must have regard to a number of factors, including the extent Aurora has considered, and made provision for, efficient non-network alternatives (clause 6.5.6 (e) (10)).

3.2. JURISDICTIONAL

Aurora is required under the Tasmanian Electricity Code (TEC), to produce an annual Distribution System Planning Report (DSPR) to inform network users and other interested parties about expected augmentations to Aurora's distribution network over the next five years. Section 8.3.2 of the TEC requires Aurora to consider feasible options for meeting forecast demand in the DSPR, including opportunities for DM and EG.

4. DRIVERS OF PEAK DEMAND ON AURORA ENERGY'S DISTRIBUTION NETWORK

Section 4 presents an overview of the underlying drivers of peak demand on the Aurora Energy's network, which consequently drives the need for network infrastructure investment.

4.1. TEMPERATURE SENSITIVE COMPONENT OF PEAK DEMAND

Aurora Energy's network is a winter peaking system. A review of Aurora Energy's 10 year forecast indicates that peak demand is expected to grow at an average rate of 1.8% per year, based on a medium growth scenario (50% POE) and 2.1% per annum based on the high growth rate (10% POE)[3].

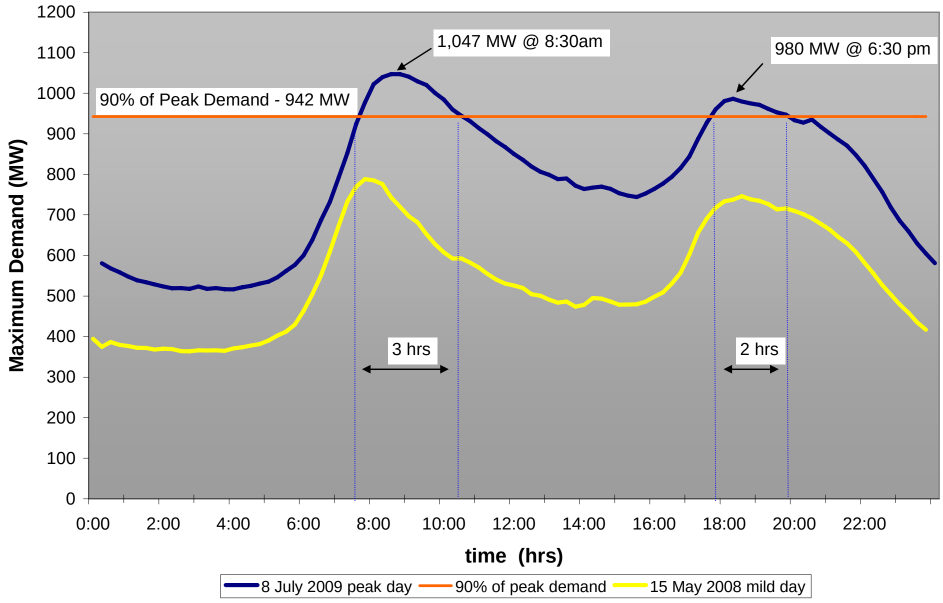
The winter daily load profile is characterised by a primary and secondary peak. The coincident maximum peak demand on the network in 2009 occurred on Wednesday 8 July 2009 at 8:30 am and reached a high of 1,042 MW[4], as rapidly increasing temperature-sensitive load in the residential sector added to the relatively flatter loads of the commercial and industrial (C&I) sector. The minimum overnight temperature recorded at Hobart Airport on this day was 0.5^{o}C, the coldest morning for the year. By 9 am the temperature had reached 2.3^{o}C, but still around 4^{o}C colder than at the same time on the three preceding days. Wednesday's overnight minimum followed three days of maximum temperatures several degrees lower than the monthly mean maximum. A secondary peak of 980 MW occurred at 6:30 pm on the same day.

Figure 1 compares the load profile of the 2009 total Aurora system peak day with a mild autumn weekday (15 May 2008). It shows that at the time of maximum system peak demand, the load on the system was some 250 MW higher than the load of a typical non-heating day. Most of this increase is attributed to temperature-sensitive space heating load in the residential and business sectors.

3 Aurora Energy, 2009 Distribution Network Connection Ten-Year Consumption and Maximum Demand Forecast, December 2009

4 Ibid

Figure 1: Aurora total system peak demand day load profile (Wed 8 July 2009)



The primary peak can also occur in the evening, with the morning peak reverting to the secondary peak. In 2008, Aurora's distribution network coincident maximum demand was 1,073 MW and occurred in the evening at approximately 6:30 pm on Monday 21 July 2008.

4.2. AURORA SYSTEM LOAD DURATION ANALYSIS

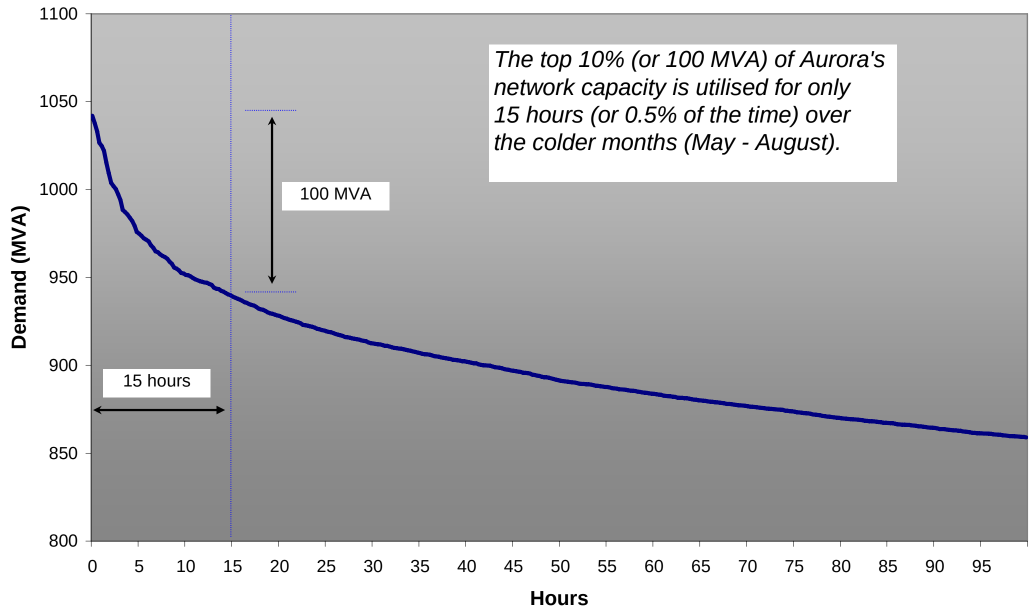
Figure 2 presents the results of a load duration analysis of Aurora Energy's winter load for the 2009 calendar year over the period 1 May – 31 August 2009[5]. The chart shows the highest loads that occurred over that period up to 100 hours. The analysis indicates that the top 10% or 100 MW of Aurora Energy's network capacity was utilised for just 15 hours over the 1 May – 31 August 2009 period, or less than 0.5% of the time. The network infrastructure required to serve the top 100 MW over 15 hours represents some $140 million[6] in asset value. However, the revenue associated with the top-end load is highly un-economic as it generates an estimated 700 MWh of electricity sales volume which equates to just $35,000 per annum of network revenue or 0.02 % of Aurora Energy's annual revenue requirement.

Traditional network augmentation is therefore a very expensive and sub-optimal strategy for dealing with short duration peaks.

5 The load duration curve is based on summing 15 minute load data for the Railton, Bridgewater, Claremont, Burnie, Kingston, Rokeby and Hadspen substations for the period 1 May – 31 August 2008 and scaling the total to the system peak.

6 Based on an estimated Regulated Asset Base (RAB) for Aurora Energy of $1.4 billion.

Figure 2: Aurora Energy estimated total system level load duration (May – August 2008)



Non-network approaches, such as demand-side management (DSM) and distributed generation (DG) options, integrated as part of Aurora Energy's overall network planning process, offer a far more cost effective strategy than continuing to allocate scarce capital to serve short duration peak loads.

4.3. Contribution of Customer and Tariff Classes to Winter Peak Demand

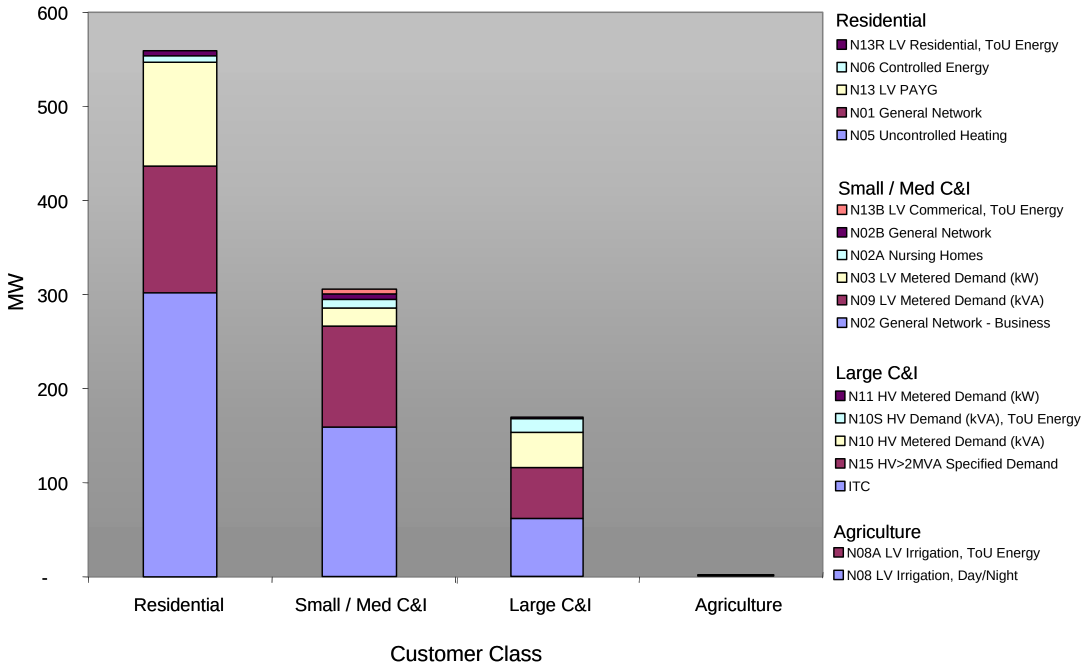
Figure 3 disaggregates the 2009 winter morning system maximum demand of 1,042 MW into the customer and tariff classes that contribute to the peak[7]. The residential sector is estimated to have accounted for 560 MW (or 54%) of the 8:30 am winter system maximum demand[8]. Of this total, space heating and water heating loads supplied on the Uncontrolled Energy N05 tariff are estimated to account for 300 MW (or 29% of total system peak).

General light and power loads supplied by the General Network tariff N01 account for 135 MW (13%) while customers on the PAYG tariff are estimated to contribute 110 MW (11%) to the system peak. The tariff conditions for the PAYG tariff do not place any restrictions on the types of end-uses that can be supplied under the tariff and there will be space heating and water heating loads supplied under the PAYG that are contributing to the peak in addition to space and water heating supplied under N05.

7 Estimates of demand contributions by customer and tariff class are derived from tariff customer counts and tariff energy provided by Aurora Energy.

8 We note that this estimate could include small business water heating loads as LV uncontrolled energy (NO5) tariff permit water heaters in non-residential premises to be connected to this tariff. It has not been possible, given the available data, to dissagregate the demand into residential and business usage.

Figure 3: Customer & tariff class contribution to winter MD (8:30am 8 July 2009)



Small to medium (SME) commercial and industrial (C & I) customers are estimated to contribute about 300 MW (or 29%) to the 8:30 am Aurora system peak, with approximately half of this attributed to customers on the General Network N02 tariff. Given the wide diversity of business types within the SME sector there'll be a diverse range of end-uses contributing to the winter peak. However, end-use loads such as space conditioning and heating, water heating and commercial lighting, will be relatively homogeneous within this sector.

The large C & I customer sector, comprising mainly Individual Tariff Customers (ITC) and customers on high voltage tariffs, is estimated to account for 170 MW (16%) of the winter morning peak. While the large C & I component of the load is likely to be predominantly baseload, demand response can come from any sector to be effective provided it occurs at the have an impact on the system peak. Large C & I customers often have discretionary loads within their operations that can be curtailed or shifted away from the peak for short periods. This demand response capability can be deployed rapidly and cost-effectively. Therefore, although this sector only accounts for a sixth of the morning peak, it should not be overlooked as a potential source of demand management capacity.

The agriculture sector, characterised as customers on the LV Irrigation tariffs (N08 and N08A), is estimated to account for less than 1% of the winter morning peak. This is on the basis that irrigation loads will be predominantly operating during the warmer months, and in any case during the off-peak periods.

4.4. Regional Load Characteristics

Aurora Energy's service territory is segmented into 11 planning areas. These areas are served by 16 zone substations, nine of which are located in the greater Hobart area and another seven in various rural locations. The majority of these assets experience winter maximum demands, while a relatively small number of substations located in the rural areas experience summer peaks.

4.5. Implications of Key Findings for Demand Management Planning

Aurora Energy's demand management efforts will need to focus on exploiting load management opportunities in the following areas:

- uncontrolled energy component of residential hot water load, electric space heating loads and discretionary appliances supplied under both the General Network and PAYG tariffs;
- space conditioning and heating, water heating and commercial lighting in the (SME) commercial and industrial (C & I) sector; and
- curtailable discretionary loads and on-site standby generation resources from the large C & I sector.

In the following sections information is provided on how other utilities, both locally and internationally, have applied demand management to these end-uses to reduce peak demand and a proposed approach for an Aurora Energy demand management strategy for the 2012 – 2017 pricing submission to the AER.

5. REVIEW OF NETWORK ACTIVITIES IN AUSTRALIA

Section 5 outlines the non-network activities undertaken by the DNSPs in New South Wales, South Australia, Queensland, and Victoria along with publicly available data on associated expenditure. A summary of proposed future DM and EG projects and trials, and the forecast budgets for these undertakings is also presented.

5.1. New South Wales

5.1.1. Country Energy

Non-network activities undertaken in the 2004 to 2008 control period

Country Energy (Country) has had little exposure to DM and EG activities, to date. The business' key projects in the area of non-network activities have focussed on air conditioning direct load control (DLC) trials.

Non-network activities proposed for the 2009 to 2014 control period

Country's capital expenditure program for DM focused on extending the business' hot water load control infrastructure, including:

- the expansion of frequency injection load control into areas where this facility does not exist currently;
- the installation of new load control receivers for new residential and commercial/industrial developments and connections; and
- the reinstatement of load control facilities in areas where injection plant and load control receivers are not operating effectively to achieve better demand management.[9]

An explicit amount for the continuation and expansion of the business' load control infrastructure was not provided in Country's EDPR proposal.

Country is also planning the development and implementation of the business' first 'intelligent network community'. The project is to include the deployment of smart meters in conjunction with other intelligent network components such as network sensors, communications infrastructure, IT infrastructure, information systems, and analytics. Country expects the trial will involve over 10,000 customers, testing and demonstrating intelligent network technologies, process and concepts and including network and customer management to provide the first large scale Australian test of an integrated intelligent network.

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9 Country Energy. (2008). *Country Energy's Electricity Network Regulatory Proposal 2009-2014.*

Country nominated that the 'intelligent network' community project be considered a pass-through event[10] by the AER under Clause 6.6.12 of the NER. As such, proposed capex and opex budgets were not provided for the project.

5.1.2. Integral Energy

Non-network activities undertaken in the 2004 to 2008 control period

Integral Energy (Integral) has utilised several 'market approaches' where specialist DM and energy efficiency service providers bid to undertake DM activities in areas of network constraints, and the selected service provider is compensated by Integral on a $ per kVA of reduced peak demand achieved. Technologies and strategies used by Integral to defer supply-side network augmentations in the 2004 to 2008 regulatory control period include:

- power factor correction in commercial and industrial facilities at a cost of approximately $150 per kVA;
- energy efficiency measures in shopping centers and hospitals with a focus on lighting upgrades, HVAC control modifications, cooling tower and chiller upgrades, and car park ventilation fan control optimisation;
- contracts with cogenerators to ensure their units would operate during peaks summer demand periods;
- curtailable arrangements with industrial customers to temporarily shed load during peak periods;
- fuel substitution of gas for electricity in industrial heating processes; and
- temporary installation of a leased generator on the 11 kV feeder system feeding a regional centre that experiences excessive loadings during holiday seasons such as Christmas and Easter.

The Independent Pricing and Regulatory Tribunal of New south Wales (IPART) has conducted three reviews of the DM and EG projects undertaken by the state's DNSPs under the D-factor scheme. Based on information contained in IPART's third review of the D-factor,[11] between 2004/05 and 2006/07 Integral's total expenditure on non-network activities (excluding foregone revenue) was some $1 million on nine demand management programs. This expenditure resulted in deferral approximately $13 million of planned capex and opex for capacity augmentations, with annual peak demand reduction totaling 31 MVA.

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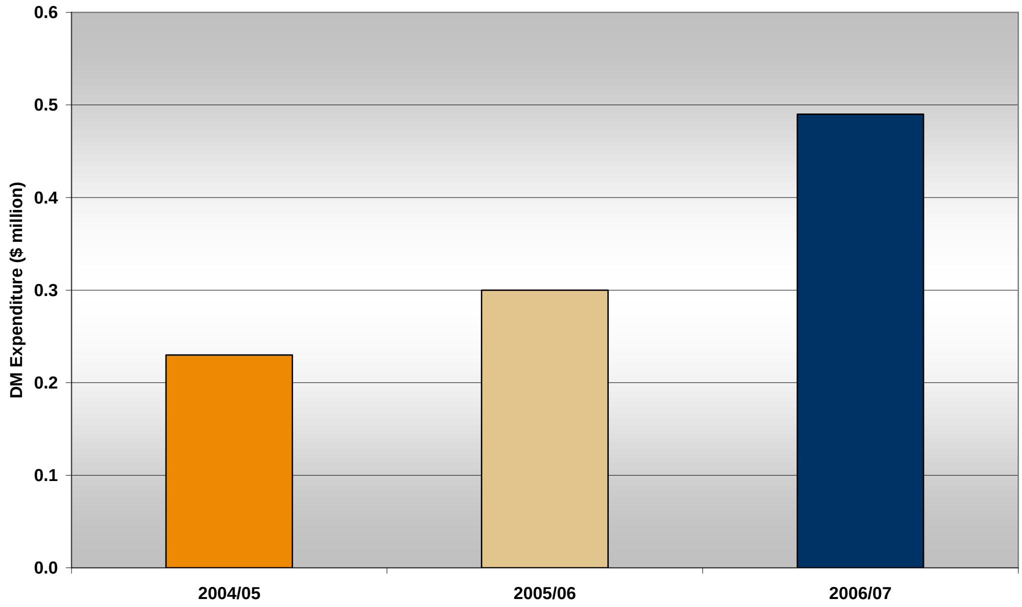
10 Nominated pass-through events are foreseen as a possibility but their timing is uncertain, so the funding for such projects is external to the ARR derived form the DNSPs building blocks.

11 IPART. (2008). *NSW Electricity Information Paper No 3/2008 - Demand Management in the 2004 distribution review: progress to date*.

Figure 4: DM costs and D-factor claims approved by IPART for Integral Energy



IPART's second review of the D-factor scheme12 provided more detail on the types of projects implemented by the NSW DNSPs between 2004/05 and 2005/06. Table 4, which has been reproduced from that report, outlines the projects implemented by Integral, the average implementation cost, and the potential network cost savings associated with each project category.

Table 4: Integral Energy DM projects average costs and savings

Expenditure Category	Number of programs	Average implementation cost ($k)	Avoided distribution cost ($k)
Customer incentives	6	40	1,624
Energy efficiency programs	2	14	1,375
Energy audits	1	93	1,366

Integral has also implemented two significant trials of tariff-based initiatives as a mechanism for managing peaks demands on its network – the Western Sydney pricing trial and the Black Town solar cities (BSC) project. These projects involved the use of advanced metering, critical peak pricing and time-of-use tariffs to, encourage program participants to reduce their household electricity loads summer peak periods on the network. The BSC trials also incorporated DLC of household air conditioners and pool pumps. Energy audits, home energy efficiency packs comprising compact fluorescent lamps (CFLs) and low flow showerheads were provided to customers as a means of introducing the program concepts to customers and engendering participation in the trials.

12 IPART. (2007). *NSW Electricity Information Paper No 2/2007 - Demand Management in the 2004 distribution review: progress to date.*

Non-network activities proposed for the 2009 to 2014 control period

Integral proposes to continue its trial program over the 2009 regulatory control period, and included an operating expenditure allowance of $1.5 million per year ($2008/09) and a capital expenditure allowance of approximately $1.5 million per year ($2008/09) for small scale trials in its EDPR. These included:

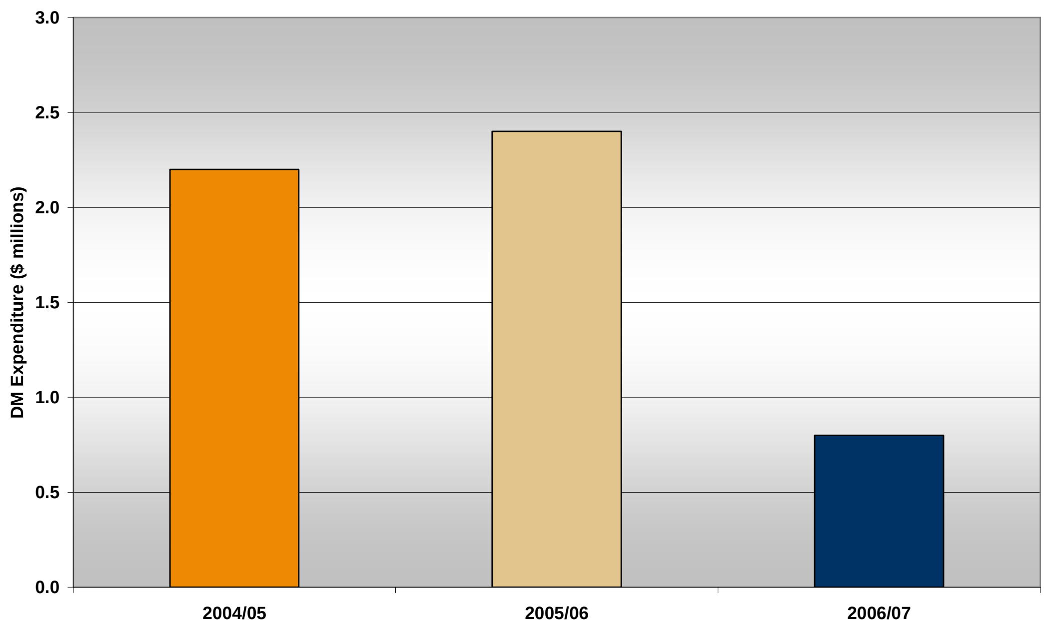
- continuing to undertake further small scale trials of advanced metering (Integral proposed that large trials of significant scale such as an AMI roll-out be treated as a cost pass through event);
- undertaking trials of DSM control equipment such as air-conditioner cycling etc; and
- undertaking further customer response trials such as pricing trials, in home-display trials, home area network integration trials, information provision trials (such as interfacing meters with internet access).

5.1.3. EnergyAustralia

Non-network activities undertaken in the 2004 to 2008 control period

Energy Australia (EA) has been the most active proponent of DSM in New South Wales, to date. According to IPART's third review of the D-factor scheme, EA implemented a total of 17 DSM programs over the period 2004/05 and 2006/07. As illustrated in Figure 5, the total DSM expenditure associated with these programs, exclusive of foregone revenue costs, was some $5 million. EA estimated that the DSM measures implemented by the business delivered a reduction in peak demand of 64MVA in the three years to 2006/07, resulting in avoided distribution costs of some $17 million.

Figure 5: DM costs and D-factor claims approved by IPART for Energy Australia



Under the D-factor scheme EA has invested mainly in 'facilitated projects', where the business has installed discrete technologies such as power factor correction equipment or on-site generation which can be directly controlled by the Distributor. These programs have been complemented by interruptible load programs in the commercial and industrial sectors and a large scale compact fluorescent light (CFL) program in the residential sector. Table 5, presents a summary of the types of network deferral projects implemented by EA between 2004/05 and 2005/06.[13]

Table 5: EnergyAustralia DM projects average costs and savings

Expenditure Category	Number of programs	Average implementation cost (k$)	Avoided distribution cost (k$)
Power factor correction	8	48	608
Embedded generators	5	640	896
CFL give-away	1	Nil[14]	190
Customer incentives	1	22	488
Combined programs	2	57	798

EA has also introduced a number of tariff-based strategies designed to influence domestic demand, as part of the business' Strategic Pricing Study (SPS). The key objectives of the SPS are to:

- test new tariffs;
- measure peak load reductions – estimate capital and maintenance deferrals, deliver lower energy cost; and
- measure price elasticities (% change in consumption for a % change in price – including own price, cross price and substitution elasticities).

Non-network activities proposed for the 2009 to 2014 control period

EA made provision for the costs and benefits of demand management based on the results achieved during the 2003-07 period under IPART's D-factor scheme in its opex requirement. The business forecast that the implementation of DM projects throughout the 2009-14 control would result in approximately $50 million of capital investment being deferred into the 2014-19 period (compared with $58 million in the 2003 to 2007 period).

13 IPART. 2007. *NSW Electricity Information Paper No 2/2007 - Demand Management in the 2004 distribution review: progress to date*.

14 EA did not claim DSM implementation costs for this project as it was able to receive NSW Greenhouse Abatement Certificates (NGACs) income for the project.

Although the opex budget for non-network activities was not specified in the business' EDPR proposal, it is assumed that the cost would be a of similar order of magnitude to the $5 million expenditure on DM programs in the period 2003 to 2007 under the d-factor scheme.

EA did not forecast specific DM or EG projects to defer growth driven capital expenditure owing to uncertainties in the timing, cost and scope of the supply-side projects that the projects would impact. Individual non-network projects aimed at deferring location specific supply-side augmentations were to be finalised in future when specific constrained network locations are identified.

5.2. South Australia

5.2.1. ETSA Utilities

Non-network activities undertaken in the 2005 to 2009 control period

During the 2005 to 2009 regulatory control period ETSA Utilities (ETSA) implemented several non-network projects and trials aimed at managing peak demand on the business network. These projects have been funded by the ESCOSA's $20 million dollar Demand Management Fund, which provided an opex allowance to ETSA to pilot DM programs and trials over the regulatory control period, and to build the business' internal DM capabilities.

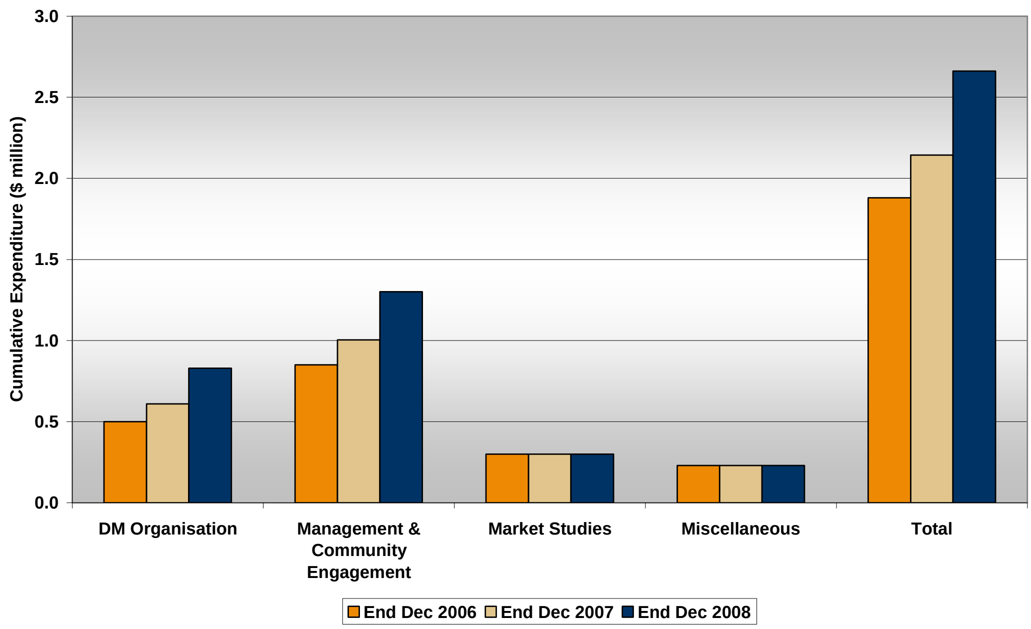
ETSA defined three strategic areas wherein expenditure would be made on resourcing and capability building. These included:

- DM capacity building;
    - development of a resource plan covering the processes and systems needed to manage and deliver DM programs within the business, and
    - implementation of the plan
- Market and technical studies;
    - research into successful overseas DM strategies, trials and programs
    - market research into customer appliance penetration and saturation data,
    - load research into customer end use data (including the contribution to peak demand at present and in future) along with customer demographics
- Management and community engagement;
    - development of an information campaign to engage stakeholders in the business' DM activities,

- establishment of a shop-front and information pack to educate customers about ETSA's DM activities and technology trials; and
- establishment of an industry-based DM Advisory Board, and
- ongoing liaison with relevant government agencies.

As at 2008, the total projected expenditure on these strategic activities was approximately $2.7 million.[15] Figure 6 presents a breakdown of this expenditure by activity type over the period October 2005 to December 2008.

Figure 6: ETSA Utilities cumulative expenditure on strategic DM



As regards the implementation of specific programs, ETSA's total cumulative expenditure over the period was approximately $8.1 million as shown in Table 6, with the majority (approximately 50%) being on DLC trials of air conditioners. This was followed by the implementation of power factor correction which accounted for 16% percent of total cumulative expenditure.

Table 6: ETSA Utilities cumulative expenditure on DM trial program implementation

Program Type	Cumulative $m End Dec 2006	Cumulative $m End Dec 2007	Cumulative $m End Dec 2008
Power factor correction	0	0.6	1.3
Embedded generators	0	0.9	0.8

15 ESCOSSA. (2008). *ETSA Utilities Demand Management Program.*

Program Type	Cumulative $m End Dec 2006	Cumulative $m End Dec 2007	Cumulative $m End Dec 2008
Direct Load Control	0	4.1	5.5
Critical Peak Pricing	0	0.8	0.2
Voluntary Load Control	0	0.4	0.3
Miscellaneous	0	0.05	0.01
Total	**0**	**6.9**	**8.1**

Non-network activities proposed for the 2010 to 2015 control period

ETSA Utilities proposed $22.6 million for DM projects which was been included in the capex and opex allowances approved by the AER.[16] Examples of non-network solutions proposed by ETSA for deployment within the 2010 to 2015 regulatory control period include:

- connection point management – deferral of both ETSA Utilities' and ElectraNet's supply-side augmentation expenditure using peak lopping EG at the Pinnaroo Power Station;
- substation management – deferral of expenditure on three substation augmentation projects through the installation of 11kV capacitor banks;
- North Adelaide DM project – deferral of zone substation expenditure via the use of customer standby generation capacity; and
- sub-transmission line management – deferral of 66kV or 33kV lines through the installation of a 9 MVAr 11 kV capacitor bank.

Additional DM activities that ETSA indicated it may pursue within this time frame include continuation of the business' successful power factor correction initiative with refinements to the pricing schedule to increase the financial incentive to take up the tariff. Evaluation of the Peakbreaker+ trial[17] which involved DLC of 1,000 customers air conditioners will also be completed. A proposal for expansion of the Peakbreaker+ program is to be developed on the basis of a widespread application, initially marketed to 10,000 customers with ducted refrigerative air conditioning units.

16 ETSA Utilities. (2009). *ETSA Utilities Regulatory Proposal 2010–2015.*

17 The Peakbreaker+ scheme evolved from refinement of ETSA's DLC schemes. The Peakbreaker+ is fitted alongside the customer's conventional electricity meter to control air conditioning compressors on a rotational basis. The unit also has two way radio communications, and additional functionality including remote supply capacity control; remote disconnect/reconnect; outage detection and notification; and remote meter reading.

5.3. QUEENSLAND

5.3.1. Energex

Non-network activities in the 2004 to 2009 regulatory control period

Energex's Annual Network Management Plan 2007–08 to 2011–12[18] outlines a number of DM projects that the business carried out to address rising network peak demand. In summary, the business has:

- implemented the 'Summer Preparedness' program which establishes agreements with large commercial and industrial customers to shift their loads to an off-peak time, support the network with their own generators when required, or allow Energex to install mobile generators at their sites for use at peak times; and

- conducted a trial of air conditioner DLC (known as 'Cool Change') with Brisbane householders.

The estimated total cost of the Summer Preparedness Program for 2006/07 were approximately $1.5 million, of which 60% was payments to customers, and 40% equipment capex and opex. Energex established agreements with customers for a total of 16 MVA of network support.

Non-network activities proposed for the 2010-15 regulatory control period

ENERGEX has developed an integrated DM Strategy with the objective of reducing network peak demand by a total of 144 MW over the 2010-15 regulatory control period. In overview the DM Strategy comprises:

- broad-based programs to reduce demand across the entire network;

- kVA pricing tariffs for large customers to,

- continuation of the curtailable load program for in the commercial and industrial sector;

- expansion of the "Cool Change' DLC air conditioner DLC program through a roll out of the technology across the network,

- implementation of pool pump DLC trials,

- optimisation of hot water load switching and conversion of continuous hot water services to an off-peak tariff,

18 Energex. (2006). *Annual Network Management Plan 2007–08 to 2011–12*.

- conduct of pricing trials to identify the benefits of Time of Use pricing and dynamic critical peak pricing tariffs in the residential sector,

- research into customer acceptance of load limiting technologies in the residential sector

- establishment of a Centre of excellence for customer electricity demand to facilitate customer confidence in adopting DM initiatives, and

- development of energy conservation 'communities' where a range of energy efficiency initiatives such as CFLs, fuel substitution, home energy audits, and second fridge buy-back programs is used to reduce demand within a geographic area.

• Peak demand management programs that aim to address specific network constraints;

- continuation of the business 'Summer Preparedness Plan'.

The proposed budget for these works is approximately $120 million in opex over the five-year control period.[19]

5.3.2. Ergon Energy

Non-network activities undertaken in the 2004 to 2009 regulatory control period

Ergon Energy's network management plan is focused on the delivery of an affordable, dependable and smart electricity supply to it customer base in regional Queensland.[20] Increasingly, the business has come to acknowledge the importance of DM and energy efficiency as necessary mechanisms to achieving its network management planning goals. Some of the key initiatives implemented by Ergon include:

- Townsville: Queensland Solar City – deployment of solar PV and DM through energy efficiency, load management, smart meters and new tariffs, along with community engagement techniques promoting sustainable behavioural change;

- Cloncurry North Single wire earth return (SWER) trial – installation of timers on hot water pumps and air conditioners, ceiling insulation, and solar hot water systems;

- Townsville commercial and industrial pilot project – contracts with commercial and industrial facilities to contribute financially to customer's capital works program in return for the opportunity to implement technical and commercial DM arrangements;

- Townsville and Magnetic Island residential air conditioning DLC; and

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19 AER. (2010). *Queensland distribution determination 2010 to 2015.*

20 Ergon Energy. (2010). *Energy Conservation and Demand Management in Ergon Energy Update for Energy Policy Steering Committee.*

- Mt Isa and Mackay energy savers trial – home efficiency checks, and rebates for solar or heat pump hot water systems, home insulation, and electric hot water or pool pump controlled network tariff.

Burns and Roe Worley (BRW), in its review of Ergon Energy's capex and opex for the 2004 to 2009 regulatory submission, noted that the business had included $14 million for non-network related expenditure.[21]

Non-network activities proposed for the 2010-15 regulatory control period

Ergon Energy's non-network program for the next regulatory control period is budgeted at $61 million – all of which is operating expenditure.[22] In addition to non-network project management costs, which are estimated at $15.4 million, proposed initiatives include:

- continuation of the Townsville commercial and industrial pilot project ($5.6 million);
- expansion of the Townsville and Magnetic Island residential DLC air conditioning pilot, with a focus on the deployment of new technology, channels to market and customer incentives ($17.2) million ;
- a launch of a controlled load tariff for pool pumps and filtration to customers ($3.5 million);
- acquisition of customer appliance and energy end use information ($2.5 million);
- promotion of existing hot water DLC tariffs ($2.5 million);
- maintenance of existing hot water DLC load control relays ($3.0 million);
- migration of customers with continuous water heaters to controlled load tariffs, and ensuring new connections are under controlled load tariffs ($3 million);
- energy audits in rural communities to support trials ($2.2 million);
- promotion of promotion of DLC for hot water systems and replacement of electric element hot water systems with solar hot water, gas or heat pump systems ($3.2 million); and
- creation of an Energy Education One-Stop Shop involves creating a centre of excellence in the field of energy conservation, energy efficiency and demand management ($3.2 million).

21 Burns and Roe Worley. (2005). *Review of Ergon Energy's Revised Capital and Operating Expenditure Submission.*

22 Ergon Energy. (2009). *Ergon Energy Regulatory Proposal 2010 to 2015.*

5.4. VICTORIA

5.4.1. SP AusNet

Non-network activities undertaken in the 2006 to 2010 regulatory control period

SP AusNet's experience to date lies largely in distributed and embedded generation. The business also offers a discounted 'interruptible' tariff to medium sized customers that are willing to accept some, or all, of their load being interrupted for short periods, and has made adjustments to time-switched water heating load in South Gippsland to load shift and defer network augmentation.

Non-network activities proposed for the 2011 to 2015 regulatory control period

SP AusNet's total proposed expenditure on DM programs to be implemented over the 2011-15 control period amounts to $3.29 million opex[23] for the following projects.

- hot water timer system load control ($1.26 million), and
- DLC of air conditioners (rebates to 2,000 participants, and installation of communications device on AC units for $2.03 million).

SP AusNet intends to conduct a number of non-network solution and technology trials in the forthcoming regulatory control period, including:

- trials of energy storage and distributed generation (approximately $1 million opex and $3 million capex);
- examination of the integration of electric vehicles into the distribution network and customer's homes ($0.23 million opex); and
- in partnership with VicUrban, undertaking a smart network pilot project (approximately $1.6 million opex and $0.3 million capex).

5.4.2. Powercor/Citipower

Non-network activities undertaken in the 2006 to 2010 regulatory control period

Powercor (PAL), since 2003, have implemented a DM strategy through the hot water load management projects funded by the business' capital augmentation budget. A demand management trial program utilising contracts with commercial and Industrial customers to curtail load on a network element at the end of a long SWER line was implemented during 2007/08 summer period to manage voltage and quality of supply issues.

23 SPAusNet. (2009). *SPI Electricity Pty Ltd Electricity Distribution Price Review 2011-2015 Regulatory Proposal Public Version.*

Citipower has not been actively involved in the design and implementation of non-network activities, to date.

Non-network activities proposed for the 2011 to 2015 regulatory control period

PAL's non-network alternatives program for the next regulatory control period is $0.7 million.[24] This expenditure relates to the continuation of the business' curtailable load DM program, and a solar SWER PV systems trial (no specific costs were associated with this trial).

CitiPower did not discuss specific non-network activities planned for the forthcoming regulatory control period in the business' EDPR proposal to the AER.

5.4.3. United Energy

Non-network activities undertaken in the 2006 to 2010 regulatory control period

To date, United Energy (UED) has had little experience in the implementation of non-network programs or trials.

Non-network activities proposed for the 2011 to 2015 regulatory control period

UED proposed a range of DSM programs aimed at different customer classes, for example:

- interruptible tariffs for business customers whereby customers agree to reduce their power consumption for agreed periods at the request of UED;
- DSM aggregation program, which involves working with a range of customers and bidding their combined interruptible load in either the wholesale energy or ancillary services market;
- trials to investigate pricing incentives, such as critical peak pricing and rebates, as mechanisms to promote behaviour change in conjunction with the AMI roll-out; and
- DLC of hot water systems and air conditioners in conjunction with the AMI roll-out.

UED budgeted $10 million for non-network initiatives over the forthcoming regulatory period. In its expenditure forecasts, UED stated that the business "…is expecting to devote only a small proportion of total operating expenditure to non-network alternatives. Most recurrent outlays on non-network options will be in respect of the Demand Management Incentive allowance (DMIA)."[25]

24 PAL. (2009). *POWERCOR AUSTRALIA LIMITED REGULATORY PROPOSAL: 2011 TO 2015.*

25 UED. (2009). *Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015.*

5.4.4. Jemena

Non-network activities undertaken in the 2006 to 2010 regulatory control period

The only non-network alternative implemented by Jemena in the current regulatory control period, is the Somerton Power Station, which consists of four 37.5MW gas fired generators connected at 66kV.

Non-network activities proposed for the 2011 to 2015 regulatory control period

No specific non-network activities were included in Jemena's capex and opex proposal for the 2006 to 2010 regulatory control period.

6. REVIEW OF INTERNATIONAL NON-NETWORK ACTIVITIES

Section 6 presents a review of non-network activities undertaken by North American and European network utilities with a particular focus on winter peaking networks. Where available, details of costs of implementing various non-network initiatives and the load reduction impacts achieved are presented.

6.1. NORTH AMERICA

6.1.1. Pacific Northwest GridWise Project

The Pacific Northwest National Laboratory (PNNL) is a US Department of Energy funded institute that conducts research into the impacts of energy use and increase energy capacity. In collaboration with several publicly-owned utilities[26] serving the northwest states of Oregon and Washington, the Bonneville Power Administration (BPA), and DOE PNNL implemented several trials known as the Gridwise Project between 2004 and 2007. The premise of the GridWise concept is that application of intelligent technologies at each level of an electricity grid; generation, transmission, distribution and consumer end-use levels; will significantly improve asset utilization and economic efficiencies of the electricity grid. Relevant trials undertaken by PNNL under the GridWise Project include the Olympic Peninsula and Grid Friendly Appliance Projects.

Olympic Peninsula Project

The objective of the Olympic Peninsula Project was to apply the GridWise principle to manage conjestion on, and defer the augmentation of, a 1.5 MW feeder. The Olympic Peninsula, the location selected for the project, was experiencing significant population growth, with demand forecast to exceed network capacity during extremely cold winter conditions. Load growth on the Peninsula was projected to grow at a rate of 20 MW per year. The Peninsula was identified as an ideal field test location for evaluating the potential of non-network alternatives to new transmission and distribution construction. The project incorporated the following customer end-use resources that were set up to respond to control and price signals:

- 5 x 40-HP (150 kW) water pumps from two water supply authorities that could be curtailed at times when water reservoir levels were above a minimum height and coinciding with times of peak time.
- Two customer owned back-up diesel generators of 175 and 600 kW rating and supplying essential building loads of around 170 kW. It was not necessary to parallel these generators to the power grid, as they could simply be operated islanded from the grid to displace building loads.

26 Public Utility District of Clallam Country, City of Port Angeles and Portland General Electric.

- 112 residential participants had a broadband internet based system incorporating VPN gateway, load control devices, communicating thermostats (to replace existing thermostats), and smart metering installed at their premises. These load control devices allowed customers to (1) receive price signals dispatched by the utility and (2) program the way their appliances would respond to the price signals. The main appliances that could be managed with the system were water heaters and thermostatically-controlled space heating and clothes dryers. Participants could also customise and pre-program their water heater and space heater settings, based on their preferred level of cost savings versus several comfort settings, via a web portal accessible from their PCs. Participants were divided into fixed, time of use (TOU) and real-time tariff categories, as well as a control group.

All participants in the program were able to override the utility control of their loads or generators. On average, load response per household to a price signal event was 1.5 kW (representing a 25% reduction per household in winter morning peak demand) or 160 kW in total. Part of this load response was achieved by space heating being shifted earlier in the morning, effectively pre-heating the home and allowing the thermostat to “cycle” the heater at reduced load over the system peak. Control of the water pumps and back-up generators also achieved effective load reduction impacts. Overall the project achieved an estimated 19-30% reduction in peak load on the feeder and estimated infrastructure savings of US$6 million.

6.1.2. Bonneville Power Administration (BPA) – Ashland Pilot

BPA is a publicly owned US electricity wholesaler and transmission network operator that distributes power to more than a hundred regional electricity distributors and retailers. Like many other network operators, BPA is facing constraints on parts of its network due to short duration peak demands. The system maximum peak demand on the BPA system occurs in winter. As an alternative to traditional supply side planning, in the mid 2000 BPA formed a group to study options to avoid the expense of building more transmission lines. In 2005, BPA teamed with Ashland, a small regional utility supplying 9,000 homes, to trial the impacts of several demand-side measures and technologies in residential applications. Ashland was an ideal location for the trial due to it’s predominantly “green" community and the high penetration of broadband network to households.

Initially, a technical assessment was conducted to determine the types of end uses contributing to the peak, including water heaters and electric space heating, and the types of DSM measures that would be suitable for managing these loads. BPA recruited 100 residential test customers to participate in the trial. Ashland installed a load management system that included load control modules on water heaters and programmable communicating thermostats on space heaters, at each location. BPA operated the load control system over the internet. The thermostats allowed BPA to remotely raise or lower the temperature setting. Using the remote switches, BPA could also turn off the heating elements in water heaters or turn off pool pumps.

The following unit impacts were achieved during the trial for the residential sector:

- an estimated average demand reduction of 0.6 kW per water heater during each curtailment event; and

- lowering the heating setpoint of the thermostat of a electrically-heated homes by 4ºF (2.2 ºC) during the morning peak period typically resulted in a demand reduction of 1.2 kW per home.

Participants in the trial were provided with the capability to override the load reduction signals issued by BPA, but rarely did. BPA found they could shift demand for two to four hours at a time, without inconveniencing homeowners. Overall the trial demonstrated average winter peak demand reductions of 2.4 kW per household (and 2 kW per household during summer).

6.1.3. Ontario Smart Price Pilots – Hydro Ottawa and Peterborough

In the mid 2000, the Ontario Energy Board approved several trials to test consumer response to different dynamic price structures. The trials investigated the extent to which dynamic pricing structures cause a reduction in peak demand and overall energy consumption, and residential consumer acceptance, understanding and communication aspects of such pricing structures. The following provides a brief overview of the Hydro Ottawa and Peterborough trials.

Hydro Ottawa

The trial operated over the 2006 / 07 winter and involved 375 participants drawn from customers with smart meters installed. A control group of 125 randomly selected customers who had smart meters installed but continued to pay the standard non-TOU tariff was also established.

Participants were placed into one of the following pricing structures:

- A seasonal (winter / summer) 3 part TOU tariff (124 participants);

- similar 3 part TOU tariff as above but adjusted with the addition of a critical peak price (CPP) component (124 participants); and

- the same TOU tariff with a critical peak rebate (CPR) incentive component added (125 participants).

Critical peaks were to occur only for 3 or 4 hours during the on-peak period of the TOU tariff (7am – 11 am and 5pm – 8 pm winter weekdays), and only on declared critical peak days which were based on temperature thresholds. Participants were notified by telephone, email or text messages one day before a critical peak event.

A critical peak price of 30¢ per kWh was set representing 3 times the on-peak price of the TOU tariff. Participants in the CPP group also received an 8% reduction on their off-peak rate to offset the increase due to the CPP. In contrast, participants in the CPR group were provided a refund of 30¢ for every kWh reduction below their “baseline” usage during the critical peak hours. Each participant’s baseline was calculated as the average usage for the same hours of the five previous non-event, non-holiday weekdays, adjusted by 125% as a weather adjustment.

Upon enrolment, participants were provided with a table of the TOU prices, periods, and seasons for the participant’s price plan on a fridge magnet, and a PowerWise electricity conservation brochure. As an incentive to enrol, participants received a “thank you payment” of $75.00 at the end of the pilot, which was adjusted based on the amount of their savings or losses on TOU pricing relative to their pre-trial tariff.

The maximum number of critical peak days planned for the pilot was nine, although only seven events were actually called due to moderate weather. Two events occurred in August (summer), two in September (summer) and three in January (winter). The resulting load shifting during critical peak hours across the summer peak days ranged from 5.7% for TOU-only participants to 25.4% for CPP participants. No statistically significant shift was detected during the critical peak days in January, except for a counter-intuitive result for January 17 where the load increased by 7.2% during the critical peak period.

There was a statistically significant 6.0% average conservation effect across all customers. Over the course of the entire pilot period, on average, participants shifted load and paid 3.0% lower bills on the TOU pilot prices than they would have on their standard tariff.

Feedback from participants revealed that participants valued the monthly usage statement and refrigerator magnet as the most useful resources to help understand the TOU prices.

Peterborough Distribution Inc

The Peterborough Distribution Inc (PDI), a water and electricity distribution service provider serving the City of Peterborough in Ontario, Canada commenced a trial in 2005 on TOU prices, conjunction with two of its conservation and demand management (CDM) programs. PDI had been billing TOU prices to about 200 customers for over two years.

Unlike the Hydro Ottawa trial discussed above, which tested response to a tariff based approaches only, the Peterborough project assessed the impacts of energy storage, load control technologies and energy efficient appliance promotion.

PDI, in conjunction with Peterborough's Housing Corp, provided technical, financial and administrative expertise to convert 124 wall mounted electric resistance heaters in public housing accommodation to electric thermal storage heaters. The storage heaters use electricity in off-peak periods and store that heat in high-density ceramic bricks for use during on-peak periods. Based on engineering calculations, the thermal storage heaters are estimated to shift 4 million kWh over the 18 year life of the 124 units. The estimated savings to the City of Peterborough's Housing Corp were $47,500 per year.

A load control program was also implemented in residential homes with existing smart meters and TOU pricing. The program utilised a radio signal control system that allowed customers to shift discretionary use of appliances, such as air-conditioners, water heaters, pool pumps, clothes washers, dryers, dishwashers, to off-peak periods. A manual override button was also provided permitting customers to use the appliance during a load control event, if absolutely necessary. The program currently controls 314 appliances for 200 residential customers, is estimated to have shifted 155 kW to off-peak periods. Energy savings to consumers are estimated at over $896,000 over the 12 year life of the 200 controllers.

A rebate incentive was also offered to residential customers to encourage them to opt for 'Energy Star' appliances when purchasing a new household appliance. As of 2007 a total of 1,750 appliances had been replaced resulting in estimated savings of 150 kW in demand and 1,500 MWh in energy over the lifetime of the appliances.

6.1.4. PSE&G myPower Sense / myPower Connection Program

Public Service Electric and Gas (PSE&G) is regulated integrated energy company engaged in the transmission and distribution of electricity and gas to 3.8 million customers in the US state of New Jersey. The maximum capacity of the electricity network is 13,300 MW.

Between 2006 and 2007 PSE&G implemented a residential pricing pilot program in two regions to investigate the potential of time-of-use (TOU) and critical peak pricing (CPP). The pilot's focus was on reducing summer peak demands. Although, the main concern for Aurora Energy is alleviating winter peak demands, the results of the PSE&G pilot provide some useful empirical evidence that consumers' do change their usage patterns of discretionary and non-temperature dependent appliances such as washing machines, dishwashers and clothes dryers, when encouraged and supported to do so.

The pilot incorporated two main streams. The first, known as myPower Sense, was designed to evaluate the demand response from customers when provided with advance notice of a CPP event and educational information only. The second, known as myPower Connection, offered the same pricing structure, but also provided customers with a free programmable thermostat with the capability of receiving PSE&G control signals that adjusted air conditioner set points in response to CPP dispatch events. Participants with the programmable thermostat had the ability to automatically respond to the CPP events and did not need to be aware that a CPP event had been called or take specific actions to curtail use of their air conditioner. An important aspect of the pilot is that it assessed the value of technology in supporting customers' ability to respond.

Other notable features of the pilot design included:

- 459 participants in myPower Sense, 377 participants in myPower Connection and a control group of 450;
- The CPP of 4 times the on-peak TOU rate and when called would apply between 1 – 6 PM;
- Participants were informed in the educational materials that up to five CPP events could be called;
- Notice of an imminent CPP event was provided to participants via email and automated telephone call the evening prior to the event;
- The programmable thermostat allowed participants the flexibility to raise the temperature set points up to 6 degrees during CPP events, and
- Contractors programmed the thermostats when they first installed them based on participant's preferences and showed participants how to modify the settings.

While there were only two CPP events, an evaluation of the pilot revealed that customers without the thermostat reduced load by an average of 1.11 kW (or 12%) while those using thermostats that automatically respond to price signals successfully reduced their on-peak period demand by 2.12 kW (18%) on summer peak days. Program participants also reduced their total summer energy use by 3 to 4 percent compared to the control group, and most customers saw lower energy bills. Notably, the majority of myPower Connection participants also reported changing the operation of appliances to lower-priced times of the day, such as washing machines (87%), clothes dryers (68%) and dishwashers (64%).

6.2. EUROPE

6.2.1. French Riviera DSM Program – Eco Energy Plan

Planning for the upgrading of the 225 kV Boutre-Carros line to supply increasing load growth in the Provence-Alpes-Côte d'Azur (PACA) region of France area commenced in 1983. The initial plan comprised double 400 kV lines on separate easements over 170 km in length. Six route options for the upgraded line were proposed. However, there was strong opposition to this project because the lines would pass through the classified scenic gorges of the Verdon Regional Park. In November, the Department of the Environment established an inquiry and the project was suspended.

In 2000, a decision was made on an alternative proposal, which comprised replacement of the existing 225 kV line by a single 400 kV line on the same easement and implementation of a DSM and renewable energy distributed generation program called the "Eco-Energy Plan" to slow down growth in peak demand.

The DSM program comprised a very large integrated DSM and distributed generation project, and is the largest DSM project in the European Union. The plan had three main objectives:

- to increase the efficiency of electricity usage and to develop scientific and technological competence in relation to electricity DSM;
- to modify the electricity consumption behaviour of residential and business consumers; and
- to contribute to the development of local renewable energy resources and establish a solid basis for future energy choices.

Preliminary studies were carried out in 2001 to quantify the level of load reduction required after the scheduled completion of the new 400 kV line in 2005 and avoid network constraints in the period to 2020, and to identify a detailed program of DSM and distributed generation measures. The studies indicated that to avoid a further new line being required before 2020, the DSM program would have to reduce load by 35 MW in winter. In May 2006, the state court, after a complaint from an environmental group, refused planning permission for the 400 kV line upgrade and therefore the DSM program remained the only way of securing supply to the region by keeping load growth within the capacity of the existing line. The winter load reduction targets for the DSM program were strengthened to meet the new constraints and raised to 45 MW. A summer load reduction target of 130 MW was also set.

The studies also quantified the end-use composition of peak demand in winter and summer. In winter, peak demand is dominated by lighting and heating and in summer air conditioning is dominant with lighting also an important contributor to the peak.

The Eco-Energy Plan was launched in March 2003. Initially six priority areas were identified (1) communication and information, (2) new building construction, (3) efficient lighting and domestic electrical appliances (4) large consumers and distributed generation (5) demonstration projects by the Eco-Energy Plan institutional partners, and (6) public housing. In 2004, a further two priority areas were added targeting existing buildings and tourism.

- Communication and Information. A general public information campaign was launched on 18 March 2003 and implemented annually in two waves on a seasonal basis, summer and winter. The campaign comprises paid advertisements in newspapers, radio and television; information booklets and posters; newsletters; a telephone information service; website and energy audit software for residential dwellings, school education program and displays in shopping centers.

- New Building Construction. Targeted information material on energy efficient lighting was developed for engineering and building design firms, supported by promotional material to assist building designers to convince their clients to invest in energy efficient buildings.

- Efficient Lighting and Domestic Electrical Appliances. Negotiations with lamp manufacturers enabled energy efficient lamps to be offered at a 20% discounted price. The program also made available loans to cover the cost of energy efficient lighting upgrades in buildings of between EUR 2 000 and 16 000 at interest rates of 2.5% over three years or 3.5% over five years.

- Large Consumers and Distributed Generation. A study was completed to identify the potential for the development of small cogeneration installations (200-300 kW) in the region, including simplifying procedures for connection to the low voltage network. Studies investigating increased hydro-electricity generation and financing the installation of 40 grid-connected PV modules in the region have also been completed.

- Demonstration Projects. A database of about 100 public sector buildings in the region has been established, including colleges, hospitals and offices owned by the national, regional and local governments, Electricité de France (EDF), and Gas de France to identify and implement energy efficiency and DSM demonstration projects. Financing of 80% of the cost of feasibility studies in hospitals. EDF also carries out an internal awareness campaign about energy saving for its staff to change the behaviour of staff in administrative buildings without implementing costly technical measures. Eco-Energy Plan partners have also brought together 29 local communities in the region to encourage them to undertake effective DSM measures such as investigation of opportunities for interruptibility; installation of energy efficient lighting, or the management of street lighting.

- Public Housing. The Eco-Energy Plan has been working with managers of public housing to improve the energy efficiency of their properties so as to reduce the energy bills of their tenants, particularly targeting properties at time of renovation. To assist the property managers, specific DSM measures are identified from energy audits of the properties.

- Existing Buildings. The Eco-Energy Plan has developed a database of products and services on energy savings in residential and commercial buildings. The database is available on the internet and it is also possible to purchase the products on-line. Prior to the development of the database, there were few energy service companies (ESCOs) in the region. Now several new ESCOs have been established.

- Tourism. Individual hotels were provided with dataloggers which they used for three weeks and then returned. The data were analysed and individual reports were provided to each hotel detailing the characteristics of the hotel's electricity use and identifying anomalies and opportunities for energy saving. Energy saving measures generally applicable across the sector such as switching off coffee machines when not in use and curtailing the use of water heaters in the middle of the day and when the hotels had low occupancy rates, were identified.

6.2.2. Electricité de France (EDF) – Tempo Program

Over the past four decades, EDF has been working towards implementing real-time pricing of electricity linked to marginal costs of supply, as a way of motivating electricity customers in France to reduce their consumption when generation costs are high and during congestion on the electricity network. In recent years, EDF's Tempo tariff option has been successful in smoothing the peak day load profile, therefore reducing marginal generation and network costs.

There are three types of electricity tariffs from which residential and small business customers can choose. While the most relevant for this review is Tempo, it is useful to briefly mention the others.

Option Base is the simplest of the three contract types and comprises a standing charge and a flat rate for electricity consumed any time of day and year. It is generally suitable for smaller homes and holiday homes with only occasional use.

Option Heures Creuses (HC) is a two-part time-of-use tariff with peak and off-peak rates. The off-peak period is from 10 pm until 6 am each night and, in some regions, also at midday. Option HC is usually used in conjunction with a water heater operated by ripple control which is switched on only during off-peak periods. Option HC suits the majority of permanently occupied homes where space heating is non-electric.

The Tempo option offers six pricing components (3 day types x 2 pricing periods, peak and off peak) based on the actual weather on particular days and on hours of use. Each day of the year is colour coded either blue, white or and red. These colours correspond to low, medium and high electricity prices. The colour of each day is determined usually by EDF based on the forecast of electricity demand for that day, which is mainly influenced by the weather. RTE, the French transmission network operator, also has the ability to determine the day colour if there is significant congestion on the electricity network.

The number of days per year of each colour is fixed; there are 300 blue days, 43 white days and 22 red days. On blue days, the electricity price is the lowest and during the off-peak period the price is extremely low. On white days, the price is higher than under Option Base or Option HC. On red days, the price is very high to encourage lower electricity usage, with the normal rate on red days over 10 times that of the off-peak rate on blue days. Red days tend to correspond with the coldest days in winter.

There are four different versions of Tempo, depending on the metering, communications and load control equipment installed at the customer's premises:

- standard Tempo (the customer has only an electronic interval meter);
- dual energy Tempo (the customer's space-heating boiler can be switched from one energy source to another);
- thermostat tempo (the customer has load control equipment which is able to adjust space heating and water heating loads according to the electricity price); and
- comfort Tempo (the customer has a sophisticated energy controller).

Customers who choose Tempo are informed each night about the colour for the next day. At 8 pm a signal is sent to each customers premise using a ripple control system. Most Tempo customers have a display unit that plugs into any power socket and picks up the signal. The display unit shows the day colour with lights, both for the current day and (from 8pm) for the next day. An (optional) beep informs the consumer if the following day will be a red day. For older systems without a display unit the information is available over the telephone or via the internet.

Customers may then respond to the signal by adjusting their electricity consumption manually by switching off appliances, adjusting thermostat settings, etc. Some customers who have the necessary communications and load control equipment are able to select load control programs which enable automatic connection and disconnection of separate water-heating and space-heating circuits.

Tempo is for high use households, such as very large houses, and those with electric heating and full time occupation, and for small business customers.

A total of 350,000 residential and 100,000 small business customers participate in Tempo. To date Tempo has achieved 450 MW in winter peak demand reduction. Compared with blue days, the Tempo tariff has led to a reduction in electricity consumption of 15% on white days and 45% on red days, which equates to, on average, 1 kW per customer. Tempo customers have saved 10% on average on their electricity bill and most are satisfied with the tariff. However, customers do not appreciate red days occurring consecutively. While the Tempo tariff has been successful, less than 20% of electricity customers in France have chosen Tempo, and tend to be customers interested in managing their energy use.

6.2.3. Winter Peak Demand Reduction Scheme – Ireland

Over the 2003/04 winter the Electricity Supply Board National Grid (ESB NG) of Ireland, facing the need for expensive T&D investment, implemented the Winter Peak Demand Reduction Scheme (WPDRS) to defer network augmentation and reduce costs. In Ireland, the need for network augmentation is driven by winter peak demands, which was 4,320 MW.

The WPDRS was offered, via the retailer, to more than 600 large commercial and industrial customers with appropriate interval metering. Each customer committed to reducing consumption between 5 and 7 pm every business day over the winter months from November to February. This reduction was achieved through reducing energy use or utilising the customers own on-site back-up generation. In return, customers received a capacity payment of EUR160 (A$240) per MW and an energy payment of EUR50 (A$75) per MWh for reliably delivering this committed reduction. Electricity retailers also received a 5% fee (based on the total payments to participants) for their role in administering the scheme.

Of the customers that were eligible to take part in WPDRS a total of 186 (29%) signed up. These participants, whose total baseline demand was 410 MW, offered 106 MW of committed load reduction. The actual average *delivered* reduction in peak demand from these participants over the 2 hour peak period was 80 MW, representing about a 2% reduction in system peak demand. The load reduction achieved was quite reliable on a daily basis; 95% of the time, the achieved load reduction was between 72 MW and 88 MW.

Compared with the previous winter, the shape of the peak on the system was altered from a sharp peak occurring at about 5.30 pm to a flatter peak occurring from about 5.30 to about 6.30 pm. The demand reduction achieved through the WPDRS led to the 2003/04 winter peak being 1.8% lower than the 2002/03 peak, even though demand for the entire year increased by roughly 3%.

The four largest contributors to the eligible load reductions offered were from the cement and paper industries (38% of eligible customers reductions offered), manufacturers of agricultural products (24%), office/banking/retail (23%) and refrigeration/meat industry (17%).

6.3. Implications of International Experience for Aurora Energy

Highlights of the findings from the review of international experience with demand management to alleviate winter peak demands relevant for Aurora Energy's demand management planning include:

- residential customers do alter their energy usage behaviour, both during summer and winter peak periods, when faced with sharp tariff signals or offered financial incentives;

- tariffs or financial incentives on their own are sufficient to induce demand response but impacts are maximised (often doubled) when customers are also offered enabling technologies that make it easy for them to respond to a load control event;

- existing communications infrastructure, such as the telephone, text messaging and broadband internet, can be deployed for alerting customers of impending load control events, without the expense of rolling out a dedicated communications capability;

- customer education, awareness raising, technical assistance and communication are essential elements to the success of DSM programs targeting mass market customers;

- interval metering is a desirable but not essential component of a residential and small business DSM program. For example, a DLC program targeting load reductions from central space heating could involve installation of smart thermostats with participants receiving a flat bill discount or discounted tariff for providing Aurora with the right to control the load (similar to traditional control tariffs targeting water heating loads); and

- Large C & I customers with standby generation and curtailable discretionary loads, whilst not a major contributor to Aurora's system peak, can provide significant winter demand response potential.

7. BROAD BASED NON-NETWORK PROGRAMS AND TRIALS

Section 7 details a proposed plan of broad based DSM and DG non-network programs and trials for implementation across Aurora Energy's distribution area.

7.1. INTRODUCTION

The AER has stated that the DMIA is a modest sum aimed at assisting DNSPs to engage in non-network solutions, and that the primary source of funding for DSM programs in a regulatory control period should be the forecast operating expenditure (opex) and capital expenditure (capex) approved in the distribution determination. Therefore it is recommended that Aurora Energy include an amount in its opex forecast to cover 'learning-by-doing' activities, and to support broader based trials where the outcomes of demand-side activities may not be known with certainty.

The implementation of pilot programs and trials will provide Aurora Energy with hands-on experience in the development of needed DSM and DG programs. Pilot programs and trials will also enable the testing and demonstration of program concepts and marketing approaches, formulation of appropriate pricing and tariff strategies, and examination of the suitability of technologies under controlled conditions. Importantly, pilots and trials provide the opportunity for program refinement prior to full-scale implementation.

7.2. PROPOSED BROAD BASED NON-NETWORK PROGRAMS AND TRIALS

The broad based and trial programs should be designed to test and demonstrate the potential application of a range of DSM and DG strategies. While the final selection of the pilots and trials to be undertaken by Aurora should be undertaken based on the results of detailed analysis of specific network requirements, consideration of the drivers of Aurora's network peak demands suggests that the following strategies be considered.

7.2.1. Residential and small business load response project

A major driver of Aurora Energy's capital expenditure program is uncontrolled residential and small business space heating and water heating load. Uncontrolled loads in existing premises in these sectors are estimated to account for almost 30% or some 300 MVA of Aurora Energy's system peak. Overall the residential sector accounts for more than half of the winter maximum demand at the system level.

For these reasons, a major focus of Aurora's non-network strategy moving forward should be on clipping short duration peak loads in the residential and small business sector. The strategy should include a combination of tariff and non-tariff DSM strategies such as dynamic direct load control of water, and space heating loads, and providing price signals (via dynamic pricing and/or incentive and rebate mechanisms) to encourage residential and small business sector to curtail or shift discretionary loads at times of maximum peak demand. It's important to note that dynamic management of load in this way need only be invoked on a relatively few days of the year.

While Aurora is now offering TOU tariffs to residential and small business customers, TOU tariffs do not in general accurately reflect the short-term demand spikes associated with peak loads – and the capacity constraints these impose on distribution networks. Dynamic pricing and incentive schemes – such as critical peak pricing (CPP) and peak time rebates (PTR) – seek to more closely mimic supply and demand conditions where for a few hours each year the cost of electricity supply is highly skewed from the average (as illustrated earlier in Figure 2). The implementation of a dynamic pricing or incentive scheme in the residential and small business customer classes would require that the Type 6 accumulation meters which record total energy consumption at a metering point, be replaced with Type 5 NEM compliant interval meters.

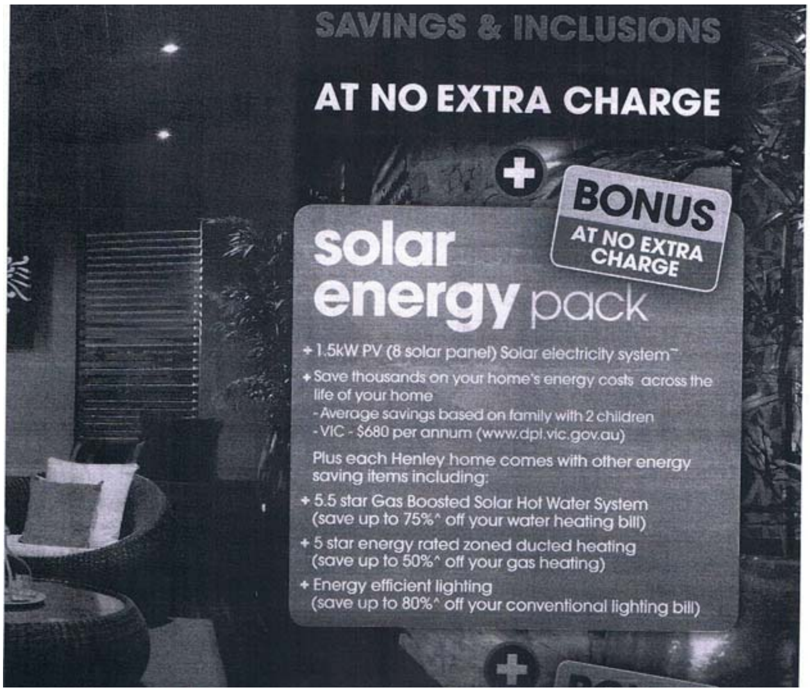
In order to provide Aurora with expertise in, and base data for, planning dynamic load management strategies with mass market customers it is recommended that a residential and small business demand response trial be implemented over the 2012 – 2017 PD period. The trial would focus on developing and testing tariff and non-tariff DSM options (and combinations of the two), marketing approaches, trial technologies such as programmable controllable thermostats (PCTs), in-home displays (IHDs), smart meters and load control devices, and measure customer demand response. The trial would need to be broad enough to cover existing households as well as new construction. The results of the trial would be used to inform the design and rollout of a larger scale peak load management program.

Aurora's network is also facing high rates of load growth associated with new construction in several planning areas, such as Hobart East and South. The residential new construction component of the trial would seek to investigate the scope for introducing demand response enabling technologies, associated pricing or rebates and load shifting technologies into new homes in Aurora's high growth areas. As such, it would seek to address a key peak demand issue for the business.

To illustrate how this approach would work, Aurora could pay a mid-stream incentive to builders and developers to sign customers up for the demand response program at the time of home customization / appliance selection. Home owners would then sign an agreement indicating their commitment to participate in the initiative, and the type of peak demand intervention they would be interested in accepting. These interventions could include DLC of thermostat controlled space heating with a rebate for participation; or CPP with a rebate for participation, or a PTR scheme. There may also be scope to test tariff and/or rebate offerings co-operatively with Aurora Retail.

The trial could also be expanded to include the integration of energy efficiency measures and renewable technologies into new homes. Aurora could work with the state government and builders to encourage incorporation of technologies which specifically target reduction in peak loads. Figure 7 provides an example of an advertisement from a Victorian builder offering. A similar ‘pack’ for Tasmania could include energy efficient lighting (such as LEDs), energy efficient heating with PCTs, and electric boosted off-peak solar water heating or off-peak heat pumps. Aurora would also support the initiative through the development and educational and marketing materials to enhance consumer adoption.

Figure 7: Example of an energy efficiency ‘pack’ offered by a Victorian builder



Source: Herald Sun Sat 10 July

It is assumed that the trial would tie in with Aurora’s current smart meter procurement program to support new tariffs and that the trials would be conducted in the Hobart East area as discussed in the location-specific initiatives in Section 8 of this report[27]. Expenditure associated with the trial would cover the costs of enabling technologies such as in-home displays, load control equipment, and communications interfaces with the smart meters. An allowance of $200 per home for 400 homes has been allowed for installation of IHDs in the Hobart East location which is to be funded from capex deferral savings of the Sandford zone substation project. This amount has been taken up in the costings for Hobart East in Section 8. An additional $0.75 million for supply and installation of enabling technologies, such as PCTs, IHDs and 2-way coms, will also be

27 The proposed DSM project is associated with the deferral of the new Sandford zone substation.

required to broaden the scope of the project to include a total of 1000 existing and new homes, based on an assumed cost of $750 per home.

Other costs for the trial would include marketing, project management and administration, incentives for builders and developers, and customer incentives. In addition to financial incentives, homebuilders associated with the trial would require training, and technical support. Aurora could also approach the State government for its endorsement and in-kind financial support, particularly for any energy efficiency initiatives being promoted by Aurora that align with current government efforts and policy to reduce energy consumption. On this basis an opex requirement of $1.0 million (excluding any State government support) would be required for these support activities.

A study will also need to be undertaken to investigate the costs, benefits and functionality and recommend the most appropriate load control architecture and technology. Options include leveraging off the National Broadband Network (NBL) backbone, utilisation of existing next G or other wireless communications infrastructure and investing in a standalone Aurora owned load control system, such as radio ripple control. The funding requirements set out above assume Aurora will leverage off the NBL or utilise an existing wireless communications network. They do not include an allowance for costs associated with an Aurora owned load control capability should Aurora decide to go this way.[28] An opex allowance to conduct this study is estimated at $0.25 million.

On this basis, a total opex requirement of $1.25 million and capex requirement of $0.75 million is suggested for a residential and small business load response trial over the 2012 – 2017 pricing determination period.

A related, but separately costed component, of this trial that addresses issues with the water heating load is discussed in the next section.

7.2.2. Residential and small business water heater study

As noted above, uncontrolled electric water heating in residential and small business is a major contributor to the peak. Further, growth in uncontrolled water heating load is a major driver of augmentation related investment in network infrastructure. Aurora Energy's current LV Uncontrolled Energy tariff (N05) permits the connection of storage water heaters onto an uncontrolled supply. N05 effectively encourages the installation of uncontrolled water heating as the N05 rate is about a third the general network residential rate (N01). While Aurora Energy also offers a controlled load tariff (N06) the bulk of the electric water heating load is supplied under the N05 and PAYG (N13) tariffs.

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28 Note that if Aurora decided to install a radio ripple control system additional costs for centralised components of the system such as long wave transmitters and central control computers would add another $2.5 million in capex to the funding requirement.

Given the impact of electric water heating on network investment and the slow turn over of water heating equipment (at least 15 years) a policy to shift electric water heating to off-peak and/or encourage more efficient forms of water heating in replacement and new installations should be investigated and implemented immediately by Aurora Energy. Current Commonwealth policies aimed at phasing out electric water heaters[29]will not address this problem, as Tasmania has been exempted due to the low greenhouse gas intensity of electricity supplied in the state due to hydro power. This suggests that without a policy intervention by Aurora Energy, the perverse impact of electric water heating on network investment will continue to persist over the long term.

The development of an effective strategy to manage the water heating load should include the following elements:

1. shifting existing electric water heaters with large storage tanks permanently away from the peak as soon as possible;

2. interrupting supply of medium capacity storage water heaters infrequently and for short periods only at time of local network peaks;

3. ensuring all end-of-life replacements and new installations of water heaters in new developments are supplied under an off-peak tariff; and

4. connection of water heaters of any type to the N05 tariff be discontinued.

Even if such a strategy were implemented immediately it would take approximately 15 years, based on the life of water heater tanks, to remove the entire stock of electric water heater load away from the peak. Therefore, each year of delay in implementing a water heater strategy presents a considerable lost opportunity in controlling network infrastructure costs.

Aurora Energy currently has limited knowledge of the installed stock of electric water heaters in its service territory. To support the development of a strategy it is recommended that research be undertaken to fill this knowledge gap. The study would have the following objectives:

- define the water heater target market by:
    - obtaining quantitative data on the numbers, types (tank sizes and element ratings) of the existing stock; and
    - obtain forecast estimates of the numbers, types (tank sizes and element ratings), technologies and fuel sources of new water heaters expected to be installed in new construction and replacements;

29 NFEE, Regulation Impact Statement - Phasing out Greenhouse Intensive Water Heaters in Australian Homes, 2009.

- identify and evaluate technical, tariff and regulatory options for shifting and/or curtailing the existing water heater load and associated Aurora, customer and societal costs and benefits;
- identify and evaluate technical, tariff and regulatory options for replacing water heaters at end of life with off-peak storage and other water heater technologies;
- examine options for encouraging off-peak storage and other water heater technologies in new construction; and
- develop a recommended strategy, which may include trials, and timing for implementing a least-cost integrated set of recommended solutions.

This study should be commissioned as soon as possible. Results are expected to also inform program design and planning of the DSM initiatives proposed in the location-specific DSM projects outlined in Section 8 of this report. The estimated expenditure for this project is $0.25 million, which would be in the form of opex.

7.2.3. Customer power factor correction program

Power factor (PF) correction is another non-network strategy that is applicable to a wide range of end uses within medium to large (and even smaller) business facilities. Commercial and industrial facilities that have 'inductive' equipment such as electric motors and fluorescent lamps often impose a poor PF onto the network. Low PF factor reduces the current carrying capacity of distribution lines and transformers thereby requiring larger capacity infrastructure to supply a given load requirement. Ultimately, poor PF leads to increases in the kWh cost of delivering energy to customers.

Clause 8.6.3 of the Tasmanian Electricity Code (TEC) requires that large customers above 2 MVA maintain a PF in the range 0.85 to 0.95 depending on supply voltage. Smaller customers of 100 kVA to 2 MVA must comply with a PF of 0.8 to 0.9, once again depending on supply voltage. It is not clear whether there is any enforcement of these requirements in Tasmania and therefore there may be customer sites which fail to meet the minimum PF level. Further, even if customers meet these requirements there is still scope for deriving network benefits by encouraging customers to raise their PF above the minimum requirement.

Aurora Energy has also introduced kVA network tariffs for some business customers, with approximately half the C&I load currently supplied under kVA tariffs at the present time. KVA tariffs provide the appropriate price signaling for the business to equitably recover the costs of poor PF while providing customers with poor PF a price incentive to raise their PF. While it has been outside the scope of this study to examine PF data of individual customers, from experience elsewhere, despite the kVA tariff driver there are likely to be many customer sites with poor PF factor that have yet to invest in improving the PF at their sites. Factors preventing customers from implementing PF correction equipment include lack of awareness of PF correction technologies, lack of technical expertise, time and resources to fully investigate the options, poor understanding of the PF correction business case and lack of capital.

If the average power factor of Aurora Energy's medium/large C&I sector could be raised from 0.85 to 0.95 the resulting peak load reduction would be in the order of 11% of the peak demand contribution of the medium/large C&I customer segment. We estimate this to equate to about 30 MVA of peak load reduction across the network. This could be achieved by Aurora implementing an aggressive PF correction program designed to overcome the barriers to the take-up of PF correction technologies supported by the current kVA tariff offerings. The program would identify customers with poor PF and offer technical expertise and resources, business case information and potentially financing solutions to assist them with the installation of power factor correction equipment. This program could be implemented at relatively low cost and be delivered and leveraged in partnership with PF correction equipment suppliers.[30]

A PF correction program has been proposed as a strategy for reducing load to achieve capex deferrals in the location-specific projects discussed in Section 8. Aurora could utilise these location-specific PF projects to gain experience in implementing such a program during 2012 – 2017 PD ahead of a broader based program being introduced state-wide in the following PD. The estimated expenditure to fund a study to investigate PF correction potential (at the customer level), design a program and business case is estimated at $0.15 million. This funding requirement would be in the form of opex. An additional funding allowance to cover PF correction equipment incentives funded out of deferral benefits has been allowed for in the budgets for the location-specific DSM projects discussed in the next section.

7.2.4. Energy storage with integrated renewable distributed generation trial

Trials to test and demonstrate different distributed generation and energy storage solutions will provide a range of long term benefits to both Aurora and its customers. Trials should aim to explore the potential of energy storage and embedded generation in particular, given the physical characteristics of Aurora's network and operating environment, which includes a significant rural network and challenging topography.

Energy storage provides a tool to balance supply and demand through the day and provides a good opportunity to integrate large amounts of renewable energy. In this context energy storage technologies could be used as an alternative to traditional network augmentation solutions particularly in locations where network investment is driven by infrequent, but sharp short term peaks and the costs of network augmentation are very high. Storage could be installed at the end of long lines to reduce demand at the load point, thereby improving network stability and lowering losses. Another relatively new technology for this type of application is small scale renewables incorporating storage technology such as fuel cells, flow batteries, flywheels, and ultra batteries.

30 For example, ETSA Utilities entered into a joint venture with Clipsal to offer power factor correction equipment to facilities with an excessively low power factor.

An Aurora trial would demonstrate the role of energy storage in rural networks integrated with grid supply and / or renewable based distributed generation. Funding for the trial would need to cover the testing and evaluation of the potential application of storage and a renewables based distributed generation system. The trial would involve review and selection of a test system, selection of a suitable rural site for the trial and design, installation, testing and evaluation.

The key R&D objectives of the project would be to:

- pioneer and demonstrate new design and operating practices for electricity networks;
- develop intelligent management methods for networks and storage that integrates multiple storage technologies;
- provide the business with practical experience in planning and implementing alternative network support solutions;
- achieve network support and reliable supply from renewable energy sources; and
- provide operational and cost data to support business cases for energy storage technologies in other parts of the network.

A potential site for the trial could be Bruny Island, given the environmental sensitivity of the area, supply constraints and the sharp, short duration peak load characteristics. Further analysis of Bruny Island as a location for DSM opportunities is provided in Section 8 of this report.

The estimated expenditure for this project is $0.7 million in capex and $0.3 million in opex. The capex estimate is based on the market cost of renewable technologies such as advanced mini wind and photovoltaics, and assessed at $2,000 – $5,000 / kVA. For the purpose of this analysis a budget estimate of $3,500 / kVA has been assumed. The capex excludes the energy storage component of the installation which has been estimated at a further $ 0.62 million. This capex has been taken up in the avoided cost benefit of upgrading the Bruny Island submarine cables and is itemised in the location-specific projects in Section 8. The opex estimate is based on the labour resources required to develop, design, model and assess this project, as well as install and operate equipment and has been estimated at 50% of one FTE over 5 years.

7.2.5. Institutional partnership trial

The institutional segment includes primarily public sector customers such as state and local governments, schools and higher learning institutions, hospitals, and police, and fire departments. The focus of this trial would be to create an ‘energy partnership’ with a local council to generate peak demand reductions, and energy cost savings, through municipal retrofits, and community outreach. The trial would seek to develop community specific educational and marketing materials and outreach programs to enhance participation in a suite of measures including load control of water heating, renewable energy technologies, and energy efficiency programs.

A combination of market research with homeowners and businesses in conjunction with alliances with the local council, and public and private sector institutions would be used to target customers on Aurora's network that would best benefit from integrated DSM and DG measures, and to then develop and promote the adoption of integrated proposals that include a comprehensive range of options.

A number of other DNSP's have successfully worked with local councils to deliver co-operative DSM programs within specific geographic areas. For example, Ergon Energy has implemented a DSM program on Magnetic Island focusing on the eco-tourism market. Tourists are made aware that they are staying in a solar- powered and energy-efficient precinct. Local operators also benefit from the cost savings due to energy efficiency as well as enhanced comfort. The high profile and visible technologies also enhance credibility. The project also has an education and awareness raising component that further enhances the experience for tourists.

A potential location for a similar trial in Aurora's service area would be Bruny Island in partnership with the Kingborough local council. The local council would benefit in being able to promote the island as an energy efficient destination and local operators would benefit from attracting the eco-tourist segment. Aurora could also work in conjunction with property developers to develop sustainable infrastructure and communities which are energy efficient, innovative and minimise their impact on peak demand. The trial could form the first step in a longer term strategic approach to a fully self-sufficient energy supply system for the island.

The institutional partnership trial supports the distributed energy storage and renewable trial discussed in Section 7.2.4 and the Bruny Island DSM project discussed in Section 8. An additional opex component associated with the institutional partnerships trial would cover the costs of market research, establishing 'energy partnerships' with local council and institutions, and the development of targeted educational, marketing and outreach materials. A budget expenditure of $0.25 million is proposed. It has been assumed that program-set and administration costs would be covered under the opex forecast for the establishment of Aurora's non-network solutions team discussed in the Part 4 report: "Development of Business Structures to Support Non-Network Planning".

7.2.6. Curtailable / DG program with large C&I customers

Although the large C&I sector is not a major contributor to the peak, contributing some 16% of the overall load, large C&I customers typically offer cost effective and rapidly deployable DSM and DG opportunities. Therefore, procedures and capability for contracting load reductions from large C&I customers should be an integral part of Aurora's non-network strategy. A large C&I program would recognise two separate but related opportunities in this sector;

- discretionary curtailable loads; and
- embedded and standby generators.

Discretionary Curtailable Loads

A load curtailment agreement is a contract between Aurora (or another program host such as a retailer, or demand aggregator) and a customer, whereby the customer switches off or shifts load at the request of the host. Load curtailment agreements are used to reduce loads on peak demand days, and are generally dispatched for less than 50 hours per year.

This DSM approach generally suits medium to large commercial, industrial, and institutional customers who have loads or processes that can be switched off for a given period of time without having a negative impact on their operations. Requests by the program host to reduce load are made anywhere from one day to one hour in advance of the actual dispatch period for a load reduction event, depending upon the amount of time that a customer needs to ensure the security and safety of their operation. Verification of customer load reductions generally rely on interval meter data but other verification methods can be used depending on the specific circumstances of the participant.

Customers are compensated for turning off load through a payment from Aurora that covers the cost of switching off the load plus a small profit margin. Generally, the terms and conditions, commercial arrangements, and load reduction commitments of curtailment agreements are negotiated on a customer-by-customer basis.

The commercial arrangements often include two payment streams to induce customer participation. The first – an availability payment (or standby payment) – is a fixed amount to cover any upfront costs of committing the load reduction resource. Availability payments are made irregardless of whether or not a customer's load is dispatched. The second – a dispatch payment – covers the variable costs of reducing load, and are based on the amount of the load reduction and the amount of time over which it was provided, for every dispatch event. In addition to the payment of incentives, other costs associated with the program include marketing the program to customers, establishing contracts and commercial arrangements, and administering the program.

Embedded and standby generator agreements

Embedded generation can provide dual benefits to a distribution network. First, if an embedded generator can be relied upon to be available during peak periods, then the local load can be supplied by the generator rather than through the distribution network, with the result that local capacity upgrades may be deferred. Second, small-scale embedded generators can reduce electrical losses on the system by supplying load and therefore reducing the amount of electricity that must be imported from the transmission system.

Embedded generation technologies can encompass a wide range of generator technology types and capacities. These can range from large gas-fired cogeneration facilities in large customer premises to small stand-by generators sited in customers' premises for emergency use that could be deployed for load response on a contractual arrangement.

It is not necessary for the latter type to have export capability as such units can still provide useful quantities of load response by supporting the site's own load for short periods of time.

Aurora could act as a promoter and facilitator of embedded generation, arranging feasibility assessments and installation for large customers. It could even consider owning and operating these facilities and on-selling the energy and heating services back to the customer and deriving the revenues from these sales in addition to the network benefits. Aurora could also enter into contractual arrangements with the owners of existing stand-by generators located within customers' premises for use in curtailing load as described earlier. As a first step Aurora could conduct research into the existing and proposed standby-generation capacity with a view to creating a database of the standby generation potential within its service territory that could be contracted with for short periods at times of local peak demands.

Issues that will need to be addressed include connection costs, which may impact the cost-effectiveness of some embedded generator projects, and environmental compliance. The latter is likely to be more of an issue with the operation of diesel generators within built-up areas such as the CBD.

Several curtailable load and embedded generator opportunities have been discussed in the location-specific projects in Section 8. Costs to cover incentives to customers have been taken up as part of the deferral value of network augmentation projects in these areas. An additional opex component is required under the broad based initiatives to enable Aurora to develop a database of existing standby generators, set up capability to evaluate embedded generation opportunities and feasibility assessments, develop dispatch systems and procedures and develop draft contract templates for contracting with large C&I customers for curtailable load and generator capacity. A total opex requirement of $0.20 million is proposed for these tasks.

7.2.7. LED streetlighting trial

Streetlighting is estimated to account for 0.5 – 1% of the evening peak. Energy efficient streetlighting technologies such as light-emitting diodes (LED), offer the potential for significant energy and peak demand savings of up to 30 – 50% of the existing energy and peak demand of luminaries in current use. There are several ongoing and completed trials of LED streetlighting in both Australia and overseas. EnergyAustralia and the City of Sydney council have installed 250 LED streetlights in CBD as part of an evaluation to assess the cost-effectiveness of the technology. Another trial, conducted by the US DoE in San Francisco California in 2008, demonstrated the energy, lighting quality and maintenance benefits of LED streetlighting.[31]

31 US DOE, "LED Streetlighting: Host City of San Francisco California", December 2008

The US trial found that the economic viability of LED streetlights are sensitive to many site specific variables such as energy and maintenance costs, luminaire lifetime, initial capital cost and whether LEDs are installed to replace existing luminaries or as part of a new streetlighting installation.

Given that energy efficient streetlighting has potential to clip the evening peak, Aurora could seek an allowance in its 2012-2017 PD submission to fund the installation of LED lighting in selected locations as part of a trial. The aim of the trial would be to assess the economic, DSM and technical viability of LED streetlighting in Tasmanian urban areas to both Aurora and local councils. Several locations are discussed as potential sites for such a trial Section 8 however funding for such a trial cannot be justified on capex deferral savings alone due to the high cost of LED streetlighting at the present time.

It is recommended that Aurora seek $0.25 million to conduct a trial of 100 luminaires. This would cover $0.10 million in capex costs for procurement of luminaries based on an assumed cost of $1000 per luminaire. Funding to cover project staffing and design is estimated at an additional $0.15 million. Further funding for research, monitoring and report could be sourced from the DMIA. Aurora could also seek co-contribution funding from participating local councils. Results of the trial will assist Aurora in identifying the most cost-effective applications of LED streetlighting and provide data to develop a business case for potential wider-scale implementation in conjunction with local councils.

7.3. SUMMARY OF FUNDING REQUIREMENT FOR BROAD BASED PROGRAMS AND TRIALS FOR THE 2012 - 2017 PRICING DETERMINATION PERIOD

The total budget for Aurora's broad based programs and trials has been estimated approximately $4.1 million, with opex and capex requirements estimated at $2.55 million and $1.55 million, respectively. Table 7 summarises the forecast budget requirements for each of the items discussed above.

Table 7: Proposed Opex/Capex for the 2012-2017 PD for broad based non-network initiatives

Budget Item	Opex $(m)	Capex $(m)
Residential and small business load response project	$1.25	$0.75
Residential and small business water heater study	$0.25	n/a
Customer power factor correction program	$0.15	n/a
Energy storage with integrated renewable distributed generation trial	$0.30	$0.70
Institutional partnership trial	$0.25	n/a
Curtailable / DG program with large C&I customers	$0.20	n/a
LED streetlighting trial	$0.15	$0.10
Grand Total	**$2.55**	**$1.55**

8. PROPOSED LOCATION-SPECIFIC NON-NETWORK PROJECTS FOR THE 2012-17 EDPR

Section 8 presents the results of the assessment of non-network (demand-side management and distributed generation) solutions in several Aurora Energy planning areas. This assessment has been based on a detailed review of the 11 area strategic planing reports recently prepared for Aurora by Aurecon.

8.1. INTRODUCTION

Projects with good prospects for non-network solutions were initially identified by conducting a judgemental screening of all proposed capex projects planned by Aurora Energy for 2012 – 2017 regulatory control period. Factors considered in the screening process included magnitude of the required load reductions to achieve a deferral, capital cost, customer composition, lead time and load growth.

The following capex projects where identified from the screening analysis as having good potential for deferral by the application of non-network strategies:

- Blackmans Bay Zone Substation;
- Bruny Island Feeders;
- Sandford Zone Substation;
- Wynyard Terminal Substation; and
- Bridgewater 33 kV Injection Point & Austins Ferry Zone Substation

In conducting the detailed assessment of non-network solutions in each of the above areas the following data sources were reviewed and/or utilised to conduct further analysis:

- Aurecon Strategic Plans for the 11 planning areas;
- Aurora's May 2010 capex plan for next 2012 – 2017 regulatory control period;
- planning area load models;
- winter 15 minute terminal substation SCADA load data; and
- customer numbers and winter energy data by tariff class.

8.2. Blackman's Bay Zone Substation

8.2.1. Background

The South planning area incorporates the region south of Hobart including the coastal towns of Kingston, Blackmans Bay, Margate, Electrona and Bruny Island. The Kingston area is experiencing high growth from residential and commercial development in new land releases as well as infill and higher density development. The area also consists of small acreage farming and forestry allotments.

The Kingston area is supplied by the Kingston terminal substation which comprises 2 x 35 MVA 110/11 kV transformers providing a firm capacity of 35 MVA and 12 x 11 kV distribution feeders. The load at Kingston currently exceeds the firm N-1 rating.

The establishment of the new Kingston 110/33 kV injection point and the Browns Rd zone substation in 2012 will alleviate the constraints on Kingston TS for several years. However, the 11 kV load is forecast to exceed firm capacity at Kingston TS and Browns Rd by 2016.

8.2.2. Proposed Supply-side Network Solution

The preferred network solution is to establish a new 2 x 25 MVA 33/11 kV zone substation at Blackman's Bay by 2016/17. The Blackman's Bay ZS will be supplied from the new Kingston 110/33 kV terminal substation.

Without an alternate non-network solution Aurora's planned network solution would require capex of $12.6 million in 2016/17[32] to establish the Blackman's Bay ZS and a further $4 million in 2018/19 for additional feeder works.

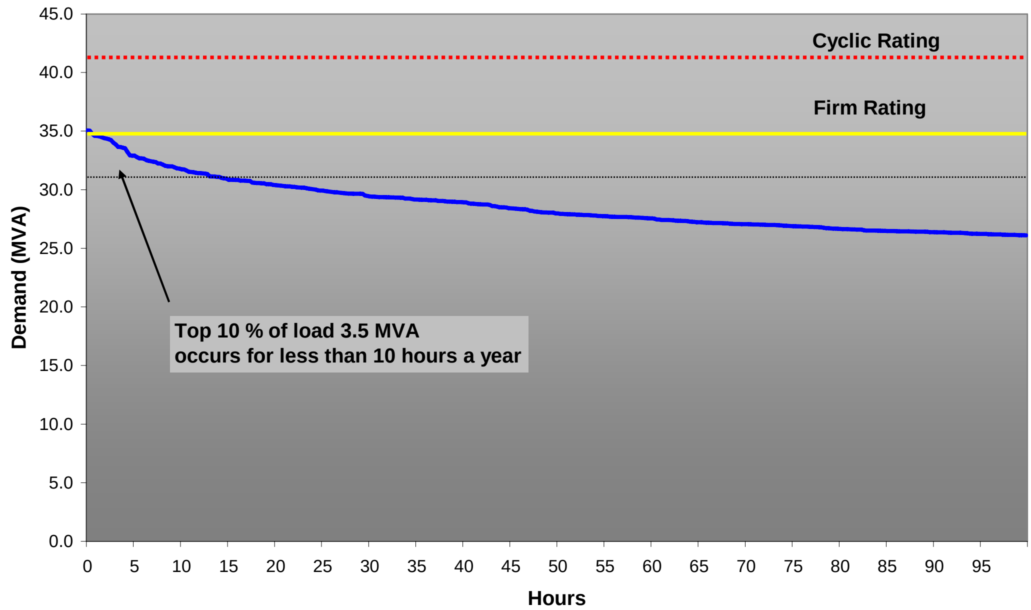
8.2.3. Load Characteristics

Load Duration Analysis

As shown in Figure 8, the forecast maximum demand on the Kingston terminal substation, following deloading to Brown's Road in 2012 is expected to exceed 35 MVA by 2016. Based on actual 2008 load data from the Kingston TS the peak occurred at 6:45 pm on Monday 21 July. The top 3.5 MVA (or 10%) of the load occurs for less than 10 hours a year or just under 0.5% of the time.

32 Source: Aurecon, South Area Strategic Plan, Revision 5 20 May 2010 & advice from P. Milbourne 16 / 6 / 2010.

Figure 8: Kingston TS Forecast 2016 Load Duration for Top 100 hours



Note 1: Forecast based on actual 1 May 2008 – 31 Aug 2008 SCADA data from Kingston TS.

Peak Day Load Profile

A comparison of the peak day profile to a mild weekday day shows that there is a 12 MVA difference in magnitude between the maximum demand and mild day evening peak load. This difference is attributed to temperature-dependant load, predominantly residential space heating.

Figure 9 shows a forecast of the 21 July 2008 peak day load profile projected out to 2016 based on Aurora's medium growth rate scenario. This is compared to a forecast mild weekday day profile based on actual SCADA load data of 15 May 2008.

The peak day load is characterised by a primary peak in the evening that occurs at 6:30 pm and a secondary peak at around 8:00 am, and a baseload of around 10 MVA. By 2016 the primary peak is expected to have reached Kingston terminal substation's firm rating.

A comparison of the peak day profile to a mild weekday day shows that there is a 12 MVA difference in magnitude between the maximum demand and mild day evening peak load. This difference is attributed to temperature-dependant load, predominantly residential space heating.

Figure 9: Kingston Terminal Substation - Forecast Peak Day Load July 2016 vs Mild Day

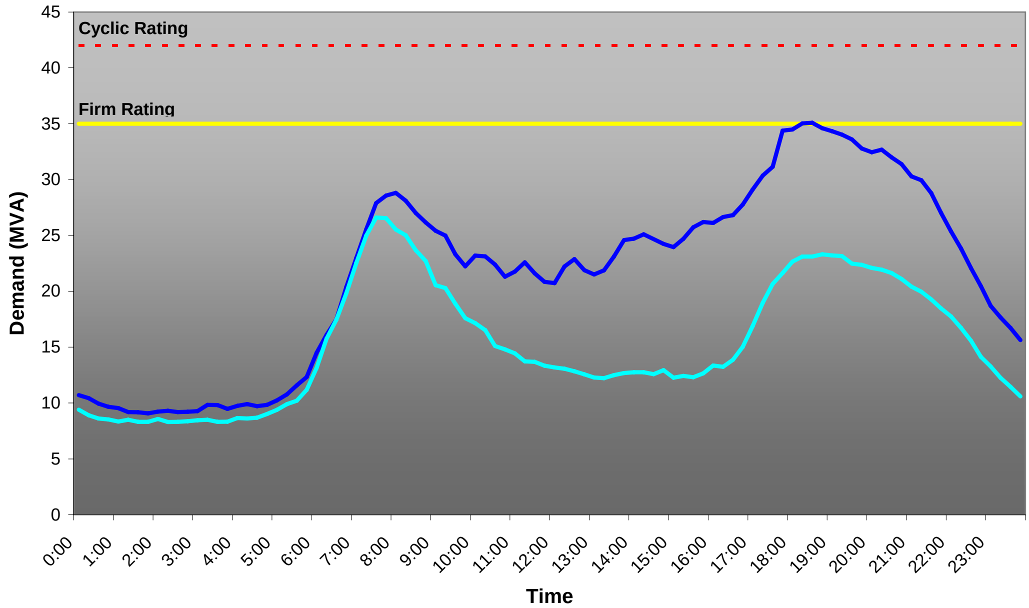


Table 8 presents estimates of the contribution of customer classes and network tariffs to the 2016 forecast evening peak based on analysis of billing data. Residential loads, mainly supplied under tariffs N01, N05 and PAYG, are estimated to account for 24 MVA (or 69%) of the evening peak. Small to medium C & I customers are estimated to account for 24% of the peak, while the large C & I sector accounts for the remaining 7%.

Table 8: Customer Contribution to Evening Peak on Kingston TS

Customer Class	Network Tariff Codes	Counts (Note 1)	Contribution to Evening Peak	
			MVA	% of peak
Residential	N01	12,419	7.5	21%
Residential	N05	11,412	14.3	41%
Residential	N06	2,217	0.2	1%
Residential	N13	1,357	2.3	7%
Agriculture	N08, N08A	6	0	0%
Small / Med C & I	N02, N02A, N02B, N03, N09, N13B	1,645	8.5	24%
Large C & I	N10, N10S, N11, N15, ITC	2	2.5	7%
	Totals	15,429	35.3	

Note 1: count excludes N05 and N06 to avoid double counting with N01 and N02.

Uncontrolled loads on the N05 tariff, such as residential electric space heating and uncontrolled water heating are significant contributors to the peak and are estimated to account for 14 MVA or 41% of the evening peak. There will also be additional uncontrolled space heating and water heating load supplied under the PAYG. This is estimated to account for an additional 1 – 2 MVA. Other significant residential end-uses, supplied under the N01 tariff, likely to be contributing to the evening peak include electric cooking, lighting, dishwashers and refrigeration.

Significant end-use loads in the small / medium C & I segment will include commercial lighting, water heating, space heating, cooking and refrigeration. The large C & I sector, comprises 2 customers and accounts for an estimated 2.5 MVA of winter evening peak demand.

There will also be streetlighting load that will coincide with the evening peak. We estimate streetlighting contributes in the order of 0.5 – 1% of peak demand to the evening peak.

8.2.4. Forecast Load Characteristics

Load Forecast

The current load forecast for Kingston TS indicates a load growth rate of 0.96 MVA per annum based on Aurora's medium load growth scenario. Table 9 provides estimated load forecast for Kingston TS and load over firm based on Aurora's current load model.

Table 9: Moderate Growth Scenario Load Forecast for Kingston TS (MVA)[33]

FY Ending	2011	2012	2013	2014	2015	2016	2017
Annual/Forecast Load	39.94	31.24	32.20	33.16	34.13	35.08	36.03
MVA over Firm	4.94	0.0	0.0	0.0	0.0	0.08	1.03

Load Reduction Targets

To achieve at least a one year deferral of the Blackman's Bay ZS will require sufficient non-network resources to address at least one year of load growth. Therefore, based on the load growth rate at Kingston, 1 MVA of non-network capacity is required to achieve a 1 year deferral and 2.0 MVA is required to achieve a 2 year deferral of the Blackman's Bay zone substation. Relative to maximum peak demand on Kingston TS this target represents a 3 to 6 % reduction in peak demand.

33 Source: Aurora NW-#30060429-v6-Kingston_Load_Model_2008.xls

8.2.5. DSM and DG Potential

The following provides an indicative assessment of the DSM and DG potential on the Kingston terminal substation:

- if a third of the N05 load and 25% of the N13 (PAYG) load is comprised of water heating then water heating contributes about 6 MVA to the peak. If water heating is mostly made up of medium to large storage tanks and a conservative 25% of this load could be shifted away from the peak, potential load reductions from controlling water heating are estimated at 1.5 MVA. This should be combined with a program supported by appropriate tariffs to facilitate a switch to off-peak electric storage, off-peak electric heat pump and/or off-peak electric boosted solar water heating at end of life water heater replacement;

- a further 1 – 2 MVA of load reduction could be obtained by encouraging residential and small business customers to shift usage of discretionary appliances away from the peak period using a combination of financial incentives (tariffs, bill credits and/or rebates), information and load control technology;

- there will be additional opportunities to reduce load by direct load control of space heating with programmable controllable thermostats (PCTs) and by facilitating improvements in lighting and appliance energy efficiency in the residential and small / medium business sectors. However, further end-use and load research is required to quantify this potential;

- although the contribution to peak demand from the large C & I sector is relatively small there may be existing embedded generation and/or curtailable load opportunities available from the two large customers supplied off Kingston TS. We understand this includes a fish farm, which may have processing and pumping loads, and the Antarctic Division head office; both sites may offer opportunities for load curtailment. It is assumed that 0.5 MVA of curtailable load is available from these customers;

- conversion of streetlighting to high efficiency streetlighting technologies such as light-emitting diode (LED) technology could achieve a further 0.2 – 0.4 MVA of peak load reduction; and

- given the load growth expected in the South planning area opportunities to minimise on-peak load growth by working with builders and developers to incorporate DSM and DG in new buildings should be investigated. DSM and DG measures typically have the highest cost-effectiveness when incorporated at time of construction build rather than retrofitted at a later date once inefficient equipment is already installed. As a minimum Aurora should ensure, with the support of a program and appropriate tariffs, that all new residential and small / medium commercial developments incorporate off-peak water heating and off-peak space heating. Assuming that each MVA of new load growth has a similar composition to the existing load, load growth could be reduced by more than 40% or 0.8 MVA over 2 years by simply encouraging off-peak tariffs and load shifting technologies.

Table 10 provides an estimate of the load reduction impacts of the DSM/DG strategies described above. As shown, there is sufficient DSM & DG potential to achieve at least a 2 year deferral with sufficient margin for contingency.

Table 10: Projected Load Reduction Impacts by DSM Strategy for Year 2016

Segment	DSM/DG Strategy	Estimated LR Impact (MVA)	2 year deferral target (MVA)
Residential	Water heating load control	1.5	
Residential/Small C&I	Load Response	1.5	
Residential/Small C&I	New Construction	0.8	
Large C & I	Curtailable Loads/Generators	0.5	
Local Council	High efficiency streetlighting	0.3	
Totals		**4.6**	**2.0**

Note that since Bruny Island is to be supplied from Kingston when the Browns Rd substation is installed, the Bruny Island DSM project, which is discussed in the Section 8.3, may also be utilised to deliver approximately 0.2 MVA of peak shaving from distributed storage.

Timing

A DSM solution would need to be proven and operational by winter 2014 in order to defer the commissioning date for Blackman's Bay ZS beyond 2016. This allows for a 2 year margin of safety to revert to peak shaving generation (standby unit) or a network solution if the DSM target is not achieved. Most of the DSM potential is in the residential and small / medium business customer sectors. DSM from small customer sectors typically requires longer planning and implementation time frames to ensure sufficient market saturation occurs to achieve the specified load reduction targets. Therefore, DSM planning should commence no later than 2012, the first year of the next PD.

8.2.6. Cost Benefit Analysis

Deferral Benefit

The avoided cost of the network solution establishes the maximum expenditure that Aurora Energy should spend on DSM. This value is determined by calculating the worth to the business of deferring the planned network solution. Table 11 provides estimates of the benefit of deferring Aurora Energy's $16.6 m associated with the establishment of Blackmans Bay zone substation by 1 and 2 years, respectively.

Table 11: Estimated 1 & 2 year Benefits for Deferral of Blackman's Bay ZS (WACC 6.64%)

1 Year Deferral			2 Year Deferral		
Target MVA	Deferral Benefit	DSM Cap $/kVA	Target MVA	Deferral Benefit	DSM Cap $/kVA
1.0	$682,000	$708	2.0	$1,322,000	$686

Aurora Energy could therefore spend up to $690 / kVA over the 2 year deferral period to procure DSM resources from the Kingston area. Typically, a threshold value of $100 per kVA[34] begins to make DSM options viable.

DSM & DG Costs

The key modelling inputs underlying the assessment of the cost-benefit of each of the DSM programs reviewed included:

- Program set-up and administration;
- Marketing;
- Capital upgrades to customer's equipment and operating expenditure for operation of standby generators; and
- Customer incentive payments and rebates.

Model inputs for each of the DSM and DG programs assessed for this location are presented in Appendix A. DSM initiatives have been selected on a least cost basis with only sufficient DSM resources being procured to achieve the required annual load reduction for the 2 year deferral of the Blackman's Bay ZS. A summary of the recommended DSM / DG strategy, associated cost estimates and a comparison to the 2 year deferral benefit are presented in Table 12.

Table 12: Summary of DSM Program Budget Costs for Blackman's Bay ZS

Segment	DSM / DG Strategy	Estimated DSM Costs $/kVA	Total DSM Costs ($k)	2 year Deferral Benefit ($k)	Estimated LR Impact (MVA)	2 year deferral target (MVA)
Residential	Water heating load control	$330	$660		1.0	
Residential/ Small C&I	Load Response	$340	-		-	
Residential/ Small C&I	New Construction	$260	$300		0.6	

34 CRA International, "Independent Review of the Demand Management & Planning Project Results for the Sydney Inner Metropolitan Area", EnergyAustralia, November 2007.

Segment	DSM / DG Strategy	Estimated DSM Costs $/kVA	Total DSM Costs ($k)	2 year Deferral Benefit ($k)	Estimated LR Impact (MVA)	2 year deferral target (MVA)
Large C & I	Curtailable Loads / Gens	$100	$100		0.5	
Local Council	High efficiency streetlighting	$3,500	-		-	
Totals			$1,060	$1,322	2.1	2.0

The total estimated DSM cost of $1.06 million is comprised of $0.53 million in opex and $0.53 million in capex related costs.

8.2.7. Conclusion

The analysis indicates that there is likely to be the 1 to 2 MVA of DSM capacity at Kingston required to achieve at least a one year deferral of the Blackmans Bay zone substation. This load reduction target represents a 3 to 6% reduction in peak demand, which is considered moderately achievable.

Most of the required DSM capacity is likely to come from the small customer sectors. DSM from these sectors presents higher risks and will require more detailed and longer term planning than DSM initiatives with larger customers. There may be additional DSM capacity in the form of embedded generation and/or load curtailment available from the two large C&I sector customers. This potential opportunity should be investigated and confirmed as a first priority, before detailed planning of the small customer DSM program is undertaken. DSM from larger customers is typically very cost-effective, can be implemented relatively quickly with minimal planning and presents lower risks.

The estimated deferral value of $700 / kVA is considered to be good and allows for a DSM budget of $1.06 m over the 2 year deferral period. On balance, there appears to sufficient DSM potential at Kingston to justify proceeding to more detailed assessment and planning.

8.3. BRUNY ISLAND FEEDERS

8.3.1. Introduction

Bruny Island is supplied by two submarine cables; Cable 1 (Fdr 33271) is supplied from Kingston substation and is around 60 years old, while Cable 2 (Fdr 33275), currently supplied from the Electrona substation, is around 50 years old. Supply to Cable 2 will be switched to Kingston when the Browns Rd zone substation is installed. Cable 2 supports around 80% of the load on the island and serves to reduce load and subsequent stress on the older cable. Cable 1 is used as a back up for Kermandie substation or Feeder 006 and current constraints are such that it is not possible to run the entire island off cable 1 during winter. Both cables are rated at 76 amps per phase continuous. The peak cyclic rating is 106 amps (2.02 MVA @ 11,000 volts nominal).

Load growth of the island has been steadily increasing and has been driven by changes in demographics and tourism. When both cable 1 and cable 2 loads are combined present peak loadings are approaching 100 amps or 95% of the cyclic load. During peak periods loading on cable 2 exceed the cable's nominal rating.

Another concern is that the cables are difficult to condition monitor. When the cable is operating at its cyclic rating there is a risk that localised hot spots could weaken the cable joints leading to premature failure. If one cable fails and this incident coincides with peak demand there is a higher probability of a second failure.

8.3.2. Proposed Supply-side Network Solution

A proposal to replace the ageing Cable 2 has been considered in the past under the project title of Bruny Island Replacement Submarine Cable. Advice from Aurora Energy indicates the cost of replacing the cable is in the order of $4 million. There is no planned commissioning date for this project. Aurora Energy is also considering installing diesel generator capacity on the island to mitigate cable failure risks.

8.3.3. Load Characteristics

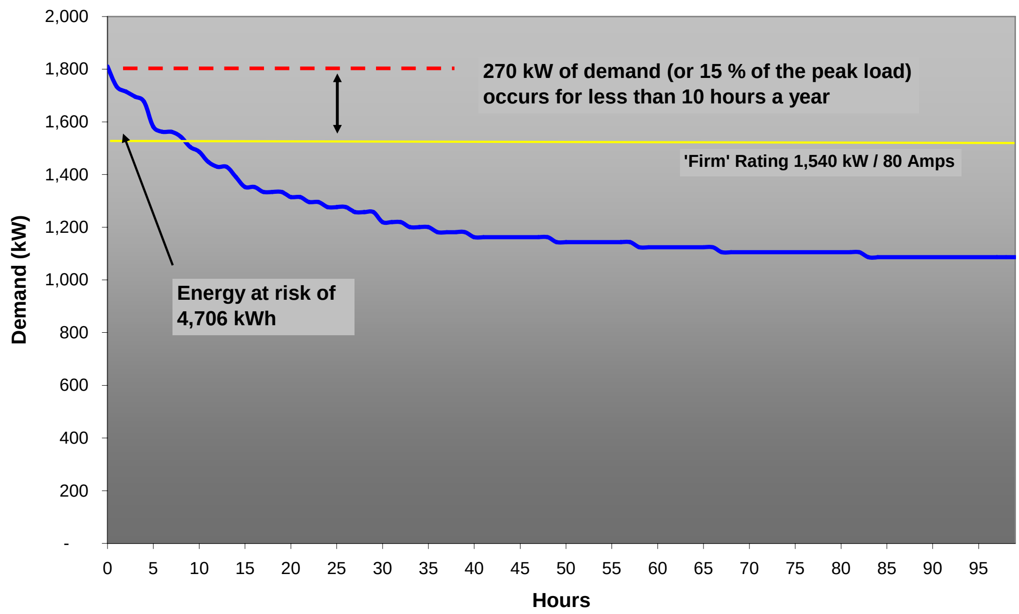
Load Duration Analysis

As shown in Figure 10, the maximum demand on Bruny Island based for the combined loading of the two cables was 1,810 kW (95 amps) and occurred at 7:30 pm on Good Friday, 10 April 2009. This MD equated to 270 kW above Aurora Energy's preferred combined cable loading of 1,540 kW (80 amps).[35]

This load exceeded 1,540 kW (80 amps) for only 10 hours of the entire year, or just over 0.1% of the time. All these hours occurred over the Easter long weekend. The load above firm also represents 4,706 kWh of energy at risk.

35 Email advice from Brent D'Alton to Futura dated 3 June 2010 that keeping peak demand below 80 amps combined for the entire island will buy Aurora Energy considerable time. Even peak load reductions down to 90% of 106 amps = 95 amps offer a significant reduction in risk.

Figure 10: Cable 1 and 2 Load Duration for Top 100 hours (1 Apr 09 - 31 Mar 10).

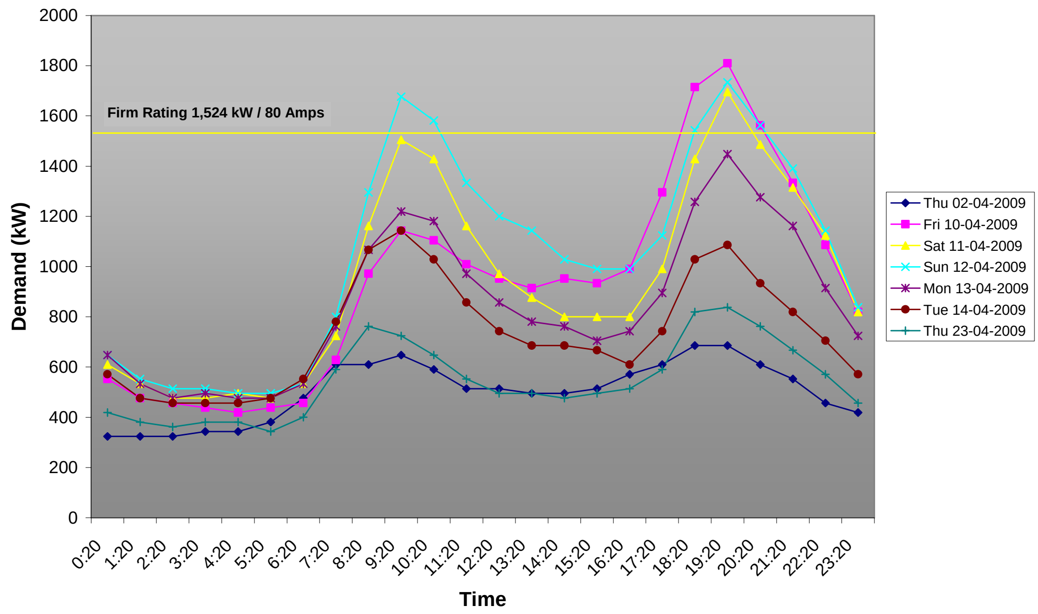


Peak Day Load Profile

The electrical load on Bruny Island comprises predominantly residential load with small to medium commercial load. There are a total of 1,470 residential premises on the island. We estimate from billing data analysis that about a third to half of these are permanently occupied whilst the remainder are holiday homes. The median annual consumption for residential customers is 4,900 kWh. Over 100 residential customers consume more than 15,000 kWh per year. Further, there are about 300 small business customers on the island but no significant commercial or industrial loads.

Figure 11 provides daily load profiles for the five days over the 2009 Easter holidays from Good Friday to Easter Tuesday and compares these to a pre and post Easter weekday. The load peaked on the evening of Good Friday, followed by sharp morning (and evening peaks) that reached or exceeded the 'firm' level on Easter Saturday and Sunday. The load on the morning of Good Friday was well below 'firm' possibly indicating that many holidaymakers were still traveling to their holiday destination. The maximum duration of the peak was two hours in the morning (8:30 to 10:30 am) and three hours in the evening (5:30 to 8:30 pm). The load profiles can be seen to gradually diminish in magnitude over Easter Monday and Tuesday as holidaymakers begin to leave. Non-permanent residents appear to be adding 1,000 kW to the island's baseload of around 800 kW at the time of the evening peak.

Figure 11: Load Profiles for 2009 Easter days relative to pre & post Easter weekdays



The Easter 2010 load profiles show almost identical load characteristics, although peak demands were lower due to the milder weather conditions relative to 2009.

Figure 12: Load Profiles for 2010 Easter days relative to pre & post Easter weekdays

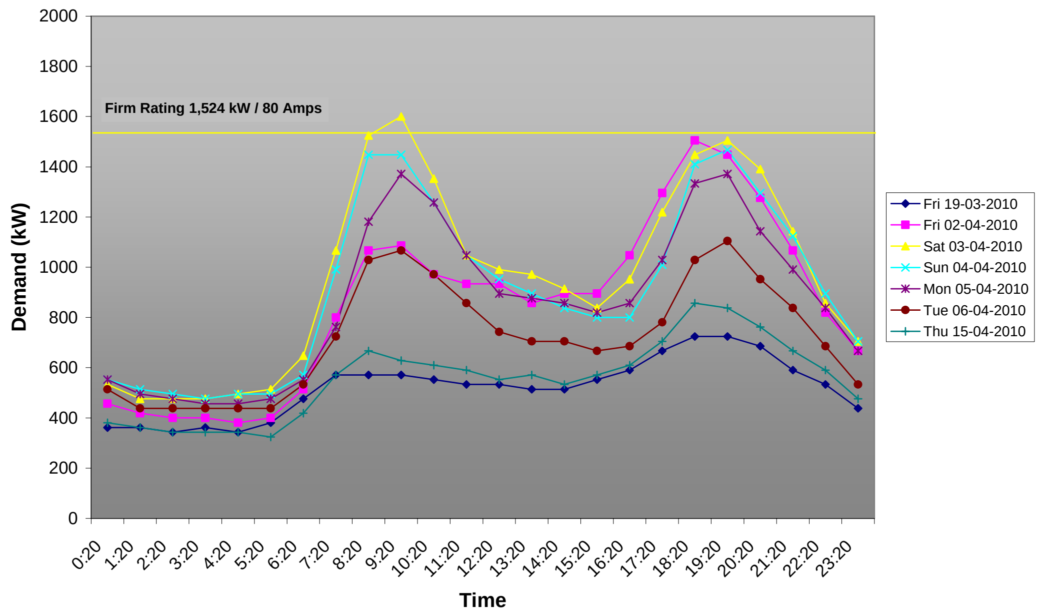


Table 13 presents estimates of the contribution of customer classes and network tariffs to the morning and evening peak based on an analysis of billing data. Residential loads, mainly supplied under tariffs N01 and N05, are estimated to account for 93% of the evening peak and 81% of the morning peak. The remaining load is estimated to come from the small commercial segment.

Table 13: Customer Contribution to Morning and Evening Peaks

Customer Class	Network Tariff Code	Counts (Note 1)	Estimated Contribution to Evening Peak		Estimated Contribution to Morning Peak	
			kVA	% of peak	kVA	% of peak
Residential	N01	1,449	870	47%	680	42%
Residential	N05	1,104	800	44%	600	37%
Residential	N06	118	10	0%	5	0%
Residential	N13	23	30	2%	25	2%
Agriculture	N08	3	0	0%	0	0%
Small C & I	N02	289	140	7%	320	19%
	Totals	1,764	1,850		1,630	

Note 1: count excludes N05 and N06 to avoid double counting with N01 and N02.

Uncontrolled loads, such as water heating and electric space heating, supplied on tariff N05 are estimated to account for 44% of the evening peak and 37% of the morning peak. Significant end-uses on the N01 tariff likely to be contributing to the morning peak include electric cooking, clothes washing and refrigeration. End uses on the N01 tariff likely to be contributing to the evening peak include lighting, electric cooking, refrigeration and dishwashers. Important end-uses in the small commercial segment on tariff N02 are likely to be lighting, water heating, space heating, cooking and refrigeration.

8.3.4. Forecast Load Characteristics

Load Forecast

There are no load forecasts derived specifically for the Bruny Island cables. Based on load forecasts developed by UES for Electrona, load on Bruny Island is expected to increase at 2.8% per annum. Further information provided by Aurora Energy during the preparation of this report indicates that a new load enquiry for a proposed 'self catering accommodation' premise could add a further 400 - 500 kW to the peak[36].

Load Reduction Targets

For DSM to be effective, maximum demands on the combined cables need to be kept at or below 80 amps. The load reduction target for the island loading is estimated as: maximum demand of 1,810 kW (95 amps) – 1,540 kW (80 amps) = 270 kW. This represents a 15% load reduction relative to peak demand based on current loads excluding load growth.

36 Email advice from Brent D’Alton to Futura dated 3 June 2010

Aurora Energy also consider that a 5% load reduction would be useful in reducing load at risk. This target equates to 100 kW of peak load reduction.

A load reduction target of 270 kW is considered to be quite significant relative to peak demand on the island, while a 5% load reduction target of 100 kW is considered to be quite achievable.

8.3.5. DSM and DG Potential

There is limited information on the characteristics of end-use loads on Bruny Island at the present time to accurately calculate the DSM potential. However, an indicative analysis based on "best guess" assumptions suggests that:

- if half to three-quarters of the N05 load is comprised of water heating then water heating contributes about 400 – 600 kW to the system peak. If water heating is mostly made up of medium to large storage tanks and a conservative 25% of this load could be shifted to non-peak periods potential load reductions from controlling water heating are estimated to be in the order of 100 to 150 kW. This should be combined with a program, supported by appropriate tariffs, to facilitate a switch to off-peak electric storage, off-peak electric heat pump and/or off-peak electric boosted solar water heating at end of life water heater replacement;

- a further 100 kW of load reduction by encouraging shifting of discretionary appliance usage away from the peak periods as part of a community load response program;

- there may be additional opportunities for load reduction from space heating and by improving the energy efficiency of lighting and appliances in the residential and small business sectors;

- opportunities to minimise on-peak load growth by working with builders and developers to incorporate DSM and DG in new buildings should be also be investigated. As a minimum Aurora should ensure, with the support of a program and appropriate tariffs, that all new residential and small / medium commercial developments incorporate off-peak water heating and off-peak space heating. Assuming that each MVA of new load growth has a similar composition to the existing load, annual load growth could be reduced by more than 30%, or a 0.1 MVA reduction in new load expected to occur over 5 years based on annual load growth of 2.8%, by simply encouraging take up of off-peak tariffs and technologies in new construction; and

- given the short frequency and duration of peak loads distributed storage technology, such as sodium sulphur (NAS) or zinc-bromide battery systems, could be effective as a peak shaving strategy. This approach is likely to be more acceptable to the local community than deploying diesel generation given the importance of tourism and ecologically sustainable development on the island. Due to the high cost of distributed storage at the present time ($2,500 - $4,000 / kVA) we have assumed Aurora will deploy a small scale system of around 200 kVA on Bruny Island as part of a technical trial involving combined storage and renewable energy generation.

Table 14 provides an estimate of the load reduction impacts of the DSM/DG strategies described above. As shown, the strategies provide the load reduction target required to provide an effective level of contingency network support on Bruny Island over the next 5 year PD period.

Table 14: Projected Load Reduction Impacts by DSM Strategy to Year 2017

Segment	DSM/DG Strategy	Estimated LR Impact (MVA)	5 year contingency planning target (MVA)
Residential	Water heating load control	0.1	
Residential/Small C&I	Load response	0.1	
Residential/Small C&I	New Construction	0.1	
All sectors	Peak shaving with dist. storage	0.20	
Totals		**0.50**	**0.50**

8.3.6. Cost Benefit Analysis

Deferral Benefit

The avoided cost of the network solution establishes the theoretical maximum amount that Aurora Energy could spend on DSM on Bruny Island. Typically, this value is determined by calculating the value of deferring the planned network solution. However, as there is no planned schedule for the submarine cable replacement project we have estimated what DSM could be worth based on several approaches.

There is currently an estimate 4.706 MWh at risk at times of system peak where load exceeds 80 amps. Based on the current Value of Customer Reliability (VCR) of $55,000 per MWh the cost of unserved energy is estimated at $260,000 in the event that load shedding is required to bring the load to the 'firm' level. We consider this quantity of unserved energy to be a conservative as it does not take into account load growth.

Further, every year that construction of the submarine cable project is avoided represents cost savings to Aurora of $265,000 (based on capex of $4 million and an assumed WACC of 6.64%).

Aurora Energy has also allocated $500,000 in its capex budget for the next pricing determination to procure generators for load support on the island. DSM could be viewed as an alternative strategy to the installation of a generator and therefore presents an upper limit on a potential DSM budget.

On balance, a reasonable, and defensible, upper limit for DSM related capex and opex expenditure on Bruny Island is $300,000 annually or $1.5 million over the 2012 – 2017 PD. If 286 kVA of demand reductions could be achieved this equates to a cap of $ 1,050 / kVA for procurement of DSM resources.

DSM & DG Costs

The key modelling inputs underlying the assessment of the cost-benefit of each of the DSM programs reviewed included:

- program set-up and administration;
- marketing;
- capital upgrades to customer's equipment and operating expenditure for operation of standby generators; and
- customer incentive payments and rebates.

Model inputs for each of the DSM and DG programs assessed for Bruny Island are presented in Appendix A. DSM initiatives have been selected on a least cost basis with only sufficient DSM resources being procured to provide sufficient network support of around 0.5 MVA over the 5 year period of the 2012 – 2017 PD. A summary of the recommended DSM / DG strategy, associated cost estimates and a comparison to the 2 year deferral benefit are presented in Table 15.

Table 15: Summary of DSM Program Budget Costs for Bruny Island Network Support

Segment	DSM / DG Strategy	Estimated DSM Costs $/kVA	Total DSM Costs ($k)	5 year network support benefit ($k)	Estimated LR Impact (MVA)	5 year network support target (MVA)
Residential	Water heating load control	$330	$160		0.1	
Residential/ Small C&I	Load response	$340	$150		0.1	
Residential/ Small C&I	New Construction	$260	$125		0.1	
All sectors	Peak shaving with dist. storage	$3000	$620		0.2	
Totals			$1,055	$1,500	0.5	0.5

The total estimated DSM cost of $1.05 million is comprised of $0.30 million in opex and $0.75 million in capex related costs.

8.3.7. Conclusion

The preliminary DSM analysis indicates that sufficient DSM opportunities exist on Bruny Island to achieve at least 100 kW and potentially more, of peak load reduction to provide pre-contingency support. However, further research is required to gather data on the types and quantities of end-use loads to more accurately assess the DSM potential. Aurora should also work closely with the proponents of any new connected loads to ensure these incorporate best practice energy efficiency and load management technology to minimise impact on the peak. Off-peak water heating, storage space heating and high efficiency lighting technologies should be strongly encouraged and incentivesed. Additional peak shaving could be addressed with distributed energy storage technology.

The proposed non-network supply strategy for Bruny Island is a hybrid approach involving DSM as a first priority combined with distributed storage technology.

8.4. SANDFORD ZONE SUBSTATION

8.4.1. Introduction

The Hobart East planning area is supplied via a highly meshed network comprising a group of 110 / 33 kV terminal substations and 33 / 11 kV zone substations. The region is one of the highest growth areas of the state and comprises a mix of urban, larger residential allotments and rural areas. Load growth is expected to come from infill development in existing urban areas as well as new urban subdivision development on the fringes of the existing urban areas.

The load at Rokeby terminal substation, one of the substations in the group, is currently above firm N-1 rating. The substation supplies the suburb of Rokeby and other eastern shores suburbs including Lauderdale and the South Arm peninsula. The current configuration at Rokeby includes 2 x 35 MVA 110/11 kV transformers providing a firm capacity of 35 MVA and 10 x 11 kV distribution feeders.

Load transfers to Howrah zone substation and Rosny in 2011 and 2012 will deload Rokeby and defer the need for additional capacity until 2017. There are also two 11 kV feeders from Rokeby to Lauderdale and South Arm which are expected to exceed their planning ratings by 2015. Any non-network solution would need to deload Rokeby TS as well as address the constraints on the feeders serving Lauderdale and the peninsula.

8.4.2. Proposed Supply-side Network Solution

The preferred network solution is to establish a new 2 x 25 MVA 33/11 kV zone substation at Sandford in 2017 to deload Rokeby terminal substation and address feeder constraints serving Lauderdale and South Arm. The new zone substation would be supplied from Mornington terminal substation via 2 new 33 kV underground feeders.

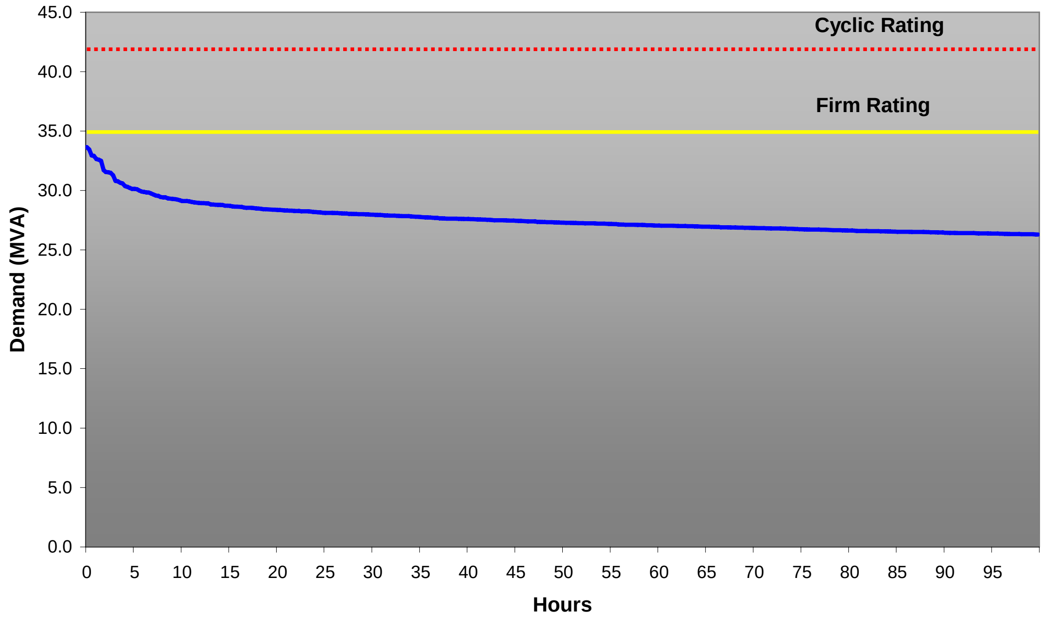
Without an alternate non-network solution Aurora's planned network solution would require capex of $11.9 million in 2016/17[37] to establish the Sandford ZS and associated underground 33 kV works.

8.4.3. Load Characteristics

Load Duration Analysis

As shown in Figure 13, the maximum demand on the Rokeby terminal substation is expected to reach 34 MVA by 2016/17. Based on actual 2008 SCADA load data from the Rokeby terminal station the peak occurred at 6:30 pm on Monday 21 July. The top 3.5 MVA (or 10%) of the load occurs for less than 5 hours a year or just 0.1% of the time.

Figure 13: Rokeby TS Forecast 2016 Load Duration for Top 100 hours



Note 1: Forecast based on actual 1 May 2008 – 31 Aug 2008 SCADA data from Rokeby TS.

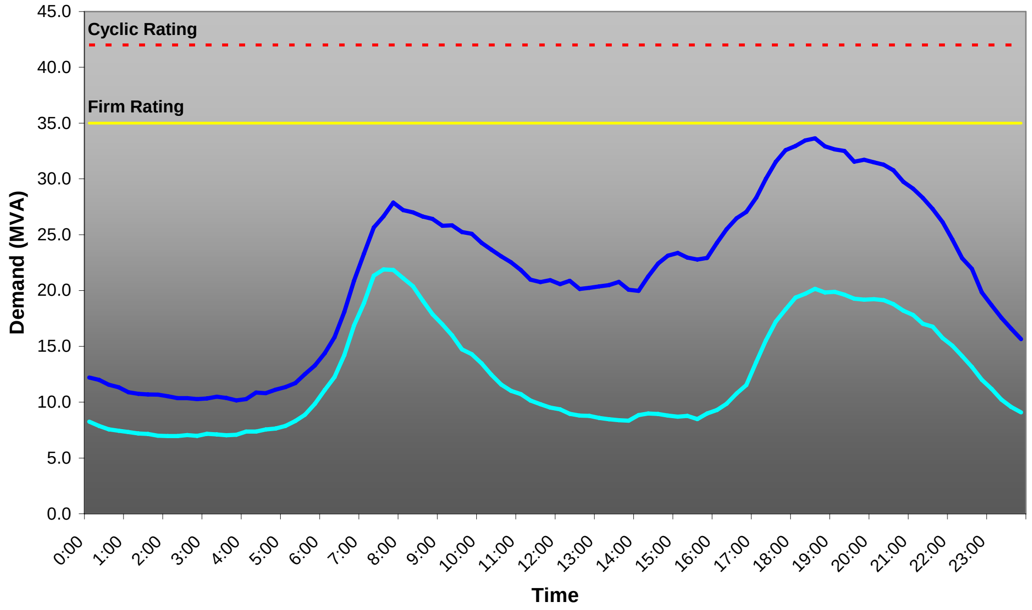
Peak Day Load Profile

The electrical load served by the Rokeby terminal substation comprises a mix of residential, small to medium C & I loads and several large C & I loads.

Figure 14 shows a forecast of the 21 July 2008 peak day load profile projected out to 2016 based on Aurora's medium growth rate scenario. This is compared to a forecast mild weekday day profile based on actual SCADA load data of 15 May 2008.

37 Source: Aurora Energy, May Recut PD SD Capex # 1 (spreadsheet) dated 11 May 2010)

Figure 14: Rokeby Terminal Substation - Forecast Peak Day Load July 2016 vs Mild Day



The peak day load is characterised by a primary peak in the evening that occurs at 6:30 pm and a secondary peak at around 7:45 am in the morning. By 2016/17 the primary peak is expected to have reached the terminal substation's firm rating. The baseload is approximately 10 MVA.

A comparison of the peak day profile to a mild weekday day shows that there is a 15 MVA difference in magnitude between the two evening peaks, which is attributed to temperature-dependant load such as residential space heating.

Table 16 presents estimates of the contribution of customer classes and network tariffs to the 2016 forecast evening peak based on analysis of billing data. Residential loads, mainly supplied under tariffs N01, N05 and PAYG, are estimated to account for 20 MVA (or 58%) of the evening peak. Small to medium C & I customers are estimated to account for 31% of the peak, while the large C & I sector accounts for the remaining 11%.

Table 16: Customer Contribution to Evening Peak on Rokeby TS

Customer Class	Network Tariff Codes	Counts (Note 1)	Contribution to Evening Peak	
			MVA	% of peak
Residential	N01	12,559	5.6	16%
Residential	N05	11,981	11.0	31%
Residential	N06	2,230	0.2	1%
Residential	N13	2,807	3.5	10%

Customer Class	Network Tariff Codes	Counts (Note 1)	Contribution to Evening Peak	
			MVA	% of peak
Agriculture	N08, N08A	16	0	0%
Small / Med C & I	N02, N02A, N02B, N03, N09, N13B	1,755	10.8	31%
Large C & I	N10, N10S, N11, N15, ITC	3	3.9	11%
	Totals	17,140	35	

Note 1: count excludes N05 and N06 to avoid double counting with N01 and N02.

Uncontrolled loads, including residential electric space heating and water heating, supplied on tariff N05 are estimated to account for 11 MVA or 31% of the evening peak. There will also be additional 1 – 2 MVA of uncontrolled space heating and water heating load from the PAYG segment. Significant end-uses on the N01 tariff likely to be contributing to the evening peak include electric cooking, lighting, dishwashers and refrigeration.

Significant end-use loads in the small / medium C & I sector contributing to the peak will include commercial lighting, water heating, space heating, cooking and refrigeration. The large C & I sector, comprising 3 large customers, accounts for an estimated 4 MVA of peak demand.

There will also be streetlighting load that will coincide with the evening peak. We estimate streetlighting contributes in the order of 0.5% of peak demand to the evening peak.

8.4.4. Forecast Load Characteristics

Load Forecast

The load forecast for Rokeby TS shows that load is growing at the rate of 0.79 MVA per annum based on the medium load growth scenario. Table 17 provides estimated load forecast for Rokeby TS and load over firm based on Aurora's current load model. The over firm constraint in 2011 is relieved by load transfers to Howrah and Rosny.

The load model shows no capacity limitations from 2012 onwards, however Aurora's capex plan[38] and Aurecon report[39] indicate Rokeby TS is expected to be commissioned in 2016.

38 Ibid

39 Source: Aurecon, Fig 8-25 Hobart East Area Strategic Plan, Revision 5 20 May 2010

Table 17: Moderate Growth Scenario Load Forecast for Rokeby TS (including load transfers)

FY Ending	2011	2012	2013	2014	2015	2016	2017
Annual/Forecast Load	36.47	30.44	31.22	32.02	32.80	33.59	34.38
MVA over Firm	1.47	0.0	0.0	0.0	0.0	0.0	0.0

Load Reduction Targets

To achieve at least a one year deferral of the Sandford ZS will require sufficient non-network resources to address at least one year of load growth. Therefore, based on the annual load growth rate at Rokeby, 0.8 MVA of non-network capacity is required to achieve a 1 year deferral and 1.6 MVA is required to achieve a 2 year deferral of the Sandford zone substation. This target represents a 2 to 5 % reduction in peak demand.

8.4.5. DSM and DG Potential

The following provides an indicative assessment of the DSM and DG potential within the area supplied by the Rokeby terminal substation:

- if a third of the N05 load and 25% of the N13 (PAYG) load is comprised of water heating then water heating contributes about 5 MVA to the peak. If water heating is mostly made up of medium to large storage tanks and a conservative 25% of this load could be shifted away from the peak, potential load reductions from controlling water heating are estimated to be in the order of 1.5 MVA. This should be combined with a program supported by appropriate tariffs to facilitate a switch to off-peak electric storage, off-peak electric heat pump and/or off-peak electric boosted solar water heating at end of life water heater replacement;

- a further 1 – 2 MVA of load reduction could be obtained by encouraging residential and small business customers to shift usage of discretionary appliances away from the peak period using a combination of financial incentives (tariffs, bill credits or rebates), information and load control technology;

- there will be additional opportunities to reduce load by direct load control of space heating with programmable controllable thermostats (PCTs) and by facilitating improvements in lighting and appliance energy efficiency in the residential and small / medium business sectors. However, further end-use and load research is required to quantify this potential;

- curtailable load and embedded generator arrangements with one or more of the customers in the large C & I sector could provide an additional 0.5 – 1 MVA of load reduction opportunities. However, further research into the site load characteristics (from interval meter data) and availability of curtailable loads and/or embedded generation is required to more accurately quantify and confirm this potential,

- conversion of streetlighting to high efficiency streetlighting technologies such as light-emitting diode (LED) technology could achieve a further 0.2 MVA of peak load reduction; and

- given the load growth expected in the Hobart East planning area opportunities to minimise on-peak load growth by working with builders and developers to incorporate DSM and DG in new buildings should be investigated. DSM and DG measures typically have the highest cost-effectiveness when incorporated at time of construction build rather than retrofitted at a later date once inefficient equipment is already installed. As a minimum Aurora should ensure, with the support of a program and appropriate tariffs, that all new residential and small / medium commercial developments incorporate off-peak water heating and off-peak space heating. Assuming that each MVA of new load growth has a similar composition to the existing load, load growth could be reduced by more than 30% or 0.50 MVA over 2 years by simply encouraging take-up of off-peak tariffs and load shifting technologies.

Table 18 provides an estimate of the load reduction impacts of the DSM/DG strategies described above. As shown, there is sufficient DSM & DG potential to achieve at least a 2 year deferral with sufficient margin for contingency.

Table 18: Projected Load Reduction Impacts by DSM Strategy for Year 2016

Segment	DSM/DG Strategy	Estimated LR Impact (MVA)	2 year deferral target (MVA)
Residential	Water heating load control	1.50	
Residential/Small C&I	Load Response	1.50	
Residential/Small C&I	New Construction	0.50	
Large C & I	Curtailable Loads/Generators	0.75	
Local Council	High efficiency streetlighting	0.20	
Totals		**4.45**	**1.60**

Timing

A DSM solution would need to be proven and operational by winter 2014 in order to defer the commissioning date for Sandford ZS beyond 2016. This allows for a 2 year margin of safety to revert to a network solution if the DSM target is not achieved. Most of the DSM potential is in the residential and small / medium business customer sectors. DSM from small customer sectors typically requires longer planning and implementation time frames to ensure sufficient market saturation occurs to achieve the specified load reduction targets. Therefore, DSM planning should commence no later than 2012.

8.4.6. Cost Benefit Analysis

Deferral Benefit

The avoided cost of the network solution establishes the maximum expenditure that Aurora Energy should spend on DSM. This value is determined by calculating the worth to the business of deferring the planned network solution. Table 19 provides estimates of the benefit of deferring Aurora Energy's $11.9 m associated with the establishment of the Sandford zone substation and 33 kV underground lines, by 1 and 2 years, respectively.

Table 19: Estimated 1 & 2 year Benefits for Deferral of Sandford ZS (WACC of 6.64%)

1 Year Deferral			2 Year Deferral		
Target MVA	Deferral Benefit	DSM Cap $/kVA	Target MVA	Deferral Benefit	DSM Cap $/kVA
0.8	$503,000	$636	1.6	$975,000	$616

Aurora Energy could therefore spend up to $600 / kVA over the 2 year deferral period to procure DSM resources from the Rokeby area.

DSM & DG Costs

The key modelling inputs underlying the assessment of the cost-benefit of each of the DSM programs reviewed included:

- program set-up and administration;
- marketing;
- capital upgrades to customer's equipment and operating expenditure for operation of standby generators; and
- customer incentive payments and rebates.

Model inputs for each of the DSM and DG programs assessed for this location are presented in Appendix A. DSM costs have been assessed by developing a DSM supply curve and only procuring sufficient DSM resources, from least to highest cost, to achieve the necessary annual load reduction for the 2 year deferral of the Sandford ZS. A summary of the recommended DSM / DG strategy, associated cost estimates and a comparison to the 2 year deferral benefit are presented in Table 20. Sandford area could be a good location to test customer load response to critical peak signals and therefore a small allowance has been included for a residential load response trial.

Table 20: Summary of DSM Program Budget Costs for Sandford ZS

Segment	DSM / DG Strategy	Estimated DSM Costs $/kVA	Total DSM Costs ($k)	2 year Deferral Benefit ($k)	Estimated LR Impact (MVA)	2 year deferral target (MVA)
Residential	Water heating load control	$330	$370		0.5	
Residential/ Small C&I	Load Response	$340	$150		0.2	
Residential/ Small C&I	New Construction	$260	$220		0.4	
Large C & I	Curtailable Loads / Gens	$100	$150		0.8	
Local Council	High efficiency streetlighting	$3,500	-		-	
Totals			$890	$975	1.9	1.6

The total estimated DSM cost of $0.89 million is comprised of $0.47 million in opex and $0.42 million in capex related costs.

8.4.7. Conclusion

The analysis indicates that there is likely to be at least 0.8 to 1.6 MVA of DSM capacity at Rokeby to achieve at least a one year deferral of the Sandford zone substation. This load reduction target represents a 2 to 5% reduction in peak demand, which is considered moderately achievable.

Most of the required DSM capacity is likely to come from the small customer sectors. DSM from these sectors presents higher risks and will require more detailed and longer term planning than DSM initiatives with larger customers. There may be additional DSM capacity in the form of embedded generation and/or load curtailment available from the three large C&I sector customers in the area. This potential opportunity should be investigated and confirmed as a first priority, before detailed planning of the small customer DSM program is undertaken. This should include scoping analysis of site load characteristics (from interval meter data), availability of curtailable loads and/or embedded generation and preliminary discussions with customers. DSM from larger customers is typically very cost-effective, can be implemented relatively quickly with minimal planning and presents lower risks.

The estimated deferral value of $600 / kVA is considered to be good and allows for a DSM budget of $890 k over the 2 year deferral period. On balance, there appears to sufficient DSM potential and a high deferral benefit at Rokeby to justify proceeding to more detailed assessment and planning.

8.5. WYNYARD TERMINAL SUBSTATION

8.5.1. Background

The Burnie region is supplied by the Burnie terminal substation which comprises 2 x 60 MVA 110/22-11 kV transformers and 12 x 22 kV feeders. The terminal station serves a diverse mix of customer types including urban residential, industrial, the Burnie airport, high density rural and low density rural. The Burnie CBD is supplied separately from the Emu Bay terminal station.

The Burnie terminal substation is currently operating at 10 MVA above its N-1 firm capacity limit of 60 MVA. Peak loads are approaching the terminal station's cyclic rating of 72 MVA. With the closure of the Australian Paper Mill in July 2010, a new 22 kV connection point is to be established from Emu Bay which will effectively deload the Burnie TS by around 10 -15 MVA.

Further, the Wynyard area is currently supplied from three feeders 91004, 91005, 91006 off the Burnie terminal substation. These feeders are currently operating at close to their maximum rating. The feeders mainly serve industrial and other large loads including Burnie Airport. A new industrial subdivision in Wynyard is also being established next to Burnie Airport which is located in Wynyard.

8.5.2. Proposed Supply-side Network Solution

The preferred network solution is to establish a new 2 x 60 MVA 110/22 kV terminal substation at Wynyard by 2014. The Wynyard terminal substation will deload feeders 91004, 91005, 91006, 91009 and 91012 and remove 28 MVA off the Burnie terminal substation.

The total capex cost to establish the Wynyard TS is $24.2m[40]. Aurora Energy's component of this cost, to cover distribution feeder works, is $4.4 m.[41]

8.5.3. Load Characteristics

Load Duration Analysis

As shown in Figure 15, the maximum demand on the Burnie terminal substation, following deloading of the 22kV feeders to Emu Bay is expected to exceed 60 MVA by 2014. Based on actual 2008 load data from the Burnie TS the peak occurred at 6:45 pm on Monday 21 July. The top 6 MVA (or 10%) of the load occurs for under 10 hours or under 0.5% of the time.

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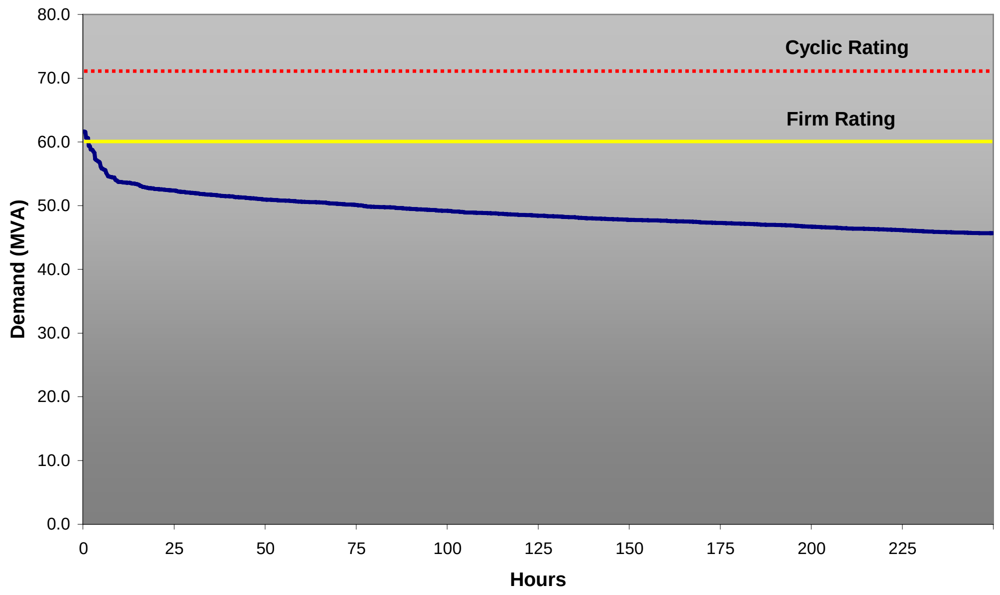
40 Source: Aurecon, North West Area Strategic Plan, Revision 5 20 May 2010

41 Source: Aurora Energy, May Recut PD SD Capex # 1 (spreadsheet) dated 11 May 2010)

Figure 15: Burnie TS Forecast 2014 Load Duration for Top 250 hours



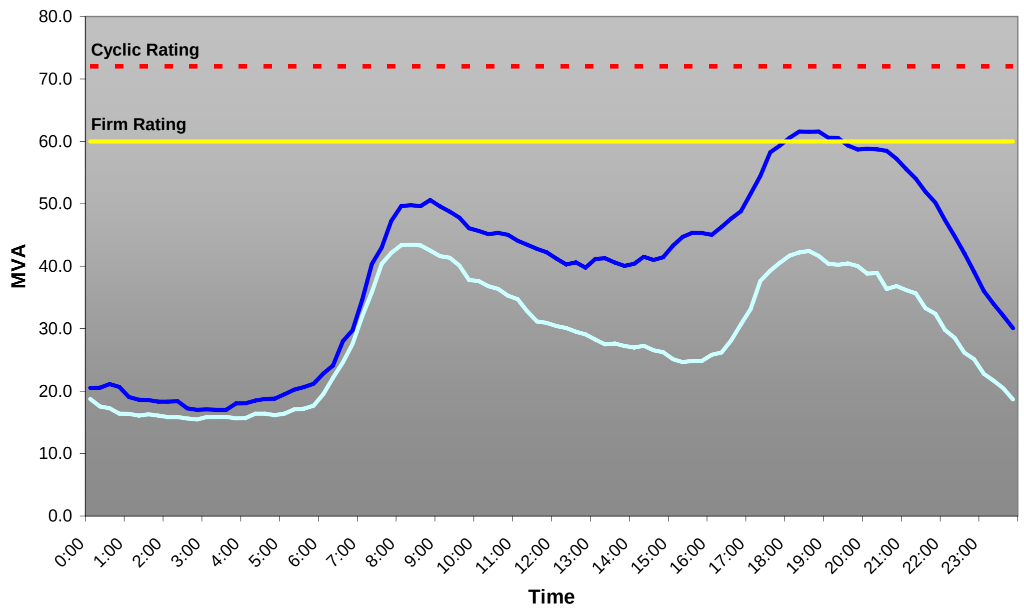
Note 1: Forecast based on actual 1 May 2008 – 31 Aug 2008 SCADA data from Burnie TS.

Peak Day Load Profile

The electrical load served by the Burnie terminal substation comprises a mix of residential, and small / medium commercial loads and several large industrial spot loads.

Figure 16 shows the 2008 peak day load profile projected out to 2014 based on Aurora's medium growth scenario and compares this to a forecast mild weekday day profile based on actual SCADA load data of 15 May 2008.

Figure 16: Burnie TS - Forecast Peak Day Load July 2014 vs Mild Day



The peak day load is characterised by a primary peak in the evening that occurs at 6:45 pm and a secondary peak at around 8:30 am. By 2014 the primary peak is expected to have reached the terminal substation's firm rating. The baseload is approximately 20 MVA.

A comparison of the peak day profile to a mild weekday day shows that there is a 20 MVA difference in magnitude between the two evening peaks. This difference is attributed to temperature-dependant load, predominantly residential space heating.

Table 21 presents estimates of the contribution of customer classes and network tariffs to the 2014 forecast evening peak based on analysis of billing data. Residential loads, mainly supplied under tariffs N01, N05 and PAYG, are estimated to account for 35 MVA (or 57%) of the evening peak. Small to medium C & I customers are estimated to account for 24% of the peak, while the large C & I sector accounts for the remaining 19%.

Table 21: Customer Contribution to Evening Peak on Burnie TS

Customer Class	Network Tariff Codes	Counts (Note 1)	Contribution to Evening Peak	
			MVA	% of peak
Residential	N01	12,537	8.9	15%
Residential	N05	11,943	16.2	27%
Residential	N06	2,588	0.3	0%
Residential	N13	4,942	9.4	15%
Agriculture	N08, N08A	506	0	0%
Small / Med C & I	N02, N02A, N02B, N03, N09, N13B	3,786	14.6	24%
Large C & I	N10, N10S, N11, N15, ITC	19	11.6	19%
	Totals	21,790	60.9	

Note 1: count excludes N05 and N06 to avoid double counting with N01 and N02.

Uncontrolled loads, including residential electric space heating and water heating, supplied on tariff N05 is are estimated to account for 16 MVA or 27% of the evening peak. There will also be additional 5 – 6 MVA of uncontrolled space heating and water heating loads supplied under the PAYG. Significant end-uses on the N01 tariff likely to be contributing to the evening peak include electric cooking, lighting, dishwashers and refrigeration.

Significant end-use loads in the small / medium C & I segment will include commercial lighting, water heating, space heating, cooking and refrigeration.

The large C & I sector, comprising around 19 customers, accounts for an estimated 12 MVA of peak demand. Significant industrial customers in this segment include the Fonterra dairy processing plant at Wynyard which has a winter demand of 0.8 – 1 MVA, the Burnie Airport and several other dairy processing plants including Bonlac and Lactos.

There will also be streetlighting load that will coincide with the evening peak in the order of 0.5 – 1% of peak demand.

8.5.4. Forecast Load Characteristics

Load Forecast

The current load forecast for Burnie TS indicates annual load growth of 0.47 MVA per annum based on the medium load growth scenario. Table 22 provides estimated load forecast for Burnie TS and load over firm based on Aurora's current load model for Burnie TS after an assumed 10 MVA load transfer to Emu Bay around 2011.

Table 22: Moderate Growth Scenario Load Forecast for Burnie TS

FY Ending	2011	2012	2013	2014	2015	2016	2017
Annual/Forecast Load	60.32	60.80	61.27	61.74	62.19	62.63	63.04
MVA over Firm	0.32	0.80	1.27	1.74	2.19	2.63	3.04

Load Reduction Targets

For the purposes of this analysis it is assumed that the over firm load up to 2014 shown in Table 22 will be taken up by Emu Bay via deloading and that DSM will address annual load growth. From Table 22 annual load growth is estimated at 0.5 MVA. Therefore, 0.5 MVA is required to achieve a 1 year deferral and 1.9 MVA is required to achieve a 4 year deferral of the Wynyard terminal substation. A 4 year deferral is required to shift the project into the next PD period. The load reduction targets represent around a 1 – 3 % reduction in peak demand.

8.5.5. DSM and DG Potential

The following provides an indicative assessment of the DSM and DG potential on the Burnie terminal substation:

- there is 2.5 MVA of customer owned embedded generation from the Fonterra plant and possibly other sites including the airport that could potentially be secured under a load curtailability arrangement;

- assuming that some industrial customers operate at least 2 shifts, industrial customers could conservatively provide 8% of 12 MVA (large C&I contribution to peak), which equates to 1 MVA, under a curtailable load agreement;

- it is possible that some of the large C & I customer load contributes to inefficient utilisation of the network because of poor power factor. Assuming that half the large C & I load imposes a power factor on the network of 0.85 and that Aurora encourages these customers via a targeted program to raise their power factor from 0.85 to 0.95 potential demand reductions equate to 5% of the large C & I load or 0.5 MVA;

- if a third of the N05 load and 25% of the N13 (PAYG) load is comprised of water heating then water heating contributes about 8 MVA to the peak. If water heating is mostly made up of medium to large storage tanks and 25% of this load could be shifted away from the peak, potential load reductions from controlling water heating are estimated to be in the order of 2 MVA. This should be combined with a program supported by appropriate tariffs to facilitate a switch to off-peak electric storage, off-peak electric heat pump and/or off-peak electric boosted solar water heating at end of life water heater replacement;

- a further 1 – 2 MVA of load reduction could be obtained by encouraging residential and small business customers to shift usage of discretionary appliances away from the peak period using a combination of financial incentives (such as tariffs, bill credits or rebates), information and load control technology;

- there will be additional opportunities for load control of space heating via load control technology and by facilitating improvements in lighting and appliance energy efficiency in the residential and small / medium business sectors;

- opportunities to minimise on-peak load growth by working with builders and developers to incorporate DSM and DG in new buildings should be also be investigated. As a minimum Aurora should ensure, with the support of a program and appropriate tariffs, that all new residential and small / medium commercial developments incorporate off-peak water heating and off-peak space heating. Assuming that each MVA of new load growth has a similar composition to the existing load, annual load growth could be reduced by 30%, or 0.6 MVA in reduction of new load expected to occur over 4 years based on annual load growth of 0.47 MVA, by simply encouraging take up of off-peak tariffs and technologies in new construction; and

- conversion of streetlighting to high efficiency streetlighting technologies such as light-emitting diode (LED) technology could achieve a further 0.1 – 0.2 MVA of peak load reduction.

Table 23 provides an estimate of the load reduction impacts of the DSM/DG strategies described above. As shown, there is sufficient DSM & DG potential to achieve at least a 2 year deferral with sufficient margin for contingency.

Table 23: Projected Load Reduction Impacts by DSM Strategy for Year 2014

Segment	DSM/DG Strategy	Estimated LR Impact (MVA)	4 year deferral target (MVA)
Residential	Water heating load control	2.00	
Residential/Small C&I	Load Response	1.50	
Residential/Small C&I	New Construction	0.60	
Large C&I	PF correction	0.50	
Large C & I	Curtailable Loads/Generators	3.50	
Local Council	High efficiency streetlighting	0.15	
Totals		**8.25**	**1.9**

Timing

A DSM solution would need to be operational by the first year of the next PD in order to defer the commissioning date for Wynyard TS past 2014. DSM that can be deployed this rapidly is best sourced from large C & I customers. DSM from residential and small / medium business customers requires longer planning and implementation time frames.

8.5.6. Cost Benefit Analysis

Deferral Benefit

The avoided cost of the network solution establishes the maximum expenditure that Aurora Energy should spend on DSM. This value is determined by calculating the worth to the business of deferring the planned network solution. Table 24 provides estimates of the benefit of deferring Aurora Energy's $4.4m component of the capex associated with the new Wynyard terminal substation project by 1 and 4 years respectively. Benefits are based on cost of capital savings only and exclude benefits of deferring capex associated with Transend's component of the works. Inclusion of Transend benefits would substantially increase the total project benefits and would allow a larger quantum of non-network capacity to be procured.

Table 24: Estimated 1 & 2 year Benefits for Deferral of Wynyard TS Feeders (WACC of 6.64%)

1 Year Deferral			4 Year Deferral		
Target MVA	Deferral Benefit	DSM Cap $/kVA	Target MVA	Deferral Benefit	DSM Cap $/kVA
0.5	$212,000	$453	1.9	$771,000	$412

Based on Aurora Energy's savings alone up to $400 / kVA could be spent on DSM initiatives over the 4 year deferral period.

DSM & DG Costs

The key modelling inputs underlying the assessment of the cost-benefit of each of the DSM programs reviewed included:

- Program set-up and administration;
- Marketing;
- Capital upgrades to customer's equipment and operating expenditure for operation of standby generators; and
- Customer incentive payments and rebates.

Model inputs for each of the DSM and DG programs assessed for this location are presented in Appendix A. DSM initiatives have been selected on a least cost basis with only sufficient DSM resources being procured to achieve the required annual load reduction for the 4 year deferral of the Wynyard TS distribution feeders. A summary of the recommended DSM / DG strategy, associated cost estimates and a comparison to the 4 year deferral benefit are presented in Table 25.

Table 25: Summary of DSM Program Budget Costs for Wynyard TS Distn Feeder Works

Segment	DSM / DG Strategy	Estimated DSM Costs $/kVA	Total DSM Costs ($k)	4 year Deferral Benefit ($k)	Estimated LR Impact (MVA)	4 year deferral target (MVA)
Residential	Water heating load control	$330	-		-	
Residential/ Small C&I	Load Response	$340	-		-	
Residential/ Small C&I	New Construction	$260	-		-	
Large C & I	Curtailable Loads / Gens	$100	$770		1.9	
Local Council	High efficiency streetlighting	$3,500	-		-	
Totals			$770	$771	1.9	1.9

The total estimated DSM cost of $0.77 million is comprised of opex related costs.

8.5.7. Conclusion

The analysis indicates there is sufficient DSM capacity at Burnie that can be secured relatively quickly to achieve at least a 1 year, and possibly longer, deferral of the proposed Wynyard terminal substation. The magnitude of load reductions required of around 0.5 – 1.9 MVA equates to 1 – 3% of peak demand which is considered a modest and achievable target. Most of this target could be achieved cost-effectively from DSM opportunities in the large C & I sector. Additional DSM capacity could also be sourced from residential and small / medium business customers to provide additional deferment of the Wynyard TS distribution feeder works.

The average value of around $500 per kVA also provides good scope to secure viable quantities of DSM capacity, and allows for a DSM budget of $770 k over the 4 year deferral period. On balance, there appears to sufficient DSM potential and a high deferral benefit at Burnie to proceed to more detailed assessment and planning.

8.6. BridgeWater 33 KV Injection Point & Austin's Ferry Zone Substation

8.6.1. Background

The Hobart-West planning area comprises the Hobart CBD and suburbs west of the Derwent River, from Lower Taroona in the South to Bridgewater in the North. Electricity is distributed to the area from a group of 110/11kV and 33kV terminal and 33/11 kV zone substations. The area is considered a medium growth area and comprises a mix of commercial, urban residential, and industrial loads. Future growth is expected to come from new housing subdivisions and industrial redevelopment resulting from the new transport hub to be established at Brighton, north of Bridgewater.

The Bridgewater 110 / 11 kV terminal substation is equipped with 2 x 35 MVA transformers, providing a firm capacity of 35 MVA. Claremont zone substation, which is supplied by the Creek Rd 110 / 33 kV terminals substation is equipped with 2 x 22.5 MVA 33/11 kV transformers providing a firm capacity of 22.5 MVA.

Bridgewater terminal substation is forecast to exceed firm capacity in 2014. Claremont zone substation has already exceeded its firm capacity. The Claremont transformers are approaching end of life and are due for replacement in 2020.

8.6.2. Proposed Supply-side Network Solution

The preferred network solution is to install 2 x 60 MVA 110 / 33 kV transformers and switchgear at the existing Bridgewater 110/11 kV site and establish a new 2 x 25 MVA 33 / 11 kV transformer zone substation at Austin's Ferry supplied from Bridgewater, by 2016. This will deload Bridgewater, Creek Rd and Claremont substations.

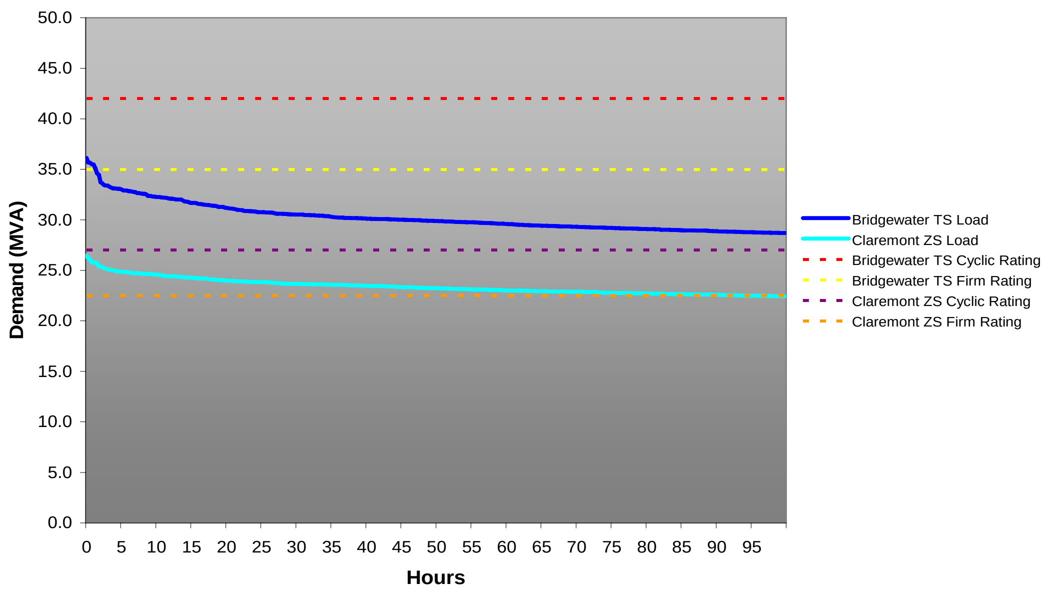
Aurora Energy's capex to establish the new Austin's Ferry ZS is $15.05m.[42] It is assumed that costs associated with the new Bridgewater 33 kV injection point, estimated at $13m[43], are borne by Transend.

8.6.3. Load Characteristics

Load Duration Analysis

Figure 17 shows a forecast winter load duration analysis for the Bridgewater and Claremont substations. Based on 2008 SCADA data the peak occurred at 5:45 pm on Monday 21 July. The top 3.5 MVA (or 10%) of the load at Bridgewater occurs for 10 hours a year or just 0.1% of the time, while at Claremont the top 10% of the load occurs for less than 30 hours a year or just 0.3% of the time.

Figure 17: Bridgewater & Claremont Forecast 2016 Load Duration for Top 100 hours



Note 1: Forecast based on actual 1 May 2008 – 31 Aug 2008 SCADA data from Bridgewater TS&Claremont ZS.

Peak Day Load Profile

Figure 18 and Figure 19 show a forecast of the 21 July 2008 peak day load profile out to 2016 versus a milder weekday day (15 May 2008) profile for the Bridgewater and Claremont substations, respectively. The peak day load on both substations is characterised by a primary peak in the evening between 5:45 pm and 6:00 pm and a secondary peak at around 7:45 - 8:00 am in the morning.

42 Source: Aurora Energy, May Recut PD SD Capex # 1 (spreadsheet) dated 11 May 2010)

43 Source: Aurecon, Hobart West Area Strategic Plan, Revision 5 20 May 2010

By 2016 the primary peak at Bridgewater is expected to have reached the terminal substation's firm rating, while Claremont will be over firm by 4 MVA in the evening and 1 MVA in the morning. Therefore, at Claremont a DSM solution will need to address both the morning and evening peaks to maintain load below firm. The baseload on both substations is approximately 10 – 12 MVA.

Figure 18: Bridgewater TS Forecast Peak Day Load July 2016 vs Mild Day

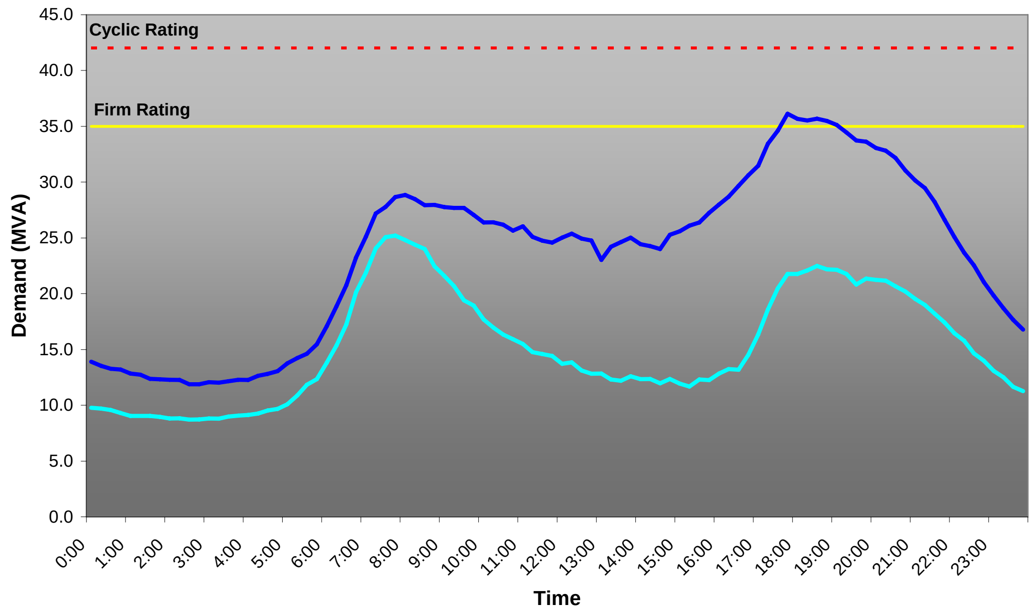
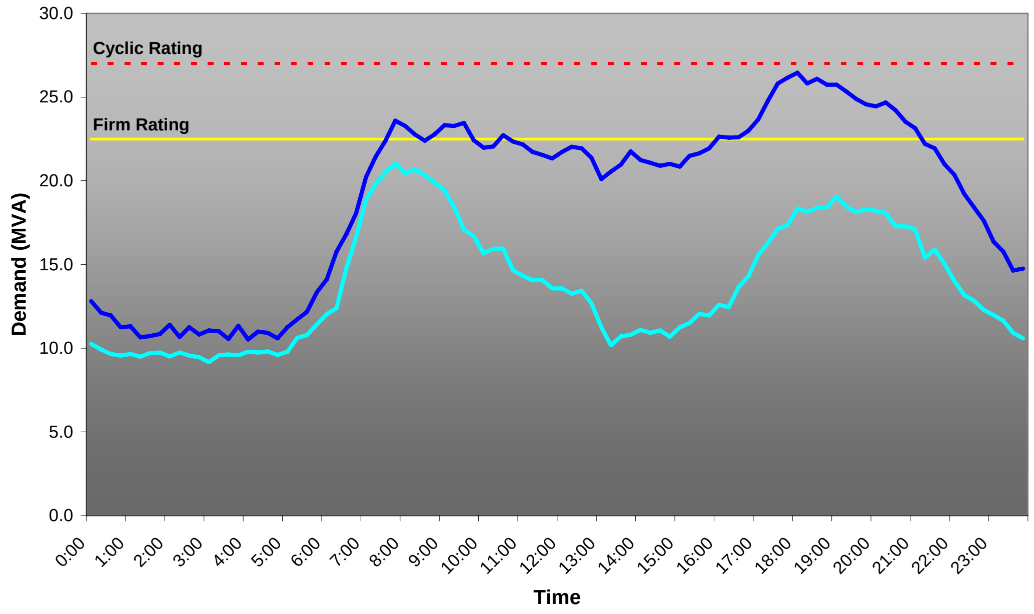


Figure 19 shows the peak day and milder day load profiles (based on SCADA load data for the 15 May 2008) for the Claremont substation.

Figure 19: Claremont ZS - Forecast Peak Day Load July 2016 vs Mild Day



A comparison of the peak day profile to the milder weekday day shows that there is a combined 20 MVA difference in magnitude between the two evening peak loads. This difference represents the magnitude of temperature-dependant load, primarily residential space heating, experienced by the two substations.

Table 26 presents estimates of the contribution of customer classes at the network tariff level to the 2016 forecast evening peak based on analysis of billing data. Residential loads, mainly supplied under tariffs N01, N05 and PAYG, are estimated to account for 40 MVA (or 71%) of the evening peak. Small to medium C & I customers are estimated to account for 18% of the peak, the large C & I sector accounts for 12%, while the agriculture sector accounts for the remaining 1%.

Table 26: Customer Contribution to Evening Peak on Bridgewater/Claremont Substations

Customer Class	Network Tariff Codes	Counts (Note 1)	Contribution to Evening Peak	
			MVA	% of peak
Residential	N01	17,973	9.2	16%
Residential	N05	16,649	18.5	32%
Residential	N06	2,189	0.2	0%
Residential	N13	9,056	12.3	22%
Agriculture	N08, N08A	312	0.3	1%
Small / Med C & I	N02, N02A, N02B, N03, N09, N13B	3,822	10.0	18%
Large C & I	N10, N10S, N11, N15, ITC	11	7.1	12%
	Totals	31,174	57.5	

Note 1: count excludes N05 and N06 to avoid double counting with N01 and N02.

Uncontrolled loads, including residential electric space heating and water heating, supplied on tariff N05 is are estimated to account for over 18 MVA or 32% of the evening peak. There will also be additional uncontrolled space heating and water heating loads supplied under the PAYG tariff. It is estimated that there is an additional 6 – 8 MVA of uncontrolled space and water heating load supplied under this tariff. Other significant end-uses on the N01 tariff likely to be contributing to the evening peak include electric cooking, lighting, dishwashers and refrigeration.

Significant end-use loads in the small / medium C & I segment will include commercial lighting, water heating, space heating, cooking and refrigeration.

The large C & I sector, comprises 11 customers and accounts for an estimated 7 MVA of peak demand. The largest of these customers is understood to be the Cadbury plant which has a peak load of 5 MVA.

There is also an estimated 0.25 – 0.5 MVA of coincident streetlighting load, assuming that streetlighting accounts for 0.5 – 1% of peak demand.

8.6.4. Forecast Load Characteristics

Load Forecast

The current load forecast for Bridgewater and Claremont combined indicates a load growth rate of 0.85 MVA per annum based on the medium load growth scenario. Table 27 provides the load forecast and load over firm for the Bridgewater and Claremont substations based on Aurora's current load model.

Table 27: Moderate Growth Scenario Load Forecast for Bridgewater/Claremont substations

FY Ending	2011	2012	2013	2014	2015	2016	2017
Annual/Forecast Load - Bridgewater	34.04	34.47	34.89	35.30	35.70	36.10	36.48
MVA over Firm - Bridgewater	0.0	0.0	0.0	0.30	0.70	1.10	1.48
Annual/Forecast Load - Claremont	24.28	24.74	25.17	25.61	26.04	26.47	26.89
MVA over Firm - Claremont	1.78	2.24	2.67	3.11	3.54	3.97	4.39
MVA over Firm – Total	1.78	2.24	2.67	3.41	4.24	5.07	5.87

Load Reduction Targets

For the purposes of this analysis it is assumed that the over firm load ramping up to 5 MVA by 2016 will be addressed by load transfers away to other substations in the group. Therefore, 0.85 MVA of DSM and DG capacity is required to achieve a 1 year deferral and 1.7 MVA is required to achieve a 2 year deferral of the new Austin's Ferry zone substation. This represents around a 1.5 – 3 % reduction in peak demand.

8.6.5. DSM and DG Potential

The following provides an indicative assessment of the DSM and DG potential on the combined Bridgewater/Claremont terminal substation:

- if a third of the N05 load and 25% of the N13 (PAYG) load is comprised of residential / small business water heating load then water heating contributes about 9.5 MVA to the peak. If water heating is mostly made up of medium to large storage tanks and a conservative 25% of this load could be shifted away from peak times, potential load reductions from controlling water heating is estimated at 2.5 MVA. This should be combined with a program supported by appropriate tariffs to facilitate a switch to off-peak electric storage, off-peak electric heat pump and/or off-peak electric boosted solar water heating at end of life water heater replacement;

- a further 1.5 – 2.5 MVA of load reduction could be obtained by encouraging residential and small business customers to shift usage of discretionary appliances away from the peak period using a combination of financial incentives (tariffs, bill credits and/or rebates), information and load control technology;

- there will be additional opportunities to reduce load by direct load control of space heating with programmable controllable thermostats (PCTs) and by facilitating improvements in lighting and appliance energy efficiency in the residential and small / medium business sectors. However, further end-use and load research is required to quantify this potential;

- although the contribution to peak demand from the large C & I sector is relatively small there may be discretionary curtailable load and existing embedded generation opportunities from the Cadbury plant and other sites supplied off the two substations that could be contracted under a curtailable load agreement. Assuming that some of these large C & I customers operate at least 2 shifts, industrial customers could conservatively reduce load by at least 10% which equates to 0.7 MVA;

- it is possible that some of the large C & I customer load contributes to inefficient utilisation of the network due to poor power factor. Assuming that half the large C & I load imposes a power factor on the network of 0.85 and that Aurora encourages these customers via a targeted program to raise their power factor from 0.85 to 0.95, potential demand reductions equate to 5% of the large C & I load or 0.2 MVA;

- conversion of streetlighting to high efficiency streetlighting technologies such as light-emitting diode (LED) technology could achieve a further 0.2 – 0.4 MVA of peak load reduction; and

- given the medium to high load growth expected in the Hobart West planning area opportunities to minimise on-peak load growth by working with builders and developers to incorporate DSM and DG in new buildings should be investigated. DSM and DG measures typically have the highest cost-effectiveness when incorporated at time of construction build rather than retrofitted at a later date once inefficient equipment is already installed. As a minimum Aurora should ensure, with the support of a program and appropriate tariffs, that all new residential and small / medium commercial developments incorporate off-peak water heating and off-peak space heating. Assuming that each MVA of new load growth has a similar composition to the existing load, load growth could be reduced by more than 40% or 0.60 MVA over 2 years by simply encouraging take-up of off-peak tariffs and load shifting technologies.

Table 28 provides an estimate of the load reduction impacts of the DSM/DG strategies described above. As shown, there is sufficient DSN & DG potential to achieve at least a 2 year deferral with sufficient margin for contingency.

Table 28: Projected Load Reduction Impacts by DSM Strategy for Year 2016

Segment	DSM/DG Strategy	Estimated LR Impact (MVA)	2 year deferral target (MVA)
Residential	Water heating load control	2.5	
Residential/Small C&I	Load Response	2.0	
Residential/Small C&I	New Construction	0.6	
Large C & I	PF Correction	0.2	
Large C & I	Curtailable Loads/Generators	0.7	
Local Council	High efficiency streetlighting	0.3	
Totals		**6.3**	**2.0**

Timing

A DSM solution would need to be in place by 2014 in order to defer the commissioning date for the Austin's Ferry ZS past 2016. This allows for a 2 year margin of safety to revert to a network solution if the DSM target is not achieved. To provide time for the DSM initiatives to achieve sufficient market saturation to meet specified load reduction targets by 2014, DSM planning should commence no later than 2012 (the first year of the next PD).

8.6.6. Cost Benefit Analysis

Deferral Benefit

The avoided cost of the network solution establishes the maximum expenditure that Aurora Energy should spend on DSM. This value is determined by calculating the worth to the business of deferring the planned network solution. Table 29 provides estimates of the benefit of deferring the $15 m capex associated with the new Austin's Ferry zone substation project by 1 and 2 years respectively.

Table 29: Estimated 1 & 2 year Benefits for Deferral of the Austin's Ferry ZS

1 Year Deferral			2 Year Deferral		
Target MVA	Deferral Benefit	DSM Cap $/kVA	Target MVA	Deferral Benefit	DSM Cap $/kVA
0.85	$637,000	$758	1.70	$1,234,000	$734

Benefits are based on cost of capital savings only and exclude benefits to Transend associated with deferring the new Bridgewater 33 kV injection point. Inclusion of Transend benefits would substantially increase the total project benefits and allow greater scope for DSM implementation.

The analysis assumes that the load reduction target is based on DSM addressing annual load growth only and excludes the load over firm existing on the Bridgewater and Claremont assets prior to 2016, which are assumed to be addressed by load transfers. On Aurora Energy's savings alone up to $730 / kVA could be spent over the 2 year deferral period on DSM initiatives.

DSM & DG Costs

The key modelling inputs underlying the assessment of the cost-benefit of each of the DSM programs reviewed included:

- program set-up and administration;
- marketing;
- capital upgrades to customer's equipment and operating expenditure for operation of standby generators; and
- customer incentive payments and rebates.

Model inputs for each of the DSM and DG programs assessed for this location are presented in Appendix A. DSM initiatives have been selected on a least cost basis with only sufficient DSM resources being procured to achieve the required annual load reduction for the 2 year deferral of the Austin's Ferry ZS. A summary of the recommended DSM / DG strategy, associated cost estimates and a comparison to the 2 year deferral benefit are presented in Table 30.

Table 30: Summary of DSM Program Budget Costs for the Austin's Ferry ZS

Segment	DSM / DG Strategy	Estimated DSM Costs $/kVA	Total DSM Costs ($k)	2 year Deferral Benefit ($k)	Estimated LR Impact (MVA)	2 year deferral target (MVA)
Residential	Water heating load control	$330	$375		0.5	
Residential/ Small C&I	Load Response	$340	-		-	
Residential/ Small C&I	New Construction	$260	$375		0.6	
Large C & I	PF Correction	$300	$95		0.2	
Large C & I	Curtailable Loads/Generat ors	$100	$125		0.6	
Local Council	High efficiency streetlighting	$3,500	-		-	
Totals			$970	$1,234	1.9	1.7

The total estimated DSM cost of $0.97 million is comprised of $0.45 million in opex and $0.52 million in capex related costs.

8.6.7. Conclusion

The analysis indicates that there is likely to be at least 0.85 to 1.7 MVA of DSM capacity at the Bridgewater / Claremont area to achieve at least a one year deferral of the Austin's Ferry zone substation. This assumes that DSM will be utilised to address annual load growth only, and not the over firm load. The annual load growth target represents a 1.5 to 3% reduction in peak demand, which is considered achievable.

Most of the required DSM capacity is likely to come from the small customer sectors. DSM from these sectors presents higher risks and will require more detailed and longer term planning than DSM initiatives with larger customers. There may be additional DSM capacity in the form of embedded generation, load curtailment and power factor correction available from the large C&I sector customers in the area, such as Cadburys.

This potential opportunity should be investigated and confirmed as a first priority, before detailed planning of the small customer DSM program is undertaken. This should include scoping analysis of site load characteristics (from interval meter data), power factor, availability of curtailable loads and/or embedded generation and preliminary discussions with customers.

The estimated deferral value of $750 / kVA is considered to be good and allows for a DSM budget of $970 k over the 2 year deferral period. On balance, there appears to sufficient DSM potential and a high deferral benefit at Bridgewater / Claremont to justify proceeding to more detailed assessment and planning.

8.7. SUMMARY OF DSM OPEX / CAPEX REQUIREMENTS FOR CONSTRAINED NETWORK ELEMENTS

Potential DSM and DG opportunities have been identified at five locations on Aurora Energy's network that are subject to planned network augmentation amounting to $55 million in expenditure in the forthcoming 2012 – 2017 pricing determination.

Table 31 provides a summary of the findings in each of the five locations including Aurora's planned augmentation capex, DSM & DG potential available in these locations, years of deferral required to shift the capex into the next PD period, load reduction targets to achieve the necessary deferral period, deferral benefits and budget DSM project implementation costs. There is a potential 24 MVA of DSM & DG capability that could be investigated in these locations versus a total requirement of 7.7 MVA needed to defer each of the planned augmentation projects into the next PD period. Note that in the case of the Bruny Island feeders, DSM will be utilised as a contingency support strategy to maintain loadings below a firm level to minimise the probability of a feeder failure.

The estimated benefit of deferring the planned capex is $5.8 million, while the cost of implementing the DSM strategy to achieve these deferrals is estimated at $4.7 million over the next 2012 – 2017 regulatory control period.

Table 31: Summary of Estimated Costs and Benefits of Location-Specific DSM Initiatives

Aurora Network Project	Planned Network Augment. Capex $k	Years of Deferral Required to shift capex to next PD	Estimated Available DSM & DG (MVA)	DSM/DG Costs & Benefits		
				DSM/DG Target (MVA)	Deferral Benefit $k	DSM Costs $k (Note 2)
Blackman's Bay ZS	$16,600	2	4.6	2.0	$1,322	$1,060
Bruny Island Feeders (Note 1)	$4,000	5	0.5	0.5	$1,500	$1,055
Sandford ZS	$11,900	2	4.5	1.6	$975	$890
Wynyard TS	$4,400	4	8.3	1.9	$771	$770
Bridgewater 33 kV & Austins Ferry ZS	$15,050	2	6.3	1.7	$1,234	$970
TOTALS	**$51,950**		**24.2**	**7.7**	**$5,802**	**$4,745**

Notes

(1): Benefits at Bruny Island relate to DSM & DG being deployed for contingency support and to reduce load at risk. The target includes the first year target plus an allowance for load growth over the 5 years of the next PD.

(2): Total DSM costs are budget estimates only and include capex and opex related cost items. More detailed business cases are required to refine costs.

9. SUMMARY OF FUNDING REQUIREMENTS TO IMPLEMENT PROPOSED NON-NETWORK INITIATIVES

Sections 7 and 8 of this report identified a work program of non-network initiatives for the forthcoming 2012 – 2017 PD period. This section provides a summary of the recommended funding requirements for these initiatives. The total budget for Aurora's proposed broad based and location-specific non-network activities is $8.9 million, with opex and capex requirements estimated at $5.1 million and $3.8 million, respectively. Of this total budget, it is expected that $2 million would be covered by the DMIA.

Table 32 summarises the forecast budget requirements for each of the broad based and location-specific projects discussed in Sections 7 and 8.

Table 32: Summary of Funding for Non-Network Projects for the 2012 - 2017 PD period

Budget Item	Opex $ (m)	Capex $ (m)
Broad based programs and trials		
Residential and small business load response project	$1.25	$0.75
Residential and small business water heater study	$0.25	n/a
Customer power factor correction program	$0.15	n/a
Energy storage with integrated renewable distributed generation trial	$0.30	$0.70
Institutional partnership trial	$0.25	n/a
Curtailable / DG program with large C&I customers	$0.20	n/a
LED streetlighting trial	$0.15	$0.10
Sub-total – Broad based programs and trials	**$2.55**	**$1.55**
Location-specific non-network programs		
Blackman's Bay ZS	$0.53	$0.53
Bruny Island Feeders	$0.30	$0.75
Sandford ZS	$0.47	$0.42
Wynyard TS	$0.77	n/a
Bridgewater 33 kV & Austins Ferry ZS	$0.45	$0.52
Sub-total – Location-specific non-network programs	**$2.52**	**$2.22**
Grand Total	**$5.07**	**$3.76**

All broad based programs that provide direct reductions in peak demand should be funded from capex/opex requested in Aurora's PD submission. Projects that are more focussed on research, 'learning-by-doing' or capability building should be funded from the DMIA. The DMIA may also be used to fund background research and analysis to inform projects that will lead to direct reductions in peak demand.

APPENDIX A: DSM & DG COST ASSUMPTIONS

The following lists the DSM & DG program assumptions and budget cost estimates used for the location specific non-network initiatives outlined in Section 8 of this report.

RESIDENTIAL & SMALL BUSINESS WATER HEATER LOAD CONTROL

Market Characteristics

Eligible market: All N05 and N13 tariff customers with electric water heating.

Program take-up: 25 % of eligible market.

Peak Load Impacts

Diversified peak load reduction per water heater: 0.5 kW.

Cost Assumptions

Capital cost: $150 per water heater for RF load control module and dispatch costs. Costs assume that Aurora will utilise existing radio or broadband communications infrastructure.

Customer incentives: Participating customers would each receive a $75 incentive payment in the form of either a rebate or bill discount per year.

Program set-up and administration: $25,000

Program marketing: $25,000 to cover local seminars, news items, bill inserts and other awareness raising campaigns.

RESIDENTIAL & SMALL BUSINESS LOAD RESPONSE

Market Characteristics

Eligible market: All N01 and N13 tariff customers.

Program take-up: 20% of eligible market.

Peak Load Impacts

Diversified peak load reduction per customer by load shifting: 0.5 kW.

Cost Assumptions

Capital cost: $200 per customer for smart metering and dispatch costs (note these costs are additive with water heater load control costs as both water heater load control and load response enablement functions could be performed by a single interval meter).

Customer incentives: Participating customers would each receive a $75 incentive payment in the form of either a rebate or bill discount per year.

Program set-up and administration: $25,000.

Program marketing: $75,000 to cover local seminars, news items, and working with trade allies such as builders and developers.

Load Management in New Construction

Market Characteristics

Eligible market: All new N01, N05 and N13 connections.

Program take-up: 75% of eligible market.

Peak Load Impacts

Diversified peak load reduction per customer by load shifting: 1.0 kW

Cost Assumptions

Capital costs: $250 incremental above standard metering costs per customer for smart metering, load control modules and dispatch costs.

Customer incentives: $75 per customer per year for rebates or bill discounts for voluntary load reductions, and $100 once off rebate to offset costs of off peak storage water heating.

Program set-up and administration: $25,000

Program marketing: $25,000 to cover local seminars, news items, and working with trade allies such as builders and developers.

Distributed Energy Storage

Market Characteristics

Eligible market: n/a

Program take-up: n/a

Peak Load Impacts

Diversified peak load reduction per site: 200 kVA (assumed for Bruny Island)

Cost Assumptions

Capital costs: $3,000 per kVA including connection costs (based on sodium sulphur (NAS) battery system)

Customer incentives: n/a

Program set-up and administration: $15,000.

Program marketing: $2,500.

POWER FACTOR CORRECTION

Market Characteristics

Eligible market: All N10, N10S, N11, N15, and ITC tariff customers with co-incident peak power factor of less than 0.90

Program take-up: 100% of eligible market.

Peak Load Impacts

Diversified peak load reduction per site: 5% of customer’s peak load at time of system peak.

Cost Assumptions

Capital costs: $400 per kVA reduced for power factor correction capacitor banks installed at customers premises.

Customer incentives: As modelled, customers would pay 25% of the capital costs for the supply and installation of capacitors (excluded from the program total) with Aurora Energy energy contributing the remaining 75% eg $300 per kVA per participant.

Program set-up and administration: $25,000.

Program marketing: $40,000

LARGE COMMERCIAL AND INDUSTRIAL CURTAILABLE LOAD AGREEMENTS

Market Characteristics

Eligible market: All N10, N10S, N11, N15, and ITC tariff customers

Program take-up: 50% of eligible market.

Peak Load Impacts

Diversified peak load reduction per site: 0.5 MVA per site on average.

Cost Assumptions

Capital costs: $20,000 to establish a dispatch system.

Incentives: $15,000 per site availability payment and $1,200 / MWh for dispatch assuming 50 hrs of dispatch per year.

Program set-up and administration: $35,000.

Program marketing: $40,000. As part of marketing this program we have assumed that Aurora Energy would undertake visits to each site, perform a technical assessment of potential curtailable loads and standby generators and prepare a detailed offer for customers that are interested in the program.

HIGH EFFICIENCY LED STREETLIGHTS

Market Characteristics

Eligible market: Streetlights in Blackman's Bay ZS, Sandford ZS, Wynyard TS and Bridgewater 33 kV & Austins Ferry ZS catchment local council areas.

Program take-up: 100% of eligible market.

Peak Load Impacts

Diversified peak load reduction per site: 60% of streetlighting peak load at time of system peak from installation of LED luminaries, based on US DOE street lighting trials in California[44].

Cost Assumptions

Capital costs: $750 per LED luminaire for supply and installation assuming LED luminaires are retrofitted to existing streetlighting installations[45].

Incentives: $400 per LED luminaire subsidy to councils.

Program set-up and administration: $20,000.

Program marketing: $10,000

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44 Source: US DOE, “LED Streetlighting: Host City of San Francisco California”, December 2008

45 ibid