# 10 Technologies to achieve demand management

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| Key points |
| * Demand management technologies — particularly advanced metering — underpin efficient network pricing and improved operational efficiencies for network businesses, provide information to customers and retailers, and, over the longer run, can contribute to the development of a smart grid. * The deployment of demand management technologies is frustrated by several obstacles, the most important of which are that retail price regulations stymie time‑based tariffs and that the benefits are split amongst many parties. * Nevertheless, the efficiencies from smart meter deployment are mainly associated with electricity distribution networks. These efficiencies are determined by the pace and location of smart meter rollouts and, over the longer run, their integration into the smart grid. Given this, network businesses should be the prime (but not exclusive) decision‑makers. To achieve this: * minimum functionality smart meters should be treated like other distribution network assets by the Australian Energy Regulator (AER) in regulatory determinations, with distribution businesses free to determine the location and pace of their rollout — as with other demand management options * the National Electricity Rules would need to change as they currently limit the capacity for distributor-initiated smart meter rollouts * incentive arrangements intended to address the wider efficiency gains of demand management in other parts of the energy supply chain would need to be strengthened. * Smart meters should be subject to an appropriate minimum standard (preferably internationally accepted) that allows interoperability with add-on technologies, and allows several parties to access data. Distributors should not have a monopoly on the provision of advanced metering infrastructure, with third parties also able to install add‑on technologies and higher-functionality smart meters. Retailers are likely to play a major role in this regard. * Like all other network investments, consumers will ultimately bear their costs, but in many cases, the costs could be recovered from electricity bills over many years and would be more than offset by the benefits. The rollout of metering technologies needs active community consultation and communication. * Direct load control of electrical appliances — especially air conditioners — can be a substitute or complement to smart meters, but mandating standards that Australian electrical appliances have to be compatible with direct load control is not justified. |
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Electricity demand management relies on technology solutions to achieve time‑based pricing, to support load management and to provide information to consumers so they may increase their energy efficiency. Advanced metering infrastructure —‘smart’ meters’[[1]](#footnote-1) — is the cornerstone of such technology solutions. As well as having several other important functions, the meters make it possible to set prices that reflect the true costs of supplying power at a given time — ‘cost‑reflective’ prices (chapter 11). The evidence suggests that when faced with cost-reflective prices, many people would lower their consumption at peak times, reducing the network investments needed to meet demand during these periods, and placing downward pressures on their electricity prices. People choosing to maintain their consumption during peak periods would pay a higher price, which would fully reflect the costs of network provision at those times, and eliminate current cross‑subsidies. Network prices at non-peak times would be considerably cheaper. Other technologies that remotely control the power usage of certain appliances (‘direct load control’)[[2]](#footnote-2) — such as air conditioners — can also reduce peak demand and lower network costs, and are often complements to smart meters (figure 10.1 and section 10.7).

As discussed in chapter 9, there is considerable uncertainty about the costs and benefits of specific demand management options, including how these might change over time. There is also uncertainty about the extent to which consumers might respond to demand management options, and the role of supporting technologies in assisting behavioural change. Further, changes to the patterns of electricity use, such as from the uptake of electric vehicles, could potentially exacerbate peak demand or, if carefully managed, provide an opportunity to smooth consumption.

Notwithstanding these uncertainties, the efficient implementation of supporting technologies and price signals will be fundamental to reducing peak demand and network costs. Any rollout of these technologies will need to be supported by appropriate regulations and processes — the focus of this chapter.[[3]](#footnote-3)

Section 10.1 provides background to smart metering technologies and recent experiences with their implementation. Section 10.2 looks at the challenges of installing smart meters, while section 10.3 examines various models for deploying smart meters and their advantages and disadvantages. Section 10.4 details a ‘hybrid’ approach that draws on the best features of these models, while reducing their downsides. It is important that rollouts are not just distributor-centric, but take account of other parties, most especially consumers (section 10.5). Section 10.6 outlines issues relating to the information hub that would underlie a smart meter network. Finally, direct load control of appliances can act as a substitute or complement to smart meters (section 10.7).

Figure 10.1 Technology pathways to achieve demand management for residential consumersa

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| Figure 10.1 Technology pathways to achieve demand management for residential consumers. This figure shows the approaches that can be used to manage demand either with or without smart meters. In the case of with smart meters, an approach involves the use of time-based pricing. In the absence of smart meters, an option would be to use direct load control of consumer appliances. |

a The chart (and this chapter) focuses on low energy-using household and small business customers. Smart metering and other demand management technologies are also applicable to industrial and commercial customers, but many of these already have the metering technology and are exposed to time-varying prices (chapter 11). Such parties (or aggregators acting as intermediaries for them) may also have load shedding agreements with networks or, depending on developments in the regulatory framework, may be able to offer their demand responses as a de facto generator in the wholesale spot market (AEMC 2012u, p. 112). The Australian Energy Market Commission has examined these issues in detail.

## 10.1 Understanding smart meters

### Smart meters can promote better demand management and operational efficiencies

Smart meters measure and record users’ consumption of electricity over 30‑minute intervals (which is a requirement for cost-reflective pricing) and are capable of being remotely read. (Box 10.1 describes the various types of metering installations; of which types 1 to 4 qualify as ‘smart meters’.)

Smart meters require a relatively large outlay, but they can provide versatile demand management options. They allow two-way flows of information that, in addition to facilitating time-based pricing, can allow:

* control of customers’ equipment, such as direct load control of air conditioners and pool pumps, subject to those customers’ agreement
* interactions with consumer ‘add‑on’ technologies to enable automated ‘set and forget’ controls for equipment and appliances, and to inform a customer’s energy use decisions. In that vein, current options include in‑home displays, web portals or via a home ‘gateway’ — a connection between the smart meter and a home computer and the internet. For example, Origin Energy, Jemena and SP AusNet in Victoria have provided web portals for customers who have a smart meter installed (DPI 2012c).

These demand management options can help reduce the ‘transaction costs’ for consumers in responding to price signals and, hence, can elicit a higher level of demand response than might otherwise be the case. For example, they can eliminate the time and inconvenience consumers might incur in managing their electricity use by providing ‘no-fuss’ automated solutions.

Smart meters produce significant efficiencies in electricity networks (and to a lesser degree) through the energy supply chain more generally, such as:[[4]](#footnote-4)

* lower meter reading costs. For example, Futura (2009, p. 90) estimated that the Victorian rollout would produce meter reading savings with a net present value of between $430 and $520 million in 2009 prices
* savings through remote connections and disconnections
* reduced call centre costs, for example in relation to complaints about billing errors

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| Box 10.1 Metering installation types |
| The type of metering installation and its accuracy requirements are determined in accordance with the National Electricity Rules and depend on the size of the load.   |  |  | | --- | --- | | Size of load (annual energy consumption) | Metering installation type | | Greater than 1000 GWh | 1 | | Between 1000 GWh and 100 GWh | 2 | | Between 100 GWh and 750 MWh | 3 | | Between 750 MWh and zero | 4, 5, 6 and 7 |   ***Smart meters — types 1 to 4***  Type 1 to 3 metering installations must be capable of:   * measuring active (kW) and reactive energy (kvar) and include facilities for storing interval energy data for at least 35 days * measuring energy in 30 minute intervals in both directions * being remotely read (that is, data extraction via a communications link).   Type 4 meters are similar to types 1 to 3, but are intended for low power-using consumers and are not required to measure reactive energy (Ausgrid 2012e, p. 10; Gill 2011, p. 7). While the current from reactive power does no work at load, it heats the wires, and wastes energy — hence the value of measuring it.  ***Old style meters — types 5 and 6***  Type 5 and 6 metering installations are older technologies with functions that reflect the historical nature of the grid and pricing practices.   * Type 5 metering installations are manually-read interval meters and include facilities for storing interval data for at least 200 days. These can support time-based charges. * Type 6 metering installations are manually-read ‘accumulation’ meters that record total energy consumption, but not its time of use.   ***Sometimes terminology muddies the waters***  There are also so-called type 7 ‘metering’ installations. These are actually unmetered and relate to small and predictable loads, such as street lights, illuminated signs, and sprinkler control systems, where usage is not recorded (AEMO 2009b, pp. 76ff).  Moreover, some meters labelled as type 5 (Kema Australia 2013, p. 4.41) are actually type 4 meters in their technical capacity. In a regulatory peculiarity, Type 4 meters rolled out mandatorily in Victoria were given honorary status as type 5 meters to comply with the National Electricity Rules. As discussed later, type 1 to 4 meters are treated as contestable in the Rules, so that prime responsibility for the meter does not lie with the distributor. The Victorian Government received a derogation to the Rules to establish the capacity for the distribution business to be the exclusive responsible party for what are technically type 4 meters, with this achieved by re-labelling the meter type (AEMC 2008e). |
| *Sources*: AEMC (2008e, 2012d); AEMO (2009b); Ausgrid (2012e); Kema Australia (2013); National Electricity Rules v.54. |
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* lower operations and maintenance costs, such as quicker detection of network anomalies and reduced amount of time between a breakdown and restoration of supply — part of the real time management of the grid (the ‘smart’ grid)
* deferred and avoided capacity investments in distribution and transmission networks and in generation
* improved voltage control and other reductions in electricity technical losses
* ability to measure power (by time) that is locally generated and exported into the distribution system, for example by a solar photovoltaic (PV) roof top unit
* lower theft rates of electricity
* ability to set emergency demand limits to share limited supply at times of network stress or supply shortages
* improved hedging and reduced cost of billing inquiries and bad debt for retailers.

Various participants in this inquiry indicated how these benefits arise:

… [Smart meters] can also provide ‘real time’ information on the operation of the distribution system, which allows companies to locate faults that lead to power interruptions more quickly and accurately. … [this] can be used to optimize the size and dispatch of work crews, thereby reducing operating costs. [Smart meters] can also monitor the loading and condition of distribution system components, which can help companies optimize their inspection and maintenance cycles as well as extend the periods for replacing capital equipment. Automated meter reads also tend to improve billing accuracy and the timeliness with which bills are produced … In addition … more sophisticated metering systems will be increasingly necessary for distributors to cope with the more diverse and ‘distributed’ (i.e. less centralized) nature of new generation technologies. (Pacific Economics Group, sub. DR48, p. 7)

NSP’s [Network Service Providers] are suffering from a lack of detailed information about behaviours and the contribution of new consumption and production technologies at the consumer level. While smart meters alone will not solve these problems, the information and capabilities that can be provided [by these meters] and utilised by NSP’s will be a key enabling technology for increased network utilisation and reliability. (Sinclair Knight Merz, sub. DR61, p. 6)

Most Australian households outside Victoria do not have smart meters (or even non-remotely read interval meters). As a result, few households face time-based tariffs for their electricity use.[[5]](#footnote-5) Only in Victoria is the smart meter household penetration rate high. However, a government-imposed moratorium on time-based tariffs for residential users in Victoria applies until the middle of 2013, at which point customers may voluntarily switch to a simple time-based tariff (O’Brien 2012). (Meanwhile, customers are paying for the cost of their installation, adding around $25 a quarter to households’ electricity bills.) In contrast, a much higher share of business users have smart meters and, to varying degrees, already face time-based prices.

### Mixed results from rollouts and uncertainties about costs and benefits

Smart meters are a relatively new, but not revolutionary, technology. The associated hardware, information technology (IT) and communications technologies are continuing to mature, which is consistent with declining costs (or stable costs with increasing functionality) over time. For example, Frost and Sullivan (2011) estimate that the price of smart meters in the European market will fall by over 30 per cent between 2010 and 2017. This is mainly a consequence of scale economies, with two providers serving 90 per cent of the European market.

Evidence about the role of smart meters in demand management is increasing with the completion of a number of large-scale rollouts. Smart meter rollouts have occurred or are occurring in many European countries, including France, Italy, Spain, Sweden, the Netherlands and, more recently, in the United Kingdom.[[6]](#footnote-6) Smart meters are also common in many areas of the United States and Canada. The most prominent Australian example of a broad scale rollout is in Victoria.

International and Australian experience demonstrates that a carefully managed implementation is crucial to realise the potential net-benefits from smart meters. For example, the rollout in Victoria faced multiple setbacks, including implementation costs that exceeded original estimates (box 10.2). The benefits from the Victorian rollout are also likely to be lower than planned given the initial moratorium on time‑based tariffs. That, and inadequate community engagement, led to a significant number of customers refusing to have a meter installed.

The Commission’s attempt to quantify the costs (and benefits) of smart meters revealed a wide range of potential estimates (chapter 9). Implementation costs are sensitive to small changes in a range of assumptions, including:

* the density of a rollout and the topography, which affects:
* the feasibility of different communications technologies (given the technical performance and associated cost of options)

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| Box 10.2 The Victorian smart meter rollout |
| In 2004, The Essential Services Commission (ESC 2004a) proposed the mandatory rollout of (technologically-proven) manually read interval meters, which would enable time-based charging. However, in response to a study of the incremental costs and benefits of more advanced metering (CRAIIC 2005), in 2006, the Victorian Government directed distributors to install 2.4 million smart meters in Victorian homes and small businesses from 2009 to 2013, with customers to pay the costs directly. The Government did not impose a particular technology for the smart meters installed, although it did prescribe a relatively high level of minimum functionality of the meters and standards for associated service levels (DPI, pers. comm., 28 Feb 2013).  The Government expected that the rollout would lower electricity prices for consumers, increase retail competition, improve service quality and increase the efficiency of electricity suppliers. However, the rollout experienced significant problems, which provide lessons for the rollout of smart meters in other parts of the National Electricity Market (NEM).  *Consumer engagement.* The Victorian Auditor-General’s Office (VAGO 2009, p. 13) questioned the adequacy of consultation with consumers in the process leading up to the rollout. After the rollout was in progress, a review by Deloitte (2011a, p. 9) and a broader Government review (DPI 2011) emphasised the need for customer engagement so that people were aware of the benefits of the meters. In response, the Government announced it was giving consumer and welfare groups a voice in the smart meter rollout through a new Ministerial Advisory Council (DPI 2011), as well as undertaking other measures (such as a smart meter website and a price comparison web portal).  *The Government moratorium of time-based pricing.* In March 2010, the Victorian Government placed a moratorium on distributors automatically reassigning customers to ‘time-of-use’ pricing when a smart meter was installed. The moratorium stemmed from concerns about the impacts on consumers, particularly vulnerable consumers. The moratorium added further delays to the realisation of benefits from the smart meter rollout. As Powercor and CitiPower noted, the net benefit of smart meters ‘won’t be achieved until time of use pricing comes in and other initiatives’ (trans., p. 5). Following analysis of the customer impacts of time-based pricing, the Government has since decided that flexible pricing would be encouraged on a voluntary basis for residential consumers. The moratorium on distributors will be lifted from mid‑2013 (DPI, sub. DR94, p. 9; pers. comm., 28 Feb 2013).  *Excessive initial optimism.* Despite initial optimism that a smart meter rollout would produce net benefits, the most recent analysis (Deloitte 2011a) found that the rollout would be likely to incur a net cost over its lifetime. Nevertheless, given that a large share of the investments was sunk, that study found that a continued rollout would pass a cost–benefit test. The Deloitte study was preceded by many other studies looking at aspects of the project (CRAIIC 2005; Futura 2009; EMCa and Strata Energy Consulting 2010; and Oakley Greenwood 2010a & 2010b), which suggested positive net benefits. It appears that costs were significantly underestimated (VAGO 2009 p. 30 and Deloitte 2011a, p. 7). For example, the Deloitte study (p. 7, found rollout costs of $2.2 billion compared with a 2010 study estimate of $1.6 billion. This is around $800  (Continued next page) |
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| Box 10.2 (continued) |
| compared with around $600 per meter based on installing 2.9 million meters at around 2.7 million small customer points (AER 2011f, p. 16). From 2009 to 2015, the AER estimated that distributors would ultimately spend over $2 billion on the rollout (AER 2011f, p. 6). It also appears that initial benefits were over-estimated. For example, Deloitte estimated benefits of just over $2 billion, while the Futura (2009) study estimated $2.6 billion. The discrepancies do not necessarily denote error — but changing prices, more information, and judgments about included and excluded items.  *Incentives for distributors to contain costs seemed to have been weak* (VAGO 2009, p. 17; AER 2011f, p. 28; AER 2011g, p. 1)*.* Victorian cost-recovery regulations for smart meters (overseen by the AER) effectively took the form of cost pass-through. This provides few incentives for cost management (albeit addressing cost uncertainty well). In 2012, the AER approved proposals by the distributors to upwardly revise their smart meter charges (2012z, p. 5), noting that the higher charges were attributable to all the distributors spending more than their approved expenditure allowances in 2011. Some distributors spent close to 120 per cent of their approved budget, which was allowed by the Victorian regulation. The Victorian Government decided in late 2011 to tighten its cost recovery regulation, including removing the cost overrun allowance and reversing the onus of proof of prudent expenditure (DPI 2011).[[7]](#footnote-7) These changes will apply to the AER’s future assessments of distributors’ expenditures and charges.  *Flaws in cost–benefit analysis.* VAGO (2009) was critical of the initial study (CRAIIC 2005) that prompted the rollout of smart versus ordinary interval meters, arguing that it only considered the incremental costs and benefits, failed to reconsider the overall costs and benefits of a smart meter rollout, and did not consider implementation and technology risks. Regardless of the merits of VAGO’s comments, cost–benefit analysis is challenging when it is used to inform a commitment to make a single large indivisible investment (a mandatory universal rollout) and where there are large technical uncertainties (as there were at the time).  *Technology risks were not addressed sufficiently.* The 2005 cost–benefit study noted the need for technology trials (CRAIIC 2005, p. 6). In 2006, the department administering the project provided advice to Government that a technology trial be conducted, but that the Government should endorse the universal rollout *before* the results of the trial. VAGO (2009, pp. 34ff) claimed that these decisions introduced ‘significant risks’ to the project, which was compounded by insufficient oversight of the trials, and the failure to adequately use them to inform the subsequent rollout. Since then, distribution businesses throughout the NEM have conducted many trials.  After some teething problems that put the rollout at risk, in December 2011, the Government confirmed its commitment to the smart meter rollout and introduced several changes to deliver greater benefits to households (DPI 2011). Victorian network businesses say that significant benefits are being (and will be) realised (Powercor and CitiPower, trans. p. 5). |
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* installation costs, with an uncoordinated rollout raising the per unit cost of installing a new meter compared with a street-by-street approach
* the pace of technology changes, particularly those affecting communications options and, so‑called, back‑end IT software, and the resulting impact on costs
* the speed of a rollout, including whether any market power is conferred on installers or other suppliers
* the functionality of meters, and expectations about the extent to which meter costs might decline over time and with large purchases.

The degree of uncertainty about costs is highlighted by international evidence. In evaluating international projects on a cost per meter basis, Rousseau (2007) reported estimates ranging between $114 and $740 in 2007 values, while more recently, Deloitte (2012, p. 27) reported a range between $170 and $900. Elsewhere, Hierzinger et al. estimated the full costs of rolling out smart meters to 50 million United Kingdom residents to be around £220 per meter or roughly A$330 (2012, p. 88).

While accurate comparisons are difficult, it appears some international rollouts have occurred (or are occurring) at lower cost than in Victoria (although the functionality of meters is usually more limited and the associated communication systems slower and less versatile). For example, Gill (sub. DR51, p. 1) noted:[[8]](#footnote-8)

Early Smart Meter Cost Benefit Analysis undertaken by the Ministerial Council on Energy estimated the cost of a smart meter with integrated communications to be less than $100. This estimate was based on costs for ‘similar’ meters deployed in both Europe and the USA. We now know that meters deployed in Victoria’s advanced meter rollout were between 100 per cent and 200 per cent higher.

The benefits of smart meters are also uncertain. They depend crucially on the application of efficient network tariffs and, in turn, consumers’ acceptance of these tariffs and their responsiveness to prices. As discussed in chapter 9, benefits will also vary according to the length of the transition to efficient network pricing structures, and the extent to which retailers pass these through to end-users.

## 10.2 Rolling out smart meters involves major challenges

The fundamental obstacle to the optimal rollout of smart meters (and many other demand management technologies) is that their economic value is only maximised if a coherent set of regulatory and commercial arrangements are present, many beyond the control of a single agent. Removing one element can reduce or even eliminate the value of the investment in smart meters. An optimal arrangement would:

1. require cost-reflective network charges for retailers
2. involve retail tariffs that provide lower electricity network costs for consumers with low critical peak demands
3. ensure that non‑network solutions are a major part of the decision-making of network businesses (as opposed to the customary tendency to seek network solutions)
4. reduce the risks from regulatory uncertainty and political decision-making, such as price moratoriums, which can undermine the economic and commercial basis for rollouts
5. create regulatory incentive arrangements that recognise that the benefits in lowering network investment requirements extend over more than one regulatory period
6. address the ‘split incentives’ problem — this problem arises because smart meters can yield cost reductions through the entire supply chain — retailers, distribution businesses, transmission network service providers, and generators. No single party is easily able to appropriate the full return from lowering costs and nor would they have strong incentives to fully disclose the magnitude of any benefits in any negotiations. A coalition of the willing is unlikely to form naturally
7. roll out smart meters at the times and in the places that provide the greatest economic value. A smart meter is worth little if it sits in splendid isolation and its functionality is not used for the long‑term benefit of consumers. Their benefits rely on being in a crowd and at the right time and place
8. remove regulatory barriers that discourage the installation of smart meters by distribution businesses
9. let a variety of parties make choices in this area (retailers, consumers, distribution businesses, third parties). Assigning roles in the rollout of smart meters must: avoid stifling innovative new products from retailers or third parties that can rely on smart meters as an enabling technology (for example, in home displays, apps for controlling appliances or optimising power consumption); ensure there is a capacity for multiple parties to use the information from smart meters; and allow parties other than distributors the freedom (with the consent of consumers) to install meters if that is in their commercial interest. In other words, a special case would need to be made to prevent any party from installing a meter. However, given the desirability of interoperability, there would need to be compatible standards for smart meters and appliances
10. unbundle the contestable component of advanced metering infrastructure — such as add-on technologies — from the network charge (an issue addressed in more detail below)
11. overcome scepticism from consumers about the value of smart meters following the difficulties experienced in Victoria.

On the face of it, this formidable list makes the prospects for a successful rollout daunting. However, many of these challenges can be sufficiently addressed so that workable (if not perfect) regulatory arrangements are feasible. The items on the ‘list’ are not of equal importance and some key ones are addressed in other chapters, such as:

* reforms in network and retail pricing (a and b) are feasible (chapters 11 and 12)
* cultural change in network decision‑making (c) would be improved through privatisation and, in the meantime, improvements to the governance of state‑owned corporations (chapter 7), and would be reinforced through reforms to reliability standards and incentive regulation to remove any biases in favour of capital expenditure (capex) (chapters 5, 15 and 16)
* putting the ‘N’ solidly in the NEM through a national licensing regime, the full shift of retail regulatory functions to the AER and a NEM‑wide coherent approach to hardship policies (chapter 11) would weaken the capacity for political interference (d). In some respects, by tying their hands, a national approach helps state and territory governments resist political demands on them
* a capacity to capture benefits that are experienced across more than one regulatory period (e) and more than one party (f) are (partly) examined in chapter 12, though aspects are still considered in this chapter.

Accordingly, many of the pieces of the jigsaw of reforms required to implement demand management technologies are addressed elsewhere in this report. As a result, this chapter concentrates on some of the key coordination problems in achieving a coherent rollout that arise if (f) to (j) are not achieved. It also addresses some of the concerns relating to consumer receptiveness to change (k).

The starting point for unpacking the dilemmas presented by coordination of a rollout is the tensions between beneficiaries, which arise from the ‘split incentives’ problem.

### ‘Split incentives’ across market participants

The efficiencies from adopting demand management technologies occur throughout the supply chain.[[9]](#footnote-9) The long‑run efficiency gains appear to be greatest for distribution and generation, and are still significant for transmission, but appear to be relatively modest for retailers (Futura 2009; Oakely Greenwood 2010b; and the Commission’s own calculations). Despite the efficiency gains from avoiding excessive investment in generation, some generators face potential financial losses from demand management because it can reduce the wholesale spot price during peak periods — as the spot price forms the basis for recovery of the large (sunk) investments in generation.[[10]](#footnote-10) Furthermore, depending on whether demand management simply shifts consumption to another period, or whether it results in lower overall consumption, generators may also lose unit sales of power, and higher cost peaking generators may be dispatched less often.

Accordingly, each party may have an incentive to either resist the change if they believe they will experience a cost or, where there are likely benefits, to free ride on investments in demand management made by others — the so-called ‘split-incentives’ problem (an example of ‘market failure’). In the absence of successful commercial negotiations to share benefits, any individual party will tend to underinvest in demand management because they are unable to appropriate all of the benefits that flow onto other parties.

A supplier that was vertically integrated along the entire supply chain could internalise the sum of possible demand management gains (and, in the case of generator, potential losses) and evaluate them against the likely costs of implementing demand management solutions (Pacific Economics Group, sub. DR48, pp. 8‑9). However, as noted in chapter 2, the reforms that led to structural separation of the competitive segments of the electricity sector in the 1990s — while reaping significant economic benefits — have frustrated such coordinated decision-making. Ausgrid claimed that hot water load control in New South Wales — introduced in the 1950s by the vertically integrated electricity supplier at the time — would not proceed now, despite the large savings it offers (Maltabarow 2012, p. 5).

#### Underinvestment in smart meters and the split-incentives problem

Smart meter investments suffer acutely from the split-incentives problem (though these would also apply to other technological options, such as direct load control):

A key economic obstacle to a market-driven rollout is the fragmentation of benefits among multiple stakeholders, which disperses investment incentives. (Schächtele and Uhlenbrock 2012, p. 1)

Fragmentation across the value chain has reduced the incentive for any single player to invest in smart meter or customer applications (McKinsey 2010, p. 49)

… evidence to date suggests that no single party has sufficient incentive to invest the upfront costs in installing smart meters, the benefits in terms of cost savings are likely to accrue across all parties, but should ultimately flow to the consumer. However, consumers do not have sufficient information to assess the costs and benefits, retailers do not have any certainty that they will retain a consumer long enough to recoup the costs of the meter, and distribution network service providers do not have the certainty that they would recover their investment through the price determination process. (AEMC 2012t, p. 3)

Of course, there are certain circumstances in which rollouts could still occur commercially.

* Over time, the costs of the technology may fall enough that it is worthwhile for distribution businesses to make the investments on their own account.
* At least some parties could negotiate with each other, reducing, though not eliminating, the split incentives problem. Negotiations are most likely to occur between a few parties where there is a common interest in the choice of the location of meters and the pace of their rollout. That is likely to rule out generators (who have weak incentives anyway) and to a lesser extent, retailers. The prospects for commercially negotiated arrangements are likely to be improved for transmission and distribution businesses. There are only a limited number of such businesses across the whole NEM, and even fewer at the state level, and they share a common interest in relieving pressures on the network. Grid Australia (sub. DR91, p. 23) pointed out that in New South Wales, Ausgrid and TransGrid had made ‘possibly hundreds of millions of dollars’ of savings from joint planning and integration of augmentation and replacement programs. Presumably, such joint planning could extend to demand management.

These qualifications are important because they imply that regulation may not have to play as significant a role in addressing the split incentive problem as first thought.

Nevertheless, the essential lesson from the split incentives problem is that some financial incentive will be required for any given party to roll out meters at the *optimal* time (and location). Ultimately, regardless of how the money is raised, customers will have to pay, and should do so if there is good evidence that, in the long term, net benefits of this investment will flow through to consumers.

## 10.3 Creating the optimal incentives for deploying demand management technologies

The best approach for smart meter investments has been widely debated in Australia and overseas, and there are many competing options.

### Rollouts through edict?

One obvious way of overcoming the problem is for the government to direct a universal rollout of meters over some specified period, with the costs met as a charge on consumers’ electricity bills. To the extent that smart meters achieve their goals, the consumer outlays on meters should be more than offset by subsequent savings in energy use and reduced payments for network and generation infrastructure and other operating expenses.

Some governments have taken this course, including the Victorian Government. International examples also exist.[[11]](#footnote-11) In response to legal requirements to rollout meters, two European countries — Italy and Sweden — had completed full rollouts by 2012. In the United Kingdom, the Government has mandated a rollout, though current penetration rates are low. Legal requirements for universal rollouts are also in place in Finland, France, Greece, and Malta.

The usual approach under the mandated rollouts is that governments make an in‑principle decision to roll out meters, with the ultimate decision based on the outcomes from cost–benefit analysis. For example, in 2009, the European Union issued a directive requiring member states to install intelligent metering systems to at least 80 per cent of customers, *where such a rollout is assessed positively*. The European Union requires member states to undertake a cost–benefit analysis. It has provided guidance on how consistent analysis should be undertaken (Giordano et al. 2012).

The key advantage of a mandated rollout is that it avoids the split incentive problem. The investment decision can take account of the costs and benefits throughout the supply chain. However, it has several major deficiencies, including that:

* it may result in rollouts that, while passing a cost–benefit analysis, are not sequenced to maximise benefits. For example, it can be desirable to deploy meters first in more congested parts of the network (such as a given metropolitan area), yet governments may set timelines that do not allow efficient targeting
* it is easier to ignore the preferences of consumers where the decision is by edict. Clearly, there has been a backlash in Victoria. Moreover, in some countries, such as Netherlands, plans for a mandatory rollout were shelved following consumer opposition (Kema International 2012, p. 35). In this inquiry, several consumer groups indicated the importance of engagement with consumers and their capacity to participate in the decision‑making (Public Interest Advocacy Centre, sub. DR65, p. 8; Consumer Action Law Centre, sub. DR79, p. 10) — a matter considered in greater detail in section 10.5
* the decision to rollout is made by a party that faces significant information asymmetries (compared with network businesses)
* a point‑in‑time cost‑benefit analysis may not be appropriate where new developments over time affect the pace and location of meters (or improve the quality of the cost–benefit analysis underpinning the investment decision). For example, a legal requirement to roll out meters by a certain date loses the option value of waiting if subsequent information shows that delay is optimal. The ENA observed wryly that ‘We go back to 1996 and we were all going to have smart meters within two or three years. That hasn’t happened. It is evolving’ (trans. p. 334).

It is notable that most countries (and states within the United States) have not mandated meter rollouts at this stage, though some are considering this. Decisions about smart meter rollouts have largely been left to utilities.

In the Commission’s view, it would be premature to mandate a rapid NEM-wide rollout of smart meters at this stage, though governments could consider this at a future time if alternative models do not successfully address the split incentive problem.

### A negotiated settlement orchestrated by a lead player?

Another option to facilitate investment in smart meters would be to mandate a lead business player that would then engage with other beneficiaries. The leader would coordinate the costs and benefits of demand management along the supply chain, and each party would contribute to a common funding pool in proportion to the benefits they acquire. The Australian Energy Market Commission (AEMC) suggested a form of contractual agreement that apportioned the costs and benefits of smart meters across parties (AEMC 2012e).

This approach shares similarities with Littlechild’s (2011a, b) public contest model for interconnectors (chapter 20) and seeks to address the hold-out problem among multiple beneficiaries that cannot individually appropriate the full benefit of their investments in demand management. While theoretically possible, coordinating all the disparate commercial interests of potential beneficiaries from demand management raises issues of implementation costs and is likely to be a slow process. (As noted above, candidates for cooperation would most likely be transmission and distribution businesses.)

### A ‘market-based’ rollout?

On the face of it, a market-based approach centred on individual consumer preferences appears highly desirable. Under that model, provision of meters would be contestable, with any party — retailers, distributors, smart meter manufacturers and third parties — able to make an offer that consumers could accept or reject. Common standards would ensure compatibility with network businesses’ needs and would avoid customer lock-in to a particular suppliers’ product. Having a choice on whether to invest in a smart meter and face time-based pricing resonates with most consumers. This approach was advocated by the New South Wales Independent Pricing and Regulatory Tribunal (IPART 2012d), underpinned the AEMC Power of Choice report, and was a view held by many other participants in this inquiry (box 10.3).

King (2012) puts the case well:

This approach is simple. There is a basic meter that a consumer can have as part of their electricity connection if they want. But there is also a selection of ‘approved’ smart meters from competing suppliers that a consumer can pay to have installed. If you have a smart meter then, depending on its functionality, different retailers can compete for your business through the package of electricity prices that they offer to you. What are the benefits of this? First, if you don’t want a smart meter (fear of radiation or Martians) then nothing changes. But if you do want to use a smart meter to manage your power consumption then you can choose the one that best suits you. In other words, consumer ownership of meters creates consumer buy-in and control.

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| Box 10.3 Many participants saw competitive provision of smart meters as desirable |
| Various participants (AER, sub. DR92; EnergyAustralia, sub. DR82; ERAA, sub. DR76; GDFSEA, sub. DR68; Macquarie, sub. DR54) and others favour a market-led rollout that relies on harnessing the self-interest of consumers to drive installations:  As set out in the AER’s submission to the AEMC, the AER generally supports a contestable model for rolling out interval meters, where this model can be delivered at lower cost and improve meter service offerings. The AER favours such an approach which would see the following:   * Competition for the provision of meters and meter services providing impetus for innovation and economic efficiencies over time; * Consumer preferences determining who provides interval meters and how they should be provided — that is, having choice on the range of [distribution service provider] related services that might be bundled with the provision of a meter, or attached to the meter; * Arrangements developed to prevent consumer ‘locking-in’ concerns in relation to energy contracts and meter type (and to prevent inefficient meter churning); * Some consumers having the option of whether to face a cost-reflective tariff or remain on a flat tariff — at least in the short term. (AER, sub. DR92, p. 15)   Competition between retailers underpins the incentives that retailers have to roll out smart meters to their customers and to deliver the range of services and products that customers want at a price they are willing to pay. (ERAA, sub DR76, p. 3)  … retail competition creates incentives for retailers to install and deliver the smart meter services that customers seek in a cost-effective manner. (GDFSEA, sub DR68, p. 2)  Under our proposed model, the onus will be on the retailer or [distribution service provider] service provider to elicit consumer consent to a smart meter through offering appropriate retail pricing offers and value added services. … Ultimately, it will be up to consumers to make choices based on the net benefits that end use services provide. (AEMC 2012u, pp. 68‑9)  The rollout of time-of-use meters should be at the discretion of the customer or its retailer, rather than being mandated by governments or distributors. (IPART 2012d, p. 8) |
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Under a market-led approach, consumers would have several motivations for taking up a meter.

1. Consumers may want to make energy savings. They could use the meter, in-home displays and other complementary technologies to discover their in-time power use, and use the information to make informed decision-making about actions to reduce power consumption. Retailers may assist in that process.
2. They may be able to access different billing arrangements — for example, more frequent billing or (the easier adoption of) prepaid packages.
3. So long as cost-reflective time-based pricing retail tariff options are given to customers (chapter 11), then non-peaky customers would tend to adopt smart meters, access (lower) time-based prices that do not include the cost of subsidising more peaky consumers and, in doing so, exit the average price pool. Those remaining on the flat average tariff would then face an average that would progressively rise (as less-peaky customers exit the average price pool) and result in them facing a higher share of the peak costs their consumption generates (AEMC 2012u, pp. 164‑5).

#### However, there are problems in the market-based approach

Unlike many markets, there are several major and compounding deficiencies with uncoordinated action though individual choice.

Without smart meters, consumers have a poor understanding of their consumption profile and its implication for cost-reflective prices.

* Schächtele and Uhlenbrock (2012) summarised recent smart meter cost–benefit studies.[[12]](#footnote-12) They found consumers had a high degree of uncertainty about the benefits of smart meters, reflecting highly variable consumption profiles and uncertainty about how they could adapt to time varying tariffs.
* Wissner and Growitsch (2010) identified information deficiencies faced by consumers and the likelihood that if they underestimate the savings from using a smart meter (and discount for the uncertainties) they would have a low willingness to pay.

Similarly, retailers would not have the information to target non-peaky customers with time-based tariffs (since the information relies on the smart meters being present already). Moreover, retailers face costs in developing and marketing new tariffs to customers. The payoff from new tariffs and the marketing of them is reduced if the relevant customer group is small and only gradually increasing. PricewaterhouseCoopers considers this would materially limit retailers’ incentives to roll out smart meters to consumers (PwC 2011, p. v).

Retailers have other conflicting motivations to deploy meters. On the one hand, any individual retailer may gain a competitive edge by offering some of the distinctive features and benefits associated with smart meters, which would increase, or at least retain its market share (ERAA 2012c, p. 3). In addition, smart meters would allow a retailer to move to monthly or even fortnightly billing, which could reduce working capital and the risk of bad debts.[[13]](#footnote-13) On the other hand, smart meters may allow consumers to reduce their energy bills, placing downward pressure on retailers’ profits.

Overall, a market-based approach would be likely to lead to the relatively slow adoption of smart meters. Indeed, the Dutch Government considered that without regulation, a market-led rollout would only achieve a 30 per cent penetration rate, which was one reason for its initial (but subsequently over-turned) decision to mandate a rollout (Hierzinger et al. 2012, p. 60). In Germany, which has also adopted a market-led rollout, only 500 000 meters have been installed, though operation of a smart grid would require at least 42 million meters (Hierzinger et al. 2012, p. 44). Slower adoption rates under a market-led approach would undermine the incentives provided by price signals discussed in (iii) above. The slower the pace of adoption, the smaller would be the price differences between the standard flat tariff and a time-based tariff, reducing even further the motivation for consumers to adopt meters. Since smart meter costs are upfront investments with immediate costs, if the benefits are deferred the commercial case for rolling them out, or the case for consumers to adopt them, might evaporate.

In addition, a piecemeal rollout driven by the pace of consumer choice runs the risk of not achieving a critical mass of installations needed to realise:

* the level of demand response required to support a deferral of network investment in peak capacity
* the substantial operating efficiencies that can flow from smart meters (for networks and retailers). For example, the potential savings from reducing network constraints in a region where substantial network investments would otherwise be required would be significantly reduced with a ‘patchwork’ approach to their rollout. So too would the benefits of remote metering and intelligent monitoring and management of the network.

A piecemeal rollout would also be likely to lose economies of scale in meter procurement, installation, communication infrastructure and supporting IT and data management systems.

* Cost advantages accrue with installation density, making universal installation within a given area generally lower cost. (Any countervailing risks of market power that allow smart meter suppliers and/or installation contractors to inflate prices during a large‑scale rollout can be limited by sensible phasing, contracting with a variety of suppliers and avoiding excessively tight mandatory completion dates).
* Some studies find that state‑mandated comprehensive rollouts have lower costs per meter. One of the largest international suppliers of smart meters, Landis+Gyr, estimated that installation costs for a mass rollout would average around $40 per meter, whereas ad hoc rollouts would cost around $80 (trans. p. 32). A literature survey identified many possible economies of scale and learning from comprehensive rollouts, though also potentially higher governance costs to enforce state regulation (Schächtele and Uhlenbrock 2012, p. 281).[[14]](#footnote-14) Scale economies alone would not justify intervention because scale and learning economies occur in many products. Acting on these would risk creating statutory monopolies throughout an economy. Nevertheless, scale economies are relevant amongst other considerations in choosing the best option for deploying smart meters.
* Ausgrid experiences as a metering service provider in the contestable market (smart meters) and the non‑contestable metering market (non‑smart meters) is that the cost of providing metering services at a contestable site is around five times that of the non‑contestable site. The main reason for this disparity is the loss of economies of scale in metering reading services associated with the greater inefficiency of meter reading routes (NSW DNSPs 2013, p. 5).
* Within any region, the cost of smart meters is likely to be most efficiently incurred and coordinated by a single party, which may, if it wishes, use competitive tenders to lower costs.

Cumulatively, these considerations suggest that the uptake of smart meters under a consumer choice approach would be likely to be low and slow. This outcome significantly limits the potential for network efficiencies, particularly those from deferring investment to meet peak demand.

In theory, network businesses could attempt to stimulate the uptake of smart meters with a side payment to the customer (akin to the kinds of rebates used for direct load control air conditioners in Queensland). However:

* unlike direct load control of air conditioners, the demand response would be uncertain
* this might produce offsetting reductions in the incentives offered by retailers and third parties if they believe they can free ride on network businesses’ concessions
* it would be still likely to achieve a patchy rollout, reducing network savings, and undermining its commercial feasibility.

As detailed comprehensively by the AEMC (2012u), market-led approaches clearly have some advantages. However, in the Commission’s view, smart meters are not like many other goods. In particular, they suffer from the problem that the benefits to any given consumer depend substantially on the actions of other consumers. This suggests some coordination in their adoption. Nevertheless, to the extent possible, it would be desirable not to throw the baby out with the bathwater, and to try to achieve some of the benefits of a market-based approach in a coordinated model (the goal of the Commission’s preferred model — section 10.4).

### A lone ranger?

In its draft report, the Commission recommended that the AER be responsible for mandating when and where distribution networks should implement smart meters — at least in the initial rollout — based on information from the businesses and using cost–benefit analysis. This would allow distributors to be the only lead business player (‘the lone ranger’), with the AER required to judge the overall costs and benefits of smart meters throughout the supply chain. The approach shares some similarities with government-mandated rollouts, but is regulator-led, makes better use of information from network businesses and would be more likely to lead to the optimal sequencing of rollouts. It would maintain the option value of waiting. In many respects, the approach advocated by the Commission in the draft report was similar to that used by AEMO in relation to certain transmission investments in Victoria (chapter 16).

Despite these advantages, the Commission has reconsidered its view, prompted by fresh analysis, consideration of some of the broader issues raised by the AEMC’s final Power of Choice report (2012u) and scepticism of several participants about mandated arrangements led by the AER, for example, NSW DNSPs (sub. DR85, attachment A, p. 2).

In particular, unlike investments in transmission reliability, investments in smart meters are more akin to other kinds of investments that network businesses propose in revenue determinations under incentive regulation. For example, split incentives apply to other demand management options proposed by the businesses, and yet ultimate responsibility for undertaking them still resides with the distribution businesses, not the regulator. There is an inconsistency in treating one type of demand management approach in a different way from others. Similarly, purchases of type 5 (manually-read interval) and type 6 (accumulation) meters are treated by the AER as network investments, raising the question of why a superior meter with significant network benefits would be subject to a different approach.

In that context, the Commission has shifted its position and proposed a hybrid model that involves coordination led by distribution businesses (a regulated model), but with room for other parties to innovate and customise smart meters for different consumers (a market-based model). The next section details how this model would work.

## 10.4 A hybrid approach that blends a market-based and regulated approach

In the Commission’s view, a variant on the current regulatory arrangements applying to other capex and operating expenditure (opex) made by distribution businesses is likely to lead to better outcomes, provide scope for roles by all parties, be more flexible and require less onerous supervision than the Commission’s initial proposal. To function well, the new model has several interrelated requirements.

### Specify a minimum level of functionality

Minimum standards are required that allow information sharing, open access, and interoperability — such as agreed communication protocols and a capacity to link to third party peripherals and smart appliances. Minimum standards would, in effect, create a ‘vanilla’ smart meter, with the potential for parties to add additional functionality through linked appliances, in-home displays and other innovations. Appropriate standards would allow all parties to access the benefits available from the deployment of smart meters. Parties could also install meters with higher levels of functionality, as long as they were compatible with the standards.

The existing Rules are largely silent on any such smart meter standards.[[15]](#footnote-15) However, some standards have been developed through the National Smart Metering Program, which was established by the then Ministerial Council on Energy in 2008 (box 10.4).

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| Box 10.4 Smart Metering Infrastructure Minimum Functionality Specification |
| 1. Measurement and recording  2. Remote acquisition of data and meter event logs  3. Local acquisition of meter information  4. Visible display and indicators on meter  5. Meter clock synchronisation  6. Load management through a controlled load contactor or relay  7. Supply contactor operation  8. Supply capacity control  9. Home area network using open standard  10. Quality of supply and other event recording  11. Meter loss of supply detection  12. Remote meter service checking  13. Meter settings reconfiguration  14. Software upgrades  15. Plug and play device commissioning  16. Communications and data security  17. Tamper detection  18. Interoperability for meters/devices at application layer  19. Hardware component interoperability  20. Meter communications: issuing messages and commands  21. Customer supply (safety) monitoring. |
| *Source*: NSMP (2011). |
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The standards followed collaboration between retailers, distribution businesses, metering providers, consumer organisations, market operators and jurisdictions.[[16]](#footnote-16) However, it is important that any standard should (as far as possible) be consistent with international standards. This would avoid creating a ‘koala standard’ that could increase the cost of smart meters for the Australian market and operate as a trade barrier that denies Australia the benefit from lower cost similar meters produced for the global market (Gill, sub. DR51, p. 1; Frost and Sullivan 2011).

As Europe prepares to install tens of millions of smart meters, Australia should position itself to benefit from resulting lower prices. This will only be possible if a review of metering standards is undertaken. (Gill, sub. DR51, p. 1)

Given there has been strong progress in this area, the Standing Council on Energy and Resources should finalise a minimum technical standard for advanced metering infrastructure, including smart meters, but should take into account the risks and costs of ‘koala’ standards.

### A leading, but not exclusive, role for distributors

Under the Commission’s model, the AER would treat the capex and opex costs of ‘vanilla’ smart meters like current accumulation and non-remotely read interval meters, with their costs recovered through regulated revenue allowances (with the precise funding model discussed later). An advantage of this approach is that consumers would not face the full cost of smart meters upfront, but, as for other network assets, would pay for their cost over the life of the asset. (As discussed later, the benefits of smart meters in terms of savings in network augmentation and operational efficiencies, and greater amenity should mean that over the lifetime of the meter, these costs are more than offset by savings in consumers’ overall electricity bills.)

A clear benefit from a rollout led by distributors is their knowledge about the diverse network cost savings within its network and, consequently, its ability to tailor a rollout to best achieve those benefits (Jemena, sub. DR77, p. 18). Importantly, this includes a superior ability to forecast future constrained network regions that could benefit from a smart meter rollout. This gives them a significant informational advantage in determining the costs and benefits of any particular rollout when compared with other parties, including the AER.

Smart meters are also an intrinsic element of the so-called ‘smart grid’, whose fundamental role is real-time control of the electricity network (distribution *and* transmission) with the use of sensors, information and communication technology, with links to the customer through smart meters (Joskow 2012; Pacific Economics Group, sub. DR48, pp. 7‑8; City of Sydney, sub. DR58, p. 6; Landis+Gyr, sub. DR95, p. 3). While benefitting consumers, smart grids mainly relate to the management of the network — particularly as intermittent generation grows in importance. On that basis, the network operators are again the dominant players.

Given the above, not surprisingly, the biggest sources of efficiencies relating to smart meters occur upstream of retailing, as shown in the various cost–benefit studies of smart meter rollouts, such as Deloitte (2011a) and Futura (2009). The latter found that direct benefits to retailers represented between 1.9 to 2.1 per cent of the total benefits (p. 10, p. 14). Where there are split incentives, *prime* investment decision-making would optimally lie with the party that has the most to gain, simply to reduce negotiating and coordination costs with other parties.

Distributor-led arrangements also remove the costs of the AEMC’s proposed measures to address the risk of consumer ‘lock in’ when retailers are responsible for installing meters. Lock in occurs when a retailer charges a customer moving to another retailer an exit fee in excess of the real cost of exit (roughly the depreciated value of the smart meter). Regulations are the usual method for addressing such lock in, and balance the need for retailers to recover the costs of any meter it installs (avoiding stranded assets) and the need to avoid contracts that impose excessive exit fees (avoiding market power). However, the AEMC (2012u) has proposed a solution that avoids regulatory oversight of lock-in, but that raises its own challenges:

The retailer would be obligated to ensure a working meter at a consumers premises (NEM compliant at a settlements point). It would also be responsible for managing and contracting with a metering coordinator (MC) to engage metering service providers on a consumer’s behalf. Separating the MC role from the retailer means that a consumer can change its retailer without the need for it to change MC, thus reducing the need to replace the meter. (p. 89)

Such an arrangement creates another regulated structure in the electricity market, with rules about how parties may contract with each other (such as stipulated standard contracts).

Moreover, the AEMC’s structural separation of meter coordination from retailers raises a separate issue of compensation for distributors for the lost economic value of any pre-existing meter they own (a stranded asset problem). The AEMC has proposed a set of arrangements involving exit fees to address this issue (AEMC 2012u, pp. 92‑3).

The AEMC’s proposals in both of the above instances would be likely to solve the problems they target, but they are problems that largely do not exist in the Commission’s proposed model. They underline the fact that making a fully-fledged ‘market-based’ rollout work requires complex ancillary arrangements that would not usually be required in most markets. The market contemplated is very much a managed one, a relevant consideration when weighing up other managed models for rolling out meters.

While not a reason in itself, it is revealing that the dominant international model for rollouts has been distributor-led. A distributor-led arrangement was also the assessment of the (then) Ministerial Council on Energy in their 2008 evaluation of four possible scenarios for a mandated national rollout.[[17]](#footnote-17)

However, unlike other infrastructure in the distribution network, smart meters would not be fenced-off like substations. Other parties should be able to access information collected by meters (but constrained by privacy provisions). They should also have open access to the meters for peripheral devices (subject to agreement with the customer) and could reach commercial agreements with network businesses to install meters, or if they wish, to invest in network compatible networks in their own right. For example, a retailer wishing to compete for customers by offering a meter with greater functionality and with an associated set of peripherals could negotiate with the distribution business to pay the incremental cost of the higher-functioning meter. Unbundling metering charges from other network charges to retailers (as advocated by GDF Suez, sub. DR68) would provide the transparency needed to encourage such commercial negotiations.

The issue of exit fees for peripherals installed by a retailer would be solved without any intermediary, and would draw on the generic Australian Consumer Law’s provisions against unfair contracts (as is the case, for example, with mobile phone plans) were a retailer to set excessive exit fees.

#### Recovering prudent costs

Network businesses on the whole were supportive of the rollout of smart meters by distributors, but noted that this was only so long as the business case was satisfied and all relevant costs were accounted for (ENA, sub. DR71). By treating ‘vanilla’ smart meters as part of the distribution network (similar to poles, wires and substations), the implications is that distributors could recoup the costs of rollouts in ways analogous to other network costs.

The AER could compensate distribution businesses for such smart meter rollouts using two quite distinct approaches.

##### Rate of return regulation provides certainty, but weak incentives

Under the first approach, the AER would approve a rate of return on an agreed rollout of meters, with no or limited potential for the distribution business to amend its plans (effectively ‘rate of return’ regulation). This would ensure that the rollout occurred as set out in the regulatory proposal and insulate the distribution business from any cost risks associated with rollouts (thereby providing certainty for the business about an adequate return).[[18]](#footnote-18) Most importantly, it would directly address the split incentives problem, because the distribution business would be adequately rewarded regardless of where the benefits accrue throughout the supply chain. However, this approach would effectively replicate many of the features of the Commission’s draft proposal, with its disadvantages. In particular, the distribution business would have no incentive to seek other non-smart meter solutions to demand management. And unless competitive tendering for smart meters were required, nor would it provide incentives to contain the costs of rollouts.

##### An adapted form of incentive regulation is likely to perform better

Under the second approach, an adapted form of current incentive regulations would be used to recoup the cost of their investment in smart meters. The AER would make an ex ante determination of an aggregate revenue allowance based on an initial building block proposal by the business, which would include any demand management options, such as smart meters and direct load control. The AER would approve a revenue allowance for the total capex and opex using the approaches set out in the Rules (chapter 5). For example, it could question the costs and prudency of any proposed spending on smart meters, and, combined with its analysis of other capex and opex proposals by the business, it could reject, accept or modify the total expenditure allowance depending on its findings. However, in keeping with incentive regulation, it would not require a distribution business to actually make the specific investments set down in its proposal, whether they be smart meters, substations or pole replacements.

The business would have the freedom to make its own capex and opex choices. It could decide to roll out more or fewer smart meters than it projected in its original regulatory proposal, find implementation savings, seek purchasing discounts, and take account of changing circumstances. The business would take any savings as profits. This approach would mean that any rollout would meet a *commercial* cost‑benefit criterion, at least to the distributor.

However, its Achilles’ heel is that, absent other incentives, it would lead to underinvestment because:

* the business might not be able to appropriate a sufficient share of the network savings that occur in subsequent regulatory periods. As noted by PricewaterhouseCoopers:

… current incentive schemes do not deal well with projects that have an upfront cost in return for potential future benefit (this is because incentive schemes reward or penalise distributors for any divergence between forecast and actual expenditure over a regulatory period, and so benefits created for future regulatory periods are omitted). (PwC 2011, p. v)

* returns to other parties would not be included in the commercial decision‑making of the distribution business.

In relation to the former, this issue is not unique to smart meters, and, where the issue is sufficiently large to impact investment decisions, has a solution. In approving revenue determinations, the AER must, to some extent, track individual projects between regulatory periods, taking this into account in its determinations. A similar process is needed for the efficient operation of the Efficiency Benefits Sharing Scheme (chapter 5).

In relation to the latter, the existing incentive regulatory regime includes a scheme intended to address some of the barriers to demand management — the Demand Management and Embedded Generation Connection Incentive Scheme. Some see it as deficient. Ausgrid, for example, has claimed that it could not appropriate the benefits of demand management for transmission or wholesale generation costs, and that these benefits would be eight times greater than those recognised under the current regulatory framework (Maltabarow 2012, p. 4). The Commission examines that scheme in greater detail in chapter 12, but the critical point is that complementary reforms to such incentives would be required to create optimal incentives for rollouts.

It is notable that, notwithstanding its view that a market-led rollout is desirable, the AEMC has recognised the benefits of a smart meter rollout similar to that proposed by the Commission above. It has proposed that this option would sit alongside the market-based approach:

We have proposed that network businesses would be able to do targeted roll outs of smart meters in a defined area subject to AER approval as part of the DNSPs regulatory determination. (AEMC 2012u, p. 94)

##### The relevance of the Regulatory Investment Test for Distribution

The recent introduction of a Regulatory Investment Test for Distribution (RIT‑D) in the Rules (s. 5.17) may, in cases involving large-scale smart meter rollouts, also assist in drawing attention to, and quantifying, the wider benefits of smart meters.[[19]](#footnote-19) The RIT‑D requires distribution businesses making integrated investment projects of more than $5 million to undertake a cost–benefit test. This would have several implications for the rollout of smart meters.

* One of the aspects of the RIT‑D is the consideration of other options, which, in the case of a conventional network augmentation, could include smart metering and direct load control as other ways of managing load.
* The RIT‑D would apply to any large-scale rollout of meters in its own right.[[20]](#footnote-20) This would require publication of a cost–benefit test, but as in the current Regulatory Investment Test for Transmission (RIT‑T), there is no requirement for the AER to approve the outcome of the test. As a result, there is inevitably scope for a network business to influence the outcome towards their preferred project.

A key issue is whether a tougher test than the present RIT‑D should apply. The Commission has recommended that large-scale transmission investments would be treated in a manner similar to a contingent project and be subject to a mini-revenue determination and a cost–benefit test for the specific project (with the detail spelt out in chapter 17). In principle, the same approach could be adopted for distribution investments.

However, there are some complexities in adopting the Commission’s proposed RIT‑T/contingent project approach as the model for large-scale investment by a distribution business generally, or specifically for large-scale investments applying only to smart meters.

* The latter would involve a separate incentive regulatory regime for smart meter rollouts alone. Applying the text would entail significant complexities in addressing the large degree of substitutability between smart meter rollouts and other demand management options for distribution businesses (such as direct load control). These substitution possibilities are likely to be more substantial than those applying between lumpy transmission assets and other expenditures by transmission network service providers.
* AEMO can provide impartial and informed advice on transmission assets, but there is no obvious party to do this for smart meter rollouts.
* From a pragmatic perspective, it may be difficult for the regulator to determine whether a rollout of meters represents a single integrated investment, or a series of separate sequenced regionally-based investments. (This is unlike large lumpy assets like zone substations). Unless there is clarity on this point, it would be difficult to test whether the deployment of demand management technologies would meet a suitable threshold test for consideration. (By way of example, $38 million is the threshold for transmission assets under the Commission’s RIT‑T proposal.)
* In practice, the Commission envisages a smart meter rollout process that would typically mean that even integrated rollouts in a region — say to 10 000 households — would fall well under a threshold like that applying to the Commission’s proposed RIT-T/contingent project approach. As an illustration, Deloitte (2011a) calculated that the total costs of deploying meters under the present Victorian rollout were around $800 a meter. This includes some fixed costs, such as IT systems. Nevertheless, if that average value applied, a rollout in a given area to 10 000 residences would cost around $8 million, well under the Commission’s proposed $38 million RIT-T/contingent project threshold. Accordingly, there may be few occasions in which a tougher RIT-D approach of the kind described above would actually be triggered.

Accordingly, at this stage the Commission does not support any extension of the RIT/contingent project approach to distribution investments, whether for smart meters alone or especially for all large-scale distributor investments. However, that option could be re-considered depending on the outcomes from adopting the Commission’s recommendations for large-scale transmission projects and on the pattern of rollouts of smart meters. Regardless, any such approach should only apply to large-scale rollouts.

The current RIT-D would still have value by making it transparent and clear to customers and other stakeholders whether the rollouts were likely to provide overall network savings (with the benefits of reducing pressures on electricity bills). The AEMC also considered that the RIT-D would serve a useful purpose as a cost‑benefit test (2012u, p. 94).

However, in its current form, the RIT‑D has at least one clear deficiency. For most investments, the RIT‑D is intended to clarify (but not require) that a proposed investment passes a cost–benefit test, and that no other options are preferred. The exception is that for reliability-related investments, the test identifies the option that maximises the present value of the net economic benefit, which, as the Rules explicitly acknowledge, could be negative (clauses 5.17.1(b) and 5.17.1(c)(9)(v) of the Rules). This is contrary to an incentive framework for reliability as spelt out in chapter 15, which should induce distribution businesses to only undertake reliability investments that meet a cost–benefit test. The exception for reliability-related investments should be removed from the Rules. It is likely that the main impacts of such a change would not relate to investments in smart meters, though these are widely regarded as having significant reliability benefits.[[21]](#footnote-21) Irrespective of this, the Rules should be amended so that the RIT‑D becomes a genuine cost–benefit test, with benefits exceeding costs. This is consistent with the Commission’s recommendation in relation to the Regulatory Investment Test for Transmission (recommendation 17.4).

An additional concern about the RIT-D is the threshold that triggers it, and the potential risk that a set of separate, but very similar investments would each be subject to the test — with the compliance costs that this entails. This could apply to many distribution investments, but is especially relevant to smart meter rollouts, as the Commission envisages that these would be sequenced and localised. Some regional rollouts would be extensive — with costs well over $5 million dollars — and justifiably subject to the RIT‑D process. However, that would not always be true. Undertaking RIT-Ds for each of a succession of modestly-sized rollouts that just exceeded the current threshold appears to be unnecessary. This is particularly so because, under the Commission’s approach, a distribution business that proposed a rollout of smart meters as part of its revenue proposal for the coming regulatory period would still have to justify the prudency of its proposal to the AER (as it would for other investments under current arrangements). The added benefits of a full RIT-D for each component of a larger-scale rollout are unlikely to be high.

A higher threshold (or the scope for exemptions in these cases) would resolve this problem. The appropriate threshold for the RIT‑D and the scope for widened exemptions should be assessed if, after some experience with the test, it appears to raise compliance costs by more than its value in improving transparency of the investment process.

### Amend the Rules so that network businesses face no biases towards accumulation and non-remotely read interval meters

The current Rules create incentives for distribution businesses to install manually read meters instead of smart meters, even when replacing old meters or installing meters in new dwellings (box 10.5).

In practice, this means retailers have the primary responsibility for remotely-read interval meters (smart meters), and distribution businesses the exclusive responsibility for manually read meters. As noted by the AEMC:

… LNSPs [local distribution network service providers] have the incentive to install manually read interval meters for which they are exclusively responsible for providing (ie. they are the Responsible Person). If a LNSP wanted to install a remotely read metering installation, which may be cheaper to read and lead to lower long term costs, the retailer would be responsible for providing the metering installation unless it agreed to give this responsibility to the LNSP. Under the current arrangements, the LNSP cannot seek AER approval for expenditure on a remotely read interval meter (type 4 metering installation) as these meters are a contestable service. (AEMC 2012d, pp. 12‑13)

The current distinction in the Rules regarding the provision of metering services based upon the type of meter should be removed, so that network businesses would be able to install remotely read smart meters and access the demand response needed to defer network investment in peak capacity.[[22]](#footnote-22) It is hard to see how the current regulations that induce distributors to install what in most circumstances would be an inefficient metering arrangement is consistent with the National Electricity Objective and the long‑term interests of consumers.

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| Box 10.5 Current Rules on who installs what meter |
| When contestability was introduced into the NEM, four market segments were envisaged: networks, generation, retailing and metering, with only the first regarded as having natural monopoly characteristics. The implication was that the other segments could be supplied efficiently through competitive markets, so that economic regulation was not required for those segments. In some cases — most notably retailing and large-scale generation — networks have now been fully vertically separated. In others, such as metering and distributed generation, networks can offer contestable services, but are subject to restrictions to address the risk that they might gain unfair commercial advantages in contestable markets (for example, by cross-subsidising such services or using information from a regulated activity for the benefit of a contestable one — Ausgrid 2012d, p. 2).  In relation to metering, these concerns about residual market power and the contestable supply of metering have been expressed in various ways.   * State and territory regulators developed ring-fencing guidelines for their network businesses. Many of these guidelines relate to ring fencing of retailing from distribution, and do not specify smart meters or other emerging technologies as expressly ring-fenced (AER 2012e, p. 6). The AER is currently seeking to create NEM-wide ring-fencing guidelines. * Distribution businesses are able to exclusively supply manually-read Type 5 and 6 meters, with recoupment of costs through regulated revenues. (Distribution businesses are the ‘responsible person’ under s. 7.2.3 of the Rules v.54.) Such meters do not have natural monopoly characteristics, yet are still regulated assets that can be part of the regulated asset base of a distribution business (Kema Australia 2013, pp. 59‑60) * However, a distribution business is the responsible person for Type 1 to 4 meters (smart meters) only if a market participant: * has accepted the offer of a distribution business to fulfil that role or * requests that the distribution business fulfil that role.   As smart metering is classified as a contestable service, distribution businesses cannot seek regulatory approval for smart metering expenditure, which reduces their incentive to invest in anything other than manually-read meters. Consequently, they would typically replace an old meter with a Type 5 or 6 meter (and install such meters in new premises).  Much of the discussion on smart metering is underpinned by the notion that the only relevant consideration is the presence or absence of natural monopoly (understandably since this was the focus of market delineation at the commencement of the NEM). However, market failures — most notably in coordination — can also justify a privileged role for a single party to roll out ‘vanilla’ smart meters. |
| *Sources*: AER (2012e); Ausgrid (2012d); Kema Australia (2013, pp. 106ff); Metropolis (2012, pp. 3‑4, 11). |
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|  |

### The links to retail price regulation

A smart meter rollout provides an efficient and flexible mechanism for introducing time-based retail charges (with greater versatility than non-remotely read type 5 interval meters). The full benefits of smart meters would require that state and territory governments remove retail price regulation (chapter 12).

Nevertheless, it would be still be possible to initiate the Commission’s reforms for smart meters ahead of the removal of price regulation. The outcome would be a slower (and sub-optimal) diffusion of smart meters. However, under incentive regulation, a distribution business would only install meters if it expected that this would minimise its costs (so as to maximise its revenue allowance).

For example, a business might roll out meters where it gained sufficient benefits from:

* network management
* remote meter reading
* increasing the use of smart appliances so as to defer network investment. This would not require that retailers set cost-reflective tariffs, but could be encouraged through direct incentives from distribution businesses.

Accordingly, the Standing Council on Energy and Resources should proceed with the immediate implementation of the Commission’s model for rolling out smart meters so that the regulatory arrangements for taking advantage of price deregulation would be in place.

## 10.5 There must be a role for other parties

### Retailers and third parties

One of the main reasons for rolling out smart meters is to facilitate time-based pricing and so elicit a demand response from consumers. Under the Commission’s proposals, retailers would face cost-reflective network charges. Retailers could then use the information provided by meters to produce retail tariffs for those customers who currently provide cross-subsidies to peaky consumers and those peaky users who may respond to time-based charges. Retailers could make money from clever tariff development and market segmentation, with offers that were appealing to certain consumers. The imperative would be to ensure retailers had access to the relevant smart meter information needed to achieve that.

Retailers (and other third parties) would also be able to develop products — whether it was advice on energy efficiency, direct load control, phone apps and in‑home displays — that drew on the functionality of the smart meter. Retailers would be in the best position to undertake such a role because of their direct relationship with an existing or prospective customer. As the Energy Retailers Association of Australia stated, because meeting and shaping consumer needs is a retailer’s core business, they have the primary relationship with consumers and:

… are best placed to educate and inform consumers about the benefits of new technology and how these benefits align with consumer needs, such as energy cost management. (2012b, p. 7)

The fundamental point is that a basic smart meter is unlikely to excite much interest with a consumer, as opposed to the view expressed by King (2012) that they are akin to consumer electronic devices.[[23]](#footnote-23) In contrast, the most attractive feature of the new technology is likely to be the potential for consumers to reduce their overall electricity bills by utilising the add-on capabilities of smart meters, better tariff classes and usefully distilled information on electricity usage patterns. These are separable from the meters themselves. While this part of the market should be fully contestable, innovation in these areas is likely to be driven by competing retailers and equipment manufacturers.

An important driver of competition in the contestable part of the market is separate billing of any other products and services that complement the ‘vanilla’ smart meter — such as an in-home display. In that way, consumers would be able to compare the prices of the various offers by electricity retailers, distribution businesses, appliance retailers and others. In the absence of such separate billing, a retailer or distributor might simply conceal the cost of an add-on in a more generic fixed charge, undermining competition.

However, the charges for the ‘vanilla’ meters should not appear as a separate billing item because the meters are likely to reduce other network and energy costs by more than the cost of the meters (as discussed later), without these offsetting savings being visible to the consumer.[[24]](#footnote-24) But, given other electricity cost pressures, overall electricity bills would not fall by as much as the savings realised from smart meters. In this instance, with separate billing, consumers would see the addition of a separately itemised metering charge to their bills, but would not see the savings, which would be subsumed into the accompanying non-itemised charges. Were those other charges to rise, the consumer would observe an overall electricity bill that would not go down by the amount of the metering charge (or might even rise). To give a tangible example, suppose that a smart meter charge of $100 per year were added to people’s bills, and that the smart meter facilitated a saving in the rest of the electricity bill of $300 (or a net saving of $200). However, if other (unrelated) electricity charges were to increase by $300 due to other cost pressures, a consumer would only see a new charge for the smart meter and no apparent saving, and falsely (but understandably) assume that the only reason their bill had increased was due to the smart meter.

Pricing transparency is intended to assist, not confuse customers — so that ‘vanilla’ metering costs should be bundled with other network costs. Nevertheless even with bundled charges, a major role for the AER would be to ensure that there are genuinely offsetting benefits, and communicate this to consumers so they can be satisfied that smart meters are not adding to their overall electricity costs.

### The role of the consumer

Other than at the street level, consumers are generally not aware of the investments made by network businesses. Planning issues aside, most would not consider that they had a major role in deciding when a new substation should be built or its technical specifications. However, this does not hold for smart meters as:

* they are attached to the premises of the household
* they provide a potential role for consumer decision‑making about power usage and billing
* they collect (and make available) much more information about household electricity consumption than old meters, raising concerns about privacy and hacking. As an indicator of their importance, privacy concerns dominated the public and consumer advocacy debate about a mandated smart meter rollout in the Netherlands, leading to the decision to have a voluntary rollout (Hierzinger et al. 2012, p. 60). (As discussed below, these problems can be resolved)
* there are misperceptions about their safety in terms of fires and electromagnetic radiation (Deloitte 2011a, pp. 52‑54, p. 104)
* the benefits can be hard to explain, except for customers who have elected to have solar PV units installed and see the smart meter as an essential component of getting paid for the power they export to the grid. The Deloitte study found that in Victoria there was ‘very limited understanding in the general population on the reasons for installing smart meters and what they are to be used for’ (2011a, p. 54). Research undertaken for Smart Grid Australia (2012, p. 34) found that 38 per cent of Australians had a negative view about the introduction of smart meters and nearly 45 per cent of Queensland and New South Wales respondents had not even heard of them (compared with 6 per cent of Victorians). In Victoria, 25 per cent of consumers had *very* unfavourable views about the introduction of smart meters and 60 per cent of respondents had unfavourable views. Overwhelmingly, consumers thought that the energy industry should be responsible for educating them about the benefits, with retailers and distributors seen as the most reliable source of information (Smart Grid Australia 2012, pp. 35‑6)
* while people accept that billing for electricity use requires metering, there seems to be much less awareness that electricity costs vary significantly during critical peak periods, and that the only efficient and equitable way of measuring and charging for that use is through some kind of interval meter. Were supermarket pricing like electricity pricing, there would be no individual prices on any supermarket item and only one total bill when the shopper paid at the checkout.[[25]](#footnote-25) What seems to be absurd in the grocery market is now seen as normal in electricity, and represents a barrier to the adoption of smart meters.

In that context, many consumers are likely to resist the rollout of a technology for which they would be obliged to pay, but that has uncertain future benefits for them.

This problem is well recognised in Australia and overseas.[[26]](#footnote-26) This emphasises the importance of retailer and third party involvement, and of broad education and marketing, including:

* informing consumers about the real costs imposed by just a few hours of peak demand. People are sometimes willing to change their behaviour if they are aware of the broader public (and private) benefits of curtailing peak demand, as shown by consumers’ responses to entreaties to conserve water during the recent drought
* indicating the general savings to network operations, and providing estimates of the bill savings these would entail, especially to consumers who are not large users of electricity at peak times, without overselling the magnitude or the timing of those savings (a point emphasised by Smart Grid Australia 2012, p. 7). The results of RIT‑Ds — in a digestible form — should assist this
* raising awareness and showing examples of how to make savings by shifting peak‑time consumption. Pricing pilots could be helpful to inform retailers about the likely strategies employed by consumers to shift their consumption, and ways to communicate messages effectively to different consumers
* providing options to reduce price risks, such as through participation in controlled load programs, or offering a range of ‘smoothed’ tariffs
* addressing safety and privacy concerns. Following the consumer backlash to smart metering in Victoria, the Victorian Government has tried to address consumers’ concerns by better communicating the statutory protections of people’s privacy. As noted by DPI (2013b), energy businesses in Australia must comply with the Federal Privacy Act (1988), which includes the National Privacy Principles. These Principles set clear restrictions on the use, disclosure and storage of personal information. The collection, use and disclosure of metering data by electricity companies is also subject to strict confidentiality rules set out by the Essential Services Commission’s licensing framework and the National Electricity Rules. A national licensing regime (discussed in chapter 11) would ensure that uniform privacy provisions were in place across the entire NEM, avoiding state-specific provisions. The Public Interest Advocacy Centre (PIAC 2013, p. 7) argued that a consumer information campaign would help address consumer concerns about privacy and security issues
* indicating that decisions about using the add-on capabilities of smart meters would be subject to consent by the consumer
* using targeted hardship programs and, in the future, electricity storage technologies to address the fears of vulnerable users who have no discretion in their power use, such as when power use is required for medical needs.

Many mass marketing and informational costs are fixed for a sufficient number of consumers, and could be more effective if pitched on a broader scale or, at least, on a community-by-community basis (akin to the transition to digital television).

Moreover, if the AER is performing well in its regulatory responsibilities, then the revenue allowances it provides to network businesses should take account of the network (and upstream) savings from demand management. Accordingly, electricity bills for the average consumer should fall compared with the counterfactual. Given its role in regulatory determinations (and in the ancillary incentive schemes that promote demand management), and its improved benchmarking capabilities, the AER is in the best position to quantify these net benefits, and to make the information publicly available. A smart meter rollout that raises average electricity bills above counterfactual levels will have failed consumers.[[27]](#footnote-27)

#### A collective funding principle to pay for smart meters

Ideally, within a geographic region, a rollout of ‘vanilla’ smart meters would be financed through a fixed charge included in network tariffs to retailers. The asset life of meters is around 15 years, while the communication module within the meter has an expected life of around seven years. Accordingly, the annual charge would only be a share of the total meter’s full price.

The savings from smart meters (and the associated effects of cost-reflective pricing) stem primarily from the reduction in network costs to meet peak demand, from savings in general network operations and management, and reductions in energy consumption (chapter 9). While, on average these savings are likely to offset meter charges, these savings are not equivalent for all consumers.

Trials find that low-income households tend to benefit from time-dependent charges. For example, some studies suggests 80 per cent of low income households (which tend to have flatter load profiles) would be better off under time-based pricing without even altering their consumption patterns. Further, if they respond to price signals, 92 per cent of low income households would be better off (Faruqui 2010). (Nevertheless, it would be important to provide information to lower-income consumers in particular so that they are aware of the likely effects of time-based pricing — and can make prudent judgments about their energy using practices.)

However, it is important to distinguish between low-income consumers and low power-usage consumers. Low total consumption does not necessarily equate with low use at critical peak times. The best available evidence is from interval meter data (table 10.1), which unfortunately adopts an extremely broad interpretation of peak use (defined as a 15 hour period during each weekday). This limits the use of the results to isolate the contribution of average low-usage customers to the short periods where peak (and network) costs are highest. Nevertheless, of the people who have low off-peak usage (of 0–4 kWh per off peak period per day), just over 10 per cent had high peak usage (of 10+ kWh per peak period per day).

Accordingly, there may be equity concerns for disadvantaged groups who consume power at peak times.

In addition, while smart meters should have offsetting *long‑run* savings in network costs and energy bills, these savings are not necessarily realised immediately but are spread over several regulatory periods. Depending on how the AER addresses this inter-temporal issue in its revenue determinations, the fixed metering charges may initially be higher than the immediate network savings. Some consumers (particularly those on low incomes, who tend to spend a greater share of their income on electricity — chapter 2) may find these initially higher fixed metering costs difficult to meet.

Given these concerns, state and territory governments could develop criteria for assistance to low income households for the cost of smart meter fixed charges and time-based charging. It would be desirable that such criteria be consistent, at least, across the NEM and possibly also consistent across utility services more broadly (recommendation 11.8).

Table 10.1 Relation between peak and off-peak consumptiona

Percentage of households, by kWh consumption in peak and off-peak periods

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | | | | | | |
|  | **Peak period** | *High usage*  *(10+ kWh peak use per day)* | 3 | 18 | 44 |  |
|  | *Medium usage*  *(5–9 kWh peak use per day)* | 7 | 10 | 1 |  |
|  | *Low usage*  *(0–4 kWh peak use per day)* | 16 | 1 | 0.1 |  |
|  |  |  | *Low usage*  *(0–4 kWh off peak use per day* | *Medium usage*  *(5–9 kWh off peak use per day)* | *High usage*  *(10+ kWh off peak use per day)* |  |
|  |  |  | **Off-peak period** | | |  |
|  | | | | | | |

a Based on Interval data from 1000 households. High usage is defined as 10+ kWh per day, Medium as 5‑9 kWh per day and Low as 0–4 kWh per day. The peak period is defined very broadly as between 7 am to 10 pm on weekdays. To illustrate how to read the diagram, 3 per cent of households have high peak use and low off-peak use.

*Data source*: Simshauser (2012).

#### Would all consumers get smart meters?

The supply-side efficiencies of smart meters rely on high rates of penetration. However, since network businesses are likely to be the prime decision-maker under the Commission’s proposal, they may decide that it is not economic to install smart meters in a given location. For example, data from sensors on street level transformers might show little peak demand in a given area, or that the network savings might be too small if the network has recently been augmented. This is a desirable outcome from an efficiency perspective. It would not prevent a retailer or other party installing a meter at the request of any of the relevant consumers concerned (potentially accompanied by commercial agreements with a distribution business to pay some of the costs).

Beyond these cases, there are few grounds for providing exemptions for the installation of smart meters. Targeted relief for the costs of installation for vulnerable consumers is likely to be more efficient than failing to install meters (as discussed above). This reflects:

* the relatively high cost of installing and procuring smart meters on a case‑by‑case basis when, for example, an exempted household moves residence or the customer opts to transfer to time‑based charges
* the likely increase in fixed costs for the low proportion of households continuing to require physical meter readings. The annual cost of quarterly meter reads could be in the order of $80–$200 per meter, which would significantly contribute towards the cost of a new smart meter. Indeed, in some states in the United States, utilities are able to bill customers who opt out of smart meters with an additional charge reflecting these costs (though some states do not permit any opt outs). In California, the opt‑out charge was an initial US$75 fee and a monthly bill of US$10 (Cho 2012).

#### In conclusion … smart meter rollouts need to be supported by consumer engagement

In conclusion, the importance of involving consumers in any rollout, associated pricing and other aspects of the regulatory process is critical, and would involve both consultation and information provision, and some championing by governments (as occurred in the case of water conservation). Failure to do this could lead to a consumer reaction that undermines the case for investment in technologies and stalls progress towards pricing changes that will benefit consumers over the longer term. Chapter 11 discusses the engagement process for pricing reform — of which a smart meter rollout is a significant prerequisite. More generally, chapter 21 proposes reforms that would give consumers much more power in the regulatory process.

## 10.6 Control of the information hub

Apart from allowing efficient pricing, smart meters provide a wealth of information and options to use that information for a range of purposes by multiple market participants. As discussed above, smart meters can be used to collect valuable information about household consumption patterns. The price responsiveness of consumers could also be gauged with add-on technologies to enable retailers to communicate real-time prices to end-users. The use of this information would be subject to appropriate privacy considerations. In addition, with the agreement of end-users, smart meters allow the centralised implementation of sophisticated load management programs and can broaden the range of options to support emergency management of system reliability.

This raises the question of which party or parties should operate a central command and control hub of the smart meter platform (or whether any such universal coordination or central control is needed at all). This includes responsibility to implement and operate a single meter data management system (MDMS), which validates data and coordinates the communication of commands and information to and from meters (figure 10.2). Under a distributor-led rollout, the communications infrastructure would be controlled and maintained by distributors, since it closely interacts with their network functions. As such, distribution businesses would also operate the network management systems (NMS) — the IT platform that links to the communications system and interfaces with the MDMS.

Some participants suggested that AEMO could operate a central MDMS, as it is independent from distributors and already has some responsibilities for smart meters. (AEMO currently facilitates the communication of metering information between distributors and retailers.) The efficiencies and risks from having a single MDMS would have to be thoroughly analysed, but the option appears to have some merit. In particular, a central MDMS operated by AEMO:

* could deliver scale economies because it would spread the costs of fixed IT expenditures
* would allow prioritisation of communication flows and commands to smart meters from a variety of parties, including:
* AEMO itself (to protect overall system security)
* retailers (to manage both network and wholesale market events, billing to their customers, and deliver demand management services, such as direct load control, on behalf of their customers)
* transmission and distribution businesses (to manage peak network events and implement load management according to contracted arrangements)
* other approved third parties (such as demand aggregators)
* gives confidence that a distributor‑led rollout would not disadvantage other market players who might have legitimate reasons to access smart meter information and, with the agreement of customers, make use of the control and communication functions offered by this technology.

Figure 10.2 The smart meter platform

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| Figure 10.2 The smart meter platform. This figure shows how smart meters communicate to and from a residence, with data and information flowing through communication infrastructure, a distributor’s NMS and being stored in a central MDMS that both distributors and retailers can communicate with and access information from. |

Currently, the transactions settlement and business-to-business system operated by AEMO is not a real time system. It would require an overhaul to be used as the seed of a central MDMS. Equally, however, an alternative where each distributor developed its own MDMS (as occurred in Victoria) would require sizeable investment. Appropriate empirical analysis would have to inform the relative costs and merits of either approach.

Any system would need to ensure consumer privacy and have appropriate security safeguards. In particular, the National Electricity Rules (and National Energy Customer Framework) should provide clear guidance about which parties are approved to access data. Currently, the Rules assume an arrangement where a consumer’s agent, such as their retailer, can receive, relay and store data on behalf of their consumers. A central MDMS would give retailers timely access to data (collected from multiple distribution businesses) allowing them to efficiently perform their exclusive role in interacting with and providing data to end-users.

## 10.7 Direct load as an alternative or complementary option

Direct load control can act as a complement or substitute for smart meters.

In the absence of smart meters, direct load control technologies probably offer the most practical option to implement peak demand management.[[28]](#footnote-28) Indeed, NSW DNSPs (sub. DR85, p. 2) said that direct load control has a key role to play in managing peak demand for electricity distribution networks. The use of direct load control technology as an alternative to smart meters is most relevant for households, as most businesses already have smart meters, reflecting the lower relative cost of a smart meter installation for larger users.

Where there are already smart meters and cost-reflective pricing, direct load control may act as a complement because it ‘locks-in’ power savings at critical peak periods, without a household having to make choices about their power use at these times. (The corollary is that it reduces the risks of ‘bill shock’ if a person forgets to reduce their power use during a critical period.)

In either case, direct load control allows a network provider to predictably ‘clip’ household demand during peak periods. Predictability is important because it means that the network businesses can be certain that they can reduce peak load capacity requirements without reliability problems (figure 10.3).

However, in the absence of cost-reflective pricing, such schemes require the use of incentive payments to ensure households realise some benefits from reducing their peak consumption.[[29]](#footnote-29)

Figure 10.3 ‘Clipping the peak’ — the impact of direct load control

KW consumed by hour on four daysa

|  |
| --- |
| 16.00  20.00  00.30  noon  midnight  250  200  150  100  50  0  No curtailment 35o C 14/03/2007  Switching  No curtailment  average  No curtailment 40oC  10/01/2007  Curtailment 36oC  15 min off in 30 mins  15/03/2007  kWh |

a Based on data from 68 homes in Glenelg South Australia.

*Data source*: ETSA Utilities (2008).

Most direct load trials have focused on incentives to manage the peak power use of air conditioners and pool pumps. Direct load control of pool pumps can operate all year round, similar to the off-peak programming of electric hot water services.

For air conditioners, direct load control would typically only be used on the handful of hottest days each summer. Because cooling is highly valued during critical peaks on extremely hot days, direct load control does not involve completely switching off air conditioners. In some trials, the fan in the unit continues to operate, but the compressor of the air conditioner is cycled on and off remotely, such that the unit does not operate for 7.5 to 15 minutes out of every half hour window. However, in the recent application of direct load control of air conditioners, the energy use of the unit is limited, allowing the compressor and the de-humidifier to always remain on, increasing consumer comfort. For example, 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 to 50 or 75 per cent of their usual energy use when the electricity network reaches peak demand. Households receive a one‑off incentive of between $250 and $500 per air conditioning system, depending on its features (pers. com. Energex and Energex 2013).

Trials find that the managed use of the compressor and power supply to an air conditioner has little impact on customer comfort levels if the compressor is set to operate between half and two thirds of the time (Futura 2011). Comfort levels can be increased further by extending the direct load control function to cool the house prior to and following a period of direct load control.

### Technology will be a friend to direct load control

Technological change will aid the management of electricity demand through remote control of appliances. While adopting new technologies can be costly, the real cost can fall dramatically as scale economies result from mainstream take-up. The horizon of potential automated demand management solutions is large and rapidly developing. For example, mobile phone apps can already remotely control some compatible appliances (Landis+Gyr 2012; Owano 2012). Peak load pricing and the diffusion of smart meters would accelerate such innovation.

### Should direct load control capability be mandated?

Some participants have suggested mandating a demand response capability in the future manufacturing standards of key appliances, such as air conditioners, pool pumps and, in the future, electric vehicle batteries (Wilkenfeld 2011b). There is a potential rationale for compulsion because many appliances are long‑lived and consumers may fail to consider the future benefits of direct load control when making initial purchases. Retrofitting is very costly, while building in a capacity at manufacture is low cost.[[30]](#footnote-30) Moreover, a standard avoids the development of multiple, potentially incompatible technologies and could encourage the more rapid diffusion of direct load control.

However, the Commission is not convinced that mandated standards are justified or will be necessary. Currently, there is a limited motivation for consumers to take up the technology. This would be likely to change if there were greater financial incentives to do so, either through payments, such as that of Energex, or through avoided higher bills if critical peak pricing were introduced. Not all air conditioning brands would need to be compatible with direct load control technologies to achieve change. By August 2011, two out of roughly 78 potential brands of air conditioning on sale in Australia had a demand response capability built in and ready to use, and a further six were compatible, subject to the addition of an extra part (Wilkenfeld 2011b, p. 9). The Equipment Energy Efficiency Committee noted that the manufacturers that have responded did so for commercial reasons (E3 2012, p. 2).[[31]](#footnote-31) It could be expected that other brands would respond if consumer (and network) demand for direct load control were sufficiently high. Indeed, information provided by a network business indicated that by early 2013, even more air conditioners were configured for direct load control, and major appliance retailers were advertising their benefits over alternative units. Their uptake would be further hastened by:

* the wider global uptake of energy management technologies. It is hard for Australia to act as a first mover in this area as it is a small country with little domestic capability in appliance manufacturing. An option — already in progress — is for Australia to seek the international adoption of its already highly developed standard (box 10.6; E3 2012, p. 2)
* informing consumers about the benefits of this additional functionality.

However, there are grounds for monitoring the extent of uptake of these technologies and, if rates are low, examining why this might be the case before any consideration of mandating of standards. In particular, until the regulatory barriers to critical peak pricing are overcome, mandating a standard is likely to be premature. A Regulatory Impact Statement concerning a mandated standard is currently underway (DRET 2012a, p. 57).

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| Box 10.6 The Australian standard for demand response capability |
| Published in 2007, the AS4755 *Framework for demand response capabilities and supporting technologies for electrical products* applies to the interface between a demand response enabling device (DRED) and a variety of electrical products. An appliance that includes a demand response interface is frequently termed a ‘smart appliance’.  A demand response capability could be applied to the manufacturing standards of numerous electrical devices, but is currently being investigated for air conditioners, pool pumps and electric vehicles. Different parts of the standard apply to particular appliances and each is in different stages of development. Standards relating to air conditioning are most advanced. Compliance with the standard would be included in the energy rating labels of appliances.  A small number of air conditioners available on the market today are compatible with the AS4755 standard. These appliances can be activated for direct load control with the installation of a DRED. The DRED can be:   * a self-contained unit that receives remote signals to control load, processes them according to its settings, and sends instructions to the attached appliance * a ‘receiver’ attached to the appliance, with smart meters performing many of the other functions.   DREDs can be activated by a range of signals from the network provider or retailer, including those sent through power lines, phone lines, radio frequencies, and the internet. Passing signals through smart meters offers the potential for more sophisticated and personalised appliance responses and two-way communication with the network. It can also remove the need to roll out a communication network exclusively for direct load control.  However, even where smart meters are not present, an entirely new communication system may not be necessary as some distribution networks already have a system present for hot water control that could communicate with DREDs for little additional cost. For instance, networks in Queensland and New South Wales may be able to use their existing ability to send signals down power lines to operate DREDs on air conditioners. |
| *Sources*: Wilkenfeld (2011a, b). |
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Recommendation 10.1

The Regulatory Investment Test for Distribution in the National Electricity Rules should be altered so that a preferred investment option cannot have costs that exceed the benefits. The current $5 million threshold value and the use of exemptions should be reviewed if the test imposes unjustifiably high compliance costs on distribution businesses, the Australian Energy Regulator and other parties.

Recommendation 10.2

The Standing Council on Energy and Resources should finalise a minimum technical standard for advanced metering infrastructure, including smart meters, which should:

* ensure that distribution businesses and other parties can purchase off‑the‑shelf equipment from global manufacturers of smart meters with no, or minimum, modification
* incorporate capacities for:
* interoperability with add-on technologies that distributors, retailers and third parties wish to offer customers
* open access to information for distributors, retailers and third parties, subject to privacy provisions
* direct load control.

Recommendation 10.3

The National Electricity Rules should be amended so that distribution businesses would be able to include the rollout of advanced metering infrastructure, including smart meters, as an eligible category in their regulatory revenue proposals to the Australian Energy Regulator. During the regulatory period, distribution businesses should be able to decide on the timing, location and number of smart meters in any rollout. These changes should be accompanied by:

* engagement with consumers and retailers about the process, and the implications of smart meters for them
* the development of an incentive program by the Australian Energy Regulator that takes account of the benefits of smart meters:
* in reducing network expenditures in subsequent regulatory periods
* accruing to others in the energy supply chain
* time-based network charges to retailers (recommendation 11.1)
* options for direct load control.

1. The term ‘smart meters’ is used to describe the smart meter itself, and associated technologies, such as IT equipment, back end software, and two-way communication equipment. Smart meters come in several forms, but all can be remotely read and provide details of consumption over time. Manually-read interval meters (‘type 5’ meters), also allow time-based charging, but cannot provide timely feedback to consumers, facilitate direct load control, or provide a range of other efficiency benefits to distributors. [↑](#footnote-ref-1)
2. Achieved through a ‘demand response enabling device’ (DRED), as described in box 10.6 at the end of this chapter. [↑](#footnote-ref-2)
3. The term rollout refers to a coordinated program to install smart meters in a given geographic area. Although this may imply some degree of universality, it does not necessarily imply a government-mandated rollout throughout an entire jurisdiction. [↑](#footnote-ref-3)
4. For example, see Futura (2009), Giordano et al. (2012) and Oakley Greenwood (2010b). [↑](#footnote-ref-4)
5. With the exception of an off-peak tariff for directly wired electric hot water services. Kema Australia (2013) has detailed information about the deployment of smart meters throughout the NEM, and the extent to which they support time-based pricing. [↑](#footnote-ref-5)
6. The United Kingdom is commencing a rollout of 53 million smart meters to all residential properties and small and medium businesses over the period 2014–2020. The project is expected to deliver a net-benefit of £7.2 billion (DECC 2012). [↑](#footnote-ref-6)
7. The *Electricity Industry Act 2000 (Vic)* provides an ongoing basis for regulation of advanced metering infrastructure in Victoria, and empowers the Victorian Government to make cost recovery orders, though some provisions of the National Electricity Rules also apply (Victorian Government 2011). From 2016, the National Electricity Rules will be the only basis for regulating advanced metering infrastructure in Victoria. [↑](#footnote-ref-7)
8. Dr Gill was the head of the team tasked to develop the minimum functionality specification of smart meters in Australia. [↑](#footnote-ref-8)
9. Estimates of these gains and their origins are discussed in depth in CRA (2008a, 2008b); Futura (2009); Mott Macdonald (2007, p. 47ff); and Oakley Greenwood (2010b). [↑](#footnote-ref-9)
10. Hedging behaviours and gentailing adds complexity to the analysis, but ultimately demand management acts effectively as new competition in the generation market, reducing returns to incumbents. [↑](#footnote-ref-10)
11. The Commission used several sources to assess the current state of rollouts internationally, including information provided by several participants in this inquiry; Frost and Sullivan (2011); ICER (2012); Kema International (2012, pp. 22ff); Schächtele and Uhlenbrock (2012); Sentec (2012); the UK National Audit Office (2011) and, most comprehensively, Hierzinger et al. (2012). [↑](#footnote-ref-11)
12. Including Frontier Economics (2007); ATKearney (2008); Mott MacDonald (2007) for the British Government; and Nabe et al. (2009) for the German Federal Network Agency. [↑](#footnote-ref-12)
13. However, this is contested. Futura (2009, p. 66) considered that the costs associated with more frequent billing exceeded working capital benefits, though this may not apply with emerging technologies. [↑](#footnote-ref-13)
14. Macquarie Corporate and Asset Finance (sub. DR54, pp. 4‑5) questioned these scale effects, saying that in the United Kingdom ‘we see competitive commercial organisations … installing tens of thousands of smart meters efficiently using a 'checker board' approach to scheduling and installation’. The AEMC (2012u, p. 84) said that under a market-led approach, scale economies ‘would not necessarily be lost’. However, neither provided estimates of the costs per meter under competing models. The fact that competing businesses in a market-led approach can install many meters does not reveal the efficiency of an alternative (unobserved) planned rollout model. [↑](#footnote-ref-14)
15. Chapter 7 of the National Electricity Rules contains a minimum functionality specification for meters, but this mostly relates to the accuracy and basic capacity for recording information for all metering types. The only significant difference between requirements for smart and other meters is that smart meters must have a capacity for electronic data transfer from the metering installation to the metering data services database and a capacity to store interval energy data for a period of at least 35 days. [↑](#footnote-ref-15)
16. Such a standard was supported by a diverse group of participants representing most stakeholders, including the Total Environment Centre (sub. DR50, p. 7); the Energy Networks Association (sub. DR71, attachment B, p. 1); Landis+Gyr (sub. DR95, p. 1); and the Energy Retailers Association of Australia (ERAA 2012c, p. 11). [↑](#footnote-ref-16)
17. The other three scenarios examined were a retailer-led rollout, a centralised communications rollout and a direct load control rollout without smart meters. [↑](#footnote-ref-17)
18. As an illustration of the uncertainties with the regulatory return of smart meter costs, the AER deemed that in Victoria, SP AusNet’s rollout was not prudent, a problem that would have been less likely had the AER given in-principle ex ante approval of the proposed approach. The AER considered that SP AusNet’s adoption of WiMax (as the communications technology) involved a substantial departure from the commercial standard that a reasonable business would exercise under the circumstances. The AER adjusted the proposed advanced metering budget of SP AusNet by around $70 million (ACT 2012). The decision went to the Australian Competition Tribunal for merits review, which remitted some matters back to the AER for consideration. [↑](#footnote-ref-18)
19. In that respect, the recent comprehensive guidelines for cost–benefit analysis of smart meters in the European Union would provide a useful framework (Giordano et al. 2012). [↑](#footnote-ref-19)
20. This takes as given that the Rules have been changed along the lines of recommendation 10.3 (thus removing the constraints imposed by schedule 7.2.3 of the Rules). Moreover, the Commission has judged that the various exemptions from a RIT-D (as set out in schedule 5.17.3 of the Rules) would not apply to large-scale smart meter rollouts. The guidelines for the application of the RIT-D currently being developed by the AER should make this clear, or if necessary, the Rules changed to ensure that large-scale smart metering rollouts would not be exempt. [↑](#footnote-ref-20)
21. These benefits can arise by relieving peak capacity constraints that would otherwise have led to reduced reliability, improving the performance of the grid, improved fault-detection, and their importance to the ‘smart grid’ (which in its own right has significant advantages for network reliability). The importance of advanced metering infrastructure in these areas has been noted by the AEMC (2012u, p. 3, p. 122); CRA (2008a, p. 75); Futura (2011, p. 32); Joskow (2012); and Kema International (2012, p. 52). [↑](#footnote-ref-21)
22. The AEMC has recommended this change (2012u, p. 106). [↑](#footnote-ref-22)
23. Moreover, unlike most consumer electronic devices, smart meters have a relatively long life and it would be costly to replace them quickly. This is not likely to be true for some peripherals and other add-ons (for example, software that helps households manage their energy use). [↑](#footnote-ref-23)
24. Currently, there is no separately itemised charge for a type 5 or 6 meter. [↑](#footnote-ref-24)
25. Ehrhardt-Martinez et al. (2010, p. 1) citing a previous study. [↑](#footnote-ref-25)
26. For example, the AEMC (2012u, pp. 24‑50) provides a comprehensive analysis in the Australian context. Ehrhardt-Martinez et al. (2010) examine international evidence about the magnitude of electricity savings from the use of smart meters, and how these depend crucially on the nature of consumer engagement. [↑](#footnote-ref-26)
27. The test should be whether the present value of the savings in electricity bills over the life of the meter exceed the costs to customers from funding the rollout and ongoing operation of meters. In the shorter-term, customers may pay now to save later, which is one reason why it can be difficult to explain the benefits. [↑](#footnote-ref-27)
28. Demand limiting switches are a similar technology approach, but are not remotely controlled by a utility provider. They require the end-user to pre-program decisions about what appliances to switch off during peak periods in order to stay within a nominated consumption limit. This approach requires greater customer effort than direct load control of household air conditioners and pool pumps. An advantage of direct load control for network providers is that they can coordinate the use of power between households (having some households’ air conditioner cycled on while others are cycled off) and can secure a more reliable demand response. [↑](#footnote-ref-28)
29. This requires individually contracting with end-users, but to avoid excessive administration costs, ‘participant’ households are typically offered a uniform flat incentive payment. Since end-users value the use of power (or particular appliances) at peak times differently, compared with a price mechanism, incentive payments are a blunt and inefficient instrument to reduce peak use. Moreover, financing such payments through a higher average consumption price can distort pricing efficiency or lead to distributional concerns (chapter 11). [↑](#footnote-ref-29)
30. For example, to retrofit an air conditioner to enable direct load control requires electrical re-wiring, and could cost around $1500 (EnergyAustralia and Transgrid 2009). However, with an appliance that was originally designed and manufactured to incorporate a demand response capability, direct load control is possible for only a fraction of that cost. Wilkenfeld (2011b, p. 17) estimates that the interface cost per appliance would be around $10 per appliance. [↑](#footnote-ref-30)
31. The committee comprises members from all states and territories, and New Zealand. The E3 program overseen by the committee is part of the National Framework for Energy Efficiency (and is supported by national legislation, which replaces various state-based regulations). [↑](#footnote-ref-31)