29 February 2008

Cost Benefit Analysis of Smart Metering and Direct Load Control

Work Stream 4: Consumer Impacts

Phase 2 Consultation Report

NERA
Economic Consulting

Report for the Ministerial Council on Energy Smart Meter Working Group

Project Team

Ann Whitfield

Adrian Kemp

Daniel Young

Tara D'Souza

Katherine Lowe

Yuliya Hedynach

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com

Contents

Glossary

ACOSS	Australian Council of Social Services
CPP	Critical Peak Price/Pricing
CRA	Charles River Associates
CUAC	Consumer Utilities Advocacy Centre
DLC	Direct Load Control
EMCa	Energy Market Consulting associates
ESC	Essential Services Commission (Victoria)
ESAA	Energy Supply Association of Australia
ESCOSA	Essential Services Commission of South Australia
EWOV	Energy and Water Ombudsman of Victoria
GST	Goods and Services Tax
HAN	Home Area Network
HEET	Home Energy Efficiency Trial
IHD	In-home display
ICRC	Independent Competition and Regulatory Commission (ACT)
IPART	Independent Pricing and Regulatory Tribunal (NSW)
kVa	Kilovolt-ampere
kW	kilowatt (1000 watts) and kilowatt hours (kWh)
MW	Megawatts (1,000,000 watts)
NIEIR	National Institute of Economic and Industry Research
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NERA	NERA Economic Consulting
NPV	Net present value
NSLP	Net system load profiles
OTTER	Office of the Tasmanian Energy Regulator
PV	Photovoltaic (solar cells)
RFI	Request for Information
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SPP	Statewide Pricing Pilot (study conducted in California)
SMS	Short Messaging Service

SMWG	Smart Meter Working Group
SWIS	South West Interconnected System
TOU	Time of Use

Executive Summary

NERA Economic Consulting (NERA) has been engaged by the Ministerial Council on Energy's (MCE) Smart Meter Working Group (SMWG) to consider the impact a national mandated rollout of either smart meters or a non-smart meter direct load control (DLC) alternative will have on consumers.[1] This analysis is part of a broader assessment of the costs and benefits associated with:

- a smart meter rollout led by distributors (Scenario 1);
- a smart meter rollout led by retailers (Scenario 2);
- a non-smart meter DLC rollout led by distributors (Scenario 3); and
- a smart meter rollout with centralised communication infrastructure (Scenario 4).

This project is being carried out in conjunction with a number of other consultants (Energy Market Consulting associates (EMCa)), Impaq Consulting, KPMG and Charles River Associates (CRA)) each of whom have been engaged to consider the costs and benefits associated with other parts of the electricity supply chain. In accordance with the Terms of Reference for this study, the analysis has been conducted in two phases with the objective of each phase being:

- to inform consideration of a national minimum functional specification for a smart meter (Phase 1); and
- to consider the costs and benefits associated with each of the specified scenarios and assess the jurisdictional and regional variations in costs and benefits (Phase 2).

This report forms the output from the Consumer Impact workstream with respect to Phase 2 of the study.

Our focus for Phase 2 has been to consider the likely response of residential and small commercial customers to the introduction of time of use (TOU) tariffs, critical peak pricing (CPP) and DLC and to estimate the resultant effect on jurisdictional load profiles.[2] In addition, we have assessed the distributional effects of each scenario on consumers in each jurisdiction, and particularly for disadvantaged consumers.

We have also considered the customer service benefits associated with the functionalities recommended for inclusion in the national minimum specification for smart meters. These benefits would remain the same across the different smart meter roll-out scenarios (ie, scenarios 1, 2 and 4). Given that the benefits are related to the functionalities of smart meters, these benefits would not arise under scenario 3 (a non-smart meter DLC rollout).

---

[1] The term 'consumer' is used throughout this report to refer to residential customers and small commercial customers below the relevant jurisdictional threshold for mass market meters. The scope of the analysis relates to customers connected to the main grid in each jurisdiction, ie, in Western Australia it relates to the South West Interconnected System (SWIS) whilst for the Northern Territory it means the network around Darwin and Katherine only .

[2] The tariff assumptions considered were developed by KPMG as part of the retail workstream, and are summarised in Tables 3.2 and 3.4 below.

Estimated demand response from the introduction of time-of-use tariffs and critical peak pricing

To estimate the potential demand response from the introduction of TOU tariffs and CPP in each jurisdiction, NERA has reviewed demand responses achieved in a number of domestic and international trials. We calculate the potential demand response using estimates of both the own-price elasticity of demand and the elasticity of substitution (between peak and off-peak periods), which are then applied to tariffs derived by KPMG as part of the retail workstream. The elasticity estimates adopted are based primarily on the California State-wide Pricing Pilot study[3], as it is the most comprehensive study undertaken to date estimating the demand response from of TOU tariffs and CPP.

The resultant estimates of demand response during peak times and as compared against a daily average for those customers in TOU tariffs and CPP are presented in Table E1 and TableE2, for residential and commercial customers, respectively.[4]

Table E1: Residential - estimates of the response to TOU and CPP for those customers on TOU tariffs and CPP

		NSW/ACT	NT	Qld	SA	Tas	Vic	WA
Peak times	***Summer***							
	Critical peak day	-17.3%	-10.6%	-18.6%	-14.5%	n.a	-16.7%	-21.5%
	Peak day (non-CPP)	-5.2%	-1.0%	-4.6%	-2.8%	-1.4%	-4.5%	-5.8%
	Winter							
	Critical peak day	-7.8%	-3.4%	-4.3%	n.a	-6.0%	n.a	-4.4%
	Peak day (non-CPP)	-1.9%	-0.2%	-1.2%	-0.7%	-1.1%	-1.7%	-1.4%
Daily Average	***Summer***							
	Critical peak day	-5.4%	-5.4%	-7.8%	-7.2%	n.a	-7.3%	-6.6%
	Peak day (non-CPP)	0.0%	0.2%	-0.1%	0.4%	0.1%	-0.1%	0.2%
	Winter							
	Critical peak day	-3.2%	-2.2%	-1.6%	n.a	-3.0%	n.a	-1.3%
	Peak day (non-CPP)	0.0%	0.1%	0.0%	0.2%	0.0%	0.0%	-0.2%

3 CRA, *Impact Evaluation of the California Statewide Pricing Pilot*, March 2005.

4 The description of the demand response estimation methodology can be found in Section 5.1.

Table E2: Commercial- estimates of the response to TOU for those customers on TOU tariffs

		NSW/ACT	NT	Qld	SA	Tas	Vic	WA
		Base						
Peak times	***Summer*** Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.4%	-0.4%
	Winter Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.3%	-0.3%
Daily Average	***Summer*** Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.4%	-0.4%
	Winter Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.3%	-0.3%

These estimated reductions in demand for customers on CPP and TOU tariffs are then combined with the take-up rate assumptions adopted by KPMG as part of the retail workstream:

- 7.5 per cent for CPP and 35 per cent for TOU for residential customers;
- 40 per cent for TOU for small commercial customers.

The resulting estimate for the overall change in maximum demand and total energy consumption for each jurisdiction is as set out in Table E3, for 2016.

Table E3: All customers – estimated overall change in maximum demand and overall consumption, by jurisdiction (base demand response case, 2016)

	NSW/ACT		NT	Qld	SA	Tas	Vic	WA
	Base	Summer Peaking						
Change in maximum demand	-0.26%	-0.46%	-0.19%	-0.77%	-0.96%	-0.34%	-0.61%	-1.20%
Change in energy consumption	-0.02%	-0.02%	0.00%	-0.03%	-0.04%	-0.02%	-0.03%	-0.01%

In the case of NSW we have estimated the demand response both on the basis of the 2006/7 profile (when NSW was winter peaking) as well as a sensitivity assuming that NSW becomes summer peaking. Both results are reported in Table E3.

In response to comments made as part of the Phase 1 report, for Phase 2 we have also considered a number of 'upside' assumptions that increase the degree of demand response obtained from the introduction of TOU and CPP tariffs. These include an increase in the uptake rate for CPP tariffs offered to residential consumers to 15 per cent (from 7.5 per cent) and an additional 3 per cent 'energy conservation' impact for residential consumers arising as a result of increased customer awareness of their energy consumption, prompted by the introduction of TOU and CPP tariffs. The resultant impact on overall maximum demand and consumption in each jurisdiction from these 'high demand response' assumptions is presented in Table E4 below.

Table E4: All customers – estimated overall change in maximum demand and overall consumption, by jurisdiction (high demand response case, 2016)

	NSW/ACT		NT	Qld	SA	Tas	Vic	WA
	Base	**Summer Peaking**						
Change in maximum demand	-0.62%	-1.00%	-0.49%	-1.31%	-1.80%	-0.89%	-1.05%	-2.00%
Change in overall energy consumption	-0.24%	-0.24%	-0.21%	-0.40%	-0.45%	-0.38%	-0.29%	-0.40%

Estimated demand response from the introduction of direct load control (scenario 3)

DLC has the potential to deliver benefits to both distributors and retailers, specifically by:

- allowing distributors to actively manage demand during system peaks and in so doing reduce potential network constraints. This can in turn reduce the need for network augmentation; and
- allowing retailers to actively manage their exposure to peak wholesale prices.

There are a range of household and commercial appliances that could potentially be incorporated into DLC programs. The most common are air conditioners and, to a lesser extent, swimming pool pumps.

The critical assumptions for determining the demand response associated with DLC, is the likely proportion of households that would participate in these programs. For the purposes of this study, KPMG have estimated a lower bound take-up rate for DLC of 10 per cent and an upper bound of 20 per cent.[5] The resultant reduction in demand during a DLC event is

[5] The 10% take-up rate was estimated by KPMG as part of workstream 3. Both take-up rates are expressed as a percentage of the entire population. When expressed as a proportion of those people with eligible appliances only, the take-up rates are higher. For example, a 10% take-up rate for the entire population represents an 11.7% take-up rate for those customers with air-conditioners in Western Australia, whilst for Victoria it is 14.2% (based on estimates of the proportions of households in those jurisdictions with air-conditioners in 2016).

estimated to be between 0.85 and 1.59 per cent (with a 10 per cent take up rate) and 1.70 and 3.17 per cent (with a 20 per cent take up rate).

Estimated incremental demand response from smart meter functionalities 15 and 16

This Phase 2 report also considers further the issue of the additional demand response that may be associated with incorporating either an interface for load control devices (functionality 15) or an interface to a Home Area Network (HAN) using an open standard (functionality 16) in a smart meter rollout.

Functionalities 15 and 16 both provide the capability for DLC as part of a smart metering rollout.

In addition, functionality 16 would allow customers to install an in-home display (IHD), which increases the availability and accessibility of information to customers. The results of both domestic and international trials on the potential for IHDs to enhance customers' responsiveness to TOU tariffs and CPP, or to engender an additional energy conservation effect are mixed. We have therefore assessed two indicative cases for the additional demand response that may be associated with the provision of an IHD:

- the first is a zero additional demand response, consistent with the preliminary findings of trials being undertaken by EnergyAustralia as well as other international studies.[6] This assumption has been adopted in our base demand case; and
- the second is an additional 4 per cent demand reduction, consistent with the most recent findings of the Integral Energy trials and a study undertaken for Hydro One in Canada. This assumption has been adopted in the high demand response case, and is in addition to the 3 per cent additional conservation impact that has also been included in that case.

Distributional impacts on customers

The final part of our analysis involved considering the impact of time-of-use pricing, critical peak pricing and participation in direct load control programs for customer bills. This analysis highlights that the bill impacts on customers will vary according to individual household characteristics. These characteristics include:

- the individual household load profile, which is affected by the appliance mix, usage of appliances within the home and the time over which that usage occurs;
- total electricity consumption; and
- the scope and motivation that the household has to change existing electricity use patterns, or conserve electricity.

To ensure that the estimated bill impacts reflect the effect of a change in tariff structures, rather than the level of prices, we have applied the retail tariffs estimated by KPMG which maintain revenue neutrality for the retail and network businesses. This means that they do

[6] See discussion in Section 7.1 and description of Australian and international studies in Appendix A.

not include the potential second round price reductions associated with business cost efficiencies being passed through to customers, nor the initial price rises likely to be necessary to fund the initial rollout of smart metering.

Our analysis indicates that, in general, households with a relatively low proportion of total consumption during peak periods (for example households where occupants work during the day), are likely to be better off after the introduction of time of use tariffs, without necessarily needing to change usage behaviour. This highlights that under flat tariff arrangements, these households are currently cross-subsidising households who use a greater proportion of electricity during peak periods. Conversely, households with large peak electricity use are currently benefiting from paying a tariff that is lower than the cost of supplying electricity to them, given their current time of electricity use.

Finally, our analysis and results highlight a number of consumer issues that should be further considered as part of the policy framework of a future rollout of smart metering. These include:

§ the underlying regulatory framework for the introduction of smart metering will need to consider how hardship policies and other consumer protections and assistance programs (including information protection) should be modified to ensure that existing protections are not eroded;

§ new mechanisms for ensuring that households facing financial stress are identified and provided with information on assistance available, prior to utilising remote disconnection functionalities;

§ designing education programs about the introduction of smart metering and associated innovative tariff products, to assist consumers in understanding how best to manage their consumption in order to minimise their bills and to maximise the potential for demand response. The focus group results suggest that for low income households, providing oral information can sometimes be more effective than information provided in the form of leaflets or brochures;

§ providing an opportunity for households to readily shift between tariff products, if they discover that they are actually financially worse off from the new tariff product offering;

§ the need to consider the relationship between network businesses (offering time of use network tariffs and/or critical peak pricing) and the customer, given that most customers only receive a bill from a retailer and the retailer will not have an obligation to pass these new tariff structures onto customers and the strength of commercial incentives to pass through price signals may vary. Alternatively, an incentive mechanism could be designed to ensure that time of use tariffs and/or critical peak prices are transparently conveyed by retailers to customers; and

§ ensuring that there is sufficient notice of critical peak events, to provide the opportunity for a household to respond appropriately to the pricing signals presented.

1. Introduction

NERA Economic Consulting (NERA) has been engaged by the Ministerial Council on Energy's Smart Meter Working Group (SMWG) to consider the impact a staged national mandated rollout of either smart meters or direct load control mechanisms will have on consumers.[7] This analysis is part of a broader assessment of the costs and benefits associated with:

- a smart meter rollout led by distributors (Scenario 1);
- a smart meter rollout led by retailers (Scenario 2);
- a non-smart meter direct load control rollout led by distributors (Scenario 3); and
- a smart meter rollout with centralised communication infrastructure (Scenario 4).

This project is being carried out in conjunction with a number of other consultants (Energy Market Consulting associates (EMCa)), Impaq Consulting, KPMG and Charles River Associates (CRA)) each of whom have been engaged by the SMWG to consider costs and benefits associated with other parts of the electricity supply chain. These include the transitional implementation costs of a smart meter rollout or a direct load control (DLC) alternative and the retailer, network and broader electricity market and greenhouse gas impacts associated with each of the scenarios listed above. This includes the potential cost efficiencies that distributors may be able to achieve.

In accordance with the Terms of Reference for this study, the analysis has been conducted in two phases with the objective of each phase being:

- to inform consideration of a national minimum functional specification for a smart meter (Phase 1); and
- to consider the costs and benefits associated with each of the specified scenarios and assess the jurisdictional and regional variations in costs and benefits (Phase 2).

This report forms the output from the Consumer Impact workstream with respect to Phase 2 of the study. In assessing consumer impacts, this report considers both small residential and small commercial customers. 'Small' customers have been taken as being those with a total annual demand below 160/MWh for all jurisdictions with the exception of Queensland (100 MWh/year), Tasmania (150 MWh/year) and the Northern Territory (750/MWh/year).[8] The analysis is restricted to those small customers connected directly to the main grid.[9]

---

7 The term consumer is used throughout this report to refer to residential customers and small commercial customers below the relevant jurisdictional threshold for mass market meters.

8 The threshold adopted for small customers for these three jurisdictions reflects data availability. In particular the thresholds adopted for Queensland and Tasmania reflect the thresholds applying to the introduction of retail competition in those jurisdictions, whilst for the Northern Territory data is not further disaggregated in relation to customers below 750 MWh/year.

9 In the case of Western Australia this means the South West Interconnected System (the SWIS) whilst for the Northern Territory it means the network around Darwin and Katherine only.

In identifying the consumer benefits associates with smart meters or a DLC alternative, we have drawn a distinction between:

- the impact of smart meters or DLC on the level and pattern of customer demand; and
- improvements in the level of customer service.

In relation to changes in demand, we have sought to quantify the change in consumption patterns and levels across each jurisdiction and in turn to quantify the effect on consumers using the consumer surplus metric. The term consumer surplus in this analysis refers to the difference between the value consumers place on using electricity compared to what they actually pay for electricity. It is therefore a measure of the economic benefit derived by consumers from using electricity. Changes in prices and electricity demand will change total consumer surplus and therefore change the benefit derived by consumers from using electricity. This change in benefit is used as our measure of the effect of smart meter functions on consumers.

We have focused on the likely response of residential and small commercial customers to the introduction of time of use (TOU) tariffs, critical peak pricing (CPP) and direct load control (DLC) and the resultant effect on jurisdictional load profiles. This information was provided to CRA to enable it to estimate the market and greenhouse related costs and benefits associated with the rollout of smart meters or a DLC alternative. The TOU tariffs and CPP were provided by KPMG as part of their analysis of retail impacts.

In addition we have focused on the distributional effects of each scenario on consumers, particularly for disadvantaged consumers.

In relation to service standards, in the majority of cases changes in service levels as a result of a rollout of smart meters is difficult to quantify. We have therefore undertaken a qualitative assessment, based on the analysis carried out as part of Phase 1 of the assignment.

The remainder of this chapter outlines the consultation process undertaken as part of Phase 2 and the report structure.

1.1. Consultation

The analysis in this report builds on that undertaken in Phase 1.

The Phase 1 analysis benefited from information provided by a number of organisations, particularly relating to the smart meter trials that are currently being conducted across Australia. In particular the analysis was informed by:

- the results of a number of practical smart meter and direct load control trials that have been undertaken in Australia and internationally and jurisdictional reviews of these issues (see Appendix A for a summary of these trials and jurisdictional reviews. Information from a number of additional trials and reviews has been added, where these have come to our attention following Phase 1);

- the feedback provided by a number of consumers that were selected to participate in a series of consumer focus groups carried out in Brisbane, Adelaide and Melbourne;
- information provided by the Consumer Utilities Advocacy Centre (CUAC) and Australian Council of Social Service (ACOSS);
- information provided by EnergyAustralia, Energex, Ergon, ETSA Utilities, Integral Energy, Country Energy, Western Power, Aurora Energy, ActewAGL, United Energy Distribution and the Power and Water Corporation; and
- information provided by Energy Efficient Strategies in relation to air conditioner ownership.

The Phase 1 Customer Impact Report set out NERA's proposed approach to Phase 2, including our proposed methodology and initial series of estimates. The report sought particular feedback from stakeholders on these proposed assumptions. Overall, feedback on our assumptions was limited. Where we did receive feedback this has informed the further analysis in Phase 2.

As part of Phase 2 we have also undertaken the following further consultation:

- a series of interviews with retailers (and follow-up data requests) conducted in each jurisdiction, focusing on the types of products that they may actively choose to market following a smart meter rollout or DLC alternative;
- a Request for Information (RFI) that was sent to distributors seeking feedback in relation to the Phase 1 assumptions for the relevant jurisdiction in relation to residential and commercial elasticities, the 2006-07 net system load profile and the contribution of residential and commercial customers to the net system load profile;
- information provided by Energy Efficient Strategies in relation to the use of pool pumps within each jurisdiction in Australia;
- a series of sixteen additional customer focus groups involving consumers in both urban and rural areas in South Australia, Victoria, New South Wales, Queensland, Tasmania and Western Australia.[10] These focus groups were conducted by Red Jelly and covered consumers' attitudes to different tariff offerings and DLC and ways in which consumers may modify their behaviour faced with different pricing structures;[11]
- a workshop on customer bill impacts and the demand response analysis, held in Sydney on 16 November 2007 involving representatives from fourteen consumer advocacy groups drawn from all jurisdictions (with the exception of the Northern Territory); and

---

[10] The ACT and the Northern Territory where not included due to budget considerations.

[11] The Red Jelly Phase 2 focus group report is attached in Appendix D.

§ further discussions with EnergyAustralia, Integral Energy, ETSA Utilities, Aurora Energy and Energex.

NERA would again like to thank those that have provided assistance on these issues.

1.2. Report structure

The remainder of this report is structured in the following manner:

§ Chapter 2 discusses the effect of smart meters on consumers, particularly in relation to likely changes in demand, customer service and the costs of providing electricity services. In addition, we outline the likely consumer impact from direct load control in the absence of a smart meter;

§ Chapter 3 sets out some key assumptions in relation to the future structure of retail tariffs under the smart meter rollout scenarios and uptake rates for both different tariff offerings and DLC, drawn from the analysis conducted by KPMG as part of workstream 3;

§ Chapter 4 presents a summary of the key findings from trials conducted both within Australia and overseas on the impact of TOU tariffs, CPP and DLC on peak demand and overall energy consumption;

§ Chapter 5 sets out the demand-side response estimated in relation to the introduction of TOU and CPP tariffs for each jurisdiction under each of the smart meter rollout scenarios[12] and the associated change in consumer surplus. It also discusses how the demand-side response may differ between rural/regional and urban areas within each jurisdiction;

§ Chapter 6 sets out the demand-side response estimated in relation to direct load control for each jurisdiction, under rollout scenario 3 (with no smart meter);

§ Chapter 7 presents the analysis of the incremental impact on demand of the smart meter functionalities 15 and 16;

§ Chapter 8 discusses the distributional impact on consumers within each jurisdiction focusing on high, medium and low income consumers in both urban and rural/regional areas. In addition this section presents a number of case studies that have been developed to illustrate the potential impacts on households with differing characteristics;

§ Chapter 9 summarises the customer service impacts associated with a smart meter rollout; and

§ Chapter 10 draws out some key conclusions of the consumer impact analysis.

---

[12] For the purposes of this analysis the smart meters are assumed not to incorporate either functionality 15 (DLC capability) or 16 (HAN, allowing for both DLC capability and provision of an in-home display). These functionalities are considered separately in section 7.

In addition to the main body of the report, Appendices A to D provide detailed information on some of the research and analysis undertaken as part of Phase 2 of this study. Specifically:

- Appendix A provides a summary of recent reviews, practical trials and studies of the responsiveness of consumers;
- Appendix B sets out the methodology used to estimate the demand side response associated with the introduction of TOU tariffs and CPP and the assumptions underlying this analysis;
- Appendix C sets out the methodology and assumptions used to estimate the demand side response associated with DLC, both under scenario 3 and where facilitated by the functionality assumed for smart meters; and
- Appendix D provides Red Jelly's report in relation to the Phase 2 consumer focus groups.

2. The Effect of Smart Meters and Direct Load Control on Consumers

Phase 2 of the analysis considers the customer impact of three alternative scenarios for a rollout of smart meters (which may or may not have the capability to facilitate DLC)[13] and the customer impact of a rollout of DLC, which does not involve smart meters. In this chapter we consider in general terms the way in which customers may be affected by both smart meters and DLC, and in doing so set out the framework within which we have conducted our analysis.

2.1. The Effect of Smart Meters on Consumers

To consider the effect of smart meters on consumers it is necessary to first examine what it is that a smart meter does for a consumer. A smart meter is simply an electricity recording device that collects data at discrete intervals and provides that information remotely to the relevant electricity company. Simply changing from an accumulation meter to a smart meter is therefore unlikely to have a direct effect on consumers because consumers are likely to be indifferent about how their electricity use data is collected, stored and used to calculate an electricity bill. What is relevant to a consumer is whether the functionalities of a smart meter provide new capabilities for electricity retailers and distributors to offer innovative products that in turn affect how consumers use and are charged for electricity, or improve the service that is provided. The effect of a smart meter on a consumer is therefore dependent on how retailers and distributors respond to the new capabilities, and the cost of implementing these new capabilities.

Smart meters provide the ability for retailers and distributors to offer new tariff structures to consumers, particularly TOU tariffs or CPP. They may also allow retailers or distributors to offer DLC. In addition, retailers may choose to provide electricity use data to customers that may in turn prompt them to conserve electricity and/or better manage their own electricity demand. Smart meters also provide the potential ability for retailers or distributors to improve customer service levels.

In this section we discuss in detail how smart meters, and the capabilities they provide, are likely to affect consumers. In particular we outline how smart meters can affect consumers' patterns of electricity use within a day and between seasons, change business costs (with subsequent implications for tariffs) and change customer service levels. Our analysis does not consider the likely cost savings that may result from smart metering, which would be expected to lower the prices faced by customers in the medium to long term. These cost savings are considered within the network and retailer workstream reports.

---

[13] Phase 1 of the analysis left open the question of whether the national minimum functionality of smart meters should incorporate functionalities that enables DLC (ie, functionalities 15 and 16). The incremental impact on demand of including these functionalities within the smart meters rolled-out under scenarios 1,2 and 4 is therefore considered further in this report.

2.1.1. Facilitation of Time-of-Use tariffs and Critical Peak Pricing

As noted above, smart meters provide new capabilities for electricity retailers and distributors to offer innovative products, including new tariff structures. Two tariff structures commonly discussed in the context of smart metering are the introduction of TOU tariffs and CPP.

To facilitate the billing of customers for electricity use, all electricity within Australia is recorded at the point of entry to a customer's premises. For the majority of residential and small commercial customers below the jurisdictional threshold for mass market meters, electricity use is recorded using an accumulation meter, which is manually read on a periodic basis.

An accumulation meter, also known as a type 6 meter, records the flow of electricity into a household. It measures the amount of electricity used since the last reading and therefore provides no information about when electricity is used within a day. By simply recording the amount of electricity used and not the time of its use, an accumulation meter is unable to provide information on the amount of electricity consumed by the customer during critical network peaks or wholesale price peaks.

The lack of time of use information collected by accumulation meters means that electricity tariffs for small consumers are generally based on a flat rate (ie the same charge per kWh) irrespective of the time of electricity use, or an inclining block tariff (where the charge per kWh increases after a certain quantity of electricity has been consumed within a specified time period).[14] The tariffs are set to recover all of the costs associated with supplying electricity to an end consumer including wholesale generation costs, network costs (both transmission and distribution) and retailer costs.

Although tariffs are charged on a flat average basis the cost of delivering electricity to a customer is not constant throughout a day. Costs can vary in each time period and over the year according to changes in wholesale generation costs associated with the mix of generation for each time interval. In addition, there are additional capital costs associated with addressing network constraints which occur in peak periods of time within the year.

A consequence of the flat tariff (or inclining block tariff) is that most small electricity consumers do not face price signals that reflect the difference in the cost of providing electricity during peak, off-peak and shoulder periods throughout the day, or the cost associated with providing electricity when the network is constrained or wholesale prices are peaking.

Unlike accumulation meters, smart meters can record consumption on a half-hourly basis throughout the day and this feature provides the capability for the introduction of TOU based tariffs (where prices vary according to the time of use within a day) and

---

[14] There are currently two exceptions to this. In the case of hot water systems that are directly controlled by a remote agent to operate in off-peak periods consumers pay an off-peak tariff. The second exception is prepayment meters where consumers are charged on a time of use basis because the meter has the capability to record the time of day.

CPP (where a retailer or distributor is allowed to call critical peak periods where the price increases for the duration of the critical peak event).[15]

TOU tariffs can be structured in a number of different ways including simple peak and off-peak tariffs, or peak/shoulder/off-peak tariffs. The length of the period that is defined as peak or off-peak can vary between jurisdictions according to the characteristics of network load peaks or wholesale cost peaks during a day within each jurisdiction.[16]

By charging TOU tariffs, a consumer is given a price signal to change the pattern of electricity use during a day. As noted above, in the absence of this signal, significant capital expenditure may be required to build sufficient capacity to meet peak generation and network needs that may only be used for a small period of the year. Small reductions in demand during peak periods that lowers the peak generation and network capacity required can deliver significant capital infrastructure cost savings over time.

In addition to TOU tariffs, smart meters also allow for the application of CPP.[17] CPP allows a retailer or network operator to charge a higher electricity price for a set number of critical peak events each year. The CPP is usually higher than the peak TOU tariff and can be used when the network is reaching its peak capacity or wholesale prices are particularly high. CPP requires the electricity business to provide sufficient notice of a critical peak price period and usually requires communicating that information to customers in a number of different ways, for example via short message service (SMS), email, telephone messaging systems of an in-home display (IHD), where available. Once called, all electricity used by consumers who are affected by the CPP is charged at the high CPP for the duration of the critical peak period.

CPP provides flexibility to both electricity businesses and consumers. Consumers can choose to respond to the higher CPP by shifting demand or not consuming electricity for the duration of the critical peak period. Electricity businesses are able to call CPP events when and if required during a year. As with the TOU tariffs, CPP is a market signal to consumers to change the pattern or level of demand and can deliver significant capital infrastructure cost savings and/or retailer hedging cost savings over time.

In the short run, TOU tariffs and CPP are likely to affect the demand for electricity in one or both of two ways:

---

15 It would also be possible to introduce TOU tariffs or CPP using a manually read interval meter compared to a smart meter with two way communications. However for the purposes of our analysis we have been asked to consider the implications of TOU and CPP as part of a smart metering rollout.

16 It would also be possible to design a TOU tariff that reflected the relative intensity of carbon emissions at different times of the day. This issue is discussed further in section 3.1.

17 Critical peak pricing tends to be used on a small number of occasions during the year to signal network or wholesale market constraints. These prices are set in advance and are typically three to seven times higher than the off-peak price. They are usually implemented in conjunction with an underlying time-of-use tariff, which is the approach we have adopted in our analysis.

- First, by shifting electricity demand from periods of high prices to periods of low prices for those appliances that a consumer wishes to use, but where they have some discretion over the time of use (eg, using the washing machine on the weekends rather than on weekday afternoons); and
- Second, by reducing demand in periods of high prices if a consumer decides that the value of using the appliance at a particular time is lower than the cost of operating the appliance (eg, turning an air conditioner off during peak periods).

These two forms of consumer electricity demand response arising from TOU tariffs and CPP have been examined in some detail in a number of trials both within Australia and internationally. A summary of this evidence is set out in Appendix A, and discussed further in section 4.

In the longer run consumers may respond to TOU tariffs and CPP by investing in more energy efficient appliances and/or switching the source of fuel they use (primarily from electricity to gas), thereby further reducing the amount of electricity they use, both at peak and off-peak times. Consumer responses in the longer term have been studied in less detail in the trials and studies of which we are aware.

In summary, existing accumulation meters do not provide retailers and distributors with information on the time of electricity use and therefore do not allow for the development of TOU tariffs or CPP. Smart meters allow retailers and/or distributors to introduce TOU and CPP tariff structures. These structures in turn have the potential to alter consumer demand patterns, reducing the level of peak demand and therefore deferring network augmentation and additional investment in generating capacity. Changes in tariffs, coupled with additional information on energy usage, may also result in consumers deferring consumption from peak to off peak periods or reducing energy use altogether. These demand impacts have implications in terms of the generation dispatch pattern and therefore the level of greenhouse gas emissions.

One important determinant of potential benefits associated with the rollout of smart meters is therefore to what extent retailers and/or distributors decide to adopt TOU and CPP tariff structures, and the take-up rates associated with these tariffs. These are discussed in section 3.

2.1.2. Provision of additional information

In addition to the introduction of TOU tariffs and CPP, there is also the potential for smart meters to impact consumer demand where retailers or distributors choose to provide the additional information captured by smart meters to customers. An increased awareness by customers of their electricity consumption (resulting from either more frequent provision of usage information or more detailed information) may in turn lead to reductions in electricity usage. Such reductions may be at both peak and off peak times, and represent a structural shift in consumers' demand patterns, rather than a reaction to a change in the tariff they face.

Results from both the Phase 1 and Phase 2 focus groups observed that consumers who were most conscious of their energy consumption believed that the provision of an in-home display would prompt behavioural change by increasing their awareness of their energy usage. In Phase 2, an in-home display was presented with a price tag and these consumers were the most willing to purchase it.

Additional information may be provided to customers in a number of ways. These may include via an internet site that shows their daily usage by time of day or via an in-home display (where the smart metering specification includes the capability to interface with a home area network (HAN) (functionality 16)).

The extent of any general demand conservation effect associated with the provision of additional information has been considered in a number of studies, both in Australia and internationally. We consider the available evidence in section 4.2.4 (in relation to information provision in general) and section 7.1 (in relation to the additional conservation impact that may be achievable with an in-home display (IHD), and summarise it in more detail in Appendix A.

2.1.3. How do smart meters affect consumers?

As outlined above, smart meters allow retailers and distributors to develop new tariff structures and products (including DLC, where the smart meters incorporate this functionality). They also potentially allow them to change their customer service through changes in the capabilities to provide different services. Both of these outcomes can affect consumers.

In addition, smart meters can also deliver business cost efficiencies, which may in turn be passed through as cost savings to customers through a combination of regulation and a competitive retail market.

The effect of smart meters on consumers can therefore be categorised into three main groups being:

- changes in electricity demand and its time of use – demand response effects;
- improvements in customer service levels, through improved business processes and potential changes to regulated service standards – consumer service effects; and
- changes in prices through changes in business costs, both via business efficiency improvements and the direct costs of a smart meter program – cost effects.

Each of these effects is discussed in greater detail below.

2.1.4. Demand response impacts – via changes in tariff structure

As discussed in section 2.1.1 above, smart meters can facilitate the introduction of TOU and CPP tariffs. These new tariff structures can in turn change the level of consumer demand.

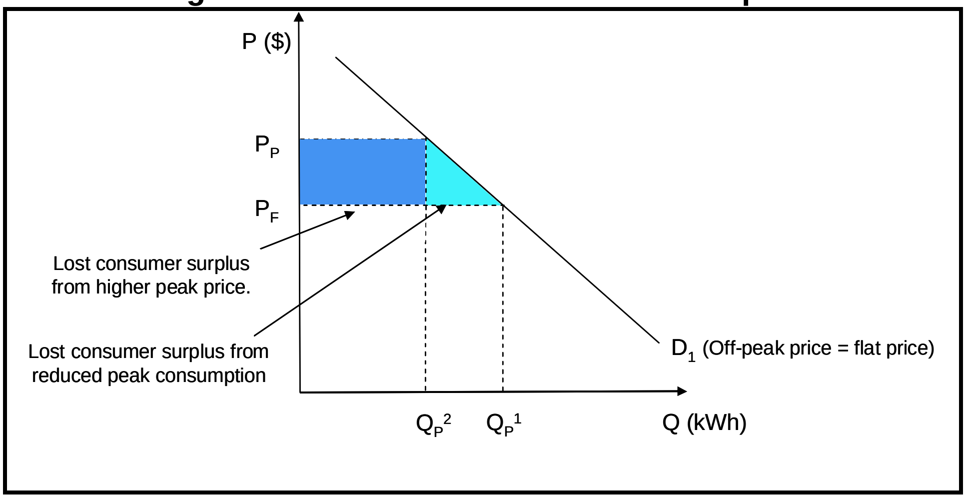
Smart meters can also result in changes in the level of consumer demand where the smart meters include a functionality that facilitates DLC. The impact on consumers of a demand response impact resulting from DLC is considered in section 2.2.

The relationship between demand response and consumer welfare is an important consideration for our analysis. One measure of consumer welfare is the economic metric referred to as consumer surplus. The term consumer surplus refers to the difference between the amount consumers are prepared to pay for their purchases and the amount they actually pay. When prices increase the difference between the amount consumers are prepared to pay and what they actually pay falls and thus consumer surplus also falls. Conversely, when prices fall the gap between what consumers are prepared to pay and what they actually pay widens and in so doing the consumer surplus metric increases. A fall (increase) in consumer surplus implies a reduction (increase) in consumer welfare.

Changes in demand response can affect consumer surplus in four ways:

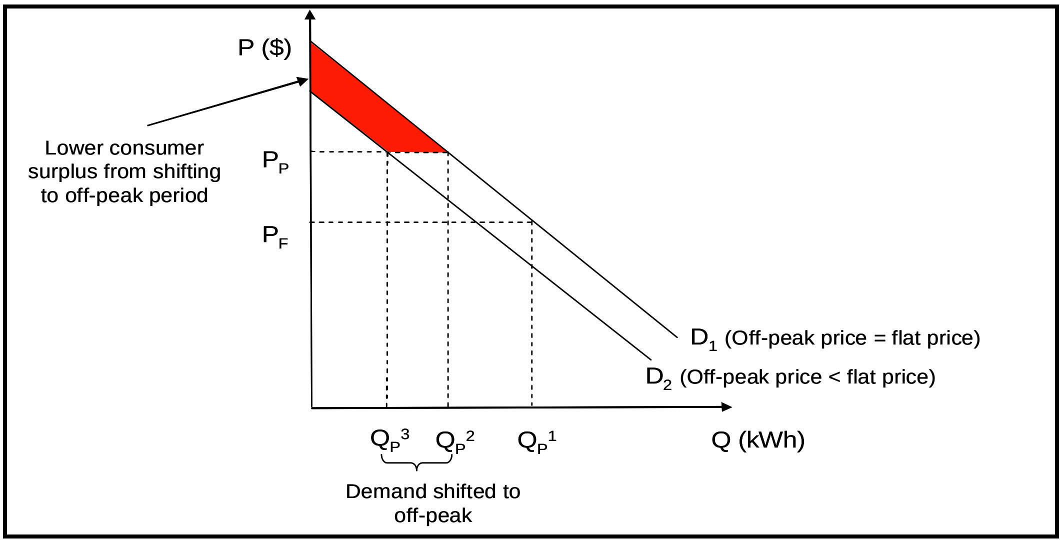
1. For peak demand, a change in the price of peak electricity from a previous flat tariff to a new higher peak tariff results in a reduction in peak electricity demand (represented as a movement along the peak demand curve). Consumer surplus falls as a result of paying a higher price for electricity that is still consumed in the peak period, and the loss of consumer surplus associated with peak consumption that no longer occurs – Figure 2.1.

Figure 2.1: Reduction in consumer surplus



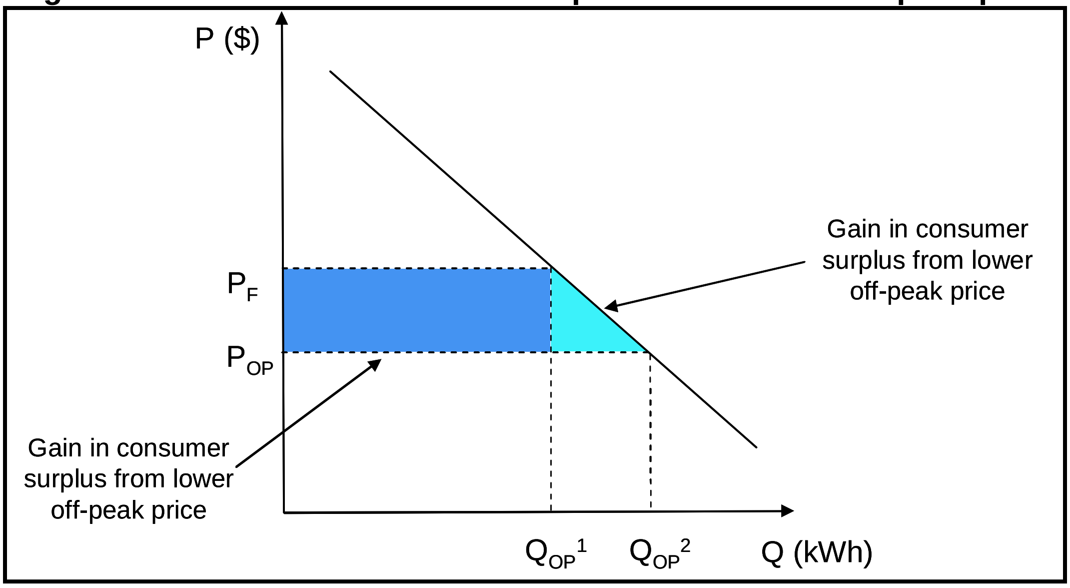
2. For peak demand, a reduction in the off-peak price (where off-peak demand is a substitute for peak demand) will result in a decrease in peak demand as consumers seek to maximise the benefit of electricity use by shifting demand between peak and off peak periods (represented as a shift in the peak demand curve). Consumer surplus therefore also falls in the peak period due to consumers having lower demand as a result of a decrease in the price of the off-peak substitute – Figure 2.2.

Figure 2.2: Reduction in consumer surplus due to cheaper off-peak alternative



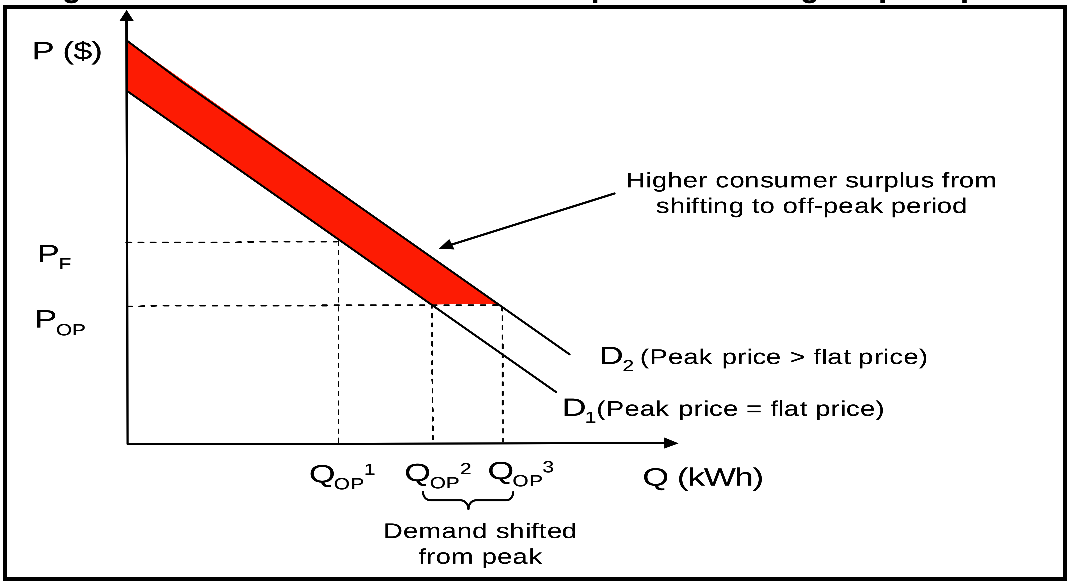
3. For off-peak demand, a change in the price of the off-peak electricity from a previous flat tariff to a lower off-peak tariff results in an increase in off-peak electricity demand (represented as a movement along the off-peak demand curve). Consumer surplus increases as a result of paying a lower price for electricity that is consumed in the peak period, including an increase in off-peak demand resulting from the lower off-peak price –Figure 2.3.

Figure 2.3: Increase in consumer surplus due to lower off-peak price



4. For off peak demand, a change in the peak price (where off-peak demand is a substitute for peak demand) will result in an increase in off-peak demand as consumers seek to maximise the benefit of electricity use by shifting demand between peak and off-peak periods (represented as a shift in the off-peak demand curve). Consumer surplus therefore increases in the off-peak period due to consumers having higher off-peak demand as a result of an increase in the price of the peak substitute – Figure 2.4.

Figure 2.4: Increase in consumer surplus due to higher peak price



The overall effect of TOU tariffs and CPP on consumer surplus (and hence consumer welfare) will therefore depend on the proportion of electricity demand that is capable of being shifted between peak and off-peak periods and the change in the price of peak and off-peak tariffs compared against the original flat tariff. A consumer that is able to shift all of its demand from peak to off-peak periods will be better off under a TOU tariff because they would face a lower price for all of their electricity. A consumer that is unable to shift any demand from peak to off-peak periods may be better or worse off depending on how tariffs are set and their peak/off-peak load profile compared against the average load profile for the particular retailer/distributor.

The above discussion outlines the affect of changes in peak and off-peak electricity charges on total consumer surplus. The change in consumer surplus however also represents both a financial transfer between the consumer and producers of electricity (because for example, higher prices mean that a consumer pays more for electricity in the peak period) and a loss in economic benefits arising from the lost opportunities associated with no longer using electricity.[18]

The changes in consumer surplus can therefore be further decomposed into two components:

§ The redistribution of the surplus between consumers, retailers, network operators and generators. For example in Figure 2.1 the increase in the peak price from P_F to P_P and the subsequent reduction in demand from Q_{P1} to Q_{P2} results in the blue shaded area P_FP_P $Q_{P1}Q_{P2}$ being redistributed from consumers to retailers, network operators and generators (ie, an increase in retailers, network operators and

---

[18] The lost opportunities associated with increases in the price of a good is commonly referred to as the deadweight loss, and is a measure of the decrease in total economic benefits arising from a change in price. Intuitively the deadweight loss arises when moving to TOU tariffs or CPP because consumers are no longer willing to consume electricity at the higher price in the peak period. This lost opportunity to consumer electricity can be valued by the difference between what consumers were prepared to pay, and the flat tariffs previously charged for that electricity no longer consumed.

generators surplus). Conversely in Figure 2.3 the reduction in off-peak price and the subsequent increase in demand results in the blue shaded area $P_F P_{OP}$ $Q_{OP1} Q_{OP2}$ being redistributed from retailers, network operators and generators to consumers; and

- Net societal gain or loss. For example in Figure 2.1 the aqua shaded triangular area represents an overall loss to society while in Figure 2.3 the aqua shaded area represents an overall gain to society.[19]

While it is relevant to measure the entire change in consumer surplus when assessing the consumer welfare related effects of a demand response, it is important to recognise that a portion of this is simply a redistribution of surplus between consumers, retailers, network operators and generators. For the overall cost benefit analysis, these redistributions are less important compared to the effect on society as a whole.

2.1.5. Consumer service

The second effect on consumers arises from smart meters providing functions that result in customer service level improvements. This can be as a result of lowering the costs of meeting existing customer service levels (eg, quality and reliability of service) required in each jurisdiction, or making improved customer service levels feasible where, in the absence of a smart meter, a higher customer service level would not be possible.

There are a number of smart meter functions that are expected to either impact customer services (eg, remote connect/disconnect) or allow distributors to improve their responsiveness to problems that occur within the network, thereby improving the overall electricity supply service provided to customers (eg. meter loss of supply detection). In addition smart meters may affect regulated service standards directly, particularly through the improvement of information made available to regulators.

The benefit that arises to consumers from improvements in customer service levels can be difficult to quantify. For example, remote service checking allows the relevant electricity business to undertake service fault checking without needing to send a technician out to investigate a problem identified by a customer. This in turn allows the customer to be informed of the likely cause of a problem and take action to rectify it faster than they otherwise could have. The value of this improved service level is, however, more difficult to quantify.

In addition, it should be acknowledged that the service impact of smart metering functions may differ between types of customers. For example, households that are rarely affected by outages may attribute little benefit from outage management

---

[19] In addition to the change in consumer surplus improving the alignment of peak tariffs with the marginal cost of delivering peak electricity to consumers and also improves the alignment of off-peak tariffs to off-peak electricity demand it is expected to improve the allocative efficiency associated with prices being aligned to marginal costs. As Energy Australia highlight in their submission to the Phase 1 report, this benefit would ideally be quantified. Whilst we acknowledge this benefit any quantification of the allocation efficiency benefits are likely to be uncertain at best, so we have not endeavoured to quantify this effect.

improvements. Similarly, lower income household may be more adversely impacted by remote disconnection capabilities, to the extent that these households may experience more frequent disconnections than higher income households. In these instances the associated hardship policies will need to be carefully designed to ensure that disconnections do not occur where household are unaware of assistance programmes available to them. The impact of a smart meter rollout on customer service levels is discussed in section 9.

2.1.6. Cost effects

The third effect on consumers arises from changes in the business costs of retailers and distributors as a result of the installation of smart meters. These cost changes are expected to be reflected in the prices paid by consumers, either as the outturn of competitive pressures amongst retailers, or through the regulatory price setting process.

Smart meters can lead to cost changes in three different ways:

§ improvements in business efficiency due to smart meter functions (eg, remote reading of meters);

§ reductions in wholesale and network costs arising from changes in the time profile of electricity use and/or lower total electricity demand; and

§ increases in business costs to recover the direct costs of smart meter installation, ongoing operating costs and supporting data management infrastructure.

For example, the remote reading of meters is likely to lower the cost of meter reading by avoiding the costs associated with manually reading accumulation meters (a business efficiency). This cost saving would be expected to be retained for a period of time by the business and either:

§ passed through to customers in the form of lower prices, as a result of competitive pressures in the retail market; or

§ in the case of regulated retail tariffs, the retailer would be able to retain the cost saving for the regulatory period before the business efficiency is passed on to customers.

The analysis presented in this report focuses only on the ‘first round’ impact on consumers related to the change in the structure of tariffs they face initially. As discussed in the following chapter, the tariffs assumptions adopted are revenue neutral, in that they are expected to result in the same level of revenue as the previous flat tariffs.

In the longer run, the net impact of smart meters on costs can be expected to flow through to tariffs and, as a result, to consumers. To the extent that any decision to rollout smart meters is predicated on an expectation of there being a positive net benefit, this implies a fall in future prices (as a result of the net reduction in costs). As a result, one would expect there to be an increase in consumer welfare (and overall economic welfare as well).

We have not captured this second round cost reduction impact in our demand modelling. One of the aims of Phase 2 of the analysis is to highlight where there are differences in the costs and benefits between jurisdictions, which in turn will inform the MCE's decision as to the timing for the rollout in each jurisdiction. Where the cost benefit analysis on the basis of the first round impact on tariffs has highlighted differences in costs and benefits between jurisdictions, we would not expect this to substantially change if the further iteration between net costs and tariffs were also included. For this reason, we do not believe that it would impact the net benefit results sufficiently to change the conclusions drawn from our analysis.

Finally, TOU tariffs and CPP that result in changes in the time pattern of demand, or in the total quantity of electricity consumed will have flow on effects for generation, retailers, network businesses and the level of greenhouse gas emissions. For example if the pricing signals provided by TOU tariffs and CPP have the effect of reducing peak demand then:[20]

§ networks may be able to defer augmentation and the expansion of transmission and distribution capacity;

§ investment in generation capacity may be deferred;

§ retailers may be able to minimise their exposure to peak wholesale electricity prices and therefore have a lower average cost per kWh supplied to their customers; and

§ the level of greenhouse gas emissions may change if the composition of generation used to supply energy requirements changes.

The work undertaken by this work stream in relation to the expected changes in demand side response is therefore an important input into the costs and benefits faced by networks, retailers and the wider electricity market.

2.2. The effect of direct load control on consumers

The analysis undertaken in Phase 2 covers the rollout of smart meters under three alternative scenarios and also the rollout of a DLC capability (scenario 3), which does not involve the use of smart meters.

As noted above, smart meters may also incorporate a DLC functionality (functionality 15 or 16). Consideration of the impact of DLC on customers is therefore relevant in the context of all four of the rollout scenarios.

The effect of DLC on customers can be divided into two categories:

§ reductions in peak electricity demand (and possibly increases in off-peak);[21] and

---

20 Each of these issues is examined in detail in the relevant workstream reports.

21 For the purposes of our analysis we have modelled direct load control as a reduction in peak consumption with no subsequent change in off-peak consumption. This reflects advice that DLC does not affect the

- changes in prices through changes in business costs, both via business efficiency improvements and the direct costs of the DLC program.

Direct load control occurs when appliances within a customer's premises are remotely controlled by a retailer, network operator or demand aggregator to lower electricity consumption without affecting the service provided by the appliance. Direct load control technology is being used to control appliances such as air conditioners, pool pumps and electric hot water systems. Importantly direct load control need not mean that an appliance is remotely turned off entirely. In the case of air conditioners, direct load control systems cycle the air conditioner compressor to lower electricity consumption whilst minimising the impact on the cooling capability of the air conditioner. This reduction in consumption translates into lower expenditure on electricity which implies a redistribution of retailer, generator and network operator surplus to consumers.

The initial effect of direct load control on customers is therefore likely to be relatively small. There is no change to the pattern of consumption as the result of DLC (ie, no substitution between peak and off-peak consumption), only a reduction in the level of peak consumption. It is likely that the function of the appliances will be maintained such that there will be no loss of value to the customer from using the appliance that is controlled. That is, the reduction in peak consumption as a result of DLC is unlikely to change the level of consumer surplus.

There may, however, be an additional customer impact arising from the pricing strategy used by the electricity business seeking to recruit customers to a direct load control program. This strategy may include a one-off rebate or incentive payment upon the purchase of an air conditioner with direct load control capabilities, on-going incentive payments to remain in the program or a discount on electricity tariffs for all consumption. Such a payment represents a benefit to consumers, but is a transfer from other market participants rather than a societal gain in itself. An electricity business would only be prepared to pay up to the point where the cost savings it achieves with a direct load control program just equals the cost of recruiting the marginal customer to the direct load control program.

Direct load control is likely to lead to cost reductions associated with the avoidance of costs associated with peak electricity demand such as the cost of network augmentation, retailers' hedging costs and the cost of additional generation investment. These benefits are likely to eventually flow through to customers in the form of lower prices. However, the overall reduction in prices will depend on the net cost impact of the DLC rollout (ie, the cost of the rollout that is recovered in tariffs compared with the resulting cost savings in relation to wholesale, retail and network expenditure). As discussed above, we have not incorporated these 'second round' cost impacts into our quantitative analysis. However, we would not expect the extension of the analysis to these second round impacts to change the conclusions reached in relation to a decision to rollout a DLC capability.

---

thermal comfort of customers, and therefore customers would be unlikely to respond through increasing off-peak consumption to off-set higher household temperatures resulting form the cycling of the air conditioner.

2.3. Summary

The likely effect of smart meters on consumers can be broken into three categories: demand response effects; customer service effects; and cost effects.

Whether changes in demand response arising from changes in tariffs offered have a positive or negative impact on overall consumer welfare (as measured by the change in consumer surplus) will depend on the scope for customers to shift demand between peak and off-peak periods; the prices for peak and off-peak periods; and the own-price elasticity of demand for electricity in peak and off-peak periods. Changes in demand response associated with DLC will result in a customer benefit associated with the payment customers receive to join the program, and reduced expenditure on electricity, but no loss of welfare from reduced consumption.[22]

The customer service related effects arise from improvements in service levels that result from the capabilities of smart meters. The cost effect is the net effect of the costs of the smart meter rollout and the resulting benefits in relation to business efficiencies and investment deferral on the tariffs faced by customers.

These effects have been compared with a direct load control program without smart meters (scenario 3), where the consumer benefit includes the payment received for being involved in the program, the reduction in electricity expenditure and the net reduction in costs associated with business efficiencies and other cost reductions compared with the costs of the rollout. As with the smart meter rollout, the direct load control program will lead to cost changes associated with the reduction in peak demand that will eventually be reflected in customer prices and create another round of increased demand in periods with price reductions.

---

[22] This statement relies on the assumption that the thermal comfort of customers is unaffected by DLC. If this assumption does not hold, then there may be welfare losses arising from DLC.

3. Retail Tariff and Direct Load Control Assumptions

This section sets out the assumptions that have been made in relation to the retail tariffs that may be offered following a rollout of smart meters (including the associated take-up rates) as well as the expected take-up of direct load control offers, both where DLC is facilitated by a smart meter rollout and where it is offered as a stand-alone capability (ie, scenario 3).

Many of the assumptions in this section draw on work undertaken by KPMG as part of the retail workstream. The tariff assumptions are the basis for considering the potential demand response arising from the introduction of TOU tariffs and CPP.

3.1. Structure of Tariffs Offered

In order to estimate the demand response from the introduction of new tariff structures by retailers it has been necessary to make some assumptions on the structure of the tariffs that retailers may choose to actively market following a rollout of smart meters, and the likely uptake of those tariffs.

KPMG as part of the retail workstream has derived some assumed tariff structures and levels. These have been based on discussions with retailers and current tariff offerings, as well as analysis by KPMG. The derivation of the tariffs are discussed in more detail in the retail workstream report.[23]

KPMG has assessed two alternative outcomes for tariff structures. The first is associated with smart meters with the base functionality and assumes the following alternatives are offered:

§ For residential consumers: flat tariffs; TOU; CPP

§ For small commercial consumers: flat tariffs; TOU tariffs

The second outcome assumes that smart meters incorporate a DLC functionality (ie, functionality 15 or 16), and assumes that DLC tariffs are also offered to residential customers, alongside the other offers. KPMG has assumed that the DLC product offered to consumers will also incorporate TOU tariffs. The tariffs offered to small commercial customers remain the same.

These tariff structures have been assumed to be offered in all jurisdictions.

In all cases it is assumed that retailers will continue to offer tariffs similar to the existing flat tariff structure (ie, c/kWh tariffs). The flat tariffs that have been assumed by KPMG are based on retailer’s current tariff offerings, adjusted for the estimated cost of carbon post-2012.[24]

---

[23] KPMG, (2008), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts, Phase 2 Report.

[24] The impact of an assumed carbon trading scheme post- 2012 has been estimated by the market modelling workstream using CRA’s CEMOS model, and is assumed to increase over the period of analysis. Further

It is also assumed that retailers will offer both TOU tariffs and CPP for residential customers, and KPMG has assumed that these tariffs would be offered jointly, rather than only CPP. Retailers' motivation for introducing TOU tariffs and CPP will differ. Retailers may have an incentive to introduce TOU tariffs in order to unwind current cross-subsidies, and prevent some of their customers being offered more attractive tariffs by competitors. In contrast, the motivation for retailers to offer CPP would be either to reduce the costs of hedging at peak times or because they are offering the product on behalf of distributors, in order to avoid the costs of peak network augmentation.[25]

Where smart meters also have the capability to facilitate DLC it has been assumed that retailers will offer DLC tariffs to residential consumers in addition to TOU and CPP. Whilst CPP and DLC may appear to be substitute products (both offering a means to reduce peak demand), experience elsewhere has shown that where both products are offered together, a high overall take-up rate is achieved.[26] As a result, if retailers are targeting a reduction in peak demand (either for their own purposes or on behalf of distributors) it is likely to be more effective for them to offer both products.

In relation to tariffs for small commercial customers, KPMG has assumed that retailers offer both flat tariffs and TOU. KPMG has not assumed that CPP and DLC tariffs will be marketed to small commercial customers, since such customers are assumed to typically have less flexibility to alter their pattern of electricity consumption.

We note that in jurisdictions where full retail competition has yet to be introduced (eg, Western Australia, Tasmania), it is possible that the jurisdictional government could decide to require regulated retail tariffs to reflect a TOU structure. Similarly, in jurisdictions that do have full retail competition, standing offer tariffs could be required to have a TOU structure. This would have implications for the assumed take-up rate for TOU tariffs, as discussed in the following section.

KPMG has assumed that the mix of tariff products offered to consumers does not differ depending on the rollout scenario, ie, whether a smart meter rollout is retailer-led, distributor-led or has centralised communications. Once the smart meter capability is in place, KPMG considers that retailer's incentives to offer the different

---

details can be found in the Market Modelling workstream report. The impact of a carbon emissions trading scheme has been reflected in all of the tariffs used in our analysis.

25 Where CPP is being driven by distributors, they would need to come to an arrangement with the retailers (who are the party with the relationship with end-use customers) to offer these tariffs, which would be likely to involve a payment to the retailers to provide them with an incentive to offer the tariff. The difficulties of distributors influencing end-use customer tariffs are discussed further in both NERA's Overview Report and KPMG's Retail Workstream Report

26 Personal communication, Thomas Van Denover, Comverge Inc., 2 November 2007. The higher take up rate occurred where CPP was mandatory and DLC was seen as a method of managing CPP events without having to actively change electricity consumption behaviour.

tariff products would be expected to be the same.[27] For DLC business systems would need to be developed to allow retailers to use load control capabilities.

We note that the TOU tariff assumed by KPMG is based around a peak/shoulder/off-peak structure, that in the majority of cases reflects existing retailer offers in each jurisdiction. As discussed in section 2.1.1, different time periods under TOU tariffs can be chosen to reflect the likely peaks in network load or wholesale costs during the day. It would also be possible for TOU tariffs to be structured to reflect the relative intensity of carbon emissions at different times of the day. However, there is non-coincidence between these different tariff objectives, ie, times of high carbon emissions occur when off-peak generation is running, which is not at times of high wholesale costs (reflecting peak generation) and is unlikely to coincide with peak network load. As a result, there is a trade-off in objectives in tariff design, and the commercial drivers for a retail business (which relate to high wholesale market costs) is likely to lead to tariff structures that do not maximise the potential for a reduction in carbon emissions or peak network demand.

In addition to making assumptions in relation to the types of tariff products that may be offered, the consultant teams have also needed to make assumptions as to what stage in a rollout these products would be offered. That is, what proportion of customers would need to have a smart meter installed before the retailers would find it worthwhile to introduce the new tariff structures, given upfront marketing costs and any required changes to billing systems.

In relation to the stage in the rollout at which the new tariff structures may be introduced we note the following:

- TOU tariffs could be introduced to customers as they received a smart meter, ie, in line with the smart meter rollout. Retailers' billing systems are currently set-up to facilitate billing on a TOU basis, since they already offer peak and off-peak rates. Some retailers (eg in Tasmania and NSW) already offer TOU tariffs once customers have an interval meter.

- CPP tariffs may also be introduced early in the rollout process. CPP is a more complicated concept to explain to consumers, and so it is probable that retailers would begin to market this option early in the rollout, to increase the proportion of consumers that may be willing to take it up; and

- DLC tariffs (where DLC is facilitated by the smart meter specification) would be introduced once retailers could expect to obtain control of a reasonable amount of of load using these tariffs.

The customer demand modelling has assumed that all new tariff structures are introduced at the same time (ie, once TOU has been introduced, CPP and DLC (where available) are offered too). We have therefore adopted the assumption of all tariffs being introduced progressively and in line with the rollout of smart meters. This

[27] KPMG, (2008), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts, Phase 2 Report.

assumption has the affect of potentially overestimating the demand response in the earlier years of the rollout, to the extent that DLC and CPP are not introduced until a minimum number of smart meters have been installed. However, we do not consider that this is a material overestimation.

3.2. Take-up rates

KPMG has made the following assumptions in relation to the take-up of the different tariff options offered.

Table 3.1: Take-up rate assumptions (for all scenarios)

	NSW/ACT	NT	Qld	SA	Tas	Vic	WA
Residential							
Smart meters without DLC functionality:							
Flat	57.5%	57.5%	57.5%	57.5%	57.5%	57.5%	57.5%
TOU	35%	35%	35%	35%	35%	35%	35%
TOU + CPP	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Smart meters with DLC functionality (ie, functionalities 15 & 16):							
Flat	55%	55%	55%	55%	55%	55%	55%
TOU	30%	30%	30%	30%	30%	30%	30%
TOU + CPP	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
DLC + TOU[28]	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Small commercial customers:							
For all smart meter cases							
Flat	60%	60%	60%	60%	60%	60%	60%
TOU	40%	40%	40%	40%	40%	40%	40%

Source: KPMG, (2007), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts, Phase 2 Report.

The take-up rate assumptions are discussed in section 6.3.1 of KPMG's retail workstream report.[29] We note that in the case of Tasmania, although KPMG has assumed that DLC tariffs may be offered, NERA's demand analysis indicates that it is unlikely that there would be periods in which DLC would be operated (based on the criteria set out in Section 6.2 (Table 6.1), as a result of Tasmania being winter peaking.

Take-up rates have been assumed to be the same in all jurisdictions. The focus group results (discussed below) indicate that differences in consumer attitudes between and within jurisdictions would affect the uptake of various product offers. It is also

---

[28] The 7.5% take-up rate is expressed as a percentage of the overall population and translates into a higher percentage of those customers that are eligible for DLC (ie, those customers with an air-conditioner). The latter take-up rates range from 8.1% in Northern Territory to over 20% in Tasmania, and depend on the penetration of air-conditioning in each jurisdiction. KPMG has assumed that the DLC product offered to consumers will also include TOU tariffs.

[29] KPMG, (2008), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts, Phase 2 Report, sections 6.3, 6.4 and 6.5.

possible that jurisdictions without full retail competition (eg, Western Australia) may be able to achieve higher uptake rates if regulated retail tariffs themselves were to reflect a TOU structure. Similarly, if standing offer tariffs were required to have a TOU structure this may imply higher take-up rates in areas of some jurisdictions where retail competition is less developed (eg, rural Queensland). KPMG as part of the retail workstream has considered jurisdictional factors that may be expected to influence take-up rates. However KPMG has concluded that there is no firm basis on which a distinction could be made, on the basis of available information.[30]

In the case of DLC, KPMG has estimated that 7.5% of all customers would take-up DLC.[31] Customers are eligible to participate in a DLC program where they have an air-conditioner. Given the difference between jurisdictions in the stock of air-conditioners, this results in a different uptake rate assumption, where expressed as a proportion of the total population.

Take-up rates have also been assumed to be the same under each roll-out scenario. The willingness of customers' to take-up alternative tariff offers is not expected to be affected by the roll-out scenario adopted for smart meters. Similarly, the capability for retailers to influence customers' willingness to take-up alternative tariffs (eg, by providing an in-home display, where this functionality is supported by the smart meter specification[32]) is not expected to change depending on the roll-out strategy, since the capability of the smart meter is the same under each of the roll-out scenarios.

The Phase 2 consumer focus groups canvassed participants' views as to their willingness to adopt alternative tariff structures (including DLC). Respondents were presented with alternative tariff assumptions[33] and expressed their views on the attractiveness of each, and their preference overall. In addition, participants were asked how they may modify their behaviour when faced with each tariff.[34]

A consistent finding across all of the focus groups was that participants were much more willing to consider a DLC tariff option when compared to other alternatives. This was generally consistent across all jurisdictions, between urban and regional centres and across different income groups. In particular, however, consumers in Adelaide, Queensland, Sydney and Perth and high income earners more broadly expressed the greatest interest in the DLC option.

Participants viewed DLC options as providing them with a way to 'do the right thing' and reduce electricity consumption without needing to think about it and in that respect it not impacting their lifestyle. The fact that they would also reduce their

---

30 KPMG, (2008), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts, Phase 2 Report, section 6.6.

31 KPMG, (2008), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts, Phase 2 Report, section 6.5.

32 The issue of whether the provision of IHDs is expected to influence the take-up of TOU or CPP is discussed in section 3.2.1 below.

33 The tariff assumptions presented were based on the alternatives developed by KPMG in the retail workstream.

34 Red Jelly's Report on the Phase 2 focus groups is included as Appendix D to this report.

electricity costs and receive a payment for adopting DLC was viewed as a bonus, although some respondents thought the level of payment ($75 per annum) was high (‘electricity companies must be making lots of money’).

Some concern was expressed regarding the capability of the technology and its compatibility with appliances, as well as liability issues with respect to potential equipment damage. These concerns were perceived to be the biggest barrier in New South Wales and Victoria for a household considering the offer overall.

In contrast to their willingness to consider DLC, the vast majority of participants did not see much benefit to them in adopting CPP. Views included that the need to change behaviour to avoid CPP prices would impact on people’s way of life and that only the ‘naive’ or ‘greeny’ would do so. Some participants in Adelaide commented that they needed to have air conditioning on hot days. Participants commented that they could leave the house (eg, go to a shopping centre) in order to avoid CPP events, but that they would have no incentive to adopt this form of tariff in the first place. The 5 per cent discount offered on tariffs at off-peak times was considered to be too low to outweigh the disadvantages and the potential risks of a high electricity bill.

In relation to TOU tariffs, some participants expressed interest and noted that it may make them more conscious of their usage and that they could save money without having to change their entire lifestyle. The motivation to adopt TOU tariffs was related to how much money participants thought they may save. Some higher-income respondents thought it may be too much trouble to monitor and so they would not choose to take it up or, if they did, they would be unlikely to change their behaviour. Others (particularly those on low incomes) saw it as a potential way to save on their bills and were prepared to modify their behaviour (eg, doing the vacuuming, ironing and washing on the weekends). They also commented that they would need to see the proof of savings actually being achieved in order to remain on this form of tariff. Some participants commented that they would be likely to shift their demand, rather than reduce it overall. Participants that were at home during the day were more likely to see TOU tariffs as negative, as they felt they had less scope to modify their behaviour.

Overall, the most popular combination for those not at home during the day was TOU tariffs and DLC.[35] Some high income earners saw an opportunity to counteract peak rates during the day with DLC on air conditioning and then benefit from off-peak tariffs in the evenings.

Participants in the focus groups were also given the option of remaining on flat tariffs. These were perceived as straightforward and easy by some high income earners who did not want to make any changes and for whom DLC had too many barriers or was not relevant. For those who were very nervous about the benefits of TOU or DLC or for whom it all seemed to hard to investigate (‘too much choice’) they had a preference to stay on current tariffs, but might be won over with reassurances on the

[35] We note that there would be no benefits resulting from customers that are not at home during the day adopting DLC or TOU options, since their actual level of consumption during the day would not change (ie, they would not be home and have the air-conditioning on or clothes dryer running).

level of savings available and/or the technical aspects of DLC. It was noticeable that for participants from WA, who have not yet had the experience of full retail competition, the concept of alternative electricity tariffs was very new.

There were notable differences in viewpoints between age groups in participants. In Townsville and Dubbo there was some resistance observed among the older generations (60+) toward changing lifestyles and habits.

In relation to jurisdictional differences, participants in Adelaide believed that they could not go without air conditioning in summer as it is just too hot. Participants in Townsville mostly felt that they could not live without air conditioning in a tropical climate. Although air conditioning is very important in Perth during the summer it did not seem to be perceived as much of a necessity as in Adelaide.

From the focus groups conducted in Queensland, in particular Brisbane, it appeared that environmental issues were more ‘top of mind’ than in other States generally. Participants were more likely to actually reduce consumption of electricity rather than shifting energy use. These consumers, as well as some from the Victorian groups, were more likely to be motivated by environmental factors to save energy in conjunction with monetary concerns. This was not the case elsewhere.

Overall, the findings of the focus group appear reasonably consistent with the take-up assumptions made by KPMG in the retail workstream. In particular, the relatively low take-up rate assumed for CPP reflects the lack of support by participants for this form of tariff.

Participants did appear to be more willing to adopt DLC. We have therefore looked at a sensitivity that assumes a higher take-up rate for DLC where facilitated by the capability of a smart meter (15%). We have also examined the impact of assuming a higher take-up rate for CPP (15%), on the basis that the relative ‘newness’ of the concept may make the focus group results unrepresentative of the take-up rates that may be achievable, particularly over time as a result of marketing and consumer education. Both of these higher uptake assumptions are reflected in the high demand response case (section 5.1.3).

3.2.1. Impact of Functionality 16 on take-up rates

Phase 1 of the analysis left open the question of whether the national minimum functionality for smart meters should incorporate the ability for a smart meter to interact with a HAN (functionality 16). Where a smart meter does incorporate this functionality, it facilitates the provision of an in-home display (IHD) that can display information to customers about their electricity usage and whether charges currently reflect off-peak, shoulder or peak tariffs and whether there is an upcoming CPP period.

It is possible that the provision of an IHD may influence the level of take-up for TOU and/or CPP tariff options, by making it easier for customers to understand their own usage patterns and the changes in the tariff structure they face. A submission from the Energy and Water Ombudsman of Victoria (EWOV) expressed the view that the provision of an IHD would increase take-up rates for TOU tariffs and CPP and make retailers more willing to offer these tariffs, although did not provide evidence to support this view.[36]

The Phase 2 focus groups discussed in-home displays with participants and canvassed views on whether the provision of an IHD (at a cost of $100) would make customers more likely to consider TOU or CPP tariffs. Some singles/couples saw opportunities with an IHD to really get on top of their electricity costs and felt that they would recoup the $100 cost. They also liked the idea of control that the device was perceived to facilitate. Low and medium income earners who were considering the TOU option saw the IHD as a practicable complement to monitoring electricity use to ensure savings were being achieved. However, when the option of accessing similar information on the internet was presented, this was welcomed given its lack of any additional costs.

The more environmentally conscious consumers in Queensland and Victoria (specifically Warragul) tended to be the most willing to purchase the IHD for the stated cost. They also believed that the device would allow them to change their behaviour above and beyond changes required to reduce their energy bill (ie, increase consciousness and conserve rather than just shift use).[37]

Putting the $100 price tag on an IHD meant that only those participants that felt that they would seriously monitor their usage and get their money back on savings indicated that they would purchase one, or those higher income earners who saw some novelty value.

Retailers have highlighted that where new tariff structures are offered to customers, there is a need to ensure that there is effective communication and information provided to the customer, and that an IHD may be an effective way to achieve this.[38] Alternative communication strategies could be via a website, leaflets and fridge magnets (displaying TOU periods). In addition retailers may offer an IHD as a way of distinguishing retail product offerings and developing brand loyalty, as a way of retaining customers.

We have not assumed that retailers will be more inclined to market TOU tariffs or CPP if they also have the capability to provide an IHD, in the absence of clear evidence that this would be the case. As a result, there is no difference in the assumed take-up rates for TOU and CPP where functionality 16 is included in the specification of a smart meter.

3.3. Assumed Retail Tariffs

The following tables set out the assumed level and structure of retail tariffs, as developed by KPMG in the retail workstream. Retail tariffs have been developed for

---

36 EWOV submission, p. 5.

37 The evidence in relation to whether provision of an IHD may result in increases in the extent of energy conservation is discussed in section 7.1.

38 KPMG, (2008), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts, Phase 2 Report.

both residential and small commercial customers. The structure of the DLC offer is discussed in section 3.4.

The tariffs have been designed to be revenue neutral. That is, the new tariff structures are expected to recover the same amount of revenue as the previous flat tariffs. The assumption of revenue neutrality ensures that the demand impact associated with the change in tariff structures isolates only that impact associated with the new tariff structures facilitated by the smart meters, and not also any impact from an overall change in the level of revenue recovery (ie, increase/decrease in average tariffs).

The exception is the DLC component of tariffs, which is assumed to be funded from the savings realised by retailers (or distributors) from DLC, ie, hedging cost savings (or capex deferral, in the case of distributors). Retailers would be margin neutral in relation to DLC but not revenue neutral.

The tariffs adopted in the modelling also incorporate the expected impact on generation costs from the introduction of a carbon trading scheme from 2012. This impact has been estimated by the market modelling workstream, and increases over the period of analysis.[39] For simplicity the tariffs below are shown *without* the impact of carbon.

Table 3.2 sets out the tariff assumptions for residential customers.

Table 3.2: Tariff assumptions (c/kWh, excl GST and carbon) – Residential (2007 dollars)

		TOU tariffs				CPP	
State	Flat Tariff	Peak	Off-peak	Shoulder Period 1	Shoulder Period 2	CPP factor^	CPP Discount*
NSW/ ACT	$0.1222	$0.2459	$0.0758	$0.0872	n.a.	5	5%
NT	$0.1501	$0.1714	$0.1233	n.a.	n.a.	4	5%
Qld	$0.14	$0.2318	$0.0748	n.a.	n.a.	5	5%
SA	$0.17	$0.2540	$0.0853	n.a.	n.a.	5	5%
Tas	$0.14	$0.2120	$0.0800	$0.1100	n.a.	4	5%
Vic	$0.1346	$0.2489	$0.0752	n.a.	n.a.	5	5%
WA	$0.1394	$0.2470	$0.0800	$0.1495	$0.1200	4	5%

^ CPP price is the peak price multiplied by the CPP factor
* Discount applied to off-peak and shoulder tariffs only.

Where retailers offer a CPP component of TOU tariff, the tariff applying for the CPP period is a multiple (4 or 5 times, depending on the jurisdiction) of the peak rate. This is referred to as the 'CPP factor' in the table above. The off-peak and any shoulder rates applying under the TOU rate are then 5 per cent lower than the standard TOU rate. CPP periods are assumed to last for 4 to 5 hours during peak times on 12 nominated days during the year, with customers receiving 2 to 24 hours notice.

The relevant time periods for TOU tariffs for residential customers are set out in Table 3.3. The majority of jurisdictions are assumed to have only peak and off-peak

[39] See CRA International, (2008), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 5: Market Impacts, Phase 2 Report.

periods, with NSW, Tasmania and WA also having shoulder periods. These structures are based on current tariff offerings by retailers in those jurisdictions.

Table 3.3: Applicable Time periods for TOU tariffs – Residential

State	TOU tariffs			
	Peak	**Off-peak**	**Shoulder Period 1**	**Shoulder Period 2**
NSW/ ACT	M-F 2pm-8pm	Everyday 10pm-7am	All other times	-
NT	Everyday 6am-8pm	All other times	-	-
Qld	M-F 7am-9pm	All other times	-	-
SA	M-F 7am-9pm	All other times	-	-
Tas	M-F 6.30-am-11am M-F 4.30pm-10pm	Everyday 10.30pm-6.30am	All other times	-
Vic	M-F 7am-7pm	All other times	-	-
WA	Summer: M-F 11am-5pm Winter: 11am-5pm, 5pm-9pm	Everyday 9pm-7am	Summer: M-F 7am-11am, 5pm-9pm Winter: M-F 11am-5pm	Weekends 7am-9pm

Tables 3.4 and 3.5 provide the comparable assumptions for small commercial customers. KPMG has assumed that small commercial customers are not offered CPP tariffs, as these customers are likely to be less able to defer or reduce consumption in response to a CPP price signal.

Table 3.4: Tariff assumptions (c/kWh, excl GST and carbon) – small commercial customers (2007 dollars)

State	Flat Tariff	TOU tariffs			
		Peak	**Off-peak**	**Shoulder Period 1**	**Shoulder Period 2**
NSW/ ACT	$0.140	$0.2510	$0.0875	$0.1250	n.a.
NT	$0.175	$0.2000	$0.1258	n.a.	n.a.
Qld	$0.173	$0.2570	$0.0933	n.a.	n.a.
SA	$0.174	$0.2350	$0.1000	n.a.	n.a.
Tas	$0.14	$0.2010	$0.0820	n.a.	n.a.
Vic	$0.165	$0.2210	$0.0994	n.a.	n.a.
WA	$0.155	$0.2240	$0.1012	n.a.	n.a.

Table 3.5: Applicable Time periods for TOU tariffs – small commercial customers

State	TOU tariffs			
	Peak	**Off-peak**	**Shoulder Period 1**	**Shoulder Period 2**
NSW/ ACT	M-F 2pm-8pm	M-F 7am-2pm All other times	M-F 8pm-10pm	-
NT	Everyday 6am-8pm	All other times	-	-
Qld	M-F 7am-9pm	All other times	-	-
SA	M-F 7am-9pm	All other times	-	-
Tas	M-F 7am-8pm	All other times	-	-
Vic	M-F 7am-11pm	All other times	-	-
WA	Summer: M-F 8am-10pm Winter: 9am-11pm	Everyday 9pm-7pm	-	-

Tariff offers are assumed to be constant across all jurisdictions. That is, there is no differentiation between urban and rural/regional areas.

The tariffs are also assumed to be constant across all of the roll-out scenarios. In the longer term, the level of tariffs would be expected to differ between the roll-out scenarios, as a result of differences in net costs between the roll-out scenarios. This is the second round impact discussed in section 2.1.6. This impact has not been incorporated in our analysis for the reasons already discussed.

3.4. Direct Load Control – Scenario 3

In addition to DLC offers facilitated by the roll-out of smart meters with a DLC capability (ie functionality 15 or 16), we have also examined a non-smart meter roll-out of DLC. This is the basis for scenario 3, as developed by the SMWG.

Under scenario 3, the party responsible for the roll-out must make an offer to retrofit a DLC capability on all existing appliances that are assumed to participate in a DLC roll-out (ie, air-conditioners and potentially pool-pumps). In addition all new appliances from 2009 onwards are assumed to be capable of incorporating a DLC capability.[40] It is assumed that in the case of the device installed in new appliances there would be an applicable Australian standard from 2009.[41] The exact device is assumed to be different in NSW and Queensland compared to other states, as EMCa

[40] It has not been assumed that all new air conditioners would automatically have a DLC device installed but, rather, would be *capable* of having a standard device installed where a customer wanted to take-up a DLC offer. Installation costs for DLC devices in new air conditioners have been estimated by EMCa to be below those for the retrofitting of devices in existing air conditioners (see EMCa's Transitional Costs report, section 11).

[41] This assumption is based on discussions with representatives that are currently designing the Australian Standards in this area.

has assumed that a DLC capability in these jurisdictions would be facilitated by the existing ripple control systems.[42]

In relation to DLC tariffs, the key features of the DLC offer are:[43]

§ the number of hours for which the customer can be subject to DLC (which in turn impacts the potential level of demand response achievable);

§ the payment made to the customer for accepting DLC; and

§ the assumed level of take-up.

We have assumed that a DLC tariff would be offered to customers that allowed their air-conditioners to be controlled for a number of hours at a time, on up to 15 occasions over a year. The assumption on the length of period for which an air-conditioner could be controlled is based on discussions with ETSA Utilities.[44] We understand that subject to trials currently underway it is likely that a 6 hour period is the maximum that could be adopted without impacting on customers' thermal comfort. It has therefore been adopted in our analysis for the purposes of estimating the maximum benefit potentially associated with DLC. We have conducted sensitivity analysis on the basis of shorter control periods, reported in Appendix C.2.1.

The limit on the number of occasions a year on which DLC could be utilised is also based on the structure of the DLC offers in the trials conducted by ETSA Utilities. We understand that other utilities have offered DLC tariffs with no limit on the number of occasions on which DLC may be used, or with a limit expressed in terms of the total number of hours over the year which may be under load control, rather than the number of occasions. Ultimately the structure of the DLC offer would depend on the factors that were considered to make the offer most attractive, maximising take-up, and balanced against the need of the business.

Customers that choose a DLC tariff are assumed to receive a flat fee per year to participate. A number of trials have adopted this flat-fee approach. An alternative would be for end-use tariffs to be discounted by a certain percentage, for customers accepting DLC. We have adopted a flat fee of $75 a year, based on a view of the typical level of payments for similar programs. Any participation fee would ultimately have to be related to the benefits resulting from the DLC program. We note that for the ETSA Utilities DLC trial $100 is offered as a participation incentive.

Section 3.2 has discussed the take-up rates assumed for DLC where it is offered as part of a smart meter roll-out, together with TOU and CPP tariffs. KPMG has also

---

[42] See discussion in EMCa, Workstream 6 Transitional Costs, Consultation Report (2008), section 11.

[43] The structure of the DLC tariff offer discussed in this section in relation to scenario 3 has also been assumed under the smart meter roll-out scenarios 1,2 and 4. The only difference in the assumptions between scenario 3 and scenarios 1,2 and 4 is the take-up rate for a DLC offer, which is assumed to be higher under scenario 3 for the reasons given above.

[44] We note that ETSA Utilities' analysis of the optimal time period is still to be undertaken.

considered the potential take-up of DLC where it is offered as a stand-alone product under scenario 3.

A take up rate of 10 per cent has been assumed by KPMG (expressed as a proportion of the overall population).[45] This is slightly above the take-up rate assumed for DLC where it is offered as part of a smart meter roll-out. Under scenario 3, a DLC tariff is the only 'energy smart' tariff that is offered, and so may be expected to attract more consumers than under a smart meter roll-out where other 'energy smart' tariffs are also offered (ie, TOU and CPP).

In the case of Tasmania, we note that KPMG has assumed that DLC tariffs may be offered. However, the demand analysis conducted by NERA indicates that there would in fact be no periods in which DLC would be operated in Tasmania (on the basis of the criteria set out in section 6.2 (Table 6.1)), as a result of that jurisdictions winter-peaking profile.

Section 3.2 discussed the response from focus group participants in relation to the relative attractiveness of a DLC tariff option. In general, participants were much more willing to consider a DLC tariff option compared to other alternatives. In relation to scenario 3 this implies that customers may be relatively more willing to take-up a DLC option. We have therefore considered a take-up rate of 20% as part of our high demand response case analysis (again, expressed as a proportion of the overall population).

[45] Again, this assumed take-up rate is higher when expressed as a percentage of only those customers with an air-conditioner. For example, as a percentage of customers with airconditioners, the assumed take-up rate is 11.7% in Western Australia and 13.9% in Victoria (based on estimates of the number of air-conditioners installed in those jurisdictions in 2016).

4. The Impact of Time of Use Tariffs and Critical Peak Pricing on Demand

The capability of a smart metering system to meter and record consumption on a half hourly basis and provide for two way communication enables retailers and/or network operators to introduce TOU based tariffs and CPP. As discussed in section 2.1, the introduction of these tariff structures is expected to result in a demand response by consumers and to lead to changes both in the amount of energy consumed in any one day and the pattern of consumption over the day.

This section summarises some of the findings of studies and trials that have been carried out in relation to TOU tariffs and CPP. A fuller summary of each of the studies mentioned, and others, is provided in Appendix A.

In order to provide some additional context, we also summarise participants' views from the focus groups on how they might adapt their behaviour in response to TOU tariffs and CPP.

4.1. Phase 2 Focus Groups

The Phase 2 consumer focus groups discussed with participants the ways in which they would modify their behaviour if faced with TOU tariffs or CPP.

High income earners commented that they may choose to run certain appliances at off-peak times (washing machines, dishwashers) and that they may become more conscious of general electricity usage. However some felt that it would be too difficult and too much trouble to monitor and so a TOU tariff would end up costing them more. Some commented that they would use the same amount of electricity, but just at different times. There was a particular thread throughout many of the higher income groups in that they did not want to have to make changes that would impact their lifestyle.

In contrast, lower income earners saw TOU tariffs as an opportunity to try to further reduce their bills. Although many of these consumers perceived that they were already using an absolute minimum amount of electricity they felt that TOU tariffs offered them an opportunity to further reduce their bills if they modified their behaviour. These views appear somewhat inconsistent and may reflect the financial insecurity faced by low income earners such that they are willing to try anything to save money.

Lower income earners overall tended to be more willing to modify their behaviour, and to even be uncomfortable, out of sheer necessity to keep bills at a minimum. They said they would be able to achieve savings by shifting the times when they used certain appliances (eg, washing machines). However, those households where family members were home over the day felt they would end up paying more, as much of their electricity use during the day was non-discretionary and so could not be shifted.

4.2. Evidence From Trials on the Extent of Demand Changes

Although the demand response to pricing signals may vary substantially across individual customers the more fundamental issue from a retailer, network operator and generator perspective is what happens to aggregate consumption levels and patterns of consumption throughout the day and over the year.

A number of trials have been conducted both in Australia and overseas on the impact on customers' demand of the introduction of TOU tariffs and CPP. In addition, trials have also been conducted that examine the impact on customer demand of the provision of additional information to customers on their energy usage, either combined with the introduction of TOU and/or CPP tariffs or as a separate initiative. These studies include some that examined information provision by means of an IHD and others that looked at information provision by other means.[46]

The results of the studies are useful for considering the potential impact of smart meters on customer demand. A number of different metrics are relevant, including the impact on peak demand in CPP periods, the impact of peak demand under TOU tariffs and the overall reduction in consumption achieved by the introduction of each tariff structure.

4.2.1. Trials/studies involving critical peak pricing

Where CPP pricing has been introduced, studies have estimated both the percentage reduction in peak demand that has been achieved and the extent of that reduction that arises as a result of a shift in demand to non-CPP periods, and the extent of reduction that represents overall energy conservation.

In California, the Statewide Pricing Pilot (SPP) is one of the most comprehensive international trials of TOU pricing, CPP and enabling technology that has been undertaken in the last five years. The SPP found a 13% reduction in peak demand and a 2.4% reduction in overall consumption on summer critical peak days. For winter critical peak days the reductions were 3.91% in peak demand and 0.62% in overall consumption. Overall the SPP therefore found that reductions in peak demand from CPP were achieved largely as the result of demand shifting to non-critical peak periods, with only low levels of conservation achieved overall.

Trials conducted in Australia have found higher levels of energy conservation on CPP days than were observed in the Californian SPP. Country Energy found that it achieved a 25% reduction in demand on CPP days and an 8% reduction in overall energy consumption. Preliminary results in the trials conducted by EnergyAustralia and Integral found a conservation effect in summer CPP periods of between 7 and 15%. Final information on the overall reduction in peak demand achieved is not yet available from these trials, but preliminary results indicate that the reduction in peak demand outlined above is statistically significant. However, both trials have reported that the conservation of energy dominated the deferral effect.

---

[46] Full citations for each of the studies discussed in this section are given in Appendix A.

One possible reason for the higher levels of conservation observed in Australia may be the strict energy-related building codes present in California, which have already resulted in significant energy conservation.[47] As a result, the scope for further efficiency savings may be greater in Australia than it is in California. In addition, much of the critical peaks in Australia are driven by demand for air conditioning and it would be expected that any reduction in the usage of these appliances would not be deferred until a later time, and thus the energy that would otherwise be consumed will be conserved.

In Victoria the potential reduction in residential peak demand resulting from CPP has been estimated at between 8 and 18 per cent (CRA, 2002 based on an end-use model) and 20 per cent (ESC, 2002, based on an own use elasticity of -0.1). In South Australia work by CRA in 2004 found the potential for a 10 per cent reduction in peak demand using a smart meter with CPP. Overall energy conservation estimates were not reported for these studies.

Overseas, the Ontario Smart Price Pilot found reductions of 17.5 per cent in peak demand for the CPP group and 25.4 per cent for the critical peak rebate group.[48] On non-CPP days there was an 8.5 per cent reduction for the CPP group and 11.9 per cent for the critical peak rebate group. Overall consumption was reduced by 7.4 per cent for the CPP group. Results for the CPP rebate group were not statistically significant.

Ofgem in the UK has estimated a 2.5% reduction in peak demand associated with CPP and a 1% reduction in overall consumption.

From the above studies it is clear that CPP can impact demand in peak periods. However, a significant proportion of this reduction is achieved by shifting demand to off-peak periods, rather than reducing consumption overall. Overall energy conservation has been negligible in some overseas studies, although has been more pronounced in the trials conducted by the NSW distributors. .

4.2.2. Trials/studies involving time of use tariffs

In relation to the introduction of TOU tariffs, the Californian SPP found a 4.71 per cent reduction in peak demand in summer for non-critical peak days and a 0.17 per cent overall *increase* in consumption, whilst for non critical peak days in winter they found a 1.39 per cent decrease in peak demand and a 0.02 per cent reduction in overall consumption. The Ontario Smart Price Pilot found that the reduction in peak demand was not statistically significant, but that overall consumption was reduced by 6 per cent.

In Australia, Integral Energy found no statistically significant difference in the response of participants paying seasonal TOU tariffs relative to the control group.

---

[47] *Regional Differences in the Price-Elasticity of Demand for Energy*, Mark A. Bernstein, James Griffin, RAND Corporation 2005, p. 27.

[48] In the Ontario Smart Price Pilot one of the customer groups were required to pay the TOU tariff but then received a critical peak rebate for every kWh they were able to reduce their consumption below a baseline level. This trial is discussed in more detail in Appendix A.

Trials conducted by Energex have also found no change in peak demand as a result of the introduction of TOU tariffs only.

In Victoria, CRA and Impaq Consulting in 2005 calculated a 10 per cent reduction in peak demand using elasticities drawn from the Californian SPP and assuming a 100 per cent take-up of TOU tariffs. In Tasmania, the Office of the Tasmanian Energy Regulator (OTTER) estimated a 10 per cent reduction in peak demand using smart meters with TOU tariffs. This estimate was based on customer responsiveness factors that were developed using the observed response of customers in Tasmania to Aurora Energy's pay as you go TOU tariffs. Overall energy reductions were not reported for these studies.

In Northern Ireland a 10 per cent reduction in peak demand has been found from TOU tariffs with a 3.5 per cent reduction in overall consumption. In the US, Puget Sound Energy found between a 5 and 6 per cent reduction in peak demand from TOU tariffs and a 5 per cent reduction in overall consumption.

As in the case of CPP, studies that have looked at the impact of TOU have tended to find that, where peak demand is affected, this is typically associated with a shift in demand to off-peak periods and only relatively moderate reductions in consumption overall.

4.2.3. Trials/studies involving direct load control

In South Australia, trials of demand management conducted by ETSA Utilities have found a 17 per cent reduction in peak demand from direct load control of air-conditioners of residential customers.

Trials conducted by Energex in Queensland found a 12 per cent reduction in peak demand and a 13 per cent reduction in overall consumption for residential customers on TOU tariffs who were provided with timers for their appliances that enabled them to be turned off between 4.30pm to 8.30pm. They found a 34 per cent reduction in peak demand for customers on TOU tariffs with DLC.

The Californian SPP found that the average reduction in peak demand for participants with enabling technology was twice the reduction achieved by participants without enabling technology.

4.2.4. Trials/studies involving information provision

Studies on the impact of information provision on electricity demand have had mixed results.

The Californian SPP included an information group that faced a standard flat tariff but were provided with information on how they could reduce load during peak periods, and were also informed of CPP periods and requested to avoid energy. The results from this group led CRA to conclude that a demand response in the absence of a price signal was not sustainable.

Similarly, Energex found no response from customers that were only provided with information on energy efficiency.

In contrast EnergyAustralia did find that the information group in their trials responded in a significant manner, although their responsiveness was lower and more variable than those facing TOU tariffs or CPP.

Other studies have focused on the impact on demand of providing feedback to customers on their energy use, including by means of an IHD. The results of these studies are discussed separately in section 7.1, where we consider the incremental impact on demand of functionality 16.

5. Demand Side Response – Time of Use Tariffs and Critical Peak Pricing

This section sets out our analysis of the likely response of residential and also small commercial customers to the introduction of TOU and CPP tariffs. This analysis is a critical input for assessing the potential for network augmentation investments to be deferred, and the market benefits including greenhouse gas emission impacts that could result from changes to the jurisdiction load profiles resulting from a consumer demand response to new tariff products. This analysis has been carried out as part of a broader assessment of the likely impact on jurisdictional load profiles from a transition from accumulation meters[49] with flat average tariffs to smart meters that enable TOU and CPP to be offered in addition to smart tariffs.

In addition, the potential demand response estimates have been used to estimate the change in consumer surplus associated with the introduction of TOU and CPP tariffs.

Our estimate of the demand impact of direct load control (either combined with smart meters or as an alternative to a smart meter rollout) is set out in section 6.

5.1. Methodology

We have estimated the response of residential and small commercial customers to the introduction of TOU tariffs and CPP by applying relevant elasticity estimates to the residential and small commercial accumulation metered half-hourly load data observed in each jurisdiction over 2006/07 on critical peak days, non-peak working days and weekends, adjusted to reflect the introduction of a carbon trading scheme.

We have considered each jurisdiction separately, with the exception of the ACT and NSW. NSW and the ACT are treated as one region in the National Electricity Market (NEM), and as a result the CRA market benefits modelling are unable to calculate benefits for the ACT separate from NSW. Due to this limitation we have only estimated the demand response for the entire NSW/ACT NEM region.

The methodology that has been used in this analysis and the basis for our assumptions is outlined in Box 5.1. Appendix B provides a more detailed description of the approached used to estimate the change in load profile for each jurisdiction.

---

[49] Combined with current meter replacement practices.

Box 5.1: Methodology used to estimate the response of residential and small commercial customers to the introduction of TOU tariffs and CPP

To estimate the demand side response associated with the transition from accumulation[50] meters to smart meters we first identified the level and profile of residential and small commercial consumption relative to the overall jurisdictional load profile. This was carried out by disaggregating:

- jurisdictional half-hourly load data into consumption by users of accumulation meters and consumption by users of interval meters; and
- the accumulation metered half-hourly load data into consumption by residential customers and consumption by commercial users taking into account both the time profile over the day and differences in peak day versus non-peak day consumption patterns.

Once the jurisdictional load profiles were disaggregated it was necessary to make assumptions about:

- short run own-price elasticity and the elasticity of substitution[51] measures applying to residential customers during summer and winter on critical peak days, non-peak work days and weekends;
- short run own-price elasticity measures applying to commercial customers;
- long run own-price elasticity and the elasticity of substitution measures applying to both residential and commercial customers;[52] and
- the structure of TOU tariffs, the relationship between peak and CPP and relevant take-up rates. These assumptions were developed by KPMG and are set out in section 3.1 and 3.2.

Based on these assumptions the demand side response of residential and small commercial customers was estimated by:

- identifying twelve critical peak days (selected on the basis of the highest half-hourly demand) in each jurisdiction over the 2006/07 financial year;
- dividing the year into two periods of six months with summer assumed to apply from November to April and winter assumed to apply from May to October; and
- applying separate winter and summer based elasticity assumptions and tariff assumptions to the residential and small commercial accumulation metered half-hourly load data observed in each jurisdiction over 2006/07 on critical peak days, non-peak working days and weekends.

For NSW a sensitivity analysis based on an assumed summer peaking profile was undertaken in addition to the analysis based on the 2006/07 profile.

---

50 The base assumptions for each jurisdiction adopted for the cost benefit analysis reflects a continuation of each jurisdictions current metering policy, which in many cases is for current accumulation meters to be replaced by manually read interval meters on a new and replacement basis (see NERA's Overview Report for the overall cost benefit analysis). References to 'accumulation meters' in this section should be taken as references to the existing metering policy in each jurisdiction.

51 To simplify our analysis we have assumed that the own-price elasticity of demand for consumers in peak compared with off-peak periods is the same. While in practice this may not be the case, we are unaware of any evidence of differences in own-price elasticities between peak and off-peak periods.

52 Due to the revenue neutrality assumption, the long-run effects are expected to be minimum. We outline this in greater detail below.

The residential and commercial elasticity estimates that have been assumed to apply in each jurisdiction are set out in Table 5.1. Short run and long run elasticities are assumed to be the same.[53]

Table 5.1: Elasticity assumptions

Measure	Tas (based on zone 1 in SPP)	Qld, SA and WA (based on zone 3 in SPP)	NT (based on zone 4 in SPP, adjusted)	NSW/ACT and Vic (based on zone average in SPP)
Residential				
Summer				
Critical peak day				
Elasticity of substitution	-0.039	-0.102	-0.077	-0.076
Own price elasticity	-0.041	-0.043	-0.022	-0.041
Non-peak weekday				
Elasticity of substitution	-0.034	-0.093	-0.071	-0.069
Own price elasticity	-0.043	-0.047	-0.026	-0.044
Weekend				
Own price elasticity	-0.014	-0.026	-0.014	-0.020
Winter				
Critical peak day				
Elasticity of substitution	-0.027	-0.024	-0.016	-0.025
Own price elasticity	-0.010	-0.011	-0.003	-0.011
Non-peak weekday				
Elasticity of substitution	-0.026	-0.024	-0.016	-0.025
Own price elasticity	-0.017	-0.019	-0.012	-0.019
Weekend				
Own price elasticity	0.020	0.023	0.013	0.023
Commercial				
Own price elasticity	-0.02	-0.02	-0.02	-0.02

These assumptions have been based on the short run elasticity estimates observed in the Statewide Pricing Pilot (SPP).[54] The SPP is the most comprehensive study that has been undertaken in relation to the demand impacts of TOU tariffs and CPP, in terms of the number of participants and the coverage of the study.

The SPP estimates were developed across four distinct climatic zones. An assessment of the climatic conditions prevailing in each of the four zones revealed some similarities with climate conditions experienced in the various jurisdictions in Australia. Accordingly and where relevant, separate climatic based estimates have been assumed to apply across each jurisdiction.

In the case of the Northern Territory, feedback following the Phase 1 report expressed concern that the SPP elasticities may not be appropriate, given the much higher level of humidity in the Northern Territory than any of the comparable areas in the SPP

[53] The reason for this change in approach since Phase 1 is discussed more fully below.

[54] CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005.

given the much higher degree of humidity experienced. For this Phase 2 analysis we have adjusted the elasticity estimate for zone 4 in the SPP to reflect differences in reported elasticity estimates for California and Florida, which has similarly humid conditions.[55]

Our analysis incorporates an adjustment to the SPP elasticities for each jurisdiction where there are two or more consecutive CPP days, resulting in a higher reduction in average energy consumption on those consecutive days (10% in summer and 5% in winter). This adjustment reflects an assumption that the daily-read capability of smart meters can be used to provide feedback to customers on 'how they went' on a CPP day, which may result in an enhanced response on a consecutive CPP day. This is an upper end estimate of potential additional demand response on consecutive CPP days (the lower end being zero).[56]

A number of studies have indicated that commercial customers are less responsive to TOU tariffs and CPP.[57] We have therefore assumed that the elasticity of substitution[58] for commercial customers is zero. In the short run commercial customers have also been found to be less responsive to daily electricity prices and we have therefore assumed that the own-price elasticity measure would be half of that attainable by residential customers on a non-peak day and that the same estimates would apply across each jurisdiction.

In relation to long-run elasticities, the initial analysis presented in NERA's Phase 1 Consumer Impact report assumed that the elasticity of substitution measures were the same as those applying in the short run while the long run own-price estimates were based on National Institute of Economic and Industry Research (NIEIR) estimates developed for the National Electricity Market Management Company's (NEMMCO) Statement of Opportunities.[59]

In the long run, improvements in residential electricity efficiency are likely to be the result of purchases of more efficient appliances, changes to home insulation, or household electricity use practices (eg, the installation of timers). We would expect that the long run own-price elasticity estimates should therefore be appropriately applied to changes in the average price faced by the household, as reflected in the total bill, over the medium to long term. This suggests that it is changes in a household's total bill over time that is likely to motivate investment in more energy efficient appliances when it becomes time to replace them.

---

55 Relative elasticity estimates were taken from ***Regional Differences in the Price-Elasticity of Demand For Energy***, Mark A. Bernstein, James Griffin, RAND Corporation 2005.

56 See discussion in Stream 4 Phase 1 report, p 43-45 for a further explanation.

57 See for instance ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002, pg. 85 and ESCOSA, Assessment of Demand Management and Metering Strategy Options, August 2004, pg. 25.

58 Also referred to as the 'cross-price elasticity'.

59 NIEIR, The price elasticity of demand for electricity in NEM regions – A report for the National Electricity Market Management Company, June 2007.

The Phase 2 tariffs have been designed to be revenue neutral. This implies that total electricity bills will, at least on average, not change. Consequently, applying long-run elasticity estimates to changes in the bill over the long run are expected to result in little or no change in electricity use, except perhaps through usual improvements in the energy efficiency of appliances.

Revenue neutrality appears to be a reasonable assumption to make in the short term, as electricity businesses will still need to raise the same amount of revenue to cover their predominately fixed costs.[60] However, in the longer run a roll-out of smart meters can be expected to change the costs that businesses face. This is the 'cost effect' or 'second round' impact discussed earlier. In the long-run therefore, higher demand response may result, as prices reflect changes in the costs faced by an average consumer. However, as discussed in section 2.1.6 we have not incorporated second round cost changes into our analysis, as they would not be expected to impact the results sufficiently to affect the conclusions that can be drawn.

The result of this approach is to likely lower the resultant estimates of demand response over the long-run.[61] We have taken this into consideration as part of our analysis of the overall costs and benefits of the scenarios considered.

5.1.1. Results

The application of the elasticity measures set out above and the tariffs and take-up rate assumptions set out in section 3 to the assumed residential and small commercial load profiles in each jurisdiction results in changes to both the pattern and level of consumption in each jurisdiction.

Table 5.2 presents the estimates of the change in maximum demand and overall change in consumption for those customers that are on TOU tariffs and CPP. Since the elasticity estimates differ over winter and summer months the results are presented for each alternative. The results apply in both the short run and the long run and are the same for all of the smart meter roll-out scenarios (ie, scenarios 1, 2 and 4).

---

60 In the short term, we would expect that revenue is likely to increase associated with the costs of the new metering and load management systems.

61 This presumes that cost changes are reflected in user charges, rather than fixed charges. If cost changes result in changes to fixed charges then we would expect no difference in the long-run demand response compared to those estimated in this study.

Table 5.2: Residential - estimates of the response to TOU and CPP for those customers on TOU tariffs and CPP

		NSW/ACT		NT	Qld	SA	Tas	Vic	WA
		Base	Summer peaking						
Peak times	***Summer***								
	Critical peak day	-17.3%	-19.6%	-10.6%	-18.6%	-14.5%	n.a	-16.7%	-21.5%
	Peak day (non-CPP)	-5.2%	-5.2%	-1.0%	-4.6%	-2.8%	-1.4%	-4.5%	-5.8%
	Winter								
	Critical peak day	-7.8%	-5.7%	-3.4%	-4.3%	n.a	-6.0%	n.a	-4.4%
	Peak day (non-CPP)	-1.9%	-1.9%	-0.2%	-1.2%	-0.7%	-1.1%	-1.7%	-1.4%
Daily Average	***Summer***								
	Critical peak day	-5.4%	-6.5%	-5.4%	-7.8%	-7.2%	n.a	-7.3%	-6.6%
	Peak day (non-CPP)	0.0%	0.0%	0.2%	-0.1%	0.4%	0.1%	-0.1%	0.2%
	Winter								
	Critical peak day	-3.2%	-1.5%	-2.2%	-1.6%	n.a	-3.0%	n.a	-1.3%
	Peak day (non-CPP)	0.0%	0.0%	0.1%	0.0%	0.2%	0.0%	0.0%	-0.2%

For customers on CPP tariffs, peak reductions in load in summer range from 10.6 per cent in the Northern Territory to 21.5 per cent in WA. Overall energy conservation on those days in those jurisdictions is 5.4 per cent and 6.6 per cent, respectively. For Tasmania, there are no CPP days that fall within the summer period. This is not surprising, given that Tasmania is a winter peaking state, with residential load driven by space heating and a low penetration of air conditioners.

In winter, peak reductions in load are the highest in NSW/ACT (7.8 per cent, under our base demand assumption) and lowest in Queensland (4.3 per cent), with overall consumption reductions of 3.2 per cent and 1.6 per cent respectively. There were no winter CPP days in South Australia or Victoria. The NSW/ACT result is driven by the winter peaking profile for NSW in 2006/7. Adopting an assumption of NSW becoming summer peaking results in an increase in the percentage peak demand reductions achieved in summer, with a corresponding fall in the reductions achieved in winter (both shown in Table 5.2).

For customers on TOU tariffs, peak reductions in load in summer range from 1.0 per cent in the Northern Territory and 1.4 per cent in Tasmania to 5.2 per cent in NSW/ACT and 5.8 per cent in WA. In winter the greatest reduction in peak demand was 1.9 per cent for NSW/ACT (under our base demand assumption) and the lowest was 0.2 per cent in the Northern Territory. Overall reductions in consumption over the year are close to zero for all jurisdictions in both summer and winter.

When the reductions in demand for customers on CPP and TOU tariffs are combined with the take-up rate assumptions set out in section 3.2 (ie, 7.5 per cent for CPP and 35 per cent TOU), the overall estimate for the change in residential consumption is as set out in Table 5.3. The results are shown for 2016, as representing the first financial year in which the rollout of smart meters is complete across all jurisdictions in the modelling.

Table 5.3: Residential – overall change in maximum demand and consumption (2016)

	NSW/ACT Base	NT	Qld	SA	Tas	Vic	WA
Change in maximum demand	-0.99%	-0.18%	-1.65%	-1.31%	-0.66%	1.38%	0.29%
Change in overall energy consumption	-0.10%	0.00%	-0.13%	-0.14%	-0.09%	-0.15%	-0.06%

Whilst Table 5.3 indicates that *residential* maximum demand increases in two jurisdictions (Victoria and Western Australia). In these jurisdictions the impact of the introduction of TOU tariffs and CPP is to shift the timing of peak demand, rather than reduce its level. The new peak occurs outside the defined peak periods for TOU tariffs and does not coincide with the timing of the jurisdictional system peak loads. Residential consumption during peak periods is lower under the TOU and CPP tariffs than under flat tariffs and hence shifts in residential consumption still contribute to a decrease in overall maximum demand in these two jurisdictions.

Table 5.4 below sets out the peak demand reductions for small commercial customers on TOU tariffs. CPP tariffs are assumed not to be offered to small commercial customers.[62]

Table 5.4: Commercial - estimates of the response to TOU for those customers on TOU tariffs (2016)

		NSW/ACT Base	NT	Qld	SA	Tas	Vic	WA
Peak times	***Summer*** Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.4%	-0.4%
Peak times	***Winter*** Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.3%	-0.3%
Daily Average	***Summer*** Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.4%	-0.4%
Daily Average	***Winter*** Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.3%	-0.3%

Table 5.5 presents the estimates of the overall change in small commercial consumption, given an uptake rate assumption for TOU tariffs of 40 per cent. Since the elasticity of substitution has been assumed to be zero for small commercial customers,[63] and the own-price elasticity does not vary with the time of day, their

[62] This is a change from the assumptions made in the Phase 1 report.

[63] This reflects findings from several studies that commercial customers are not responsive to TOU tariffs, see discussion in Appendix B (B1.2).

response to TOU tariffs is uniform across the day and thus the results are presented as a change in daily consumption.

Table 5.5: Small commercial customers - overall change in maximum demand and consumption (2016)

	NSW/ACT	NT	Qld	SA	Tas	Vic	WA
	Base						
Change in maximum demand	-0.08%	0.00%	-0.14%	0.41%	-0.14%	0.17%	-0.13%
Change in overall energy consumption	0.01%	0.00%	0.04%	0.04%	0.03%	0.03%	0.02%

The maximum demand of small commercial customers is shown in Table 5.5 to increase in Victoria. As with residential demand, these increases occur outside the defined peak period and hence they do not coincide with or contribute to overall maximum demand in the state.

These results indicate that the introduction of TOU tariffs and CPP could be expected to result in changes in both the pattern and level of residential and small commercial electricity consumption. As noted at the outset of this section Appendix B contains a more detailed overview of the demand response analysis that has been undertaken in Phase 2 including the basis for the assumptions made and the manner by which the jurisdictional load profiles have been disaggregated. This appendix also explores the sources of jurisdictional variations.

Finally, Table 5.6 shows the estimated impact of the introduction of TOU and CPP tariffs to the total jurisdictional maximum demand and energy consumption. The changes are shown for 2016, the first financial year in which the rollout of smart meters is complete across all jurisdictions in the modelling.

Table 5.6: All customers - overall change in maximum demand and consumption (2016)

	NSW/ACT		NT	Qld	SA	Tas	Vic	WA
	Base	Summer Peaking						
Change in maximum demand	-0.26%	-0.46%	-0.19%	-0.77%	-0.96%	-0.34%	-0.61%	-1.20%
Change in energy consumption	-0.02%	-0.02%	0.00%	-0.03%	-0.04%	-0.02%	-0.03%	-0.01%

The overall impact on jurisdictional load is much smaller than is the case for customers facing TOU or CPP tariffs. This is unsurprising, since the consumption of these customers accounts for only a fraction of the demand in each jurisdiction.

The highest overall demand response occurs in Western Australia, which has the highest assumed contribution of accumulation metered consumption to system load. Demand response is lowest in the Northern Territory, where lower elasticities have been assumed. It is also low in New South Wales and Tasmania, because the winter peaking characteristics of the assumed load profiles in these jurisdictions mean that the higher summer elasticities have a smaller effect on maximum demand.

5.1.2. Change in consumer surplus

As discussed in section 2.1.3 we have estimated the change in consumer surplus associated with the above demand responses and sought to further decompose this into the redistribution of surplus and the net societal loss (or gain).

Since the calculation of the redistribution of surplus simply shows the value of the transfer of surplus from or to consumers it was necessary to identify that portion that would be transferred from or to retailers, generators and network operators. This allocation has been based on an estimate of the composition of final domestic electricity prices that is set out in KPMG's Retail work stream report.[64] According to the estimates contained in this report:

§ retailer costs account for approximately 15 per cent of the total electricity price paid by consumers (5 per cent retail margin, 7 per cent retail operating costs and 3 per cent market fees);

§ energy costs account for approximately 41 per cent of the total electricity price paid by consumers; and

§ network costs account for approximately 44 per cent of the total electricity price paid by consumers.

This allocation of costs has therefore formed the basis for the allocation of the transfer of surplus between the various segments of the supply chain.

The table below indicates the results of the consumer surplus calculations for 2016, since this is the first financial year in which the rollout of smart meters is assumed to be fully complete in all jurisdictions.

[64] KPMG, (2008), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts, Phase 2 Report, Section 3.1.2.

Table 5.7: Change in consumer surplus ($'000, 2016)

	NSW/ACT		NT	Qld	SA	Tas	Vic	WA
	Base	Summer Peaking						
Net societal gain	-$4,818	-$6,122	-$18	-$6,844	-$1,144	-$459	-$4,029	-$1,799
Transfer to consumers	$7,426	$9,412	$30	$14,976	$3,170	$768	$7,608	$3,005
Change in consumer surplus	$2,608	$3,290	$12	$8,132	$2,026	$309	$3,578	$1,205

5.1.3. High demand response case

The demand response results reported above do not appear to be out of line with many of the results from trials of TOU and CPP, both within Australia and overseas. However, there is a large degree of variance amongst the findings of the various trials.

Given the uncertainties around many of the assumptions feeding into the demand analysis, in addition to the main analysis discussed above, we have also considered the likely impact on demand response of varying a number of assumptions.

Specifically, we have considered a number of 'upside' assumptions that increase the degree of demand response obtained from the introduction of TOU and CPP tariffs. These assumptions are:

§ an increase in the uptake rate for CPP tariffs to 15 per cent; and

§ an additional 'energy conservation' impact arising as a result of increased customer awareness of their energy consumption, prompted by the introduction of TOU and CPP tariffs.

As discussed in section 3.2, the results of the customer focus groups did not indicate that many people would be prepared to voluntarily take-up CPP tariffs, as a result of concerns around being unable to avoid the high prices during CPP periods, and the relatively low level of discount (5 per cent) offered on non-peak tariffs. Notwithstanding this response, it is informative to consider how much additional demand response may be elicited with a higher uptake of CPP. Some of the perceived barriers to CPP may relate to the relative 'newness' of the concept. In addition, CPP tariffs could be structured to offer a greater degree of discount at non-peak times, making a CPP offer more attractive.

In increasing the uptake of CPP to 15 per cent we made offsetting changes to the uptake of flat tariffs (reducing it by 7.5 per cent) and left the assumed uptake for TOU tariffs without a CPP element at 35 per cent. These assumptions again have the impact of increasing the overall level of demand response achieved, as the total number of customers exposed to some form of time-varying tariff has increased.

The second change in assumptions is the imposition of an across-the-board reduction in consumption for residential consumers, representing an additional conservation impact from the introduction of smart metering. Introducing TOU tariffs and CPP can result in both a shift in consumption, with consumers choosing to run their appliances at off-peak rather than peak times, and also changes in the overall level of consumption. Our analysis relates to the change in consumption and consumption patterns as a result of changes in the prices faced by consumers.

However, it is possible that the roll-out of smart metering and the introduction of TOU and CPP could also result in a *structural* change in demand patterns. That is, consumers may become more aware of their energy use and as a result may modify their behaviour (eg, turning lights off, buying more energy efficiency appliances) as a result of this increased awareness, rather than as a result of the prices they face. This potential impact was discussed in section 2.1.2.

Evidence of a general conservation impact from the introduction of TOU tariffs and CPP is mixed.

The Californian SPP found no overall conservation impact. In contrast, Country Energy has reported an overall conservation effect from their trials of 8 per cent.[65] In addition, the conservation effects observed on critical peak days by EnergyAustralia, Integral Energy and Country Energy in their smart meter trials were much greater relative to those in the Statewide pilot. One reason for the higher conservation impacts observed in Australia may be that in California there had already been substantial conservation efforts prior to the introduction of TOU/CPP tariffs, as a result of the earlier energy market crises. Consumers may therefore have already modified their behaviour to conserve energy, with a resulting reduction in the scope for further energy conservation following the introduction of TOU/CPP tariffs. The strict building codes in California may also be an explanatory factor. The scope for TOU/CPP pricing to elicit more of a conservation effect may therefore be greater in Australia.

We note that the available information on higher conservation rates in Australia relates only to NSW. However, based on the rationale above then there may be similarly higher scope in other jurisdictions. We consider the adoption of an additional conservation impact to be an aggressive assumption in driving higher demand responses.

In other overseas studies, conservation impacts have been observed ranging from 3% in Northern Ireland to 8 per cent[66] in Norway.

A recent study by Sustainability First in the UK has reviewed the international evidence of the impact of smart metering on energy savings and concludes that:

---

65 The trials conducted by Country Energy involved all participants being provided with an IHD. The conservation impact therefore needs to be considered in this light. The potential impact of IHDs on customer demand is discussed further in section 7.1.

66 Reported in *Smart Meters: Commercial, Policy and Regulatory Drivers,* Gill Owen and Judith Ward, Sustainability First, March 2006, p. 20. The 8% reduction reported for the Norwegian study is made up of a 4% fall in consumption for the households in the study compared to an average 4% increase in households in general. The impact of electric heating in Norway was seen as an important driver of the results.

> 'there is a need to get further good, long tern evidence before a real assessment of the energy saving potential is made. In the meantime, based on the available evidence and taking a cautious view, it is reasonable to assume that some energy savings will result but that it could be as low as 1% and for electricity would be unlikely to be more than around 3%.'[67]

This 1 to 3% estimate is maintained in a further report published in July 2007.[68]

Of the overseas studies that found an overall conservation effect, the Northern Ireland study appears to have involved the largest number of participants, and was conducted over a sustained period. We have therefore adopted a 3 per cent energy saving as representing a realistic potential upside conservation impact.

The impact of adopting both of these upside assumptions in relation to the additional demand response achieved is presented in Table 5.6:

Table 5.8: Demand Impact of High Demand Response Case Residential – overall change in maximum demand and consumption (2016)

	NSW/ACT	NT	Qld	SA	Tas	Vic	WA
	Base						
Change in maximum demand	-2.48%	-1.55%	-2.64%	-2.47%	-2.14%	0.26%	-1.38%
Change in energy consumption	-1.38%	-1.28%	-1.41%	-1.41%	-1.37%	-1.43%	-1.35%

The increased uptake of CPP and assumed 3 per cent conservation impact causes the estimated demand response to be greater than under the previous assumptions. In particular, the conservation assumption causes the estimated decrease in energy consumption to be much greater than was the case where no such assumption was imposed.

Similarly, the change in overall maximum demand and consumption in each jurisdiction under the amended assumptions are shown in Table 5.7 below. The same general pattern of results across jurisdictions holds as compared to the results under the low demand response assumptions. However, there are significantly greater reductions in both maximum demand and consumption due to the introduction of the upside assumptions.

---

67 *Smart Meters: Commercial, Policy and Regulatory Drivers*, Gill Owen and Judith Ward, Sustainability First, March 2006, p.20.

68 *Smart Meters in Great Britian: the next steps?* Gill Owen and Judith Ward, July 2007, p.36, Published by Sustainability First.

Table 5.9: Demand Impact of High Demand Response Case All customers– overall change in maximum demand and consumption (2016)

	NSW/ACT		NT	Qld	SA	Tas	Vic	WA
	Base	Summer Peaking						
Change in maximum demand	-0.62%	-1.00%	-0.49%	-1.31%	-1.80%	-0.89%	-1.05%	-2.00%
Change in overall energy consumption	-0.24%	-0.24%	-0.21%	-0.40%	-0.45%	-0.38%	-0.29%	-0.40%

5.1.4. Difference between urban and rural/regional responses

The discussion in this section has focused on the aggregate demand response in each jurisdiction that may be achievable from the introduction of TOU tariffs and CPP.

KPMG has assumed that the same structure of retail tariffs will be offered throughout each jurisdiction.[69] That is, customers in both urban and rural areas will be offered TOU and CPP tariffs. From a retailer's perspective the commercial incentives to offer CPP tariffs relate to the ability to avoid high wholesale prices, and the location of the demand reduction is not important. Distributors will have an incentive to offer CPP tariffs (facilitated by the retailer) where there are benefits in relation to avoiding the need to augment the network to meet peak demand. Given the localised nature of network constraints, the benefits of reducing peak demand may accrue both in urban and rural areas.

In relation to TOU tariffs, retailers have a stronger incentive to offer these tariffs where they face competition for customers that are currently paying more than the underlying cost to serve them. To the extent that retail competition may be stronger in urban areas, given the greater customer density and therefore greater degree of scale economies for new entrants in marketing and obtaining new customers, there may be a stronger incentive for retailers to offer TOU tariffs in urban rather than rural areas. However, this need not be the case, and KPMG has assumed that in fact tariff offers will be the same across all customers within a jurisdiction.

Although tariffs may be the same, there may be a difference in uptake between urban and rural areas, as a result of differences in income distributions and age distributions. As discussed in section 3.2, the customer focus groups found that older customers, particularly in rural areas, were less inclined to see TOU tariffs as attractive options. KPMG has however estimated a single uptake figure for each jurisdiction, which does not distinguish between urban and rural areas.

---

69 KPMG, (2008), Cost Benefit Analysis of Smart Metering and Direct Load Control, Workstream 3: Retailer Impacts, Phase 2 Report. See discussion in section 6 and KPMG's tariff assumptions in Appendix A.

In addition, there is the potential for the demand elasticities of consumers in rural and urban areas to differ. However, we are not aware of any studies that estimate the difference for the own-price elasticity between urban and rural consumers.

Given the above uncertainties, KPMG has assumed that tariff offers will be the same across all customers within a jurisdiction and that uptake rates will also be the same. NERA has adopted these assumptions in the demand modelling presented in this report, together with an assumption of the same elasticity of demand for both urban and rural consumers.

6. Demand Side Response – Direct Load Control

In addition to the customer impact of a smart meter roll-out, phase 2 of the analysis also considers the impact on consumers of a non-smart meter roll-out of DLC capability (scenario 3). This section sets out how we have estimated the potential demand reduction that might result from DLC.

6.1. Methodology

From a consumer's perspective the benefits associated with DLC are largely limited to the incentive payment received for being part of the direct load control scheme and the potential reduction in electricity bills arising from the reduction in consumption during peak direct load control events.

Although the benefits appear somewhat limited from an individual consumer's perspective, the aggregated demand response attainable across a large number of consumers has broader implications for networks, retailers and the market in general. Specifically, aggregated load control can be used by:

- distributors to actively manage demand during system peaks and in so doing has the potential to reduce network constraints and reduce the system's peak load and its duration, which can in turn reduce the network augmentation requirements; and
- retailers to actively manage their exposure to wholesale prices; and
- reduce spikes in wholesale spot prices.

To enable the network, retailer and market benefits associated with DLC to be estimated it has been necessary to:

- identify the appliances that would be subject to direct load control;
- consider the aggregated demand response that could be achieved through direct load control of those appliances; and
- estimate the influence of the aggregated demand response on the jurisdictional load profiles.

There are a range of household and commercial appliances that could be the subject of remote automated load control. The most common appliances controlled through DLC programmes are air conditioners and swimming pool pumps.

Air conditioners can be remotely controlled by either switching off the appliance for the entire length of the direct load control event (curtailment) or cycling the compressors on and off for discrete periods of time over the length of direct load control event (ie, 15 minutes off in 30 minutes). As one would expect the curtailment option produces the greatest reduction in energy consumption, however, the cycling option can also achieve significant reductions in consumption with only minimal effects on the thermal comfort of consumers. Under the cycling alternative a 15 minute off in 30 minutes cycling period implies a 50 per cent cycling strategy which in turn means that 50 per cent of the energy that would otherwise have been consumed in the half hour is conserved.[70] In both cases energy is conserved rather than shifted as a result of DLC.

Pool pumps can also be controlled via DLC systems. Our understanding is that there are two potential forms of DLC that could be applied to pool pumps. One is to place pool pumps on timer switches, shifting their operation from peak to off-peak times. This happens in many jurisdictions already and is similar to existing arrangements for off-peak electric hot water. Under this approach the energy load associated with pool pumps is shifted, but the same amount of energy is used overall. The second approach is to use DLC to remotely turn off pool pumps for a certain period whilst they are operational and then to remotely turn them back on. Under this approach there is an overall reduction in energy use, rather than a shift in the time of the energy use.

According to an estimate prepared by George Wilkenfeld and Associates Pty Ltd for the Australian Greenhouse Office, air conditioners account for between 40 and 50 per cent of residential demand on system peak summer days and 30 to 40 per cent of commercial demand.[71] The magnitude of this contribution is significant, and the increased growth and penetration of air conditioners is a broader reaching issue facing distributors in most jurisdictions. A key focus of the analysis undertaken in relation to DLC has therefore been on residential air conditioners.

Phase 2 of the analysis has also considered the additional impact on demand from extending DLC to swimming pool pumps. Swimming pool pumps also contribute to residential demand on peak summer days.

6.2. Air conditioning - residential

In relation to the DLC response expected under Scenario 3 we have assumed the following:

§ retrofitting of a DLC control device to the existing stock of air conditioners (where possible); and

§ air conditioners manufactured from 2009[72] onward will be compatible with a standard device that would provide the technological capability to be directly controlled by a remote agent, in the absence of a smart meter.

Box 6.1 sets out the framework that has been used to estimate the demand impact associated with DLC of residential air-conditioners. Table 6.1 presents the key assumptions underlying the analysis.

---

[70] In practice a smaller proportion is likely to be conserved, given air conditioners would usually cycle as part of their own thermostat controls.

[71] George Wilkenfeld and Associates Pty Ltd, A National Demand Management Strategy for Small Air conditioners: the role of the National Appliance and Equipment Energy Efficiency Program (NAEEEP), November 2004.

[72] The estimated date from which air conditioners will be manufactured with the capability was provided by representatives that are currently designing the Australian Standards in this area.

In order to estimate the potential reduction in demand from DLC of residential air-conditioners, we have assumed that DLC would adopt a cycling strategy rather than curtailment. That is, air-conditioners could be remotely cycled minimising the impact on customers' thermal comfort.

KPMG has assumed a participation rate of 10 per cent for DLC programs (expressed as a percentage of all customers, not just those with airconditioners).[73] This is consistent with the proportion of people that adopt green power tariff offerings. However, in light of the feedback from the customer focus groups that (subject to practical implementation concerns) DLC was a relatively attractive option, we have also estimated the impact of doubling this participation rate assumption. This higher uptake case represents a 'high demand impact' case, similar to that considered for TOU and CPP.

The cycling is assumed to be 50 per cent for all jurisdictions. We understand that this is the cycling strategy that has been adopted by both ETSA Utilities and Energex as part of their DLC trials. We also understand that this assumption is also consistent with practice in the US.[74] In the case of the Northern Territory we understand that the high levels of humidity raise some potential issues with the ability to operate air-conditioners in this cycling mode without generating high levels of moisture. However, in discussions with DLC proponents in the US we understand that they do operate 50 per cent cycling of air-conditioners in areas with similar humidity without encountering these issues.[75]

In relation to the time period over which air-conditioners can be cycled without a reduction in thermal comfort, our Phase 1 analysis had assumed a 2 hour period. However, discussions with ETSA Utilities indicate that longer periods may be possible, and they have been trialling periods of up to 6 hours. We note that ETSA Utilities' analysis of the optimal time period is still to be undertaken. Moreover, for some jurisdictions, the length of time over which thermal comfort may be affected will vary. However, for the purposes of our analysis we have adopted a 6 hour period as representing the likely maximum period for which DLC could achieve a demand response. We have tested the sensitivity of this assumption by also analysing the impact on demand of assuming 2 hour and 4 hour cycling periods.

A more detailed description of the assumptions is set out in Appendix B, which also contains the results of the sensitivity analysis.

---

[73] Note that this uptake rate is higher when expressed as a percentage of those customers with airconditioners, eg, it is 11.7% in Western Australia and 13.9% in Victoria (based on estimates of the number of air-conditioners installed in those jurisdictions in 2016).

[74] Personal communication, Thomas Van Denover, Comverge Inc., 2 November 2007.

[75] The actual cycling approach would need to be tailored to the individual circumstances of each jurisdiction and locality.

Box 6.1: Framework for the estimation of aggregate demand response

To estimate the size of the aggregated demand response that could be achieved during peak wholesale price and/or peak network demand periods and the influence of this response on the jurisdictional load profiles the following steps were undertaken:

1. Estimate the total number of air conditioners in each jurisdiction that will have the capability of being controlled across each year of the forecast horizon;
2. Develop an estimate of the energy that could be conserved per air conditioner on a half hourly basis if distributors or retailers were able to cycle air conditioners for 15 minutes out of every 30 minutes over a six hour period;
3. Assume a rate of take up across all consumers in each jurisdiction having regard to the likely product offerings of distributors and/or retailers;
4. Multiply the estimates developed in steps 1, 2 and 3 to estimate the overall reduction in consumption attributable to direct load control;
5. Identify the days on which a direct load control event is likely to be called in each jurisdiction by either a distributor or a retailer and the six hour block over which this event could be called; and
6. Deduct the aggregate demand response from the half hourly jurisdictional load data during the times identified in step 5.

Table 6.1: General assumptions

Comparative energy consumption	1.9 kW
Cycling strategy	50%
Take up rate[76]	10% (20% high case)
Proportion of trial participants that may not be at home during the trial	10%
Number of days and terms of direct load control event	Up to 15 days with direct load control event extending for a maximum of six hours 8 events in NSW, 15 in NT, 14 in Qld, 15 in SA, 0 in Tas, 15 in Vic and 15 in WA.
Selection criteria for direct load control event days	Above 30° Celsius and the maximum demand levels reached on those days were in the top 5 percentile of the jurisdiction's 2006/07 load duration curve; or the wholesale prices reached on those days were in the top 5 percentile of prices paid in the jurisdiction over 2006/07.

The table below shows the stock of existing, new and replacement air conditioners in each year that could be subject to direct load control assuming a 10 per cent take up rate. If a 20 per cent take up rate were assumed the number of air conditioners that would be subject to direct load control set out in the table above would double.

[76] The base take-up rate has been estimated by KPMG as part of the retail workstream and is expressed as a percentage of the entire population. In relation to the percentage of consumers with air-conditioners (ie, those that are eligible to participate in the DLC program), this percentage ranges from 8% to over 20%, depending on the penetration of air-conditioners in each jurisdiction.

Table 6.2: Estimated number of existing, new and replacement air conditioners that could be subject to direct load control assuming a 10 per cent take up rate

	NSW	NT	Qld	SA	Tas	Vic	WA
2015 - 2019	161,950 – 170,672	2,751 – 2,994	135,315 – 149,655	59,740 - 61,767	n.a.	102,164 – 108,282	62,586 – 67,534
2020 - 2024	172,829 – 187,066	3,051 – 3,361	153,307 – 175,506	62,248 – 64,967	n.a.	109,797 – 119,379	68,773 – 76,343
2025 - 2029	190,365 – 201,758	3,437 – 3,727	181,267 – 204,072	65,598 – 67,693	n.a.	121,782 – 130,753	78,260 – 85,557
2030	204,192	3,794	209,690	68,062	n.a.	132,773	87,269

The tables below set out the maximum reduction in load associated with air conditioning that could occur during a direct load control event assuming either a 10 per cent or a 20 per cent take up rate.

Table 6.3: Estimated half hourly demand reduction attainable during direct load control events with a 10 per cent take up rate (MW)

	NSW	NT	Qld	SA	Tas	Vic	WA
2014/15	123.1	2.1	102.8	45.4	n.a.	77.6	47.6
2019/20	131.3	2.3	116.5	47.3	n.a.	83.4	52.3
2024/25	144.7	2.6	137.8	49.9	n.a.	92.6	59.5

Table 6.4: Estimated half hourly demand reduction attainable during direct load control events with a 20 per cent take up rate (MW)

	NSW	NT	Qld	SA	Tas	Vic	WA
2014/15	246.2	4.2	205.7	90.8	n.a.	155.3	95.1
2019/20	262.7	4.6	233.0	94.6	n.a.	166.9	104.5
2024/25	289.4	5.2	275.5	99.7	n.a.	185.1	119.0

Measured against the projected jurisdictional load profiles these MW reductions translate to a reduction in demand during direct load control events of between 0.85 and 1.59 per cent assuming a 10 per cent take up rate and between 1.70 and 3.17 per cent assuming a 20 per cent take up rate.

Since the reduction in energy consumption achieved through the 50 per cent cycling strategy has only a minimal impact on thermal comfort levels the change in consumer surplus simply reflects the reduction in expenditure during these direct load control event periods and the incentive payment received from the remote agent. That is, the change in consumer surplus is simply a financial redistribution from retailers, generators and networks to customers.

In contrast to the residential sector there is limited information currently available on the number of air conditioners owned by small commercial customers, which has made it difficult to undertake any analysis in relation to this sector. As a consequence our analysis of this issue has focused upon residential customers and thus the estimated demand side response may be viewed as representing the ***lower bound*** of the potential response to the direct load control of air conditioners under each uptake rate assumption.

Having said that, the likely demand response from any direct load control program targeted at small businesses is expected to be lower than that attainable from residential customers. This reflects the overall lower level of demand responsiveness of small commercial customers. This conclusion is consistent with the Essential Services Commission of South Australia's (ESCOSA) view that the demand management potential associated with the direct load control of small businesses air conditioners was likely to be low.[77]

6.2.1. Pool Pumps

In estimating the DLC response possible from pool pumps, it was assumed that customers with air conditioners subject to load control would also retrofit their pool pumps to contribute to their potential load reduction. References here to 10 and 20 per cent take up rates refer to participation of customers with air conditioners. Only a proportion of these customers will also have a pool pump connected to the program.

We have further assumed that:

§ the likelihood of the pool pumps in the program being in operation is uniform throughout the daylight hours; and

§ pool ownership rates amongst those with air conditioners on the DLC program is equal to those of the general population.

Data obtained from George Wilkenfeld and Associates Pty Ltd was used as inputs for the number of pools and the average size and running time per day of pool pumps in each jurisdiction.

The table below shows the number of pool pumps that we have assumed to be subject to direct load control at the 10 per cent take up rate for air conditioners.

[77] ESCOSA, Draft Decision Demand Management and the Electricity Distribution Network, September 2004, pg. 10.

Table 6.5: Estimated number of pool pumps that could be subject to direct load control assuming a 10 per cent take up rate

	NSW	NT	Qld	SA	Tas	Vic	WA
2015 - 2019	22,155 – 23,638	930 – 1,060	26,765 – 32,026	5,395 – 6,028	n.a.	7,315 – 8,024	8,750 – 9,549
2020 - 2024	23,999 – 26,272	1,092 – 1,257	33,421 – 41,068	6,175 – 6,861	n.a.	8,202 – 9,204	9,752 – 10,948
2025 - 2029	26,811 – 28,739	1,299 – 1,468	43,142 – 51,834	7,032 – 7,690	n.a.	9,462 – 10,473	11,254 – 12,440
2030	29,167	1,510	54,100	7,841	n.a.	10,715	12,724

The tables below set out the maximum reduction in load associated with pool pumps that could occur during a direct load control event assuming either a 10 per cent or a 20 per cent take up rate.

Table 6.6: Estimated half hourly demand reduction attainable during direct load control events with a 10 per cent take up rate (MW)

	NSW	NT	Qld	SA	Tas	Vic	WA
2014/15	5.9	0.2	7.6	1.3	n.a.	1.7	2.2
2019/20	6.2	0.2	9.3	1.5	n.a.	1.8	2.4
2024/25	6.8	0.3	11.7	1.6	n.a.	2.1	2.1

Table 6.7: Estimated half hourly demand reduction attainable during direct load control events with a 20 per cent take up rate (MW)

	NSW	NT	Qld	SA	Tas	Vic	WA
2014/15	11.7	0.4	15.2	2.6	n.a.	3.4	4.3
2019/20	12.4	0.5	18.5	3.0	n.a.	3.7	4.7
2024/25	13.5	0.6	23.4	3.3	n.a.	4.1	4.1

Relative to the total demand reductions available from the DLC program the demand reductions available from switching off pool pumps during a load control period are modest. These range from 2 per cent of total reductions in Victoria to almost 10 per cent in the Northern Territory, where average pool ownership rates are the highest in Australia.

7. Smart Meter Scenarios - Incremental Demand Impact of Functionalities 15 and 16

The demand response reported in section 5 in relation to TOU tariffs and CPP has assumed a smart meter roll-out that does not include functionalities 15 and 16, which provide the capability for direct load control to be implemented within a smart metering system.

Functionality 15 is an interface for load control devices. This would enable the smart metering system to control certain electric devices in the home (notably air-conditioners and pool pumps). Functionality 15 would therefore provide a DLC capability as part of a smart meter roll-out.

Functionality 16 is an interface to a HAN using an open standard. This functionality has the potential to enhance demand side-response in two ways:

§ it would allow customers to be provided with in-home displays (IHDs) which in turn would increase the availability and accessibility of information – potentially leading to both an enhanced elasticity response to TOU and CPP and to an energy conservation effect; and

§ it would provide a DLC capability.

Three alternative performance cases were considered for functionality 16 (cases A, B and C).

The Phase 1 analysis found that the net benefits associated with each of these two functionalities was highly uncertain, both as a result of uncertainties in relation to cost estimates (in particular the device costs associated with the DLC capability for both functionalities) and also uncertainty in relation to the demand impact. As a result, both of these functionalities have been considered further as part of the Phase 2 analysis.

7.1. Increase in demand response associated with in-home displays

Our Phase 1 report discussed the potential for the provision of IHDs to elicit a greater level of response to TOU and CPP by increasing the amount of consumption and pricing information made available to consumers and enhancing the accessibility of this information.

Phase 1 considered the potential impact of IHDs in relation to:

i. enhancing the response to TOU;

ii. enhancing the response to CPP;

iii. enhancing the response to consecutive CPP days; and

iv. driving an increase in general energy conservation.

Our Phase 1 report noted that it was difficult to isolate the *incremental* impact of IHDs on demand. In order to separate out the impact of the IHD it is necessary to compare demand responses between customers that face TOU and/or CPP prices but do not have an IHD with those that face the same tariffs but were provided with an IHD. A number of the studies we have reviewed involving in-home displays do not allow that distinction to be drawn. Some caution must therefore be exercised when interpreting the results of these studies since findings that changes in tariffs result in changes in customer behaviour in trials which involve IHDs do not equate to findings that the provision of the IHD is the cause of that change in behaviour.

Our phase 1 survey of the information available from a range of studies and trials, both in Australia and overseas, indicated that the evidence of the impact of IHD on customer demand was very mixed.

Preliminary findings from the trials conducted by EnergyAustralia and Integral had indicated no statistically significant difference in behaviour in relation to CPP days from customers with an IHD and customers without. We understand that more recent results from the trials being conducted by Integral have found a significant difference in behaviour, with customers in the trial reducing their peak demand in CPP periods by a greater amount than customers without an IHD, by around 5 per cent. We note that these results are still preliminary.

In relation to the potential for an IHD to result in increased conservation, IHDs have the potential to increase customers' awareness of their energy consumption. The awareness may both be in terms of the cost of that consumption, and also in relation to greenhouse gas emissions. In-home displays generally have the capability to display this information.[78] Any general energy conservation effect may be expected to be higher the more customers look at their in-home display. That is, where an in-home display also provides other information which customers may access frequently (such as weather updates), their awareness of their energy consumption may be higher.

However, the effect of an in-home display needs to be assessed in terms of the enhanced ability to provide this information to customers, compared with other channels (eg, provision of information via a customer's bill).

The trials conducted by Country Energy, in which customers were given a smart meter, indicated that on-going education was important notwithstanding the fact that consumers had in-home displays.[79] This may suggest that any general demand response associated with the provision of an in-home display may not be maintained in the longer run, in the absence of continuing customer education.

According to the results of a UK study involving energy consumption displays attached to stoves, customers that were provided with the display were able to achieve average reductions in energy usage of 15.2 per cent while the information package

---

78 The exception is displays which only have 'three light' capabilities.

79 Smart metering & Customer trials, A retailer perspective, ERAA Retail Energy Market Briefing, 30 July 2007, slide 10.

group were able to achieve average reductions in energy usage of 3 per cent.[80] The authors of this study further found that while the information pack group were more aware of energy-savings behaviours they did not appear to actually adopt those behaviours. The authors concluded that this demonstrated that the display increased motivation to modify energy usage relative to what otherwise would have been achieved with information only.[81] However, this study only covered a very small number of consumers (41 consumers).

A report prepared for the Californian Information Display Pilot Technology Assessment also contained a review of in-home display studies extending back from 1986. In summary this review found that customers were able to achieve savings of 4 to 11 per cent.[82] The in-home display studies referred to in this report include:

- a study of in-home displays undertaken in Canada and California in 1986 that resulted in conservation of 4 to 5 per cent in Canada and no change in consumption in California;
- the UK study cited above pertaining to stoves;
- a study undertaken in Norway that suggested feedback could result in reductions of 9 per cent;[83] and
- a Northern Ireland trial involving prepayment meters with a display that resulted in reductions of 11 per cent when participants were provided with instructions and 4 per cent when no instructions were provided.

It is worth noting in this context that:

- the Norway study actually related to more frequent billing and the format of billing rather than in-home displays; and
- the results presented for the Northern Ireland trial differ from those cited in the Ofgem "Domestic Metering Innovation" report which stated that a recent TOU trial involving 186 participants resulted in peak reductions of 10 per cent and conservation levels of 3.5 per cent and an earlier trial involving 100 participants achieved average reductions in consumption of 3 per cent[84]

In the UK in 2006 Sarah Darby published a report that reviewed the results of a number of studies relating to the effectiveness of feedback on energy consumption.[85]

---

80 G. Wood, M. Newborough, Dynamic energy-consumption indicators for domestic appliances: environment, behaviour and design, 17 November 2002.

81 G. Wood, M. Newborough, Dynamic energy-consumption indicators for domestic appliances: environment, behaviour and design, 17 November 2002, pg. 835.

82 Primen, Final Report – California Information Display Pilot Technology Assessment, December 2004, pp. 5-6.

83 We note that other references to the Norwegian study cite an 8% overall demand reduction (see section 5.1.3).

84 Ofgem, Domestic Metering Innovation, 1 February 2006.

85 S. Darby, The Effectiveness of Feedback on Energy Consumption – A review for DEFRA of the Literature on Metering, Billing and Direct Displays, April 2006.

One of the key findings of this review was that studies examining direct feedback through either a meter or a display monitor had observed savings of between 5 to 15 per cent. However, the report also cautioned against the difficulties in comparing studies, given the considerable differences in sample size (only 3 in one case), duration of study and additional interventions in some cases such as insulation or the provision of financial incentives to save.

A further trial was undertaken by Hydro One in Canada between July 2004 and September 2005 involving 435 participants that were provided with in-home displays that measured their electrical consumption in real time and displayed electricity consumption in both kWh and in monetary terms. [86] A control group was established and the participants in this trial were not provided with any additional educational material on electricity conservation. Participants were also not subject to time varying tariffs or CPP. According to Hydro One, participants in the trial were able to achieve aggregate reductions in consumption of 6.5 per cent.[87] For customers without electric heating the reduction was 5.1 per cent. Since tariffs were unchanged in this trial the conservation effect represents a shift in the participants' demand curves.

Although the results of this trial indicate substantive conservation benefits it is unclear whether these same levels of conservation could be achieved in Australia given the differences in both the climatic conditions and the greater reliance on central heating in Ontario.

In the UK, a report prepared for Centrica by Frontier Economics also raises questions about placing too much reliance on the Hydro One study, given its relatively short duration and limited sample size. Frontier adopted as a base case for their assumptions a reduction of 1% in consumption associated with an IHD that was assumed to persist for 15 years.[88]

Given the above we have assessed two indicative cases for the additional demand response that may be associated with the provision of an IHD.

§ The first is a <u>zero additional demand response</u>, consistent with the preliminary findings of the EnergyAustralia trials. This assumption has been adopted in our base demand case;

§ The second is an <u>additional 4% demand reduction</u>, consistent with the most recent findings of the Integral Energy trials. This assumption has been adopted in the high demand response case, and is in addition to the 3% additional conservation impact that has also been included in that case.

---

[86] Hydro One Brampton Networks Inc., Conservation and Demand Management Plan, Annual Report to December 31 2005, p.7-8.

[87] We note that figures of 7-10% conservation have been quoted in other reports in relation to the Hydro One trial. The Hydro One Annual Report actually says that an overall average reduction of 7-10% 'is feasible' if customers were to be provided with energy conservation 'tips' in addition to an IHD. This was not a feature of the trial, and therefore is only a speculative figure.

[88] Frontier Economics, *Smart Metering - a report prepared for Centrica*, October 2007.

7.2. Direct load control capabilities

Both functionalities 15 and 16 have the capability to also enable DLC of consumer appliances.

From a direct load control perspective there are two principal differences between the functionalities:

1. the cost of retrofitting a DLC capability in appliances is substantial for functionalities 15 and 16A&B, and much lower for functionality 16C. As a result we have assumed that there is no retrofitting of DLC capability under functionalities 15 and 16A&B but that there is a retrofit under 16C; and

2. under functionality 15 there is no mandated standard associated with the DLC capability, compared with functionality 16 where we have assumed that there will be a common Australian standard from 2009.[89] The lack of a common standard may lower customer uptake for DLC facilitated by functionality 15 compared with functionality 16, as there is a need to ensure compatibility between appliances and smart meter capabilities.

Consistent with point 1 above, we have estimated the demand impact associated with DLC in functions 15 and 16A&B assuming no retrofitting of the existing stock of air conditioners. As a result, the pool of appliances that DLC can be applied is lower than for our scenario 3 analysis. Appendix B provides further details of the assumptions adopted and our estimate of available load under control where smart meters are assumed to have these functionalities.

Since the costs of retrofitting have been assumed to be less substantial where a smart thermostat is installed, the analysis of function 16C includes both new and replacement air conditioners and the existing pool of air conditioners. That is, the expected load under control is the same as that estimated for scenario 3.

The detail of our analysis of DLC capability for these functionalities is provided in Appendix B. The analysis largely follows that already outlined for scenario 3. The one important difference is the assumptions that we have needed to make regarding the interaction of DLC with TOU and CPP tariffs. Since we are considering smart meter scenarios, demand will already be affected by the availability of TOU and CPP tariffs. We therefore need to take this into account in estimating the ***additional*** impact associated with adding the DLC capabilities.

The other difference between our analysis of DLC for scenario 3 and our analysis of DLC for the incremental smart meter functionalities is the take-up rates assumed. In a smart meter scenario customers are also offered other ‘energy-smart’ tariffs (ie, CPP, TOU), which is likely to decrease the take-up of DLC compared to scenario 3 in which DLC is the only ‘energy-smart’ tariff that is offered. We have therefore

---

[89] This assumption has been based on discussions with the representatives currently designing the Australian Standards in this area and is discussed further in Appendix C.3.

adopted an assumption that DLC take-up is 7.5% rather than the 10% assumed for scenario 3.[90] We have also considered an upside assumption of a 15% take-up rate for DLC tariffs facilitated by functionality 16. Given point 2 above about the potential for a lower uptake under functionality 15, we have not applied this higher take-up rate to functionality 15.

7.2.1. Results – functionalities 15 and 16

Tables 7.1 and 7.2 below present the *incremental* reduction in peak demand and the overall energy conservation associated with functionalities 15 and 16, compared to our base demand response case, based on the assumptions outlined above. The reductions relate to overall changes in consumption, rather than only for those customers on CPP and TOU tariffs.

Table 7.1 presents the incremental impact on overall demand, for our base assumptions (7.5% DLC uptake, no additional conservation effect).

Table 7.1: All customers – incremental change in consumption assuming 7.5% DLC uptake and no additional conservation impact

	NSW/ ACT	NT	Qld	SA	Tas	Vic	WA
Functionalities 15 and 16A&B							
Change in maximum demand	-0.04%	-0.24%	-0.34%	-0.60%	n/a	-0.33%	-0.49%
Change in energy consumption	-0.00%	0.00%	0.00%	-0.01%	n/a	0.00%	-0.01%
Functionality 16C							
Change in maximum demand	-0.04%	-0.55%	-0.78%	-1.08%	n/a	-0.64%	-0.92%
Change in energy consumption	0.00%	-0.01%	-0.01%	-0.02%	n/a	-0.01%	-0.02%

In the case of Tasmania, there is no incremental demand response in the base demand case from the inclusion of either functionality 15 or functionality 16, as Tasmania is winter peaking and does not have air-conditioning load operating at peak times that could be interrupted through DLC. We note that the same result also applies for Tasmania in relation to the non-smart meter DLC rollout scenario.

[90] These take-up rates are both expressed as a percentage of the overall population, rather than only those customers with eligible devices.

Table 7.2 presents the equivalent results for the high demand response case (15% DLC uptake, 7% additional conservation effect), for functionality 16 only.[91] In the high demand response case the 7% additional conservation effect is comprised of an additional 3% conservation effect unrelated to the presence of IHDs (see discussion in section 5.1.3) and a further 4% conservation effect resulting from IHDs. The impact on demand is expressed as the incremental change compared to our base demand case.

Table 7.2: All customers – incremental change in consumption assuming 15% DLC uptake and 7% additional conservation impact

	NSW/ACT	NT	Qld	SA	Tas	Vic	WA
Functionality 16A&B							
Change in maximum demand	-0.83%	-1.10%	-1.56%	-2.54%	-1.54%	-1.20%	-1.41%
Change in energy consumption	-0.55%	-0.61%	-0.93%	-1.00%	-0.89%	-0.66%	-0.98%
Functionality 16C							
Change in maximum demand	-0.83%	-1.61%	-2.37%	-3.43%	-1.20%	-1.97%	-2.97%
Change in energy consumption	-0.56%	-0.62%	-0.94%	-1.02%	-0.89%	-0.56%	-0.99%

We note that in the high demand response case there is an incremental impact on demand in Tasmania. This arises as a result of the conservation effect assumed, and not DLC.

These results highlight that the assumed conservation effect resulting from the adoption of an IHD, and the associated participation rate for direct load control programs, will significantly affect the resulting change in maximum demand and overall energy consumption. How realistic these assumptions are will be an important consideration in assessing the likely demand response benefits associated with these functions.

As noted in Box 5.1 (and discussed in Appendix B Box B1), we have also estimated the demand response for NSW adopting an assumption of NSW becoming summer peaking. Table 7.3 illustrates the increase in both peak demand reduction and the overall reduction in energy consumption for functionalities 15 and 16 arising as a result of adopting a summer peaking assumption.

[91] As discussed in the previous section, we have not estimated as high demand response case for functionality 15 as the lack of a standard for DLC devices under functionality 15 means that higher take-up rates may be unrealistic. In addition functionality 15 does not include an IHD.

Table 7.3: NSW Summer Peaking sensitivity All customers – overall change in consumption

	NSW/ACT	
	Base assumption	**NSW Summer Peaking**
BASE DEMAND		
Functionalities 15 and 16A&B		
Change in maximum demand	-0.04%	-0.26%
Change in energy consumption	0.00%	0.00%
Functionality 16C		
Change in maximum demand	-0.04%	-0.62%
Change in energy consumption	0.00%	-0.01%
HIGH DEMAND		
Functionality 16A&B		
Change in maximum demand	-0.83%	-1.41%
Change in energy consumption	-0.55%	-0.56%
Functionality 16C		
Change in maximum demand	-0.83%	-2.07%
Change in energy consumption	-0.56%	-0.57%

8. What is the distributional impact of smart metering on consumers?

The impact of smart metering and direct load control programs on individual households will vary according to the household's characteristics. Assessing whether, on average, consumers are better or worse off provides a potentially misleading assessment of the impact of smart metering and direct load control on consumers. We have therefore sought to examine the likely affect on customers in a variety of circumstances.

The introduction of smart metering will potentially affect customers in a number of ways including:

§ providing an opportunity to benefit from lower bills because of opportunities provided by new tariff product offerings;

§ increases in tariffs resulting from the pass through of the initial smart metering rollout costs; and

§ improvements in the service provided to customers.

As part of our assessment of the impact of smart metering and direct load control on consumers we have therefore considered the impact of new tariff products that may result from smart metering on consumer bills. This assessment seeks to consider the likely impact on a range of consumers with different characteristics. In this chapter we present the detailed results from this assessment of bill impacts arising from new product offerings, with a particular focus on low income and otherwise vulnerable segments of our community.

Importantly, many of these consumer "benefits" can be equally considered as a "cost" to retailer businesses as lower bills means less revenue for retailers. The economic benefits from changes in demand therefore arise from lower overall energy consumption leading to reduced energy generation and other costs. These issues are explained in more detail in the Phase 2 overview report.

The introduction of smart metering is expected to lead to higher tariffs during the initial rollout, with resultant business cost efficiencies in the future that would be passed through to customers in the form of lower bills. This means however that tariffs are expected to increase initially, before the benefits are realised and passed through to customers. This initial impact is therefore an important consideration in the analysis, particularly for vulnerable customers.

Finally, while this chapter focuses on bill impacts, we acknowledge that smart metering provides capabilities that are likely to deliver other benefits to consumers. These include improved information on household electricity usage and improved service provision. These additional benefits are examined in greater detail in chapter 9 below.

The remainder of this chapter is structured as follows:

- Section 8.1 provides a qualitative assessment of the scope of consumers to react to smart metering products, particularly to time of use tariffs and critical peak pricing, focusing on the factors that affect a consumer’s ability to respond to price changes;
- Section 8.2 provides a profile of consumers in each state and territory, to provide a basis for considering differences in the likely impact of smart metering product offerings on consumers. It also reports the results of our detailed assessment of the bill impact on low, median and high income households for each state and territory of Australia; and
- Section 8.3 provides a case study assessment of the bill impacts on consumers with differing characteristics, such as larger families, elderly pensioners and single occupants. These are designed to provide an indication of the possible affect that new product offerings will have on segments of the population.

8.1. Consumer reactions to time of use and critical peak pricing

Critical to an assessment of consumer reactions to time of use and critical peak pricing is an assessment of the scope for individual households to respond to the new pricing products that are being offered. In principle, a consumer is unlikely to adopt a new tariff product unless they expect to be better off (ie, face a lower overall bill). This means that there are two factors that will influence a consumer’s decision about adopting a new time of use or critical peak pricing product:

- a belief that most of their current consumption is mainly in off-peak periods, such that their overall bill decreases without having to change current electricity usage behaviour; and/or
- a belief that they can relatively easily change the existing time of electricity use to increase the amount of electricity used in off-peak, compared to peak periods, (ie, through changing when clothes washing occurs or when a dryer is used).

For an individual consumer to be better off under the new tariff arrangements, their expectations about the two factors described above need to be realised.

In this section we examine the factors that affect a consumer’s current time of use of electricity, and their ability to change the existing pattern of that usage.

8.1.1. Determinants of electricity demand and its time of use

Household demand for electricity is derived from demand to use appliances that require electricity for their operation. The main determinant therefore of electricity demand and its time of use is the types of end-use appliances within a home, and when they are most commonly used.

Appliance use can be broadly grouped into three usage categories:

- discretionary (ie, when its time of use can vary through the day);
- semi-discretionary (ie, when its time of use can vary through the day, however there are strong preferences for its use at particular times of the day); and

- non-discretionary (ie, when its time of use does not vary through the day).

Discretionary appliances include washing machines, dryers, dishwashers, pool pumps and air-conditioners, amongst others. They are generally appliances whose time of use, given a time difference in electricity price, could be shifted to a new time.

Semi-discretionary appliances include televisions, computers and kitchen appliances. In general they are used to prepare meals at certain times of the day, or are associated with leisure/work times. These appliances generally satisfy household preferences for their use at specific times within the routine of an ordinary household's day. There are usually strong preferences to continue to use these appliances at those times. For example, it is unlikely that many households would decide to cook and eat dinner after 10pm solely to take advantage of lower off-peak electricity tariffs. A household may however choose to make more use of a gas barbeque to lower electricity use during peak periods.

Non-discretionary appliances include lighting and refrigerators. These are appliances that operate either all day (as in the case of a refrigerator) or in the evening in the case of lighting, and are essential for modern living. Whilst there may be substitutes for these (ie, candles and oil lanterns) these substitutes are not perfect.

In general, the more appliances that a household owns, the greater the household's electricity use.[92] This is particularly the case for households with high energy using appliances such as air-conditioners, swimming pools (with an associated pump) and electric hot water systems. Understanding the mix of appliances and when they are used is therefore critical to developing an understanding of the likely impact of new tariff product offerings on a particular household.

For example, households with electric hot water heating use more electricity than those using gas for hot water heating. Households with access to gas, but who have existing electric hot water systems, have the potential to lower electricity use by replacing the hot water system with a gas alternative. For households who already have gas hot water heating there is however less opportunity to change existing electricity demand.

Knowing the appliances present in a household is not sufficient however to gain a complete understanding of electricity use patterns. A household's individual characteristics are also expected to influence total electricity use and its pattern of use. These household characteristics can be loosely categorised into the following groups:

- number and age of occupants;
- economic (ie, income and employment); and
- location (ie, differences in climatic conditions).

[92] IPART, Residential energy use in Sydney, the Blue Mountains and Illawarra: Results from the 2006 household survey, electricity and gas interim report, June 2007, pg15

In general, two identical households with the same appliances can have very different total electricity demand and usage profiles, according to when occupants are usually home (during the day, or at night). To obtain a complete picture of the likely impact of new tariff product offerings on a household it is therefore necessary to consider both the appliance number and mix, and the household's characteristics.

In the remainder of this section we outline how household characteristics are expected to impact on electricity use.

Household demographic characteristics

In general, as the number of occupants within a household increases total household electricity use also increases. The amount of incremental electricity use however decreases with each additional occupant within the household, reflecting the fact that there is some fixed amount of electricity associated with residing in a household, which is shared across the number of occupants of the household.[93]

Similarly, households with different family structures also differ in terms of total electricity use. For example, in a study reporting the results of a survey of customers in the Sydney region, the Independent Pricing and Regulatory Tribunal (IPART) found that households with teenagers, on average, used more electricity than households with the same number of occupants but with younger aged children.[94] This result is likely to reflect differences in the appliance mix and activity within the home.

Occupants of houses also tend to have higher electricity use compared to units, even once the number of occupants have been normalised. This is likely to reflect both the mix and number of appliances within a house compared to a unit, and the likely electricity required for heating and cooling a larger home.

Finally, as stated above households that are connected to gas as a substitute energy source on average use less electricity than those not connected to gas. This reflects the use of gas for hot water heating, cooking and/or space heating. Hot water heating and space heating are also both significant contributors to a non-gas-using household's total electricity bill, which EnergyAustralia estimates as 37 per cent.[95]

Economic characteristics

Household income is an important determinant of electricity demand and the propensity for shifting demand. On average higher income households use more electricity compared to lower income households. This is likely to be in part a result of the underlying differences in appliance use and mix characteristics between households with different income. For example, higher income households tend to have a larger number of appliances, particularly high energy using appliances such as

---

93 IPART, Residential energy use in Sydney, the Blue Mountains and Illawarra: Results from the 2006 household survey, electricity and gas interim report, June 2007, pp7-8.

94 Ibid, p8.

95 Energy Usage Gauge, Energy Australia website, http://www.energyusage.energyaustralia.com.au/

air conditioners and pool pumps, compared to low income households. They are also likely to live in larger premises that require higher electricity use for heating and cooling.

As outlined in further detail below, there is some evidence that higher income households respond more to critical peak prices than low income households. This again is likely to reflect the opportunity that a higher income household may have to lower electricity consumption, given the number of discretionary appliances available. For a household where almost all electricity use is non-discretionary, then there is less opportunity to lower electricity use during critical peak periods.

Location characteristics

The geographic location of a household will also affect its pattern of electricity use. For example, households in tropical climates, such as Darwin or Townsville are more likely to have a relatively flat load as air conditioner use will be required for longer period to combat consistent heat and humidity. Similarly, winter peak loads occur in cooler climate areas such as Canberra and Tasmania. Households close to the ocean will have different load profiles compared to those households located further inland.

The prevailing climatic conditions are therefore expected to affect the appliances that are present within a household and how they are used.

In summary, electricity demand is a function of the number and mix of appliances within a household and their use. The appliance number, mix and use are likely to be in turn a function of household income, number of occupants, household type and circumstances, employment status and location. The result of a household's combination of these factors is likely to determine its total electricity use and the time of its use. These are therefore expected to vary across jurisdictions and between individual households.

8.1.2. Factors affecting a household's ability to change the time of electricity use

The factors outlined above affect a particular household's electricity consumption and the likely time of electricity use. The resultant household electricity consumption and daily usage profile is then the starting point for considering the scope that a household has to change the pattern and level of its electricity use in response to new tariff product offerings.

In our view, households with a large number of predominately discretionary appliances have the greatest *potential* to respond to new time of use electricity products. Whether they do in fact respond to these pricing signals however is likely to depend on income and other household circumstances, particularly their individual preferences for usage of appliances at particular times, and their general interest in energy conservation.

The process by which a household might respond to price changes can be broken into two parts that reflect its response in the short run compared with the long run. In the short run households can change the time of electricity use by choosing to undertake electricity intensive tasks in off-peak or shoulder periods, for example moving clothes washing to the evening or on weekends. In the long run however, households can choose to invest in more energy efficient appliances and/or appliances with timers to allow tasks to be scheduled into off-peak periods.

We are only aware of one study, by CRA International, which has sought to quantify the responsiveness of electricity demand to time of use pricing between households with different characteristics. The results found that:[96]

- as the number of persons per household increase the level of responsiveness fell, with the elasticity of substitution[97] estimated to be 25 per cent higher for a two person household than a four person household;
- the responsiveness of demand to changes in price was greater for higher income households (over $100,000) than low income households (less than $40,000) with the percentage reduction in peak period energy use on critical days being nearly 50 per cent greater for higher income households; and
- households with central air conditioning were more price responsive than those without, with the elasticity of substitution estimated to be approximately three times higher for households with central air conditioning than for those without and the daily price elasticity estimated to be 50 per cent higher.

It is difficult to apply these results to our analysis however we conclude that in general low income households are probably less likely to respond to new pricing signals. The lower capacity to respond in the short run is likely to reflect a lower number of discretionary appliances within the household. Lower income household's capacity to respond in the long run may also be lower due to an inability to switch to gas hot water systems if the household is a tenant or a regional customer without access to gas, or the tendency to use older appliances that are less energy efficient due to budget constraints.

This intuition is supported by the results from the focus groups conducted as part of both Phase 1 and Phase 2 of this project. Participants in the low income groups all indicated that they felt as though they were doing all they could to reduce their electricity consumption in an effort to save money. This was echoed by consumer advocates as part of a workshop conducted during Phase 2.

In contrast the higher income focus group participants indicated that unless they would benefit from significant reductions in their bills they would be unlikely to make any changes to their overall consumption. However, some participants indicated that they would be willing to shift some discretionary appliance usage (such as washing machines, dryers and dishwashers) into evening and weekend times.

Further, a household's understanding of the contribution of particular appliances to total electricity demand, will affect its ability to make meaningful behavioural choices.

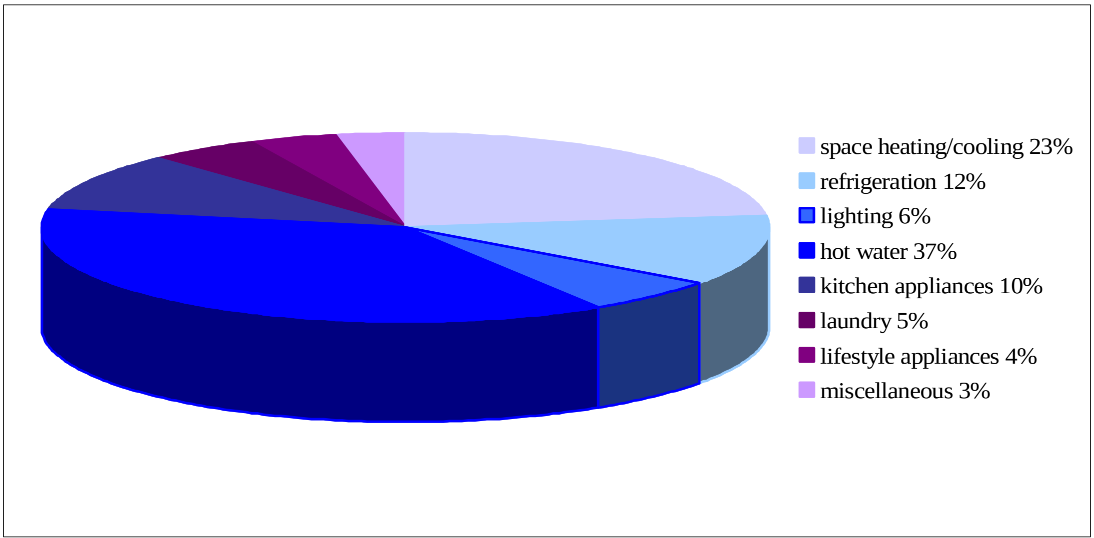
---

96 CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pp. 74-75.

97 The elasticity of substitution is a measure of the responsiveness of demand to a change in the ratio of peak to off-peak tariffs.

Figure 8.1 below shows the estimated contribution of different appliances categories to total household consumption. The large contribution of refrigeration, hot water and space heating shows that if consumers can make changes in these areas they will benefit from lower electricity bills. For example, a household lower its bill by ensuring that fridge seals are working properly, or by reducing air conditioner and hot water use.

Figure 8.1: Composition of residential electricity bills by end-use



Source: Energy Usage Gauge, www.energyaustralia.com.au

8.1.3. Responsiveness of vulnerable customers

A particular concern from any change to electricity tariff structures is the likely impact on vulnerable customers.

Low income households are generally considered to be vulnerable, particularly when this is combined with relatively high electricity consumption as a result of the number of household occupants or load requirements for certain medical equipment, being unemployed and thereby spending greater time at home, poor housing stock that requires greater heating and/or cooling, and/or limited access to hot water heating substitutes such as gas. Given likely limited opportunity to shift consumption, examining the current load profile for vulnerable customers compared to the state average will be important to determine whether vulnerable customers are likely to be better off from the introduction of time of use tariffs.

We have assumed that the new tariff product offerings will be non-mandatory and therefore one would expect that any household including a vulnerable household would not change from the current flat tariff offerings unless they would be better off from the change. However, if these tariffs are not voluntary it will be important to ensure that vulnerable customers would be no worse off from their introduction and an appropriate safety net provided. Whether a vulnerable customer would be better off will depend on their circumstances and appliance mix as outlined above.

There are two possible outcomes for a vulnerable customer from changing to a time of use offering. Vulnerable customers will be either:

- Better off, because their current load profile is relatively flat, such that a relatively higher proportion of total electricity use occurs in off-peak times than the average load profile such that shifting to time of use tariff results in a lower average cost of electricity;[98] or

- Worse off, because the vulnerable customer currently has high peak use and less opportunity to shift time of use consumption patterns due to household circumstances.

In section 8.3 below we examine a number of circumstances as part of the case study analysis which may indicate what kind of customers may be better or worse off from the introduction of TOU tariffs, critical peak pricing and direct load control programs.

8.2. Assessment of consumer impacts from time of use and critical peak pricing, by jurisdiction

To determine the likely impact of time of use and critical peak pricing we have estimated the change in the household bill in each jurisdiction for households with average consumption, and where possible households in rural/regional areas compared with major urban centres.

We had originally hoped to undertake an analysis by a selection of postcodes in each jurisdiction. From this we had wanted to consider the relationship between income, electricity consumption and the load profile from transformer level data where available within each jurisdiction. Unfortunately, distributors were unable to provide this level of detailed data in the timeframe necessary to complete the analysis. For this reason the jurisdictional analysis outlined below is undertaken using average jurisdictional consumption and state wide load profile information.

A summary of the methodology used is contained in Box 8.1.

98 Alternatively vulnerable customers may be better off because they might be able to more easily flatten their current load profile, away from peak periods.

Box 8.1: Distributional impact assessment methodology

To determine the likely impact from the introduction of time of use and critical peak pricing on the average household, we have estimated the expected bills of an average consumption household in each state and territory. The methodology used is as follows:

1. Calculate the current average bill for each household using current regulated tariffs and average consumption in the jurisdiction.
2. Apply new product tariff assumptions for each state to calculate average bills assuming no change in electricity consumption.
3. Calculate the likely demand response applying the methodology described in Appendix B, based on the elasticity of substitution and own-price elasticity assumptions applied in the earlier analysis.
4. Recalculate average bills based on the new product tariff and new electricity consumption following household response.

This approach does not take into consideration the likely differences in the elasticities of substitution and own-price elasticities associated with households holding different appliance mixes and other characteristics that will differ within jurisdictions. The results are therefore only indicative of the likely impact on household bills from the introduction of time of use and critical peak pricing tariff products.

The remainder of this section provides a profile of residential households in each jurisdiction and presents the bill impact results. The bill impact results reflect the estimated demand response in each jurisdiction, in relation to each of the tariff products offered. We have not presented a ‘no demand response’ bill impact as the revenue neutrality assumption underlying the tariffs modelled by KPMG means that customers who do not modify their demand will not see a change in their bill.

8.2.1. New South Wales

General overview

New South Wales has a total population of 6.5 million with a majority (4.1 million) living on the Sydney coastal strip. The remainder of the population live in regional areas or in the major cities of Newcastle, with a population of approximately 493,000, and Wollongong, with about 263,000.[99] The 2006 census estimated that there were approximately 2.7 million households in New South Wales.

Total residential electricity consumption in New South Wales and the Australian Capital Territory was 22,123 GWh in the 2006 financial year.[100] Forecasts by the Energy Supply Association of Australia (ESAA) indicate that electricity consumption growth in New South Wales and the Australian Capital Territory will be modest at 1

[99] ABS, 2006 Census QuickStats

[100] ESAA, Electricity Gas 2007, Table 3.2

to 2 per cent per annum, with maximum demand growth likely to be a percentage higher.[101] Residential electricity consumption represents approximately 39 per cent of total state consumption, whilst the commercial and services industry represents approximately 29 per cent of total consumption.[102]

Climatic conditions in the state are quite varied. Coastal areas can be more temperate than conditions prevailing inland, which is characterised by long, dry summers. In Sydney, average summer temperatures range from 24.1 to 25.3 degrees Celcius with maximums reaching 39 degrees. In the western parts of Sydney however, summer temperatures can be a couple of degrees higher than coastal areas. In winter temperatures range from 15.2 to 16.2 degrees Celcius.[103] Although New South Wales' peak electricity demand in 2006/07 occurred during the winter period, it is generally expected that maximum demand will more frequently arise in the summer in the future with increasing numbers of air conditioners being installed.[104]

This divergence in temperatures and consumer's associated responses to these conditions can be observed in the marked difference between EnergyAustralia and Integral Energy's net system load profile (NSLP). Integral, which services the newer suburbs to the west of the city that experience warmer temperatures, has a higher load factor than EnergyAustralia and Country Energy, which makes its wholesale electricity costs higher.[105]

Finally, a large proportion of residential customers have access to natural gas in urban and some regional areas of New South Wales. This provides an opportunity to many households to substitute electricity use with gas, particularly for hot water systems and heating purposes.

Demographic and income characteristics

The average household in New South Wales contains 2.6 people.[106] Almost 68 per cent of households are families; 23 per cent are single occupant households and 3.5 per cent are group households.[107] Of the approximate 1.7 million households in New South Wales that are families, 46 per cent are couples with children, 36 per cent are couples without children and 16.1 per cent are one parent families.[108]

---

[101] ibid; calculated using Table 2.8

[102] ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006

[103] Australian Bureau of Metrology, based on 2005 data

[104] As discussed in Appendix B.2 Box B.2, our base case demand modelling for NSW is based on the 2006/7 load profile and therefore reflects a winter peak. However we have also estimated the impact of NSW becoming summer peaking. The bill impacts reported in this section for NSW reflect the base case winter peak assumption only.

[105] Integral, Submission to IPART, 2007 Retail Pricing Review, p12

[106] ABS, 2006 Census QuickStats

[107] ibid

[108] Ibid; remaining 1.7 per cent were other family structures.

The median household weekly income was $1036 in 2006, yet in the Sydney statistical region it was $1,154.[109] Nearly 43 per cent of households were earning less than $52,000 per annum in the same year with about 20 per cent earning less than $26,000 of which about 42 per cent were family households. Approximately 18 per cent of households' gross annual earnings were over $104,000.[110]

In addition, the age structure of the population differs between the metropolitan Sydney area and the balance of the state comprised mainly of regional areas. The median age of persons in the Sydney area is 35 whilst elsewhere it is 40 years of age. Moreover the average household size is larger in Sydney, perhaps reflecting the slightly larger proportion of group homes (3.9 per cent). 44 per cent of people are aged between 25 and 54 in Sydney, compared to 38.5 per cent outside of Sydney. The proportion of persons aged over 65 is over 4 per cent higher outside of the Sydney area.[111]

Electricity consumption profile

Average residential electricity consumption in the New South Wales electricity region (which includes the ACT) was 7501 kWh in the 2006 financial year.[112] A survey conducted by IPART in 2003, found that electricity use increases, on average, with income. In addition, the survey found that households in the Blue Mountains had the highest average consumption of 8,574 kWh whereas households in the Illawarra had the lowest average consumption of 6,993 kWh.[113] Households in Sydney used on average, 7,981 kWh of electricity.[114]

Air-conditioner and swimming pool penetration

The estimated penetration of air conditioners in New South Wales as at the end of 2005 was 54.1 per cent.[115] A 2006 ABS report estimated that there were approximately 270,600 households with in-ground pools in New South Wales of which approximately 70 per cent were in the Sydney area. There was also an estimated 59,100 above ground pools in the state with approximately 59 per cent in the Sydney area.[116]

---

[109] ibid

[110] ABS, 2006 Census Tables, category number 2068

[111] ABS, 2006 Census QuickStats

[112] ESAA, Electricity Gas Australia 2007, calculated using Tables 3.2 and 3.3

[113] IPART, Residential energy use in Sydney, the Blue Mountains and Illawarra: Results from the 2006 household survey, electricity and gas interim report, June 2007, pp13 and 25.

[114] Ibid.

[115] Energy Efficient Strategies, Status of Air Conditioners in Australia – A report prepared for NAEEEC, January 2006.

[116] ABS, Domestic Water and Energy Use, New South Wales, October 2006, Table 12

Impact of time of use and critical peak pricing

For New South Wales we have been able to estimate the likely bill impact for an average customer using the NSW jurisdictional NSLP, and the residential contribution that has been estimated as part of our demand response analysis (see Appendix B for a discussion) for each of the tariff products developed by KPMG.

The results indicate that, in general, households under each of the tariff products (assuming average consumption, profile and demand response) would face lower bills if they adopted one of the three new tariff products – Table 8.1 below.

Table 8.1: NSW estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	7,501	-	$1,075	-
TOU	7,480	-0.3%	$1,063	-1.2%
CPP + TOU	7,489	-0.2%	$1,054	-2.0%
DLC + TOU	7,449	-0.7%	$984	-8.5%

For example, a residential household with average consumption and load profile facing the CPP and TOU product, would have reduced their bill by approximately 2 per cent under the critical peak tariff arrangements with an average demand response. By participating in a direct load control program the household would be even better off, with savings of approximately 8.5 per cent, of which over 80 per cent result from the $75 annual payment for participating in the direct load control program.

The annual savings associated with a household with average consumption and load profile facing time-of-use prices would be approximately $12, or 1.2 per cent compared with the previous bill.

As discussed above, the bill impacts reported in this section reflect our base case demand assumption for NSW, which is winter peaking. Adopting the summer peaking sensitivity would *increase* the savings made by consumers, since the demand response estimated for TOU and CPP events which occur in summer is higher than for winter.

While these results present the bill impacts for a household with average consumption, and a load profile that matches the jurisdictional load profile, this does not mean that on average households will be better off under the critical peak pricing arrangements, the time of use product and direct load control programme. This is because the actual impact on any individual household will depend upon the particular load profile characteristics of the household. Some households will therefore be better off, some worse off and some may not experience any change in their bills. We have been unable for the purposes of this analysis to determine the proportion of households that are likely to be better off under each tariff product.

The resultant impact on peak demand for the household with average consumption is approximately 3.9 per cent for time of use, 4.1 per cent for the critical peak pricing and 4.5 per cent for the direct load control tariff (see Table.8.2 below). In line with the tariffs considered, the overall demand conservation is relatively low under each approach at less than 1 per cent, with the DLC option offering the greatest overall reduction in electricity use.

Table.8.2: NSW estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	1,696	-	5,805	-	7,501	-
TOU	1,630	-3.9%	5,850	0.8%	7,480	-0.3%
CPP + TOU	1,625	-4.1%	5,864	1.0%	7,489	-0.2%
DLC + TOU	1,620	-4.5%	5,829	0.4%	7,449	-0.7%

To consider the likely differences between rural and urban areas we have undertaken a similar calculation to that presented above but using the Country Energy NSLP to proxy the regional residential user as its network largely covers the inland, regional areas of the state. The assumed contribution of residential load to the NSLP was assumed to be the same as for the total of the state. Accordingly, the difference in results observed is a result of the differences between the load profiles for rural NSW compared to the state load profile.

For an average residential user in the Country Energy network area the annual electricity bill is estimated to decrease under the critical peak tariff by about 2.3 per cent without any demand response and up to 4.2 per cent where there is a resultant demand response. Similarly for time-of-use tariffs, bills are estimated to be lower than those estimated using the state base NSLP.

The results highlight the lower amount of electricity consumed by households in Country Energy's network during peak periods compared to households in other parts of the state (see Table 8.3). To demonstrate these differences more clearly the different NSLPs for the different distributors have been applied to NSW average consumption.

Table 8.3: Country Energy estimated bill with demand response

Scenario	Consumption (NSW average, kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	7,501	-	$1,075	-
TOU	7,483	-0.2%	$1,056	-1.8%
CPP + TOU	7,496	-0.1%	$1,031	-4.2%
DLC + TOU	7,375	-1.7%	$966	-10.2%

Table 8.3 presents the impact on bills after the household has responded to the price changes. Whilst higher bill reductions occur for a household participating in a DLC programme this change is primarily due to the $75 participation payment (about 60 per cent of the bill reduction).

Table.8.4: Country Energy estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	1,655	-	5,846	-	7,501	-
TOU	1,588	-4.0%	5,895	0.8%	7,483	-0.2%
CPP + TOU	1,585	-4.2%	5,911	1.1%	7,496	-0.1%
DLC + TOU	1,553	-6.2%	5,822	-0.4%	7,375	-1.7%

As indicated above, there is a marked difference between Integral's peak demand compared to EnergyAustralia and Country Energy. Using the Integral Energy load profile we observe that both peak consumption and critical peak event consumption is higher at 23 per cent and 7.3 per cent, respectively compared with the state average. Customers with more peak consumption are expected to face higher bills, and similarly gain lower bill reductions under TOU pricing compared to other, average customers. The tables below illustrate these differences in the bill impacts.

Table 8.5: Integral Energy estimated bill with demand response

Scenario	Consumption (NSW average, kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	7,501	-	$1,075	-
TOU	7,478	-0.3%	$1,069	-0.6%
CPP + TOU	7,486	-0.2%	$1,067	-0.8%
DLC + TOU	7,352	-2.0%	$976	-9.2%

Table.8.6: Integral Energy estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	1,735	-	5,766	-	7,501	-
TOU	1,667	-3.9%	5,811	0.8%	7,478	-0.3%
CPP + TOU	1,662	-4.2%	5,824	1.0%	7,486	-0.2%
DLC + TOU	1,626	-6.3%	5,726	-0.7%	7,352	-2.0%

The above results indicate that changing the profile alone results in lower bill savings within Integral Energy's area compared with the state average or applying the Country Energy profile. Also when we assume no demand response, an Integral Energy customer is expected to face a small increase in their bills of 1.4 per cent under CPP and approximately 0.6 per cent with TOU.

This highlights the difference that household characteristics will have on the bill impacts of changing to time of use tariffs. It is problematic however to make conclusions for the impact generally on New South Wales consumers based on their income and where they live, but it highlights what kind of consumption load profiles will lead to increases or decreases in electricity bills.

8.2.2. Australian Capital Territory

General overview

The Australian Capital Territory (ACT) has a total population of approximately 324,000, represented by 131,000 households.[117] The majority, or about 323,000, of the population lives in the Canberra statistical division. The ActewAGL NSLP represents less than 10 per cent of the New South Wales region.

Climatic conditions differ in the Australian Capital Territory compared with the remainder of New South Wales. Average winter temperatures in Canberra range from 9 to 10.5 degrees Celsius, with average minimum temperatures of -4.7 degrees.[118] In summer, Canberra's average temperature ranges from 22.2 to 24.5 degrees Celsius. The ACT generally experiences a very distinct winter season and electricity and gas demand for space heating outstrips summer peak demand for air conditioning. This is similar to the load profile observed for Tasmania.

As such, residential customers experience significant differences in their electricity bills between winter and summer, reflecting the increased consumption during the winter periods to reflect additional heating requirements and the lower use of air conditioning relative to other states.

As part of a study into the effectiveness of energy efficiency programs in Canberra,[119] data was collected on electricity consumption and bill information of participants, prior to and after the introduction of energy efficiency measures in the home. The study results indicate that although total electricity consumption decreased as a result of the efficiency improvements in many households, the pattern of use between winter and summer remained the same, with significant increases in consumption during the winter period. The study also found that the main contributing factor to high electricity bills were the use of electric hot water systems, inefficient electricity heater use, and a lack of window coverings for homes. These results suggest that, at least in the ACT, there may be limited scope for energy efficiency improvements, particularly during the winter months.

Natural gas is also accessible to customers in the ACT from the Eastern Gas Pipeline (EGP), which transports gas from Longford in Victoria. This gives the opportunity for some customers to substitute gas for electricity use in space and water heating and cooking.

Demographic and income characteristics

The average household size in the Australian Capital Territory is 2.6, with the majority of households being families (67.9 per cent). The remaining households are either inhabited by single occupants, 22.1 per cent, or are group households, 5.1 per

---

117 ABS, Census 2006 QuickStats

118 Australian Bureau of Metrology, data based on 2005 statistics

119 Essential Services Consumer Council, Water and Energy Savings Trial – WEST Two 2004 Final Report, October 2006

cent.[120] Of the 84,508 families in the ACT, 47 per cent were couples with children and 36.2 per cent were couples without children. A remaining 15 per cent of households are lone parent families.[121]

Median household income in the ACT is the highest in the country with weekly earnings of $1509.[122] However, there are nearly 11 per cent of households that have gross earnings less than $26,000 per annum, or less than $500 per week. Of these households, nearly 36 per cent are families. Compared to New South Wales where 18 per cent of households earned over $104,000 per year or $2,000 per week, the ACT has nearly 31 per cent of households in this category. This is the highest proportion of high income households of any state or territory in the country.[123]

The age structure of the Australian Capital Territory is quite similar to that living in the greater Sydney area with the median age of 34 years. However, the smaller population living outside Canberra do not show as marked a difference compared to that observed in New South Wales with the median age being the same.[124]

Electricity consumption profile

Average electricity use was 8,194 kWh in 2006-07. This average consumption is significantly higher than the New South Wales average, reflecting the prevailing dominance of electricity as a primary source of energy for winter heating. By examining the distribution of consumption, we observe that nearly 40,000 households consume more than 10,000 kWh per annum, while 19,000 customers consume less than 3,000 kWh.[125]

Impact of time of use and critical peak pricing

While the ACT is within the NSW National Electricity Market Region, we have considered the likely bill impacts on customers in the ACT, separately from New South Wales. This reflects some of the differences in the load profile and characteristics of residential customers as outlined above.

The likely impact of both time of use tariffs and a critical peak pricing tariff in the Australian Capital Territory is different from New South Wales, reflecting the relatively flat load shape relative to the remainder of the New South Wales region. This means that residential households would achieve bill savings from time of use pricing, based on the tariffs developed by KPMG, without needing to shift demand significantly between peak and off-peak periods. These savings are estimated to be in the order of 3.8 per cent for the critical peak pricing product.

---

120 ABS, 2006 Census QuickStats

121 Ibid; 1.6 per cent was other family structures.

122 Ibid

123 ABS, 2006 Census Tables, category number 2068

124 Ibid

125 ActewAGL, RFI response

Table 8.7 presents the estimated bill for an average consumption household, achieving and average demand response.

Table 8.7: ACT estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	8,194	-	$1,160	-
TOU	8,172	-0.3%	$1,143	-1.4%
CPP + TOU	8,181	-0.2%	$1,135	-2.2%

The associated demand response by households responding to these tariff products is presented in Table 8.8 below, which shows the change in peak and off-peak demand. Despite the average residential consumption being higher in the ACT, peak use is proportionally lower, as can be seen below. This means that for the customer with average consumption, the bill savings are proportionally higher compared with the average consumption customer in NSW.

Table 8.8: ACT estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	1,830	-	6,364	-	8,194	-
TOU	1,762	-3.8%	6,411	0.7%	8,172	-0.3%
CPP + TOU	1,756	-4.0%	6,424	1.0%	8,181	-0.2%

Whilst we have considered the likely bill impacts arising from the introduction of time of use and critical peak pricing in the ACT, it should be acknowledged that many of the justifications for the introduction of these forms of tariffs are not present in the ACT. For example, there are unlikely to be significant or potentially any benefits arising from demand shifting in the ACT because there is currently sufficient excess capacity in the network that there would not be network savings from avoiding network investment. The resultant cost savings that would finance the bill reductions for those customers that would benefit from time of use pricing or critical peak pricing are therefore less likely to be present in the ACT. For these reasons, it is unlikely that there would be a case for introducing time of use or critical peak pricing in the form considered here.

In addition, care should be taken when considering the potential introduction of critical peak pricing in circumstances where the network peaks occur in winter. There are likely to be significant social concerns arising from, particularly vulnerable customers, not being able to afford to heat their premises if they rely on electricity as their primary heating energy source during critical peak pricing events. If winter peaks were a concern justifying the introduction of critical peak pricing would require that vulnerable customers are not disadvantaged.

8.2.3. Queensland

General overview

Queensland has a total population of 3.9 million residents, of which 1.76 million live in the Brisbane statistical division.[126] There are approximately 1.6 million residential electricity connections.[127] Total electricity consumed in the residential sector was 12,456 GWh in the 2006 financial year, which represents approximately 27 percent of total electricity consumed in the state.[128, 129]

Due to strong economic growth Queensland has experienced growth in electricity demand over the last financial year of 4.5 per cent.[130] The ESAA reported forecast total demand to increase to the 2016 financial year by an average 3.5 per cent and peak demand to increase by an average 4.3 per cent.[131] Queensland has also recently extended full retail competition to residential customers as of July this year.

Climatic conditions in Queensland vary between each region quite significantly. The north is characterised by tropical conditions of heat and humidity most of the year and has a wet season between December and March. In the south east more temperate conditions prevail with average summer temperatures slightly higher than those experienced in Sydney at 26.7 to 27.8 degrees Celsius. However, winters in the south east are much warmer than those as far south as Sydney. Average winter temperatures in Brisbane are from 18.4 to 18.7 degrees Celsius.[132] Therefore Queensland does not experience the peaks in demand for electricity during the winter months as those experienced in the southern states like New South Wales, Victoria and Tasmania.

Residential customers have access to natural gas in the Brisbane area from the Roma to Brisbane Pipeline. Gas is accessible to commercial customers in Gladstone, Mount Isa and along the pipelines running from Ballera and in the Bowen and Surat basins. The gas distribution network outside of the Brisbane area is not significant such that regional residential customers would have access to gas for substitution.

Demographic and income characteristics

The average household in Queensland contains 2.6 persons, which is the same as New South Wales. Households are primarily occupied by families at 67.1 per cent, with over half having children. Specifically, 43.3 per cent are couples with children, 39.1 per cent are couples without children, and 15.9 per cent are single parent families. In

126 ABS, 2006 Census QuickStats

127 ESAA, Electricity Gas Australia 2007, Table 3.2

128 Ibid, Table 3.3

129 ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006.

130 ESAA, Electricity Gas Australia 2007, Table 3.3

131 ESAA, Electricity Gas Australia 2007, calculated using Table 2.8.

132 Australian Bureau of Metrology, data based on 2005 statistics

addition, there are 21 per cent single occupant households, and 4.2 per cent group households.[133]

The median household weekly income in Queensland is $1033, which slightly exceeds the national median of $1,027. In Brisbane, median household weekly income is $1,111.[134] Higher income earners are less prevalent in Queensland than in New South Wales and the ACT, with approximately 15 per cent earning more than $2,000 per week, however lower income households that earn less than $500 per week are broadly similar in proportion in Queensland to New South Wales at 18 per cent (compared to 20 per cent in NSW).[135] Queensland therefore has a slightly higher proportion of households earning between $500 and $2,000 per week than in New South Wales.

The age structure of households in Queensland mimics that of New South Wales whereby the large urban area of the capital tends to be younger, on average, than the balance of the state. Median ages outside of Brisbane are 37 years compared with 35 years within Brisbane.[136]

Electricity consumption profile

In the 2006 financial year average household consumption was estimated by the ESAA at approximately 7767 kWh per household.[137]

Air-conditioner and swimming pool penetration

Despite the warm climate, air conditioning penetration in Queensland is only higher than in New South Wales and Tasmania, which experience winter, rather than summer peaks in electricity demand. In 2005 the penetration of air conditioners in Queensland was estimated at 58.2 per cent of households.[138] Whilst air conditioner usage in the north is predictably quite flat, similar to the Northern Territory, peak electricity growth is quite high in the south. Energex is currently investing in DLC programmes in its Brisbane network area to relieve some of the network stress experienced on summer peak days.[139]

Impact of time of use and critical peak pricing

A household with average consumption and load profile in Queensland is estimated to have a lower bill under the time of use and direct load control program tariffs, after an

---

[133] ABS, 2006 Census QuickStats

[134] ibid.

[135] ABS, 2006 Census Tables, category number 2068

[136] ibid.

[137] ESAA, Electricity Gas Australia 2007, calculated using Tables 3.2 and 3.3

[138] Energy Efficient Strategies, Status of Air Conditioners in Australia – A report prepared for NAEEEC, January 2006.

[139] Energex RFI response

estimation of an appropriate level of a demand response. Table 8.9 presents the results.

Table 8.9: Qld estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	7,767	-	$1,152	-
TOU	7,742	-0.3%	$1,132	-1.7%
CPP + TOU	7,752	-0.2%	$1,103	-4.3%
DLC + TOU	7,742	-0.3%	$1,055	-8.4%

The greatest change in a customer's bill results under the DLC option, however of the $97 savings $75 are from the participation payment.

The changes underlying the results following the demand response are primarily driven by the shift between peak and off-peak electricity, rather than a reduction in overall electricity use. Electricity use is estimated to decline by less than half a per cent resulting from the change in tariffs. Table 8.10 presents these results.

Table 8.10: Qld estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	3,256	-	4,511	-	7,767	-
TOU	3,139	-3.6%	4,603	2.0%	7,742	-0.3%
CPP + TOU	3,124	-4.0%	4,628	2.6%	7,752	-0.2%
DLC + TOU	3,125	-4.0%	4,617	2.3%	7,742	-0.3%

As with the other jurisdictions, the highest peak demand reductions occur for households on critical peak pricing (yet nearly matching the direct load control). This reflects the additional demand response arising from critical peak events, over and above the time of use effects. For Queensland the direct load control is only estimated to reduce peak demand by an additional 0.4 per cent over and above time of use. Although this seems quite small it represents approximately 31 kWh annually with our assumed air conditioner size of 1.9 kW and a cycling strategy of 50 per cent this translates into the household having its air conditioner cycled for about 32 hours out of a possible 72 hours per year.[140] A household with a larger air conditioner and more periods of cycling would likely make greater energy savings.

To consider the likely differences in energy bills between rural and urban regions, we have undertaken a similar analysis to that presented above, using the state average consumption to show the differences underlying the individual NSLPs for the Energex and Ergon Energy network areas, which broadly represent the regional and urban areas of Queensland.

[140] 7767 x 0.004 = 31.068/(1.9/2 due to 50% cycling) = 32.7 hrs

Peak demand is about 8 per cent higher using the Ergon Energy profile than the Energex profile, which drives the bill impacts for an average consumption household in each area. With no assumed demand response the Ergon TOU bill impact is an increase of about 2 per cent, compared to an estimated decrease of 1.3 per cent using the Energex profile. Similar results occur for time of use and DLC products.

8.2.4. Victoria

General overview

The 2006 census estimated the total population in Victoria at approximately 4.93 million with over 70 per cent of those living in the Melbourne statistical division (around 3.59 million people).[141] The ESAA reported residential connections as at the end of June 2006 of about 2.1 million. Total residential electricity consumption was 12,638 GWh or 26 per cent of total state electricity consumption.[142, 143]

Victoria's climate is characterised by distinct winter conditions, similar to Canberra, and therefore experiences peaks in electricity demand during this season for space heating. Melbourne experiences milder winters than in Canberra with average temperatures ranging from 12.8 to 13.5 degrees Celsius and minimums of 2.5 degrees. However, summer maximums are 42.9 degrees and averages ranged from 20.7 to 23.1, which lead to summer peaks.[144]

Many residents of Victoria have access to natural gas to supplement electricity for household energy needs. Victoria has the highest residential consumption of gas.[145] Pipelines from production in the Gippsland basin in the south east provide gas to areas along the north coast and into New South Wales. In addition, gas is transported from Gippsland west into Melbourne, and gas from the Otway basin is transported to coastal areas further west and into South Australia. Piped gas is also available as far north as Albury, up to Bendigo and as far central west as Horsham.

Demographic and income characteristics

Similar to New South Wales the average household size in Victoria is 2.6 persons with 68.1 per cent of households being families. Single person households represent 23.3 per cent of all households, and 3.8 per cent are group households.[146]

The median household income in 2006 was $1022 weekly, but in the Melbourne area it was slightly higher at $1,079 and much lower in the balance of the state at $820 per week.[147] Families in Victoria represent about 42 per cent of the nearly 20 per cent of

---

141 ABS, 2006 Census QuickStats

142 ESAA, Electricity Gas 2007, Table 3.2

143 ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006

144 Australian Bureau of Metrology, data based on 2005 statistics

145 ABARE, Australian Energy Consumption and Production 1974-75 to 2004-05, Table F

146 ABS, 2006 Census QuickStats

147 ibid.

households with gross weekly income less than $500, which is a similar proportion to that observed in Queensland and New South Wales. There are approximately 16 per cent of households with gross weekly earnings greater than $2,000 and 30 per cent between $1,000 and $2,000.[148]

There is a larger difference in median ages between the balance of the state compared to Melbourne, when compared to Queensland and New South Wales. The median age in Melbourne was 36 whilst that in the remainder of the state was 39. 28.2 per cent of the population is over 55 years of age in rural/regional areas, compared to 23.1 per cent in the Melbourne area.[149]

Electricity consumption profile

Average residential electricity consumption was 5990 kWh last financial year.[150] This is the lowest average consumption in the country and reflects the lower electricity requirements of households based on the high penetration of gas as indicated above. However, although gas penetration is the highest in Victoria there are still many regional areas without access to gas. In these areas off-peak electricity tariffs are available for hot water heating and a move to time of use may impact their bill significantly depending on a number of factors.[151]

Air-conditioner and swimming pool penetration

In 2005 approximately 60.5 per cent of households had air conditioners.[152] This is similar to the penetration rate in Queensland.

Impact of time of use and critical peak pricing

In Victoria, the impact of the introduction of time of use tariffs, critical peak pricing and direct load control following a demand response for a household with average consumption and load profile is presented in Table 8.11.

Table 8.11: Vic estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	5,991	-	$943	-
TOU	5,969	-0.4%	$929	-1.5%
CPP + TOU	5,973	-0.3%	$909	-3.7%
DLC + TOU	5,931	-1.0%	$845	-10.4%

---

148 ABS, 2006 Census Tables, category number 2068

149 ABS, 2006 Census QuickStats

150 ESAA, Electricity Gas Australia 2007, calculated using Tables 3.2 and 3.3

151 See Box.8.4 for an examination of this issue

152 Energy Efficient Strategies, Status of Air Conditioners in Australia – A report prepared for NAEEEC, January 2006.

Changing to the time of use tariff product would result in a bill decrease of approximately $14 each year, or around 3.7 per cent compared with current bills. For a household with average electricity consumption and on critical peak pricing, the bill would decrease by around 1.5 per cent.

Finally, for a household with average consumption and participating in a direct load control program, the bill is estimated to decrease by $98 (10.4 per cent of the average bill), reflecting the $75 annual participation fee and the bill savings associated with reduced consumption and substituting peak demand for off-peak electricity use.

Similar to New South Wales, the demand reductions in total peak demand is highest for direct load control (5.2 per cent), than critical peak pricing (4.1 per cent) and time of use tariffs alone (3.5 per cent). Table 8.12 presents these results.

Table 8.12: Vic estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	2,050	-	3,941	-	5,991	-
TOU	1,978	-3.5%	3,991	1.3%	5,969	-0.4%
CPP + TOU	1,967	-4.1%	4,006	1.7%	5,973	-0.3%
DLC + TOU	1,943	-5.2%	3,988	1.2%	5,931	-1.0%

8.2.5. Tasmania

General overview

Tasmania is a much smaller state when compared to others in the National Electricity Market (NEM) having about 476,000 residents and just under half of these live in the greater Hobart area. At the end of the 2006 financial year there were 216,983 residential electricity connections. Total residential consumption was 2014 GWh or 22 per cent of total Tasmanian consumption.[153, 154]

Demand for space heating in Tasmania drives winter electricity use peaks. This is a similar pattern to that observed in the ACT. Hobart experiences average winter temperatures of 9.9 to 11.8 degrees Celsius.[155] Tasmania does not however, generally experience the extreme summer conditions that occur in the ACT.

Tasmania experienced a modest growth in connections over the last year, which was similar to that observed in New South Wales and total consumption has been in decline.[156] Tasmania's introduction into the NEM has resulted in it being a net exporter of electricity into the adjacent Victorian NEM region. The ESAA forecast that modest consumption increases will occur in Tasmania in the future.

153 ESAA, Electricity Gas Australia 2007, Table 3.3

154 ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006

155 Australian Bureau of Metrology, data based on 2005 statistics

156 ESAA, Electricity Gas Australia 2007, Tables 3.2 and 3.3

Since the commission of the Tasmanian Gas Pipeline in 2002 and the concurrent construction of the distribution system, an estimated 38,500 customers are expected to have access to the gas system in Tasmania.[157] Competition is not restricted in the retail gas market and full retail contestability is expected to be extended to residential electricity customers by 2010.[158]

Demographic and income characteristics

Households in Tasmania, shared with those in South Australia, have the lowest household size of 2.4 occupants. However, similar to other states approximately 67.3 per cent were family households. Single person households were 25.9 per cent of the total and 3.1 per cent were group households.[159]

Median weekly income in Tasmania is the lowest of all the jurisdictions at $801 per week, which is approximately 20 per cent lower than the national median. In the greater Hobart area gross household income is $904 per week.[160] There are a higher proportion of households earning less than $500 per week in Tasmania than the previously mentioned states with 24.4 per cent. In addition, a much lower proportion of households earn greater than $2,000 per week - 9.2 per cent compared to about 18 per cent in New South Wales. Households earning between $500 and $1,000 and $1,000 and $2,000 each represented approximately 28 per cent of total households.[161]

The age structure in Tasmania does not differ significantly between greater Hobart and the state as a whole. However, the proportion of residents over 55 years of age in the Hobart area is slightly lower than the state which is about 3 per cent higher than the national average.[162]

Electricity consumption profile

Average residential electricity consumption in the 2006 financial year was 9,283 kWh.[163] This was the highest average residential consumption in the NEM despite Tasmania having the lowest median income. Examining this figure in conjunction with the characteristics described above, it is clear that it is the result of the widespread use of electric heating required during winter and the majority of the population not having access to natural gas for heating purposes. As the reticulated natural gas network is developed it would be expected that average electricity use would fall in Tasmania.

Information provided by Aurora based on the postcode areas by income show that average consumption in the lower and higher income areas was higher outside of the

---

157 Stated connections after distribution expansion program in April 2007, Aurora, 2006 Annual Report

158 Office of the Tasmanian Energy Regulator website, http://www.energyregulator.tas.gov.au

159 ABS, 2006 Census QuickStats

160 ibid.

161 ABS, 2006 Census Tables, category number 2068

162 ABS, 2006 Census QuickStats

163 ESAA, Electricity Gas Australia 2007, calculated using Tables 3.2 and 3.3

major urban centres. The medium income areas had similar levels of average consumption.

Air-conditioner and swimming pool penetration

Air conditioner penetration is relatively low in Tasmania at 19.8 per cent, reflecting the colder climatic conditions.[164] This is the lowest penetration rate for air conditioners of any other jurisdiction in Australia. Separately wired heat pumps are commonly used for space heating in the cold winter season. Aurora Energy currently provides a lower tariff, similar to off peak hot water services, for these appliances.

Impact of time of use and critical peak pricing

For Tasmania we have considered the impact of time of use tariffs and a critical peak pricing tariff on a household with the state wide average residential consumption of 9,283 kWh and the state load profile. The time of use tariffs result in a small bill decrease of 0.5 per cent or $9 for the year. There is a greater saving associated with the CPP tariff of $17 per annum or an estimated 1.1 per cent. Table 8.13 presents the results following a change in demand.

Table 8.13: Tas estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	9,283	-	$1,508	-
TOU	9,261	-0.2%	$1,499	-0.5%
CPP + TOU	9,269	-0.2%	$1,491	-1.1%

In Tasmania, given that the maximum network demand usually arises during winter months, we anticipate that the likely demand response from a critical peak pricing event is likely to be lower than for other jurisdictions. This is because the scope to reduce electricity demand in winter is likely to be significantly lower than in summer, where air conditioners are used. The results are presented in Table 8.14 below.

Table 8.14: Tas estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	3,444	-	5,839	-	9,283	-
TOU	3,391	-1.6%	5,870	0.5%	9,261	-0.2%
CPP + TOU	3,386	-1.7%	5,883	0.7%	9,269	-0.2%

The additional response on CPP is slightly lower than that in NSW which reflects the one summer event day in New South Wales (that has a higher elasticity estimate) compared to all winter peaks in Tasmania (which would be lower).

---

[164] Energy Efficient Strategies, Status of Air Conditioners in Australia – A report prepared for NAEEEC, January 2006.

8.2.6. South Australia

General overview

There were approximately 1.5 million residents of South Australia in the last census, of which 1.1 million lived in the greater Adelaide area.[165] At the end of the 2006 financial year there were 679,069 residential connections and consumption was approximately 4,200 GWh or 39 per cent of total electricity consumed in the state.[166,167]

South Australia experiences distinct, long, dry and very hot summer conditions, which results in significant peaks in demand for electricity during the summer months. Although Adelaide experiences summer average temperatures that are lower than Brisbane the maximum temperature is nearly 7 degrees higher. Consecutive days of maximum temperatures are longer than in any other state, and at times extend for up to four days.

Before 2004, when the SEAgas Pipeline was commissioned, the only gas available to consumers in Adelaide was from the Cooper basin in the north of the state via the Moomba to Adelaide Pipeline System (MAPS). The SEAgas Pipeline, which sources gas from the Otway basin, now also provides gas into the State. Outside of Adelaide, distributed gas is available in the Barossa Valley, Berri, Peterborough, Port Pirie, Mount Gambier, Murray Bridge and Wyalla.

Demographic and income characteristics

Jointly with Tasmania, South Australia has the lowest average household size of 2.4 occupants. Median household weekly income is also at the lower end across the jurisdictions at $887 which is approximately 15 per cent lower than the national median. Outside of the Adelaide area, the weekly gross household income is $783.[168] The income distribution in South Australia is similar to that observed in Tasmania with about 12 per cent of households earning more than $2,000 per week and 23 per cent earning less than $500.[169]

Similar however to other states is the composition of household structures, with about 67 per cent being families, 25 per cent were single person households and the remaining were group homes. In both Adelaide and the balance of the state the median age is higher than that for Australia as a whole at 38 and 40, respectively. Also the proportion of persons over 55 years of age is higher in all of the state, more significantly outside of Adelaide at 4 per cent higher than the rest of Australia.

---

165 ABS, 2006 Census QuickStats

166 ESAA, Electricity Gas 2007, Table 3.3

167 ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006

168 ABS, 2006 Census QuickStats

169 ABS, 2006 Census Tables, category number 2068

Electricity consumption profile

Annual average residential electricity consumption was 6,185 kWh in the 2006 financial year.[170] ETSA Utilities estimated that excluding controlled load (off peak hot water) average residential consumption is approximately 5,100 kWh per annum. Growth in electricity consumption is expected to be modest, approximately 1 to 2 per cent per annum. ETSA Utilities has also indicated that in South Australia residential load is quite flat until the evening peak which occurs around 6pm whereas other states can experience a residential peak in the morning, especially in the winter months in winter peaking states like New South Wales, Tasmania and the ACT.

In 2004, CRA conducted a study for ETSA Utilities, which estimated different customer classes' contribution to peak demand using 2001 data.[171] They found that residential customers' peak day load was highly sensitive to temperature at about 2.5 times between 2 and 6 pm when compared to a low demand day. This was found to be slightly different for low income households with the peak occurring between 4 and 6pm and increases of 5 times over a low demand day. CRA stated that it "may reflect the fact that these customers may more commonly operate their air conditioners manually (as opposed to having them thermostatically set), and wait longer to turn them on than do customers with higher levels of disposable income."[172]

Air-conditioner and swimming pool penetration

Given the climatic conditions prevailing in South Australia, air conditioning penetration is amongst the highest in the country with approximately 85 per cent of households owning an air conditioner in 2005.[173] Participants in focus groups conducted in Adelaide indicated that the air conditioner was considered a necessity in the summer months.

An ABS survey conducted in 2004 also revealed that air conditioning penetration was not distinctly different between households of different income levels, with the lowest income quintile, having an approximate penetration rate 12 per cent lower than the highest quintile. In 2004 the ABS estimated the penetration rate at 81.8 per cent of households.[174]

Impact of time of use and critical peak pricing

For South Australia, a household with average consumption and load profile is estimated to have a lower bill (of 1.3 per cent) under the assumed time of use tariff compared to a flat tariff following. The same average household would achieve

170 ESAA, Electricity Gas Australia 2007, calculated using Tables 3.2 and 3.3

171 CRA, Peak Demand on the ETSA Utilities System: Discussion Paper, February 2004, p9.

172 Ibid.

173 Energy Efficient Strategies, Status of Air Conditioners in Australia – A report prepared for NAEEEC, January 2006.

174 ABS, Domestic Use of Water and Energy: South Australia, October 2004, Table 3.17

greater savings where they respond to the price through lowering consumption, under the CPP and TOU product of 4.1 per cent or $48.

With direct load control, the household with average consumption has the most favourable bill outcome in part due to the $75 associated with participating in the program. The household is estimated to have bill savings of an additional $18 resulting from energy cost savings and time of use savings on top of the participation payment. Table 8.15 below shows the results for all products after a demand response.

Table 8.15: SA estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	6,185	-	$1,186	-
TOU	6,164	-0.3%	$1,170	-1.3%
CPP + TOU	6,177	-0.1%	$1,138	-4.1%
DLC + TOU	6,165	-0.3%	$1,093	-7.8%

The associated demand response for peak and off-peak periods under each of the tariff product offerings investigated is presented in Table 8.16 below.

Table 8.16: SA estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	3,248	-	2,937	-	6,185	-
TOU	3,163	-2.6%	3,001	2.2%	6,164	-0.3%
CPP + TOU	3,152	-3.0%	3,025	3.0%	6,177	-0.1%
DLC + TOU	3,150	-3.0%	3,015	2.6%	6,165	-0.3%

We have also considered the likely bill impact for low income households, based on the assumed residential contribution to the NSLP to a low income profile which was estimated using information in the 2004 CRA study. For low income households, the results show a distinct divergence from the average results presented above by increasing the proportion of electricity consumed during peak periods. This therefore has the effect of increasing the bill (before assuming any demand response) as a result of the higher charges applicable in peak periods, albeit by less than 1 per cent.

Table 8.17 shows the estimated bill impact results once a demand response is assumed. However we note that lower income households may have a lower ability to respond to tariff changes, to the extent they have already minimised their use of electricity and have less scope to achieve further reductions in response to tariff signals. As a consequence, low income households with such a profile may more likely face a 1 per cent increase rather than the reductions shown in the table.

Table 8.17: SA low income profile estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	6,185	-	$1,186	-
TOU	6,163	-0.4%	$1,178	-0.7%
CPP + TOU	6,175	-0.2%	$1,146	-3.4%
DLC + TOU	6,167	-0.3%	$1,081	-8.9%

Table 8.18: SA low income profile estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	3,294	-	2,891	-	6,185	-
TOU	3,210	-2.5%	2,952	2.1%	6,163	-0.4%
CPP + TOU	3,199	-2.9%	2,976	2.9%	6,175	-0.2%
DLC + TOU	3,073	-6.7%	3,094	7.0%	6,167	-0.3%

8.2.7. Western Australia

General overview

Western Australia has a similar sized population to South Australia but covers a considerably larger area with approximately 74 per cent of the state's population of 1.96 million living in the Perth area. In 2006, there were approximately 849,000 households.[175]

Total electricity consumption in Western Australia was 14,351 GWh in the 2006 financial year, which was an increase of 4.8 per cent over the previous year.[176] Approximately 20 per cent of electricity consumed is in the residential sector.[177] Like Queensland, Western Australia is expected to have high electricity demand growth to support the strong economic growth occurring in those jurisdictions.

Climatic conditions in Western Australia are similar to those observed in New South Wales on average, but with higher extremes. The northern part of the state is similar in climate to northern Queensland and Darwin. In Perth, average summer temperatures range from 21.1 to 26.1 degrees Celsius and winter temperatures are between 15 and 15.3 degrees.[178] As such, the Perth area experiences summer peaks in demand for electricity as air conditioner use increases. Households also have access to reticulated natural gas in metropolitan areas.

---

175 ABS, 2006 Census QuickStats

176 ESAA, Electricity Gas Australia 2007, Table 3.3

177 ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006

178 Australian Bureau of Metrology, data based on 2005 statistics

Demographic and income characteristics

The average household size is 2.5 in Western Australia. Families with children accounted for nearly 60 percent of all households and a further 14.8 per cent are single parent family households. The remaining households are comprised of 22.9 per cent single occupant homes and 3.3 per cent group homes.[179]

The median household income in Western Australia is $1066 per week. This is slightly higher than the national median of $1027. Outside of the Perth area the median income is slightly lower at $1,005 per week.[180] The proportion of households earning less than $500 per week is similar to that in Queensland at 17 per cent, however the proportion of the households earning more than $2,000 is higher at about 17 per cent as well, which is closer to that observed in New South Wales. Households earning between $1,000 and $2,000 per week were about 30 per cent, which is similar to that observed in South Australia.[181]

Electricity consumption profile

Average residential electricity consumption in Western Australia for the 2005 financial year was 5,758 kWh.[182]

Air-conditioner and swimming pool penetration

Given the high maximum degree days in summer the penetration of air conditioners is the third highest of the jurisdictions at 69.6 per cent, as estimated for 2005.[183] About 21 per cent of households with air conditioners owned two or more units.[184] The ABS estimated the frequency of use from a survey and reported that 32.9 per cent of households use their air conditioners for between 3 and 6 months whilst 48.2 use their air conditioner for 1 to 3 months of the year.[185] Also the number of households in the Perth area with a swimming pool was estimated at 97,700.[186]

Impact of time of use and critical peak pricing

For a household with an average consumption profile in Western Australia the annual electricity bill is estimated to fall under each of the new tariff product offerings. Under the critical peak tariff a 2.4 per cent saving is estimated, and a less than 1 per cent bill saving associated with the TOU product. This shows that if a household is able to make changes in their electricity consumption pattern they can save money on

---

179 ABS, 2006 Census QuickStats

180 ibid.

181 ABS, 2006 Census Tables, category number 2068

182 ESAA, Electricity Gas Australia 2006, calculated using Tables 4.1 and 4.2

183 Energy Efficient Strategies, Status of Air Conditioners in Australia – A report prepared for NAEEEC, January 2006.

184 ABS, Domestic Use of Water and Energy: Western Australia, October 2006, Table 4

185 Ibid

186 Ibid, Table 22

their bill, of up to $21 in this case. Where a household is able to reduce demand by higher than the average, then the potential bill saving would be greater. The change in the bill under each product is presented in Table 8.19 below.

Table 8.19: WA estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	5,758	-	$854	-
TOU	5,751	-0.1%	$847	-0.8%
CPP + TOU	5,745	-0.2%	$833	-2.4%
DLC + TOU	5,752	-0.1%	$770	-9.8%

After the estimated demand response it can be observed that the greater savings achieved under the CPP product is due to the greater reduction in peak electricity use, as shown in Table 8.20 below.

Table 8.20: WA estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	1,278	-	4,481	-	5,758	-
TOU	1,235	-3.4%	4,517	0.8%	5,751	-0.1%
CPP + TOU	1,223	-4.3%	4,522	0.9%	5,745	-0.2%
DLC + TOU	1,222	-4.4%	4,530	1.1%	5,752	-0.1%

8.2.8. Northern Territory

General overview

The Northern Territory has a population of about 193,000, which is more than half the size of Tasmania's however the Territory is nearly 20 times larger. However, about half the population live in the Darwin area alone. In Alice Springs there are about 21,000 residents, and finally an additional 8,000 people in the Katherine area.[187]

In the 2006 financial year there were 61,555 residential connections.[188] Residential consumption of electricity represents approximately 14 per cent of total consumption with a significant portion of 37 per cent being consumed by the commercial and services sector.[189]

As for Queensland, the climate varies depending on the part of the Territory with the northern parts like Darwin experiencing the tropic climates of warm to hot weather and humidity with a wet season between December and March. Average temperatures in Darwin do not vary significantly between winter and summer.

---

187 ABS, 2006 Census QuickStats

188 ESAA, Electricity Gas Australia 2007, Table 3.2

189 ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006

Residents in the Darwin area have access to reticulated natural gas and both gas and solar hot water systems are prevalent.

Demographic and income characteristics

Consistent with many of the other jurisdictions the Northern Territory's average household size is 2.5 occupants. There is a higher than average number of group households, which was 4.3 per cent and an even higher proportion in the Darwin area at 5.1 per cent. A consistent number of families and single person households exist in the Northern Territory at 59.9 per cent and 19 per cent, respectively.[190]

The median household income is $1,192 per week, which is the second highest in the country after the Australian Capital Territory. In the Darwin statistical division the weekly household income is higher at $1,282.[191] Income distribution is similar to that observed in Queensland with about 13 per cent earning less than $500 per week and about 20 per cent of households earning more than $2,000.[192]

Electricity consumption profile

Average residential consumption in the 2006 financial year was 8,597 kWh.[193] This was the second highest average consumption that year, after Tasmania. The high average consumption can be attributed to the high penetration of air conditioners given the hot and humid climatic conditions throughout the Northern Territory.

Air-conditioner and swimming pool penetration

The Northern Territory has the highest penetration rates of air conditioning with 91.9 per cent of households estimated to own an air conditioner in 2005.[194] However, due to the relatively stable warm weather the electricity network does not experience significant summer peaks, as in other jurisdictions such as South Australia, as air conditioner use occurs on a more frequent and stable basis.

Impact of time of use and critical peak pricing

In the Northern Territory, a household using average consumption and with the assumed contribution to the NSLP would be only marginally better off under time of use tariffs (0.1 per cent lower bill) compared with the existing flat tariff arrangements following a demand response. This reflects the load profile being fairly flat throughout the year and households are estimated to be unlikely to be able to shift load considerably between peak and off-peak periods due to the reliance on air conditioning, as described above. This is evidenced by the low estimated demand response associated with time of use tariffs and the relatively even amount of

---

190 ABS, 2006 Census QuickStats

191 ibid.

192 ABS, 2006 Census Tables, category number 2068

193 ESAA, Electricity Gas Australia 2007, calculated using Tables 3.2 and 3.3

194 Energy Efficient Strategies, Status of Air Conditioners in Australia – A report prepared for NAEEEC, January 2006.

electricity consumed between peak and off-peak periods. Table 8.21 illustrates these results with total consumption after the demand response and the bill following the introduction of the new tariffs.

Table 8.21: NT estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	8,597	-	$1,389	-
TOU	8,597	0.0%	$1,387	-0.1%
CPP + TOU	8,600	0.0%	$1,379	-0.7%
DLC + TOU	8,550	0.0%	$1,304	-6.1%

For a household with average consumption and load profile, the critical peak pricing product would lead to the household's bill decreasing by nearly 1 per cent following the estimated demand response. This product also does not lead to the highest peak electricity reductions compared with direct load control (peak load reductions of 1.7 per cent under direct load control). This reflects the high penetration of air conditioners in the Northern Territory. With direct load control, a household with average consumption is estimated to have a bill decrease of approximately $85.

The change in peak and off-peak demand is presented in Table 8.22 below.

Table 8.22: NT estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	4,680	-	3,917	-	8,597	-
TOU	4,647	-0.7%	3,950	0.8%	8,597	0.0%
CPP + TOU	4,637	-0.9%	3,963	1.2%	8,600	0.0%
DLC + TOU	4,600	-1.7%	3,950	0.8%	8,550	-0.6%

The Power and Water Corporation of the Northern Territory was able to provide us with a representative residential profile from the Darwin area. By utilising this profile we get different results from those observed above using the state profile and assumed residential contribution. The possible savings with the CPP product following a demand response are higher than those estimated state wide, at up to 2.4 per cent. However, the TOU product was estimated to result in an increase in the bill with and without a response of less than half a per cent. Table 8.23 below summarises the change in bill following a demand response, the change in peak demand is the similar as that identified above.

Table 8.23: NT estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	8,597	-	$1,389	-
TOU	8,596	0.0%	$1,393	0.3%
CPP + TOU	8,603	0.0%	$1,355	-2.4%

8.2.9. Summary of results

Table 8.24 below presents a summary of the changes in demand and total bills in relation to demand and the bill under a flat tariff.

Table 8.24: Summary of jurisdictional bill impacts

State and tariff	Change in electricity demand			Total bill change
	Peak	Off-peak	Total	
New South Wales				
TOU	-3.9	0.8	-0.3	-1.2
CPP + TOU	-4.1	1.0	-0.2	-2.0
DLC + TOU	-4.5	0.4	-0.7	-8.5
Australian Capital Territory				
TOU	-3.8	0.7	-0.2	-3.8
CPP + TOU	-4.1	0.9	-0.1	-5.3
Victoria				
TOU	-3.5	1.3	-0.4	-1.5
CPP + TOU	-4.1	1.7	-0.3	-3.7
DLC + TOU	-5.2	1.2	-1.0	-10.4
South Australia				
TOU	-2.6	2.2	-0.3	-1.3
CPP + TOU	-3.0	3.0	-0.1	-4.1
DLC + TOU	-3.0	2.6	-0.3	-7.8
Tasmania				
TOU	-1.6	0.5	-0.2	-0.5
CPP + TOU	-1.7	0.7	-0.2	-1.1
Queensland				
TOU	-3.6	2.0	-0.3	-1.7
CPP + TOU	-4.0	2.6	-0.2	-4.3
DLC + TOU	-4.0	2.3	-0.3	-8.4
Western Australia				
TOU	-3.4	0.8	-0.1	-0.8
CPP + TOU	-4.3	0.9	-0.2	-2.4
DLC + TOU	-4.4	1.1	-0.1	-9.8
Northern Territory				
TOU	-0.7	0.8	0.0	-0.1
CPP + TOU	-0.9	1.2	0.0	-0.7
DLC + TOU	-1.7	0.8	-0.6	-6.1

In general the results show that for a household using average consumption, and matching the state load profile, there would be bill reduction benefits associated with changing from an existing flat tariff product to a time-of-use or critical peak pricing product.

In addition, the greatest benefits are achieved from the combined DLC and TOU product. The reason for this is the payment of the $75 participation fee associated with DLC, in addition to the electricity savings that result. In essence, the DLC product shares some of the benefits from load reduction (the associated network deferral benefits) only with those customers participating in the DLC program. In contrast, under TOU or CPP the benefits resulting from demand reductions that result are shared across all customers, in the form of lower prices. A distinction therefore between DLC and TOU/CPP programs is the sharing of the benefits between customers.

Finally, these results are only indicative of the likely impact on an average household within each jurisdiction. This is because they are based on averages, within which there is a complete distribution of load profile and consumption characteristics. In addition, the elasticity estimates also represent averages. Actual demand response is therefore likely to be within a distribution around the assumed average. The actual bill impact will therefore vary according to the individual characteristics of the household. To examine how different characteristics impact on likely bills, the remaining section presents a series of case study assessments.

8.3. Case study assessment of consumer bill impacts

To obtain a better understanding of the implications of new tariff product offerings on households with different characteristics we have developed a number of case study households. For each of these households we have drawn upon data on average consumption for similar households, and developed load profile assumptions based on the number of large appliances likely to be used within these households. Ideally the load profiles assumptions would be based on actual household level data of consumption, time of use and household demographic characteristics, however because information at that level is not available, we have based these profiles on expectations of industry experts, consumer group representatives and average state load profiles. The results are therefore only indicative of the likely impact of the introduction of time of use and critical peak pricing on household bills with similar characteristics.

The case studies that have been examined are as follows:

- Small family, low income;
- Retired couple, low income;
- Large household, high income;
- Single unemployed occupant;
- Large family, median income; and
- Single unemployed mother.

For each of the case studies we have examined the household bill prior to the introduction of new product offerings, and under each of the product offerings being examined as part of the Phase 2 analysis. These include a time of use tariff, time of use in combination with a critical peak pricing tariff, and a time of use tariff in combination with participation in a direct load control programme.

An overview of the methodology applied to estimate the case study bill impacts is provided in Box 8.2 below.

Box 8.2: Case studies assessment approach

To determine the likely impact from the introduction of time of use and critical peak pricing on particular household types we have estimated the expected annual expenditure for each case study household identified. The methodology used is as follows:

1. Choose average annual consumption based on household characteristics obtained from a survey of household characteristics conducted by the Independent Pricing and Regulatory Tribunal (IPART) in 2006.[195]
2. Modify the profiles developed for the aggregate demand response analysis to represent the likely behaviour of the identified household's characteristics (ie, increased peak consumption if assumed to be home during the day).
3. Calculate the current average bill using the flat tariffs developed by KPMG and using a supply charge available from public sources and concessions where applicable.[1]
4. Apply the new product tariff assumptions for each case study assuming no change in demand.
5. Estimate the likely demand response by applying the methodology described in Appendix B and used in the analysis above based on the elasticity of substitution and own price elasticity assumptions developed during Phase 1.
6. Recalculate the annual average bill based on the new electricity consumption and the new tariff products.

This approach does not take into account possible differences in demand responses due to differences in household characteristics. Households in similar circumstances may therefore be able to response more or less than the average used in our analysis. These results are therefore indicative of the average response although the average response for different household types would be expected to be different.

Notes: [1] Supply charges used were: A1 Residential, Synergy; Gazetted Power Tariff, Power and Water Corporation; Tariff 31, Aurora; average TOU and standard, Country Energy, EnergyAustralia and Integral; residential tariffs GD and GR, Origin; Always @ home, ActewAGL; Tariff 11, Qld Gazette; TOU 128, AGL SA Standing Offer. Concessions used were retailer websites.

The remainder of this section presents the case study results in detail.

8.3.1. Case study 1: small family, low income (Sharon)

Description

Sharon is a single mother who lives with her two children in south eastern Queensland. They live in a small three bedroom home that Sharon rents. Both of her children are school aged with one old enough to mind the other when they usually arrive home

[195] IPART, Residential energy use in Sydney, the Blue Mountains and Illawarra: Results from the 2006 household survey, Electricity and Gas – Interim Report, June 2007.

from school mid afternoon. Sharon is therefore able to work a full time job without requiring childcare for the younger child. She earns $31,000 per annum.

Their house has access to mains gas, which is used for cooking and hot water heating. Given the warm climate Sharon owns an air conditioner as well as a washing machine and dryer. We've assumed the dryer is not often used. Their average annual consumption is 7980 kWh.

Estimated bill impact

Table 8.25 below presents the change in Sharon's bill associated with each of the tariff products that have been developed for Queensland.

Sharon's current bill is $1,188 and with 40 per cent of total electricity consumed during the peak periods of 7am to 9pm on working days.

Assuming that Sharon does not change her consumption profile at all, the shift to time of use tariffs would lead to a reduction in her annual bill of around 2.3 per cent, or $27 for the year. The combination of a critical peak pricing tariff with a daily time of use component is estimated to result in a slightly greater effect, reflecting the discount on off peak electricity.

Table 8.25: Sharon's estimated bill with no change in demand

Scenarios	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	7,980	-	$1,182	-
TOU	7,980	-	$1,155	-2.3%
CPP + TOU	7,980	-	$1,149	-2.8%

The impact of critical peak pricing on Sharon's bill results in a larger bill saving compared to the TOU tariff as more electricity is shifted from the critical periods into the relatively less expensive off peak periods. Sharon's peak demand reduces by over 4 per cent as a result of the change in tariffs. For TOU alone her peak reduction is 3.6 per cent.

Both of these options result in overall consumption decreasing by an estimated maximum of 0.3 per cent, or the equivalent of using a 2 kW air conditioner for about 11 hours less in the year (22 kWh). This illustrates that the savings achieved are through shifting consumption primarily. The focus group results indicate that low income customers currently undertake every effort to conserve electricity to save money. Therefore, whilst Sharon may be able to move her washing to the weekends to take advantage of off peak rates she may not be able to reduce her overall consumption.

Table 8.26: Sharon’s estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	7,980	-	$1,182	-
TOU	7,958	-0.3%	$1,135	-4.0%
CPP + TOU	7,969	-0.1%	$1,101	-6.9%
DLC + TOU	7,959	-0.3%	$1,058	-10.5%

Participation in DLC has no additional impact on consumption compared to the TOU tariffs alone – reflecting that Sharon possibly doesn’t use her air conditioner during many DLC events because she is mostly at work during the day. The larger reduction in her annual bill (10.5 per cent) reflects the annual payment of $75 received for participation in the programme.

Box 8.3: Consecutive CPP days

During the 2006/07 year there were a number of consecutive CPP days that would have fallen during the school holiday period. In this case, our assumption that on most working days there is no one in the house when CPP events are likely to be called, means that this is not necessarily true because Sharon’s children may be at home. This could increase the CPP estimated bills.

For example, doubling the summer critical and consecutive critical peak period demand results in an increase in the annual bill of around 10 per cent compared to the initial reduction of 2.8 per cent. If Sharon is unable to respond to the CPP event this will very likely increase her electricity bill. Moreover, even if this bill increase could be offset by corresponding shifts to cheaper off peak supply she may very well face a higher than average summer electricity bill.

The estimated change in peak and off-peak electricity demand under each of the tariff product offerings is presented in Table 8.27 below. It demonstrates that the highest decrease in total demand arises with a CPP and TOU tariff product, of approximately 0.5 per cent above the TOU change.

Table 8.27: Sharon’s estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	3,169	-	4,811	-	7,980	-
TOU	3,054	-3.6%	4,904	1.9%	7,958	-0.3%
CPP + TOU	3,039	-4.1%	4,929	2.5%	7,969	-0.1%
DLC + TOU	3,042	-4.0%	4,916	2.2%	7,959	-0.3%

8.3.2. Case study 2: retired couple, low income (Mr & Mrs Harris)

Description

Mr and Mrs Harris are retirees living in South Australia. Their combined pension is $25,000 per annum and as pensioners they hold a concession card for their energy bills which entitles them to receive a $120 rebate that covers both electricity and natural gas.[196] They own their house, which is located in a metropolitan area. They do have access to gas, which they use for cooking and hot water.

Since Mr and Mrs Harris are retired they are usually home during business hours, especially if it is hot, in which case they will use their air conditioner. They also use a washing machine and infrequently a clothes dryer. Their average annual consumption is 5810 kWh, which is below the state average of 6,185 kWh.

Estimated bill impact

Table 8.28 below presents the bill impact of the Harris' consumption as a result of a change in prices.

Table 8.28: The Harris' estimated bill with no change in demand

Scenarios	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	5,810	-	$1,052	-
TOU	5,810	-	$1,052	0.0%
CPP + TOU	5,810	-	$1,068	1.5%

The table above indicates that shifting to the TOU tariff option would have no impact on the Harris' electricity bill, given their breakdown of electricity into peak and off-peak periods. However, they would face a slightly higher bill under the CPP and TOU combination which indicates that the higher prices paid for peak consumption is not completely offset by the lower price achieved in off peak given their electricity consumption profile over the day.

If the Harris' are able to change the time of their electricity use, they would be able to lower their overall bill as Table 8.29 below shows.

Table 8.29: The Harris' estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	5,810	-	$1,052	-
TOU	5,790	-0.4%	$1,052	-0.1%
CPP + TOU	5,801	-0.2%	$1,022	-2.9%
DLC + TOU	5,786	-0.4%	$1,015	-3.6%

Table 8.30 below shows the reduction in peak demand that the Harris' may achieve on average. As stated, the reduction for CPP is estimated to be greater than under TOU and therefore results in a greater bill reduction than under the TOU product. Therefore the Harris' would be better off under TOU alone without a change given their profile however with peak demand shifting they could achieve savings of $30 per annum.

---

[196] We have allocated half of the rebate to this bill as the household is assumed to also receive a gas bill that the concession would apply.

Table 8.30: The Harris' estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	3,075	-	2,735	-	5,810	-
TOU	2,995	-2.6%	2,794	2.2%	5,790	-0.4%
CPP + TOU	2,985	-2.9%	2,816	3.0%	5,801	-0.2%
DLC + TOU	2,989	-2.8%	2,797	2.3%	5,786	-0.4%

8.3.3. Case study 3: Large household, high income (the Jones)

Description

The Joneses live in a large house in metropolitan New South Wales. Mr Jones works full time and his wife works part time. Together they are earning $200,000 per annum. They have three young children, all of which are under 7 years of age and therefore employ a nanny to assist with childcare. This means that the house is usually occupied during the day.

Energy for cooking, hot water and winter heating is provided via access to mains gas. Large electricity using appliances include a washing machine, dryer, dishwasher, swimming pool filter pump, ducted air conditioning and a plasma television. Electricity consumption on average is 11,694 kWh per annum.

Bill impact

Table 8.31 below illustrates the impact of the Jones' choosing either a TOU tariff or combination TOU and CPP. Both tariff products result in an increase in their electricity bills if they are unable to change their demand.

Table 8.31: The Jones' estimated bill with no change in demand

Scenarios	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	11,694	-	$1,591	-
TOU	11,694	-	$1,640	3.1%
CPP + TOU	11,694	-	$1,654	4.0%

The slightly higher bill under the CPP option reflects the family's use of an air conditioner during CPP events which outweighs the discount available in off peak times.

However, allowing the Jones to change their pattern of electricity use the family is able to reduce the impact of the tariff and limit the impact to 1.7 per cent or $27 per annum. The family is able to reach a slightly better outcome with a demand response under the combined CPP and TOU tariff of a 1.6 per cent increase. This indicates that the family would need to reduce peak electricity use by significantly more than the average to lower their electricity bill and benefit from these tariffs. Participating in a DLC programme however would increase the peak response compared to the TOU and in combination with the incentive payment results in a 3.3 per cent lower bill.

Table 8.32: The Jones' estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	11,694	-	$1,591	-
TOU	11,655	-0.3%	$1,618	1.7%
CPP + TOU	11,670	-0.2%	$1,616	1.6%
DLC + TOU	11,619	-0.6%	$1,538	-3.3%

Table 8.33 below shows the change in peak demand under each of the tariff products considered. The reduction in peak electricity with TOU tariffs would presumably be a result of shifting some discretionary load. However despite the larger peak demand reduction under CPP this is not sufficient to lower the overall bill. The results with DLC show that air conditioning load is being reduced in addition to the TOU response and therefore represents the best possible savings opportunity for this family's situation.

Table 8.33: The Jones' estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	2,959	-	8,735	-	11,694	-
TOU	2,845	-3.9%	8,810	0.9%	11,655	-0.3%
CPP + TOU	2,836	-4.2%	8,833	1.1%	11,670	-0.2%
DLC + TOU	2,833	-4.3%	8,786	0.6%	11,619	-0.6%

8.3.4. Case study 4: single occupant household, low income (Tracy)

Description

Tracy rents a unit alone in the Australian Capital Territory. She is physically unable to work and therefore relies on disability support payments of less than $31,000 per annum and receives a concession rebate of $151.35 on both her electricity and gas bills.[197] She is usually home during business hours. Given the climate in the ACT Tracy owns a small heater she uses frequently in the winter and has a small air conditioner that is used on very hot days. Otherwise she uses a washing machine for laundry and rarely uses her dryer. Her average annual consumption is 5751 kWh.

Bill impact

Table.8.34 below shows that since Tracy is home during the day she would face an estimated small increase in her bill under the TOU product as her profile is presumably quite flat.

---

[197] We have allocated half of the rebate to this bill as the household is assumed to also receive a gas bill that the concession would apply.

Table.8.34: Tracy's estimated bill with no change in demand

Scenarios	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	5,751	-	$789	-
TOU	5,751	-	$800	1.4%
CPP + TOU	5,751	-	$803	1.7%

With a demand response she may be able to achieve small savings and more significantly by participating in a DLC programme, which could save her $78, most of the benefit however is by receiving the $75 up front payment for participation rather than decreased consumption from the air conditioner. Table.8.36 illustrates the results following the demand response.

Table.8.35: Tracy's estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	5,751	-	$789	-
TOU	5,733	-0.2%	$790	0.1%
CPP + TOU	5,740	-0.2%	$785	-0.5%
DLC + TOU	5,705	-0.8%	$711	-9.9%

Table.8.36 below shows how Tracy consumes the bulk of her electricity during off peak times in part due to the length of the peak period being relatively short compared to some other jurisdictions, for example Queensland.

Table.8.36: Tracy's estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	1,365	-	4,386	-	5,751	-
TOU	1,312	-3.9%	4,421	0.8%	5,733	-0.3%
CPP + TOU	1,308	-4.1%	4,431	1.0%	5,740	-0.2%
DLC + TOU	1,303	-4.5%	4,401	0.4%	5,705	-0.8%

8.3.5. Case study 5: large family, medium income (the Lloyds)

Description

The Lloyds live in regional Tasmania in a large house. Mr Lloyd works full time, as does his adult daughter. Mrs Lloyd has retired and is caring for her two grandchildren who live with them and so is usually home during the day. They also have another child living at home whilst attending tertiary studies who has a varied schedule. Their annual household income is $62,000. To heat the house in winter they use a heatpump. The Lloyds also own and frequently use their dishwasher, washing machine and dryer. Their average annual consumption 11,213 kWh which is higher than the Tasmanian average of 9,283 kWh.

Bill impact

Table 8.37 below presents the estimated impact of the Lloyds moving to a TOU or combination TOU and CPP tariff product. Under both scenarios the family's bill increases in part because of the higher proportion of electricity consumed during peak times.

Table 8.37: The Lloyd's estimated bill with no change in demand

Scenarios	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	11,213	-	$1,778	-
TOU	11,213	-	$1,862	4.7%
CPP + TOU	11,213	-	$1,889	6.3%

Table 8.37 also shows that the increase in the bill under TOU tariffs is approximately $84, and is less than that under CPP which indicates that the family's peak electricity use is not offset by the discount in off peak prices under the CPP scenario.

However, when the family responds to the changes in prices they are able to significantly reduce the change in their bill yet are unable to achieve the same as under the flat rate. Table.8.38 shows the results.

Table.8.38: The Lloyd's estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	11,213	-	$1,778	-
TOU	11,177	-0.3%	$1,850	4.0%
CPP + TOU	11,187	-0.2%	$1,866	5.0%

Table 8.39 shows the change in the Lloyd's peak electricity use which was reduced significantly under the CPP scenario. However, it can also be observed that a very closely corresponding increase in off peak consumption occurred which resulted in a small net decrease in total consumption.

Table 8.39: The Lloyd's estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	4,899	-	6,314	-	11,213	-
TOU	4,823	-1.5%	6,354	0.6%	11,177	-0.3%
CPP + TOU	4,817	-1.7%	6,370	0.9%	11,187	-0.2%

8.3.6. Case study 6: single, unemployed mother (Jill)

Description

Jill rents a house in regional Victoria with her two young children. She is currently not working and so relies on her support payments from the children's father and mother's allowance which combined is less than $28,000 per annum. As neither child is of a school age the family spends a lot of time in the home during peak hours. Jill owns and uses a washing machine, clothes dryer, air conditioner, electric stove and is currently on an electric off peak hot water tariff. Her annual consumption is 9695 kWh.

Bill impact

Table.8.40 below shows the change in Jill's estimated annual bill as a result of the new tariff products. Without a change in demand Jill would face a higher bill under both a TOU and CPP product which reflects her current use of peak demand.

Table.8.40: Jill's estimated bill with no change in demand

Scenarios	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	9,695	-	$1,442	-
TOU	9,695	-	$1,526	5.9%
CPP + TOU	9,695	-	$1,549	7.4%

However, Jill may respond to the increase in price and shift some peak consumption into off peak and reduce her overall use of peak consumption (see Table 8.41 below) as a result of the higher price. This behaviour would result in a bill reduction of nearly 2 per cent from no response under TOU, yet still increases the bill compared to the standard, flat tariff.

Table 8.41: Jill's estimated bill with demand response

Scenario	Consumption (kWh pa)	Change (%)	Estimated bill ($ pa)	Change (%)
Current	9,695	-	$1,455	-
TOU	9,657	-0.4%	$1,442	-0.9%
CPP + TOU	9,647	-0.5%	$1,455	-0.1%
DLC + TOU	9,141	-5.7%	$1,255	-13.8%

The use of an air conditioner during peak periods could be offset by participation in a DLC programme for which she would benefit from additional bill peak savings and the annual $75 payments which represents approximately 20 per cent of her current quarterly bill.

Table 8.42: Jill's estimated change in electricity demand

Scenario	Peak demand (kWh)	Change (%)	Off-peak demand (kWh)	Change (%)	Total electricity demand (kWh)	Change (%)
Current	3,756	-	5,939	-	9,695	-
TOU	3,640	-3.1%	6,016	1.3%	9,657	-0.4%
CPP + TOU	3,479	-7.4%	6,168	3.9%	9,647	-0.5%
DLC + TOU	3,165	-2.9%	5,976	1.2%	9,141	-5.7%

Box 8.4 describes the potential impact of the switch to time of use hot water from an off-peak rate.

Box 8.4: Off peak hot water

Many customers in regional Victoria and South Australia have electric hot water heaters that are currently wired to take advantage of cheaper overnight electricity rates.[198] In Victoria, the transition to smart metering means that many of these customers will be charged for electric hot water heaters at the prevailing TOU rate, which would predominately be the off-peak rate.

Since most off peak water heaters are programmed to heat up over night and are large enough to service the household without heating during the day presumably moving to a time of use tariff would mean that the hot water use would be charged at the TOU off peak rate. In this case the customer would face only the difference in the current off peak rate and the TOU off peak rate. The largest bill change faced by the customer will be the remaining consumption and how much of that would be charged at the higher peak rates. For example:

Jill's consumption is 9695 kWh and if hot water represents 30 per cent of that she will experience an increase in her annual bill of approximately 6 per cent by choosing to move to a TOU product and assuming her current off peak rates and an average residential profile. If hot water heating represents 40 per cent of her consumption her bill will increase by approximately 14 per cent (see Table 8.43).

Therefore customers who are currently on off peak hot water tariffs and who choose to move to TOU tariffs will face increasing bills as the proportion of hot water heating to total consumption increases and the difference between the current off peak rate and the TOU off peak rate increases. However, this is due to the price differential in the tariffs rather than the meter capability to provide this service – as overnight heating would still be provided in the same manner. In particular the TOU off peak tariff has been assumed by KPMG to be higher than that currently applied to off peak hot water. We understand that current off peak tariffs are relatively low because they were used as a measure to attract customers to the product and provide a means of load control to the network owner, given the high proportion of household consumption required for electric hot water heating. If customers that do currently face these tariffs for off-peak hot water are unable to reduce their consumption, they will perhaps require assistance to make the transition to new TOU tariffs.

Table 8.43: Jill's consumption (30 per cent contribution)

Consumption Time		Consumption (kWh) Current	Consumption (kWh) New	Price ($/kWh) Current	Price ($/kWh) New	Change
Off Peak	Hot water	2,909	2,892	0.07		
	Other	2,977	3,068	0.16		
	Total	5,885	5,961		0.8	
Peak		3,810	3,681	0.16	0.25	
Total		9,695	9,642	1287.04	1363.42	5.9%

198 In the urban centres access to gas makes electric hot water systems less popular, also in South Australia electric hot water systems must be replaced by gas hot water systems where gas is available.

9. Customer Service Benefits

As discussed in section 2, the roll-out of smart meters has the potential to enhance the level of customer service through such things as faster fault resolution, avoided cost of service call-outs and improved management of the security and reliability of the network.

The quantitative effects of these potential improvements in customer service are not easily discernible and thus our consideration of these functions has been of a qualitative nature.

Our Phase 1 report identified a number of customer service benefits associated with the functionality incorporated in the national minimum specification for smart meters. These benefits are summarised in Table 9.1 below.[199] These benefits would remain the same across the different smart meter roll-out scenarios (ie, scenarios 1, 2 and 4).

Given that the benefits are related to the functionalities of smart meters, these benefits would not arise under scenario 3.

Table 9.1: Analysis of customer service related functions

Number	Function	Conclusions on Customer Impacts
11	Import/export metering	Customer benefit from avoided cost of installing required metering facilities when own-generation installed – quantified under Network work stream. No material change to retail tariffs expected as a result of this functionality, and so no impact on the uptake of PV cells or other generation and hence no demand impact.
12	Remote connect/disconnect	Reduction in Unserved Energy (USE) following a network outage: estimated by the Network stream No change in USE arising from re-connections for non-payment Benefit from facilitating of prepayment offerings: low.
19	Quality of supply & other event recording	Future improved service standards, resulting from reduction in costs of achieving service levels – uncertain. Faster service complaint resolution
20	Meter loss of supply detection and outage detection	Reduction in service call-outs for which the customer would have to pay.

A number of the functionalities of smart meters are expected to create the opportunity to improve customer service levels. Our Phase 1 analysis indicated that many of these potential customer service improvements (eg quality of supply and other event recording, (function 19); and meter loss of supply detection and outage detection, (function 20)), will only affect consumers indirectly because they are likely to lower the cost of meeting service standards by network businesses. This creates a second round customer benefit as these cost savings are passed through in the form of lower prices. Further, by lowering the cost of meeting service standards, it creates the potential for regulators to increase service levels, which would in turn benefit consumers. Finally, the benefits arising from these functions may lead to improved localised solutions, without necessarily impacting on major service level performance indicators, such as SAIFI (System Average Interruption Frequency Index) and SAIDI

[199] For a fuller discussion of each of the customer service benefits identified in Table 8.1 and discussed above the reader is referred to NERA's Phase 1 Report for Workstream 4: Consumer Impacts.

(System Average Interruption Duration Index). We have therefore been unable to quantify the likely benefit that these customer service functions would provide.

The remaining functions included within the recommended minimum national specification for smart meters are remote connect/disconnect and import/export metering. The potential consumer benefits from these functions are anticipated to be relatively low.

For remote connect/disconnect, whilst there are likely to be benefits of having a connection reinstated more quickly, particularly after non-payment of a bill, these benefits are expected to be offset by the costs associated with being disconnected more quickly. The time without supply is therefore anticipated to be the same both under conventional connection/disconnection processes and the remote connect/disconnect function.

An additional benefit of remote connect/disconnect, however, is that it facilitates the introduction of prepayment tariffs. There is some evidence to suggest that prepayment meters are valued by customers, which suggest that there will be some benefit associated with this additional functionality. However, in discussions with retailers, there is not strong evidence that prepayment tariffs will be adopted across Australia. For this reason we have assumed that the effect of remote connect/disconnect in relation to providing the capability for prepayment meters is likely to be low.

The main benefit from import/export metering is the potential avoided cost of installing a second meter to record exports of electricity resulting from a PV installation. For each PV installation the benefit has been estimated by CRA as likely to be in the order of $320-373.[200] However this is a small proportion of the total cost of PV (likely in excess of $15,000 per household) and is therefore unlikely to effect on a decision to install PV. In addition the likely uptake of PV cells is anticipated to be small over the lifetime of a smart meter, given current policies promoting PV installation. CRA has assumed that at the end of the 20 yea analysis period there would be 5% of customers with local generation.[201] The overall benefit to a customer is therefore anticipated to be low.

Therefore, in summary, these consumer service functions are expected to deliver some benefits, although they are likely to be relatively low or uncertain. We anticipate that most of the benefits arising from these functions will result from business efficiencies in the meeting of customer service level requirements, which would flow through to customers in the form of lower tariffs.

[200] See CRA Phase 2 Network Workstream Report, section 6.2.

[201] See CRA Phase 2 Network Workstream Report, section 6.2.

10. Conclusions

The Phase 2 analysis of consumer impacts associated with the introduction of smart metering or direct load control has focused on two critical issues. The first is estimating the demand response that might be expected to result from the introduction of new innovative tariff products, such as time of use tariffs, critical peak pricing and direct load control products. These estimates are an important element of the overall national cost benefit, as they form the basis for the modelling of the generation market benefits, and the potential network deferral benefits associated with the introduction of smart metering and direct load control mechanisms.

The second is the likely impact on household bills from the same tariff products, according to the circumstances of individual households. This analysis was conducted on the basis of jurisdictional consumption and load profile data, and a number of case study households were also developed to demonstrate the possible bill impact for households with certain characteristics. The aim of this analysis is to consider the differing impacts on consumer groups with different characteristics.

The demand response estimation provides an indication of what might be observed under each of the tariff products considered. Whilst we have sought to provide a robust estimate of the likely demand response that would result from the introduction of tariff products enabled through smart metering, there is considerable uncertainty about how much demand would actually be affected by time of use and/or critical peak pricing. This is because there are a number of uncertain variables that will affect, potentially considerably, the actual demand response that would be observed from the introduction of smart metering. These include:

§ the actual structure of time of use tariffs and critical peak prices that are offered to customers in each jurisdiction. Where the structure of tariffs and the relationship between peak and off peak tariffs and the relationship between peak and critical peak prices vary considerably from those considered in our analysis, this would be expected to affect the demand response that might result from their introduction;

§ the likely take up rates for households shifting from current tariffs to time of use and critical peak pricing tariffs, and participation in direct load control programs;

§ the actual responsiveness of households in each jurisdiction to changes in both the average tariff and the peak/off-peak tariffs. We have relied on elasticity estimates from the Californian State-wide Pricing Pilot, and while we have sought to ensure that these estimates reflect the climatic conditions in Australia we recognise that the actual responsiveness will depend on a range of household characteristics including appliance mix within each jurisdiction. The current smart metering trials being undertaken in Australia are expected to provide greater insights into the likely responsiveness of households to new tariff product offerings;

§ the actual load profiles that occur into the future. Load profiles change on a yearly basis according to climatic conditions and changes in the pattern of electricity use; and

- the expected electricity conservation that may result from the greater awareness created about energy efficiency from the introduction of smart metering and the associated public information programs.

Ultimately the benefits that would result from changes in the load profile resulting from the introduction of time of use tariffs and critical peak pricing, relies on the predictability of these load shifts occurring. An important element of the trials should therefore be an examination of the variance in demand response over a period of years resulting from time of use and critical peak pricing. This will allow the value of these tariff products to be properly assessed against direct load control alternatives that provide load reductions with greater certainty.[202]

Finally, in relation to the estimated demand response, we expect that our estimates tend toward the higher end of possible demand responses, despite our reasonably conservative elasticity assumptions. This in part reflects the fact that we have not considered the potential demand response fatigue that could result from multiple critical peak event days during particularly long heat waves, and also due to the uncertainty in the conservation effect applied. As the joint submission from the Consumer Utilities Advocacy Centre, the St Vincent de Paul Society Victoria, and Alternative Technology Association on Phase 1 of our assessment highlight, the demand response achievable on the fourth consecutive critical peak day, is likely to be lower than the earlier days, affecting the overall shift in maximum demand that would result.[203] Again, in our view, this is an area where further trial work would provide valuable information on the appropriate tariff structures to design to improve the resultant certainty of the demand response and its associated benefits.

The approach we have adopted to estimate the change in demand resulting from participation in direct load control has been to estimate the amount of load that might potentially be controlled in each jurisdiction, and applied a 50 per cent cycling assumption for a period of up to 6 hours. The resultant demand reduction is therefore very sensitive to:

- the amount of load that is available for participation in a direct load control program;
- the cycling rates applied; and
- the length over which cycling can be made, without impacting on the thermal comfort of customers.[204]

Differences in these assumptions can potentially result in large changes in the likely demand response that could result from direct load control programs in each jurisdiction.

Finally, our analysis of the demand response impacts from smart meters assumes that customers receive the time of use tariff signals and/or critical peak pricing signals through product offerings from retailers. For jurisdictions with retail competition for small residential

[202] Importantly, direct load control does not provide complete certainty about the load reduction obtainable. It relies on an understanding of the air conditioner and pool pump usage patterns of households, which can change over time.

[203] Consumer Utility Advocacy Centre, St Vincent de Paul Society Victoria, & Alternative Technology Association, (2007), Submission to Phase 1, National Cost Benefit Analysis of Smart Metering and Direct Load Control, p. 6.

[204] It may be possible to develop a direct load control program where customers thermal comfort is affected, but it is likely to require higher financial compensation to encourage participation in such a program.

customers, changes in network tariffs may or may not be passed through to customers. This has the potential to dilute the tariff signals to customers, thereby lowering the expected demand responses resulting from the introduction of those tariffs. To maximise the effectiveness of the demand response signals to customers, it will be important that further consideration be given to both the policy framework and associated business incentives for the passing through of network time of use tariffs and/or critical peak prices to customers by retailers.

Bill impacts from time of use tariffs, critical peak pricing and participation in direct load control programs will vary according to individual household characteristics. These include:

- the individual household load profile, which is affected by the appliance mix, usage of appliances within the home and the time over which that usage occurs;
- total electricity consumption; and
- the scope and motivation that the household has to change existing electricity use patterns, or conserve electricity.

Our analysis indicates that, in general, households with a relatively low proportion of total consumption during peak periods (for example households where occupants work during the day), are likely to be better off after the introduction of time of use tariffs, without necessarily needing to change usage behaviour. This highlights the fact that under flat tariff arrangements, these households are currently cross-subsidising households who use a greater proportion of electricity during peak periods.

Whether a vulnerable household is worse or better off from the introduction of time of use tariffs and/or critical peak prices will depend on their individual circumstances, and whether these tariff products are voluntarily applied. Assuming that households would only change to a new tariff product offering if they believe they will be better off, suggests that no household will be worse off. However, evidence from the UK indicates that some consumers will shift even though it would make them worse off.[205] This could be because the household had a different expectation about their load profile or ability to shift demand, compared to the reality once the customer had committed to the TOU and/or CPP tariff product.

Over time, as costs change and the benefits of smart metering are passed through to customers, households remaining on flat tariffs may become faced with higher tariffs. This highlights the importance of providing adequate information to customers about the likely bill changes from new tariff product offerings, to allow them to make appropriate decisions about the tariff products they should use. One approach may be to consider requiring the inclusion on the bill of the savings (or increases) that results from time of use tariffs or critical peak pricing compared against flat tariff arrangements, assuming the same consumption.

Our jurisdictional bill analysis demonstrates that for all jurisdictions, a household with average consumption and the state wide jurisdictional load profile would have had a slightly lower bill under the time of use tariff (on the basis of the assumed demand response), compared to the jurisdictional flat tariff. This does not mean however that the majority of

[205] Waddams, C., (2007), "Deregulating Residential Electricity Markets: What's on Offer?", *CUAC Expert Forum on Electricity Pricing Forum Papers*, Melbourne, 16 August, page 13.

households within each jurisdiction would be better off. Rather, it highlights that there is a segment of households that are likely to be better off under time of use tariffs.

Finally, where a household is able to participate in a direct load control program, our analysis indicates that they would be almost universally better off because of the resultant significantly lower bill. This result is driven by the direct load control program customer receiving part of the network deferral benefits associated with the load control through the participation pay (which we have assumed for our analysis was $75 per annum). This is contrasted against time of use tariffs and/or critical peak pricing where the resulting network benefits are shared across all customers, in the form of lower overall prices (not reflected in our analysis), rather than just being given back to members of these tariff classes.

The bill impact analysis that we have undertaken has considered the likely impact for a household with specific characteristics at this point in time. In practice however, it is possible that the same household that initially achieved a bill decrease, may start having bill increases relative to the flat tariff alternative as household circumstances change over time. Understanding a household's consumption pattern life cycle may therefore be important, and highlights the need to consider how freely households are able to change between tariff product offerings if smart metering is implemented

Our focus group results also suggest that rural and/or more elderly households are less likely to change to new tariff product offerings, due to the complexity of the new tariff arrangements, even if they could potentially be better off.

Finally, our analysis and results highlight a number of consumer issues that should be further considered as part of the policy framework of a future rollout of smart metering. These include:

- the underlying regulatory framework for the introduction of smart metering will need to consider how hardship policies and other consumer protections and assistance programs (including information protection) should be modified to ensure that existing protections are not eroded;
- new mechanisms for ensuring that households facing financial stress are identified and provided with information on assistance available, prior to utilising remote disconnection functionalities;
- designing education programs about the introduction of smart metering and associated innovative tariff products, to assist consumers in understanding how best to manage their consumption in order to minimise their bills and to ensure that the potential for demand response is maximised. The focus group results suggest that for low income households, providing oral information can sometimes be more effective than information provided in the form of leaflets or brochures;
- providing an opportunity for households to readily shift between tariff products, if they discover that they are actually financially worse off from the new tariff product offering;
- the need to consider the relationship between network businesses (offering time of use network tariffs and/or critical peak pricing) and the customer, given that most customers only receive a bill from a retailer and the retailer will not have an obligation to pass these new tariff structures onto customers. Alternatively an incentive mechanism could be

designed to ensure that time of use tariffs and/or critical peak prices are transparently conveyed by retailers to customers; and

§ ensuring that there is sufficient notice of critical peak events, to provide the opportunity for a household to respond appropriately to the pricing signals presented.

Appendix A. Recent reviews, practical trials and studies of the responsiveness of consumers

Over the last five years a number of Australian regulators have examined the evidence on the likely demand side response resulting from the introduction of smart meters and other demand management techniques. These reviews of demand side response studies have been for the purpose of considering the likely costs and benefits from the introduction of smart meters to small end-use customers. Much of this evidence has been sourced from a number of practical trials that have been conducted internationally and within Australia. These trials have sought to statistically simulate the demand response of residential and commercial consumers to the introduction of smart meters, TOU tariffs and CPP. In addition, these trials have provided valuable insight into the value that can be attributed to other functionalities of a smart meter including direct load control capabilities.

In developing the elasticity of substitution and the own-price elasticity assumptions that we have used as part of our analysis we have undertaken a comprehensive review of the demand response trials and previous reviews. The remainder of this appendix provides an overview of our review.

A.1. Jurisdictional reviews

Since 2002 there have been three reviews undertaken by jurisdictional regulators of the costs and benefits associated with the introduction of interval meters and other demand side management techniques. Each of these reviews has also considered the appropriate elasticity estimates to apply and are discussed in detail below.

A.1.1. Victoria

In November 2002 the ESC released a position paper (herein referred to as the ESC 2002 Position Paper) setting out the estimated costs and benefits arising from the installation of interval meters and the introduction of TOU tariffs in Victoria.[206]

One of the principal benefits cited in the position paper was a result of an assumed reduction in peak demand arising from moving from a flat tariff structure to TOU tariffs with a CPP element. This reduction in peak demand was estimated by decomposing the projected maximum demand into consumption by residential and commercial customers consuming less than 160 MWh pa. Separate elasticity estimates for these two groups of consumers (-0.1 for residential consumers and -0.025 for commercial consumers) were then applied to the estimated peak demand levels using TOU tariffs with a CPP element. The CPP was assumed to apply on summer weekdays and was 3.6 times higher than the off-peak price. Based on these assumptions the ESC estimated that residential peak consumption could be reduced by 20 per cent and commercial peak consumption could be reduced by 5 per cent.[207]

[206] ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002.

[207] ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002, pp. 79-87.

The elasticity measures utilised by the ESC in this study were based on a review of a number of US studies. This review established a range of -0.1 to -0.3 for the own price elasticity measure for residential consumers facing TOU tariffs. Studies relating to residential consumers facing CPP and enabling technologies with and without two way communications established a range for the elasticity of substitution between peak and off-peak usage between 0.31 to 0.4 and 0.06 to 0.33 respectively.[208]

The review of US studies pertaining to small and medium sized businesses facing TOU tariffs established a range of -0.019 to -0.092 for the own price elasticity estimate.[209]

On the basis of these studies the ESC concluded that the following elasticity of demand measures should be utilised in the analysis:

§ -0.1 for residential customers facing TOU prices and -0.15 for residential customers facing CPP with two way communication; and

§ -0.025 for small and medium sized businesses facing TOU pricing and -0.0375 for small and medium sized businesses facing dynamic pricing with two way communication.[210]

In addition to the review of US studies the ESC engaged CRA to develop an engineering end use model. This model estimated hourly loads by end-use drawing on a range of factors including the technical characteristics of end users, weather conditions, assumptions about customer behaviour and the number of appliances utilised by customers. The results of the bottom up model suggested that a reduction in peak demand of approximately 8 – 18 per cent was possible for the residential sector (compared to 20 per cent estimated using an elasticity of demand measure of -0.1) while a reduction in peak demand of 5 per cent was possible for small and medium sized businesses (which was comparable to that estimated using the elasticity of demand measure of -0.025).

In 2005 CRA and Impaq Consulting were engaged by the Victorian Department of Infrastructure to assess the costs and benefits of adding communications functionality to the interval meters being rolled out in the mandatory rollout and the optimal deployment time.

To estimate the benefits of a faster roll out and adding communications functionality CRA examined the likely demand side response of consumers. This examination drew on the results of the Californian Statewide Pricing Pilot that estimated an elasticity of substitution between peak and off-peak usage of -0.076 and an own price elasticity of demand measure of -0.041. Based on these measures CRA estimated that peak demand amongst residential consumers could fall by up to 10 per cent assuming a 100 per cent uptake of TOU tariffs.[211]

In February 2007 Dr. David Cornelius undertook an assessment of the costs and benefits associated with the inclusion of the in-home display transponder or an in-home display within

---

[208] ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002, pp. 62-66.

[209] ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002, pp. 62-66.

[210] ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002, pg. 85.

[211] CRA and Impaq Consulting, Advanced Interval Meter Communications Study, Draft Report, 23 December 2005, pg. 60.

the minimum functionality adopted in Victoria. Within this assessment it was assumed that the in-home display would give rise to an enhanced demand response during peak times and greater energy conservation relative to customers who did not receive information on a real time basis. These assumptions imply a higher own price elasticity of demand and thus it was assumed for the purposes of this analysis that:

- the own price elasticity measures during peak periods would be -0.15 to -0.20 although it was also noted in this analysis that a business case prepared by the Intelligrid Consortium assumed that the elasticity of demand could increase from -0.20 to -0.30;
- customers could reduce their energy consumption by 4 per cent to 10 per cent over the year. This estimate was based on a report prepared by EPRI that indicated that residential customers with access to direct feedback about their energy use reduce their energy consumption by 4 per cent to 20 per cent.

The additional demand response flowing from the provision of in-home displays during peak times and over the year was then translated into a reduction in network capital and operating expenditure by assuming that: [212]

- average customer load at peak times ranged from 2 to 4 kW and over the year accounted for 4,000 kWh;
- CPP were 200 to 300 per cent higher than peak prices; and
- the aggregate value of network and generation deferral could be estimated assuming a value of $130/kW year for each kW reduction; and
- the value of reduced operating costs could be estimated assuming a value of $15/MWh for each MW hour of energy conserved.

On the basis of these assumptions and a number of other cost assumptions it was concluded that the number of customers that would need to take up the in-home display would need to be between 2 per cent to 5.3 per cent to achieve the required break even point for the inclusion of an in-home display transponder in the minimum functionality and 17 per cent for the roll out of an in-home display to all customers.[213]

A.1.2. South Australia

In 2004 ESCOSA undertook a detailed examination of the demand management options available to ETSA Utilities and the costs and benefits associated with each of these options. As part of this examination ESCOSA engaged CRA to assess the extent to which demand side management techniques could facilitate a one year deferral of augmentation on three constrained segments of ETSA Utilities' distribution system (North Adelaide, Modbury and Findon-Fulham Gardens). The demand side techniques considered by CRA included,

[212] David Cornelius Consulting, Including an IHD in the AMI minimum functionality – Cost Benefit Analysis, 4 May 2007, pg. 4.

[213] David Cornelius Consulting, Including an IHD in the AMI minimum functionality – Cost Benefit Analysis, 4 May 2007, pp. 5-6.

amongst others, direct load control, voluntary load control and interval metering coupled with CPP.

The study revealed at an early stage that no demand side technique could elicit the level of response required in the Modbury and Findon-Fulham Gardens area to alleviate the constraints.[214] The study therefore focused on the ability of a range of techniques to alleviate the constraints in North Adelaide.

When considering the direct load control alternative CRA assumed a per customer load reduction of 0.62 kVA could be achieved by cycling residential air conditioners using a 25 per cent cycling strategy while a 2.28 kVA reduction could be achieved if the air conditioners were completely interrupted. For small businesses it was assumed that a reduction of 0.77 kVA was achievable. Overall CRA estimated that the direct load control option could reduce peak demand by 0.23 MVA in the North Adelaide region or 36 per cent of the required load reduction.[215] Table 7 of this report indicates that direct load control of small businesses and residential customers could not on its own result in the deferral of network augmentation, however, when combined with a range of other demand management techniques such as curtailable load, voluntary load control, standby generation and power factor correction, the required network augmentation could be deferred. Based on these results ESCOSA endorsed the introduction of a direct load control pilot program involving 1,000-2,000 residential customers with air conditioning, pool pumps and other suitable equipment.[216]

CRA's review of the potential for interval meters and CPP to elicit the required demand side response led it to conclude that this alternative could not on its own deliver the response required to enable the deferral of network augmentation. In reaching this conclusion CRA assumed a CPP that was five times higher than the price in the base period and assumed own price elasticity estimates of -0.025 for residential consumption and -0.004 for small to medium sized businesses.[217, 218] Combined these assumptions led CRA to conclude that peak consumption could be reduced by about 10 per cent per household (0.2 kVA per household) which when combined with a response from small and medium businesses in the North Adelaide region translated to a reduction of 0.48 MVA.[219] Although this reduction met 96 per cent of the target reduction, the cost per kVA reduced by the roll out ($750 per kVA) was found to be substantially higher than the savings achieved from deferring augmentation by one year ($72 per kVA). This factor coupled with the recognition that interval meters and CPP could not guarantee a load reduction led ESCOSA to conclude that it would not be appropriate to have a wide scale roll out of interval meters to all customers. ESCOSA did,

---

214 ESCOSA, Demand management and the Electricity Distribution Network Draft Decision, September 2004, pg. 12.

215 ESCOSA, Demand management and the Electricity Distribution Network Draft Decision, September 2004, pp. 35-36 and Table 7.

216 ESCOSA, Demand management and the Electricity Distribution Network Draft Decision, September 2004, pg. 36.

217 ESCOSA, Assessment of Demand Management and Metering Strategy Options, August 2004, pg. 25.

218 These elasticity assumptions are significantly different from those assumed as part of the ESC review and are likely to be responsible for the differences in the conclusions drawn.

219 CRA, Assessment of Demand Management and Metering Strategy Options, August 2004, pp. 25-26.

however, recommend that a CPP trial be undertaken with larger customers that already had interval meters.[220]

A.1.3. Tasmania

In 2006 the Office of the Tasmanian Energy Regulator (OTTER) undertook a review of the economic implications of an interval meter rollout.[221] This review examined both the costs and benefits associated with the rollout and considered the potential influence of the introduction of TOU tariffs on demand side response and in turn Tasmania's load profile.

Within its consideration of the potential demand side response OTTER reviewed the results of a number of studies and trials undertaken in California, Northern Ireland, New South Wales, Victoria and South Australia. In so doing OTTER observed that the majority of the studies reviewed were carried out in areas with summer peak conditions and relatively high levels of air conditioner penetration which was in direct contrast to the conditions experienced in Tasmania. In view of these differences OTTER concluded that it would not be appropriate to apply the elasticity results of these studies directly and that a more appropriate, albeit optimistic, measure of the potential reduction in peak demand could be established using customer responsiveness factors.[222]

The customer responsiveness factors were developed in conjunction with Aurora Energy and drew on the observed response of Tasmanian customers to Aurora Energy's pay as you go TOU tariffs. The responsiveness factors in effect measured the likely reduction in peak demand arising under a number of alternative rollout scenarios. The assumed responsiveness factors are set out in Table A.1. This table also sets out the break even reduction in peak demand calculated by OTTER when estimating the reduction in peak required to ensure that the alternative rollout scenarios broke even in net present value (NPV) terms. The results of this analysis led OTTER to conclude that for all scenarios a consumer response that exceeded the total available small customer peak load would be required to ensure that the benefits of the roll out exceeded the costs.

Table A.1: Assumed reduction in peak and break even reduction in peak under alternative rollout scenarios

Scenario	Assumed reduction in peak	Break even reduction in peak
New and replacement manually read interval meters with TOU tariffs	2% reduction	325% reduction
Five year accelerated rollout of manually read interval meters with TOU tariffs	2% reduction	225% reduction
New and replacement smart meters without TOU tariffs	3% reduction	238% reduction
Five year accelerated rollout of smart meters without TOU tariffs	3% reduction	136% reduction
New and replacement smart meters with TOU tariffs	10% reduction	238% reduction
Five year accelerated rollout of smart meters with TOU tariffs	10% reduction	136% reduction

Source: OTTER, Draft Report, pg. 33.

220 ESCOSA, Demand management and the Electricity Distribution Network Draft Decision, September 2004, pg. 38.

221 OTTER, Costs and Benefits of the Rollout of Interval Meters in Tasmania – Draft Report, August 2006.

222 OTTER, Costs and Benefits of the Rollout of Interval Meters in Tasmania – Draft Report, August 2006, pg. 28.

A.2. Smart meter and direct load control trials

A number of practical trials have been undertaken internationally and domestically over the last five years which have examined the demand side response flowing from the introduction of TOU tariffs, CPP and direct load control mechanisms. The remainder of this section provides an overview of these trials and the findings in relation to demand side response.

A.2.1. International trials

A.2.1.1. Californian Statewide Pricing Pilot

The Californian Statewide Pricing Pilot is one of the most comprehensive international trials of TOU pricing, CPP and enabling technologies that has been undertaken in the last five years. This pricing pilot involved 2,491 residential and commercial customers of Pacific Gas and Electric Company, San Diego Gas and Electric and Southern California Edison. These participants were located in four distinct climate zones across California. The climate characteristics of each of the four zones used in the trial are set out in the table below.

Table A.2: Climate conditions

	Summer[1]		**Winter[2]**	
Climate Zone	Critical peak temperature	Average temperature	Minimum temperature 2005	Average temperature 2005
Zone 1	25.8 °C	23.8 °C	0.6 °C	12.65°C
Zone 2	29.1 °C	27.3 °C	-2.4 °C	13.18°C
Zone 3	34.2 °C	31.6 °C	1.2 °C	13.80°C
Zone 4	39.9 °C	36.8 °C	-1.7 °C	14.45°C

Source:
1. Source: CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 24.
2. U.S. Department of Energy. Energy Efficiency and Renewable Energy

As a part of this pilot CRA was employed to estimate the average impact of TOU tariffs and CPP on the trial participants over the period July 2003 to December 2004. CRA's final report was released in March 2005[223] and its key findings are summarised in the following section.

A.2.1.1.1. Residential trial

Of the 2,491 trial participants 1,861 were residential customers. These participants were assigned to one of five groups and were subject to different tariff structures. The five groups used in the trial included:

- control group (553 participants) – this group were subject to the standard flat tariff structure;

[223] CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005.

- information group (252 participants) – this group were subject to the standard flat tariff structure and were provided with material which informed them of the manner by which load could be reduced during peak periods. On critical peak days this group were requested to avoid energy and informed in the same manner as the critical peak price fixed group;
- TOU group (200 participants) – this group were subject to seasonal peak and off-peak tariffs;
- critical peak price fixed group (606 participants) – this group were subject to seasonal TOU tariffs in non critical peak periods and were required to pay the CPP when a CPP event was called. A critical peak period could be called up to fifteen times a year between 2 pm to 7 pm on weekdays and the notification period for this group was one day in advance of the event; and
- critical peak price variable group (250 participants) – as with the critical peak price fixed group this group were subject to seasonal TOU tariffs in non critical peak periods and the CPP when a CPP event was called. Once again a critical peak event could be called up to fifteen times a year, however, the critical peak period was not fixed and could be called on the day of the event for a variable length of time. Another distinguishing feature of this group was that the group largely consisted of households with air conditioners. This group also had the option of obtaining free enabling technology (ie, price sensitive thermostats).

The TOU tariffs and critical peak tariffs used for residential participants are set out in the table below. Under the tariff structure adopted in the trial the CPP were approximately 6.6 times higher than the off-peak prices while the peak prices were approximately 2.4 times higher than the off-peak prices. These tariffs were designed to be revenue neutral for the average customer that elected not to change their load profile and to provide customers with an opportunity to reduce their bill by up to 10 per cent if they reduced or shifted peak usage by 30 per cent.

Table A.3: Residential tariffs

Period	**Tariffs (per kWh)**
Off-peak	\$0.09-\$0.10
Peak	\$0.22-\$0.24
Critical Peak Price – Fixed	\$0.59
Critical Peak Price - Variable	\$0.65
Standard tariff paid by Control Group and Information Group	\$0.13 - \$0.14

Source: CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 14.

The results of this study were used by CRA to ascertain the effect of the alternative tariff structures on peak, off-peak and total consumption and to estimate the elasticity of substitution and the elasticity of demand. The elasticity measures were estimated using a constant elasticity of substitution demand model which consisted of two equations.[224] The first equation modelled the ratio of peak to off-peak consumption as a function of the ratio of peak and off-peak prices and formulaically was defined as:

---

[224] CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pp. 33-37.

$$\ln \frac{Q_{peak}}{Q_{offpeak}} = a + b \ln(\frac{P_{peak}}{P_{offpeak}}) + d\,(CDH_{peak} - CDH_{offpeak}) + \sum_{i=1}^{N} q_i D_i + e$$

Where Q_{peak} = average energy use per hour in the peak period for the average day;

$Q_{offpeak}$= average energy use per hour in the off-peak period for the average day;

β = elasticity of substitution between peak and off-peak energy use;

P_{peak} = average price during the peak period;

$P_{offpeak}$ = average price during the off-peak period;

δ= measure of weather sensitivity;

CDH_{peak} = cooling degree hours per hour during peak price period;

$CDH_{offpeak}$ = cooling degree hours per hour during off-peak price period;

θ_i = fixed effect coefficient for customer i;

Di = binary variable equal to 1 for the ith customer and 0 otherwise where there are N customers; and

ε= error term

The second equation modelled daily consumption as a function of daily electricity prices and formulaically was defined as:

$$\ln Q_{daily} = a + c \ln(P_{daily}) + d\,(CDH_d) + \sum_{i=1}^{N} q_i D_i + e$$

Where Q_{daily} = average daily energy use per hour;

χ= price elasticity of demand for daily energy;

P_{daily}= average daily price weighted by consumption in peak and off-peak periods;

δ= measure of weather sensitivity;

CDH_{peak} = cooling degree hours per hour during the day; and

θ_i = fixed effect coefficient for customer I;

Di = binary variable equal to 1 for the ith customer and 0 otherwise where there are N customers; and

ε= error term.

Critical peak pricing fixed group

Participants in the critical peak price fixed group were able to achieve an average peak reduction across all zones of 13.1 per cent on critical days in summer and 3.9 per cent on critical days in winter.[225] While some conservation was observed (daily consumption was estimated to have fallen by 2.4 per cent in summer and 0.6 per cent in winter) CRA concluded that the reduction in energy use during peak periods was simply deferred to off-peak periods.[226] Separate results were presented for each zone which are set out in Table A.4. These zonal results demonstrate that in summer the response was greatest in warmer climates while in winter the response was greatest in the cooler climates. The results further demonstrate that higher responses could be elicited in summer than winter which is consistent with OTTER's conclusion regarding the limitations on Tasmania's ability to achieve the demand reductions observed in warmer climates facing summer critical peaks.

Using the available data CRA estimated an elasticity of substitution of -0.076 in summer and -0.025 in winter and a daily price elasticity estimate of -0.041 in summer and -0.011 in winter.[227] The elasticity estimates for each individual zone are set out in the table below.

Table A.4: Critical peak price fixed - elasticity estimates on critical peak summer and winter days

	Measure	Zone 1	Zone 2	Zone 3	Zone 4	Average
Summer	Elasticity of substitution	-0.039	-0.061	-0.102	-0.113	-0.076
	Daily price elasticity	-0.041	-0.042	-0.043	-0.032	-0.041
	Reduction in peak	-7.61%	-10.10%	-14.8%	-15.83%	-13.06%
	Reduction in daily consumption	-2.02%	-2.22%	-2.71%	-2.10%	-2.37%
Winter	Elasticity of substitution	-0.027	-0.026	-0.024	-0.024	-0.025
	Daily price elasticity	-0.010	-0.013	-0.011	-0.004	-0.011
	Reduction in peak	-4.25%	-4.09%	-3.70%	-3.39%	-3.91%
	Reduction in daily consumption	-0.58%	-0.75%	-0.59%	-0.23%	-0.62%

Source: CRA, Impact Evaluation of the California Statewide Pricing Pilot Tables 4-10, 4-11, 4-23 and 4-24.

CRA compared these estimates with those that had been estimated in other studies and noted that while there were difficulties in making such comparisons the Californian estimates were at the low end of the range reported in other studies and lower than earlier estimates undertaken in California. CRA suggested that this difference may simply reflect the fact that significant conservation and load management programmes had been implemented since earlier estimates had been undertaken and this factor coupled with the response elicited from the Californian energy crisis may have reduced the ability or willingness of customers to further reduce energy use.[228]

---

225 CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 61.

226 CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 7.

227 CRA, Impact Evaluation of the California Statewide Pricing Pilot Tables 4-10 and 4-24.

228 CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 12.

Critical peak pricing variable group

The critical peak price variable group consisted of a large number of households that had central air conditioning. This group were also offered enabling technology which assisted with switching off certain appliances at critical peak times. The composition of this group was substantially skewed toward air conditioner ownership relative to the critical peak price fixed group and this factor coupled with the difference in the availability of enabling technology meant that the results from the two groups could not be directly compared. Differences in the uptake of the enabling technology within this group, however, allowed for some comparison of the effect of the technology on consumption. According to this comparison the average reduction in peak demand for those participants with enabling technology was twice as high as that achieved by participants without the technology.[229]

Time of use group

The reduction in peak demand for participants facing the TOU tariff fell substantially over 2003 and 2004 from 5.9 per cent in 2003 and just 0.6 per cent in 2004.[230] In reporting these results CRA observed that the smaller size used for this group may have resulted in outliers having a substantial influence on the results and thus it expressed some caution in drawing any conclusions from these results. According to CRA if the results were to be believed then one could only conclude that TOU tariffs on their own can not achieve sustainable reductions in peak demand.

> One interpretation of the results is that, by the summer of 2004, customers had concluded that they saved little by responding to the rates and stopped doing so. Another possible interpretation is that customers need the frequent reminders associated with critical day notifications and the increased sensitization resulting from the much higher peak period prices on critical days in order to ingrain changes in behaviour that result in sustainable impacts even on normal weekdays.[231]

As an alternative to these results CRA suggested that the critical peak price fixed group's response to TOU tariffs on non-critical days could be utilised as a measure of the influence of TOU tariffs on consumption.[232] The results from the critical peak price fixed group on non-critical peak days are presented in the table below.

---

[229] CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 9.

[230] CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 8.

[231] CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 100.

[232] CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 8.

Table A.5: Critical peak price fixed - elasticity estimates on non-critical peak summer and winter days

	Measure	Zone 1	Zone 2	Zone 3	Zone 4	Average
Summer	Elasticity of substitution	-0.034	-0.055	-0.093	-0.105	-0.069
	Daily price elasticity	-0.043	-0.044	-0.047	-0.039	-0.044
	Reduction in peak	-2.23%	-3.33%	-5.55%	-6.47%	-4.71%
	Reduction in daily consumption	0.22%	0.22%	0.15%	0.04%	0.17%
Winter	Elasticity of substitution	-0.026	-0.026	-0.024	-0.024	-0.025
	Daily price elasticity	-0.017	-0.020	-0.011	-0.004	-0.019
	Reduction in peak	-1.56%	-1.39%	-1.38%	-1.33%	-1.39%
	Reduction in daily consumption	-0.06%	-0.03%	-0.01%	0.00%	-0.02%

Source: CRA, Impact Evaluation of the California Statewide Pricing Pilot Tables 4-10, 4-11, 4-23 and 4-24.

Information only group

The results from the information only group led CRA to conclude that at a minimum demand response in the absence of a price signal is not sustainable.[233]

Other observations

This study also examined the effect of consecutive critical peak day and the influence of household characteristics on the responsiveness of residential consumers. In relation to consecutive critical peak days CRA found that:

- the elasticity of substitution on the second day was larger in absolute terms than the first critical peak day; and
- the reduction in peak demand on the second critical peak day was not statistically different from the first critical peak day average response.

In relation to household characteristics CRA made the following observations:[234]

- as the number of persons per household increased the level of responsiveness fell with the elasticity of substitution estimated to be 25 per cent higher for a two person household than a four person household;
- the responsiveness of demand to changes in price was greater for higher income households (over $100,000) than low income households (less than $40,000) with the percentage reduction in peak period energy use on critical days being nearly 50 per cent greater for higher income households; and
- households with central air conditioning were more price responsive than those without with the elasticity of substitution estimated to be approximately three times higher for households with central air conditioning than for those without and the daily price elasticity estimated to be 50 per cent higher.

---

233 CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 10.

234 CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pp. 74-75.

A.2.1.1.2. Commercial and industrial sector trial

The commercial and industrial sector trial involved 630 participants that were separated into two groups on the basis of consumption[235] and then allocated to the control group (260 participants), the time of use group (100 participants) or the critical peak price variable group (270 participants).

The participants in the critical peak price variable group were further allocated into Track A or Track C with Track A being drawn from the general population and Track C being drawn from a smart thermostat pilot that involved customers with central air conditioning and smart thermostats. A large number of participants in Track A also had central air conditioning but only half had enabling technology.

A summary of the results of this trial are set out in the table below.

Table A.6: Commercial and industrial sector results

Group	Consumption band	Reduction in peak demand
Time of Use	Less than 20 kW	2003 results -0.03% 2004 results -6.8%
	20-200 kW	2003 results -3.9%and 2004 results -8.6%
Critical Peak Price – Variable Track A	Less than 20 kW	2004 results -6.0% on critical peak days and -1.5% on non peak days 2005 results -7.6% on critical peak days and -1.9% on non peak days
	20-200 kW	2004 results -9.1% on critical peak days and -2.4% on non peak days 2005 results -4.3% on critical peak days and -0.9% on non peak days
Critical Peak Price – Variable Track C	Less than 20 kW	-18.2% for enabling technology and +4.5% for incremental impact of price on critical peak days and +1.1% on non peak days
	20-200 kW	-11.0% for enabling technology and -3.2% for incremental impact of price on critical peak days and -0.9% on non peak days

Source: Impact Evaluation of the California Statewide Pricing Pilot Tables 1-2 and CRA, California's Statewide Pricing Pilot: Commercial and Industrial Analysis Update, June 2006, Table 3-2.

When reviewing the results for the Critical Peak Price – Variable Track A group CRA examined the difference in response between those in the critical peak price variable that had enabling technology and those that did not. CRA found that for large customers there was no statistically significant response on critical peak event days where the participants did not have enabling technology. In contrast participants with enabling technology had an elasticity of substitution of approximately -0.09. For smaller customers that did not have access to enabling technology the elasticity of substitution was approximately half that of those with enabling technology (-0.0412 versus -0.0815).

---

[235] The consumption bands were less than 20kW and 20kW - 200kW

The elasticity of substitution was estimated for the time of use group over both the summer and winter periods. The summer 2003 and 2004 estimates varied markedly with the larger participants elasticity of substitution ranging from -0.093 to -0.21 and the reduction in peak demand ranging from 4 to 8.6 per cent. For smaller participants the elasticity of substitution ranged from -0.005 (not statistically significant) in 2003 to -0.13 in 2004 with the associated reduction in peak ranging from zero per cent. In winter the elasticity of substitution and reduction in peak demand estimates for smaller participants were once again not statistically significant while for larger participants it was estimated to be -0.072. In referring to these results CRA noted that the reduction in peak and elasticity of substitution estimates were higher than other studies but did not proffer any explanation for the relatively high responses observed.[236] CRA did, however, express caution when interpreting the results and cited the small sample size as potentially distorting the results.[237]

A.2.1.1.3. Californian automated demand response system pilot

An extension of the Statewide Pricing Pilot was carried out over the period July 2004 to September 2005 by Rocky Mountain Institute.[238] This trial used a sample of residential participants in Zone 3 that were exposed to CPP and who were provided with automated demand response technology that could control air conditioning, swimming pool and spa loads. The participants in this study all had centralised air conditioning and were also screened for swimming pool and spa ownership.

A number of critical events were called over the sample period and the consumption of trial participants was compared to the consumption of other large load residential customers. This comparison suggested that those in the trial were able to reduce their peak period consumption by 43 per cent on critical peak days and 27 per cent on non-critical peak days.[239] According to the authors of this study the automated demand response technology was an important element with customers having the technology being able to reduce their peak consumption by more than twice that achieved by customers in other demand response programs who did not have technology.[240] The authors also observed that where participants had pool pumps the pool pump operations contributed 32 per cent of the total peak reduction on critical peak days and 50 per cent on non critical peak days.[241]

A.2.1.1.4. Ofgem cost benefit analysis and the Statewide Pricing Pilot

Within its recent review of the costs and benefits associated with a smart meter roll out, Ofgem referred to the Californian Statewide Pricing Pilot and noted that in view of the differences in climate conditions between California and the UK a reduction in peak demand of 2.5 per cent would be more appropriate than the 4.7 per cent reduction estimated in the

---

236 CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pp. 123-125.

237 CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 13.

238 Rocky Mountain Institute, Automated Demand Response System Pilot – Final Report, Vol. 1. 31 March 2006.

239 Rocky Mountain Institute, Automated Demand Response System Pilot – Final Report, Vol. 1. 31 March 2006, pg. 6.

240 Rocky Mountain Institute, Automated Demand Response System Pilot – Final Report, Vol. 1. 31 March 2006, pg. 17.

241 Rocky Mountain Institute, Automated Demand Response System Pilot – Final Report, Vol. 1. 31 March 2006, pg. 17.

Pricing Pilot.[242] Ofgem also assumed a reduction in overall consumption of 1 per cent which was lower than the results contained in the studies it reviewed which suggested consumption could be reduced by between 5-10 per cent. Ofgem recognised the conservatism in this assumption but noted that there were a number of problems with the studies and the evidence for such high assumed responses was not strong.[243]

A.2.1.1.5. Ontario Smart Price Pilot

A pricing pilot has also recently been undertaken in Ontario. This pricing pilot referred to as the 'Smart Price Pilot' was initiated by the Ontario Energy Board and was developed to test the responsiveness of consumers to different time of use price structures. Commencing in August 2006 the seven month trial involved 373 participants that were separated into three groups and were subject to alternative tariffs.

The first group, called the time of use group (124 participants) were subject to the existing regulated TOU tariff and were not informed of critical peak events. The second group was called the critical peak price group (124 participants) and participants in this group were required to pay an adjusted TOU tariff with a CPP element payable on CPP days. The third group was termed the critical peak price rebate group (125 participants) and were required to pay the regulated TOU tariff and received a critical peak rebate for every kWh a consumer was able to reduce their consumption below a baseline level[244] during the critical peak event. A control group of 125 participants was also established. This group had smart meters but were not subject to TOU tariffs.

The tariffs used in this study were designed to be revenue neutral. A summary of the tariffs used in the trial are set out in the table below.

Table A.7: Ontario Smart Price Pilot tariffs

Period	Paid by	Summer tariff (per kWh)[1]	Winter tariff (per kWh)[2]
Off-peak	Regulated time of use group, Critical peak rebate group	$0.035	$0.034
Off-peak	Adjusted time of use	$0.031	
Mid-peak	All groups	$0.075	$0.071
On-Peak	All groups	$0.105	$0.097
CPP	Adjusted time of use	$0.30	
Critical Peak Rebate	Critical peak rebate group	$0.30	

Source: Ontario Energy Board Smart Price Pilot, July 2007, pg. 2.
1. In summer off-peak extends from 10 pm – 7 am weekdays and all day on weekends and holidays. Mid-peak extends from 7 am – 11 am and 5 pm – 10 pm weekdays. On-peak extends from 11 am – 5 pm weekdays.
2. In winter off-peak extends from 10 pm – 7 am weekdays and all day on weekends and holidays. Mid-peak extends from 11 am – 5 pm and 8 pm – 10 pm weekdays. On-peak extends from 7 am – 11 am and 5 pm – 8 pm weekdays.

242 Ofgem, Domestic Metering Innovation, February 2006, pg. 18.

243 Ofgem, Domestic Metering Innovation, February 2006, pg. 18.

244 The baseline level was calculated by multiplying the average usage for the same hours of the five previous non-event, non-holiday weekdays by a weather adjustment set to 125%.

The terms of the trial allowed a CPP event to be called up to nine times for three to four hours each during the on-peak period on days that reached pre-specified temperature and humidity thresholds. Notification was provided to participants in the CPP and critical peak rebate groups one day in advance of the event by telephone, email or text message.

Seven critical peak events were called throughout the trial with four called in summer and three called in winter. Of the seven critical events called only two of the events called in summer elicited a statistically significant reduction in peak usage. Although there was not a statistically significant reduction in load on the remaining two peak days in summer it was noted that the summer over which the critical peak events were called was relatively moderate and thus there may have been less load shedding than would have occurred in the face of extreme climate conditions.[245] The winter peak events did not elicit a statistically significant reduction in load and on one day there was actually an increase in peak consumption. It was postulated that this increase could have been a statistical anomaly or simply reflected the fact that participants found it harder to shift load during winter. Overall it would appear that participants found it easier to shift load in summer relative to winter.[246]

The table below sets out the average reduction in load during critical peak events across both winter and summer and the reduction in overall consumption achieved by each of the three groups. Reviewing this table it is apparent that participants in the time of use group did not demonstrate a statistically significant shift in load on critical peak event days.

Table A.8: Ontario Smart Price Pilot results

Group	Reduction in peak on critical peak days	Reduction in peak period usage during summer	Reduction in overall consumption
Time of use	5.7% not statistically significant at the 90% confidence interval	n.a. not statistically significant at the 90% confidence interval	6.0%
CPP group	17.5%	8.1%	7.4%
Critical peak rebate group	25.4%	5.2%	4.7% not statistically significant at the 90% confidence interval

Source: Ontario Energy Board Smart Price Pilot, July 2007, Appendix E, pg. 3.

A survey of the trial participants also found that participants were on average able to save \$4.17 per month with \$1.44 of this saving attributable to load shifting and the remainder due to conservation. According to trial participants the most useful resources to help them understand the TOU tariffs were the fridge magnet and monthly usage statements.

245 Ontario Energy Board Smart Price Pilot, July 2007, pg. 33.

246 Ontario Energy Board Smart Price Pilot, July 2007, pg. 38.

A.2.1.2. Other international trials

A.2.1.2.1. Northern Ireland TOU tariff trial

In Northern Ireland a study of the implications of using TOU tariffs was carried out amongst 186 participants using prepayment meters. The tariff structure used in this trial consisted of three rates which were used over four time periods. On average participants in the trial were able to reduce their peak demand by up to 10 per cent and their overall consumption by 3.5 per cent.[247]

A.2.1.2.2. United Kingdom – cooking appliances energy consumption display study

A small study conducted in the UK involving forty one consumers has also assessed the differences in cooking related consumption patterns arising when consumers were provided with:

- an energy consumption display which provided real time consumption information for cooking appliances;
- an information package; or
- a display and an information package.

A control group was also considered in this study.

According to the results of this study:

- the information package group achieved average reductions in energy usage of 3 per cent;
- the electronic consumption display group achieved average reductions in energy usage of 15.2 per cent; and
- the information package plus electronic consumption display group achieved average reductions in energy usage of 8.9 per cent.[248]

The authors of this study further found that while the information pack group were more aware of energy-savings behaviours they did not appear to actually adopt those behaviours. The authors concluded that this demonstrated that the display increased motivation to modify energy usage relative to what otherwise would have been achieved with information only.

A.2.1.2.3. Puget Sound Energy TOU tariff trial

In the US Puget Sound Energy commenced a TOU tariff trial in June 2001 which involved 240,000 customers that were transferred from flat tariffs to a TOU tariff. The tariff structure used in this study consisted of two rates which differed by 1 cent per kWh. On average participants were able to achieve 5-6 per cent reductions in peak demand and reduce their

---

[247] Ofgem, Domestic Metering Innovation, February 2006, pg. 44.

[248] G. Wood, M. Newborough, Dynamic energy-consumption indicators for domestic appliances: environment, behaviour and design, 17 November 2002.

overall consumption by 5 per cent.[249] The trial was abandoned in November 2002 after the introduction of metering charges appeared to limit the available savings with 90 per cent of customers saving less than the metering charge.[250]

A.2.1.2.4. Other studies involving residential customers

In 2006 Sarah Darby published a report that reviewed the results of a number of studies relating to the effectiveness of feedback on energy consumption.[251] Some of the key findings of this review were:

- studies examining direct feedback through either a meter or a display monitor had observed savings of between 5 to 15 per cent; and
- studies examining indirect feedback through billing had observed savings of between zero and 10 per cent although this varied according to the quality of information provided with historic feedback comparing current consumption with historic consumption found to be more effective than comparisons with other households.

This review also referred to a study involving consumers checking consumption via an accumulation meter. According to the results of this the study savings of between 10 to 20 per cent were observed.[252]

A.2.1.2.5. Georgia Power Company real-time tariffs

Georgia Power Company has introduced a real-time tariff which exposes industrial customers to market prices that are set either one hour in advance or a day ahead. According to Georgia Power industrial customers subject to the hour in advance real-time tariffs are relatively price responsive with elasticities ranging from 0.2 at moderate price levels to -0.28 when prices reach up to $1 per kWh. The elasticities of industrial customers subject to tariffs set one day ahead ranged from -0.04 (for moderate prices) to -0.13 (for higher prices).

A.2.1.2.6. Hydro One, Canada

A pilot study was undertaken by Hydro One in Canada to determine whether provision of a real-time feedback device is sufficient to empower residential customers with the information needed to reduce their electricity consumption.

The trial was conducted between July 2004 and September 2005 involving 435 participants that were provided with in-home displays that measured their electrical consumption in real time and displayed electricity consumption in both kWh and in monetary terms, together with

---

[249] FERC, Assessment of Demand Response and Advance Metering, Staff Report, August 2006, pg. 56.

[250] FERC, Assessment of Demand Response and Advance Metering, Staff Report, August 2006, pg. 56.

[251] S. Darby, The Effectiveness of Feedback on Energy Consumption – A review for DEFRA of the Literature on Metering, Billing and Direct Displays, April 2006.

[252] S. Darby, The Effectiveness of Feedback on Energy Consumption – A review for DEFRA of the Literature on Metering, Billing and Direct Displays, April 2006, pg. 10.

information on carbon emissions.[253] A control group was established and the participants in this trial were not provided with any additional educational material on electricity conservation. Participants were also not subject to time varying tariffs or CPP.

Participants in the trial were able to achieve aggregate reductions in consumption of 6.5 per cent. Within the overall sample, households with non-electric heating showed energy savings of 8.2% with a range within this sample of a 5.1% reduction (for customers without electric hot water) to a reduction of 16.7% (for an electric hot water house).

The aggregate reduction for households with electric space heating was much lower at 1.2%.

Since tariffs were unchanged in this trial the conservation effect represents a shift in the participants' demand curves. The results indicated a sustained response over the study time period.

The study notes that an overall average reduction of 7-10% 'is feasible' if customers were to be provided with energy conservation 'tips' in addition to an IHD. The provision of energy conservation tips was not a feature of the trial.

A.2.1.2.7. NEXUS, California Bill Analysis Pilot 2005

Nexus Energy Software conducted a trial in 2005 in California which focused on the demand impact resulting from the provision of bill analysis to customers on residential CPP tariffs.[254] There were 152 customers in the trial and 118 in a control group. The bill analysis presented customised content to participants via a website based on their home energy survey data and monthly bill data. It also provided personal recommendations for achieving electricity savings.

NEXUS found that most participants (77%) visited the website at some point during the program. For comparable utility sites offering bill information, about 1-3% of a target population typically visits a website on their own when informed of its benefits.

46% of survey respondents stated that they took actions during the critical peak periods that they would not have taken if they hadn't received the bill analysis. 49% of respondents stated that they took additional actions during regular peak periods because of the bill analysis. However, the average load reductions across the peak period were not found to be statistically significant.

A.2.1.2.8. Trials amongst commercial customers

There have been relatively few trials carried out amongst commercial customers over the last five years and thus it is useful to look at earlier trials undertaken in this area. Two such trials referred to by the ESC in its 2002 position paper[255] were those carried out by Southern

---

[253] Hydro One Brampton Networks Inc., Conservation and Demand Management Plan, Annual Report to December 31 2005, p.7-8; *Summary The Impact of Real-time Feedback on Residential Electricity Consumption: The Hydro One Pilot,* March 2006.

[254] Presentation by NEXUS, *California Bill Analysis Pilot*, 18 April 2006.

[255] ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002, pg. 63.

California Edison and Pacific Gas and Electric Company in the US. The results from these two trials are summarised in the table below.

Table A.9: Trial results for small and medium sized businesses

Trial	Own price elasticity estimates
Southern California Edison Trial	-0.033 to -0.035 (consumption less than 500 kW)
	-0.087 to -0.092 (consumption 200 kW – 500 kW)
Pacific Gas and Electricity Company Trial	-0.019 to -0.038

Source: ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002, pg. 63

A.2.2. Australian trials

Domestic trials of smart meters and direct load control mechanisms have been carried out by a number of companies including EnergyAustralia, Integral Energy, Country Energy, Energex and ETSA Utilities. An overview of these trials and their findings is set out below.

A.2.2.1. EnergyAustralia smart meter trial[256]

In 2005/06 the network arm of EnergyAustralia commenced a smart meter pricing study in Sydney which involved 756 residential consumers, 272 small businesses (less than 40 MWh pa) and 272 medium sized businesses (40 -160 MWh pa).

The 756 residential consumers were split into three sub groups on the basis of their annual consumption[257] and then assigned to one of the following six groups:

1. Control group – this group were not informed that they were part of the trial and were used to monitor consumption amongst consumers that continued to face the standard tariff;
2. Information group –this group also continued to face the standard tariff but were provided with information about when dynamic peak events[258] were being called and were provided with material that informed them of the cost of electricity at these peak times and the benefits of consuming in off-peak versus peak periods;
3. Seasonal TOU tariffs group – this group were subject to TOU tariffs with separate peak periods specified for summer (December to February) and winter (June to August). In non-peak months, a shoulder and off-peak structure applies;

[256] The information in this section was obtained from a number of presentations made by EnergyAustralia including: EnergyAustralia's Strategic Pricing Study" Empirical Approach to Demand Response Analysis, 26 April 2007; EnerygAustralia's Smart Meter Roll Our: An Update and Next Steps, MMI Conference 2007, 14-16 May 2007; Summer and Winter Demand response from EnergyAustralia's Strategic Pricing Study, 20 June 2007; Advanced Tariff Design, Workshop on AMI: "Metering: A portal for change" UNSW, 17 May 2006.

[257] The consumption bands used by EnergyAustralia are 2-5.4 MWh pa, 5.4-9 MWh pa and 9-40 MWh pa.

[258] EnergyAustralia has adopted the terms dynamic peak events and dynamic peak pricing rather than critical peak event and critical peak pricing.

4. Medium dynamic peak pricing with in-home display group – this group were provided with an in-home display and were subject to TOU tariffs with a dynamic peak price of $1/kWh;
5. High dynamic peak pricing with in-home display group – this group were also provided with an in-home display and were subject to TOU tariffs with a dynamic peak price element, however, the dynamic peak price was twice as high as the medium dynamic peak price group ($2/kWh). This group was established to test whether a higher dynamic peak price could illicit a greater response than the medium peak price signal; and
6. High dynamic peak pricing <u>without</u> an in-home display – the only difference between this group and the preceding group is that participants were not provided with an in-home display.

For the small and medium sized business sample groups control groups were established and the remainder of participants were assigned to group's four to six. Participants in the trial were also provided with web access which enabled them to monitor their daily consumption.

The tariff structures adopted in the study of residential customers and the ratio of peak to off-peak prices are set out in the table below.

Table A.10: EnergyAustralia tariffs

Period	Seasonal Time of Use[1] (per kWh)	Time of Use and Dynamic Peak Pricing Medium[2] (per kWh)	Time of Use and Dynamic Peak Pricing High[2] (per kWh)
Off-peak	$0.045	$0.075	$0.065
Shoulder	$0.070	$0.095	$0.085
Peak	$0.360	$1.000	$2.000
Access charge	$0.32 / day	$0.32 / day	$0.32 / day
Ratio of Peak to Off-peak	8:1	13:1	31:1

1. Under the Seasonal TOU tariff the shoulder period is as follows: summer and winter - weekdays 7am to 2 pm and 8 pm to 10pm and weekends 7am-10pm; and autumn - 7am to 10pm. The peak period under this tariff extends from 2pm to 8pm on weekdays during the summer and winter months. Off-peak occurs between 10pm to 7am irrespective of the season or day.
2. Under the Dynamic Peak Pricing tariff the shoulder period extends from 7 am to 10 pm and the dynamic peak price event can be called at any time during the shoulder period. Off-peak occurs between 10pm to 7am irrespective of the season or day.

Under the terms of the trial both the retail and network arms of EnergyAustralia are able to call up to six dynamic peak pricing events a year[259] (combined twelve times a year) which may extend from 30 minutes up to four hours during the shoulder period. The terms of the trial also require EnergyAustralia to notify users two to 24 hours in advance of the event via email, SMS, phone message or, where relevant, via the in-home display.

259 The terms of the trial further state that a maximum number of four peak events per calendar month and one event per day can be called by EnergyAustralia.

Preliminary results

A number of dynamic peak events have been called since the commencement of the trial. The preliminary results of the study indicate that statistically significant reductions in both peak and overall consumption were possible on dynamic peak price event days amongst those customers in the dynamic peak pricing groups. The conservation effect observed by EnergyAustralia is in stark contrast to the deferral effect observed in the Statewide Pricing Pilot.

Based on the preliminary results EnergyAustralia has made the following observations:

§ the responsiveness of residential participants facing a high dynamic peak price varied only marginally from residential participants facing the medium dynamic peak price which suggests that there may be diminishing returns achievable at higher peak prices;

§ there was no statistically significant difference between the response of those participants with or without an in-home display;

§ the information group can respond in a significant manner although their responsiveness is lower and more variable than those facing price signals via TOU tariffs or dynamic peak pricing. The responsiveness of the information group observed in EnergyAustralia's trial is in direct contrast to the lack of responsiveness observed in the Statewide Pricing Pilot; and

§ businesses are less responsive than residential consumers and their response is less consistent. This observation is consistent with the results of other studies involving small to medium sized businesses.

A survey undertaken amongst participants found that they were interested in monitoring how well they were doing and were also interested in having an in-home display if one was provided free of charge.

A.2.2.2. Integral Energy smart meter trial[260]

Integral commenced a two year smart meter trial on 1 August 2006 involving 900 residential customers[261] and a control group[262] of 340 customers located in the western suburbs of Sydney.

The 900 participants in the trial were split into three groups with the first group subject to seasonal TOU tariffs, the second group subject to TOU tariffs with dynamic peak pricing and the third group were also subject to TOU tariffs and dynamic peak pricing but were provided with an in-home display. Participants in the trial were also provided with access to a web site which provided information on consumption and pricing.

---

260 The information in this section was obtained from an Integral Presentation entitled Trials update, 19 June 2007 and has been supplemented in relation to the most recent results from conversations with Integral personnel.

261 This sample group was formed after surveying 6,000 customers each of whom were offered an incentive to participate in the trial. The overall take up rate for this offer was 15% although Integral has noted that the take up rate for dynamic peak pricing was greater than the take up rate for seasonal TOU tariffs.

262 The control group were not informed that they were part of the trial.

The tariff structures adopted in the study of residential customers and the ratio of peak to off-peak prices are set out in the table below.

Table A.11: Integral tariffs (1 August 2006 – 1 July 2007)

Period	Seasonal Time of Use[1] (per kWh)	Time of Use and Dynamic Peak Pricing[2] (per kWh)
Off-peak	$0.097449	$0.083204
Shoulder	n.a.	$0.107646
Peak	$0.303996	$1.670306
Access charge	$0.3887664/day	$0.3887664/day
Ratio of Peak to Off-peak	3:1	20:1

1. Under the Seasonal TOU tariff the peak period in summer extends from 1pm to 8pm on weekdays between 1 November and 31 March. In winter the peak period extends from 5pm to 7pm on weekdays between 1 June to 31 August.
2. Under the Dynamic Peak Pricing tariff the shoulder period extends from 1 pm to 8 pm on non dynamic peak price days and off-peak period prevails at all other times.

The terms of the trial allow Integral to call a dynamic peak pricing event up to twelve times a year during the pre-defined peak period (weekdays 1 pm to 8 pm). Notice of the dynamic peak price event can be provided between two to 24 hours in advance of the event via SMS, email, phone message or, where relevant, via the in-home display.

Preliminary results

Since the trial's inception a number of dynamic peak events have been called by Integral. One such event occurred on 11 January 2007 and the preliminary results from this event indicate that:

- there was a statistically significant reduction in demand amongst those participants paying the dynamic peak pricing tariff during dynamic pricing events;
- there was <u>no</u> statistically significant difference in the demand response amongst participants in the dynamic peak price groups that either had or did not have the in-home display. This result is consistent with the preliminary results observed in the EnergyAustralia trial; and
- there was <u>no</u> statistically significant difference in the reaction of customers subject to seasonal TOU tariffs relative to the control group.

The results of the study further suggest that energy was conserved by those participants subject to dynamic peak price tariffs rather than simply being deferred to hours outside the peak pricing event.

A survey of the participants in the trial has also found that of the customers supplied with an in-home display over 85 per cent had utilised the display in the six months preceding the survey while just 9 per cent of customers having access to the website had logged on to the website.

We understand that preliminary analysis of more recent CPP events has found a statistically significant increase in the level of peak demand reduction that is achieved by those customers with an IHD, compared with customers without an IHD, in the order of a further 5% reduction.

A.2.2.3. Country Energy smart meter trial[263]

Country Energy initiated a smart meter trial in December 2004 in Queanbeyan and Jerrabombera (Home Energy Efficiency Trial, HEET). The trial involved 150 residential consumers who were provided with an in-home display and were subject to seasonal TOU tariffs with a CPP element. The objective of the HEET project was to test customer propensity to shift load if provided with real time information about their consumption and the relative cost of that consumption at different times of the day. As such, CPP signals were sent to customers based on weather and wholesale market events rather than network constraints.

The specific tariffs used in this study are set out in the table below. Under this tariff structure the dynamic peak price was five times higher than the off-peak price.

Table A.12: Country Energy tariffs

Period	**Tariffs (per kWh)**
Off-peak (10 pm to 7 am)	$0.0703
Shoulder (all other times)	$0.127
Peak (November to February 2 pm to 8 pm and March to October 7 am to 9 am and 5 pm to 8 pm Monday to Saturday)	$0.1887
Critical peak price (ie, Summer - November to February 2 pm to 8 pm and Winter – March to October 7 am to 9 am and 5 pm to 8 pm Monday to Saturday)	$0.3774
Access charge	$0.3978/day
Ratio of CPP to off-peak price	5:1

Under the terms of the trial Country Energy[264] was able to trigger a CPP event twelve times a year and provide participants with notice between two to 24 hours in advance of the event. These dynamic peak pricing events were restricted to the peak periods and participants could be notified by email, an SMS message, or a message and audible signal on the in-home display.

Preliminary results

To assess the responsiveness of the trial participants to these events Country Energy compared the consumption of the trial group over the dynamic peak period with the trial group's consumption over the same period in the days preceding and following the event. The preliminary results of this trial indicate that on days in which dynamic peak events were called the trial participants reacted by deferring their consumption to later periods.

---

263 The information in this section was obtained from the following Country Energy presentations: The Country Energy Home Energy Efficiency Trial, IEA DRR Task XIII Workshop, 11 November 2005; and Smart Meters and Customer Trials ERAA Retail Energy Market Briefing, 30 July 2007.

264 It is important to recognise that the area in which this trial was undertaken is not currently subject to network constraints and thus the imperative for the DNSP to be able to trigger a dynamic peak price event was lower than what may be experienced in other areas.

Preliminary results also suggest that:

- CPP events can facilitate up to a 25 per cent reduction in peak demand over both winter and summer; and
- over the 24-month trial period, participants were able to reduce their energy consumption by approximately 8 per cent; and
- some customers were able to reduce their overall consumption while others adapted to the TOU tariff structure and shifted consumption to take advantage of cheaper tariff periods.

Country Energy conducted regular surveys with trial participants to track behavioural changes. Overall, the surveys showed that participants' energy efficiency awareness increased during the trial, and that customers made conscious decisions about appliance and energy use as a result of their participation in the HEET project.

A.2.2.4. Energex smart meter trial[265]

A trial of smart meters was also undertaken by Energex in two Brisbane suburbs over Autumn 2005. The trial involved 370 participants that were separated into five groups and subject to either:

1. a TOU tariff;
2. a TOU tariff and a timer that enabled appliances to be switched off between 4.30 pm to 8.30 pm;
3. a TOU tariff and a direct load control mechanism that enabled Energex to control appliances on weekday peak periods;
4. existing tariffs and direct load control mechanism that enabled Energex to control appliances on an ad-hoc basis; and
5. existing tariffs and education about consumption and ways in which consumption could be adjusted over the day.

The TOU tariffs used in the trial are set out in the table below.

Table A.13: Energex TOU tariffs

Period	Tariffs (per kWh)
Off-peak (8.30 pm to 7 am)	$0.055
Shoulder (7 am to 4.30 pm weekdays and 7 pm to 8.30 pm weekends)	$0.11
Peak (4.30 pm to 8.30 pm on weekdays)	$0.288
Access charge	$7.20/month
Ratio peak to off-peak price	4:1

[265] The information in this section was obtained from Energex, Imagine…residential energy management, assisted by utilities, for consenting customers – An approach to large-scale demand response from the residential segment, 2006 Qld State Energy Outlook Conference 25-26 July.

Trial results

The results of Energex's trial indicated that:

§ participants facing a TOU tariff and subject to direct load control were able to achieve a 34 per cent reduction in peak demand which was almost three times higher than those participants that were not subject to direct load control. This result is broadly consistent with the additional responsiveness observed amongst participants with enabling technology in the Statewide Pricing Pilot;

§ participants that were subject to TOU tariffs and were required to control their own loads with a timer were able to reduce their overall energy consumption by 13 per cent and reduce their peak requirements by 12 per cent;

§ participants subject to the existing tariffs and ad hoc direct load control achieved similar levels of peak reduction to the time of use and timer group with reductions of up to 12 per cent per event achieved; and

§ Participants subject to the TOU tariff only and those subject to the existing tariff with education neither deferred nor conserved energy. The finding in relation to the information group is consistent with the responsiveness of the information group observed in the Statewide Pricing Pilot.

A.2.2.5. ETSA Utilities demand management trial[266]

In 2005 ETSA Utilities commenced a five year demand management trial that was designed to examine both the reduction in peak demand arising from a range of demand management initiatives and the level of acceptance amongst consumers. The specific initiatives being trialled by ETSA Utilities include, amongst others, direct load control, CPP, interval meters and voluntary load control for large customers.

Since the commencement of the programme ETSA Utilities has completed two direct load control trials which have entailed ETSA Utilities cycling the air conditioners of participants on and off for discrete periods of time over the length of direct load control event (i.e. 7.5 minutes off in every 30 minutes and 15 minutes off in every 30 minutes of the switching trials that were conducted over periods of two to five hours).

The first of these trials was undertaken in 2006 and involved 20 participants in the Adelaide metropolitan area. During this trial ETSA Utilities tested a range of switching periods and examined the overall effect of the direct load control action on the load profile. The results of this first trial indicated a reduction in peak demand of approximately 17 per cent.

The second trial was undertaken in the Glenelg area over the summer of 2006/07. This trial involved approximately 750 air conditioners and consumption was monitored at the site using interval meters as well as at the street transformer and substation level. ETSA Utilities

---

266 The information contained in this section has been obtained from a presentation made by ETSA Utilities entitled Demand Management Programme – Delivering Energy to South Australians.

trialled a number of switching periods and found that air-conditioners can be cycled for 15 minutes in every 30 minute period without affecting comfort levels. It was further found that to reduce load a random overlapping switching programme was required. On 15 March 2007 the air conditioners of 68 premises were cycled and according to ETSA Utilities the peak was reduced by approximately 30 kW from a no curtailment peak on a day of 35^{o}C external ambient temperature.

This second trial provided further important results in that of the original sample population of approximately 2,400 suitable air conditioning units, approximately 50% were found to be what is termed “new generation” equipped with advanced diagnostics and requiring a more elaborate and time consuming installation process of the direct load control unit than is the case for the simpler older model air conditioners. The size of the market penetration of “new generation’ units was unexpected and much higher than industry sources had been led to believe.

A further trial is therefore planned and expected to commence from October 2007 for the 2007/08 summer period, which will involve 1,100 customers in Mawson Lakes, Northgate and Murray Bridge who have “new generation” air conditioners installed.

A.3. Estimates of the own price elasticity of demand

In Australia one of the most recent studies of the long run own price elasticity of demand was undertaken by the National Industry of Economic and Industry Research (NIEIR) using time series data extending from 1980 to 1995.[267] This study was undertaken on behalf of NEMMCO and separate estimates were developed for each jurisdiction in the National Electricity Market (NEM) and for residential, commercial and industrial consumers. The jurisdictional estimates developed by NIEIR are set out in Table A.14.

Table A.14: Long run own price elasticity estimates[1]

Jurisdiction	Range	Mean
New South Wales	-0.22 to -0.52	-0.37
Victoria	-0.23 to -0.53	-0.38
Queensland	-0.14 to -0.44	-0.29
South Australia	-0.17 to -0.47	-0.32
Tasmania[1]	-0.14 to -0.32	-0.23
NEM	**-0.20 to -0.50**	**-0.35**

Source: NIEIR, The own price elasticity of demand for electricity in NEM regions, June 2007, pg. 3.

The long run own price elasticity estimates across alternative customer classes were:

- -0.25 for residential consumers;
- -0.35 for commercial customers; and
- -0.38 for industrial customers.

The long term nature of these elasticity estimates implies that consumers are able to switch to an alternative fuel source by replacing their electricity based equipment and appliances if it is

[267] NIEIR, The price elasticity of demand for electricity in NEM regions – A report for the National Electricity Market Management Company, June 2007.

more cost effective to do so. Given this ability one would expect, all other things being equal, that in the long run demand would be more elastic than demand in the short run and thus using a long run elasticity measure to estimate changes in demand in the short run may overstate the actual change in demand that would flow from a change in price.

The NIEIR has also observed that:

- price elasticity of demand may be non-linear and thus higher price changes may not result in a proportionately larger change in demand; and
- the responsiveness to price changes may not be symmetrical and demand is likely to be less responsive in the face of falling prices.

A number of studies of the short and long run own price elasticity of demand have also been published internationally over the last ten years. The table below provides a summary of these studies which is based on the results of the reviews undertaken by the Productivity Commission in 2001[268] and IPART in 2003.[269,270]

Table A.15: Summary of recent international studies

Authors	Country	Residential own price elasticity of demand estimates		Small and medium sized business estimates	
		Short run	Long run	Short run	Long run
Fillippini and Pachauri [1]	India	-0.16 to -0.39	n.a.	n.a.	n.a.
Tiwari [2]	India	-0.70	n.a.	n.a.	n.a.
Beenstock et al. [3]	Israel	n.a.	-0.579	n.a.	n.a.
Fatai, Oxley and Scrimgeour [4]	New Zealand	-0.18 to -0.24	n.a.	n.a.	n.a.
Filippini [5]	Switzerland	-0.60 peak -0.79 off-peak	-0.71 peak -1.92 off-peak	n.a.	n.a.
Reiss and White [6]	US	-0.39	n.a.	n.a.	n.a.
Miller [7]	US	n.a.	-0.37	n.a.	n.a.
Wade [8]	US	-0.23	-0.31	-0.24	-0.25
Silk and Joutz [9]	US	-0.62	n.a.	n.a.	n.a.
Herriges and King [10]	US	-0.2 summer -0.4 winter	n.a.	n.a.	n.a.

Sources:
1. Filippini, M and Pachauri, S., Elasticities of electricity demand in urban Indian households, CEPE Working Paper No. 16, Centre for Energy Policy and Economics, Zurich, Switzerland.
2. Tiwari, P., Architectural, Demographic and Economic Causes of Electricity Consumption in Bombay, Journal of Policy Modelling, Vol. 22, no. 1, pp. 81-98.
3. Beenstock M., Goldin, E and Nabot, D, The demand for electricity in Israel, Energy Economics, Vol. 21, No. 2.
4. Fatai, K, Oxley, L, and F. Scrimgeour, 2003, Modelling and forecasting the demand for electricity in New Zealand: A comparison of alternative approaches, The Energy Journal, Vol. 24, No. 1.
5. Filippini, M, Swiss residential demand for electricity, Applied Economic Letters, 6, pp 533-538/
6. Reiss, P. and White, M, Household electricity demand, revisited, Unpublished manuscript Graduate School of Business, Stanford University.
7. Miller, J, Modelling residential demand for electricity in the US: a semiparametric panel data approach, Unpublished draft manuscript, Rice University.

---

[268] C. Sayers and D. Shields, Productivity Commission, Electricity Prices and Cost Factors, Staff Research Paper, August 2001.

[269] IPART, Inclining Block Tariffs for Electricity Network Services, Secretariat Discussion Paper, June 2003.

[270] See also, Langmore, M. and Duffy, G., Domestic electricity demand elasticities, Issues for the Victorian Energy Market, June 2004.

8. Wade, S, Price Responsiveness in the NEMS Buildings Sector model, Report No. EIA/DOE-0607(99).
9. Silk, J and Joutz, F, Short run and long-run elasticities in US residential electricity demand: a cointegration approach, Energy Economics, Vol. 19, no. 4, pp. 493-513.
10. Herriges, J and King, K, Residential Demand for Electricity Under Inverted Block Rates: Evidence from a Controlled Experiment, Journal of Business and Economic Statistics, Vol. 12, No. 4, pp. 419-430.

A.4. Summary of results from trials and jurisdictional reviews

Table A.16 and Table A.17 provide a summary of the estimated elasticity measures and assumed reductions in peak demand and consumption flowing from each of the jurisdictional reviews, practical trials and elasticity studies outlined in the preceding sections.

Reviewing these tables it is apparent that the range of short run elasticity measures is wide for both residential and commercial customers. Specifically:

§ for small to medium sized businesses the short run elasticity measures range from -0.004 to -0.24 with a large number of observations centred around -0.02 to -0.04; and

§ for residential customers the short run elasticity measures range from -0.011 to -0.79 although differences can be observed between the ranges established for trials undertaken in relation to CPP, TOU tariffs, direct load control and enabling technologies and academic studies.

Table A.16: Summary of results for small to medium sized businesses

Study/Trial	Elasticity estimates	Reduction in peak demand and consumption
Statewide Pricing Pilot - Time of Use group	§ Less than 20 kW elasticity of substitution -0.13 in summer and no statistically significant estimate for winter. § 20 kW – 200 kW elasticity of substitution -0.093 to -0.21 in summer and -0.072 in winter. § Given the small sample size and the large variation in results CRA noted that some caution should be observed when interpreting these results.	§ Less than 20 kW - no statistically significant reduction. § 20 kW – 200 kW – 0-7% reduction in peak demand in summer and 5% in winter.
EnergyAustralia	n.a.	Businesses less responsive than residential consumers.

Study/Trial	Elasticity estimates	Reduction in peak demand and consumption
Georgia Power Company (real time tariffs)	One hour in advance tariffs -0.28 to 0.2 and when prices set one day ahead -0.04 to -0.13.	n.a.
Southern California Edison	§ Less than 500 kW own price elasticity -0.033 to -0.035. § 200 kW – 500 kW own price elasticity -0.087 to -0.092.	n.a.
Pacific Gas and Electric Company	-0.019 to -0.038	n.a.
ESC (2002)	-0.025 with time of use and -0.0375 CPP (own price)	5% reduction in small and medium sized business peak demand.
CRA SA (2004)	-0.004 (own price)	§ No separate estimate for reduction in peak demand assuming smart meter and TOU tariff for small and medium sized businesses. § 0.77 kVA load reduction for air conditioner direct load control with 25 min. cycling (per customer)
NIEIR	Long run estimates: § -0.35 for commercial customers § -0.38 for industrial customers.	n.a.
Wade	-0.24 (short run) and -0.25 (long run)	n.a.

Table A.17: Summary of residential customer results

Study/Trial	Elasticity estimates	Reduction in peak demand and consumption
Critical Peak Pricing Trials		
Statewide Pricing Pilot	§ Summer -0.041 (own price) and -0.076 (elasticity of substitution) § Winter -0.011 (own price) and -0.025 (elasticity of substitution)	§ Critical peak days - summer 13.06% reduction in peak demand and 2.4% reduction in overall consumption; winter 3.91% reduction in peak demand and 0.62% reduction in overall consumption. § Non-Critical peak days - summer 4.71% reduction in peak demand and 0.17% increase in overall consumption; winter 1.39% reduction in peak demand and -0.02% reduction in overall consumption.
Ontario Smart Price Pilot	n.a.	§ Critical peak days 17.5% reduction in peak for CPP group and 25.4% for critical peak rebate group. § Non-Critical peak days 8.5% reduction in peak for CPP group and 11.9% for critical peak rebate group. § Overall consumption reduced by 7.4% for CPP group. Results for CPP rebate group not statistically significant.
EnergyAustralia	n.a.	§ Statistically significant reduction in residential and customers consuming less than 160 MWh pa. § Conservation of energy dominated deferral effect. Preliminary results indicate a conservation effect of between 7-15% on summer CPP days.[271] § No statistically significant different response for participants with and without in-home display.
Integral Energy	n.a.	§ Statistically significant reduction in demand by participants subject to dynamic peak price tariffs. § Conservation of energy dominated deferral effect. Preliminary results indicate a conservation effect of between 7-15% on summer CPP days.[272] § Preliminary results indicate a statistically significant different response for participants with and without in-home display, in the order of 5% additional reduction in peak demand.
Country Energy	n.a.	§ 25% reduction in peak demand during CPP events. § 8% reduction in energy consumption over the trial.

[271] Preliminary result reported as an average across EnergyAustralia and Integral trials (from communication between NERA and EnergyAustralia and Integral).

[272] See previous footnote

Study/Trial	Elasticity estimates	Reduction in peak demand and consumption
ESC (2002)	-0.15 (own price)	30% reduction in residential peak demand using formulation specified in Position Paper.
CRA Vic (2005)	§ -0.041 (own price) § -0.076 (elasticity of substitution).	10% reduction in residential peak demand.
CRA SA (2004)	-0.025 (own price)	§ 10% reduction in peak demand assuming smart meter with CPP. § 0.62 kVA load reduction for air conditioner direct load control with 25 min. cycling (per customer).
Ofgem	n.a.	2.5% reduction in peak demand and 1% reduction in overall consumption.
Time of Use Pricing Trials		
Statewide Pricing Pilot	§ Summer -0.044 (own price) and -0.069 (elasticity of substitution) § Winter -0.019 (own price) and -0.025 (elasticity of substitution)	§ Summer 4.71% reduction in peak demand and 0.17% reduction in overall consumption. § Winter 1.39% reduction in peak demand and 0.02% reduction in overall consumption.
Ontario Smart Price Pilot	n.a.	§ Reduction in peak demand not statistically significant. § Overall consumption reduced by 6%.
Northern Ireland	n.a.	§ 10% reduction in peak demand. § 3.5% reduction in overall consumption.
Puget Sound Energy	n.a.	§ 5-6% reduction in peak demand. § 5% reduction in overall consumption.
Integral Energy	n.a.	No statistically significant difference in response of participants paying seasonal TOU tariffs relative to the control group.
Energex	n.a.	No change in peak demand.
ESC (2002)	-0.1 with time of use (own price)	20% reduction in residential peak using elasticity measures and 8-18% using end use models.
OTTER (2006)	n.a.	10% reduction in peak demand assuming smart meter with TOU tariffs.
Direct Load Control and Enabling Technologies		
Statewide Pricing Pilot	n.a.	Average reduction in peak demand for participants with enabling technology twice the reduction achieved by participants without enabling technology.
Californian automated demand response pilot	n.a.	§ Critical peak days 43% reduction in demand. § Non-Critical peak days 27% reduction in demand.
CRA SA (2004)	n.a.	0.62 kVA load reduction for air conditioner direct load control with 25 min. cycling (per customer).
ETSA Utilities	n.a.	17% reduction in peak demand from direct load control of air conditioners of residential consumers.
Energex	n.a.	§ 34% reduction in peak demand with TOU tariffs and direct load control.

Study/Trial	Elasticity estimates	Reduction in peak demand and consumption
		§ 13% reduction in peak demand for TOU tariff with timer. § 12% reduction in peak demand for TOU tariff with ad-hoc load control.
Academic Short Run Own Price Elasticity Studies		
Fillippini and Pachauri	-0.16 to -0.39	n.a.
Tiwari	-0.70	n.a.
Fatai et al	-0.18 to -0.24	n.a.
Filippini	-0.60 peak and -0.79 off-peak (short run)	n.a.
Reiss and White	-0.39	n.a.
Miller	-0.37	n.a.
Wade	-0.23	n.a.
Silk and Joutz	-0.62	n.a.
Herriges and King	-0.2 summer and -0.4 winter	n.a.
Long Run Own Price Elasticity Studies		
NIEIR	-0.25	n.a.
Beenstock et al.	-0.579	n.a.
Filippini	-0.71 peak and -1.92 off-peak	n.a.

Appendix B. Estimating the revised demand forecasts resulting from the introduction of TOU and CPP

This appendix provides a description of the methodology and assumptions used in the analysis of consumer's demand response to the introduction of TOU tariffs and CPP.

The remainder of this appendix is structured as follows:

§ Section B.1 provides an overview of the principal assumptions underlying the analysis;

§ Section B.2 sets out the methodology used to estimate the demand side response arising from the transition from accumulation meters to smart meters with the core functionality[273] and the effect on jurisdictional load profiles;

§ Section 0 presents the results of the demand side response analysis; and

§ Section B.4 provides jurisdictional summaries of the assumptions made and the overall results.

B.1. Assumptions

To develop an estimate of the likely demand side response arising from the transition from accumulation meters to smart meters in each jurisdiction, a number of assumptions have been made about:

§ the tariff products likely to be offered by retailers to residential customers and to small commercial customers;

§ the responsiveness of consumers to time of use prices and CPP; and

§ the composition of jurisdictional load profiles.

The analysis also considers likely intra-jurisdictional variations in each of these assumptions.

B.1.1. Product offerings

Smart meters allow a customer's electricity use to be measured and recorded for each half-hourly period of a day. This data facilitates the introduction of both TOU tariffs and CPP.

A review of international and domestic practical trials (see Appendix A) indicates that the reduction in peak electricity consumption attainable under a TOU tariff structure is lower than that attainable when the TOU tariff was coupled with CPP. For instance, CRA's Statewide Pricing Pilot impact study found that summer peak demand could be reduced by 13.06 per cent when trial participants were subject to CPP while summer peak demand could only be reduced by 4.71 per cent when TOU tariffs alone were in place.[274] The ESC also

---

[273] Excluding functionalities 15 and 16, which are subject to a separate analysis.

[274] CRA, Impact Evaluation of the California Statewide Pricing Pilot, March 2005, pg. 61.

concluded in its 2002 Position Paper[275] that a reduction in peak demand of 20 per cent[276] could be achieved with time of use pricing while a reduction of 30 per cent[277] could be achieved if CPP were implemented. Similar differences in response have also been observed in the Ontario Smart Pricing Pilot.[278]

As a result, we have considered that retailers may offer both TOU tariffs and CPP to residential consumers following a smart meter roll-out, as well as a continuation of the current flat tariff structure. Small commercial customers are assumed to be offered TOU tariffs or a flat tariff structure.

The level and structure of residential TOU tariffs and CPP used in this analysis have been developed by KPMG as part of the retail workstream. The assumed tariffs are reported in section 3 of the main report.

The tariff assumptions developed by KPMG include carbon emission related costs that may affect wholesale electricity prices in the future. They do not include the 'second round' impact of any roll-out of smart meters on net costs.

B.1.2. Elasticity of demand

There are two measures of the elasticity of demand that are relevant when considering the responsiveness of demand to a transition from flat or inclining block tariffs to TOU tariffs and CPP. These two measures are:

§ the elasticity of substitution between peak and off-peak demand (herein referred to as the elasticity of substitution) which measures the change in the ratio of peak to off-peak consumption arising as a consequence of a change in the peak to off-peak price ratio;[279] and

§ the own-price elasticity of demand which measures the percentage change in peak (or off-peak) demand arising as a result of a one per cent change in the peak (or off-peak) price of electricity.

Stepping through the transition from flat tariffs to TOU tariffs one would expect that the peak price would be set at a higher level than the off-peak price. The difference in prices across the two periods would, by virtue of the elasticity of substitution, cause some consumption to be shifted from peak periods to off-peak periods. Overall demand on a particular day may also change if the proportion of electricity consumed in the peak and off-peak periods result in the weighted average price being different to that which was paid under the flat tariffs.

---

[275] ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002.

[276] ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002, pg. 58.

[277] This has been calculated using the ESC methodology specified on page 58 and replaces the -0.1 elasticity measure with an estimate of -0.15.

[278] Ontario Energy Board Smart Price Pilot, July 2007, Appendix E, pg. 3.

[279] Where alternative tariffs apply in shoulder periods there will also be an elasticity of substitution between the peak and shoulder periods and the shoulder and off peak periods.

The transition from a flat or an inclining block tariff to a TOU tariff with a CPP element may therefore cause short and long-run changes to:

- § the pattern of consumption for each 30 minute interval within a day; and
- § the absolute level of consumption.

It should be noted in this context that the tariff assumptions developed by KPMG have been designed to maintain revenue neutrality.[280] Revenue neutral tariffs have been used in other trials to ensure that the design of the TOU tariffs recovers the same amount of revenue as was recovered under the flat or inclining block tariff structure assuming that consumption patterns throughout the day are unchanged. If revenue neutrality is not maintained then it is possible that, even without a change in consumption patterns throughout the day, there may be a change in daily demand because the new weighted average price payable under TOU tariffs differs from the current tariffs. In the absence of revenue neutrality it is possible that a portion of the change in demand attributed to the transition from accumulation meters to smart meters simply reflects the change in the weighted average price paid by users and is not directly attributable to the transition to TOU tariffs or CPP. In other words, the same change in demand could occur if the flat tariff structure was maintained but the level of tariff was changed.

Trials undertaken both internationally and domestically have demonstrated that the responsiveness of residential and commercial customers to pricing signals can differ substantially. Accordingly separate elasticity measures have been used to estimate the demand side response arising from these two types of customers.

Residential elasticity assumptions

Appendix A contains a detailed overview of the studies and trials that have been undertaken in relation to the responsiveness of residential customers to time of use and CPP in the short run. As noted in that appendix the most recent and comprehensive study of this issue was carried out by CRA in California as part of the Statewide Pricing Pilot. This study involved participants located in four distinct climate zones and resulted in the estimation of elasticity of substitution and own-price elasticity measures across the four climate zones on critical peak days, non-peak weekdays and weekends and over summer and winter periods.

A summary of these elasticity estimates and the climate conditions prevailing in each zone is set out in Table B.1.

[280] This is in contrast to the assumptions underlying the retail tariffs developed for the Phase 1 analysis.

Table B.1: Statewide Pricing Pilot elasticity estimates

Measure	Zone 1	Zone 2	Zone 3	Zone 4	Average all zones
Summer					
Critical peak day					
Critical peak temperatures observed	25.8 °C	29.1°C	34.2°C	39.9°C	n.a.
Elasticity of substitution	-0.039	-0.061	-0.102	-0.113	-0.076
Daily price elasticity	-0.041	-0.042	-0.043	-0.032	-0.041
Peak weekday (non-CPP)					
Average temperatures observed	23.8 °C	27.3 °C	31.6°C	36.8°C	n.a.
Elasticity of substitution	-0.034	-0.055	-0.093	-0.105	-0.069
Daily price elasticity	-0.043	-0.044	-0.047	-0.039	-0.044
Weekend					
Daily price elasticity	-0.014	-0.018	-0.026	-0.020	-0.020
Winter					
Critical peak day					
Elasticity of substitution	-0.027	-0.026	-0.024	-0.024	-0.025
Daily price elasticity	-0.010	-0.013	-0.011	-0.004	-0.011
Peak weekday (non-CPP)					
Average temperatures[1]	11.8-13.5 °C	10.6-15.7 °C	12.6-15.0 °C	12.5-16.4 °C	n.a.
Elasticity of substitution	-0.026	-0.026	-0.024	-0.024	-0.025
Daily price elasticity	-0.017	-0.020	-0.011	-0.004	-0.019
Weekend					
Daily price elasticity	0.020	0.025	0.023	0.019	0.023

Source: CRA, Impact Evaluation of the California Statewide Pricing Pilot Tables 4-10, 4-11, 4-23 and 4-24.
1. U.S. Department of Energy. Energy Efficiency and Renewable Energy 2005 temperature estimates.

Reviewing the estimates in this table it is apparent that the responsiveness of consumers is higher in summer than winter and higher on critical peak days than non-peak weekdays. The relative responsiveness of consumers located in warmer climates (zones 2-4) is also higher than those located in colder climates (zone 1) in summer but lower in winter.

Given the comprehensive nature of the Californian study and the similarities in climatic conditions prevailing in Australia and California it would appear that the results of this study form a reasonable basis for estimating the likely demand side response arising from the transition from accumulation meters to smart meters.

To determine the appropriateness of particular zonal results to each jurisdiction a comparison of the climate conditions prevailing in Australia and the four climate zones in California was carried out. Based on this comparison it was concluded that there were broad similarities in the climatic conditions prevailing in:

- Tasmania and Zone 1;
- the Northern Territory and Zone 4; and
- Queensland, Western Australia and Zone 3.

In the case of the Northern Territory, feedback following the Phase 1 report expressed concern that the SPP elasticities may not be appropriate, given the much higher level of humidity in the Northern Territory than any of the comparable areas in the SPP given the much higher degree of humidity experienced. For this Phase 2 analysis we have adjusted the elasticity estimate for zone 4 in the SPP to reflect differences in reported elasticity estimates for California and Florida, which has similarly humid conditions.[281]

The climate conditions in New South Wales and Victoria were viewed as broadly comparable with the average conditions prevailing across all four zones. In the case of South Australia the average climatic conditions are similar to those observed in Zone 2, however, the maximum temperatures in South Australia are substantially higher and this factor coupled with the high level of air conditioner penetration in South Australia may lead one to conclude that Zone 3 is the more appropriate comparator than Zone 2 or the overall average.

Table B.2: Elasticity assumptions applied for Phase 1 base case

Measure	Tasmania (Based on Zone 1)	Queensland, South Australia and Western Australia (Based on Zone 3)	Northern Territory (Based on Zone 4, adjusted)	New South Wales and Victoria (Based on Average all Zones)
RESIDENTIAL				
Summer				
Critical peak day				
Elasticity of substitution	-0.039	-0.102	-0.077	-0.076
Own price elasticity	-0.041	-0.043	-0.022	-0.041
Peak weekday (non-CPP)				
Elasticity of substitution	-0.034	-0.093	-0.071	-0.069
Own price elasticity	-0.043	-0.047	-0.026	-0.044
Weekend				
Own price elasticity	-0.014	-0.026	-0.014	-0.020
Winter				
Critical peak day				
Elasticity of substitution	-0.027	-0.024	-0.016	-0.025
Own price elasticity	-0.010	-0.011	-0.003	-0.011
Peak weekday (non-CPP)				
Elasticity of substitution	-0.026	-0.024	-0.016	-0.025
Own price elasticity	-0.017	-0.019	-0.012	-0.019
Weekend				
Own price elasticity	0.020	0.023	0.013	0.023
COMMERCIAL				
Own price elasticity	-0.02	-0.02	-0.02	-0.02

In the **long run** residential customers have the option of replacing appliances that are more energy efficient, or are fuelled by an alternative source of energy. Thus the responsiveness of

[281] Relative elasticity estimates were taken from *Regional Differences in the Price-Elasticity of Demand For Energy*, Mark A. Bernstein, James Griffin, RAND Corporation 2005. The results of this paper indicated that the short-run price elasticity of electricity in Florida was approximately 68 per cent of the elasticity estimated for California. This adjustment was applied to the zone 4 results from the SPP.

residential customers to electricity prices is higher than that observed in the short run. However, under the assumption of revenue neutral tariffs, although consumers on TOU tariffs or CPP face higher prices at peak times, they will face lower prices at off-peak times and overall the electricity bill for the average consumer would not change. For the purposes of this analysis we have therefore assumed that the elasticity of substitution and own-price elasticities are the same in both the short and long-run.

Commercial elasticity assumptions

The responsiveness of commercial customers to changes in the overall price paid for electricity and differentials between peak and off-peak prices has generally been found to be:

- lower than that of residential customers in the short run; and
- higher than that observed in residential customers in the long run.

A lower level of responsiveness to changes in price amongst commercial customers in the short-run is consistent with what one would expect given the limited options available for commercial customers to reduce their total consumption and to shift consumption between peak and off-peak times. This latter point is particularly relevant when considering the elasticity of substitution because in many jurisdictions the peak period extends beyond core business hours. For instance in Queensland, Victoria, Tasmania and the Northern Territory where the peak period extends from 7 am to 9 pm, 7 am to 11 pm, 7 am to 8 pm and 6 am to 8 pm respectively, the ability of commercial customers in these locations to defer consumption beyond these hours is somewhat limited. These limitations suggest that the elasticity of substitution will be negligible for commercial customers, if the current period definitions are retained.

The short-run US based trials referred to in the ESC's 2002 Position Paper established a short-run own-price elasticity range of -0.019 to -0.092[282] for commercial customers that were substantially lower than the -0.1 to -0.3 residential customer range. The more limited response of commercial customers to pricing signals observed in the US trials and studies has also been observed in EnergyAustralia's smart meter trial. In view of these findings it has been assumed that the percentage reduction in consumption attainable by commercial customers is approximately half of that attainable by residential customers on a non-peak day, which implies an own-price elasticity of demand of approximately -0.020.

As with the long run residential own-price elasticity estimates, the long run own-price elasticity measures for commercial customers has been assumed to be the same as the short run estimates, given the assumption of revenue neutrality and the absence of 'second round' effects incorporated into the tariffs in the longer term.

[282] ESC, Installing Interval Meters for Electricity Customers – Costs and Benefits - Position Paper, November 2002, pp. 62-66.

B.1.3.Decomposing jurisdictional load profiles

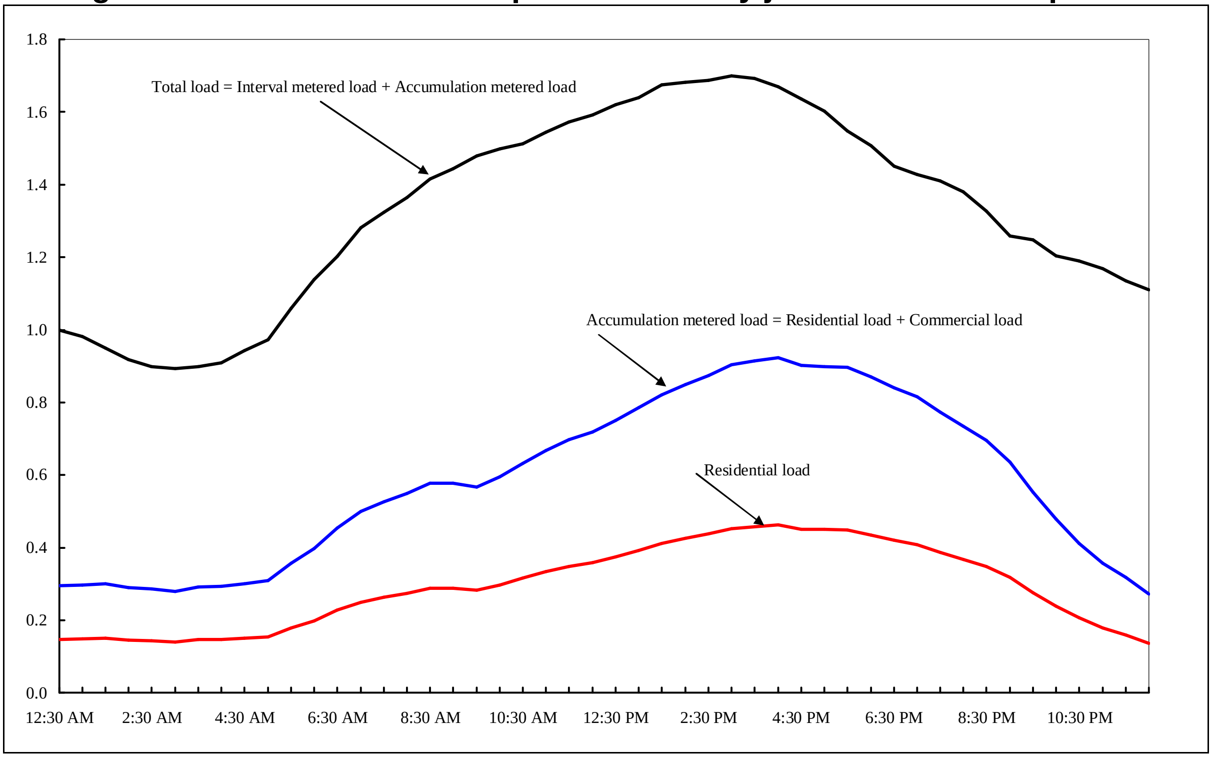
To apply the elasticity measures outlined above to residential and commercial consumers that would receive a smart meter (ie, those consumers with consumption levels below the threshold set in each jurisdiction for mass market meters) it was necessary to:

§ remove the load accounted for by consumers already utilising interval meters; and

§ disaggregate the remaining load that can be attributed to accumulation metered consumption (total load less interval metered load) into the load accounted for by residential versus commercial customers.

Figure B.1 provides an illustrative example of the decomposition analysis that was undertaken to identify both the level and pattern of consumption of residential and commercial customers.

Figure B.1: Illustrative decomposition of daily jurisdictional load profile



This decomposition analysis was carried out using actual load data for each jurisdiction over the most recent financial year extending from 1 July 2006 to 30 June 2007. To ascertain whether this year was a representative year in the national electricity market a comparison of the actual summer and winter maximum demand in each jurisdiction was made using the 10 per cent, 50 per cent and 90 per cent probability of exceedence (POE) maximum demand estimates developed in NEMMCO's 2005/06 Statement of Opportunities (SOO). Figure B.2 illustrates this comparison and demonstrates that:

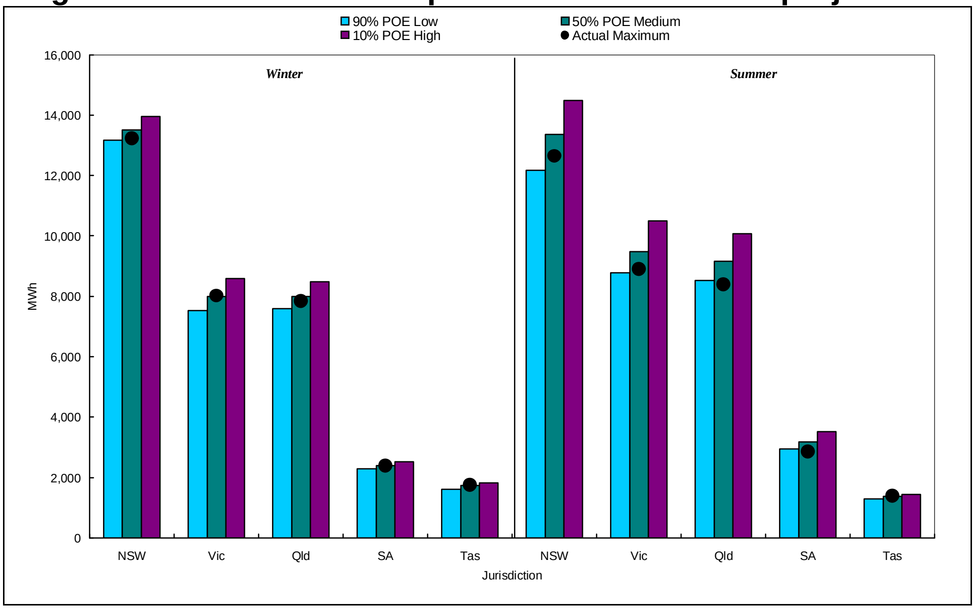
§ over the winter period the actual maximum demand was relatively close to the 50% medium POE estimates; and

§ over the summer period the actual maximum demand in Tasmania was relatively close to the 50% medium POE estimate while in New South Wales and Victoria actual maximum demand was closer to the 90% low POE and in South Australia and Queensland actual maximum demand was below the 90% low POE.

This comparison suggests that 2006/07 was not an abnormal year in terms of breaching the maximum demand projections set by the 10% high POE.

There is an important qualification to the above in the case of NSW. NSW was winter peaking in 2006/7. Given the growth of air-conditioning load in NSW, there appears to be a general expectation amongst stakeholders that NSW will be predominately summer peaking over the timeframe of this analysis. Indeed, the NEMMCO SOO projections for NSW show NSW moving to becoming summer peaking.[283] We have addressed this issue by modelling demand response for NSW both on the basis of the 2006/07 demand profile and also on the basis of proxies for the response that may be expected if NSW was summer peaking. This is discussed further in Box B.2.

Figure B.2: Actual consumption versus NEMMCO projections



Source: NEMMCO, 2005 Statement of Opportunities

A review of the Western Australian Independent Market Operator's July 2006 Statement of Opportunities indicates that the maximum demand observed over 2006/07 (3,215 MW) was closer to the 50 per cent POE maximum demand forecasts than the 10 per cent and 90 per cent POE forecasts under the expected economic growth (3,287 MW), low (3,259 MW) and high economic growth (3,332MW) scenarios.

In view of the foregoing it has been assumed that, except in the case of NSW, 2006/07 was broadly representative of an average year and therefore electricity demand and the load

283 NEMMCO Statement of Opportunities (2007), Pages 3-36.

profile observed over this year has formed the basis for all of the demand response analysis undertaken for Phase 1. As discussed above, we have also conducted a sensitivity in the case of NSW assuming that NSW moves to becoming summer-peaking (see Box B.2).

B.1.3.1. Estimating the load accounted for by accumulation metered customers

Identifying the load accounted for by customers currently utilising accumulation meters in 2006/07 was relatively straightforward for New South Wales (including the Australian Capital Territory), South Australia and Victoria. Since the advent of full retail contestability in these jurisdictions NEMMCO has, as part of the settlement process, collected net system load profile data that represents consumption and an assumed load profile of customers in these states using accumulation meters.

We note that this data does include some large customers that are above the jurisdictional interval metering threshold but who do not as yet have an interval meter. We have been unable to gather information in relation to the total consumption of these customers, and the profile of that consumption, in order to remove their consumption from the net system load profile.

However, we do not consider that the inclusion of consumption from non-interval metered large customers is likely to materially affect the results of our analysis. The number of such customers in each jurisdiction is limited. Under our methodology their consumption is effectively allocated to commercial customers, who are in turn subject to a relatively low elasticity estimate. Moreover, it would appear plausible that these customers may also move to interval metering as part of a national roll-out.

Although Queensland and Tasmania are part of the NEM, net system load profile data is only collected when full retail contestability is in place and thus there is no such information available for these two states over the 2006/07 period. It would appear that interval load data is also not collected in a centralised manner in either the Northern Territory or Western Australia. In the absence of this information it was necessary to make some assumptions about the level and profile of interval metered consumption in these jurisdictions.

The specific assumptions made for these four jurisdictions are outlined below.

Queensland

Information provided by Ergon and Energex allowed disaggregation of the daily load profile into interval metered consumption and accumulation metered consumption on an illustrative peak and non-peak day. According to these estimates interval metered customers accounted for between 40 per cent to 50 per cent of total load on a peak day and 44 per cent to 51 per cent of total load on a non-peak day. This was extrapolated over the half-hourly 2006/07 load data to estimate the load accounted for by both interval metered customers and accumulation metered customers.

Tasmania

The assumptions surrounding the level and profile of interval metered consumption in Tasmania were made by reference to OTTER's 2005-06 Tasmanian Energy Supply Industry Report. According to this report large customers average aggregate consumption is 700 MW and their demand accounts for 40 per cent of the state's maximum demand and 60 per cent of total energy consumption.[284] The 700 MW large load estimate was deducted from Tasmania's total 2006/07 half-hourly load data and the remaining load was assumed to be accounted for by accumulation metered customers.

Western Australia

The assumed level and profile of interval metered consumption in Western Australia was estimated using a study contained in Western Power's 2007 Transmission and Distribution Annual Planning Report. This peak load profile study of the South-West Interconnected System set out the estimated load profile for commercial, residential and mixed residential/commercial during a summer substation peak. The commercial estimate was assumed to represent consumption by interval metered customers on a peak day.

To estimate the proportion of consumption of this group on a non-peak day the relationship between peak and off-peak interval metered consumption observed in Queensland was used. The proportion of total load accounted for by commercial customers on peak and non-peak days was then deducted from Western Australia's total 2006/07 half-hourly load data to estimate the load accounted for by accumulation metered customers.

Northern Territory

In the Northern Territory there was little information available on the current level and profile of interval metered consumption. According to the Utilities Commission's Northern Territory Market Information Paper 2006/07 the consumption of customers on the regulated network with consumption of less than 160MWh per annum was 40 per cent of total demand in the territory. A similar breakdown was not available for the 14 per cent of consumption on the non-regulated network, so it was assumed that this was substantially attributable to large users.

To be able to estimate the contribution of residential customers to the consumption of accumulated metered customers, ABARE electricity consumption data was examined.[285] These data revealed that residential customers in the Northern Territory accounted for 14 per cent of total electricity consumption. This amounts to 35 per cent of the accumulation metered consumption. The pattern of peak and off-peak consumption assumed was based on that estimated for Western Australia, normalised to these averages.

B.1.3.2. Disaggregating accumulation metered load

To enable separate elasticity measures to be applied to residential and small commercial/industrial customers currently utilising accumulation meters it was necessary to further disaggregate the estimated accumulation meter load profiles in each jurisdiction. Requests were made to network service providers to provide any information they had on the contribution of residential consumption to peak demands and overall load. These requests

---

[284] OTTER, Tasmanian Energy Supply Industry Performance Report, 2005/06, pg. 17.

[285] ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006.

yielded some information from distributors in South Australia, Queensland, the Australian Capital Territory, Victoria and Western Australia but limited information elsewhere.

ETSA Utilities was able to provide a breakdown of its demand profile by customer segment between 4pm and 4.30 pm on 20 January 2006 and 17 February 2007. According to this information residential customers accounted for 58 per cent of residential plus small commercial and industrial demand on 20 January 2006 when the maximum temperature was 26.9° Celsius and 70 per cent on 17 February 2007 when the maximum temperature was 41.5° Celsius. This information is broadly consistent with a detailed study that CRA undertook for ETSA Utilities in 2004. In this study CRA estimated the total load accounted for by residential, commercial and industrial consumers on an illustrative peak and non-peak days and the profile of consumption over the day. The table below sets out the proportion of accumulation metered load accounted for by residential customers estimated by CRA over three time periods.

Table B.3: South Australian residential consumption as a proportion of accumulation metered load

Time and Type of Day	South Australia
Peak day	
Midnight to 8 am	82%
8 am to 6 pm	70%
6 pm to Midnight	82%
Non-peak day	
Midnight to 8 am	58%
8 am to 6 pm	65%
6 pm to Midnight	70%

Source: CRA, Peak Demand on the ETSA Utilities System, February 2004, pp. 6-12.

The table below sets out the proportion of accumulation metered load accounted for by residential customers based on information provided by Ergon and Energex.

Table B.4: Queensland residential consumption as a proportion of accumulation metered load

Time and Type of Day	Queensland
Peak day	
Midnight to 8 am	68%
8 am to 6 pm	51%
6 pm to Midnight	74%
Non-peak day	
Midnight to 8 am	61%
8 am to 6 pm	52%
6 pm to Midnight	66%

Source: Ergon Energy and Energex.

Examining the South Australian and Queensland results a number of observations can be made. First, the proportion of accumulation metered consumption accounted for by residential consumers is generally lower in Queensland than it is in South Australia. The peak contribution of residential consumption is also lower in Queensland, which may reflect the lower levels of air conditioner penetration in that state.

The information contained in these two tables has been used to disaggregate the accumulation metered data in South Australia and Queensland with the peak day profiles applied on the twelve critical peak days and the non-peak day profiles being applied to all other days.

For the remaining states and territories there was only limited jurisdictional-specific information available and thus some consideration was given to whether the estimates for South Australia or Queensland could be extrapolated to other states and territories.

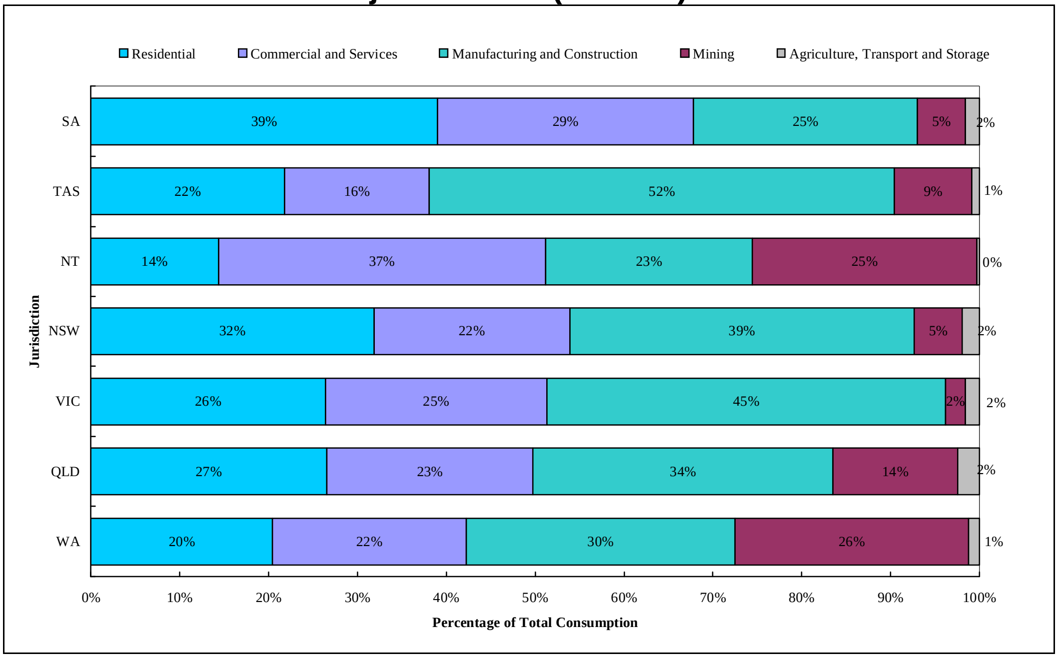
In the case of New South Wales (including the Australian Capital Territory) this consideration was informed by a comparison of:

§ the proportion of electricity consumed in each jurisdiction by residences versus other sectors; and

§ air conditioner penetration rates across jurisdictions.

The comparison of energy consumption across each jurisdiction was carried out using ABARE final energy projections for 2006/07, which are summarised in Figure B.3.[286] A summary of air conditioner penetration rates in each jurisdiction are set out in Table B.5.

Figure B.3: Composition of electricity consumption by industry and jurisdiction (2005/06)



Source: ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006.

286 Source: ABARE, Total Final Energy Consumption by Industry and Fuel, December 2006.

Table B.5: Air conditioner penetration in 2005

State	Penetration Rate
Tasmania	19.8%
New South Wales	54.1%
Queensland	58.2%
Victoria	60.5%
Western Australia	69.6%
Northern Territory	91.9%
South Australia	85.0%

Source: Energy Efficient Strategies, Status of Air Conditioners in Australia – A report prepared for NAEEEC, January 2006.

Examining these sources it would appear that both the composition of small user consumption (ie, residential versus commercial and services consumption) and air conditioner penetration rates are broadly similar in Queensland and New South Wales. In view of these similarities and in the absence of any other information the Queensland estimates have been used for the purpose of decomposing the net system load profile for New South Wales.

Similar conclusions can also be drawn about the similarities between consumption and air conditioner penetration rates in Queensland and Victoria. Information provided by United Energy Distribution also indicates that there are some similarities in the contribution of residential consumption to peak demand in Victoria and Queensland. According to the data provided by United Energy Distribution residential customers accounted for 41 per cent of total peak demand in 2002 while commercial customers and industrial customers accounted for 26 per cent and 33 per cent respectively.[287] In providing this information United Energy noted that the data may not be completely accurate and should only be used as a guide. Comparing these estimates with the Queensland estimates it would appear that the two are broadly in line (with United Energy Distribution's estimates suggesting that residential consumption accounts for approximately 62 per cent of peak demand).[288] In view of these similarities the more detailed Queensland estimates have been used to disaggregate the Victorian net system load profile on peak and non-peak days.

Reviewing the data presented above it would appear that residential consumption in the Northern Territory is quite unique with consumption from this sector accounting for just 14 per cent of overall electricity consumption compared to an average of 28 per cent in other states. Air conditioner ownership is also substantially different from that observed in other states with the penetration rate exceeding 90 per cent. Consumption patterns and air conditioner penetration levels are also somewhat distinctive in Tasmania and thus it did not seem appropriate to apply the Queensland or South Australian estimates to either the Northern Territory or Tasmania. Instead it was assumed that the time path of consumption over peak and non-peak days mimicked that observed in Queensland but[289] the average

---

[287] Alinta Asset Management, Demand profile information, 17 August 2007, pg. 1.

[288] Calculated by assuming that industrial load represents interval metered load (41%/(41%+26%)=62%).

[289] Given the relatively stable colder climate conditions experienced in Tasmania one would expect the residential load profile to be relatively flat over peak and non-peak days which is consistent with the peak to non-peak relationship observed in Queensland but quite different from that observed in South Australia. Accordingly, the Queensland time and peak versus non-peak profile was assumed to be more appropriate for Tasmania. Similarly, the hotter and

residential consumption estimated by ABARE as a proportion of small user consumption (56 per cent[290,291] in Tasmania and 35 per cent[292] in the Northern Territory) was maintained over the year.

In Western Australia the South-West Interconnected System load profile study was used to disaggregate residential and mixed residential/commercial consumption and to estimate the relative proportion of small customer load accounted for by these two groups. Since this study was only undertaken on a peak day it has been assumed that the relationship between peak day and non-peak day consumption in Western Australia is similar to that observed in Queensland.

It should be noted in this context that the information received from Ergon and Energex are based on load sampled from two days. One would expect estimates based on averages over the year may vary from these figures, but informational deficiencies mean that we do not have access to more accurate data. In light of these limitations, the results generated using these assumptions are necessarily approximations of reality.

B.2. Framework used to estimate the demand side response

To estimate the demand side response associated with the introduction of TOU tariffs and CPP and to develop the resulting load profile for each jurisdiction the following six steps were followed:

1. Disaggregate total half-hourly load data for each jurisdiction into consumption by users of accumulation meters and consumption by users of interval meters;
2. Disaggregate the accumulation metered half-hourly load data for each jurisdiction into consumption by residential customers and consumption by commercial users taking into account both the time profile over the day and differences in peak day versus non-peak day consumption patterns;
3. Identify twelve critical peak days in each jurisdiction during the 2006/07 financial year using the total half-hourly load data. These were selected by choosing twelve days which had the highest half-hourly demand;
4. Apply separate residential and commercial elasticity measures and assumptions relating to the uptake of TOU tariffs and CPP to the residential and commercial accumulation metered half-hourly load data in each jurisdiction to derive a new residential and commercial half-hourly load profile for 2006/07 (see Box B.1 for a description of the way in which the elasticity measures were applied to residential load);

---

relatively stable climate conditions experienced in the Northern Territory coupled with the high air conditioner penetration rates could be expected to produce a relatively flat residential load profile over peak and non-peak days.

290 Calculated as 22%/(22%+16%).

291 ABARE's estimate is broadly in line with information provided by Aurora Energy which indicated that residential consumption accounted for 20.3% and commercial consumption accounted for 20.7%.

292 Calculated as 14%/40%, as described in section B.1.3.1.

5. Combine the new residential and commercial half-hourly load profiles with the half-hourly interval metered data to derive a new total half-hourly load profile for each jurisdiction; and
6. Compare the original total half-hourly load profile with the new half-hourly load profile to estimate the demand impact of the introduction of TOU tariffs and CPP.

The process described above is conducted for each of the financial years from 2009 to 2016 and 2020, 2025 and 2030 respectively. For each year, expected load profiles obtained from CRA specific to that year are used as the load data inputs and tariffs are adjusted by the expected carbon price for that year.

The assumptions in relation to tariff structures and levels have been developed by KPMG as part of the retail workstream. For some jurisdictions the TOU tariffs include shoulder as well as peak and off-peak periods. In order to combine these tariff structures with the SPP elasticity estimates (which were calculated on the basis of a TOU structure of peak and off-peak only) we have averaged expected demand in the shoulder periods with the off-peak periods. The impact of this on the estimates of demand impact that result from our demand model is likely to lead to a higher estimation of demand response at peak times in those states with shoulder periods than would otherwise be the case. This is because, by averaging shoulder and off-peak tariffs, the extent of the price difference between peak periods immediately adjacent period is increased. In turn, the greater price difference drives greater shifting away from the peak period.

Box B.1: Application of residential elasticity measures

Separate elasticity measures have been assumed to apply over the summer and winter periods in each jurisdiction and different estimates have been applied to weekdays, weekends, public holidays and critical peak days during these seasonal periods. In order to apply these seasonal estimates over the year-long residential load profile it was necessary to apply summer and winter elasticities separately. The summer elasticities have been applied over the six month period extending from November to April while the winter elasticities have been applied over the period May to October.

In order to apply the critical peak elasticities it was necessary to identify 12 critical peak days during the year. The critical peak elasticities and CPPs were applied to these 12 days during the relevant peak period specified for that jurisdiction and the remaining days over the year were simply treated as a normal weekday or weekend.

For each type of day in each season, the new average daily quantity per half-hour, $Q_d{}^2$, was expressed as a function of the previous average quantity and prices using the following formula:

$$Q_d{}^2 = Q_d{}^1 e^{h\left(\frac{P_d{}^2}{P_d{}^1}\right)}$$

Where h is the own-price elasticity for that type of day in that season.

For each type of day in each season, the new ratio of peak to off-peak consumption was expressed as a function of the previous ratio and prices by the formula:

$$\frac{Q_P{}^2}{Q_{OP}{}^2} = \left(\frac{Q_P{}^1}{Q_{OP}{}^1}\right) e^{\frac{e\left(\frac{P_P{}^2}{P_{OP}{}^2}\right)}{\left(\frac{P_P 1}{P_{OP}{}^1}\right)}}$$

Where e is the elasticity of substitution from peak to off-peak for that type of day in that season.

Finally, peak and off-peak quantities per half-hour were identified using the relationship between them and the average daily quantity, ie:

$$Q_d{}^2 = \frac{h_P Q_P{}^2 + h_{OP} Q_{OP}{}^2}{h_P + h_{OP}}$$

Where h_P and h_{OP} are the number of half-hours per day that the peak and off-peak prices apply.

Box B.2: Sensitivity Analysis for NSW Becoming Summer Peaking

Our base case demand analysis for NSW is based on the 2006/7 actual demand profile, under which NSW was winter-peaking.

NEMMCO's SOO projections show NSW electricity demand moving to becoming summer peaking. If NSW becomes summer-peaking, the potential demand response can be expected to increase as a result of:

- the higher elasticity of demand estimated for CPP and peak TOU periods that occur in summer rather than winter; and
- a greater response from DLC, which we have assumed in our demand model only to be utilised on peak days where the temperature is above 30 degrees Celsius.[293]

In order to assess the potential impact on the results of the cost benefit analysis from adopting an assumption of NSW becoming summer peaking we have therefore re-calculated the demand response on the basis of the following assumptions:

1. applying the higher summer elasticity estimate to all CPP periods for NSW, including those that occur in winter; and
2. constraining the model to select 15 DLC days, regardless of temperature.

The demand response for NSW is reported in this report for both the base case (ie, based on 2006/7) and the summer-peaking sensitivity.

CRA has also estimated the market benefits on the basis of both the base BSW demand response estimate and the summer-peaking sensitivity.

[293] See Section 5.1 and Section 6.2.

B.3. Results

Drawing on the assumptions outlined in section B.1 and the methodology outlined in the preceding section, the demand side response of residential and commercial customers as a result of the introduction of TOU tariffs and CPP (and associated take-up assumptions) was estimated across each half hour of the annual load profile.

Table B6 provides a summary of the estimated response of those residential customers on TOU and CPP both at peak times and over the day on critical peak days and non-peak days in each jurisdiction over the summer and winter periods. In Victoria and South Australia critical peak days were only called in summer and thus there are no critical peak day estimates for winter. Similarly in Tasmania the critical peak periods were only called in winter so there are no critical peak day estimates for summer.

Table B.6: Residential - estimates of the response to TOU and CPP for those customers on TOU tariffs and CPP

		NSW/ACT		NT	Qld	SA	Tas	Vic	WA
		Base	Summer peaking						
Peak times	***Summer***								
	Critical peak day	-17.3%	-19.6%	-10.6%	-18.6%	-14.5%	n.a	-16.7%	-21.5%
	Peak day (non-CPP)	-5.2%	-5.2%	-1.0%	-4.6%	-2.8%	-1.4%	-4.5%	-5.8%
	Winter								
	Critical peak day	-7.8%	-5.7%	-3.4%	-4.3%	n.a	-6.0%	n.a	-4.4%
	Peak day (non-CPP)	-1.9%	-1.9%	-0.2%	-1.2%	-0.7%	-1.1%	-1.7%	-1.4%
Daily Average	***Summer***								
	Critical peak day	-5.4%	-6.5%	-5.4%	-7.8%	-7.2%	n.a	-7.3%	-6.6%
	Peak day (non-CPP)	0.0%	0.0%	0.2%	-0.1%	0.4%	0.1%	-0.1%	0.2%
	Winter								
	Critical peak day	-3.2%	-1.5%	-2.2%	-1.6%	n.a	-3.0%	n.a	-1.3%
	Peak day (non-CPP)	0.0%	0.0%	0.1%	0.0%	0.2%	0.0%	0.0%	-0.2%

When the reductions in demand for customers on CPP and TOU tariffs are combined with the take-up rate assumptions set out in section 3.2 (ie, 7.5% for CPP and 35% TOU), the overall estimate for the change in residential consumption both during peak periods and over the entire day is as set out in Table B7.

Table B.7: Residential – overall change in maximum demand and consumption

	NSW/ACT (Base)	NT	Qld	SA	Tas	Vic	WA
Change in maximum demand	-0.99%	-0.18%	-1.65%	-1.31%	-0.66%	1.38%	0.29%
Change in overall energy consumption	-0.10%	0.00%	-0.13%	-0.14%	-0.09%	-0.15%	-0.06%

Table B8 below sets out the peak demand reductions for small commercial customers on TOU tariffs. CPP tariffs are not assumed to be offered to small commercial customers.[294]

Table B.8: Commercial - estimates of the response to TOU for those customers on TOU tariffs

		NSW/ACT (Base)	NT	Qld	SA	Tas	Vic	WA
Peak times	***Summer***							
	Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.4%	-0.4%
	Winter							
	Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.3%	-0.3%
Daily Average	***Summer***							
	Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.4%	-0.4%
	Winter							
	Peak day	-0.2%	0.0%	-0.4%	-0.5%	-0.4%	-0.3%	-0.3%

Table B9 presents the estimates of the overall change in small commercial consumption, given an uptake rate assumption for TOU tariffs of 40%. Since the elasticity of substitution has been assumed to be zero for small commercial customers their response to TOU tariffs is uniform across the day and thus the results are presented as a change in daily consumption.

Table B.9: Small commercial customers - overall change in maximum demand and consumption

	NSW/ACT (Base)	NT	Qld	SA	Tas	Vic	WA
Change in maximum demand	-0.08%	0.00%	-0.14%	0.41%	-0.14%	0.17%	-0.13%
Change in overall energy consumption	0.01%	0.00%	0.04%	0.04%	0.03%	0.03%	0.02%

294 This is a change from the assumptions made in the Phase 1 report.

Combining the revised half-hourly load data for residential and commercial customers with the original interval metered half-hourly load data, estimates were made of the change in the maximum demand and energy consumption for the entire jurisdictional load. Table B.10 shows these changes for 2016, the first financial year in which the rollout of smart meters is complete across all jurisdictions in the modelling.

Table B.10: All customers – overall change in maximum demand and consumption (2016)

	NSW/ACT		NT	Qld	SA	Tas	Vic	WA
	Base	Summer Peaking						
Change in maximum demand	-0.26%	-0.46%	-0.19%	-0.77%	-0.96%	-0.34%	-0.61%	-1.20%
Change in energy consumption	-0.02%	-0.02%	0.00%	-0.03%	-0.04%	-0.02%	-0.03%	-0.01%

The table shows the results for NSW based on both a continuation of a winter peaking profile and a move to a summer peaking profile.

Examining these tables it is clear that there are significant variations across jurisdictions. These variances can be explained by the different characteristics for each jurisdiction that have been assumed in the analysis underlying the results.

The pattern of annual load is a key factor in determining the effect on maximum demand of introducing changes to tariffs. Decreases in critical peak period consumption are often not passed completely through to decreases in maximum demand because of ‘peak-shifting’, where a new consumption peak may form just before or after the critical peak period, during a non-peak day or even on a weekend or public holiday where off-peak prices apply. For this reason, jurisdictions with ‘peakier’ demand may be able to derive greater reductions in maximum demand than those with flatter load profiles or those for which off-peak daytime consumption is close in magnitude to critical peak demands.

Another factor that influences the magnitude of the change in maximum demand is the contribution of residential and commercial customers to the overall jurisdictional load profile. Areas where customers with accumulation meters account for higher proportions of demand, particularly at peak times, are likely to experience greater reductions in maximum demand as a result of the likely tariffs enabled by a smart meter rollout.

Northern Territory and Western Australia have the highest such contributions to system load. However, the share of residential customers in this contribution is low for these jurisdictions, in particular for Northern Territory where residential customers are assumed to account for only 35 per cent of net system load profile. Due to the differing own and cross elasticities assumed for residential customers, estimated residential demand reductions are greater than for commercial customers, and jurisdictions with a lesser proportion of residential load are, all things being equal, likely to experience a smaller reduction in maximum demand.

The tariffs and elasticities that have been assumed are also important in determining the magnitude of changes to residential and commercial demands. The ratio of CPP to normal peak price has been assumed to be 5:1 or 4:1, depending on the jurisdiction. The ratio of magnitude of shoulder or off-peak prices to peak prices has not been constrained across jurisdictions. Due to the differing design of each of the tariff schemes used, this may cause prices at off-peak times to be lower than would otherwise be the case and influence the way in which ‘peak shifting’ may occur, particularly in jurisdictions where off-peak demand is not significantly lower than critical peak levels.

Section B.1.2 describes how different residential elasticity estimates were selected for the various jurisdictions so as to use estimates derived from areas exhibiting similar temperature patterns. A result of this process is that New South Wales and Victoria have lower assumed cross elasticities in summer than all other jurisdictions except Tasmania, which is winter peaking, and Northern Territory, where we understand that the capability for demand response may be limited due to the much higher level of humidity in the Northern Territory than any of the areas that elasticity estimates were derived from.

B.4. Jurisdictional assumptions and results

B.4.1.New South Wales and the Australian Capital Territory

B.4.1.1. Assumptions

Elasticity estimates

The elasticity estimates used in this analysis are set out in the table below.

Table B.11: New South Wales (including Australian Capital Territory) elasticity assumptions

Period	Residential: Elasticity of substitution	Residential: Own-price elasticity	Commercial own-price elasticity
Summer			
Critical	-0.076	-0.041	-0.025
Weekday	-0.069	-0.044	-0.025
Weekend	n.a.	-0.020	-0.025
Winter			
Critical	-0.025	-0.011	-0.025
Weekday	-0.025	-0.019	-0.025
Weekend	n.a.	0.023	-0.025

Tariffs

The tariffs used in this analysis are based on assumptions made by KPMG and are set out in the table below.

Table B.12: New South Wales (including Australian Capital Territory) Tariff Assumptions (c/kWh) (excl GST and carbon)

State	Flat Tariff	TOU tariffs: Peak M-F 2pm-8pm	TOU tariffs: Off-peak Everyday 10pm-7am	TOU tariffs: Shoulder Period 1 All other times	TOU tariffs: Shoulder Period 2	CPP: CPP factor^	CPP: CPP Discount*
NSW/ ACT	$0.1222	$0.2459	$0.0758	$0.0872	n.a.	5	5%

^ CPP price is the peak price multiplied by the CPP factor
* Discount applied to off-peak and shoulder tariffs only.

Disaggregating total load data

The demand response estimates for NSW are based on an analysis which utilises 2006/7 load profile data for NSW. In 2006/7 NSW was winter peaking. As discussed in Box B.2, we also conducted a sensitivity analysis for NSW based on an assumption that NSW will become summer peaking.

The half-hourly total load data and net system load profile data for New South Wales and the Australian Capital Territory was obtained from NEMMCO. According to the net system load profile data accumulation metered consumption accounted for 29 per cent of energy consumption in New South Wales and the Australian Capital Territory over 2006/07 and on critical peak days the net system load profile accounted for a maximum of 53 per cent of the total load. Country Energy has also provided information on this issue in relation to the Australian Capital Territory specific estimates. According to this information customers' consuming less than 160MWh per annum accounted for 72 per cent of peak demand and 60 per cent of total load. These Australian Capital Territory specific estimates are higher than those assumed for the combined New South Wales/Australian Capital Territory region.

Information was sought from distributors in New South Wales and Australian Capital Territory on the contribution of residential and small commercial customers to peak demand. Limited information was provided in response to this request and thus the Queensland estimates were used for the purpose of disaggregating the net system load profile. The Queensland study was viewed as being the best proxy given the similarities in the composition of small user consumption, air conditioner penetration rates and the relationship between maximum demand on critical peak days and non-peak days between the two states. The specific proportions used for peak and non-peak days and over various time blocks in the day are set out below.

Table B.13: Residential consumption as a proportion of accumulation metered load

Peak day	
Midnight to 8 am	68%
8 am to 6 pm	51%
6 pm to Midnight	74%
Non-peak day	
Midnight to 8 am	61%
8 am to 6 pm	52%
6 pm to Midnight	66%

B.4.1.2. Results

A summary of the results obtained using the assumptions outlined above are set out in the tables below.

Table B.14: New South Wales (including Australian Capital Territory) - demand response at peak times for customers on CPP and TOU

	Residential	Commercial
Summer		
Critical peak day	-17.3%	n.a.
Non- peak day	-5.2%	-0.2%
Winter		
Critical peak day	-7.8%	n.a.
Non- peak day	-1.9%	-0.2%

Table B.15: New South Wales (including Australian Capital Territory) estimate of the effect on jurisdictional load profile[1]

	Base	Sensitivity – summer peaking
Change in maximum demand	-0.26%	-0.46%
Change in overall energy consumption	-0.02%	-0.02%

1. Impact based on assumed take-up rates of 35% for TOU and 7.5% for TOU and CPP.

B.4.2.Northern Territory

B.4.2.1. Assumptions

Elasticity estimates

The elasticity estimates used in this analysis are set out in the table below.

Table B.16: Northern Territory elasticity assumptions

Period	Residential: Elasticity of substitution	Residential: Own-price elasticity	Commercial own-price elasticity
Summer			
Critical	-0.077	-0.022	-0.025
Weekday	-0.071	-0.026	-0.025
Weekend	n.a.	-0.014	-0.025
Winter			
Critical	-0.016	-0.003	-0.025
Weekday	-0.016	-0.012	-0.025
Weekend	n.a.	0.013	-0.025

Tariffs

The tariffs used in this analysis are based on assumptions made by KPMG and are set out in the table below.

Table B.17: Northern Territory tariffs (c/kWh) (excl GST and carbon)

State	Flat Tariff	TOU tariffs: Peak Everyday 6am-8pm	TOU tariffs: Off-peak Everyday All other times	TOU tariffs: Shoulder Period 1	TOU tariffs: Shoulder Period 2	CPP: CPP factor^	CPP: CPP Discount*
NT	$0.1501	$0.1714	$0.1233	n.a.	n.a.	4	5%

^ CPP price is the peak price multiplied by the CPP factor
* Discount applied to off-peak and shoulder tariffs only.

Disaggregating total load data

To separate interval metered consumption from accumulation metered consumption it was assumed that the proportion of total consumption accounted for by interval metered large customers would, on a peak day, be the same as that observed in Western Power's study of peak load profile on the South-West Interconnected System. To estimate the proportion of consumption of this group on a non-peak day the relationship between peak and off-peak interval metered consumption observed in Queensland was utilised (see Table B.24).

The table below sets out the proportion of total load that has been assumed to be accounted for by accumulation metered customers in the Northern Territory on a peak and non-peak day.

Table B.18: Accumulation metered consumption as a proportion of total consumption

Time	Peak Day [1]	Non-Peak Day [2]
12:00 am	55%	55%
6:00 am	51%	51%
8:00 am	47%	45%
10:00 am	46%	42%
12:00 pm	47%	42%
2:00 pm	48%	40%
4:00 pm	49%	44%
6:00 pm	52%	46%
10:00 pm	57%	41%

Source:
1. Utilities Commission Northern Territory Market Information Paper 2006/07.
2. Relationship between peak and non-peak day consumption based on information received from Ergon and Energex.

The proportion of accumulation metered load accounted for by residential consumption was based on ABARE data which estimated that residential consumption accounts for 28 per cent of small user consumption. This average consumption was assumed to be maintained over the year however, a load profile was overlayed using the profile of consumption observed in Queensland. The specific proportions used for peak and non-peak days and over various time blocks in the day are set out below.

Table B.19: Residential consumption as a proportion of accumulation metered load

Peak day	
Midnight to 8 am	38%
8 am to 6 pm	28%
6 pm to Midnight	41%
Non-peak day	
Midnight to 8 am	34%
8 am to 6 pm	29%
6 pm to Midnight	37%

B.4.2.2. Results

A summary of the results obtained using the assumptions outlined above are set out in the tables below.

Table B.20: Northern Territory - demand response at peak times for customers on TOU and CPP

	Residential	Commercial
Summer		
Critical peak day	-10.6%	n.a.
Non- peak day	-1.0%	0.0%
Winter		
Critical peak day	-3.4%	n.a.
Non- peak day	-0.2%	0.0%

Table B.21: Northern Territory estimates of effect on jurisdictional load profile[1]

Change in maximum demand	-0.19%
Change in overall energy consumption	0.00%

1. Impact based on assumed take-up rates of 35% for TOU and 7.5% for TOU and CPP.

B.4.3.Queensland

B.4.3.1. Assumptions

Elasticity estimates

The elasticity estimates used in this analysis are set out in the table below.

Table B.22: Queensland elasticity assumptions

Period	Residential: Elasticity of substitution	Residential: Own-price elasticity	Commercial own-price elasticity
Summer			
Critical	-0.102	-0.043	-0.025
Weekday	-0.093	-0.047	-0.025
Weekend	n.a.	-0.026	-0.025
Winter			
Critical	-0.024	-0.011	-0.025
Weekday	-0.024	-0.019	-0.025
Weekend	n.a.	0.023	-0.025

Tariffs

The tariffs used in this analysis are based on assumptions made by KPMG and are set out in the table below.

Table B.23: Queensland Tariff Assumptions (c/kWh) (excl GST and carbon)

State	Flat Tariff	TOU tariffs				CPP	
		Peak M-F 7am-9pm	**Off-peak** Everyday	**Shoulder Period 1**	**Shoulder Period 2**	**CPP factor^**	**CPP Discount***
Qld	$0.14	$0.2118	$0.0748	n.a.	n.a.	5	5%

^ CPP price is the peak price multiplied by the CPP factor
* Discount applied to off-peak and shoulder tariffs only.

Disaggregating total load data

The half-hourly total load data for was obtained from NEMMCO. Since full retail contestability for small users only commenced on 1 July 2007 there was no net system load data available for Queensland and thus an estimate of the accumulation metered load had to be made. This assumption was based on information provided by Ergon and Energex. A summary of these assumptions is set out in the table below.

Table B.24: Accumulation metered load as a proportion of total load

Peak day	
Midnight to 8 am	52%
8 am to 6 pm	51%
6 pm to Midnight	57%
Non-peak day	
Midnight to 8 am	52%
8 am to 6 pm	46%
6 pm to Midnight	47%

The proportion of accumulation metered load accounted for by residential consumption was also based on the information provided by Ergon and Energex. The specific proportions used for peak and non-peak days and over various time blocks in the day are set out below.

Table B.25: Residential consumption as a proportion of accumulation metered load

Peak day	
Midnight to 8 am	68%
8 am to 6 pm	51%
6 pm to Midnight	74%
Non-peak day	
Midnight to 8 am	61%
8 am to 6 pm	52%
6 pm to Midnight	66%

In relation to the information received from Ergon and Energex, it should be noted that the data shown at Table B.24 and Table B.25 are based on load sampled from two days. One would expect estimates based on averages over the year may vary from these figures, but at this stage informational deficiencies mean that we do not have access to more accurate data. In light of these limitations, the results generated using these assumptions are necessarily approximations of reality.

B.4.3.2. Results

A summary of the results obtained using the assumptions outlined above are set out in the tables below.

Table B.26: Queensland - demand response at peak times for customers on TOU and CPP

	Residential	Commercial
Summer		
Critical peak day	-18.6%	n.a.
Non- peak day	-4.6%	-0.4%
Winter		
Critical peak day	-4.3%	n.a.
Non- peak day	-1.2%	-0.4%

Table B.27: Queensland estimates of effect on jurisdictional load profile[1]

Change in maximum demand	-0.77%
Change in overall energy consumption	-0.03%

1. Impact based on assumed take-up rates of 35% for TOU and 7.5% for TOU and CPP.

B.4.4. South Australia

B.4.4.1. Assumptions

Elasticity estimates

The elasticity estimates used in this analysis are set out in the table below.

Table B.28: South Australia elasticity assumptions

Period	Residential: Elasticity of substitution	Residential: Own-price elasticity	Commercial own-price elasticity
Summer			
Critical	-0.102	-0.043	-0.025
Weekday	-0.093	-0.047	-0.025
Weekend	n.a.	-0.026	-0.025
Winter			
Critical	-0.024	-0.011	-0.025
Weekday	-0.024	-0.019	-0.025
Weekend	n.a.	0.023	-0.025

Tariffs

The tariffs used in this analysis are based on assumptions made by KPMG and are set out in the table below.

Table B.29: South Australia Tariff Assumptions (c/kWh) (excl GST and carbon)

		TOU tariffs				CPP	
State	**Flat Tariff**	**Peak** Everyday M-F 7am-8pm	**Off-peak** Everyday All other times	**Shoulder Period 1**	**Shoulder Period 2**	**CPP factor^**	**CPP Discount***
SA	$0.17	$0.2540	$0.0853	n.a.	n.a.	5	5%

^ CPP price is the peak price multiplied by the CPP factor
* Discount applied to off-peak and shoulder tariffs only.

Disaggregating total load data

The half-hourly total load data and net system load data was obtained from NEMMCO. According to this data the net system load profile accounted for 43 per cent of energy consumption in South Australia over 2006/07. On critical peak days the net system load profile accounted for a maximum of 63 per cent of the load.

The proportion of the net system load accounted for by residential consumers was based on CRA's South Australian study. The specific proportions used for peak and non-peak days and over various time blocks in the day are set out below.

Table B.30: Residential consumption as a proportion of accumulation metered load

Peak day	
Midnight to 8 am	82%
8 am to 6 pm	70%
6 pm to Midnight	82%
Non-peak day	
Midnight to 8 am	58%
8 am to 6 pm	65%
6 pm to Midnight	70%

B.4.4.2. Results

A summary of the results obtained using the assumptions outlined above are set out in the tables below.

Table B.31: South Australia estimates - demand response at peak times for customers on TOU and CPP

	Residential	Commercial
Summer		
Critical peak day	-14.5%	n.a.
Non- peak day	-2.8%	-0.4%
Winter		
Critical peak day	n.a	n.a.
Non- peak day	-0.7%	-0.4%

Table B.32: South Australia estimates of effect on jurisdictional load profile[1]

Change in maximum demand	-0.96%
Change in overall energy consumption	-0.04%

1. Impact based on assumed take-up rates of 35% for TOU and 7.5% for TOU and CPP.

B.4.5.Tasmania

B.4.5.1. Assumptions

Elasticity estimates

The elasticity estimates used in this analysis are set out in the table below.

Table B.33: Tasmania elasticity assumptions

Period	Residential: Elasticity of substitution	Residential: Own-price elasticity	Commercial own-price elasticity
Summer			
Critical	-0.039	-0.041	-0.025
Weekday	-0.034	-0.043	-0.025
Weekend	n.a.	-0.014	-0.025
Winter			
Critical	-0.027	-0.026	-0.025
Weekday	-0.010	-0.017	-0.025
Weekend	n.a.	0.020	-0.025

Tariffs

The tariffs used in this analysis are based on assumptions made by KPMG and are set out in the table below.

Table B.34: Tasmania Tariff Assumptions (c/kWh) (excl GST and carbon)

State	Flat Tariff	TOU tariffs: Peak M-F 6.30-am-11am M-F 4.30pm-10pm	TOU tariffs: Off-peak Everyday 10.30pm-6.30am	TOU tariffs: Shoulder Period 1 All other times	TOU tariffs: Shoulder Period 2	CPP: CPP factor^	CPP: CPP Discount*
Tas	$0.14	$0.2120	$0.0800	$0.1050	n.a.	4	5%

^ CPP price is the peak price multiplied by the CPP factor
* Discount applied to off-peak and shoulder tariffs only.

Disaggregating total load data

The half-hourly total load data for was obtained from NEMMCO. Since full retail contestability for small users has not commenced there was no net system load data available for Tasmania and thus an estimate of the accumulation metered load had to be made. This estimate was based on OTTER's 2005-06 Tasmanian Energy Supply Industry Report which stated that the average aggregate consumption of large customers in Tasmania was 700 MW. This average aggregate consumption was deducted from Tasmania's total 2006/07 half-hourly load data and the remaining load was assumed to be accounted for by accumulation metered customers.

Although information was sought on the contribution of residential customers to peak demand it would appear that this information is not available and thus the proportion of accumulation metered load accounted for by residential consumption was estimated using ABARE electricity consumption data. According to this data residential consumption accounts for approximately 56 per cent of consumption by small users. This average consumption was assumed to be maintained over the year however, a load profile was overlayed using the profile of consumption observed in the information provided for Queensland by Ergon and Energex. The specific proportions used for peak and non-peak days and over various time blocks in the day are set out below.

Table B.35: Residential consumption as a proportion of accumulation metered load

Peak day	
Midnight to 8 am	66%
8 am to 6 pm	49%
6 pm to Midnight	71%
Non-peak day	
Midnight to 8 am	58%
8 am to 6 pm	50%
6 pm to Midnight	64%

B.4.5.2. Results

A summary of the results obtained using the assumptions outlined above are set out in the tables below.

Table B.36: Tasmania estimates of demand response at peak times for customers on TOU and CPP

	Residential	Commercial
Summer		
Critical peak day	n.a	n.a.
Non- peak day	-1.4%	-0.4%
Winter		
Critical peak day	-6.0%	n.a.
Non- peak day	-1.1%	-0.4%

Table B.37: Tasmania estimates of effect on jurisdictional load profile[1]

Change in maximum demand	-0.34%
Change in overall energy consumption	-0.02%

1. Impact based on assumed take-up rates of 35% for TOU and 7.5% for TOU and CPP.

It should be noted that the demand response assumed as a result of the introduction of TOU and CPP in Tasmania is a maximum demand response, and in practice is likely to be below this. This is because around 20% of Aurora's customers already face TOU prices, as a result of being on prepayment options (Pay As You Go). The *additional* demand response arising as a result of the rollout of smart meters would therefore relate to CPP offers (which are not a feature of the current PAYG arrangement) and any increased uptake of TOU tariffs. The current 20% uptake level for PAYG in Tasmania does not necessarily reflect the potential uptake for TOU tariffs, given that for some customers the restrictions associated with prepayment may present a barrier to them currently choosing a TOU tariff, whilst for others the attractiveness of the current PAYG may be the prepayment element, distinct from PAYG. Although the estimates of demand response derived for Tasmania are therefore likely to overstate the potential response (all else being equal), this has been taken into account in interpreting the overall cost benefit analysis for Tasmania.

B.5. Victoria

B.5.1.1. Assumptions

Elasticity estimates

The elasticity estimates used in this analysis are set out in the table below.

Table B.38: Victoria elasticity assumptions

Period	Residential: Elasticity of substitution	Residential: Own-price elasticity	Commercial own-price elasticity
Summer			
Critical	-0.076	-0.041	-0.025
Weekday	-0.069	-0.044	-0.025
Weekend	n.a.	-0.020	-0.025
Winter			
Critical	-0.025	-0.011	-0.025
Weekday	-0.025	-0.019	-0.025
Weekend	n.a.	0.023	-0.025

Tariffs

The tariffs used in this analysis are based on assumptions made by KPMG and are set out in the table below.

Table B.39: Victoria Tariff Assumptions (c/kWh) (excl GST and carbon)

		TOU tariffs				CPP	
State	**Flat Tariff**	**Peak** M-F 7am-7pm	**Off-peak** All other times	**Shoulder Period 1**	**Shoulder Period 2**	**CPP factor^**	**CPP Discount***
Vic	$0.1346	$0.2489	$0.0752	n.a.	n.a.	5	5%

^ CPP price is the peak price multiplied by the CPP factor
* Discount applied to off-peak and shoulder tariffs only.

Disaggregating total load data

The half-hourly total load data and net system load data was obtained from NEMMCO. The net system load profile accounted for 34 per cent of energy consumed in Victoria over 2006/07 and on critical peak days the net system load profile accounted for a maximum of 53 per cent of the total load.

Although information was sought on Victorian specific estimates of the contribution of residential customers to peak demand no information was forthcoming and thus the study undertaken for Ergon and Energex was used for the purpose of disaggregating the net system load profile. The Queensland study was viewed as being the best proxy given the similarities in the composition of small user consumption, air conditioner penetration rates and the relationship between maximum demand on critical peak and non-peak workdays between the two states. The specific proportions used for peak and non-peak days and over various time blocks in the day are set out below.

Table B.40: Residential consumption as a proportion of accumulation metered load

Peak day	
Midnight to 8 am	68%
8 am to 6 pm	51%
6 pm to Midnight	74%
Non-peak day	
Midnight to 8 am	61%
8 am to 6 pm	52%
6 pm to Midnight	66%

B.5.1.2. Results

A summary of the results obtained using the assumptions outlined above are set out in the tables below.

Table B.41: Victoria estimates - demand response at peak time for customers on CPP and TOU tariffs

	Residential	Commercial
Summer		
Critical peak day	-16.7%	n.a.
Non- peak day	-4.5%	-0.4%
Winter		
Critical peak day	n.a	n.a.
Non- peak day	-1.7%	-0.3%

Table B.42: Victoria estimates of effect on jurisdictional load profile[1]

Change in maximum demand	-0.61%
Change in overall energy consumption	-0.03%

1. Impact based on assumed take-up rates of 35% for TOU and 7.5% for TOU and CPP.

B.5.2.Western Australia

B.5.2.1. Assumptions

Elasticity estimates

The elasticity estimates used in this analysis are set out in the table below.

Table B.43: Western Australia elasticity assumptions

	Residential		
Period	Elasticity of substitution	Own-price elasticity	Commercial own-price elasticity
Summer			
Critical	-0.102	-0.043	-0.025
Weekday	-0.093	-0.047	-0.025
Weekend	n.a.	-0.026	-0.025
Winter			
Critical	-0.024	-0.011	-0.025
Weekday	-0.024	-0.019	-0.025
Weekend	n.a.	0.023	-0.025

Tariffs

The tariffs used in this analysis are based on assumptions made by KPMG and are set out in the table below.

Table B.44: Western Australia Tariff Assumptions (c/kWh) (excl GST and carbon)

		TOU tariffs				CPP	
State	Flat Tariff	**Peak** Summer: M-F 11am-5pm Winter: 11am-5pm, 5pm-9pm	**Off-peak** Everyday 9pm-7pm	**Shoulder Period 1** Summer: M-F 7am-11am, 5pm-9pm Winter: M-F 11am-5pm	**Shoulder Period 2** Weekends 7am-9pm	**CPP factor^**	**CPP Discount***
WA	$0.1394	$0.2470	$0.0800	$0.1495	$0.1200	4	5%

^ CPP price is the peak price multiplied by the CPP factor
* Discount applied to off-peak and shoulder tariffs only.

Disaggregating total load data

The half-hourly total load data for Western Australia was obtained from the Western Australian Independent Market Operator. Net system load data was not available for Western Australia and thus an assumption about the accumulation metered load had to be made. This assumption was made by reference to a Western Power study of the peak load profile on the South-West Interconnected System. To estimate the proportion of consumption of this group on a non-peak day the relationship between peak and off-peak interval metered consumption observed in the information provided by Ergon and Energex was utilised (see Table B.24).

The table below sets out the proportion of total load that has been assumed to be accounted for by larger customers with interval meters in Western Australia on a peak and non-peak day. Deducting the proportion of load accounted for by interval metered customers we were able to estimate the load accounted for by accumulation metered customers.

Table B.45: Interval metered consumption as a proportion of total consumption

Time	Peak Day [1]	Non-Peak Day [2]
12:00 am	26%	27%
6:00 am	33%	33%
8:00 am	37%	40%
10:00 am	37%	42%
12:00 pm	35%	43%
2:00 pm	34%	45%
4:00 pm	31%	38%
6:00 pm	23%	32%
10:00 pm	25%	46%

Source:
1, Western Power 2007 Transmission and Distribution Planning Report
2. Relationship between peak and non-peak day consumption based on information provided by Ergon and Energex.

The proportion of accumulation metered load accounted for by residential consumption was also based on the Western Power peak load study. Since this study only considered peak day consumption it was assumed that the relationship between residential consumption on a peak and off-peak day would be the same as that observed in Queensland.

Table B.46: Residential consumption as a proportion of accumulation metered load

Peak day	
Midnight to 8 am	47%
8 am to 6 pm	47%
6 pm to Midnight	52%
Non-peak day	
Midnight to 8 am	43%
8 am to 6 pm	45%
6 pm to Midnight	46%

B.5.2.2. Results

A summary of the results obtained using the assumptions outlined above are set out in the tables below.

Table B.47: Western Australia estimates - demand response at peak times for customers on TOU and CPP tariffs

	Residential	Commercial
Summer		
Critical peak day	-21.5%	n.a.
Non- peak day	-5.8%	-0.4%
Winter		
Critical peak day	-4.4%	n.a.
Non- peak day	-1.4%	-0.3%

Table B.48: Western Australia estimates of effect on jurisdictional load profile[1]

Change in maximum demand	-1.20%
Change in overall energy consumption	-0.01%

1. Impact based on assumed take-up rates of 35% for TOU and 7.5% for TOU and CPP.

Appendix C. Estimation of impact of direct load control: scenario 3 and incremental analysis for functionalities 15 and 16

Direct load control allows household and commercial appliances that have the required technological capability to be directly controlled by a remote agent (retailer, distributor or demand response aggregator) during a direct load control event, through an automated alteration of the appliance's normal mode of operation.[295] This technological capability, referred to as a demand response capability, may be included within the appliance at the time it is manufactured or it may be added at a later stage through retrofitting.

DLC can be rolled-out independently of a roll-out of smart meters (ie, scenario 3) or may be part of the functionality of smart meters.

This appendix provides additional detail on the way in which we have estimated the demand impact of DLC for both scenario 3 and for the incremental analysis of functionalities 15 and 16 for a smart meter.

C.1. Estimation framework for DLC

To estimate the size of the aggregated demand response that could be achieved during peak wholesale price and/or peak network demand periods from the direct load control of residential air-conditioners and the influence of this response on the jurisdictional load profiles the following steps were undertaken:

1. Estimate the total number of air conditioners in each jurisdiction that will have the capability of being controlled via a demand response enabling device across each year of the forecast horizon;

2. Develop an estimate of the energy that could be conserved per air conditioner on a half hourly basis if distributors or retailers were able to cycle air conditioners for 15 minutes out of every 30 minutes over a six hour period;

3. Assume a rate of take up across all consumers in each jurisdiction having regard to the likely product offerings of distributors and/or retailers;

4. Multiply the estimates developed in steps 1, 2 and 3 to derive the total amount of energy that could be controlled;

5. Identify the days on which a direct load control event is likely to be called in each jurisdiction by either a distributor or a retailer and the six hour block over which this event could be called; and

6. Deduct the aggregate demand response from the half hourly jurisdictional load data during the times identified in step 5.

---

[295] Standards Australia, Framework for demand response capabilities and supporting technologies for electrical products – AS 4755-2007, pg. 4.

The contribution of pool pumps to the load under control was estimated under the assumption that customers with air conditioners participating in a load control program will also place any pool pumps they own on the same program. The total take up of air conditioners on the DLC program was multiplied by the proportion of households owning pools, the average pool pump power and the likelihood that a pool pump will be running when a DLC event is called to estimate the likely demand response from switching off pool pumps participating on the program.

C.2. Scenario 3

Step 1: Estimate number of air conditioners that have direct control capability

Under scenario 3 it is assumed that both existing air conditioners and new and replacement air conditioners are capable of participating in the DLC rollout.

Energy Efficient Strategies have extensively studied air conditioner numbers and penetration and have provided us with historic ABS estimates of the stock of air conditioners, air conditioner penetration rates, ownership and saturation in each jurisdiction and their projections through to 2020.[296] Since the forecast period for the incremental analysis extends to 2029/30 it was necessary to extend these forecasts for a further ten years. To do this the growth rate of the forecast stock levels from 2015 to 2020 was examined. This examination revealed a diminishing growth rate and thus the forecasts to 2029/30 were assumed to follow this same diminishing growth rate.

Using the historic estimates of the stock of air conditioners in each jurisdiction an estimate of the time path for air conditioner replacement from 2009 was developed by assuming a 14 year life for air conditioners.[297] The estimate of the initial stock of airconditioners plus the number of air conditioners replaced in each year of the forecast period coupled with the growth in the stock of air conditioners in each year was then assumed to be capable of participating in the scheme.

Table C.1: Stock of all air conditioners in each jurisdiction

Year	NSW	NT	Qld	SA	Tas	Vic	WA
2015	2,649,588	185,066	2,471,534	751,558	89,616	1,883,431	1,002,165
2020	2,913,009	213,353	2,923,565	791,412	98,113	2,090,112	1,140,639
2025	3,213,338	234,870	3,468,204	834,526	108,284	2,323,995	1,301,397
2030	3,446,736	259,247	4,012,017	865,870	113,042	2,533,723	1,451,210

Source: George Wilkenfeld and Associates Pty Ltd

Step 2: Estimate the level of energy that could be conserved on a per air conditioner basis

To estimate the level of energy that could be conserved by each air conditioner that is subject to the scheme over each half an hour of the duration of the direct load control event it has been necessary to make an assumption about:

---

296 The air conditioner penetration rate estimates referred to by Energy Efficient Strategies were compared with the estimates provided by distributors and were found to be broadly in line with the air conditioner penetration rates cited by the distributors that responded to this information request.

297 Energy Efficient Strategies, Status of Air Conditioners in Australia, pg. 12.

- the comparative energy consumption of air conditioners in the scheme; and
- the cycling strategy that will be adopted by the distributor or the retailer.

The energy consumption of an air conditioner will depend on the size and type of the unit. In a report prepared for VENCorp, Energy Efficient Strategies estimated the average energy requirement of residential air conditioners by having recourse to the registration of air conditioners in Australia since 1990. According to this estimate the average energy requirement of the stock of residential air conditioners including both small and large energy consuming air conditioners was 1.9 kW.[298]

This average is lower than that observed amongst ETSA Utilities' trial participants (4.27 kW) because ETSA Utilities specifically targeted air conditioners with a load in the range 2.5 kW to 10.3 kW.[299] Since the composition of the future air conditioners is unknown, the average estimate developed by Energy Efficient Strategies has been used in this analysis and the sensitivity of the results to this estimate have been tested by replacing this assumption with the average observed in ETSA Utilities' trial.

Although the energy efficiency of the stock of air conditioners is expected to improve over time this may be offset somewhat by the greater number of large air conditioners being purchased.[300] Accordingly the historic average energy consumption estimated by Energy Efficient Strategies has been utilised.

It is envisaged that the direct load control scheme will be a voluntary scheme and thus the terms of the scheme as they relate to the period of cycling, the duration of the direct load control event and the number of times an event may be called could vary substantially across jurisdictions and amongst customers within a jurisdiction. For the purposes of this analysis it has been assumed that distributors and retailers will be able to cycle air conditioners for 15 minutes out of every 30 minutes over a six hour period on fifteen occasions over the summer months. The 50 per cent cycling assumption has been based on the findings of the direct load control trials undertaken by ETSA Utilities which suggest that air-conditioners could be cycled for 15 minutes in every 30 minute period without affecting the thermal comfort level.[301]

These two assumptions have been tested in the sensitivity analysis undertaken at the end of this section.

Step 3: Estimate a level of take up of direct control services by residential customers

The take up rate of a direct load control service by residential customers with demand response enabled air conditioners will be inextricably linked to the number of customers

---

298 Energy Efficient Strategies, Electrical Peak Load Analysis Victoria 1999-2003, December 2004, pg. 2.

299 ETSA Utilities, Case Study 1 Report of Customer Response to the Remote Management of Domestic Air-conditioners, April 2006, pg. 1.

300 George Wilkenfeld and Associates Pty Ltd, A National Demand Management Strategy for Small Airconditioners: the role of the National Appliance and Equipment Energy Efficiency Program (NAEEEP), November 2004, pg. 4.

301 ETSA Utilities, Demand Management Interim Report No. 1, June 2007, pg. 36.

approached and the incentive payment paid by a distributor, retailer or third party demand response aggregator.

The number of customers approached by either a distributor or retailer will depend on the size of air conditioning units. For instance a distributor that is seeking to reduce peak demand by 1 MW in a constrained network area with 20,000 possible participants and an average air conditioner load of 1.9 kW may only select customers with air conditioners with an electrical load of 2.5 kW and thus the take up rate it would require would be 4 per cent.[302] If, however, the distributor selected customers with the average air conditioner load then it would require a take up rate of 5.3 per cent.

From a distributor's perspective the value of direct load control arises when network constraints can be alleviated. Direct load control will therefore tend to be undertaken in those areas that are currently experiencing network constraints. The number of customers that are likely to be approached by a distributor to be part of such a scheme will therefore be limited relative to the overall pool of residential customers that are capable of having their air conditioner load directly controlled.

Although the pool of customers that could be approached by retailers will not be limited in the same manner as distributors, they will have to consider the trade off between having the direct load control capability and having to pay customers to be part of such a scheme.

These two factors suggest that distributors and retailers will target a relatively small proportion of the total pool of residential customers that are capable of having their air conditioner directly controlled. KPMG has assumed a take-up rate of 10 per cent for DLC as part of the retail workstream. Given the uncertainty surrounding this assumption an upper bound take up rate of 20 per cent has been tested.

These proportions refer to the take up amongst all residential electricity customers of direct load control. Since the penetration of air conditioners varies widely between jurisdictions, the proportion of customers with air conditioners assumed to participate in a DLC program varies between jurisdictions, from a lower bound of 11 per cent in South Australia and the Northern Territory to an upper bound of 14 per cent for NSW.[303]

Step 4: Calculate the aggregate demand response that could be achieved in each half hour of a direct load control event

Consideration was also given to the potential for participants in the scheme not to have been at home operating their air conditioners at the time of the event. While we would expect the distributors and retailers to have specifically targeted customers that were typically home at the time of such events it is still possible that people may be away at any particular direct load control event. To reflect this possibility we have assumed that 20 per cent of the air conditioners within the trial may at any one time not contribute to the aggregated demand response.

---

[302] For simplicity this take up rate calculation assumes that all participants are home at the time required.

[303] Note that NERA's demand modelling indicates that DLC is not expected to be called in Tasmania as a result of its winter-peaking load.

The demand reductions were estimated on the basis of the above assumptions and the results calibrated to each jurisdictional load profile based on estimates of air conditioning load as a proportion of residential demand developed by CRA for South Australia and Queensland.

The table below sets out the estimated demand reduction attainable in each jurisdiction over each half hour of a direct load control event.

Table C.2: Estimated half hourly demand reduction assuming a 10 per cent take up rate (MW)

Year	NSW	NT	Qld	SA	Tas	Vic	WA
2015-2019	66.3 - 110.5	1.3 – 2.0	54.9 – 95.7	27.1 – 41.7	n.a.	48.5 – 72.1	29.3 – 44.9
2020-2024	120.3 – 142.2	2.1 – 2.6	106.4 – 133.4	44.2 – 49.4	n.a.	77.6 – 90.7	48.5 – 58.0
2025-2029	144.7 – 153.3	2.6 – 2.8	137.8 – 155.1	49.9 – 51.4	n.a.	92.6 – 99.4	59.5 – 65.0
2030	155.2	2.9	159.4	51.7	n.a.	100.9	66.3

Applying a 20 per cent take up rate results in the assumed estimates of half hourly demand reduction attainable during a direct control event set out in the table above doubling.

Reviewing this table it is apparent that the estimated demand reduction differs:

- across each jurisdiction, reflecting differences in the number of air conditioners assumed in each jurisdiction; and
- over time reflecting the growth in the number of air conditioners owned by households.

Step 5: Identify the days on which a direct load control event is likely to be called

A direct load control event involving air conditioners will only tend to be called on relatively hot days. For the purpose of this analysis a temperature threshold of 30 degrees Celsius was used. Although a higher threshold of 34 to 35 degrees Celsius may seem appropriate, the summer period over 2006/07 was unseasonably cold in a number of states including Queensland, South Australia, New South Wales and Victoria. Actual summer demand was also relatively low in a number of NEM jurisdictions when compared to NEMMCO’s 2005 Statement of Opportunities 90 per cent low POE (see Figure B.2). A lower temperature threshold was therefore assumed for this analysis.

The motivations for a distributor to call a direct load control event are quite different from those exhibited by a retailer. For a distributor a direct load control event will be called when network constraints are being reached while a retailer will want to call an event when wholesale electricity prices are high. In many cases the days on which a retailer would choose to implement a direct control event would overlap with the days selected by a distributor. There may, however, be days in which the wholesale electricity price is high but network constraints are not being reached (ie, if an interconnector between states goes down). On these types of days it may be that only the retailer wishes to implement a direct control event. To ensure that both types of days were considered in this analysis consideration was given to both load and price data over 2006/07.

To identify the days on which a direct load control event could be called in each jurisdiction an initial temperature filter of 30 °Celsius was applied. The days on which this occurred were then examined further to determine whether:

§ the maximum demand levels reached on those days were in the top 5 percentile of the jurisdiction's 2006/07 load duration curve; or

§ the wholesale prices reached on those days were in the top 5 percentile of prices paid in the jurisdiction over 2006/07.

A maximum number of fifteen direct load control event days were assumed and in those jurisdictions where more than fifteen events could have been called, the top fifteen were selected by picking those with the highest maximum demand and/or price levels. In many cases the days on which a retailer directed direct load control event would have been called coincided with the conditions which would have resulted in a distributor calling such an event.

Applying the selection criteria stated above resulted in the identification of:

§ fifteen direct control event days in Victoria, South Australia and Western Australia;

§ fourteen direct control event days in Queensland;

§ eight direct control event days in New South Wales and the Australian Capital Territory; and

§ no direct control event days in Tasmania.

To determine the six hour period over which to apply the direct load control event the maximum demand levels over the day were reviewed and the six hour period that had the highest maximum demand over a consecutive six hour period was selected.

Step 6: Develop new half hourly jurisdictional load data over the forecast period

Drawing on the estimated half hourly demand reductions set out in Table C.2 and using the days and times identified in step 5, revised half hourly load estimates for each jurisdiction were developed by deducting the aggregate demand response from the base load profiles. The benefits of this demand response were then provided to the other work streams to consider the implications of the demand response on networks, retailers, the wholesale market and for greenhouse gas emissions.

C.2.1.Results and sensitivity analysis function Scenario 3

The tables below set out the maximum reduction in load that could occur during a direct load control event assuming a 10 per cent take up rate.

Table C.3: Maximum reduction in load during direct load control events with a 10 per cent take up rate

	NSW	NT	Qld	SA	Tas	Vic	WA
2014/15	-1.12%	-1.04%	-1.06%	-1.70%	n.a.	-1.50%	-0.80%
2019/20	-1.00%	-1.01%	-0.98%	-1.62%	n.a.	-1.34%	-0.81%
2024/25	-1.03%	-1.01%	-0.95%	-1.59%	n.a.	-1.34%	-0.85%

The differences in results for each jurisdiction reflect differences in the number of air conditioners assumed to be part of the trial and differences in the season that the maximum demand for the year is assumed to occur. In New South Wales the maximum demand for the year is assumed to occur in winter and thus the direct load functionality does not result in a reduction in maximum demand but on peak summer days demand is reduced and this translates to an overall reduction in energy consumption.

Sensitivity analysis was undertaken to test the overall sensitivity of the estimated change in maximum demand in 2014/15 to the length of time over which the direct load control event could be carried out which was assumed to be six hours in the base case analysis has been tested using two and four hour duration periods.

The results of this analysis are set out in the table below. In the case of New South Wales and Western Australia varying the underlying assumptions had negligible effects. In South Australia and Victoria lengthening the duration of the direct load control event had no effect on maximum demand which is in stark contrast to the Northern Territory and Queensland where increasing the duration did allow for additional reductions in maximum demand. This difference is likely to reflect variations in the length of the thermal related spikes experienced in these jurisdictions (ie, in South Australia the spikes are relatively short in duration while in the Northern Territory they can extend for some hours).

Table C.4: Results of sensitivity analysis (measured as the change in maximum demand from C.3)

	NSW	NT	Qld	SA	Tas	Vic	WA
2 hour duration DLC event	0.01%	0.14%	0.15%	0.06%	n.a.	0.08%	0.04%
4 hour duration DLC event	0.00%	0.10%	0.12%	0.04%	n.a.	0.05%	0.03%

C.3. Analysis of DLC capability of smart meters (functionalities 15 and 16)

Both functionality 15 and 16 allows household and commercial appliances that have the required technological capability to be subject to DLC. Our analysis has considered DLC of residential air-conditioners and pool pumps under this functionality.

The principal difference between function 16 Case C compared with functionalities 15 and 16A&B is that the cost of retrofitting is substantial in the latter of these functionalities. Given the substantive nature of these costs the analysis of functionalities 15 and 16A&B is based on the following two key assumptions:

§ there is no retrofitting of the existing stock of air conditioners; and

§ air conditioners manufactured from 2009[304] onward will have the technological capability to be directly controlled by a remote agent via a smart meter.

Since the costs of retrofitting have been assumed to be less substantial where a smart thermostat is installed the analysis of function 16 Case C includes both new and replacement air conditioners and the existing pool of air conditioners.

The remainder of this section discusses the analysis that has been undertaken in relation to each of these functionalities.

C.3.1.Function 16 Case C

For function 16 Case C it is assumed that retrofitting is possible and thus the pool of air conditioners extends to existing, new and replacement air conditioners and is the same as that assumed for the analysis of DLC in scenario 3. The only differences relating to the analysis of customers on DLC programs under scenario 3 and functionality 16C is that under functionality 16C a lower take up of 7.5 per cent is assumed and these customers are also on the same TOU tariff as ordinary TOU customers.

C.3.1.1. Results Functionality 16C

The table below sets out the estimated demand reduction attainable in each jurisdiction over each half hour of a direct load control event under functionality 16C.

Table C.5: Estimated half hourly demand reduction attainable during a direct load control event assuming a 10 per cent take up rate (MW)

Year	NSW	NT	Qld	SA	Tas	Vic	WA
2015-2019	123.1 – 129.7	2.1 – 2.3	102.8 – 113.7	45.4 – 46.9	n.a.	77.6 – 82.3	47.6 – 51.3
2020-2024	131.3 – 142.2	2.3 – 2.6	116.5 – 133.4	47.3 – 49.4	n.a.	83.4 – 90.7	52.3 – 58.0
2025-2029	144.7 – 153.3	2.6 – 2.8	137.8 – 155.1	49.9 – 51.4	n.a.	92.6 – 99.4	59.5 – 65.0
2030	155.2	2.9	159.4	51.7	n.a.	100.9	66.3

If a 20 per cent take up rate were assumed then the estimate of half hourly demand reduction attainable during a direct control event set out in the table above would double.

C.3.2.Functionalities 15 and 16A&B

As highlighted above, the only difference from a demand impact perspective between functionality 16C and functionalities 15 and 16A&B is that the latter functionalities only assume a DLC capability for new and replacement air conditioners, and not a retrofit.

[304] The estimated date from which air conditioners will be manufactured with the capability was provided by representatives that are currently designing the Australian Standards in this area.

In relation to the analysis therefore, it is only Step 1 that is different. The estimation of the total number of air-conditioners in each jurisdiction that will have a DLC capability on a new and replacement basis only is set out below.

Step 1: Estimate the number of air conditioners that have a direct control capability

The estimate of the number of new and replacement air conditioners was again based on data provided by Energy Efficient Strategies coupled with forecast growth rates over the period of analysis, as already outlined.

The number of air conditioners replaced in each year of the forecast period coupled with the growth in the stock of air conditioners in each year resulting from this analysis is given in the following table.

Table C.6: Stock of new and replacement air conditioners

Year	NSW	NT	Qld	SA	Tas	Vic	WA
2015	1,427,659	114,847	1,318,739	449,344	43,166	1,175,364	616,937
2020	2,668,852	191,198	2,670,813	740,134	87,972	1,944,345	1,059,084
2025	3,213,338	234,870	3,468,204	834,526	108,284	2,323,995	1,301,397
2030	3,446,736	259,247	4,012,017	865,870	113,042	2,533,723	1,451,210

Source: George Wilkenfeld and Associates Pty Ltd

The remaining steps of the analysis are as set out for functionality 16C above.

C.3.2.1. Results Functionality 15 and 16A&B

The table below sets out the maximum reduction in load that could occur during a direct load control event assuming a 7.5 per cent take up rate.

Table C.7: Functionalities 15 and 16A&B - Estimated half hourly demand reduction attainable during a direct load control event assuming a 7.5 per cent take up rate (MW)

Year	NSW	NT	Qld	SA	Tas	Vic	WA
2015-2019	36-94	0.81-1.67	29.3-80.6	16.2-37.0	n.a.	30.2-63.3	18.0-39.2
2020-2024	110-142	2.0-2.6	97.2-133.4	41.4-49.4	n.a.	72.2-90.7	45.1-58.0
2025-2029	145-153	2.6-2.8	137.8-155.1	49.9-51.4	n.a.	92.6-99.4	59.5-65.0
2030	155	2.9	159.4	51.7	n.a.	100.9	66

Note: These results are approximate because the effect of TOU and CPP tariffs and DLC are amalgamated in the model outputs.

Appendix D. Phase 2 Customer Focus Groups – Red Jelly Report

[see accompanying report]

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com