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**Productivity Commission**

# Electricity Network Regulatory Frameworks

Supplement to  
Inquiry Report

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The costs and benefits of  
demand management  
for households

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**Publications Inquiries:**

Media and Publications  
Productivity Commission  
Locked Bag 2 Collins Street East  
Melbourne VIC 8003

Tel: (03) 9653 2244  
Fax: (03) 9653 2303  
Email: [maps@pc.gov.au](mailto:maps@pc.gov.au)

**General Inquiries:**

Tel: (03) 9653 2100 or (02) 6240 3200

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### **Key points**

- Demand management can significantly delay or avoid network investments and reduce the need for peaking generators. The technologies underpinning demand management may also produce other benefits, such as those associated with remote metering and the provision of information on energy consumption to consumers.
  - However, there are also costs, most particularly the costs of the technologies needed to allow demand management to occur.
- The potential for net benefits from demand management is conditional on a number of factors, including:
  - the package of measures used. In combination, direct load control, smart meter rollouts and critical peak pricing can significantly reduce critical peak demand if well implemented
  - a sufficient demand response
  - the deployment of technologies on a schedule that takes account of the network characteristics of individual distribution businesses, and the customers they serve
  - the use of genuine cost-reflective time-based pricing. The shallow price differences between peak and non-peak electricity use of many time-of-use pricing schemes provide weak incentives to shift demand away from the mostly costly peaks. This means poorly targeted demand management options perform badly in cost-benefit analyses.
- Several steps can be taken to address the potential downside risks, including:
  - undertaking trials prior to the wider introduction of these initiatives
  - deploying smart meters (and associated time-based charging) when and where network businesses assess it as producing net benefits — which will often be where regional network constraints are looming
  - ensuring that any scheme effectively targets critical peak energy use
  - requiring rigorous analysis of the costs and benefits of smart meter rollouts. For large-scale rollouts, the cost-benefit test would be done as part of the Regulatory Investment Test for Distribution (RIT-D)
  - using direct load control as a complement to smart meters.
- While recent data help provide more information about the range of possible net benefits, the estimates nevertheless have wide confidence intervals.

Electricity networks must be able to carry power reliably during critical peak periods and peaking generators must be available to supplement energy supply at these times. As discussed in chapter 9, the investments in infrastructure to meet critical peak demand can be very large and, given current pricing arrangements, are inefficiently high. Demand management during peak periods would reduce such

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costs, and mitigate electricity price pressures. Moreover, some of the technologies used to achieve demand management can also significantly reduce network costs in other ways (chapters 9 and 10) — with this contributing significantly to the size of the benefits. The magnitude of the benefits and costs also depends on the way that demand management is implemented.

Putting aside power factor correction<sup>1</sup> (which mainly relates to medium and large non-residential customers) and distributed generation (chapter 13), demand management takes the form of:

- direct load control at critical peaks to smooth consumption. Direct load control can (with the consent of the consumer) also help address the problems posed by intermittent energy output from renewable generation on the stability of the grid, and to reduce the impacts of failures in generators (and other key assets)
- higher prices when demand is higher (though there are several variants of such pricing, as discussed later)
- rebates or incentives to reduce demand at critical peaks.

This paper explores the potential costs and benefits of several demand management options for *households*, which provides some guidance for effective policy in this area. It also highlights some of the risks of ad hoc policymaking. This technical paper is accompanied by a spreadsheet, which lays out the key assumptions and the detailed calculations. Figure 1.1 sets out the structure of the technical paper.

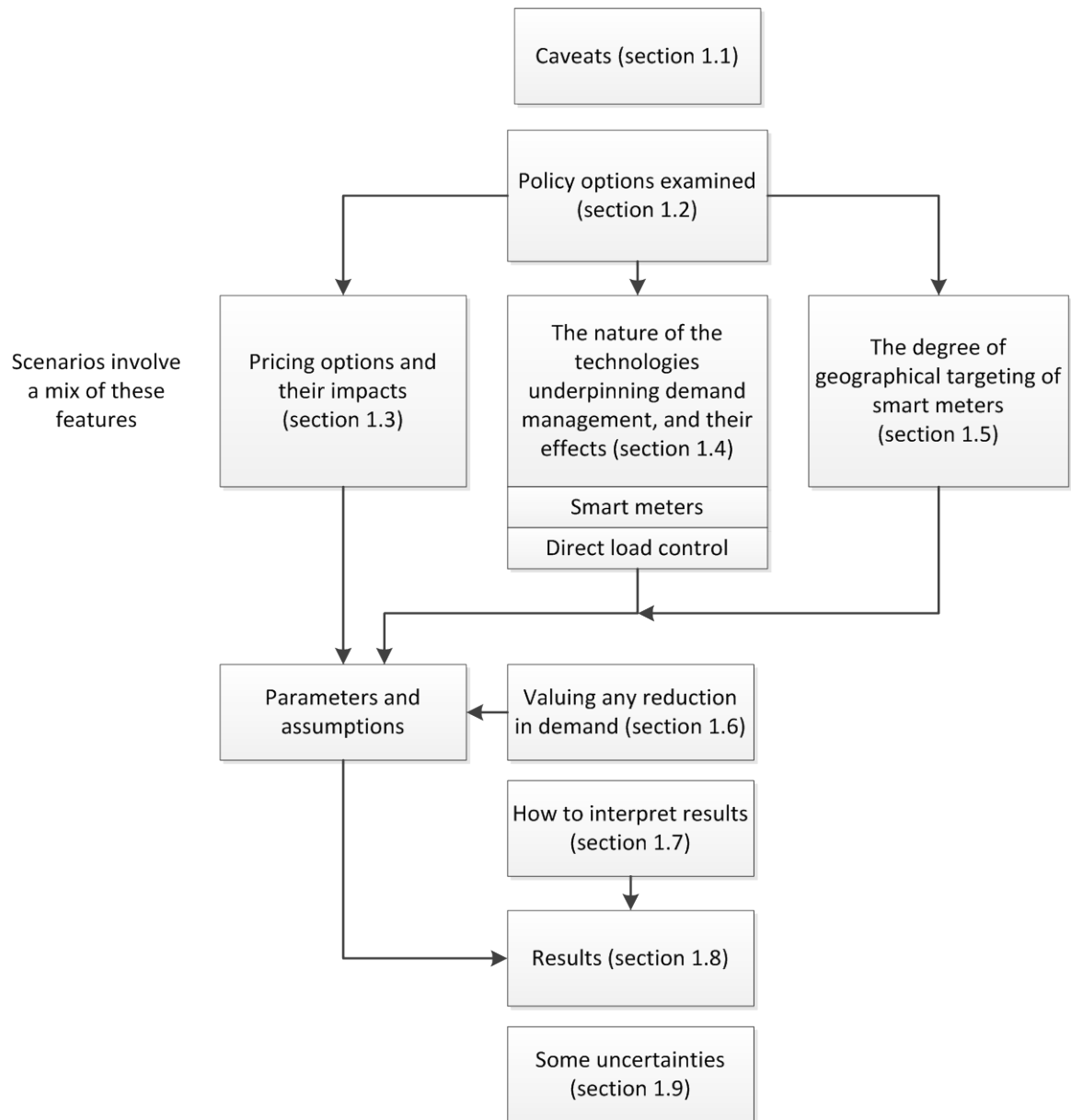
## 1.1 Some essential caveats

The Commission emphasises that the results in this technical paper are indicative. Estimates have been derived using a relatively simple and tractable modelling approach. Previous cost-benefit studies of demand management options (box 1.1) have found quite disparate estimates of net benefits, highlighting the challenges involved in this area (chapters 9 and 10). This paper draws on the methods and data in this previous work to help explore the options that the Commission has raised in its inquiry report. Due to data limitations, sometimes it has been necessary to use estimates for costs and benefits from specific trials. These estimates may be different in real world commercial settings.

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<sup>1</sup> Power factor describes how efficiently generation of electricity is converted into useful work. A power factor below the maximum of one indicates that the network and generators must supply more than the minimum volt-amperes of ‘reactive power’ necessary for a given amount of ‘real power’ provided to the consumer. Poor power factor is addressed by installing capacitor banks operating at low voltage to reduce the total power supplied to a customer’s premises (Futura 2011, p. 6), with benefits for upstream network infrastructure.

Figure 1.1 Technical paper structure



There may also be substantial economies of scale and scope from the large-scale deployment of advanced metering infrastructure and direct load control. While the Commission has sometimes cited stakeholders' views on such economies, it has not been able to undertake a full analysis of their possible size. This may result in the overestimation of some costs. However, this is not certain. The Commission notes that a recent evaluation of Victoria's deployment of smart meters found earlier studies had underestimated the costs involved (Deloitte 2011a).

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### Box 1.1 Previous cost benefit studies of smart meter rollouts

There have been multiple studies of the costs and benefits of introducing smart meters and the potential for demand management schemes in Australia. Most were ex ante assessments of the future net benefits from introducing smart meters and demand management in Victoria (described in detail in chapter 10). At the time, they were undertaken, these studies faced several major forecasting challenges relating to the costs of smart meters, their functionality, the responsiveness of consumers, and the practical issues in developing and operationalising communication, billing and information systems. These studies typically suggested that a state-wide rollout in Victoria would provide net benefits.

However, a more recent cost benefit analysis of the smart meter rollout in Victoria (Deloitte 2011a) was able to use actual cost data for some estimates because the rollout had been partly implemented. Using these data and various additional forecasts, Deloitte found that for the period 2008 (the time of project commencement) to 2028, the program would likely produce net costs (due largely to cost blowouts in the initial years of the program). However, Deloitte still recommended that the rollout be completed, given that the costs that most contributed to this adverse outcome had already occurred (and were therefore ‘sunk’), while many of the benefits could be realised in the future. As such, the *continuation* of the program from 2012 to 2028 was expected to deliver a substantial net benefit.

The most comprehensive cost benefit study of a *national* rollout was undertaken for the then Ministerial Council for Energy by a number of consultants (NERA 2008a, 2008b; KPMG 2008; CRA 2007; 2008a,b; and EMCa 2008). The study suggested that a universal rollout would result in net benefits for most states in the NEM. However, net benefits were unlikely for the ACT and Tasmania, and uncertain in South Australia (depending partly on demand response) (NERA 2008a).

The variations between these successive studies — discussed at greater length in chapter 10 — demonstrates the importance of assumptions and changing circumstances on cost–benefit estimates.

The uncertainties in the modelling analysis means that ranges, not point estimates, of net benefits are most useful for policy purposes. Even these ranges depend on assumptions that will change with technological developments and new patterns of demand.

The Commission has calculated three outcomes for any given policy experiment — low, medium and high:

- the ‘low’ case involves selecting the values in the ranges for parameters that give the worst welfare outcome
- the ‘high’ case involves selecting the values in the ranges for parameters that give the best welfare outcome

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- the ‘medium’ case describes the outcome occurring when parameters are set at the median value of the range.

The ‘medium’ case is the most likely, given that the probability that all parameter values are either at their worst or best possible setting is low. The Commission has also estimated an indicative 25<sup>th</sup> and 75<sup>th</sup> percentile outcome of any scenario using a simple statistical approach (described later) — which reduces extreme outcomes.

However, while there is uncertainty about the size of the benefits of demand management, the ranges for the *preferred* policy approaches shown below (section 1.8) are likely to exaggerate the real degree of uncertainty. One of the strengths of the Commission’s recommended approach for managing the deployment of smart meters in chapter 10 (and any other demand management technologies) is that rollouts are sequenced, with distribution businesses re-assessing the benefits and costs of each staged rollout at the time it occurs. Any significant investment (greater than \$5 million) is also subject to a RIT-D (a cost-benefit study) prior to its commencement. As any rollout would be remunerated through the standard incentive regulatory arrangements, the regulated business would also have strong incentives to minimise the costs of any rollout (in contrast to the arrangements that applied in Victoria — chapter 10).

In that sense, the Commission’s approach provides flexibility in the timing and scale of rollouts. Were the technologies for smart metering, the associated IT and for direct load control to develop at a faster pace, or the network infrastructure costs of critical peak demands to rise more than expected, then a rollout might be accelerated. In other circumstances, rollouts would be appropriately delayed. Moreover, the Commission’s recommended sequenced approach allows learning about the realised costs and benefits, which would then inform future ex ante cost-benefit tests. By design this should avoid circumstances in which each successive rollout failed an ex post cost-benefit test.

## 1.2 The various policy options

The formulation of the scenarios (table 1.1) is based on several choices about the:

- type of pricing — critical peak or time-of-use pricing compared with flat energy charges
- nature of the technology — advance metering technology (AMI or colloquially smart meters ) or direct load control alone. The outcomes from deploying non-remotely read interval meters (type 5 meters) is not modelled. Type 5 meters can also be used for some forms of cost-reflective pricing, but they

cannot provide immediate feedback to consumers or retailers about consumption patterns, and produce no other savings associated with the management of the network. Currently distribution businesses often replace accumulation meters with type 5 meters. For example, Ausgrid has been replacing old accumulation meters with type 5 meters since 2004 (Ausgrid 2013). However, this replacement strategy partly reflects regulatory barriers to the deployment by distribution businesses of more advanced metering infrastructure — chapter 10. It is unlikely that replacing accumulation meters with type 5 meters would be the most efficient *long-term* strategy

- degree of geographical targeting — NEM-wide rollouts or rollouts targeted at peaky and constrained regions.

The scenarios have drawn on the choice of policies previously evaluated by decision makers, such as a NEM-wide or state-by-state rollout of smart meters.<sup>2</sup>

Table 1.1 **The nature of the policy experiments<sup>a</sup>**

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
<b>Pricing arrangements</b>				
Critical peak pricing	Yes	Yes		
Weakly targeted 'time of use' (TOU) pricing			Yes	
<b>Technology choice</b>				
Smart meter rollout	Yes	Yes	Yes	
Direct load control only				Yes
<b>Degree of geographical targeting</b>				
Targeted regional (constrained and peaky areas)	Yes			
NEM-wide rollouts		Yes	Yes	Yes

<sup>a</sup> The counterfactual in each case are accumulation meters with flat energy use charges. Victoria is excluded from any results because it already has smart meters.

### 1.3 The type of time-based pricing applied.

In its various scenarios, the Commission examines two pricing options — untargeted 'time of use' (TOU) pricing and 'critical peak pricing' (CPP). Under TOU, electricity prices are set in advance for a given part of each day (such as 'peak', 'shoulder' and 'off-peak' times). TOU prices and periods may change

<sup>2</sup> The number of customers participating in the various demand management options and the amount of critical peak electricity demand at stake differs substantially across the scenarios. As such, the magnitude of the costs and benefits also differs substantially. The assumed number of customers for most scenarios has been based on trial participation rates.



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during the year — reflecting seasonal patterns of demand<sup>3</sup> — but usually do not change more than twice a year. Accordingly, TOU prices are highly predictable for consumers and can habituate them to certain demand responses (such as installing timers on pool pumps or routinely turning on dishwashers later at night).

The peak periods included in TOU are relatively long. For example, Ausgrid's peak rate of TOU pricing applies for around 6 hours per weekday or nearly 1600 hours a year (a deficiency according to Ausgrid<sup>4</sup>). In Queensland, Energex's TOU peak period is over 1000 hours a year. Accordingly, the peak TOU charge must be much less than in critical peak pricing schemes, which involve substantially higher prices for short periods for extreme demand peaks (typically between 30–80 hours per year).

For example, where appropriate electricity meters allow time-based charging, Ausgrid (a distribution business in New South Wales) sets its network charges for a peak period from 2 pm to 8 pm, a shoulder period from 8 pm to 10 pm and 7 am to 2 pm with off peak from 10 pm to 7 am. Its residential TOU network prices at peak periods (as proposed for 2012-13) are around ten times those at off-peak times (Ausgrid 2012, p. 29).

However, consumer behaviour is determined by retail prices and only indirectly by the network component of those prices. While retailers will often incorporate time-varying network charges into their retail tariffs, their effects are diluted because other costs are also important in determining final retail charges, and because retailers tend to smooth wholesale power price variations (where they use hedges to contain the risk of variability). Consequently, a TOU *network* charge that varies significantly over peak and off-peak periods is usually translated into much smaller price relativities at the *retail* level. For example, in New South Wales, Origin Energy's peak retail energy prices for residential customers in the Ausgrid network area are only around four times those of the off-peak rates (Origin Energy 2012).<sup>5</sup> Accordingly, a ten-fold price differential at the network side was more than

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<sup>3</sup> In the literature on the demand response of customers, this is sometimes referred to as seasonal time of use (TOU) pricing or STOU pricing.

<sup>4</sup> Ausgrid noted that there were opportunities to improve the design of its time of use tariffs, highlighting the broad definition of its tariff. Its definition for time of use (peak, shoulder and off-peak) covers both the evening winter and summer peak across the whole network. Ausgrid argued that such a broad definition 'has the potential to undermine economic efficiency even if peak energy charges are set reflective of LRMC because the network is not congested on all business days' (2012, p. 31).

<sup>5</sup> Even these charges are at the upper end of the variations in retail TOU charges for various electricity retailers in Australia.

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halved when expressed in retail prices. This dilution of network charging variations is important in modelling demand responses.

In contrast to TOU pricing, CPP only applies for the limited number of hours a year when demand reaches extreme levels — such as during heat wave conditions when air conditioning loads are particularly high. CPP network price variations are much greater than TOU network prices, and so this is reflected in a larger differential in retail prices during peak times compared with off peak. For example, Deloitte modelled a critical peak retail price that was 15 times that of the off-peak rate (scenario E by Deloitte 2011b, p. 44). In South Australia, Origin Energy’s ‘Smart Rates Adelaide Solar City Energy Plan (Option 1)’ sets a critical peak retail price of \$3.90 per kWh or around 14 times the off peak charge of around 28 cents per kWh. In contrast, Origin Energy’s ‘Smart Time of Use All Season Plan’ sets a peak retail price of around 54 cents per kWh, only around three times higher than the off peak rate of around 17 cents per kWh. Accordingly, demand responses to CPP can be expected to be greater than those arising from TOU prices alone. Consumers are typically informed of the critical periods and the associated prices one day ahead of the anticipated critical peaks, but, given the uncertain timing of peak events, CPP may not elicit habituated demand management responses (though CPP is often accompanied by TOU charging).

A third pricing approach is dynamic or real time pricing, in which electricity prices may change on an hourly (or even on a more granular basis) at all times. The latter would not generally apply to residential consumers and small businesses, and is not examined in this paper.

Capacity charges — which relate to the maximum capacity requirements of a customer over a given year — are also only applied to high energy users (chapter 10).

## **The effects of pricing**

The sensitivity of peak demand to pricing is measured by the peak price demand elasticity (the percentage reduction in peak demand associated with a percentage increase in the peak price of electricity over standard electricity charges). The Commission has assumed elasticities between -0.1 and -0.2 (with a middle case of -0.15), which is within the (rather wide) ranges found in a variety of the studies, including Deloitte (2011b, volume 2, pp. 50ff), NERA (2008b), Langmore and Duffy (2004) and Faruqui and Palmer (2011).

Such low elasticities reveal that people are reluctant to substitute consumption away from peak demand periods when the price changes are small. However,

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cost-reflective consumer energy tariffs at critical periods are many times those during off-peak periods. In some instances, the (retail) critical peak charge has been 20-30 times the off-peak rate, although usually the relativity is lower than this (Futura 2011, pp. 69-70). For example, with an elasticity of -0.15 and an eight-fold difference between a flat retail tariff and a critical peak price, the expected reduction in critical peak demand effect is 27 per cent. Accordingly, even with a 'low' elasticity, the demand response can be large.

Trials bear out the significance of critical peak pricing. Trials in New South Wales, Queensland and South Australia suggest reductions in energy use during critical peak events of 21–37 per cent (figure 1.2). In contrast, 'shallow' TOU charging has been less effective in reducing energy use during critical peak events with trial reductions of between 2 and 4 per cent.

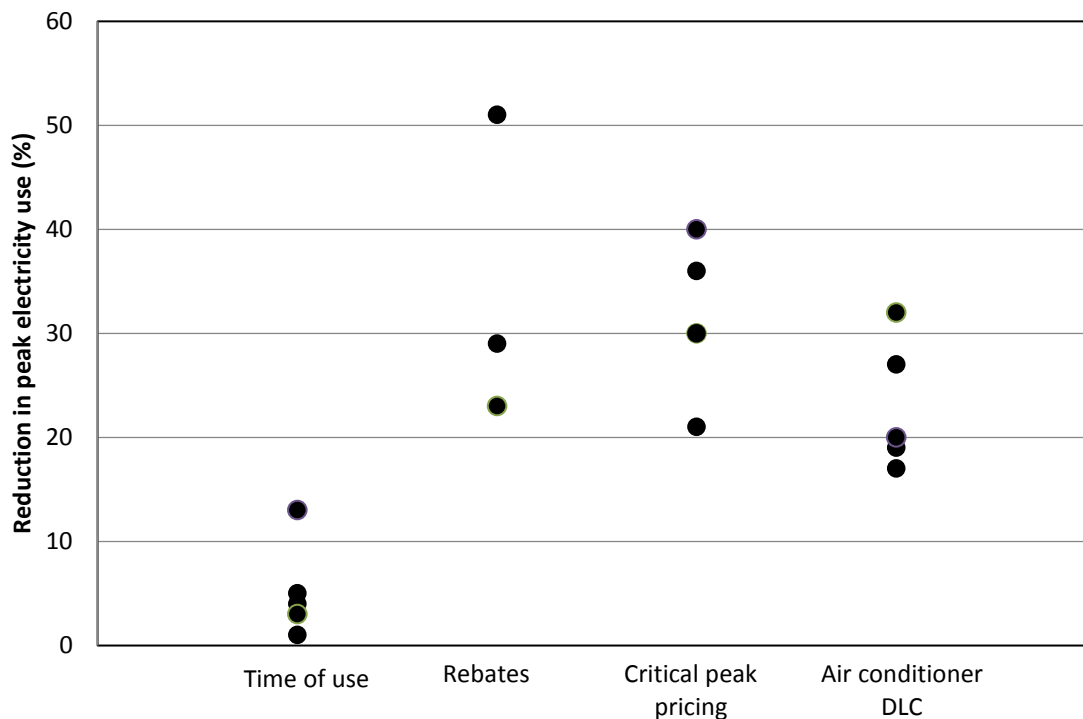
An important issue in any modelling of the effects of time-based charging is the persistence of demand responses. Etrog Consulting (2012, p. 57) and Faruqui and Palmer (2011, p. 20) found that customer responses to changes in prices persisted over time.

## **1.4 The nature of technology that targets peak demand periods**

### **Smart meters**

Smart meters measure electricity consumption over given periods — such as at half hourly intervals — and can be read remotely by the distribution business, avoiding the need for a person to manually read the meter for billing purposes. They also allow distribution businesses to use the meters as network sensors to assess the performance of the network and to give customers information about their power use. When paired with compatible appliances, they provide the scope for direct load control. Smart meters are supported by IT management and communication systems ('backend' systems), which are a major source of their costs.

**Figure 1.2 Reduction in critical peak electricity use for Australian trials**  
Average reduction by type of demand management



<sup>a</sup> Many demand management schemes have been trialled or introduced in Australia. They have included weakly targeted TOU pricing, critical peak pricing, rebates for curtailing electricity consumption during critical peak events, and the use of direct load control (DLC in the figure) technology (also targeting critical peak events). In some cases, several approaches have been used together. The chart is based on household responses of various demand management policies. (In some cases, the policies included more than one type of approach, such as CPP combined with year round TOU. Where that is the case, the Commission has categorised the policy by its most important element.) In most cases the CPP results show the demand response for particular critical peaks in a given season (such as in summer), while others show averages responses to critical peaks over all seasons. Given the selection biases, the scale of reduced peak energy use from a wider role out of demand management in Australia may be smaller than that achieved through trials. This is partly because consumer participation in demand management schemes and trials has been voluntary and so is more likely to include those with a greater interest and capacity for demand reductions. In addition, some trials have restricted eligibility to consumers who have greater scope to reduce peak energy use (for example, households with air conditioners).

*Data source:* Futura (2011, pp. 13-15, p. 60).

In contrast, accumulation meters simply record the total power usage, and must be read manually. They cannot facilitate time-based charging. A type 5 interval meter can record power usage over time, but does not give consumers timely feedback on their energy use, provides little information to retailers to allow them to set new tariffs, and cannot be read remotely.

Accordingly, smart meters have the joint benefits of underpinning sophisticated pricing initiatives (including rebates and incentives); facilitating information flows between network businesses, retailers and customers; managing the network and its

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costs; and assisting the direct load control of appliances (though they are not a prerequisite for this form of demand management).

Smart meters have been installed and operated as part of trials throughout Australia. A rollout is nearly completed in Victoria, but full use of time-based pricing in Victoria is still subject to a moratorium (due to elapse in 2013). These experiences help to provide cost estimates for other rollouts. While smart meters have also been introduced overseas, differences in the expected use of smart meters and variations in electrical systems reduce the applicability of overseas experiences for deriving cost estimates.

In the scenarios below, any change in a metering type is from accumulation meters — the most prevalent form of meter in Australia (AEMC 2012) to smart meters.

### *Costs*

Several factors affect the costs of smart meters, and these have contributed to uncertainty about the costs of any rollout program.

- The number of smart meters required at any given time is uncertain. Given the differences in peak energy use, the rollout of smart meters to small businesses may occur at a different time to households.
- Different smart meters are needed for premises with three-phase power, those that utilise direct load control; and those where there are two separate elements that record the flow of electricity separately. (The latter is used to calculate the feed in energy from photovoltaic units and for some forms of controlled loads, such as a single element off peak hot water system where the boost function would be a separate element.) Smart meters needed for premises with three-phase power can be double the cost of meters used with single-phase power.<sup>6</sup>
- There has been limited information on the cost of installing smart meters and the software and backend systems required to use them effectively. Cost blowouts in IT in many areas of business are common.
- Gradual rollouts of smart meters mean that a distribution business would have to maintain two systems — one for standard accumulation meters (involving manual meter reading for example), and one for smart meters (for example, IT systems, and information provision to retailers). This is one of the reasons why

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<sup>6</sup> The AER (2012, p. 11) approved a charge for SP AusNet's 'single phase single' meter charges of around \$130 per customer, while the allowed charges for its meter with 'Multi phase current transformer connected' was around \$260.

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the implementation process can affect the costs and benefits of smart meter rollouts.

Drawing on the Victorian evidence, the main cost of meters is their upfront purchase and installation (box 1.2 and table 1.2). However, with economies of scale and purchasing (Deloitte 2012, p. 27), technological change, and a common specification that was consistent with internationally recognised standards, costs could fall significantly.

**Box 1.2 Recent estimates of smart meter costs from Victoria**

Final determinations released by the Australian Energy Regulator (AER 2011, p. 16) and cost estimates from Deloitte (2011a, p. 7) suggest that the gross costs of the AMI rollout in Victoria would be around \$2.2-\$2.3 billion to supply around 2.9 million meters to around 2.7 million 'small customer' supply points by 2015. This implies that networks will spend around \$800 for each meter that they eventually roll out. Yet early estimates were for the gross costs to be around half of this. For example, NERA estimated that aggregate gross meter costs (including all backend systems) as between \$270 and \$434 per meter under a distributor-led rollout (NERA 2008a, p. 145). In part, the difference may be explained by:

- the change in technical standards proposed initially for the smart meters and the later decision to choose more advanced metering infrastructure
- the potential effects of inflation more generally.

However, with the prospect of technology change, the general decline in the costs of electronic equipment, and the potential to use a lower standard of functionality than actually selected in the Victorian AMI rollout, a lower bound cost of \$270 for the total system costs per meter may still be reasonable.

The figures above include the costs of communication infrastructure and data management. The actual purchase price of smart meters accounted for about 45 per cent of the Victorian rollout cost (table 1.2).

There are other significant additional costs associated with smart meters (table 1.2). These include the need to develop IT systems to record each consumer's electricity consumption data in real time and linking the consumption data to billing systems and network management systems. There are also costs in establishing effective systems to provide information to consumers and retailers about real time electricity usage and to provide a communication system to alert households in advance about a peak pricing day (where meters are used for critical peak pricing).

Using table 1.2, the gross cost of supplying and installing smart meters is likely to be in the range of \$270-\$800 per unit depending on their functionality. The

Commission has used these figures to provide the upper and lower bound estimates used in its calculations.

**Table 1.2 Key components of an advanced metering rollout**  
Victorian AMI rollout

<i>Cost item</i>	<i>Cost estimate</i>
'Smart' electricity meters and communication modules for each property	Purchase – 45 per cent Installation – 10 per cent
Communications infrastructure to transmit messages to and from the meters	7 per cent
'Backend' IT systems including: network management communication protocols data storage and management utilising the information for network management	25 per cent
Project management of the initial transition	10 per cent

*Sources:* AER approved determination spreadsheets and information from various studies, particularly Deloitte (2011a) and Oakley Greenwood (2010a,b), which itself drew on work by Futura (2009). The cost shares in the United Kingdom's rollout are similar in at least some components (Hierzinger et al. 2012, p. 88). The cost shares in the United Kingdom are 55 per cent for metering and installation, 23 per cent for communication technologies (which may encompass some costs that are categorised as IT costs in the Victorian rollout), 10 per cent IT costs and 10 per cent for other costs, such as industry set up costs and marketing. This provides some triangulation of the Victorian costs.

Information from the Victoria rollout indicates that the other costs of operating smart meters would be around \$25 a year per meter. The Commission has assumed that annual costs associated with smart meters would be in the order of \$20–30 a year per meter, although there is a risk that costs could be higher.

The IT software will also require updates over time. Following Deloitte (2011a, p. 12), the Commission has assumed that these costs are likely to be incurred seven years after installation and would range between \$100 and \$150 per meter.

### **Benefits**

The principal benefits of smart meters arise from a mixture of demand management and other benefits, including:

- their use in curtailing investment in generation and network infrastructure (the core of demand management)

- 
- ensuring that, if consumers value continuing to use power at critical peak times, the tariffs they pay appropriately reflect the real costs of their behaviour
  - energy savings for consumers who were otherwise unaware of their usage patterns<sup>7</sup>
  - in the event of major unanticipated electricity system failures, it may be feasible to have less costly load shedding (for example, by switching off power to many individual premises for only short periods, rather than cutting off whole areas for long periods)
  - raising network management efficiency
  - manual meter reads should not be required for any premises with smart meters, though the size of the gains are strongly dependent on sufficient local penetration rates
  - connections, disconnections and special reads (such as when consumers dispute their bills) can be conducted remotely
  - networks can be notified about outages almost immediately without relying on public reporting, allowing them to respond more rapidly (and reducing call centre costs). A network business can distinguish between an electrical fault affecting the network and one that relates to the premises of the customer (with faults in the latter the responsibility of the customer)
  - the incremental costs of installing a smart meter are reduced to the extent that there was a need to replace old accumulation meters.<sup>8</sup>

The benefits of the demand management associated with smart meters are potentially large if their rollout successfully defers or avoids network augmentation (the cost of which is discussed below).

Non-demand management benefits are also significant. Recent Australian studies provide varying estimates of the non-demand management benefits from smart meters (Deloitte 2011a,b; Futura 2009; NERA 2008a,b; Oakley Greenwood 2010a,b), though these only incorporate some of the factors above. Drawing on information from the most recent analysis of Victoria suggests an average ‘other’ benefit from each meter could be in the range of around \$45-\$70

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<sup>7</sup> For example, if a smart meter is accompanied by an in-home display, consumers can then make more informed decisions about energy conservation or realise the potential for lowering their costs during peak periods. The Commission has not included any benefits or costs from in-home displays, given uncertain evidence about their benefits (Futura 2011, p. 14) and the fact that they are an optional feature of smart meters.

<sup>8</sup> Mechanical accumulation meters have an expected life of 40 years and electronic ones a life of 15 years.



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each year (based on estimates cited by Deloitte 2011a for Victoria and a national study by CRA 2008a).<sup>9</sup>

However, there are doubts about when such benefits may eventuate, with evidence from the early rollout of smart meters in Victoria indicating that such benefits are yet to be realised (AER 2011). (Indeed, network operators indicated that meter reading costs had actually increased — due to the need to implement automated systems capable of collecting real time data from smart meters.) While such benefits may eventually materialise, the Commission notes that the limited operating lifespan for smart meters (15 years) would make it less likely that the projected cost savings will be achieved in full. For the purposes of modelling, the Commission has used a range of between \$50 and \$65 a year as the estimate of the overall non-demand management benefits of smart meters.

The extent to which smart meters provide any such demand management and other benefits depend on complementary policies — such as pricing or incentive initiatives — and the timing and geographical specificity of their rollout. For example, the capacity of smart meters to reduce peak demand in any given area requires a sufficient penetration of meters. Accordingly, the benefits are highly dependent on the context in which they are rolled out.

### **Direct load control**

Direct load control involves a capacity to interrupt the use of power by an appliance. Electric water heating has been subject to direct load control to avoid use of peak hour electricity since the 1960s, and constitutes the largest single source of peak power saved through demand side participation in the NEM (Futura 2011, p. 10, p. 30).

Much of the current interest in direct load control relates to air conditioner and pool pump use. Network businesses have conducted trials of direct load control of these appliances, and have found significant reductions in critical peak demand. Network businesses can implement direct load control without the need to install smart meters (although smart meters and critical peak pricing can still be useful in providing a signal for consumers to take up direct load control). From a network operator's perspective, the capacity to control load at critical peaks provides reasonable certainty over the timing, quantum and location of energy savings. Reliable demand forecasts at the localised level are necessary for a network business to reduce its investments in capacity.

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<sup>9</sup> The estimates from Deloitte required conversion of a net present value of benefits into an estimated annual cost per meter over its life. An eight per cent discount rate was used.

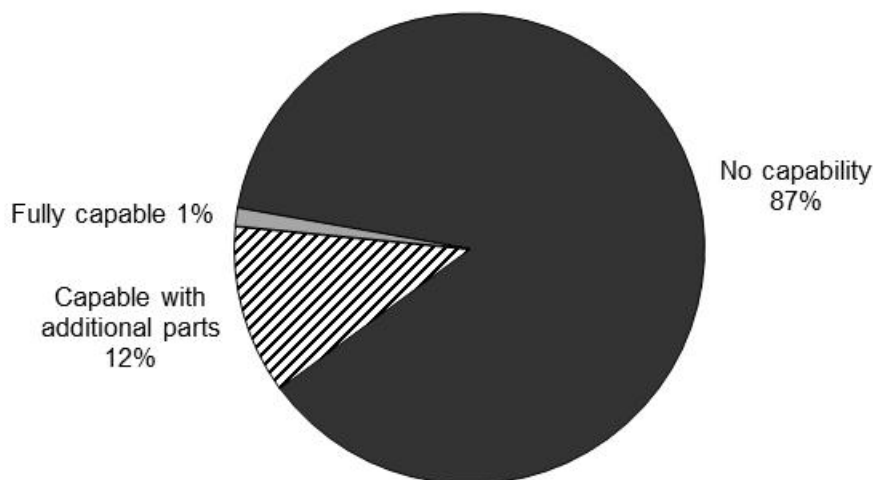
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While direct load control can be installed across a range of appliances, the most beneficial form of direct load control relates to air conditioners, which make a particularly large contribution to critical peak demand. Direct load control of air conditioners — especially that involving capping power to the compressor at critical peak times — has shown little impact on consumers’ comfort levels (Energex, pers. comm., 19 March 2013).

Direct load control trials in New South Wales and Queensland have demonstrated the effectiveness of communication and other technologies to control *compatible* appliances. However, a hurdle to the wide use of direct load control is that most *existing* appliances do not have the capability to be controlled remotely. Figure 1.3 provides evidence for 2011, though the Commission understands that many more appliance manufacturers are incorporating direct load control capabilities into new air conditioners (chapter 10).

Figure 1.3 **Air conditioners compatible with direct load control<sup>a</sup>**  
August 2011

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<sup>a</sup> Excludes air conditioners that exceed 30 kW of power.

Data source: Wilkenfeld (2011, p. 9).

The wide take-up of direct load control would require either:

- the retrofitting of a large stock of appliances (which can be costly, as discussed below)
- the incorporation of the appropriate technologies in new appliances and sufficient time that old appliances have been scrapped and replaced with newer models.

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## Cost estimates

The evidence suggests that retrofitting costs are not trivial.

- In 2007-08, Energex trialled direct load control of air conditioners without smart meters. It retrofitted around 900 air conditioners in Brisbane to enable direct load control without the need for smart meters (McGowan 2009). The indicative per participant cost of this trial was \$1500 (EnergyAustralia and TransGrid 2009, p. 15). A key consideration in selecting which air conditioners were included in the study (of the 2300 offered as test vehicles by consumers) was the ease of retrofitting (McGowan 2009).<sup>10</sup>
- The *Peakbreaker* trial of direct load control in South Australia by ETSA Utilities found that it took around 30 minutes<sup>11</sup> to two hours to retrofit an air conditioner (leading to an average cost of roughly \$300). Once again, the trial tended to focus on air conditioners that were the cheapest to retrofit (box 1.3).

### Box 1.3 Selection of air conditioners for the Peakbreaker trial

Following a community education campaign to recruit people for a direct load control trial, the trial managers identified 1691 air conditioning units that met the trial criteria — being either split system or ducted refrigerated air conditioners. Air conditioners that were older and/or consumed less electricity were outside the scope of the trial. By contacting all commercial premises within the trial area, an additional 701 air conditioners were included in the trial — bringing the total up to 2392.

Of those 1108 (46 per cent) were compatible with a demand response enabling device (DRED). Just over 1150 of the units — around 50 per cent of the sample — were typically more modern air conditioners, and could be retrofitted (such as with an emulator). It was not possible to determine if 128 air conditioners (5 per cent) could be retrofitted.

In total, 784 air conditioners were converted for direct load control — 754 with a DRED (68 per cent of those compatible) and 30 air conditioners that were not compatible with a DRED (only 3 per cent of those that could be retrofitted without a DRED). The 30 non-DRED compatible air conditioners were selected because a relatively cost-effective means of retrofitting of direct load control had been identified for one brand of air conditioner.

Source: ETSA Utilities (2009, pp. 68-71).

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<sup>10</sup> Accordingly, \$1500 may underestimate the true costs of retrofitting the overall stock of air conditioners (though the costs of retrofitting may change with innovation).

<sup>11</sup> If the component could be installed to a unit outside the house.

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However, the main purpose of the trials was to assess customers' receptiveness, demand response, and the technology. They were not commercial pilots. The Commission has been told by distribution businesses that they would not retrofit old air conditioners, but would rely on the compatibility of an increasing number of new air conditioners with direct load control. Accordingly, the lack of compatibility of old air conditioners with direct load control has an effect on the commercially viable pace of the adoption of direct load control, but not on the costs. In the longer run, in-built direct load control capability may become standard among air conditioners — which may occur due to the adoption of new technical standards or if there are commercial benefits from including this feature. Wilkenfeld (2011) estimated that in this instance, the costs could be \$10 per appliance for interface costs and \$150-250 for activation, leading to a cost range of between \$160 and \$260. There are also ongoing management costs, which are estimated at around \$25 per year by Deloitte (2011a, p. 51).

The presumption in these figures is that the differences between the costs of installing an air conditioner with direct load control would not be much higher than a traditional air conditioner (a view put to the Commission by a distribution business). Some other costs associated with encouraging the uptake of direct load control are likely to decrease. For example, marketing costs are likely to fall because appliance retailers are increasingly fulfilling that role as part of their usual marketing of appliances.

Any significant consumer uptake of any kind of voluntary direct load control of air conditioning or other appliances requires some payoff for consumers. Were network business to implement (and governments to allow) critical peak pricing for household electricity users, their uptake would be motivated by consumers' preferences to lower their power use during such periods (and with the certainty that direct load control provides).

However, in the absence of such pricing, direct load control is likely to require financial incentives to consumers, which add to costs. In Australian trials of direct load control, incentives have included credits on electricity bills, ongoing cash payments or alternative services (such as servicing of air conditioners). Payments have ranged from \$30 up to \$125 per household per year depending on the number of appliances (Futura 2011, pp. 119-124). In South-East Queensland, there are one-off rebates for purchasing air conditioners compatible with these technologies, subject to the customer agreeing that the network can cap the appliances' energy consumption when the electricity network reaches peak demand (while not

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compromising comfort).<sup>12</sup> In its analysis of the net benefits of direct load control, the Commission assumed that participating households would be eligible for annual payments of between \$30–\$100 a year for three years, recognising that even ‘ongoing’ payments only apply for a limited number of years.

### *The benefits*

Trial results suggest significant reductions in critical peak use. For example, McGowan (2009, pp. 16-17) found reductions in peak loads of between 17 and 35 per cent in the case of air conditioning trials in Queensland and South Australia.

However, the results of direct load control trials may be affected by so-called ‘selection bias’, in which the households that volunteer to participate have different characteristics and responsiveness to households in general. For example, they may be more conscious of their electricity bills and more responsive to incentive payments than other households. Consequently, it is important not to assume that a significant share of households would voluntarily participate and that a wider group of households would respond by the extent observed in recent trials. The Commission has assumed responsiveness in peak demand of between 15 and 25 per cent in its modelling from participation in direct load control.

Moreover, unlike pricing initiatives, the behavioural responses appear to wane over time. The evidence from Australian trials and programs is that some consumers who initially join direct load control schemes subsequently choose to discontinue their participation (which may reflect the way in which incentives are provided).

## **1.5 The degree of geographical targeting of smart meters**

There are two broad options:

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<sup>12</sup> In South-East Queensland, Energex provides incentives for households to install so-called PeakSmart compatible air conditioners (and letting the network use them to control peak demand). A small device installed in PeakSmart air conditioners receives remote signals that cap the energy consumption of the air conditioners when the electricity network reaches peak demand. Households receive an incentive of \$250 in gift vouchers for purchasing and installing a split inverter PeakSmart compatible air conditioner and a \$500 in gift vouchers for purchasing and installing a PeakSmart compatible ducted system. (Energex offers similar incentives for people signing up to pool pumps timed to operate outside of peak hours.)

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## Targeted rollouts

First, rollouts could be targeted at areas where demand was peakier and where there were benefits from avoiding or deferring network augmentation (which, in any given period, requires that additional capacity would soon need to be built in the absence of demand management).

As noted by Ernst and Young, constraints tend to be localised:

Whilst peak demand represents the maximum load on a section of the network within a given timeframe, NSPs [Network Service Providers] do not build network capacity to meet whole-of-system peak demand. Rather, network businesses identify localised network constraints and build additional capacity to address these specific constraints. In a network with multiple localised constraints, all of these constraints are unlikely to occur at the time of system peak demand. This may be due to the geographical size of the network, the network topology and local customer characteristics (such as customer density, load factor, customer type etc). (2011, p. 69)

Addressing localised constraints through demand management requires several conditions to be in place:

- network business must be able to forecast such impending constraints a sufficient time ahead that a smart meter rollout could occur and that demand management would be a realistic alternative to network augmentation. Currently, it appears that network businesses sometimes consider demand management as an alternative to network augmentation only at the time when an investment decision must otherwise be made to avoid an imminent constraint. If a demand management solution requires more time than augmentation to relieve an anticipated constraint, then there will be a tendency to build. Were demand management to have occurred earlier, then the build may have been avoidable
- new tariffs could be developed and sufficient demand responses could be elicited
- there is enough certainty that a demand response solution will constrain demand in a given locality.

Experiences with trials and the imminent adoption of time-based pricing in Victoria should make it easier to meet the latter two conditions. Moreover, changes to the regulatory incentive arrangements that have previously encouraged augmentation ahead of other solutions should increase the likelihood that demand management options are considered.

Targeted rollouts would eventually lead to a NEM-wide rollout of meters, but implementation would be delayed for areas with lower peak use or where existing network infrastructure was sufficient for the medium term.

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## A NEM-wide approach

As in Victoria and some European countries, an alternative approach is a mandatory and universal rollout of smart meters throughout the NEM (realistically achieved over several years).

### 1.6 Valuing any reduction in peak demand

Reducing the growth in peak demand reduces the need for additional investment, and accordingly provides potentially large savings. The question is the appropriate measure of these cost savings. Two (readily confused<sup>13</sup>) measures are cited as relevant to the cost of augmenting electricity supply.

#### **The upfront cost of a lumpy investment needed to resolve a constraint — short-run marginal cost**

One measure of the cost is the value of the entire upfront investment needed to add a given increment to supply. This is the short-run marginal cost (SRMC) of network and generation replacement at the point when supply constraints are so great as to require a new large fixed investment.<sup>14</sup> In the case of generation, the marginal cost at this point might be the cost of building a peaking generator. In distribution networks, it might be the construction of a new zone substation. If achieved in time, a relatively modest reduction in demand arising from demand management may defer the lumpy investment.

The Commission received advice from Ausgrid about the short-run marginal cost of new capacity, with the costs being:

- \$1000 per kW for generation
- \$400–\$1000 per kW for transmission (with a preferred estimate of \$800)
- \$1500–\$2000 per kW for distribution (with a preferred estimate of \$1500).

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<sup>13</sup> For example, Ernst and Young (2011) undertook a thorough examination of the rationales and drivers for demand side participation in the NEM, including estimates of the value of deferring investment. They estimated that the deferral value for distribution networks lay between \$50 and \$300 per kVA per annum, but were puzzled by the gap between these estimates and Ausgrid's estimate of \$1,600/kW to \$5,100/kW for distribution and transmission combined (ibid, p. 89). The distinction is that the former measure is the long-run marginal costs, and the latter the full upfront investment cost for expanding the network by a kW for the life of the investment (the short-run marginal cost when a system is constrained).

<sup>14</sup> Subsequently, the short-run marginal cost would be low (reflecting operational costs alone).

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AECOM (2012) developed a range of SRMC estimates based on the ratio of growth-related capital expenditure and increased maximum demand. When the estimates from Ausgrid and AECOM are consolidated, and outliers removed, the best estimates of the SRMC of additional capacity are:

- \$900 per kW for generation
- \$470–\$900 per kW for transmission
- \$2200–\$3300 per kW for distribution.

This suggests that short-run marginal costs of delivering peak power to consumers could be as high as \$3600–\$5100 per kW. However, for the short-run savings from demand management to be that high would require sufficient reductions in peak electricity demand to simultaneously avoid or defer the need for new generation, transmission and distribution capacity. The scope of regionally-focused demand management to defer network augmentation is more likely to occur in just the distribution network.

### **A long-run perspective on the costs of capacity**

The other cost measure is the long-run marginal cost (LRMC) of supplying capacity. As discussed in chapter 11, there are different ways of calculating the LRMC, but fundamentally, it measures the annualised cost of supplying the required capacity over the life of the asset. Accordingly, unlike the SRMC, the LRMC is measured in per year terms. The Commission reviewed existing estimates of the long-run marginal cost of delivering an additional kW to an end user during peak periods,<sup>15</sup> and found the following ranges plausible:

- \$150 to \$220 of distribution infrastructure costs for an additional kW per year
- \$30 to \$70 of additional transmission capacity costs for each kW per year
- \$90 of generation infrastructure costs for an additional kW per year.

This suggests that, in aggregate, the long-run marginal cost of delivering peak power to consumers is likely to be somewhere in the range of \$270–\$380 per kW per year.<sup>16</sup>

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<sup>15</sup> The information was obtained from personal communications with various network businesses; network business pricing proposals; Futura (2009, p. 70); Oakley Greenwood (2010a, p. 39, p. 41); Deloitte (2012, pp. 20-23), the Queensland Department of Employment, Economic Development and Innovation (2011, p. 1) and AECOM (2012, pp. 57ff).

<sup>16</sup> These figures were revised from the draft technical paper following inclusion of data from AECOM (2012), which was recommended as a useful data source by a major distribution business.



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## Both measures have value

Both the SRMC and LRMC have value in considering the impacts of demand management. In areas where a large lumpy investment must be made, a relatively small amount of demand management may sufficiently address constraints that an entire investment may be deferred for one or more years. (Given it is deferral, not complete avoidance of the need for investment, the value is the deferral value, not the value of the whole investment.)<sup>17</sup>

However, more commonly, the appropriate measure of deferred or avoided investment is the LRMC, which recognises that, on average, demand management can steadily reduce (and sometimes avoid altogether) the required incremental expansion of the network. Most studies of the impacts of demand management have used estimates of the LRMC in valuing savings in network augmentation. In all of its scenarios, the Commission has used a LRMC estimate of between \$270 and \$380 per kW per year (as derived above).<sup>18</sup>

## 1.7 Interpreting the results of the cost-benefit scenarios

The tables below identify the costs and benefits for each of the scenarios. Such costs and benefits are depicted in several ways:

- (i) as the net present value (NPV) of the stream of cost and benefits over the life of the smart meters using a real discount rate of 8 per cent<sup>19</sup>
- (ii) as the NPV of the stream of costs and benefits *per household* using smart meters or direct load control. The advantage of this measure is that it recognises that the number of households that could participate in a demand management policy differs substantially across the scenarios. For example, in the scenario where network distributors roll out smart meters

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<sup>17</sup> Where the deferral is for just one year, the deferral value of an investment is around  $I \times r / (1+r)$ , where  $r$  is the discount rate and  $I$  is the value of the lumpy investment. This also approximately equal to the LRMC, which provides a link between the two measures.

<sup>18</sup> However, in one variation of scenario 1, the Commission also considers the benefits of a one-year deferral of a lumpy distribution network investment. This variation is shown in the accompanying spreadsheet (in the 'Constrained peaky networks (v2)' tab), but not in the results of this paper or the main report.

<sup>19</sup> Determining the 'right' discount rate for cost-benefit analysis is very difficult. In undertaking this indicative analysis, the Commission has adopted 8 per cent, in line with the findings of Harrison (2010, p. viii).

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sequentially, region by region, the calculations are based on a single regional rollout with 100 per cent participation rates in each region. By definition, these results relate to a smaller number of households than an analysis of a rapid NEM-wide rollout. In turn, the *absolute* value of the costs and benefits of any given regional rollout is also small compared with an untargeted rapid NEM-wide rollout. However, an absolute measure of costs and benefits would be misleading because, on a per household basis, the net benefits are greater for a sequenced and targeted regional rollout than a NEM-wide untargeted rollout. Given this, (ii) is a better measure than (i)

- (iii) as a benefit–cost ratio. This provides a single useful metric of whether a policy passes a cost-benefit test. A value lower than one means that the estimated present value of the costs of a policy is more than the estimated present value of its benefits, which suggests that the policy should not be implemented (the NPV would be negative)
- (iv) as an annuity over the 15 year life of the technology underpinning demand management, reflecting that present values of streams of future net benefits are often not popularly understood. The annuity is the dollar reduction per year in a household’s bill over the 15-year period. For example, the annuity value of the medium case in scenario 1 is around \$150 a year, while the value is around \$330 for the high case and \$15 for the low case. Since the probability of achieving the net benefits associated with either the low case or high case is small, a narrower range than \$15–\$330 may be appropriate. Box 1.4 sets out a method for calculating a more reasonable range based on the 25<sup>th</sup> to 75<sup>th</sup> percentile of the distribution of outcomes. In the case of scenario 1 — the Commission’s preferred policy approach — the resulting range in the annuity for the 25<sup>th</sup> to 75<sup>th</sup> percentile is between a \$100 and \$200 annual saving per household (the value reported in chapter 9 of the main report).

Comparisons between alternative policies would be reasonably straightforward were it possible to estimate cost-benefit ratios precisely or where, across all possibilities, one scenario was always superior to others. Where that is not the case, judgment is required to determine the best policy response. For example, it may be better to implement a policy that has a reasonable prospect of covering a larger proportion of peak consumption — and thereby, large absolute benefits — even if the benefit-cost ratio is lower than that of a policy with relatively low take-up. Moreover, a risky policy with potentially large net benefits may be worth examining closely if there may be ways of mitigating the downside risks.

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## 1.8 Results of analysis

### The best options to implement demand management

The modelling carried out suggests that the most promising policy option is the targeted and sequenced rollout of smart meters (policy scenario 1) with:

- rollouts timed to address emerging localised network constraints and aimed at areas where demand tends to be peaky
- critical peak pricing to create incentives for consumers to shift demand to other times or to seek direct load control
- the smaller scale of the rollout allowing targeted information and education campaigns, hence increasing the demand response achievable over the near term.

#### Box 1.4 Estimating the 25<sup>th</sup> to 75<sup>th</sup> percentile of costs and benefits

The Commission developed the following approach to estimate percentiles:

- the distribution of net benefits is assumed to follow a beta distribution, which has the advantage that it need not be symmetric about the mean (or median) and that it is strictly bounded between a low and a high value. The two parameters of the beta distribution —  $\alpha$  and  $\beta$  — determine its shape and statistical moments
- it is assumed that the value of  $\beta$  in the beta distribution is 2 (a reasonable assumption)
- using the method of moments, it is possible to estimate the remaining parameter of the beta distribution ( $\alpha$ ). The estimated value of  $\alpha$  is calculated such that the inverse of the beta cumulative probability density function  $\text{BetaInv}(0.5, \alpha, \beta, L, H)$  = the median, where L and H are the low and high estimates of the range of net benefits
- the values of the net benefit per household associated with the 25<sup>th</sup> and 75<sup>th</sup> percentile are calculated as  $N_{25} = \text{BetaInv}(0.25, \alpha, \beta, L, H)$  and  $N_{75} = \text{BetaInv}(0.75, \alpha, \beta, \text{low}, \text{high})$
- the annuity values associated with  $N_{25}$  and  $N_{75}$  are calculated.

Table 1.3 summarises the key assumptions and results of this scenario.<sup>20</sup> It includes the estimated NPV of the benefits per household, the annuity value over the 15 year period, and a benefit–cost ratio under low, mid-point and high cases. (A summary table discussed later in the technical paper — table 1.6 — provides the 25<sup>th</sup> to 75<sup>th</sup> percentile annuity estimates for all scenarios.)

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<sup>20</sup> All models assume a discount rate of 8 per cent.

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Under a targeted rollout that takes account of impending capacity constraints — the most preferred policy case — there is a likelihood of significant net benefits per household. In this scenario, the median present value of the net benefits over the life of a smart meter is close to \$1400 per household.

The net benefit estimates of the use of direct load control devices for air conditioners are close to that of scenario 1 (table 1.4). The key determinants of the magnitude of the benefits are the demand response of direct load control programs and the costs of direct load control devices.

### **Some less beneficial options**

The rapid and early NEM-wide introduction of smart meters combined with critical peak pricing may not yield net benefits for households (table 1.5). This mainly reflects the high up-front costs of meters and the delay in achieving network savings when many areas of the network are not congested, even at critical peak times.

The outcomes for a NEM-wide rollout with untargeted TOU pricing involve the same costs as a NEM-wide rollout with critical peak pricing, but the benefits are less because demand responses by consumers are lower with such untargeted price signals. Consequently, it is likely that a NEM-wide rollout with TOU pricing would lead to higher overall costs for households. However, there may be grounds for combining seasonal TOU pricing with CPP since this would encourage habitual demand responses.

## **1.9 Some uncertainties**

Several factors would affect the net benefits estimated above (and summarised in table 1.6), including the:

- extent to which smart meter costs fall over time given technological developments and economies of scale in their manufacturing
- benefits that might be gained from adopting a minimum specification for the smart meters that was consistent with widely accepted international standards, and thus did not require any special Australian ‘koala’ customisation of the smart meters.
- the possible development of innovative new services that rely on smart meters and that are valued by consumers
- degree to which smart meters could encourage the development of a ‘smart grid’ with the benefits that this entails

**Table 1.3 A regional rollout aimed at a constrained and more peaky area (scenario 1)**

Key assumptions and results for a single region<sup>a</sup>

	<i>Units</i>	<i>low</i>	<i>mid-point</i>	<i>high</i>
<b>Assumptions</b>				
Smart meters	number	10 000	10 000	10 000
Relevant critical peak demand	MWh	28	32	36
Up front cost	\$ per appliance	800	535	270
IT Refresh cost	\$ per appliance	150	125	100
Annual cost	\$ per appliance per year	30	25	20
Value of demand management savings (network/generation)	\$/kW per year	271	326	381
Maximum demand management response	% of relevant critical peak demand	19	27	34
Cost profile	Install costs all occur up front. IT refresh after 7 years.			
Demand management savings profile	Demand response in the first year is 1/7 <sup>th</sup> of the maximum response (reached in year 7), with linear growth in the response between the minimum and the maximum.			
<b>Results</b>				
Discounted costs	\$ Million (NPV) <sup>b</sup>	11	8	5
Discounted benefits	\$ Million (NPV)	13	22	34
Net benefit	\$ Million (NPV)	1	14	29
Net benefit per household	\$( NPV)	130	1 370	2 920
Benefit cost ratio	ratio	1.1	2.7	6.9
Annuity per household	\$	15	154	328

<sup>a</sup> For scenario 1, the 25th and 75th percentile values of the net benefit per household is around \$900 and \$1900 respectively, which translates into a rounded range of an annuity for 15 years of between \$100 and \$200 (based on a 15 year life of the meter). <sup>b</sup> NPV denotes the net present value. It takes account of the fact that people prefer a dollar today than later and allows a stream of costs and benefits that vary over time to be represented in a single number. A discount rate of 8 per cent has been used in calculating the NPV.

- potential for greater and more rapid recruitment of consumers into direct load control schemes through innovative marketing and incentive arrangements (recognising that the form of marketing may significantly affect participation rates)
- extent of penetration of direct load control technologies in appliances or lowered costs for retrofitting
- the strength of incentives for distribution businesses to undertake demand management, which depends on the exact design of the incentive regulation regime (chapters 5 and 12)

Regardless, as emphasised in section 1.1, the Commission’s estimates rely on many assumptions and varying estimates, with these sometimes being critical for the impacts shown in the tables above.

**Table 1.4 Direct load control without smart meters (scenario 4)<sup>a</sup>**

	<i>Units</i>	<i>Low</i>	<i>Mid-point</i>	<i>High</i>
Direct load control devices	number	124 000	310 000	1 240 000
Relevant critical peak demand	MWh	76	91	4 455
Up front cost	\$ per appliance	260	210	160
Annual cost	\$ per appliance per year	25	25	25
Value of demand management savings (network/generation)	\$/kW per year	271	326	381
Maximum demand management response	% of relevant critical peak demand	15	20	25
Cost profile	Install costs all occur up front for any group of participants. Consumers also receive annual payments (\$30 to \$100 year) ahead of first three years. Software for direct load control updated after 7 years			
Demand management savings profile	Maximum demand management achieved in year 4, with participation in DLC falling to 70% of maximum participation by year 15			
Discounted costs	\$ Million (NPV)	97	199	452
Discounted benefits	\$ Million (NPV)	98	449	2 949
Net benefit	\$ Million (NPV)	16	275	2 416
Net benefit per household	\$ (NPV)	131	887	1 948
Benefit cost ratio	ratio	1.2	2.7	6.3
Annuity per household	\$	14	96	212

<sup>a</sup> The 25th and 75th percentile values of the net benefit per household is \$570 and \$1240 respectively, which translates into a rounded range of an annuity over the 15 year life of the meters of between \$65 and \$140.

Table 1.5 **NEM-wide rollout over five years (scenarios 2 and 3)**

Key assumptions and results<sup>a</sup>

	<i>Units</i>	<i>low</i>	<i>mid-point</i>	<i>high</i>
<b>Shared assumptions</b>				
Smart meters	number	6 200 000	6 200 000	6 200 000
Relevant critical peak demand	MWh	11 550	13 200	14 850
Up front cost	\$ per appliance	800	535	270
IT Refresh cost	\$ per appliance	150	125	100
Cost profile	Smart meters phased in over five years (1.24 million per year). Refresh of IT components 7 years after installation			
Annual cost	\$ per appliance per year	30	25	20
Value of demand management savings (network/generation)	\$/kW per year	271	326	381
<b>Scenario 2 NEM-wide rollout with critical peak pricing</b>				
Discounted costs	\$ Million (NPV)	5 993	4 317	2 641
Discounted benefits	\$ Million (NPV)	3 311	4 968	7 126
Net benefit	\$ Million (NPV)	-2 682	651	4 485
Net benefit per household	\$(NPV)	-433	105	723
Benefit cost ratio	ratio	0.6	1.2	2.7
Annuity over 15 years per household	\$	-49	12	81
<b>Scenario 3 NEM-wide rollout with untargeted time of use prices</b>				
Discounted costs	\$ Million (NPV)	5 993	4 317	2 641
Discounted benefits	\$ Million (NPV)	2 026	2 445	2 849
Net benefit	\$ Million (NPV)	-3 968	-1 872	208
Net benefit per household	\$(NPV)	-640	-302	34
Benefit cost ratio	ratio	0.3	0.6	1.1
Annuity per household	\$	-72	-34	4

<sup>a</sup> It is assumed that the demand saving benefits of a NEM-wide rollout are realised over a protracted period, with the impacts modelled using a generalised logistic function. The delayed impacts reflect several factors, such as the fact that network businesses would set low cost-reflective prices in any unconstrained regions, it would be hard to convince people of the need for high cost-reflective prices where there are no looming constraints, and the greater uncertainty of demand-side effects across regions given disparate pricing regimes. For scenario 2, the 25th and 75th percentile values of the net benefit per household is -\$100 and \$315 respectively, which translates into a rounded range of an annuity over the 15 year life of the meters of between -\$10 and \$35. For scenario 3, the 25th and 75th percentile values of the net benefit per household is -\$420 and -\$185 respectively, which translates into a rounded range of an annuity over the 15 year life of the meters of between -\$45 and -\$20.

**Table 1.6 Summary of outcomes**

	<i>Regional rollout in peaky and constrained areas</i>	<i>NEM-wide rollout with critical peak pricing</i>	<i>NEM-wide rollout with weakly targeted time of use pricing</i>	<i>Direct load control without smart meters</i>
Scenario	(1)	(2)	(3)	(4)
Low	1.1	0.6	0.3	1.2
Medium	2.7	1.2	0.6	2.7
High	6.9	2.7	1.1	6.3
<b>25<sup>th</sup> and 75<sup>th</sup> percentile of annuity value per household over 15 years</b>				
25 <sup>th</sup> P (\$)	100	-10	-45	65
75 <sup>th</sup> P (\$)	200	35	-20	140



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