

Demand-Side Participation in the Australian National Electricity Market

A Brief Annotated History

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EXECUTIVE SUMMARY

This paper presents a brief history of almost 20 years of activity in developing and implementing policy and regulatory initiatives aimed at increasing demand-side participation in the Australian National Electricity Market (NEM). This activity commenced with the publication of the first design for the NEM in 1992 and has continued with various levels of enthusiasm ever since.

The paper takes a broad view of demand-side participation and covers all policy and regulatory initiatives directed at achieving increased implementation of demand-side management (DSM) by electricity businesses participating in the NEM.

Three main groups of actors have developed and implemented demand-side participation initiatives:

- State Governments, particularly during the reform process for the electricity industry;
- electricity industry regulators; and
- institutions responsible for the operation and governance of the NEM.

During the 1990s, vertically integrated electricity utilities in Australia were unbundled into separate generation, transmission, distribution, and electricity retailing businesses. Following this unbundling, only the “wires” businesses have any incentive to implement projects that cost-effectively reduce load on the system. An incentive occurs when a load reduction project is less expensive than building poles and wires to augment or expand an electricity network.

Consequently most of the demand-side participation initiatives undertaken in Australia have been directed at electricity businesses responsible for managing and operating electricity transmission and distribution networks (i.e., grids). Electricity distributors, in particular, have been the target of many initiatives, most of which are directed at encouraging distributors to implement projects to reduce peak loads on their networks and thereby defer requirements to augment or expand their network infrastructure. Despite the development and implementation of a large number of initiatives, the level of demand-side participation in the NEM implemented by electricity network businesses is quite low.

Since 2003, three State Governments in Australia have imposed obligations on electricity retailers to achieve set energy efficiency targets. The obligations require retailers operating in each State to achieve annual energy efficiency targets. In two states, New South Wales and Victoria, the obligations are accompanied by energy efficiency certificate trading schemes (also known as “white certificate” schemes). In South Australia, energy efficiency trading may occur, but no certificates are issued. The imposition of these obligations has resulted in significant levels of energy savings, which are likely to increase over the next 10 years. In addition the obligations imposed in New South Wales and Victoria have stimulated the development of an energy efficiency services industry in each of these States.

The Australian NEM is a competitive energy-only wholesale electricity market operating through a gross pool. The experience in Australia suggests that achieving high levels of demand-side participation in this type of market is difficult. To increase demand-side participation in the NEM, it may be necessary to implement some fundamental changes to the structure of the market, such as introducing forward capacity and ancillary services markets that enable bidding by, and reveal the value of, demand-side resources.

In contrast, imposing energy efficiency obligations on electricity retailers in Australia has been successful in achieving significant levels of energy savings. Energy efficiency obligations effectively overcome, through public policy means, the critical barriers to efficiency improvements that end-users face. The savings achieved could be increased by extending the obligations to all States covered by the NEM and increasing the energy efficiency targets.

ABBREVIATIONS AND ACRONYMS

ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AUD	Australian dollar
CBA	Cost benefit analysis
COAG	Council of Australian Governments
DEUS	Department of Energy Utilities and Sustainability (New South Wales)
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DSM	Demand-side management
ESC	1. Essential Services Commission (Victoria) 2. Energy Savings Certificate (New South Wales)
ESCO	Energy services company
ESCOSA	Essential Services Commission of South Australia
ESS	Energy Savings Scheme (New South Wales)
GGAS	Greenhouse Gas Reduction Scheme (New South Wales)
GGRT	Greenhouse Gas Reduction Target
GHG	Greenhouse gas
GPT	Government Pricing Tribunal of New South Wales
GW	Gigawatt
GWh	Gigawatt-hour
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
MCE	Ministerial Council on Energy
MEU	Ministry of Energy and Utilities (New South Wales)
MWh	Megawatt-hour
NECA	National Electricity Code Administrator
NEM	Australian National Electricity Market
NGAC	New South Wales Greenhouse Abatement Certificate
NSSC	National Stakeholder Steering Committee
PGGGRT	Priority Group Greenhouse Gas Reduction Target
QCA	Queensland Competition Authority
REES	Residential Energy Efficiency Scheme (South Australia)
RERT	Reliability and Emergency Reserve Trader
SAIIR	South Australian Independent Industry Regulator
SCO	Standing Committee of Officials
tCO ₂ -e	Tonnes of carbon dioxide equivalent
TER	Tasmanian Energy Regulator
TWh	Terawatt-hour
UPWG	User Participation Working Group
VEEC	Victorian Energy Efficiency Certificate
VEET	Victorian Energy Efficiency Target
VENCorp	Victorian Energy Networks Corporation

1. INTRODUCTION

The purpose of this paper is to present a brief history of the development and implementation of policy and regulatory initiatives aimed at increasing demand-side participation in the Australian National Electricity Market (NEM).

For its 2008 review of demand-side participation, the Australian Energy Market Commission (AEMC) defined demand-side participation as^{1,2}:

...the ability of consumers to make decisions regarding the quantity and timing of their energy consumption which reflects their value of the supply and delivery of electricity.

This is quite a narrow definition; in contrast, this paper takes a broader view. The paper covers all policy and regulatory initiatives directed at achieving increased implementation of demand-side management (DSM) by electricity businesses participating in the NEM. DSM consists of actions taken on the customer's side of the meter to change the amount and/or timing of electricity use in ways that will provide benefits to the electricity supply system³.

The paper commences with an outline of electricity industry restructuring in Australia, which includes a brief description of the NEM. Then the demand-side participation initiatives themselves are described in approximately chronological order, classified by the type of actor undertaking the initiatives.

2. ELECTRICITY INDUSTRY RESTRUCTURING IN AUSTRALIA

The restructuring of the Australian electricity industry has now been proceeding for more than 20 years since the industry itself set up a reform working group during 1990. This reform process has been the most profound and major restructuring in the 100-year life of the industry.

The restructuring consists of:

- introduction of competition in electricity generation and retailing;
- unbundling of electricity industry functions;
- reorganisation of the electricity market;
- separation of network charges;
- privatisation of electricity businesses in some States; and
- formalisation of electricity industry regulation.

2.1 Introduction of Competition

A major objective of electricity industry restructuring in Australia has been to introduce competition into the industry wherever possible. The two “wires” functions – transmission and distribution – are considered to be natural monopolies. In contrast, the generation and retail supply functions have been opened to competition.

¹ Australian Energy Market Commission (2008). *Statement of Approach, Review of Demand-Side Participation in the National Electricity Market*. 3 March, p 1.

² See the list of references (page 52) for information on how to access documents referenced in this paper.

³ For the purposes of this paper, DSM comprises end-use energy efficiency, load management, and distributed generation. Load management includes direct load control, demand response, interruptible loads, load shifting, power factor correction, and fuel substitution.

2.2 Unbundling of Electricity Industry Functions

Until the mid-1990s, in some Australian States (e.g., Victoria, South Australia, and Tasmania) the four functions of generation, transmission, distribution, and electricity retailing (also called “electricity supply” in some countries) were carried out within a single, vertically-integrated, monopoly business. In other States (e.g., New South Wales and Queensland) generation and transmission were contained in a single monopoly business, whereas distribution and retailing were carried out by a number of businesses, each with a monopoly franchise covering a specified geographic area within the State.

A major objective of electricity industry restructuring in Australia has been to unbundle the four functions into separate businesses:

- several competing generation businesses have been established in each State;
- a single monopoly transmission business has been established in each State;
- geographic monopoly franchises for distribution businesses have been retained in States that already had them and have been created in the other States. In some States, the number of existing franchises, and therefore of distribution businesses, has been reduced;
- in some States, a two-tier system has been established for electricity retailing:
 - ◆ “First-tier” retailers are attached to a distribution business with a monopoly geographic franchise in that State. First-tier retailers can sell electricity to customers throughout the State, whether or not the customers are located within the accompanying distribution franchise. The retail business is “ring fenced” from the distribution business (i.e., established as a separate accounting entity within one holding company);
 - ◆ “Second-tier” retailers are stand-alone businesses not attached to a distribution business in the relevant State. Second-tier retailers can also sell electricity to customers throughout the State. A second-tier retailer in one State may be a first-tier retailer in another State.
- in other States, the original first-tier retailers have been separated from the monopoly distribution businesses.

2.3 Reorganisation of the Electricity Market

The reorganisation of the electricity market is the third major change in the structure of the Australian electricity industry. Currently, the reorganised electricity market is in three parts: wholesale, ancillary services, and retail.

2.3.1 Wholesale Electricity Market

The major Australian wholesale electricity market, the NEM, comprises the sale of bulk electricity by generators to electricity retailers and large end-use customers in southern and eastern Australia. The NEM operates in the States of New South Wales, Victoria, Queensland, South Australia, and Tasmania and in the Australian Capital Territory (ACT) (see Figure 1, page 3). Western Australia and the Northern Territory will always be excluded from the “National” Electricity Market because of the lack of electrical interconnections and the vast distances between their load centres and the interconnected electricity network in the southern and eastern States. Western Australia has a wholesale electricity market that operates only in that State.

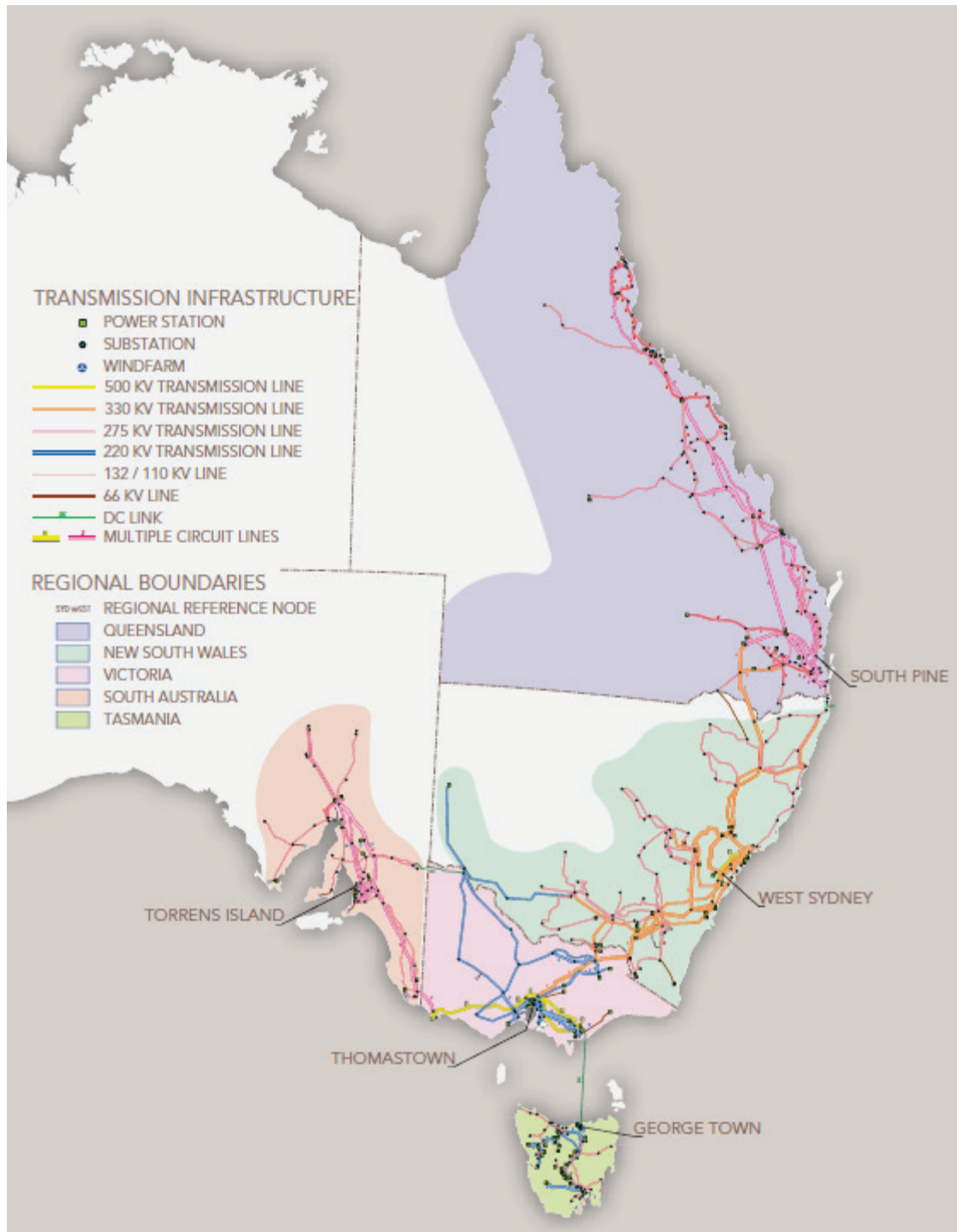


Figure 1. The Interconnected System Covered by the Australian National Electricity Market

The NEM operates on the world's longest interconnected power system – from Port Douglas in Queensland to Port Lincoln in South Australia – a distance of about 5,000 kilometres. The NEM includes approximately 46,000 megawatts (MW) of installed generation. More than AUD 10 billion of electricity is traded annually in the NEM to meet the demand of more than eight million end-use customers.

The market operator for the NEM is the Australian Energy Market Operator (AEMO)⁴. AEMO operates both the NEM and the retail and wholesale gas markets in southeastern Australia. AEMO is responsible for generator dispatch, reliability management, and financial settlements in the NEM. AEMO was established in 2009 by combining the functions of its predecessor, the National Electricity Market Management Company (NEMMCO), with that of various gas markets operators and electricity transmission planning bodies. AEMO is incorporated as a company limited by guarantee under the Corporations Act. AEMO is owned 60% by government members and 40% by industry members.

The NEM commenced on 13 December 1998 and it currently operates under a detailed set of rules called the *National Electricity Rules*⁵. The NEM comprises a physical spot market with energy traded through a commodities-type pool and a spot price set every five minutes (and averaged over half-hour periods) by the most expensive generator selected to run. All electricity sold at the wholesale level is accounted for through the pool (this is called a “gross pool” or “energy-only pool”). There are five geographic regions in the NEM, corresponding mostly to the boundaries of the five member States. Constraints on interconnectors can cause marginal spot prices to separate between the regions.

In addition to physical spot trading through the NEM, there is a separate over-the-counter short-term forward trading market. In this market, purchasers lock in prices for future delivery of bulk electricity through financial hedging contracts (“contracts for differences”). Under a standard bilateral hedging contract, the purchaser (typically an electricity retailer) agrees to purchase a specified physical quantity of electrical energy from the spot market at a set price (the “strike price”). If the actual price paid in the spot market by the purchaser is higher than the strike price, the counterparty to the contract (typically an electricity generator or a financial institution) pays the purchaser the difference in cost. Conversely, if the price paid is lower than the strike price, the purchaser pays the counterparty the difference.

Hedging contracts are financial instruments and can be traded in a market similar to other financial markets. There are numerous variations on the standard hedging contract available in the market, often containing complicated financial arrangements. The purpose of hedging contracts is to manage the price risks involved in purchasing electricity from the wholesale spot market. Prices in the spot market are highly volatile and the spot price can spike to several hundred times the average price for short periods, with a maximum price of AUD 12,500/MWh.

The NEM is one of the few purely cash-settled electricity markets in the world. This arrangement enables entities such as hedge funds and banks to participate in a separate financial market associated with the wholesale electricity market in which financial contracts do not involve physical delivery of electricity. Participants in the financial market contribute to market liquidity without a requirement to own electricity generation assets.

⁴ See the AEMO website at <http://www.aemo.com.au/>

⁵ Australian Energy Market Commission (2011). *National Electricity Rules*. Version 42.

2.3.2 Ancillary Services Markets

The NEM also includes a range of different markets for ancillary services, managed by AEMO, including:

- eight distinct markets for Frequency Control Ancillary Services in which providers make offers of services to manage frequency within specifications up to a 5-minute horizon; and
- long-term contracts for Network Control Ancillary Services and System Restart Ancillary Services negotiated between AEMO (on behalf of the market) and the market participant providing the service.

2.3.3 Retail Electricity Market

The retail electricity market comprises sales of electricity by retailers to end-use customers. Within the area covered by the NEM, the retail market is partly competitive and partly operates on a franchise basis.

In the jurisdictions in which the NEM operates, retailers can sell electricity to all end-use customers down to the household level (i.e., all customers are contestable). Small customers may continue purchasing electricity from their local first-tier retailer as franchise customers under prices controlled by the electricity industry regulator. Alternatively, small customers can choose to purchase electricity under a competitive retail contract from a first- or second-tier retailer in their State. Large customers may purchase electricity directly from the wholesale spot market or under competitive retail contracts. The vast majority of large customers choose to purchase under contracts. There are no controls on prices under competitive retail contracts for either small or large customers.

Under this structure for the retail electricity market, each retailer actually shields its customers from the price volatility in the NEM wholesale spot market. In effect, retailers provide price risk insurance for their customers, with the retail price paid by the customer including an insurance premium component.

Currently, there is a move to abolish retail price controls for all customers in all jurisdictions in which the NEM operates. This is likely to be introduced progressively over the next few years as competition in the retail electricity markets in each jurisdiction becomes more effective.

2.4 Separation of Network Charges

Originally, network charges, covering the cost of transporting electricity from the generator to the point of end-use, were bundled together with energy charges in calculating the electricity price to be charged to the end-use customer.

Following the establishment of the NEM, both generators and end-use customers are required to pay separate network charges. In the wholesale market, market participants who purchase electricity directly from the spot market are responsible for also paying connection charges and “use of system” charges directly to their local transmission and distribution network owners. In the retail market, network charges incurred by end-use customers are paid for them by their electricity retailer who packages these network charges together with the energy charge. In some electricity bills the network charges are separately identified, but many bills continue to show one price to the end-use customer.

2.5 Privatisation of Electricity Businesses

For the 50 years prior to the mid-1990s, the majority of electricity businesses in Australia were owned by State governments. Some distribution/retail businesses were owned by local governments (municipalities) and a handful of relatively small electricity businesses located in remote areas were privately owned.

Commencing in the mid-1990s, some State governments (e.g., New South Wales and Victoria) consolidated their hold on the Australian electricity industry by legislating to take ownership of the local government electricity businesses. After unbundling the electricity industry functions into separate businesses, some State governments (e.g., Victoria and South Australia) sold these businesses to the private sector, including foreign owners from the United States, United Kingdom, and Southeast Asia. All other States retained electricity businesses in government ownership.

In the mid-2000s, there was a wave of selling of electricity businesses by the original private sector owners to new private sector purchasers. These new purchasers often own more than one electricity business. The end result has been some rebundling of the ownership of the previously unbundled electricity industry functions; for example, a single owner may own both an electricity generator and a retail business, although these must be operated as separate businesses.

In 2007, the Queensland Government sold its electricity retailing businesses. In 2011, the New South Wales Government sold its electricity retailing businesses and the rights to trade output from some of its electricity generators. Existing private sector electricity businesses purchased all these assets.

2.6 Formalisation of Regulation

Prior to the mid-1990s, regulation of the Australian electricity industry was carried out on an informal basis because most of the businesses were government-owned and were operated as a public service rather than as profit-making commercial ventures. For example, increases in electricity prices were often agreed upon in informal meetings between the senior management of the electricity businesses and the relevant government Minister.

Once competition was introduced into the electricity industry, and particularly as some electricity businesses became privately owned, a more formal system of economic regulation was required. Consequently State and Territory governments established new agencies to regulate the electricity industry (plus often other industries as well).

When the NEM commenced in December 1998, it operated under a detailed set of rules called the *National Electricity Code*. A separate organisation, the National Electricity Code Administrator (NECA), was responsible for administering the *Code*, for making sure that participants complied with the rules, for ongoing development of the *Code*, and for undertaking reviews of various parts of the rules. The *National Electricity Code* was authorised by the Australian Competition and Consumer Commission (ACCC), a federal government body responsible for administering the federal *Trade Practices Act*. Any changes to the *Code* required ACCC authorisation.

In June 2001, following general dissatisfaction with the original governance arrangements for the NEM, the Council of Australian Governments (COAG) endorsed the need for a national energy policy and agreed to commission an independent review of the strategic direction for stationary energy market reform in Australia. The final report of the review, known as the Parer Report, was published in early 2003 and recommended significant changes to the organisations that governed and operated the NEM^{6,7}.

Also in June 2001, COAG agreed to establish a new Ministerial Council on Energy⁸ (MCE) to provide a forum for national leadership on energy issues. The MCE includes federal, State, and Territory energy ministers, in addition to ministers from New Zealand and Papua New Guinea

⁶ Council of Australian Governments Energy Market Review (2002). *Towards a Truly National and Efficient Energy Market*. Canberra, Commonwealth of Australia.

⁷ See also section 6.3, page 29.

⁸ See the MCE website at <http://www.mce.gov.au/>

as observers. The MCE has responsibility to provide effective policy leadership to meet the opportunities and challenges facing the energy sector and to oversee the continued development of national energy policy. A key task of the MCE is to identify policies and programs that will deliver significant improvements in energy efficiency through coordinated action by federal, State, and Territory government agencies.

By mid-2003, the existing jurisdictional-based regulation resulted in the Australian electricity industry being regulated by 13 separate agencies. The MCE initiated rationalisation of this situation, with regulation of the industry being progressively transferred to national regulatory agencies. In particular, the MCE agreed to a series of far-reaching reforms of energy markets. These initiatives are set out in the MCE Communiqué of 11 December 2003⁹ and the associated MCE report to COAG on reform of energy markets¹⁰.

At its December 2003 meeting, the MCE recommended to COAG that NECA be abolished and two new statutory commissions be established:

- an Australian Energy Market Commission (AEMC); and
- an Australian Energy Regulator (AER).

These bodies were established under a new *National Electricity Law*¹¹ and commenced operation on 1 July 2005. The NEM now operates under the *National Electricity Rules*¹², which are authorised by the *National Electricity Law*.

The AEMC¹³ has responsibility for rule-making and market development in relation to the NEM. The AEMC reports directly to the MCE. The MCE has the power to direct the AEMC to carry out reviews of the NEM and the *National Electricity Rules*. The AEMC is responsible for:

- administration and publication of the *National Electricity Rules*;
- the Rule-making process under the *National Electricity Law*;
- making determinations on proposed Rules;
- undertaking reviews on its own initiative or as directed by the MCE; and
- providing policy advice to the MCE in relation to the NEM.

The AER¹⁴ regulates the wholesale electricity market and is responsible for the economic regulation of the electricity transmission and distribution networks in the NEM.

Under the *National Electricity Law* and *National Electricity Rules*, the AER's key responsibilities currently include:

- regulating the revenues of transmission network service providers by establishing revenue caps;
- regulating the revenues of distribution network service providers;
- monitoring the wholesale electricity market;
- monitoring compliance with the *National Electricity Law*, *National Electricity Rules*, and *National Electricity Regulations*;
- investigating breaches or possible breaches of provisions of the *National Electricity Law*, *Rules*, and *Regulations*;
- instituting and conducting enforcement proceedings against relevant market participants;

⁹ Ministerial Council on Energy (2003a). *Communiqué*. Perth, 11 December.

¹⁰ Ministerial Council on Energy (2003b). *Report to the Council of Australian Governments: Reform of Energy Markets*. Perth, 11 December.

¹¹ Parliament of South Australia (1996). *National Electricity (South Australia) Act 1996. Schedule – National Electricity Law*.

¹² Australian Energy Market Commission (2011). *Op. cit.*

¹³ See the AEMC website at <http://www.aemc.gov.au/>

¹⁴ See the AER website at <http://www.aer.gov.au/content/index.phtml/tag/aerAboutUs/>

- establishing service standards for electricity transmission network service providers;
- establishing ring-fencing guidelines for business operations with respect to regulated transmission services; and
- exempting network service providers from registration.

State and Territory regulators continue to be responsible for regulation of some retail functions within the jurisdictions in which the NEM operates. This includes the responsibility for regulating retail prices. Previously, the individual State and Territory regulators adopted somewhat different regulatory approaches within their jurisdictions. As the responsibility for regulating all electricity functions is progressively transferred to the AER, it is likely that a single national approach to regulation will be adopted.

3. DEMAND-SIDE PARTICIPATION IN THE NATIONAL ELECTRICITY MARKET

Participation by the demand side in the NEM has been an issue since a competitive electricity market was first mooted in the early 1990s. Initial commitments to include the demand side were not followed through, in either the original version or the current version of the market rules.

3.1 Initial Design and Operation of the National Electricity Market

The first outline design of the NEM, the *National Grid Protocol* published in 1992, included a strong statement about the role of demand management (i.e., DSM) and renewable energy in the competitive electricity market¹⁵:

Demand management and renewable energy options are intended to have equal opportunity alongside conventional supply-side options to satisfy future requirements. Indeed, such options have advantages in meeting short lead-time requirements.

These commitments were not followed through during the subsequent six years of detailed technical development and market trials. When the NEM commenced on 13 December 1998, there were no specific provisions in the market rules that enabled equal opportunities for DSM and renewable energy.

Later editions of the *National Electricity Code* did contain some demand-side participation-related provisions in sections concerned with the planning, development, and regulation of electricity networks. For example, a 2002 edition of the Code included the following provisions.

Under section 6.10.3 of the *Code*, “Principles for regulation of distribution service pricing”, there was a requirement for the regulatory regime administered by the jurisdictional regulator to have regard to the need to:

...create an environment in which generation, energy storage, demand-side options and network augmentation are given due and reasonable consideration.

Similarly, section 5.6.2 of the *Code*, “Development of networks within a region”, included the following provision:

...the [electricity network operator] must consult with affected Code Participants and interested parties on the possible options, including but not limited to demand-side options, generation options and market network services provider options to address potential projected limitations of the relevant transmission

¹⁵ National Grid Management Council (1992). *National Grid Protocol: First Issue*. Melbourne, NGMC, p iii.

system or distribution system except that the [network operator] does not need to consult on a network option which would be a new small network asset.

A small network asset was generally defined as less than AUD 10 million capitalised expenditure.

The demand-side participation-related provisions in the *National Electricity Code* did not require operators of transmission and distribution networks to actually implement any demand-side options and consequently network operators did very little in this area.

3.2 Current Operation of the National Electricity Market

In the current version of the *National Electricity Rules*^{16,17}, as in the original *National Electricity Code*, demand-side participation-related provisions are in sections concerned with the planning, development, and regulation of electricity networks, in particular in Chapters 5, 6, and 6A of the *Rules*.

Chapter 5 of the *Rules* is concerned with connection to the electricity network (i.e., grid).

In section 5.6.2 “Network Development”, each transmission network operator must conduct an annual planning review with each distributor connected to its transmission network within each region. This annual planning review must consider, among other things:

...the potential for augmentations, or non-network alternatives to augmentations, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the market.

“Non-network alternatives” include distributed generation and DSM measures, including demand response.

Section 5.6.2 also requires distributors, when planning for a network augmentation, to:

...consult with affected Registered Participants, AEMO and interested parties on the possible options, including but not limited to demand-side options, generation options and market network service options to address the projected limitations of the relevant distribution system except that a [distributor] does not need to consult on a network option which would be a new small distribution network asset.

This wording is very similar to that in the 2002 version of the original *National Electricity Code*.

In section 5.6.2A, transmission network operators must prepare an annual planning report that includes, among other things:

...other reasonable network and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements...Other reasonable network and non-network options include, but are not limited to, interconnectors, generation options, demand-side options, market network service options and options involving other transmission and distribution networks.

Chapter 6 of the *Rules* is concerned with the economic regulation of electricity distribution services, and Chapter 6A covers economic regulation of electricity transmission services.

Section 6A.3.1 of Chapter 6A specifies that the form of economic regulation for electricity transmission services is a revenue cap, whereas section 6.2.5 in Chapter 6 lists several possible

¹⁶ Australian Energy Market Commission (2011). *Op. cit.*

¹⁷ At the time of writing, the current version of the National Electricity Rules is Version 42.

different forms of economic regulation for electricity distribution services, including a revenue cap and a price cap.

Sections 6.5.6 and 6.5.7 require the AER to consider the extent to which electricity distributors have considered, and made provision for, efficient non-network alternatives when assessing their expenditure forecasts. The AER has the discretion to reject proposals for capital expenditure on network infrastructure if non-network alternatives would be more economically efficient. Sections 6A.6.6 and 6A.6.7 include similar provisions in relation to electricity transmission network operators.

Sections 6.5.8 and 6.6.2 require the AER to consider the possible effects on incentives for non-network alternatives when establishing distribution regulatory guidelines, models, and schemes – such as the efficiency benefit sharing scheme (section 6.5.8) and the service target performance incentive scheme (section 6.6.2).

Section 6.6.3 enables, but does not require, the AER to:

...develop and publish an incentive scheme or schemes (demand management incentive scheme) to provide incentives for [distributors] to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way.

In developing and implementing a demand management incentive scheme (DMIS), the AER must have regard to, among other things:

...the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a [distributor's] incentives to adopt or implement efficient non-network alternatives; and...

...the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

Chapter 11 of the *Rules* is concerned with savings and transitional arrangements.

Section 11.27.4 “National Transmission Statement” requires AEMO to carry out an annual review that considers, among other things:

...possible scenarios for additional generation and demand-side options to meet demand forecasts.

The foregoing are the major demand-side related provisions in the current version of the *National Electricity Rules*. As with similar provisions in the original *National Electricity Code*, the provisions in the *Rules* do not require operators of transmission and distribution networks to actually implement any demand-side options. The two major changes from the original *Code* are:

- the ability of the AER to reject proposals by electricity distributors or transmission network operators for capital expenditure on network infrastructure if non-network alternatives would be more economically efficient; and
- the ability of the AER to develop demand management incentive schemes for electricity distributors.

3.3 Initiatives to Increase Demand-Side Participation

Despite (or maybe because of) the generally weak nature of the demand-side-related provisions in the market rules, there has been an ongoing series of studies and initiatives, starting before the NEM commenced, to develop ways to increase participation by the demand-side in the market. These initiatives have been taken by three main groups of actors:

- State Governments, particularly during the reform process for the electricity industry;
- electricity industry regulators; and
- institutions responsible for the operation and governance of the NEM.

4. INITIATIVES BY STATE GOVERNMENTS

During the 1990s, the process of reforming the electricity industry in each Australian State provided an opening for State Governments to embed into the new industry structure mechanisms to ensure that the demand side received equal opportunity as the supply side in meeting customer demand for energy services. Only the New South Wales and South Australian Governments made any attempt to carry this out.

4.1 Electricity Industry Reform in New South Wales

The reform of the electricity industry in New South Wales included several mechanisms to require electricity businesses to implement DSM and energy efficiency. Although these initiatives did not directly achieve demand-side participation, once the NEM commenced in 1998, the initiatives did provide opportunities for consumers to make decisions regarding the quantity and timing of their energy consumption.

The *Electricity Supply Act 1995*, which established a competitive electricity market in New South Wales in preparation for the commencement of the NEM, also imposed several conditions on the licences for electricity distributors and electricity retailers, including¹⁸:

- a requirement that electricity distributors consider energy efficiency and DSM as an alternative to network augmentation (see Schedule 2, sections 6(5) and 6(6)); and
- a requirement that electricity retailers develop plans for reducing greenhouse gas (GHG) emissions from the electricity they sell (see Schedule 2, section 6(4)).

4.1.1 Electricity Distributors

In 1999, electricity distributors in New South Wales themselves took the initiative to develop a *Code of Practice* on DSM for electricity distributors.

The first edition of the *Code* specified how electricity distributors should carry out investigations of DSM options¹⁹.

In May 2001 a second edition of the *Code* strengthened its provisions and for the first time the *Code* was formally recognised under electricity supply regulations in New South Wales²⁰. The innovation in the second edition of the *Code* was the introduction of a market-based procurement process for demand-side options for electricity system support (including DSM, embedded generation, and storage options) and their evaluation at the same time and in the same manner as supply-side options. The approach in this edition of the *Code* was focused not just on the network, but rather on the electricity system as a whole. Constraints that arose within the distribution network could be addressed by changes in customer behaviour, by changes in equipment used by customers, or by installation of small-scale generation at a local level, as well as by augmentation of the distribution network. These options could be devised and implemented by customers or third parties or by the electricity distributor itself.

¹⁸ Parliament of New South Wales (1995). *Electricity Supply Act 1995 No 94*. Sydney.

¹⁹ Ministry of Energy and Utilities (1999). *Code of Practice: Demand Management for Electricity Distributors*. Sydney, MEU.

²⁰ Ministry of Energy and Utilities (2001). *NSW Code of Practice: Demand Management for Electricity Distributors*. Sydney, MEU.

In September 2004 a third edition of the *Code* was published²¹. Although the first two editions of the *Code* were purely advisory, the third edition was formally issued in accordance with Clause 6 of the *Electricity Supply (Safety and Network Management) Regulation 2002*. This requires electricity distributors in the State of New South Wales to take the *Code* into account in the development and implementation of their network management plans. In particular, the network management plan must specify where it or its implementation departs from the provisions of the *Code* and, if so, what arrangements are in place to ensure an equal or better outcome.

The third edition of the *Code* requires electricity distributors in New South Wales to:

- publish information that makes transparent the underlying assumptions and decision-making process relating to investments that expand their distribution networks;
- publish detailed information regarding the need for network expansion in a way that enables interested parties to identify likely locations of forthcoming constraints;
- use a formal process to determine whether DSM investigations are warranted for identified emerging constraints, and publish the results;
- carry out DSM investigations that provide opportunities for market participation;
- analyse DSM and network expansion options on an equal basis according to the published methodology and assumptions and publish the result of those determinations;
- implement DSM options where they are determined to be cost effective; and
- prepare and publish reports on these activities annually.

Important changes in the third edition of the *Code* as compared with the second edition include:

- greater focus on transparency and disclosure, including specification of a range of tables and maps to be produced by distributors as part of the planning and procurement process;
- specification of recommended processes for procuring network support through DSM, including negotiable and standard offers; and
- outlining of matters to be taken into account in analysing the relative costs and benefits of the DSM and network options.

This *Code of Practice* stimulated the development and implementation of small-scale, location-specific DSM programs targeted at achieving load reductions on specific elements of the electricity network (e.g., a substation or an electricity line). At the time of writing, New South Wales electricity distributors are still continuing to implement this type of DSM program.

4.1.2 Electricity Retailers

From 1995 to 1997, electricity retailers in New South Wales complied with the requirement in the *Electricity Supply Act 1995* that they develop plans for reducing GHG emissions. In 1997, the New South Wales Government introduced a benchmark (or target) for the overall reduction in GHG emissions, which was to be achieved by the New South Wales electricity sector. Electricity retailers were required to contribute to the achievement of the statewide target by meeting individual “retailer apportioned benchmarks” related to their market share. During the period from July 1997 to June 2001, most retailers failed to meet their apportioned benchmarks for GHG emissions reductions. Consequently the environmental licence conditions for electricity retailers were widely regarded as being ineffective.

²¹ Department of Energy, Utilities and Sustainability (2004). *Demand Management for Electricity Distributors*. NSW *Code of Practice*: Sydney, DEUS.

In 2003, the original environmental licence conditions for electricity retailers were repealed. New conditions requiring retailers to achieve specified reductions in GHG emissions under the New South Wales Greenhouse Gas Reduction Scheme (known as “GGAS”) were introduced. In 2009, additional obligations were placed on retailers to achieve energy efficiency targets under the New South Wales Energy Savings Scheme (ESS). Both these schemes included trading of emission reductions (see section 8.1, page 46).

4.2 Electricity Industry Reform in Other States

4.2.1 Victoria

Electricity reform in Victoria included the development and implementation of the *Electricity Distribution Code*²². The *Code* requires each electricity distributor together with each other distributor in Victoria to submit to the Victorian regulator, the Essential Services Commission (ESC), a joint annual report called the “Transmission Connection Planning Report,” detailing how together all distributors plan to meet predicted demand for electricity supplied into their distribution networks from transmission connections over the following 10 calendar years. The report must include a description of feasible options for meeting forecast demand at each transmission connection including opportunities for embedded generation and DSM.

Each distributor must also submit to the Commission an annual report called the “Distribution System Planning Report,” detailing how it plans over the following five calendar years to meet predicted demand for electricity and to improve reliability to its customers. The report must also include a description of feasible options for meeting forecast demand, including opportunities for embedded generation and DSM.

4.2.2 Queensland

Electricity reform in Queensland included the development and implementation of the *Electricity Industry Code*²³. The *Code* requires each electricity distributor in Queensland to develop a network management plan that details how the distributor will manage and develop its supply network over the following five financial years. The plan must include the distributor's DSM strategy, including a description of the existing and planned programs and opportunities for demand-side participation.

In the 2009 State Budget, the Queensland Government announced the establishment of an Energy Conservation and Demand Management Program through which the Government invested AUD 47.7 million in a demonstration program to reduce the growth in energy demand, particularly in periods of peak use. The program was implemented by the Government in collaboration with the two Queensland electricity distributors. Government funding for initiatives under the program ceased after 2010, when the DSM measures are expected to be continued by the distributors as part of their regulated activities.

4.2.3 South Australia

Similar to the legislative provisions in New South Wales, the *Electricity Act 1996* in South Australia imposed a condition on electricity distributor licences requiring distributors to conduct investigations on the cost-effectiveness of implementing DSM strategies that may permit proposed expansions or augmentations of the distribution network to be avoided or postponed. The licence held by the sole electricity distributor in South Australia contains a condition that substantially repeats the wording of the *Act*.

²² Essential Services Commission of Victoria (2011). *Electricity Distribution Code*. Version 6. Melbourne, ESC.

²³ Queensland Government (2011). *Electricity Industry Code*. Eighth Edition. Brisbane.

4.2.4 Tasmania

Electricity reform in Tasmania included the development and implementation of the *Tasmanian Electricity Code*²⁴. The *Code* requires the sole electricity distributor in Tasmania to prepare an annual report called the “Distribution System Planning Report,” detailing how it plans over the following five years to meet predicted demand for electricity, to improve reliability to its customers, and to meet set supply reliability standards. The report must include a description of feasible options for meeting forecast demand, including opportunities for embedded generation and DSM.

5. INITIATIVES BY REGULATORS

During the 1990s, economic regulation of the electricity industry in Australia was carried out at the State level. The individual State-based regulators varied widely in how they treated demand-side participation, first in State-based electricity markets, and then in the NEM. From 1999, the regulatory responsibility was transferred progressively to the national Australian Energy Regulator.

5.1 Initiatives by the New South Wales Electricity Regulator

The electricity industry regulator in New South Wales was the most active State-based regulator in facilitating increased demand-side participation in the electricity market, starting before the NEM commenced.

5.1.1 Pricing Regulation to Promote Energy Efficiency in Australia

This 1993 conference paper²⁵ was prepared by two DSM practitioners and was the first proposal in Australia that revenue regulation could be used to promote DSM. Under revenue regulation, a portion of the total revenue of an electricity business is set each year by the regulator at a particular dollar figure calculated according to an established formula. Provided the regulated portion of revenue remains within this “cap”, the business is free to set the structure and levels of retail prices in any way it chooses. Any over- or under-collection of revenue in one year is corrected in determining the revenue cap for the following year. The proposal was later taken up and implemented by the then-New South Wales Government Pricing Tribunal, the body that regulated electricity prices in New South Wales and was the predecessor to the New South Wales Independent Pricing and Regulatory Tribunal (IPART).

5.1.2 1997 Pricing Determination

In September 1994, the then-New South Wales Government Pricing Tribunal (GPT) published a draft proposal²⁶ on how it would treat DSM in its regulation of electricity prices. The GPT’s most controversial recommendation was the introduction of revenue regulation (rather than price regulation) for electricity distributors as a mechanism to overcome the bias against demand-side options. This proposal caused some concern among the electricity industry in New South Wales, partly because the concept of revenue regulation was not well understood.

A final determination²⁷ on electricity prices in New South Wales was published in March 1996 by IPART as the successor to the GPT. This determination was published at the same time that the restructuring of the electricity industry was being implemented. In its determination, to apply from 1997 to 2000, IPART introduced three separate formulae to calculate the maximum allowable revenue for each type of electricity business:

²⁴ Tasmanian Economic Regulator (2010). *Tasmanian Electricity Code*. Revised 3 November 2010. Hobart, TER.

²⁵ Crossley, D. and Gordon, N. (2003). Pricing regulation to promote energy efficiency in Australia. *Electricity Supply Association of Australia Seminar on Demand Management*, Sydney, 17 June.

²⁶ Government Pricing Tribunal (1994). *Price Regulation and Demand Management*. Sydney, GPT.

²⁷ Independent Pricing and Regulatory Tribunal (1996). *Electricity Prices: March 1996*. Sydney, IPART.

- the revenue formula for the New South Wales transmission network operator was based on peak and shoulder energy sales (MWh) plus maximum demand (MW);
- the revenue formula for the network services parts of the New South Wales electricity distributor businesses was based on customer numbers, total energy sales (MWh) and (for rural distributors only) the total length of distribution lines owned by each business; and
- the revenue formula for the retail supply parts of the New South Wales electricity distributor businesses was based on customer numbers and total energy sales (MWh) for each business.

The revenue formulae introduced by IPART therefore achieved at best only a partial decoupling of revenue from the volume of energy sales and consequently only partly removed the bias against demand-side options.

5.1.3 2000 Pricing Determination

This determination was the first to be made by IPART under the provisions of the *National Electricity Code*, which governed the operation of the then-new NEM. This determination was to apply for the period from 2000 to 2004. During 2000, regulation of transmission network operators in New South Wales was transferred to the national Australian Competition and Consumer Commission (and was subsequently transferred on 1 July 2005 to the Australian Energy Regulator).

In March 1999, IPART released a discussion paper²⁸ that outlined the various options available to control the price of electricity network services, particularly price caps and revenue regulation. The paper included a discussion of the various forms of revenue regulation and the effect of revenue regulation in reducing the bias against demand-side options inherent in price cap regulation.

In June 1999, IPART released a major report on pricing for electricity networks and retail supply²⁹. In this report, IPART proposed to retain revenue regulation for the network services parts of electricity distributors' businesses, with the formula for the maximum allowable revenue remaining much the same as in the 1997 determination. In addition, IPART proposed that, in assessing the prudence of a distributor's capital expenditure, it would look for clear evidence that the distributor had investigated demand-side and distributed resource options as a crucial part of its network planning function. In contrast, IPART proposed that the appropriate form of regulation for franchise electricity retailers should be a price cap on the retail margin allowed per kilowatt-hour of sales. This change in the form of regulation for retailers was made in response to opposition by the retailers to revenue regulation.

In its final determination³⁰ on the regulation of electricity distribution networks published in December 1999, IPART departed from its original proposal and implemented a fixed revenue cap, rather than a variable formula, to regulate the maximum allowable revenue of the electricity distributors. In addition, distributors could increase their revenue caps by including payments for DSM and other network support services up to an amount determined by the IPART through an examination of avoided network costs. This provided a small incentive for distributors to implement DSM programs.

IPART decided to implement a fixed revenue cap because:

- there was industry and stakeholder support for a revenue cap;

²⁸ Independent Pricing and Regulatory Tribunal (1999a). *Regulation of Electricity Network Service Providers – Price Control Issues and Options*. Sydney, IPART.

²⁹ Independent Pricing and Regulatory Tribunal (1999b). *Pricing for Electricity Networks and Retail Supply*. Sydney, IPART.

³⁰ Independent Pricing and Regulatory Tribunal (1999c). *Regulation of New South Wales Electricity Distribution Networks – Determination and Rules Under the National Electricity Code*. Sydney, IPART.

- revenue caps do not create a bias against DSM;
- revenue caps are simpler to understand and administer than a revenue formula;
- revenue caps provide flexibility in offering services and pricing options;
- revenue caps provide equally strong incentives for distributors to pursue efficiency gains; and
- revenue caps are cost reflective.

5.1.4 Demand Management Inquiry

During 2002, at the request of the Premier of New South Wales, IPART undertook an Inquiry into the opportunities for demand management (i.e., DSM) in New South Wales. The key question posed by the Inquiry was whether DSM options that could meet customers' energy needs at lower cost, and perhaps with lower environmental impact, were being bypassed in favour of "build and generate" options and, if so, what could be done to encourage the greater use of DSM.

The report of the Inquiry³¹ defined three broad types of DSM:

- environmentally-driven DSM – those activities with a focus on reducing energy consumption and GHG emissions;
- network-driven DSM – those activities with a focus on solving network capacity constraints and reducing the cost of network services; and
- retail market-driven DSM – the focus is on reducing costs to end-users and reducing electricity retailers' exposure to high wholesale market pool prices.

Based on the evidence presented to it during the course of the Inquiry and case studies of DSM projects in New South Wales and elsewhere, IPART concluded that there were substantial cost-effective opportunities to use DSM in New South Wales that were being overlooked.

IPART recognised that there were significant barriers to the implementation of DSM in New South Wales, particularly those related to the immaturity of the market for DSM and lack of DSM experience in the electricity industry. IPART's recommendations were aimed at encouraging and facilitating the implementation of efficient and effective DSM programs in the short to medium term, to increase industry's experience with, and confidence in, DSM options.

IPART's recommendations were designed:

- to achieve better price signals to identify opportunities for DSM;
- to encourage better planning processes and clearer regulation; and
- to incorporate environmental and social objectives into decision making.

The major recommendations included:

- that the New South Wales Government establish a DSM Fund or Funds;
- that DSM be built into customer choice through programs aimed at improving the information to end-users about energy efficiency;
- that IPART would work with electricity distributors and other stakeholders to develop network planning processes that provided greater clarity to the treatment of investment in non-network projects and DSM;
- that rebates on network charges or distributor payments for load reductions should be included as negative revenue in calculating regulated revenue;

³¹ Independent Pricing and Regulatory Tribunal (2002). *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services: Final Report*. Sydney, IPART.

- that the New South Wales Government, retailers, and distributors should work with the NEM:
 - ◆ to facilitate the aggregation of customer demand and the formation of energy cooperatives and to encourage the participation of specialist aggregators in the market; and
 - ◆ to develop energy contracts that incorporate real-time energy market signals with the objective of influencing forward energy prices and generator bids by lowering demand.

5.1.5 DSM Regulatory Framework Study

This report³², published in 2003, was prepared for IPART by a consultancy firm.

The report examined options for integrating the costs of DSM into the regulatory framework for the four New South Wales electricity distributors and studied the feasibility of, and developed a framework for, congestion pricing for distribution networks. The report addressed disincentives and regulatory barriers to the uptake of DSM by the distributors.

Based on analysis of the financial impacts of DSM on the distributors, the report found two areas that must be addressed to provide appropriate financial treatment for distributors that pursue efficient DSM initiatives:

- funding of DSM implementation costs; and
- correction of any lost revenues arising from consumption volume impacts of DSM under a simple weighted average price cap.

The report found that DSM implementation costs should be funded from the reduced or avoided distribution costs that were achieved through the implementation of DSM. The report identified two possible mechanisms that could correct the possible disincentives and align the financial drivers for distributors with the economic benefits arising from DSM.

These two mechanisms were:

- an incentive mechanism that allocates both the DSM implementation costs and avoided distribution cost benefits to distributors, allowing them to fund DSM initiatives, and retain a share of the net value created. This provides a positive financial incentive to distributors to pursue cost-effective DSM alternatives; and
- a cost recovery mechanism that allocates both the DSM implementation costs and avoided distribution costs to end-users, with distributors recovering DSM costs from end-users and passing the benefits through as reduced tariffs. This transfers the risk and benefits of DSM to end-users, insulating distributors from positive or negative financial impacts, but also removes the financial incentive for distributors to pursue DSM.

The incentive mechanism was preferred on the basis that it provided a stronger incentive to distributors to pursue DSM options, and was consistent with the broader incentive regulation framework adopted by IPART. Lost revenues due to volume impacts would have to be corrected by an explicit adjustment to distributor revenues under either mechanism.

³² Sinclair Knight Merz (2003). *Reducing Regulatory Barriers to Demand Management*. Sydney, Independent Pricing and Regulatory Tribunal.

5.1.6 2004 Pricing Determination for Electricity Distributors

This determination was to apply from 2004 to 2009. The determination was the last made by IPART before the regulation of electricity distributors was transferred to the national Australian Energy Regulator.

The most significant change in this determination from IPART's previous regulatory practice was that a weighted average price cap was applied to electricity distributors, rather than a revenue cap³³. A price cap links revenue to the volume of energy sold, and therefore is biased against demand-side options. In its determination, IPART implemented several mechanisms to mitigate the effects of this inherent bias.

In February 2004, IPART published a draft decision³⁴ on the treatment of DSM in the regulatory framework for electricity distribution pricing. In the report, IPART expressed its belief that DSM could play an important role in helping the four New South Wales electricity distributors to better manage their networks and lower the cost of service provision. In determining the regulatory framework, IPART therefore sought to ensure it provided no regulatory barriers to distributors undertaking efficient DSM projects.

In its final report³⁵ published in June 2004, IPART aimed to ensure that regulatory barriers to DSM were removed and to neutralise the potential disincentive for DSM created by the change from revenue regulation to a weighted average price cap form of regulation. IPART considered that its final decisions represented a generous treatment of DSM activities. This generosity was warranted, at least in the short term, to help overcome the barriers to the greater use of demand-side solutions in supplying network services and to support the then-emergent market for these solutions.

The main mechanism that IPART implemented to reduce the bias against DSM was a D-factor included in the weighted average price cap control formula that allowed electricity distributors to recover:

- approved non-tariff-based DSM implementation costs, up to a maximum value equivalent to the expected avoided distribution costs;
- approved tariff-based DSM implementation costs³⁶; and
- approved revenue foregone as a result of non-tariff-based DSM activities.

IPART also decided to treat rebates and payments made by distributors for load reductions as negative prices under the weighted average price cap.

IPART published a final determination³⁷ that included the detailed formulae developed to implement its decision in relation to DSM undertaken by distributors. The D-factor was calculated according to a formula with the following structure³⁸:

$$D_{t+1} = \frac{\text{Foregone Revenue}_{t-1} + \text{DSM Cost Pass Through}_{t-1}}{\text{Smoothed Revenue Requirement}_{t+1} - \text{Foregone Revenue}_{t-1} - \text{DSM Cost Pass Through}_{t-1}}$$

³³ IPART did not publish the reasons for making this change.

³⁴ Independent Pricing and Regulatory Tribunal (2004a). *Treatment of Demand Management in the Regulatory Framework for Electricity Distribution Pricing 2004/05 to 2008/09: Draft Decision*. Sydney, IPART.

³⁵ Independent Pricing and Regulatory Tribunal (2004b). *NSW Electricity Distribution Pricing 2004/05 to 2008/09: Final Report*. Sydney, IPART.

³⁶ Tariff-based DSM programs use price signals to encourage electricity customers to modify their energy use (e.g., at times of peak electricity demand).

³⁷ Independent Pricing and Regulatory Tribunal (2004c). *NSW Electricity Distribution Pricing 2004/05 to 2008/09: Final Determination*. Sydney, IPART.

³⁸ This is a simplified form of the actual formula, which is detailed in the determination.

In late October 2004, IPART established a consultation group to develop principles and guidelines to give effect to the DSM incentives outlined in IPART's final determination and report. The consultation group included representatives from the New South Wales electricity distributors, industry, Government, and user/consumer groups.

In April 2005, IPART released a series of publications on the implementation of the DSM incentives. These publications were the output of the consultation group. Two of the publications covered:

- calculation of avoided distribution costs; and
- methodology for estimating foregone revenue.

The IPART Guideline on avoided distribution costs³⁹ was concerned with calculating avoided distribution costs for the purposes of establishing a cap for recovery of costs for non-tariff DSM measures. The Guideline established a set of principles and a formula for calculating avoided costs.

The IPART Guideline on foregone revenue⁴⁰ established principles for estimating foregone revenue based on:

- the amount of energy, demand, or capacity affected by the non-tariff DSM measures; and
- the price/tariff applicable to the foregone energy/demand/capacity.

5.2 Initiatives by the South Australian Electricity Regulator

The South Australian electricity industry regulator, initially called the South Australian Independent Industry Regulator (SAIIR) and later the Essential Services Commission of South Australia (ESCOSA), was the second most active State-based regulator in Australia in relation to DSM.

5.2.1 Guideline on Demand Management for Electricity Distribution Networks

In August 2002, SAIIR published a discussion paper⁴¹ to provide a basis for consulting with the South Australian electricity distributor and the wider community on the possible framework for meeting the electricity distributor's statutory DSM obligations under both the *National Electricity Code* and the *South Australian Electricity Act 1996*.

The discussion paper provided an overview of three broad options that were considered to be available to SAIIR to ensure that the South Australian distributor met its DSM obligations in a satisfactory manner:

- regular reporting by the distributor to SAIIR providing an annual summary of the DSM initiatives that the distributor had considered and/or implemented during the previous year for major projects (defined as projects with a capital cost of over AUD 10 million);
- including in the distributor's published regional development plans consideration of possible DSM initiatives as alternatives to network augmentation or expansion;
- the development of a Code of Practice on DSM, similar to the New South Wales Code. It was considered that the introduction of such a Code in South Australia might be considered to be "heavy-handed", and could result in additional costs for the distributor and SAIIR.

³⁹ Network Demand Management Consultation Working Group (2005a). *IPART Guideline – Calculation of Avoided Distribution Costs*. Sydney, IPART.

⁴⁰ Network Demand Management Consultation Working Group (2005b). *IPART Guideline – Methodology for Estimating Foregone Revenue*. Sydney, IPART.

⁴¹ South Australian Independent Industry Regulator (2002). *Demand Management for Distributors: Discussion Paper*. Adelaide, SAIIR.

In January 2003, the ESCOSA, as the successor to SAIIR, published a position paper⁴² on DSM for electricity distributors. This paper included a statement of how ESCOSA believed the South Australian distributor could meet its regulatory DSM obligations. The key components of the ESCOSA plan were as follows:

- the distributor would be required to publish annual regional development plans in accordance with a guideline to be developed by ESCOSA;
- the distributor would be required to consult with interested parties on DSM alternatives to all network extensions and/or augmentations with an estimated capital cost over AUD 2 million;
- the distributor would be required to provide to ESCOSA, and publish on the distributor's website, an annual report summarising details of all network extensions/projects with an estimated capital cost of AUD 2 million or above that were considered and/or constructed during the previous financial year. The report would also be required to provide details of the consultation process used and the DSM alternatives considered and/or adopted; and
- customers and other interested parties would be provided with information on network capacity and given the opportunity to comment on and provide alternative solutions to network constraints and possible network extension/augmentation projects.

In September 2003, ESCOSA published *Electricity Industry Guideline No 12 Demand Management for Electricity Distribution Networks*⁴³ that specified how ESCOSA required the South Australian distributor to meet its obligations to report and consult on its system constraints and DSM plans. The purpose of the *Guideline* was to ensure the quality and transparency of assessments and comparisons of network augmentations, extensions, and DSM alternatives. The *Guideline* put into effect the plan outlined in ESCOSA's earlier position paper.

In the *Guideline*, ESCOSA stated that it wished to encourage all customers and interested parties to participate in the process of determining the ways in which emerging constraints in the South Australian distribution network were addressed. ESCOSA believed that this would require the distributor to regularly disclose sufficient information about where constraints are likely to emerge and to seek and evaluate alternatives put to it from customers and other interested parties.

This *Guideline* set out requirements for the South Australian distributor:

- to publish an annual Electricity System Development Plan that identified in detail any actual and forecast constraints on the distributor's network;
- to maintain a register of parties that were interested in the distributor's long-term planning and DSM activities and/or in providing the distributor with alternative solutions to address emerging system constraints;
- to consult with customers and interested parties in relation to system constraints;
- to identify DSM options to address specific system constraints as they arose, and more broadly-focused DSM options where strategic, long-term load reduction was appropriate;
- to undertake a formal consultation process in relation to major network projects, including determining whether the project met a Reasonableness Test and issuing Requests for Proposals;

⁴² Essential Services Commission of South Australia (2003a). *Demand Management for Distributors: Position Paper*. Adelaide, ESCOSA.

⁴³ Essential Services Commission of South Australia (2003b). *Demand Management for Electricity Distribution Networks: Electricity Industry Guideline No 12*. Adelaide, ESCOSA.

- to develop and maintain expertise in system support options;
- to consider non-network alternatives before commencing a major network project and ensure that all network enhancement and other system support options and proposals were given fair consideration, including ensuring that DSM options were given due consideration and comparable weighting to that accorded to network enhancement options;
- to prepare an annual DSM compliance report to inform the general public, interested parties, the market, and ESCOSA about the distributor's DSM initiatives and activities undertaken in the previous 12 months and highlight opportunities for future development; and
- to provide information to ESCOSA that would assist it in determining whether the investment mix was prudent and was therefore appropriate for the distributor to recover its investment from its customers.

5.2.2 2005 Distribution Pricing Review

In February 2004, ESCOSA commissioned a consultancy firm to produce a report⁴⁴ on peak demand on the interconnected distribution system in South Australia. The report formed part of an investigation carried out for the ESCOSA 2005 Distribution Pricing Review that set the distribution prices the South Australian distributor would be allowed to charge customers.

This study was part of ESCOSA's investigation of whether, in some instances, options such as the mandatory rollout of interval meters or the use of DSM programs might be more cost-effective than building additional distribution capacity to meet increase in peak demand.

The study identified the customer types and associated end-uses that contributed to peak demand on the South Australian distribution network, and those that offered the most potential to provide demand reductions.

In September 2004, ESCOSA published a draft decision⁴⁵ concerning the funding of DSM initiatives through the distributor's regulated revenue during the 2005 to 2010 regulatory period. In the draft decision, ESCOSA determined that it would approve an amount of AUD20 million as funding for DSM initiatives by the South Australian electricity distributor over the five-year regulatory period beginning July 2005. The initiatives included pilot programs for power factor correction for large customers, standby generation, direct load control of residential air-conditioning and other residential systems, and critical peak pricing for customers with interval meters already installed; investigation of opportunities for curtailable load control and voluntary load control initiatives; review of the opportunities for the distributor to act as a demand management aggregator; and establishment of DSM capabilities within the distributor. No funding was to be provided for a general rollout of interval meters to all customers.

The electricity distributor was required to submit by 1 March 2005 to ESCOSA for its approval a proposed program for implementation of these DSM initiatives and expenditure of the approved funding over the regulatory period. The approved funding was to be treated as operating expenditure during the regulatory period, and this decision would not impact on ESCOSA's consideration of approved capital expenditure for network augmentation purposes in the regulatory period.

⁴⁴ Charles River Associates (2004). *Peak Demand on the ETSA Utilities System*. Adelaide, ESCOSA.

⁴⁵ Essential Services Commission of South Australia (2004). *Demand Management and the Electricity Distribution Network: Draft Decision*. Adelaide, ESCOSA.

In its final distribution price determination⁴⁶ for the 2005 to 2010 regulation period, ESCOSA made specific provision for the South Australian electricity distributor to commit approximately AUD 20.5 million over the five-year regulatory period to trial a number of DSM initiatives that might result in less need for peak-driven expansion of the electricity grid. The range of initiatives to be trialled included:

- power factor improvements in business and manufacturing premises;
- trials of voluntary load curtailment programs for large customers;
- direct load control of domestic equipment such as air-conditioners and pool pumps;
- use of standby generation, and
- the use of incentives for customers to reduce demand at times of peak demand.

5.2.3 Review of Guideline on Demand Management

In July 2006, ESCOSA initiated a review of the effectiveness of *Guideline 12 Demand Management for Electricity Distribution Networks*.

In its final decision on the review⁴⁷ published in June 2007, ESCOSA noted that, since the introduction of *Guideline 12* in September 2003, very few DSM proposals had been submitted to the South Australian electricity distributor in response to a Request for Proposals (RFP) and none had proceeded to the stage of implementation. ESCOSA's view was that the reasons for the limited take-up of DSM options to address network constraints went well beyond any inadequacies of *Guideline 12*.

ESCOSA's final decision sought to encourage a collaborative, interactive approach among the South Australian electricity distributor, customers, and energy service providers. It proposed amendments to the Reasonableness Test that determines whether or not the distributor will issue an RFP for a network constraint. It also incorporated requirements on the distributor to include additional information within Reasonableness Test reports and RFPs. The final decision also proposed a set of general performance indicators to be used in the assessment of initiatives being trialled under the distributor's DSM program.

5.3 Initiatives by Other State-Based Regulators

5.3.1 Victoria

In its electricity distribution price review for the period 2006 to 2010⁴⁸, the Victorian electricity industry regulator, the Essential Services Commission (ESC), examined whether any features of its regulatory framework impeded the distributors' ability to implement a least-cost alternative to network augmentation, including DSM options.

The Commission concluded that the following features of the regulatory framework might act as a barrier to the implementation of DSM and non-network solutions:

- the weighted average price cap;
- the building blocks approach to the revenue requirement; and

⁴⁶ Essential Services Commission of South Australia (2005). *2005-2010 Electricity Distribution Price Determination. Part A – Statement of Reasons*. Adelaide, ESCOSA.

⁴⁷ Essential Services Commission of South Australia (2007). *Review of Electricity Industry Guideline 12. Demand Management for Electricity Distribution Networks. Final Decision*. Adelaide, ESCOSA.

⁴⁸ Essential Services Commission of Victoria (2006). *Electricity Distribution Price Review 2006-10. October 2005 Price Determination As Amended in Accordance with a Decision of the Appeal Panel Dated 17 February 2006. Final Decision Volume 1: Statement of Purpose and Reasons*. Melbourne, ESC.

- the service incentive mechanism that financially rewarded or penalised distributors for their service performance.

The Commission stated that the rollout of interval meters that it had proposed would assist with the impact of all these issues.

The Commission considered that where DSM measures resulted in the deferral of capital expenditure for grid augmentation and deferral benefits accrued within a regulatory period, these cost savings were retained in full by the distributors and were therefore available to cover any DSM implementation costs incurred. Where capital expenditure deferral benefits accrued across regulatory periods the benefits to the distributors were reduced because these benefits would be returned to customers at the subsequent price review. This could reduce the viability of DSM initiatives to the distributors.

To resolve this issue, in its distribution price determination, the Commission allowed specific provision for DSM initiatives of AUD 0.6 million for each distributor to provide additional revenue for the trial of DSM initiatives during the 2006 to 2010 regulatory period. Specifically, the amount provided was intended to cover the costs of negotiating with potential demand-side suppliers, developing technical and operating standards, and legal costs associated with entering agreements with demand-side suppliers. The Commission required distributors to report on an annual basis the demand-side activities that were undertaken and the outcomes that were delivered.

5.3.2 Queensland

In both its 2001 and 2005 determinations on the regulation of electricity distribution, the Queensland electricity industry regulator, the Queensland Competition Authority, implemented a revenue cap for each of the two Queensland electricity distributors.

In its 2005 determination for the period 2005 to 2010⁴⁹, the Authority stated that DSM is a sensible means for the electricity distributors to help manage the growth in peak demand on their networks. Although the Authority could help guide the establishment of efficient distribution prices which would assist DSM by using price signals to indicate areas of the network operating under capacity constraint, the Authority believed that more comprehensive DSM programs were beyond the Authority's responsibilities.

The Authority also stated that because grid augmentation initiatives formed part of the regulatory asset base and therefore earned an immediate return, the Authority similarly regarded DSM expenditure as legitimate expenditure for electricity distributors. The Authority was not convinced about the need to introduce incentives for DSM into the revenue cap arrangements. The Authority therefore did not consider DSM in its determinations and did not make any special provision for DSM costs incurred by the distributors.

In June 2009, the Queensland Government amended the *Electricity Regulation 2006* to require each electricity distributor to submit annual DSM plans to the Queensland energy regulator, the Director-General of the Department of Employment, Economic Development and Innovation. Before the commencement of each financial year each distributor must submit a Demand Management Plan detailing:

- the organisation's long-term DSM strategy and overarching principles;
- a description of initiatives to be carried out under the strategy for the year;
- forecasts of capital and operating costs of planned initiatives; and
- performance targets for each initiative.

⁴⁹ Queensland Competition Authority (2005). *Final Determination: Regulation of Electricity Distribution*. Brisbane, QCA.

At the end of the year, each distributor must report actual outcomes against forecast outcomes of each initiative.

5.3.3 Tasmania

In its 2007 determination on electricity pricing for the period 2008 to 2012⁵⁰, the then-Tasmanian electricity industry regulator, the Tasmanian Energy Regulator, implemented a revenue cap for the maximum prices that the sole Tasmanian electricity distributor could charge for distribution services. The regulator did not include any specific provision in its determination that related to DSM.

During the 2007 electricity pricing investigation, the Tasmanian distributor developed pricing principles that included a provision that the distributor would negotiate with individual customers to ensure that tariffs reflected the economic value of specific services, including services associated with embedded generation, DSM, interruptible load, and higher or lower quality/reliability services than the quality/reliability associated with standard tariffs.

5.4 Initiatives by the National Electricity Regulator

From 1999, responsibility for economic regulation of electricity transmission services in the NEM was transferred progressively from State-based regulators to the national electricity regulator, initially the Australian Competition and Consumer Commission (ACCC) and then, from 1 July 2005, the Australian Energy Regulator (AER). During their regulation of transmission services, neither the ACCC nor the AER has made any specific provisions for demand-side participation in the NEM.

On 1 January 2008, responsibility for economic regulation of electricity distribution services in the NEM was transferred from State-based regulators to the AER. In regulating distribution networks, the AER has made use of the provision in Section 6.6.3 of the *National Electricity Rules* that enables the AER to develop and publish demand management incentive schemes⁵¹. Between 2008 and 2010, the AER progressively developed such schemes to cover electricity distributors in each of the States covered by the NEM.

5.4.1 New South Wales and the Australian Capital Territory

In its distribution determination for New South Wales and the Australian Capital Territory (ACT) for the period 2009 to 2014⁵², the AER implemented a Demand Management Incentive Scheme (DMIS) that has two components:

- the existing D-factor scheme established by the New South Wales regulator; and
- a Demand Management Innovation Allowance (DMIA) scheme.

The D-factor scheme is essentially unchanged from the scheme developed and applied by the New South Wales regulator IPART in its 2004 determination⁵³.

In February 2008, the AER released a DMIA scheme to apply to the New South Wales and ACT distributors for the period 2009 to 2014⁵⁴. The aim of the scheme is to encourage distributors to undertake efficient broad-based DSM that may provide long-term benefits to consumers and distributors. The scheme allows each distributor to recover a fixed dollar amount broadly proportionate to the relative size of the distributor's annual revenue over the regulatory

⁵⁰ Office of the Tasmanian Energy Regulator (2007). *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania. Final Report and Proposed Maximum Prices*. Hobart, TER.

⁵¹ See also section 3.2, page 9.

⁵² Australian Energy Regulator (2009a). *New South Wales Distribution Determination 2009-10 to 2013-14. Final Decision*. Melbourne, AER.

⁵³ Independent Pricing and Regulatory Tribunal (2004b). *Op. cit.*

⁵⁴ Australian Energy Regulator (2008a). *Demand Management Incentive Scheme for the ACT and NSW 2009 Distribution Determinations. Demand Management Innovation Allowance Scheme*. Melbourne, AER.

control period 2009 to 2014. These amounts vary from AUD 100,000 to AUD 1 million per distributor per annum. To obtain the allowances under the DMIA scheme, distributors must undertake efficient DSM programs and make claims for the associated costs, to be approved by the AER. If a distributor does not carry out any DSM programs that are approved under the scheme, it will not be eligible for the allowance. Assessment of DSM programs will be carried out in two stages; a prior approval stage to establish the aims of the program, followed by final approval at the end of the DSM program.

Between February and November 2008, the AER carried out further investigation on the optimum design of the original DMIA and developed a replacement DMIA⁵⁵ that was implemented in the final determination. The replacement DMIA is designed to supplement a distributor's approved capital expenditure and operating expenditure to facilitate investigation and implementation of DSM strategies. It aims to provide incentives for distributors to conduct research and investigation into innovative techniques for managing demand so that, in the future, DSM projects may be increasingly identified as viable alternatives to network augmentation.

The replacement DMIA consists of two parts, Part A and Part B.

Part A includes the same fixed dollar amounts as in the original DMIA. The amounts will be provided to each distributor as an annual allowance in the form of a fixed amount of additional revenue at the commencement of each year of the regulatory control period. In the second year of the subsequent regulatory control period, a single adjustment will be made to return the amount of any underspend or unapproved amounts to customers. The distributors must submit annual public reports on the outcomes and expenditure under the DMIA, which the AER will publish. DSM projects and programs eligible for approval under the DMIA scheme must meet all of a set of criteria defined by the AER.

Part B of the replacement DMIA is intended to enable distributors to recover revenue foregone resulting from a reduction in the quantity of energy sold that is directly attributable to a DSM project approved under Part A of the DMIA. Recovery is limited to revenue foregone as a result of non-tariff-based DSM projects or programs⁵⁶. There is no cap applied to the amount of foregone revenue that can be recovered, but recovery is limited to revenue foregone within the next regulatory control period in which the DMIA applies and does not include revenue foregone in the current or subsequent regulatory control periods. A distributor will be unable to recover foregone revenue resulting from DSM programs funded out of the distributor's regulatory allowance or reductions in revenue resulting from government policy changes in relation to DSM. The AER will not allow a distributor to recoup foregone revenues resulting from DSM carried out independently of the DMIA. The recovery of the foregone revenue is subject to the AER's approval and the AER's assessment of foregone revenue will occur subsequent to the AER's approval of a distributor's DSM projects under the DMIA.

Calculation of foregone revenue is based on the following key components:

- the amount of a change in energy consumption or demand directly attributable to the DSM initiative; and
- the price/tariff applicable to the foregone energy/demand.

⁵⁵ Australian Energy Regulator (2008b). *Demand Management Incentive Scheme for the ACT and NSW 2009 Distribution Determinations. Demand Management Innovation Allowance Scheme. [Replacement Scheme]*. Melbourne, AER.

⁵⁶ Tariff-based DSM programs use price signals to encourage electricity customers to modify their energy use (e.g., at times of peak electricity demand).

5.4.2 Queensland and South Australia

In September 2008, the AER released a DMIS⁵⁷ to apply to electricity distributors in Queensland and South Australia for the regulatory period 2010 to 2015. This scheme was implemented in the AER's final distribution determinations for Queensland⁵⁸ and South Australia⁵⁹.

The DMIS for Queensland and South Australian electricity distributors is designed to complement the broader regulatory framework in providing incentives for distributors to carry out non-network alternatives and encourage distributors to explore ways to manage expected demand for distribution services in other ways. The AER stated that the DMIS is not designed to be the sole or primary source of funding for DSM expenditure in a regulatory control period. The primary source of a distributor's recovery for DSM expenditure in a distribution determination is to be the approved forecasts of operating and capital expenditure in the AER's distribution determination for that distributor. Before approving forecasts of operating and capital expenditure, the AER will require distributors to satisfactorily demonstrate that efficient non-network alternatives to capital and operating expenditure have been properly considered in the development of forecasts.

The AER stated that the DMIS aims to provide incentives for distributors to investigate and conduct broad-based and/or peak-related DSM projects throughout the regulatory control period. It aims to increase the current stock of knowledge and experience with network DSM to encourage greater consideration of non-network alternatives to augmentation in the decision-making processes of distributors. The scheme aims to provide incentives for distributors to conduct research and investigation into innovative techniques for managing demand so that, in the future, DSM projects may be increasingly identified as viable alternatives to network augmentation.

Similar to the New South Wales DMIA, the DMIS for Queensland and South Australia includes a Part A comprising a DMIA and a Part B concerned with the recovery of foregone revenue. Unlike the New South Wales DMIA, the Victorian DMIS does not include a D-factor scheme. Also, the AER stated that Part B of the DMIS will not apply to the Queensland electricity distributors because the AER had determined that a revenue cap will apply to distribution services provided by these distributors during the 2010 to 2015 regulatory control period, and under a revenue cap, a distributor's ability to recover its allowed annual revenue is not affected by the quantity of electricity sold. Part B does apply to the South Australian electricity distributor.

In Part A, similar to the New South Wales DMIA, the DMIA is provided to each distributor as an annual, ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the regulatory control period. In the second regulatory year of the subsequent regulatory control period, a single adjustment will be made to return the amount of any underspend or unapproved amounts to customers. The total amount recoverable under the DMIS within a regulatory control period is capped at an amount based on the AER's understanding of the costs of typical DSM project costs and is scaled to the relative size of each distributor's average annual revenue allowance in the previous regulatory control period. For the regulatory period 2010 to 2015, these amounts varied from AUD 3 million for the single South Australian distributor to AUD 5 million for each of the two Queensland distributors. All other reporting and DSM project approval processes are similar to the New South Wales DMIA.

⁵⁷ Australian Energy Regulator (2008c). *Demand Management Incentive Scheme: Energex, Ergon and ETSA Utilities 2010-15*. Melbourne, AER.

⁵⁸ Australian Energy Regulator (2010a). *Queensland Distribution Determination 2010-11 to 2014-15*. Melbourne, AER.

⁵⁹ Australian Energy Regulator (2010b). *South Australia Distribution Determination 2010-11 to 2014-15*. Melbourne, AER.

In Part B, the criteria and processes for recovering foregone revenue are similar to those in the New South Wales DMIA.

5.4.3 Victoria

In April 2009, the AER released a DMIS⁶⁰ to apply to Victorian electricity distributors for the regulatory period 2011 to 2015. This scheme was implemented in the AER's final Victorian distribution determination⁶¹.

The purpose and scope of the Victorian DMIS are identical to those for the DMIS applied to electricity distributors in Queensland and South Australia.

Similar to the Queensland and South Australian DMIS, the Victorian DMIS includes a Part A comprising a DMIA and a Part B concerned with the recovery of foregone revenue. Part B applies to all the Victorian distributors because the AER had determined that a price cap, rather than a revenue cap, will apply to distribution services provided by the Victorian distributors.

In Part A, similar to the Queensland and South Australian DMIS, the DMIA is provided to each distributor as an annual, ex-ante allowance, and the total amount recoverable under the DMIA within a regulatory control period is capped at an amount based on the AER's understanding of the costs of typical DSM project and program costs. For the regulatory period 2011 to 2015, these amounts varied from AUD 1 million to AUD 3 million per distributor. All other reporting and DSM project approval processes are similar to the New South Wales DMIA.

In Part B, the criteria and processes for recovering foregone revenue are similar to those in the New South Wales DMIA.

5.4.4 Tasmania

In October 2010, the AER released a DMIS⁶² to apply to the single Tasmanian electricity distributor for the regulatory period 2012 to 2017. This scheme is to be implemented in the AER's final Tasmanian distribution determination. At the time of writing the AER has not yet released its final determination, although it has released a final framework and approach paper⁶³ that sets out the AER's likely approach to the application of a DMIS to the Tasmanian distributor.

The purpose and scope of the proposed Tasmanian DMIS are identical to those for the DMIS applied to electricity distributors in Queensland and South Australia.

The proposed Tasmanian DMIS includes only a DMIA and does not include a scheme concerned with the recovery of foregone revenue. This is because the AER intends to apply a revenue cap rather than a price cap to distribution services provided by the Tasmanian distributors.

Similar to the Queensland and South Australian DMIS, the DMIA is provided to the distributor as an annual, ex-ante allowance, and the total amount recoverable under the DMIS within a regulatory control period is capped at an amount based on the AER's understanding of the costs of typical DSM project costs. For the regulatory period 2012 to 2017, this amount is proposed to be AUD 2 million. All other reporting and DSM project approval processes are similar to the New South Wales DMIA.

⁶⁰ Australian Energy Regulator (2009b). *Demand Management Incentive Scheme: Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011-15*. Melbourne, AER.

⁶¹ Australian Energy Regulator (2010c). *Victorian Electricity Distribution Network Service Providers. Distribution Determination 2011-2015. Final Decision*. Melbourne, AER.

⁶² Australian Energy Regulator (2010d). *Demand Management Incentive Scheme: Aurora Energy. Regulatory Control Period Commencing 1 July 2012*. Melbourne, AER.

⁶³ Australian Energy Regulator (2010e). *Framework and Approach Paper Aurora Energy Pty Ltd. Regulatory Control Period Commencing 1 July 2012 Final*. Melbourne, AER.

6. INITIATIVES BY NATIONAL ELECTRICITY MARKET INSTITUTIONS

When the NEM commenced in December 1998, several new organisations were established, including the market operator and organisations to develop the market and review and manage changes to the market rules. Over time, some of these NEM institutions have undertaken studies and implemented policy initiatives aimed at increasing demand-side participation in the market.

6.1 Code Change Panel Review

The first formal review of demand-side participation carried out within the institutional structure of the NEM was initiated in 2000 by the Code Change Panel constituted by the then-National Electricity Code Administrator (NECA).

In mid-2000, NECA commissioned a consultancy firm to conduct a survey of market participants to ascertain the current level of, and attitudes toward, demand-side participation in the NEM⁶⁴. Based on feedback from the survey respondents, the consultants identified mechanisms that could be implemented for enhancing demand-side participation in the NEM. The consultants concluded that mechanisms that may encourage greater demand-side participation would need to focus on:

- refinements to the *National Electricity Code*;
- improving the awareness and understanding of end-use customers on the national market, particularly the wholesale market, risk management issues, and the benefits of demand-side participation; and
- encouraging greater participation in the market by specialist third-party demand-side aggregators and co-operatives.

In November 2000, NECA proposed changes to the *Code* that would⁶⁵:

- improve the accuracy of demand forecasts; and
- make the arrangements for demand-side bidding, which already existed in the *Code*, more attractive to end-use customers.

The final *Code* changes were gazetted on 11 October 2001.

6.2 VENCORP Study

The Victorian Energy Networks Corporation (VENCORP) was responsible for the efficient operation of gas and electricity industries in the State of Victoria.

In 2001, VENCORP commissioned consultants to assist in providing the Victorian Government with a definition of the relevant issues regarding the role and status of demand-side participation in the electricity market in Victoria and a range of practical options available to the Government to facilitate the proper functioning of demand-side participation.

⁶⁴ PHB Hagler Bailly (2000). *Survey of Demand-Side Participation in the National Market*. Adelaide, National Electricity Code Administrator.

⁶⁵ National Electricity Code Administrator Code Change Panel (2000). *Demand-side Participation: Report*. Adelaide, the Panel.

The consultants' report⁶⁶ stated that, from its inception, the NEM had viewed demand response as an important contributor to efficient market function. The assumption was that price signals would let customers decide – on entirely individualised terms – as to when reducing their electricity consumption would be more strategically economical for them than continuing to consume.

The consultants concluded that the level of demand response achieved to date represented only low hanging fruit. Significant additions totalling at least a doubling of the current amount were likely to become available as the market matured, assuming that market signals were allowed to continue to function and that the barriers identified in the report were addressed.

The design of the NEM envisaged that demand response would provide a check on the market power of suppliers and reduce the need for investment in low duty-cycle generation plant, thereby contributing to security of supply. The consultants concluded that, to achieve these goals, levels of demand response on the order of 500 MW would be required. Although it was impossible to quantify the impact that any Government policy initiative or program would have on the amount of demand response available in the market, the consultants recommended a range of initiatives as comprising sufficient facilitation to bring forward an effective amount of demand response.

These initiatives included:

- improving customer awareness;
- maintaining market price signals;
- extending market price signals and demand response capabilities to the residential sector;
- facilitating the entry of demand response aggregators;
- improving certainty for the use of standby generators;
- enhancing network operators' roles in and benefits from demand response;
- providing wholesale and retail contract market solutions; and
- reviewing the ancillary services market.

6.3 Independent Review of Energy Market Directions

In June 2001, the Council of Australian Governments (COAG) agreed to commission an independent review of the strategic direction for stationary energy market reform in Australia. The final report of the review, known as the Parer Report^{67,68}, was published in December 2002.

The review considered measures to increase demand-side participation in the NEM and concluded that there were few effective measures for stimulating the demand side to influence pool prices or the need for additional generation capacity in the NEM. Consequently this was where the immediate policy focus needed to be.

The review considered that the low level of demand-side involvement in the NEM was attributable to three factors:

- in the short term the demand for electricity was inelastic and there were natural limits to the DSM capability likely to be available;

⁶⁶ Charles River Associates (Asia Pacific) and Gallagher and Associates (2001). *Electricity Demand-Side Management Study: Review of Issues and Options for Government*. Melbourne, CRA.

⁶⁷ Council of Australian Governments Energy Market Review (2002). *Op. cit.*

⁶⁸ See also section 2.6, page 6.

- residential consumers with the most “peaky” demand faced no price signals regarding their use of electricity, and these consumers accounted for approximately half the load in many markets; and
- the then-current provisions in the *National Electricity Code* relating to demand-side participation in the NEM were unworkable, and those parties offering to curtail demand could not gain the full value of what they brought to the NEM.

The Parer Report proposed three policy measures that could be implemented to increase demand-side participation in the NEM:

- mandating an accelerated rollout of interval meters for all NEM households over the next five to 10 years;
- removing retail price caps and introducing full retail competition into all markets as soon as practicable, but in any event within the next three years; and
- introducing a “pay-as-bid” mechanism for demand reduction into the NEM dispatch and market systems.

Following the completion of the Parer Report, the Ministerial Council on Energy (MCE) directed its Standing Committee of Officials (SCO) to consider three factors that would facilitate greater demand-side participation in the NEM. These factors were:

- the costs and benefits of interval metering in the NEM;
- alignment of retail price caps with supply costs and a periodic review of the need for price caps in jurisdictions where full retail competition was operating; and
- the scope to facilitate a demand response pool in the NEM.

The MCE SCO report⁶⁹ was published in December 2003. Responding to the proposals in the Parer Report on demand-side participation in the NEM, the MCE recommended to COAG that:

- the MCE should consider the costs and benefits of introducing interval metering;
- in all jurisdictions where full retail competition was operating, each jurisdiction should align their retail price caps with costs and periodically review the need for price caps; and
- the MCE should examine options for a demand-side response pool in the NEM.

6.4 Ministerial Council on Energy User Participation Working Group

In 2004, the MCE SCO established a User Participation Working Group (UPWG) to undertake further work on end-user participation in the NEM.

6.4.1 UPWG Discussion Paper

The Working Group published a discussion paper⁷⁰ that proposed a set of policy directions as a path to achieve the objective of enhanced end-user participation in the NEM.

Demand-Side Response

The paper identified a number of concerns with the pay-as-bid demand-side response pool proposed by the Parer Report. Demand-side response mechanisms enable end-users to be financially rewarded when they choose to switch off or reschedule their energy use in response to market signals. The paper considered two potential market-based demand-side response mechanisms within the NEM:

⁶⁹ Ministerial Council on Energy (2003). *Report to COAG on Reform of Energy Markets*. Canberra. MCE.

⁷⁰ User Participation Working Group, Ministerial Council on Energy Standing Committee of Officials (2004). *Improving User Participation in the Australian Energy Market*. Canberra, MCE.

- a pay-as-bid mechanism that would dispatch and pay for demand-side response in the physical energy supply market; and
- a demand-side aggregation facility that would broker the demand-side response from a number of end-users and sell this package of response in either the financial or the physical market.

The benefits of both mechanisms included the potential moderation of spot prices and financial returns for end-users who provided demand-side response. A pay-as-bid mechanism raised a number of efficiency concerns, including its ability to effectively price and dispatch demand-side response in the spot market. The UPWG concluded that an aggregation facility that facilitated demand-side response in the financial market appeared to be a more promising mechanism to maximise available value to end-users.

Interval Metering

The UPWG concluded that interval metering technology coupled with appropriate time-of-use tariffs had the potential to deliver a range of benefits to market participants. Interval meters might encourage consumers to address their energy consumption by moderating electricity load at times of high wholesale spot prices or network congestion. The reduction of peak energy demand might benefit the market in delaying the need for investment in the electricity supply industry and lessening wholesale spot price peaks. Interval meters and associated time-of-use tariffs were potentially more equitable than existing less differentiated pricing arrangements, and more cost-reflective tariffs enable consumers to gain benefits from load shifting.

The UPWG proposed to carry out an assessment of the benefits derived from the existing interval meter stock to provide information on areas in which benefits of interval meters could be enhanced and which additional customer classes might benefit from greater application of interval metering technology. The UPWG concluded that a wide scale mandatory rollout of interval metering across all customer classes might be premature at the then-current stage of market development.

The UPWG also concluded that low cost, remotely activated load control and measurement technology may be a cost-effective alternative to interval meters for the small customer classes. The UPWG proposed to further explore this concept.

Retail Pricing

The UPWG concluded that in those jurisdictions where full retail competition had been introduced, various forms of retail tariff regulation were being applied as a safety-net mechanism to ease the transition to a competitive market for small customers. The UPWG recognised the need for the development of a transparent and predictable process. Enhanced market efficiency should be promoted through the alignment of regulated retail prices with energy costs to reflect growing levels of competition. Such a defined process would also allow for periodic review of the need for retail price regulation as the retail market matured.

The UPWG proposed to develop an overarching set of policy principles that would guide all governments that had introduced full retail competition to ensure transparent decision-making on retail price regulation issues.

6.4.2 MCE Policy Statement

A policy statement⁷¹ based on the work of the UPWG was released by the MCE in August 2004. The policy statement considered two issues in particular:

- market mechanisms to promote demand-side response in the NEM; and
- the role of interval metering technology.

Market Mechanisms to Promote Demand-Side Response

The MCE concluded that the then-current low level of end-user participation in the NEM reduced effective competition and diluted the benefits of market reform for energy consumers. Direct participation in the NEM should enable energy users to capture a greater share of the economic return achieved from reducing their energy consumption during high priced periods and network congestion. A market-based approach should allow buyers and sellers to capture the optimal value of demand-side response at least-cost.

The MCE considered that a flexible and accessible market-based demand-side aggregation mechanism was an attractive proposition, as it would create a secondary market to flexibly manage delivery and payment for demand-side response products rather than requiring additional structural changes to the existing spot market mechanism. It was also a structure that would be accessible by a broader cross-section of energy users.

The MCE agreed not to proceed with work on the Parer Report's pay-as-bid demand-side response bidding proposal. Preliminary work revealed several challenging design and implementation issues with no guarantee of higher levels of demand response in the NEM. A number of structural and compliance issues imposed an additional element of market risk and undermined its usefulness as a mechanism to induce direct end-user participation in the wholesale spot market. The proposal did not appear to present the most efficient or least-cost approach to improving overall user participation levels.

The MCE also stated that it would consider the need for further work to investigate the feasibility of a short-term forward market in facilitating demand-side bidding in the wholesale market. A number of markets used a multi-settlement approach in which the demand side and the supply side both bid and settled in a day ahead market, otherwise known as a short-term forward market. A voluntary short-term forward market had the potential to:

- assist demand-side response by providing a framework for demand-side resources to have greater certainty regarding the benefits that could be gained from load reduction; and
- assist the market to arrive at an efficient balance between committed generation and expected demand.

Role of Interval Metering Technology

The MCE stated that peak demand and load, which were increasingly driven by the growing penetration of air conditioners and other energy-using equipment in Australian households, were costly issues for the NEM. Metering complemented by remotely activated load control technology, other energy management technologies, and the right price incentives, could:

- moderate demand and load by assisting consumers to voluntarily manage their energy use;
- increase user participation;
- defer investment in new generation and network capacity; and
- contribute to a more effective energy retail market.

⁷¹ Ministerial Council on Energy Standing Committee of Officials (2004). *User Participation Policy Statement*. Canberra, MCE.

The MCE recognised the important role of interval metering and load control technologies in developing a more efficient energy market with stronger user participation and improved energy use management and endorsed further deployment of advanced interval metering technology as a long-term goal for the efficient development of the retail market. The MCE agreed that all NEM jurisdictions that had not then done so should review the use of interval meters and assess the relative benefits of an interval meter rollout by 2007. The MCE also agreed to commission a study to identify low cost load control technology and other technologies that could assist consumers in voluntarily managing their energy use.

6.5 Australian Energy Market Agreement

In June 2004, all Australian federal, State and Territory governments entered into the Australian Energy Market Agreement⁷² to give effect to the recommendations in the MCE report to COAG (see section 6.3, page 29).

Section 2.1(b)(iv) included the following provision as one of the objectives of the Agreement:

[E]nhance the participation of energy users in the markets including through demand-side management and the further introduction of retail competition, to increase the value of energy services to households and businesses[.]

6.6 Consultancy Report on Network Incentives for Distributed Generation and Demand-Side Response

In early 2007, the MCE's Energy Market Reform Working Group commissioned an independent review of the then-draft *National Electricity Rules* to identify any structural or regulatory impediments that might impede electricity distributors' incentives to support the development or uptake of economically efficient demand-side response and distributed generation.

The consultant's report, published in August 2007, consisted of two parts: the first part⁷³ reviewed the effect of the proposed initial *National Electricity Rules* on incentives to undertake demand-side response and distributed generation. The second part⁷⁴ considered six case studies with a view to identifying any distortions in the valuation and utilisation of demand-side response and distributed generation arising under the initial *Rules*.

The consultants identified a range of potential incentive barriers to demand-side response and distributed generation both in the revenue and pricing *Rules* and in the non-revenue and non-pricing *Rules*. They concluded that regulatory limitations to the efficient pricing of network services were a significant impediment to cost and benefit alignment. For example, in most of the case studies examined, constraints to efficient tariff rebalancing and to tariff reassignment limit electricity distributors' ability to align their prices and/or revenues with the costs they incurred.

The report proposed changes to the draft *National Electricity Rules* that would reduce or eliminate these barriers. In December 2007, many of these changes were incorporated into the *Rules* as amendments to Chapter 6.

6.7 Consultancy Report on Network Planning and Connection Arrangements

In early 2007, the MCE SCO engaged consultants to provide expert advice to assist in the development of a national framework for electricity distribution network expansion and

⁷² Australian Energy Market Agreement dated 30th day of June 2004.

⁷³ NERA Economic Consulting (2007a). *Part One: Distribution Rules Review – Network Incentives for Demand-Side Response and Distributed Generation*. Melbourne, NERA.

⁷⁴ NERA Economic Consulting (2007b). *Revised Demand-Side Response and Distributed Generation Case Studies*. Melbourne, NERA.

planning, connection charges, and capital works contributions. In particular, the consultants were to address the potential impacts of a new distribution framework on incentives for distributed generation and demand response in the NEM.

The consultants' report⁷⁵, published in August 2007, found that in some existing distribution network planning and connection arrangements, electricity distributors' incentives were not aligned closely with the promotion of efficient investment. One consequence of the existence of imperfect incentives was that the distributors might not naturally seek demand response and/or network support services provided by distributed generation as an alternative to undertaking network augmentations, even where it would be efficient for them to do so. The consultants concluded that administrative measures had an important role to address the shortcomings in the incentive arrangements.

The consultants' report was used to inform the terms of reference for the AEMC review of the national framework for electricity distribution network planning and expansion (see section 6.8. page 34).

6.8 AEMC Review of Demand-Side Participation in the National Electricity Market

In October 2007, the Australian Energy Market Commission wrote to the MCE stating that it intended to investigate the potential for amendments to the *National Electricity Rules* to better facilitate demand-side participation in the NEM. The objective of the AEMC review was to identify whether there were barriers or disincentives within the *Rules* that inhibited economically efficient demand-side participation.

The AEMC review addressed three questions in relation to demand-side participation:

1. Can measures that facilitate demand-side participation improve the efficiency of investment in, and operation and use of, electricity services in the NEM?
2. Are there obstacles or disincentives to efficient demand-side participation in the NEM?
3. Where obstacles or disincentives are identified, how can the *Rules* be changed to reduce or remove the obstacles and disincentives in order to facilitate efficient demand-side participation in the NEM?

The AEMC is carrying out the review in three stages:

- Stage 1 – considered demand-side participation in the context of the AEMC's then-current work program in order to develop recommendations that could be considered in the context of relevant *Rules* change proposals and reviews (this stage has been completed);
- Stage 2 – reviewed the *National Electricity Rules* more broadly to identify where there may be barriers to the efficient integration of the demand-side in the NEM and to develop proposals for *Rules* changes to reduce or remove the barriers where economic efficiency would be improved (this stage has been completed); and
- Stage 3 – will undertake a further review with the purpose of identifying any additional or remaining barriers to economically efficient demand-side participation in the NEM and to develop proposals for *Rules* changes to reduce or remove the barriers where economic efficiency would be improved (at the time of writing this stage has not yet commenced).

⁷⁵ Allen Consulting Group and NERA Economic Consulting (2007). *Network Planning and Connection Arrangements – National Frameworks for Distribution Network*. Sydney, ACG and NERA.

6.8.1 Demand-Side Participation Review Stage 1

The main purpose of Stage 1 was:

- to develop a conceptual framework for subsequent consideration by the AEMC of the role of demand-side participation in the NEM; and
- to make recommendations that facilitated demand-side participation within the bounds of the National Transmission Planner Review, the Congestion Management Review, and the Comprehensive Reliability Review, again for consideration by the AEMC.

The scope of Stage 1 was therefore limited to the then-current AEMC work program.

In Stage 1, AEMC commissioned a consultancy study of the role of demand-side participation in the NEM. The consultant's report⁷⁶, published in May 2008, focused on the following elements of the NEM:

- the network planning and information provision framework;
- the regulatory investment test;
- arrangements for network support and services, including network support contracts by transmission network operators and network ancillary services contracted by the market operator;
- proposed changes to the Value of Lost Load;
- proposed changes to the Reserve Trader arrangements; and
- proposals relating to the concept of a standing demand-side reserve capability.

The consultant's major recommendations were:

- to address the possibility that electricity distributors may have insufficient information about the likely feasibility of non-network alternatives to network investments:
 - ◆ the National Transmission Planner should be required to develop a methodology for the explicit inclusion of demand-side participation in the expected load forecasts published on an annual basis in the National Transmission Network Development Plan, by transmission exit point; and
 - ◆ the AEMC should consider the role of the National Transmission Planner in providing strategic direction for demand-side participation;
- to facilitate demand-side participation, the regulatory investment test should:
 - ◆ ensure that the timeframe over which demand-side participation options are required to be presented as alternatives to a network solution is sufficient to allow these options to be considered viable;
 - ◆ clearly define how “national market benefits” should be interpreted for non-network options;
 - ◆ take into account differences in risk profiles between network and non-network options; and
 - ◆ define an option-value benefit associated with an investment that defers a proposed network investment.

⁷⁶ NERA Economic Consulting (2008a). *Review of the Role of Demand-Side Participation in the National Electricity Market*. Melbourne, NERA.

- the AEMC should further examine the likely costs and benefits of placing an obligation on transmission network operators to estimate the amount of demand-side participation that would be needed to address identified areas of congestion and when the demand-side participation would be required;
- the AEMC should request the market operator to consider how technical requirements may be modified to better facilitate demand-side participation as a means of providing network control ancillary services;
- the roles and responsibilities for the provision of network support and control services between the market operator and transmission network operators should be clarified to ensure that demand-side participation as a means of providing network support and control services is facilitated; and
- for the Reserve Trader arrangements⁷⁷, efficient demand-side participation would be enhanced through improving the methodology for incorporating demand-side participation in the approach to determining the reserve adequacy. Specifically, electricity retailers should be required to provide information on contracted demand response on a confidential basis to the market operator.

6.8.2 Demand-Side Participation Review Stage 2

The second stage of the review was a more extensive analysis of the then-current version of the *National Electricity Rules* to identify how, if at all, the *Rules* materially disadvantaged economically efficient demand-side participation.

In the final report of Stage 2⁷⁸, published in November 2009, the AEMC found that, in the context of the current technology that supported demand-side participation and subject to a number of then-proposed amendments to the *National Electricity Rules*, the NEM framework did not materially bias against the use of demand-side participation. Overall, the costs and opportunities to participate provided by the framework were appropriate. The prospective rollout of smart meters and smart grid technology, however, might change the market environment significantly.

The report set out the AEMC's specific findings and recommendations for each of the topic areas considered in Stage 2 of the review.

Economic Regulation of Electricity Networks

The AEMC concluded that the existing NEM framework supported the setting of appropriate and cost-reflective network charges but there were practical limitations to how accurate the cost signals could be. These practical limitations meant that network charges were too imprecise to signal costs at different locations and times with sufficient accuracy to attain all the opportunities for economically efficient demand-side participation. Imprecise network charges meant that it was unlikely that customers were able to make efficient consumption decisions.

The AEMC stated that bilateral contracts for demand-side participation could be used as a means of complementing the signals provided through imperfect network prices to ensure that electricity consumption at peak times was economically efficient. Electricity distributors and transmission network operators regulated under a price cap had private incentives to contract in a way that was consistent with socially efficient levels of demand-side participation. The AEMC concluded that these electricity network businesses did not need to be compensated for demand-side participation that reduced network demand and hence

⁷⁷ See also section 6.12, page 43.

⁷⁸ Australian Energy Market Commission (2009a). *Review of Demand-Side Participation in the National Electricity Market. Stage 2 Final Report*. Sydney, AEMC.

revenues. A reduction in revenue caused by demand-side participation under a price cap could increase profits if the demand-side participation created a correspondingly larger reduction in costs.

The AEMC recommended changes to the NEM framework to better encourage economically efficient demand-side participation, including changes to the treatment of different types of costs between and over regulatory periods and to incentives for innovation on demand-side participation and for connecting embedded generators.

Network Planning Standards and Service Incentives

The AEMC found that service incentives schemes included in the *National Electricity Rules* allowed for an economic assessment of the costs and benefits of service outcomes. In addition, it found that probabilistic planning standards were likely to be more consistent with efficient use of demand-side participation as compared with deterministic standards because probabilistic standards are more amenable to handling demand-side participation with different degrees of “firmness”. Consequently the AEMC recommended that a review be undertaken to consider whether the form of planning standards for distribution networks should be derived on an economic basis and, if so, how.

Distribution Network Planning

The AEMC found that there was a lack of planning obligations in the then-version of the *Rules*. Although there were jurisdictional planning arrangements, these were not consistent. This inconsistency limited the ability of demand-side participation proponents to be effectively involved in the planning process.

Network Access and Connection

The AEMC found that the connection process did not appear to be a significant barrier for embedded generation but the flexibility afforded in determining minimum technical standards was causing delays and increasing costs for embedded generators. The AEMC recommended that the Reliability Panel should consider further the appropriate minimum technical standards for embedded generators as part of its Technical Standards Review.

Wholesale Market Participation

The AEMC found that the demand side could participate as a direct participant in the wholesale electricity market as scheduled load, or by receiving spot price pass-through with a retailer, or by being a counterparty to financial contracts derived from prices in the wholesale market. The AEMC concluded that it was simpler and more cost effective for customers to access the wholesale market indirectly, through a retailer or through contracting and financial trading. Participating through a retailer overcame the significant but proportional costs of participating directly in the wholesale spot market.

The AEMC found that the level of remuneration available in the wholesale market was not a barrier to demand-side participation and consequently concluded that demand-side participants should not be provided with additional compensation in the form of an uplift or similar type of payment.

The AEMC identified a barrier in relation to the aggregation of loads to provide market ancillary services but noted that a *Rules* change proposal was being developed to address this barrier.

Reliability

The AEMC investigated existing intervention mechanisms in which, where the market did not deliver sufficient capacity to meet the desired reliability standards, the system operator could

intervene and buy additional capacity or issue directions to market participants. The AEMC concluded that these mechanisms provided opportunities for customers to provide additional services in the NEM.

The AEMC identified a need for a mechanism to pay end-users who are not scheduled but who are willing to modify their behaviour if requested. The then-pending introduction of a short-term reliability mechanism would meet this need.

The AEMC found that market efficiency and the use of reliability mechanisms might be enhanced in two ways. The first was by improving the provision of information to AEMO on volumes of demand-side participation already in the market. This would allow AEMO to have better information before intervention mechanisms were used. The second was to consider further the role of small-scale embedded generators to provide additional services directly to the market.

6.8.3 Ministerial Council on Energy's Response to Demand-Side Participation Stage 2 Report

In July 2010, the MCE provided its response⁷⁹ to the AEMC's Stage 2 Final Report for the review. The MCE response noted its support of the Stage 2 recommendations, including the proposed *Rules* changes to enhance participation of the demand-side and the need for a further review to consider the implications of developments in smart grid and smart meter technologies in the NEM. The MCE also indicated that the Stage 3 Demand-Side Participation Review should also consider a number of other issues specifically related to the operation and effectiveness of price signals and energy efficiency obligation schemes.

6.8.4 Demand-Side Participation Review Stage 3

At the time of writing, Stage 3 of the AEMC's demand-side participation review has not been commenced.

The Stage 2 Final Report identified several issues that required further consideration because they were likely to increase the scope for more active demand-side participation in the NEM. Particularly, the rollout of smart grids and smart meters across the NEM will enable two-way flows of energy and information providing greater capacity for active management of energy by consumers or their agents. Consequently it was concluded there is a need for a further stage of the review to identify and address the implications for regulatory frameworks of more interactive power and data flows between the demand side and the supply side.

6.9 AEMC Review of National Framework for Electricity Distribution Network Planning and Expansion

In December 2008, the MCE directed the AEMC to conduct a review into the current electricity distribution network planning and expansion arrangements in the NEM.

In September 2009, the AEMC released its final report⁸⁰ and proposed draft rules⁸¹ for inclusion in the *National Electricity Rules*. Aspects of the proposed new Framework for Electricity Distribution Network Planning and Expansion that seek to address barriers to, and balance incentives for, distributed generation and demand response include:

⁷⁹ Ministerial Council on Energy (2010a). *Demand-Side Participation in the National Electricity Market. Ministerial Council on Energy Response to the Australian Energy Market Commission's Stage 2 Final Report*. Canberra, MCE.

⁸⁰ Australian Energy Market Commission (2009b). *Review of National Framework for Electricity Distribution Network Planning and Expansion. Final Report*. Sydney, AEMC.

⁸¹ Australian Energy Market Commission (2009c). *Distribution Annual Planning and Reporting Requirements and the Regulatory Investment Test for Distribution. Draft Rule Change Request (including draft Rules)*. Sydney, AEMC.

- requirements for electricity distributors to actively engage with non-network proponents through the development and adoption of a Demand Side Engagement Strategy including:
 - ◆ publishing a demand-side engagement facilitation process document;
 - ◆ establishing and maintaining a database of non-network case studies and proposals; and
 - ◆ establishing and maintaining a Demand Side Engagement Register;
- information requirements for distributors to identify and describe any forecast system limitations for sub-transmission assets and zone substations including detailed information on system limitations so that distributed generation and demand response proponents are more easily able to identify investment opportunities;
- enhanced transparency with requirements for distributors to publicly report on their activities and actions taken to promote non-network alternatives, including the adoption of embedded generation, in their annual planning reports; and
- a Regulatory Investment Test for Distribution that includes a requirement to consider credible non-network alternatives such as distributed generation and requires consideration of market benefits, including network losses, when determining the most efficient option.

In September 2010, the MCE released its policy response to the AEMC's proposed new framework⁸². The MCE considered that the proposed design of the national framework would promote a clear and efficient planning process and support the efficient development of distribution networks. The MCE was satisfied that the proposed framework provides appropriate levels of transparency and information regarding electricity distributor planning and investment activities to allow other market participants to make efficient investment decisions.

In particular, the MCE supported the AEMC recommendations for a Demand Side Engagement Strategy and recommendations requiring distributors to engage proactively with non-network providers in the development of potential solutions to system limitations. The MCE concluded that this is a practical way to enable non-network providers to raise credible alternatives to distribution system investments and overcome a perceived failure by distributors to consider non-network solutions to network constraints and planning problems. The MCE noted that non-network solutions will only be developed where justified on economic grounds or where otherwise required to meet reliability or system security standards.

At the time of writing, the AEMC proposals are proceeding through the AEMC's *Rules* change process and have not yet been incorporated into the *National Electricity Rules*.

6.10 National Connections Framework for Electricity Distribution Networks

The development of a national connections framework for electricity distribution networks arose from the MCE SCO policy response⁸³ to the consultancy report on network planning and connection arrangements (see section 6.7, page 33).

In essence, the policy response proposed that the process for network connection, as contained in Chapter 5 of the *National Electricity Rules*, should be simplified and streamlined

⁸² Ministerial Council on Energy (2010b). *National Framework for Electricity Distribution Network Planning and Expansion. Ministerial Council on Energy Response to Australian Energy Market Commission's Final Report*. Canberra, MCE.

⁸³ Ministerial Council on Energy (2008). *Electricity Distribution Network Planning and Connection: A National Framework for Electricity Distribution Networks. MCE Standing Committee of Officials Policy Response*. Canberra, MCE.

as it related to the distribution network. The revised process would contain two possible routes to connection:

- standard connections, which would be provided on the basis of standard applications and agreements, facilitating a short time period (five business days) for a connection offer to be made following an application for connection; and
- negotiated connections, which would be provided on a more individual basis, with greater time allowed for offers to be prepared that relate specifically to the particular connection being sought.

Distributors would be required to have at least one standard connection service for a customer load category (likely to be small customers), and at least one standard connection service for micro embedded generators (such as residential solar). Customers in these categories would be able to pursue a negotiated arrangement if they preferred. Distributors would also be able to develop standard contracts for other categories of customers (both load and embedded generators).

In March 2009, the MCE Network Policy Working Group released its final report⁸⁴ on a national connections framework for electricity distribution networks. Two issues were addressed by the report:

- the appropriate definition of “micro embedded generators” for the purpose of the proposed regulatory framework, and the approach to be taken in relation to the technical requirements for micro embedded generators; and
- the minimum content of standard and negotiated connection agreements for connection to electricity distribution networks, including both load and embedded generation contracts, and the coverage of the necessary content within Chapter 5 of the *National Electricity Rules*.

In November 2009, the MCE released Draft Rules⁸⁵ covering the electricity connection framework for retail customers and embedded generators. The framework will form a new Chapter 5A of the *National Electricity Rules*. In part, the new framework seeks to streamline the connection processes for non-registered embedded generators, such as residential solar. Aspects of the Draft Rules that seek to address barriers to distributed generation and demand-side response include:

- requirements for distributors to propose standing offers for basic micro embedded generation connections for retail customers;
- the ability for distributors to propose additional standing offers for other types of standard connections, including for embedded generators;
- the establishment of a separate, simpler, negotiating framework enabling any retail customer or non-registered embedded generator to negotiate a connection with a distributor if they wish; and
- the provision of access to cost-effective, accessible dispute resolution processes.

At the time of writing, the Draft Rules are proceeding through the AEMC's *Rules* change process and have not yet been incorporated into the *National Electricity Rules*.

⁸⁴ Ministerial Council on Energy Network Policy Working Group (2009). *National Connections Framework for Electricity Distribution Networks. Final Report*. Melbourne, Allens Arthur Robinson.

⁸⁵ Ministerial Council on Energy (2009). *National Electricity (Retail Connection) Amendment Rules 2010. Draft 27 November 2009*. Canberra, MCE.

6.11 Prime Minister's Task Group on Energy Efficiency

In March 2010, the then-Australian Prime Minister established a Task Group on Energy Efficiency to advise the Australian Government, by mid-2010, on options to improve Australia's energy efficiency by 2020. The Task Group report⁸⁶ was published in October 2010.

Almost a quarter of submissions to the Task Group argued that the NEM is excessively supply-side focused and fails to effectively balance the incentives and obligations for supply and demand solutions. Other submissions noted that recent and ongoing work in reforming the NEM arrangements is improving the balance between demand and supply solutions. In particular, one submission stated that two recent major reforms have changed the way in which electricity network companies approach non-network investment and DSM. The first was the introduction of the new Chapter 6 of the *National Electricity Rules*, which led to non-network alternatives becoming a part of electricity distributors' mainstream planning processes. The second was the introduction of demand management incentive schemes.

The Task Group noted that, although the AEMC, in its 2009 demand-side participation review, concluded that the NEM framework does not materially bias against the use of demand-side participation, in practice there has been no significant increase in activity or investment in energy efficiency in the NEM. Accordingly the Task Group considered that some relatively small but fundamental adjustments to NEM frameworks could lead to noticeable improvements in the take-up of energy efficiency opportunities.

The Task Group proposed the following initiatives related to demand-side participation in the NEM.

6.11.1 Regulatory Investment Test

The Task Group proposed that the AEMC and/or the AER should provide stronger regulatory oversight of the regulatory investment test process. Electricity distributors and transmission system operators are currently required to assess all proposed network expansions against alternatives (including DSM and distributed generation). This requires the network business to provide information to enable interested parties to comment on the justification for the project and the options identified and to propose alternative solutions where appropriate. Strong regulatory oversight in this area (which does not depend on dispute processes) would assist in transparency and ensure that electricity networks businesses undertake due diligence in these assessments.

6.11.2 Demand Management Incentive Schemes

The Task Group proposed that the AER should review the effectiveness of demand management incentive schemes, looking in particular at the option of moving to a national scheme, and opportunities for enhancing the existing schemes to provide stronger incentives for take-up of DSM in the NEM.

Several submissions to the Task Group suggested a large expansion of the existing schemes to drive a step change in new investment in DSM and to overcome existing cultural and information barriers.

⁸⁶ Prime Minister's Task Group on Energy Efficiency (2010). *Report of the Prime Minister's Task Group on Energy Efficiency*. Canberra, Department of Climate Change and Energy Efficiency.

6.11.3 Distributed Generation Connection Processes

The Task Group proposed that the MCE (working with the AEMC) should accelerate and expand the current work to streamline distributed generation connection processes.

The Task Group found that distributed generators (including cogeneration and trigeneration) encounter many obstacles to connecting to the grid. These included uncertainty over technical standards; a lack of transparency about opportunities to address network constraints; additional network management costs because networks were designed without significant distributed generation in mind; resulting uncertainty about what costs may reasonably be charged to distributed generators in planning for connection; and the challenge of small generators negotiating with a large monopoly electricity distributor. Work currently being undertaken by the MCE and AEMC to address these issues includes more standardised and simplified connection processes and standard technical connection requirements.

The Task Group proposed that this existing work should be accelerated and expanded to further consider:

- more transparent connection pricing so that it is clearer what the distributed generator should pay to the electricity distributor in connection costs, and also what the distributors should pay to the distributed generator to compensate for avoided transmission charges and for any network support services;
- a distributed generation ombudsman role or other option for improving the ability of distributed generation proponents to resolve technical connection matters;
- consolidating distribution planning information in a single consistent report; and
- improved arrangements for jurisdictional setting of reliability standards to reduce their impact on levels of distributed generation and demand-side participation.

6.11.4 Cost-Reflective Price Signals

The Task Group recommended more efficient, cost-reflective price signals in energy markets, including time-of-use pricing where appropriate.

The Task Group found that the capacity of energy users to make energy-efficient decisions is strengthened if their energy charges accurately reflect costs, including generation and network costs. Without the applicable metering technology to support cost-reflective pricing, it is unlikely that all the opportunities for cost-effective energy efficiency would be realised.

Barriers to efficient price signals will be considered in Stage 3 of the AEMC review of demand-side participation in the NEM. The Task Group proposed that this should be expanded to include barriers to time-of-day or block tariffs and mechanisms to encourage retailers to increase the pass-through of price signals to consumers.

The Task Group also proposed that the AEMC should be asked to consider improved forward price transparency. This is important given that most energy efficiency investments take time to pay back and expected price increases will generally improve their economics. Small distributed generators and consumers in particular are less likely to be able to estimate these forward prices than larger market participants, and so operate at a disadvantage. Unless all market players have access to information about forward energy prices, it is unlikely that efficient decisions will be made.

6.11.5 Energy Efficiency Performance Review

The Task Group proposed that the AER should be required to undertake a regular energy efficiency performance review of relevant NEM participants, which would allow for monitoring of improvements over time.

The Task Group found that consistent, reliable information is lacking on energy efficiency measures undertaken by businesses in the NEM and any associated savings in energy, demand, and cost. It is therefore not possible to compare the energy efficiency performance of different businesses in the NEM. Improved measurement, monitoring, and reporting of energy efficiency performance measures and their effectiveness within the NEM would help resolve this issue.

6.12 Role of the Reliability and Emergency Reserve Trader

Since the commencement of the NEM, the market operator has had the power to contract for reserves (termed “reserve trading”). Reserve trading essentially enabled the market operator to procure additional reserves if a shortfall of reserves was forecast. It acted as a safety net in the event that the NEM did not deliver sufficient reserves to ensure that the reliability standard of 0.002% unserved energy was met.

The reserve trading function was included in the *National Electricity Rules* under provisions establishing a Reliability and Emergency Reserve Trader (RERT). The current RERT mechanism allows AEMO to intervene in the market to ensure reliability of supply and to maintain power system security. The RERT enables AEMO to contract for additional reserves up to nine months ahead of a period in which reserves are projected to be insufficient to meet the relevant power system security and reliability standards, and, where practicable, to maintain power system security and dispatch these additional reserves should an actual shortfall occur.

The RERT is implemented by AEMO and allows:

- AEMO to obtain capacity that may not otherwise be available to the market;
- parties who have non-market generation capacity to make themselves known to AEMO and to declare what price those parties seek to be paid to use that capacity; and
- individuals or groups of consumers to declare what remuneration they would seek to have their load shed, in excess of the saving in energy cost.

The RERT mechanism currently provides an avenue for demand-side participation in the NEM. In fact, the RERT is more likely to attract, and has actually contracted, demand-side capacity, because most supply-side capacity is already planned to be available for peak demand periods.

In July 2010, the AEMC commissioned a review of the RERT mechanism to be carried out by the Reliability Panel, a specialist body within the AEMC. In particular, the Panel was required to determine whether the RERT should expire in line with the *National Electricity Rules* on 30 June 2012, or whether the RERT should be extended beyond the current expiry date.

In its final report of the review⁸⁷, the Reliability Panel agreed with submissions that demand-side capacity would be more efficiently used if it were to contract directly with electricity retailers or other intermediaries rather than contract with AEMO through the RERT. This would allow market participants to make contracting decisions that are most efficient for each participant.

The Reliability Panel recommended that the RERT should expire on 30 June 2013. The Panel noted that the transitional arrangements to extend the RERT by one year will allow more time for recommendations from ongoing work on the role of the demand side in the electricity market to be implemented.

⁸⁷ Australian Energy Market Commission Reliability Panel (2011). *Review of the Reliability and Emergency Reserve Trader*. Final Report. Sydney, AEMC.

7. NATIONAL ROLLOUT OF SMART METERS

Since 2006, NEM institutions have also been involved in several work programs in relation to a proposed national rollout of smart meters. This work is too extensive to review in detail in this paper and a summary only will be presented.

In February 2006, COAG committed to the progressive national rollout of smart electricity meters from 2007 to allow the introduction of time of day pricing and to allow users to better manage their demand for peak power. COAG decided that the rollout would occur only where benefits outweighed costs for residential users, and in accordance with an implementation plan that had regard to costs and benefits and took account of different market circumstances in each State and Territory.

The MCE was tasked to develop the details and provided an initial report on a smart meter rollout to COAG in November 2006. This report confirmed that a national smart meter rollout would provide a platform for a wide range of electricity market benefits, including improved customer service capability, reduced retailer risks, and network capital and operating cost reductions. The MCE report also presented a methodology for identifying benefits and costs associated with a smart meter rollout and provided the basis for an implementation plan.

In April 2007, COAG agreed to an implementation strategy to facilitate a national smart meter rollout⁸⁸ and tasked the MCE with investigating costs and benefits of smart meters nationally and jurisdictionally. COAG noted that the economic benefits would be maximised and the costs of installation minimised if a smart meter rollout was large in scale and based on a consistent national framework and functionality. Smart meters could facilitate significant savings to consumers from informed energy consumption and could also play a role in addressing the challenges of GHG reductions where retailers offer time of day pricing. They could provide a wider range of energy price choices tailored to consumer usage patterns and could provide tools for consumers to more fully understand and manage their total energy needs to reduce their GHG impact.

In December 2007, the MCE reviewed the first stage⁸⁹ of a smart meter cost-benefit analysis (CBA) and subsequently agreed to a national minimum functionality⁹⁰ for smart meters. In June 2008, the MCE reviewed the second stage⁹¹ of the CBA and noted a wide range of potential net benefits, but that benefits and costs were not certain in all jurisdictions. On this basis, the MCE supported the development of a national smart metering framework and smart meter deployments in Victoria and New South Wales.

In June 2008 the MCE agreed to extensive pilots and business cases in most jurisdictions to confirm benefits, costs, and risks⁹². The MCE also agreed to consider further deployment timelines and any requirement for further analysis by June 2012, based on the findings of the pilots and rollouts at that time.

In 2008, a National Stakeholder Steering Committee (NSSC) for the smart meter rollout was formed. The NSSC was made up of consumer and electricity industry representatives, and was involved in the development of the technical and operational aspects of the smart metering framework. The NSSC built on the results of the national CBA to further inform costs and benefits. In December 2010, the NSSC completed the bulk of its terms of reference.

⁸⁸ Council of Australian Governments (2007). *COAG National Reform Agenda. Competition Reform April 2007*. Canberra, COAG.

⁸⁹ NERA Economic Consulting (2007c). *Cost Benefit Analysis of Smart Metering and Direct Load Control. Phase 1 Overview Report*. Melbourne, NERA.

⁹⁰ Ministerial Council on Energy (2007). *MCE Decision Paper. A National Minimum Functionality for Smart Meters*. Canberra, MCE.

⁹¹ NERA Economic Consulting (2008b). *Cost Benefit Analysis of Smart Metering and Direct Load Control. Phase 2 Overview Report for Consultation*. Melbourne, NERA.

⁹² Ministerial Council on Energy (2008). *Smart Meter Decision Paper*. Canberra, MCE.

At the time of writing, it is expected that broader issues identified by the NSSC will be taken up in work programs carried out by the MCE, the AEMC, and AEMO. These work programs will complete the national framework for smart metering. Regulatory arrangements for cost recovery, customer protection measures, and safety standards for smart metering are being assessed by the MCE as part of the national framework in consultation with stakeholders.

In December 2008 and July 2009, the MCE released successive drafts of amendments to the *National Electricity Law* related to smart meters. These amendments are the first stage of the national legislative framework. The *National Electricity (South Australia) (Smart Meters) Amendment Act 2009* was passed by the South Australian Parliament in October 2009 as the lead legislating body for all the NEM jurisdictions. The amended *Act* provides a head of power for State and Territory energy ministers to require electricity distributors to conduct pilots of smart meters and related technology, including direct load control, or to require distribution businesses to roll out smart meters. The *Act* supports the COAG commitment to a staged national mandated rollout of electricity smart meters in areas where benefits outweigh costs. It also supports the MCE's decision in June 2008 that "the underlying regulatory arrangements for National Energy Market jurisdictions will remain within a consistent national framework."

An initial Rule under the amended *Act* was approved by MCE and made by the South Australian Minister for Energy on behalf of all the NEM jurisdictions. The Rule came into effect on 1 January 2011 as Part ZF of Chapter 11 of the *National Electricity Rules*. The initial Rule implements the decision made by MCE in June 2008 that electricity distributors should be exclusively responsible for meter provision and meter data services for the period of a mandated smart meter rollout in a jurisdiction. The Rule is not intended to pre-empt decisions about what should happen after the rollout or who should be responsible for other services enabled by smart meters, and it is only intended to apply for the period of the mandated rollout⁹³. Neither the *Act* nor the initial Rule have any effect other than where a Minister of a particular jurisdiction makes a decision to issue a determination under the *Act*, and neither is intended to preclude market participants deploying smart meters in the absence of a Ministerial determination.

At the MCE's request, the AEMC provided advice on the existing economic regulatory framework in the *National Electricity Rules* to ensure it gives electricity distributors reasonable opportunities to recover the efficient, direct costs of smart meters rollouts and pilots while providing incentives to ensure benefits are passed through to consumers as soon as possible. At the time of writing, it is intended that the MCE will assess the AEMC's advice and develop a Rule change package to be submitted to the AEMC's Rule change process for eventual incorporation into the *National Electricity Rules*.

8. ENERGY EFFICIENCY OBLIGATIONS

Energy efficiency obligations have been imposed on electricity retailers by three State governments in Australia. The obligations require retailers operating in each State to achieve annual energy efficiency targets. In two States, New South Wales and Victoria, the obligations are accompanied by energy efficiency certificate trading schemes (also known as "white certificate" schemes). In South Australia, energy efficiency trading may occur, but no certificates are issued.

In energy efficiency certificate trading schemes in which non-obligated parties are allowed to create and trade certificates, third parties such as energy services companies (ESCOs) can carry out energy efficiency projects and sell the resulting certificates to obligated parties. This

⁹³ Ministerial Council on Energy Standing Committee of Officials (2011). *National Electricity Amendment Bill – Smart Meters*. MCE Standing Committee of Officials Final Policy Response. Canberra, MCE.

provides a funding source for energy efficiency activities and can stimulate the development of an energy efficiency services industry. This has occurred in New South Wales and Victoria.

8.1 New South Wales and the ACT

8.1.1 Greenhouse Gas Reduction Scheme

Energy efficiency certificate trading in New South Wales and the ACT commenced as part of a larger scheme, the Greenhouse Gas Reduction Scheme (known as “GGAS”)⁹⁴. Obligations to reduce GHG emissions under GGAS were imposed from 1 January 2003. The Scheme started operating in mid-2003 in New South Wales and two years later in the ACT. The New South Wales Scheme became the first operational white certificate scheme in the world.

GGAS aims to reduce GHG emissions associated with the generation and use of electricity through project-based activities to offset the production of emissions. The GGAS legislation imposes a benchmark target for GHG emissions on the electricity sector as a whole in New South Wales and the ACT. The benchmark target was set at 7.27 tCO₂-e of GHG emissions per capita in New South Wales by 2007. Between 2003 and 2007, the benchmark progressively dropped to this per capita level and will remain at that level until 2021 or until GGAS is terminated.

The overall benchmark target is implemented by setting individual benchmark emissions levels for certain obligated parties, principally electricity retailers. Obligated parties are known as “benchmark participants”. Each year, the Scheme Administrator sets individual benchmark reductions of GHG emissions for each benchmark participant based on their contribution to the supply of electricity in New South Wales. Each benchmark participant then has to reduce the average GHG emissions from the electricity they supply or consume to the pre-set individual benchmark level.

When the emissions attributed to a benchmark participant exceed its pre-set benchmark level, the participant has to reduce its average GHG emissions. Alternatively the benchmark participant can purchase certificates, called “New South Wales Greenhouse Abatement Certificates” (NGACs), to offset its excess emissions and surrender these certificates. NGACs are transferable and can be freely traded between any parties. One NGAC represents one abated tonne of CO₂-e.

A penalty is payable when a benchmark participant does not reduce their attributed GHG emissions to their pre-set individual benchmark level or purchase sufficient NGACs to make up the shortfall. Benchmark participants are allowed to carry forward a shortfall of up to 10% of their greenhouse benchmark from one year to the next. The penalty is increased in line with inflation.

Under the original GGAS, NGACs could be created in four ways:

- through low-emission generation of electricity;
- through activities that result in reduced consumption of electricity (“demand-side abatement”);
- through the capture of carbon from the atmosphere in forests (“carbon sequestration”); and
- through industrial activities that reduce on-site GHG emissions not directly related to electricity consumption.

⁹⁴ See the GGAS website at <http://www.greenhousegas.nsw.gov.au/>

Demand-side abatement consisted mainly of energy efficiency projects, and NGACs created from these projects were essentially white certificates.

8.1.2 Energy Savings Scheme

In early 2009, the New South Wales Government decided to discontinue the energy efficient component of GGAS and establish a new, “pure” energy efficiency certificate trading scheme, the Energy Savings Scheme (ESS)⁹⁵. The ESS commenced on 1 July 2009 and will operate until 2020 unless a national energy efficiency scheme with similar objectives is implemented before that time.

The ESS is an energy savings scheme as opposed to a GHG reduction scheme. Reductions in energy savings are measured in kilowatt-hours instead of carbon dioxide equivalents and kilowatt-hour savings are converted to tCO₂-e. A new type of certificate called an “Energy Savings Certificate” (ESC) has been established, which has the same value as a certificate created under GGAS of one abated tonne of CO₂-e.

The ESS operates only in New South Wales and requires electricity retailers to reduce their electricity sales over time through energy efficiency activities. The energy savings obligation imposed on retailers commenced at 0.4% of annual electricity sales in 2009, ramps up to a maximum of 4% of annual electricity sales in 2014, and then will remain at 4% of annual sales until 2020.

Retailers may undertake energy efficiency activities themselves, or they can purchase certificates from companies carrying out energy efficiency activities accredited under the ESS. After purchasing sufficient certificates, the retailers then surrender these to meet their target reductions. Under the ESS, the total energy savings requirement each year is set as a given percentage of the liable electricity sales for that year.

8.2 Victoria

The Victorian Energy Efficiency Target (VEET) scheme⁹⁶ commenced on 1 January 2009 and is scheduled to end on 31 December 2029. During this period, VEET will operate in three-year phases. Obligated parties are major energy retail businesses in the State of Victoria, including both electricity and gas retailers. Although VEET is a “pure” white certificates scheme, the unit of measurement is emissions abatement (tCO₂-e) rather than reduction in energy use (kWh).

The VEET scheme has three objectives:

- to reduce GHG emissions;
- to encourage more efficient use of electricity and gas; and
- to encourage the development of an industry specialising in improving household energy efficiency.

The VEET legislation establishes an annual target of avoided GHG emissions to be achieved by major electricity and gas retailers in Victoria through improvements to household energy efficiency. The targets for energy savings by retailers are 2.7 megatonnes of GHG avoided in each of the three years 2009 to 2011 (a total of 8.1 megatonnes over three years) and 5.4 megatonnes of GHG avoided in each of the three years 2012 to 2015 (a total of 16.2 megatonnes over three years). Electricity and gas retailers are allocated individual annual targets based on their share of the combined electricity and gas market in Victoria in the previous year.

⁹⁵ See the ESS website at <http://www.ess.nsw.gov.au/>

⁹⁶ See the VEET website at <http://www.esc.vic.gov.au/public/VEET/>

The VEET scheme is based on the creation of tradable certificates known as Victorian Energy Efficiency Certificates (VEECs). One VEEC represents lifetime abatement of one tonne of carbon dioxide equivalent.

VEECs may be created by implementing any of a list of eligible energy efficiency activities prescribed by regulations; the regulations also deem the number of VEECs that can be created for each activity. Eligible activities are prescribed on the basis that they are most likely to generate maximum GHG abatement at least cost in the VEET scheme. Six categories of activities are specified as eligible activities in the regulations for Phase 1 of VEET. These activities are all in the household sector, although the scope may be extended to the small business and commercial sectors in later phases of VEET. The list of eligible activities will be reviewed every six months and this will provide an opportunity to add measures to the list, such as products for which there is currently no accepted energy performance test or standard.

Certificate creators offer householders energy efficiency products selected from the list of eligible activities. If they choose to accept the offer, householders sign a form assigning to the certificate creator the right to create VEECs based on an eligible activity having taken place in the householders' premises. Once the VEECs have been created and registered, the creator is free to sell them to the obligated parties (energy retailers).

8.3 South Australia

The South Australian Residential Energy Efficiency Scheme (REES)⁹⁷ commenced on 1 January 2009 and, although it is intended to be ongoing, it will initially apply until 31 December 2014. The REES will operate in three-year phases.

Obligated parties are all licensed retailers of electricity and gas in the State of South Australia who supply more than 5,000 residential customers. Although the REES is an energy efficiency target scheme, the unit of measurement is emissions abatement (tCO₂-e) rather than reduction in energy use (kWh).

The primary objectives of the REES are:

- to improve energy efficiency and reduce GHG emissions within the residential sector;
- to assist households prepare for likely energy price increases from emissions trading; and
- to reduce total energy costs for households, particularly low income households.

For each year of the REES, obligated retailers are required to achieve three targets:

- Greenhouse Gas Reduction Target (GGRT) – to achieve a set amount of GHG savings (tCO₂-e) by implementing approved energy efficiency activities in households;
- Priority Group Greenhouse Gas Reduction Target (PGGGRT) – to achieve a set proportion of the GGRT in priority group households;
- Energy Audit Target – to undertake a set number of energy audits in priority group households.

The South Australian Minister for Energy has set the targets to be achieved by electricity and gas retailers each year during the first three year phase of the REES. The GGRT has been set at 155,000 tCO₂-e in 2009; 235,000 tCO₂-e in 2010; and 255,000 tCO₂-e in 2011.

The Scheme Administrator allocates individual targets to obliged retailers based on formulae established in regulations. The formulae take into account GHG emissions associated with residential energy sales, accredited GreenPower sales to residential customers, and residential customer numbers. To meet targets for priority group households, retailers must be able to

⁹⁷ See the REES website at <http://www.escosa.sa.gov.au/site/page.cfm?u=290>

substantiate that householders hold one or more specified benefit cards or are recognised to be in hardship on criteria to be determined by the Scheme Administrator.

The REES is not based on tradeable energy efficiency certificates (white certificates); instead retailers accumulate credits toward their three targets. The scheme permits unlimited banking of credits by retailers. Where retailers undertake energy audits or achieve GHG savings in excess of their targets in any one year, they may choose to carry those credits over to help meet targets in subsequent years. Retailers may also choose to transfer any excess credits to another obliged retailer; this will enable a limited amount of trading.

The scheme does not permit retailers to borrow credits from future years to meet targets; if they do not meet their target in any given year, they will be liable for a shortfall penalty. A shortfall penalty will not be imposed if the retailer has achieved 90% or more of its target and any such shortfall must be carried over to the subsequent year.

To claim credits toward their GHG reduction targets, retailers must implement “approved energy efficiency activities”. A long list of eligible energy efficiency activities (including deeming values and minimum specifications) has been set by the Minister for Energy. Retailers may also apply to the Scheme Administrator to implement an energy efficiency activity that is not currently on the approved list. The Scheme Administrator will assess the application, and if approved, establish the description, specification, and deemed credit value for that activity.

To claim credits for energy audits, retailers must ensure that any audits undertaken comply with the minimum specification as set by the Minister for Energy. Energy audits must usually be undertaken in the home, but the REES also provides flexibility to conduct the audit by phone or office-based interview in which the interview is conducted in accordance with the minimum specification and the priority group household resides in a regional or remote area of South Australia. A retailer may not meet more than 10% of its energy audit target with interviews conducted by phone or in an office. An audit carried out by phone or in an office will be valued at 50% of one credit toward the retailer’s energy audit target.

9. IMPACTS OF DEMAND-SIDE PARTICIPATION INITIATIVES

There has now been nearly 20 years of activity in developing and implementing policy and regulatory initiatives aimed at increasing demand-side participation in the Australian NEM. However, the level of demand-side participation has been, and currently remains, quite low.

Until recently, it has not been possible to quantify the level of demand-side participation because no information about the implementation of DSM by electricity businesses was publicly available.

In November 2010, the first survey of DSM in Australia was carried out⁹⁸. This survey covered only DSM implemented by electricity network businesses (distributors and transmission system operators) and there are several limitations to the results. First, the survey does not cover all types of DSM in the Australian electricity sector. For example, DSM projects established by electricity retailers or by AEMO for system reliability purposes have not been captured. Second, some still-existing DSM measures established prior to the unbundling of functions within the electricity supply industry are not captured. For example, there are thousands of megawatts of load management delivered through residential off-peak storage water heater programs that have not been captured. Third, electricity network businesses do not have complete data, or even estimates, for all the DSM activity they are currently implementing. For example, the impact of time of use tariffs in reducing peak demand is often not fully quantified in the data collected for the survey.

⁹⁸ Dunstan, C., Ghiotto, N., Ross, K. (2011). *Report of the 2010 Survey of Electricity Network Demand Management in Australia*. Prepared for the Australian Alliance to Save Energy by the Institute for Sustainable Futures, University of Technology, Sydney.

The results of the survey do confirm that the level of demand-side participation in the NEM implemented by electricity network businesses is quite low:

- a total of 115 DSM projects were implemented and reported by 19 electricity network businesses for the three financial years of 2008/09, 2009/10, and 2010/11;
- the DSM projects reported in 2008/09 resulted in 328 GWh of energy savings, equivalent to about 0.16% of Australia's total electricity use in the same year (204 TWh);
- the total expected energy savings from DSM projects in 2010/11 reduces to 51 GWh, which is equivalent to about 0.02% of the expected total electricity use in Australia in 2010/11 (222 TWh);
- in 2008/09, the peak demand reductions reported by electricity network businesses totalled 86 MW, which equates to about 0.2% of Australia's total summer peak demand of 42.6 GW in 2008/09; and
- the expected peak demand reduction resulting from DSM in 2010/11 increases to 367 MW, which will provide about 0.8% of the expected total summer peak demand in Australia in 2010/11 (44.3 GW).

In contrast, the energy efficiency obligations imposed on electricity retailers in three States will result in significant amounts of energy savings. For example, in the New South Wales Energy Savings Scheme, the energy savings obligation imposed on retailers commenced at 0.4% of annual electricity sales in 2009, ramps up to a maximum of 4% of annual electricity sales in 2014, and then will remain at 4% of annual sales until 2020.

10. CONCLUSION

This paper has presented a brief history of almost 20 years of activity in developing and implementing policy and regulatory initiatives aimed at increasing demand-side participation in the Australian NEM. This activity commenced with the publication of the first design for the NEM in 1992 and has continued with various levels of enthusiasm ever since.

Three main groups of actors have developed and implemented demand-side participation initiatives:

- State Governments, particularly during the reform process for the electricity industry;
- electricity industry regulators; and
- institutions responsible for the operation and governance of the NEM.

During the 1990s, vertically integrated electricity utilities in Australia were unbundled into separate generation, transmission, distribution, and electricity retailing businesses. Following this unbundling, only the "wires" businesses have any incentive to implement projects that cost-effectively reduce load on the system. An incentive occurs when a load reduction project is less expensive than building poles and wires to augment or expand an electricity network.

Consequently most of the demand-side participation initiatives undertaken in Australia have been directed at electricity businesses responsible for managing and operating electricity transmission and distribution networks. Electricity distributors, in particular, have been the target of many initiatives, most of which are directed at encouraging distributors to implement projects to reduce peak loads on their networks and thereby defer requirements to augment or expand their network infrastructure. Despite the development and implementation of a large number of initiatives, the level of demand-side participation in the NEM implemented by electricity network businesses is quite low.

Since 2003, three State Governments in Australia have imposed obligations on electricity retailers to achieve set energy efficiency targets. The obligations require retailers operating in each State to achieve annual energy efficiency targets. In two states, New South Wales and Victoria, the obligations are accompanied by energy efficiency certificate trading schemes (also known as white certificate schemes). In South Australia, energy efficiency trading may occur, but no certificates are issued. The imposition of these obligations has resulted in significant levels of energy savings that are likely to increase over the next 10 years. In addition the obligations imposed in New South Wales and Victoria have stimulated the development of an energy efficiency services industry in each of these States.

The Australian National Electricity Market is a competitive energy-only wholesale electricity market operating through a gross pool. The experience in Australia suggests that achieving high levels of demand-side participation in this type of market is difficult. To increase demand-side participation in the NEM, it may be necessary to implement some fundamental changes to the structure of the market, such as introducing forward capacity and ancillary services markets that enable bidding by, and reveal the value of, demand-side resources.

In contrast, imposing energy efficiency obligations on electricity retailers in Australia has been successful in achieving significant levels of energy savings. Energy efficiency obligations effectively overcome, through public policy means, the critical barriers to efficiency improvements that end-users face. The savings achieved could be increased by extending the obligations to all States covered by the NEM and increasing the energy efficiency targets.

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