Oakley Greenwood

Policy options for maximising downward pressure on electricity prices

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- - Australian Industry Group
- - Brotherhood St Laurence
- - CHOICE
- - Energy Efficiency Council.

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1. Executive summary

Electricity bills have increased rapidly over the past five years. This has generated significant concern among households and businesses. It has also been commented on in a number of recent reviews of various aspects of the electricity market, but these reviews have generally been undertaken from an electricity industry or market (rather than consumer) perspective, and have often addressed the impact of various aspects of the market on prices separately rather than seeking to address the topic holistically.

This independent report was commissioned by the Australian Industry Group, Brotherhood St Laurence, CHOICE and the Energy Efficiency Council to support informed debate by the entire community – homeowners, renters, landlords, small businesses and large business, including businesses with significant exposure to carbon prices and regional and global trade issues. The sponsoring organisations do not necessarily support or oppose any of the policies and data that are set out in the paper. The report looks into:

- the causes of recent and likely future electricity price rises, and
- options to keep electricity bills affordable.

1.1. Causes of recent and likely future electricity price rises

From the late 90s to 2006 or so, growth in peak demand was probably the most significant contributor to increases in electricity prices. This growth in peak demand was largely attributable to the increased take-up and use of air conditioning in the residential sector, and has required investment in both peaking generation and additional capacity in transmission and distribution networks.

More recently, electricity prices have continued to increase, despite the fact that the rate of growth in peak demand has slowed. In fact, in several NEM jurisdictions prices have increased more quickly in the past three to five years than they did during the preceding decade. The largest single factor in the price increases that have occurred since 2006 has been increased network charges – the charges that are included in consumers' bills for the use of the transmission and distribution systems (poles and wire) that deliver electricity from the power plants to end users. While growth in peak demand has played a role in this increase, in several jurisdictions – particularly where the increases in electricity price have been the highest – the need to replace old distribution infrastructure assets that have reached the end of their useful lives has been a very large part of the cause.

In some jurisdictions the reliability standard that distribution networks must maintain has also contributed to the rise in electricity prices. Higher reliability requirements generally increase the need for network infrastructure, which increases costs and therefore prices.

Looking forward, most studies forecast that price rises will continue – with some studies forecasting that 2017 prices for residential customers likely to be double their 2011 levels. Further increases in network charges – due largely to the need to replace aged assets but also in part to continued growth in peak demand and existing reliability standards – are expected to be a significant cause of these increases. However, some studies expect the wholesale market to contribute even more to the rise in residential electricity prices. The most significant factor putting upward pressure on the cost of generating electricity is expected to be increases in the prices generators have to pay for the fuel they use due to increased exposure of Australia's coal and gas resources to world prices. The introduction of the carbon price has had an impact on prices from its introduction in 2012. Its contribution to further price increases is expected to decrease given the current outlook for international carbon prices and the fact that the floor price has been removed.

1.2. Options to keep electricity bills affordable

This report looks at options to keep electricity bills affordable, with a focus on options in the structure and operations of the electricity market. The most critical factors for making sure that consumers' bills are as low as possible over the long term are to ensure that:

- Consumers have adequate information, access to services and other resources to assist them in using electricity in the amounts, times and types of equipment that maximises their welfare;
- The electricity supply industry meets consumers' demands as cost-effectively as possible;
- The prices that the industry provides to consumers are as cost reflective as practically possible, as this will promote economically efficient decisions by consumers regarding their use of electricity, which in turn will increase the likelihood that the aggregate demand presented to the electricity industry contains as little deadweight loss or economically inefficient consumption as possible;
- The lower costs to serve that result from the two steps above are reflected in future prices throughout the electricity supply chain and to consumers.

From these perspectives, a total of 19 options were identified that could put downward pressure on electricity prices. They are organised and discussed based on the part of the electricity supply value chain whose operation they would affect.

This report recognises that low income and vulnerable residential consumers have specific concerns that will need to be considered if some of the options identified here are implemented. This report does not seek to address in detail the implications of the options presented for vulnerable and at risk residential consumers. While these issues can be addressed in part through a robust system of consumer protections (as discussed briefly in the last section of the report), further work will be needed to ensure the specific proposals will not have an adverse impact on vulnerable and at-risk residential consumers.

1.2.1. Options applicable to the generation sector

Prices in the generation sector have been relatively stable and are projected to increase primarily due to the cost of generation fuels (over which policy does not have a great deal of control without introducing other biases) and the introduction of a price on carbon. As a result, the policy options that have been offered for consideration address other means for reducing price pressure in the sector, including:

- Facilitating the provision of demand response by consumers in order to reduce peak demand in the generation market and thereby investment requirements; should this occur there would also be a corresponding (though lower) impact on distribution system peak demands and capital investment requirements
- Considering the addition of a capacity mechanism to the NEM market design if the above and other approaches for facilitating demand response are not successful
- Reviewing the NEM's reliability standard to determine whether a lower standard would be acceptable in light of the reduction it would cause in the amount of capacity required, and therefore capital expenditure.

A review and possible reform of the gas supply market to ensure it is as liquid and competitive as possible is also warranted, given the growing importance of gas as a fuel for electricity generation and direct use by major customers in a carbon-price world.

1.2.2. Options applicable to the network sector

There is significant potential for measures that build on current regulatory arrangements that would reduce upward pressure on prices in the network sector. These can be thought of in four separate areas:

- Enhanced and strengthened regulation, including:
  - Greater exercise of existing regulatory powers by the AER
  - The introduction of and provision of support for consumer advocate as a regular participant in network regulatory processes;

  These options could be pursued at the same time, and in parallel with all other options.
- Incentives to encourage greater efficiency in network capital and operating expenditures, including:
  - The introduction of a capital efficiency carryover mechanism, which would provide an incentive for network businesses to be more economically efficient in their capital expenditure
  - Making total expenditure the basis on which network businesses would earn a return, thereby assisting in overcoming any bias that exists toward capital expenditure as compared to expenditures on maintenance, demand-side management and/or distribute generation.

  These two options should be seen as alternatives to one another. Given the nature of the two options and their 'fit' with existing regulatory processes, it would probably be more appropriate to work with the capital efficiency option first.
- Increased network business proactivity in finding, using and supporting demand side response and demand side resources, including distributed generation. Four separate options are presented in this area:
  - Increased use of interval metering, which could work in concert with more direction from the AER regarding the use of network price structures that provide more efficient pricing signals to consumers. Such pricing would help ensure that the demand of electricity end-users reflected their assessment of the value derived from electricity as compared to the cost of supplying it
  - A requirement for networks to prepare and publish demand-side plans

- The introduction of targets with incentives/penalties for networks to use demand-side resources to defer augmentation (note that there a number of approaches that can be taken to setting the target)
- The development of a role for networks to serve as owners of – and earn returns on – assets and services that facilitate demand response and/or distributed generation. This would allow network businesses to use certain network assets (primarily communications and control technologies) to provide demand management services to retailers or aggregators.

The first of these four options above can be pursued in parallel with all other options.

The second and third options reflect differing levels of obligation being put on networks to become actively involved in enlisting the demand side of the market to provide the most economically efficient approaches for meeting aggregate consumer demand within the network. Either or both could be undertaken, or they could be undertaken sequentially.

Implementation of the fourth option should be conditional on a study of its likely impacts on innovation and competition in demand-side services.

- Review of the nature and level of the reliability standards that are applied to network business. There is a substantial body of research that suggests that the deterministic nature of the reliability standards that apply to the distribution businesses – and in some cases the level of those standards – are imposing costs that exceed the benefits that consumers obtain from the reliability delivered. There may also be value in considering harmonisation of network reliability standards, which currently vary based on state-level legislation and license requirements.
- Privatisation of government-owned network businesses.

Other, more radical options also exist that could be investigated instead of these approaches, or if these approaches do not sufficiently improve the economic efficiency of the sector.

1.2.3. Options applicable to the retail sector

Although the retail sector's operating costs and margin account for only about 10% to 15% of the average residential bill, there are several options applicable to the sector that would put downward pressure on prices or provide consumers with better information or other benefits. Three options are offered for consideration in this sector:

- A requirement that retailers provide more cost-reflective pricing options, including an unbundled price as an option to all customers on request. This would provide visibility to network price signals (both the structure and level of the network price) and assist with increasing energy literacy among smaller customers. It would support and encourage more innovative pricing by networks and assure that the price signal was visible to the consumer.
- Monitoring of retail costs and margins to ensure competition is effective. This would focus on identifying where competition is or is not effective, and is or is not providing benefits to consumers. In any instances in which competition was found to not be effective or to not be providing benefits to consumers, it would also seek to determine the reasons for these shortcomings and means for correcting them. Where it was found to be effective if would facilitate the decision to remove retail price regulation.

- Implementing the National Energy Consumer Framework. The National Energy Customer Framework (NECF) provides a comprehensive set of consumer protection measures for small electricity and gas customers. It also provides far more uniformity in how electricity and gas retailers are directed to interact with their customers than currently exists in the consumer protection approaches that have been developed independently within each of the jurisdictions. This greater level of uniformity is beneficial to the retailers as it reduces their costs of operation, which should therefore reduce upward pressure on prices to consumers.

1.2.4. Options applicable to government

Governments at the federal, state and local levels have an obvious and important role to play as policymakers and as consumers in their own right. While it is absolutely critical that governments maintain and strengthen policies to help households and businesses improve their energy efficiency, this report does not examine or recommend any specific policies to improve energy efficiency.

This report sets out two options to ensure that policies that improve energy efficiency also reduce upward pressure on electricity prices:

- Review and revitalisation of on-going government energy efficiency policies. The Council of Australian Governments is currently undertaking a review of climate change and energy efficiency policies, partly to review their 'complementarity' to a carbon price and partly to review their effectiveness. These are important questions, but it must be remembered that many of the energy efficiency policies being considered under the review were not implemented to serve as complements to the carbon price, but rather to address other issues in the energy market and energy affordability.

  This review would deliver greater benefits if, in addition to assessing the complementarity of the measures with carbon pricing it also assessed the impact of the various programs on their 'complementarity' with the National Electricity Market, their impact on relevant market failures, and their potential impact on electricity prices and its affordability.

- Explicit consideration of the impacts of new energy and environment related policies introduced at any level of government on the dynamics of the energy market, and their interactions with the NER and relevant energy market regulation. Where possible, this could be incorporated within any Regulatory Impact Statement or similar analytic measure used by the government in question.

It also discusses the application of the intent of these options to the possible development of a national Energy Savings Initiative.

It should be noted that there is also a role for government to lead by example. This would include ensuring that its own facilities and operations are energy efficient and provide demand response where possible.

1.2.5. Other considerations

Fully optimising supply and demand requires action beyond just the electricity market - it also requires efficient markets for other goods and services (e.g. appliances, insulation) and policies and programs to address other market failures, such as information asymmetries, transaction costs and access to capital. The report recognises that optimising demand patterns will require these other markets to be efficient, and policies to be in place that address factors and market failures outside the electricity market – but it does not examine these issues.

2. Background, purpose and approach

2.1. Background and purpose

Electricity bills have increased rapidly over the past five years. This has generated significant concern among households and businesses. It has also been commented on in a number of recent reviews of various aspects of the electricity market, but these reviews have generally been undertaken from an electricity industry or market (rather than consumer) perspective, and have often addressed the impact of various aspects of the market on prices separately rather than seeking to address the topic holistically.

This report was commissioned by the Australian Industry Group, Brotherhood St Laurence, CHOICE and the Energy Efficiency Council to support informed debate by the entire community – homeowners, renters, landlords, small businesses and large business, including businesses with significant exposure to carbon prices and regional and global trade issues. This report looks into:

- the causes of recent and likely future electricity price rises, and
- options to keep electricity bills affordable.

This report was commissioned as an independent thought piece to provide input to both public debate and the supporting organisations' consideration of policy options. The paper is intended to assist the organisations that commissioned the report to develop their respective policy positions, and these organisations do not necessarily support or oppose any of the policies and data that are set out in the paper.

2.2. Approach

2.2.1. Conceptual framework

This report looks at options to keep electricity bills affordable, with a focus on the structure and operations of the electricity market. The most critical factors for making sure that consumers' bills are as low as possible over the long term are to ensure that:

- Consumers have adequate information, access to services and other resources to assist them in using electricity in the amounts, times and types of equipment that maximise their welfare;
- The electricity supply industry meets consumers' demands as cost-effectively as possible;
- The prices that the industry provides to consumers are as cost reflective as practically possible, as this will promote economically efficient decisions by consumers regarding their use of electricity, which in turn will increase the likelihood that the aggregate demand presented to the electricity industry contains as little deadweight loss or economically inefficient consumption as possible;
- The lower costs to serve that result from the two steps above are reflected in future prices throughout the electricity supply chain and to consumers.

Fully optimising supply and demand requires action beyond just the electricity market - it also requires efficient markets for other goods and services (e.g. appliances, insulation) and policies and programs to address other market failures, such as information asymmetries, transaction costs and access to capital.

The report recognises that optimising demand patterns will require these other markets to be efficient, and policies to be in place that address factors and market failures outside the electricity market – but it does not examine these issues. Rather, this report focuses on options in the design, operation and regulation of the electricity market that will improve the overall efficiency of the electricity market and thereby put downward pressure on total consumer bills.

As noted above, this report focuses on options to improve the overall efficiency of the electricity market in order to put downward pressure on consumers' bills. However, the report does not address the distribution of the benefits and costs of these options in detail, and some low income and vulnerable consumers have specific concerns that will need to be considered if some of the measures identified here are implemented. This report does not seek to address in detail the implications of the different measures for vulnerable and at risk residential consumers. These issues can be addressed in part through a robust system of consumer protections (see Section 8). Further work will need to be undertaken to ensure the options proposed here will not have an adverse impact on vulnerable and at risk residential consumers.

2.2.2. Approach used

The framework was applied in two basic steps:

1. Identify the factors that are contributing to electricity prices being higher than they would be under the most efficient conditions.
2. Identify potential solutions to those problems and assess them with regard to a set of explicit criteria.

These are described in further detail below.

Step 1: Identify the factors contributing to high electricity prices

In order for electricity prices to be as low as possible, the electricity industry itself needs to be as efficient as possible. This will mean that the cost of operating the electricity system is as low as possible, while still allowing applicable supply quality and reliability standards to be met.

In order for consumers to make efficient choices about their use of electricity they need:

- prices that reflect the cost of producing and delivering that electricity
- information on ways they can modify their use of electricity, including the cost of those modifications and their impact on the consumer.
  - for residential consumers the impacts of most importance are likely to concern comfort and convenience
  - for business consumers they are likely to concern the cost of doing business, and their impact on the business' processes and products, as well as their impact on the comfort and convenience of their customers and employees.
- the ability to act on that information and incentives, which can be impeded by bounded rationality, access to capital, access to skilled experts and third parties and principal-agent issues.

It is worth noting, as evidenced in the first two conditions above, that efficiency in the demand- and supply-- sides is interactive:

- an informed and responsive demand side will mean that the electricity being produced is being used in as economically efficient a way as possible,
- and an efficient electricity supply industry will meet the aggregate demand of those consumers at the least possible cost.

Step 2: Identify and assess potential solutions

The solution options were assessed with regard to the following criteria:

- Magnitude of impact – All other things being equal, policies that address areas where greater gains can be made will be preferred. This is likely to be influenced at least in part by the part of the supply chain to which the potential solution would apply (the relative contribution of the various sectors to final price is discussed in the following section). The assessment of the magnitude of impact of the various options undertaken in this study is in most case qualitative, owing to the time and other resources available to the assignment.
- Measurability of impact – This is important in order to assess whether the policy is working, needs to be amended or should be abandoned.
- Timing of benefits and costs – This will determine an option's near- as well as longer term impacts on prices. Policy options with different time profiles of costs and benefits require different considerations and communications strategies.
- Likelihood of success – This is affected by a number of factors including the number of parties that need to agree to implement the policy, the number of parties that need to take discretionary actions in order for the policy's benefits to be achieved, how easily (or otherwise) the policy is to implement as well as its on-going administrative requirements, its consistency with existing policies and government positions, and its total costs.
- Specific stakeholder groups – Different policy options will affect different stakeholder groups differently. The assessment will identify the specific customer segments and portions of the electricity supply industry that each policy option would affect, both positively and negatively.
- Consistency with electricity market philosophy and direction – Policies that are more consistent with existing policy settings and, in the case of the electricity market, the design of the market and its rules are likely to be easier to implement.

3. Recent and near-term future electricity prices and price increases

This section provides an overview of the degree to which electricity prices have increased over the past decade or so, the degree to which they are expected to increase within the foreseeable future, and the factors that have been – and are expected to be – responsible for those increases. Due to the availability of data, the review focuses on the residential sector. While the level of price increases in other sectors is not known in as much detail, most of the factors driving costs in the electricity sector will have affected the prices of other consumers as well.

The purpose of this section is to identify where policy options are likely to have the most scope to put downward pressure on price or to assist consumers in managing their bills.

3.1. Factors that caused the price increases of the past several years

From the late 90s to 2007 or so, growth in peak demand was probably the most significant contributor to increases in electricity prices. This growth in peak demand was largely attributable to the increased take-up and use of air conditioning in the residential sector. That uptake, in turn, was driven primarily by the strong economic growth that characterised the period and the increase in discretionary household income it produced, the availability of imported air conditioning equipment at very low prices, and the fact that electricity for residential users was (and largely still is) priced the same regardless of the time it is used. As noted in *The Boomerang Paradox*[1]: “the number of households in QLD’s capital (Brisbane) increased by 35% over the 12 years to FY10, whereas peak electricity demand increased by 104% over the same period; households with air-conditioners had risen from 23% to 72% with 34% of homes running two or more air-conditioners”[2].

This increase in peak demand required investment in both peaking generation and additional capacity in transmission and distribution networks.

More recently, electricity prices have continued to increase, despite the fact that the rate of growth in peak demand has slowed. In fact, in several jurisdictions within the National Electricity Market (NEM) prices have increased more quickly in the past three to five years than they did during the preceding decade. These price increases have been the subject of significant study, though virtually all of the published work in this area addresses only residential electricity prices.

An unpublished OGW study conducted in 2011 assessed the causes of the price increases and the relative contribution of each of the various parts of the electricity supply chain – and policy measures – to the cost of residential electricity in each of the NEM jurisdictions in the middle and latter parts of the last decade.

1 Paul Simshauser, Tim Nelson and Thao Doan, *The Boomerang Paradox*, http://www.aglblog.com.au/wp-content/uploads/2010/10/No.17-Boomerang-Paradox-Final-Oct-20101.pdf

2 Summarised in *The Boomerang Paradox* from K Orchison, K, “Distance cuts down the options”, *The Australian - Climate Change Special Report*, 4 March 2010, p.4.

Table 1 below shows the increase, in nominal dollars, of the average residential bill each of the NEM jurisdictions in the second half of the last decade. It also identifies the share of the increase that was due to inflation, and the degree to which the bills would have been affected by increased usage. As can be seen, in every state but one the majority of the price increase has been due to real increases in the price of electricity, rather than the effects of either inflation or increased consumption -- in fact, in four of the seven jurisdictions average electricity consumption fell over the period.

Table 1: Increase in average residential electricity bill[3] (nominal dollars), by state, and the relative contribution of inflation and consumption to the increase

			%change due to		
State	Period covered	Total change in nominal dollars	Real electricity price	Inflation	Change in volume (average annual consumption)
QLD	FY 2006-07 thru FY 2010-11	$427.32	73.7%	29.2%	-2.9%
NSW	FY 2006-07 thru FY 2010-11	$458.48	75.1%	29.3%	-4.4%
ACT	FY 2006-07 thru FY 2010-11	$301.27	61.5%	42.7%	-4.1%
VIC[4]	FY 2006-07 thru CY 2011	$417.12	74.3%	29.6%	-3.9%
SA	FY 2005-06 thru CY 2010	$225.57	46.7%	52.1%	1.2%
TAS	CY 2006 thru FY 2010-11	$373.25	69.9%	28.2%	1.9%

Source: OGW analysis

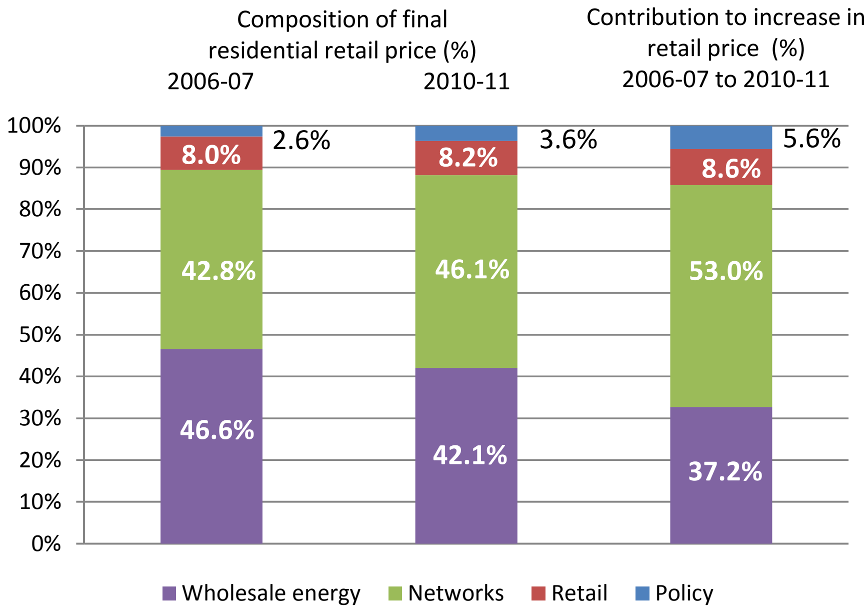
The relative contribution of each of the various parts of the electricity supply chain – and government policy measures – to the cost of residential electricity in each of the NEM jurisdictions is shown in Figure 1 below.

3 The information on price movements was in all cases developed from the annual filings of one or more distributors in each state. It was calculated based on the average consumption of all residential customers (total residential class consumption divided by total number of residential customers) and the standard single-rate tariff for the relevant year in each jurisdiction (except Victoria post 2008, where the standing offer tariff was used).

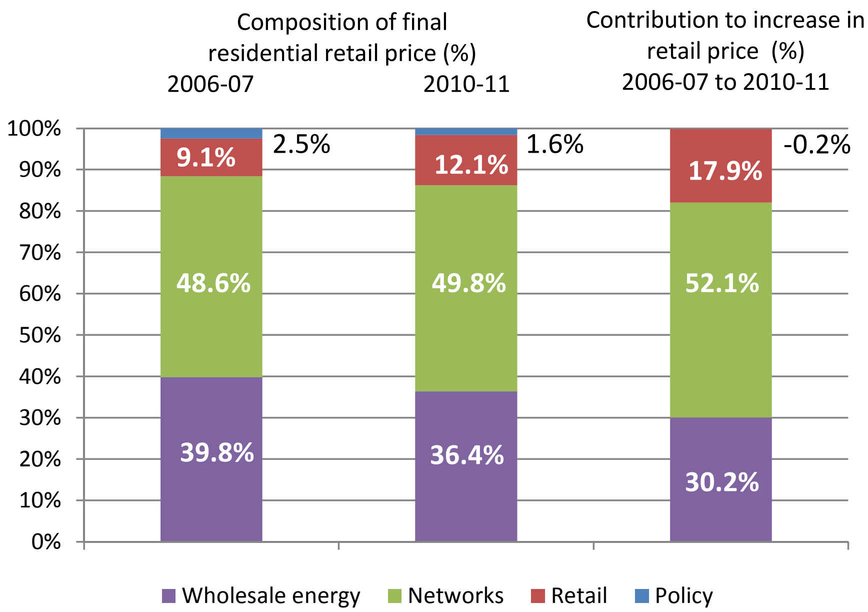
4 Results for CY 2011 were estimated from part-year data.

Figure 1: Composition of residential retail electricity prices across the NEM jurisdictions and contribution of various factors to price increase[5]

Queensland

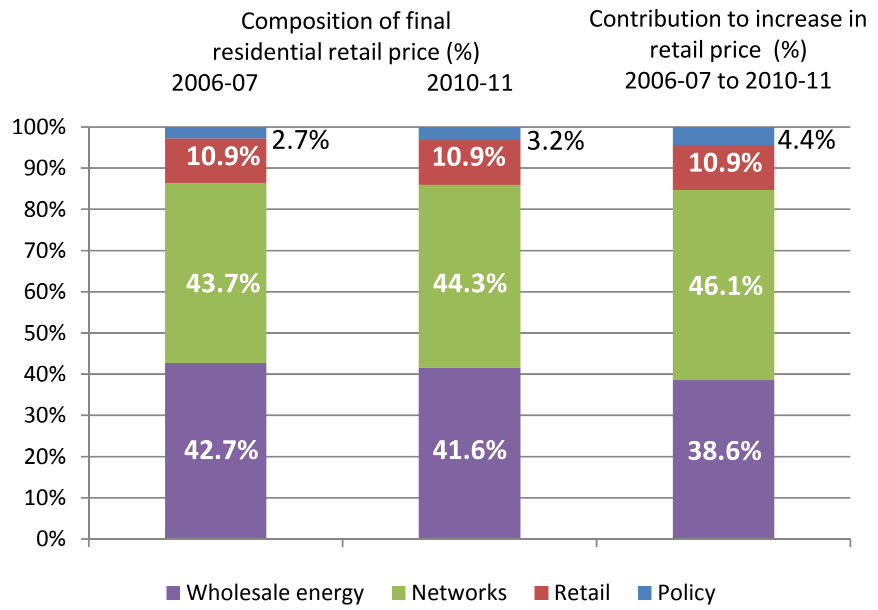


New South Wales

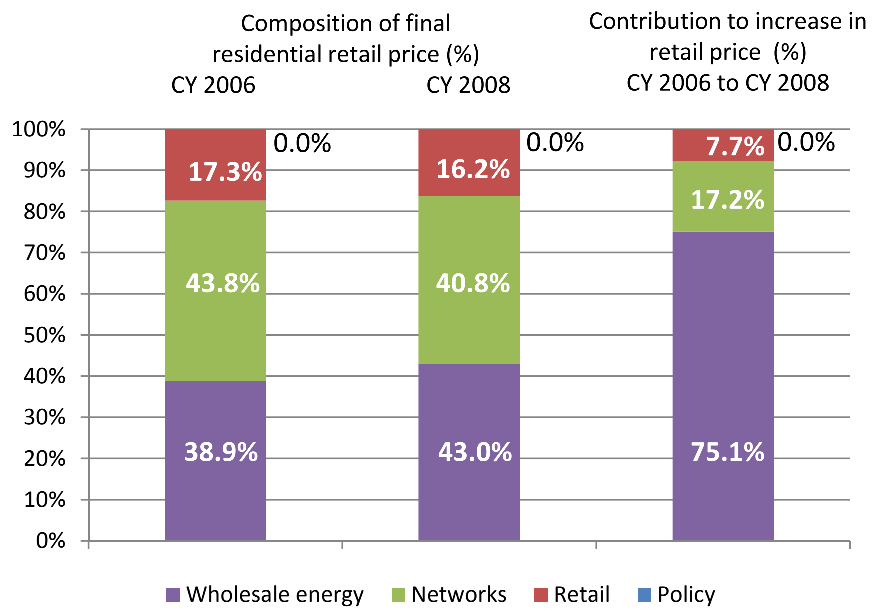


5 The cost stack information was developed from regulatory price determinations in each state. Some states do these annually (e.g., QLD) but most have undertaken multi-year price determinations at least at some point, and Victoria ceased doing them when the state de-regulated retail pricing for small customers. As a result, data had to be smoothed across years between determinations and could only be reported for Victoria where reasonably accurate data could be accessed.

ACT

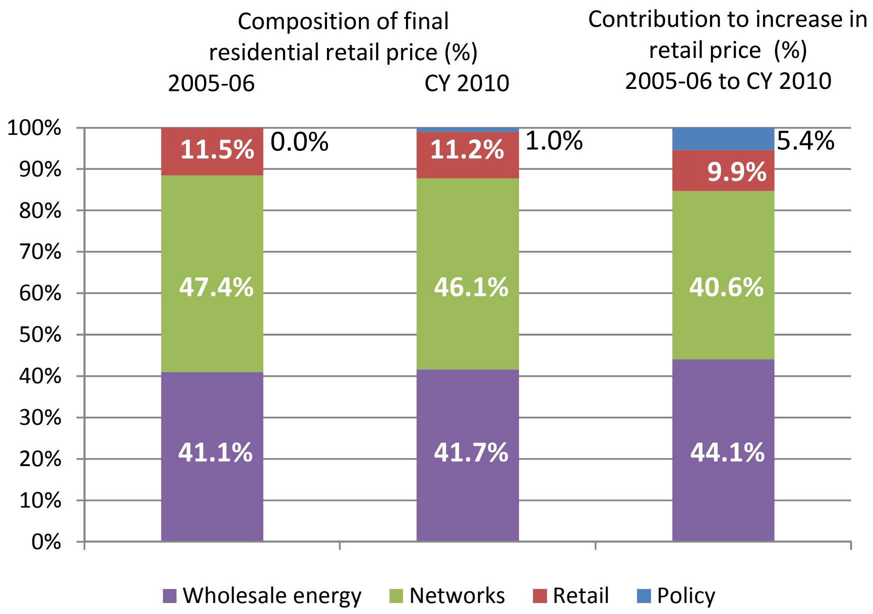


Victoria[6]

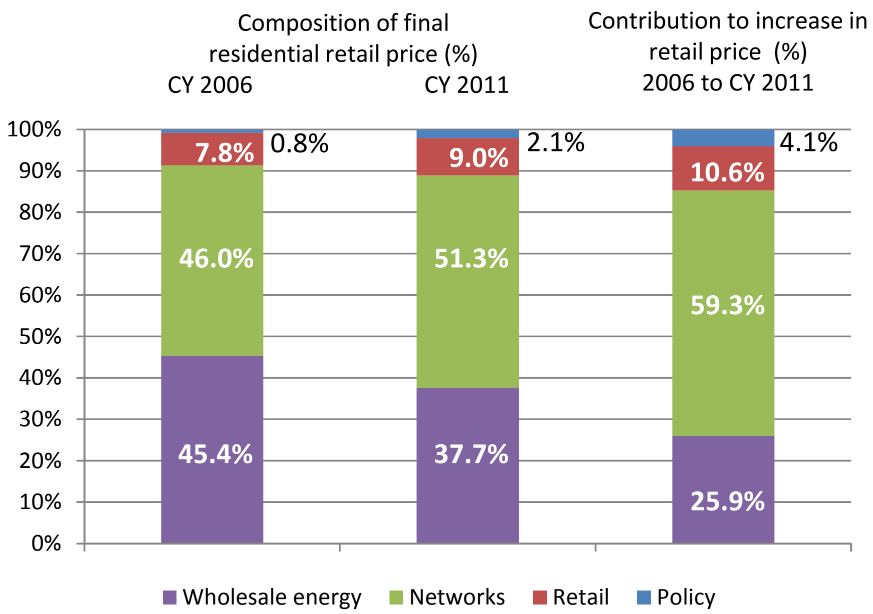


6 Relevant data for Victoria was only available for the period 2006 to 2008, which is a materially shorter period than that for which data was available for the other jurisdictions. Electricity costs in the 2006 to 2008 period were significantly influenced by drought conditions (which reduced available generation capacity and increased forward contract market prices) and worldwide shortages of turbines and increases in steel prices (which increased forward investment costs). In combination, these factors increased wholesale energy prices. Subsequently, each of those factors subsided and wholesale prices fell in Victoria and across the NEM. As a result, the relative contribution of the wholesale energy market to residential electricity prices will have changed.

South Australia



Tasmania



Similar results have been reported in other studies. For example, the *NSW Electricity Network and Prices Inquiry*, which was undertaken by the (then) NSW Department of Industry & Investment in the second half of 2010 found that:

Electricity prices increased by 41% in nominal terms across Australia in the three years from June 2007 to June 2010, and by 43% in Sydney over the same period. These steep increases follow a sustained period of relatively flat prices in the mid 1990s and only modest increases in the early 2000s as greater competition was introduced to the electricity market and stronger regulatory frameworks were introduced for the remaining monopoly elements in the industry.[7]

3.2. Factors expected to affect prices in the coming years

A number of parties have also produced forecasts of electricity prices in the coming years.

In its most recent rolling three-year forecast of residential electricity prices, entitled *Final Report: Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, which was published in November 2011, the Australian Energy Market Commission (AEMC) stated:

Taking into account a price on carbon, between the base year (2010/11) and the final year (2013/14) of the projection period, the weighted average national residential electricity price is projected to increase by 37 per cent in nominal terms. This is equivalent to a nominal price increase in the total residential electricity price of 8.34c/kWh, over that period. The average annual growth rate of national residential electricity prices over the three year projection period is expected to be approximately 11 per cent.[8]

Table 2 below presents the price increases that the AEMC study forecast over the period, and the contribution being made to those price increases by each part of the electricity supply chain.

Table 2: Projected national average residential price increases 2010-11 through 2013-14, including the effects of a carbon price

Component	Nominal percentage increase between 2010/11 2013/14	Nominal price increase between 2010/11 2013/14 (c/kWh)	Percentage of total price increase attributable to component
Green energy component (government policies and programs)	55%	0.68¢	8.1%
Retail component	30%	0.87¢	10.4%
Impact of carbon price on retail costs		0.14¢	1.7%
Distribution component	34%	2.80¢	33.6%
Transmission component	29%	0.50¢	6.0%
Wholesale electricity component	43%	1.59¢	19.1%
Impact of carbon price on wholesale market		1.76¢	21.1%
Total	37%	8.34¢	100.0%

Source: AEMC, *Final Report: Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011, p 19.

7 NSW Department of Industry & Investment, *NSW Electricity Network and Prices Inquiry*, December 2010, p 7.

8 AEMC, *Final Report: Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014,* November 2011, p 19.

The AEMC report provides a similar analysis on a state-by-state basis. Table 3 below shows the relative contribution of each part of the electricity supply chain to forecast residential electricity prices in each of the NEM jurisdictions over the 2010-11 to 2013-14 timeframe.

Table 3: Expected price rises in residential electricity prices 2010-11 through 2013-14 by electricity supply chain component

Component	QLD	NSW	ACT	VIC[9]	SA	TAS
Government policies and programs	1.1%	12.2%	4.1%	12.7%	11.9%	-0.4%
Feed-in tariff	*0.2%*	*6.1%*	*3.9%*	*0.7%*	*6.6%*	*0.0%*
LRET	*3.1%*	*3.7%*	*2.7%*	*3.8%*	*5.1%*	*2.5%*
SRES	*-1.6%*	*1.6%*	*-2.3%*	*-2.0%*	*-1.8%*	*-2.9%*
Energy efficiency and demand management schemes; and smart meter roll-out in Victoria	*-0.6%*	*0.8%*	*-0.2%*	*10.2%*[10]	*2.0%*	*0.0%*
Retail component (including the impact of the carbon price)	8.4%	7.1%	7.1%	31.5%	2.7%	11.9%
Distribution component	40.2%	36.1%	14.2%	15.3%	39.9%	22.5%
Transmission component	6.0%	6.2%	6.1%	0.1%	10.7%	15.4%
Wholesale electricity component (including carbon price)	44.3%	38.3%	68.5%	40.4%	34.8%	50.5%
Total % increase (2010/11 to 2013/14)	41.5%	41.8%	41.6%	32.7%	36.2%	25.0%
Total price increase (¢/kWh)	8.59	9.51	6.74	7.46	8.68	5.19
Carbon price impact (¢/kWh)						
2012-13	1.84	1.94	2.41	1.43	1.18	1.13
2013-14	1.93	2.03	2.47	1.45	1.21	1.12

Source: AEMC, *Final Report: Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011, p 6.

9 Because retail price regulation was removed in Victoria at the beginning of 2009, the AEMC study had to estimate the wholesale, retail and premium feed-in tariff payment components of the residential price, rather than relying on the results of regulated tariff determinations as was done for the rest of the states. It should also be noted that the figures for Victoria are based on the standing offer, while the majority of the residential customers in Victoria are on market contracts which can entail prices that are lower by 10 to 20% as compared to the standing offer. Finally, it should also be noted that while some of the retail margin in other states is likely to be included in the wholesale price component (due to the allowance made in the regulated tariff), all of the retail margin in Victoria is included in the retail component.

10 The Victorian costs are for the Advanced Metering Infrastructure (smart meter) Roll-out; they do not include the costs attributable to the Victoria Energy Efficiency Target (VEET).

A few studies have looked farther out in time. *The Boomerang Paradox* [11] assessed in significant detail the likely cost drivers in each link of the electricity supply chain, including the factors affecting forward costs of generation plant and generation fuels – primarily gas. The study considered four scenarios based on higher and lower gas prices and whether or not a carbon price was introduced. The results for the high gas, no carbon price scenario are summarised in Table 4 below.

Table 4: Cumulative change in electricity price FY08 to FY15, for Sydney and Brisbane, excluding carbon prices

Component	Incremental impact on final residential electricity price (¢/kWh)	Per cent increase on base cost
FY08 base price:	13.66 c/kWh	
Generation fuel costs	4.62 ¢/kWh	33.8%
Generation capacity costs	2.59 ¢/kWh	19.0%
Renewables (RET) costs	0.50 ¢/kWh	3.7%
Transmission costs	0.51 ¢/kWh	3.7%
Distribution costs	3.57 ¢/kWh	26.2%
Smart meter costs	0.87 ¢/kWh	6.3%
Retail opex and margin	1.32 ¢/kWh	9.7%
GST	1.41 ¢/kWh	10.3%
Total incremental cost	15.39 ¢/kWh	112.7%

Source: P Simshauser, T Nelson and T Doan, *The Boomerang Paradox*, April 2010, pp 18 – 20.

As can be seen, increases in the cost of generation fuel – essentially gas and coal – constituted the single biggest driver of the cost increases even without consideration of a carbon price. The high gas cost with carbon price scenario resulted in a price that was an additional 4.9% higher than that shown in the table. The low gas cost with carbon price scenario resulted in a price that was 5.9% lower than that shown in the table.

And, while increases in distribution charges were found to be the second largest contributor to prices over the timeframe, the combination of generation fuel costs and generation capacity costs resulted in the generation sector having essentially twice the impact on expected residential prices in 2015 as compared to 2008 as the distribution sector.

11 AGL Applied Economics and Research, *The Boomerang Paradox*, April 2010.

A study by Port Jackson Partners looked at the cost increases in residential electricity prices over essentially the same period, but broke that into two separate time bands – 2007 to 2011 and 2011 to 2017. As can be seen in Figure 2 and Table 5, which follows it, this study is projecting that the factors driving price increases from 2011 to 2017 will be quite different from the factors that drove prices in the preceding period of 2007 to 2011. Most markedly, it projected that wholesale sector prices, after remaining virtually flat from 2007 to 2011, would double from then to 2017, and grow from accounting for under 7% of the price increases experienced between 2007 and 2011 to become the single most significant factor in residential electricity price increases in the 2011 to 2017 period. By contrast, retail costs and margins and renewable energy costs are projected to account for much less of the upward pressure on residential electricity prices from 2011 to 2017 as compared to the 2007 to 2011 period. Network costs will account for about the same proportion of price increases in the two periods, but while they were the biggest factor from 2007 to 2011, they are now projected to account for just a bit less of the upward pressure on prices in the 2011 to 2017 than costs in the wholesale sector.

Figure 2: Component costs of residential electricity prices price 2007 to 2017

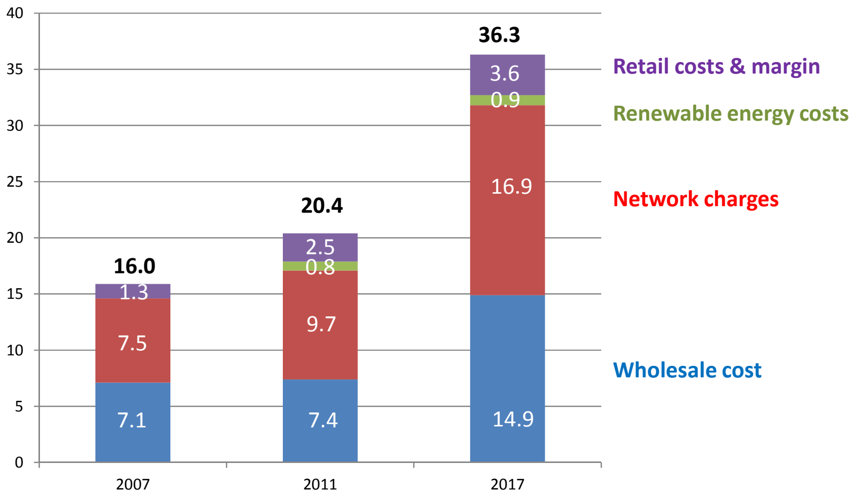


Table 5: Increases in the component costs of residential electricity prices 2007-11 and 2011-17

Component	2007 to 2011		2011 to 2017	
	% increase	contribution to overall increase	% increase	contribution to overall increase
Retail costs and margin	92.3%	26.7%	44.0%	6.9%
Renewable costs	NA	17.8%	12.5%	0.6%
Network charges	29.3%	48.9%	74.2%	45.3%
Wholesale electricity	4.2%	6.7%	101.4%	47.2%
Total		100.0%		100.0%

Source: Edwin O'Young, Port Jackson Partners, *Australia's future electricity price environment*, Presentation to Electricity Price & Market Dynamics Review Conference (IIR Conferences), April 2011.

The AGL and Port Jackson Partners studies also largely agree on the reasons for the sharp increase in wholesale sector costs, as shown in Table 6.

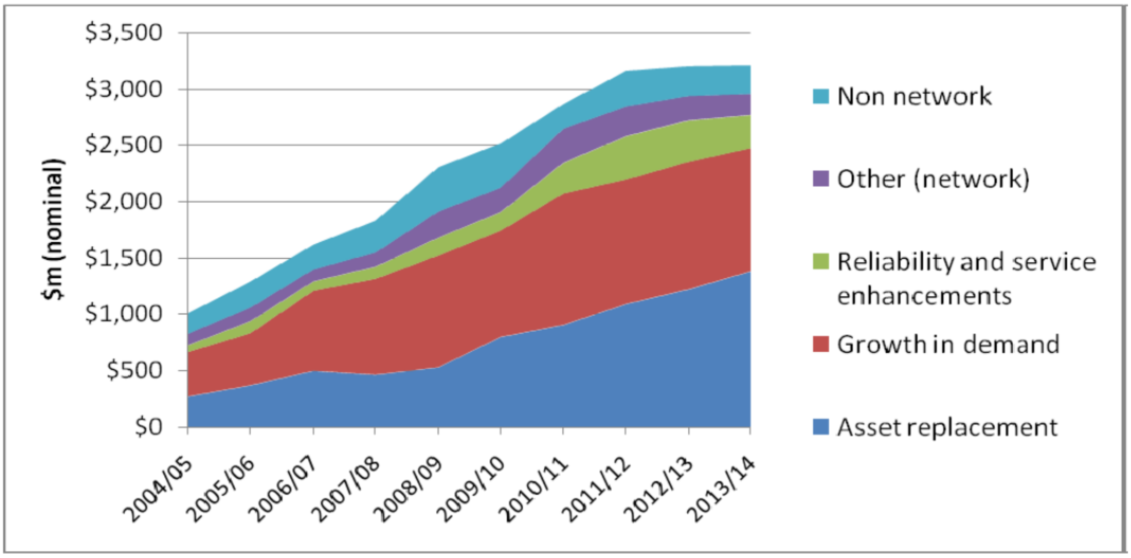
Table 6: Factors wholesale electricity costs from 2011 to 2017

Factors driving wholesale sector costs from 2011 to 2017	
AGL Applied Economics and Research	**Port Jackson Partners**
A run-up in unit fuel prices as Australian coal and gas resources shift from being priced on their local extraction costs plus a margin to world export market prices	Increasing coal prices as coal suppliers gain an export option and as coal contracts come up for renewal
An increase in the cost of power plants exacerbated by the increase of capital costs that resulted from the Global Financial Crisis	Increasing gas prices as the east coast gas market also gains export options
Deteriorating load factors	Suboptimal investment in peaking generation as regulatory uncertainty is making investment in baseload gas uneconomic (while further coal-fired power stations remain unlikely to be built)
Community environment concerns which have led to a tightening of performance standards that will cause a shift in power generation investments from very low cost coal to lower CO_2 emitting gas, and increased use of higher cost renewable capacity via legislated targets, and the possible taxation of carbon emissions	Impact of a carbon price on coal and gas

Sources: AGL Applied Economics and Research, *The Boomerang Paradox*, April 2010, and Port Jackson Partners, *Australia's future electricity price environment*, April 2011.

The *NSW Electricity Network and Prices Inquiry* identified the drivers of network costs over the period 2004-05 through 2013-14, based on the regulatory determinations for those years. As shown in Figure 3 below, growth in demand was the driving force of network costs (and therefore charges to consumers) in NSW in the period from 2005-06 through 2008-09, and is expected to remain a significant component into the future. However, the replacement of aged assets has been the primary driver of network cost increases in the years since 2008-09 and is expected to continue to be the main driver through 2013-14.

Figure 3: NSW distributors' capital expenditure by purpose 2004/05 to 2013/14 (nominal $)



Source: *NSW Electricity Network and Prices Inquiry*, p 28. Note: Based on actual expenditure from 2004/05 to 2009/10 and forecast expenditure to 2012/14, and includes EnergyAustralia's transmission system capex.

The NSW Industry & Investment study also noted that prices in NSW

> *are expected to continue to increase at a faster rate than other jurisdictions largely because of expected increases in revenues to be recovered by distribution businesses as a result of the 2009 determinations by the AER. The largest increases in allowed revenues in the current determinations of the AER are forecast for EnergyAustralia and Country Energy (over 70 per cent in real terms) and Country Energy (52%). This compares to forecast rises in average revenues of 37% in Queensland, 24% in South Australia and 11% in Victoria.*[12]

Finally and most recently, the Australian Energy Market Operator (AEMO) has revised its forecast of total electricity consumption and peak demand through 2021-22[13]. In June 2012 AEMO published a revision of its 2011 forecast[14]. The revised document forecasts that growth in annual electricity consumption over the period will be 1.7%, well down from its original forecast of 2.3%. Similarly, it described its revised forecast growth rate for peak demand as "much lower than in previous years", though in each of the three largest states in the NEM demand growth is still forecast to be higher than growth in total energy consumption, leading to continuing deterioration in system load factors.

12 NSW Industry & Investment, op cit, pp 26 - 27.

13 AEMO' s *Statement of Opportunities* is an annual rolling ten-year forecast of electricity consumption and peak demand for several scenarios of weather and economic conditions. It is used as the starting point for generation investment decisions and is also an important input to the calculations that help determine regulated retail prices at the jurisdictional level.

14 AEMO, *National Electricity Forecasting Report for the National Electricity Market 2012*, June 2012, available at http://www.aemo.com.au/en/Electricity/Forecasting/2012-National-Electricity-Forecasting-Report .

AEMO's revised forecast was published after all of the studies referred to above. The reduced rate of growth in peak demand in the revised forecast will change the time at which additional generation capacity will be needed, and will also reduce the amount of network capacity augmentation that needs to be undertaken during the forecast period. This will reduce the pressure that capacity expansion is having on forecast electricity prices. However, it will have very little impact on unit fuel prices or the capital required to fund the replacement of aged distribution infrastructure assets that is forecast to be needed over the period. In addition, the continued deterioration of annual system load factor in the revised AEMO forecast means that a greater proportion of the total infrastructure in the NEM will actually be needed for only a very few hours per year. This will put upward pressure on electricity prices and bills as compared to what would have been the case had load factors remained unchanged.

3.3. Factors that affect electricity prices and their controllability

In light of the above it is worth briefly reviewing the factors that affect the costs incurred by the electricity sector and therefore electricity prices, and the degree to which they can be controlled. Table 7 provides such a review.

Table 7: Degree to which the factors affecting electricity prices can be controlled by government policy

Factor	Description	Level of controllability by policy
Supply side factors		
Cost of fuel	Cost paid by electricity generators for the fuel used to generate electricity, most relevantly for coal and gas	Largely not under the control of government policy although it should be noted that resource development policies can affect fuel prices
Cost of construction materials	Costs for the materials such as concrete and steel used to build electricity generation and network infrastructure	Largely uncontrollable by government policy
Regional/world demand for electricity generation and transport equipment	Most of the specialised equipment used in electricity generation and transport such as turbines and transformers is manufactured overseas and is subject to world prices. Demand in other parts of the world for can affect prices paid in Australia.	Not controllable by government policy
Cost of capital	Electricity generation and transport assets are built with debt financing. Higher capital costs increase the costs that must be recovered in electricity prices.	Not directly controllable by government energy policy, but it should be noted that how risk is apportioned between market participants and consumers can affect the cost of capital applicable to energy asset investments. In addition, the consistency (or otherwise) of government policy can affect investors' perception of sovereign risk and thereby the cost of capital.
Labour costs	Though labour costs are not a major input to the cost of electricity, times of high wage inflation increase upward pressure on electricity prices and vice versa	Largely not controllable by government policy and not controllable by energy policy on its own
Availability of substitutes	Where alternative means exist for meeting consumers' needs (gas, wood, solar or wind) they can affect the amount of electricity required and therefore the amount of fuel and infrastructure required	Largely not under the control of government policy although resource development policies and other policies can affect the availability of certain alternatives
Demand side factors		
Weather	Warmer summers and cooler winters increase electricity consumption for space cooling and space heating; multiple consecutive days of very hot weather are the primary cause of peak demand on the generation and transmission systems and many parts of the distribution networks	Not controllable by government policy

Factor	Description	Level of controllability by policy
Economy	Electricity consumption is higher when the economy is strong and growing and lower when the economy is weaker, due to the rise and fall of economic activity	Not directly controllable by energy related policy
Load duration curve[15]	The peakier the load duration curve, and therefore the lower the load factor, of aggregate consumer demand the more infrastructure that needs to be in place per unit of electricity sold, thereby increasing unit costs	Can be affected by government policy (as noted below) but the most significant factors driving the load duration curve are outside direct government control
Roles of market participants – particularly the availability of parties to act as agents for consumers	The roles and responsibilities of the parties involved in the electricity market (market participants) – and particularly whether any parties are specifically empowered and resourced to act as agents for consumers – can affect the degree to which the consumer's perspective is incorporated into aspects of electricity system planning that affect price. Relevant examples include the setting of reliability standards, and the use of demand response to defer and/or reduce capital requirements	Controllable by government policy, licensing and regulatory arrangements
Pricing, product and service offerings	How electricity is priced can affect demand. Current pricing – particularly for smaller electricity consumers does not reflect the fact that the cost of supplying electricity varies significantly by time of day, season and location. Prices that do not reflect these differences result in overconsumption when prices are lower than costs and over-conservation when prices exceed costs.	Controllable to a degree in the NEM's de-regulated market through licensing and the regulatory framework.
Government policy	Government policy concerning energy efficiency, environmental standards of various sorts and renewable energy utilisation (e.g., RET, ESI) can help consumers save money on their power bills. Similarly, government programs to assist vulnerable customers can have a direct impact on the affordability of electricity for those consumers. However, all of these programs and policies will also affect the costs incurred and revenues received by the electricity supply industry. Where revenue is reduced to a greater extent than costs, there will be an upward pressure on electricity price, at least in the short term, though there may be a reduction in prices in the longer term.	Controllable by government; requires careful analysis and balancing of different and sometimes competing policy objectives.

15 A load duration curve is used to to illustrate the relationship between the capacity requirements and capacity utilisation of an electricity system. In the curve, the amount of electricity required in aggregate by customers in each half hour over a period of time (typically a day, week, season or year) is ordered from highest to lowest. The height of the highest demand is related to the amount of generation and network capacity that will be needed to meet customers' needs. The area under the curve represents the total amount of energy that customers require over the period. The more the load duration curve looks like a rectangle, the more efficiently the electricity system's assets will be used and, all other things being equal, the lower the per-unit price of electricity will be.

4. Options for putting downward pressure on costs and improving affordability in the Generation sector

Consistent with the approach described in section 2.2, this section first considers how efficient the generation sector is, and then discusses options for improving the efficiency of its operation and how its costs are communicated to consumers.

4.1. Is the sector as efficient as possible?

Wholesale electricity prices in the spot market have not risen appreciably in comparison to inflation[16]. In fact, prices in the spot market have often been below the long-run marginal cost (LRMC) of generation, which is likely to have discouraged investment, particularly in larger baseload generation facilities.

On the other hand, prices have, at times and in certain locations, risen to levels that are not readily explainable and that have raised concerns on the part of consumers, governments and market regulators. Furthermore, as gas and coal prices rise, it will be critical to ensure that the wholesale market is operating efficiently and competitively.

It is also the case that the costs incurred in the generation of electricity as embodied in the spot price are not particularly well communicated to consumers. Even large consumers – who have the types of meters that support the communication of more sophisticated pricing, and the technical expertise to understand and respond to those price signals – generally opt for and receive electricity prices that are no more finely differentiated than in terms of three different time periods within a day (peak, shoulder and off-peak) for each of three different seasons (summer, winter and shoulder). The pricing for most business customers is significantly less differentiated, and most residential and small business customers receive electricity energy prices that are entirely undifferentiated -- the price remains the same all day, every day of the year.

While large customers can receive entirely cost reflective prices from the spot market – by taking full exposure to the spot price either by becoming a market participant or opting for a retail contract that provides pool-price pass through – this is rarely done. The first of the two approaches is available to only the largest of customers (those with demands greater than 30 MW). Only a handful of consumers have taken this option in the history of the NEM. More commonly a large electricity user will enter into a contract with the retailer that exposes the customer's load directly to the pool price, but then also adds a feature whereby the retailer purchases financial hedges for that customer on an individual basis. Such an arrangement will then remove most of the price and volume risk that the customer would face from the spot price alone. Any remaining volume risk faced by the customer can be mitigated by the exercise of demand reduction at times when the customer's consumption may exceed the volume of contracts it has available at a particular wholesale market price.

Other customers – though generally only down to medium-sized commercial and industrial businesses – can use demand response to reduce the impact of their loads on their bills – but only where their retailer is willing to provide such an arrangement, and only through the retailer from whom they purchase their electricity.

In addition, almost all electricity users face significant information and other barriers regarding management of their electricity usage. These include:

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16 See http://www.aemo.com.au/Electricity/Data/Price-and-Demand/Average-Price-Tables

- Their technical ability to determine how to respond to time-varying prices effectively – most customers lack in-depth knowledge about how electricity is consumed within their facilities and operations, or ways that consumption can be reduced[17].
- Their access to and competition for capital within the business or household – even where a consumer may have an appreciation of the benefits of reducing or managing their consumption of electricity, the capital they are likely to have – or be able to access – will be finite and as a result, those uses will have to compete with other uses of capital. In the case of a business this will include investments in the core function of the business, and for households it will include uses such as holidays and other investments in the home.
- Their timeframe for investment decision making – electricity assets are long-lived, whereas most consumers will expect any investment they make to show a return or pay their investment costs back within a much shorter time.
- Split incentives where the costs of the energy consumption are borne by one party (such as a tenant in a commercially leased building) while the capital costs for managing energy consumption would be borne by another party (in this case the building owner).
- The materiality of electricity costs in comparison to other costs experienced by the business, organisation or household. For most business consumers, electricity costs will account for less -- and in the majority of cases, significantly -- less than 2% of total business revenue[18], even where the electricity bill is hundreds of thousands of dollars annually. Business managers only have so much time available and can be expected to focus on the areas of cost that have the most impact on their commercial returns – primarily their costs and the quality of their product.

It should be noted that these barriers are relevant for virtually all electricity users and concern all parts of the electricity bill, not just the portion that represents their use of wholesale electricity energy.

Despite (or perhaps because of) these barriers, the wholesale electricity market must be considered a meaningful locus for government policy involvement given the information presented in section 3 above, in particular, the fact that:

- The generation of electricity currently represents approximately 40% of the consumer's bill
- Wholesale electricity prices are expected to double between 2011 and 2017, and to account for just under half of the total increase consumers are likely to experience in their power bills over that time.

17 Among residential consumers this includes a lack of understanding about how much electricity different appliances and end uses consume. A study published in the Proceedings of the National Academy of Science referred to by the Climate Spectator found that participants underestimated energy use and savings by a factor of 2.8 on average, with small overestimates for low-energy activities and large underestimates for high-energy activities. This is likely to result in these consumers worrying unjustifiably about end uses that do not account for much of their bill and giving inadequate attention to things that could make a material difference to their bill. See http://www.climatespectator.com.au/commentary/do-energy-consumers-know-best

18 An Ai Group energy efficiency survey published on 13 July 2012 surveyed over 300 businesses and found that 75% spent less than 2% of sales revenue on energy (electricity, gas and liquid fuels combined). See *Energy shock* at www.aigroup.com.au/policy/reports.

4.2. Possible solutions

This section discusses areas in which policy undertakings could improve the efficiency of the generation sector in terms of its operation or pricing, and consumers' ability to respond to those prices. Three possible solutions are discussed:

- Improving consumers' ability to 'sell' demand response into the wholesale market
- Establishing a capacity market mechanism whereby peak demand capacity – and the ability to provide it through demand reductions – would be treated as a commodity within the NEM
- Reviewing the standard that is currently used to define the level of reliability that the generation sector is expected to meet.

It should be noted that the first two of these options are logical alternatives to one another; they would not be implemented at the same time. We discuss them in the order we do because (a) the AEMC has recommended that an approach of the first type be implemented, and (b) the second represents a more significant departure from the current market design and would require significantly more work to develop, implement and properly resource.

The third of the options could be implemented in combination with either of the other two options, or even if neither of the other two options is implemented.

4.2.1. Option G-1: Ability for consumers to sell demand response to the wholesale market

As noted above, this option has been recommended in the AEMC's *Power of Choice Review*. Under this option, consumers will be able to sell their demand reduction to the wholesale market much as generators sell supply.

Key features

Key features of the approach include[19]:

- The consumer would be able to provide demand response to the wholesale market either directly, through his/her electricity retailer, or through a third party. (Note that a minimum size – probably 30 MW – would be required for the consumer to provide the demand response directly to the wholesale market.)
- The consumer, retailer or aggregator providing verified demand reduction would receive the market price for electricity at the time the demand reduction was in place[20]
- The consumer that provides the demand response would have to pay their regular retailer for the amount of energy that was reduced due to the provision of the demand response (thereby leaving the retailer no worse off in terms of expected revenue)[21]
- Similarly, the retailer in question would be required to pay the wholesale market at settlement the spot price for the amount of energy that was reduced due to the provision of the demand response – that is, as if demand response had not been exercised

19 A detailed description of this option can be found in section 5 of the AEMC's *Draft Report: Power of choice - giving consumers options in the way they use electricity*, September 2012.

20 If demand response participates in the market as a scheduled load it can set market price.

21 Because the consumer's retail electricity price will be less than the wholesale market spot price at the time the demand response is called for, the consumer will benefit in an amount equal to the difference between the spot price and their retail electricity price for every kilowatt-hour they reduce their consumption by during the demand response event.

Key benefits of the approach as compared to present arrangements within the NEM and previous approaches to facilitating participation of the demand side in the NEM include:

- This allows the consumer providing the demand reduction to capture a significant proportion of the benefit provided by that demand reduction to the electricity supply chain and all consumers (in terms of potentially reduced capital costs)
- By requiring (a) the provider of demand response to pay the retailer the retail price for the energy not consumed and (b) the retailer to settle with the wholesale market for the electricity verified to have not been consumed at the prevailing wholesale price, the arrangement (i) leaves the retailer no worse off, (ii) should not affect any hedging contract arrangements, and importantly (iii) avoids the 'missing money' problem[22] that has generally plagued demand response arrangements in energy-only markets
- It increases competition to the market for demand response.
- There is the potential that the involvement of the demand side will improve dynamic efficiency, that is, make the market more efficient under a wider range of changing conditions.

Magnitude of impact

The potential magnitude of this measure is material.

AEMO estimates that there is currently 521 MW of demand response in the NEM, 218 MW of which is described as being very likely to reduce consumption in response to high prices, and the remaining 303 MW of which it described as having an even chance of doing so[23]. By contrast, experience in electricity markets in which effective arrangements for demand response have been implemented and in place for some time indicates that somewhere in the range of 6% of 8% of aggregate consumer peak demand can be met through demand response. In the NEM, given its peak demand of approximately 35,000 MW, this would be equivalent to something in the range of 2,100 to 2,800 MW – a fivefold increase on present levels.

A study commissioned by EnerNOC[24], the largest demand-side aggregator in Australia, that was conducted by CME estimated that if peak demand in the NEM were reduced by 3,000 MW – equal to about a 9% reduction – it would have avoided approximately $2.3 billion in generation capacity costs – and $15.8 billion if the avoided cost of transmission and distribution capacity that would also not be needed is taken into account.

22 The missing money problem typically arises when a market provides payment for demand response. In such cases, the money used to pay the consumers that provide demand response has to be recovered from an uplift on electricity prices to all consumers or some other form of levy. The option put forward by the AEMC avoids this by treating the demand response as a form of generation and ensuring that all of the financial transactions associated with that generation proceed as they would usually.

23 AEMO, *National Electricity Forecasting Report for the National Electricity Market 2012*, Appendix D, p D-2.

24 CME, *Reducing electricity costs through Demand Response in the National Electricity Market*, August 2012.

The study also concluded that if that amount of demand reduction had been in place, total electricity prices would be 9% lower than their current levels. Based on the proportion of capital cost saved in the generation, transmission and distribution sectors this would translate into an expected 1.3% reduction in the contribution of the generation sector to final electricity prices[25].

Measurability of impact

As can be understood from the previous section, the measurability of the demand reduction provided through this mechanism is one of its integral and critical elements. Although it is beyond the scope of the current paper to discuss them in full here, verification protocols have been developed elsewhere and in Australia that have been shown to provide suitably accurate assessments of the demand response delivered to support its financial valuation and settlements in the market.

Measurability of the impacts of the mechanism on the market can be undertaken through aggregation of the individual claims, all of which will be known to AEMO, the market operator.

Timing of option benefits and costs

This option would provide immediate benefits to participating consumers, but might take several years to show wider benefits through investment deferral or lower spot prices.

Deferral of investment in new generation capacity is unlikely before 2018 given the current level of installed capacity in the NEM and the rate of growth in peak demand, which was revised downward in AEMO's revised forecasts published in June 2012.

It could have an impact on price sooner than that if the demand response brought forward by the measure (a) is large enough to change price and is bid into the market in a way to do so, and (b) is exercised on a consistent basis in relation to a specific price level (or levels). While this may happen, it does not seem likely in at least the first year or two years of the option being in place[26].

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25 It should be noted that the CME study used a static rather than dynamic approach to estimate avoided costs. Such an analysis assumes every kW reduction would reduce costs in all three parts of the electricity supply chain, ignores the fact that the change in loadshape would affect the timing and nature of other capacity additions, ignores the fact that bidding behaviour in the wholesale market would change (as the base and intermediate generators would no longer get the revenue associated with periods of high peak demand and would therefore be likely to change their bids in other periods to ensure revenue adequacy over the course of the year), and does not account for the costs that would be incurred in effecting the demand response. As a result, the actual impacts of a 3,000 MW reduction in peak demand on price would almost certainly be lower than those projected. However, other assessments that have compared the results of static and dynamic analyses of the impacts of demand reductions suggest that the impacts are still material.

26 Under the approach proposed by the AEMC demand response would be able to participate in the market on either a 'non-scheduled" or "scheduled basis". On a non-scheduled basis, the demand side provider can receive the prevailing spot price (based on what the load would have been if demand had not been reduced), and it is not required to meet any specific dispatch requirements. Under the scheduled approach the demand response provider must let the market operator know how much demand it will shed at what price point and for how long. Once the bid is accepted the amount of demand response promised must be available for the time specified.

Likelihood of success

The availability of and ability to deploy demand response has been proven in numerous markets[27], including on a somewhat limited scale in the NEM.

The administrative costs associated with the option are likely to be fairly low, and relate primarily to reviewing the verification of demand reductions delivered (to be provided by the demand response providers) and exercise of the information within the NEM settlement process. Any costs associated with these activities incurred by AEMO would be recovered in the NEM market fees. It is unlikely there would be any cost to government.

Rather, the majority of the cost of this option would be incurred by private parties (i.e., outside the market). These will include costs borne by consumers who wish to provide demand response and aggregators/retailers who wish to provide the demand response to the market. Primary costs will be for the control and other technologies that enable demand response, and the monitoring/verification processes and systems that will be needed (primarily by aggregators and retailers). Note that these costs will influence the price at which demand response participates but experience in other markets and from analyses here indicate that significant levels of demand response can be provided at costs significantly lower than those that characterise the top end of the NEM price duration curve.

Effect on specific stakeholder groups

The measure can be expected to have direct and positive impacts on consumers that can provide demand response, and aggregators that can develop a successful business model to assist them in doing so. Customer groups most likely to benefit at least initially will be larger commercial and industrial establishments with the potential to reduce peak demand by at least 100 to 200 kWh. This has to do with transaction costs faced by the aggregator, including verification costs. Wider spread use of Advanced Metering Infrastructure could open up potential participation by smaller and ultimately mass-market consumers.

There is also the potential for other consumers to experience lower electricity costs due to this option. This could result if the demand response brought forward (a) changes the spot price in the wholesale market (which would affect the price paid by all electricity consumers)[28], or (b) is sufficiently concentrated geographically and exercised in such a way that it defers the need for specific network capacity augmentations (which would affect the price paid by electricity consumers within that distribution service area).

Generators – in particular peaking generators – will lose revenue due to (a) a lower volume of electricity required from them at those times when demand response is activated, and (b) the potential for spot prices to be lower than they otherwise would have been due to the presence of demand response[29].

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27 Demand response mechanisms have been incorporated into several US regional electricity markets, including the Pennsylvania New Jersey and Maryland (PJM) market, the New York Independent System Operator (NYISO) market and the Independent System Operator New England (ISO-NE) market.

28 Demand response brought forward under this option could affect wholesale market prices in two ways: (1) where the demand response is provided on a scheduled basis it could set spot price, and could do so at a lower level than it would otherwise have been, which in turn will affect forward contract prices, and (2) where demand response is provided on a non-scheduled basis, the potential that it *might* be activated could influence generators to moderate their bids

29 The potential for demand response to be activated might influence generators to reduce their bid prices where that lower bid price would keep the demand response from being activated and thereby reduce volumes and therefore generators' revenue.

Importantly, retailers will not be directly negatively affected by the workings of this option. The approach proposed in the AEMC draft report would ensure they receive the revenue that would have been generated if the consumer providing demand response had not reduced his load. However, the approach would open up the ability for a separate party to have an on-going commercial relationship with the customer regarding the use of electricity, which may be of concern to retailers[30].

Consistency with electricity market philosophy and direction

The arrangement introduces a mechanism to allow a demand side player to capture the marginal value of balancing supply and demand at peak. In doing so, it treats the demand-side provider very similarly to a generator. The option is consistent with the philosophy of the NEM.

4.2.2. Option G-2: Capacity market mechanism

Key features

The optimum cost of developing and operating a generation sector is dependent on the type, timing, location and dispatch order of generation plant. In an efficient market the full costs and an economic profit (and no more) will be paid to the generation sector by customers.

There are a number of ways of determining how that payment should be made. A market is generally described as a capacity market if it includes a payment for availability regardless of energy production, plus a payment for dispatched energy. In principle there is no difference in the cost of the optimum generation sector in a capacity market or an energy-only market, but the total cost will be split across capacity and a (different) energy payment than currently occurs in the NEM energy-only market.

A capacity market mechanism is at times presented as a means to reduce costs. This may or may not be valid depending on the circumstances, as the level of a capacity payment is generally determined administratively with some level of guaranteed payment to generation and thus cost to consumers. That is, a capacity mechanism shifts the risk of forecasting inaccuracy from generators to consumers. On the other hand, energy prices are generally less volatile and therefore risks are more contained.

A capacity market can be seen as providing a more explicit value for demand response because it includes (a) an explicit price, and (b) the ability for demand response (and supply-side resources) to receive an availability payment. As noted above, the availability payment shifts the risk of forecast errors to electricity consumers in aggregate (as energy prices will presume a portion of fixed costs are recovered in the availability payment) whereas forecast risk in the energy-only model resides with investors in peaking generation.

30 Some retailers have commented that this option could increase hedging costs. This is currently being assessed by the AEMC.

Magnitude of impact

A capacity market has the potential to bring forward more demand response than the NEM has to date as evidenced by the comparison of the 7% contribution of demand response to installed capacity in the Western Australia Wholesale Energy Market (WEM) with the 3% contribution in the NEM, although there is concern this may have resulted in an overall over-investment in supply and demand side resource, as reflected in the "capacity cushion" in that market[31]. In addition, the introduction of capacity market would constitute a fundamental change in the design of the NEM; it is therefore worth considering less substantial changes first. The AEMC proposal for payment to Demand Response described above is such an option.

Note also that there may be a limit to the amount of demand response that can be accepted within a capacity mechanism based on the availability of the resource at different times of the year and different times of day in which it is likely to be needed.

Measurability of impact

The measurability of the impact of this option would be relatively straightforward as the increase in the amount of demand response in the market could be readily discerned on a pre-/post- basis.

The impact of the option on the overall costs of the electricity supply chain would also be able to be measured on a pre-/post- basis, though a number of other factors might affect those costs over the time period in which the market transitioned from its current energy-only basis to the capacity mechanism – these other factors would need to be isolated and removed from the analysis.

Timing of option benefits and costs)

It is likely that the consultation required to consider and to agree that a capacity mechanism should be introduced and the need to allow existing market participants and market bodies to build the systems and procedures required to operate the mechanism would take some time – probably no less than 2 to 3 years, and potentially significantly longer.

Once implemented, a capacity mechanism would immediately provide an explicit price signal for demand response, and the market would begin to take up the potential to offer demand response.

Likelihood of success

As mentioned above, the likelihood of success with regard to this option will depend on (a) the ability for key parts of the market and industry to be persuaded that it is appropriate, and (b) measures to be put in place that help ensure that the overall costs of the electricity generation sector remain below what they would have been under a continuation of the energy-only market design. This will largely centre on processes to ensure that the price set for capacity is appropriate.

Effect on specific stakeholder groups

The introduction of a capacity market mechanism would provide:

- larger consumers with an opportunity to earn availability payments for being willing to reduce their consumption upon notification;

31 A capacity cushion is the amount by which reserve exceeds the amount deemed to be needed to meet the reliability standard and will be zero if there is a perfect match.

- all consumers with the potential for electricity costs to be lower if the introduction of a capacity payment led to a net improvement in long term investment and operating efficiency;
- however, consumers would also now be exposed to forecast risks previously borne by investors in generation plant[32].

There may be negative impacts on generators depending on the final design and how the transition is managed. In the transition, existing plant could be utilised less and suffer reduced revenue. While generators face this risk at present from competitive entry of other generators, it is also the case that some generation assets could be stranded if the capacity payment brought forward sufficient reliable demand side participation. In the longer term, there may be less opportunity for generators to invest in additional capacity.

Retailers should not be materially disadvantaged, at least in revenue terms. However, the involvement of demand response aggregators may increase competition for the allegiance of customers.

Consistency with electricity market philosophy and direction

The implementation of a capacity mechanism would represent a significant departure from the energy-only design of the NEM, as it would explicitly introduce capacity/demand as a priced commodity in the market. It should be noted that the AEMC, in its Power of Choice Review, noted this fact and felt that other mechanisms more in keeping with the NEM market design be tried before trying this option.

4.2.3. Option G-3: Review of reliability standards

Key features

The NEM reliability standard of 0.002% unserved energy requires that sufficient supply-side capacity be in place to meet 99.998% of the aggregate consumer demand that could be expected to occur over the course of a year[33].

32 In an energy market, generators are paid only when they generate electricity. As a result, where a generation plant is not dispatched as often or as much as much as required to repay its capital costs (due to lower demand or the dispatch of demand response), its investors will bear the costs. In a capacity market, by contrast, the market operator makes a decision about how much capacity is needed to meet demand and enters into capacity contracts with generators to have that amount of capacity available, should it be needed. As a result, investors get paid regardless of whether or not they are dispatched, and that payment is recovered from all consumers in the market. In the event that demand is less than the amount contracted for, consumers will have paid for generation capacity that was not used.

33 A simplistic way of conceptualising this is as a requirement that consumers not experience more than 10.5 minutes of supply interruption per year. This simplification assumes that the consumer's electricity usage is spread evenly across all hours of the year – which is generally not the case. Therefore, meeting the standard would require a significantly lower duration of supply interruptions during waking hours when most consumers use more than their average amount of electricity.

It is possible that a lower level of reliability could reduce electricity supply chain costs more than it would decrease value to consumers due to the interruption of business processes and reduction in comfort, convenience and amenity. Note however that the NEM has generally delivered better than 0.002% reliability – and because this higher level of reliability is likely to be the result of there being more generation capacity available than is actually needed, this is likely a contributing factor to the generally lower than LRMC price outcomes). Note also that debate on performance in this area can easily be clouded by the impact of rare security-of-supply events that are largely independent of the level of supply-side capacity – for example, a bushfire taking out multiple transmission circuits resulting in widespread interruptions to control the risk of a complete system shutdown.

The cost savings that would be obtained by a reduction in capacity requirements to a different (lower) reliability level could be quantified and compared to the impacts of lower reliability on businesses within the NEM, the economy in the NEM jurisdictions and the comfort and quality of life of NEM electricity consumers in general.

Magnitude of impact

The magnitude of the impact of such a review would potentially be relatively limited as compared to the impact of the other options discussed here. This is because it would only affect a portion of the capacity associated with peak demand.

Measurability of impact

Measurability of the supply chain cost reductions would be very clear and transparent as the impact of capacity requirements at the current and revised reliability levels could readily be compared and valued.

Measurability of the costs to the community in terms of business interruption and loss of amenity are significantly more difficult to quantify with certainty, though techniques for doing so exist and have been applied in several studies, the results of which have been used to provide a quantitative estimate of the value of incremental changes in electricity supply reliability to consumers for network planning purposes and the setting of regulatory incentives.

Timing of option benefits and costs

A review and change of reliability standard would be unlikely to change cost impacts that would affect electricity pricing before 2018, given AEMO's current demand forecast. However, such a change would then have an enduring downward impact on electricity supply costs as compared to a higher standard.

Likelihood of success

Likelihood of success would be high, as the mechanism could readily be implemented, and, as a standard, would definitely affect the amount of capital expenditure on generation infrastructure.

The costs would consist solely of the assessment of the potential capex implications of specific changes in the reliability standard and the relationship of that to the costs that such a change would impose on different consumer segments (which could also be compared with the amount of compensation consumers would require to accept specific reductions in supply reliability) and the economy within the NEM. It is unlikely that such studies would cost more than $1.5 million.

Such a change in generation system reliability standards would probably not impose any incremental on-going costs, unless some form of compensation were to be considered for specific customer segments (see further discussion below).

It should be noted, however, that the costs of the study could be incurred and no benefit achieved if the study were to determine that current reliability standards are correct or that the benefits of reducing them are insufficiently material.

Effects on specific stakeholder groups

To the extent that a reduction in reliability standards reduces electricity supply chain costs, all customers would benefit from reduced electricity prices.

However, specific customer segments that require a level of reliability above the revised standard (in the event the standard were to be reduced) would incur damages (either tangible or intangible) and/or costs for mitigating those impacts through reliability enhancements within their own facilities. For instance, hospitals might need additional backup generation capacity, as would residential customers whose health depends on special electrical medical equipment or the maintenance of particular temperature or other conditions[34].

Consistency with electricity market philosophy and direction

Such a change would be entirely consistent with existing NEM design, processes and philosophy.

34 Many of these types of consumers require special consideration regardless of the actual reliability standard within the market, but lower standards are likely to mean that those considerations will need to be relied upon more frequently or to a greater extent.

5. Options for putting downward pressure on costs and improving affordability in the Networks sector

Consistent with the approach described in section 2.2, this section first considers how efficient the network sector is, and then discusses options for improving the efficiency of its operation and how its costs are communicated to consumers.

5.1. Is it as efficient as it could be

There are a number of reasons to believe that the efficiency of the network sector could be increased – particularly in terms of asset utilisation. These include:

- Price increases in the past several (and next few) years are forecast to significantly exceed historical trend in several jurisdictions. While this, in and of itself, does not indicate that the sector is inefficient, the fact that pricing practice does not reflect cost drivers significantly reduces the ability of the demand side of the market to respond in ways that would reduce costs for both the user and the network service provider (and thus all electricity users);
- Difficulties that have been noted in the regulatory process and outcomes; and
- There have been significant differences in costs, prices and outcomes between government-owned and privately-owned network businesses.

In addition, costs are not communicated well to consumers:

- Prices to small consumers are generally expressed in a fixed daily or monthly charge and either a flat consumption charge (in $/kWh) or a set of flat consumption charges in which the $/kWh per-unit price increases as consumption increases (generally referred to as an inclining block tariff)[35]. Despite the fact that network costs are primarily driven by capacity requirements and therefore vary by both time and location, very few distribution companies use time-varying tariffs. And, where time of use pricing is in place, it rarely reflects actual costs, which are driven by consumption during critical, localised peaks that may only last 40 hours a year. For example, in Victoria some network time-of-use tariffs have a 'peak' that lasts from 7AM to 11PM.
- It is also the case that network prices are directed at different customer classes, rather than how various customers use the network. For example, small commercial and residential customers are often subject to tariffs with different structures and different price levels despite the fact that they use the same level of distribution system asset and have the same types of meters. It would be less discriminatory for network tariffs to be based on the level of distribution asset used by the consumer (probably defined in terms of the voltage level at which the consumer takes supply) and the details of the consumer's usage as discussed above.
- Larger customers are likely to be subject to and receive prices based to a greater extent on factors related to network capacity requirements (including power factor, any time maximum demand, and fixed charges) but even these could be significantly improved with available metering and communications technology;
- Significant information and other barriers exist in all customer classes and with regard to the bill as a whole, and not just the network portion of the bill, as discussed in section 4.1.

35 There may be some examples of declining block energy pricing structures for larger commercial/industrial customers.

These costs are material in terms of consumers' current bills and the increases that are projected to affect their bills in the next five years and likely beyond. For example:

- The network sector currently represents between 45% and 50% of the consumer's bill; and
- Network charges are expected to increase by about 75% between 2011 and 2017, and to account for about 45% of the total increase consumers are likely to experience in their power bills over that time.

Based on these facts, the network sector market must be considered a meaningful locus for government policy involvement. However, as noted in section 3, there are a number of factors that drive network costs and the relative importance of each will vary across networks and for any given network across time.

5.2. Possible solutions

This section discusses areas in which policy undertakings could improve the efficiency of the network sector in terms of its operation or pricing, and consumers' ability to respond to those prices. A total of ten possible solutions are discussed across four different areas, as summarised below:

- Enhanced and strengthened regulation – Two separate options are presented in this area:
  - Option N-1a: Greater exercise of existing regulatory powers by the AER
  - Option N-1b: Introduce and support a consumer advocate as a regular participant in network regulatory processes

These two options can be pursued in parallel, and in parallel to all other options.

- Incentives to encourage greater efficiency in network capital and operating expenditures -- Two options are presented in this area:
  - Option N-2a: Capacity efficiency carryover mechanism
  - Option N-2b: TOTEX as a more effective incentive for cost-efficiency.

  These two options should be seen as alternatives to one another. They would not be undertaken simultaneously; one would be preferred and tried in advance of the other. Should the option that was tried first not work, consideration could be given to trying the other. Given the nature of the two options, it would probably be more likely that option N-2a would be tried first.

- Increased network business proactivity in finding, using and supporting demand side response and demand side resources, including distributed generation – Four separate options are presented in this area:
  - Option N-3a: Increased use of interval metering
  - Option N-3b: Mandated demand-side plans
  - Option N-3c: Targets with incentives/penalties for networks to use demand-side resources to defer augmentation (note that there a number of approaches that can be taken to setting the target)
  - Option N-3d: Role and return for networks as owners of assets that facilitate demand response and/or distributed generation.

Of these, the first – increased deployment of interval metering - could work in concert with more direction from the AER regarding the use of network price structures that provide more efficient pricing signals to consumers. Such pricing would help ensure that the demand of electricity end-users reflected their assessment of the value derived from electricity as compared to the cost of supplying it.

The second and third options reflect differing levels of obligation being put on networks to become actively involved in enlisting the demand side of the market to provide the most economically efficient approaches for meeting aggregate consumer demand within the network. Either or both could be undertaken, or they could be undertaken sequentially.

The fourth option would allow network businesses to use certain network assets (primarily communications and control technologies) to provide demand management services to retailers or aggregators. Its implementation should be conditional on a study of its likely impacts on innovation and competition in demand-side services.

- Review of applicable reliability standards (Option N-4)
- Privatisation (Option N-5).

Each of these options is discussed below. However, it should be noted that the solutions discussed here focus primarily on improving the present regulatory arrangements, and therefore, would most logically be tried first. Other, more radical approaches do exist, and could be investigated instead of the options presented here, or in the event that these options do not sufficiently rectify the observed inefficiencies. These more radical approaches include (but are certainly not limited to):

- increasing the ability for new entities to build and own extensions to existing networks, or new networks embedded within existing networks;
- establishing a standing mechanism for registering end-users' demand response capability that distributors would be required to take account of in any network augmentation planning
- introducing a standing price (specific to each distribution network level) for delivered demand reductions
- introducing periodic license reviews to assess the degree to which network businesses have performed to expectations and reserving the right to make the license contestable in the event that performance has been below a stated level;
- undertaking a comprehensive forward-looking review of the regulatory framework to determine its ability to encourage innovation and meet the likely changing conditions of electricity generation and use.

5.2.1. Option N-1a: Greater exercise of regulatory power by the AER, including in regard to network capital expenditure and returns (Enhanced and strengthened regulation)

Key features

The current regulatory process as practiced by the AER uses a propose/respond model, which has significant potential difficulties including:

- Significant information asymmetries – While any form of regulation will suffer from this to some degree (after all it virtually impossible for the regulator to know more or even as much about a business as its owner or operator), how the regulatory process seeks to overcome this asymmetry is of key importance.

- Limitations on the AER's capabilities and resources available to reduce that information asymmetry. Addressing this will require additional funding for more and better trained staff, additional training of existing staff, and additional resources in the form of tools and the ability to contract expertise where needed.

Areas in which existing regulatory powers could be more effectively exercised include:

- More scrutiny of augmentation and other costs, through approaches such as benchmarking
- More effective use of incentive mechanisms to harness the self-interest of network owners and operators for the good of consumers
- More scrutiny of and direction regarding pricing structures (to increase cost-reflectivity). The Rules require that prices be set between stand-alone and marginal values. This direction, combined with the National Electricity Objective ("to promote efficient use of electricity services…") should provide adequate scope for the AER to become involved. The key issues appear to be (a) the degree to which the AER is "policing" the Rules, and whether the underlying incentives within the various regulatory control mechanisms being used (i.e., the weighted average price cap and the revenue cap) provide appropriate incentives to the business to set cost-reflective prices.
- Consideration of the differences in debt financing costs between private- and government-owned networks, including (a) re-consideration of the debt risk premium and the difference in debt costs for private and government-owned network businesses and (b) development of recommendations regarding guidelines on dividend policy for government-owned businesses.

Magnitude of impact

The potential impact of improvements in these areas is very high, given that they address the major determinants of network costs.

Measurability of impact

Measurability of the impacts would require calculation of the cost reductions realised due to the new regulatory approach having changed the approach or costs proposed by the network business. The problem with this is that the counterfactual cannot be enunciated with a particularly high level of confidence.

A better approach would be to assess costs before and after use of the new regulatory approaches in comparison to the Australian businesses and possibly a set of international businesses.

Timing of option benefits and costs

It is likely that development of the skills, resources and processes required for this change would take some time, and would then not be put in motion until the first regulatory determination thereafter, with impacts on price to be felt thereafter. The likely time to benefit realisation then could be anywhere from 2 years (for benefits resulting from changes that do not require significant capability or process development, such as a change in debt risk premium) to 5 or more years where significant capability or process development is required.

Likelihood of success

The costs for one-off changes in approach that do not require significant development of capabilities or processes (such as a change in debt risk premium) could be expected to be relatively low.

By contrast, the costs for changes that require the development of new regulatory processes, significant skill development within the regulator's staff and/or more concerted/in-depth examination and review of network proposals could be expected to be relatively high and require on-going support.

Effects on specific stakeholder groups

Network businesses would potentially experience a reduction in absolute net revenue, but not necessarily any reduction in net revenue as a percentage of costs, capital employed or profitability, particularly if the network business is able to improve the efficiency of its operation.

All customer segments should benefit through reduced network charges, but one aspect of the enhanced level of regulatory scrutiny recommended would be to ensure that cost reductions are allocated appropriately across the various customer segments.

Consistency with electricity market philosophy and direction

Some aspects of these changes might be seen by some parties as introducing a somewhat more heavy-handed regulatory regime – particularly those aspects that concern the regulator taking a more forensic and directive role in terms of assessing the efficiency of proposed costs and/or the structure of pricing.

5.2.2. Option N1-b: Introduce and support a consumer advocate as a regular participant in network regulatory processes (Enhanced and strengthened regulation)

Key features

Under this option an office would be established and funded to support consumer input to electricity market reviews and regulatory reviews and determinations. The objective would be to overcome the significant information and resource asymmetry that currently exists between the electricity supply industry and consumers with regard to their ability to research and present submissions to electricity market reviews, regulatory reviews and regulatory determinations.

The office would be set up to represent the interests and concerns of all consumers – from small residential and business consumers to large commercial and industrial facilities and enterprises - using its own staff and external expertise, which could include existing consumer and industry advocacy organisations. Funding could be provided through a market fee or general tax revenue.

Magnitude of impact

It is not possible to estimate the impact of this option. It would be reasonable to expect such an office to enhance the regulatory process and particularly its relevance to and representation of the concerns of electricity consumers. It is also reasonable to assume that this would have some flow over impact on the content of the decisions made in the various market reviews and regulatory reviews and determinations in which the office participated.

Measurability of impact

It will be difficult to quantify accurately the impact of this option. However, the degree to which it raises issues that are not raised by other parties and the degree to which the issues it raises influence market reviews and regulatory decisions will provide a very good indication of its impact. Another key indicator will be the degree to which consumer and industry advocacy groups feel the office has done a good job of representing and balancing the interest and concerns of different types of consumers.

Timing of option benefits and costs

Costs would be incurred upfront and on an on-going basis to establish and support this office. It could be expected that the office would start to operate immediately and therefore its benefits for the market and regulatory review process would begin being felt as soon as it began participating in those reviews. Impacts on decisions would be somewhat later, and would depend on the timing of the reviews and the degree to which the office was able to influence outcomes.

Likelihood of success

The success of such an office will depend on the quality of the people and external sources of expertise it uses, the adequacy of its funding and its ability to fairly represent the interests and concerns of all electricity consumers.

Effects on specific stakeholder groups

By definition it should be expected that this option would provide benefits to electricity consumers. It should also make market and regulatory review processes more robust.

Consistency with electricity market philosophy and direction

The ability for different stakeholder groups to be represented in market reviews and regulatory processes is entirely consistent with and supportive of the NEM market philosophy and direction.

5.2.3. Option N-2a: Capital efficiency carryover mechanism (Greater efficiency in network capital and operating expenditures)

Key features:

The new regulatory test for network investment (RIT-D) that is being considered will require more explicit consideration of demand-side resources and documentation of that consideration. However, the nature of the tariff re-setting process itself may create a disincentive for networks to employ demand management strategies (whether through price or direct engagement with demand side providers) to reduce peak demand in the later years of a regulatory period. This is driven by two factors:

- The benefits from reducing peak demand, and therefore capital expenditure, diminish the further into the five-year regulatory control period a network business is (i.e., the financial benefits to the business from reducing capital expenditure in year 4 of the regulatory control period are less than in year 3). This is because not only does actual capital expenditure gets rolled into the regulated asset base (RAB) at the commencement of the next regulatory control period[36], but also, there is currently no efficiency carryover mechanism for capital expenditure; and
- Forecasts of maximum demand for the next regulatory control period are generally based on a combination of starting year figures (e.g., weather corrected demand in year 4 of the current regulatory control period), adjusted for the forecast growth in peak demand due to, for example, growth in customer numbers, penetration of air-conditioners etc., over the next regulatory control period. In this scenario, the higher the starting year peak demand, the higher will be the forecast maximum demands for the following regulatory control period, thus, the higher the capital expenditure allowance will be.

36 This is important because the RAB is the approved capital base on which distribution businesses in the NEM are allowed to earn a financial return.

A capital efficiency carryover mechanism would partially overcome this problem by providing a fixed term over which the network would be able to receive enhanced revenue. This would provide a continuous (and even) incentive to reduce capital expenditure, relative to forecasts, throughout the regulatory control period.

A similar scheme – the Efficiency Benefits Sharing Scheme (EBSS) – has already been implemented by the AER to provide networks with an incentive to reduce their operating costs. The scheme provides a fixed five-year term over which the benefits of improved operating efficiency are shared between the network and the customer base. After that period, all of the benefits flow to the customer base. It is worth noting that the AER considered a parallel scheme for incentivising greater efficiency in network capital expenditure. However, due to difficulties associated with the treatment of deferred capital expenditure, it decided not to include capital efficiency in the scheme at that time[37]. The AER also stated, that "should a means of addressing [its] concerns regarding inappropriate incentives to defer capex be identified, [it] would reconsider applying an EBSS to capex"[38].

Another, more complex option to administer would be for businesses' forecasts of maximum demand for a regulatory control period to be inclusive of the estimated impact of demand reduction initiatives that have occurred in the previous regulatory control period. This would further align the financial benefit to businesses from reducing peak demand with the economic benefits to the community of reducing peak demand. The interrelationship with a capital efficiency carryover scheme would need to be considered in more detail, to confirm the extent to which the combined benefit to the business is consistent with dynamic efficiency outcomes.

Magnitude of impact

It is not possible within the scope of this project to assess the magnitude of the impact of this option quantitatively. However, it is reasonable to expect that benefits could be reasonably material, given the proportion of total network costs that are represented by network capital expenditure.

Measurability of impact

Assuming an appropriate approach can be developed to address the AER's concerns, measuring the impact of this incentive mechanism would be part and parcel of the implementation and use of the scheme.

Timing of option benefits and costs

Assuming an acceptable scheme can be developed, its impacts would begin to affect the network costs charged to consumers in the first regulatory period after the scheme is first put in place (i.e., no sooner than six years after the scheme is first implemented). It should be noted, however, that development of an acceptable scheme would be likely take at least one year, but almost certainly less than two years.

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37 AER, Final decision, Electricity distribution network service providers, Efficiency benefit sharing scheme, June 2008, pp 9 – 11, http://www.aer.gov.au/sites/default/files/ac11908-Final%20decision%20-%20Distribution%20EBSS%20%2826%20June%202008%29.pdf

38 Ibid, p 11.

Likelihood of success

The past history of the AER's consideration of such a scheme suggests that (a) the regulator sees merit in the concept, but (b) has identified specific concerns that need to be addressed. In addition, a parallel scheme exists for operating cost efficiencies. Together, these facts indicate that the issues associated with developing a successful scheme are well-known, and will (a) focus the development effort, and (b) provide a relatively easy way for determining the likely success of the developmental effort. It should be noted, however, that success in designing an acceptable mechanism is not assured.

In this regard, it is worth noting that the distribution businesses themselves were mixed in their reactions to the specific incentive that the AER considered in 2008. Some felt it was a good idea, but some felt it was not. This indicates that the design may need to consider how specific aspects of the incentives affect different distribution businesses.

Implementation of the scheme would impose on-going administrative costs on the network businesses and the regulator, but it could be assumed that these would be relatively minor as compared to the potential benefits. It should also be noted that the administrative processes of any such scheme would probably be very similar to those of the EBSS, meaning that there would not be significant costs in developing them.

Effects on specific stakeholders

Both the network business and consumers would benefit from the implementation of this policy. The benefit experienced by individual consumers would be proportional to their network charges.

Consistency with electricity market philosophy and direction

Such an approach is entirely consistent with the AER's incentive-based approach to network regulation.

5.2.4. Option N-2b: TOTEX as a more effective incentive for cost-efficiency (Greater efficiency in network capital and operating expenditures)

Key features

At present the regulatory framework that applies to distribution businesses within the NEM gives different incentives for capex (capital expenditure such as poles and wires) and opex (operational expenditure like maintenance and demand-side payments). Under the current system there is a pronounced bias toward capital expenditure in the cost recovery process because it is generally only capital expenditure on which the distribution business is allowed to earn a return[39]. It may be possible to provide an incentive to the network business to substitute operating costs for capital expenditure where that reduces total cost. This would involve moving to a TOTEX (total expenditure) incentive mechanism, where an incentive could be provided by allowing the network to retain a portion of the return it would have earned on the

39 The regulatory framework calculates the annual revenue recovery requirement of a distribution business as a function of its operating expenses plus its undepreciated capital base times the WACC. This approach means that operating expenses should be recovered dollar for dollar, but capital investments should be recovered at a level that accounts for the cost of financing the expenditure plus a financial return. While distribution businesses can make greater than anticipated earning by reducing their operating expenditure as compared to amount forecast in setting the revenue requirement, the ability to earn a financial return on capital expenditure provides an incentive to undertake capital expenditure where the allowed WACC is greater than the distribution business' cost of capital.

capital expenditure that has been reduced, or allowing the additional operating expense to earn a return.

This approach represents another way of addressing issues associated with both the Weighted Average Cost of Capital (WACC) and enhancing the efficiency of network businesses' capital and operating expenditure. It should be noted, however, that the bias to incur capex really only exists if the WACC is too high relative to the business' actual cost of capital, or if the business is able to arbitrage an inconsistent treatment of capex and opex within the efficiency carryover mechanism(s) themselves. The former case will incentivise the business to prefer capital expenditure to operating expenditure or demand management because it provides greater earnings. In the case of the latter, all other things being equal, a network business at present receives a greater benefit from reducing opex than capex towards the backend of the regulatory control period because actual capex gets rolled into the RAB at the start of the next regulatory control period. This limits the financing costs incurred by the network business that are associated with such an overspend, whilst providing the business with a reward of five years of opex cost reductions due to the opex efficiency carryover mechanism (the EBSS). It is also important to note, however, that the bias can work in the other direction as well. A capital constrained private business, for which the difference between the WACC and its actual cost of capital is much closer than for a Government-owned businesses, may in fact be incentivised to put more expenditure towards opex in regulatory submissions as compared to capex.

By providing incentives for the network business to reduction its total expenditure, this option is seeking to enhance the efficiency of both capital and operating expenditure in a single mechanism.

Magnitude of impact

This option would primarily affect costs to be incurred due to growth in peak demand or replacement of aged assets. As such it could be expected to have the potential to produce a moderate level of cost reduction. A proportion of the benefit could be used as an incentive to the network owner.

Measurability of impact

The impact of this approach could be measured by comparing network costs under this approach with those that would have resulted if this provision had not been provided. However, it may be difficult to know exactly what the counterfactual would have been except by comparing the nature and balance of capex and opex in previous proposals made by the network business. It should be noted that this will only be possible in the first one or two regulatory determinations following introduction of the policy, as after a period of time it could be considered that 'standard' practice might have changed to some extent in any case.

It should also be noted that the identification of the counterfactual would require a non-trivial level of effort from the regulator or whoever was undertaking the assessment of the impact of this change.

Timing of option benefits and costs

Impacts on customers would be expected to begin to be experienced in the first regulatory period following introduction of this policy change. Given that consideration of this change would require consultation and detailed implementation planning it would seem unlikely that benefits could be experienced any sooner than about three years from the time it is first put forward

Likelihood of success

The process to consider and implement this approach would require some but not significant costs, and would be similar to the process being undertaken at present in considering a shift from the weighted average price cap to a revenue cap form of regulation.

Some costs would be incurred in developing the capabilities and systems to administer this mechanism, but those would probably not be significant and would be a one-off.

Effect on specific stakeholder groups

Network businesses would potentially experience a reduction in absolute net revenue, but not necessarily any reduction in net revenue as a percentage of costs and possibly an increase in net revenue as a percentage of capital employed.

All customer segments should benefit through reduced network charges; one aspect of the enhanced level of regulatory scrutiny would be to ensure that cost reductions are allocated appropriately across the various customer segments

Consistency with electricity market philosophy and direction

This change is consistent with the NEM market design, regulatory approach and NEO

5.2.5. Option N-3a: Increased use of interval metering and time-varying pricing (Better use of demand-side resources, including distributed generation)

Note that this solution has been recommended in the AEMC's *Power of Choice Review*.

Key features

This option would feature the roll-out of interval metering to customers with sufficient consumption (threshold to be determined) to make it likely that load profile changes can be made that will lower the bill of the consumer and put downward pressure on electricity prices.

Magnitude of impact

The impact of the measure is impossible to quantify without detail regarding the threshold down to which the meters would be introduced and the structure and level of the pricing that would be put in place. However, a number of studies and trials conducted in Australia and overseas have found that the introduction of Critical Peak Pricing can result in sizable peak demand reductions – often amounting to 20% or more.

However, it is certain that to the extent that time varying prices are introduced:

- existing intra-class cross subsidies within the set of customers receiving the meters, and inter-class cross-subsidies between those customers and the customers that remain on accumulation meters, will be reduced;
- at least some level of load shifting behaviour is likely to take place; and
- consideration will need to be paid to determining whether and to what extent those time-varying prices may impose costs on vulnerable customers that could result in them making sacrifices in other areas such as education, nutrition, health and/or safety[40]. Where time-

40 For examples, a recent AGL study suggested that under CPP 30% of households would be immediately better off, and another 40% would be better off once they adjusted. The remaining 30% that had previously been subsidised and could not easily adjust to the new tariff would be worse off. While not all of these would be likely to be vulnerable customers, a proportion would be.

varying prices are found to impose the potential for such sacrifices, adequate support mechanisms will need to be developed and implemented, and adequately resourced and supported. More generally, an assessment of the existing consumer protections and safeguards in each jurisdiction will need to be undertaken to ensure they are adequate for addressing these and other issues that arise from the wider use of smart meters and new pricing regimes.

Measurability of impact

Key benefits of this change that could be readily monitored and evaluated include:

- the degree to which the new pricing results in changes in consumption patterns and levels, and
- the degree to which the new pricing approach reduces cross subsidies within the customer group that receives the meters, and between the customers that receive the meters and those that remain on accumulation meters.

Timing of option benefits and costs

Reductions in cross subsidies within the newly metered group and between the newly metered group and the consumers that remain on accumulation meters would commence as soon as the newly deployed meters began being used for settlement and consumer billing.

The impact of any changes made by individual consumers to the ***level*** of their consumption would be experienced in their first bill.

The impact of any changes made by individual consumers to the ***timing*** of their consumption would be experienced in their first bill, assuming they are billed on a time-varying basis.

The impact of any changes in the aggregate load profile of the customers receiving the interval meters would affect:

- wholesale market dispatch arrangements and spot prices immediately,
- contract market prices and therefore market offers within the near term (certainly within a year or two at the most),
- regulated retail tariffs at the next time they were set, and
- the timing and nature of capacity augmentation required in the distribution, transmission and generation sectors (and therefore the costs that will need to be recovered in the prices of those sectors) in the mid to longer term.

Likelihood of success

The reduction in intra- and inter-class subsidies is a certain outcome of this initiative.

At least some degree of load shape change can be assumed to take place, though the exact amount is impossible to predict.

The ability to provide adequate and fairly allocated support for vulnerable consumers that are disproportionately or unacceptably negatively impacted by the pricing arrangements and/or the cost of the metering is far less certain and as mentioned above would require careful analysis, adequate resourcing and attention to detail in implementation.

More importantly, the experience of the Victorian smart meter roll-out demonstrates the importance of consumer education and understanding of the potential the benefits of the metering and pricing structures. Significant attention will need to be paid to developing and implementing information and support campaigns that assist consumers in making the transition to the new pricing structures. This is likely to be critical for acceptance of the initiative at any level, let alone its success.

Effects on specific stakeholder groups

These would include the following:

- consumers with usage patterns that are flatter or essentially inverses of the net system load profile (NSLP)[41] will benefit without any effort (though it should be noted that it is these customers that are currently cross-subsidising the usage patterns of customers with actual load profiles that are peakier than the NSLP);
- correspondingly, consumers with peakier load profiles than the NSLP will be disadvantaged by these pricing arrangements, though they will now be paying a cost that more closely reflects the cost of supplying them;
- consumers with larger volumes of discretionary consumption will have a greater opportunity to make savings by shifting or eliminating consumption from high cost-to-serve time periods;
- correspondingly, consumers with smaller volumes of discretionary consumption[42] will have less opportunity to do so; and
- in the short term, and to the extent that the time pattern of consumption changes, the relative revenue outcomes of different types of generators could change.

Further, residential consumers with low levels of energy literacy and/or engagement with the energy market may be less likely to switch to time variant pricing (where it is offered on an opt-in basis), or may switch to contracts that do not lead to better outcomes for their individual circumstances. This again underscores the importance of developing and implementing information and support campaigns that assist consumers in making the transition to the new pricing structures.

Consistency with electricity market philosophy and direction

This change is consistent with the NEM market design, AEMC and MCE (now SCER) policy directions, the regulatory framework and the NEO.

41 The net system load profile is the consumption profile that is used in calculating the wholesale market cost of serving residential and small business customers and as such is a significant input to the development of regulated tariffs for these customer groups. It is the aggregate load profile of all consumption that is not served through an interval meter. In some cases, other loads whose consumption profile can be relatively easily and accurately determined – such as controlled water heating and streetlighting – are also removed.

42 This will include many households that simply use less electricity than average, and particularly households that do not use air-conditioning and whose use of other end uses are already outside peak hours or cannot be shifted outside peak hours. Individual outcomes will depend on the specifics of the pricing arrangement and the consumer's load profile. However, while these households may have less load that can be shifted, to the extent that their profile is less peaky than the NSLP, more cost-reflective pricing arrangements should lower their bill on an annual basis. Seasonal or other differences (e.g., monthly increases due to a CPP pricing structure) may still pose specific affordability issues.

5.2.6. Option N-3b: Mandated demand-side plans (Better use of demand-side resources, including distributed generation)

Key features

This approach would require network businesses to publish demand management plans on a regular basis.

Queensland has implemented a policy of this type, and the plans have assisted the state's distribution businesses in preparing their regulatory proposals. It has also resulted in (or at least contributed to) the Queensland DNSPs having arguably the largest demand-side programs of any distribution companies within Australia.

Care would need to be taken in adopting such an initiative to include a requirement that the plan to be developed includes a demonstration that the demand-side initiatives to be undertaken are efficient.

Magnitude of impact

It is not possible to estimate the level of demand-side activity that would be undertaken due to the result of a requirement that DNSPs publish demand-side plans.

However, it could be assumed that the requirement to prepare a plan would (a) increase the familiarity of network staff with demand side planning principles and assessment techniques, and (b) result in at least the minimum amount of demand-side activity required and in accordance with the guidelines of the plan being undertaken. The impact of that demand-side activity would depend on the specific content of the plan and the extent to which the activities undertaken were incremental to the activities the distribution company would have undertaken in the absence of the plan.

Measurability of impact

For distribution businesses that currently undertake little or no demand-side activity it could be assumed that whatever activity is undertaken due to the plan would constitute the impact of the plan. However, for distribution businesses that are already undertaking material levels of demand-side activity the incremental impact of the requirement to file a demand-side plan is likely to be more difficult to assess with accuracy.

In either case, the impact of certain aspects of the intent of a plan – particularly where it involves capability building – are inherently difficult to assess.

Timing of option benefits and costs

The time at which the effects of activities undertaken as a result of the demand management plan will be felt will depend on the nature of the activities, but the initiation of the activities within the plan can be expected to commence soon after the plan is submitted and approved.

Likelihood of success

Distribution businesses can be required to prepare and submit demand management plans, if required to do so by the regulator or the business' shareholder or stakeholder. The likelihood of success is high in terms of the production of demand management plans, but the additional demand reduction that would occur from such plans is less certain.

Effects on specific stakeholder groups

The impact of the demand management plan on different consumer segments will depend on how the costs of the plan and the activities undertaken under it are allocated to the various customer segments, and the extent to which the various customer segments are able to receive direct or only indirect benefits from the activities to be undertaken under the plan. For example, in some US jurisdictions industrial customers opposed utility demand-side activities because they felt that they were funding a significant proportion of the activities, but did not have an opportunity to derive direct benefits from them because virtually all of the activities were targeted at residential consumers.

Consistency with electricity market philosophy and direction

This approach is somewhat out of keeping with the regulatory approach generally used in the NEM. That approach seeks to provide incentives to encourage and reward activities that produce outcomes that accord with the NEO. It is worth noting the requirement that exists in Queensland was imposed by the government (which is also the owner of the distribution companies operating in the state) rather than either the jurisdictional regulator or the AER.

Care would also need to be undertaken to ensure that this approach did not either undermine or duplicate outcomes that would be produced in any event by the RIT-D.

5.2.7. Option N-3c: Demand reduction targets, incentives and penalties for networks (Better use of demand-side resources, including distributed generation)

Key features

Under this option a target would be set regarding each distribution business' involvement in demand management. It should be noted that there are a number of approaches that can be taken to setting the target itself. The target could relate to inputs, such as the amount or proportion of funds to be devoted to demand management activities, or outcomes, such as the amount of end-use or system peak demand reduction to be achieved, or the number or value of augmentation projects to be deferred. Typically in such schemes, penalties are applied where targets are not met and in some cases, incentives are provided for achieving or exceeding the target.

Targets that focus on inputs such as the amount of money spent on demand management activities are probably best considered as transitional, capability building mechanisms as they lack focus on outputs or the cost-effectiveness and economic efficiency of outcomes.

Assuming that the overall objective of the scheme would be to put downward pressure on price by making the demand side of the market more efficient (in terms of load factor) or more responsive to price, thereby reducing the need for infrastructure that will only be needed for a short amount of time over the course of a year, the following types of targets would seem to be of value:

- Reduction by a specified percentage of the forecast growth in network system peak demand – such a target would produce downward pressure on network augmentation capex over time, and would also be likely to reduce peak demand on the generation and transmission sectors (because system peak demand in most networks is highly coincident with generation system peak demand);

- Reduction by a specified percentage of the capital that is forecast to be spent on augmentation projects driven by increased peak demand[43] – such a target would put downward pressure on network costs and therefore network prices in the near term and as long as the target remained in force, but would be a bit less likely than the approach above to reduce peak demand on the generation and transmission sectors because peak demand on specific parts of the network is more likely to occur at times that vary from the time generation and transmission system peaks occur.

In either case – but particularly where the target refers to augmentation capital expenditure – care will need to be taken in setting a level for the target that appropriately balances the meaningfulness of its outcome with its achievability.

These sorts of targets have not been widely used, but where they have been implemented they have generally addressed network system peak demand. Their primary goal has not been to reduce network augmentation capital expenditure in the near term.

Two jurisdictions in the US have used such a target:

- California – The Energy Action Plan and Loading Order were issued in 2003 in response to a crisis in the state's wholesale energy market. These measures specified energy efficiency and demand response as the 'preferred' options for meeting increased demand in the state. By 2010, 1,777 MW of demand response had been enrolled state-wide in emergency demand response programs and another 1,106 MW in price-triggered demand response programs. In 2007, the state implemented the Energy Efficiency Risk Reward Mechanism which provided financial incentives for incumbent investor-owned utilities to meet or exceed energy efficiency and demand response targets. The financial incentives were structured as a percentage of the net benefits achieved due to deployment of the energy efficiency or demand reduction measures. The incentive mechanism was suspended, however, because of complexities and concerns in implementation.
- Texas – The state first set energy efficiency targets for the state's distribution entities in 1999. In 2011 legislation was passed requiring that starting in 2013, each distribution company must meet at least 30% of its annual growth in demand through energy efficiency. Where that amount of energy is equal to or greater than 0.4% of the utility's summer peak demand, the target switches to an annual reduction of 0.4% in peak demand which must then be achieved in each year. As these targets have not yet taken effect there is no information on whether they have been able to be achieved.

Magnitude of impact

Estimating the impact of a target mechanism is not possible until the nature of the target to be used has been established.

Because the mechanism also generally includes penalties for not meeting the target, it is reasonable to expect that (a) the regulator will seek to set the target at an achievable level, and that (b) the regulated entities will seek to meet the target (unless doing so is more costly to them than paying the penalty).

43 Note that in both cases, adjustments might need to be considered for distribution systems whose peak demand growth is being driven largely by growth in customer numbers.

Measurability of impact

How readily the impact of the scheme can be measured with confidence will depend on the nature of the target that is set. Targets expressed in reductions of peak demand at the end-user level will probably be measured using a combination of deemed and measured approaches similar to those used in the energy savings initiatives that have been implemented in Victoria, South Australia and New South Wales. If the target is expressed in terms of network system peak demand, it will need to be measured after the fact and adjusted for the weather conditions in the year the target is measured. As implied, the latter measurement, while more accurate and potentially more useful, will be more difficult to undertake, and will not be available until after at least the peak demand season following the target year.

Timing of option benefits and costs

If the scheme targets network system peak demand, it may not make any impact on the costs incurred by the network in meeting peak demand for some time. This is because network capital expenditure requirements take place in local parts of the network where consumer demand has reached the capacity of the infrastructure serving the area. To affect augmentation capital expenditure sufficient reduction in peak demand needs to be in place before the point in time when additional infrastructure is needed to ensure reliability of supply. A scheme focussed on network system peak demand may not deliver the amount of demand reduction in the time frames needed for these local concerns. Over time, however, if the demand reduction activities continue and their impacts are permanent once the measures are installed, they will slow the rate at which augmentations are needed in most local areas within the network. The exceptions will be areas whose local peak demand differs from that of the system, which could be by season or time of day.

In contrast, a system that targeted network augmentation costs would place downward pressure on network costs relatively quickly, but in all likelihood less downward pressure on generation costs, depending on the level of the target[44].

Such schemes would also produce impacts in the generation sector, and the reduction of demand would also affect generation requirements. Assuming the network time of peak demand is similar to that in the generation sector, it would also affect peak demand on the generation sector. As noted earlier, these impacts would be expected to affect the generation sector in the short term, if the demand reduction was dispatchable in response to price, or in the longer term through the load forecast, if the demand reduction was non-dispatchable.

Likelihood of success

As noted above, there is a high likelihood that the targets set in such a program would be met. As also noted, it is important to understand clearly what impact the target is likely to have on various objectives.

44 This is because reducing augmentation capex requires focussing on reducing peak demand only in areas where augmentation is needed and can potentially be deferred by demand reduction strategies that can be implemented in the amount needed and time available before the augmentation is needed. A target related to a reduction in overall demand within the network service area would not need to take such constraints into account and could therefore be achievable at a higher level.

Effects on specific stakeholder groups

If the target is implemented at the network peak demand level it is likely that it will put upward pressure on network costs in the near term and downward pressure on both network costs and generation costs over the longer term. These impacts would presumably flow through to network charges to consumers. If the scheme is targeted at augmentation costs there would be downward pressure on network costs, but less impact on generation costs.

Depending on the how the scheme is designed (in terms of targeted consumer segments) and implemented, there is the possibility that certain segments of the consumer base will have less opportunity to benefit directly from the program. The extent of this problem can be mitigated by careful program design and appropriate cost allocation procedures.

Consistency with electricity market philosophy and direction

The use of targets and incentive mechanisms is common in regulation to encourage networks to undertaken behaviours and produce outcomes deemed to be in the interests of consumers. The AER's service target performance incentive scheme (STPIS) is a good example of such a mechanism. The STPIS is designed to (a) encourage distribution businesses to increase their reliability of supply where this can be done within the economic value that customers derive from that increased reliability, and (b) endure that other capital and operating cost efficiencies implemented by the distribution business do not result in a deterioration of service reliability. The STPIS does this by instituting incentive payments for increases in service reliability and penalties for reductions in service reliability. The level of the incentive or penalty is related to the economic value that customers derive from increased reliability.

The use of such an approach to encourage network involvement in demand reduction would seem entirely consistent with such precedents.

5.2.8. Option N-3d: Role and return for networks as owners of assets that facilitate demand response and/or distributed generation (Better use of demand-side resources, including distributed generation)

Key features

Some demand reduction strategies depend or can be significantly facilitated by centralised assets. An example is direct load control of air conditioners via ripple control or through smart meters. Where demand response can be aided by or depends upon a capital asset that serves a relatively large number of customers, the network business may be well suited to serve as the asset owner and operator on an open access basis for retailers, aggregators and possibly even individual customers.

Under this approach, networks would be allowed to invest in such technologies and then provide access to them for retailers or aggregators to exercise the demand response capabilities of customers with whom they have made appropriate commercial arrangements. If the investment is allowed within the regulated asset base, access to the demand response service would most likely be provided as a prescribed service.

Magnitude of impact

Use of the networks in an asset ownership and operator capacity could activate the demand response capabilities of the small end of the consumer base more quickly than otherwise. This is because there is no other party in the market at present that is in a position to make a large capital investment and has access to these customers on an assured basis.

There is a risk that such an investment could preclude other innovative approaches that could provide the same benefit at similar or lower costs, or a greater degree of flexibility.

Measurability of impact

The impact of this sort of scheme would be easy to measure. Key elements would include

- costs (note that the incremental cost of this platform would be minimal where the capability is offered as part of a smart grid or AMI deployment);
- number of consumers providing the demand response;
- aggregate demand response delivered.

Timing of option benefits and costs

Items affecting the development time include the amount of time needed to decide to allow such arrangements and the construction time of the assets themselves. Once the assets are in place, which can be undertaken on a progressive roll-out basis, the only other factor affecting timing would be the sign-up of customers, which would require the interest and participation of retailers and aggregators.

Once consumers were signed up into the scheme, demand response could be dispatched as needed for use in the wholesale market or to reduce local peak demand.

Impacts would be reflected in the contract market relatively quickly – certainly within two years at the outside. By contrast, program impacts on the generation and network sectors would be evidenced as the amount of demand response available was able to influence generation investment decisions and the relationship of peak demand and available network capacity at the local level.

Likelihood of success

As a capability made possible by infrastructure undertaken for other purposes – such as smart grid or AMI deployment -- the chances for success would be relatively high, due to the low incremental cost of adding the capability. This might be less true in the case of an investment in stand-alone technology dedicated solely to this capability alone, though that would be subject to the costs of such technologies.

Effects on specific stakeholder groups

This approach would provide access to the demand response potential of the small end of the electricity market, allowing residential consumers to reduce their peak demand in ways that benefit the system while maintaining their own comfort, and providing them a benefit for doing so.

Networks would benefit to the extent that this scheme would potentially increase their asset base and provide a valuable tool for use in slowing the rate at which augmentation of the network needs to be undertaken at the local level, particularly in residential-dominated local infrastructure areas.

Retailers and aggregators may feel that the provision of this service infringes on their realms of operations.

Providers of other technologies could be disadvantaged once such centralised approaches were put in place. For example, emerging technologies that allow similar levels of control to be exercised on end-use loads and can be implemented on a load (or facility) basis may offer the same capability but at lower capital cost or increased technological or commercial flexibility. Therefore, it would be important to conduct a technology assessment to ensure that there are not already or soon to be available non-centralised approaches that can provide the same capability at less cost or with more flexibility or improved competition outcomes.

Consistency with electricity market philosophy and direction

Subject to the consideration of alternative technologies, such an approach is entirely consistent with the role of the distribution businesses as owners and operators of infrastructure assets to which access is provided on a non-discriminatory basis.

5.2.9. Option N-4: Review of reliability standards

Key features

Two specific improvements are suggested:

- That jurisdictions review the level at which their reliability standards are set, and
- That jurisdictions review the approach used for assessing network reliability.

It should be noted that the latter may require a re-consideration of the former.

A recent study conducted by the AEMC identified that reductions in the reliability standards that apply to distribution networks in NSW could be expected to deliver benefits (in the form of reduced customer bills) that would exceed their costs (as measured by the monetised costs and inconvenience that outages cause residential and business consumers)[45].

Network reliability standards in NSW are set using a deterministic approach. In most cases the deterministic element is expressed in terms of system redundancy. For example, the commonly used reliability standard of ‘n-1’ requires that all loads within the area of the network in question must continue to be able to be supplied in the event of the failure of a single network element. In essence, the network must be able to function as normal with any single piece of its equipment out of service. Clearly, this requires assets to be in place that will, in all likelihood, seldom be used[46].

An alternative approach sets reliability standards in terms of the probability, magnitude and value of a loss of load. This approach is currently in use in Victoria and has been shown to have reduced network capital requirements[47].

Magnitude of impact

The NSW study assessed four different reliability scenarios. Three involved reduced levels of reliability – modest, large and extreme – while the fourth was an increased level of reliability. In all of the reduced reliability scenarios benefits were at least twice as high as costs. In the increased reliability scenario costs were more than three times higher than benefits.

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45 See http://www.aemc.gov.au/market-reviews/completed/review-of-distribution-reliability-outcomes-and-standards.html

46 Within the Sydney CBD the reliability standard has been n-2, which requires that all loads within the area of the network in question must continue to be able to be supplied in the event of the failure of any two network elements, thereby requiring a significantly greater level of investment than the n-1 standard.

47 SP AusNet – *Distribution System Planning Report 2011 – 2015,* – page 4, states that: “*The risk assessment on the subtransmission network including zone substations is based on the probabilistic planning criteria….These works will be undertaken where it is economic to do so, i.e. where probabilistic planning analysis indicates that the value to customers of expected unserved energy exceeds the costs of capital for an efficient augmentation project. The benefits associated with reliability improvements and network loss reductions are also considered when carrying out economic evaluations.*”

The net benefits through 2028/29 of the three reduced reliability scenarios were $500 million, $2 billion and $2.5 billion respectively. Table 8 shows the bill savings and changes in the number of additional minutes of power outages that would be experienced by the average consumer under each of the three reduced reliability scenarios.

Table 8: Bill savings from reduced network reliability standards

Factors Reduced reliability scenario	Annual bill saving	Additional time without power
‘Modest’	$3	2 minutes
‘Large’	$12	13 minutes
‘Extreme’	$15	15 minutes

Source: AEMC, *Final Report - NSW Workstream, Review of Distribution Reliability Outcomes and Standards*, August 2012, pp iii - iv.

By contrast, under the improved reliability scenario, in 2028/29 the average NSW consumer would pay around $11 more a year on the distribution reliability component of their electricity bill in return for around four minutes fewer supply interruptions.

A high level analysis provided by AEMO, in a submission to the AEMC's draft report estimated that NSW customers could save up to $50 a year on their electricity bills from 2015 without any detrimental effect to current reliability levels, if a probabilistic approach to distribution reliability was adopted over the current and next financial year[48]. The analysis was not undertaken on a comprehensive basis and also assumed that the measure could be implemented within a very short time, so the result must be treated with caution. However, it does indicate that the approach is worth further consideration.

Measurability of impact

The impact of changing either the level at which reliability standards are set, or the approach used for assessing network reliability can be estimated as indicated by the studies referred to above that were undertaken for NSW. These would probably need to be recreated on a state-by-state basis to provide an estimate of benefits across the NEM, but would only need to be done once to establish the business case for undertaking either or both of these changes.

Timing of option benefits and costs

The effects of these changes would begin to be felt no later than the first regulatory period following their implementation, as they would change the level of investment that network businesses would need to undertake.

Likelihood of success

A reduction in the reliability standard can be implemented relatively easily and without any material cost.

48 AEMC, *Final Report - NSW Workstream, Review of Distribution Reliability Outcomes and Standards*, August 2012, p iv

One of the key factors regarding its success, however, will be the degree to which the electricity users (households and businesses) – and governments -- understand that in exchange for some reduction on the bill it can be expected that interruptions in the supply of electricity will be more frequent and/or last longer. This is important in order to resist the somewhat natural reaction when an outage occurs – particularly if the outage is widespread and lasts for more than a few hours – to call for increased reliability in order to ensure that the electricity sector can continue to deliver the level of convenience, comfort and continuity that the community's households and businesses have come to expect.

This underscores the importance of (a) understanding the likely effects of reduced supply reliability on different segments of electricity consumers, (b) ensuring that the savings available from reduced supply reliability materially exceed the inconvenience and costs that the reduced level of reliability can be expected to cause, and (c) ensuring that these trade-offs and a realistic expectation of service levels going forward have been understood by and agreed to by the community. This will undoubtedly be a process that requires some time and resources to complete.

Effect on specific stakeholder groups

The likely effect of reduced reliability on different consumer segments will need to be assessed within each distribution service area. As discussed above, this will be very important for a proper assessment of the distribution of the costs and benefits of such a policy, and the implementation of an effective campaign for building support for the new standard, including consideration of differing standards in different geographic areas or voltage levels of the distribution system.

Consistency with electricity market philosophy and direction

Such an approach would be entirely consistent with the existing regulatory framework.

5.2.10. Option N-5: Privatisation of government-owned network businesses

Key features

Government ownership of electricity distribution (and other electricity infrastructure) businesses has a number of features that may impede economic efficiency. These include:

- a potential conflict of interest in government's role as the shareholder seeking to maximise dividends, its role as the licensing authority, and its political drivers to deliver outcomes to voters; and
- a documented tendency for these businesses to have higher operating costs and overall costs to serve than their privatised counterparts at no commensurately higher quality of service.

Magnitude of impact

Comparisons of the costs and service quality of government- and privately owned distribution businesses suggest that significant opportunity exists for increased economic efficiency and downward pressure on network charges from privatisation. See for example:

- Mountain, B.R., *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*. Energy Users Association of Australia, Melbourne, May 2011
- Mountain, B.R. & Littlechild, S, 'Comparing electricity distribution network revenues and costs in New South Wales, Great Britain and Victoria', Energy Policy, vol. 38, 2010, 5770-82

- NSW Department of Industry & Investment, *NSW Electricity Network and Prices Inquiry, Final Report,* December 2010
- Public Interest Advocacy Centre, 'A fair comparison: PIAC submission to the Productivity Commission Inquiry, Electricity Network Regulation', April 2012

Measurability of impact

The studies noted above provide an estimate of the potential savings that could be achieved through privatisation

Changes pre and post privatisation in these metrics (and others) would provide a relatively straightforward means for measuring the impact of any privatisation undertaken

Timing of option benefits and costs

It could be expected to take a few years for the changes in operation and practice to be felt. The rate at which those changes would be expressed in network charges would also depend on the conditions of the sale (in some cases, sales of these assets have prescribed the maximum rate at which reductions in workforce can be undertaken, for example), and the timing of regulatory re-sets.

Likelihood of success

A number of factors will influence the likelihood of success of any privatisation efforts including, the political and economic conditions within the states in which privatisation is to be considered, the nature and aggressiveness of the regulatory regime in place after privatisation takes place, the conditions of the sale itself (as mentioned above), and the behaviour of the state government in its exercise of related powers such as licensing after the privatisation

The process could be expected to provide a cash injection to the state government at the time of the sale, but a sacrifice of a source of on-going dividends

Effect on specific stakeholder groups

The likely effect of this measure on specific stakeholder groups can be expected to include the following:

- State treasuries may be advantaged by a large one-off inflow but disadvantaged by the loss of dividends. Depending on the size of the one-off inflow and how it is managed this could result in either a net gain for the state government or the need for an increase in taxes to maintain current government services (or a reduction in government services).
- Public concern about privatisation and concerns in some sectors about reductions in network staffing.
- Electricity consumers are likely to benefit through decreases in their network charges. The degree to which they benefit will be in proportion to the percentage of their bill that is represented by distribution network charges. Because small users require most of the distribution business' assets to receive their electricity it is likely that these consumers will realise among the largest impacts.

Consistency with electricity market philosophy and direction

Privatisation of network businesses is consistent with the design, philosophy and direction of the NEM.

6. Options for putting downward pressure on costs and improving affordability in the Retail sector

Consistent with the approach described in section 2.2, this section first considers how efficient the retail sector is, and then discusses options for improving the efficiency of its operation and how its costs are communicated to consumers.

6.1. Is it as efficient as it could be

Full retail contestability (FRC) has been introduced almost everywhere in the NEM[49]. Studies conducted by the AEMC have indicated that competition is reasonably effective in Victoria, South Australia and the ACT. However, of those three jurisdictions, only Victoria has fully de-regulated retail electricity pricing for smaller consumers. In all of the other jurisdictions prices for small consumers are still subject to regulation.

Perusal of the websites of the various jurisdictional regulators indicates that consumers have a relatively large range of retail electricity market offers to choose from – even in the jurisdictions in which retail prices for small consumers are regulated, and statistics available from the Australian Energy Market Operator (AEMO) indicate that a high percentage of residential consumers in each of the NEM jurisdictions in which FRC has been introduced have exercised their ability to choose their retailer and a market (rather than regulated) electricity contract.

However, despite the high switching rates exhibited in a number of the NEM jurisdictions, there is considerable evidence that, in general, electricity remains a low-engagement product, with price being the main feature sought (though there is a sizable segment of the customer base that has an interest in being able to purchase green power), and switching between retailers is driven in large part through extensive door-to-door sales campaigns by the retailers (rather than active customer choice).

There is some concern that the marketing cost associated with this level of switching is unproductive, however, and that it makes retail electricity prices higher than they could be. On the other hand, marketing is a feature of competition, and competition also places downward pressure on marketing costs to the extent that marketing expenditures can create headroom that other retailers can use to provide a greater discount to price conscious buyers.

It is also the case that, in general, the pricing structures offered to small consumers are not particularly reflective of the costs their consumption imposes on the electricity supply chain. Most small consumers get price signals that are almost entirely expressed in simple $/kWh terms. Although a few retailers offer static time- of-use (TOU) price structures, most retail pricing structures are based on either inclining block prices or a flat price that pertains all day for every day of the year.

While this has primarily been a reflection of the limitations of the metering in place within the facilities of small consumers, there has also been reluctance on the part of governments to expose smaller consumers to time-varying prices even where more sophisticated metering is in place. Victoria has a moratorium in place on the use of time varying pricing for small consumers, and NSW has limited the use of time-varying pricing to an opt-in basis.

49 The only places where FRC has not been implemented are Tasmania and the Ergon Energy service area within Queensland.

In addition, most electricity consumers (and especially smaller consumers) do not have a great deal of sophistication about electricity or electricity pricing. Their level of energy literacy is low, and this can make it difficult for consumers to feel confident that they are making the right choice when it comes to choosing a retail market offer. While this can result in inactivity, it can also result in frequent switching on the consumer's part in order to try to get a better deal.

By contrast, retail pricing arrangements for larger customers are generally supported by interval meters and are characterised by:

- network charges being passed through directly to the customer, which allows the network to send very cost reflective price signals to these consumers (though, as discussed in section 5, the networks do not always do so), and
- energy generally being charged on a static time of use basis, with no more than three daily time periods (peak, shoulder and off-peak) and three seasons (summer, shoulder and winter).

In addition, larger customers can issue a tender for retailers to respond to in regard to their electricity contract. By contrast, smaller consumers need to shop the various retailer websites (or that of their regulator) to identify, compare and choose between the different offers – or simply react to unsolicited door-knock or telemarketing offers from retailers.

Some demand response arrangements exist, but the consumer can only provide demand response through the serving retailer. Not all retailers have sought out high levels of demand-response from consumers, however, or optimised the use of the demand response they have contracted, – and it can be observed that the level of demand response in the NEM is materially lower than in a number of other markets.

It should be recalled that the retail costs and margins generally comprise only 10% to 15% of a small consumer's final bill (it will account for even less in the case of larger consumers). The key drivers of a retailer's costs are:

- Wages and other operating costs
- Hedging and risk management associated with its purchases from the spot market
- Government policy (primarily related to environmental and energy efficiency programs and requirements).

This relatively small share of the final bill accounted for by the retail function suggests that there may be less scope for operational efficiency gains within the retail sector to produce meaningful downward pressure on electricity prices. However, the retailer is the entity that prices electricity and associated services, and that interacts with the consumer. As such, it can be seen as a link in the electricity supply chain that can be a useful target for or deliverer of government policy aimed at putting downward pressure on electricity prices.

6.2. Possible solutions

This section discusses areas in which policy undertakings could improve the efficiency of the retail sector in terms of its operation or pricing, and consumers' ability to respond to those prices. Three independent policy options are discussed:

- A requirement to provide more cost-reflective pricing options
- Monitoring of retail costs and margins to ensure competition is effective
- Implementing the National Energy Consumer Framework.

6.2.1. Option R-1: Pricing options (general population) to support load profile changes, including requirement to offer unbundled pricing options

Key features

Retailers could be required to offer an unbundled price as an option to all customers on request. This measure would provide visibility to network price signals (both the structure and level of the network price) and assist with increasing energy literacy among smaller customers (network charges are generally passed through transparently and directly on the bills of larger customers).

It would therefore encourage more innovative pricing by networks and assure that the price signal was visible to the consumer.

Magnitude of impact

The impact of this option on electricity prices would probably be low to moderate unless either (a) 'passive' savings are relatively material and well-publicised, or (b) retailers or third parties offer technology solutions that enable consumers to achieve savings with good paybacks.

Measurability of impact

The impact of this measure could be measured in several ways:

- Its impact on network pricing – that is, the degree to which networks provide more time-varying tariffs once their visibility to the end-use customer is possible[50]
- Take-up by consumers – which would identify how many consumers choose to see (and potentially respond to) the network tariff
- Impact on bills and load shape – this could be done through comparison of the bills of customers that sign up for this billing arrangement before and after the billing change. A control group across the same time period should also be used.

Timing of option benefits and costs

It is likely that some effects would be seen relatively soon after the new billing arrangements were available as consumers change their behaviour in response to the price signal. Further changes might follow due to either investment by consumers in equipment changes or control technologies to increase savings, or fatigue with behavioural changes, which would reduce savings.

Likelihood of success

This option would not be difficult for a jurisdiction to implement. It can be mandated through the licensing power of the states, though if this approach is used it would be important for the requirements to be uniform across jurisdictions.

It must be noted, however, that this option would impose costs on retailers for changes in their billing engines and their bill printing software. The retailers would presumably seek to have these costs recognised by jurisdictional regulators and incorporated within regulated retail prices (where relevant).

50 Note that there are reasons for networks to set cost-reflective tariffs even where those tariffs may not be directly visible by end-use consumers, however.

Effect on specific stakeholder groups

This option could be expected to affect stakeholders as follows:

- Retailers will incur costs as described above and seek to pass them through to the regulated tariff (where applicable)
- Networks may be encouraged to offer more cost-reflective tariffs
- Consumers may benefit in one or both of two ways: consumers whose usage pattern will provide bill reductions without modifications will benefit passively (reduction in hidden cross subsidies) and consumers who can shift their usage to respond to the network price signal will also benefit; however, some consumers may face higher prices
- To the extent that consumers do change their usage patterns there may be reductions in infrastructure costs in either or both the network and generation sector (to the extent that higher cost periods of the network and generation sectors coincide)

Consistency with electricity market philosophy and direction

The requirement to offer specified opt-in pricing arrangements is not inconsistent with the electricity market design and regulatory practice.

6.2.2. Option R-2: Monitoring of retail costs and margins to ensure effective competition

Key features

To date, only Victoria has fully deregulated retail pricing of electricity despite the fact that competition has been found to be at effective levels in other jurisdictions as well. It has also been observed that:

- Victoria has the highest level of consumer switching, and the largest number of competing retailers; and
- retail operating costs and margins make up a higher proportion of the bill of small consumers in Victoria as compared to the other jurisdictions, and as a corollary, the highest net margin for retailers.

This could indicate either that retailers in Victoria have been able to achieve above-market profits, or that retail regulation in the other states is not allowing a fully competitive market return to be realised by the retailers.

In order to shed light on this – and to use the resulting information to inform further development of competition in the retail sector – this option would provide:

- monitoring of the effectiveness of competition in those states where prices have been de-regulated and the degree to which this has provided benefits to consumers; and
- publication of the results.

The monitoring would focus on identifying where competition is or is not effective, and is or is not providing benefits to consumers. In any instances in which competition was found to not be effective or to not be providing benefits to consumers, it would also seek to determine the reasons for these shortcomings and means for correcting them.

This should include assessment of the impacts of the vertical integration of generation and retail operations and whether the market poses any structural and systemic barriers to new entry or the viability of small to medium size retail-only operations.

Magnitude of impact

The impact of continued monitoring and publication of findings could be material to the extent that it increases the competitiveness of the market or makes the benefits of retail competition clearer to consumers and jurisdictional policymakers.

Measurability of impact

At present the fact that Victoria has fully deregulated retail electricity pricing while other states have not provides a useful comparison, but there are many other variables that make isolation of the effect of deregulation on unit prices or consumers' bills or the range of product and service innovation difficult. It is important to recognise that because of this the comparisons will be indicative.

Timing of option benefits and costs

The monitoring studies would not take more than 4 to 6 months to complete per jurisdiction, but it is not possible to predict how long it would take for their findings to be implemented for two reasons: (a) it will depend on the nature of the findings, and (b) it will depend on the interest and commitment of the jurisdictions in question to act on the findings.

Despite this, the monitoring effort is likely to be a very important step in addressing increasing scepticism in the community about the electricity market in that it will identify what is working and what isn't and how the latter might be corrected.

Likelihood of success

This monitoring would presumably be undertaken through studies of the competitiveness of the retail electricity market in each of the NEM jurisdictions. Similar studies have been undertaken by the AEMC in the past, the costs of which have been relatively minor (unlikely to be more than $250K per jurisdiction).

Presumably another round of studies would be sufficient to provide updated information, insight and avenues for improvement.

Effect on specific stakeholder groups

Direct impacts are likely to be low, but the results of the monitoring effort should be of value to both retailers and consumers (particularly smaller consumers).

Consistency with electricity market philosophy and direction

This effort is entirely consistent with the design and philosophy of the NEM.

6.2.3. Option R-3: Continued support for NECF

The National Energy Customer Framework (NECF) provides a comprehensive set of consumer protection measures for small electricity and gas customers. This is a significant benefit to consumers, and addresses a number of the issues discussed in sections 2 and 8.

It also provides far more uniformity in how electricity and gas retailers are directed to interact with their customers than currently exists in the consumer protection approaches that have been developed independently within each of the jurisdictions. This greater level of uniformity is beneficial to the retailers as it reduces their costs of operation, which should therefore reduce upward pressure on prices to consumers.

The framework and its details have been developed and accepted by the jurisdictions in principle. However, at the moment only Tasmania and South Australia have adopted the NECF, resulting in a patchwork system for consumer protection across the National Electricity Market.

In moving the NECF to implementation it is important to ensure that it can adequately address the issues that could arise from advances in metering technology and the introduction of TOU and other innovative pricing structures. Modifications to the NECF, where needed to accommodate changes in technology and/or tariffs, should precede the introduction of such measures.

7. Options outside the energy market to reduce consumption and/or peak demand

7.1. Overview of current government involvement

Governments at the federal, state and local levels have an obvious and important role to play as policymakers and as consumers in their own right.

In their role as policymakers governments at the federal, state and local levels have implemented and continue to be involved in a variety of program and policy initiatives that concern electricity use, energy efficiency and related environmental matters. These can be of significant value in addressing market failures – such as information asymmetries, transaction costs, access to capital and the like – that cannot be adequately addressed by the electricity market on its own. And, as gas and coal prices increase, the value of energy efficiency for helping consumers afford the electricity they need for healthy and safe lives significantly increases.

A non-comprehensive list of the types of policy initiatives that have been and are being implemented by governments in Australia includes:

- Information and capacity building programs:
  - Information to improve energy literacy and to assist consumers in evaluating different retail contract offers and pricing options
  - Appliance labelling
  - Commercial Building Disclosure & NABERS
  - Mandatory energy use disclosure for residential dwellings for sale or rent
  - Programs that build the capacity of larger energy users to undertake energy efficiency and demand management, such as the EEO program
- Minimum standards for goods in complex markets:
  - Energy-using equipment performance standards
  - Building standards
- Incentives
  - For transforming the market and facilitating take-up of improved end-use technologies and controls
  - For end-use technology retrofit and replacement programs that put downward pressure on electricity price
  - To support access to capital – for example, the Low-Carbon Australia and the Clean Energy Finance Corporation (CEFC)
  - For investment in substitutes such as cogeneration and renewable energy, where there are well-documented barriers that will take some time to overcome

7.2. Possible options

These involvements reflect the fact that governments have a number of objectives with regard to energy-related issues. These include:

- Educating consumers about energy issues

- Helping consumers control their costs and make more informed decisions about energy matters
- Reducing the environmental impacts of energy consumption.

However, it is also important that governments take into account the impact that the policies they implement are likely to have on the electricity market, which is governed by the National Electricity Rules (NER) and has an explicit objective.

It is important that policies implemented for a specific purpose (or set of purposes) do not impede other acknowledged objectives – or if they do, that this is a conscious decision arrived at in full appreciation of the interactions and trade-offs between the various objectives. This gives rise to the recommendation below.

7.2.1. Option P-1: Review, prioritise and revitalise on-going government initiatives concerning energy efficiency and related issues

The Council of Australian Governments is currently undertaking a review of climate change and energy efficiency policies, partly to review their 'complementarity' to a carbon price and partly to review their effectiveness. These are important questions, but it must be remembered that many of the energy efficiency policies being considered under the review were not implemented to serve as complements to the carbon price, but rather to address other issues in the energy market and energy affordability.

This review could be highly effective if, while remaining under its current terms of reference it also assessed the impact of the various programs on their 'complementarity' with the National Electricity Market, their impact on relevant market failures, and their potential impact on electricity prices and its affordability. This could include providing ideas for improving the performance, where applicable, of programs with regard to any or each of the criteria upon which the programs are being assessed.

7.2.2. Option P-2: Explicit consideration of the impacts of new energy and environment related policies on the dynamics of the energy market, and their interactions with the NER and relevant energy market regulation

Key features

Under this option, explicit consideration would be made of the impacts of new energy and environment related policies introduced at any level of government on the dynamics of the energy market, as well as their interactions with the NER and relevant energy market regulation. Where possible, this could be incorporated within any Regulatory Impact Statement or similar analytic measure used by the government in question. Alternatively, it could simply be an instruction that this consideration be documented, along with relevant guidelines regarding how it should be undertaken. The objective of the consideration would be to

- identify and quantify the flow-on effects of the proposed policy in question on the electricity market and its consumers
- propose mechanisms (where needed) to reduce any negative impacts of the proposed policy on the electricity market and its consumers, or enhance its beneficial impacts on that market and its consumers
- quantify (to the extent possible) the cost of the mechanisms and the degree to which they would reduce or enhance the impacts of the policy on the electricity market and its consumers and on the objectives of the proposed policy and its key stakeholder groups.

The addition of this consideration would acknowledge that the energy and electricity system is affected by changes in a wide range of human activity.

A key issue in this assessment would be the impact of government policy (including the degree and frequency of changes in government policy) on the climate for investment in electricity infrastructure assets and the implications of changes in the investment climate for the costs and reliability of the electricity supply chain.

Magnitude of impact

It is not possible to estimate the magnitude of the impact of this option, however, it is reasonable to expect that it would be at least moderately material.

Measurability of impact

Measurement is the objective of this option. Specifically, the objective of this option is to measure the impacts of policies and amendments to policies with regard to their combined or interacting objectives.

Timing of option benefits and costs)

This option will produce effects as each proposed policy is reviewed.

Likelihood of success

Implementation of this process would improve the likelihood of success (and reduce the likelihood of negative unintended consequences) of government policies that affect the electricity market and it consumers. Related costs include the cost of the review activities to be undertaken, and the time to do so.

While the need to undertake such a review can simply be stated by the head of any government, reinforcement in applicable guidelines and strong leadership are likely to be needed to ensure that it becomes part of standard practice within various government departments.

Effect on specific stakeholder groups

The electricity industry and electricity consumers could be expected to benefit from this option.

Consistency with electricity market philosophy and direction

This measure is consistent with the electricity market philosophy as it would introduce consideration of the NEO in government policymaking considerations.

7.2.3. Option P-3: A National Energy Savings Initiative

Key features

The Commonwealth government is currently considering the implementation of a National Energy Savings Initiative (NESI) that would harmonise or replace three state-based programs that have been operating since 2009 – the Victorian Energy Efficiency Target (VEET), the South Australian Residential Energy Efficiency Scheme (REES) and the New South Wales Energy Savings Scheme (ESS) - and another state-based scheme that is scheduled to commence operations in January 2013 – the ACT Energy Efficiency Scheme (ESS).

This consideration falls somewhere between the operations of the two options discussed above. However, the nature and scope of a NESI makes it a prime opportunity for putting into place the overall thrust of the options being considered within this paper – that is, to undertake measures that seek to improve the efficiency of the electricity supply industry.

Each of the state-based programs that would be rolled into the NESI have been designed with one or more of the following objectives:

- to assist consumers in reducing their electricity bills, particularly in light of the commencement of carbon pricing,
- to reduce greenhouse gas emissions, and
- to stimulate the market for energy efficiency products and services.

The common theme of the four state-based programs is that they require the electricity retailers operating within the state to demonstrate that they have achieved a specified target of electricity (or in some cases electricity or gas) savings within consumers' facilities. The VEET and the NSW ESS require the electricity retailers to surrender 'certificates' documenting the electricity savings. The certificates are created though the installation of energy efficiency measures, and can be bought and sold between end-use consumers, third parties such as energy service companies and electricity retailers. The REES and the ACT ESS by contrast simply set the target and require the electricity retailers to demonstrate that they have been involved either directly or by funding the installation of a sufficient number of energy efficiency measures in end-use customers' facilities to meet the target.

Similar programs have been implemented in other countries, and it has almost universally been the case that (a) the obligated electricity companies have been able to meet their required targets, and (b) the market for third-party provision of energy efficiency products and services has been strengthened.

However, the state-based programs that have been implemented in Australia have generally not taken into account either (a) the impact of the programs on the electricity system's annual loadshape, and therefore the electricity supply chain's costs and revenues (and consequently electricity prices)[51], or (b) the time variation of the carbon intensity of electricity generation and therefore the actual greenhouse gas emission reduction potential of different energy efficiency measures.

The first of those issues could be counteracted, or at least moderated, by additional program features that would reduce the negative impact of these programs on the utility loadshape, or even improve the loadshape. Examples of the types of approaches that could be considered in this regard include:

- separate incentives for the take-up of measures that improve system load factor; or
- an adjustment factor that increases the certificate value of (or incentive available for) energy efficiency measures that improve system load factor and reduces the certificate value or incentives available to energy efficiency measures that reduce system load factor.

It is worth noting in this regard that:

- the Commonwealth government – through the ESI Secretariat – is currently:
  - quantifying the benefits and costs of harmonising the existing state-based programs or replacing them with a national program, including the potential for such a program to reduce compliance and administrative costs

51 Energy efficiency programs that help consumers reduce their consumption can be very useful in assisting the consumers that participate to save money. However, in those cases where the program reduces consumption but does not have similar impact on peak demand, it can put upward pressure on electricity prices, thereby potentially increasing the bills of consumers that do not take part in the program.

- considering the use of an adjustment factor to the incentive offered for each energy efficiency measure based on the measure's impact on the utility's load factor

- a study undertaken for the AEMC found that, while the three state-based ESI programs that have been implemented to date have had a modest downward pressure on wholesale electricity prices, they have also had a very small negative impact on system load factor which could put upward pressure on network unit prices[52].

The addition of features that ensure that the programs do not have a negative impact on the utility's annual system load factor would allow the benefits generally delivered by these programs to be achieved without the risk of upward pressure on electricity prices.

Magnitude of impact

The ESI Secretariat is currently assessing the likely benefits and costs of a NESI with and without an adjustment factor for load factor impacts.

Measurability of impact

The study the ESI Secretariat is currently conducting will provide a forecast of the impact of the adjustment factor approach, based on the extent to which it changes the relative payback of energy efficiency measures with better and worse load factor impacts. It may also be possible to compare take-up after the implementation of the adjustment factors with take-up in the state-based programs without such factors.

Another factor that should be addressed in assessing the impact of a NESI is that of addtitionality. This aspect of such programs has only been assessed robustly in the UK.

Timing of option benefits and costs)

The NESI itself is likely to lead to relatively rapid reductions in energy bills for those homes and businesses that participate. It is also likely to result in (probably quite) small increases in unit energy prices in the short term, and corresponding small rises in energy bills for those homes and businesses that do not undertake energy efficiency activities. However, to the extent that features are added to reduce negative impacts on load factor, this impact will be reduced or even be removed entirely. Furthermore, to the extent that the NESI reduces wholesale electricity prices and results in the deferral of infrastructure, it should put downward pressure on the final electricity prices paid by consumers over the mid- to longer term.

Likelihood of success

A national ESI would be certain to deliver energy savings to those homes and businesses that undertake energy efficiency activities with the support of the scheme. There would be greater uncertainty around its impact on electricity prices, however.

The adjustment factor approach would impose very little if any incremental costs on the administrative costs of the various energy efficiency programs currently in place in the jurisdictions or the national ESI that is being considered. These incremental costs would be limited to the cost of doing the underlying analysis to specify the appropriate adjustment factor for each energy efficiency measure.

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52 See *Stocktake and Assessment of Energy Efficiency Policies and Programs that Impact or Seek to Integrate with the NEM: Stage 2 Report*, available at http://www.aemc.gov.au/Media/docs/Oakley-Greenwood---Stage-2-Report--Stocktake-and-Assessment-of-Energy-Efficiency-Policies-and-Programs-that-Impact-or-Seek-to-Integrate-with-the-NEM-84e621b9-e0a8-440b-843f-5239e07b3054-0.pdf

If a separate peak demand reduction target program were to be undertaken, however, it would have development and implementation costs not unlike those of the NESI itself.

Effect on specific stakeholder groups

Those groups that are most likely to seek, or be sought, to generate certificates would benefit most from a NESI. The ESI Secretariat, on behalf of the Commonwealth government, is looking at specific targets or mechanisms to ensure that low-income households receive a fair share of these benefits.

The adjustment factor approach would not have any material incremental impact on either the consumers that participate in energy efficiency programs, or the retailers that must deliver energy savings through them. It would, however, mitigate the potential negative impacts of the program on non-participants.

The only possible exception to this is that the adjustment factor approach would provide greater and lesser incentives to different energy efficiency measures, thereby shifting the relative benefit provided by these programs to manufacturers and suppliers of those technologies. It is unlikely that this will cause any material issues for these stakeholders, however, as the programs will continue to provide incentives to consumers to use their products.

Consistency with electricity market philosophy and direction

This measure serves to improve the consistency of this policy initiative with the NEO.

8. Vulnerable customers

As mentioned earlier, this paper does not discuss in detail measures that should be considered to assist vulnerable consumers cope with the current and likely increasing price of electricity. However, the following issues are of critical importance for considering what is meant by the term 'vulnerable' consumer, and how policy should address the electricity sector in general and these consumers in particular:

- That the overall arrangements within the electricity market – including pricing arrangements – should be designed and selected for their ability to (a) make the electricity sector itself as efficient as possible, and (b) provide the bulk of consumers with prices that reflect the real cost of supplying electricity so that their usage patterns can reflect the value that they place on using electricity for different purposes at different times, while (c) providing means to protect 'vulnerable' consumers from the impact of such pricing. This reflects the fact that for some consumers the cost of electricity will entail a significant proportion of their available income or operating costs, and they may have limited opportunities or ability to change their consumption level or pattern sufficiently to relieve that pressure.
- These 'vulnerable' consumers can be businesses as well as households. Paying their energy bills may require sacrifices in other areas of importance to health, safety or on-going household or business operating costs. Special arrangements will be required to assist them in dealing with their electricity consumption and paying for it. Government has a critical role to play in developing and supporting these arrangements, and the electricity industry has a role to play in assisting with the implementation of those arrangements.
  - Among households, low-income households generally spend the largest proportion of their income on energy. However, some low-income households with concession cards have a significant level of assets and funds in savings, and relatively modest energy bills. In addition, recent research by AGL[53] suggested that families with multiple children and modest-income could be particularly vulnerable, as they have higher energy bills and limited 'discretionary' spending.
  - Some of the most vulnerable SMEs are with those with high energy costs as a proportion of turnover and limited ability to pass on rising energy prices to consumers, through international competition or other factors. Many of these businesses have been stressed by other factors like the high dollar and reductions in demand for products and services. While businesses that are Emissions-Intensive and Trade Exposed (EITE) are compensated for 66% and 94.5% respectively of the impact of the carbon price on their EITE activities, they are not compensated for other factors that increase electricity costs – such as network investment.
- Support for vulnerable consumers can and should take multiple forms depending on the nature of the group and their needs. Support for low income households can include direct payments that take into account their energy needs and support their efforts to make behavioural changes to reduce their electricity consumption without compromising their health, safety or well-being. However, mechanisms that improve the energy efficiency of housing stock inhabited by these consumers and the major energy using equipment within that housing stock should also be considered.

53 See P Simshauser, and T Nelson, *The Energy Market Death Spiral - Rethinking Customer Hardship*, http://www.aglblog.com.au/wp-content/uploads/2012/07/No-31-Death-Spiral1.pdf

- Support for vulnerable businesses is generally best targeted at facilitating and supporting improvements in their energy efficiency.
- Consumer protection is essential to support the participation of these consumers in the energy market.
  - Consumer protection currently varies between jurisdictions in both its quality and nature, with substantially higher protection in Victoria than other states.
  - Consumer protection will also need to evolve with the energy market, and changes in retail pricing will need to occur in tandem with a process to ensure existing protections (and concessions) keep pace with new tariffs. For example, while shifting to monthly billing could provide many benefits, the current protections relate to a three-month billing cycle for initiating bill disconnection processes and so on.
  - The Council of Australian Governments (COAG) consulted extensively during the design and adoption of the National Energy Customer Framework (NECF). The NECF was intended as a national regime for the sale and supply of electricity and gas by retailers and distributors to retail customers. It contains a range of consumer protections and is a significant step toward a simplified regulatory regime for retailers and distributors.
  - The NECF deals primarily with the following matters:
    - the retailer-customer relationship and associated rights, obligations and consumer protection measures
    - distributor interactions with customers and retailers, and associated rights, obligations and consumer protection measures
    - retailer authorisations
    - compliance monitoring and reporting, enforcement and performance reporting.

    In theory, the NECF came into effect on 1 July 2012. However, implementation has stalled in most jurisdictions.
- Government also has an important role to play in addressing other market failures, such as information asymmetries, transaction costs, and access to capital.

It should also be noted that the AEMC's Power of Choice Review is addressing this issue from the perspective of the electricity market. Their recently released *Draft Report: Power of choice - giving consumers options in the way they use electricity* makes the following recommendations about managing the impacts of increased electricity prices on vulnerable consumers, all of which are consistent with the views put forward above:

- Arrangements should be put in place to allow consumers that have a limited capacity to respond to electricity price signals to remain on a retail tariff which has a flat network component, but to have the option to choose a time varying tariff.
- Governments should support programs that target advice and assistance to these consumers to help them manage their consumption.
- Governments should review their energy concession schemes to ensure that they are appropriately targeted.