11 Moving to time-based pricing for the distribution network

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| Key points |
| * Under current pricing approaches, households and many businesses are not exposed to the much higher costs of supplying electricity during critical peak periods. * Consequent overconsumption of power during these peaks increases network investment needs, pushing up prices for customers. And those (often low income consumers) who use electricity less at peak times subsidise more intensive users. * The broad case for moving to cost reflective, ‘time-based’, pricing for distribution network services is strong. As its use for some larger businesses exemplifies, it is practically feasible, with smart meters providing the technical means to extend the approach to households. Moreover, the pays offs from doing so are potentially very significant. * However, there are many complexities and challenges in giving practical effect to time-based pricing. A coherent, iterative and consultative implementation process that harnesses the detailed knowledge of those at the coalface is therefore required. * While not seeking to prescribe the pricing regimes that should emerge from this process, the Commission expects that network prices would be low for most hours of the day, but ramp up significantly during defined periods for critical peak demand events (such as a heatwave) * Such changes would not give distribution businesses carte blanche to gouge consumers. Distribution Network Service Providers would remain subject to an overall revenue constraint. * Given the broad end point is clear but the means and timeframes for getting there less so, the Commission has focused on ways to help ensure that there is an effective implementation process and conducive regulatory framework. It is recommending: * the Standing Council on Energy and Resources oversee and drive the process * some supporting changes be made to licensing arrangements for network providers and the National Electricity Rules * specific arrangements be employed to provide targeted assistance to vulnerable consumers adversely affected by the change in pricing approach * distribution businesses and energy retailers be required to demonstrate that they have engaged appropriately with their customers about the changes. |
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## 1 Introduction

As discussed in previous chapters, current ‘average’ pricing of the electricity network means that households and many businesses are not exposed to the much higher costs of providing electricity during peak periods.

The misalignment of costs and prices has three major undesirable consequences:

* The value of some of the consumption in peak demand periods that is encouraged by artificially low prices is likely to be much lower than its underlying cost.
* Since networks (and generation) must be built to meet critical peak demands, more investment in electricity networks (and in peaking generators) is required, pushing up average electricity prices for customers.
* Consumers who use electricity less at peak times cross-subsidise others. Often this will see low income consumers cross-subsiding higher income consumers.

The broad case for embodying a cost reflective, time-based component in prices for access to the electricity network — and especially the distribution component of the network — is strong.[[1]](#footnote-1)

The conceptual argument has long been recognised internationally (Joskow and Wolfram 2012). Reflecting this, there is already provision in the National Electricity Rules for the sorts of pricing approaches that would be required to give effect to time-based charges for access to the distribution network.

The approach is practically feasible. It is already employed for some industrial and commercial users, as well as in various non-electricity markets where demand and/or supply costs are time sensitive. And the smart meters necessary to implement time-based pricing at the household level are already in place in much of Victoria.

Most importantly, as established in earlier chapters, the pay-offs from introducing generally applicable, cost reflective, time-based pricing — hereafter referred to simply as time-based pricing — would be potentially large.

* Various empirical studies suggest that many electricity consumers will economise or shift the time of their consumption to avoid higher charges in peak periods (chapter 9). Reflecting such a demand response, AGL Energy estimated savings for households of $1.6 billion from removing price regulation, installing smart meters and implementing a limited-form of time-based (network and retail) pricing (Simshauser et al. 2011). The Commission’s modelling likewise indicates that, provided there is a sensible transition process, there would be a sizeable dividend (chapter 9).
* Because low income customers tend to place fewer demands on the network during peak periods than those on higher incomes, generalised time-based pricing would unwind the cross subsidies entailed in the current ‘average cost’ pricing regime, and thereby improve equity in the broad.

It is therefore unsurprising that many major players are supportive of such an approach — the NEM policy maker (the AEMC) and all peak industry bodies representing the supply chain (the Electricity Network Association, the Energy Retailers Association and the Energy Supply Association). Consumer groups also acknowledge the benefits, though they want the risks managed for low-income consumers.

There will of course be many practical complexities and challenges in implementing widespread time-based pricing, not the least of which is ensuring that households and other consumers understand its implications and the means by which they adjust their power demands in response to it.

From a technical perspective, the absence of smart meters for households other than in Victoria suggests that an early focus could be on extending time-based pricing for industrial and commercial users. This would in fact provide a vehicle for ‘stress-testing’ the approaches employed and time for complementary reforms (chapter 12) to take effect, before extension of fully fledged time-based pricing to the household sector. The significant upfront cost of smart meters (chapter 9) further suggests that each roll out should be carefully coordinated and roll outs should focus initially on those segments of the household market where peak demand has the greatest impacts on network capacity requirements. (This would be consistent with the general thrust of draft recommendation 10.1 dealing with the roll out of smart meters.) But at the same time, there is little point in incurring the expense of installing smart meters and then waiting a long time before taking advantage of the opportunities they provide to much better signal the true costs of meeting critical peak demand in network pricing structures.

A further complicating factor is that the peakiness of demand, its duration and its timing vary geographically. Such differences should be reflected in a time-based pricing regime, though in a way that recognises the costs of introducing further complexity to tariff structures as well as the benefits. Scheme design and the surrounding regulatory architecture will also need to be cognisant of the role that retailers play (box 11.1) in translating time-based network charges into the prices customers face; and of any impacts of hedging by network operators and retailers in muting the degree of price differentiation evident to customers (chapter 12). And changes to the structure of network prices will also need to be compatible with controls on the overall level of returns earned by providers.

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| Box 11.1 The role of retailers |
| The price of electricity that is visible to households and businesses incorporates:   * charges for transmission and distribution network services, that are passed on to retailers * wholesale energy and risk management costs from the spot and contracts market * retail costs, including for customer procurement, billing services and a profit margin.   The retailer recovers these costs from customers.  As detailed in chapter 12, some barriers to competition and other factors might mute the incentives for retailers to reflect time-based differentiation in network charges in final electricity prices. Nonetheless, as discussed there, the Commission is confident that these incentives can be strengthened, such that time-based network charges would translate reasonably directly into the prices faced by many households and businesses.  This figure shows what pricing elements impact upon the retail market and then flow on to customers. |
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The upshot of such practical complexities and challenges is three-fold.

First, the goal should not be to achieve the ‘perfect’ scheme that accords with some highly stylised text book model. Rather it should be to develop a workable, and generally acceptable, approach that provides a means to avoid much of the unnecessary cost that is currently incurred when catering for critical peak load demand.

Second the real world complexities strongly suggest that the detailed knowledge of those at the coalface should be harnessed in determining the parameters of a pricing regime that would best meet this objective. In other words, the regime should be developed carefully from within — rather than being externally imposed at the outset.

Thirdly, and related to the previous two points, there needs to be a coherent, iterative and consultative implementation process — both to put the flesh on the bones and to:

* ensure an appropriate degree of gradualism that takes account not only of the most efficient way to progressively roll out smart meters and the need for trialling of specific pricing menus, but also of the potential for the current stock of aged appliances to constrain efficient demand responses to time-based prices
* facilitate coordinated action in various other related areas — for example, in regard to the licence conditions for distribution businesses and those parts of the National Electricity Rules that have implications for time-based pricing
* help bring all of the various stakeholders on board by providing assurance that the reforms would be workable and beneficial
* ensure that customers understand the implications for their electricity bills and how they can moderate the impacts of significantly higher charges during peak periods
* ensure that there are well designed, targeted, mechanisms in place to assist those vulnerable consumers who would be disadvantaged by the changes, (or, if warranted on equity grounds, others facing a very substantial additional burden, such as those located in more remote areas where the costs of meeting critical peak demand are very high.)

Indeed, the latter is likely to be especially critical. While time-based charging would almost certainly have some very positive equity benefits, along with technological impediments, concern about the impacts on a sub-set of consumers has seemingly been an important reason for the limited use of the approach to date in both Australia and overseas.

The remainder of this chapter is concerned with mapping out in more detail how this process should unfold in regard to distribution businesses and some of the key requirements it should meet. Complementary (though somewhat different) pricing reforms for transmission networks are considered in chapter 18.

Finally, it is important to note that implementation of robust time-based pricing would not obviate the need to consider non-price options for helping to manage demand. For instance, the extension of load management schemes to harness the demand management potential of large businesses and industrial users could offer immediate benefits that are worth capturing — as noted in chapter 9, this option is being examined in a separate AEMC review.

## 2 How do distribution businesses currently price?

The National Electricity Rules require that distribution businesses recover approved revenue in excess of marginal costs in the least distortionary way possible.

However, as noted earlier, rarely are the costs of meeting ‘peak’ demand (box 11.2 for some definitions) well reflected in the network charges paid by households in particular. Pricing to reflect critical peak demand costs has been restricted to trial settings and any time of use (TOU) tariffs that are in place are typically much flatter than would be required to signal the escalation in network costs that occurs during critical peaks. Also, though charges for industrial and commercial users that incorporate a cost reflective peak and/or critical peak component — and sometimes other peak capacity charges — are becoming more evident, they are still not very widespread. The upshot is that distribution businesses recoup a high and excessive (AEMC 2012, p. 21) proportion of their fixed costs from non-peak usage charges (box 11.3).

This feature of distribution pricing structures appears to be driven heavily by an equity objective — and an underlying assumption that low-use (household) consumers are often low income. Several factors may help to explain this emphasis:

* State-owned distribution businesses are legally required to pursue certain social and equity obligations, and some refer to that motive in their pricing proposals.
* Now privately owned distribution businesses may still retain a public sector ethos — or legacies from the more direct controls that applied when they were government owned — that encourages ‘simple and fair’ pricing. (Some participants have informally asserted this.)
* Although state governments no longer regulate distribution revenues, they continue to set licence conditions and, therefore, have a pervasive influence on those businesses’ activities. Some privately owned distributors claim to be influenced by unwritten ‘guidance’ from jurisdictional governments, backed by the potential to write conditions into licence agreements or to restrict other aspects of commercial activity, if businesses do not fall into line.

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| Box 11.2 Some terminology relevant to discussions of peak demand |
| Terminology in this area is often confusing, ambiguous or overlapping. Accordingly, the meaning behind some commonly used terms is detailed below.   * *Time based pricing/dynamic pricing/time dependent pricing* — terms often used interchangeably to refer to prices that vary over time. The usually relevant time dimension is hours, but prices may also vary from season to season or from weekday to weekend. * *Cost-reflective pricing* of the network — requires that prices signal the underlying costs of supply at the time of consumption. This requires that a peak period be defined sufficiently narrowly to ensure that the costs of peak capacity are recovered from consumption driving such investment. * *Time of Use (TOU) tariffs* — a specific price structure where the day is divided into two to three consumption periods — ‘peak’ and ‘non-peak’ and sometimes ‘shoulder’ periods. A TOU tariff may additionally vary from season to season, depending on whether summer or winter peaks are more common. A feature of such tariffs is that the difference between peak and non-peak charges is not normally very large. This is because the ‘peak’ period tends to be very broad, with anything from 1000 to 3000 ‘peak’ hours over a year. The peak consumption in the NEM that drives significant additional network investment is much more short-lived — as few as 40 or so hours a year. Hence, the ‘peak’ price under a TOU tariff does not relate well to, or serve to reduce, the more intense peak consumption that is of concern in the NEM from a network investment perspective. * *Critical Peak Price (CPP)* — a type of peak network price that is applied very narrowly to signal when demand is very high and supply very tight. A CPP is applied when a critical peak event is declared by a distributor. Where they have been applied for industrial or commercial users, it has usually been for a 2 to 6 hour window on 5 to 10 days per year. To assist the demand response and to avoid ‘bill shock’, customers are normally notified the day ahead of such an event and reminded 2 hours prior to commencement. Where applied, CPPs have been set to reflect the full cost (see below) of meeting a customer’s peak demand. * *Peak capacity charge* — a charge for drawing on the network at a particular point in time (or, in the absence of a capacity meter, during a particular half hour). When applied to a very narrow peak, it is effectively a CPP (though in some cases ‘peak’ capacity charges have potentially applied to business users for over 3000 hours per year). The targeted peak may be related to an individual customer’s maximum demand, maximum demand at a substation, or the times of system peaks.   *Peak charges based on Long Run Marginal Cost* (LRMC) — the components of an overall tariff that reflect the marginal cost of supplying peak capacity over a period which is sufficiently long to make all network and other costs variable. |
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The ‘moratorium’ on time-based network pricing in Victoria is one such example of the latter, with its implementation more akin to a ‘gentlemen’s agreement’ unsupported by any specific written direction. Instances of more explicit directions include the South Australian legislation setting out derogations from the Rules for the 2010 distribution determination, and requiring that fixed supply charges not increase by more than $10 per year. Similarly, in 2011, the Queensland Government directed its state-owned distribution businesses, Energex and Ergon Energy, not to pass on nearly $100 million of approved additional revenue, consequent on a review by the Australian Competition Tribunal of a parameter involved in determining the companies’ cost of capital. The Government indicated that, as the owner of the two companies, it would accept a lower rate of return on its equity.

To the extent that lower use consumers tend to have lower incomes, then shifting fixed costs into off-peak variable charges improves ‘vertical’ equity (the gap between rich and poor). In doing so, however, it creates scope for ‘horizontal’ inequities, as relatively low users (whether low or high income) are cross subsidised by people on the same income who are heavier users (and who therefore pay more due to the artificial inflation of the variable off-peak price). Taken together with the previously noted equity concern that the lack of time of use pricing may in an aggregate sense disadvantage low-income consumers, the collective equity impact of the current distribution network pricing regime is far from clear.

Importantly, equity objectives could be much more certainly pursued through instruments targeted explicitly and transparently at the needs of vulnerable (or otherwise unreasonably disadvantaged) consumers — such as through government-funded rebates for those who would otherwise face difficulty meeting electricity costs (or the fixed cost of a smart meter — chapter 10). Separately addressing legitimate needs of this nature would in turn mean that time-based pricing options (and other pricing reforms) could be examined through an efficiency lens, without the complicating and potentially confounding intrusion of equity considerations. Addressing equity issues as part of the pricing reform process — including the implications for the National Electricity Rules and the licensing of distribution businesses — is discussed in more detail in section 11.3.

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| Box 11.3 How are peak network costs currently recovered in charges? |
| A significant part of the total revenues earned by Victorian and New South Wales distribution businesses is recovered through non-peak usage charges (between 40–66 per cent), with smaller proportions recouped from peak period and fixed charges. Moreover, capacity charges are mainly applied to large business users and, with ‘peak’ period ‘time of use’ tariffs far from universal across the household sector, for households the reliance on non-peak usage charges is higher again.  However, Ausgrid has recently sought to rebalance its tariffs, increasing the proportion of its revenue recovered through fixed charges and peak energy charges (Ausgrid 2012). Also, while its forecast revenue from capacity charges is projected to be much the same as in the 2008-09 to 2012-13 regulatory control period, there has been rebalancing of these charges across the customer base. A program to replace household accumulation meters with interval meters has assisted Ausgrid to rebalance their tariffs.  Revenue recovered by tariff component  Per cent, by NSW and Victorian distribution network service providersa  Revenue recovered by tariff component. This figure shows the percentage of the total distribution network tariff made up by non-peak energy, peak energy, fixed and capacity charges, in selected distribution businesses in New South Wales, across all Victoria and for Energex in Queensland.  a Ausgrid, Essential and Endeavour Energy and Energex are based on forecast 2012-13 revenues, while Victorian distribution network service providers’ revenues are based on 2010 revenues. Capacity charges apply to parties — mainly large businesses — that place a sufficient volt-ampere (VA) loading on the network infrastructure (which may require particular substation capacities). |
| *Source*: AER (2012); Ausgrid (2012); Energex Pers. Comm. |
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#### Do the National Electricity Rules facilitate time-based and other efficient pricing approaches?

Principles and requirements for determining network prices are set out in Clause 6.18 of the Rules. The content and wording of the clause provides both the scope and encouragement for distribution businesses to adopt efficient pricing regimes. Moreover, in assessing the pricing proposals of distribution businesses, the Australian Energy Regulator (AER) can pursue changes to non-compliant proposals.

However, as the current pattern of distribution network charges exemplifies, the existence of this clause has not precluded substantial divergences from efficient pricing approaches. Most notably, while sub-clause 6.18.5(b)(1) refers directly to Long Run Marginal Cost, it indicates only that businesses ‘must take [the concept] into account’ in deciding tariffs or charging parameters. The legal convention is that ‘take into account’ is a weak condition, even when preceded by ‘must’. The AER echoed this view, claiming that:

… the requirement to ‘take into account LRMC’ is very broad and provides limited scope for enforcement… (AER 2012a, p. 17)

A further more specific illustration is the seeming lack of discipline in the Rules on inefficient cross subsidies. Clause 6.18.5(a) requires that expected network revenue from each tariff class — a grouping of customers with similar consumption requirements and traits[[2]](#footnote-2) and for which a distribution business faces a collective revenue constraint — lies between the avoidable and stand alone costs. In essence, the former represents the cost savings from not serving a particular tariff class assuming all other services continued to be provided; while the latter represents the much higher cost that would be entailed in serving the customers concerned through a dedicated set of assets. Unsurprisingly given the economies of scale and scope that characterise distribution, there is a large divergence between these lower and upper cost bounds. This means that within an overall revenue constraint, a wide mix of charging structures that potentially bear little resemblance to the true costs of supply will be compliant with the rules (table 11.1).

Table 11.1 Some estimates of distribution network costs and charges

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| --- | --- | --- | --- | --- |
| Business | Tariff classa | Standalone cost | Avoidable cost | Tariff revenue |
|  |  | $m annual | $m annual | $m annual |
| ETSA (2012-13) | Major business | 75 | 4 | 12 |
|  | HV business | 84 | 3 | 36 |
|  | LV business | 386 | 71 | 330 |
|  | LV residential | 524 | 208 | 401 |
| ETSA (2010-11) | Major business | 72 | 4 | 9 |
|  | HV business | 80 | 3 | 25 |
|  | LV business | 367 | 67 | 247 |
|  | LV residential | 499 | 198 | 303 |
| Ausgrid (2012-13) | Sub-transmission | 202 | 4 | 6 |
|  | HV business | 558 | 6 | 49 |
|  | LV business and residential | 2129 | 263 | 2047 |
| Ausgrid (2010-11) | Sub-transmission | 598 | 3 | 5 |
|  | HV business | 880 | 5 | 38 |
|  | LV business | 1384 | 58 | 672 |
|  | LV residential | 1405 | 178 | 745 |

aSub-transmission is 33kV and above, HV is high voltage (nominally 5 -22kV), LV is low voltage.

*Sources*: ETSA Utilities (2010a, pp. 59; 2012a, p. 66); Ausgrid (2010c, pp. 44; 2012b, p. 34).

In making this observation, the Commission is not suggesting that the notion that prices should lie between avoidable and stand alone costs is of itself flawed. Rather, it is simply observing that the very large divergence between the two cost parameters negates any use this clause might otherwise play in compensating for the relatively weak nature of Clause 6.18.5(b)(1). Therefore, as discussed in section 11.3, the Commission considers that a tightening of Clause 6.18.5(b)(1) would be helpful in facilitating time-based pricing for distribution networks (as well as to support some other efficiency enhancing pricing reform).

## 3 Implementing time-based pricing

As noted at the outset of the chapter, the real world complexities of designing and implementing time-based pricing for distribution network services point to the need for a coherent, iterative and consultative implementation process — and one which harnesses the detailed knowledge of those at the coalface.

Given this, the Commission has focussed its attention on setting out some key requirements for that process to be effective and appropriately gradual, rather than trying to prescribe in advance what sort of detailed time-based tariff structures would be appropriate. The Commission’s expectation, based on time-based pricing regimes for industrial and commercial users (box 11.4), is that network prices would be low for most hours of the day and most days of the year, but would ramp up considerably for relatively short, critical peak demand events (such as a heatwave) that impose large costs on the system. Peak periods could also be defined more routinely (on a day-to-day basis, but, if so, the peak price would be considerably less than that at critical peaks).

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| Box 11.4 Time based pricing regimes for industrial and commercial customers |
| Current time-based pricing regimes for a relatively small number of larger industrial and commercial customers provide one indication of the sorts of tariff structures that might emerge where time-based pricing extended to othSP Aer customers, including households.  SP Ausnet’s critical peak tariffs for businesses apply from 2 pm to 6 pm on a maximum of 5 days across the December to March period. These charges are uniform across the network, but vary across business customer classes from $1.20 to $3.20 per kWh (or more)[[3]](#footnote-3), compared to normal peak charges of 0.2 cents to 7.6 cents per kWh and off peak usage charges of 0.1 cents to 2.13 cents per kWh. SP-Ausnet uses long range weather forecasts to signal the likelihood of a critical peak day a week in advance, and gives one day’s formal notice that critical peak event tariffs will apply.  While these schedules highlight that robust time-based pricing would involve some steep but short-lived price spikes (balanced by offsetting lower prices during other periods), considerable caution is required in extrapolating likely time-based tariff structures for households from what currently happens for some larger industrial and commercial customers., The different demand traits of household customers — and the additional degrees of freedom in setting time-based tariffs (within an overall revenue constraint) when all or most customers are in the net — are two considerations here. The important point is that it would be distribution businesses in consultation with the regulator, retailers and customers who would be best placed to determine what structures would be most appropriate. |
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However, it is the businesses that know their networks best and who (especially with the installation of smart meters) could quickly see how electricity consumers were responding to any particular tariff structure. It is therefore these businesses (in consultation with the regulator, retailers and customers) — and not an external party like the Productivity Commission — that should have responsibility for formulating detailed tariff structures, and iterations in them over time.

Importantly, this does not amount to giving distribution businesses carte blanche to gouge consumers under the guise of time-based pricing. As at present, tariff structures would still sit within an overall revenue constraint. The Commission is also proposing specific rule changes to ensure that the peak demand forecasts that bear upon revenue resets make appropriate allowance for the likely demand responses to time-based pricing (draft recommendation 11.4).

Likewise, giving those at the coalface responsibility for developing detailed time-based pricing structures is not to throw vulnerable consumers to the wind. As noted earlier, because low income or otherwise vulnerable consumers tend to be relatively low users of power at peak times, many would in fact be made better off by the rebalancing of prices under a time-based charging regime. And, as previously noted, to cater for those vulnerable consumers who would be materially worse off, the Commission is proposing specific, targeted compensation (see draft recommendation 11.6).

### LRMC as the underlying basis for time-based network charges

While the Commission has not sought to prescribe in great detail what efficient time-based prices might look like, it is important that the broad basis for such prices is conducive to meeting the underlying objective — namely, achieving a reasonable alignment between the benefits and costs of distribution services at all times of the day and year. In the Commission’s view, and consistent with a wide body of economic and other opinion, this basis should be some measure of the LRMC of meeting peaks in demand.

In reaching this position, the Commission has been cognisant of the practical challenges in calculating LRMC, including current deficiencies in the data, and the fact that augmentations to network capacity are typically lumpy (see below). However, these are not insurmountable, and even proxies for LRMC are likely to provide a basis for prices that much better signal the true costs of meeting peak demand, than do the prices currently charged to most customers.

#### Unpacking the concept of LRMC

While the current Rules make provision for the use of LRMC, they provide little guidance on what it implies for time-based pricing of peak demand (or for other pricing purposes), or how it should be computed.

In essence, LRMC is the marginal cost of supplying a good or service over a period which is sufficiently long to make all costs variable. Hence, for a distribution network, it includes the cost of any additional infrastructure required to meet (a marginal increment in) demand. This feature is critical in setting prices that will:

* help to ensure that the overall value that customers collectively place on network augmentations to cater for peak demand — and hence their willingness to pay — exceeds the cost
* provide appropriate incentives for customers to economise, where feasible, on their use of power at peak times.

The latter in turn offers scope for major savings from deferring expensive new investment to meet typically short lived peaks in demand.[[4]](#footnote-4)

As alluded to above, proxies for LRMC will sometimes be required. A case in point is the use of so-called Long Run Incremental Cost (LRIC) in circumstances where network investment is lumpy[[5]](#footnote-5). In this context, LRIC is essentially the cost of the minimum physically and economically viable network ugrade. In other words, it is still a measure of LRMC, though one that takes account of the realities of how network augmentation must and does proceed.

Also, and contrary to perceptions in some quarters, predicating time-based charges on estimates of LRMC that are sufficiently forward-looking[[6]](#footnote-6) is unlikely, of itself, to lead to undue volatility in electricity prices. This is more a problem that relates to short run marginal cost pricing in circumstances where high fixed costs have to be recouped at the point in the investment cycle.[[7]](#footnote-7)

LRMC, once computed, could be encompassed in charges in a variety of different ways — including volumetric charges, access charges, charges linked to a customer’s maximum demand, and targeted charges based on particular demands placed on particular parts of the network (such as a localised substation, neighbourhood feeder, sub transmission line, transformer or even interconnector). The precise nature and combination of these is again a matter for distribution businesses (in consultation with affected parties).

However, if LRMC pricing is to play an effective role in managing and moderating peak load demand, then the tariff structure must have a significant time-based component. The Commission’s expectation is therefore that pricing proposals submitted to the regulator would involve significant and appropriate use of critical peak prices and (especially for businesses) peak capacity charges.

#### Issues related to the geographic differentiation of LRMC

The costs of meeting peak load demand and of augmenting the distribution network vary considerably across different locations. Significant differences of this nature should ideally be reflected in an efficient time-based pricing regime. As AEMC (2012) observed in its *Power of Choice Review*:

[Distribution businesses] have to ensure they provide sufficient capacity to meet demand in every part of their network, so differing demand patterns in different locations can have a substantial impact on costs. (pp. 63–4)

Where the network costs of supplying customers differs by location, the network tariff should likewise vary by location. (p. 206)

In this context, it is important to recognise that the peakiness of demand and the timing and duration of those peaks varies by location. Hence, an otherwise efficient time-based pricing regime that does not make provision for such variations will not capture all of the benefits potentially on offer. While the Commission has not been able to source comprehensive data on the nature and significance of localised network peaks, it has been told by distribution businesses that there is considerable variation. For example:

* in the outer suburbs of a large city, peaks may occur slightly earlier or later than in inner suburbs, largely reflecting differences in commuting distances
* in an area of the network with a high share of dairy farms, peaks tend to be early in the morning
* at a more aggregated regional level, peaks depend on the season.

The latter observation is supported by AEMC data showing that peaks are typically in summer in South Australia, Victoria, Queensland and NSW, and over winter in Tasmania (chapter 9).

Again, the precise way in which significant geographical differences in costs related to peak demand should be encompassed in time-based prices is a matter for DNSPs, the regulator and their customers. However, at a broad level, the Commission’s expectation is that any geographic component of a time-based charge for access to the distribution network would reflect significant differences in:

* the rate of growth in peak demand and the timing of network peaks within discrete locations of the network
* the location of end users relative to generation sources and hence their call on distribution poles and wires during times of congestion
* the location-specific costs of expanding the network.

The Commission recognises that significant geographic differentiation in time-based charges could exacerbate equity concerns about the approach in the broad. However, most of these concerns could be addressed as part of the more general protection to be provided for vulnerable consumers (see draft recommendation 11.6). And though it is not clear why on equity grounds support should go beyond this vulnerable group, Governments could choose to provide more general assistance for all consumers in any areas where time-based pricing led to large increases in electricity bills. Like support for vulnerable consumers, any such support should be transparent and delivered efficiently (see below).

#### How good is the current information on LRMCs?

Accurately estimating LRMCs (or LRICs) in the distribution sector is intrinsically challenging. As SP AusNet observed:

… the long-run marginal costs of consumption are in a state of constant flux, and are affected by short and long-run factors, they are reliant on accurate consumption forecasts, accurate costing of capital and labour costs, accurate knowledge of the timing of required capital investment costs and perfect information of future technological advances. (SP AusNet 2012)

Moreover, network investments are not just related to peak load growth (or options to cost-effectively manage demand). The need to replace ageing assets, or to address externally imposed reliability requirements, are but two examples of other investment drivers. Indeed, because of economies of scope, investments will often have more than one objective. In these circumstances[[8]](#footnote-8), the LRMC related to the peak demand component would need to be apportioned.

In this environment and within a system that has not been oriented to time-based pricing, DNSPs have tended to use compromised forms of LRMC for setting charges, which usually straddle a mix of marginal and average cost concepts. And as Turvey (2000, p. 26) has previously noted, data on maximum demands at different points in the distribution network — which might be used to geographically differentiate time-based charges — is lacking.

There are some published estimates of LRMCs relating more directly to peak demand. (see, for example, Colebourne 2010, ETSA 2012). However, they are clearly early work in progress and would be at best a starting point for calibrating the LRMCs necessary to implement a robust time-based pricing regime.

In the face of the current data deficiencies and the intrinsic difficulties of assembling such data, some might argue that trying to predicate a time-based charging regime on LRMC is simply too hard.

Yet there is widespread agreement that prices for electricity should play a much stronger role in managing demand. In moving from a system in which the need to collect, and the means to collect, time-focused cost data have been relatively limited, it is inevitable that new data will need to be assembled. And if this is the case, then the Commission sees no reason why the data effort should not target LRMC — the most appropriate basis for underpinning time base charging designed to deliver more efficient consumption and investment outcomes. As discussed below, the data that becomes available as a result of the much more widespread use of smart meters (draft recommendation 10.1) should be helpful in this regard.

#### Some related demand forecasting issues

Forecasts of peak (or maximum) demand are integral to the network planning and revenue determination process, and thereby to the timing and scale of network augmentations and the prices paid by consumers.

A phased introduction of time-based pricing will increase the complexity of the AER’s task in this area. Specifically, there will be a need for forward looking adjustments that take account of the potential reductions in demand from more cost reflective prices at peak times, and the consequences for efficient levels of new investment and the revenues required to support them. As alluded to earlier, the Commission is proposing specific rule changes to give effect to this requirement (see draft recommendation 11.4).

This added dimension to the revenue determination process could, if undertaken well, provide a potentially powerful spur for DNSPs to implement efficient time-based pricing. That is, a distributor which did not implement time-based pricing to the degree provided for in the determination could expect to experience a revenue shortfall over the regulatory period.

There would also presumably be a concomitant financial incentive for distributors to invest in collecting and assembling data that would, over time, enhance the sophistication of estimates of the LRMCs of meeting peak demand. As well as benefiting distributors, through revelation via prices, it would assist the AER to progressively improve its demand forecasts. Indeed, this could be seen as a form of benchmarking — though one which targeted allocative efficiency by establishing a LRMC price benchmark, rather than technical efficiency which is the more usual focus of benchmarking exercises.

This interactive and iterative process would not, of course, eliminate the scope for errors in this component of the demand forecasts used by the AER in its revenue determinations[[9]](#footnote-9). Hence, there would be value in the AER improving its forecasting capacity, especially in regard to the price responsiveness of different groups of consumers at peak times. The progressive roll out of smart meters would help here — improving the quality of data on maximum loads across networks, allowing better identification of localised network constraints, and indicating the feasibility of reducing peak loads through pricing and other load management or distributed generation approaches. So too would the proposed increase in the innovation allowance for distribution businesses to fund trials of new time-based tariff structures and calculate demand elasticities (chapter 12). Indeed, trialling of new tariff structures, and carefully assessing their results, should be a key part of the process for progressively moving towards a robust time-based pricing regime (see below).

#### Defining ‘peak’ demand

While the broad concept of peak demand is a relatively simple one, there are currently various obstacles to giving it appropriate effect within a time-based pricing structure.

At a high level, time-based prices will only do their job well if the definition of the peaks that underpin those prices is a good reflection of the actual peakiness of demand — demand that drives investment in additional network capacity. There is general agreement that current ‘time-of-use’ tariffs generally apply ‘peak’ periods much too broadly (and or frequently) to materially moderate peak network demand and the investment burden that comes with it.

However, as stakeholders’ differing expressions of the duration and frequency of peak demand exemplifies, there is no clear consensus on precisely how peak, and more particularly critical peak, demand should be defined. The fact that the frequency, duration and significance of peaks varies by location adds further to the definitional difficulty. Also, the demand response of customers to time-based pricing is explicitly intended to moderate peaks, as some customers economise on power or shift their consumption to non-peak periods. Hence, the definition of the peaks cannot be set solely on the basis of the current demand environment.

Given these complexities, the Commission has not sought to specify how peak demand should be defined within a time-based pricing regime. This again is a matter that should be determined by distributors in consultation with the other relevant stakeholders as part of the implementation process — though the Commission reiterates that peak period charges should be much more targeted to actual demand peaks than at present. As well as efficacy in meeting this targeting requirement, some key considerations in regard to definitions include:

* the capacity to translate definitions into relatively simple and understandable time-based tariff structures that facilitate the desired demand management approach
* the need to consider the costs and confusion that inevitably accompany changes in definitions.

The implication of the latter is that implementation of potential improvements in definitions (and hence tariff regimes) identified as experience with time-based pricing increases may need to delayed. In other words, the usual cost-benefit trade-off should apply.

#### Some bottom lines on the use of LRMC pricing

The Commission recognises that, especially in the near term, there would be practical difficulties in operationalising widespread time-based pricing for distribution networks predicated on LRMC. In addition, lots of other things would have to happen elsewhere in the system to ensure that the pricing regime was well configured to meet the underlying demand management and investment objectives (see below).

Nevertheless, the Commission reiterates that it does not see these difficulties as insurmountable. The collection of better data, facilitated by the progressive roll out of smart meters, would ameliorate many of these difficulties. As would ongoing engagement between network businesses, retailers, customer representatives, the AER and State and Territory Governments on the means of iterating to a robust time-based charging regime. These considerations are reflected in specific recommendations below.

As discussed above, data issues and other considerations such as the lumpiness of network augmentation will have implications for how closely estimates of LRMC approach the conceptual ideal. But this would be no different from other markets where time-based pricing applies.

More importantly, a system that pays greater heed to the LRMC of meeting peak demand, and sets prices accordingly, would be a significant improvement on the current approach where these peak-related costs are spread across the tariff structure and therefore largely hidden from consumers. Put simply, if prices are to perform a role in managing demand and reducing the need to invest in additional network capacity, they must be considerably better targeted.

### Facilitating an effective implementation process

#### Provision for external oversight

The general case for introducing time-based pricing for distribution networks cannot reasonably be disputed. Nor, in the Commission’s view, is there any need to debate the underpinning basis for such pricing — it should be the LRMC of meeting peak demand. So the task ahead is to move as quickly and as a smoothly to this end point as is possible given the various detailed matters that have to be resolved, and the complementary changes that have to be made elsewhere in the system. The latter include:

* progressive and coordinated roll outs of smart meters which, in some parts of the NEM, may not occur for a number of years (chapter 10). Without the provision of real-time information to network businesses, people cannot be charged time-based prices
* improvements to the incentive regulation regime to overcome biases against demand management and hence to move to time-based pricing (chapter 5)
* wider use of weighted average price caps to further enhance the incentives for distribution businesses to price efficiently (chapter 12)
* removal of retail price regulation that would otherwise frustrate time-based pricing and stifle retail competition and innovation (chapter 12), and their replacement with targeted and transparent means of support for vulnerable consumers
* addressing the potential for reliability and network planning requirements to over-ride customer preferences and hence the strength of the demand management impact of time-based pricing (chapters 14-16).

There must also be arrangements in place to provide consumers with advance warning that critical peak prices are to be applied and thereby with the opportunity to adjust their power consumption. In some cases, people might request that the distribution business or retailer control their key power-using appliances — mainly air-conditioning — during these peak hours (‘direct load control’ (chapter 10)).

The Commission envisages that much of the necessary development work will occur within distribution businesses and the AER — including in regard to the methodologies for estimating LRMC and future demand within a time-based regime, supporting data collection, definitions of peak demand, and the options for translating all of this into network charges. Indeed, with a commitment to the introduction of time-based pricing and changes to the Rules that would penalise distribution businesses that do not take reasonable steps along this path (see below), businesses would have a strong commercial incentive to pursue necessary development work.

Distribution businesses and the AER would obviously need to consult on an ongoing basis. And both would need to engage with other key stakeholders during the process (including retailers, customer representatives and, through SCER, State and Territory governments).

The Commission is proposing some mandatory requirements in regard to engagement by DNSPs and retailers with their customers (draft recommendation 11.8). But these relate to the actual introduction of time-based network prices (and smart meter technology for households), not to the prior developmental work. For this earlier stage of the process, consultation on an ‘as needs’, discretionary, basis would be most appropriate.

The Commission does, however, see the need for some external discipline on the development and implementation process. Given the complexities of the task, the many other changes in the system that have to occur, and the likely aversion of some stakeholders to moving expeditiously to time-based pricing, it is easy to see how the process could stall. Therefore, giving a suitably authoritative and knowledgeable external body responsibility for driving the process could be extremely helpful. Amongst other things, that body could establish realistic reform milestones and timelines, oversight progress against those timelines and, if required, bring stakeholders together to resolve specific road blocks or unduly slow progress in the broad. This would be akin to the valuable oversighting role that CoAG has played on a variety of major national reforms.

Indeed, the Commission considers that one of the CoAG family — the Standing Council on Energy and Resources (SCER) — would be well suited to this task. It has responsibility for pursuing priority issues of national significance in the energy and resources sectors. Among its specific functions are to facilitate national oversight and coordination of governance, policy development and program management in these sectors; provide national leadership on key strategic issues; and enhance national consistency between regulatory frameworks — all of which would fit well with a responsibility for driving the implementation of time-based pricing. However, in performing this oversighting task, it is important that SCER avoids prescriptive approaches that are not underpinned by a thorough assessment of benefits and costs.

Draft recommendation 11.1

***The Standing Council on Energy and Resources should be tasked with overseeing the progressive implementation of cost-reflective, time-based pricing for electricity distribution network services, predicated on the long run marginal costs of meeting peak demand. Amongst other things, the Council should:***

* ***following consultation with key stakeholders, set timelines for the various steps in the development and implementation process, having regard to:***
* ***the Commission’s specific proposals in relation to this process (draft recommendations 11.2 to 11.7)***
* ***progress in making necessary changes elsewhere in the system***
* ***monitor compliance with those timelines***
* ***address any areas where greater engagement between key stakeholders (distribution businesses, retailers, state and territory governments, the Australian Energy Regulator and customer representatives) would assist the expeditious implementation of the new pricing regime***
* ***if and as necessary, take specific steps to address implementation delays.***

The Commission has also identified some more specific changes that would contribute to the implementation of an efficient and sustainable time-based pricing regime. (Complementary reforms, that would help ensure that time-based pricing provides a significant dividend, are discussed in chapter 12).

#### An NEM-wide licensing regime for network providers

One specific step that could be taken reasonably quickly to facilitate the implementation of time-based pricing for the distribution network would be to establish a single set of licence requirements for all network providers operating in the NEM. Such a change would of course have wider benefits — including for the transmission component of the NEM and by assisting the introduction of:

* an NEM-wide reliability framework (chapter 14)
* a common and efficient approach across jurisdictions to the provision of assistance to vulnerable consumers (see below).

More specifically — and in combination with making the AER responsible for enforcement — a NEM-wide licensing regime would reduce the risk that the pursuit of non-efficiency objectives by state and territory governments could frustrate the introduction of cost reflective, time-based pricing.

In making this observation, the Commission is not questioning the right of jurisdictions to pursue equity and other non-efficiency related objectives linked to the provision of electricity services. But in the past, this has sometimes occurred in ways that have been inimical to the longer term interests of consumers overall and the wider community. One example is the implementation of reliability standards where the benefits for consumers (as reflected in their willingness to pay) are seemingly considerably less than the costs involved in upgrading networks (chapter 14). And of more direct relevance to time-based pricing are the previously discussed instances of jurisdictional governments intervening implicitly or explicitly to modify charging regimes for equity reasons. This is in conflict with the principle that has been endorsed by all Australian governments that support for low income or otherwise disadvantaged consumers should be provided through targeted and transparent instruments.

While individual state and territory governments retain discretion over the licensing requirements for network businesses in their jurisdictions, there remains a risk of actions that would be prejudicial to the efficient implementation of time-based pricing. Indeed, in this context, the shift in responsibility for enforcing compliance with licence conditions to the AER is no less important than a move to common requirements — particularly in jurisdictions where governments also own the network providers.

Against this backdrop, the Commission is proposing that a single set of NEM-wide licensing requirements replace the current state and territory provisions, with these new requirements being incorporated in the Rules.

These common requirements should be developed by state and territory governments under the auspices of the SCER. Importantly, the Commission’s expectation is that a robust and transparent process (similar to the use of a Regulatory Impact Statement) would inform the development process to minimise the possibility that there would be gravitation towards the most stringent (and costly) jurisdictional provisions in each area. The Commission further notes that the development of aspects of these new requirements might sensibly be tasked to the AEMC, who could undertake a framework review to assist the process of developing national conditions. It is also important that jurisdiction-specific licence conditions are only included where the framework review (which would effectively act as a regulatory impact statement) can demonstrate a clear and cogent basis for such divergence.

While the AER would be responsible for enforcement of the new licence conditions, it could sensibly seek advice on technical issues from the AEMO or state-level regulators. Provision could also be made for the AER to delegate responsibility for assessing compliance with particular licence conditions to an independent jurisdictional regulator, but not to a state or territory government.

The Commission has not sought to identify all of the particular matters that should be encompassed in the new licensing regime. However, reliability, the provision of assistance to disadvantaged customers or any requirements to provide non-commercial services, and technical standards and safety requirements would be some of the matters to be addressed.

Below, the Commission has made some specific proposals relating to those consumers requiring support to meet higher bills following the introduction of time-based pricing, or to help pay for the cost of smart meters. Suffice to say at this point that the criteria governing that support — or support provided through the provision of non-commercial services — should be explicit in the new licensing requirements. Additionally, the requirements should specify how such community service obligations are to be financed (see below).

The Commission notes that preparatory work would have to occur to develop national criteria that identify customers in need of support and a uniform approach to funding that assistance. This should not delay the development of national licence conditions. As such, until uniform criteria and sources of funding are developed, each state and territory government would continue to be responsible for targeted financial support to address the affordability of electricity.

draft Recommendation 11.2

The Standing Council on Energy and Resources should initiate a process to establish a uniform set of licence conditions for all transmission and distribution network businesses in the National Electricity Market. The Council should task the Australian Energy Market Commission to undertake a framework review to assist that process.

The development of a uniform set of licence conditions should have regard to the Commission’s proposed changes to the reliability framework (draft recommendations 15.1 and 16.1) and should not in any way conflict with, or impede, the implementation of that framework.

The uniform licence conditions should be included in the National Electricity Rules and replace the current state and territory licence conditions.

It may not be immediately feasible to develop standardised provisions governing technical standards and safety, though these should ultimately be encompassed in the national set of licence conditions.

The justification for any jurisdiction-specific conditions included in the new licensing regime should be clearly and cogently spelt out in the supporting framework review.

Before incorporation into national licence conditions, preparatory work would be needed to develop a common approach to the identification of customers in need of special support to meet their electricity bills or pay for smart meters (draft recommendation 11.6), but:

* pending agreement on appropriate national criteria and approaches to funding, each state and territory government should continue to be responsible for targeted financial support to address affordability.

The Australian Energy Regulator should be responsible for ensuring compliance with the new conditions and would have the authority to:

* issue and retract licences
* seek advice from relevant agencies on any technical matters relating to compliance assessment.

Provision could also be made in the Rules for the Australian Energy Regulator to delegate responsibility for assessing compliance with particular licence conditions to a relevant state-level regulator.

#### Tightening and augmenting aspects of the Rules

The Rules bearing on the use of LRMC for price setting are not emphatic about the desirability of using this benchmark, so much as permissive (section 11.2). The Commission’s assessment is that several clauses could weaken the discipline on DNSPs to employ the approach.[[10]](#footnote-10) However, the key clause in this regard is 6.18.5(b)(1) which, as noted earlier, requires only that LRMC be ‘taken into account’ when determining tariffs. This allows the AER to approve a tariff consistent with LRMC, but does not compel it to require that a business sets prices on this basis. Commenting on the current rules, the SCER noted that the way in which:

… the regulatory regime administered by the AER incentivises distributors to implement [efficient time-based] tariffs is unclear. Absent particular incentives to do so, there is no particular reason to expect that they will set tariffs in such a way to maximise the impact on peak demand, although nothing prevents them from doing so. (SCER 2011, p. 12)

While this vagueness in the Rules persists, it is unlikely that the AER could require adherence to genuine LRMC methodologies, putting at risk the transition to cost reflective, time-based, pricing — or at the very least detracting from the quality of the pricing regimes that emerge.

The timing of a rule change to address this problem would of course be dependent on progress in getting in place the many other preconditions to enable the commencement of time-based pricing. This timing might reasonably be the subject of discussions between stakeholders and the SCER as part of the latter’s proposed oversighting responsibility (see draft recommendation 11.1). But it is an important change to be made at some point. In essence, clause 6.18.5(b)(1) should require that time-based pricing be predicated on LRMC, with the task of the AER being to determine whether pricing proposals are reasonable from this perspective recognising the practical computational challenges.

At some point in the transition process, the rules governing the setting of tariff classes (clause 6.18.3(d)(1)) should also be tightened. As it currently stands, this clause refers to the need to group customers on an economically efficient basis, but again on a ‘have regard to’ rather than a ‘must’ basis. Also, it does not explicitly refer to the geographic dimension of efficiency in regard to the setting tariff classes — an omission which has the potential to impede variations in time-based prices across regions to reflect significant differences in the cost of meeting peak demand. The Commission is therefore proposing a remedial amendment to address these shortcomings.

Finally, the rules will also have to be amended to give the AER the power, when assessing pricing proposals, to consider whether a business’s forward peak demand forecasts make reasonable provision for the impacts of time-based pricing in constraining demand. Otherwise, the benefits of the approach in delaying or deferring investments in peak load capacity will be diminished or even lost. As an adjunct to this, and in keeping with the earlier discussion on these matters, the AER will need to develop its demand forecasting capacities.

Draft Recommendation 11.3

When the process of implementing cost-reflective, time-based prices for distribution network services is sufficiently advanced to reasonably allow for a tightening of relevant clauses in the National Electricity Rules:

* clause 6.18.5(b)(1) should be amended so as to ensure that time-based tariffs are determined by (rather than ‘take into account’) a reasonable estimate of the long run marginal cost for the service concerned
* clause 6.18.3(d)(1) should be amended so as:
* ***to ensure that the grouping of customers for the purposes of setting time-based tariffs is based on economic efficiency (rather than ‘having regard to’ it)***
* ***to make it explicit that significant differences in the long run marginal cost of meeting peak demand between locations and across customer groups should be reflected in network pricing structures.***

Draft Recommendation 11.4

When the process of implementing cost-reflective, time-based prices for distribution network services is suitably advanced, the requirements governing assessments by the Australian Energy Regulator of pricing proposals by distribution network service providers should be amended such that the regulator:

* can only approve a distribution business’s peak demand forecasts if they include reasonable forward estimates of the likely demand response to time-based pricing
* subject to the above condition, must approve any reasonable estimate by a distribution business of the long run marginal costs of meeting peak demand.

To support these changes, the Australian Energy Regulator should develop a capacity to model demand responsiveness to time-based pricing.

#### Guidelines to support methodological development and data collection

As discussed above, the Commission sees much of the responsibility for methodological development and data collection residing with DNSPs. Such development and data collection would in turn be informed and assisted by trials and experiments with time-based pricing as part of the phased implementation process (chapter 12). To support this testing process, the Commission is proposing an increase in the Innovation Allowance for distribution businesses (draft recommendation 12.2) — subject to the proviso that this additional revenue stream funds specific projects, developed in close cooperation with retailers, that shed light on:

* the responsiveness of customers to time-based prices and/or
* the means to introduce time-based pricing that would help to empower consumers to respond effectively and to minimise initial uncertainty and confusion.

The Commission also sees a potentially significant benefit in the AER developing guidelines on key methodological and definitional issues to underpin the operation of the new regime. The area in which guidelines would be most helpful would be the methodology for computing the LRMCs of meeting peak demand. Such guidelines might reasonably specify factors that should be included in the estimation of LRMC and an approved methodology or methodologies for that estimation (including, as previously noted, the use of LRIC for lumpy investment costs). For obvious reasons, the guidelines should be developed in consultation with network businesses and should not be overly prescriptive. This is an area where it is important that the AER remain open to the use of different approach depending on the particular circumstances of a network business. Indeed, the Commission’s expectation is that the guidelines would require iteration as experience with time-based pricing, and calculating the costs of peak demand, increased. The Commission further notes that a change in the current Rules would be required to enable the AER to publish guidelines of this nature.

The AER should also have the scope to publish binding guidelines about efficient tariff structures, the definition of network ‘peaks’ and associated critical peak pricing events. Establishing sound approaches in these areas at an early stage of the implementation process is likely to be very useful in buttressing the bona fides of time-based pricing as a means to curb peak demand and reduce network infrastructure needs. Again, however, it is important that any such guidelines be developed in consultation with relevant stakeholders, not be overly prescriptive and formulaic, and provide scope for iteration over time.

DRAFT RECOMMENDATION 11.5

Clause 6.2.8(a)(3) of the National Electricity Rules should be amended to:

* require the Australian Energy Regulator to publish guidelines on the methodology or methodologies that are appropriate for estimating the long‑run marginal costs of meeting peak demand, and the factors that should be encompassed in those estimates
* give the Australian Energy Regulator the authority to publish binding guidelines about efficient, time-based tariff structures, including definitions of ‘peak’ pricing events.

These guidelines should be developed in consultation with the relevant stakeholders and should be improved over time as the implementation of time-based pricing progresses.

The Commission further notes that the AEMC is currently evaluating a rule change proposal that includes a requirement for distribution businesses to publish an annual planning report covering the subsequent five years, with information provided at the sub-transmission, feeder and zone substation level. This could help to overcome some of the current gaps in the data relevant to estimating locational differences in the cost of meeting peak demand, and thereby to incorporating a geographical dimension in future time-based prices. (This proposed rule change, and the grounds for extending the required forecast beyond five years, are discussed in chapter 10.)

#### Addressing affordability and equity issues

##### The distributional effects of time-based pricing

In broad terms, cost reflective, time-based, pricing may see DNSPs recoup a significant proportion of their total revenue from those drawing on the system during peak demand periods. Other things being equal, they will then be less reliant on revenues from fixed charges and usage tariffs during non-peak periods. If this rebalancing is appropriately translated into retail electricity prices:

* those who continue to use large amounts of power at peak times will face considerably higher bills
* those who were already low users at peak times, or those willing and able to respond to the price incentive to economise on peak period consumption, will experience lower bills — or at least lesser increases.

As noted earlier, low-income households tend to be relatively low users of peak load power. Hence, as a group, they could well benefit from the removal of the current cross subsidies from those who put relatively small demands on the network at peak times to those whose demands are larger. In its recent submission to the Senate Select Committee Inquiry into Electricity Prices, the South Australian Council of Social Service (2012, p.16) said that:

* Low income households have less peaky demand because their houses are usually relatively small, air conditioning penetration is lower, and where airconditioners are fitted they tend to be smaller.
* As a result of this less peaky demand, the introduction of cost reflective retail and network pricing would see average bills for these households fall by 10 to 20 per cent — implying ‘that it is a reform worth pursuing.’

Even so, it is almost inevitable that some low income households, or otherwise vulnerable consumers, would be among those disadvantaged by the introduction of time-based pricing (and by the associated recoupment of the costs of smart meter installation).

##### The efficient pursuit of equity objectives

Equity as well as efficiency matters for community wellbeing. Hence, the Commission recognises that, in pursuit of equity objectives, governments may reasonably seek to intervene to improve the affordability of electricity services for some consumers — and by implication, the cost of the distribution network charges they incur.

However, such objectives can be achieved in a variety of ways, some of which are more efficient than others. Using the most efficient means to address genuine equity or hardship issues will minimise the costs imposed on those not in receipt of support, and thereby deliver a better outcome for the community as a whole.

The key here is to use measures that explicitly target vulnerable (or otherwise unreasonably disadvantaged) consumers. Indeed, as the Commission discussed in its recent report on urban water, targeted mechanisms are already employed for utility services (box 11.5). In contrast to cross subsidised usage charges, such targeted instruments do not lead to inefficient demand responses by consumers who do not require support. And if well designed, targeted support may also have relatively little impact on the demand responses of recipients.

As well as concessions and rebates, an appropriate suite of instruments for helping vulnerable consumers to accommodate time-based pricing might include targeted subsidies for demand response compatible air-conditioners, or for improving the thermal efficiency of their dwellings (chapter 10). These could be funded from general government revenue or a small increase in the fixed access charge. More broadly, there may be a case for some shift away from service-specific support to assistance via the Australian Government tax transfer system (see below).

Some other options that have been suggested would clearly be inappropriate.

* Exempting all low income groups from time-based prices, or making it optional for all consumers — as proposed in a recent report by Deloite (2012) for the Victorian Department of Primary Industries — would significantly negate or eliminate the sort of demand response that such prices are intended to induce. Thus in the latter case, those currently putting sizeable demands on the system at peak times would presumably opt to retain the inefficient, and often inequitable, subsidies they currently receive. In the former case, a blanket exclusion of low income consumers would deny many of them the savings that time-based pricing would otherwise bring.
* The same sorts of considerations also militate against completely eschewing geographic differentiation in time-based prices to assist vulnerable consumers in parts of the network where peak demand is expensive to meet. Indeed, appropriate and transparent price signals might be particularly valuable in high cost areas to encourage exploration of potentially more economical alternatives for meeting consumers’ needs at peak times, such as distributed generation (chapter 13). That said, the appropriate level of geographic differentiation and the way it should be introduced are complex matters on which the Commission is seeking further information (see below).

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| Box 11.5 Utility concessions and rebates |
| In addition to welfare measures provided by the Australian Government (and funding for concessions under the National Partnerships Agreement for utility concessions to pension card holders), state and territory governments provide a variety of concessions and rebates to households for their electricity and other utility services. Although administered by state and territory governments, eligibility for the latter tends to be linked to commonwealth concession cards, with over 5 million card holders (including 3.6 million Pensioner Concession Card holders).  Energy concessions and rebates are generally worth in the order of $200 to $400 a year to the recipient, although in Victoria the amount of assistance is determined as a percentage of the electricity bill (AEMC 2012, p. 23). Emergency payments may also be available through community welfare organisations. Such forms of assistance can be provided directly to a consumer as a rebate, or indirectly through their retailer as a discount on their electricity bill. As well as differences in value and form, eligibility requirements also vary across jurisdictions.  In its report on the urban water sector, the Commission (PC 2011c) analysed the role of concessions and rebates in addressing affordability issues for vulnerable consumers. It concluded that compared to delivery through cross-subsidised usage charges, these forms of assistance can better target those in genuine need and involve smaller costs to efficiency (see text). |
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##### Current arrangements for delivering support must be improved

In view of the potential for poorly configured support for vulnerable (or otherwise unreasonably disadvantaged) consumers to undermine the effectiveness of time-based pricing, the Commission considers that robust criteria for such support should be developed — and, as noted earlier, incorporated in the new NEM-wide licence conditions for network providers (see draft recommendation 11.2).

Ideally, eligibility criteria would principally target support at households who have both low income (or are otherwise financially vulnerable) *and* face inherently high supply costs. In practice, neither existing concession nor currently operational definitions of ‘vulnerable’ closely accord with these requirements.

More generally, as noted by Australia’s Future Tax System Review Panel (2009) and in the Commission’s urban water inquiry (2011c), current concessions:

* are utility specific, with a confusing array of assistance collectively available for essential services
* employ a range of approaches of varying effectiveness and administrative efficiency, and with differing impacts on economic efficiency and equity in the broad
* tend to treat holders of Pensioner Concession Cards (including aged pensioners) more favourably, despite some pensioners receiving higher incomes than other vulnerable groups.

But while the case to improve the delivery of financial assistance to households facing long term difficulty affording utility services appears a strong one, the best way forward is less clear — with the choice in reality being between imperfect alternatives.

Accordingly (and consistent with the Commission’s previous recommendation in its urban water inquiry), the Council of Australian Governments should, as soon as practicable, commission a review of all forms of assistance for utility services provided across all levels of government. That should include an assessment of whether the Australian Government tax and transfer system could deliver aspects of that support more equitably and efficiently. Based on the outcomes of this review, criteria for assistance for vulnerable consumers, and the means of funding that assistance, should then be written into the NEM-wide network licence conditions.

Delivery of electricity sector specific assistance would of course continue to be the responsibility of parties ‘downstream’ from network operators. However, inclusion of criteria in the licensing conditions would eliminate, or greatly reduce, the scope for jurisdictional governments to compromise the benefits of time basing pricing by pursuing equity or other social objectives through inefficient pricing impositions on network businesses.

draft RECOMMENDATION 11.6

The implementation of cost-reflective, time-based pricing for distribution network services should be accompanied by assistance for vulnerable consumers, which should target those who:

* are potentially exposed to large price increases and who do not have reasonable opportunities to switch their demand to non-peak periods
* will potentially face significant difficulty in meeting the charges used to recover the costs of smart meters.

The Standing Council on Energy and Resources should develop common criteria for identifying who should receive such assistance, and when it should be delivered through electricity specific mechanisms rather than through the Australian Government’s tax and transfer system. These criteria should be based on the outcomes of a review commissioned by the Council of Australian Governments of concessions for utility services across all levels of government (consistent with recommendation 8.1 of the Productivity Commission’s Urban Water Sector Inquiry report).

These criteria, and a commitment to transparent funding of the electricity sector-specific support should then be reflected in the new National Electricity Market-wide licence conditions for network businesses (draft recommendation 11.2).

### The nature of the transition to time-based pricing

The generalised use of time-based pricing for distribution network services is a large step and a big change from the past. While many customers will be winners, there will be some losers There will be adjustment costs for network businesses, retailers, their customers and the AER. And some important complementary initiatives are required. Accordingly, a carefully planned transition is essential, which involves appropriate engagement between the various stakeholders, and should take into account the costs of change.

As outlined above, the Commission is proposing that this transition process be oversighted and driven by the SCER (draft recommendation 11.1). Specifically the SCER would be responsible for setting timeliness for the various steps in that process, monitoring progress and, as necessary, taking action to address delays.

In the Commission’s view, a first and relatively easy step would be to extend cost reflective, time-based, pricing of the network to all large industrial and commercial customers. Such customers already have the required metering, with some already subject to prices that signal the much higher costs of meeting peak demand.

But for smaller businesses and households, the transition to time-based pricing is likely to take considerable time. Indeed, the Commission’s modelling indicates that, even putting adjustment costs to one side, a ‘big bang’ approach would most probably fail a cost-benefit test (chapter 9).

In considering what is required for an orderly and effective transition, it is worth reiterating the desired end point. Time based prices for distribution network services would most probably target around 40 to 80 critical peak hours a year, with retailers reflecting these prices in their tariff offerings to final customers. As discussed earlier, as well as requiring carefully coordinated roll outs of smart meters, this sort of pricing regime would also necessitate a number of other complementary changes. That includes cost-effective means to signal critical peak prices to customers in advance; the removal of retail price regulation; and appropriate incentive regulations so that distribution businesses are not financially penalised for engaging in demand management. It would also require effective engagement by distributors and retailers with customers (see below). And while the Commission is confident that retailers will pass on time-based prices for network services to many final customers (and provide complementary demand management services and technologies), this should not be assumed.

Another key component of the transition process will be to determine an appropriate path to move from current pricing structures for households and small businesses to the sort of pricing endpoint spelt out above. Obviously, this path will be influenced by actions in other areas — including the roll out process for smart meters (where the lessons learned from Victoria are instructive (chapter 10)); as well as by the outcomes of the tariff trialling process. Accordingly, the Commission has not sought to prescribe particular price paths.

However it observes that wider use of TOU network tariffs embodying relatively broad peak (and shoulder) components might be beneficial as an initial step. While Ausgrid’s experiences in NSW indicate that such charges do not achieve significant network efficiencies or offer much prospect of lowering consumer bills overall, they could nonetheless help to:

* increase consumer acceptance of time-based pricing. A survey of Energy Australia customers on TOU tariffs found that 71 per cent believed it was a fairer pricing system (this reflects that TOU tariffs reduce cross-subsidisation between consumers, even if not significantly changing consumption habits).
* provide some useful information and data on the demand responsiveness of customers to time-based differences in prices.

That said, such benefits would not provide a basis for retaining these sorts of pricing regimes for any longer than an interim period. As noted, they are unlikely to be effective in moderating peak demand. (In a cost-benefit analysis of various options to reduce peak demand costs, Deloitte (for ESAA, sub. 23) found that TOU prices had the lowest benefits of any measure — and only one sixth of the benefits of critical peak pricing.) Moreover, an extended period of use would see expensive smart meter technology effectively lying idle. Indeed, the Commission’s modelling suggests that if the transition to more robust forms of time-based pricing is too slow, the case for rolling out smart meters in the medium term becomes commensurately more problematic.

With these sorts of considerations in mind, the Commission is seeking more information on appropriate transitional price paths.

The Commission seeks further input from participants on the types of price paths that might be appropriate in transitioning to cost-reflective, time-based network pricing, including on:

* any impediments to the early extension of such pricing to all large commercial and industrial users
* the benefits and costs (including that of a smart meter) from initially extending the use of ‘time-of-use’ network prices — employing peak, shoulder and non-peak tariffs — to all households and small businesses
* any ways that such prices could be usefully and quickly improved to be more targeted — such as through seasonal loadings — to reflect the costs of providing network services at peak times
* how quickly it would be appropriate to introduce greater geographic differentiation in network prices
* what indicators should be used to review how well the price transition process is progressing.

It is also seeking further input on how the nature and speed of the transitional price path might be influenced by the costs and benefits of technologies (other than the smart meter itself) to improve responsiveness to price signals and assist with informed energy use decisions, including:

* ‘smart appliances’ that are enabled with a demand response capability (chapter 10) (such as to allow direct load control with a customer’s agreement)
* ‘add-on’ technologies, such as Home Area Networks, in-home displays, online portals and phone Apps, that draw on information provided by a smart meter to assist with a consumer’s energy management
* information technology systems to communicate to customers, such as to provide notification of critical peak events.

#### The importance of effective engagement and customer education

Whatever the particular transition path adopted, it is critical that there is appropriate consultation and information exchange between the various stakeholders. As outlined earlier, distribution network businesses, retailers, the AER, state and territory governments and customers (or their representatives) will all need to be satisfied that the reforms are progressed appropriately.

One of the tasks of the SCER in its role of oversighting the implementation process (see draft recommendation 11.1) would be to ensure that, in a broad sense, there has been adequate engagement between the parties. A further focus, and one that is already an objective within the SCER’s *Demand Side Participation Work Plan,* would be to ensure customers can easily assess the costs and benefits of electricity consumption decisions and access information about options to change their consumption. Within this framework, the SCER could add forward priorities to the objectives of ‘informing choice’ and ‘enabling demand response’. Consequent actions and decisions should be informed by evidence from robust pricing and technology trials, and based on a cost-benefit framework.

However, in the Commission’s view, there would be benefits from imposing a formal requirement on distribution network businesses to engage with retailers very early in the development phase of revising network price structures. Specifically, it would help to:

* reduce the possibility that the costs of meeting peak network demand continued to be hidden (or excessively smoothed out) in the retail price face by consumers
* increase the confidence of retailers entering the market and encourage the development of more innovative retail tariff offers (chapter 12)
* assist distribution businesses to understand the potential problems that changes to network tariffs could impose on retailers (box 11.6).

Similarly, a formal requirement for distribution businesses and retailers to engage with consumers is warranted to ensure that consumers are well placed to respond appropriately to time-based pricing; are aware of the implications for their electricity bills; and are aware of the support mechanisms in the event that the new pricing regime will create financial difficulties for them. More specifically, such engagement and education should encompass the timing and cost of smart meter installation; the basis for the different components of time-based prices; the timetable for steps in the transition to the new pricing regime; the way in which consumers will be advised of critical peak pricing events; and the various options available to consumers to better manage their demand.

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| Box 11.6 Ameliorating the transitional costs for retailers |
| Retailers already have to deal with different network tariffs applying across customer classes and the service areas of distribution businesses. However, with cost reflective, time-based, pricing, the complexity of the price formulation process would increase and with it the administrative costs of appropriately reflecting those prices in retail tariffs. (As raised in chapter 10, the operation of a centralised smart meter data management system could help to lessen, though not eliminate, this additional administrative burden for retailers.)  With the introduction of time-based network prices, retailers would also have to reassess their hedging strategy (smoothing of price volatility in the wholesale energy market) and communicate tariff changes to their customers. Advanced notice of network pricing changes is helpful.  An existing instrument to inform retailers and customers about forthcoming distribution prices is a statement of expected price trends, which distributors are required to update for each regulatory year (cl. 6.18.9(3) of the Rules). But prior to an actual change in network tariffs, retailers only need be given 20 business days’ notice. In the absence of earlier engagement, such short notice could make a smooth transition to time-based pricing difficult for retailers. Indeed, the sort of engagement catered for by this rule is seemingly of a much more minor kind than the sort required for major pricing reforms. |
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Draft recommendation 11.7

The Australian Energy Regulator should require:

* distribution network businesses to demonstrate that they have actively engaged with retailers very early in the development of new time-based pricing structures, including on ways to incorporate those charges in retail prices to clearly signal to customers the costs of meeting peak network demand
* distributors and retailers to demonstrate that they have engaged with, and educated, customers prior to the introduction of smart meters, and again prior to the introduction of new time-based customer tariffs.
* ***Such engagement should occur sufficiently early to ensure that customers have the knowledge and time to respond appropriately to time-based pricing (including of the various means to manage their peak demand); are aware of the implications for their electricity bills; understand the way in which advance warning of critical peak pricing events will be communicated; and are aware of the support mechanisms in the event that the new pricing regime creates financial difficulties for them.***

1. In chapters 18, the Commission is proposing various changes to achieve more efficient charges, including over time, for transmission network services. However, the broad underlying goal is the same as for time-based pricing for distribution networks considered in this chapter. [↑](#footnote-ref-1)
2. In practice, such traits may include voltage supply level, volume of use, and nature of end use (domestic, business, commercial or industrial), but not geographic location (although the Rules would allow it). [↑](#footnote-ref-2)
3. As SP-Ausnet applies critical peak pricing based on the maximum kVA recorded during critical peak events, the kWh actually consumed may be less than this due to variation in consumption during these event and because of the power factor. [↑](#footnote-ref-3)
4. LRMC pricing could, in theory, be employed to recoup the entire costs of running a distribution network. However, the focus here is on using LRMC as the basis for setting a higher usage charge during periods of peak demand. The balance of a DNSP’s revenue would then come from the sorts of two part charges that are currently levied — a base (non-peak) usage charge and a fixed charge set to, in combination, equate the expected revenue for a network business to its regulated revenue allowance. [↑](#footnote-ref-4)
5. ‘Lumpy’ network investments are large forward-looking investments with declining unit costs as the size of the investment increases. [↑](#footnote-ref-5)
6. Calculating LRMC (or more precisely LRIC) over a forward-looking interval smooths the forecast investment cost over the asset life. While the profile of returns under LRIC depend on assumptions about asset lives and depreciation profiles, and a dynamic price sequence results from the re-optimisation of estimates over time (as demand and capital costs change), the key point is that a distribution business should recover its investment costs over the lifetime of the asset. [↑](#footnote-ref-6)
7. The use of short run marginal cost pricing in these circumstances would, in essence, require the incorporation of a congestion component in charges when a network reached full capacity. Once these congestion charges had paid for the fixed costs of the existing network, new capacity would be installed and prices would fall sharply. This cycle would be repeated as the augmented network reached capacity. [↑](#footnote-ref-7)
8. and also depending on the precise methodology adopted to calculate LRMC [↑](#footnote-ref-8)
9. The Commission notes that planning arrangements would provide some insurance against overly optimistic estimates by the AER of the impacts of time-based pricing on demand. In effect, the processes used for network planning and the levels of investment required make provision for shortfalls between projections of maximum demand and actual outcomes. This would provide a cushion for forecasting errors. [↑](#footnote-ref-9)
10. These include clause 6.18.3(d)(1) relating to the efficient allocation of customers to tariff classes; clause 6.18.3(d)(2) relating to the avoidance of undue transactions costs in defining customer classes; 6.18.5(a) requiring that revenues recouped from each tariff class lie between incremental and stand alone cost; 6.18.5(b)(2)(i) relating to the transactions costs associated with a tariff or charging parameter; and 6.18.5(b)(2)(ii) relating to the capacity of consumers to respond to price signals in a tariff. [↑](#footnote-ref-10)