



UNIVERSITY OF
TECHNOLOGY SYDNEY

INSTITUTE FOR SUSTAINABLE FUTURES



INVESTING IN SAVINGS: FINANCE AND COOPERATIVE APPROACHES TO ELECTRICITY DEMAND MANAGEMENT

A scoping study for the Clean Energy Finance Corporation

2013

ABOUT THE REPORT

This report has been commissioned by the Clean Energy Finance Corporation (CEFC) as a contribution to public dialogue about solutions to rising electricity costs and reducing carbon emissions. The CEFC's mission is to accelerate Australia's transformation towards a more competitive economy in a carbon constrained world, by acting as a catalyst to increase investment in the clean energy sector.

The CEFC has the mandate and investment capacity to provide capital to accelerate the adoption of Demand Management, thereby contributing to lower consumer electricity bills, improvements in the investment environment for other clean energy activities and significant emissions reductions.

The CEFC is seeking to understand the near-term opportunities for such investment, to identify any impediments and, reflecting its public policy objectives, approaches that could deliver economy-wide outcomes.

With the benefit of this report, the CEFC will investigate more fully the opportunities to invest in demand management and work collaboratively to support its wider implementation.

The report has been prepared by the Institute of Sustainable Futures and the views reflected therein are those of the Institute.

ABOUT THE AUTHORS

The Institute for Sustainable Futures (ISF) was established by the University of Technology, Sydney in 1996 to work with industry, government and the community to develop sustainable futures through research and consultancy. Our mission is to create change toward sustainable futures that protect and enhance the environment, human well-being and social equity. We seek to adopt an inter-disciplinary approach to our work and engage our partner organisations in a collaborative process that emphasises strategic decision-making.

For further information visit: www.isf.uts.edu.au

Research team: Chris Dunstan, Samantha Sharpe, Jenni Downes

Please cite this report as:

Dunstan, C., S. Sharpe and J. Downes (2013) *Investing in Savings: Finance and Cooperative Approaches to Electricity Demand Management – A scoping study for the Clean Energy Finance Corporation*, Institute for Sustainable Futures: Sydney

ACKNOWLEDGEMENT

The research team would like to thank the staff of the Clean Energy Finance Corporation and all of the stakeholders contacted for their time and valuable perspectives on the issues and proposals discussed in this scoping study.



UTS: INSTITUTE FOR SUSTAINABLE FUTURES
JULY 2013

INVESTING IN SAVINGS: Finance and Cooperative Approaches to Electricity Demand Management

A scoping study for the Clean Energy Finance Corporation

AUTHORS

Chris Dunstan
Samantha Sharpe
Jenni Downes

INSTITUTE FOR SUSTAINABLE FUTURES

University of Technology, Sydney
PO Box 123
Broadway, NSW, 2007

www.isf.edu.au

© UTS July 2013

TABLE OF CONTENTS

EXECUTIVE SUMMARY	8
1 INTRODUCTION	13
1.1 CEFC and Demand Management	13
1.2 What is Demand Management?	14
1.3 Opportunites for CEFC involvement	17
2 NETWORKS AND DM: THE STATE OF PLAY	19
2.1 Rising electricity prices and rising bills	19
2.2 Rapid increase in network investment	21
2.3 Current DM activity by network businesses	22
2.4 Potential for DM	28
2.5 Barriers to DM	32
3 UNLOCKING DM POTENTIAL	36
3.1 Reducing regulatory barriers to DM	36
3.2 DM Targets: Mandatory vs Collaborative	38
3.3 Reporting DM performance	43
3.4 Incentives for DM	44
3.5 Implementing Collaborative DM Targets	48
4 INVESTMENT OPPORTUNITIES FOR CEFC	50
4.1 Loans for network businesses for DM	50
4.2 Positive and negative risk sharing	52
4.3 Capitalising DM expenditure	53
4.4 Alternative options for CEFC to support DM	55
5 INTEGRATION WITH REGULATORY REFORM	57
5.1 Existing economic regulatory regime	57
5.2 Regulatory reform	64
6 BENEFITS FOR CONSUMERS	74
6.1 Impacts on prices and bills	74
6.2 Spreading of costs of peak demand	74
6.3 Potential costs savings	75
6.4 Flow through to customers	76
7 STAKEHOLDER ENGAGEMENT	78
7.1 Initial engagement	78
7.2 further actions for stakeholder engagement	79
8 CONCLUSIONS AND NEXT STEPS	80



APPENDICES	85
A. DEMAND MANAGEMENT MEASURES	86
B. PROPOSED DM, REFORM AND FINANCE PROCESS	89
C. PRECEDENTS FOR DM TARGETS	90
C.1 Queensland Energy Conservation and Demand Management Program	92
C.2 Ontario Electricity Conservation and Demand Management	94
C.3 US State-Based Schemes	98
D. EXAMPLES OF NETWORK DM	116
E. REFERENCE LIST	120



TABLE OF FIGURES

Figure 1: Differing perspectives on demand management.....	15
Figure 2: Types of decentralised energy measures	16
Figure 3: Creating a demand management option*	16
Figure 4: Trends in residential electricity prices in Australia	19
Figure 5: Components of a typical NSW annual electricity bill, 2007/08 and 2012/13.....	20
Figure 6: Components of electricity prices by state, 2011/12.....	21
Figure 7: Electricity network capital expenditure (T&D) by jurisdiction, 2006–2015	22
Figure 8: Network peak demand reduction by project type (MW)	23
Figure 9: Peak demand reduction by state	24
Figure 10: DM expenditure by state	24
Figure 11: Peak demand reduction from network, energy market and state-based DM.....	25
Figure 12: Summary of peak demand reduction results from DM trials in Australia	27
Figure 13: Potentially avoidable capital expenditure vs total network capex (\$m 2010).....	29
Figure 14: Potential of decentralised energy to reduce electricity costs '	29
Figure 15: Peak power by source category (\$m/MWp).....	31
Figure 16: Peak power by cost component (\$m/MWp).....	31
Figure 17: Institutional barriers to demand management.....	32
Figure 18: Top 10 barriers to demand management.....	33
Figure 19: Institutional barriers to demand management.....	35
Figure 20: Policy tools to address barriers to demand management	36
Figure 21: US utility demand management (DM) actual peak load reductions.....	43
Figure 22: Recommended process for providing finance facilities NSPs	51
Figure 23: Impact of DM on electricity business revenue	53
Figure 24: AER Better Regulation Review workstreams.....	69
Figure 25: Average annual electricity bill vs. average weekly earnings.....	75
Figure 26: Absolute total benefit of demand reduction in the NEM 2013/14 to 2022/23.....	76
Figure 27: Interaction of financing with targets, regulation and reform processes.....	89
Figure 28: Energex Demand Management Targets to 2014/15	92
Figure 29: Ergon Energy Demand Management Targets to 2016/17.....	92



ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CEFC	Clean Energy Finance Corporation
COAG	Council of Australian Governments
DLC	Direct Load Control
DE	Decentralised Energy
DG	Distributed Generation
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DNSP	Distribution Network Service Provider
DSR	Demand Side Response
DSP	Demand Side Participation
DRET	Department of Resources, Energy and Tourism
EE	Energy Efficiency
FY	Financial Year
IPART	Independent Pricing and Regulatory Tribunal
kW	kilowatt
kWh	kilowatt hour
MW	Megawatt
MWp	Megawatt peak
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
OECD	Organisation for Economic Co-operation and Development
PLM	Peak Load Management
PV	(Solar) Photovoltaic
SCER	Standing Committee on Energy and Resources
TOU	Time of Use



EXECUTIVE SUMMARY

Overview

This scoping study examines the potential for the Clean Energy Finance Corporation to help reduce customer electricity bills and foster clean energy investment in Australia by supporting electricity network businesses to implement Demand Management (DM). The report concludes that the benefits of network DM are likely to be significantly greater and realised more quickly if regulatory reform is complemented with a cooperative approach to performance targets, reporting and incentives.

It has been recognised for over two decades that electricity DM has been under-utilised in Australia. In addition to reducing carbon emissions, DM can reduce business and household electricity bills through:

- lower customer energy consumption (via improving end use energy efficiency)
- lower wholesale energy prices and reduced need for peak electricity generation, and
- deferred or avoided network capital expenditure (which has been the main driver of recent electricity bill increases).

DM in the electricity sector can also directly and indirectly increase the uptake of clean energy initiatives, such as increased energy efficiency and renewable and low emission generation.

According to the Australian Energy Market Commission (AEMC), it is estimated that the 'economic cost savings of peak demand reduction in the National Electricity Market (NEM) is likely to be between \$4.3 billion to \$11.8 billion over the next ten years ... which equates to between 3 per cent and 9 per cent of total forecast expenditure on the supply side'. These savings amount to 'approximately \$500 per consumer per annum (in South Australia and Queensland). In NSW, the savings per consumer is expected to be around \$350 per annum ... [and] in Victoria, around \$120 per consumer per annum'.¹ More recently, the Productivity Commission has estimated savings from DM could yield net benefits of between \$900 and \$1900 per household.²

The AEMC and Productivity Commission's estimates underpinned the December 2012 Council of Australian Government (COAG) Standing Committee on Energy and Resources (SCER) reforms aimed at enhancing productivity and significantly reducing electricity bills.

The proposed COAG/SCER electricity reforms are expected to reduce the barriers to cost-effective DM, but these reforms are likely to take at least two years to come into effect, as the next Australian Energy Regulator (AER) five-year network regulatory pricing determinations do not take effect until 1 July 2015 for the ACT, NSW, Queensland and South Australia, and later in Victoria and Tasmania.³

In the meantime, the CEFC could help accelerate the implementation of DM by offering finance to electricity network businesses provided that the following key conditions are met:

¹ Australian Energy Market Commissions, 2012, *Power of Choice Review – Giving consumers options in the way they use electricity (Final Report)*.

² Productivity Commission, 2013, *Electricity Network Regulatory Framework, Final Report Vol. 2*.

³ The current ACT/NSW regulatory control period ends on 30 June 2014. However the next ACT/NSW determination process has been deferred as a result of the AEMC's November 2012 network regulation rule change. The period of 1 July 2014 to 30 June 2015 will be a transitional regulatory control period with a transitional determination made by the AER, followed by a substantive determination for the subsequent regulatory control period (1 July 2015 - 30 June 2019).



1. The Australian Energy Regulator using the current Better Regulation work-stream process to clarify that network businesses are able to retain a fair share of the avoided capital expenditure benefits delivered by DM.
2. Government explicitly requesting (but not mandating) that NSPs adopt public DM targets to reduce demand, capital expenditure and customer energy bills; and that it requests that the network businesses regularly report progress against these targets.
3. The CEFC engaging with the AER and network businesses to establish as soon as possible a framework to support financing of cost-effective DM.

Demand management and current activities

Electricity network investment has been the main driver of the rapid electricity bill increases seen in Australia over the past five years, particularly in New South Wales and Queensland. Electricity prices nationally have risen in real terms by 70 per cent between June 2007 and December 2012.⁴ Network charges now make up half of the average Australian electricity bill.⁵ These charges have been increased rapidly to recoup the more than \$40 billion which is being invested in electricity distribution and transmission networks within the current 5-year regulatory period.⁶ This level of investment exceeds and will be expended over a shorter time period than that of the National Broadband Network.⁷

DM lowers or shifts the demand for a good or service (in this case electricity) as an alternative to providing additional supply. There is very little reliable data available on DM activity in Australia. However, the available evidence suggests that recent DM amounts to the equivalent of about one per cent of the generation capacity in the NEM, a fraction of the available cost-effective DM potential.

Impediments to the higher uptake of DM include:

- poorly designed regulation that rewards investment in growing network infrastructure but financially penalises utilities that undertake DM,
- entrenched organisational and regulatory practices and values which favour infrastructure over DM solutions,
- a lack of attention to DM on the part of network managers, shareholders, regulators and policy makers,
- limited expertise and experience in Australia in large scale DM, and
- a lack of relevant and reliable DM data and information.

The relative neglect of DM also represents a risk to electricity customers and private, institutional and state government shareholders as technological change may make redundant some current network investments before they reach their full expected asset lifetimes.

Reflecting these concerns and opportunities, COAG and SCER have initiated a program of reform. Much of this reform relates to how the AER regulates network businesses. However, even if implemented promptly these reforms will take time, as many are only intended to take effect in the AER's next economic regulatory determinations (for the period 2015-2020).

⁴ Productivity Commission 2013, *Electricity Network Regulatory Frameworks*, Report No. 62, Canberra, p.2.

⁵ Department of Resources, Energy and Tourism, 2012, *Electricity Prices (factsheet)*.

⁶ Langham et al., 2010, *Building Our Savings: Reduced infrastructure costs from improving building energy efficiency*. Institute for Sustainable Futures, University of Technology Sydney.

⁷ *ibid.*



Internationally, there are many examples of demand management investments which significantly reduce the need for network investment and therefore lower customer electricity bills, while also increasing the reliability, productivity and profitability of the electricity network. These international precedents highlight the success of combining obligations (measurable performance against some target) and incentives to demand management activities. Similar conditions could be created in Australia. This study details how such a system of targets, reporting and incentives could operate in Australia.

Investment opportunities for the CEFC

Emerging clean, decentralised energy technologies and business models are likely to present investment opportunities for the CEFC in relation to the falling cost of solar PV and battery storage, the increasing penetration of advanced meters and time of use pricing, the rising take-up of electric vehicles and the expanding potential of smart energy management and energy efficient products. Peak focussed demand management is also likely to become more important as the proportion of the national electricity output supplied by variable output renewable energy generation, such as wind and solar, rises in response to the national 20% Renewable Energy Target.

On the other hand, continued high levels of investment in electricity network infrastructure will increase 'sunk costs' which will then no longer be avoidable with DM. This will crowd out and diminish future business opportunities for clean energy technologies and add to the incremental cost of developing and deploying these technologies.

The CEFC has the mandate and investment capacity to provide capital to accelerate the adoption of DM activities in the NEM. By doing so, the CEFC can contribute to lower consumer electricity bills, improvements in the investment environment for other clean energy activities and reduced carbon emissions.

Creating a secure environment for DM investment

For the CEFC to invest successfully in network DM, a number of external conditions would need to be met. These conditions relate to policy direction, regulatory certainty and NSP commitment to undertake DM.

To provide financial support for network DM, the CEFC would need to be confident that it would be able to recover its investment, including returns to cover the CEFC's cost of funds. While the risk profile of each investment is different, the CEFC would at least need to be confident of the network businesses' commitment to DM and its capacity to ensure successful DM project implementation. The network businesses' commitment and capacity would need to be supported by clear policy intent from the Commonwealth and/or the relevant state government, and regulatory certainty around the treatment and recovery of DM expenditure. Each of these conditions is outlined in more detail below.

The current electricity market reform processes established by COAG/SCER have the potential to address both the policy and the regulatory conditions, but this potential must be converted into explicit policy and regulatory intent.

Policy conditions – clear policy intent from federal and state governments

A clear statement of policy intent is needed, indicating governments' commitment to:

- the long-term interests of consumers, including via the delivery of all cost-effective DM
- establishing clear accountability and performance measures for DM by creating network DM targets and reporting in collaboration with the network businesses.



Governments could quickly signal their intent to prioritise cost-effective DM by asking Network businesses to set 'collaborative targets for DM' and to provide a plan of measures they could take to reduce customer bills. (Network businesses could reduce bills either directly by helping customers save energy, or indirectly by helping customers to reduce peak demand on the networks and cutting network expenditure.) Furthermore, network businesses could be asked to report what they have already achieved and how much they believe they can reduce costs to consumers, and by when. An initial report on these matters could be requested to be provided to government within a few months.

Such a process is likely to lead to network businesses being more engaged in strategies to expand DM activity in the short term. Conversely, in the absence of clear policy leadership, the uptake of finance for DM by network businesses is likely to be low.

Regulatory conditions – certainty around DM investments by network businesses

The AER can facilitate the uptake of DM activities by clarifying its regulatory intent of no disadvantage for network businesses that engage in cost-effective DM activities. Specifically, the AER should make it clear that cost-effective DM expenditure undertaken in the current regulatory period can be offset against avoided supply side investment in the next regulatory period. This would provide an important reassurance for network businesses that wish to expand DM activity in the current regulatory period.

There are a number of further dimensions to providing regulatory certainty, including:

- **Regulatory incentives to offset project risk:** While some network businesses have been expanding DM activities in recent years, there remain both real and perceived project risks for network businesses in building up DM expertise and experience. The regulatory system should recognise this risk by offering financial incentives to network businesses. This would involve sharing with network businesses and their shareholders some of the potential customer benefits of DM that may otherwise not occur at all.
- **Opex/capex substitutability:** As DM expenditure is usually operating expenditure, but avoidable costs are normally capital expenditure, the network businesses must be able to offset costs in the former against savings in the latter both within and between regulatory periods.
- **Removing incentive bias against DM:** There are number of major biases in the current regulatory system which encourage network supply side expenditure and discourage DM. For example, as noted by the Productivity Commission, 'all [network] capital spending – regardless of its efficiency – is rolled into the regulatory asset base (RAB) at the end of the five-year regulatory period'.⁸ Such provisions do not apply to DM, which is mainly operating expenditure. These biases need to be addressed.
- **Balanced regulatory risk:** The risk created by regulation associated with DM must be no greater than the risk involved in supply side expenditure.

Some of the above regulatory conditions can only be established if the Australian Energy Regulator (AER) changes the provisions the electricity network regulatory determinations and associated schemes. Such changes would take up to two years to be fully implemented.

⁸ Productivity Commission 2013, Electricity Network Regulatory Frameworks, Report No. 62, Canberra, p.220.



Stakeholder engagement and next steps

Many stakeholders contacted in the preparation of this report, including regulators and some network businesses, have shown a strong level of interest in tapping into DM opportunities. There is a strong recognition among many NSP officers that DM needs to (and is likely to) play a major role in the future of the electricity supply industry. This recognition extends to interest in learning more about the potential for accessing finance to support DM. However, NSP officers are generally even more interested in the potential for facilitating network DM expenditure by clarifying and reforming the regulatory system.

In this context, should the CEFC wish to develop further the opportunities for financing network DM, the appropriate next steps are:

1. Engage in the current AER reform process to bring greater clarity to the treatment of DM expenditure in relation to offsetting future supply side capital expenditure.
2. Inform policy makers of: the potential for network DM; the importance of setting clear policy directions relating to the adoption of all cost-effective DM; and the need for clear NSP targets and accountability.
3. Seek support from policy makers to establish a reliable baseline of current and proposed network DM activity, and to articulate current activities and future opportunities for network DM investment. (Similar to reporting arrangements in the Energy Efficiency Opportunities program.)
4. Engage with network businesses in relation to: the potential for DM, the AER reform process, and the role of financial support as a precursor and complement to regulatory reform.
5. Offer financing solutions to assist network businesses where required.



1 INTRODUCTION

This scoping study examines the potential for the Clean Energy Finance Corporation (CEFC) to help reduce customer electricity bills and foster clean energy investment in Australia by supporting electricity network businesses to implement Demand Management (DM), whilst reducing emissions and facilitating a lower carbon economy.

Demand management, which involves reducing or shifting consumption as an alternative to providing more supply, has significant potential to reduce carbon emissions from the electricity system and to provide cost savings to consumers and the wider economy.

This report discusses CEFC investment in DM through loans to network businesses, including operational aspects of finance provision and recovery. The report also outlines complementary regulatory, policy and industry-level changes to maximise the consequent benefits for network businesses, the CEFC, consumers and the wider economy. These complementary measures were identified from a scan of DM support policies and incentive programs both nationally and internationally, and interviews with relevant key stakeholders in Australia including network businesses and regulators.

This scoping study establishes a clear rationale for CEFC interest in network DM and develops a possible model for investment, which has been discussed with some key stakeholders. Further work is needed to test and operationalise the model with a wider range of stakeholders and to place it within the CEFC investment framework, and the wider energy regulatory and policy environment. This proposed further work is highlighted in Section 8.

1.1 CEFC AND DEMAND MANAGEMENT

The CEFC's mission is to accelerate Australia's transformation towards a competitive economy in a carbon constrained world. It pursues this mission by facilitating increased flows of finance into the clean energy sector.⁹ Clean energy technologies include: renewable energy, low emission generation and energy efficiency and demand management technologies.

Consistent with its commercial approach, the CEFC seeks to understand the near-term opportunities for investment and to identify impediments to such investment; and, reflecting its public policy objectives, the CEFC is also interested to understand the investment opportunities that could deliver economy-wide outcomes.

The CEFC is keen to understand more fully the opportunities to invest in demand management (DM) in the distribution/ transmission sector, and the constraints on that investment.

The Garnaut Climate Change Review – Update 2011 observed that 'when the network company can profit from investing less rather than more, then it will seek ways to foster distributed generation and to set economically efficient tariffs'.¹⁰

The *CEFC Expert Review*¹¹ directs the Corporation towards investment in the network company area through the provision of recommendation 2.8:

⁹ *Clean Energy Finance Corporation Act 2012*, s.3, & s.60.

¹⁰ *Garnaut, R., 2011, Transforming the electricity sector (Update Paper Eight, Garnaut Climate Change Review – Update 2011), Commonwealth of Australia.*

¹¹ *Clean Energy Finance Corporation, 2012, Report of the Expert Review Panel, Commonwealth of Australia.*



The CEFC can finance capital expenditure that is directed towards the efficient use of energy and the application of demand management enabling technologies.¹²

Further, the Expert Review Panel notes that not all demand management reduces energy consumption and carbon emissions. However,

to the extent that [demand management] lowers future network upgrade costs and defers investment in new generation, it is a valuable tool in minimising the cost of moving to a cleaner energy future. Therefore the Panel recommends the CEFC consider enabling technologies associated with demand management within the ambit of the energy efficiency area.¹³

Electricity distribution and transmission network businesses, also known as or network service providers (NSPs), and the organisations that regulate them, impact on and are impacted by many if not all of CEFC's investments – including renewable, low emissions and energy efficiency investments.

The CEFC commissioned this scoping study to consider strategies to accelerate demand management within the electricity system, particularly by Network Service Providers. CEFC hopes that this report will contribute to a clearer understanding of the working functions of the NSPs relating to DM, as well as CEFC's opportunities for investment.

1.2 WHAT IS DEMAND MANAGEMENT?

'Demand management' (also known as demand side management¹⁴) refers to activities that lower or shift the demand for a good or service as an alternative to providing additional supply. Demand management is usually undertaken by organisations responsible for ensuring reliable and adequate supply of a good or service (such as energy, water or transport utilities) where moderating demand is more cost-effective than increasing supply.

In the energy sector, demand management (DM) usually refers to actions by the utility to encourage 'decentralised energy' measures, which include: 1) end use energy efficiency 2) peak load management, and/or 3) distributed generation.

Other terms are sometimes used to describe DM or facets of DM. For example demand side response (DSR) usually refers to short term load reduction by customers in *response* to high prices or incentives offered by utilities at times of very high demand. Demand side participation (DSP) on the other hand, focuses on the consumer as the central agent, acting on their own initiative either in response to signals from utilities or to price and other conditions in the market. Figure 1 shows the spectrum of all these activities.

¹² Clean Energy Finance Corporation, 2012, *Report of the Expert Review Panel, Commonwealth of Australia*, p.16.

¹³ *ibid.*

¹⁴ Dunstan, C. et al. 2011, *Think Small: The Australian Decentralised Energy Roadmap*. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.



Figure 1: Differing perspectives on demand management



Demand side participation is arguably a more appropriate term if customers or third party aggregators bid reduced demand directly into the competitive wholesale electricity market (as is currently proposed by the Australian Energy Market Commission) while demand management is a more accurate term for action by regulated monopoly electricity network businesses, where the emphasis is on the electricity utility *managing* demand proactively.

The three types of ‘decentralised energy’ measures that can be promoted through demand management are described in Table 1.

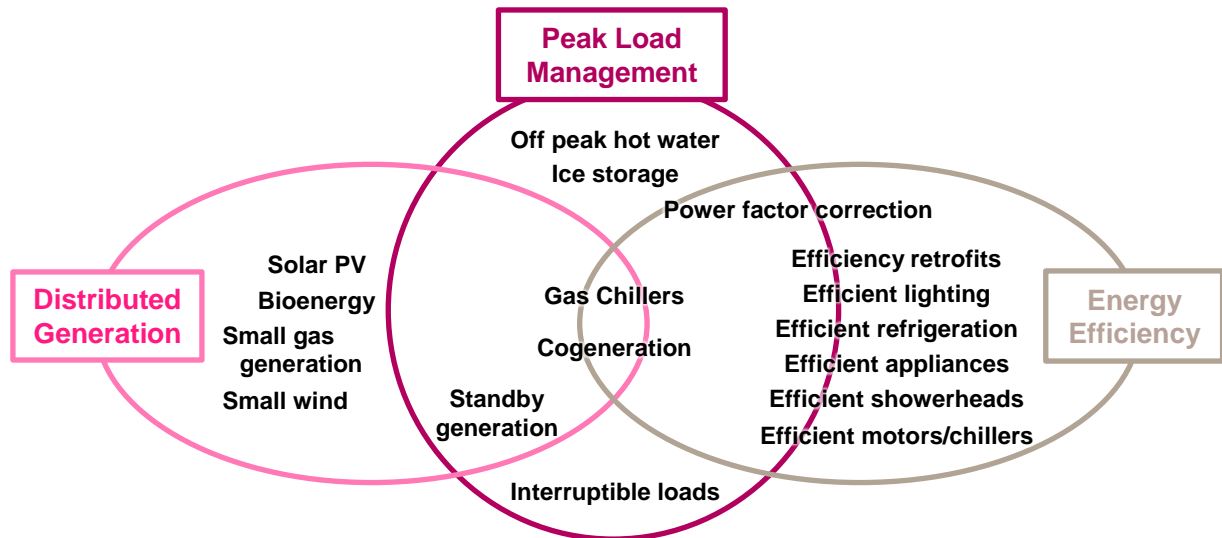
Table 1: Decentralised energy measures promoted by demand management

<p>Peak load management (LM or PLM)</p>	<p>Actions that influence the timing of energy use. This occurs when customers are provided with information, technology and/or incentives to shed or interrupt their load at times of peak demand and shift it to times of lesser demand. The objective of peak load management is generally not to reduce emissions, but to limit unnecessary electricity price rises. This could enable greater implementation of other low emission DM options.</p>
<p>Energy efficiency (EE)</p>	<p>Both technologies and behaviours that deliver the required energy services to consumers using less energy input. Energy efficiency behaviours (sometimes called ‘energy conservation’) can be carried out by individuals or undertaken in an organisational context, and generally involve reducing unnecessary energy consumption. Examples include individuals turning lights off when not in a room, and organisations adjusting building management system settings to reduce total energy consumption while maintaining the desired level of occupant comfort. Energy efficiency technologies are appliances and equipment (‘hardware’) that reduce electricity or fuel consumption while maintaining service output.</p>
<p>Distributed generation (DG)</p>	<p>Generation technologies that are ‘embedded’ within the electricity network, that supply electricity on-site or to the local area, and that may provide other services such as heating and cooling from the ‘waste’ heat associated with electricity generation, with a maximum size of 30MW. Technologies include solar PV panels, small wind turbines, gas or biomass micro turbines, fuel cells and cogeneration (combined heat and power), and solar or biomass heating.</p>



Figure 2 illustrates different types of activities (or ‘measures’) in each of these categories and how they interact with peak demand. (See Appendix A for a more detailed list of measures.)

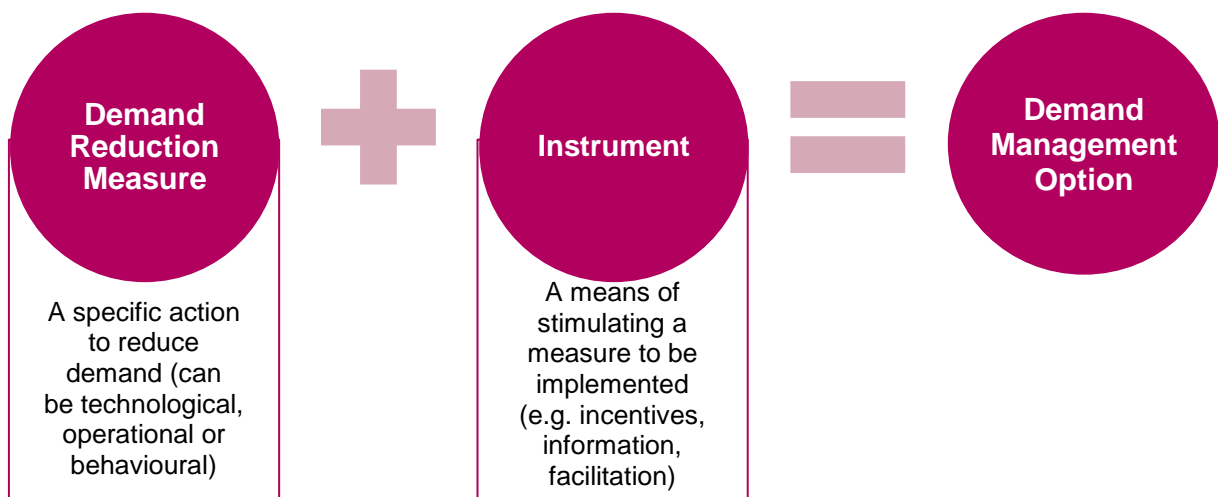
Figure 2: Types of decentralised energy measures



Source: ISF, Australian Decentralised Energy Roadmap, 2011.

Decentralised energy measures are usually related to a particular end-use of electricity by a customer. Network service providers (NSPs) therefore cannot generally undertake DM measures themselves, but need to encourage customer buy in. In order to stimulate a measure to occur, an NSP (or other party) generally needs to use a specific ‘instrument’ to facilitate it. When a specific instrument is applied to stimulate a specific measure, this represents a specific demand management option that can be applied by an NSP, as shown in Figure 3.

Figure 3: Creating a demand management option*



* ‘Option’ in this sense should not be confused with the more specific meaning of ‘option’ in finance language.



1.3 OPPORTUNITIES FOR CEFC INVOLVEMENT

Analysis suggests that the value of increasing demand management activities in the NEM could be significant; and much of this can be delivered at a cost below the long run marginal cost of new supply. In addition to the potential cost savings, described in Section 2.4, DM is estimated to be able to reduce greenhouse gas emissions from the electricity sector by 73 megatonnes of carbon dioxide (Mt CO₂) per annum, which translates to a 35% reduction in Australia's CO₂ emissions from 2009 levels.¹⁵ According to the CSIRO Intelligent Grid research collaboration cluster, as well as delivering benefits to consumers in the form of reduced bills, and to the environment in the form of emissions reduction, the wider application of demand management could also enhance the operational and financial performance of electricity network businesses.¹⁶

The benefits of increasing the pace of adoption of demand management in the NEM are therefore clear. However as described in Section 2.5, this is not just a regulatory issue. Regulatory approaches that increase the incentive and obligation for electricity networks to investigate demand management are important, but their effectiveness is limited by the length of time that these approaches take to have an impact, and they do not necessarily address the learning and information barriers that also exist.

The benefits from reducing peak demand are split among different actors within the electricity system, and so the incentives for individual actors to participate in demand management are diminished because they are unable to fully capture the benefits.¹⁷ Information barriers also exist to the implementation of demand management. The costs associated with searching and learning about the new activities involved, combined with the fact that the benefits cannot be fully captured, further reduces incentives for wider applications of demand management.

There are also significant future risks to electricity networks arising from failure to develop DM opportunities now and in the past. These risks include:

- possible sudden cuts in capital expenditure in the next regulatory period
- potential network overcapacity, limiting development of future lower cost decentralised energy (energy efficiency, demand management and distributed generation)
- the potential for network assets to become stranded if decentralised energy reduces the need for network capacity.

In order to overcome these issues, and given the knowledge of the wider benefits of increasing demand management, external support for NSPs to undertake DM is justified. Networks have long-term capital works programs that cannot be easily reoriented. Tapping the identified benefits of the increased demand management for electricity networks, electricity customers and the wider economy could be accelerated by bringing forward some of the value of these benefits to finance network DM now. If only one-third of current growth-related capital expenditure by the electricity networks was redirected (approximately \$1 billion per annum) this could unlock savings of \$2 to \$3 billion per annum.¹⁸

¹⁵ NERA Consulting, 2012, *Peak Energy Savings Scheme Design Options: A Report for the Energy Savings Initiative Secretariat*, Prepared for the Commonwealth Department of Resources, Energy and Tourism.

¹⁶ *ibid.*

¹⁷ *ibid.*

¹⁸ Dunstan, C. et al. 2011, *Think Small: The Australian Decentralised Energy Roadmap*. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.



A collaborative approach of performance targets, reporting and incentives could accelerate the wider adoption of demand management. This would in turn reduce the potential for network over-investment in the short to medium term (2–3 years) and would improve the business case for DM for when the proposed COAG/SCER reforms are established. This approach recognises that while DM may be in the long term interests of NSPs, active engagement and material support from government can help remove barriers to DM and expedite its adoption.¹⁹

Any incentives (in the form of financial assistance such as loans, or loan guarantees) would need to be contingent on electricity networks adopting specific and credible plans and targets for demand management. This would ensure best practice is transferred to the wider industry, and would enable cost reductions in demand management over time.

The CEFC is well positioned to act as a conduit for the provision of this finance because:

- encouraging demand management is relevant to CEFC's wider goal of promoting a cleaner energy supply
- the CEFC has the finance and monitoring capacity to ensure DM activities are implemented in a cost-effective manner
- CEFC has the ability to act as 'patient capital' and obtain repayment of loans plus returns through regulatory revenue determinations.

This report is set out as follows:

- **Chapter 2** presents the current state of play regarding networks and demand management.
- **Chapter 3** describes the key mechanisms that can enable greater uptake of demand management in the short and medium term.
- **Chapter 4** sets out the role that the CEFC can play in facilitating this greater uptake.
- **Chapter 5** demonstrates how CEFC involvement can integrate with existing economic regulation and the current reform processes.
- **Chapter 6** describes the benefits that successful uptake of DM can provide for consumers.
- **Chapter 7** presents conclusions of the report and outlines potential next steps.

¹⁹ *ibid.*



2 NETWORKS AND DM: THE STATE OF PLAY

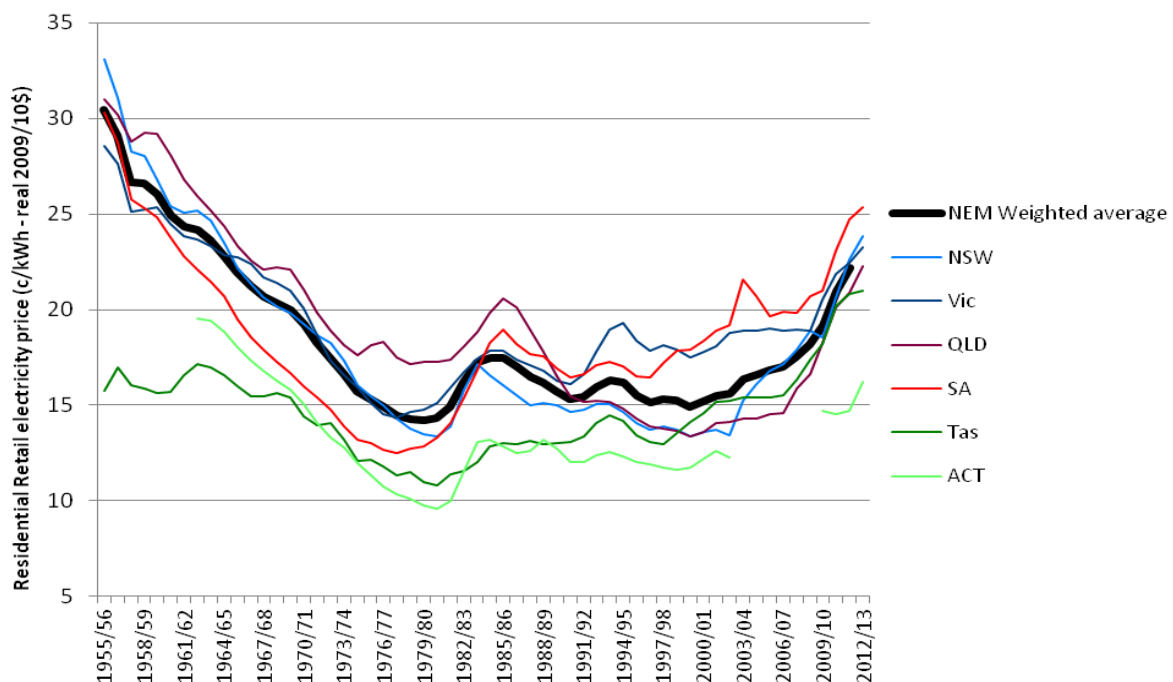
Peak demand management is under-utilised by electricity network businesses in Australia. However, it is important to understand and characterise this activity, as it provides the knowledge base for electricity networks in Australian circumstances.

The current usage of demand management within the Australian electricity system is low, equivalent to about 1% of the generation capacity in the National Electricity Market (NEM).²⁰ The absence of a balanced investment environment for network business and the consequent failure to implement cost-effective DM has contributed to the recent rapid increase in electricity prices and bills in Australia. Section 2.1 outlines the recent trends in demand, prices and bills. Section 2.2 discusses network investment growth over recent years and its implications for electricity bill increases. Section 2.3 describes the current volume and value of network DM activities. Section 2.4 examines the potential uptake of demand management across a number of scenarios. Section 2.5 examines the barriers to uptake of demand management in light of the current experience, and potential for demand management within the NEM.

2.1 RISING ELECTRICITY PRICES AND RISING BILLS

Australia’s electricity prices have risen rapidly in recent years as shown in Figure 4 below. While absolute residential electricity prices are still lower than in some other countries, prices are currently rising at a faster rate than in most OECD countries.²¹

Figure 4: Trends in residential electricity prices in Australia



Source: ISF, NEM Report Card, 2011.

²⁰ Futura Consulting, 2011, *Power of choice – giving consumers options in the way they use electricity*.

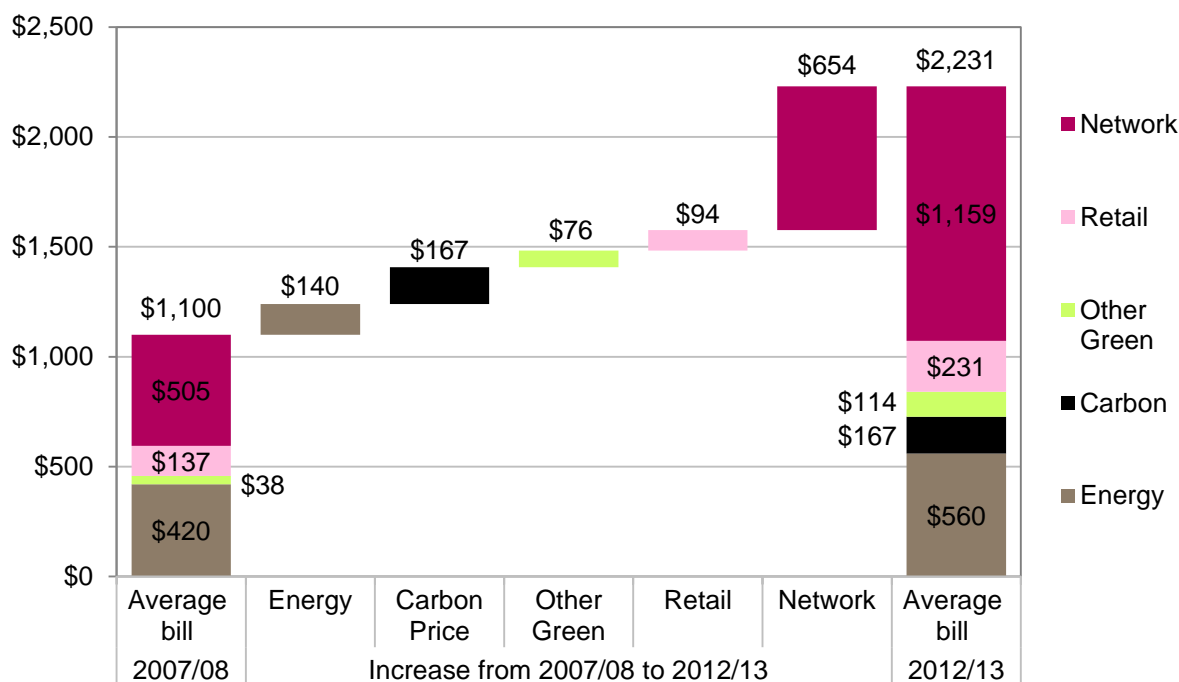
²¹ Ison, N., Usher, J., Cantley-Smith, R., Harris, S. and Dunstan, C. (2011). *The NEM Report Card: How well does the National Electricity Market serve Australia?* Prepared by the Institute for Sustainable Futures and the Monash University Faculty of Law for the Total Environment Centre.



Several factors have contributed to these price rises. The most significant of these is network investment as discussed in Section 2.2 below. Figure 5 shows that the network cost component of an average bill in NSW more than doubled over the last 5 years, increasing \$654 from \$505 in 2007/08 to \$1,159 in 2012/13.

The contribution of different cost components varies from state to state, as shown in Figure 6. Network charges are the biggest component of prices in NSW and Queensland where network reliability standards have been strengthened and capital expenditure has increased dramatically in recent years. Network costs are lowest in the ACT, probably due mainly to the relatively compact and accessible nature of the urban form. The retail margin is particularly high in Victoria, where there is no regulation of retail electricity charges.²² The carbon price accounts for about 7% to 8% of the total price while the renewable energy target and other state-based ‘green schemes’ account for about 5%.²³

Figure 5: Components of a typical NSW annual electricity bill, 2007/08 and 2012/13



Source: IPART, Review of regulated retail prices and charges for electricity 2013 to 2016, (2012).²⁴

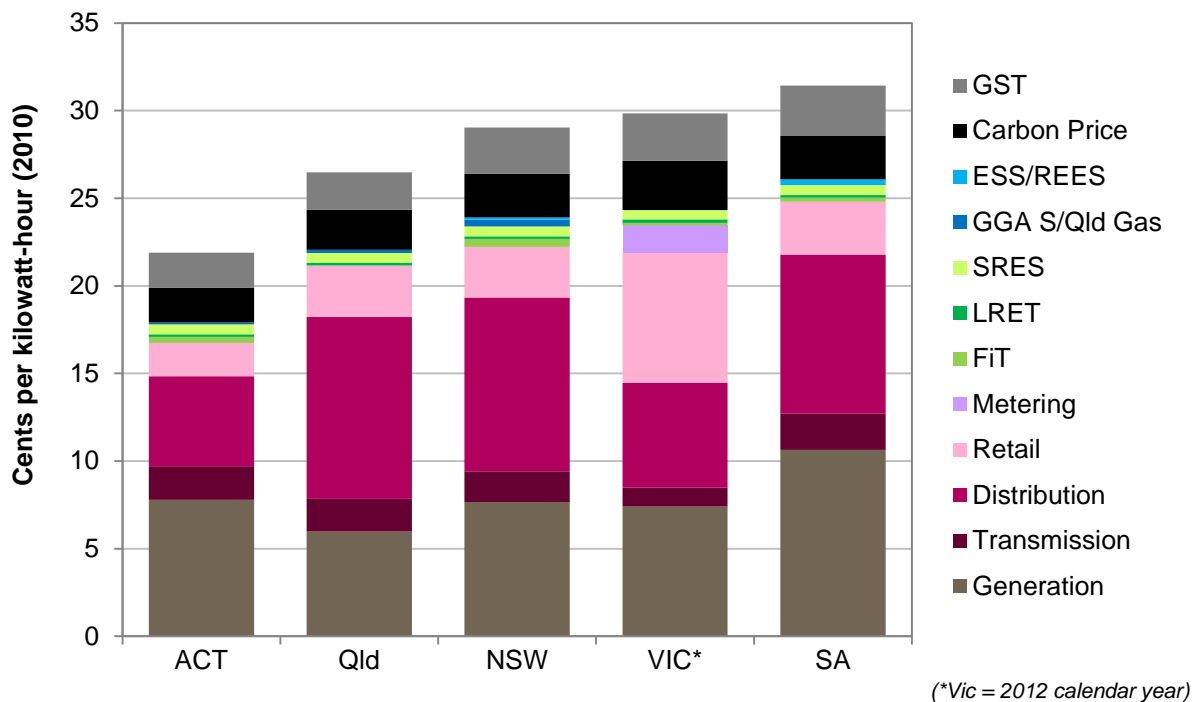
²² South Australia is in the process of removing retail price regulation. The ACT, NSW and Queensland maintain retail price regulation.

²³ Australian Energy Market Commission, 2010, *Future Possible Retail Electricity Price Movements*.

²⁴ Note while IPART is not explicit in this report, it is understood that it includes GST in each of the components.



Figure 6: Components of electricity prices by state, 2011/12



Source: AEMC Future Possible Retail Electricity Price Movements, 2010; Treasury modeling.

An estimated one-third of the current investment in the networks is to cater for growth, and in particular, growth in peak demand. Peak demand refers to the points of highest electricity demand during a single half-hour period within the electricity system. Peak demand events occur for less than forty hours per year (or less than 1% of the time) yet account for approximately 25% of the average residential bill.²⁵ This is because the electricity network must be built to accommodate this peak, even if this level of utility only occurs in very small periods of time each year.

Peak demand growth is projected to continue to outpace growth in energy consumption over the next decade, placing further upward pressure on electricity prices.²⁶ As electricity demand becomes ‘peakier’ – ie as it is characterised by higher maximum demand relative to average demand, the efficiency of the network diminishes, and the investment that is made to augment the network becomes less and less efficient.

2.2 RAPID INCREASE IN NETWORK INVESTMENT

To date the response to increased peak demand has been largely a supply side response – with more network capacity built to carry greater levels of supply. Demand management solutions have had very little uptake in the Australian electricity system. Only 1% of peak demand in the national electricity market is currently met with demand side measures²⁷ and this activity is concentrated in one state, Queensland.²⁸ Further, annual expenditure on

²⁵ Productivity Commission (2012) *Electricity Network Regulation (Draft report)*, Melbourne.

²⁶ Dunstan, C. et al. (2011) *Think Small: The Australian Decentralised Energy Roadmap*, CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.

²⁷ Wright, G., 2012, *Demand management targets for networks in the National Electricity Market (discussion paper)*. Total Environment Centre, Sydney.

²⁸ Dunstan, C., Giotto, N. & Ross, K., 2011, *Report of the 2010 Survey of Electricity Network Demand Management in Australia (SENDMA)*. Sydney.

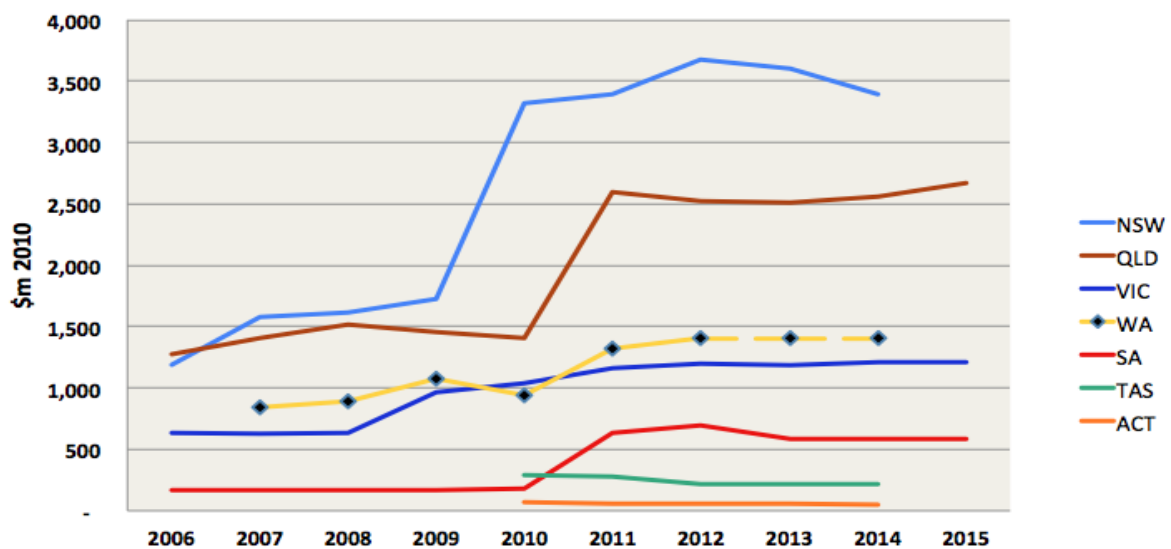


demand management (DM) currently represents less than one per cent of total annual expenditure on electricity supply, as discussed in Section 2.3.²⁹

The AER notes that network investment in the current regulatory cycle is 'running at historically high levels', with transmission and distribution networks spending \$7 billion and \$35 billion respectively on network infrastructure in the current five-year regulatory period.³⁰ This expenditure is larger than the cost of the National Broadband Network and occurs over a shorter period of time. The spread of this expenditure by state is shown in Figure 7.

New South Wales and Queensland both show marked increases in capital expenditure in the period from 2009. Across Australia, network augmentation expenditure accounts for approximately \$3.7 billion of the transmission and \$10 to \$16 billion of the distribution investment.³¹ Augmentation-related expenditure is therefore expected to account for between 35 and 50 per cent of all electricity network capital expenditure forecast to take place within the current five-year period. That said, not all of this will be related simply to growth in peak demand.³²

Figure 7: Electricity network capital expenditure (T&D) by jurisdiction, 2006–2015



Source: E Langham et al. (ISF), *Building Our Savings*, 2010 (updated).

2.3 CURRENT DM ACTIVITY BY NETWORK BUSINESSES

Although there is currently no comprehensive national survey or database, it is clear that there is already a significant amount energy efficiency, peak load management and distributed generation deployed in Australia.³³ There has also been some important recent progress by network businesses in relation to DM as illustrated in Appendix D. However, it is also clear that few of the Australia's decentralised energy resources are deployed as a result of network DM and there remains large untapped potential for cost-effective DM.

²⁹ Dunstan, C. et al. 2011, *Think Small: The Australian Decentralised Energy Roadmap*. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.

³⁰ Australian Energy Regulator, 2011, *State of the Energy Market report* (excludes WA and NT).

³¹ NERA Consulting, 2012, *Peak Energy Savings Scheme Design Options: A Report for the Energy Savings Initiative Secretariat*, Prepared for the Commonwealth Department of Resources, Energy and Tourism.

³² *ibid.*

³³ As discussed in Section 1.2, end use energy efficiency, peak load management and distributed generation are the 'measures' delivered through DM.

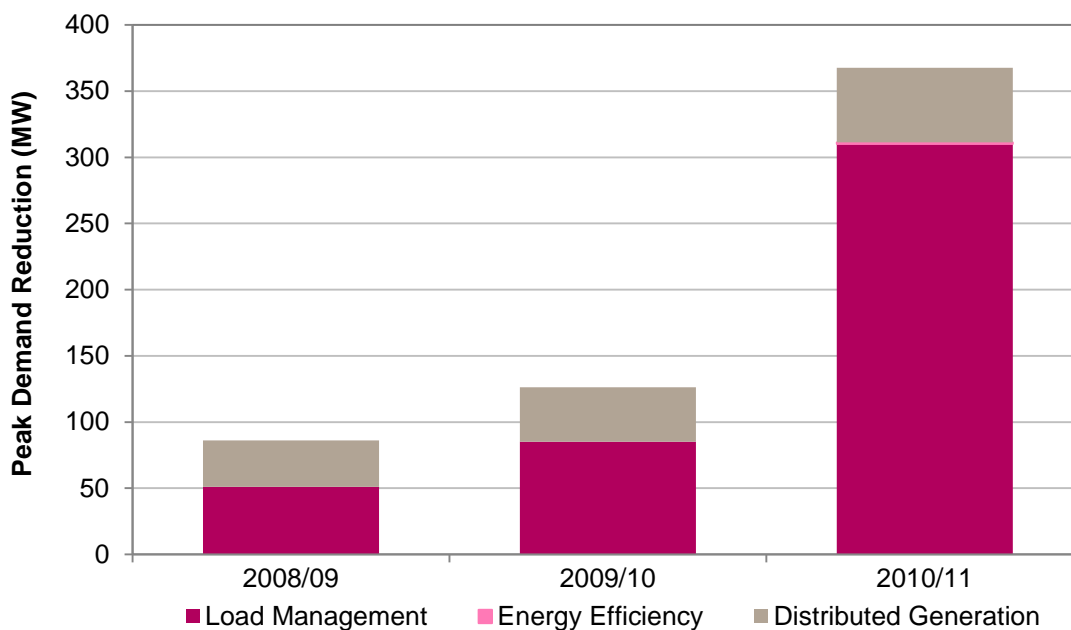


Demand and peak demand activities by networks

Peak demand activities are of critical interest to electricity networks because the electricity network must be built to a size which can cater for peak demand. While other actors may be interested in demand management activities that result in electricity use reductions – such as energy efficiency to provide resource efficiency and carbon emissions reductions – for electricity networks, DM is of potential interest if it addresses peak electricity demand times in areas at or approaching their network supply capacity.

The latest available figures, from the 2011 *Survey of Electricity Network Demand Management in Australia*³⁴, identify just over 350MW of demand reduction from network DM projects in Australia in 2010/11, as presented in Figure 8. This was a substantial increase on 2009/10 figures (126MW), but still small in an electricity system that has more than 45,000 MW of generation capacity.

Figure 8: Network peak demand reduction by project type (MW)



Source: ISF, *Report of the 2010 Survey of Electricity Network Demand Management in Australia, 2011*.

This survey found that across 19 of the 20 Australian network businesses there are 97 load management programs, spread over a range of initiatives as illustrated in Table 2.³⁵ These data suggest that NSPs are expanding their DM activity. Appendix D provides examples of recent DM undertaken by NSPs in Australia.

It is important to note that this survey of DM undertaken by NSPs over the preceding decade does not encompass all electricity sector DM. For example, it excludes residential off peak water programs that have been established over many decades and probably amount to some thousands of megawatts of peak demand reduction. While these are an important part of DM practice in Australia, such programs were, typically, established several decades ago, not initiated by the NSPs and are not focussed on addressing network constraints or peaks.

³⁴ Dunstan, C., Giotto, N. & Ross, K., 2011, *Report of the 2010 Survey of Electricity Network Demand Management in Australia (SENDMA)*. Prepared for the Australian Alliance to Save Energy by the Institute for Sustainable Futures, University of Technology, Sydney.

³⁵ *ibid.*



Table 2: Number and types of peak load management projects in Australia

Peak Load Management Project Type	No. of Projects
Power factor correction	23
Direct load control. Including hot water, air conditioning and pool pumps	17
Stand-by generators for peak demand supply, incl. cogeneration and diesel	16
Tariff trials, including time of use	10
Load shifting	8
Commercial and residential energy efficiency projects	3
Fuel Switching	1
Mixed projects, where multiple elements are use in a particular location	8
Other	11
TOTAL	97

Source: ISF, Australian Decentralised Energy Roadmap, 2011.

The majority of reported network demand management projects are taking place in Queensland³⁶, as shown in Figure 9 and Figure 10. This stems from Queensland electricity distributors, Energex and Ergon Energy developing comprehensive demand management programs as part of their current regulatory revenue determinations. Outside Queensland, much of the network DM activity appears to be focussed around trials and pilots.

Figure 9: Peak demand reduction by state

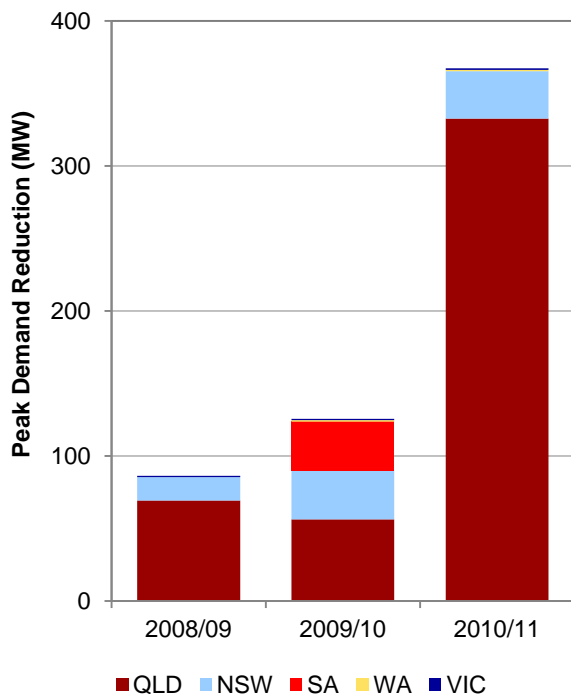
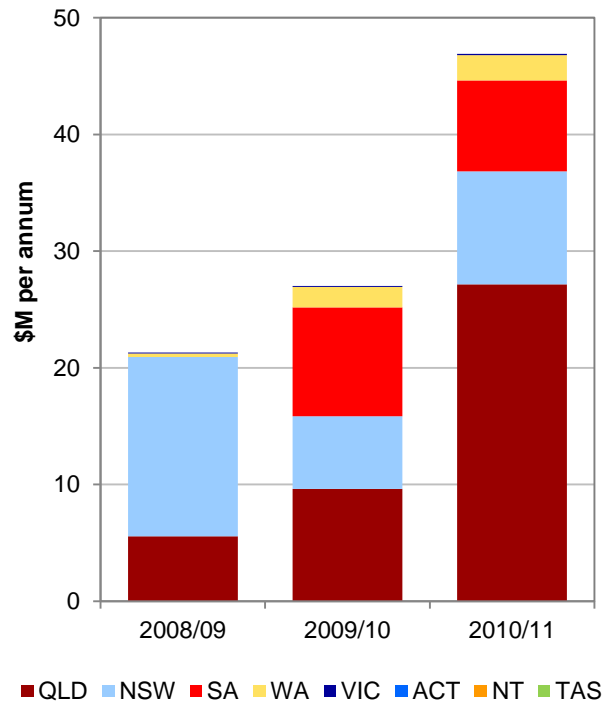


Figure 10: DM expenditure by state



Source: ISF, Report of the 2010 Survey of Electricity Network Demand Management in Australia, 2011.

³⁶ *ibid.*



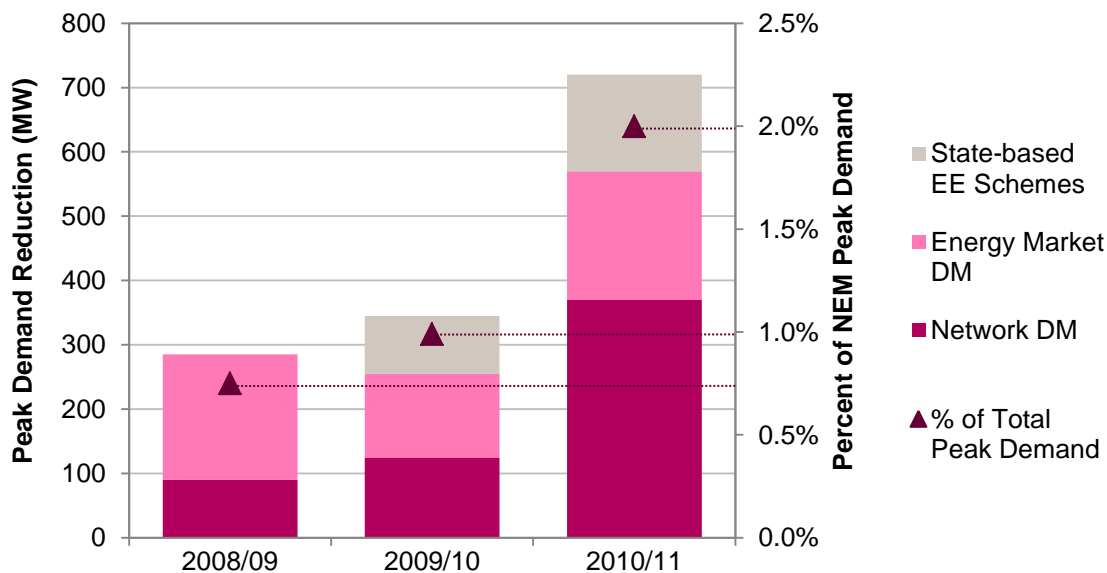
Electricity distributors are not the only source of demand management within the electricity system. In its 2011 *Electricity Statement of Opportunities* report, AEMO identified 142 MW of capacity that was ‘very likely’ to be available across the NEM through demand side participation over the 2011–12 summer.

Another study highlights demand management activities instigated by electricity retailers and by state government policies and programs.³⁷ These programs include the NSW Government’s Energy Efficiency Scheme (EES), the South Australian Government’s Residential Energy Efficiency Scheme (REES) and the Victorian Government’s Victorian Energy Efficiency Target (VEET).

Energy efficiency policies and schemes can contribute to peak demand management even though many of the activities that they promote target savings across the whole day. For example energy efficiency activities in commercial refrigeration reduce energy used by this equipment across the whole day, including the times of peak demand. Significant reductions in peak demand can be achieved from energy efficiency activities. This has been demonstrated in the US where utility energy efficiency and peak demand management programs are reported to be delivering peak demand reduction equal to 4.4% of the US peak demand, as shown later in Figure 21. This means that the amount of US peak DM activity is comparable to total Australian peak demand in the NEM.

The above mentioned schemes have a number of objectives around market development and capacity building for energy efficiency in addition to energy savings. Figure 11 shows the target and estimated energy savings achieved by these schemes and activities. In 2010/11 about 350MW in peak demand savings was achieved across the NEM by these activities – about the same amount achieved in that year by the NSPs.

Figure 11: Peak demand reduction from network, energy market and state-based DM



Source: ISF, NEM Report Card, 2011.

³⁷ Ison, N., Usher, J., Cantley-Smith, R., Harris, S. and Dunstan, C. (2011). *The NEM Report Card: How well does the National Electricity Market serve Australia?* Prepared for the Total Environment Centre by the Institute for Sustainable Futures and the Monash University Faculty of Law.



Use of regulatory incentives

In Australia, regulatory incentives for network DM have often taken the form of direct funding allocation to the businesses.³⁸ For example, in South Australia the electricity industry regulator, the Essential Services Commission of South Australia (ESCOSA), provided \$ 20.4 million for DM initiatives to be implemented by the sole electricity DNSP in the State, ETSA Utilities, over the five-year regulatory period beginning July 2005.³⁹

ETSA Utilities was required to submit to the regulator for approval a program for the implementation of DM initiatives and expenditure of the approved funding over the regulatory period. The approved funding was treated as operating expenditure, and did not impact on the regulator's consideration of approved capital expenditure for network augmentation purposes in the regulatory period.⁴⁰

At the end of the five-year period, after 27 trials were completed, only \$11.7million of the allocated budget of \$20.4 million (in 2004 dollars) had been spent, so ETSA submitted a proposal for a further five trials focusing on the characteristics of the evolving 'smarter grid' technology to be funded to June 2012 by the \$8.7 million.

A summary of the annual cost expenditure in each ESCOSA-determined category is set out in Table 3 below, and shows that, in accordance with the trial outcomes, Direct Load Control (DLC) accounted for 63% of the total expenditure. This was followed by Power Factor Correction (PFC) at 6%, Standby Generation (SG) at 4% and Voluntary and Curtailable Load Control (VCLC) at 2%. Expenditure on other categories was insignificant. Data on the savings from the trials were not made available.

Table 3: Summary DM expenditure by ESCOSA by category

	(\$'000)		
	Life to Date (2010) cost	2010 to 2012 Budget	Total
DM Program	11,752	20	11,772
Administration and Reporting	2,138	123	2,261
Power Factor Correction	660	0	660
Standby Generation	373	-54	319
Direct Load Control (DLC)	6,931	-54	6,877
Critical Peak Pricing (CPP)	7	0	7
Voluntary/Curtailable Control	268	0	268
Interval Meters	0	0	-
Aggregation	4	0	4
DM Org within ETSA Utilities	1,370	5	1,375
Other	0	-	-
Phase IV Trial	3,889	8,655	12,544
DLC with AMI Trial	17	263	280
Proof of Concept Trial	27	27	54
Defined Area Trial	1,800	3,428	5,228
Communications Trial	1,962	2,639	4,601
Technology Integration Trial	83	2,298	2,381
Total	15,641	8,655	24,296

Source: ETSA, *Annual Demand Management Compliance Report, 2011*.

³⁸ Crossley, D. 2010, *International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks*. Prepared for the Australian Alliance to Save Energy by Energy Futures Australia.

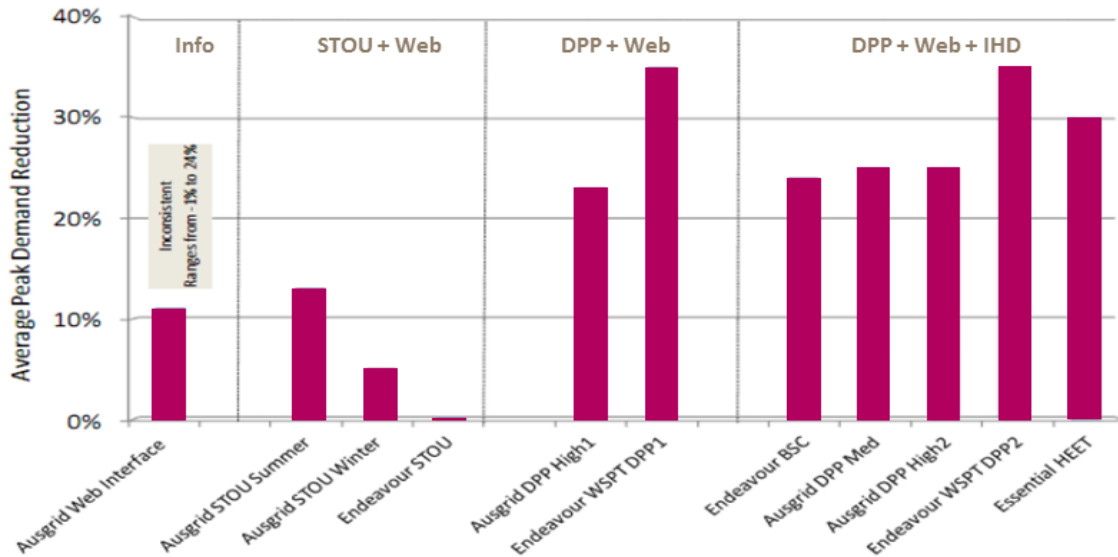
³⁹ ETSA Utilities, 2011 *Annual Demand Management Compliance Report*.

⁴⁰ Crossley, D. 2010, *op cit*.



A number of peak demand management trials have also been conducted by NSW electricity distributors. On average these trials have achieved between 5% and 35% reductions in peak demand, as shown in Figure 12.

Figure 12: Summary of peak demand reduction results from DM trials in Australia



Source: AEMC Power of Choice Review Final Report, 2012.

Another example of a direct regulatory funding allocation to NSPs is the Demand Management Incentive Schemes (DMIS). To date, the take-up rate within the current regulatory period of this allocation by electricity networks has been low. The most recent AER report⁴¹ on DMIA expenditures for non-Victorian distribution NSPs (DNSPs) states that DNSPs claimed \$2.2 million in DMIA expenditures in 2011–12, just over twice the amount in 2010–11, as shown in Table 4.

Table 4: Annual aggregate DMIA expenditure by DNSPs

DNSPs	2009-10	2010-11/2011	2011-12/2012
Non-Victorian	\$360,398	\$1,005,751	\$2,218,125
Victorian	N/A	\$551,936	–

Source: AER Demand management incentive scheme assessment report 2011-12 (Non-Victorian DNSPs).

AER-approved DMIA expenditure from 2009–10 to 2011–12 accounts for approximately 14 per cent of the total allowance available to the non-Victorian DNSPs in their current five-year regulatory control periods, as shown in Table 5. This low uptake of DM by NSPs even where money is allocated specifically for the purpose suggests that funding alone is not sufficient to drive rapid expansion of network DM.

⁴¹ Australian Energy Regulator, 2013, *Demand management incentive scheme assessment report 2011-12 (Non-Victorian DNSPs)*.



Table 5: Approved DMIA expenditure and remaining allowance by DNSP

DNSP	DMIA claimed 2011-12	DMIA approved 2011-12	DMIA approved to date	DMIA remaining	DMIA claimed 2011-12
ActewAGL	\$19,675	\$19,675	\$58,521	\$473,890	11.0%
Ausgrid	\$661,335	\$661,335	\$715,950	\$4,608,155	13.4%
Endeavour Energy	\$268,642	\$268,642	\$437,580	\$2,756,884	13.7%
Energex	N/A	N/A	\$51,553	\$5,515,602	1.0%
Ergon Energy	\$540,108	\$540,108	\$1,009,486	\$4,197,669	19.4%
Essential Energy	\$728,365	\$728,365	\$1,311,084	\$1,883,380	41.0%
SA Power Networks	N/A	N/A	N/A	\$3,124,293	0.0%
TOTAL	\$2,218,125	\$2,218,125	\$3,584,274	\$22,199,773	13.9%

Source: AER Demand management incentive scheme assessment report 2011-12 (Non-Victorian DNSPs).

2.4 POTENTIAL FOR DM

Energy policy and market development in Australia have historically had a strong supply-side focus, leaving significant scope for introducing cost-effective demand-side efficiencies such as:

- end-use energy efficiency
- better utilised energy infrastructure (capacity).

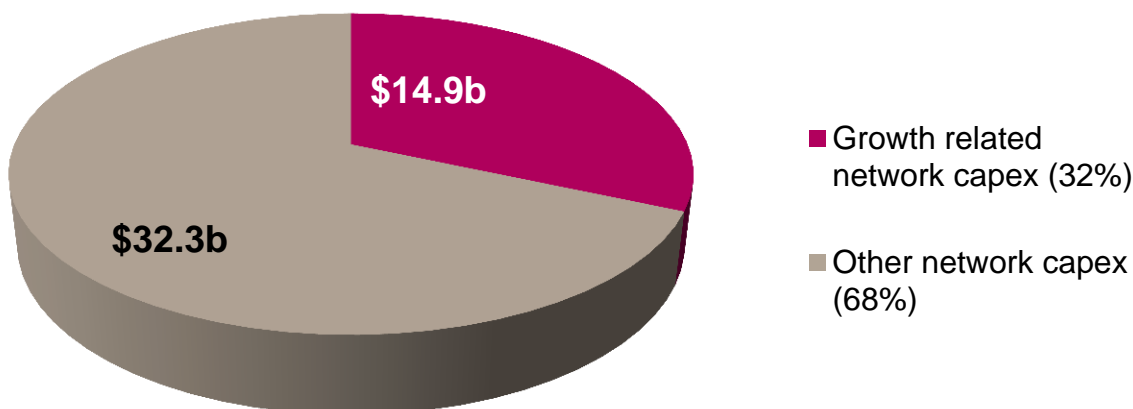
Rising peak demand is one of the three primary drivers of this network investment, and peak demand growth is projected to continue to outstrip growth in energy consumption over the next 10 years, placing continued upward pressure on electricity prices.

The NEM is also highly centralised with a number of large-scale electricity generators and a large transmissions and distribution network to support the delivery of electricity from these large generators. This is slowly changing as more and more smaller-scale renewable generators connect to the grid. It is also changing in the face of growing evidence that decentralised energy (energy efficiency, peak load management and distributed generation) built to local scales, has the potential to reduce the need for costly network infrastructure and increase the flexibility of the electricity network to support multiple small scale and intermittent generators and demand management options.

As shown in Figure 13, around one-third of total approved network investment, or almost \$15 billion, is growth related and most of this is driven by peak demand growth and is thus potentially avoidable if demand growth were to be reduced or eliminated through DM. In practice, it would not be practical or cost-effective to avoid all of this \$15 billion of capital expenditure through DM. However, it is also likely that DM could also assist in displacing or deferring a share of the non-growth related capital expenditure driven by factors such as reliability requirements and asset replacement. So while it is clear that much more detailed and transparent analysis of the potential for DM to defer and avoid network infrastructure spending is urgently required, it is also clear that DM could trim a significant share of this \$47 billion expenditure.



Figure 13: Potentially avoidable capital expenditure vs total network capex (\$m 2010)

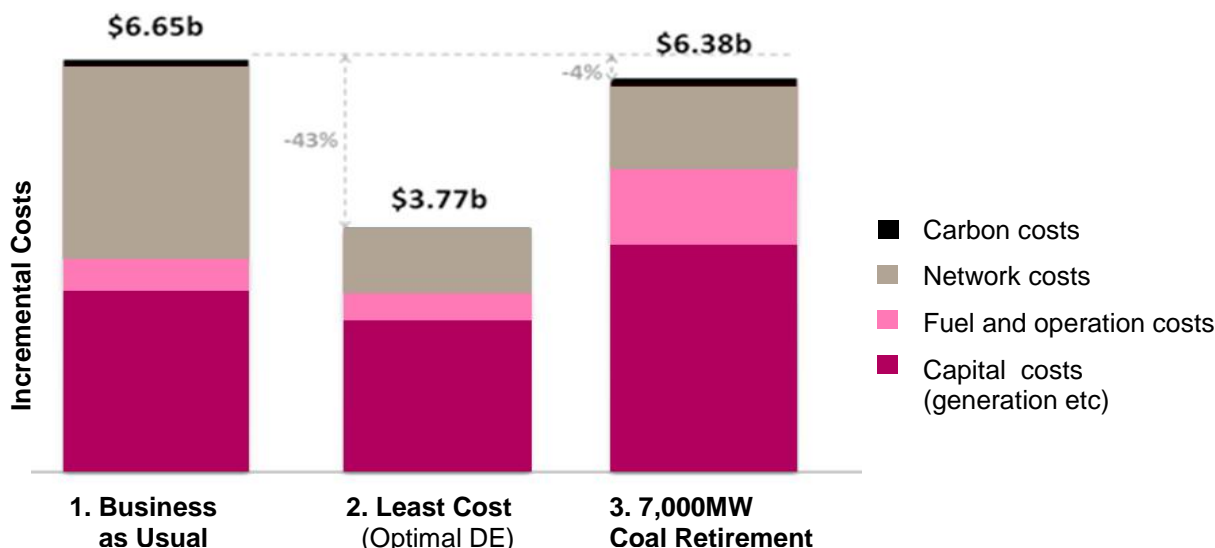


Source: ISF, Australian Decentralised Energy Roadmap, 2011.

If deployed strategically, DM presents a means of achieving substantial reductions in this component of network spending. Analysis in 2010 found that decentralised energy measures could reduce annual electricity system by almost \$3 billion per annum by 2020 compared to ‘business as usual’ system, as shown in Figure 14.

These savings could be either be passed on to consumers as bill savings, or ‘recycled’ to maximise carbon emission abatement by investing in additional decentralised energy and gas-fired generation and retiring up to 7000MW of coal fired power stations at no extra cost to consumer. (If this analysis were to be repeated today the achievable savings in 2020 would still be significant but somewhat lower as some of the potentially avoided network costs have now been spent.)

Figure 14: Potential of decentralised energy to reduce electricity costs^{42,43}



⁴² Dunstan, C., Cooper, C., Glassmire, J., Ison, N., and E. Langham (2011). *Evaluating Costs of Decentralised Energy, Working Paper 4.3 (ver. 2)*.

⁴³ Dunstan, C. et al. 2011, *Think Small: The Australian Decentralised Energy Roadmap*. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.



The AEMC Power of Choice review reported an estimate ‘that economic cost savings of peak demand reduction in the National Electricity Market (NEM) is likely to be between \$4.3 billion to \$11.8 billion over the next ten years ... which equates to between 3 per cent and 9 per cent of total forecast expenditure on the supply side’. These savings amount to ‘approximately \$500 per consumer per annum (in South Australia and Queensland). In NSW, the savings per consumer is expected to be around \$350 per annum ... [and] in Victoria, around \$120 per consumer per annum’.⁴⁴

Another recent study, using a different methodology, has concluded:

The Council of Australian Governments’ review (the ‘Parer Review’ in 2002) and the report of the Energy Reform Implementation Group in 2006 recommended that action should be taken to strengthen demand-side participation.

Our analysis leads to the conclusion that if the Parer Review recommendation had been implemented and 3,000 MW of [Demand Response] had been available to reduce peak demand from what it is now, \$15.8bn of expenditure on generation, transmission and distribution infrastructure could have been avoided.⁴⁵

The Productivity Commission estimated in the draft report of its Inquiry into Electricity Network Regulatory Frameworks that DM ‘could yield net benefits of between \$1500-3400 per household’.⁴⁶ This estimate underpinned the December 2012 Council of Australian Government’s (COAG) Standing Committee on Energy and Resources (SCER) reforms and the Prime Minister’s proposed ‘plan to make sure that families pay \$250 less per year for electricity’.⁴⁷ In its Final Report, the Productivity Commission, noted,

If a smart meter rollout is implemented efficiently and targeted at regions where capacity constraints are impending, then the relevant households could get a stream of benefits that add to around \$900–\$1900 per household in net present value terms. This stream of benefits is equivalent to an annual benefit of around \$100–\$200 over the life of the meter.⁴⁸

These estimates focussed on the use of smart meters and time of use pricing. If the benefits of non-price based energy efficiency DM programs were to be included then the total benefits would be expected to be significantly higher.

It should be noted that these estimates have not been endorsed by the NSPs themselves, but they do serve to provide an indication of the potential scale of benefits that could be achieved through DM and more efficient development of electricity networks in Australia.

Potential for Peak Load Management

Demand side solutions are consistently lower cost for our electricity system when compared with supply side solutions (ie new generation – both fossil fuel and renewable – and new network infrastructure). Cost curve analysis in Figure 15 and Figure 16 shows demand management activities – particularly industrial, commercial and residential energy efficiency measures – are well below the cost per MWh of supply side solutions for meeting peak demand.

⁴⁴ Australian Energy Market Commissions, 2012, *Power of Choice Review – Giving consumers options in the way they use electricity (Final Report)*.

⁴⁵ Mountain, B., 2012, *Reducing Electricity Costs through Demand Response in the National Electricity Market*.

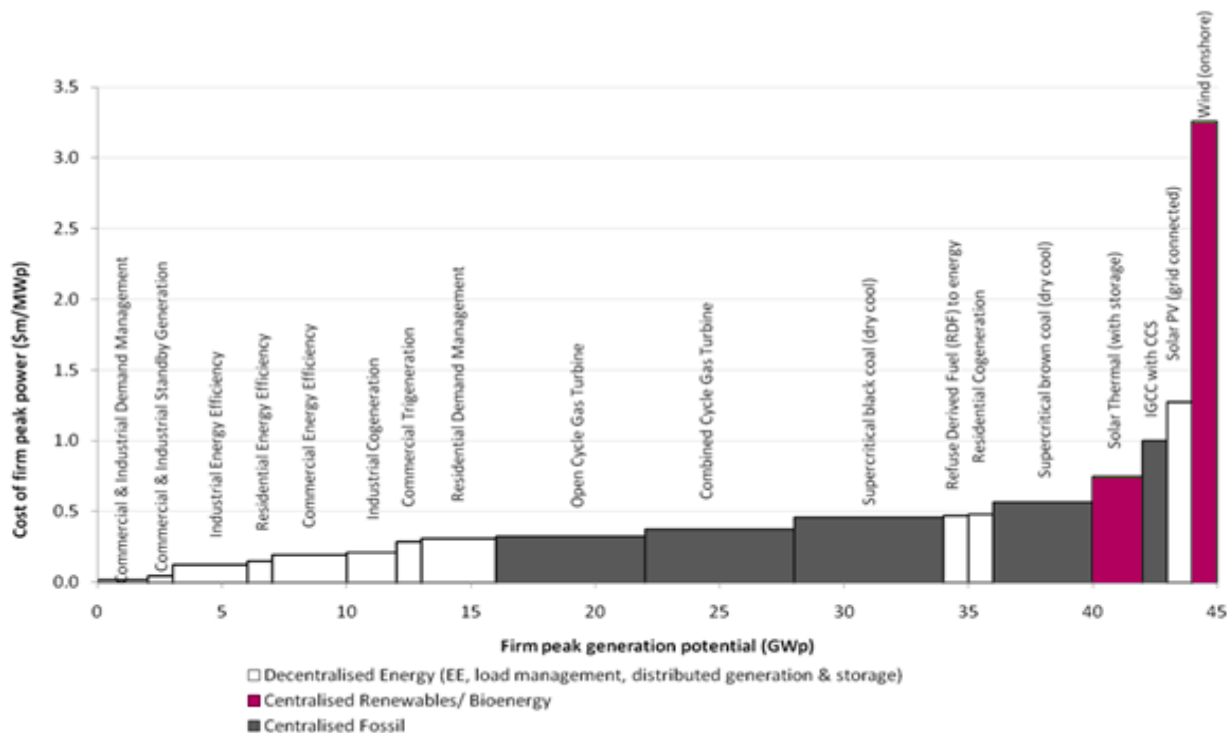
⁴⁶ Productivity Commission, 2012, *Electricity Network Regulatory Frameworks (Draft Report)*.

⁴⁷ Julia Gillard, 2012, *Transcript of Interview with Paul Bongiorno, Rafael Epstein and Patricia Karvelas*, Meet The Press, 2 Dec 2012.

⁴⁸ Productivity Commission, 2013, *Electricity Network Regulatory Frameworks (Final Report)*.

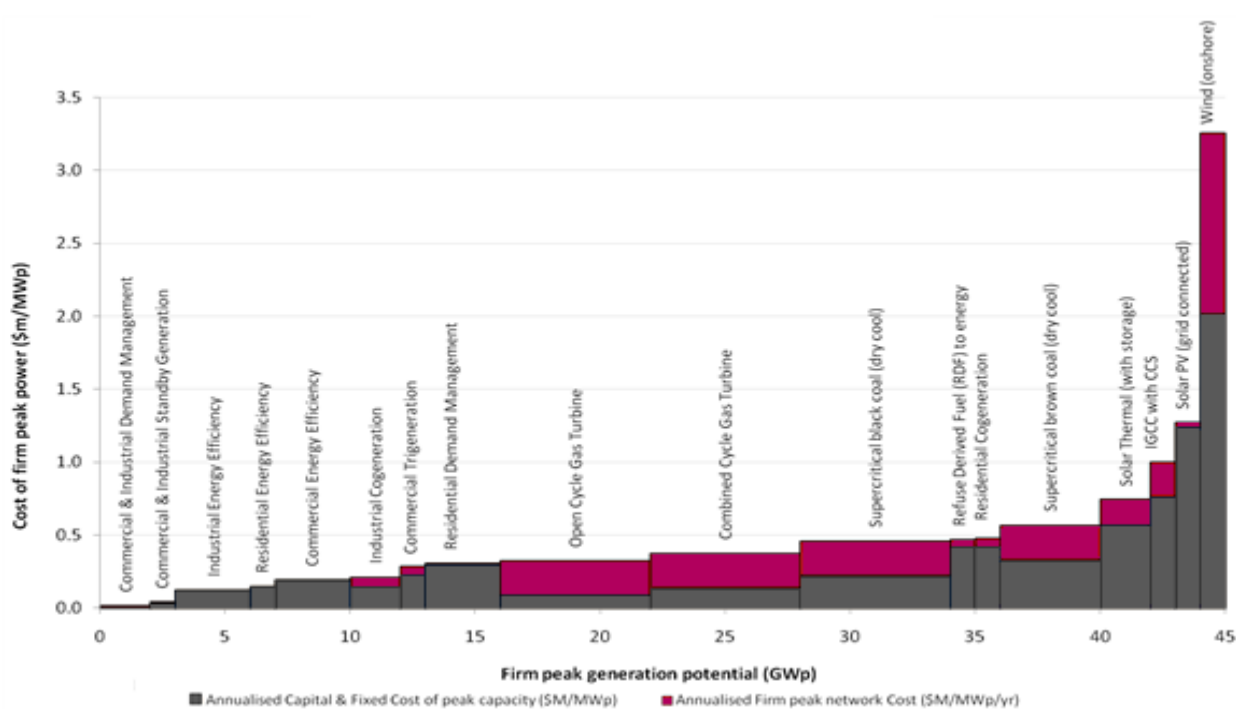


Figure 15: Peak power by source category (\$m/MWp)



Source: ISF, Evaluating the Costs and Potential of Decentralised Energy, CSIRO Intelligent Grid Research Program, 2010.

Figure 16: Peak power by cost component (\$m/MWp)



Source: ISF, Evaluating the Costs and Potential of Decentralised Energy, CSIRO Intelligent Grid Research Program, 2010.



2.5 BARRIERS TO DM

The previous sections have highlighted the current uptake of demand management within the electricity system and compared this with the benefits that a wider uptake of demand side solutions in the electricity system would offer. These benefits include significant reductions in the amount of investment required to deliver electricity in the NEM, and also the opportunity of increased flexibility in the electricity system as it decarbonises.

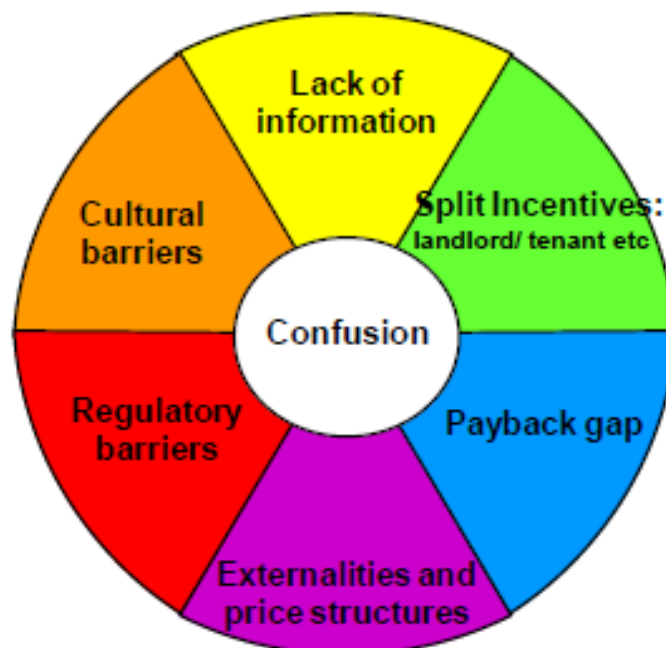
This section looks at the barriers that are preventing the wider take-up of demand management. The electricity system is complex, and as this analysis of the barriers shows, the inertia and institutional forces within the system that are preventing the wider uptake of demand management are also complex and multi-layered.

A survey of energy market participants and stakeholders highlights six types of institutional barriers to demand management activities as highlighted in Figure 17. These include:

- information barriers
- spilt incentives
- payback gaps
- externalities and price structures
- regulatory barriers
- cultural barriers.

These barriers interact to create confusion which is itself a further barrier to demand management.

Figure 17: Institutional barriers to demand management



Source: ISF, *Survey of Barriers to Demand Management*, 2011.

Not all barriers to electricity demand management are equally important. Figure 18 shows the ten barriers to demand management that stakeholders (including utilities as shown) rated in a survey as being the most significant. The barriers of most significance to NSPs include:

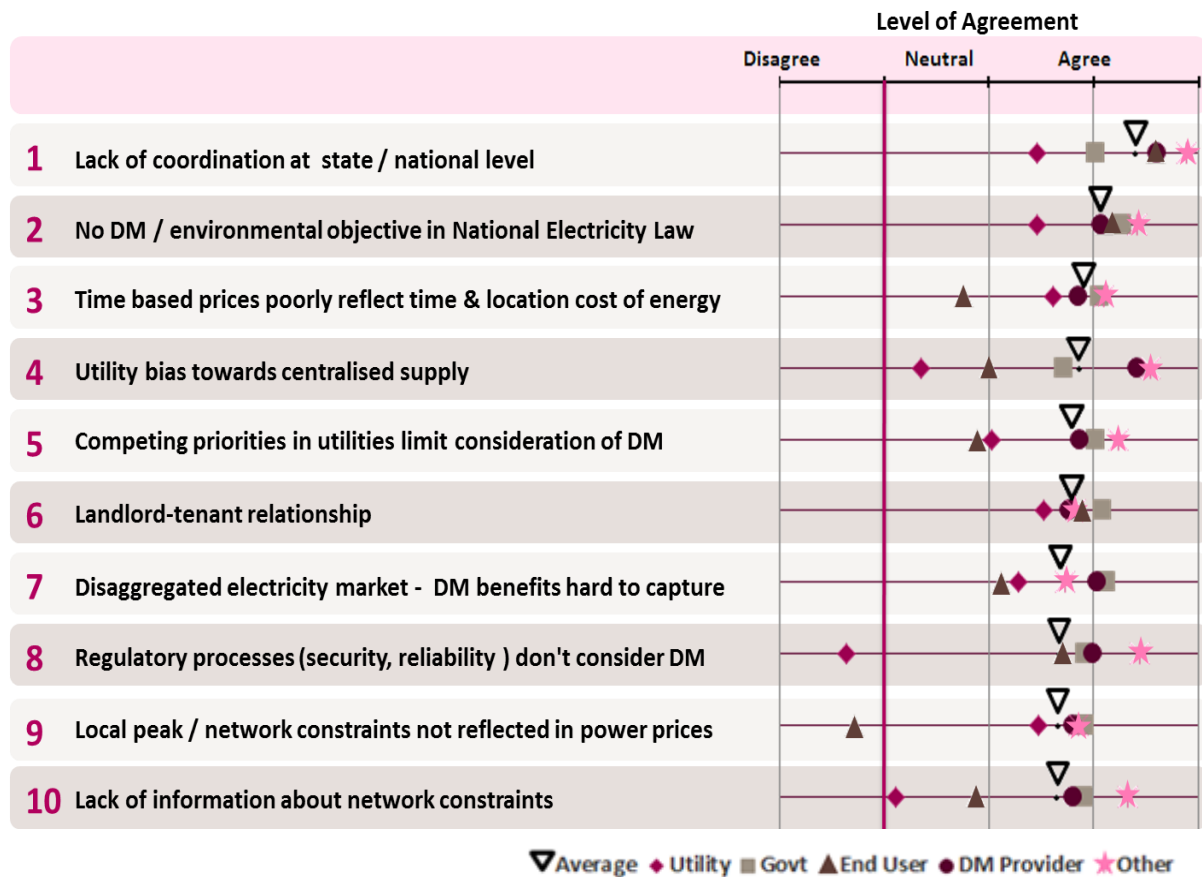
- regulatory processes that do not consider DM investments on an equivalent basis to network augmentation



- cultural bias favouring supply side solutions and limited experience of and expertise in demand management within the networks
- price structures which create a mismatch between cost of electricity and the time and location of use
- split incentive barriers between energy users and networks in a disaggregated electricity system which mean that the benefits of demand management are hard to capture and that they accrue to DM proponents.

The top ranked barrier – lack of coordination at state and national level – relates to a number of these specific barriers, but also to information barriers. Information barriers can also be considered as knowledge gaps, and these exist in both a tacit and codified form. Usually, when information barriers are referred to, this points to codified knowledge gaps. Codified knowledge gaps assume a tacit knowledge base built on experience and practice and the transmission of this knowledge both within the industry and to other key stakeholders. Issues of coordination speak more to a tacit knowledge gap that has not yet developed into an explicit information need.

Figure 18: Top 10 barriers to demand management



Source: ISF, Survey of Barriers to Demand Management, 2010.



Regulatory barriers

Regulatory barriers are a major impediment to the implementation to network DM. In its 2012 'Power of Choice' directions paper, the AEMC found that the current arrangements could be discouraging distribution businesses from pursuing efficient DM projects.⁴⁹ Stakeholders – and the businesses themselves – generally agreed with this finding. According to the businesses, under the current arrangements there are insufficient financial rewards to motivate them to undertake DM. The result is a preference for network capital investment – which consumers pay for over the long term – and under-development of the potential of the demand side.

The factors contributing to this preference for capital investment relate to the following characteristics of the businesses' planning and investment decision-making framework:

- the regulatory frameworks for assessing and approving operating expenditure (opex) and capital expenditure (capex) and the potential profit associated with DM projects
- differing financial returns of opex and capex (the regulatory framework has a powerful influence on this)
- the inability of businesses' planning processes and procedures to generate network and DM solutions
- the businesses' approach to risk management and decision-making at all levels within the organisation
- the ways in which network businesses recover their allowed costs through their tariff structures
- the ways in which the businesses' planning and investment frameworks support them in managing the risks and uncertainty associated with DM projects, especially given that the DM market is in the early stages of development and the technology is constantly evolving.⁵⁰

These factors are plotted in Figure 19 on the basis of their ability to be influenced by the regulatory framework and business. The incentives for and assessment of expenditure related to DM are both seen as highly influenced by the regulatory framework.

There are also technology specific regulatory barriers. For example, the 'ring fencing' limitations on NSPs supporting and investing in distributed generation limits their ability to use distributed generation strategically to benefit the network and customers. This issue has also been highlighted by the AEMC which states in recommendation 21 of its Power of Choice Review Final Report:

*The AER should give consideration to the benefits of allowing distribution businesses to own and operate distributed generation assets when developing the national ring fencing guidelines for these businesses.*⁵¹

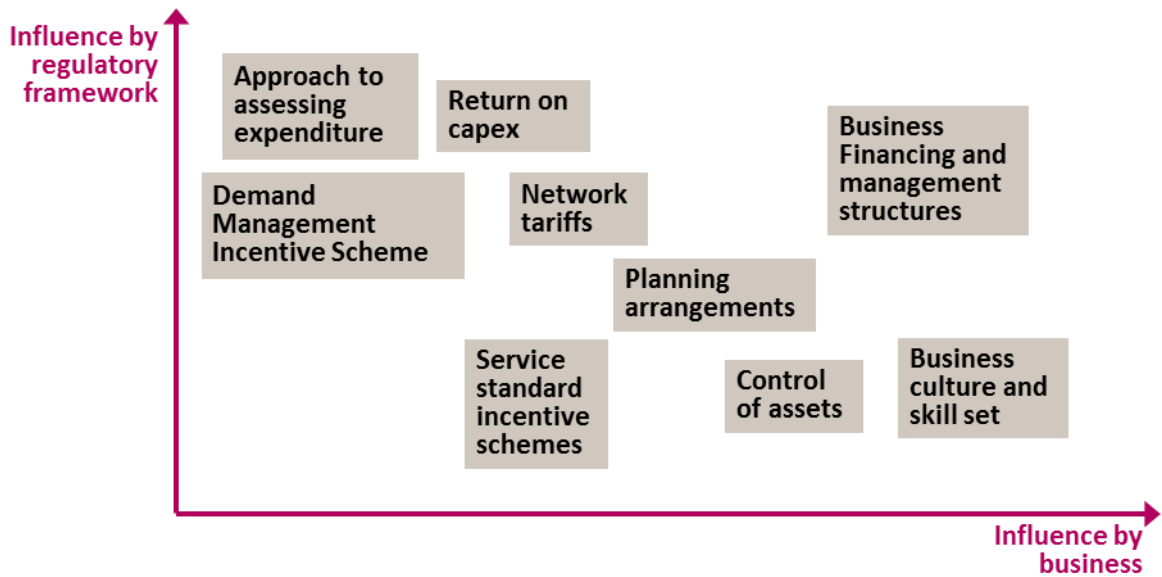
⁴⁹ The AEMC referred in its report to DM as 'Demand Side Participation' or DSP.

⁵⁰ Australian Energy Market Commission, 2012, *Power of Choice Review – Giving consumers options in the way they use electricity (Final Report)*.

⁵¹ Ibid.



Figure 19: Institutional barriers to demand management



Source: AEMC Power of Choice Review Final Report, 2012.

It is also important to recognise that there is a cultural dimension to the relatively slow uptake of DM in Australia. In concluding its Inquiry into DM in 2002, the Independent Pricing and Regulatory Tribunal of NSW found,

It is the Tribunal’s strong view that there is significant untapped potential for efficient demand management. To a large extent, one of the major obstacles continues to be a culture which favours traditional 'build' engineering solutions and which pays little more than lip service to alternative options.⁵²

⁵² Independent Pricing and Regulatory Tribunal of NSW (2002), *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services*.



3 UNLOCKING DM POTENTIAL

There is a range of policy tools available to address the barriers to tapping the large potential for DM in Australia. Many of the most effective tools are highlighted in the ‘Policy Palette’ in Figure 20.

Figure 20: Policy tools to address barriers to demand management⁵³



Source: ISF, Australian Decentralised Energy Roadmap, 2011.

The key elements from the above palette in the context of network DM are **regulatory reform, targets, information and incentives**, and are discussed individually below.

3.1 REDUCING REGULATORY BARRIERS TO DM

To provide financial support for network DM, the CEFC would need to be confident that it would be able to recover its investment, including a return to cover the CEFC’s cost of funds. While the CEFC may choose to share risk with NSPs, it would as a minimum need to be confident that the NSP had the capacity and commitment to successfully implement a DM project, and that the regulatory system would not create barriers to the recovery of prudent DM expenditure. To provide the CEFC with the required level of confidence, the following NSP conditions are required.

Box 1: Required NSP conditions

- Demonstrated management commitment to successful implementation
- Clear DM performance measures and savings targets
- Effective risk management processes.

⁵³ DE or ‘decentralised energy’ includes end use energy efficiency, peak load management, and distributed generation measures.



To facilitate the above NSP conditions, some or all of the following regulatory conditions are required.

Box 2: Required Regulatory conditions

- **Efficient cost recovery:** Where an NSP undertakes DM at a cost lower than the avoided cost of network supply or augmentation, the NSP must be able, via customer network charges, to recover, as a minimum, the full cost of the DM measure or program. (In addition, the NSP should be able to recover some share of the avoided supply costs, as discussed below.) NSPs should be explicitly encouraged to include specific DM operating expenditure in their regulatory proposals well in advance of the next regulatory determinations.
- **Inter-period offsets:** NSPs must be able to capture and offset the value of future avoided costs (in the next regulatory period) against current DM expenditure (in the current regulatory period). This means that the regulator must clearly and explicitly take these actual and avoided costs into account at the five-yearly regulatory determination.
- **Opex/capex substitutability:** As DM expenditure is usually operating expenditure but avoidable costs are normally capital expenditure, the NSP must be able to offset costs in the former against savings in the latter. NSPs should be able to earn the equivalent of a return on investment for DM expenditure.
- **Removing incentive bias against DM:** There are number of major biases in the current regulatory system which encourage network supply side expenditure and discourage DM. For example, as noted by the Productivity Commission, 'all [network] capital spending – regardless of its efficiency – is rolled into the regulatory asset base (RAB) at the end of the five-year regulatory period'.⁵⁴ Such provisions do not apply to DM, which is mainly operating expenditure. These biases need to be addressed.
- **Balanced regulatory risk:** The risk created by regulations associated with DM must be no greater than the risk involved in supply side expenditure.
- **Regulatory incentives to offset project risk:** Given the actual and perceived project risks associated with building up DM expertise and experience in relatively unfamiliar areas, the regulatory system should offset this risk by offering financial incentives to NSPs. This will involve sharing with NSPs and their shareholders some of the benefits of DM that would otherwise accrue to customers. Failure to do so will likely mean the benefits of DM accrue to no one. In this context, the current DM Incentive Allowances may be counter-productive, as they create the semblance of an incentive, but are so relatively small that they have been largely neglected by the NSPs.

Some of the above regulatory conditions can only be established if the Australian Energy Regulator (AER) changes the provisions the electricity network regulatory determinations and associated schemes. This is likely to take up to two years to be achieved. Note that the first two of the above conditions are critical to the viability of providing finance for DM. The AER could create these conditions by simply clarifying the provisions of the existing determinations.

⁵⁴ Productivity Commission 2013, Electricity Network Regulatory Frameworks, Report No. 62, Canberra, p.220.



To facilitate the above regulatory conditions, the following government policy conditions are required (see Box 3).

Box 3: Required government policy conditions

- Commitment to the long term interests of consumers, including through the delivery of all cost-effective DM
- Establishment of clear accountability and performance measures for DM, including for example, establishing network DM targets and reporting in collaboration with the NSPs
- Primary focus on customer bills rather than price
- Incentives to engage NSPs' interest and offset start-up costs (to the extent that regulatory incentives are inadequate for this purpose).

The current electricity market reform processes established by the Council of Australian Governments and the Ministerial Standing Committee on Energy and Resources have the potential to address both the regulatory and policy conditions, but this potential must be converted into explicit regulatory and policy intent.

The first three policy conditions above could be established relatively quickly by a statement of policy intent by government. The fourth condition is contingent on the absence of effective regulatory incentives and may therefore be unnecessary.

The remainder of this chapter focuses on those key elements not currently being addressed – specifically, targets, reporting and incentives.

3.2 DM TARGETS: MANDATORY VS COLLABORATIVE

The implementation of performance measures and targets is fundamental to the strategic management of any organisation or government policy. Electricity NSP managers routinely adopt performance indicators and targets and track progress in relation to many key aspects of their operations, such as cost, profitability, dividends, reliability, safety, power quality, customer satisfaction and price. It is understood that some of these performance targets apply, not just to how the organisation is judged, but also to the remuneration of senior executives – a powerful motivator for management priorities. However, to date DM targets have generally not been adopted by Australian NSPs (the Queensland DNSPs Energex and Ergon Energy being the main exceptions as discussed below).

Some network managers and shareholders, policy makers, and regulators are concerned that DM can reduce NSP revenue, profit and dividends. However, this is only the case where network regulations are poorly designed and 'couple' kWh throughput to profit. Provided regulations are well designed, DM targets can help NSP achieve other objectives such as lowering costs, and enhancing profitability, dividends, reliability and customer satisfaction, while also lowering customer bills. The impact of DM on price is less definitive, as it depends on what is currently driving NSP costs and what types of DM are deployed.

In order to stimulate the clean energy sector, state, territory and federal governments in Australia have imposed legislative targets on electricity retailers in relation to renewable energy, energy efficiency, greenhouse gas emissions and gas fired generations.⁵⁵ However, they have not to date imposed specific performance targets in relation to DM,

⁵⁵ For example, the Large Renewable Energy Target, the Small Renewable Energy Scheme, the NSW and ACT Greenhouse Gas Abatement Scheme, the NSW Energy Savings Target, the Victorian Energy Efficiency Target, the South Australian Residential Energy Efficiency Scheme and the Queensland Gas Scheme.



even though such targets have been in place in numerous jurisdictions overseas for many years, as described in Appendix C.

In principle, governments could establish through legislation or regulation a similar scheme for DM targets to apply to electricity retailers or networks in Australia. Indeed, the federal government has considered the possibility of a peak demand savings component in its proposed National Energy Savings Initiative.⁵⁶ However, while there are some clear advantages associated with a mandatory approach to DM targets, there are also three major weaknesses:

1. A mandatory scheme would take an extended period of time, at least until 2015, to be negotiated between jurisdictions, and then to be legislated and implemented.
2. In the wake of the controversy over rising electricity prices and the imposition of new cost obligations on electricity utilities in the form of the carbon price and renewable energy schemes, governments are likely to be reluctant to impose an additional obligation on electricity suppliers that could lead to any increase in electricity prices, *even if this also leads to lower average electricity bills.*
3. As network capital expenditure is currently the major driver for higher electricity bills, and the major source of avoidable cost for DM, the greatest benefit is likely to derive from applying the target to networks rather than retailers. However, as network capacity constraints are very time and location specific, *nominating effective and efficient mandatory DM targets for NSPs would be problematic.* Allocating equitable targets to NSPs with different peak demand and capital expenditure profiles is likely to be contentious. Measuring, reporting and verifying DM outcomes in very different organisational, climatic and economic circumstances across Australia without well-established precedents and conventions is likely to be very challenging.

The AEMC has also cautioned against mandatory targets:

*For networks, DSP outcomes should be measured on a project by project basis, given that the value of DSP will be specific to the location and demand characteristics. Higher level measures may be too volatile to be helpful.*⁵⁷

An approach more likely to be effective is for government to engage cooperatively with NSPs in setting non-mandatory **collaborative targets for DM**. Collaborative targets would involve government setting an overall DM target and working with each NSP to identify how much DM they could contribute to achieving that target. The Canadian province of Ontario provides a successful example of this approach (see Appendix C.2 for more details).

Such collaborative targets could be initiated by individual state or territory governments, the Australian Government or cooperatively by both levels of government and they would not require legislation or a change to the National Electricity Rules.

The key objective of collaborative targets would be to encourage electricity network businesses to volunteer to set quantitative goals for helping their customers to reduce the growth in peak demand, energy consumption and energy bills. Given the voluntary dimension of collaborative targets, they would only be effective to the extent that the NSPs responded to government leadership. However, as collaborative targets would need to focus on DM options that are mutually beneficial for NSPs and customers, the NSPs would have good reason to respond positively.

⁵⁶ NERA Consulting, 2012, *Peak Energy Savings Scheme Design Options: A Report for the Energy Savings Initiative Secretariat*, Prepared for the Commonwealth Department of Resources, Energy and Tourism.

⁵⁷ Australian Energy Market Commission, 2012, *Power of Choice Review - Giving consumers options in the way they use electricity (Final Report)*, p.224.



The setting and achievement of ambitious collaborative DM targets would require the removal of regulatory disincentives to DM by the AER (this is already in train as described above) and the provision of meaningful incentives (which are discussed below).

Precedents

There are numerous precedents for DM targets in Australia and overseas. Some of the most noteworthy are:

- **Ontario Electricity Conservation and Demand Management Program:** Sets targets of peak demand reduction of 1330 MW and energy savings of 6000 GWh between 2011 and 2014.⁵⁸
- **Queensland Energy Conservation and Demand Management Program:** (\$47 million).⁵⁹
- **US Energy Efficiency Resource Standards (EERS) and Efficiency Goals (EG):** 15 states and one power authority have implemented peak reduction targets within their EERS or EG, or award additional certificates for peak reductions. Targets are available for California, Colorado, Delaware, Florida, Maine, Maryland, Pennsylvania, Texas and Vermont.⁶⁰
- **UK Energy Efficiency Obligations:** a white certificate scheme has been in place in the UK since 1994. Though not targeted specifically at peak demand, it is estimated that this has resulted in an 800 MWe reduction in peak demand.⁶¹

A full list and details of reviewed state-based and international schemes incorporating peak demand are set out in Appendix C.

Defining DM targets

DM targets can be defined using a range of possible units. DM targets can relate either to inputs (such as the amount or proportion of funds to be devoted to demand management activities) or outcomes (such as the amount of end-use or system peak demand reduction to be achieved, or the number or value of augmentation projects to be deferred). Energy consultants Oakley Greenwood suggest that input targets should be considered as transitional or capacity building mechanisms. Two types of outcome-based targets they suggest are:

- reducing, by a specified percentage, the forecast growth in network system peak demand
- reducing, by a specified percentage, the capital that is forecast to be spent on augmentation projects driven by increased peak demand.⁶²

The two most obvious metrics for DM targets are energy (MWh per annum) and peak demand (MWp or MWp/year). Energy efficiency targets are typically denominated in MWh per annum, and this is appropriate where the objective is primarily carbon emission abatement. On the other hand, if the primary objective is reducing infrastructure costs,

⁵⁸ Ontario Executive Council, cited in Dunstan, C. et al. 2011, *op cit*.

⁵⁹ Queensland Government, 2009a, cited in Dunstan, C. et al. 2011, *Think Small: The Australian Decentralised Energy Roadmap*. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.

⁶⁰ Wright, G., 2012, *Demand management targets for networks in the National Electricity Market, (Discussion Paper)*. Total Environment Centre, Sydney.

⁶¹ *ibid*.

⁶² Oakley Greenwood. 2012. *Policy options for maximising downward pressure on electricity prices*. Prepared for The Australian Industry Group, by Brotherhood St Laurence, CHOICE and the Energy Efficiency Council.



which are mainly driven by peak demand, then denominating the DM target in peak demand (MWp) is more appropriate. In practice, policy makers often pursue both cost and carbon objectives and consequently DM targets often combine both MWh and MWp components, as highlighted in Appendix C.

However, there are other options for denominating DM targets. The Alternative Technology Association (ATA) and the Total Environment Centre (TEC) propose that targets could be based on such things as:

- current peaks (either network wide, or weather-corrected peaks within each distributor's service area) or forecast peak growth.
- weather-corrected network load factor.
- per capita reduction in peak demand.⁶³
- capital expenditure to meet peak demand growth as a proportion of network-wide peaks or peak growth.⁶⁴

The ATA and the TEC suggest that targets could be set annually or in line with five-yearly regulatory reviews.

If the primary objective of the DM target is to maximise the value of savings to energy customers, then it is possible to denominate the target in dollars. Such value-based DM targets could focus on the value of deferred and avoided network capital expenditure, the value of customer bill savings, or a combination of the two. The avoided network capital expenditure could be quantified as the value of network infrastructure deferred or avoided. The customer bill savings could be characterised as the value of avoided retail bills, which would capture the value of avoided energy consumption and avoided peak demand across the whole value chain from generation and transmission to distribution and retail margin.

While such value based targets could be challenging to enforce as mandatory targets since the value of network expenditure avoided varies from place to place and time to time, they could be ideally suited to collaborative targets as outlined earlier.

Scale of DM targets

The scale of the targets is a crucial decision for government. If the government is adopting collaborative targets, one option is not to set any target at all and simply ask the NSPs to nominate their own DM targets. This approach has two obvious risks. Firstly, it could lead to very modest targets as NSPs seek to minimise the chance of underperformance. Secondly, it could lead to very disparate targets across the NSPs as they apply different approaches to estimating achievable cost-effective DM potential.

The alternative approach is for the government to set an indicative, overall benchmark DM target and then to engage with NSPs or invite NSPs to set individual DM targets for each NSP.

The overall target should strike a balance between the low level of current network DM activity and the large potential for DM as described in Section 2.4 (which cites estimates of cost savings of peak demand reduction in the National Electricity Market (NEM) between \$4.3 billion and \$11.8 billion over the next ten years). Moreover, the Queensland and NSW Governments have already announced network capex reductions of about \$1.5 billion⁶⁵ and

⁶³ Wright, G., 2012, op cit.

⁶⁴ Alternative Technology Association, 2012, *Submission on the Productivity Commission's Review of Electricity Network Regulation*.

⁶⁵ Steven Wardill, 'Infrastructure and service cuts aimed at tackling skyrocketing household electricity bills in Queensland', *The Courier Mail*, 8 December 2011.



\$2 billion⁶⁶ respectively. This compares to annual national network capital expenditure of about \$9 billion per annum. Former Prime Minister Julia Gillard flagged the government’s ‘plan to make sure that families pay \$250 less per year for electricity’.⁶⁷ This amounts to more than 10 per cent of the current typical household energy bill.

Accordingly, while the setting of targets is clearly a matter for government and should be based on thorough analysis and consultation, a DM savings target in the order of \$1 billion dollars per annum to be achieved within say, four years would be broadly consistent with the estimates for savings potential, described in section 2.4. While a target at such a scale would likely fall short of the cost-effective potential for DM, it would still be large enough to deliver a significant reduction in customer bills and carbon emissions and a boost to industry development. Whatever the overall target, it would then need to be appropriately apportioned to the NSPs with regard to their local demand, investment and market conditions and capacity.

Mandatory DM targets

As described in the previous section, there are several reasons why collaborative targets are preferable, and mandatory DM targets are unlikely to be practical, particularly in the short term. However, if effective collaborative DM targets cannot be implemented in the short term, then it may be prudent to consider the mandatory option. It is beyond the scope of this study to consider mandatory DM targets in detail, however it is recognised that there are numerous precedents for mandatory DM targets overseas and that a mandatory DM target can be developed in a flexible, market friendly manner and need not necessarily be applied to, or be delivered by, NSPs.

For example, Green Energy Trading also suggests a DM Certificate trading scheme, with certificates worth a specified \$ per MWp value to reflect different locational investment values (see Table 6 below). Green Energy Trading suggests the scheme could be managed by the Clean Energy Regulator (CER).⁶⁸

Table 6: Example values for DM certificate-based target scheme

Investor	Location	Peak Metric	Investment	Annual Value
Generation	NEM-wide	Coincident region peak	\$400/kw	\$40/kw
Transmission	Regional	Coincident region peak	Region 1 = \$100/kw	\$10/kw
	Locational (terminal station)	Local peak	T Location a = \$500/kw T Location b = \$50/kw	\$50/kw \$5/kw
Distribution	Regional	Coincident DNSP peak for region	D Region 1 = \$600/kw	\$60/kw
	Locational (zone sub)	Local peak	D Location a = \$1000/kw D Location b = \$200/kw	\$100/kw \$20/kw

Source: Green Energy Trading, *Creating a Community Financial Dividend through Managing Peak Electricity Demand*.

⁶⁶ Quoted in Michael West, ‘Time to switch off on bloated power industry’, Sydney Morning Herald, 7 November 2012.

⁶⁷ Julia Gillard, 2012, *Transcript of Interview with Paul Bongiorno, Rafael Epstein and Patricia Karvelas*, Meet The Press, 2 Dec 2012.

⁶⁸ Green Energy Trading, 2012, *Creating a Community Financial Dividend through Managing Peak Electricity Demand*. Discussion Paper.



3.3 REPORTING DM PERFORMANCE

An essential precondition for any form of target or goal is a means of measuring performance. At present, there is no comprehensive system for measuring and reporting of network DM. The only comprehensive assessment of electricity network DM to date was the 2011 Survey of Electricity Network Demand Management in Australia (as presented in Section 2.3).⁶⁹

There has been some effort to improve reporting of NSPs' DM activity. For example, under the new Distribution Network Planning and Expansion Framework Rule which commenced in January 2013, DNSPs are required through their Annual Planning Review to report:

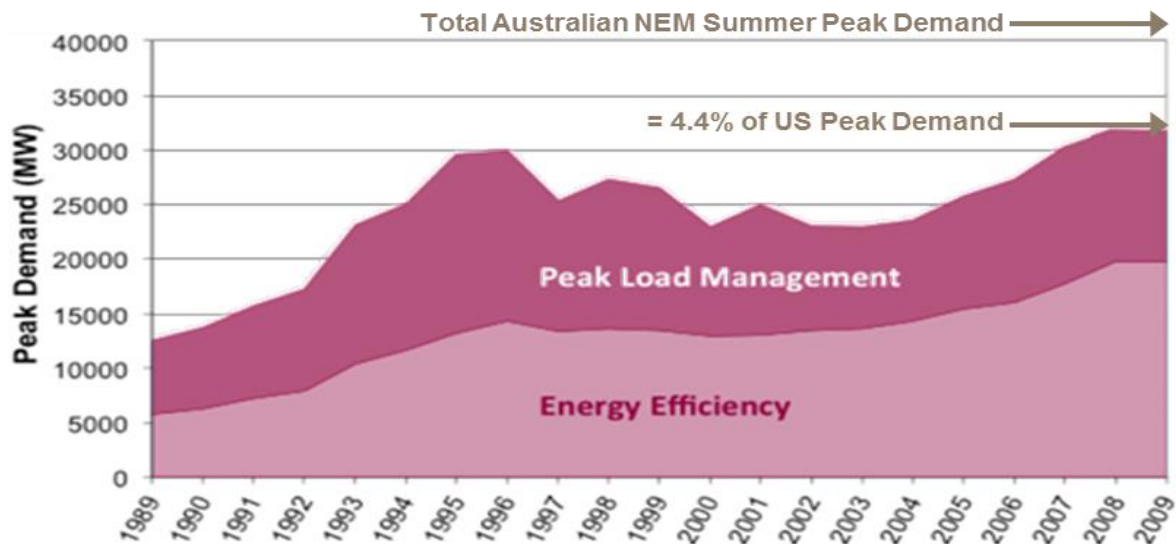
*information on the Distribution Network Service Provider's demand management activities, including a **qualitative summary** of:*

- (1) non-network options that have been considered in the past year, including generation from embedded generating units;*
- (2) actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units; and*
- (3) the Distribution Network Service Provider's plans for demand management and generation from embedded generating units over the forward planning period.⁷⁰*

However, a 'qualitative summary' is clearly insufficient for either meaningful DM targets or for financing contracts.

In contrast to Australia, in the US there has been comprehensive quantitative reporting of DM costs and outcomes for over two decades as illustrated in Figure 21.

Figure 21: US utility demand management (DM) actual peak load reductions



Sources: US Energy Information Administration & AEMO.

⁶⁹ Dunstan, C., Giotto, N. & Ross, K., 2011, *Report of the 2010 Survey of Electricity Network Demand Management in Australia (SENDMA)*. Prepared for the Australian Alliance to Save Energy by the Institute for Sustainable Futures, University of Technology, Sydney.

⁷⁰ *National Electricity Rules Chapter 5 Version 55 Network Connection, Planning And Expansion*, p.589 (emphasis added).



Network DM reporting should become standardised and regular. Such information should be centrally collated and published annually to allow comparison between NSPs and to monitor trends over time. An illustration of the sort of information that should be reported in is included in Section 3.5.

3.4 INCENTIVES FOR DM

As noted above, in the absence of any obligation or penalty for non-compliance, collaborative targets for DM would require the offer of incentives to be effective. The Futura Report prepared for the AEMC Power of Choice Review stated that one of the 'Market, Regulatory and Institutional arrangements' needed to support DM is:

*adequately funded and designed incentive allowances that provide appropriate targets and rewards for encouraging distribution businesses to actively invest in both short and long term DSP opportunities and localised and broad based initiatives.*⁷¹

Possibilities for DM incentives include:

1. a separate dedicated DM fund
2. incentives in the existing regulatory system (e.g. AER's DMEGCIS/DMIA)
3. financing for DM.

Each of these options is discussed below. It is important to note that while these incentives may be directed towards utilities or other intermediaries, they are only effective to the extent that they are ultimately directed to energy users in order to stimulate changes in energy using behaviour.

DM Fund

During the stakeholder engagement process for the AEMC Power of Choice Review, and in the AER's initial stakeholder workshop on DMEGCIS reform, it was discussed whether, if all disincentives to DM were addressed through regulatory reform which created a level playing field between DM projects and capital asset projects, NSPs undertaking DM should receive any extra reward/incentive.⁷² Given the variety of non-regulatory barriers discussed in Section 3.1 however, even if a regulatory level playing field was provided, further incentives would still be needed to overcome these barriers.

The simplest and arguably most effective form of incentive would be to establish a fund to offer direct cash payments to NSPs and others for meeting specific DM performance outcomes. The establishment of a 'Demand Management Fund' was the primary recommendation of the 2002 NSW Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, which led directly to the creation of the NSW Energy Savings Fund in 2005.⁷³

As noted by Crossley, a DE Fund '*could be established to encourage investment in cost-effective DM. Network businesses would be invited to bid for funding, but funding would also be open to other DM providers to make a more competitive pool of service providers*'.⁷⁴

⁷¹ Futura Consulting, 2011, *Investigation of existing and plausible future demand side participation in the electricity market (Final Report for the Australian Energy Market Commission)*.

⁷² Australian Energy Market Commission, 2012, *DSP and Profit Incentives for Distribution Network Businesses (Staff Paper, Fourth Stakeholder Reference Group Meeting, Power of Choice Review)*.

⁷³ The Energy Savings Fund was subsequently rolled into the Climate Change Fund, which in turn was later diverted to fund the blow out in expenditure under the NSW Solar Bonus Scheme.

⁷⁴ Crossley, D. 2010, *International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks*. Prepared for Australian Alliance to Save Energy by Energy Futures Australia.



There are numerous examples of such funds overseas. In the US, over twenty states have instituted 'public benefit funds' or 'system benefit funds' to support energy efficiency and/or demand management. These are often in addition to DM programs undertaken by utilities.⁷⁵ As Crossley notes:

In the United States, many states that adopted electricity industry restructuring also created public benefits funding mechanisms to help ensure the continued implementation of DM programs. Public benefits funding mechanisms for electricity DM typically involve the collection of a small per-kilowatt-hour public benefits charge (also often known as a 'system benefits' or 'wires' charge) as a part of the revenues of an electricity utility (typically an electricity distributor). These revenues are used to fund DM programs implemented either by utilities or by designated government or independent organisations.

By the end of the 1990s, public benefits funding had emerged to be perhaps the most significant new policy supporting energy efficiency DM in the United States in a decade. Since that time, although the move toward electricity industry restructuring has largely stalled.

The required funding level across these 18 states varies from 0.003 to 0.3 US cents per kilowatt-hour with a median value of between 0.11 and 0.12 3 US cents per kilowatt-hour. Combined annual expenditures are over US\$900 million and annual incremental savings are nearly 2.8 million megawatt-hours. Cost-effectiveness estimates from nine of the most active states show the programs, in aggregate, to be very cost-effective with median benefit/cost ratio in the range of 2.1 to 2.5 and median cost of energy savings equal to 3 US cents per lifetime kilowatt-hour saved, public benefits funding for energy efficiency DM has continued unabated. Every state (18 in all) that initiated public benefits energy efficiency DM programs continues to operate those programs today.⁷⁶

In the UK, the Office of Gas and Electricity Markets has established the Low Carbon Networks Fund as part of the electricity distribution price control arrangements. The Fund is providing up to £500m (about AU\$773m) between 2010 and 2015 to support projects sponsored by the distribution NSPs 'to try out new technology, operating and commercial arrangements'.⁷⁷

The main disadvantages of a DM fund in the current Australian context are the absence of likely funding sources and the time that it would likely take to establish it. Another more general disadvantage is that such funds are often vulnerable to 'funding raids' by governments seeking a quick solution to financial difficulties, as was the case of the NSW Energy Savings Fund which was ultimately diverted to help pay for the blowout in costs of the NSW Solar Bonus Scheme.

Incentives in the regulatory system

Incentives in the regulatory system can comprise one or both of the following components:

- recovery of revenue foregone and DM program costs
- direct incentives to encourage the use of demand-side resources for network support.

⁷⁵ Pew Centre, 2010, cited in Dunstan, C. et al. 2011, *op. cit.*

⁷⁶ Crossley, D. 2010, *International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks*. Prepared for Australian Alliance to Save Energy by Energy Futures Australia.

⁷⁷ Office of Gas and Electricity Markets (UK), 2013, *Low Carbon Networks Fund (webpage)*
<http://www.ofgem.gov.uk/Networks/ElecDist/lcnf/Pages/lcnf.aspx>



Revenue recovery

There are currently two types of revenue recovery models operating in the US:

1. **Direct cost recovery:** utilities can recover the costs of DM programs on a timely basis.
2. **Lost fixed-revenue recovery:** utilities can cover any prudent costs that may not otherwise be recovered due to reduced sales from the DM program.⁷⁸

As Crossley notes,

*There are two views among policy makers and regulators about how **foregone revenue and DM program costs** should be treated. One view maintains that both foregone revenue and DM program costs are entirely the responsibility of the network business and should be fully taken into account when the business is evaluating the cost-effectiveness of DM versus network augmentation options. A second view maintains that the network business should be allowed to recover at least some of the foregone revenue and DM program costs and the value of this recovery should not be included in the cost benefit analysis of DM versus network augmentation options.*

In New South Wales, the introduction of revenue regulation [1999-2004] did not result in a major increase in the implementation of DM by electricity distributors. For the five year regulatory period to 2009, the regulator changed its method of regulating distributors from revenue regulation to price control but also allowed distributors to recover foregone revenue and DM project costs. To achieve this, the regulator introduced a D-factor into the weighted average price cap control formula that allowed distributors to recover:

- *non-tariff-based DM implementation costs, up to a maximum value equivalent to the expected avoided distribution costs;*
- *tariff-based DM implementation costs;*
- *revenue foregone as a result of non-tariff-based DM activities.*

These provisions are regarded as generous and have stimulated distributors in New South Wales to increase their implementation of DM measures to defer network augmentations.⁷⁹

The AEMC has also observed:

Ausgrid states that the application of a 'D-factor' incentive resulted in a positive incentive for businesses to seek and implement demand management alternatives to network investments. Since its introduction, this has resulted in much more active and effective processes than has resulted in other NEM jurisdictions with identical regulatory obligations but no incentive arrangements. For example, in 2004/05 and 2005/06, NSW DNSPs spent approximately \$8.26 million on 26 DM projects under the D-factor scheme. NSW DNSPs have avoided \$24.23 million of planned capital expenditure and operating expenditure over the 2004/05-2005/06 period as a result of approved demand management projects undertaken in conjunction with the D-factor mechanism.⁸⁰

⁷⁸ Australian Energy Market Commission, 2012, *DSP and Profit Incentives for Distribution Network Businesses* (Staff Paper, Fourth Stakeholder Reference Group Meeting, Power of Choice Review).

⁷⁹ Crossley, D. 2010, *International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks*. Prepared for the Australian Alliance to Save Energy by Energy Futures Australia.

⁸⁰ Australian Energy Market Commission, 2012, *Demand Side Participation and Profit Incentives for Distribution Network Businesses* (Power of Choice Review Directions Paper Supplementary Paper).



Direct incentives

As discussed in Section 2.3, in Australia direct incentives in the regulatory system have usually taken the form of direct payments to NSPs. However, the main direct incentive model operating in the US is a system for **performance incentives based on avoided costs**: utilities can keep as before-tax profit a minor portion of the avoided cost that they would otherwise have incurred had they not implemented the DM program. Roughly half of the 50 states in the US have some form of performance incentive in place or pending⁸¹ – an example is shown on the following page in Box 4.

The options for making changes to regulatory incentives for DM are discussed in further detail in Section 5.2.

Financing for DM

The third broad type of incentive that can be applied to encourage DM is financing. As finance needs to be repaid, it has the disadvantage of being a much less powerful motivator. However for the same reason, it also has the advantage of usually being a much lower cost option.

In Australia, financing has the advantage of having an identifiable source of funds through the CEFC. Any reforms aimed at changing incentives within the regulatory system would take some time to implement. Financing for DM could be used as an incentive in the short-term and is discussed in more detail in Section 4.

Box 4: Example of performance incentives

In Ontario, performance incentives accrue to networks for reaching 80% of their CDM target, up to a cap of 150%. The incentive is calculated in a stepped manner, with a higher \$/kW rate for higher performance, as shown in Table 7 below.⁸²

Table 7: Performance-based DM incentives

Range	Performance Tiers		Performance Incentive	
	Range Begins	Range Ends	¢/kWh	\$/kW
1	80%	up to 100%	0.30	13.50
2	100%	up to 110%	0.45	20.25
3	110%	up to 120%	0.75	33.75
4	120%	up to 130%	1.05	47.25
5	130%	up to 140%	1.35	60.75
6	140%	up to 150%	1.80	81.00

Source: Ontario Energy Board, Conservation and Demand Management Code.

⁸¹ Australian Energy Market Commission, 2012, *DSP and Profit Incentives for Distribution Network Businesses* (Staff Paper, Fourth Stakeholder Reference Group Meeting, Power of Choice Review).

⁸² Ontario Energy Board, 2010, *Conservation and Demand Management Code*.



3.5 IMPLEMENTING COLLABORATIVE DM TARGETS

There are many ways in which collaborative DM targets could be implemented. It should be emphasised that while a collaborative targets approach could potentially deliver significant savings for electricity consumers more quickly than relying in regulatory reform alone, it will only do so if it is consistent with and supported by the longer term reform program of government. The following provides one possible approach which draws together the above themes of targets, reporting, regulatory reform and incentives.

STEP 1: The CEFC announces its interest in and willingness to provide finance to support cost-effective network DM, in accordance with its Investment Mandate.

STEP 2: The Federal Minister for Energy, either in their own right or through the Standing Committee on Energy and Resources, writes to the Australia Energy Regulator (AER) to request that they take all reasonable steps within their power that are consistent with the current National Electricity Rules to facilitate cost-effective network DM that is likely to deliver net customer bill reductions. Similar letters could be dispatched to the Western Australian Economic Regulatory Authority (ERA) and the Northern Territory Government.

STEP 3: The Federal Minister for Energy, either in their own right or through the Standing Committee on Energy and Resources, announces an Indicative DM or Energy Savings Target, for example a 10 per cent reduction in customer energy bills below business as usual, or \$1 billion per annum in customer energy bills, to be achieved within four years (as suggested in section 3.2).

STEP 4: The Federal Minister for Energy, either in his own right or through the Standing Committee on Energy and Resources writes to the CEO of each distribution and transmission network service provider, requesting that they report on the following matters:

1. **Demand vs. Trend:** How does coincident peak summer and winter demand (MWp) and annual energy consumption (GWh p.a.) in the past three years compare to the levels forecast in their respective current network pricing determination?
2. **DM performance:** How much coincident peak summer and winter demand (MWp) and annual energy consumption (GWh p.a.) has been reduced across each NSP's network system in the current year as a result of DM options that they the NSP has supported over the past three years?
3. **NSP cost savings:** By how much have the NSP's capital and operating expenditure been reduced as a consequence of points 1 and 2?
4. **Customer bill savings:** By how much have customer energy bills been reduced in the current year as a result of points 1 and 2?
5. **NSP revenue impact:** What has been the impact on NSP revenue of DM options undertaken over the past three years?
6. **DM plans and targets:** What additional DM options does the NSP plan to undertake in next three years and how are these expected to impact on the above factors (peak demand, energy consumption, customer bills and NSP expenditure and revenue)?
7. **DM potential:** What additional cost-effective DM options could the NSP undertake in the next three years if there were incentives in place to do so (including access to finance for DM) and what would the impact be on the above factors (peak demand, energy consumption, customer bills and NSP expenditure and revenue)?



These letters could also:

- ask that these reports be provided within, say, four months;
- offer a collaborative consultation process to refine the detailed reporting template and guidelines, within say, two months;
- emphasise that this request is not a regulatory direction, but rather an invitation to collaborate with government in delivering savings to business and residential electricity customers;
- advise that the AER (and its WA and NT counterparts) have been requested to provide all reasonable assistance within their power to facilitate cost-effective network DM;
- indicate that should a lack of access to finance present a barrier, the CEFC is prepared to facilitate finance for network DM;
- indicate that this reporting process is intended to become an annual event.
- express an aspiration that this collaborative system can be effective in delivering benefits to customers, thus obviating the need to consider a more onerous or mandatory DM obligation.

STEP 5: NSPs respond to the request for information and offer of support by reporting on current DM activities and plans and opportunities to increase DM activity.

STEP 6: Government, regulators, CEFC and NSPs collaborate to develop network DM in Australia, including the use of CEFC finance where appropriate.



4 INVESTMENT OPPORTUNITIES FOR CEFC

4.1 LOANS FOR NETWORK BUSINESSES FOR DM

Over-investment by networks in capital expenditure has ultimately been the result of NSPs responding to the rules and incentives created by government policy and regulators at the state, territory and Commonwealth levels. In order to encourage network businesses to change their practices quickly to support the interests of consumers, external support and incentives are not only required but justified.

NSPs have long term capital works programs that cannot be easily or quickly reoriented. The availability of CEFC finance specifically targeted to DM investments which also reduce emissions is one area where the CEFC could play a unique role.

CEFC financing for DM could provide a number of benefits, to both privately-owned and government-owned networks, as set out in Table 8.

Table 8: Potential benefits of CEFC financing for DM

1. Specifically targetting DM investments which also reduce carbon emissions.
2. Potential to address existing capital constraints.
3. Potential concessions on repayments, especially in regard to repayment timing in the current versus subsequent regulatory periods.
4. Potential for upside and downside risk-sharing.
5. Potential strategic support from CEFC in engaging with the AER over regulatory reform to ensure expenditure recovery.

Given that networks are currently spending around \$9 billion per annum on capital expenditure, these facilities need to be large to have a meaningful impact. For example, based on a plausible benefit to cost ratio of 3:1, the achievement of savings of \$1 billion per annum (suggested above) would likely require DM expenditure to be quickly ramped up to the order of \$300–400 million per annum in funding.⁸³

Loans would need to be contingent on electricity networks adopting specific and credible investment plans and targets for demand management, so that best practice could be transferred to the wider industry, enabling the creation of cost reductions in demand management over time.

This financing could be wound back after 2016 as barriers to cost-effective DM are removed and more balanced regulatory structures are created for DM and network investment. This is particularly important in relation to the next round of electricity network economic regulatory decisions to be made by the Australian Energy Regulator for the five-year periods commencing in each state (excluding WA) between 2014 and 2016.

Financing should be contingent on network businesses adopting specific and credible plans and targets to reduce customers' energy bills. It would also help the CEFC itself to be able to support investments that manifestly deliver short term benefits to energy consumers. Though the CEFC is an independent agency, this activity is consistent with the roles of the CEFC as proposed in the CEFC Expert Review Panel Report, its Act and Investment Mandate.

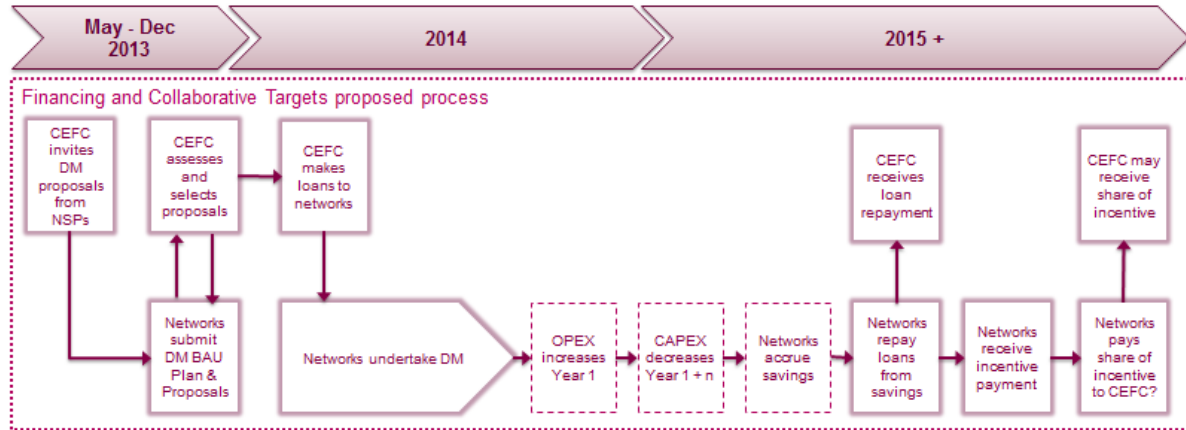
⁸³ Dunstan, C. et al. 2011, *Think Small: The Australian Decentralised Energy Roadmap*. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.



The process could follow a process similar to that outlined below in Figure 22 (and in greater detail in

Figure 27 in Appendix B).

Figure 22: Suggested process for providing finance facilities NSPs



Each of the above steps is described in more detail in Table 9.

Table 9: Possible pathway for financing network DM

Step	Description
1. CEFC invites proposals from Network Service Providers	CEFC outlines the conditions under which finance for network DM can be made available to NSPs consistent with its Investment Mandate and its Act.
2. Networks Submit a DM and BAU Plan & Proposal	NSP proposals would be required to include: <ul style="list-style-type: none"> • proposed level of finance required. • performance targets: avoided network augmentation capex, customer bill savings and CO₂ reductions. • proposed repayment schedule. • details of DM activity, NSP involvement and risk assessment.
3. CEFC assesses and selects proposals	Criteria assessment to include: <ul style="list-style-type: none"> • customer cost and carbon impact • additionality assessment • risk/reward assessment • strategic value in precedent setting, etc. • requirement for complementary regulatory reform.
4. CEFC and selected NSPs sign agreement	In accordance with standard CEFC investment practice.
5. CEFC makes loans to networks	Loans could be provided in 2013–14, with repayments to occur in the next regulatory period (post July 2015) when



Step	Description
	networks reap the benefits of their investment in demand management. Loans can be 'invested' by networks in both investments in DM-related capital (such as generators, etc.) but also more broadly in operating expenditure for the wide variety of initiatives and programs that constitute normal demand management activities.
6. Networks undertake DM activities using CEFC finance	As per proposal and contract.
7. Networks accrue savings and report on DM performance	NSPs will generally see an increase in opex in Year 1, followed by a decrease in capex in following years.
8. Networks repay CEFC loans from savings	As per contractual terms, including any risk sharing.
9. AER makes an incentive payment for DM performance	In accordance with existing or reformed incentive structure as appropriate.
10. Networks pay a share of the incentive to CEFC	As per contractual terms, including any risk sharing.

For the CEFC to be able to provide financial support for network DM it would need to recover its investment and a modest return to cover the CEFC's cost of funds. While the CEFC would be prepared to share risk with networks businesses (see Section 4.2 below), it would need to have a strong level of confidence that the regulatory system would not create barriers to the recovery of prudent DM expenditure. This is discussed further in Section 5.

4.2 POSITIVE AND NEGATIVE RISK SHARING

The preceding section sets out how repayment of CEFC loans depends on an increase in CEFC-financed operating expenditure in one year being followed by a decrease in capital expenditure in the following years, providing a 'surplus' for the network to make repayments from. One of the benefits for networks of making CEFC finance available is the opportunity for provision of concessions (e.g. repayment deferral into the next regulatory period).

The CEFC can also assist NSPs through risk sharing. Loans by the Clean Energy Finance Corporation to network businesses to finance DM activities can encourage a greater uptake of DM by helping to reduce the risk perceived by networks, since that risk could be shared with the CEFC.

If the CEFC's 'investment' only accrues principal repayment plus the minimal interest rate, then the CEFC is likely to underperform if some of the financed network DM activities do not meet their minimum targets for reduced peak demand (and therefore do not result in sufficient 'savings' to make repayments). This risk can be balanced and offset through a portfolio approach with associated sharing of benefits. One way for this to happen is for networks to share with the CEFC a proportion of any incentives received in the following regulatory period.



For this to provide effective ‘upside’ opportunity for the CEFC, there needs to be a mechanism to motivate networks to over-achieve, in order to ensure that potential incentives offer enough benefit to the CEFC to offset the risk of underperforming loans.

One way to do this is to use DM targets with associated performance incentives for over-achieving such targets, as shown earlier in Box 4 in Section 3.4. This constitutes another reason for the CEFC to engage in joint discussions with NSPs and the regulators (the AER, etc.).

A detailed discussion of this is provided in Sections 3.4 and 3.5.

4.3 CAPITALISING DM EXPENDITURE

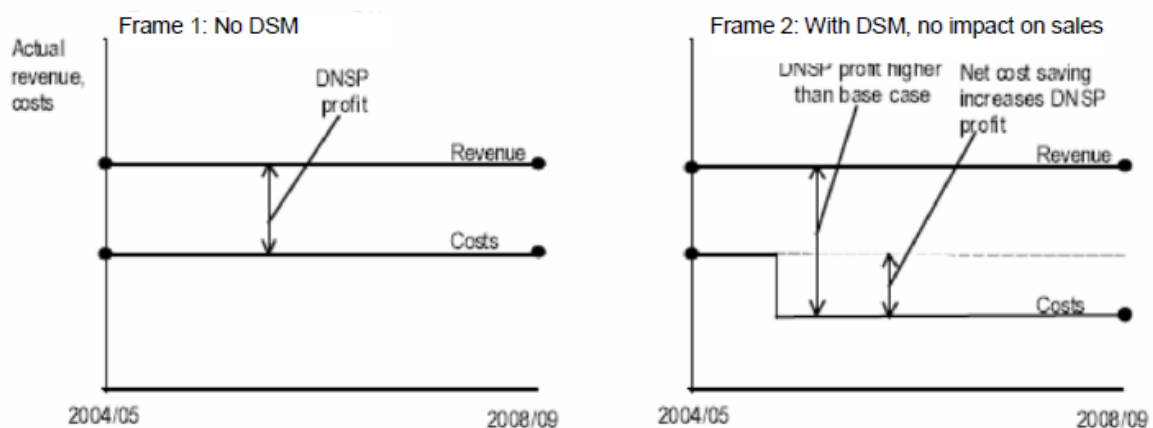
The current regulatory structure of linking prices to asset values, together with the use of price caps in NSW, Victoria and South Australia, creates a disincentive for demand management as outlined previously. This is because the structure is based on prices linked to asset values, together with the historical use of price caps. This has created two complementary drivers for Network Service Providers (NSPs):

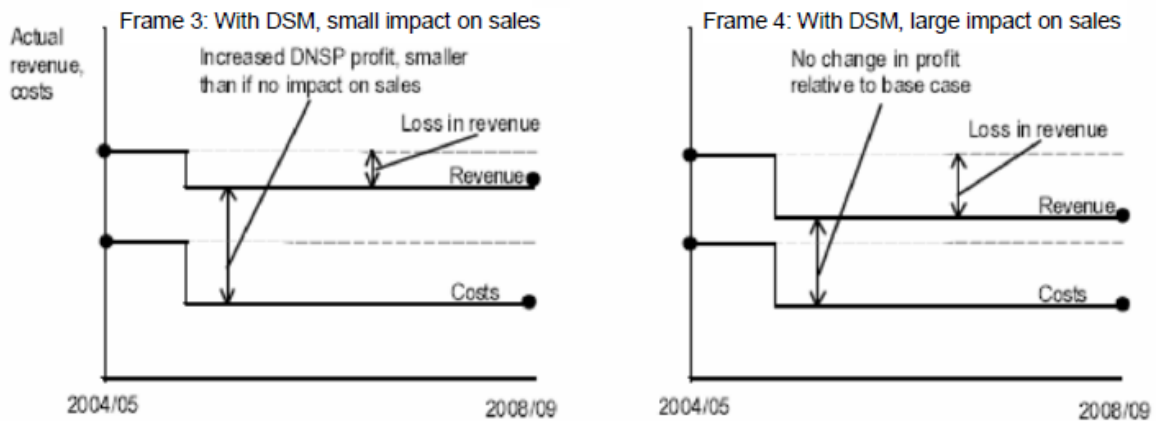
- to maximise the optimised asset base, in order to maximise the capacity to raise revenue, and
- to maximise sales in order to maximise profits while also minimising prices to customers.

These drivers are complementary, because the strongest justification for an increase in the asset base is increased demand. Both these drivers create disincentives to carry out demand management.

Demand management can potentially lead to both reduced sales, and less growth in the asset base, as shown in Figure 23.

Figure 23: Impact of DM on electricity business revenue





Source: *Energy Futures Australia, 2010, International best practice in using energy efficiency and demand management to support electricity networks.*

If DM expenditure was able to be 'capitalised', networks would receive returns on their DM expenditure, thus providing a more 'level playing field' between network expansion and demand management. Capitalising the value of demand management into the regulated asset base for the next regulatory period could help reduce the longer-term regulatory disincentives to investing in cost-effective DM.

Capitalising DM expenditure could also assist in facilitating finance for DM programs, whether provided by the CEFC or other sources.

For this approach to work, the following would need to be in place⁸⁴:

- Expenditure on demand management would need to be treated as an equivalent substitute for network infrastructure capital expenditure to overcome network constraints.
- Demand management projects would need to be valued as the net present benefit of deferral of the next-most expensive option, not their historical cost.
- Demand management would need to be 'capitalised' at the value of the benefit of deferral of the full capacity of the network augmentation option, not just the proportion used, because the next-most expensive option would be to build the whole network option.
- Valuation of network augmentation would need to be based only on that proportion of the network augmentation that is actually needed to supply demand on an annual basis. This is neutral to both options, because the alternative option can be sized to the capacity actually needed, namely demand management.
- Returns should be performance-based, ie DM expenditure would only be considered an 'asset' to receive a return on, to the extent that it reduces peak demand and avoids/defers network augmentation.
- The value of a demand management investment would need to be included in the asset base for the life of the project, regardless of when the network supply-side option was required, but subject to demand management delivering the intended demand reduction.

⁸⁴ Tarlo, K., 2003, *Capitalising Demand Management into the Asset Base: Preliminary Assessment*. Prepared for Public Interest Advocacy Centre's Utility Consumers' Advocacy Program, by the Institute for Sustainable Futures, University of Technology, Sydney.



This approach implies the NSP accruing all the immediate net benefit of DM relative to network augmentation. This may be a desirable approach, at least for a period, in order to stimulate NSPs to embrace widespread cost-effective DM (that otherwise may not occur at all). While this would deny customers a windfall associated with avoided network costs, customers would still benefit from avoided generation and retail costs on their bills, as well as enjoying any direct customer DM incentives and (uncosted) environmental benefits associated with DM programs.

The United Kingdom's Office of Gas and Electricity Markets (OFGEM) proposed in 2002 to allow distributors to retain the benefits of capital expenditure efficiency savings for a fixed period, rather than just up to the end of the regulatory period in which the investment occurred.⁸⁵

Capitalising DM-related expenditure (ie treating any DM opex as capex) was one of the options considered in the AEMC Power of Choice Review, through a potential new rule such as the one below:

*All expenditure relating to capital, either capital assets or expenditure which delays or defers the need for such capital asset must be treated the same in respect to power of the incentive and how such costs are treated at the regulatory resets.*⁸⁶

On its own, capitalising the value of demand management investments would not remove all the disincentives to carrying out demand management as discussed in section 2.5. Overcoming these barriers requires positive incentives, such as the provision of financial assistance in the form of loans from the CEFC. Together, these proposals could provide effective motivation for networks to undertake a more optimal level of DM.

While capitalising DM expenditure is possible and plausible, regulators may be uncomfortable with treating DM 'opex' as 'capex'. In this case, it is also possible to create a 'level playing field' by providing incentives for DM operating expenditure that act in a similar manner to returns on capital investment.

4.4 ALTERNATIVE OPTIONS FOR CEFC TO SUPPORT DM

There are a number of benefits to DM by NSPs, such as avoiding or deferring specific network investment, that are unlikely to be easily captured through DM undertaken by other parties. However, the success of the CEFC in offering finance to NSPs depends on factors outside of the CEFC's control, particularly in relation to establishing greater government policy certainty and accountability and in relation to treatment of DM expenditure and savings by the AER and other regulators. If both of these conditions are not met then the capacity of the CEFC to offer finance to NSPs for network DM is likely to be very limited.

In these circumstances, alternative options that the CEFC may wish to consider include:

1. Offering finance to electricity retailers to develop DM options to customers as a strategy to attract and retain customers.
2. Offering finance to electricity retailers to develop DM options for customers as an alternative to retailers using generation capacity or financial hedges to manage exposure to high peak prices in the wholesale market. However, in the short term, such offerings may be more attractive to the smaller retailers as it is understood that

⁸⁵ Office of Gas and Electricity Markets (UK), 2003, *Electricity Distribution Price Control Review: Initial Consultation*.

⁸⁶ Australian Energy Market Commission, 2012, *DSP and Profit Incentives for Distribution Network Businesses (Staff Paper, Fourth Stakeholder Reference Group Meeting, Power of Choice Review)*.



most of the large electricity retailers also have large generation portfolios which are likely to benefit from high wholesale price spikes associated with high electricity demand.

3. Offering finance to third party aggregators to develop products and attract end users to participate in demand side bidding into the wholesale electricity market, which has been proposed by the AEMC and is currently planned to begin in 2015. However, there still remains some uncertainty over how this function will be designed and how it will operate.

It is beyond the scope of this report to consider these options.



5 INTEGRATION WITH REGULATORY REFORM

There remains some uncertainty over the extent to which the proposed process of collaborative targets, reporting and incentives fits with the existing regulatory processes and current reform options. The following two sections set out firstly, how the process could integrate into the existing economic regulatory regime for the energy market, and secondly, how it could complement potential outcomes from the regulatory reform processes currently in train.

5.1 EXISTING ECONOMIC REGULATORY REGIME

The treatment of demand management projects in the current regulatory regime depends on whether the particular demand management project is included in the distributor's regulatory proposal for a regulatory control period.

If the NSP proposes a DM option in its regulatory proposal (as capital or operating expenditure, as did Queensland DNSPs Energex and Ergon in the current regulatory period) the business is able to recover the costs of implementing the DM option itself, but not any capital expenditures that might be avoided (e.g. network augmentation expenditure). (Note that this is an area nominated for potential reform by the AEMC Power of Choice Review – see Section 5.2).

If, however, the DM option was not included in the regulatory proposal, but was identified during the regulatory control period, then the direct costs of the option are not recoverable, but any savings from successful deferral or avoidance of capital expenditure are retained by the NSP until the next regulatory control period. Any deferred or avoided opex can be retained for a period of five years under the efficiency benefits sharing scheme (EBSS).

As most NSPs have not included substantial DM activity in their current regulatory proposals, any NSPs contemplating DM options (for example through access to CEFC finance) in these last two years of the regulatory control period would only be able to retain any savings from deferred or avoided capital expenditure that were achieved within the very short period before the end of the regulatory control period. Unless reforms are made to the treatment of DM activity for the next regulatory control period, the NSP will not be able to retain any capital expenditure savings in this next period. This is because it is expected that while DM costs might be incurred in this regulatory period, the deferred capital expenditure would occur in subsequent regulatory periods.

Therefore the way in which such projects are treated in the next regulatory period is crucial to the ability of the CEFC to recover investments.

According to PricewaterhouseCoopers, providing the required 'certainty of recovery of DM operating expenditure under an ongoing DM agreement would require a change to the Rules'.⁸⁷ Note however that the need for a rule change remains open to debate. The following sections discuss the reform opportunities in the lead up to the next regulatory control periods.

Upcoming regulatory control periods

There is an opportunity to influence how DM is treated in the next regulatory control period, and making use of this opportunity is crucial to CEFC being able to recover finance for any investments in network DM.

⁸⁷ Pricewaterhouse Coopers (PWC), 2012, *Incentives for network driven DSP*. Prepared for Energy Networks Association.



Table 10: Key dates for upcoming AER regulatory control periods by jurisdiction

	Network Regulatory Proposal due	Regulatory control period begins
NSW & ACT	31 May 2014	1 July 2015*
Qld & SA	31 Oct 2014	1 Dec 2015*
Vic	30 April 2015	1 June 2016*
Tas	31 Jan 2016	1 July 2017

* Note: NSW/ACT Regulatory control period commencement has been delayed by 12 months to 1 July 2015 (with 1 year transitional regulatory control period); Qld/SA and Vic regulatory control periods delayed by 5 months.

Source: AER five-year project calendar 2013-2017: Regulatory determinations.

Reporting of demand management activities

There are a number of sources which report on demand management activities carried out by network service providers. Some of these are individual reports by the DNSPs are required by regulation and others are aggregate reports by regulators, market operators and third parties.

Annual DMIA reporting to AER by NSPs

As part of their Regulatory Information Notice (RIN) responses to the AER, DNSPs are required to provide reports on their use of their DMIA allowance. The AER uses these DMIA reports to assess the expenditure against the DMIA criteria and approve the claims by the DNSPs.

As set out in paragraph 1.5 of schedule 1 of RIN, the annual report must:

- a. Provide an explanation of each demand management project or program for which approval is sought
- b. Explain, for each demand management project or program identified in the response to paragraph 1.5(a), how it complies with the DMIA criteria detailed at section 3.1.3 of the DMIS, with particular reference to:
 - i. the nature and scope of each demand management project or program,
 - ii. the aims and expectations of each demand management project or program,
 - iii. the process by which each demand management project or program was selected, including the business case for the project and consideration of any alternatives,
 - iv. how each demand management project or program was/is to be implemented,
 - v. the implementation costs of the project or program, and
 - vi. any identifiable benefits that have arisen from the project or program, including any off peak or peak demand reductions.
- c. Provide an overview of developments in relation to projects or programs completed in previous years, and any results to date.
- d. State whether the costs associated with each demand management project or program identified in the response to paragraph 1.5(a) are:
 - i. are not recoverable under any other jurisdictional incentive scheme,
 - ii. are not recoverable under any other Commonwealth or State government scheme, and



- iii. are not included in the forecast capital or operating expenditure approved in the AER's distribution determination for the current regulatory control period under which the scheme applies or under any other incentive scheme in that determination.
- e. The total amount of the DMIA spent in the previous regulatory year, and how this amount has been calculated.⁸⁸

The two most relevant parts of the above are reporting on the implementation costs of each project and 'any identifiable benefits that have arisen from the project or program, including any off peak or peak demand reductions'.⁸⁹ Analysis of the most recent reports by DNSPs shows that reporting in relation to this latter requirement varies greatly across DNSPs, partly because of the various life cycle stages of the projects being reported. Only two NSPs, for a total of three projects, report kW or kVA peak load reductions and no NSP included information such as deferred/avoided capex. A summary of reporting is shown in Table 11.

Table 11: Reporting by DNSPs of identifiable benefits of projects under DMIA

DNSP	Reporting
ActewAGL ⁹⁰	For the one project reported on, ActewAGL states: 'Since this project is under developing stage, no identifiable benefits have been achieved. The project has not yet entered the implementation phase.'
Ausgrid ⁹¹	For every project described, Ausgrid states: 'At this stage there are no material peak demand reductions achieved from this program' (even on previously approved projects).
Endeavour ⁹²	For one project, Endeavour provides a table detailing the average and peak kVA reduction from the project. For other projects, Endeavour indicated that results would be determined following the end of the projects.
Ergon Energy ⁹³	Ergon provides high-level indication of benefits from each project, such as 'Retain and Network Benefit Potential'. For some projects where data is available, Ergon provides % energy savings, and/or a kw or kva figure of maximum demand reduction recorded to date.
Essential ⁹⁴	For the one project reported on, Essential states: 'the technology benefits have been proven in the field installations, however actual business benefits will accrue when the technology is field proven and deployed as an enabler for peak reduction and reactive power support applications to avoid or defer network augmentation.'

There does not appear to be any other required reporting on demand management, such as DM activities carried out using sources of funding other than DMIA.

⁸⁸ Ergon Energy, 2012, *2011-12 Demand Management Innovation Allowance Annual Report to the Australian Energy Regulator*.

⁸⁹ *ibid.*

⁹⁰ ActewAGL, 2013, *Demand Management Incentive Scheme Power Factor Correction Project 2011-12*.

⁹¹ Ausgrid, 2012, *Demand Management Innovation Allowance Submission 2011-2012 Report to the AER*.

⁹² Endeavour Energy, 2012, *Demand Management Innovation Allowance 2011-2012 Report: Submission to AER*.

⁹³ Ergon Energy, 2012, *op cit.*

⁹⁴ Essential Energy, 2012, *Regulatory Information Notice (RIN) Supporting Information for Demand Management Innovation Allowance (DMIA) 2011-2012*.



New reporting requirements for NSPs under Network Expansion Framework

When information about the need for, and nature of, network investment is not provided in a timely and accurate way, it is more difficult for demand-side alternatives to be developed. DM service providers need sufficient time to consider the identified need, determine if DM can address the identified need, and determine the costs and benefits of participation.

In an effort to address this, the AEMC recently made a rule establishing a national framework for electricity distribution network planning and expansion, including new demand side obligations for distribution businesses.⁹⁵ This new rule requires the distribution businesses to have greater regard to DM potential, and to publish more information to help potential DM providers to identify DM opportunities and understand their value and operating requirements. Businesses will also be required to engage more with DM service providers.

The final rule consists of an annual planning and reporting process, and a distribution project assessment process. Three of key components of the final rule are as follows:

1. ***Distribution annual planning review***
The new rules replace current arrangements with a comprehensive and clearly defined annual planning process. All distribution businesses are required to conduct an annual planning review covering a forward planning period of five years. The planning review must include all distribution assets and activities undertaken by distribution businesses that would be expected to have a material impact on their networks. A comprehensive planning review will support the businesses in making efficient planning decisions.
2. ***Distribution annual planning report (DAPR)***
All distribution businesses must publish an annual planning report. The report will set out the outcomes of the annual planning review and will include information on: forecasts, including capacity and load forecasts; and system limitations. Public reporting on distribution business planning processes and activities will allow network users to make better informed and more efficient investment decisions.
3. ***Demand side engagement obligations***
The new rules introduce several demand side engagement obligations on distribution businesses, including a requirement to develop and document a demand side engagement strategy, and an obligation to engage with non-network providers and consider non-network options in accordance with this strategy. These requirements will encourage better engagement between distribution businesses and non-network providers, and provide greater transparency on how DNSPs assess and consider non-network options.⁹⁶

These new arrangements commenced on 1 January 2013. The AEMC notes that the impact of the Rules will depend on the extent to which demand side participants find the information useful. There is a definite possibility that the provided information may not be comprehensive enough to allow demand-side participants to understand the nature of the network problems that needs to be addressed. Further, demand-side participants may not be provided with sufficient time to propose legitimate alternatives. Both of these situations would reduce the utility of the new requirements.⁹⁷

⁹⁵ Australian Energy Market Commission, 2012, *Rule Determination: National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012*.

⁹⁶ Australian Energy Market Commission, 2012, *Distribution network planning and expansion framework (Information Sheet)*.

⁹⁷ Pricewaterhouse Coopers, 2012, *Incentives for network driven DSP*. Prepared for Energy Networks Association.



In addition to the above changes, the new Rule requires the AER to develop a Regulatory Investment Test for Distribution (RIT-D), which will replace the current regulatory test. This work by the AER is discussed in Section 5.2.

Non-NSP reporting of DM

Reporting on DM by parties other than NSPs is limited. The main instances are the AEMO National Electricity Forecasting and Statement of Opportunities Reports, the AER State of the Energy Market reports, and research reports by independent third parties.

- **AEMO National Electricity Forecasting Reports and Statement of Opportunities Reports**

The AEMO National Electricity Forecasting Reports present the results of a survey by the AEMO of demand response aggregators, network service providers (NSP), retailers and other market customers. Respondents are asked for confidential DM megawatt values that can be regarded as 'committed' or 'non-committed'. These values are then aggregated to create regional totals. In 2011, 207 MW of DM occurred, out of a maximum available of 243 MW. Forecasts for the coming summer are also reported, with approximately 303 MW reported as an 'even chance' for 2012–13 summer.⁹⁸

The most recent AEMO Statement of Opportunities Report (2012) does not contain anything specific on demand management in the wholesale market.

- **AER State of the Energy Market Reports**

The annual AER State of the Energy Market reports have a section on demand management. This section of the most recent report (2012) describes changes in the electricity market relating to demand management (such as the AEMC Power of Choice Review, DEMGCIS rule changes and roll out of smart meters through the Victorian Government initiative and Ausgrid's Smart Grid, Smart Cities project. No reporting of actual demand management activities is included.⁹⁹

However in an earlier section on demand side participation, the report summarises the information published by AEMO:

AEMO in 2012 identified 218 MW of capacity that was 'very likely' to be available across the NEM through demand side participation over the 2012–13 summer (up from 142 MW in 2011–12). It forecast annual growth in demand side participation of 3.2 per cent (for New South Wales) to 5.4 per cent (for Victoria and South Australia).

- **Independent research reports**

From time to time, research reports are published on demand management activity. Examples include the *Report of the 2010 Survey of Electricity Network Demand Management in Australia*¹⁰⁰ (some of the findings of which are presented in Section 2.1) and *Power of choice – giving consumers options in the way they use electricity: Investigation of existing and plausible future demand side participation in the*

⁹⁸ Australian Energy Market Operator (AEMO), 2012, *National Electricity Forecasting Report*.

⁹⁹ Australian Energy Regulator, 2012, *State of the Energy Market Report*.

¹⁰⁰ Dunstan, C., Giotto, N. & Ross, K., 2011, *Report of the 2010 Survey of Electricity Network Demand Management in Australia (SENDMA)*. Prepared for the Australian Alliance to Save Energy by the Institute for Sustainable Futures, University of Technology, Sydney.



electricity market.¹⁰¹ These types of reports are not institutionalised, and are therefore not comparable or consistent over time.

The current reporting practices for network DM will need to be improved in order to enhance understanding of DM practice in Australia and to allow for reliable network DM targets and/or financing for DM. Suggestions for reporting were discussed in Section 3.3.

Demand management incentive schemes

In 2008/2009 the AER developed two jurisdictional demand management incentives schemes (VIC, QLD/SA and NSW/ACT) to apply in the 2009–2014 regulatory control period. The DMIS provided upfront funding allowances to Distribution Network Service Providers (DNSP) to 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 expensive network augmentation. They involved two components: the AER's demand management innovation allowance (DMIA), providing payments for demand management related activities (as shown in Table 12); and the Independent Pricing and Regulatory Tribunal (IPART)'s D-factor scheme (for NSW).

Table 12: AER approved annual DMIA for DNSPs

DNSP	Regulatory control period	Approved annual DMIA allowance
ActewAGL (ACT)	2009-14	\$100,000
Ausgrid (NSW)	2009-14	\$1,000,000
Endeavour Energy (NSW)	2009-14	\$600,000
Essential Energy (NSW)	2009-14	\$600,000
Energex (Qld)	2010–15	\$1,000,000
Ergon Energy (Qld)	2010–15	\$1,000,000
SA Power Networks (SA)	2010–15	\$600,000
CitiPower (Vic)	2011–15	\$200,000
Jemena Electricity Networks (Vic)	2011–15	\$200,000
Powercor (Vic)	2011–15	\$600,000
SP AusNet (Vic)	2011–15	\$600,000
United Energy (Vic)	2011–15	\$400,000
Aurora Energy (TAS)	2012–16	\$400,000

Source: AER Decision 2010–11 and 2011 DMIS assessment.

The AEMC recognises that the current DMIS is not a 'true' incentive scheme which allows extra rewards, but an innovation allowance plus potentially an allowance for foregone revenue associated with certain DM projects¹⁰² which is essentially a costs pass-through scheme.

¹⁰¹ Futura Consulting, 2011, *Power of choice – giving consumers options in the way they use electricity: Investigation of existing and plausible future demand side participation in the electricity market (Final Report for the Australian Energy Market Commission)*.

¹⁰² Australian Energy Market Commission, 2012, *DSP and Profit Incentives for Distribution Network Businesses (AEMC Staff Paper for Session 1, Fourth Stakeholder Reference Group Meeting)*.



During the preliminary work conducted by AER last year in approving the DMEGCIS for NSW businesses, submissions from stakeholders on the 2008 demand management incentive scheme applying in the ACT and NSW noted that:

- The scheme failed to create sufficient incentives for long-term structural change.
- The lack of funding provided under the DMIA reduced its effectiveness.
- Demand side actions and technologies should be incentivised based on the actual reduction in electricity demand (particularly peak demand) it brings.¹⁰³

These comments echo submissions to the *Productivity Commission consultation*, which criticised DMIS because of its low uptake. As described in Section 2.1, it is currently estimated that only about 15% of the Demand Management Innovation Allowance has been spent to date.¹⁰⁴

A staff paper for the AEMC Power of Choice Review noted that:

*the Demand Management Incentive Scheme may not be the answer [to achieving an efficient level of DM]. If the underlying profit motivation towards DSP projects is not there, the increase in the size of the DMIA may need to be substantial to offset the underlying disincentive.*¹⁰⁵

In 2011, acting on a rule change request by the then Ministerial Council on Energy (MCE), the AEMC began the process of amending the DMIS to include embedded generation, with provisions of the 'Inclusion of Embedded Generation Research into Demand Management Incentive Scheme' final rule and final rule determination commencing on 22 December 2011.¹⁰⁶

In 2012, as part of the Regulatory Determination for 2014–2019 for NSW and ACT, the AER proposed amendments to its demand management and embedded generation connection incentive scheme (DMEGCIS) to apply to network businesses. The main changes are a name change, broadening of scope to include embedded generation and removal of the D-factor scheme. The proposed DMEGCIS to apply to the NSW DNSPs in the next regulatory control period would therefore function in the same manner as the DMIS in this regulatory period¹⁰⁷:

- Demand management innovation allowance provided as annual ex-ante allowance;
- DNSP able to recover revenue foregone that is directly attributable to approved non-tariff demand management projects. (Although this would not apply under a revenue cap, as there would be no foregone revenue.)

The AER delayed its final decision on the proposed DMEGCISs to allow the AEMC to finalise the Power of Choice Review so that recommendations for the DMEGCIS could be taken on board.

In March 2013, the AER released a DMEGCIS Information Paper, proposing that the previous reform process from 2012 be closed off, and that the current scheme be maintained for the current regulatory period, and for a one-year transition period in the

¹⁰³ Australian Energy Regulator, 2013, *Information Paper: Demand Management and Embedded Generation Connection Incentive Scheme*.

¹⁰⁴ Australian Energy Regulator, 2013, *Demand management incentive scheme assessment report 2011-12 (Non-Victorian DNSPs)*.

¹⁰⁵ Australian Energy Market Commission, 2012, *DSP and Profit Incentives for Distribution Network Businesses (Staff Paper, Fourth Stakeholder Reference Group Meeting, Power of Choice Review)*.

¹⁰⁶ Australian Energy Market Commission, 2011, *Rule Determination: National Electricity Amendment (Inclusion of Embedded Generation Research into Demand Management Incentive Scheme) Rule 2011*.

¹⁰⁷ Australian Energy Regulator, 2012, *Explanatory Statement: Proposed Demand Management and Embedded Generation Connection Incentive Scheme, New South Wales Distribution Network Services Providers*.



following regulatory period (for NSW and ACT). The AER would then begin work on a new scheme for the remainder of the following regulatory period. This work would begin as an informal consultation under the AER's Better Regulation Review, followed by a formal reform process once the AEMC process is completed. The proposed changes to the DMEGCIS are discussed in more detail below.

5.2 REGULATORY REFORM

Interacting with current reform processes is crucial to ensuring that the current and proposed regulatory arrangements are conducive to the proposed approach of financing and collaborative targets for network DM. This includes facilitating avoidance of unnecessary infrastructure investment, supporting demand management to reduce customer bills, and ensuring recovery of any funds provided by the CEFC in the following regulatory period.

A number of reforms to the energy market are currently in progress, including:

- *Power of Choice Review* by the Australian Energy Market Commission (AEMC) (recently completed)
- *Electricity Market Reform* by the Council of Australian Governments (COAG) through the Standing Council on Energy and Resources (SCER)
- *Better Regulation Review: Power of Choice workstream* on demand management by the Australian Energy Regulator (AER)

The proposed approach of CEFC investment in demand management and associated collaborative targets complements the recommendations made by the AEMC Power of Choice Review, and the reforms recently agreed to by COAG.

AEMC 'Power of Choice' package

The AEMC Power of Choice Review, conducted from March 2011 to November 2012, looked at potential changes to the National Electricity Market to help consumers better manage their energy consumption, as well as ways to encourage electricity companies to better facilitate consumer choice and to invest more efficiently. It was the third stage in a review of DM, which it referred to as demand side participation (DSP).

Stage 2 of the review focused explicitly on barriers in the National Electricity Rules for use of DSP, while Stage 3 had a broad focus, covering all electricity market frameworks (including electricity market arrangements and transactions that impact on the electricity supply chain, the Rules, other national and jurisdictional rules and regulations, and market behaviours) for facilitating investment in, and use of, DSP in the NEM.

The Power of Choice Review proposed a number of recommendations to the Standing Council on Energy and Resources (SCER) on required changes to the National Electricity Rules (NER) and broader market reforms. Two reforms proposed by the AEMC are of particular relevance to reducing perverse incentives to invest in additional infrastructure (sometimes referred to as 'decoupling'). The reforms are to:

- provide networks with an allowance for revenue foregone as a result of undertaking DM activities instead of traditional capex projects, and
- develop a set of pricing principles to guide network tariff structures.¹⁰⁸

¹⁰⁸ Wright, G., 2012, *Demand management targets for networks in the National Electricity Market*, (Discussion Paper). Total Environment Centre, Sydney.



In addition, the AEMC recommended changes to the application of the current demand management and embedded generation connection incentive scheme to provide an appropriate return for DM projects which deliver a net cost saving to consumers (including creating separate provisions for an innovation allowance), and a minor change to the National Electricity Rules (NER) that clarifies that AER can have regard to non-network market benefits when assessing efficiency of expenditure. These changes should result in a better equalising of capex and opex.

SCER has released a response to the recommendations, and is currently in the process of drafting a number of rule change requests (see below). Once the AEMC receives these rule changes requests, it will implement its normal consultation and deliberation process to amend the NER.

While reforming the NER and related requirements is crucial, it also takes time. Indeed, the Power of Choice Review recommendations may create Australia's most effective and comprehensive framework for avoiding costly and unnecessary electricity supply investment, just as Australia's biggest ever program of electricity supply investment is winding down.

There is therefore scope for a complementary, more collaborative approach for engagement with the industry in the meantime. Collaborative DM targets, reporting and incentives have the potential to enhance significantly the customer benefits of the DM reforms, and could do so in the current regulatory period up to and including 2015.

Moreover, the proposals discussed in this report would support the first recommendation of the Power of Choice Review Final Report, which states that:

A comprehensive communication/education strategy is developed to support implementation of the reforms recommended in this review, and to more broadly improve consumer understanding of energy use and relationship to costs.¹⁰⁹

Such a communication/education strategy would be much more effective if it were to engage the NSPs directly and if it were to be informed by a clear statement of what the NSPs (and government) are doing, are planning to do and could do for customers in the area of DM. Any such strategy that does not start from a position of what the electricity supply industry (and government) can do to reduce bills and otherwise help consumers will struggle to communicate effectively.

COAG and SCER energy market reform

The Council of Australian Governments' (COAG) Standing Council on Energy and Resources (SCER) is responsible for pursuing priority issues of national significance in the energy and resources sectors and for progressing key reform elements of the former Ministerial Council on Energy and the Ministerial Council on Mineral and Petroleum Resources.

SCER established an Energy Market Reform Working Group (EMRWG) to identify, consider and respond to priorities for energy market development, particularly focusing on some of SCER's Priority Issues of National Significance.¹¹⁰

The Energy Market Reform has a number of elements of relevance to demand management, discussed below.

¹⁰⁹ Australian Energy Market Commissions, 2012, *Power of Choice Review – Giving consumers options in the way they use electricity (Final Report)*.

¹¹⁰ Standing Council on Energy Reform, (no date), *Energy Market Reform (webpage)*
<http://www.scer.gov.au/workstreams/energy-market-reform/>



General Energy Market Reform workstream

In December 2012, the Council of Australian Governments (COAG) endorsed a package of national energy market reforms developed collaboratively by SCER to respond to the current challenges of rising electricity prices. The main element of the reform package relevant to demand side participation is around actions to reduce electricity peaks, specifically:

*Agreement to provide for greater demand-side participation to make it easier for consumers to reduce demand, particularly at peak periods, to minimise the need for new investment in energy infrastructure – drawing on the AEMC’s Power of Choice Review.*¹¹¹

SCER has stated that it will report to COAG specifically on the full set of Power of Choice Review recommendations in June 2013 (see below for further discussion).

In addition, the package includes elements around rule changes to limit over-investment in networks, including:

Commitment in-principle to a new national framework of best-practice reliability standards which give added weight to the interests of consumers and in-principle agreement to transfer reliability setting to the Australian Energy Regulator;

Early implementation of new rules that will ensure investment by network businesses is more efficient; and

*A public consultation process to improve the Limited Merits Review Regime to minimise the risk of ‘cherry-picking’ by network businesses while also ensuring review arrangements provide an effective back-stop for business.*¹¹²

As part of this, in January 2013, SCER asked the Australian Energy Market Operator (AEMO) to begin work to develop a new option for demand side resources to participate in the wholesale market for electricity, and to develop a new category of market participants for non-energy service provision.¹¹³

All of these reforms are important as they pave the way for a halt to real electricity price increases for many years to come. However, this power bill relief may come too late to avoid a critical loss in support and momentum for the Clean Energy Future package. Collaborative DM targets would complement the energy market reform process by identifying and delivering demonstrable savings to consumers in the short to medium term (in the current regulatory period) while reducing the risk of over-investment in network infrastructure, and building capacity for greater savings and more efficient investment in the next regulatory period, once the currently proposed regulatory reforms have been enacted.

The suggested approach of using the targets (where electricity network businesses volunteer to redirect a share of their capital expenditure into reducing peak demand growth and into assisting their customers to reduce energy consumption and energy bills) is particularly complementary to the reforms agreed to by SCER/COAG. Indeed, this approach could comprise a key element of recommendation 5.1.5 on ‘*balanced incentives for distribution businesses to implement efficient demand side options and to pursue innovative demand side solutions*’.¹¹⁴

¹¹¹ Prime Minister, Deputy Prime Minister, Minister for Resources and Energy, 2012, *COAG Reaches Agreement On Electricity Market Reform (Media Release)*.

¹¹² *ibid.*

¹¹³ Standing Council on Energy Reform, 2013, *Wholesale Market Demand Response in the National Electricity market (webpage)*, <http://www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/wholesale-market-demand-response-mechanism-in-the-national-electricity-market/>

¹¹⁴ Council of Australian Governments, 2012, *COAG Energy Market Reform – Implementation Plan*.



Reform to demand forecasting

As part of the above package of reforms, SCER agreed to task the AEMC with investigating the implications of differences between actual and forecast demand within the operation of the network regulatory frameworks by May 2013, and to task the Australian Energy Market Operator (AEMO) to develop demand forecasts which could be used by the AER to inform its future regulatory determination processes.¹¹⁵

In February 2013, SCER issued terms of reference for a review of demand forecasting to the AEMC. The terms of reference note that recent observations in demand suggest that there may be a sustained slowing of growth in peak demand and a decline in average demand. Given that changes in demand, particularly peak demand, have implications for the cost of providing network services to consumers, SCER has asked the AEMC to investigate the implications of differences between actual and forecast demand within the operation of the existing incentive-based network regulatory frameworks.

SCER also asked the AEMC to provide advice on:

- the merits of the Australian Energy Regulator (AER) considering differences between actual and forecast demand when undertaking network determinations for transmission and distribution network service providers; and
- whether any changes to the current NER are needed to ensure the benefits of any sustained reductions in demand flow through to consumers, including but not limited to the AER's ability to consider previously approved capital expenditure and improvements to NER around annual network tariff setting.

The AEMC was asked to provide the advice by 31 March 2013, but details have not yet been published.¹¹⁶

Response to AEMC Power of Choice Review recommendations

As part of SCER's report to COAG in November 2012, SCER committed to providing to COAG in June 2013 a report on the full set of Power of Choice Review recommendations.

In March, SCER released a response to the Power of Choice Review recommendations.¹¹⁷ In relation to the two main recommendations on distribution network incentives from Chapter 7, recommendations, both of which involved submitting a rule change proposal to the AEMC based on draft specifications in the Power of Choice Review Final Report, SCER agreed 'in principle'. SCER must now develop and submit these rule change requests.

No indication of timeframes has yet been given for this. Once requests are received by the AEMC and decisions are made, the AER will be tasked with operationalising the rule change. The section below discusses the corresponding AER reform process.

The other relevant decisions by SCER relate to flexible (ie. time of use) pricing, including rollout of smart metres in defined situations (ie new connections, refurbishments and replacements) and time of use tariffs for residential and small business consumers. In both cases, the AEMC recommended that SCER submit a rule change request requiring these in certain situations. In both cases, SCER decided that it should be left up to each jurisdiction (ie. state) to decide if and when smart meters or time-of-use pricing should be required.

¹¹⁵ Standing Council on Energy Reform, 2012, *Electricity: Putting Consumers First*.

¹¹⁶ Australian Energy Market Commission, 2013, *Market Review (Open): Differences between actual and forecast demand in network regulation (webpage)*, <http://www.aemc.gov.au/market-reviews/open/differences-between-actual-and-forecast-demand-in-network-regulation.html>

¹¹⁷ Standing Council on Energy Reform, 2013, *SCER Response to the Power of Choice Review*.



Time-of-use pricing - and associated time-of-use meters - are a potentially important element of promoting DM. If the implementation of these is to be left up to jurisdictions, and via jurisdictions, and therefore utilities themselves, to make the call on, then incentives in the form of CEFC finance may be able to facilitate this. For example, CEFC finance could help expedite time-of-use pricing where it makes sense by facilitating the rollout of time-of-use meters which are essential in time-of-use pricing.

AER 'Better Regulation Review'

In response to the changes to the National Energy Rules announced by the Australian Energy Market Commission at the end of November 2012 following the AEMC Power of Choice Review, and the further forthcoming rule change requests by SCER, the AER has started a process for reform under their Better Regulation Review. The AER described the Review as 'a program of work that will deliver improved regulation focused upon the long term interests of consumers'.

The AER describes the purpose of the Power of Choice workstream as 'Ensuring network companies are innovating and exploring demand management solutions'.¹¹⁸ The workstream will explore how best to adapt AER regulatory processes to make a positive contribution to increasing demand management. Specifically, the workstream has three components:

1. Network incentives, including the Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS) – arising from the AEMC Power of Choice Review.
2. Regulatory investment test for distribution (RIT-D) – arising from the Expansion Network framework rule determination.
3. Efficient and flexible network pricing – arising from the AEMC Power of Choice Review.

The latter two of these components are dependent on rule changes by the AEMC not yet in progress, so the initial focus of the workstream will be on contributing to the AEMC rule change processes.

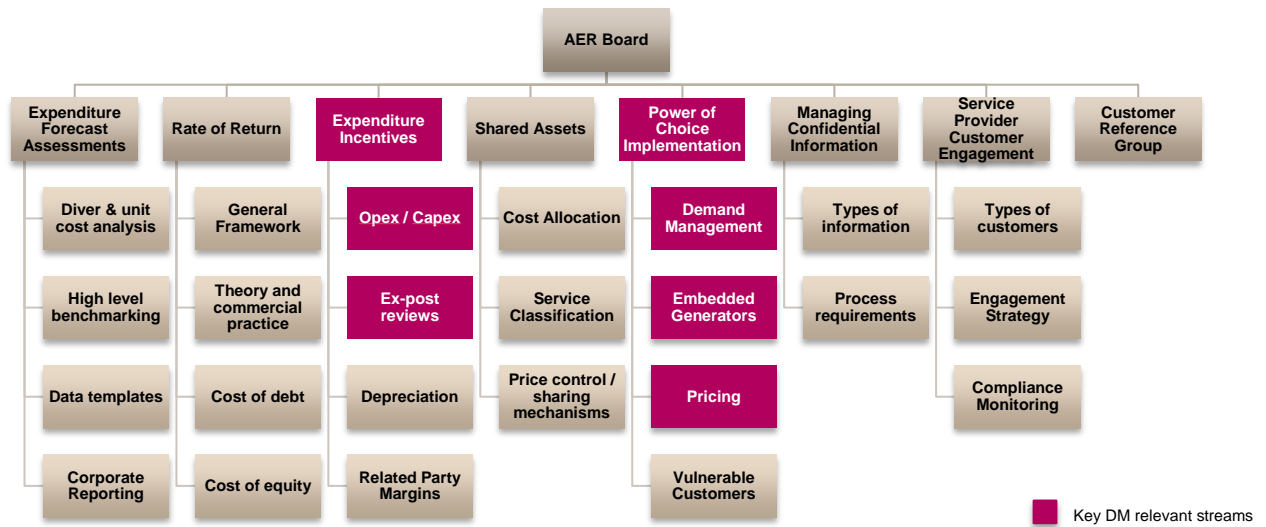
In addition, a separate stream of the Better Regulation Review, 'Expenditure Incentives' is reviewing existing incentives for efficient capex. Part of the review is to move towards neutrality between capex and opex incentives.

The two relevant streams of the Better Regulation Review are shown in Figure 24.

¹¹⁸ Australian Energy Regulator, 2012, *Better Regulation Reform Program (webpage)*, <http://www.aer.gov.au/node/18824>



Figure 24: AER Better Regulation Review workstreams



Source: AER website.

Each component and its relevance to the proposed package of targets, reporting and incentives is discussed below.

Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS)

One of the AEMC Power of Choice Review recommendations was for the National Energy Rules (NER) to be amended to reform the application of the current DM and Embedded Generation Connection Incentive Scheme (DMEGCIS) so that it:

- a) provides an appropriate return for DM projects that deliver a net cost saving to consumers; and
- b) better aligns network incentives with the objective of achieving efficient demand management.¹¹⁹

The AEMC proposed to SCER that this recommendation be implemented through a rule change which adds more principles and criteria for the application of the demand management incentive scheme. The rule change would also include an objective to clarify the purpose of the incentive scheme – that is, to correctly incentivise the network businesses to develop and pursue DM options as an efficient alternative to capital investment.

In March 2013 AER initiated informal consultations, through the publication of an Issues Paper on DMEGCIS¹²⁰, to allow it to participate in the upcoming AEMC Rule Change process. AER will then initiate a formal consultation on applying a demand management incentive scheme to ACT/NSW Distribution Network Service Providers (DNSPs) as part of the next distribution determination process.

The Issues Paper sets out the AER’s proposed approach to consulting on the form of any new demand management and embedded generation connection incentive scheme (DMEGCIS), and to applying a demand management incentive scheme to ACT/NSW DNSPs during their next regulatory control periods. Their proposal is to maintain the

¹¹⁹ Australian Energy Market Commissions, 2012, *Power of Choice Review – Giving consumers options in the way they use electricity (Final Report)*.

¹²⁰ Australian Energy Regulator, 2013, *Information Paper: Demand Management and Embedded Generation Connection Incentive Scheme*.



existing DMIS/DMEGCIS for the first year of the new regulatory period (the transitional regulatory period, 1 July 2014 – 30 June 2015), and then to introduce a new DMEGCIS during the determination for the subsequent regulatory determination period (1 July 2015 – 30 June 2019).

As guidance for coming up with a new scheme, the AER will use the draft specifications in the AEMC's Power of Choice Review Final Report and any draft rule change proposals that may be under consideration. The specifications which could be adopted include such elements as:

- permitting the network businesses to retain a share of the non-network related market benefits arising from the DM option
- allowance for foregone profit for any DM-approved activities
- allowance for performance indicators and reporting guidelines developed by the AER.

Further, the AER is allowed to maintain the Demand Management Innovation Allowance. As discussed in Section 5.1, and as acknowledged by AER, this is quite limited in scope (currently providing around \$1 million or less for most networks, as shown earlier in Table 12). The AER is currently considering the benefits of maintaining an 'innovation' allowance if better DM incentives are provided.

In the Issues Paper, the AER proposed the following timeframe for ACT/NSW DNSPs:

Transitional regulatory control period:

- ACT/NSW DNSPs submit transitional regulatory proposal by 31 January 2014,
- AER makes transitional regulatory determination by 30 April 2014.

Subsequent regulatory control period:

- Stage 2 of the Framework & Approach paper published in January 2014, including information on any demand management incentive scheme (Stage 1 was published March 2013),
- ACT/NSW DNSPs submit regulatory proposal in May 2014,
- AER makes draft determination due in November 2014,
- AER makes final determination due in April 2015.

It is clear from the above timeframes that the next year is crucial for inputting into reform of DMEGCIS, to ensure that it is effective in encouraging DNSPs to adopt a more efficient level of DM in the next regulatory period.¹²¹ However, as the new DMEGCIS will not take effect until 2015, initiatives to encourage DM activity by DNSPs in the intervening years remain crucial.

In addition to the formal Incentive Scheme, the AEMC Power of Choice Review also recommended that the AER be allowed to consider broader upstream and downstream market benefits (ie additional to any network expenditure savings – for a distribution NSP, this implies a share of the cost reductions at the transmission and generation levels) resulting from DM activities by NSPs. As part of refining incentives, the AER may explore whether the presence of these broader market benefits presents a case for allowing DNSPs, at the regulatory proposal stage, to retain capital expenditure savings resulting from DM options, something they are presently unable to do.

¹²¹ Note ISF has been commissioned by TEC using funding by National Electricity Consumer Advocacy Panel to advise on options for reform of the DEMGCIS.



One way of allowing DNSPs to be able to do this would be to create an incentive scheme that provides NSPs with a (financial) share of the broader benefits created by a DM initiative – similar to the way the Service Target Performance Incentive Scheme (STPIS) permits distributors to retain a share of the customer benefits from reliability improvement. Doing so would mean that the incentives for the network business were better aligned with the interests of all NEM players.¹²²

Given that DM expenditure is generally operating expenditure, and most of the savings derive from avoided or deferred capital expenditure, the ability of NSPs to capture the value of avoided capex in the next regulatory period would provide NSPs with the ability to recover the costs of these DM options. From the CEFC's perspective, this would provide the key source of savings for NSPs to repay finance from the CEFC.

Regulatory investment test for distribution (RIT-D)

Electricity distribution companies undertake numerous investment projects each year to augment parts of their networks. The AEMC's Final Rule Determination, 'Expansion Network framework', requires the AER to develop and publish a new Regulatory Investment Test for Distribution (RIT-D) to replace the current regulatory test for distribution projects. The RIT-D is designed to take place before significant distribution network investment decisions are made and will apply to all projects over \$5 million.¹²³

The AER aims to develop the RIT-D in a way that ensures RIT-D proponents duly assess all credible options (including both network and non-network options) before choosing the most cost-effective option available to meet consumer demand. Application guidelines will be developed by the AER to guide RIT-D proponents in applying the RIT-D, and will include a specific methodology for valuing classes of benefits. The aim is to enhance transparency and consistency in investment decision-making.

The effectiveness of the RIT-D in facilitating DM will depend on how the guidelines are written, including whether and how 'benefits' are assessed. In any case, if NSPs do not face balanced incentives for undertaking DM then the effectiveness of the RIT-D in encouraging efficient uptake of DM will be limited. Furthermore, the RIT-D will only apply to projects over \$5m and evidence to date shows that there are (and are likely to continue to be) many projects that fall under this threshold.

An issues paper was released by the AER in January 2013, followed by public submissions in February 2013. The final RIT-D and its application guidelines will be released by 31 August 2013.

Distribution network pricing rules

The AEMC has proposed changes to pricing principles to ensure prices are cost reflective. This includes requiring more consultation to give retailers and consumers more control in developing pricing tariffs (particularly the structure/nature of tariffs).

As discussed above, SCER's decision regarding specific recommendations regarding flexible (ie. time-of-use) pricing was to leave control over pricing models to jurisdictional governments. They have however, agreed 'in principle' to changes to the pricing principles and have agreed to submit a rule change proposal to the AEMC. From the AER's point of view, the reforms to efficient pricing in the Rules should result in more detailed pricing reviews. The AER will likely also have an expanded role to advise on pricing principles and set out detailed guidelines on how the consultation with retailers and consumers will need

¹²² Pricewaterhouse Coopers, 2012, *Incentives for network driven DSP*. Prepared for Energy Networks Association.

¹²³ Australian Energy Regulator, 2013, *Regulatory investment test for distribution (RIT-D) and application guidelines (webpage)*, <http://www.aer.gov.au/node/19146>



to occur. The AER plans to participate in the AEMC consultation following submission of the rule change request.

These more cost reflective tariffs could play out in different ways. For example, as some networks have invested heavily in network infrastructure, there may be a temptation to shift charges from volume related components into fixed charge components. This would likely reduce consumers' capacity to reduce bills through energy savings and therefore reduce their level of interest in DM programs. While shifting to higher fixed charges may help secure NSP revenues in the short term, it would also have equity impacts on vulnerable consumers and could in the drive customers to disconnect from the grid thus eroding NSP revenues in the longer term.

On the other hand, flexible pricing may encourage DM by promoting more peak focussed cost-reflective Time of Use (TOU) tariffs.

Expenditure Incentives Review

In addition to the work being undertaken under the Power of Choice workstream, the AER is also developing expenditure incentive guidelines, as required by the revised National Electricity Rules.¹²⁴

These guidelines will set out how the AER will improve incentives for electricity network businesses to ensure efficient capital expenditure, so customers only fund the investment necessary to provide a safe and reliable network. As part of this, the AER is also reviewing the incentives for efficient operating expenditure. In particular, it is considering revisions to the current efficiency benefit sharing scheme that applies to the approach network businesses take to expenditure assessments.

The review aims to address the following issues with the current capex incentives:

- The imbalance between capex and opex incentives
- The incentive for efficient capex declines over the regulatory control period, encouraging overspending in later years
- That NSPs can choose to ignore the incentive of obtaining revenue savings, knowing that any capex spend will ultimately be rolled into the Regulated Asset Base, with the majority of future/ongoing costs being passed onto consumers.

An issues paper was released in March 2013, with stakeholder consultations expected to finish by late May 2013. Guidelines are expected to be finalised by November 2013.¹²⁵

The issues paper addresses both 'ex ante' measures put in place at the beginning of a regulatory control period to properly incentivise efficient capex, and 'ex post' measures to apply at the end of a regulatory control period, to correct for inefficient capex spending. The AER has expressed its preference for ex ante measures to remain the principal method for incentivising, but is proposing to consider ex post measures where a significant capex overspend has occurred and where the ex post assessment has uncovered clear cases of inefficiency or imprudent behaviour by the NSP.

The AER's proposal for the primary capex ex ante measure is a continuous, asymmetric Capital Expenditure Sharing Scheme (CESS). The continuous nature of the scheme would ensure constant incentives in each year of the regulatory control period, and the asymmetric nature (e.g. greater penalty than reward) would provide stronger protection for

¹²⁴ Australian Energy Market Commission, 2012, *Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule*.

¹²⁵ Australian Energy Regulator, 2012, *Expenditure incentives guidelines (webpage)*, <http://www.aer.gov.au/node/18869>



consumers. The reward for underspending by NSPs would be 20–30%, while the penalty would be greater than 30%.¹²⁶

The combination of a Capital Expenditure Sharing Scheme with a change to allow NSPs to retain capital expenditure savings resulting from DM options (broader upstream and downstream market benefits), would enable NSPs to retain savings for a period of five years regardless of how late in the regulatory determination period the DM activity occurred. This would strengthen the ability of NSPs to recover costs of DM activities, and enable them to use this as a source to repay CEFC finance.

¹²⁶ Australian Energy Regulator, 2013, *Expenditure incentives guidelines for electricity network service providers; Issues paper*.



6 BENEFITS FOR CONSUMERS

6.1 IMPACTS ON PRICES AND BILLS

The principal benefits for consumers of increasing the amount of demand management in electricity systems are a reduction in the amount of investment in building and maintaining electricity networks, and increased efficiency of the existing network. The cost of network investment is recovered from electricity customers at a regulated rate that is determined by the Australian Energy Regulator. This is then passed through the electricity retailers and then customers as a component of their electricity tariff. Network costs have increased so much in recent years that they now make up an average of over 50% of the regulated electricity tariff (see Section 2.2).

Network costs are predominately fixed capital costs that must be recovered from the available customer base over the long term. This means that in the short term we can have the perverse situation of diminishing total electricity demand leading to higher electricity prices, because the cost of the network is being recovered from a smaller volume of electricity consumption. However, provided the DM activity is cost-effective – that is, provided the cost of DM is lower than the incremental cost of supply, increasing DM will lower overall energy bills. However the benefits of DM will not be evenly spread – DM program participants will benefit more than non-participants. It is therefore crucial that DM programs are designed with equity impacts in mind. It is also crucial that DM programs are focused on times and places of capacity constraint in order to maximise the cost savings for consumers.

6.2 SPREADING OF COSTS OF PEAK DEMAND

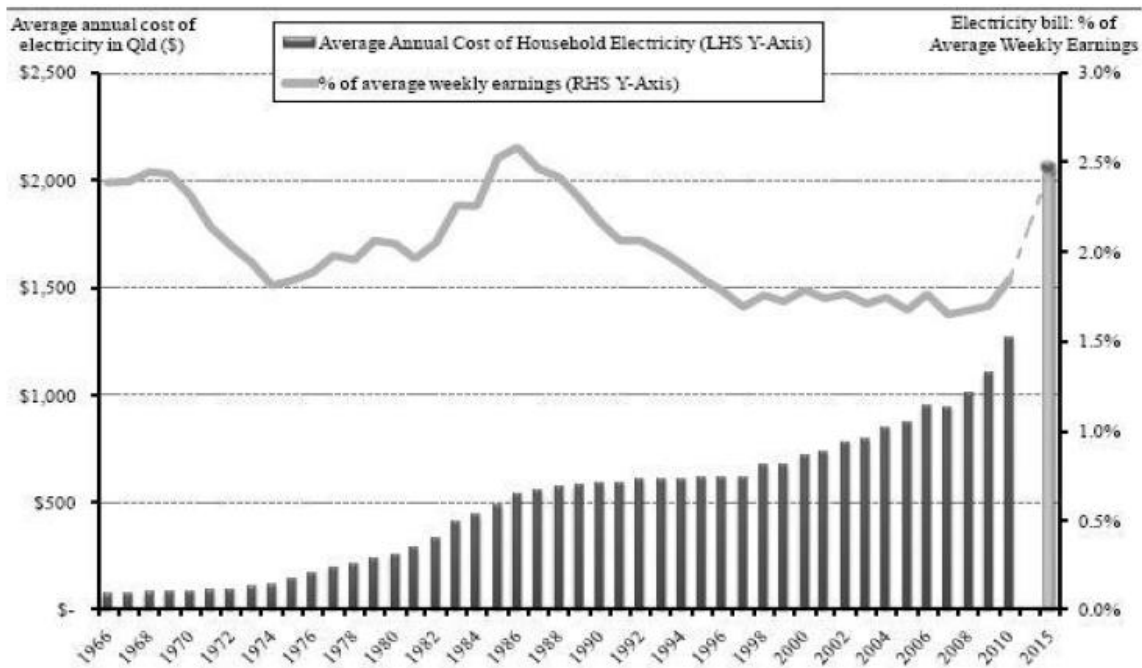
This also raises significant equity issues with electricity bills as all electricity customers must pay for the increased network through network charges, even though individual customers will have different contributions to peak demand. Low-income households tend to pay a higher proportion of their income in electricity bills than do high-income households.

From the mid-1990s to 2010 electricity bills represented less than two per cent of average weekly household earnings. This share has since been rising and is projected to grow to 2.5 per cent by 2015, as shown in Figure 25. For some households however, electricity bills can represent a much greater proportion of weekly income. IPART estimates that 12 per cent of NSW households will face bills that are greater than six per cent of their disposable income.¹²⁷ Consequently, the adverse impacts of recent electricity bill and price rises have fallen disproportionately on vulnerable consumers. This is a further reason to ensure there is an equity dimension in DM programs design. While cost-effective DM can reduce average electricity for all customers, it is important to consider the equity impacts of specific DM programs to ensure these benefits are equitably shared.

¹²⁷ Independent Pricing and Regulatory Tribunal, 2011, *Changes in regulatory electricity prices from 1 July 2011 – final report*.



Figure 25: Average annual electricity bill vs. average weekly earnings



Source: Simshauser & Downer, cited in *Power of Choice Review Directions Paper*, 2012, Australian Energy Market Commission.

6.3 POTENTIAL COSTS SAVINGS

Electricity networks are long-lived assets with high capital intensity. They require a rate of return that can attract the capital necessary for their operation. So while prices and bills can rise rapidly when capital expenditure surges, as it has done recently, reducing prices and bills will take typically take an extended period, (unless assets are written off or the regulator reduces the rate of return).

Increasing the amount of cost-effective demand management in the electricity system, by placing a DM target on the electricity networks and offering financial incentives, will reduce peak demand and network costs. However, there are likely to be short-term costs to the networks to meet these targets. These short-term costs will be outweighed by downward pressure on both electricity generation and network costs over the longer term.¹²⁸

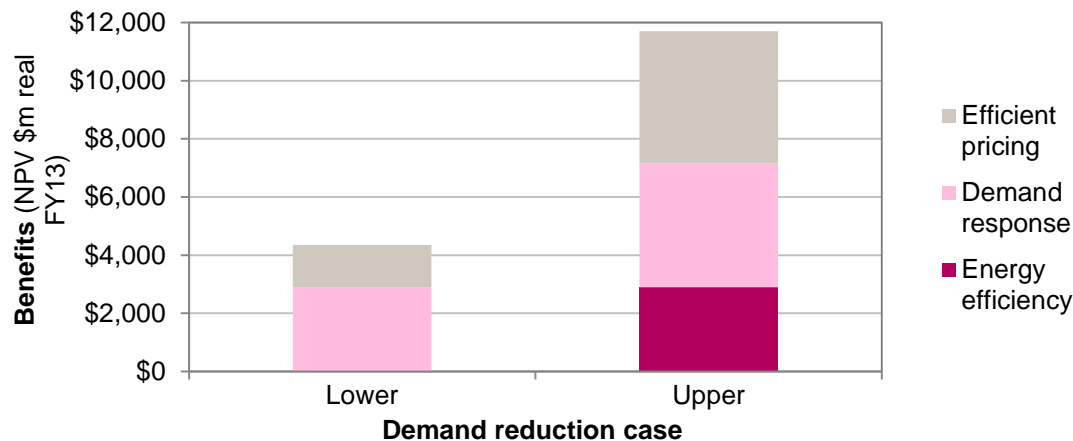
In the recent AEMC Power of Choice Review into demand side participation, Frontier Economics (consultants to the review) established that the economic cost savings of peak demand reduction in the period 2013/14 to 2022/23 will be between \$4.3 billion and \$11.8 billion.¹²⁹ This equates to between 3% and 9% of the forecast expenditure on the supply side of the NEM, with the majority accruing to electricity networks.¹³⁰ The upper and lower ranges of these figures and their composition are shown in Figure 26. The main contributing factors underlying the two scenarios are demand-based pricing (efficient pricing and demand response) and energy efficiency.

¹²⁸ Oakley Greenwood. 2012. *Policy options for maximising downward pressure on electricity prices*. Prepared for The Australian Industry Group, Brotherhood St Laurence, CHOICE and the Energy Efficiency Council.

¹²⁹ Australian Energy Market Commission, 2012, *Power of Choice Review - Giving consumers options in the way they use electricity (Final Report)*.

¹³⁰ *ibid.*



Figure 26: Absolute total benefit of demand reduction in the NEM 2013/14 to 2022/23

Source: *Power of Choice Review (Final Report)*, 2012, AEMC.

6.4 FLOW THROUGH TO CUSTOMERS

Assuming these cost savings are passed through to customers, the proportion of network charges in electricity tariffs should fall as the need for network augmentation to meet peak demand falls. The extent of the savings to customers will be different across jurisdictions of the NEM, with regions with strong peak demand growth expected to benefit the most. For the AEMC review, Frontier Economics forecast savings of approximately \$500 per customer per annum in South Australia and Queensland, \$350 in New South Wales and \$120 in Victoria.¹³¹

Increased peak demand management will also have implications for the price of electricity generation. If peak demand decreases and electricity consumption in peak times is shifted to other times this has the impact of flattening the demand curve.¹³² The price of electricity generation is determined in half-hour blocks on a bidding process. Fewer periods of peak demand, and therefore fewer half-hour periods of very high electricity generation prices in the wholesale electricity market (prices can go as high as \$12,500 per MWh) will lead to an overall reduction in the average wholesale price of electricity. This also flows through to customers in the form of a reduced electricity generation component in their electricity tariff.

Peak demand targets would not by themselves ensure reductions in network investment, only that peak energy savings are achieved. Network augmentation may not be avoided despite these savings for a number of reasons, as outlined by NERA Consulting:

- *there might be insufficient peak demand savings in locations where network augmentations are required; or*
- *the network business is not confident that planned non-network approaches will in practice avoid anticipated growth in peak demand and so undertakes the network augmentation so as to not breach system security requirements.*¹³³

¹³¹ Australian Energy Market Commission, 2012, *Power of Choice Review - Giving consumers options in the way they use electricity (Final Report)*.

¹³² NERA Consulting, 2012, *Peak Energy Savings Scheme Design Options: A Report for the Energy Savings Initiative Secretariat*, Prepared for the Commonwealth Department of Resources, Energy and Tourism.

¹³³ *ibid.*



It is therefore important that any DM incentives and targets are carefully designed to recognise the differing circumstances for NSPs. Some networks have major investment programs relating to replacing aging assets or implementation of government directed reliability standards (such as in Queensland and NSW).

These issues further highlight the need for reform to address barriers to demand management investment and to ensure that cost-effective peak demand savings and associated network augmentation deferrals are achieved.



7 STAKEHOLDER ENGAGEMENT

7.1 INITIAL ENGAGEMENT

As part of this scoping study, preliminary consultations were undertaken with a range of key stakeholders, including: senior representatives of distribution NSPs in Queensland, NSW, Victoria, South Australia and Western Australia; the Energy Networks Association; the Australian Energy Regulator; the Australian Energy Market Commission; and the Federal Department of Resources Energy and Tourism.

In each case the stakeholders were given commitments that none of their comments would be directly quoted or attributed. In most cases, the stakeholders noted that the comments offered were on an informal basis and did not necessarily represent the official position of their organisation. Moreover, most stakeholders indicated that to elicit an official response from their organisation would involve a process and timeframe which would be outside the scope of this project.

The consultations found an unprecedented level of interest on the part of regulators, and the federal government policy department, in tapping DM opportunities.

The response from NSPs has been mixed. There is a strong recognition among some NSPs that DM needs to, and is likely to, play a major role in the future of the electricity supply industry. This recognition extends to an interest in learning more about the potential for accessing finance to support DM. However, there is a greater interest in the potential for clarification and reform of the regulatory system in order to facilitate network DM expenditure.

It has emerged that AER is a key agent in the further development of the potential for financing for DM. If the AER provides clarification that cost-effective DM expenditure undertaken in the current regulatory period **can** be offset against avoided supply side investment in the next regulatory period without reform to the regulations, then there is significant potential for interest on the part of NSPs in accessing finance to expand DM activity in the current regulatory period.

On the other hand, if the AER indicates that the question of offsetting DM expenditure against future capital expenditure can only be addressed in the context of the current regulatory reform process, there are two sub-options. Firstly, this question could be resolved in the next few months through the reform consultation process around. Secondly, the issue could be resolved over a longer period in the lead-up to the next regulatory period which comes into effect from July 2015 (in NSW, ACT, Queensland and South Australia). In this last case, there would be little opportunity for the CEFC to offer finance for networks for DM in the current regulatory period.

The second key agent is the federal and state governments through the Standing Committee on Energy and Resources (SCER) which has a role of clarifying the policy intent in relation to network DM. If governments make the delivery of cost-effective DM a priority, for example by engaging with the NSPs to set collaborative targets for DM, then the NSPs are much more likely to expand DM activity in the short term. In the absence of policy leadership, the uptake of finance for DM by NSPs is likely to be low.

The third agent that is crucial to the success of finance for DM is the NSPs themselves. Based on preliminary consultations, there is a growing interest in the potential for network DM activity, both as a risk management strategy and as a business development opportunity. The NSPs, like the AER, seem to expect DM to play a much greater role in the next five-year regulatory periods. However, at this stage it is difficult to discern a clear view of the level of NSP interest in finance for DM in the current regulatory period.



Clarifying either regulatory and/or policy intent as described above is likely to have a significant impact on the potential appetite of NSPs for financing network DM.

7.2 FURTHER ACTIONS FOR STAKEHOLDER ENGAGEMENT

In the context of the above findings, the key next steps in developing the opportunities for network DM finance are:

1. Engage in the current AER reform process to seek clarification of the treatment of DM expenditure in relation to offsetting network augmentation capital expenditure.
2. Inform policy makers of the potential for network DM and the importance of setting clear policy directions relating to the adoption of all cost-effective DM, and of the need for clear NSP targets and accountability.
3. Engage with NSPs in relation to the potential for DM, the AER reform process and potential for financial support as a precursor and complement to regulatory reform.

This broader engagement would include stakeholders additional to those already consulted for this scoping study in electricity networks and regulatory institutions and include state and Commonwealth Government energy policy makers, the demand management industry and their advocates and consumer representatives.



8 CONCLUSIONS AND NEXT STEPS

This scoping study was commissioned by the CEFC to investigate options to accelerate demand management investment within the Australian electricity system, and in particular, the option of CEFC investment in demand management activities by network service providers. The role of the CEFC is to facilitate financial flows into the clean energy sector, and thereby accelerate the adoption of electricity sources with lower carbon intensity.

This report of the scoping study establishes a rationale for CEFC interest in DM and develops a possible model for investment, which has been tested with some key stakeholders. Further work is needed to test and operationalise the model with a wider range of stakeholders and better place it within the CEFC investment framework, and the wider energy regulatory and policy environment. This is highlighted in the 'Stakeholder engagement and next steps' section at the end of these conclusions.

Key Findings

DM is under-utilised in Australia

Demand management, has significant potential to reduce carbon emissions from the electricity system and provide cost savings to consumers and the wider economy. This report highlights the extent of the under-utilisation of demand management in Australia. While network DM has expanded in recent years, it still only provides the equivalent of a small fraction of the generation capacity in the NEM. The majority of current DM projects were in load management initiatives such as power factor correction, direct load control and stand-by generators. The use of energy efficiency and distributed generation projects for network DM appears to be minimal.

DM offers significant opportunities for costs savings on electricity bills

Electricity bills are now of major political and public interest after dramatic real price increases in the past five years of about 70% across the country. Electricity network charges are the main driver of electricity bill increases; these charges now make up half of an average Australian electricity bill.¹³⁴ The massive increase in electricity infrastructure investment is in turn driving the increases in network charges; more than \$40 billion is being invested on electricity distribution and transmission networks within the current five-year regulatory period.¹³⁵ This level of investment exceeds that of the National Broadband Network (NBN) and will be expended over a shorter time period and warrants a greater level of scrutiny.¹³⁶

The Australian Energy Market Commission (AEMC) projects that demand management activities targeted at peak demand reduction could generate savings to the economy of \$4.3 billion to \$11.8 billion over the next ten years. This equates to between three and nine per cent of total forecast expenditure on the supply side, and is likely to produce savings to consumers ranging between 'approximately \$500 per consumer per annum (in South Australia and Queensland). In NSW, the savings per consumer is expected to be around \$350 per annum ... [and] in Victoria, around \$120 per consumer per annum.'¹³⁷

¹³⁴ Department of Resources, Energy and Tourism, 2012, *Electricity Prices (factsheet)*

<http://www.ret.gov.au/Department/Documents/clean-energy-future/electricity-prices-factsheet.pdf>.

¹³⁵ Langham et al., 2010, *Building Our Savings: Reduced infrastructure costs from improving building energy efficiency*. Institute for Sustainable Futures, University of Technology Sydney.

¹³⁶ *ibid.*

¹³⁷ Australian Energy Market Commission, 2012, *Power of Choice Review - Giving consumers options in the way they use electricity (Final Report)*, p.8.



Excessive electricity network investment impacts clean energy investments

Significant levels of network spending are likely to crowd out and diminish business opportunities for clean energy by creating sunk costs that can then no longer be avoided by DM measures. More broadly, the continued investment represents a risk to electricity customers, state governments, and private and institutional shareholders. The risk is that these new investments may not remain viable for their full term of their expected economic lifetimes.

Other emerging technological and business model opportunities, including the falling cost of solar PV and battery storage, the increasing penetration of advanced meters and time of use pricing, the rising take-up of electric vehicles and the expanding potential of smart energy management applications, will likely present investment opportunities for the CEFC. These investments will also be negatively impacted by continuing sunk costs of investment in electricity supply and in particular network infrastructure, adding to the incremental cost of developing and deploying clean energy technologies.

Financial incentives can help remove barriers to NSPs taking up DM

Analysis presented in Section 2 shows that there are a number of interrelated barriers that prevent NSPs from wider adoption of DM. These barriers include: information barriers; split incentives; payback gaps; externalities and price structures; regulatory barriers; and cultural/ practice inertia. While NSPs generally have well-established access finance for network investment, this access has seldom been used to support DM activities. Evidence from Australia and overseas indicates that, where it is supported by clear policy intent and well-designed regulation, finance incentives can be a powerful tool to overcome these barriers to DM.

Performance targets are an effective tool to increase DM activities

Section 3 and the Appendix C demonstrate from available international evidence the ability of demand management targets and incentives to increase DM activities. These international precedents highlight the success of combining obligations (performance against some measured target) and incentives to encourage the widespread adoption of demand management activities. Section 4 takes these precedents further and highlights how such a system of 'collaboratively' derived targets for DM could be used in Australia. Stakeholders contacted as part of the preparation of this report showed an high level of interest on the part of regulators and federal government policy departments in tapping DM opportunities. The response from NSPs has been more mixed.

Creating a secure environment for DM investment

If the CEFC were to invest successfully in DM, a number of external conditions would need to be met. These conditions relate to policy direction, regulatory certainty and NSP commitment to undertake DM. To provide financial support for network DM, the CEFC would need to be confident that it would be able to recover its investment, including returns to cover the CEFC's cost of funds.

Policy conditions – clear policy intent from federal and state governments

If governments make the delivery of cost-effective DM a priority, through for example, engaging with the NSPs to set collaborative targets for DM, then the NSPs are likely to be more engaged in strategies to expand DM activity in the short term. In the absence of policy leadership, the uptake of finance for DM by NSPs is likely to be low.

The current electricity market reform processes established by the Council of Australian Governments and the Ministerial Standing Committee on Energy and Resources have the



potential to address both the policy and regulatory conditions, but this potential must be converted into explicit regulatory and policy intent.

A clear statement of policy intent is needed, indicating governments' commitments to:

- the long term interests of consumers, including via the delivery of all cost-effective DM
- the establishment of clear accountability and performance measures for DM, including for example, establishing network DM targets and reporting in collaboration with the NSPs
- a primary focus on customer bills rather than price
- incentives to engage NSPs' interest and offset start-up costs (to the extent that regulatory incentives are inadequate for this purpose).

A statement of policy intent by government could establish the first three policy conditions above relatively quickly. The fourth condition is contingent on the absence of effective regulatory incentives and may therefore be unnecessary.

Regulatory conditions – certainty around DM investments by NSPs

The research has highlighted that investment activities in supply and demand side options are treated differently by NSPs, and greater certainty around the recovery of costs and revenue on DM activities is necessary.

The Australian Energy Regulator (AER) can facilitate the uptake of DM activities by clarifying regulatory principle of no disadvantage for NSPs who engage in cost-effective DM activities. Such a clarification is necessary as at present NSPs have no guarantee that they will be able to capture savings in network capital expenditure in the subsequent regulatory period that flows from DM expenditure in the current regulatory period. This distortion applies even if the DM expenditure involves much lower costs than capital investment.

If the AER makes it clear that cost-effective DM expenditure undertaken in the current regulatory period can be offset against avoided supply side investment in the next regulatory period, this will provide a significant signal to NSPs to expand DM activity in the current regulatory period. Such a clarification would be consistent with the principles of the NEM which hold that all technologies should be treated equally.

However, if the AER considers that the question of offsetting DM expenditure can only be addressed in the context of the current regulatory reform process, there are two sub-options. Firstly, this question could be resolved in the next few months through the forthcoming reform consultation process around. Alternatively, if the AER does not provide such clarification, there will be little opportunity for the CEFC to offer finance for networks for DM in the lead-up to the next regulatory periods, beginning from July 2015.

There are a number of further dimensions to providing regulatory certainty, including:

- **Efficient cost recovery:** Where an NSP undertakes DM at a cost lower than the avoided cost of network supply or augmentation, the NSP must be able, via customer network charges, to recover as a minimum the full cost of the DM measure or program. In addition, in order to incentivise action, the NSP should be able to recover some share of the avoided supply costs where these are higher than the cost of DM
- **Inter-period offsets:** NSPs must be able to capture and offset the value of future avoided costs against current DM expenditure. This means that the regulator must clearly and explicitly take account of these actual and avoided costs at the five-year regulatory determinations



- Regulatory incentives to offset project risk: While some network businesses have been expanding DM activities in recent years, there remain both real and perceived project risks for network businesses in building up DM expertise and experience. The regulatory system should recognise this risk by offering financial incentives to network businesses. This would involve sharing with network businesses and their shareholders some of the potential customer benefits of DM that may otherwise not occur at all
- Opex/capex substitutability: As DM expenditure is usually operating expenditure but avoidable costs are usually capital expenditure, the NSP must be able to offset costs in the former against savings in the latter
- Removing incentive bias against DM: There are number of major biases in the current regulatory system which encourage network supply side expenditure and discourage DM. For example, as noted by the Productivity Commission, 'all [network] capital spending – regardless of its efficiency - is rolled into the regulatory asset base (RAB) at the end of the five-year regulatory period'.¹³⁸ Such provisions do not apply to DM, which is mainly operating expenditure. These biases need to be addressed
- Balanced regulatory risk: The risk created by regulations associated with DM must be no greater than the risk involved in supply side expenditure.

Some of the above regulatory conditions can only be established if the Australian Energy Regulator (AER) changes the provisions the electricity network regulatory determinations and associated schemes. This is likely to take up to two years to be achieved. The first of these two conditions is critical to the viability of providing finance for DM and these conditions could potentially be achieved by the AER simply clarifying the interpretation of provisions of the existing regulatory determinations.

NSP conditions – management-level commitment to cost-effective DM

This report shows there is a strong recognition among some NSPs that DM needs to, and is likely to, play a major role in the future of the electricity supply industry. This recognition extends to interest in learning more about the potential for accessing finance to support DM. NSPs can respond to both the policy and regulatory intent discussed above by:

- management demonstrating a commitment to successful implementation of DM projects
- establishing clear DM performance measures and savings targets
- developing effective risk management processes.

Alternative strategies to develop the DM market

There are a number of benefits to DM by NSPs, such as avoiding or deferring specific network investment, that are unlikely to be easily captured through DM undertaken by other parties. However, the success of the CEFC in offering finance to NSPs depends on factors outside of the CEFC's control, particularly in relation to establishing greater government policy certainty and accountability and in relation to treatment of DM expenditure and savings by the AER and other regulators. If both of these conditions are not met then the capacity of the CEFC to offer finance to NSPs for network DM is likely to be very limited.

¹³⁸ Productivity Commission 2013, Electricity Network Regulatory Frameworks, Report No. 62, Canberra, p.220



In these circumstances, 'second best' options that the CEFC may wish to consider include:

1. Offering finance to electricity retailers to develop DM options to customers as a strategy to attract and retain customers.
2. Offering finance to electricity retailers to develop DM options for customers as an alternative to retailers using generation capacity or financial hedges to manage exposure to high peak prices in the wholesale market. However, in the short term, such offerings may be more attractive to the smaller retailers as it is understood that most of the large electricity retailers also have large generation portfolios which are likely to benefit from high wholesale price spikes associated with high electricity demand.
3. Offering finance to third party aggregators to develop products and attract end users to participate in demand side bidding into the wholesale electricity market, which has been proposed by the AEMC and is currently planned to begin in 2015. However, there still remains some uncertainty over how this function will be designed and how it will operate.

Stakeholder engagement and next steps

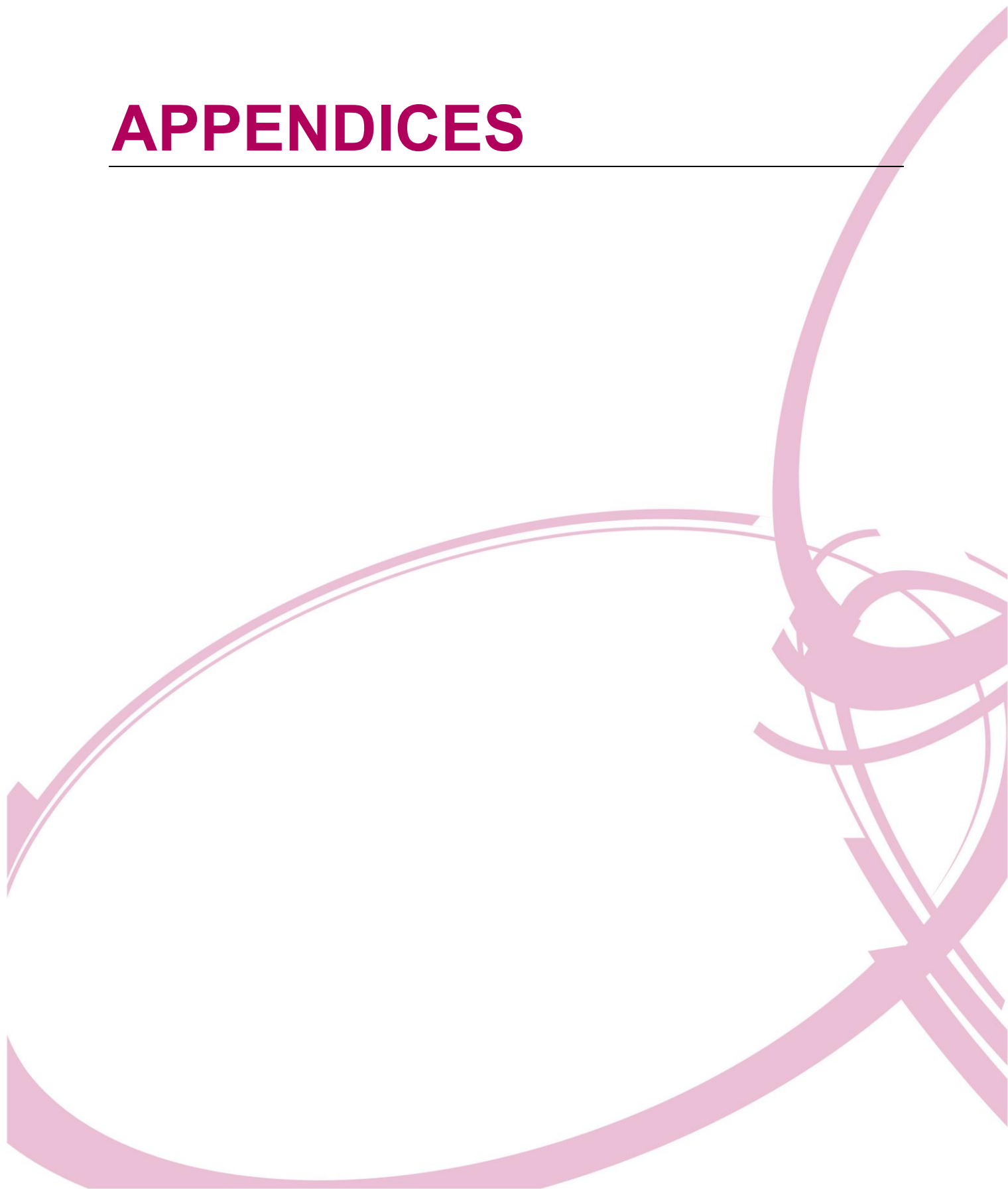
In the context of the above findings, the key next steps in engagement for developing the opportunities for network DM finance are as follows:

1. Engage in the current AER reform process to seek clarification of the treatment of DM expenditure in relation to offsetting future supply side capital expenditure.
2. Inform policy makers of the potential for network DM and the importance of setting clear policy direction relating to the adoption of all cost-effective DM and the need for clear NSP targets and accountability.
3. Engage with NSPs in relation to the potential for DM, the AER reform process and potential for financial support as a precursor and complement to regulatory reform.



UTS: INSTITUTE FOR SUSTAINABLE FUTURES

APPENDICES



A. DEMAND MANAGEMENT MEASURES

Table 13 lists a range of DM measures that could potentially be applied by NSPs. This list is not intended to be exhaustive but simply illustrate the range of measures available.

Table 13: Indicative DM measures

Measure	Notes
RESIDENTIAL	
Switch to gas cooking	Switch from electric to gas cooking
Elimination of 2nd fridges	Removal and disposal of second fridges
Lighting efficiency upgrades (res)	Replacement of inefficient lighting with LED or high-efficiency halogen lighting
Changing pool pump motor type	Upgrade to high efficiency pump
Switch timing of pool pump operation	Switch to off peak tariffs for pool pump operations
Energy Efficient Air-Conditioners (res)	Promoting installation of new air-conditioner as close as possible to 6 star efficiency for large units in living areas either at end-of-life or as an early replacement
External window shading	Install vertical external shutters/shadings to east and west windows
Home insulation – roof	Either upgrade (e.g. from R2 to R4) or install if none present and include reflective foil
Reduce heat losses from hot water system	Insulation of tank, pipes, reduce water temperature setting
EV – vehicle to grid/vehicle to house	Use of EV batteries for energy storage and network support (using battery resource)
Load management for EV charging	Minimising load of electric vehicles on network at peak periods (no charging during peak periods)
Energy efficient consumer electronics	Purchase of energy efficient models instead of average
Behaviour change – billing info	Improved customer billing information, including basic feedback, peer comparison and targeted energy saving tips
Residential Load Shifting	Includes assessments of instruments such as time-of-use tariffs, critical peak pricing to encourage shifting of demand outside of peak times
Direct Load Control (DLC) – A/C	Direct Load Control of residential air conditioners
Residential HW Conversion	Convert electric hot water units to electric boosted solar, gas boosted solar or heat pump



Measure	Notes
COMMERCIAL	
Variable speed drives/ efficient motors	Installation of VSD / efficient motors for commercial air handling
Energy efficient commercial lighting (interior & exterior)	Replacement existing inefficient lighting with more efficient technology
High efficiency heating ventilation and air conditioning (HVAC)	Upgrade to higher efficiency AC including high-efficiency chillers, at End of life of existing systems.
Energy Efficient Air Handling (e.g. VAV systems)	Installation of efficient air handling systems
Power Factor Correction (com)	Install equipment (capacitors/inductors) to correct power factor
Chilled water storage (incl. district)	Off-peak chilling of HVAC water and use in peak times to level cooling load. May be at individual building or district level.
Battery storage	Batteries which charge at off-peak and used at peak. Switch circuit to discharge during peak
Solar PV	PV on commercial roof space (optimal siting only)
Standby generation (com)	Incentive to turn on pre-existing standby generators during peak network periods
Optimise Building Management System (BMS) controls (HVAC)	Inspection of A/C, optimisation of the change of the filters, cleaning of condensing and evaporating coils, fine tuning of controls, optimal scheduling. Applies to buildings with BMS.
HVAC temperature set points	Increase temperature deadband range to reduce energy intensity of commercial HVAC
Trigeneration	Trigeneration in areas of high cooling loads and mains gas supply
Install and commission BMS controls for lighting	Applies to buildings without BMS installed already.
Upgrade of electronic equipment	Upgrades of computers, monitors and servers to energy efficient units
Delamping	Redesign/re-evaluate lighting requirements to achieve minimum power densities
Install and commission BMS controls for HVAC	BMS to schedule HVAC level and zones and to enable dispatching of load reductions. Includes set HVAC to use outside air when cooler than inside (economy cycle) where equipped.



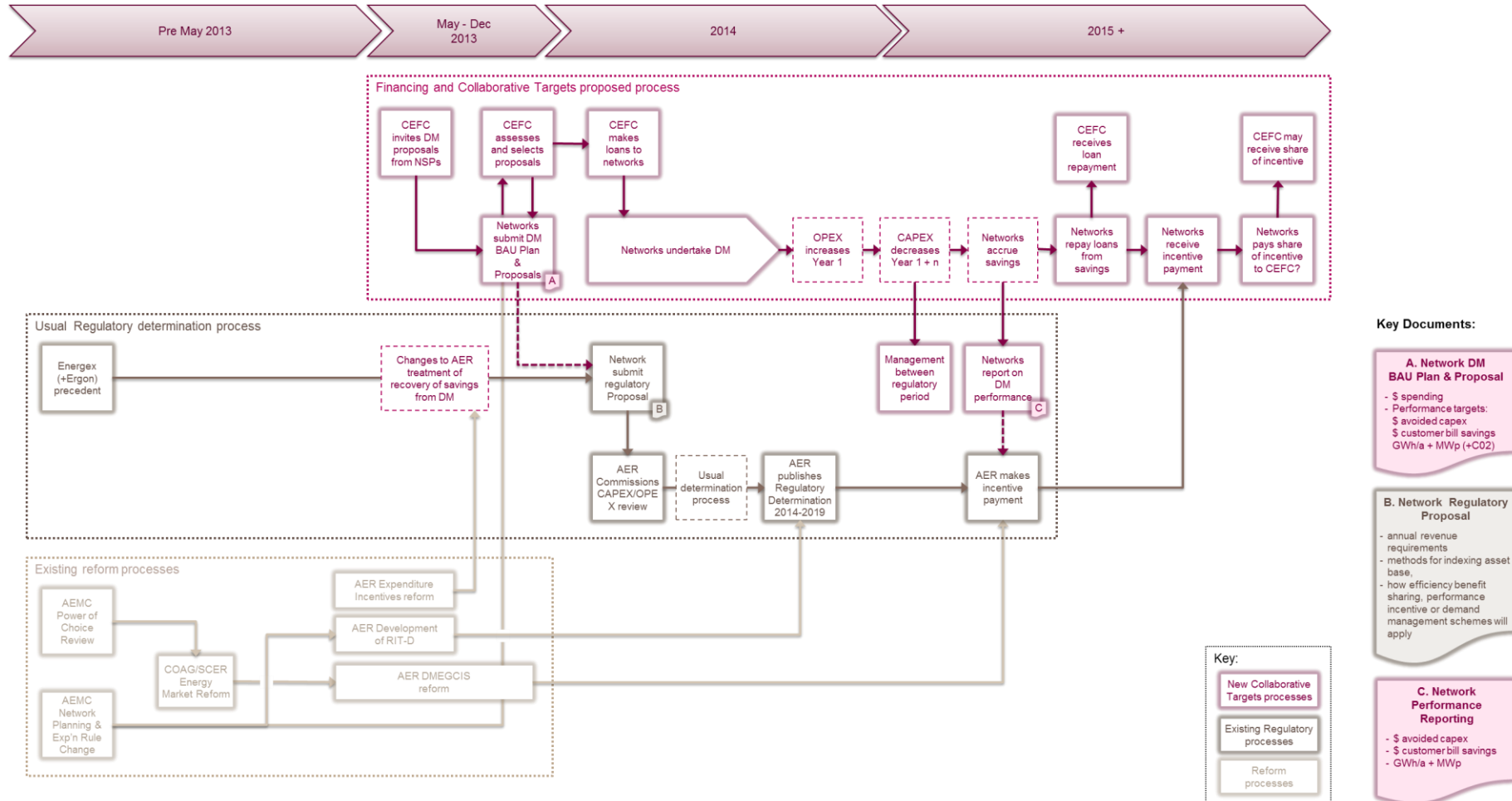
Measure	Notes
INDUSTRIAL	
Pumping efficiency improvement	Install premium efficient pumps compared to average efficiency currently installed
Load shifting of water pumping	Installing water storage tanks to allow for storing of pumped stock and irrigation water
Install efficient fans	Upgrade fans (and potentially driving motors) to high efficiency units and matching unit specification to required performance
Lighting efficiency	Replacement of high intensity discharge (HID) (often metal halide) high bay lighting with T5 high-output fluorescents
Optimise air compressors	Automatic shutdown of conveyors and compressed air , air dryers and local conveyors and local compressed air supply when not required for production. Improvement in process control
Refrigeration upgrade	Upgrade to high-efficiency refrigeration equipment, including efficient compressors, optimised floating head pressure and equipment size optimization
Standby generation	Incentives to turn on/share standby generators during peaks
Demand side response	Interruptible load from industrial sector, largely process-related
DLC refrigeration	Switch-based load control of cooling and refrigeration
Power factor correction	Install capacitor banks at customer premise to improve power factor to 0.98
Premium efficiency material handling	Installation of programmable logic controls on conveyer systems, higher efficiency drives, couplings, gear/speed reducers, regenerative braking.



B. PROPOSED DM, REFORM AND FINANCE PROCESS

The following diagram sets out the proposed process for the CEFC to provide financing facilities for DM and to recover investments from NSPs (as described in Section 4.1) and shows the interaction of this process with the existing regulatory process and current reforms.

Figure 27: Interaction of financing with targets, regulation and reform processes



C. PRECEDENTS FOR DM TARGETS

This section provides a brief introduction to various precedents for DM targets in Australia and internationally. It includes only those examples that have a specific 'peak demand' focus. Table 14 provides a summary, followed by more detailed information on each scheme.

Table 14: Summary of precedents

Region	Target	Legislated?	Funding	Penalties/Rewards
Australian state-based schemes				
Qld	144 MW + 103 MW	No, but policy direction from Government	Initial \$47 million provided by Qld Government. Subsequent program cost recovery sought and approved via AER.	If performance targets not met, AER may disallow cost recovery
International schemes				
Ontario, Canada	Conservation and Demand Management (CDM) targets rising to 1,330 MW and 6,000 GWh p.a. by 4 th year.	Overall targets issued by Minister, Individual Targets set by Energy Board, following advice from Power Authority (advice based on direct consultation with Utilities)	Costs recovered via regulatory structure	Performance incentives accrue once 80% of CDM target reached. (They do not accrue for performance exceeding 150%.)
California, US	Ranging from 455-534 MW each year between 2012 to 2020	Public Utilities Commission sets demand targets for private utilities. Public utilities develop their own goals.	Costs recovered via regulatory structure	Incentives rise as performance relative to targets rise
Colorado, US	5% of 2006 peak demand by 2018	Legislation provides minimum targets but authorised Public Utility Commission to revise goals and establish interim targets	Tariff riders on customer bills	Disincentive offset' and performance incentive
Delaware, US	15% of 2007 peak electric demand by 2015 (2011 = 52MW, 2015 = 392 MW)	Targets set in legislation	Still to be determined, but may include cost-recovery, volumetric charge to customers	Unknown
Florida, US	Summer: 3,024 MW Winter: 1,937 MW (cumulative from 2010-2019)	Public Service Commission sets goals	Unknown	None at this stage.



Region	Target	Legislated?	Funding	Penalties/Rewards
Illinois, US	0.1% reduction in peak demand each year for 10 years (EY 2009-2019)	Legislation sets overall annual targets	Cost-recovery tariffs	Non-compliance with plans requires utilities to make contribution to the Energy Efficiency Trust Fund
Maine, US	100 MW reduction in peak load electricity consumption by 2020	Targets set in the Act	Cost-recovery rates with limits	Unknown
Maryland, US	From 2007 level, 5% reduction in per capita peak demand by 2011, 10% by 2013, and 15% by 2015	Targets set in legislation	Cost-recovery rates with no specific limits	Unknown
Missouri, US	Annual 1% peak reduction, cumulative reduction of 9% by 2020, increasing by 1% each year thereafter	Cumulative target set in legislation, annual targets set by Public Service Commission	TBD	Unknown
Ohio, US	1% reduction in peak demand in 2009, 0.75% reduction in peak demand each year through 2018	Targets set in legislation	Unknown	Failure to comply with requirements will result in forfeiture to be paid to the Advanced Energy Fund
Pennsylvania, US	No current targets. Previous targets were savings of 4.5% by May 31, 2013, measured against actual peak demand from June 2007–May 2008	Targets set in legislation	Reconcilable adjustment clause to rates	Failure to achieve targets is punishable by fines.
Rhode Island, US	Summer: Range from 18,512 kW in 2011 to 32,759 kW in 2014; Winter range from 17,197kW in 2011 to 30,432 kW in 2014	Public Utilities Commission sets targets	Volumetric rate surcharge	Unknown
Texas, US	30% of electric demand growth in 2013 0.4% of each company's peak demand	Individual targets set in legislation	Included in customer tariffs, as monthly or volumetric basis	Performance bonus for exceeding goal within cost limit.
Vermont, US	Summer peak savings: 60,800 kW (three-year goal for 2012-2014). No winter peak target.	Public Service Board set targets following submissions by Utilities and workshop with a number of stakeholders including Utilities.	Volumetric charge on customer bills	Positive performance awards for meeting stretch QPIs, and forfeiture of portions of performance award for failing to meet other minimum QPIs.

Other countries that have implemented DM targets or similar initiatives that may impact on peak demand include: Belgium, Brazil, Denmark, France, Italy, Thailand and the United Kingdom*.

(*see Total Environment Centre, 2012, *Demand management targets for networks in the National Electricity Market [Discussion Paper]*.)



C.1 QUEENSLAND ENERGY CONSERVATION AND DEMAND MANAGEMENT PROGRAM

Legislation

Targets are included in the Queensland Energy Management Plan (QEMP), which outlines 28 initiatives to manage electricity consumption and peak demand in a cost-effective way.

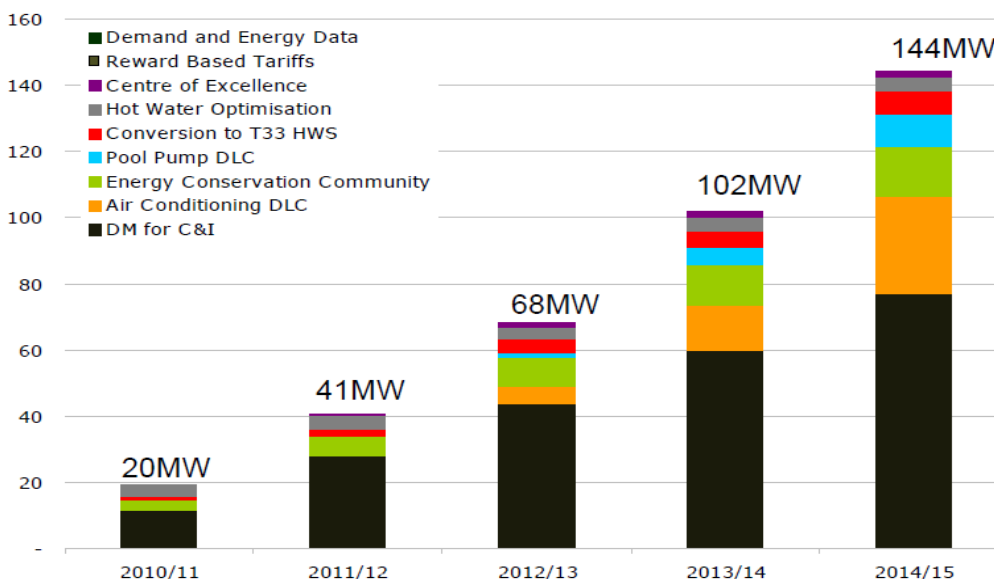
The initiatives will be further developed and implemented through the Queensland Energy Management Centre, which will include a dedicated government policy and regulatory team focused on driving the regulatory reform agenda.¹³⁹

Targets

By 2020, successful implementation of the QEMP will help avoid the equivalent of 1000 MW, saving more than \$3.5 billion in avoided network and generation costs.¹⁴⁰ Part of this will be drawn from the Peak Demand Targets for Energex and Ergon Energy:

- Energex target: 144 MW by 2014/15 (Figure 28)
- Ergon Energy target: 150MW by 2016/17 (Figure 29)

Figure 28: Energex Demand Management Targets to 2014/15



Source: Energex, 2010, Peak Demand Management, Planning for the Future

Figure 29: Ergon Energy Demand Management Targets to 2016/17



Source: Ergon Energy, 2012, Demand Management Outcomes Report 2011-12.

¹³⁹ Department of Employment, Economic Development and Innovation (DEEDI), Queensland Government, 2011, Queensland Energy Management Plan.

¹⁴⁰ ibid.



Funding

In 2009/10, the Queensland Government allocated \$47 million for demonstration projects. In 2010, Energex and Ergon sought and were allocated ~\$220 million for demand management programs from the Australian Energy Regulator.

- Energex: \$27m OEC Funding 2009–2012 + \$170m AER funding 2010–2015¹⁴¹
- Ergon Energy: 2011–12 expenditure of the demand management program was \$22.6 million, which was less than budgeted for the financial year.

Penalties/Rewards

Unknown.

Results

Energex's performance in DM programs is exceeding its targets in its key Commercial/Industrial and Residential DM Initiatives¹⁴² as shown below Table 15.

Table 15 Energex DM Performance Targets Vs Actuals (MVA Cumulative)

	2009/10	2010/11	2011/12
Residential Target	-	8	12.5
Residential Actual	-	15.4	23.4
Commercial & Industrial Target	16	26	42
Commercial & Industrial Actual	-	26.1	42.6

Source: Energex, *Network Management Plan 2012/13 to 2016/17*.

Ergon's demand management activities delivered 36MW of reductions during 2011–12, exceeding the 25MW target set in the 2011–12 Demand Management Plan. With 17MW of peak demand reductions in the previous financial year, the reductions delivered to date equate to 51% of the regulatory control period target of 103MW. Ergon Energy has now implemented demand management activities in seven network constraint locations, with the effect of deferring \$428 million of proposed network augmentations, and generating savings of \$78 million.¹⁴³ Table 16 shows the distribution of these deferrals and resultant savings.

Table 16 Ergon DM Performance, deferral and savings

Approved network constraint projects	Network Capex (nominal \$M)	Net Benefits (NPV \$M)	MVA Benefits	Deferral
Charleville SOS	134.9	44.8	1.6	Indefinite - min 10 years
St George SOS	85.7	21.5	1.2	Indefinite - min 10 years
NDM Mt Isa	22.2	1.2	3.6	3 Years
Cairns Northern Beaches	83.1	8.4	4.0	3 Years
Bohle Plains / Mount St John	75.7	0.5	5.5	2 Years
NDM Ingham	5.6	0.8	1.8	5 Years
NDM Moranbah	21.3	1.8	3.5	2 Years
TOTAL	428.5	78.8	21.2	

Source: Ergon Energy, 2012, *Demand Management Outcomes Report 2011-12*.

¹⁴¹ Energex, 2010, *Peak Demand Management, Planning for the Future*

http://pdf.aigroup.asn.au/environment/Peak_Demand_Briefing_Terry_McConnell.pdf.

¹⁴² Energex, *Network Management Plan 2012/13 to 2016/17*.

¹⁴³ Ergon Energy, 2012, *Demand Management Outcomes Report 2011-12*

http://www.ergon.com.au/_data/assets/pdf_file/0005/137183/DMP-Outcomes-2011-12.pdf.



C.2 ONTARIO ELECTRICITY CONSERVATION AND DEMAND MANAGEMENT

The following information is a summary of the material provided on the Ontario Energy Board's Electricity Conservation and Demand Management (CDM) webpage.¹⁴⁴

Legislation

In September 2009, the *Green Energy and Green Economy Act, 2009* was amended to allow the Minister of Energy and Infrastructure to issue a directive requiring the Ontario Energy Board (OEB) to specify, as a condition of licence, conservation and demand management targets for electricity distributors. Specifically, section 27.2 of the Ontario Energy Board Act was amended to include the following:

Directives re conservation and demand management targets

27.2 (1) *The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board to take steps specified in the directive to establish conservation and demand management targets to be met by distributors and other licensees. 2009, c. 12, Sched. D, s. 7.*

Directives, specified targets

(2) *To promote conservation and demand management, a directive may require the Board to specify, as a condition of a licence, the conservation targets associated with those specified in the directive, and the targets shall be apportioned by the Board between distributors and other licensees in accordance with the directive. 2009, c. 12, Sched. D, s. 7.*

Targets

The Minister issued such a directive in March 2010. The Directive set out overall peak demand and energy savings targets, for the OEB to allocate amongst the respective distributors, as a condition of a licence.

Current peak demand target:

- 1,330 MW of provincial peak demand persisting at the end of the four year period, beginning January 1, 2011 and ending December 31, 2014.

Energy savings target:

- Cumulative 6,000 GWh p.a. 2010 to 2014

Individual targets

The OEB is responsible for determining the allocation of the total CDM targets to each licensed electricity distributor, having regard to information from the Ontario Power Authority (OPA), developed in consultation with distributors.

In June 2010 the OPA provided advice to the OEB on target allocation amongst electricity distributors.¹⁴⁵ In developing its advice, the OPA sought input from all Local Distribution Companies (LDCs) via a written consultation process, utilising a consultation paper entitled, 'The Establishment of LDC Conservation Targets under the Green Energy Act – Target setting and allocation methodology advice from the OPA'.

The overall recommendations of the OPA in regards to the targets were:

- *Individual target setting methodology:* The OPA recommends that peak demand savings targets be allocated based on each LDC's relative contribution to system peak demand. Specifically, the OPA recommends using a peak demand target allocation factor which is based on each LDC's average contribution to the top 10 system peak hours, over the most recent two years of available data.

The recommended allocation methodology is:

¹⁴⁴ [http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Conservation%20and%20Demand%20Management%20\(CDM\)/Electricity%20CDM](http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Conservation%20and%20Demand%20Management%20(CDM)/Electricity%20CDM).

¹⁴⁵ <http://www.ontarioenergyboard.ca/OEB/Documents/Documents/Advice%20to%20the%20Ontario%20Energy%20Board%20-%20CDM%20Target%20AI.pdf>.



Individual LDC Peak Demand Savings Target (MW) = Dem% x LDC Provincial Aggregate Peak Demand Savings Target of 1330 MW, Where:

$$\text{Dem\%} = (\text{Dem\%Yr1} + \text{Dem\%Yr2}) \div 2$$

$$\text{Dem\%Yr1} = (\text{Sum of LDC demand at top 10 system peak hours in Year 1}) \div (\text{Sum of demand of all LDCs that have CDM Targets at top 10 system peak hours in Year 1})$$

$$\text{Dem\%Yr2} = (\text{Sum of LDC demand at top 10 system peak hours in Year 2}) \div (\text{Sum of demand of all LDCs that have CDM Targets at top 10 system peak hours in Year 2})$$

- *Individual targets:* Individual recommendations were made by the OPA for 79 Local Distribution Companies based on the methodologies above.

Individual targets were issued by the OEB (initially in November 2010 and revised in March 2011) for 81 distributors, with peak demand targets ranging from less than 1 MW to over 280 MW and energy savings targets ranging from less than 1 GWh to over 1,300 GWh. In many cases, the targets issued by the OEB were slightly different to those recommended by the OPA, though generally still in the ballpark.

Funding

Unknown.

Spending

Overall in 2011, distributors reported spending a total of \$94,129,770 on CDM programs across Ontario, as per the following table:

Consumer Program ⁹	\$17,269,593
Business Program	\$43,180,582
Industrial Program	\$3,152,722
Home Assistance Program	\$500,987
Pre-2011 Programs	\$28,356,873
Initiatives Not In Market	\$1,669,013
2011 Total LDC Spending	\$94,129,770

The reported amounts in this report include only the spending incurred directly by distributors and do not include any spending amounts for programs centrally funded by the OPA. (Centrally funded programs are those where the OPA works directly with either retailers such as appliance exchange or retirement, contractors such as HVAC incentives, and/or aggregators such as in the Demand Response 3 program.)

Penalties/Rewards

Distributors begin to accrue a performance incentive once they reach 80% of their CDM target. Performance incentives do not accrue for performance that exceeds 150% of each CDM Target.¹⁴⁶ The incentive is calculated in a stepped manner, with a higher \$/kW rate for higher performance.

Range	Performance Tiers		Performance Incentive	
	Range Begins	Range Ends	¢/kWh	\$/kW
1	80%	up to 100%	0.30	13.50
2	100%	up to 110%	0.45	20.25
3	110%	up to 120%	0.75	33.75
4	120%	up to 130%	1.05	47.25
5	130%	up to 140%	1.35	60.75
6	140%	up to 150%	1.80	81.00

¹⁴⁶ <http://www.oeb.gov.on.ca/OEB/ Documents/EB-2010-0215/Conservation%20and%20Demand%20Management%20%28CDM%29 Code.pdf>.



Specific criteria are in place regarding performance criteria:

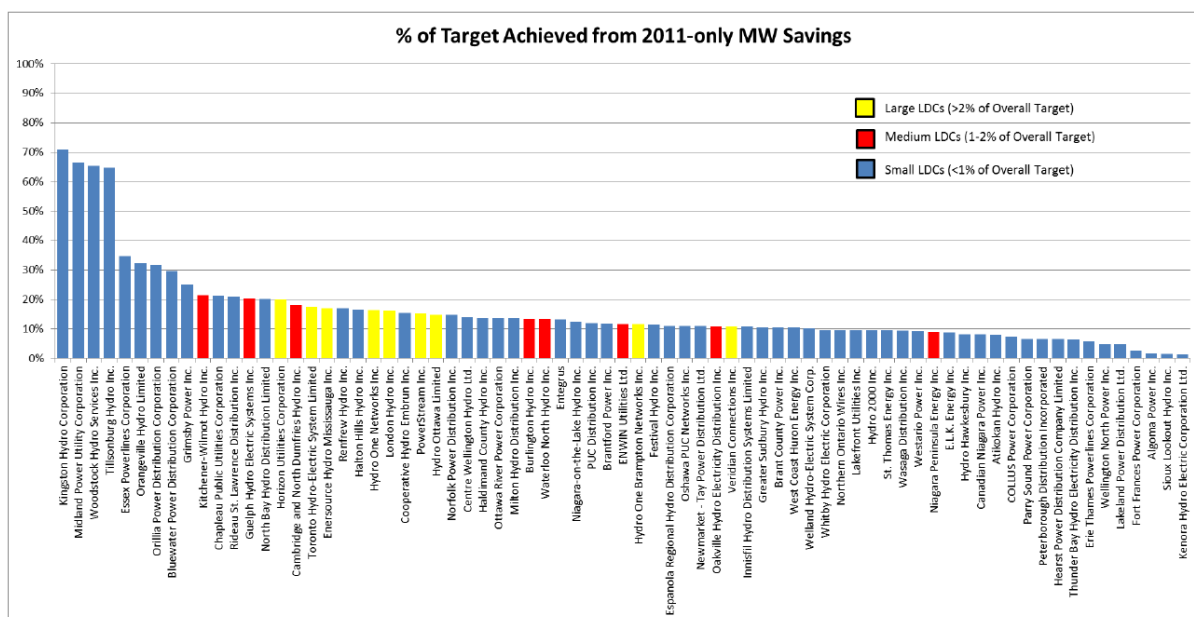
- A distributor may only claim a performance incentive in relation to its contribution to the CDM Programs. In order for a distributor to claim 100% attribution of benefits, the distributor shall demonstrate that its role was central to the CDM Programs.
- If a distributor’s role does not meet the test for centrality... the distributor shall then submit a proposal for an attribution of benefits to the Board for approval and the Board will determine whether the proposal is acceptable.
- If more than one distributor applies for an attribution of benefits for the same CDM program, the total applied for between the distributors cannot exceed 100%.
- Performance incentive payments shall be made on the basis of a distributor’s achieved verified results in meeting its CDM Targets. A distributor must provide verified results for both electricity savings (kWh) and peak demand savings (kW) at the time of its application to the Board for a performance incentive. The verification must have been completed by an independent third party selected from the OPA's third party vendor of records list.
- A distributor's performance incentive shall be calculated across the distributor's entire portfolio of Board-Approved CDM Programs and OPA-Contracted Province-Wide CDM Programs.

Results

The first annual report on the CDM targets was for the 2011 year. 2011 Peak Demand Net Savings (kW) were:

Consumer Program	49,123
Business Program	64,594
Industrial Program	57,099
Home Assistance Program	2
Pre-2011 Program Completed in 2011	44,833
2011 Total Incremental Peak Demand Net Savings (kW)	215,651

The majority of distributors reported having achieved at least 10% of their net peak demand (kW) target from their 2011 results, with 4 distributors achieving over 60%, another 4 over 30% and 7 over 20%. 24 distributors achieved less than 10%, as shown in the figure below.



2011 results were achieved through the use of the province-wide CDM programs made available by the OPA. While three Board-Approved CDM Program applications were received by the Board over the course of 2010 and 2011, ultimately no Board-Approved programs proceeded in 2011. Upon review of the first two or the three received applications, the Board determined that additional evidence was required relating to the evaluation plans. For the third application, the Board found duplication with certain OPA-Contracted Province-Wide CDM Programs, but approved some funding for two programs over a 15-month period. In all three applications, the applicants ultimately decided not to proceed.

Factors behind differential performance are not identifiable from currently available information.

Overall, distributors were mainly optimistic in their comments about the 2011 results and projections to meet the CDM Targets by the end of 2014.



C.3 US STATE-BASED SCHEMES

The information on the following US state-based schemes, except where otherwise noted, is a summary of information from the following two web resources:

- American Council for an Energy-Efficient Economy (ACEEE), 2012, State Energy Efficiency Policy Database (website). <http://aceee.org/sector/state-policy/>
- N.C. Solar Center (no date) DSIRE: Database of State Incentives for Renewables and Efficiency (webpage). N.C. State University with support from the Interstate Renewable Energy Council, Inc. <http://www.dsireusa.org/incentives/index.cfm>

The schemes are generally designated as Energy Efficiency Resource Standards (EERS). Only those EERS with a peak demand element have been included here.

California¹⁴⁷

Legislation

The California Legislature emphasized the importance of energy efficiency and established broad goals with the enactment of Assembly Bill 2021 of 2006. The bill calls for a 10% reduction in forecasted electricity consumption within 10 years.

The bill also requires the California Energy Commission (CEC), the California Public Utilities Commission (CPUC) and other interested parties to develop a statewide estimate of all cost-effective electricity and natural gas savings and to develop efficiency savings and demand reduction targets for the next 10 years. This study must be updated every three years.

Public utilities in California are not regulated by the CPUC. Still, Assembly Bill 2021 requires them to pursue energy efficiency as well. The law required them by June 1, 2007 to identify all cost-effective energy efficiency and demand reduction possibilities, and to establish energy reduction goals for the next 10 years. Public utilities are required to update these studies every three years and to submit them to the CEC.

Targets

Having already developed interim efficiency goals for each of the utilities from 2004 through 2013, the CPUC developed new goals in 2008 for years 2012 through 2020. The goals consist of separate electricity savings and demand reduction requirements for each of the three investor-owned electrical utilities and energy savings requirements for the state's three gas utilities.

Electric Peak Demand Reduction varies by utility, as shown in the following table:

	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E	251 MW	236 MW	228 MW	241 MW	257 MW	258 MW	270 MW	270 MW	269 MW
SCE	239 MW	240 MW	189 MW	193 MW	213 MW	215 MW	222 MW	222 MW	223 MW
SDGE	31 MW	41 MW	38 MW	38 MW	40 MW	40 MW	41 MW	42 MW	42 MW
Total	521 MW	517 MW	455 MW	472 MW	510 MW	514 MW	533 MW	533 MW	534 MW

The required energy savings will be primarily met through incentive programs for utility customers, but utilities can also count the energy savings resulting from these policies, including state building code, Federal and state appliance standards and statewide market transformation efforts.

Funding: Unknown.

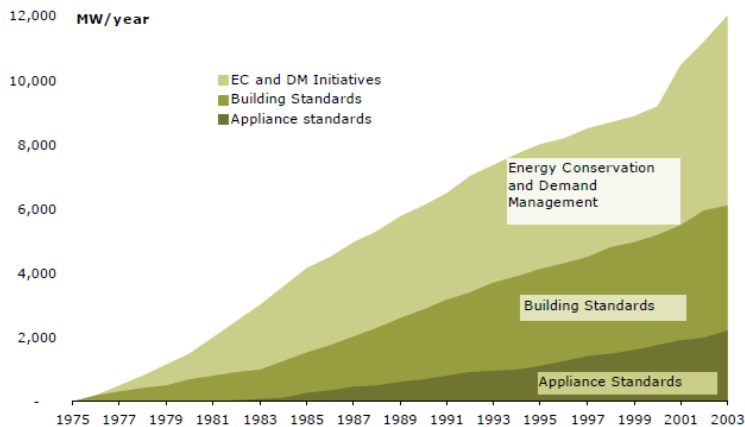
Penalties/Rewards: Unknown.

Results:

Annual Peak Savings from Efficiency Programs and Standards: California

¹⁴⁷ <http://energy.gov/savings/energy-efficiency-resource-standard>; <http://aceee.org/sector/state-policy/california>; http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA62R&re=1&ee=1.





Source: *Energex, 2009, Clean Energy Council Energy Efficiency Seminar.*

Colorado¹⁴⁸

Legislation

A House Bill required the Colorado Public Utilities Commission (CPUC) to establish energy savings goals for gas and electric utilities (thereby creating an EERS) and to give investor-owned utilities a financial incentive for implementing cost-effective efficiency programs.

Targets

The EERS statute does not directly set a fixed schedule of statewide percentages of energy savings to be achieved by particular years, nor does it require the acquisition of all cost-effective energy efficiency resources. Instead the law provided minimum energy and demand savings targets but also authorized CPUC to revise the goals and establish interim savings targets as it deems appropriate. It set an overall multi-year statewide goal for investor-owned utilities of at least five percent of the utility's peak demand and retail energy sales in the base year (2006) to be met by the end of 2018.

Current peak demand targets:

- 5% of 2006 peak demand by 2018.

Funding

The utilities recover the program costs of the plans approved by the PUC by using tariff riders, which adjust customer bills. The PUC has created incentives to reward utilities that create efficiency programs for electricity and/or natural gas.

Penalties/Rewards

The 2009/10 Demand Side Management (DSM) Plan, approved in 2008, includes a three-part incentive package that included a \$2 million 'disincentive offset' for each year that Public Service Colorado implement an approved DSM plan, a performance incentive and cost recovery via a rider on a prospective basis. (A similar three-part package was approved for Black Hills.) In each case the performance incentives are available for achieving efficiency targets - utilities achieving efficiency targets can earn a percentage of the net economic benefits generated by those savings. The total incentive (including the disincentive offset) is capped at 20% of PSCo's annual DSM expenditures.

The 'Disincentive offset' is a payment of \$2 million after taxes (approximately 3.2 million gross) for each year that 80% of the annual energy savings goal for an approved DSM plan is achieved. This amount is recovered over the 12 month period following the year in which the DSM plan is implemented. The PUC specifically notes that this 'disincentive offset' should not be considered

¹⁴⁸ [http://aceee.org/sector/state-policy/colorado:](http://aceee.org/sector/state-policy/colorado)
[http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CO46R&re=1&ee=1.](http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CO46R&re=1&ee=1)



lost margin recovery, but is an annual bonus for meeting approved DSM goals. The \$2 million disincentive offset can be adjusted downward in future years if the 80% target is not met although it was reported that the 80% target is so easily achieved as to make the payment almost automatic upon DSM program implementation.

Results

Unknown.

Delaware¹⁴⁹

Context

Almost all utilities have had peak demand programs in place before deregulation. In the 2007 base year, most utilities had some level of peak demand reduction in operation during the summer timeframe and 2007 actual consumption data reflect the utilities’ peak demand as reduced by the programs (restricted demand).

Legislation

In July 2009 the Delaware legislature enacted legislation creating energy savings targets for Delaware’s investor-owned, municipal, and cooperative electric utilities, as well the state’s natural gas distribution companies. Utilities are permitted to determine the best way to achieve the energy savings targets and to develop and fund programs towards this end.

The legislation required the Delaware Department of Natural Resources and Environmental Control (DNREC) to develop regulations implementing the standard by July 29, 2010 (one year after the enactment); however, as of this writing final regulations have not been promulgated.

Applicable Sectors:

- Municipal Utility, Investor-Owned Utility, Rural Electric Cooperative, Natural Gas Distribution Utility.

Targets

The law requires affected electric utilities to establish programs which save the equivalent of 15% of 2007 electricity consumption and peak electric demand by 2015. The standard also includes an interim reduction target of 2% of electricity consumption and peak demand by 2011.

Current peak demand target:

- Peak demand savings equivalent to 15% of 2007 peak electric demand by 2015 (2011 = 52MW, 2015 = 392 MW).

Based on actual 2007 electric peak (restricted demand), the affected energy providers would have the following savings targets:

	2007 Peak Demand (MW)	2011 2% Goal (MW)	2015 15% Goal (MW)
Delmarva Power & Light Company	1892	38	284
Delaware Electric Cooperative	345	7	52
Delaware Municipal Electric Corporation	376	8	56
Total	2,613	52	392

Funding

Based on the recommendations of the EERS Workgroup, the DNREC may establish an energy efficiency charge to fund these programs on customer bills. Any charge must be levied on a per kilowatt-hour (kWh) or per therm basis and may not vary by customer class. In addition, the chosen rate may not result in an average charge greater than \$0.58 per month per residential electric

¹⁴⁹ <http://aceee.org/sector/state-policy/delaware;>
[http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DE17R&re=1&ee=1.](http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DE17R&re=1&ee=1)



customer, or \$0.41 per month per residential natural gas customer. Utilities collect and remit any energy efficiency charges to the Delaware Energy Office for deposit into the Sustainable Energy Trust Fund (SETF), with a separate account for each utility. The funds will be used to support activities in the following areas and proportions:

- 75% to further the goal and activities of the Sustainable Energy Utility (SEU), including energy conservation, energy efficiency, renewable energy and energy financing.
- 20% to fund the Weatherization Assistance Program
- 5% to the Delaware Energy Office to cover EERS program costs

Penalties/Rewards

Unknown.

Results

Energy efficiency is defined by statute as, —a decrease in consumption of electric energy or natural gas or a decrease in consumption of electric energy or natural gas on a per unit of production basis or equivalent energy efficiency measures that do not cause a reduction in the quality or level of service provided to the energy customer achieved through measures or programs that target consumer behaviour, or replace or improve the performance of equipment, processes, or devices. Since the efficiency reduction in energy use sometimes takes place during peak energy use hours, the efficiency may contribute to reducing peak demand during those times. The Center for Energy and Environmental Policy reviewed various sources of information, including a 2009 report from the Energy Information Administration and provided the following data on demand reduction resulting from utility-administered energy efficiency programs.

Utility	Demand Savings Ratio (MW per GWh)
Pacific Gas & Electric Co	0.16
Southern California Edison Co	0.2
Connecticut Power & Light Co	0.16
United Illuminating Co	0.16
Long Island Power Authority	0.15
PacifiCorp	0.19
Northern States Power Co	0.3
City of Seattle	0.12
Austin Energy	0.37
MidAmerican Energy Co	0.21
Interstate Power and Light Co	0.25
Nevada Power Co	0.26
Sierra Pacific Power Co	0.3
Mean	0.22

Assuming achievement of the 2011 and 2015 energy efficiency goals and a range of 0.12 to 0.37 megawatts of demand reduction per gigawatt-hour, the spillover effect from efficiency to peak demand savings could range from 28 megawatts to 87 megawatts in 2011 and 213 megawatts to 658 megawatts in 2015²⁰. The EERS peak demand reduction goals are 52 megawatts and 392 megawatts in 2011 and 2015, respectively; Delaware’s concentrated efforts on energy efficiency programs could achieve between half to more than the full targeted peak demand savings without any further expenditures on demand reduction program.



Florida¹⁵⁰

Legislation

In 1980, Florida enacted the Florida Energy Efficiency and Conservation Act (FEECA), creating Florida Statutes Section 366.80-366.85 and Section 403.519. Section 366.82(6) requires the Florida Public Service Commission to review the conservation goals of each utility subject to FEECA at least every five years. Most recently, goals were established on December 30, 2009 with the passage of Order No. PSC-09-0855-FOF-EG. Each utility had 90 days from the date of issuance of the Order to file a demand-side management plan to meet the goals set by the PSC. Each utility must report out on efficiency goal status to the Florida legislature annually.

Applicable Sectors:

- Utility, Investor-Owned Utility, Rural Electric Cooperative, All Utilities with >2,000 GWh annual sales.

Utilities whose annual sales amount to less than 2,000 GWh as of July 1, 1993 are not subject to FEECA. This leaves all five Florida investor-owned utilities (Florida Power & Light Company, Progress Energy Florida Inc., Tampa Electric Company, Gulf Power Company, Florida Public Utilities Company) and two municipal utilities (Orlando Utilities Commission and Jacksonville Electric Authority) under the authority of the law.

Targets

The Florida PSC approved annual goals for each utility for summer peak reduction, winter peak reduction, and overall annual sales reductions.

Current peak demand targets:

- Summer: 3,024 MW cumulative reduction from 2010-2019
- Winter: 1,937 MW cumulative reduction from 2010-2019.

Individual targets

Goals for individual utilities for each specific year can be found in the PSC order. The goals set by the PSC were higher than each utility's proposed goals.

Funding

Unknown.

Penalties/Rewards

Neither incentives nor penalties were established with the 2009 Order, but may revisit the issue in the future.

Results

Unknown.

¹⁵⁰ <http://aceee.org/sector/state-policy/florida>;
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=FL25R&re=1&ee=1.



Illinois¹⁵¹

Context

Prior to legislation passed in 2007, there was limited funding and associated activity for utility-sector energy efficiency programs. Illinois had little involvement with utility energy efficiency programs, other than a small annual funding requirement (~ \$3 million/year) created in the Illinois restructuring legislation (HB262) in 1997 to support some small programs administered by the state Department of Commerce and Economic Opportunity (DCEO).

Legislation

Legislation passed in 2007 (Illinois Power Agency Act, or IPAA) set energy efficiency and demand response program requirements for utilities. A state policy requires electric utilities to use cost-effective energy efficiency and demand-response measures to reduce direct and indirect costs to consumers. This can be accomplished by avoiding or delaying the need for new generation, transmission, and distribution infrastructure. Because Illinois is still technically a 'restructured' state—with distribution utilities purchasing power in competitive wholesale markets—it is not clear how energy efficiency would be factored into resource planning decisions.

Applicable Sectors: Investor-Owned Utility, Retail Supplier, Illinois DCEO. (The electricity reduction goals apply to utilities that had 100,000 or more customers on December 31, 2005.)

Targets

The legislation set an energy efficiency resource standard (EERS) savings goal that sets incremental annual electric and natural gas savings targets based on previous year's consumption, beginning on June 1 of that year. The electric savings requirement began at 0.2% in 2008 and ramps up to a requirement of 2% annual savings in 2015 and thereafter.

Current peak demand targets:

- 0.1% reduction in peak demand each year for 10 years (EY 2009-2019).

Funding

SB1592 authorizes utilities to recover the costs for providing energy efficiency programs and directs utilities to design and implement cost-recovery tariffs. Energy efficiency measures must satisfy the Total Resource Cost (TRC) Test. In addition, in 2008 through 2011, annual per kilowatt-hour charges are limited based on the previous year's rates. Beginning in 2012, the estimated average net increase due to the cost of efficiency measures to 2.015% of the amount paid per kWh by customers in EY 2007 or the incremental amount per kWh paid for the measures in 2011, whichever is greater. (DSIRE)

If the rate impact cap is reached, the energy savings goals will be relaxed to the maximum savings that can be achieved within the rate impact cap. If, after 2 years, an electric utility fails to meet the efficiency standard it must make a contribution to the Low-Income Home Energy Assistance Program and transfer the program to the Illinois Power Authority.

Funds from the tariffs cover both utility- and state-administered programs. Individual electric utilities are required to administer 75% of the total funds for energy efficiency. The Illinois Department of Commerce and Economic Opportunity (DCEO) administers 25% of the funds, which are used to target government facilities, low-income households, and market transformation-oriented information and training programs. (Utilities are responsible for 100% of the demand-response measures.)

Penalties/Reward

Illinois does not have a mechanism in place for utility shareholder incentives for energy efficiency. SB1592 does not address the issue.

However there are penalties for non-compliance by utilities. Utilities that fail to submit an energy reduction plan will result in a fine of \$100,000 for each day until the plan is filed. This penalty is deposited in the Energy Efficiency Trust Fund and may not be recovered by rate payers. Plans are due on September 1 every three years. If an electric utility fails to comply with its plan after 2 years,

¹⁵¹ <http://aceee.org/sector/state-policy/illinois>;
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IL19R&re=0&ee=1.



it must make a contribution to the Low-Income Home Energy Assistance Program (LIHEAP). Large utilities (those with more than 2,000,000 customers on December 31, 2005) must contribute \$665,000, and medium utilities (those with between 100,000 and 2,000,000 customers) must contribute \$335,000. Utilities that fail to meet their plans again after the third year must make another contribution to the fund (\$665,000 for large utilities and \$335,000 for medium utilities). After three years of non-compliance, the Illinois Power Agency (IPA) shall assume control over energy efficiency incentive programs.

Results

Illinois reported an efficiency budget of \$165.5 million for 2009/2010 (Program years are summer to summer, not calendar years). Illinois electric utilities reported efficiency program savings of 553,152 MWh in 2009, a major increase from reported savings of 6,403 MWh in 2008.

Maine¹⁵²

Legislation

In June 2009, Maine enacted the Act Regarding Maine's Energy Future, which established the Efficiency Maine Trust. As a part of this Act, the Trust is responsible for creating a plan to reach the energy efficiency targets.

In pursuance of these goals, the Trust must develop triennial plans describing a three-year plan, programs, and implementation strategies for reaching these goals, as well as other energy efficiency and renewable energy goals. The triennial plans must be approved by the Maine Public Utilities Commission, and will be reanalyzed annually through Docket 2010-116. The first triennial plan was approved by the Commission in July 2010, and will expire in June 2013.

The overall goals and the programs are directed at consumers rather than utilities. Reviews to the plan were approved in February 2011, and again in January 2012.

Applicable Sectors:

- Utility.

Targets

The plan includes a goal of saving more than 3.3 trillion BTUs of energy annually by Fiscal Year 2013. Efficiency Maine has made the draft fiscal year 2014-2016 triennial plan available.

Current peak demand targets:

- 100 MW reduction by 2020.

Funding

Cost-recovery rates, with set rate impact parameters.

Penalties/Rewards

Unknown.

Results

Efficiency Maine also publishes an annual report on its activities; Fiscal Year 2011 Efficiency Maine Annual Report was published in December 2011.

¹⁵² <http://aceee.org/sector/state-policy/maine;>
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=ME17R&re=1&ee=1



Maryland¹⁵³

Legislation

In April 2008 Maryland enacted legislation setting a state goal of achieving a 15% reduction in per capita electricity consumption and 15% reduction in per capita peak demand by 2015, compared to 2007 levels.

Utilities are required to consult with the Maryland Energy Administration (MEA) on program design and implementation every three years. The first consultation was required to take place by July 1, 2008. Utilities must also submit plans for achieving the specified energy consumption and peak demand reductions to the PSC every three years, with the first plan due by September 1, 2008. The PSC is tasked with evaluating the plans based on cost-effectiveness, rate impacts for each ratepayer class, job impacts, and environmental impacts. Utilities filed their second set of plans for the 2012 - 2014 compliance period during the summer of 2011 and the plans were approved by the PSC in December 2011.

The ongoing regulatory proceedings at the PSC are taking place in Case Nos. 9153 - 9157 (each utility has a different case number).

Applicable Sectors:

- Utility (Statewide Goal).

Targets

The legislation requires the Maryland Public Service Commission (PSC) to direct the state's electric utilities to implement programs designed to achieve a 5% reduction in per capita electricity consumption by 2011 and a 10% reduction by 2015. The remainder of the overall goal of 15% is to be accomplished independently through other means.

Utility targets for per capita peak demand reduction are set at 5% by 2011, 10% by 2013, and 15% by 2015, thus utilities are responsible for the full portion of the peak demand reduction target.

Current peak demand targets:

- 5% reduction in per capita peak demand by 2011, 10% by 2013, and 15% by 2015, compared to 2007

Funding

Cost-recovery rates, with no specific limits.

Penalties/Rewards

Unknown.

Results

The Maryland PSC issues annual reports on progress made towards meeting the standards. The Empower Maryland 2011 Compliance Report indicates that the utilities' collective per capital demand reduction and energy savings achievements met the 2011 targets, but that part of the savings is attributable to factors such as moderate weather and the economic downturn rather than utility programs. In fact, collective program energy savings generally fell well short of the 2011 goal, though the utilities were able to generate peak demand savings equivalent to 105% of the 2011 goal.

Progress towards the targets also differed substantially from utility to utility.

¹⁵³ <http://aceee.org/sector/state-policy/maryland>.



Missouri¹⁵⁴

Legislation

In 2009, Missouri enacted the Missouri Energy Efficiency Investment Act, creating energy efficiency sales and peak reduction goals to be met through investment in demand side management. The targets outlined below were created by the Public Service Commission (PSC) in 2010, with benchmarks beginning in 2012

The goal of the program is to achieve all cost-effective demand-side savings.

Applicable Sectors:

- Utility, Investor-Owned Utility.

Targets

Annual benchmarks beginning in 2012.

Current peak demand targets:

- Cumulative reduction of 9% by 2020, increasing by 1% each year thereafter:

Year	Annual Peak Reductions	Cumulative Peak Reductions
2012	1.0%	1.0%
2013	1.0%	2.0%
2014	1.0%	3.0%
2015	1.0%	4.0%
2016	1.0%	5.0%
2017	1.0%	6.0%
2018	1.0%	7.0%
2019	1.0%	8.0%
2020	1.0%	9.0%
2021+	1.0%	--

Funding

Individual utilities must file an application with the PSC for approval of their demand-side management programs; recovery for any such programs will not be permitted unless the programs were approved by the PSC and result in energy or demand savings. The Total Resource Cost Test will be considered the preferred cost-effectiveness test. The only exceptions to the cost-effectiveness requirement is programs for educational purposes or for low-income customers.

The PSC may develop cost recovery mechanisms to encourage investment in demand-side programs, including capitalization of investments in and expenditures for demand-side programs, rate design modifications, accelerated depreciation on demand-side investments, and allowing utility retention of a portion of the net benefits of demand-side programs for its shareholders.

As required by statute, Docket EW-2011-0372 was opened in May 2011 to study rate design modifications associated with demand-side cost recovery before such a program can be implemented.

Penalties/Rewards:

Unknown.

Results:

Unknown.

¹⁵⁴ <http://aceee.org/sector/state-policy/missouri>;
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MO10R&re=1&ee=1.



Ohio¹⁵⁵

Legislation

In May 2008, Ohio enacted broad electric industry restructuring legislation (SB 221) containing energy efficiency requirements for investor-owned utilities. In addition to the efficiency standard, SB 221 established the Ohio Alternative Energy Portfolio Standard (AEPS), requiring utilities to obtain 12.5% of their energy for distribution from renewable resources by 2024, and an additional 12.5% of electricity from advanced resources by 2025.

The baseline for sales reductions are calculated based on the average number of total kilowatt-hours sold during the previous three years. For peak demand reductions, the baseline is calculated by the average peak demand during the previous three years. The Public Utilities Commission of Ohio (PUCO) may alter the baseline to account for new economic growth in a utility's territory or weather changes.

In order to meet the targets, utilities may implement demand-response or customer-sited programs, or transmission and distribution infrastructure improvements. In 2012, the legislature passed a bill that allows certain combined heat and power and waste energy recovery systems to qualify for the Energy Efficiency Portfolio Standard. Systems only qualify if they are installed or retrofitted on or after September 9, 2012. Certain waste energy recovery systems installed in 2002-2004 may also qualify. A system may qualify for either the Renewable Energy Resource portion of the AEPS or the Energy Efficiency Portfolio Standard. Savings from combined heat and power or waste energy recovery must be calculated by the PUCO. The amount of savings claimed from these two resources cannot exceed the annual percentage of the utility's industrial-customer load.

Targets

Electric utilities are required to implement energy efficiency and peak demand reduction programs that result in a cumulative electricity savings of 22% by the end of 2025, with specific annual benchmarks. In addition, utilities must reduce peak demand by 1% in 2009, and 0.75% annually through 2018. In 2018, the legislature must make recommendations for future peak demand reduction targets. *Current peak demand targets:* 1% reduction in peak demand in 2009, 0.75% reduction in peak demand each year through 2018.

Year	Annual Peak Demand Reduction	Cumulative Peak Demand Reduction
2009	1%	1%
2010	0.75%	1.75%
2011	0.75%	2.50%
2012	0.75%	3.25%
2013	0.75%	4.00%
2014	0.75%	4.75%
2015	0.75%	5.50%
2016	0.75%	6.25%
2017	0.75%	7.00%
2018	0.75%	7.75%

Funding:

Unknown.

Penalties/Rewards

Failure to comply with energy efficiency or peak demand reduction requirements will result in PUCO assessing a forfeiture upon the utility, which will be credited to the Advanced Energy Fund. The amount of the forfeiture is either of the following:

- An amount, per day per under-compliance or non-compliance, not greater than \$10,000 per violation
- An amount equal to the then existing market value of one renewable energy credit per megawatt hour of under-compliance or noncompliance.

¹⁵⁵ <http://aceee.org/sector/state-policy/ohio;>
[http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=OH16R&re=1&ee=1.](http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=OH16R&re=1&ee=1)



Pennsylvania¹⁵⁶

Legislation

In October 2008 Pennsylvania adopted Act 129, creating energy efficiency and conservation requirements, including requiring obligated utilities to develop plans to provide electricity and peak demand savings in line with the targets. Notably, energy efficiency measures may potentially include solar and geothermal technologies. In January 2009 the Pennsylvania Public Utilities Commission issued an order defining how these requirements, referred to as Phase I requirements, were to be implemented.

Under Phase I of the standard, utilities were required to develop plans for achieving these targets and submit them to the PUC for review by July 1, 2009. Among other required details, the plans had to be designed to provide minimum of 10% of the requirements from units of Federal, State and local government, including municipalities, school, districts, institutions of higher education and nonprofit entities. They were also required to include specific measures for households at or below 150% of the federal poverty income guidelines. In the Phase II Order, the 'carve-out' for governmental entities and non-profits was maintained, and the PUC also elected to adopt a goal that 4.5% of each utility's target be met with savings in the low-income sector.

All Phase I utility plans had been approved by the PUC by the end of 2009 and the obligated utilities are all now offering various energy programs for their customers. In June 2011 the PUC issued an order establishing an expedited process by which utilities may make minor changes to their energy efficiency and conservation plans outside of the potentially time consuming process defined in the original January 2009 Act 129 Implementation Order. The Phase II Order adopted a similar approval process and required utilities to file new plans by November 1, 2012, though these filings have now been delayed by utility challenges to the Phase II targets.

By November 30, 2013 and every five years thereafter, the PUC is required to evaluate the costs and benefits of the energy consumption reduction program, and consider developing requirements for additional incremental consumption reductions. A similar review is required for the peak demand reduction requirements. The PUC completed its first review in August 2012, determining that the benefits of the programs exceed their costs, and initiating Phase II of the standard.

Applicable Sectors:

Applies to state's investor owned utilities with at least 100,000 customers. With this limitation on applicability, the standards apply only to the following utilities: PECO Energy, PPL Electric Utilities, West Penn Power, Pennsylvania Electric (Penelec), Metropolitan Edison (Met-Ed), and Duquesne Light.

Targets

Phase I targets were: Electricity savings of 1% by May 2011 and 3% by May 2013, measured against projected electricity consumption for the period from June 2009 – May 2010. The utilities were also required to develop plans that provide for peak demand savings of 4.5% by May 31, 2013, measured against actual peak demand from June 2007 – May 2008

Phase II will run from June 1, 2013 - May 31, 2016 and requires (tentatively) energy savings that vary by utility from 1.6% to 2.9% of June 2009 - May 2010 electricity consumption. These targets are expected to result in collective savings of 3.3 million megawatt-hours (MWh) over the three-year period. Any savings in excess of the Phase I 3% target may be applied to the Phase II targets. The Phase II order provided a specific process for utilities to challenge the revised targets by requesting an evidentiary hearing. With the exception of Duquesne Light Company, it appears that all of the utilities have chosen to make such a challenge.

¹⁵⁶ <http://aceee.org/sector/state-policy/pennsylvania;>
[http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=PA14R&re=1&ee=1.](http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=PA14R&re=1&ee=1)



Current peak demand targets:

In the Phase II Order, the PUC chose to not establish additional peak demand reduction targets pending further study and evaluation, but permitted the utilities to continue existing residential demand response programs and file petitions to develop new programs.

Funding

Rate Impact Parameters:

Costs may not exceed 2% of annual utility revenue as of December 31, 2006

Utilities are permitted to recover all reasonable and prudent costs associated with their program offerings through a reconcilable adjustment clause. Related costs associated with decreased revenue and retail sales may not be included under this adjustment, but may be reflected in future utility rate-making proceedings. The total cost associated with an electric utility's energy efficiency and peak demand reduction plan may not exceed 2% of the utility's total annual revenue as of December 31, 2006. The PUC has found that the cost should be determined as an average annual amount rather than as the full cost of the multi-year plan as a whole.

Penalties/Rewards

Failure to achieve the requisite reductions in electricity consumption and peak demand is punishable by fines from \$1 million to \$20 million. (Failure to file a plan with the PUC is also punishable by a fine of \$100,000 per day). Costs associated with any such fines are not recoverable from ratepayers.

Results

Unknown.

Rhode Island¹⁵⁷**Legislation**

Rhode Island enacted legislation in 2006 requiring the state Public Utilities Commission (PUC) to establish standards for system reliability, energy efficiency and conservation procurement, including standards for energy supply diversification, distributed generation, demand response, and 'prudent and reliable' energy efficiency and energy conservation measures. These standards and guidelines, which were adopted by the PUC in 2008, must be reviewed at least once every three years. Each electric and natural gas distribution company must submit to the PUC for review and approval every three years -- beginning September 1, 2008, and ending September 1, 2017 -- a plan for system reliability, energy efficiency and energy conservation procurement.

Additional legislation enacted in June 2012 (H.B. 8233) requires utilities to support the installation efficient combined heat and power (CHP) systems at commercial, industrial, institutional and municipal facilities. Each utility must specify in its annual efficiency program plan how it will do so. Proposed plans must be approved by the state's Energy Efficiency and Resource Management Council.

Targets

In July 2011, the PUC approved energy savings targets for National Grid for 2012, 2013 and 2014. Specifically, National Grid must design its energy efficiency plans with the goal of reducing energy consumption by 1.7% in 2012, 2.1% in 2013 and 2.5% in 2014. These goals are intended to achieve electricity savings of 128,570 MWh in 2012, 158,820 MWh in 2013 and 189,068 MWh in 2014. Capacity savings for summer and winter demand were also established.

¹⁵⁷ <http://aceee.org/sector/state-policy/rhode-island;>
[http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=RI14R&re=1&ee=1.](http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=RI14R&re=1&ee=1)



Current peak demand targets¹⁵⁸:

	2011	2012	2013	2014
Summer Demand (kW)	18,512	23,204	28,664	32,759
Winter Demand (kW)	17,197	21,556	26,628	30,432

Funding

Rhode Island Statute 39-2.1.2 requires each electric distribution company to include a surcharge per kilowatt-hour delivered to fund demand-side management programs, which are implemented by the electric distribution company. The electricity surcharge took effect January 1, 2008, and will remain in place through December 31, 2017. The PUC determines the surcharge levels, which are not specified by the statute, for electricity and gas delivery.

Penalties/Rewards

Unknown.

Results

Unknown.

Texas¹⁵⁹

Legislation

Since 1999, Texas law has required electric utilities to meet energy efficiency goals, requiring electric utilities to offset 10% of load growth through end-use energy efficiency (Texas Senate Bill 7). (Demand growth being the average growth of the five previous weather adjusted peak demands for each utility.)

In 2007, after several years of meeting this goal at low costs, the legislature increased the standard to 15% of load growth by December 31, 2008 and 20% of load growth by December 31, 2009 (Texas House Bill 3693). The legislation also required utilities to submit energy savings goals. The Public Utility Commission of Texas (PUC) approved these rules in March 2008..

In 2010, the Public Utilities Commission of Texas (PUC) approved Substantive Rule 25.181, a new Energy Efficiency Rule which increases the goals from 20% of electric demand growth to 25% growth in demand in 2012 and 30% in 2013 and beyond. The rule also establishes customer cost caps to contain costs, which will inhibit some utilities from investing in cost-effective energy efficiency measures.

In the 2011 legislative session, Texas adopted Senate Bill 1125, which amends the EERS policy by requiring utilities to eventually achieve savings of 0.4% of each company's peak demand. As a result, utilities with declining or rapidly growing load growth will have more predictable and consistent goals than those that were set based on load growth. The Bill also added focus on reducing demand in the winter, which is more likely to result in real energy efficiency savings than summer demand response programs, which simply shift load and reduce peak demand. The Bill does not remove the cost caps adopted in 2010, but included the bonus under the cost cap.

Targets

- 30% of electric demand growth in 2013
- 0.4% of each company's peak demand

¹⁵⁸ [http://www.ripuc.org/eventsactions/docket/4202-EERMC-EST-Filing\(9-1-10\).pdf](http://www.ripuc.org/eventsactions/docket/4202-EERMC-EST-Filing(9-1-10).pdf).

¹⁵⁹ <http://aceee.org/sector/state-policy/texas>;
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX28R&re=1&ee=1.



Funding

Programs are typically funded through the utilities' tariff or base rate. An Energy Efficiency Cost Recovery Factor (EECRF) rate schedule is included in tariffs and permits utilities to recover the costs of providing energy efficiency programs.

'The EECRF shall be set at a rate that will give the utility opportunity to earn revenues equal to the sum of the utility's forecasted efficiency costs, net of energy efficiency costs included in base rates, the EE bonus amount that it earned for the prior year...and any adjustment for past over- or under-recovery of energy efficiency revenues'.¹⁶⁰

Sum of base rate recovery of energy efficiency costs and the EECRF cannot exceed specified amounts:

	2011 to 2012	2013 onwards
Residential	Monthly Basis = \$1.30/month Energy Basis = \$0.0010/kWh	Monthly Basis = \$1.60/month Energy Basis = \$0.0012/kWh
Non-Residential	\$0.0005/kWh	\$0.00075/kWh

The amendments also make several revisions to the energy efficiency cost recovery factor (EECRF) proceedings, including revising the procedural schedule and scope of the EECRFs and allowing an annual consumer price index (CPI) adjustment to the cost caps beginning in 2014; requiring costs to be directly assigned on a rate class basis and calculating EECRFs to provide for energy charges for residential and commercial customers billed for base rates on an energy basis and as an energy or demand charge for each commercial rate class billed on a demand basis for base rates

Alternatively, a commission order establishing a utility's base rate may also include an amount to offset energy efficiency program costs. The commission also has the option of approving an energy charge or a monthly customer charge for the EECRF.

Penalties/Rewards

All investor-owned utilities have a shared benefit incentive in place. When a utility exceeds its demand reduction goal within the prescribed cost limit it is awarded a performance bonus. The performance bonus is based on the utility's energy efficiency achievements for programs implemented in the previous year (PUCT Substantive Rule §25.181).

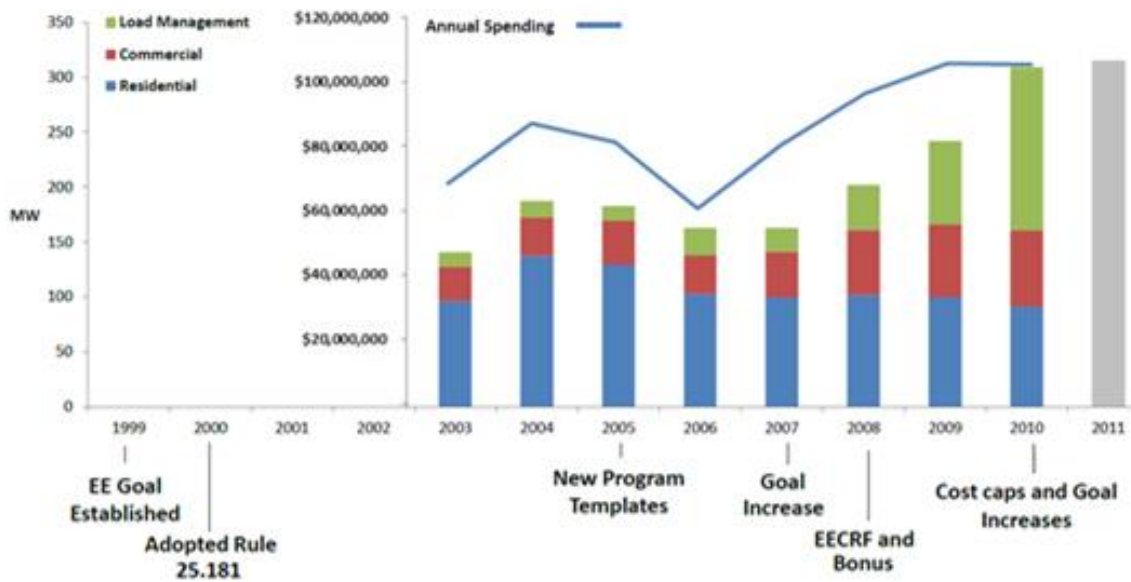
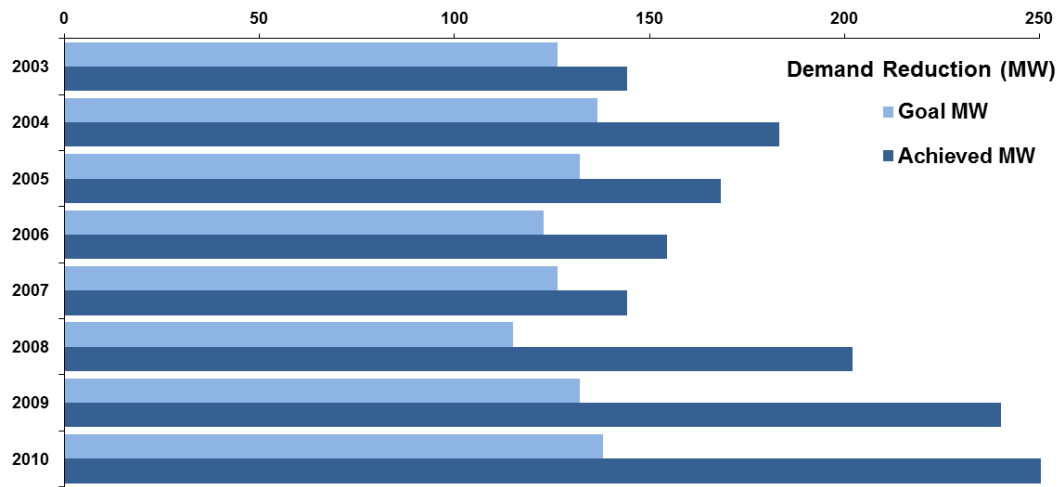
A utility that exceeds its demand reduction goal receives a bonus equal to 1% of the net benefits for every 2% that the utility exceeds its goal. The maximum bonus was originally equal to 20% of the utility's program costs. In 2011, it changed to a maximum of 10% of total net benefits.

Additionally, a utility that meets at least 120% of its demand reduction goal with at least 10% of its savings achieved through Hard-to-Reach programs (which benefit customers with an annual household income at or below 200% of the federal poverty guidelines) can receive an additional bonus equal to 10% of the regular performance bonus.

¹⁶⁰ http://www.puc.texas.gov/industry/projects/rules/38578/EUMMOT_EEIP_June_2_2011_EECRF.pdf.



Results



Vermont¹⁶¹

Context

Vermont has had extensive energy efficiency programs since 1990. Originally, programs were run by the state's utilities under jurisdiction of the Vermont Public Service Board (PSB), but in 1999 the PSB transferred operations to Efficiency Vermont, an independent, statewide 'energy efficiency utility' (EEU) supported by public benefits funding that delivers efficiency programs for the state. Vermont is one of two states that established statewide public benefits funding without electric utility restructuring.

Legislation

Vermont does not have traditional EERS legislation with a set schedule of energy-savings percentages for each year. Instead, Vermont law requires EEU budgets to be set at a level that would realize 'all reasonably available, cost-effective energy efficiency.'

Targets

Three-year Quantifiable Performance Indicators (QPIs) are established as part of the Demand Resources Plan ('DRP') process. The DRP process is used to determine the QPI targets, including corresponding incentive amounts attached to each and the financial consequences for under-performance

Current peak demand targets:

- Summer peak savings: 60,800 kW (three-year goal for 2012-2014). Winter peak savings: n/a

Targets for the previous three years (2009-2011) were: Summer peak: 51,200 kW, Winter peak: 54,000 kW.

Funding

Vermont pioneered the model of a statewide 'energy efficiency utility' (EEU) after Vermont enacted legislation in 1999 authorizing Vermont Public Service Board (PSB) to collect a volumetric charge on all electric utility customers' bills to support energy efficiency programs. Volumetric charges are assessed on a per kWh or per therm basis. Vermont PSB created the EEU, Efficiency Vermont, to use these public benefits funds to provide programs and services that save money and conserve energy.

Penalties/Rewards

Initially, there was no explicit penalty for non-performance, but a portion of the compensation Vermont pays the administrator was contingent on meeting stated goals, subject to a monitoring and verification process.

With the introduction of QPIs, performance compensation is to be paid based on the attainment of the three-year QPI targets discussed below. Currently QPIs 1-7 have a positive performance award associated with them and include 100% target levels, 'super-stretch' targets, corresponding incentive amounts attached to each (reflecting weighting), scaling calculations, and the financial consequences for under-performance. QPIs 8-14 are minimum performance requirements where the impact for failure to meet the proposed QPI target is the forfeiture of the opportunity to meet a portion of the performance award.

Results

In 2008, Efficiency Vermont saved 150 GWh at a cost of 2.9 cents per kilowatt-hour (over the life of the measures) according to its annual reports. In 2009, Efficiency Vermont saved 90 GWh at a cost of 3.8 cents per kilowatt-hour.

¹⁶¹ <http://aceee.org/sector/state-policy/vermont;>
[http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=VT12R.](http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=VT12R)



US Federal EERS

Stand-alone EERS proposals include H.R. 2529 (Markey) and S. 548 (Schumer). They call for distribution utilities throughout the country to demonstrate 15% electricity savings and 10% natural gas savings by 2020.¹⁶² They have estimated peak demand savings of 117,000 MW.¹⁶³

The federal EERS implies annual savings targets, with utilities achieving 0.33% electricity and 0.25% natural gas savings in the first year of implementation, relative to average energy sales in the preceding two years (the baseline). The initial savings targets start at modest levels, giving utilities in states without an existing EERS the opportunity to develop successful energy efficiency programs. Annual targets are higher at the end of the compliance period because savings from building codes and appliance standards build steadily in the later years. Additionally, targets have been ‘back-loaded’ to make it easier for utilities just starting to implement energy efficiency programs. Most utilities will be able to accrue savings in the early years reducing the new savings needed in the later years.

Committee-passed Federal proposals – e.g. H.R. 2454 (Waxman-Markey); S. 1462 (Bingaman) – do not include a stand-alone EERS. They do include a Renewable Electricity Standard (RES), with EE eligible to meet a portion of the standard.¹⁶⁴

	HR 2454	S 1462
Obligated entities	Electric utilities with annual sales (excluding resale) of greater than 4,000,000 MWh	Electric utilities with annual sales (excluding resale) of greater than 4,000,000 MWh; excludes HI
Targets & Timetables	Annual targets from 2012-2039; 6% of base amount in 2012 ramping to 20% in 2020 and beyond; 1/4 of the target can be met with EE; the Governor may petition to increase EE component to 2/5	Annual targets from 2011-2039; 3% of base amount in 2011 ramping to 15% in 2021 and beyond; 26.67% of the target can be met with EE upon petition by the Governor
Base amount adjustment	Electricity generated by hydro that does not qualify for the RE component, CCS, new nuclear	Electricity generated by hydro, municipal solid waste, CCS, new nuclear or capacity/efficiency improvements at existing plants
Eligible Resources	Customer facilities (including recycled energy), distribution system, CHP, fuel cells	Customer facilities (including recycled energy), distribution system, CHP
Eligible Mechanisms	Utility played a ‘significant role’ in achieving savings (including through 3rd parties or purchased savings); include savings from programs administered by the utility and funded by State, Federal, or other sources; excludes savings from mandatory building and appliance standards	Utility achieved qualified savings, other entity achieved qualified savings and sold EE savings to a utility; excludes savings from mandatory building and appliance standards
Trading of energy savings	Allows for trading of energy savings occurring in the purchasing utility’s state and that meets EM&V requirements through bilateral contracts	DOE to establish Federal EE credit trading program

¹⁶² <http://www.aceee.org/research-report/e091>.

¹⁶³ <http://www.aceee.org/sites/default/files/publications/researchreports/E091.pdf>.

¹⁶⁴ http://www.epa.gov/statelocalclimate/documents/pdf/brown_presentation_1-19-2010.pdf.



	HR 2454	S 1462
States with non-utility admin. of EE prgms	Provides for electricity savings achieved through such programs to be distributed equitably among utilities with PUC direction	Not explicitly addressed; potentially covered by section that allows for non-utility entities to receive EE credits, which could be transferred to utilities
EM&V	FERC to prescribe standards & protocols for EM&V methods; and standards requiring 3rd party verification; States may propose alternative methods that are equivalent to FERC standards	DOE to prescribe standards & protocols for EM&V methods; and standards requiring 3rd party verification
Delegation of Authority for oversight of EE savings	FERC may delegate to States the authority to oversee EM&V and to determine annual savings that may count towards the compliance obligation if the Governor submits an application	n/a

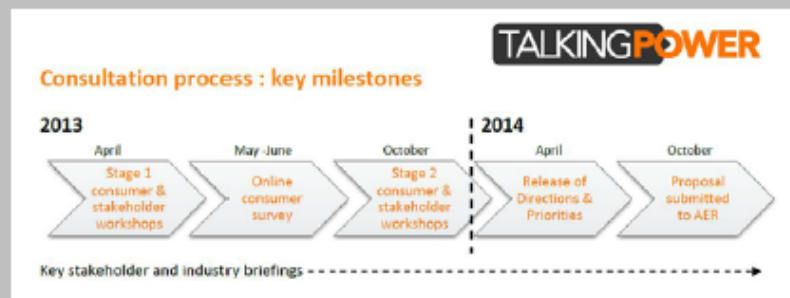


D. EXAMPLES OF NETWORK DM¹⁶⁵

'TALKING POWER' ENHANCES CONSUMER ENGAGEMENT

As network businesses enter a future characterised by significant changes in government policy, network and consumer-side technology, industry regulation and retail price reform, greater participation of consumers in decision making will deliver better outcomes.

SA Power Networks is South Australia's sole electricity distributor, delivering power to more than 835,000 homes and businesses across the State. As it prepares its plans for managing the State's electricity distribution network in the 2016–2020 regulatory period, SA Power Networks has commenced extensive community consultation in an innovative engagement program called *Talking Power*.



Talking Power is focused on SA Power Networks' residential and commercial customers, and aims to listen to and understand their views, needs and priorities for the distribution network. A comprehensive engagement plan, to take place over 2013 and 2014, will feature consumer and stakeholder workshops, an online consumer survey and regular stakeholder updates.

Realising that it is important for customers to have a clear communication channel throughout the process, the *Talking Power* website will support every stage of the engagement process. This will be the one-stop-shop for all things regarding SA Power Networks' 2016–2020 regulatory proposal.

<http://talkingpower.com.au/>

THE SMART HOME FAMILY

The Smart Home was built by Ausgrid and Sydney Water to test what life is like for a family to live with the latest energy and water efficient technologies. The Smart Home is being tested by a real family, in real time, with information broadcast via the internet.

The Smart Home is now being tested by its second family and follows the success of the original family. Everyone uses energy differently, and this second trial enables Ausgrid to see how the home performs with a different family. This family is among the first to trial technologies to be tested in the Australian Government's \$100 million Smart Grid, Smart City project. The home showcases more than 20 energy- and water-efficient appliances, efficient lighting and a standby power device.

The Smart Grid, Smart City demonstration project trials new technologies designed to make the electricity grid more efficient and give households more information and control over their energy use and costs.

This Smart Home allows the wider community to share the experience and is an opportunity to learn and plan for the future of energy use in Australia.

<http://www.smarthomefamily.com.au> <http://www.smartgridsmartcity.com.au>

¹⁶⁵ Examples provided by the Energy Networks Association of Australia.



INFORMATION AT YOUR FINGERTIPS – WEB PORTALS

Jemena's *Electricity Outlook* is a free self service web portal that gives smart meter customers greater control of their electricity use and power bill.

Combined with advanced metering technology *Electricity Outlook* enables consumers to better understand their usage and costs on a daily basis. The compare function on the portal also allows consumers to determine if they have the retail-price offering that best suits their consumption needs.

In the short term the web portal also allows consumers to notice unexpected levels of use and take immediate action by switching off appliances if they choose. In the long term, the web portal can arm households with the information to make a long-term investment in technologies that change their energy use.

Jemena distributes electricity to more than 320 000 customer sites and is playing a key part in the roll out of advanced metering technology in Victoria having installed more than 177 000 smart meters in its network area. <http://jemena.com.au/>

POSITIVE PAYBACK – IT PAYS TO SAVE

In south-east Queensland, Energex provides 59% of its customers with a demand management service, such as off-peak power for hot water, pool filtration and air conditioning.

Energex's latest initiative is the Positive Payback Program which rewards customers for buying and using energy efficient appliances.

Customers can receive gift cards for choosing PeakSmart air-conditioners. These air conditioners have a device which automatically reduces energy use at times of peak demand, saving the customer money and easing demand on the grid. Other customers can choose to install the device in their existing units.

Thanks to a partnership of network, manufacturers and retailers, more than 129 PeakSmart models are now available for customers. Combined some 30,000 customers are involved in one or more of the air-conditioner and pool pump programs and this, along with Commercial and Industrial programs, has resulted in more than 100MVA of load being removed from Energex's summer peak demand.

Importantly information collected from the peak demand programs has provided detailed facts and figures for use by the Commonwealth Government's Equipment Energy Efficiency Committee review into 'smart appliances'.

Reducing the surges in peak demand created by air conditioners allows network businesses to defer costly upgrades to network capacity for the benefit of all customers.

<http://www.energex.com.au/sustainability/rewards-for-air-conditioning-pools-and-hot-water>



PEAK DEMAND INITIATIVES DELIVER FLEXIBILITY FOR BUSINESS

A fundamental pressure on network infrastructure is the need to meet rising peak demand and to expand capacity to meet short, intense periods of demand. This is one of the key drivers of the increased network costs that have influenced rising electricity prices.

With this in mind ENA members companies are implementing innovative ways to work with customers to manage demand on those days. One of those initiatives is SP AusNet's Critical Peak Demand tariff.

This new tariff was introduced in 2011 for commercial customers that consume more than 160MWhs (megawatt hours) of electricity per annum. It allows participating businesses the opportunity to minimise electricity consumption or seek alternative supply sources during specific times on five "peak demand days" nominated by SP AusNet – usually the hottest summer days. By doing this, participating customers can reduce their tariff for the next 12 months and it also helps SP AusNet to improve the supply reliability and reduce the costly investment needed to keep the power on during these peak demand days. SP AusNet declared 5 Critical Peak Demand days between February and March 2013.

To date the Critical Peak Demand tariff has reduced the total annual peak demand across SP AusNet's electricity distribution network by three to four per cent, equivalent to the total annual demand of 22,800 houses. Customers already taking advantage of this tariff have taken steps to reduce consumption during nominated peak demand periods and have reduced their electricity costs.

<http://www.sp-ausnet.com.au/>

SAVE A BOMB IN THE POOL

Regional Queenslanders have saved \$2.8 million in electricity costs by taking advantage of a demand management and pool pump efficiency incentive program offered by Ergon Energy.

The *Save a Bomb* pool pump offer allows Ergon's customer to upgrade pool pumps to energy efficient models and utilise off peak tariffs, showing that industry, consumers and networks can work together for mutual benefit – in this case less on customers' bills and reductions in peak demand on the network.

3314 pool owners have taken up the cash back offers to purchase an energy efficient pump, while a further 7088 customers have taken up the Tariff 33 economy pricing offer. Figures also show that demand at peak times on Ergon's network has been reduced by more than 5.5 MVA as a direct result of the *Save a Bomb* pool pump offer.

Ergon and the pool industry has worked together to deliver real benefits for the future on infrastructure savings, through reduced network demand, and it is great savings news for customers

The demand savings achieved through the program are believed to have been delivered at 29 per cent less than it would have cost to build the network for the larger demand.

<http://www.ergon.com.au/>



ENERGY EFFICIENCY REDUCES POWER BILL - WESTERN POWER

Western Australia's *Perth Solar City* is the most comprehensive energy efficiency program the state has undertaken. Now in its final year, Western Power is wrapping up the four year energy efficiency program.

Over 16,000 households in Perth participated in a series of energy efficiency trials aimed at helping customers save money on power bills as well as reducing their carbon footprint. At this stage the program has shown that some households saved more than \$1,000 per year on their power bills.

Results

Program	Outcome	Average annual household bill savings
Air-Conditioner Trial	25% reduction in electricity use at peak time	N/A(note: participants received annual incentive payments)
Time-of-Use Tariff (PowerShift)	9% reduction in electricity use during the 'super peak' period	\$105.00 - \$205.00
In home Display and Time-of-Use Tariff	13% reduction in electricity use during the 'super peak' period	\$115.00 – \$235.00
Residential solar PV systems	40% reduction in average daily electricity use from the Western Power network.	\$740.00
Residential solar hot water systems	18% reduction in average daily electricity use	\$372.00
Behaviour change (Living Smart)	7.5% reduction in average daily electricity use	\$128.00
Home Eco-Consultations	12.5% reduction in average daily electricity use	\$220.00

Source: Perth Solar City Annual Report 2012 <http://www.perthsolarcity.com.au/annual-report>

Energy efficiency has clear benefits for households. The Perth Solar City Program has illustrated how households are able to reduce their bills when they are given the right tools and education to help them understand, and then change, how and when they use electricity

At the same time trials such as this can help Western Power to operate the network more efficiently, saving customers money over the longer term.

<http://www.perthsolarcity.com.au>



E. REFERENCE LIST

- ActewAGL, 2013, *Demand Management Incentive Scheme Power Factor Correction Project 2011-12*.
- Alternative Technology Association, 2012, *Submission on the Productivity Commission's Review of Electricity Network Regulation*.
- American Council for an Energy-Efficient Economy (ACEEE), 2012, *State Energy Efficiency Policy Database* (website). <http://aceee.org/sector/state-policy/>
- Ausgrid, 2012, *Demand Management Innovation Allowance Submission 2011-2012 Report to the AER*.
- Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES), 2011, *Energy in Australia*.
- Australian Energy Market Commission (AEMC), 2010, *Future Possible Retail Electricity Price Movements: 1 July 2010 to 30 June 2013*.
- Australian Energy Market Commission (AEMC), 2011, *Electricity Statement of Opportunities 2011*.
- Australian Energy Market Commission (AEMC), 2011, *Rule Determination: National Electricity Amendment (Inclusion of Embedded Generation Research into Demand Management Incentive Scheme) Rule 2011*.
- Australian Energy Market Commission (AEMC), 2012, *Demand Side Participation and Profit Incentives for Distribution Network Businesses (Supplementary Paper, Power of Choice Review Directions Paper)*.
- Australian Energy Market Commission (AEMC), 2012, *DSP and Profit Incentives for Distribution Network Businesses (Staff Paper, Fourth Stakeholder Reference Group Meeting, Power of Choice Review)*.
- Australian Energy Market Commission (AEMC), 2012, *Distribution network planning and expansion framework (Information Sheet)*.
- Australian Energy Market Commission (AEMC), 2012, *Power of Choice Review – Giving consumers options in the way they use electricity (Final Report)*.
- Australian Energy Market Commission (AEMC), 2012, *Rule Determination: National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012*.
- Australian Energy Market Commission (AEMC), 2012, *Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule*.
- Australian Energy Market Commission (AEMC), 2013, *Market Review (Open): Differences between actual and forecast demand in network regulation (webpage)*. <http://www.aemc.gov.au/market-reviews/open/differences-between-actual-and-forecast-demand-in-network-regulation.html>.
- Australian Energy Market Operator (AEMO), 2012, *Electricity Statement of Opportunities 2011 – Update*.
- Australian Energy Market Operator (AEMO), 2012, *National Electricity Forecasting Report, 2012*.
- Australian Energy Regulator (AER), 2012, *Better Regulation Reform Program (webpage)*. <http://www.aer.gov.au/node/18824>.
- Australian Energy Regulator (AER), 2012, *Decision 2010–11 and 2011 DMIS assessment*.
- Australian Energy Regulator (AER), 2012, *Expenditure incentives guidelines (webpage)*. <http://www.aer.gov.au/node/18869>.
- Australian Energy Regulator (AER), 2012, *Explanatory Statement: Proposed Demand Management and Embedded Generation Connection Incentive Scheme, New South Wales Distribution Network Services Providers*.
- Australian Energy Regulator (AER), 2010, *State of the Energy Market Report*.



- Australian Energy Regulator (AER), 2011, State of the Energy Market Report.
- Australian Energy Regulator (AER), 2012, State of the Energy Market Report.
- Australian Energy Regulator (AER), 2013, Demand management incentive scheme assessment report 2011-12 (Non-Victorian DNSPs).
- Australian Energy Regulator (AER), 2013, Expenditure incentives guidelines for electricity network service providers; Issues paper.
- Australian Energy Regulator (AER), 2013, Information Paper: Demand Management and Embedded Generation Connection Incentive Scheme.
- Australian Energy Regulator (AER), 2013, Regulatory investment test for distribution (RIT-D) and application guidelines (webpage). <http://www.aer.gov.au/node/19146>.
- Clean Energy Finance Corporation, 2012, Report of the Expert Review Panel, Commonwealth of Australia.
- Council of Australian Governments (COAG), 2012, COAG Energy Market Reform – Implementation Plan.
- Crossley, D. 2010, International Best Practice in Using Energy Efficiency and Demand Management to Support Electricity Networks. Prepared for the Australian Alliance to Save Energy by Energy Futures Australia.
- Department of Employment, Economic Development and Innovation (DEEDI), Queensland Government, 2011, Queensland Energy Management Plan.
- Department of Resources, Energy and Tourism (DRET), Commonwealth Government, 2012, Factsheet: Electricity Prices, <http://www.ret.gov.au/Department/Documents/clean-energy-future/electricity-prices-factsheet.pdf>.
- Dunstan, C., et al. 2011a, Think Small: The Australian Decentralised Energy Roadmap. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.
- Dunstan, C., et al. 2011b, Evaluating Costs of Decentralised Energy (Working Paper 4.3, ver. 2), CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.
- Dunstan, C., Giotto, N. & Ross, K., 2011, Report of the 2010 Survey of Electricity Network Demand Management in Australia (SENDMA). Prepared for the Australian Alliance to Save Energy by the Institute for Sustainable Futures, University of Technology, Sydney.
- Dunstan, C., Ross, K.E. & Ghiotto, N. 2011, Barriers to demand management: A survey of stakeholder perceptions, Institute for Sustainable Futures, UTS, Sydney, Australia.
- Electric Power Research Institute (EPRI), 2009, Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.
- Endeavour Energy, 2012, Demand Management Innovation Allowance 2011-2012 Report: Submission to AER.
- Energex, 2010, Peak Demand Management, Planning for the Future. Presentation to the Australian Industry Group. http://pdf.aigroup.asn.au/environment/Peak_Demand_Briefing_Terry_McConnell.pdf.
- Energy Futures Australia, 2010, International best practice in using energy efficiency and demand management to support electricity networks. Prepared for Australian Alliance to Save Energy.
- Ergon Energy, 2012, 2011-12 Demand Management Innovation Allowance Annual Report to the Australian Energy Regulator.
- Ergon Energy, 2012, Demand Management Outcomes Report 2011-12. http://www.ergon.com.au/__data/assets/pdf_file/0005/137183/DMP-Outcomes-2011-12.pdf.
- Essential Energy, 2012, Regulatory Information Notice (RIN) Supporting Information for Demand Management Innovation Allowance (DMIA) 2011-2012.



- ETSA Utilities, 2011 Annual Demand Management Compliance Report.
- Futura Consulting, 2011, Power of choice – giving consumers options in the way they use electricity: Investigation of existing and plausible future demand side participation in the electricity market (Final Report for the Australian Energy Market Commission).
- Garnaut, R., 2011, Transforming the electricity sector (Update Paper Eight, Garnaut Climate Change Review – Update 2011), Commonwealth of Australia.
- Green Energy Trading, 2012, Creating a Community Financial Dividend through Managing Peak Electricity Demand (Discussion Paper).
- Independent Pricing and Regulatory Tribunal of NSW, 2002, Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services.
- Independent Pricing and Regulatory Tribunal, 2011, Changes in regulatory electricity prices from 1 July 2011 – final report.
- Independent Pricing and Regulatory Tribunal, 2012, Review of regulated retail prices and charges for electricity 2013 to 2016 (Issues Paper).
- Ison, N., Usher, J., Cantley-Smith, R., Harris, S. and Dunstan, C. (2011). The NEM Report Card: How well does the National Electricity Market serve Australia? Prepared by the Institute for Sustainable Futures and the Monash University Faculty of Law for the Total Environment Centre.
- Julia Gillard, 2012, Transcript of Interview with Paul Bongiorno, Rafael Epstein and Patricia Karvelas, Meet The Press, 2 Dec 2012.
- Langham, E. et al, 2010, Building Our Savings: Reduced infrastructure costs from improving building energy efficiency. Institute for Sustainable Futures, University of Technology Sydney.
- Mountain, B., 2012, Reducing Electricity Costs through Demand Response in the National Electricity Market.
- N.C. Solar Center (no date) DSIRE: Database of State Incentives for Renewables and Efficiency (webpage). N.C. State University with support from the Interstate Renewable Energy Council, Inc. <http://www.dsireusa.org/>.
- NERA Consulting, 2012, Peak Energy Savings Scheme Design Options: A Report for the Energy Savings Initiative Secretariat, Prepared for the Commonwealth Department of Resources, Energy and Tourism.
- Oakley Greenwood. 2012. Policy options for maximising downward pressure on electricity prices. Prepared for The Australian Industry Group, Brotherhood St Laurence, CHOICE and the Energy Efficiency Council.
- Office of Gas and Electricity Markets (UK), 2003, Electricity Distribution Price Control Review: Initial Consultation.
- Office of Gas and Electricity Markets (UK), 2013, Low Carbon Networks Fund (webpage) <http://www.ofgem.gov.uk/Networks/ElecDist/lcnf/Pages/lcnf.aspx>.
- Ontario Energy Board, 2010, Conservation and Demand Management Code.
- Ontario Executive Council, cited in Dunstan, C. et al. 2011, Think Small: The Australian Decentralised Energy Roadmap. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.
- Pew Centre, 2010, cited in Dunstan, C. et al. 2011, Think Small: The Australian Decentralised Energy Roadmap. CSIRO Intelligent Grid Research Program. Institute for Sustainable Futures, University of Technology Sydney.
- Price Waterhouse Coopers (PWC), 2012, Incentives for network driven DSP. Prepared for Energy Networks Association.
- Prime Minister, Deputy Prime Minister, Minister for Resources and Energy, 2012, COAG Reaches Agreement on Electricity Market Reform (Media Release). <http://www.pm.gov.au/press-office/coag-reaches-agreement-electricity-market-reform>.



- Productivity Commission, 2012 Electricity Network Regulatory Frameworks (Draft report), Melbourne.
- Productivity Commission, 2013, Electricity Network Regulatory Frameworks, Final Report Melbourne.
- Standing Council on Energy Reform, 2012, Electricity: Putting Consumers First.
- Standing Council on Energy Reform, 2013, SCER Response to the Power of Choice Review.
- Standing Council on Energy Reform, 2013, Wholesale Market Demand Response in the National Electricity market (webpage). <http://www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/wholesale-market-demand-response-mechanism-in-the-national-electricity-market/>.
- Tarlo, K., 2003, Capitalising Demand Management into the Asset Base: Preliminary Assessment. Prepared for Public Interest Advocacy Centre's Utility Consumers' Advocacy Program, by the Institute for Sustainable Futures, University of Technology, Sydney.
- Wright, G., 2012, Demand management targets for networks in the National Electricity Market, (Discussion Paper). Total Environment Centre, Sydney.





UNIVERSITY OF
TECHNOLOGY SYDNEY



Institute for
**Sustainable
Futures**

