Attachment 5.14

Demand management opex and capex overview

January 2015

Ausgrid revised regulatory proposal attachment

Executive Summary

Demand management (DM) is a key component in the efficient management of an electricity network. *"The extent the DNSP has considered, and made provision for, efficient and prudent non-network alternatives"*[1] is one of the capex factors to be considered by the AER under the National Electricity Rules. Ausgrid's proposed portfolio of demand management activities are a prudent and efficient expenditure to lower customer demand and defer capital expenditure in the long term interest of customers.

The draft determination's rejection of both the replacement of the D-factor incentive with the proposed demand management benefit sharing scheme (DMBSS) and the broad based demand management program is a backwards step in the development of demand management. The draft determination has failed to recognise the ongoing absence of any actual incentive for DNSPs to pursue demand management as a solution to network needs, the value of demand reductions to the wider energy supply chain and the need to invest to assist customers in responding to price signals and lower their peak demand. Reliance on a modest innovation fund, the RIT-D or the uncertain impact on localised constraints from future cost reflective prices will not be sufficient to build such capacity. This will result in significantly less demand management than is cost effectively viable and higher levels of augmentation capex in the following regulatory periods. We therefore resubmit our program as per the initial submission.

In formulating our revised proposal we have:

- re-assessed our DM program in line with the lower levels of augmentation arising from the revised spatial demand forecast, and included these effects in our capital expenditure requirements;
- reviewed and confirmed that the level of targeted spatial DM activity is consistent with the outcomes from the previous regulatory period, based on its application to HV distribution plans;
- verified the business case for the optimised broad-based DM program such that a positive NPV is returned in 6.5 years and the total NPV(10 year) through to 2024 is $31 million; and
- confirmed that the optimised broad-based DM program complements and is not undermined by cost reflective tariffs.

As detailed in Attachment 6.12 of Ausgrid's substantive proposal, we propose total opex of $37.3 million ($, 2013-14) and total capex of $1.3 million ($, 2013-14) over the period. The program is 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 in the 2014-19 Regulatory period,
- Broad Based Demand Management program, with the aim of future price stability by delaying growth driven investment primarily beyond the 2014-19 regulatory period, and
- Operation costs for technical support & reporting to meet regulatory requirements of the group.

A summary 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*
Regulatory requirements	$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**
Total DM Capex	***$0.7***	***$0.1***	***$0.2***	***$0.1***	***$0.1***	***$1.3***

[1] NER, cl 6.5.7(e)(10)

Contents

1 Introduction

Demand management is built into Ausgrid's spatial demand forecasts, part of underlying Area Planning and resultant augmentation capex, applied in top-down adjustments to our HV distribution capex model and subject to a regulatory incentive scheme. Due to this, elements of demand management appear under operating expenditure, capital expenditure and in the application of incentives. This document is a summary of Ausgrid's current demand management activities and proposed demand management programs which are designed to ensure that non-network alternatives offer effective solutions to network needs.

In Section 2 is a summary of Ausgrid's current planning processes into which demand management is firmly integrated, a summary of our targeted spatial demand management programs in the 2010-14 period and the proposed program for targeted spatial demand management in 2015-19.

In Section 3 is a summary of Ausgrid's proposed broad based demand management program, a review of the draft determination and Ausgrid's response.

In Section 4 is a discussion on the Demand Management Incentive Scheme, including Ausgrid's proposed Demand Management Benefit Sharing Scheme (DMBSS).

In Section 5 is our concluding comments.

2 Targeted demand management

2.1 Overview

Targeted demand management describes DM programs with the aim of addressing specific network constraints and deferral of a defined capital investment. Ausgrid has developed comprehensive processes and has a proven track record of delivering targeted spatial DM spanning a period of over ten years. The targeted demand management program has been developed as an integral part of the least cost strategies in the network capital works area plans and as a component of the HV distribution capacity plan.

As per Ausgrid's planning procedures, following the completion of the annual spatial demand forecast, a re-assessment of network needs for projects and the viability of non-network solutions are completed. For projects identified as part of the Area Plans, the assessment for non-network solutions occurs in parallel with the consideration of other solutions. For augmentation capex investment identified as part of the Distribution Capacity Plan, historical trends are used derive the scale of capex offsets and opex requirements due to demand management. For both the Area Plans and the Distribution Capacity Plan, the capex offsets are built into our capital expenditure requirements and the corresponding opex requirements are built into our opex expenditure plans.

2.2 Assessment of DM potential

Targeted DM solutions for the sub-transmission level of the network are built into Ausgrid's strategic business plans (Area Plans) and so are coordinated in advance. 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. In the 2010-14 period, demand management was used to defer or reduce the load at risk for projects with capital expenditure comprising 11.4% of the total capex spend for the 137 growth-driven projects at the sub-transmission level ($131m of $1,148m).

Due to the reduction in forecast demand since our initial proposal in May 2014, the level of augmentation expenditure has been adjusted down by 25% and resulted in a corresponding impact on opportunities for non-network solutions. For the revised 2015-19 regulatory proposal, there are only two expenditure projects at the sub-transmission level that are classified as augmentation. However in each of these cases, the shortfall in capacity arises as a result of retirement of assets in poor condition rather than load growth. Following an assessment of each project, at this time it is not considered viable to meet the network needs using non-network options. We will undertake a further review closer to the need date to assess the viability of non-network solutions.

At the HV distribution feeder (11 kV) level of the network, the augmentation expenditure is forecast using a model based upon historical activity rather than individual assessment. Subsequently, targeted DM solutions for the HV distribution feeder level of the network has been based upon past performance in deferral of similar capital investments. In the 2010-14 period, a total of $8 million or 7.3% of the $110 million in augmentation expenditure at the 11kV level was deferred using targeted demand management. In our initial submission we proposed a similar level of targeted demand management, or $9.4 million (7%) of the $128 million in 11kV capacity reinforcements.

2.3 Revised program

For our revised regulatory proposal, we have retained our expectation that a portion of the remaining augmentation expenditure will be able to be deferred using targeted local DM projects. Furthermore, we believe that the low level of augmentation capex, forecast demand uncertainty and lack of any positive incentive for demand management significantly increases the risk of insufficient funding to manage potential load of risk.

Note also that we have retained the effect of the broad-based DM program in our demand forecasts, which has flowed through to our augmentation capital program. Because they are embodied as reductions in the demand forecast, these offsets to capital expenditure are not visible in the augmentation program models.

If the high scenario for the spatial demand forecast were to eventuate, then there would be a significant increase in requirements for augmentation expenditure for HV distribution feeders resulting in a substantial increase in the load at risk. Under this scenario, the absence of capex offsets combined with the lack of any positive incentive scheme would undermine demand management and restrict the amount of capex deferral possible. For this reason, we have made no change to our proposal in the opex requirements for targeted demand management. A total of $6 million in capex deferrals has been built into the augmentation capex for HV distribution feeders.

3 Broad based demand management

3.1 Overview

The AER did not accept Ausgrid's proposal for an investment in broad based demand management to lower customer demand and defer capital expenditure in the long-term interests of customers. The draft determination rejected the proposed program on the basis that the introduction of cost reflective pricing would deliver price signals enabling customer response sufficient to undermine the business case for broad-based demand management.

The broad based DM programs have been introduced as a step change to opex to enable customer demand response as a complement to current and future cost reflective price signals and to build capacity for deferral of emerging constraints arising in the 2015-24 period. The program builds upon the existing ½ million controlled load hot water systems in Ausgrid's network area by introducing direct load control solutions for air conditioners and pool pumps and introduces new demand response capability from non-residential customers. Where Retailer based cost reflective tariffs are introduced, program incentives will be wound back to efficient levels. The broad based program delivers benefits in excess of costs, returning a positive net present value (NPV) early in the following regulatory period and a total NPV of $31 million by 2024.

We disagree with the conclusion reached in the draft determination and resubmit our program as per the initial submission. To defer growth related capital expenditure in the 2015-19 period and build capacity for deferral of capital expenditure in the 2020-24 period, Ausgrid proposes to invest a total of $23.4 million in broad based demand management programs. The programs include $12.1 million in customer payments to introduce cost reflective price signals to customers in localised areas where demand growth is driving network investment. The programs also include $4.2 million to introduce the enabling technologies necessary for customers to respond to the price signals, $4.8 million to acquire customer participation in areas with emerging constraints and $2.3 million in project management and development costs.

A summary of costs for Ausgrid's broad based DM programs are as follows ($ million, 2013-14):

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Operating expenditure ($ million, 2013-14)						
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
Total Opex	**$1.4**	**$3.0**	**$4.0**	**$5.6**	**$8.1**	**$22.1**
(Customer incentives						**($12.1)**

included in Opex)						
Capital expenditure ($ million, 2013-14)						
All programs	$0.7	$0.1	$0.2	$0.1	$0.1	$1.3

Note that while the application of the demand management incentive allowance (DMIA) to date by Ausgrid has focused upon the development of innovative DM solutions, the scheme rules do not preclude its use for broad based demand management. We note that allowed expenditure under the DMIA may include *"broad–based demand management projects or programs—which aim to reduce demand for standard control services across a DNSP's network, rather than at a specific point on the network."*[2]

Our submission for a step change in opex to fund broad based demand management is based upon our view that investment in mature non-network solutions as the least cost solution to a network need is logically within the building block framework for standard control services. Were the AER to prefer the greater level of oversight and the 'use it or lose it' arrangement of the DMIA to fund demand management expenditure, we would be open to the inclusion of the $23.4 million broad based demand management program within the DMIA. Under this funding structure, where the market achieves outcomes that are sufficient to meet network requirements for deferral, funds would not be spent and so returned to customers.

3.2 Option value and viability

As noted in our proposal, *"in the expected period of 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"*.[3] This value was rightly recognised by the draft determination in both referencing this statement and noting that *"rather than the value of demand management falling in times of uncertain or flat demand, its option value is likely to increase. This is primarily driven by the demand management alternatives being able to be readily renegotiated or re-purposed."*[4]

This statement in the draft determination also recognises the requirement that a viable demand management solution must be 'readily negotiated' and we would add the obvious statement that it must also be negotiated in time to meet the constraint. Ausgrid's experience is that the timeliness of the demand response is commonly a key hurdle to deferral of assets below the subtransmission level of the network. The timing of the growth on an 11kV feeder or low voltage distributor is very difficult to predict as it is typically driven by unpredictable growth in new connections and the scale at this level results in 'lumpy' changes to demand which drives investment. Analysis of 76 emerging constraints at the 11kV level showed that the average time for consideration of demand management for 11kV constraints was 78 days (2.6 months). While improvements in internal processes and the lower level of expenditure now typically allows a wider window, there remains little time for the adequate consideration, investigation, development and deployment of DM solutions; particularly on feeders with a significant residential load.

In the current regulatory period, about 90% of the augmentation expenditure is on network assets at the 11kV feeder and low voltage distributor level, in contrast to the 2010-14 period where investment at the sub-transmission level offered the greater opportunities. This trend is projected to continue into the 2020-24 period. Analysis of historical 11kV constraints shows that sufficient value for deferral is offered with an average benefit value of $144 per kVA and 17% having an annual deferral value greater than $200 per kVA. Development of actionable rather than theoretical options (solutions which cannot be implemented in time) for deferral of 11kV investment offers significant potential for increasing the volume of capital investment deferred and was a focus of Ausgrid's demand management incentive allowance (DMIA) activities in the 2010-14 period.

These trials, and the development and adoption by the air conditioning industry of the AS4755 demand response standard, have shown that a low cost and reliable source of demand reductions from residential customers is now available. To be available for deferral of capex, the controlled appliances will need to be acquired in advance. The proposed 2015-19 broad based demand management program is designed to enroll customers in time to exploit these opportunities.

3.3 Program cost effectiveness

While commonly identified as broad based demand management to differentiate from spatial or in-period demand management used to defer capital investment in-period, Ausgrid's proposed broad based program is also targeted, but designed to *"target emerging constraints from the 2019-2024 period so as to maximise benefits"*.[5] By building capability through the selective introduction of demand reductions from controlled load, demand response and energy efficiency, demand growth in areas with emerging constraints can be suppressed to extend the life of existing network assets.

[2] AER, Nov 2008, Demand management incentive scheme for the ACT and NSW 2009 distribution determinations, Demand management innovation allowance scheme

[3] Ausgrid, 2014, Attachment 6.12 Demand management operating expenditure plan, page 6

[4] AER, 2014, Draft Decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 6: Capital expenditure, page 6-83

[5] Ausgrid, 2014, Attachment 6.12 Demand management operating expenditure plan, page 4

The draft determination stated that *"once more cost reflective tariffs are in place, the marginal benefits of undertaking demand management would be lower than it is today. Given these changes, we do not have confidence that the long term benefits of Ausgrid's proposed initiatives are as high as it estimates. We are not confident that the benefit of these initiatives will outweigh the costs."*[6]

We did not include cost reflective pricing in our original business case because we did not consider that it would have a material impact. We re-assessed the business case for our broad based DM program; including sensitivities for a range of impacts from future cost reflective pricing, and determined that, as expected, there is only a modest impact on the cost effectiveness of the program. We estimate that the change would lead to only a 1-2 month delay in the project achieving a net positive NPV, still about 6.5 years. This is due to the likely limited takeup of any cost reflective tariffs in the near to mid term and the poor effectiveness of broad market level tariffs in targeting local constraints. Revised modelling is available where requested.

A summary of the benefits for Ausgrid's broad based DM programs are as follows ($ million, 2013-14):

Program	2019/20 Summer demand reduction (MW)	2019/20 Winter demand reduction (MW)	2014-2024 Total Net Market Benefit Real ($M)
Residential direct load control and energy efficiency	36.1	4.2	$14.9
Power factor correction	28.0	16.5	$10.2
Non-residential demand response and energy efficiency	20.0	2.5	$5.6
Total	**84.1**	**23.2**	**$30.7**

As this estimate is based upon using whole of network average cost of extra capacity, and the broad based demand management program will target emerging constraints, we expect the program benefits will be higher than estimated resulting in a higher benefit cost ratio and a positive NPV early in the following regulatory period.

Further information on Ausgrid's broad based demand management program is contained within Attachment 6.12, Demand Management operating expenditure plan for the 2015-19 regulatory period of our initial proposal.

3.4 Cost reflective pricing impacts

Broad based demand management is not only cost effective on its own; it is complementary with any cost reflective pricing introduced by distribution networks and electricity retailers. The program supports two key gaps in the ability of cost reflective pricing to effectively defer network investment. These gaps are:

1. In the near to mid-term, tariff changes are unlikely to have a sufficient impact to be effective in deferring localised constraints.
2. Without enabling technologies, cost reflective tariffs are unlikely to be sufficiently effective on their own.

3.4.1 Effectiveness of cost reflective pricing

The impact on customer peak demand from the introduction of cost reflective pricing will be highly dependent upon the

- structure of future tariffs
- period of time required to fully introduce effective tariffs
- roll-out of any required metering
- level that any price signal is passed though in retail pricing
- customer response
- effectiveness of cost reflective pricing in deferring network augmentation

Before customers can select cost reflective tariffs, they must be offered to customers, customers will need to invest in the necessary metering and networks and Retailers will need to upgrade the necessary IT infrastructure. From our experience, this takes considerable time even under a mandatory rollout.

Ausgrid introduced interval meters as our default meter in 2003 and now have about 480,000 customers on time of use pricing, out of our customer base of 1.6 million customers. To achieve this, both the interval meters and time of use pricing were mandatory for customers using more than 15,000 kWh pa and for new and replacement meters. Ausgrid

[6] AER, 2014, Draft Decision Ausgrid distribution determination 2014-19, Attachment 7: Operating expenditure, page 7-169.

now has the largest application of cost reflective tariffs of any distributor in Australia. But, this took ten years of focused effort.

Our experience from these past ten years is that most customers perceive cost reflective tariffs as punitive, often regardless of whether they benefit financially. Building a level of trust in the community will not be straightforward. Innovative tariffs will only be accepted by customers when they perceive an advantage to being on those tariffs and customers will need some confidence that they will benefit. Smart meters offers the capability to allow customers to discover which tariffs offer the most benefit, but without a mandatory rollout, this will take some time. Until such meter offers are made to customers, it is unclear how quickly or slowly smart meters will be selected by consumers.

It also does not immediately follow that cost reflective tariffs will be applied as a consequence of smart meters being installed. In Victoria where smart meters have now been installed to the vast bulk of customers under a DNSP led roll out, there has been minimal take up of time of use pricing. Out of AGLs customer base of 454,500 domestic customers, only 831 customers have voluntarily selected flexible pricing in the first 7 months that it needed to be offered to customers from the Victorian launch date of 1 Sep 2013 (Sep 2013- April 2014).[7] This is a rate of 0.3% per annum take up of flexible pricing, with nearly all customers being able to voluntary take up flexible pricing due to almost full coverage of smart meters across Victoria. With a market led roll out of cost reflective pricing and smart meters, we would anticipate an even lower penetration than AGLs numbers due to customers needing to have their meter replaced and possibly pay for the costs as well as take up a new pricing offer they may not be familiar with.

Furthermore, as part of the AEMC's review process in the development of the new pricing rules, Faruqui and Brown[8] discussed the tariff design principles of gradualism and fairness where tariff changes are introduced slowly to allow customers to adapt and impacts on customers are considered fair and equitable. Were Ausgrid to introduce tariffs which have been shown in trials to result in material reductions in peak demand, these principles would likely slow the introduction of fully effective tariffs. As stated in the AEMC's Rule determination,

> *"Consumers are more likely to be able to respond to price signals if those signals are consistent and apply for a reasonable period of time. Sudden price changes or significant year-to-year price volatility will make it difficult for consumers to make informed consumption decisions."*[9]

The tariffs reported to offer material peak demand reductions would offer a significant public policy challenge and introduce new concepts to the community. Consequently, it is likely that a transition period would be required to build customer acceptance.

A further impact on the effectiveness of cost reflective pricing is that any price signal perceived by the customer is often diluted and can moderate any customer response. The Productivity Commission noted when examining rates in NSW that *"a ten-fold price differential at the network side was more than halved when expressed in retail prices. This dilution of network charging variations is important in modelling demand responses."*[10]

The combination of a:

- market led smart meter roll-out
- the likely gradual introduction of cost reflective tariffs
- the level that any price signal is passed though in retail pricing, and
- the ineffectiveness of broad market tariffs to influence customers in areas with emerging constraints

will dilute and delay a customer response sufficient to effectively defer network investment in the near to mid-term.

3.4.2 Enabling technologies

The absence of appropriate enabling technologies restricts the customer's ability to respond to cost reflective tariffs. The proposed broad based demand management program introduces such enabling technologies to allow customers to effectively respond to price signals and reliably reduce their electricity use at peak time.

That is, even if consumers faced perfectly cost reflective tariffs today, they would still need support to respond to those tariffs through technology enablement. Customers using up to 100 MWh p.a. have limited capacity to change their behaviour to cost reflective tariffs. The use of broad based demand management using enabling technology maximises the customer's capacity to respond to these tariffs. And of course broad based demand management can be rolled out in the absence of cost reflective tariffs as well.

Enabling technologies introduced as part of Ausgrid's proposed broad based demand management program is a key plank in maximising the benefits of cost reflective prices. For example, a program to control customer's air conditioners will extract far more demand management benefit than simply a tariff because the technology provides the needed demand response to the tariff that the consumer may have difficulty in responding to. Electricity consumers are more likely to participate by reducing demand when, not only are they given the problem of a cost reflective price, but also a

[7] Oakley Greenwood presentation, 'A Tale of Two Tariffs', slide 5, downloaded from https://s3-ap-southeast-2.amazonaws.com/wh1.thewebconsole.com/wh/1399/images/A-Tale-of-Two-Tariffs.pdf

[8] Faruqui and Brown, 2014, Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs

[9] AEMC, 2014, Rule Determination National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014

[10] Productivity Commission, 2013, The costs and benefits of demand management for households, p 7

solution to that problem in the form of a technology solution that is managed on their behalf and does not require them to have concentrated ongoing engagement. Broad based demand management solves the problem for the consumer.

Furthermore, the proposed programs are designed to be effective with or without new cost reflective tariffs, smart meters or updated back-end infrastructure. In the event that these elements are delayed, the proposed programs can still reliably deliver the demand reductions so as to defer network investment. Delaying the complementary benefits of broad based demand management by assuming a theoretical outcome from cost reflective pricing and meter competition would not be in the long term interests of consumers.

The principle of enabling technologies is supported by the Productivity Commission where they stated that *"In combination, direct load control, smart meter rollouts and critical peak pricing can significantly reduce critical peak demand if well implemented"*[11] and that *"using direct load control as a complement to smart meters"*[12] can improve outcomes. This view is supported by numerous trials, surveys and investigations. As reported by Dr. Gill Owen in an investigation into the opportunities and risks for vulnerable customers when responding to peak demand,

> *"Automation delivers the greatest and most sustained shifts in demand (compared to price incentives alone), particularly where consumers have air conditioners or electric heating. A review of trials found peak reductions of 31% with automation (16% without) for critical peak price tariffs and 16% (5% without) for ToU tariffs."*[13]

Using the above information from the Owen report, a 5% peak reduction due to time of use pricing for an average peak load of 2.5 kW per residential customer would result in a diversified peak reduction of only 125 Watts per customer. In comparison, Energex has reported an average diversified demand reduction of 600 Watts per controlled product (air conditioner, pool pump or hot water system) based on their broad-based demand management program results during the 2010-2015 regulatory period[14]. This aligns with the assumptions in our program design for about 580 watts per participating customer. An average demand reduction per household that is about 5 times greater than for tariffs alone will drive a greater numbers of viable capex deferrals by increasing the technical demand reduction potential from residential customers. Energex has also reported that their air conditioner direct load control program is enrolling about 10-15,000 customers per year through air conditioner retailer sales channels; a strong indication that customers are responding to DNSP led tariff signals when supported by enabling technology.

As noted in the Owen report, Faruqui and Palmer[15] demonstrated that reductions in peak demand from a range of alternative tariff structures are greater with an enabling technology than without. This conclusion is consistent with the Smart Grid Smart Cities trial that concluded that:

> *"In terms of product effectiveness, bundled products (i.e. a combination of pricing structure and feedback technology) were more effective in reducing customer electricity usage and changing customer behaviour than either pricing structures or feedback technologies trialled in isolation."*[16]

Furthermore, Nicholas and Strengers noted that:

> *"the family peak period is made-up of a series of tightly-linked and closely sequenced practices often culminating around (and needed to manage) a period known as 'crazy time'."*[17]

Without some form of enabling technology to aid families in responding to a price signal, the resultant demand response is likely to be limited constraining the ability of the tariff to effectively defer network capital investments.

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[11] Productivity Commission, 2013, The costs and benefits of demand management for households, p 1

[12] Ibid, p1

[13] Owen, 2013 Addressing Peak Demand, The opportunities and risks for vulnerable customers (p1)

[14] Energex regulatory proposal, October 2014, Appendix 17 Demand management program, p 27

[15] Faruqui and Palmer, 2012, The Discovery of Price Responsiveness- A Survey of Experiments involving Dynamic Pricing of Electricity.

[16] Smart Grid Smart Cities, Customer Applications Technical Compendium, p15, downloaded from https://ich.smartgridsmartcity.com.au/Home/SGSC-Report/Technical-Compendia/Customer-Applications

[17] Nicholls and Strengers, 2014, Changing Demand: Flexibility Of Energy Practices In Households With Children

4 Demand management embedded generator connection incentive scheme (DMEGCIS)

4.1.1 DM benefit sharing scheme

While the draft determination recommended the continuation of the existing Demand Management Innovation Allowance (DMIA) at the previous value of $1 million per year, no effective consideration was given to the maintenance of positive incentives for demand management formerly available through the D-Factor.

The draft decision incorrectly asserts that "*Ausgrid proposed its DMBSS in anticipation of a series of rule changes which are currently being considered by the AEMC as part of its Power of Choice review*."[18], and that "*The move to a revenue cap form of control...provide(s) distributors with opportunities to improve and expand their demand management programs*."[19]. The draft decision identifies these as reasons why it chose not to consider the introduction of any incentive for demand management.

Neither of these is true. There is nothing in the current rules that would prevent the consideration of a DM incentive scheme of the type proposed. Ausgrid's proposal reflects our concern regarding the ongoing absence of any actual incentive for DNSPs to pursue demand management opportunities, and the absence of any mechanism to recognise the value of demand reductions to the wider energy supply chain.

The move to a revenue cap has made no difference to the framework under which demand management operates. The previous arrangements for recovery of foregone revenue neutralised the potentially negative incentive of the price cap. It is appropriate that the foregone revenue arrangements should fall away with the introduction of a revenue cap, but that serves only to maintain the status quo, not improve the situation. The loss of the incentive component of the D-Factor now means that this draft decision is less supportive of demand management than the previous AER decision.

As noted by Enernoc in their submission to the AER, *"NSW DNSPs have undertaken a great many more augmentation-deferral-driven demand management projects than DNSPs in other NEM regions. It seems likely that this is because they were subject to the D-factor scheme, which provided a positive incentive for demand management projects, whereas DNSPs in other regions have only been subject to the DMIS, which, despite its name, provides no positive incentive for demand management."*[20]

On this basis, Ausgrid retains the proposal for a DMBSS in the revised proposal, under the same terms as described in the initial proposal. The details of this proposal were contained in Attachment 3.03 "*Application of Demand Management Embedded Generator Connection Incentive Scheme (DMEGCIS) proposal*" to our initial proposal. Our proposal is unchanged. Further details were provided in a response to your request for further information.[21]

The DMBSS reflects the interests of key stakeholders, including:

- the Total Environment Centre (TEC);
- Interest Advocacy Centre (PIAC);
- Enernoc; and
- Consumer Challenge Panel.

As noted in their submission to the AER, the Public Interest Advocacy Centre (PIAC) stated, *"PIAC commends Ausgrid for proposing a demand management benefit sharing scheme (DMBSS) and supports it as an interim measure before the reformed DMIS is introduced...This should be developed as a matter of urgency and applied within the current determination."*[22]

And Enernoc, commenting on the delays in implementing the recommendations of the Power of Choice reviews, states *"Ausgrid has recognised this problem and proposed a straightforward Demand Management Benefit Sharing Scheme. EnerNOC believes this is a sensible approach, and that the proposed scheme should be applied both to Ausgrid and to the other NSW DNSPs."*[23]

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[18] AER, 2014, Draft Decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 12: Demand management incentive scheme, page 12-8

[19] AER, 2014, Draft Decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 12: Demand management incentive scheme, page 12-10

[20] EnerNOC, 2014, Submission on NSW distributors' regulatory proposals for 2014-19, page 4

[21] Ausgrid, 2014, Ausgrid's response to the AER's information of 11 July 2014 (AER Ref AER Ausgrid 012)

[22] Public Interest Advocacy Centre, 2014, Moving to a new paradigm, submission to the Australian Energy Regulator's NSW electricity distribution network price determination, page 106

[23] EnerNOC, 2014, Submission on NSW distributors' regulatory proposals for 2014-19, page 5

4.1.2 Innovation allowance

The draft determination has recommended that the current innovation allowance amount of $1 million [24]per annum be continued for the 2015-19 period. The innovation allowance offers important support for the development of innovative DM solutions and building knowledge to support effective capex/opex trade-offs using demand management. Ausgrid accepts the draft decision.

5 Conclusion

Ausgrid agrees with the draft determination that *'demand management should be an integral part of good asset management for all network businesses.'*[25] That is why we have integrated demand management within our network planning and investment decision making so as to effectively consider non-network alternatives. As an integral part of our planning process, the effects of our demand management programs are embodied as reductions in the demand forecast and associated offsets to capital expenditure, so are not directly visible but form a key component to our planning and investment program.

The importance of demand management is also reflected in the National Electricity Rules where "*the extent the DNSP has considered, and made provision for, efficient and prudent non-network alternatives*"[26] is one of the capex factors to be considered by the AER under the NER.

To respond to the concerns noted in the draft determination and to better describe our demand management programs for 2015-19, we have:

- re-assessed our DM program in line with the lower levels of augmentation arising from the revised spatial demand forecast, and included these effects in our capital expenditure requirements;
- reviewed and confirmed that the level of targeted spatial DM activity is consistent with the outcomes from the previous regulatory period, based on its application to HV distribution plans;
- described how our demand management activities are integrated within the planning and investment process;
- verified the business case for the optimised broad-based DM program such that a positive NPV is returned in 6.5 years and the total NPV(10 year) through to 2024 is $31 million; and
- confirmed that the optimised broad-based DM program complements and is not undermined by cost reflective tariffs.

Ausgrid's proposed portfolio of demand management activities are a prudent and efficient expenditure to lower customer demand and defer capital expenditure in the long term interest of customers. We therefore resubmit our program as per the initial submission.

[24] In real terms this is a reduction of xx%

[25] AER, 2014, Draft Decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 6: Capital expenditure, page 6-83

[26] NER, cl 6.5.7(e)(10)