Attachment 6.12

Demand Management operating expenditure plan

May 2014

Contents

Executive Summary

We forecast $37.3 million of opex for DM Innovation Allowance (DMIA) programs, Targeted DM programs, Broad-Based DM programs, and Technical Support & Reporting

This document provides an overview of our proposed opex to support our distribution network in the 2014-19 period. In total, we propose total opex of $37.3 million ($, 2013-14) over the period, comprised of the following operational activities:

- Demand Management Innovation Allowance (DMIA) projects, to conduct research and investigation into innovative techniques for managing demand to deliver price stability in future periods and improve outcomes for targeted DM programs in the 2014-19 period,
- Targeted demand management to defer specific capital projects identified in the Area Plans for the 2014-19 period,
- A new Broad Based Demand Management program, with the aim of future price stability by delaying growth driven investment primarily beyond the 2014-19 period, and
- Operation costs for Technical Support & Reporting to serve the regulatory requirements of the group.

The total opex is provided in the table below ($ million, 2013-14):

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
DMIA Opex	$1.3	$1.8	$1.3	$0.5	$0.1	$5.0
Demand Management Programs						
- Targeted DM Opex	$0.0	$0.4	$0.4	$0.5	$0.8	$2.0
- BBDM Opex	$1.4	$3.0	$4.0	$5.6	$8.1	$22.1
- BBDM Capex	*$0.7*	*$0.1*	*$0.2*	*$0.1*	*$0.1*	*$1.3*
Technical Support & Reporting	$1.6	$3.4	$1.6	$1.6	$0.0	$8.2
Total DM Opex	**$4.2**	**$8.6**	**$7.3**	**$8.3**	**$9.0**	**$37.3**

Delivering appropriate levels of demand management is recognized as a key strategic objective of the NEM and part of the efficient operation of the electricity market in line with National Electricity Law objectives. Ausgrid is obliged to consider net market benefits of demand management and non-network alternatives as part of its investment decisions and to choose demand management and non-network alternatives when it is in the long term interests of customers.

The $5 million Demand Management Innovation Allowance is the same level of as allowance approved by the AER for demand management R&D in the 2009-14 period, and will be used as a proving ground for developing new and improved methods for reducing demand. A suite of innovation trials are proposed for the 2014-19 period.

The Targeted Demand Management Program has been developed as an integral component of the least cost strategies in the network capital works area plans for 2014-19. In the current regulatory period, targeted DM deferred the equivalent of over $300 million of capex delivering deferral benefits of over $20 million.

The cost of the Broad Based Demand Management Program is equivalent to an investment of $2.80 per customer per year to ensure future price stability – over half of which, $12 million ($, 2013-14), will be returned to customers during the period as incentive payments for delivering peak demand reductions. It is forecast to deliver 84 MVA in peak summer demand reductions by the end of the 2014-19 period, with net market benefits from the program are $38 million NPV (10 year) with a minimum benefit cost ratio of 2.0 when using the whole of network average cost of extra capacity.

Breakdown of Broad Based Demand Management Plan Opex costs ($ million, 2013-14)

Cost category	2014/15	2015/16	2016/17	2017/18	2018/19	Total 2014-19
Residential direct load control and energy efficiency	$0.81	$1.54	$1.98	$2.94	$4.39	$11.66
Power factor correction	$0.28	$0.27	$0. 27	$0. 27	$0.55	$1.65
Non-residential demand response and energy efficiency	$0.26	$1.22	$1.74	$2.39	$3.17	$8.78
Broad Based DM programs	**$1.35**	**$3.03**	**$3.99**	**$5.60**	**$8.11**	**$22.09**
Included incentives to customers						**$12.06**

The Broad Based DM Program will target emerging constraints from the 2019-2024 period so as to maximise the benefits. Annual DM plans, based upon latest spatial demand forecasts and investment plans, will guide the Broad Based DM investment. Based on experience from past DM programs, we expect the benefit cost ratio will range from 3 to 5.

The Broad Based programs in the plan are based on proven, reliable, cost effective approaches and technologies which have been pre-tested under current DMIA trials and existing DM programs. It is a new initiative, and represents a step change increase in opex for demand management activities compared to the previous regulatory period.

Introduction

The purpose of this document is to provide an overview of our forecast opex to deliver targeted, broad-based and innovation allowance demand management programs for the 2014-19 period to lower energy bills for all customers in the long term. Appendix A identifies supporting documents to this overview which provide more information on our models, input assumptions, and planning frameworks.

The introduction below provides background on the characteristics of our demand management operations, and the reasons why we are required to undertaken them to achieve the overall strategic objectives of Ausgrid.

What is demand management?

Demand management (DM) is the implementation of options to reduce demand on the electricity network at peak times, with the primary aim of addressing anticipated capacity constraints on network infrastructure. Common DM options include direct load control (such as off-peak hot water), embedded generation and customer power factor correction.

Over the past ten years, Ausgrid has established itself as an industry leader in the implementation of targeted demand management options to defer or avoid the need for specific capital investments, leading to least cost solutions in meeting the energy supply needs of the community and reducing energy costs for consumers.[1] Ausgrid's continuing program of targeted DM projects is described in this proposal.

This document also outlines Ausgrid's strategy for development and implementation of new broad based demand management initiatives in the 2014-19 period. It takes into consideration forecast trends in peak demand growth and consumer behaviour, changes to regulation & market rules, technology shifts such as demand response enabled appliances, and the projected needs for the Ausgrid network in the relevant time periods.

What is the potential for demand management?

In the long term distribution network costs are determined by peak demand as it drives the size of the network and the required asset base. Traditionally peak demand has been met by increasing network capacity however rising network costs and greater knowledge and experience of demand management options has increased the prospects for reducing peaks through demand management.

It is widely recognized by regulators and stakeholders that a less than economically efficient level of DM has been conducted in the NEM to date. This has led to several recent enquiries, regulatory reviews and rule changes. Notable examples include the "Power of Choice" review (AEMC), the Productivity Commission enquiry into "Electricity Network Regulatory Frameworks" and the Distribution Network Planning and Expansion Framework Rule Change driven by the MCE. Further to this, The AER has stated in its Strategic Priorities and Work Program 2013-14 the intent to establish stronger incentives for distribution businesses to undertake demand management.

Across the NEM and in Ausgrid's supply area peak demand growth has slowed in recent years, departing from the previous trend of steady year-on-year growth. This has led to lower forecast growth in augmentation capital expenditures but also increased the uncertainty about the optimal capital investment strategy compared to the last regulatory period. In this more uncertain environment, the "option value" of demand management programs is enhanced for the coming years.

The value and timing of capital deferrals using DM options is impacted by the rate of growth in demand. Current predictions[2] are for a substantial slowdown in growth of both energy use (kWh) and demand (kVA). This lower growth may appear to limit the opportunities for cost effective DM, however the actual impact involves the interrelationship between demand growth rates, capital deferral amounts and capacity requirements.

[1] See the history of Ausgrid's DM investigations and projects under the D-factor http://www.ausgrid.com.au/Common/Our-network/Demand-management-and-energy-efficiency/Demand-Management-at-Ausgrid.aspx also covered in the Statutory information section of Ausgrid annual reports http://annualreport.ausgrid.com.au/

[2] AEMO and Ausgrid

Given an average available system wide capacity (ie % above firm demand), higher demand growth rates provide more frequent opportunities for DM. However, achieving cost effective DM in high demand growth periods can be more difficult because larger MVA reductions are required to achieve capital deferrals, and the savings from capital deferral per MVA are lower than for low growth periods. Lower load growth scenarios can therefore create opportunities for DM because the demand reduction requirements to achieve capital deferrals are lower (making them easier to achieve and more cost effective), which can compensate for the less frequent opportunities for DM.

DM opportunities can exist even when system wide demand growth is flat or even falling, because within the overall trends there is a mix of growth and reductions at the spatial level. The current falling kWh consumption of residential customers is influenced by price and other factors but is also showing the benefit of long term energy efficiency programs to reduce greenhouse gas emissions. Changes such as building ratings, star ratings for appliances and Minimum Energy Performance Standards have gradually grown to have a material effect on consumption. Similarly the Broad Based DM Plan will change the long term outlook for investments beyond the 2014-19 period.

Both the demand and consumption forecast for the period ahead are subject to substantial uncertainty. Volatility has been experienced in electricity prices, world economic conditions, government policies, uptake of distributed generation (notably rooftop solar), new appliances, metering technologies and customer behaviour. In the expected period of high uncertainty ahead the "option value" of broad based demand management is enhanced as it provides more effective insurance against outbreaks of accelerated demand growth than traditional network build options. Compared to building network capacity, demand management can be implemented more quickly and flexibly in response to changing demand growth scenarios.

Ausgrid's experience with the D-Factor mechanism indicates that in high demand growth periods the development of effective DM options can be challenging as the lead times to find DM options are shorter and the MVA reductions required larger. Broad Based Demand Management has benefits in capital deferral under multiple growth scenarios but can deliver longer and larger deferrals in low growth periods.

Why does Ausgrid undertake demand management?

Delivering appropriate levels of demand management is recognized as a key strategic objective of the National Electricity Market (NEM) and part of the efficient operation of the electricity market in line with National Electricity Law (NEL) objectives. Ausgrid is obliged to consider demand management and non-network alternatives as part of its investment decisions and to choose demand management and non-network alternatives when it is in the long term interests of customers.

Demand management is also covered by references to "efficiency" and "conservation" amongst the listed principal objectives of the New South Wales Energy Services Corporations Act 1995, "*to be an efficient and responsible supplier of electricity and other forms of energy and of services relating to the use and conservation of electricity and other forms of energy"*.

Where it can be demonstrated to be cost effective in deferring or avoiding network capital investments, demand management can reduce overall network costs, which results in lower energy bills for all consumers in the long term. Importantly, for Ausgrid's network and in most sectors of the NEM, the top 10% of load is only present for less than 100 hours in a year. Effective demand management programs have the potential to improve the network load factor, resulting in more efficient use of electricity infrastructure.

Over the longer term, improvements in load factor reduce the overall cost of the distribution network. While the largest benefits are gained by focusing on near term investment drivers, each reduction in peak demand, if persistent, also provides longer term value by delaying the need for the next increment of growth driven investment.

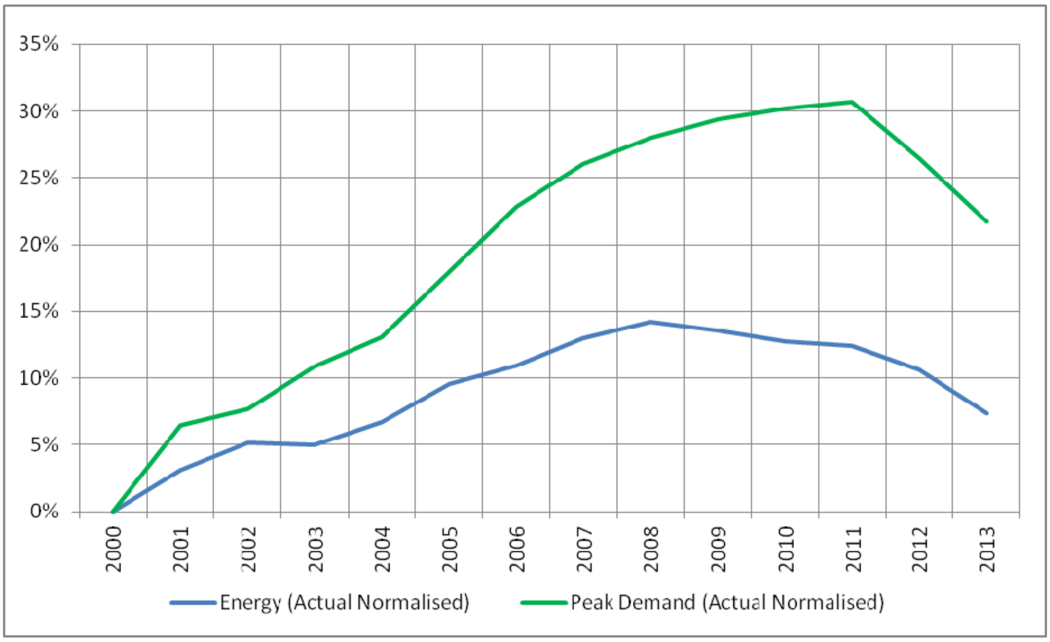

Figure 1 – Ausgrid's declining load factor (peak demand versus energy)

It is recognised that there is potential in the NEM to increase the level of cost effective DM. Ausgrid believes that DNSPs are the most suitable players in the market to be provided with a business incentive to undertake more demand-side management. Our reasoning is that:

- Peak demand is an important driver of a DNSP's short- and long-run costs and there is already a reason for DNSPs to focus on demand side options
- The DNSP has the only enduring relationship with each customer facility within its service territory
- The DNSP has access to customers' meters and meter data as well as load data at all levels of the energy system
- The DNSP is best placed to calculate and internalise the benefit of peak demand reductions to network constraints and can do so with low transaction costs. Other benefits are more visible to the market and could be readily calculated on a generalised basis
- The DNSP is already subject to a regulatory framework that ensures network investments deliver value for money to end-use customers, and efficiency gains are shared
- DNSPs already have cooperative relationships through joint planning with Transgrid (NSW TNSP) on DM options and are required under the new RIT-D to actively consult with customers on DM options.

Segment breakdown of peak demand

Erratic weather patterns have made tracking and forecasting peak demand difficult. Ausgrid's maximum summer peak demand for 2010/11 was 6,072 MW at 5:00 pm on 3 February 2011 (as recorded at bulk supply points). The load profile is shown in Figure 2 below, broken down by customer segment. It shows that the most significant contribution was from residential and small non-residential customers.

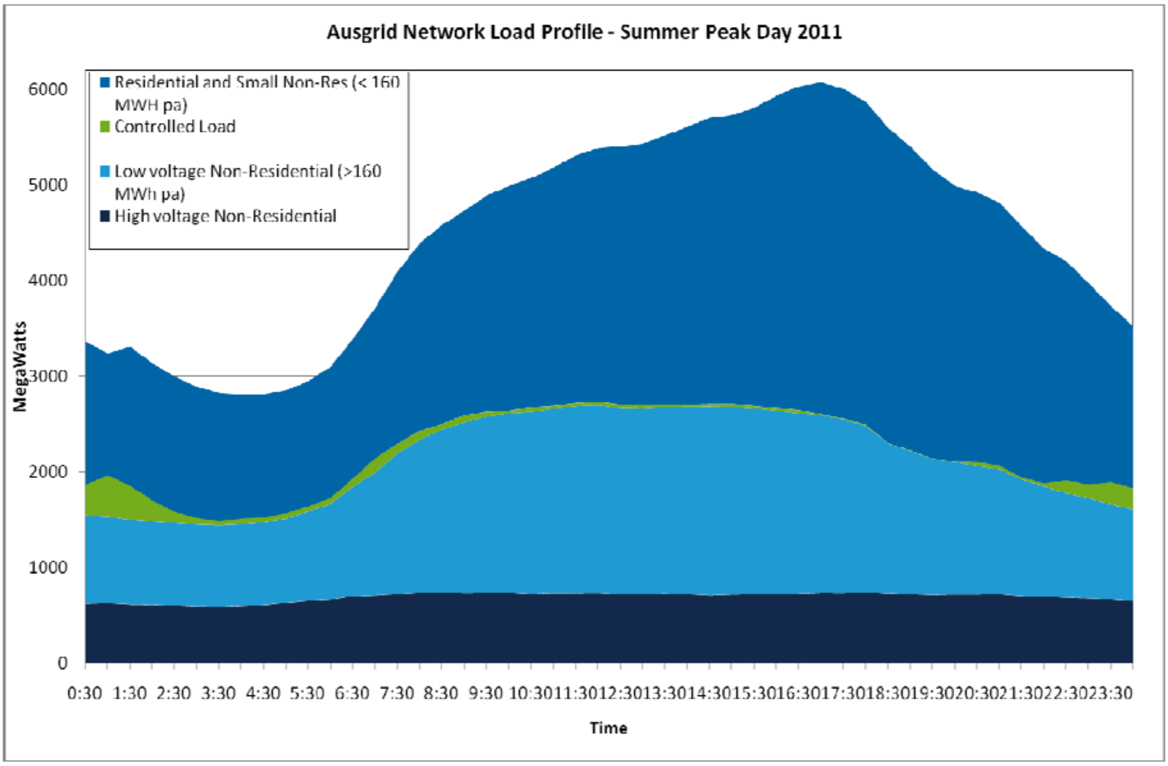

Figure 2 – Peak demand by customer sector

At the peak time of 5:00pm, the contribution from each of these sectors is shown in Figure 3 below.

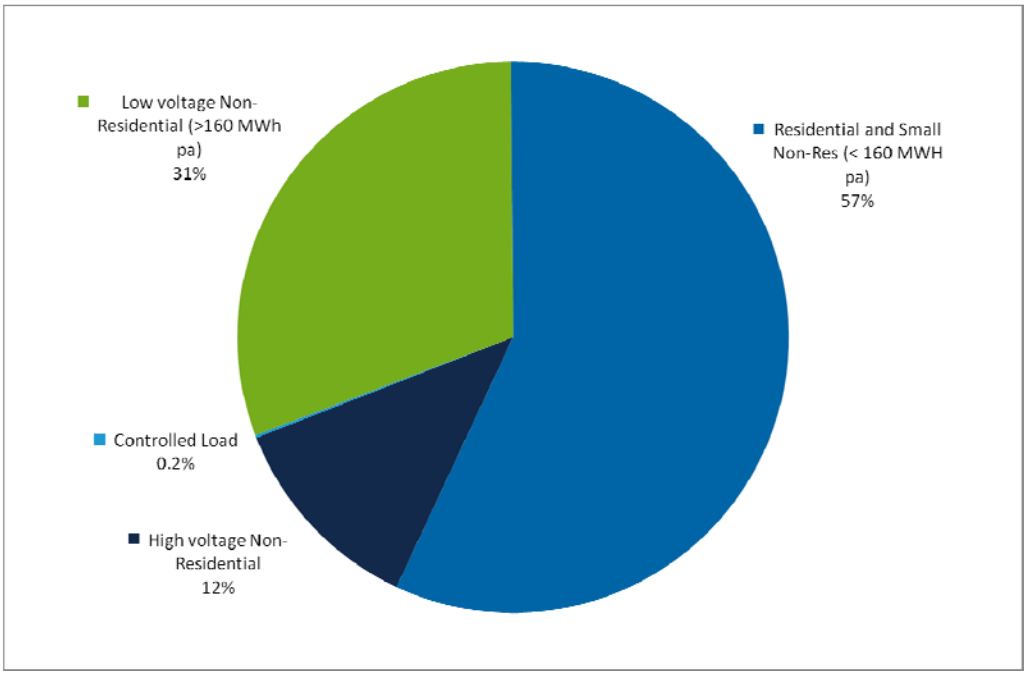

Figure 3 – Customer sector shares at time of summer peak demand (5:00pm, 3 February 2011)

With about 3,464 MW, or 57%, of the summer peak maximum demand derived from residential and small business customers, the influence of residential air conditioning load is clearly a major contributor to the maximum demand.

Although the Ausgrid network area has historically been more strongly influenced by winter peak demand, summer peak demand is now the primary influence for the majority of network assets. Maximum winter peak demand across the network was 5,869 MW on 28 July, 2008, and at a local level, winter peak demand remains the key driver for investment in many parts of the network. About 20% of Ausgrid network substations are currently winter peaking.

Types of demand management

Within the regulatory structure under which Ausgrid operates, it is possible to separate demand management activities into three different types. These types are:

1. Targeted DM, with the short term aim of deferring specific capital investments, generally within a regulatory period (as currently incentivised under the D-Factor scheme).
2. Broad-Based DM, with the medium to long term aim of delaying growth driven investment in future regulatory periods.
3. DM Innovation Trials, to conduct research and investigation into new and innovative techniques for managing peak demand.

Targeted DM

This describes DM programs with the short term (< 5 years) aim of addressing a specific network constraints and deferral of a defined capital investment, and is limited to specific network locations and points in time. Ausgrid is required under Chapter 5 Part B of the National Electricity Rules to consider non-network options prior to investing in a capacity expansion of the network with a cost of $5m or greater. Examples of typical demand management programs include network support using local embedded generation and targeted customer power factor correction.

An advantage of this type of DM program is that benefits (in capital deferral) are near term and can be clearly defined. A disadvantage is that generally there is a relatively short timeframe in which a specific quantity of demand response must be prospected, contracted and commissioned.

Ausgrid has developed comprehensive processes and has a proven track record in delivering project specific DM programs spanning a period of over ten years under the NSW D-factor scheme. Ausgrid will continue to deliver targeted DM where it is cost effective in 2014-2019 as per the requirements of the Regulatory Investment Test – Distribution (RIT-D).

Opex costs for targeted DM programs are included in this Demand Management Plan, with associated capital deferrals embedded within the network Subtransmission Area Plans.

Broad Based DM

This type of DM program has the longer term (> 5 years) aim of reducing demand growth over a broad geographical area, with the benefits of reducing capital investment requirements in the long term. An example of Broad Based DM is the ½ million controlled load hot water systems currently delivering about 300 MW of winter peak demand reductions in Ausgrid's network area. Controlled load hot water has been in place for over 60 years in Ausgrid's network area and continues to provide a valuable contribution to limiting peak demand and reduced network investment.

The advantages of Broad Based DM are that the lead times for program development are longer, and larger scale projects provide economies of scale resulting in lower costs than can be delivered in short term targeted programs. Broad Based programs, because they are delivered over a number of years, also provide greater certainty for the emerging DM service provider industry to develop business models and solutions.

Effective DM is a form of efficiency improvement. Targeted DM aimed at benefits in the short term (< 5 years) can be considered as a form of static efficiency ensuring the best allocation of resources in the short term given existing conditions, constraints and possibilities. Broad Based DM and DMIA projects can be considered as a form of dynamic efficiency effectively changing the conditions, constraints and what is possible in the longer term.

Significantly, a continuing series of individual targeted DM opportunities across a range of locations are each liable to be seen as having too short an opportunity window for development in each instance to be supported. A broad based DM program addresses this issue by creating capability across the network that will be available to address project specific DM opportunities when they occur. To be effective in deferring augmentation capital expenditure, a DM project needs to influence the demand forecast on which an investment decision is made. This can be done explicitly by adding DM impacts to a forecast developed without consideration of DM, or implicitly where DM alters actual demand and growth rates and therefore demand projections. Broad Based demand management is liable to be effective by implicitly changing actual observed demand levels and growth rates, as has happened with existing hot water load control.

Our proposed Broad Based DM program will also be structured to extract maximum value by targeting emerging constraints in the 2019-24 period. By identifying the network regions forecast to require network investment, Broad based DM will be used to lower demand growth sufficient to delay investment. Where the solutions are sufficiently low cost, such as power factor correction and OP2 rescheduling, Broad based DM can be used widely across all areas to defer low cost network investments at the low voltage (11kV) level.

DM Innovation

Exploring innovative methods of obtaining peak demand reductions is important in ensuring that continuous learning is embedded within demand management activities. Introduced for the 2009-14 period, the Demand Management Innovation Allowance allows for expenditure to invest in this type of DM activity. DMIA expenditure supports capacity building, proof of concept trials and estimation of projects costs and benefits which can then be converted into viable projects. DMIA projects are an investment in improving the dynamic efficiency of the NEM by expanding the number of efficient solutions available for networks to meet the NEL objectives. DMIA projects have been instrumental in developing and improving certainty about the 2014-19 broad based demand management program.

Barriers to greater use of DM

There are a number of barriers which can result in less DM occurring than would otherwise be economically efficient; most significant among these is the disaggregated structure of the electricity industry.

While the reduction in peak demand from customers can provide benefits to the distribution, transmission and generation sectors, it is currently difficult to capture all these benefits across the supply chain when developing business cases for demand side measures. This issue and other barriers to DM are discussed in the AEMC's Power of Choice DSP3 papers and the submissions of stakeholders, including Ausgrid.[3]

Also important is that the market for DM service providers is still relatively immature, although it has developed to a degree in response to the opportunities for targeted DM participation in NSW under the D-Factor scheme and DMIA. However this tends to result in short term programs in very specific locations providing little certainty to service providers. Furthermore, because the use of demand side options in network planning has only been utilised in relatively recent times (compared to supply side investments), many demand side options are new and proponent's projects often based on yet-to-be-proven concepts.

More consistent use of DM to defer network investment would provide certainty to the market and both discover new opportunities and improve confidence in the reliability of DM.

[3] http://www.aemc.gov.au/Markets-Reviews-Advice/Power-of-Choice-Stage-3-DSP-Review

Ausgrid's current DM processes

Ausgrid has progressively developed processes that integrate the consideration of targeted DM options into the network planning process alongside supply-side capital investment options. This process, which meets the requirements of the Regulatory Investment Test for Distribution (RIT-D) in the National Electricity Rules, includes the following key steps:

Stage 1: Identify network need for demand related investment & develop strategic plans

Stage 2: Conduct demand management screening test for credible non-network solutions

Stage 3: Conduct demand management investigation including community consultation

Stage 4: Select preferred non-network option, where viable and cost effective

Stage 5: Implement demand management solution

1. Identify the network need & develop plans

Ausgrid develops strategic business plans for meeting the expected needs for electricity services in each of 28 defined geographic areas covering the Ausgrid network. These Area Plans cover a 20 year forward planning horizon, and are reviewed every two to three years.

Based on the most recent demand forecast information, strategy options are developed to meet network needs taking into account relevant planning criteria, asset replacement requirements, and infrastructure compliance issues. A preferred strategy option is selected based on the lowest net present cost that will meet all the relevant network needs in the area.

For each of the strategy options within an Area Plan, demand management options are included alongside supply side options in developing the suite of potential projects to meet the relevant network needs. Generally at the Area Plan stage there is little or no specific information known about actual demand management options available in the area, so assumptions are made about the likely scale and cost based on previous experience with development of actual demand management programs. The demand management programs are then incorporated into the Area Plan strategies as operating expenditure where they can be identified and are considered to be cost effective. For the 2014-19 period these costs are then included in the Capital Project Plan expenditures.

2 The screening test

Each augmentation cost over $1m is screened to determine if it is reasonable to expect that a demand management or non-network solution could allow for a deferral or avoidance of the network investment. Considerations include the amount of demand reduction required, the value of deferral. Expenditure scenarios are developed that compare the construction of a network solution alone to the implementation of indicative demand management options followed by construction of a network solution at a later date. A present value analysis is conducted considering all of the likely costs and benefits associated with each scenario over at least a 15 year period. If the screening test concludes that a non-network solution may be viable, a Non-network options report will be issued and the options investigation process will begin.

3. DM Investigations

The investigation process seeks to identify potential cost effective demand management options that could defer the network investment, and to identify the size, timing and budget costs of these feasible options.

Based on the demand reduction requirements in the demand management screening test, the investigation stage identifies potential non-network solutions to achieve the demand reductions. Options are identified using Ausgrid's existing knowledge, via the public consultation (compliant with RIT-D requirements), field visits to customer sites and discussions with major customers. The investigation identifies the amount of demand reductions available and the likely cost of each non-network option identified.

When the non-network options investigation is complete, a report is published which describes the investigation process followed, identifies all demand management options considered, lists the cost and impacts ascribed to each and describes any feasible demand management options that are to be considered alongside network augmentation options.

4. Select preferred option

Following the evaluation of the credible network and non-network solutions, a project assessment report is published. This report details the identified need, both network and non-network options considered and other relevant information. Depending upon the estimated capital cost of the preferred solution, a draft project assessment report may be published for further consultation. Once a preferred solution is selected, a final project assessment report is published in all cases.

5. Implementation

Where DM options are chosen as part of a least cost strategy to address a network need, a project delivery process is initiated to develop and procure the required demand reductions.

The outcomes of the DM process are documented on Ausgrid's website, in our Annual Report, and also in the D-Factor reporting to the AER. Ausgrid's DM processes are more fully described in the following attachments:

Attachment A: Ausgrid Demand Management Policy

Attachment B: Ausgrid Demand Management Standard

Attachment C: Ausgrid Demand Management Engagement Strategy

DM Innovation Allowance (DMIA) Projects

The Demand Management Innovation Allowance of $1m per year was introduced by the AER for the 2009-14 period. This scheme has the objectives to:

- provide incentives for DNSPs to investigate and conduct broad based and/or peak demand management projects,
- increase the current stock of knowledge and experience with network demand management, and
- conduct research and investigation into innovative techniques for managing demand so that, in the future, demand management projects may be increasingly identified as viable alternatives to network augmentation.

The DMIA must meet certain eligibility criteria as stipulated by the AER. The listed criteria include that DMIA programs:

1. May be broad based or targeting at specific network constraints.
2. May be innovative, and designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts.
3. May be tariff or non–tariff based.
4. Costs must not be recoverable under any other jurisdictional incentive scheme, or included in forecast capital or operating expenditure approved in any distribution determination.

Ausgrid has included some additional criteria for the assessment process for DMIA project approval – that they should be repeatable, able to be geographically focussed at the level of a zone substation footprint and potentially cost effective compared with probable network alternatives.

Ausgrid has a documented process for DMIA project proposal and approval, progress monitoring, project close reporting, and annual reporting to the AER.

Ausgrid has initiated a number of projects under the DMIA, including dynamic control of small residential hot water systems, air-conditioning load control, reliability improvements & alternative grid connections of embedded generators, and a dynamic peak rebate trial for commercial & industrial customers. A description of these projects is included in Appendix A. The DMIA projects of the 2009-14 period have informed the development of the Broad Based Demand Management Plan for 2014-19.

Broad Based DM

Whilst Ausgrid has established processes for the development of DM projects targeting specific network constraints in the short term, there are opportunities for Broad Based DM programs implemented over longer timeframes that can be cost effective in reducing capital expenditure on the network in the long term. This view is shared in submissions to the AEMC DSP3 review, underpins broad based investment programs approved by the AER for Queensland distributors, and reflects overseas experience (particularly in the USA).

Currently, the major Broad Based DM carried out by Ausgrid is the ongoing operation of the domestic storage hot water customer load control (CLC) system. This system dates back more than 60 years and has approximately 350,000 customers on the Off Peak 1 (OP1) and 150,000 customers on the Off Peak 2 (OP2) water heating tariffs. Most off-peak load is controlled via ripple injection equipment installed in approximately 130 of the 180 network zone substations.

This system provides approximately 300 MW of demand reduction in winter (equivalent to around 5.5% of winter peak demand), and 100 MW in summer (equivalent to around 1.7% of summer peak demand). It is estimated that if it were decommissioned, Ausgrid would need to spend approximately $350 million on network infrastructure to meet the increase in peak demand at critical times. It is estimated that the benefits of the existing CLC system exceed the costs by 5 to 1.

Despite the CLC systems ongoing benefits its impact is reducing with the introduction of new minimum greenhouse performance standards for new homes (which effectively ban electric storage system), a switch from winter to summer peaking across much of the network, water efficiency measures and increased uptake of solar, gas and heat pump systems.

What types of costs do we incur to provide Broad Based DM?

The costs incurred in providing broad based demand management is dependent upon the type of program and differs from the project specific demand management programs operated by Ausgrid in the 2009-14 period.

For project specific network deferrals, demand management activities are typically restricted to those programs which have a low cost per kVA to deliver, have a high reliability of delivering demand reductions and can be implemented at relatively short notice. Programs such as customer power factor correction, relocatable diesel generators and demand response from dispatchable customer generators meet these conditions and have comprised the majority of the programs delivered in the 2009-14 period. Costs typically range from $50 to $250 per kVA for such solutions and include customer dispatch payments and incentives, generator hire, design, engineering and project management costs. Costs are typically 100% opex.

The long term goals associated with broad based demand management allows for a wider range of programs and introduces different types of costs. For example, direct load control of residential appliances such as air conditioners, pool pumps and storage hot water heaters introduces marketing and customer acquisition costs, supply and installation costs associated with the load control enabling devices and customer management costs. Projects under the Demand Management Innovation Allowance, internal expertise and knowledge sharing with other DNSPs have informed the cost estimates for the proposed programs in the Broad Based DM Plan.

Aside from management costs for each program, the types of costs to be incurred for the programs included in the Broad Based DM Plan are as follows:

Program	Customer incentive payments	Customer subsidies	Customer management IT systems	Load control enabling devices	Marketing / customer acquisition	Call Centre	Measurement & verification
Residential direct load control	✓	✓	✓	✓	✓	✓	✓
Residential energy efficiency		✓			✓	✓	✓
Power factor correction		✓			✓	✓	✓
Non-residential energy efficiency		✓			✓	✓	✓
Non-residential demand response	✓		✓	✓	✓		✓

With the exception of the costs associated with the establishment of the customer management IT systems and the replacement of controlled load switches and time clocks, costs are 100% opex.

Section 1: Outcomes last period

During the 2019-14 period, Ausgrid spent $8.0 million on targeted DM projects and is projected to spend $4.1 million under the DM Innovation Allowance to deliver its objectives.

The purpose of this section is to identify the outcomes of opex in the 2009-14 period and the reasons for variation to forecasts. Examination of previous expenditure can provide critical insights on the level of forecast opex, and the veracity of previous forecasting approaches.

1.1 Circumstances during 2009-14 period

For the 2009-14 period, the AER continued the D-Factor Incentive Scheme developed previously by IPART to support the implementation of targeted demand management programs. This scheme provides funding for implementation costs and forgone revenue related to targeted demand management programs, via an annual adjustment to revenues.

The AER also provided a DM Innovation Allowance of up to $5m for Ausgrid in 2009-14. Any part of this allowance that is not spent on eligible DMIA activities is returned to our customers in the following regulatory period.

Ausgrid does not have a broad-based DM program in the 2009-14 period, so information provided is limited to the DM Innovation Allowance projects for this period.

1.2 Summary of expenditure in the 2009-14 period

This section identifies the DM delivered by Ausgrid in the 2009-14 period and the outcomes that have been achieved from the investment. We also show the reasons why actual expenditure may have varied from forecast, and show how our forecasting processes for the 2014-19 proposal have been modified to address these factors.

The total expenditure is as shown in the tables below. Note that the projected expenditure in the current year is based on approved D-Factor & DMIA projects. Expenditure is tracked using unique project codes for each project within Ausgrid's SAP system. Once a project proposal receives internal approval to proceed, all internal and external costs are tracked in this system and reported regularly.

Table 1.1: Ausgrid's DM expenditure in 2009-14 ($ Million, real in year of expenditure)

Cost category	**2009/10 ($m actual)**	**2010/11 ($m actual)**	**2011/12 ($m actual)**	**2012/13 ($m actual)**	**2013/14 ($m est)**	**Total 2009-14 ($m est)**
Targeted DM Opex	**$3.49**	**$1.04**	**$2.22**	**$0.84**	**$0.53**	**$8.11**
DMIA Opex		**$0.05**	**$0.66**	**$0.82**	**$2.61**	**$4.14**
Total	**$3.49**	**$1.10**	**$2.88**	**$1.66**	**$3.13**	**$12.26**

1.3 Description of targeted DM (D-Factor) projects in the 2009-14 period

Wollombi Generator Project

This project consisted of a 1MW relocatable diesel generator to provide voltage support to a long rural feeder in the Wollombi area by reducing demand at times of high load. The program was completed in 2011/12 at a cost of $802,600 in the 2009-14 period.

Warringah STS DM Project

This program focused on reducing load at risk at Warringah STS in winter 2009, prior to construction of the $51m Balgowlah Zone Substation. It consisted of three elements – a network support agreement with Sydney Water for a 1.4MW cogeneration system, a dispatchable network support agreement with a third party aggregator, and installation of leased diesel generators. The program was completed in 2009/10 at a cost of $841,900 in the 2009-14 period.

Nelson Bay Generator Project

This project involved the installation of 3MVA of diesel generators connected to an 11kV feeder in order to reduce demand in the Nelson Bay area in summer 2009/10. This enabled an alternate strategy for the supply to the Nelson Bay area that was substantially less expensive to other proposed options. The program was completed in 2009/10 at a cost of $591,700 in the 2009-14 period.

Adamstown DM Project

This project consisted of the installation of 2.4MVA of temporary diesel generation at the existing Broadmeadow Zone Substation in the Newcastle area. The objective was to reduce demand on this substation in summer 2009/10, which was forecast to be above the applicable planning design criteria, prior to construction of the new $26.2m Adamstown Zone Substation. The program was completed in 2009/10 at a cost of $434,600 in the 2009-14 period.

Greenacre Park DM Project

This program focused on reducing load at risk at Greenacre Park Zone Substation in summers 2009-10 & 2011/12 prior to the construction of the $51m Potts Hill Zone Substation. It consisted of a network support contract with customer standby generators, and a relatively small customer power factor correction program. Total costs for the DM program were $1.46m in the 2009-14 period.

Terry Hills PFC and Generation Project

This program consisted of two elements - installation of 3MW of embedded relocatable generators and a customer power factor correction (PFC) program. The objective was to reduce demand on the 33kV network supplying Terrey Hills and several other zone substations from Sydney East subtransmission substation (STS) in winter 2009, enabling the deferral of an $8m investment in a new 33kV feeder to Terrey Hills Zone Substation by one year. The total cost of the DM program in the 2009-14 period was $219,100.

Willoughby STS DM Project

This program consisted of two elements – a non-dispatchable network support agreement with a gas-fired cogeneration site, and a customer power factor correction program in Sydney's Lower North Shore area supplied by Willoughby Subtransmission Substation (STS). The objective was to reduce demand on Willoughby STS by 6.3MVA in summer 2009/10 & 2.6MVA in summer 2010/11, to reduce load at risk until the commissioning of a new zone substation at a cost of $53.7m. The total cost of the DM program was $674,500 over two years.

North West Pennant Hills Generator Project

This program consisted of the installation of between 0.4MVA & 0.8MVA of temporary diesel generators in the summer season over a three year period from 2010/11 to 2012/13. The objective was to maintain network performance in the North West Pennant Hills area, enabling the deferral of a proposed $3.8m in laying new 11kV cable from Pennant Hills Zone Substation to an area north of Cherrybrook. The program completed in summer 2012/13 was the third stage of a proposed five year program.

The total cost of the DM program was $743,000 over three years. Due to a subsequent reduction in the demand forecast for the area at this time, it was determined that the need for the network capacity upgrade had been deferred indefinitely, effectively avoiding the need for the $3.8m capital project completely. This is an excellent example of the option value of DM in managing the uncertainty related to future demand growth.

Medowie DM Project

This program consists of installation of 5.0MVA of temporary diesel generators and 62kVA of power factor correction in the summer seasons of 2011/12 & 2012/13, and 2.5MVA of temporary diesel generators in summer 2013/14. The objective was to reduce load at risk in the Medowie area, prior to the construction of the new $29.6m Medowie Zone Substation. The total cost of the DM program was $2.19m.

1.4 Description of DMIA projects in the 2009-14 period

This DMIA has the objectives to:

- provide incentives for DNSPs to investigate and conduct broad based and/or peak demand management projects,
- increase the current stock of knowledge and experience with network demand management, and
- conduct research and investigation into innovative techniques for managing demand so that, in the future, demand management projects may be increasingly identified as viable alternatives to network augmentation.

The DMIA must meet certain eligibility criteria as stipulated by the AER. The listed criteria include that DMIA programs:

1. May be broad based or targeting specific network constraints.
2. May be innovative, and designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts.
3. May be tariff or non–tariff based.
4. Costs must not be recoverable under any other jurisdictional incentive scheme, or included in forecast capital or operating expenditure approved in any distribution determination.

Ausgrid has included some additional criteria for the assessment process for DMIA project approval – that they should be repeatable, able to be geographically focussed at the level of a zone substation footprint and potentially cost effective compared with probable network alternatives.

Ausgrid has a documented process for DMIA project proposal and approval, progress monitoring, project close reporting, and annual reporting to the AER.

Once a project is complete, a formal close out report is prepared and where appropriate, made available on our website for use of learnings by others.

Ausgrid has initiated 15 projects under the DMIA. A brief description of each is below.

Dynamic Load Control of Small Hot Water Systems

The project consisted of a trial to implement dynamic load control of small and medium sized hot water systems (<100 litres). The nature of the dynamic load control was to switch off the hot water cylinders for periods of typically three to five hours, and only on days as necessary to actively manage network peak demand. The project aimed to determine the technical viability, customer acceptance rates, and cost effectiveness of this approach as a demand management tool.

While the concept was found to be technically viable as the small hot water cylinders showed good tolerance for dynamic control, the low customer take-up rate and high acquisition cost per customer indicates that this product has a relatively high cost per kVA of demand reduction where the program requires the retrofit of the load control device. Development of a standardized demand response interface under the AS 4755 Australian standard for hot water cylinders may help to reduce complexity of installing a load control device and associated costs in the future.

Subsidised Off-Peak Hot Water Connections

There are up to 100,000 large electric hot water systems in houses across Ausgrid's distribution area that are currently connected to continuous electricity supply but could potentially be connected to off peak supply. These systems include electric storage, solar and heat pump models which can contribute up to 600 watts to winter peak demand and 300 watts to summer peak demand each year.

The Subsidised Off Peak Connection trial encouraged customers to connect large electric hot water systems to off-peak electricity supply. The trial included market research, development of marketing materials and implementation of conversions. The aim was to develop & demonstrate marketing approaches that would achieve high take-up rates of conversion of electric hot water systems from continuous supply to off peak electricity supply for the purposes of reducing peak demand in specific network locations.

Research conducted prior to the trial showed that about 46% of customers would consider switching to controlled load (Off Peak supply) if their hot water system was suitable. The likely take-up would be about 15% for $199 meter installation offer and 27% for $99 installation offer. While the research showed that a 67% take-up rate might be achieved if free controlled load connections were offered, this was not economical to trial.

The customer offer component of the trial resulted in mixed results but indicated that the approach offered a cost effective opportunity for demand reductions where existing marketing channels are leveraged and overhead costs such as customer contact centres are shared across other customer offers. The outcomes from this trial were used in the development of the hot water controlled load component to the 2014-19 demand management program.

Reliability Improvements of Large Embedded Generators

The purpose of this project was to test whether a combination of technical improvements and commercial incentives could improve the reliability performance of large, parallel connected embedded generators in providing network support in an interconnected system.

The project sought to demonstrate that technical improvements to protections/control systems and other processes, coupled with commercial incentives, were able to provide a sufficiently reliable outcome for large parallel connected embedded generators to be considered as effective network support in n-1 systems.

While modifications and incentives were seen to improve generator reliability during the peak winter season, it was not possible to conclusively show that the modifications improved the ability of the generator to 'ride through' network faults or disturbances. However, the analysis and alteration to relay protection settings that led to a generator outage linked to a network fault indicates that there is the potential for improvements to generator performance during network faults.

CBD Embedded Generator Connection Trial (Phases 1 & 2)

The aim of this project was to develop and design a trial embedded generator connection in the Sydney CBD that addresses the potential fault level and feeder imbalance issues which are considered to be potential barriers to their widespread uptake in these types of network locations.

Phase 1 was a conceptual design that showed an embedded generator can be connected in such a way that installation costs are minimized, yet with no adverse impacts on the network or customer reliability. Although a number of issues which need to be resolved before the proposed solution could be fully implemented, the conceptual design and the costing provide a basis for ongoing work.

Planning for Phase 2 has begun with a trial site identified with an existing customer owned generator. A draft connection design has been completed with a preliminary scope of works identified.

Market Research for Residential Air-Conditioner and Pool Pump Control Options

This trial consisted of market research to test residential air conditioner and pool pump control option take-up rates and to what extent these rates can vary for a range of customer incentives. The scope included surveying a market sample of air conditioner and pool pump owners, presenting various control options and product parameters, and determining the required level of financial incentives for them to participate in the program. The main objective was to discover the likely customer acceptance rates of various air conditioner and pool pump control options for a range of financial incentives to customers. The scope was similar to choice modelling market research conducted by Energex for their air conditioner and pool pump demand management programs.

The results from the market research have been used to inform the AS4755 air conditioner and pool pump load control trial and Ausgrid's 2014-19 demand management program.

Dynamic Peak Rebate (DPR) for Medium to Large Non-Residential Customers

The Dynamic Peak Rebate (DPR) offer provided a financial incentive to medium to large non-residential customers to reduce their demand during the peak period on the 10-20 days of the year when network assets are operating at capacity. The objective was to determine the level of demand response available from the medium to large, low voltage, non-residential customer sector by offering a dynamic peak rebate. Phase I and II of the trial showed that significant demand reductions can be achieved by a DPR program, even with short notice.

We recently completed the second phase of the DPR Trial, which was conducted from early November 2013 to mid March 2014. We despatched over 30 Commercial & Industrial (C & I) LV customers, with each dispatch event delivering 5 - 7 MVA demand reduction (DDR) against Committed Demand Reductions (CDR) of 5.3 - 7.5 MVA, resulting in overall trial performance of 94% . For the first time in Australia, DDR was calculated using a rigorous *Adjusted High 4s of 5 Baseline Methodology*, often used in more mature DM markets in the USA. The demand reductions were sourced from a variety of customers including a number of telecom exchanges and broadcasting centres, a school, TAFEs, a university campus, a shopping centre, RSL clubs and a hotel, a data centre, commercial buildings, a beverages can manufacturing facility and a number of small & light manufacturing businesses.

We plan to use the lessons learnt during this trial to implement our Broad-Based DM Program in the 2014-19 period.

AS4755 Air-conditioning and Pool Pump Load Control Trial

Air conditioners and pool pumps are the largest residential appliances with no load control option currently available to customers and offer the most potential for residential demand reductions. The focus of this trial is to test low cost direct load control options that are independent of a smart meter interface.

The project explores the potentially cost effective method of controlling residential air conditioners and pool pumps using AS4755 compliant devices and how this solution could form a component of demand management programs. The primary objective of the trial is to test a minimum of two communication platforms and associated Demand Response Enabling Devices (DREDs) by which AS4755 compliant appliances can be controlled. Secondary objectives of the trial include testing of the customer acquisition options to determine take-up rate and acquisition costs.

Results to date have confirmed that the approach is technically viable and offers a cost effective opportunity for demand reductions where existing marketing channels are leveraged and overhead costs such as customer contact centres are shared across other customer offers. The outcomes from this trial have been used in the development of the air conditioner direct load control component of the 2014-19 demand management program.

Grid Battery Trial

This project is investigating the potential benefits of using battery storage as a means for reducing peak demand on the network with a trial over the summer 2013/14 period. This project will seek to investigate how a network grid-side battery can be operated reliably and effectively for summer peak reduction purposes and to potentially improve power and supply quality parameters of the network. Another area of importance is an assessment of the reliability and performance of battery storage devices during the hotter summer months as well as the optimum battery management and control methodologies. This trial remains underway.

Off-Peak 2 Summer Scheduling

Ausgrid currently has around 160,000 customers on their Controlled Load 2 tariff (Off Peak 2), predominantly controlling domestic hot water systems. This tariff was originally intended for shifting load outside of peak times in the winter period but summer peaks are becoming the predominant driver for much of Ausgrid's growth related network investment.

This project involves trialing a new summer load control schedule for summer peak reduction for customers with Controlled Load 2 tariffs. We estimate that the existing Controlled Load 2 customer load contributes 20 to 25 MW of load during the 4 to 5pm time period on network peak days in summer. The trial aims to address issues and potential barriers related to customer acceptance and load control operation issues related to changing summer scheduling of hot water heating.

Results to date have confirmed that the approach is technically viable and offers a very cost effective opportunity for demand reductions. The outcomes from this trial have been used in the development of the off peak 2 summer scheduling component of the 2014-19 demand management program.

Verification of demand savings form energy efficiency programs

The primary objective of this project is to obtain evidence-based evaluation outcomes of the effect of energy efficiency programs on peak demand savings that can be used for the development of demand management programs. To achieve this objective an approach of collaboration with the NSW government was identified as a cost effective and mutually beneficial approach, as it leverages the outcomes and learnings from the existing state-wide energy efficiency programs. To date, this project has verified the savings for three separate programs with the information used to inform the analysis of energy efficiency programs to reduce peak demand.

Co-managing home energy demand

This trial was a collaborative research project with Transgrid and RMIT University to provide greater depth into how householders understand, and are responding to, demand management activities; identify potential strategies and opportunities to improve or expand existing demand management initiatives; gain further insight into householder's perceptions, fears and attitudes towards smart meters and how to counteract negativity; and inform future demand management research, strategies and products.

There were extensive learnings from this research project, much of which has been used to inform DMIA trials and the 2014-19 demand management program.

Triage database

This project was a collaborative effort with TransGrid, the transmission network in NSW, to develop a database of information to support the investigation of non-network solutions for transmission network investments. As TransGrid does not have visibility of the customer level electricity use and demand data, investigations for non-network solutions to transmission network investments are hampered by this lack of information. Closer collaboration with Transgrid will continue in the allocation of demand management resources in the 2014-19 period.

Load control of irrigation pumping

The primary objective of the project is to investigate the likely scale and location of pumping systems in the Upper Hunter region, the viability of load control from these systems and the projected value from the use of pumping load control to defer network investment. Up until approximately 2007, ripple control was used on major agricultural irrigation and water pumping stations for load control. However, with the advent of demand tariffs and time of use metering the bulk of ripple control relays have been removed. Other smaller water pumping facilities have traditionally been operated by time clock rather than ripple control but are expected to have been changed to operate on time of use tariffs. The past use of ripple control and time clock operation would indicate that load control of pumping systems would be acceptable to customers.

Early stage research and development of the concept identified that significant opportunities for demand reduction from pumping systems in specific rural areas of Ausgrid's network area is possible. But, due to a limited volume of near to mid term demand reduction opportunities where irrigation pumping is located, this approach has been set aside.

Large customer power factor correction

The primary objectives of the trial are to discover an optimal methodology to the implementation of power factor correction programs by testing a range of incentive & customer payback levels, and marketing approaches. This trial is underway with extensive analysis of the interval meter data for all target customers completed. This analysis has identified the technical potential from power factor correction which has been used, with experience from historical targeted power factor correction programs, in the development of the 2014-19 demand management program.

Small customer power factor correction

This project set out to explore the potential for peak demand reductions from the development and installation of low cost single step, small PFC units in the range of 12.5 to 75 kVAr. The installed cost of a single step PFC unit should be significantly less than the cost of a more sophisticated multi step unit offering an improved payback for customers.

The project research and development stages were completed indicated that such units were viable. As the success of such an approach would be dependent on customer take-up rates, this element was rolled into the large customer PFC project. If customer response is found to be sufficient to offer a viable demand reduction program, further testing of single stage PFC units will be considered.

1.5 Key outcomes of investment program

Targeted DM Program (D-Factor)

The equivalent capex deferred due to the implementation of targeted DM projects in the 2009-14 period is summarised in the table below:

Table 1.2: Demand management capex deferrals by financial year

	FY2010	FY2011	FY2012	FY2013	FY2014
Annual capex deferred ($m)	182.74	26.89	77.00	26.00	22.20

The calculation of the capex deferrals includes estimates of the “equivalent” deferral values of DM projects implemented to manage load at risk, as per the AER’s D-Factor Methodologies.

DM Innovation Allowance Program

Exploring innovative methods of obtaining peak demand reductions is important in ensuring that continuous learning is embedded within demand management activities. DMIA expenditure has supported capacity building, proof of concept trials and estimation of projects costs and benefits which can then be converted into viable projects. DMIA projects have been instrumental in developing and improving certainty about the 2014-19 broad based demand management program.

In particular, the Dynamic Load Control of Air Conditioners trial has confirmed proof of concept and forms part of the Broad Based DM Plan.

1.6 Reasons for variations from Ausgrid’s 2008 proposal

Targeted DM Program (D-Factor)

At the time of developing the 2008 proposal, Ausgrid had not yet developed a list of proposed specific targeted DM projects. The 2008 proposal was based on the concept that the potential for DM options to defer all proposed demand driven capital projects over $1m would be considered on a case by case basis during the 2009-14 period. However a reasonable observation is that the total of $8.0m expenditure on targeted DM projects was lower than expected due to the slowing in demand growth in the latter years of the 2009-14 period, resulting in a reduced opportunities for deferral of capex projects with non-network options.

DM Innovation Allowance Program

The $5 million DM Innovation Allowance was not included in Ausgrid's 2008 proposal, but instead was granted by the AER as part of the determination process. We have subsequently conducted a prudent program of trial programs within this allowance to support our 2014-19 DM Strategy, up to a total projected expenditure of $4.1m. Reasons why the actual costs have been lower than the allowance include the fact that there was an initial delay in the establishment of trial projects in the first year of the regulatory period, and also that Ausgrid conducted a number of strategic demand management trials within the Federal Government's *Smart Grid Smart City* Project in the 2011-2013 period, displacing the need for DMIA funding.The introduction of a broad based demand management strategy in the 2014-19 regulatory control periods is an outcome of the development work done under DMIA during and the changed circumstances within the 2009-14 period. As a prudent and efficient network, Ausgrid identifies strategic options to address future circumstances but has lacked the certainty to propose a broad based demand management strategy in the past. The experience gained though the DMIA and D-factor projects combined with the work in the AEMC DSP 3 Power of Choice review have allowed Broad Based DM to be considered as a prudent high level strategic option. In addition the experience of the Queensland distributors, Ausgrid's SGSC projects and the nationwide Solar Cities projects have increased the overall market knowledge about Broad Based DM opportunities.

1.7 How has Ausgrid improved its forecasting accuracy for the 2014-19 period

Ausgrid has recently improved our forecasting accuracy for targeted DM projects by fully integrating the consideration of non-network options into our Subtransmission Area Plan process. The result is that, where considered to be cost effective, DM options (and related opex costs) are now included in Area Plan Strategies along with the related capex deferrals.

In addition, in the expectation of a continuation of the DM Innovation Allowance, in this proposal Ausgrid has developed a suite of R & D trials for the forthcoming regulatory period.

Cost inputs for the new Broad Based DM Plan were derived from a range of sources; including knowledge gained from specific Demand Management Innovation Allowance projects, internal marketing expertise developed from the development and delivery of energy efficiency programs and knowledge sharing with other DNSPs who are delivering or have recently delivered similar programs (e.g. Queensland DNSPs). In addition, commissioned and internal research has been used to project appliance ownership rates, diversified appliance demand savings, opportunities from power factor correction and demand response dispatch costs. Where possible, the derived program costs were benchmarked against costs for similar programs.

Section 2: 2014-19 DM strategy

Our focus for the 2014-19 period is to deliver efficient peak demand management programs to achieve least cost electricity supply services to our customers.

The purpose of this section is to identify the key circumstances driving Ausgrid's demand management opex in the 2014-19 period. At a high level, it can be seen that the forecast for the period is increased compared to the opex from the 2009-14 period:

A key reason for this trend is that it is recognised that the previous level of investment in peak demand management was lower than would be economically efficient to achieve least cost electricity supply services to our customers.

The focus of this opex strategy is to deliver peak demand reductions that will reduce energy costs to our customers by enabling reductions in our capital works expenditure that would otherwise be required to meet demand growth. At the same time we have sought to minimise price pressures to the full extent possible by investigating avenues of efficiency delivery of non-network options to manage peak demand. These issues are discussed below.

This section identifies the past and future circumstances that have influenced our capital and operating expenditure forecasting approach and outcomes for the Broad Based DM strategy.

2.1 Past circumstances

Ausgrid's experience with DM to date has been through the continuing operation of broad based hot water load control (which has been in place for over 60 years), and targeted DM under the D-Factor mechanism initiated by IPART in 2004, and then administered by the AER.

Controlled load hot water was particularly effective at addressing winter evening system peak loads into the early 2000's however, while some residential areas are still winter peaking, much of the system has moved to be summer peaking and the majority of areas are now summer or joint summer/winter peaking. The switch to summer peaking – lead by residential air-conditioning load - has reduced the effectiveness of traditional hot water load control and simultaneously a reduction in the thermal capacity ratings of network equipment. Hot water load control is also diminishing in effectiveness though the combined impacts of conversions to gas, heat pump and solar systems, water efficiency (such as low flow shower heads), MEPS and building standards.

Controlled load hot water programs are estimated to have reduced peak demand by 7-10% during the past 40 years. Considerable capital investment would have been required without the existence of this broad based demand management tool.

Instrumental in achieving the benefits of hot water load control has been the supporting Controlled Load Tariff and control technology. The enablement of hot water load control involved a combination of control technology (power line carrier or ripple control), metering with a separate channel for hot water load, ripple signal injection equipment at zone level and supporting network tariffs.

Past D-factor and DMIA incentives have been particularly effective in encouraging more DM than would otherwise have occurred , as can be seen by the lower levels of DM conducted in NEM states where incentives are not available.

2.2 Key circumstances in the 2014-19 period

It is widely recognized by regulators and stakeholders that a less than economically efficient level of DM has been conducted in the NEM to date. This has led to several recent enquiries, regulatory reviews and rule changes.

Notable examples include the “Power of Choice” review (AEMC), the Productivity Commission enquiry into “Electricity Network Regulatory Frameworks” and the Distribution Network Planning and Expansion Framework Rule Change driven by the MCE.

There is potential for more cost effective DM to be carried out in future regulatory periods.

Peak demand has slowed, but is forecast to continue to grow. By contrast energy consumption has fallen and is forecast to remain static at best. The ratio of these two, load factor, has declined steadily for many years and is forecast to continue to do so. This feature has been observed in most electricity markets around the world, and is not due to unique or temporary local factors.

This is a problem for all asset intensive sectors of the electricity supply chain because the size and cost of the assets required varies with peak demand, while the value customers derive, and consequently our revenue, varies with energy consumption. A continuing decline in load factor will put ongoing pressure on average prices throughout the generation, transmission and distribution sectors.

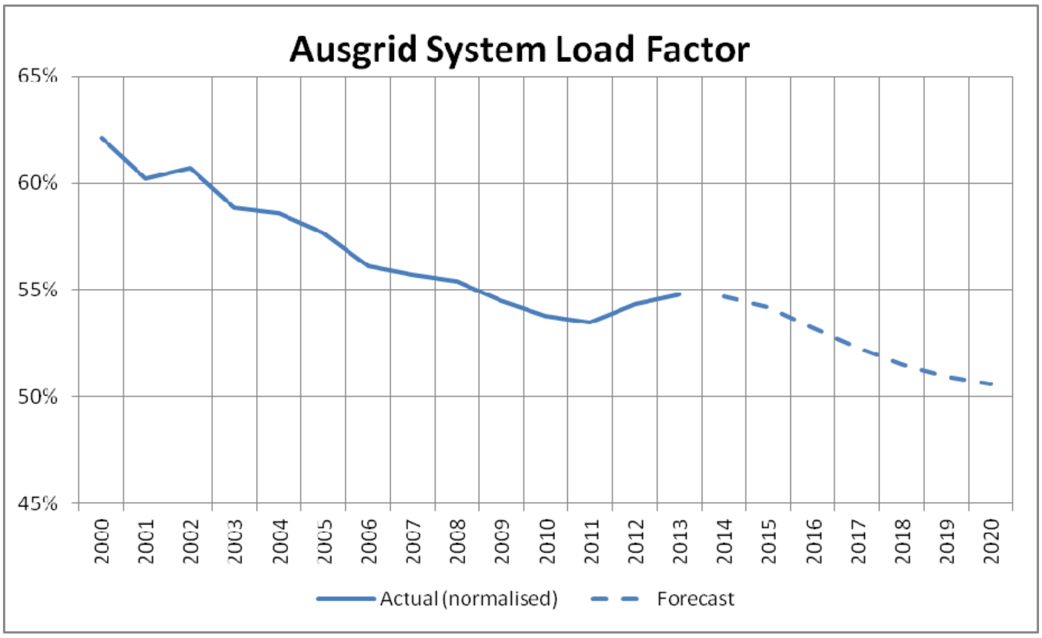

Figure 2.1 – Declining load factor resulting in inefficient asset utilisation

One of the few tools we have available to arrest this long-term decline is peak demand management. The best historical example of this approach is off-peak hot water load control products. However, this area has been ignored and allowed to decline over many years. Based on the expectations of a longer term use of demand management, and in recognition that benefits to customers arise not only in our own business but in the transmission and generation sectors, we have developed a broad-based demand management proposal for the 2014-19 period.

On first impressions, lower demand growth may appear to limit the extent of cost effective DM. However, the actual impact involves the interrelationship between growth rates, deferral amounts and capacity requirements.

Given an average available system wide capacity (% above firm demand), higher demand growth rates result in more frequent opportunities for DM. However, achieving cost effective DM in high growth periods can be difficult because larger MVA reductions are required to achieve capital deferrals, and the values per MVA are lower than for low growth periods. Lower load growth scenarios can create opportunities for DM because the demand reduction requirements to achieve capital deferrals are lower (making them easier to achieve and more cost effective), which can compensate for the less frequent opportunities for DM.

DM opportunities also exist when system wide demand is flat or even falling as within the overall change there is likely to be a mix of growth and falls at the network spatial level. The current falling kWh consumption of residential customers is influenced by price and other factors, including the benefit of long term energy efficiency programs.

Both demand and consumption forecast in the period ahead subject to substantial uncertainty due to factors such as:

- the potential rebound effect of stabilising electricity prices
- the repeal of the carbon tax and government sponsored greenhouse reduction programs
- increasing gas prices.

In the expected period of high uncertainty ahead the "option value" of broad based demand management is enhanced as it provides a more flexible, responsive and effective insurance against outbreaks of unforseen demand growth than traditional network capacity building options.

2.3 High level strategic options considered

The introduction of a broad based demand management strategy in the 2014-19 regulatory control periods is an outcome of the development work done during and the changed circumstances within the 2009-14 period. As a prudent and efficient network, Ausgrid identifies strategic options to address future circumstances but has lacked the certainty to propose a broad based demand management strategy in the past. The experience gained though the DMIA and D-factor projects combined with the work in the AEMC DSP3 Power of Choice review have allowed Broad Based DM to be considered as a prudent high level strategic option. In addition the experience of the Queensland distributors, Ausgrid's Smart Grid Smart City projects and the nationwide Solar Cities projects have increased the overall market knowledge about Broad Based DM opportunities.

The options considered for the Broad Based DM plan has been reviewed based on their ability to cost effectively defer investment and contribute to future price stability. Cost effective projects are chosen based on proven experience and research under the DMIA and D-factor. The programs also build on proven existing technology platforms (ripple injection), embody conservative assumptions and set modest goals.

In a time of changing customer demand and uncertainty of demand growth, it is difficult to determine with a high level of certainty the optimal level of DM to deploy in the future. In this context Ausgrid has proposed a relatively modest level of investment in the Broad-Based DM Program for the 2014-19 period.

Power Factor Correction and OP2 rescheduling are very low cost DM options and are considered to be suitable for wide deployment across the Ausgrid network area. However to attain sufficient magnitude of demand reductions in specific areas to achieve deferral benefits, additional DM solutions are necessary, and we have proposed a mix of program options in the Broad-Based DM Plan, both residential and non-residential, that can be directed to areas of emerging network constraints and suited to the predominant customer type and time of day of peak for that area.

Broad-based programs will be focussed in the regions of the network identified to have emerging constraints in a ten year horizon. These emerging constraints will be identified in the Area Planning process and actual expenditure will be scaled to any changes in demand forecasts and the needs of the network.

2.4 How has our strategic considerations influenced our expenditure requirements?

The current expenditure requirement for broad based demand management reflect a changed approach to demand forecasting and management which has evolved through the 2009-14 regulatory control period and has responded to the experience of falling peak demand.

Historically, the long term steady growth trend in demand and consumption allowed for demand forecasts to be developed from a simpler set of functional inputs. The current regulatory determination period has experienced greater volatility in energy and peak demand and increased the level of uncertainty in forecasting peak demand growth. Consequently demand and consumption forecasting methods have been refined to include weather correction, a probabilistic treatment of forecast new load "spots" and load transfers, an adjusted 50% POE estimation methodology, Monte Carlo simulation of temperature impacts at location level and system wide peak forecasting from aggregation of local system peaks. The future impacts of growth in embedded generation (such as solar PV) and energy efficiency initiatives are also explicitly factored into the demand forecasting process.

The strategic direction of the company has also altered with a renewed focus on the future stability of price to customers. These strategic influences have contributed to the development of a Broad Based Demand Management Plan. Fortunately, the learnings from the 2009-14 period have been able to increase Ausgrid's confidence in expenditure requirements and outcomes.

2.5 Relationship with capex program

Where cost effective targeted DM projects have been included in the preferred Area Plan strategies, the related capex project deferrals have also been built into the capital plans.

The impacts of the Broad-Based Demand Management Program have been incorporated into Ausgrid's spatial demand forecast used for capital works planning, and therefore will result in a reduction in capital expenditure on the network. Due to the gradual ramp up approach inherent for this type of program, the benefits in capital deferral largely flow to customers in the longer term. Within the 2014-19 period, we have locked in $16.0m of avoided cost in the distribution capacity capital program, and a small reduction in the targeted demand management costs in the subtransmission sector.

Section 3: Forecast method

We have relied on a bottom up approach in forecasting demand management opex for the 2014-19 period.

The purpose of this section is to provide an overview of the process we have used to derive the total opex forecast for {opex category}. In doing so, we have taken into account the business as usual operations carried forward from the 2009-14 period and the circumstances in the 2014-19 period as described in Section 2.

We have supplemented this proposal with detailed information set out in Attachment D to this overview. This includes specific data and analysis relating to our forecast processes, and derivation of key inputs such as cost escalators and volume drivers.

3.1 General approach

Ausgrid has developed a separate plan for demand management programs. The plans have largely relied on a bottom up approach to forecasting program costs. Our forecasting methods across the plans are based on robust assumptions. Synergies with other plans such as capital programs are considered and are accounted for at a high level. The impact of material step changes has also been incorporated in the forecast.

A summary of our general method is set out below, with further information provided in supporting information that sets out the models in more detail.

3.2 How does the forecast method align to BAU?

In the current regulatory reset period BAU Demand Management expenditure consists of:

1. DMIA expenditures of $5m, allowed on a “use it or lose it” basis for research and development.
2. Regulatory DM evaluation and reporting expenses as a required part of planning and investment processes.
3. Projects under the D-Factor demand management incentive scheme, which are not part of BAU expenditures but separately approved foregone revenues and efficient implementation costs (up to the value of augmentation) which are added to CPI-X revenues (a total of approximately $8m in 2009-2014). Value of DM deferral of expenditures is embedded in augmentation capital allowances.
4. Tariff measures not separately accounted for as Broad Based Demand management including TOU pricing, capacity charges and load control tariffs. In particular established hot water load control is embedded in normal operating and capex expenses and not separate identified as broad based DM.
5. Components of Smart Grid Programs as research and development into long term energy efficiency and demand management (with Commonwealth government SGSC funding).

Compared to BAU in the current regulatory period, forecast expenditures for 2014-19 comprise:

1. A lower level of targeted DM expenditure (at $2m) related primarily to the lower number of “in period” demand driven capital investments compared to the 2009-14 period.
2. A step change of $22.1 million ($, 2013-14) for the new Broad Based Demand Management strategy in response to changed conditions and increased knowledge to deliver long term price stability to customers.
3. The same DMIA expenditure of $5 million is proposed, on a “use it or lose it” basis, for research and development. This expenditure level is consistent with the allowance approved by the AER in the 2009-2014 period.
4. Regulatory DM evaluation and reporting expenses as a required part of planning and investment processes will continue. Expenses are expected to increase with the RIT-D requirements for a DM engagement strategy and increased consultation with proponents and stakeholders.

5. Projects under a DMEGCIS demand management incentive scheme, if implemented, would not be part of BAU expenditures included in building blocks. Amounts will depend on the form of revenue regulation and nature of DMEGCIS proposals. The deferral value of location specific DM in the 2014-19 period will be embedded in augmentation capital allowances.

Central to driving the changes in the BAU expenditures have been:

- External learnings from the Queensland distributors' experience, Solar Cities projects and the DSP3 Power of Choice review.
- Internal learning from DMIA & D-Factor, and Smart Grid projects.
- Increased focus internally and externally on demand management for long term price stability for customers including.
- Improvements in investment and forecasting processes including the introduction of the RIT-D for the 2014-19 period.

3.3 How has the forecast method improved since 2008 forecast

Forecast of expenditures on broad based demand management are substantially improved since 2008 when there was less confidence about the quantum of costs and less assurance of benefit delivery that now exists. Also as Ausgrid (then EnergyAustralia) was AER's first electricity distributor determination the underlying regulatory framework from which demand management values can be calculated was less well established.

Based on improved knowledge and processes, identifiable location specific demand management is now being included in the 2014-19 Area Plan expenditure proposals to recognise where DM is the most cost effective solution to a network need. Other changes since 2008 have been revised demand forecasting processes in response to the uncertainty created by volatile and slowed demand growth.

The forecast peak demand reductions resulting from the broad based demand management in this plan have been explicitly included in changing spatial demand forecasts as part of our revised forecasting and investment planning approach. New demand management impacts were not explicitly recognised in the 2008 forecast, the impact of controlled load hot water was implicitly included through the lower actual demand numbers used to develop forecasts.

3.4 Capex and opex are forecast as part of a joint process

DM is focused on deferring capital expenditure, and this generally entails an opex solution although a capital solution can also be implemented. The issues of capex and opex incentives and tradeoffs have been addressed in the AEMC DSP3 Power of Choice review. For broad based demand management capex and opex forecasts have been done jointly. For location specific DM identified within the regulatory period and not part of this plan benefits in capital deferral will fund DM (often opex) expenses.

3.5 Key assumptions underlying the forecast

Key assumptions on expenditures and benefit from the broad based demand management program are embedded in the individual project streams. High level assumptions are listed below.

Assumption	Impact of assumption
Slow peak demand growth rates	Increased scope for deferral times and values from broad based DM
Conservative participation rates for programs	Sensitivity to program recruitment costs and achieving deferral amounts

Benefits from demand reductions in 2014-19 period	Assumes 11kV Capital Works Plan will be reduced by $16m in 2014-19 period
Diversity in spatial peak demand growth	Investments in DM programs will be a function of available benefits in targeted areas related to emerging constraints
Market benefits delivered by programs	Generation and Transmission contribute to net benefits but DNSP only measures still leaves the program portfolio with positive benefit costs ratio
Leveraging existing technologies	Using existing ripple control system minimises costs
Leveraging existing distribution channels	Marketing and promotion costs minimised
Staged program development	Minimises up front cost and allows learning in program roll-out
Preference for proven solution	Minimises risk of program delivery and benefit realisation

3.6 Approach to forecast costs and benefits

Fundamental to the broad based demand management options is a trade off between short to longer term opex expenses and reductions in longer term capital costs. In the long run, targeted DM and Broad Based Demand Management attempt to address the same issues, however, the timing of impacts and the assessment process for targeted DM ensures that the two types are complementary rather than competing options. In the long-run peak demand is a key determinant of the size of capital investment so DM can either remove the need or delay the need for targeted DM regardless of when peak demand is growing (for augmentation projects) or not (for sizing replacement projects).

The potential for double counting in conducting both area specific and broad based demand management is negated because:

- identified area specific DM is included in the Capital Program and forecast demand adjusted downward
- Broad Based programs develop progressively with full impacts realised at the end of the next regulatory control period negating forecast overlap in the 2014-19 period
- by changing actual outcomes broad based demand management will alter underlying demand and forecast demand growth in future periods
- any contribution of broad based demand management which address a location specific peak reduces the amount (and expenditure) required at the locational level when it is required.

Ausgrid will first identify location specific DM projects when assessing options in our planning process (an example is a DM program targeting the deferral of a load transfer from Tarro Zone Substation). This project is included in Capital Plans as a more cost effective option than a network solution. Demand forecasts, which already include the impact of broad based demand management, are further adjusted to reflect its impact.

The process Ausgrid undertook to identify viable broad based DM opportunities involved:

- Previous learning from the D-factor, SGSC and DMIA programs and trials
- Monitoring developments in the market, and consultation with stakeholders including project proponents
- Programs identified and implemented by other DNSPs, particularly in Queensland, Western Australia and South Australia.

All the programs chosen have been tested and developed through D- factor or DMIA and use existing proven technology capacities (such as PFC and ripple load control).

In many cases the learnings were most valuable in identifying approaches and technologies which are not yet developed enough to be supported at present (e.g. batteries and fuel cells) and segments where delivering value is difficult (such as small business energy efficiency programs). The programs examined were limited to those where the cost of demand reduction per kVA was forecast to be sufficient, the size of total peak demand reduction was substantial and the likelihood of success high based on available analysis and experience.

Other program options that were considered include:

1. Building automation controls
2. Residential appliance efficiency / rebates
3. Residential small appliance load control
4. Motor energy efficiency and variable speed drives
5. Refrigeration equipment efficiency
6. Compressor efficiency
7. Ice storage
8. Rural irrigation pumping
9. Standby generator upgrades
10. Greenfield development efficiency incentives
11. Cogeneration support
12. Subsidies / rebates for energy efficient equipment / fuel switching
13. Residential appliance round-ups
14. Additional tariff options (e.g. residential capacity charging)
15. Battery storage and distributed generation

The business case for the chosen projects uses a market benefit test as required under the National Energy Law Objectives and as embodied in the RIT-D criteria and which includes the deferral benefits in transmission and generation as well as distribution.

An analysis of Ausgrid's network concludes that, for substations that are forecast to exceed 100% of capacity in the ten year horizon (defined as "emerging constaints"), up to 220MVA of demand reduction would provide benefits in deferring network capital costs over this time period. As a prudent approach we have set a lower target for the first step change to a new broad-based DM initiative in the forthcoming regulatory period, proposing a program to achieve 84MVA of demand reduction by 2019, and representing a modest expenditure of less than $3 per customer per annum in the 2014-19 period.

While broad based benefits are estimated from long term averages and primarily focussed on the period after 2014-19, the roll out of programs will be targeted to be more cost effective by focusing on emerging constrained areas of the network where the activity will deliver more immediate benefits.

In line with RIT-D guidelines all market costs were considered in calculating the net market benefit, including costs to customers such as installation costs of purchasing power factor correction equipment. Incentive payments to customers are treated as a cost for the non-residential demand response program and part transfer payment / part cost for the air conditioner load control product. We estimate that 50% of the incentive cost is consumer surplus based upon our Choice modelling DMIA trial which discovered the price points at which customers would accept the air conditioner load control offer.

Ausgrid's measure of benefits (expected capex deferral in the future) is based on the average cost of extra capacity for generation, transmission and distribution. These values are calculated to be in the order of the order of $3,800 per kVA (in 2012 dollars) comprising:

- $2,250 per kVA for Distribution
- $600 per kVA for Transmission
- $950 per kVA for peaking generation plants.

The average cost of extra capacity has been used as a concept to explain the benefits to prices delivered by broad based demand management. This reflects an average cost saving across a broad area from not needing extra capacity in any year – this will be made up of a mix of very high values where investments are imminent (due to economies of scale favouring "lumpy" investments) and very low values (where spare capacity exists). The concept/term long run marginal cost or LRMC has not been used as this has various economic meanings, is used in a specific manner in AER pricing methodologies, and is difficult to apply in a strict sense for 40 year monopoly assets.

These values are used in conjunction with conservative forecasts of reductions in system peak demand from individual programs to determine net market benefits. Program estimates of deferral are based on experience with hot water load control, D-factor projects and learnings from DMIA expenditures. The forecast consequential reduction in our capital costs from demand reductions is based on the average long run deferral costs demonstrated in capital investment programs (for distribution and transmission) and from engineering studies (for generation).

3.7 Consolidating forecasts and benefits

The impact of Broad Based DM, other than hot water load control, will be explicitly incorporated into total capex forecasts for the 2014-19 period, but benefits are not anticipated to be realised until the end of the period. Any benefits in the 2014-19 period will come from reduced requirements for identified location specific DM rather than independent changes in the capital plan expenditures.

The table below outlines how we considered the benefits from each type of DM program, as part of our planning process.

Program	Method to incorporate into capex forecast
Project specific identified	Projects identified at the start of a regulatory control period are included in Area Plan and the capital plan expenditures. (for example Tarro zone load was deducted directly from forecasts and capex delayed)
Broad based DM	Incorporated into Area Plans demand forecasts and used to identify the change in requirements for within period DM projects and timing to longer term capital projects
Tariff based DM (e.g. Time of use)	Implicitly deducted though lower actual demand and demand growth which leads to a reduction in total capex.
Project specific opportunities	DM projects identified during a regulatory control period are no included in Area Plans and supported by the value of deferred capital expenditures of the Network options they replace.

3.8 Process for deriving cost inputs

Cost inputs for the Broad Based DM Plan were derived from a range of sources including:

- knowledge gained from specific Demand Management Innovation Allowance projects,
- internal marketing expertise developed from the development and delivery of energy efficiency programs and
- knowledge sharing with other DNSPs who are delivering or have recently delivered similar programs (e.g. Queensland DNSPs).

In addition, commissioned and internal research has been used to project appliance ownership rates, diversified appliance demand savings, opportunities from power factor correction and demand response dispatch costs. Where possible, the derived program costs were benchmarked against costs for similar programs.

At $12.1 million ($, 2013-14), customer incentive payments are the largest component of the overall $22.1 million ($, 2013-14) cost. Incentive payments of $75-100 per year were selected for the residential direct load control programs, based upon experience gained from other DNSPs to achieve acceptable take-up rates at a cost effective rate per kVA. Incentive rates for the non-residential dynamic peak rebate program were based upon the actual incentive rates for dispatchable customer generators as part of project specific DM delivered in the 2009-14 period.

A total of $2.9 million ($, 2013-14) in opex costs (and $1.3 million capex) are to establish the systems and equipment necessary for the programs. This includes costs for the supply and installation of demand response enabling devices (DREDs) to control the air conditioners and pool pumps as part of the residential direct load control programs and the IT systems to store customer data, manage dispatch events and track performance. Costs for DRED installation were based upon advice received from other DNSPs currently delivering similar programs and IT system costs from internal estimates.

Customer acquisition costs comprise $4.8 million ($, 2013-14) of the total cost and were based upon in-progress and completed Demand Management Innovation Allowance projects and previous experience in delivering energy efficiency and demand management programs. The remaining $2.3 million ($, 2013-14) in costs is for project management and measurement and verification. Costs were derived from estimates of labour hours and rates for each program.

Section 4: Forecast outcomes

We have forecast $37.3 million of opex for Demand Management activities in the 2014-19 period

This section summarises the costs and benefits of Ausgrid's Demand Management Plan. Of note are that the DM Plan will deliver 84 MVA in peak summer demand reductions from broad based demand management activities and $38 million in market benefits (10 year NPV to 2023-24) at a cost of $22.1 million for broad based demand management.

4.1 Total DM expenditure and benefits

Summary of Demand Management Plan operating expenditure ($ million, 2013-14)

Cost category	2014/15	2015/16	2016/17	2017/18	2018/19	Total 2014-19
Opex ($ 13/14 real)	$4.2	$8.6	$7.3	$8.3	$9.0	$37.3
Opex ($ nominal)	$4.3	$9.0	$7.9	$9.2	$10.2	$40.5

Breakdown of Demand Management Plan operating expenditure ($ million, 2013-14)

Cost category	2014/15	2015/16	2016/17	2017/18	2018/19	Total 2014-19
DM Innovation allowance Opex	$1.3	$1.8	$1.3	$0.5	$0.1	$5.0
Targeted DM	$0.0	$0.4	$0.4	$0.5	$0.8	$2.0
Broad Based DM:						
- Residential direct load control and energy efficiency	$0.8	$1.5	$2.0	$2.9	$4.4	$11.7
- Power factor correction	$0.3	$0.3	$0. 3	$0. 3	$0.5	$1.7
- Non-residential demand response and energy efficiency	$0.3	$1.2	$1.7	$2.4	$3.2	$8.8
Technical Support & Reporting	$1.6	$3.4	$1.6	$1.6	$0.0	$8.2
Total	**$4.2**	**$8.6**	**$7.3**	**$8.3**	**$9.0**	**$37.3**

Summary of operating expenditure costs and benefits for Ausgrid's Broad Based DM programs ($ million, 2013-14)

Program	2019/20 Summer demand reduction (MW)	2019/20 Winter peak demand reduction (MW)	2014-2024 Total Net Market Benefit Real ($M)	2014-19 Opex ($M)
Residential direct load control and energy efficiency	36.1	4.2	$17.9	$11.7
Power factor correction	28.0	16.5	$12.2	$1.7
Non-residential demand response and energy efficiency	20.0	2.5	$7.6	$8.8
Total	**84.1**	**23.2**	**$37.7**	**$22.1**

4.2 Technical Support & Reporting

A total of $8.2 million ($, 2013-14) is allocated for Technical Support & Reporting over the 2014-19 period.

In addition to the delivery of the targeted, broad-based and innovation demand management initiatives described in this proposal, the key technical support & reporting functions carried out by the Demand Management & Forecasting Section include:

- Regulatory reporting to meet requirements of licence obligations and incentive schemes related to non-network alternatives,
- Process development to fulfill the obligations of the Regulatory Investment Test - Distribution Networks (RIT-D) under the National Electricity Rules,
- Implementation of the Demand Management Stakeholder Engagement Strategy,
- Research on customer use of energy (including energy efficiency, embedded generation and peak demand) supporting both demand management and demand forecasting functions,
- Management of data repositories related to customer energy usage,
- Support for energy related sustainability initiatives within Ausgrid's business operations,
- Support for Ausgrid's Corporate Communications Section on matters related to energy efficiency, demand management and greenhouse abatement.

4.3 Description of targeted DM programs

A bottom up review of the Subtransmission Area Plans has identified two demand management projects to enable cost effective deferral of capital investments. The total cost of these DM projects is $0.5 million ($, 2013-14). These are described below.

Load Transfer from Tarro Zone Substation

Demand growth at Tarro Zone Substation in the Lower Hunter Region is forecast to exceed the relevant capacity limits in Summer 2017/18. The preferred Area Plan Strategy includes a project for 11kV cable works to transfer up to 15MVA of load from Tarro to an adjacent zone substation at a cost of almost $12m. We have determined that it will be cost effective to defer the load transfer works for at least two years by implementing 1.4MVA of DM options.

At this point in time we do not know the exact type of DM options that will be implemented in the Tarro area, however this will be determined from the investigation, consultation & assessment process. The total estimated cost of this DM program in the 2014-19 period is $500,000.

Upgrade of 33kV feeder S03 at Manly Warringah

Demand growth at Manly Warringah area in the Sydney Region is forecast to exceed the relevant capacity limits in Summer 2017/18. The preferred Area Plan Strategy includes a project for upgrade of a 33kV feeder to accommodate the demand increase at a cost of $1.6m. We have determined that it will be cost effective to defer the feeder upgrade works for one year by implementing DM options.

At this point in time we do not know the exact type of DM options that will be implemented in the Manly Warringah area, however this will be determined from the investigation, consultation & assessment process. The total estimated cost of this DM program in the 2014-19 period is less than $50,000.

11kV Distribution Plans

Because the specific demand driven capital investments in the 11kV Distribution System are not known at the time of the regulatory reset, DM expenditure for the 11kV Distribution System in the 2014-19 period has been estimated based on expenditure in the current regulatory period, and scaled according to the relative level of growth driven 11kV investment proposed in 2014-19 period. This has been estimated at $1.5 million ($, 2013-14) for the 2014-19 period. At this point in time we do not know the exact location and type of DM options that will be implemented to defer 11kV capital investments in 2014-19.

The total projected expenditure for all targeted DM programs is $2.0 million ($, 2013-14) for the 2014-19 period. This is summarised in detail in the table below.

Summary of Targeted Demand Management program costs ($ million, 2013-14)

Project	2014/15	2015/16	2016/17	2017/18	2018/19	Total 2014-19
Load transfer from Tarro ZS	$ -	$ -	$ -	$0.09	$0.41	$0.50
Upgrade of 33kV feeder S03 at Manly Warringah	$ -	$ -	$ -	$0.02	$ -	$0.02
Distribution (11kV) feeder projects	$ -	$0.38	$0.38	$0.38	$0.38	$1.50
Total	**$ -**	**$0.38**	**$0.38**	**$0.47**	**$0.78**	**$2.01**

4.4 Description of broad based DM programs

Ausgrid has developed a suite of Broad Based DM programs for the 2014-19 period covering both the residential and non-residential sectors. The aim of these programs is to reduce demand growth over the longer term, with the benefits of deferring capital investment requirements in the post 2014-19 period.

The three Broad Based programs are as follows:

1. Residential direct load control and energy efficiency
2. Power factor correction (PFC)
3. Non-residential demand response and energy efficiency

The expenditure on Broad Based Demand Management is equivalent to an investment of $2.80 per customer per year to ensure future price stability – over half of which, $12 million ($, 2013-14), will be returned to customers during the period as incentive payments for delivering peak demand reductions. Net market benefits from the program are $38 million NPV (10 year) with a minimum benefit cost ratio of 2.0 when using the whole of network average cost of extra capacity.

The Broad Based DM program will target emerging constraints from the 2019-2024 period so as to maximise the benefits. Annual DM plans, based upon latest spatial demand forecasts and investment plans, will guide the Broad Based DM investment. Based upon past DM programs, we expect the benefit cost ratio will range from 3 to 5.

By the end of the 2014-19 period the Broad Based Demand Management Plan is forecast to deliver 84 MVA in peak summer demand reductions and $38 million in market benefits at a cost to Ausgrid of $22.1 million ($, 2013-14) opex (*and $1.3 million capex*).

A description of each program follows.

4.4.1 Residential direct load control and energy efficiency program

As noted in the introduction, 3,464 MW, or 57%, of the summer peak maximum demand derived from residential and small business customers. Estimates of the share of this peak contribution from residential customers indicate that over 45% of the system maximum demand is from residential customers. With about 500,000 off-peak hot water systems supplied under the existing controlled load products offering winter peak demand reductions of about 300 MW, direct load control offers a cost effective and reliable source of demand reductions. This program proposes to leverage the recently introduced Australian Standard for demand response (AS4755) and the existing controlled load tariff structure and ripple current equipment to deliver 35.6 MW of demand reductions under controlled load. A further 0.5 MW is proposed as part of a modest level of support for energy efficient appliances.

An important part of the load control program involves the rescheduling of the off peak 2 load control product to better suit summer peak demand. This tariff was originally intended for shifting load outside of peak times in the winter period but summer peaks are becoming the predominant driver for much of Ausgrid’s growth related network investment. Recent and ongoing upgrades to the controllers for this system allow a more dynamic adjustment to these schedules and these modifications offer significant demand reductions.

While the precise mix of appliances under a load control product will depend upon the specific network areas targeted and the customer mix in those areas, the load control program will focus on the three household appliances which drive both peak network demand and customer bills; air conditioners, hot water systems and pool pumps. Load control products for these appliances offers networks the opportunity to limit peak demand and the infrastructure costs required to meet this demand, but also offers customers opportunities to reduce their electricity bills.

A detailed review of the peak demand drivers from these appliances and the market potential for load control offers and use of energy efficient options has been completed, and a preliminary estimate of the likely mix of individual products over the 2014-19 period has been made. A discussion of each appliance is noted below.

<u>Air conditioner direct load control</u>

As a leading cause of summer peak demand, residential air conditioners contribute an estimated 1,260 to 1,680 MW of Ausgrid's summer peak demand of 6,000 MW. This program would introduce direct load control for residential air conditioning units to moderate the peak demand impact and offer customers an opportunity to lower their energy bills. AC load control offers the best way to reduce demand from the residential sector and so forms an important element in any broad based demand management program.

There are up to 1 million air conditioned households in the Ausgrid network area (60-70% of 1.4 million residential customers) with the average air conditioning unit drawing about 1.5 to 2 kW. This program would target households purchasing selected models which include a demand response interface (AS4755) to limit establishment costs, and will reduce electrical input by 25-50% for up to 20 peak days per year. Power input reductions would be targeted to ensure minimal impact upon customer comfort.

For communication of the load control signals, the existing ripple current equipment used for control of storage hot water cylinders or the commercial telecommunication network (GSM) will be used.

The program design would build upon experience gained through DMIA trials completed by Ausgrid and Endeavour and extensive air conditioner load control programs operated in Queensland by Energex.

<u>Pool pump direct load control</u>

There are an estimated 180,000 households with pools in the Ausgrid network area (13% of 1.4 million residential customers) with a diversified load of around 0.5kW per household. The total electrical demand due to residential pool pumps on a summer peak day is estimated to be up to 90 MW. Pool pump load is often considered to be a good candidate for shiftable load, especially on summer peak days, and pool pumps are often run both in summer and winter (although to a lesser extent). Pool pumps can be a significant part of the peak demand for some residential areas and so can play an important role in reducing demand for these areas.

The load control program would use the existing ripple current equipment for load control signals, using either the existing off-peak 2 tariff (some modifications required) or target households purchasing selected models which include a demand response interface (AS4755).

As per the air conditioning load control program, the program design would build upon experience gained in Queensland where Energex and Ergon have established both load control and energy efficiency programs for pool pumps, and DMIA trials conducted by NSW distributors.

<u>Hot water direct load control</u>

As noted, there are about 500,000 off-peak hot water systems supplied under the existing controlled load products offering winter peak demand reductions of about 300 MW. We estimate there to be about 120,000 hot water systems capable of being supplied under the controlled load products but currently supplied on continuous supply. These systems are estimated to contribute over 60 MW to winter peak demand and over 20 MW to summer peak demand.

Leveraging the existing hot water load control products can assist with managing winter peak demand for selected areas and can help arrest the long term decline in customers on a controlled load tariff.

This program will incentivise customers to convert their hot water system to supply from a controlled load tariff. Conversion of an electric storage hot water system reduces winter peak demand by about 0.60 kW (summer peak demand reduction of 0.20 kW) and reduces customer bills.

Off peak 2 summer scheduling

Ausgrid currently has around 160,000 customers on the off peak (Controlled Load) 2 tariff, predominantly controlling domestic hot water systems. This tariff was originally intended for shifting load outside of peak times in the winter period and typically these hot water cylinders are switched off between the hours of 5pm to 8pm throughout the year with a restoration period of load following afterwards, typically between the hours of 8pm to 10pm.

Although winter peaking areas are still present in the Ausgrid network area, there is an increasing amount of the network that is dominated by summer peaks (estimated to currently be around 75 to 80% of zone substations). Summer peaks typically occur earlier in the day than winter peaks and can be more variable dependent on location in the network. Summer peak times, typically occur between 2pm to 8pm and there can still be a significant amount of Controlled Load 2 load that is operating and not switched off earlier on in this time period. By extending the shut off period of this load earlier into the day and for a longer time during the summer months it is possible to potentially reduce overall summer peak demand by an estimated 20 to 25 MW between the hours of 4pm to 6pm. The Ausgrid system as a whole tends to peak between the hours of 4:30 to 5pm AEDST on summer peak days when there is a mix of business load and residential load contribution at this cross-over point.

As the equipment operating the controlled load system is upgraded to allow the required functionality, revised summer scheduling will be introduced to match the local peak demand profile.

Energy efficient pool pumps

In some circumstances, the supply of a pool pump with a controlled load circuit might not offer a cost effective demand reduction opportunity for the network or be cost effective for the household. This might be where there is a high cost to run the controlled load circuit to the pool pump. An alternative offer is to incentivise customers to replace their old pumps with higher efficiency new pumps that are rated five or more stars. A five star rated pump saves over 50% on their pumping energy when compared with a one star pump, with a similar reduction in the diversified peak demand for each pump replaced. While there is no minimum energy performance standard for pool pumps, an incentive to customers to select high star rated pumps, offers networks the opportunity to limit peak demand growth where controlled load is not an option.

The residential load control and energy efficiency program is projected to reduce summer peak demand by 35.6 MW and winter peak demand by 4.2 MW through the control of 24,500 appliances, the adoption of 1,500 energy efficient pool pumps and the rescheduling of the off peak 2 controlled load system. Customer incentive payments comprise $4.9 million ($, 2013-14), or 42% of the $11.7 million ($, 2013-14) program costs over the 2014-19 period.

4.4.5 Power Factor Correction Program (PFC) for C&I Customers

Power Factor Correction (PFC) typically offers the lowest cost way to reduce MVA demand on the network and is a common tool in project specific demand management programs. Improving the power factor for customers across our network offers both significant demand reductions and cost savings for customers.

The program is projected to permanently reduce summer peak demand by 28 MVA and 16.5 MVA in winter by the end of the 2014-2019 period. Customer incentive payments comprise $0.3 million ($, 2013-14), or 17% of the $1.6 million ($, 2013-14) program costs over the 2014-19 period.

The program will generally reflect our current practice of offering a negotiated rate for power factor correction equipment to customers identified as benefiting financially from the retrofit. Customer payback typically ranges from 1 to 4 years for most customers with low power factor and supplied at low voltage. Modest subsidies will be offered where appropriate to improve take-up.

Offering significant demand reductions across the majority of our substations, power factor correction forms an important part of the broad based DM program.

4.4.6 Non-residential demand response and energy efficiency program

Non-residential customers are the source of over half of system peak demand and typically the source of a range of low cost demand reduction opportunities. And as any network investment deferral will cover a network area with a varying range of customers, it is important that the available demand management resources cover all customer types (e.g. constraint in network area serving predominantly industrial or commercial customers).

This program proposes to deliver both permanent demand reductions and demand response capability from commercial, institutional and industrial customers. The precise mix of demand response and energy efficiency will depend upon the specific network areas targeted and the customer mix in those areas.

Demand response

Interruptible load programs for residential customers often focus on specific equipment types such as hot water heaters and air conditioners. This is primarily because the source of the load is common across a large number of customers and so equipment specific programs have a high degree of success. In essence, the sector is relatively uniform. In the non-residential sector, the equipment type, usage and the financial and operational factors associated with demand reduction are variable and so the source of the demand reduction will vary.

The demand response product will leverage the capability of market participants such as aggregators, major customers, technology providers and consultants to identify and deliver demand reductions. The Dynamic Peak Rebate trial currently underway has been used to inform the development of this aspect of the non-residential program.

The Dynamic Peak Rebate approach allows the customer to discover their own least cost demand reduction to supply reductions for network deferral or minimise load at risk. The program will incentivise non-residential LV customers (typically on EA 305 and 310 tariffs) to reduce or shift their electrical demand during the 20-30 peak hours which contribute a significant component to peak demand. Across Ausgrid's network, there are about 13,000 customers contributing about 1850 MW at summer peak.

Energy efficiency

The replacement of old plant with new energy efficient alternatives can result in a permanent peak demand reduction. And while the costs for upgrades can be significant, the energy and costs savings realised by customers allows for a cost sharing arrangement which can be beneficial to both the customer and the electricity network. Knowledge gained from past research programs (Demand Management Planning Project) and learnings from other networks (Ergon, Endeavour and Energex) has been used to develop a program which leverages the capability of market participants such as aggregators, major customers, technology providers and consultants to identify and deliver demand reductions. An additional trial is proposed for the 2014-19 period to further refine program structure.

The non-residential demand response and energy efficiency program is projected to reduce summer peak demand by 20 MW and winter peak demand by 2.5 MW. Customer incentive payments comprise $6.9 million ($, 2013-14), or 78% of the $8.8 million ($, 2013-14) program costs over the 2014-19 period.

4.5 DM Innovation projects

The need for development and exploration of new opportunities will remain an important priority in 2014-19. While Ausgrid's DMIA allowance in the current period is $1 million per year, the availability of government funding for the *Smart Grid, Smart Cities* Project has meant that much of our innovation effort has been diverted into those priorities during the current period. It is for this reason that Ausgrid's DMIA expenditure in 2009-14 is likely to be under the $5 million allowance (projected to be $4.1 million).

In the 2014-19 period we propose to continue a number of the trials developed and initiated during the 2009-14 period. These projects include the AS4755 load control, power factor correction, CBD generator connection, off peak 2 summer scheduling, RMIT research and UNSW research trials. A number of further trials are in early stages of development and are expected to be found to offer a sound model business case and warrant proceeding to the trial stage. These projects include the residential behaviour change, AC direct load control for SMEs, C&I energy efficiency and automated demand response trials. Other projects which we believe are likely to warrant investigation in future relate to electric vehicles and grid battery storage. The projects currently identified for funding in the 2014-19 period are summarized below.

Proposed DMIA Expenditure for 2014-19 (by project - $m)

DMIA Project	2014/15	2015/16	2016/17	2017/18	2018/19	2014-19 Total
AS4755 direct load control (phase 3)	$0.50					$0.50
Power factor correction (phase 2)	$0.30					$0.30
CBD Generator (phase 2)	$0.15					$0.15
OP2 Summer Scheduling (phase 2)	$0.15					$0.15
Residential customer behaviour research	$0.10	$0.10	$0.10			$0.30
Pool pump research	$0.10					$0.10
Residential Behaviour Change Trial		$0.35	$0.35			$0.70
AC Direct Load Control (DLC) for SMEs		$0.25				$0.25
C&I Energy Efficiency/Lighting Program		$0.35	$0.20			$0.55
Demand Response Automation Trial		$0.75	$0.25			$1.50
Electric vehicles - Controlled Load Trial			$0.25	$0.25		$0.50
Grid Battery Trial			$0.15	$0.25	$0.10	$0.50
Total	**$1.30**	**$1.80**	**$1.30**	**$0.50**	**$0.10**	**$5.00**

Table 6: Proposed DMIA Expenditure for 2014-19 ($m)

DMIA Costs	2014/15	2015/16	2016/17	2017/18	2018/19	2014-19 Total
Capex	$ -	$ -	$ -	$ -	$ -	$ -
Opex	$1.3	$1.8	$1.3	$0.5	$0.1	$5.0
Total	**$1.3**	**$1.8**	**$1.3**	**$0.5**	**$0.1**	**$5.0**

A brief description of the proposed DMIA projects are as follows:

1. **Air conditioner and pool pump direct load control** – continuation of trial initiated in 2012-13 to explore the potentially cost effective method of controlling residential air conditioners and pool pumps using AS4755 compliant devices. Refer Section 1.4.

2. **Power factor correction** – continuation of trial initiated in 2013-14. Refer Section 1.4.

3. **CBD Generation Trial** – continuation of trial initiated in 2011-12 to test an embedded generator connection in the Sydney CBD that addresses the potential fault level and feeder imbalance issues. Refer Section 1.4.

4. **Off peak 2 summer scheduling** – continuation of trial initiated in 2013-14 to test a new summer load control schedule for summer peak reduction for customers with Controlled Load 2 tariffs. Refer Section 1.4.

5. **Residential customer behaviour research** – collaborative research project with RMIT University to enhance our understanding of residential electricity demand trends to better inform demand management programs.

6. **Pool pump research** - collaborative research project with UNSW to enhance our understanding of residential pool pump use to better inform demand management programs.

7. **Residential Behaviour Change Trial** – subject to customer feedback technology developments, this trial will explore customer engagement models in combination with feedback technologies to determine demand reduction potential.

8. **Air-conditioner Direct Load Control (DLC) for SMEs** - investigation and trial to control air conditioning systems in small to medium size businesses

9. **C&I Energy Efficiency/Lighting Program** –to explore potential from increased take-up of efficient lighting technologies.

10. **Demand Response Automation Trial** – to test the cost effectiveness of a demand response automation system for medium to large non-residential customers supplying demand reductions.

11. **Electric vehicles** – subject to developments, this trial will explore alternative charging options for electric vehicles to limit impact upon peak demand.

12. **Grid Battery Trial** – subject to developments, this trial will test latest battery technology and how they might be utilised to reduce peak demand.

Section 5: High level review

Our forecast opex reflects the efficient costs that we would require to deliver the outcomes we are required to deliver by the National Electricity Rules. It also reasonably reflects the prudent costs that a prudent operator would require and a realistic expectation of the demand forecast and cost inputs required to achieve these outcomes.

The purpose of this section is to demonstrate that our proposed opex meets the opex objectives and criteria, with regard to the opex factors in the Rules.

5.1 Meeting the opex objectives & criteria

Check undertaken	What was checked
Double counting	1. Benefits not included in area specific proposals for 2014-19 2. Demand forecasts have been adjusted for capital plans 3. Inter-relationship between Broad Based DM, location specific DM and DMIA is quarantined by using in different expenditure streams, benefit streams and consistent accounting for impacts on peak demand.
Historical check	Ausgrid's DM costs are higher than last period due to new requirements and opportunities to manage prices in the long term interest of customers. Ausgrid is implementing a broad based solution for the 2014-19 period when it has not done so to date because of increased experience and opportunities for DM. Location Specific DM projects under the D-Factor have delivered measurable benefits. R& D expenditures under the DMIA (and supported by SGSC funding) have led to and supported the development of Broad Based DM options
Consistency with demand and energy forecasts	Reduction in peak demand forecasts associated with broad based DM have been incorporated into the peak demand forecasts used for the Area Plans, 11kV Plans, Low Voltage Plans, Customer Connection Plan, and that the outcome has been reflected in the Reliability Plan. (see individual plans) Show the assumed reduction in system peak demand from Broad Based DM and is consistent with global energy forecasts developed by Ausgrid and AEMO.
Benchmarking	Ausgrid's propose to spend on DM compared to capex for: - Broad based programs are to be offset against capex planned for beyond the 2014-19 period and reflected in lower prices to consumers in the longer term - Location specific DM will be supported by the deferral value of capex approved in the Area Plans

	Ausgrid's proposed DM costs per kVA reduction for broad based and location specific DM are included in the Plan are set a less than half the potential level originally identified as cost effective and are considered a reasonable level as the benefit cost ratio of the overall portfolio is 2.0, about double the cost.
Deliverability	Ausgrid's confidence that it can deliver the Broad Based Demand management program proposed is based on a track record in delivering Location Specific programs and observation and analysis of interstate and international DM programs.
Compliance with regulatory obligations	Ausgrid has a regulatory obligation to consider non-network options as an alternative to expansion of network capacity, and implement them where cost effective. This program is consistent with this obligation.
Consideration of substitution between opex and capex	The proposed Broad-Based DM opex will result in cost effective deferral of capex costs both within the 2014-19 period and subsequent regulatory periods.
Consistent with applicable incentive schemes	The DM proposal is formulated to be consistent with the AER's existing DM Innovation Allowance Incentive Scheme, with an allowance of $5m over five years.
Consideration of efficient and prudent non-network alternatives	The Broad-based DM proposal is based upon the implementation of a program of non-network options to cost effectively achieve savings in capital expenditure that will result in lower energy costs for customers in the long term.

Appendix A Supporting documents

The following list of documents provides support to the proposed expenditure for demand management opex on the distribution network.

	Document	Type
A	Ausgrid Demand Management Policy	Chapter 6 supporting documents – ID00283
B	Ausgrid Demand Management Standard	
C	Ausgrid Demand Side Engagement Strategy	
D	BBDM Cost Benefit Summary (Excel spreadsheet)	
E	Ausgrid website - DM section - http://www.ausgrid.com.au/Common/Our-network/Demand-management-and-energy-efficiency.aspx	Supporting reference
F	Ausgrid D-factor submission 2009/10 - http://www.aer.gov.au/node/14412	Supporting reference
G	Ausgrid D-factor submission 2011/12 - http://www.aer.gov.au/node/19880	Supporting reference
H	Ausgrid's AEMC Power of Choice DSP3 submission - http://www.aemc.gov.au/Media/docs/Ausgrid%20-%20received%2016%20September%202011-70ddcb4a-8fa3-4da2-a95d-6a641a46e15f-0.PDF	Supporting reference
I	AEMC DSP3 Completed Review - http://www.aemc.gov.au/Markets-Reviews-Advice/Power-of-Choice-Stage-3-DSP-Review	Supporting reference
J	AER Strategic Priorities and Work Program 2013-14 - http://www.aer.gov.au/publications/aer-strategic-prioirities-and-work-program-2013-14	Supporting reference
K	AEMO load forecasts - http://www.aemo.com.au/en/Electricity/Forecasting	Supporting reference
L	Australian Alliance to Save Energy (A^2SE) reports - http://www.a2se.org.au/activities/research	Supporting reference
M	Ausgrid annual reports and DM Statutory information http://www.ausgrid.com.au/Common/About-us/Corporate-reports/Annual-reports.aspx	Supporting reference
N	IGrid / UTS reports - http://igrid.net.au/node/190	Supporting reference
O	Energex regulator submission and determination- http://www.aer.gov.au/node/4461	Supporting reference
P	Ergon Energy regulator submission and http://www.aer.gov.au/node/3811	Supporting reference
Q	Energex DM Programs - https://www.energex.com.au/residential-and-business/rewards-for-air-conditioning-pools-and-hot-water	Supporting reference
R	Ergon Energy DM Programs - https://www.ergon.com.au/energy-conservation/demand-management	Supporting reference
S	National Electricity Law - http://www.aemc.gov.au/electricity/legislation.html	Supporting reference
T	NSW Electricity Supply Corporations Act - http://www.legislation.nsw.gov.au/viewtop/inforce/act+95+1995+cd+0+N/	Supporting reference
U	Energy white paper - http://ewp.industry.gov.au/	Supporting reference