



INTERNATIONAL

PHASE 2 CONSULTATION REPORT

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Level 3, 51 Allara Street

Canberra ACT 2600

Cost Benefit Analysis of Smart Metering and Direct Load Control

Stream 5: Economic impacts on
wholesale electricity market and
greenhouse gas emission outcomes

Phase 2 Consultation Report

Prepared by:

CRA International

Level 31, Marland House

570 Bourke Street

Melbourne Vic 3000, Australia

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Author(s): L Hoch, D Chattopadhyay, K McCall

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1. EXECUTIVE SUMMARY

1.1. OBJECTIVE AND APPROACH

This report, as part of Phase 2 of the Smart Meter Cost Benefit Analysis (SMCBA), assesses the economic impacts over the 2007-2030 timeframe of the minimum specification and several incremental functionalities in the smart metering infrastructure being considered for national rollout. It also assesses the economic impacts of the deployment of direct load control (DLC) delivered through means other than smart metering infrastructure. The economic impacts considered are limited to those that would be experienced in the wholesale electricity market, including impacts on carbon emissions, and do not include wider impacts on the economy as a whole.

The modelling was conducted using CRA International Pty Ltd's (CRA) CEMOS modelling suite. CEMOS models dispatch, cost and price outcomes in the wholesale electricity markets of all Australian states and territories, including the interconnected NEM regions, the Western Australian SWIS and the Northern Territory power grid. CEMOS has been calibrated against historical outcomes in the NEM.

1.2. RELATIONSHIP TO OTHER STREAMS

The modelling undertaken in Stream 5 relies on other work Streams for a number of its inputs. These include:

- The impact of the use of smart-metering infrastructure to send time-differentiated price signals on the timing and magnitude of mass-market electricity customers' demand for electricity;
- The impact of the use of smart-metering infrastructure to cycle or constrain off air-conditioning equipment on the timing and magnitude of mass-market electricity customers' demand for electricity; and
- The impact of the use of non-smart-metering infrastructure to cycle or constrain off air-conditioning equipment on the timing and magnitude of mass-market electricity customers' demand for electricity.

Inputs to these matters were provided as follows:

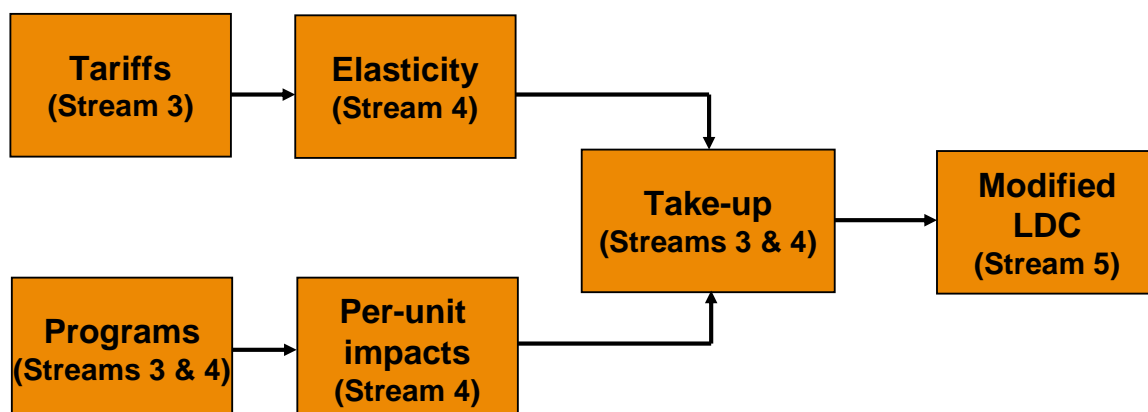
- Stream 3, which focussed on the role of and benefits accrued by retailers in the roll-out of smart metering infrastructure provided:
 - The structure and levels of time-of-use and dynamic price signals that might be made available through the use of smart-metering infrastructure, and

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- The structure and features of programs that might be offered to encourage mass-market electricity customers to allow their air-conditioning equipment to be cycled or constrained off through the use of either smart-metering infrastructure or non-smart-metering control gear.
- Stream 4, which focussed on customer reaction to and benefits from smart metering infrastructure provided:
 - The response that consumers could be expected to show in their demand to such electricity price structures and levels (i.e., their elasticity of demand), and
 - The average per-unit demand and energy reduction impacts that would result from the cycling or constraining off of the air-conditioning equipment of mass-market electricity customers.

As shown in Figure 1, these inputs were combined to estimate how the load duration curve within each jurisdiction could be expected to change from its current shape.

Figure 1: Inputs from other work Streams to Stream 5



This change in the load duration curve represents the impact that smart metering infrastructure (or non-smart-metering control gear) would have on the operation of the wholesale electricity market.

Other inputs to the Stream 5 analysis were taken primarily from publicly available sources regarding the current configuration of the wholesale electricity market within each jurisdiction and forecasts of expected future electricity demand.

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1.3. FUNCTIONALITIES CONSIDERED

Phase 2 assessed the economic impacts of four different set of functionalities:

- The national minimum functional specification of smart metering infrastructure that was developed in Phase 1;¹
- Two sets of incremental functionality that add the ability to cycle or constrain off appliances such as larger air conditioners (larger split and all ducted systems)², pool pumps, clothes dryers, etc.³ to the national minimum specification. Both include an in-home display (IHD) and an interface to a home area network (HAN) that allows the smart metering infrastructure to communicate with and control the end-use equipment:
 - One version of this incremental functionality is applicable only to new and replacement equipment, as it communicates with the end-use equipment via dedicated switches built into the appliances themselves; and
 - The other version of this functionality is applicable to both new and existing equipment installations because it communicates via existing controls of the equipment, such as the remote controls that are used with split air-conditioning systems.

As a result, the eligible population for the second version of the incremental functionality is significantly larger than that for the first, at least in the early years of the analysis timeframe.⁴

Both versions of the incremental smart meter functionality include universal provisions of in-home displays, which can be used to provide customers with information about a wide range of energy and price related topics, including current electricity price; current and period to date electricity consumption, cost and carbon emission rates; instantaneous impact of individual appliances on consumption and cost rates; energy saving tips, and feedback on the impact of energy use profiles on a daily basis. These capabilities – supplemented by educational efforts and possibly financial incentives – were assumed to provide the basis for these functionalities providing enhanced peak demand reductions and energy conservation impacts.

1 A complete description of the smart metering infrastructure minimum functional specification that was modelled in Phase 2 can be found in NERA's *Smart Meter Cost Benefit Analysis: Phase 2 Overview Report*.

2 The switches would either be added on to the appliances or come as OEM equipment with new appliances.

3 Although these controls can be used to operate a wide range of end-use appliances, the modelling considered their application only to air-conditioning.

4 Over time, all existing end-use equipment will be replaced, thereby allowing the technology applicable to new and replacement applications to characterise essentially the entire population.

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- The deployment of dedicated communications and controls for direct load control of customers' end-use equipment that does not include smart metering infrastructure.

The impacts of each of the functionalities were assessed at two different take-up rates by the applicable eligible populations.

1.4. SPECIFIC BENEFITS CONSIDERED

The Terms of Reference for the study specified that the following benefits were to be considered:

- Market price impacts;
- Generation investment;
- Greenhouse reductions – including modelling of changes to dispatch and losses, and accounting for the specific emissions intensities of generation deferred;
- Reliability and service levels; and
- Future potential for technology & service innovation.

The modelling provided quantitative assessment of the impact of the functionalities described above on:

- Generation system investment (capex) – the change in type, amount and timing of generation plant that is projected to be constructed over the analysis timeframe due to the change in the demand for electricity due to the functionalities;
- Generation system operating expenses (opex) – the change in fuel and variable operation and maintenance costs required over the analysis timeframe that is projected to result due to changes in the magnitude and timing of electricity consumption due to the functionalities;
- Unserved energy (USE) – the change in the amount of electricity that customers required but was unavailable due to generation system constraints over the analysis timeframe as a result of the implementation of the functionalities;⁵ and
- Carbon emissions (CO₂) – the change in the amount of carbon released into the atmosphere over the analysis timeframe as a result of the types of plants being used to generate electricity and the amount and timing of electricity required by consumers due to the functionalities.

⁵ Changes in USE essentially measure the change in the overall reliability of the generation system.

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The first two of the factors above combine to create the production costs that influence wholesale electricity prices in the spot market.⁶ However, in the NEM, generators typically bid a small amount of their generating capacity at prices significantly above their production costs. As the price in the NEM is set by the highest cleared offer price, it is these prices (rather than the production costs themselves) that set the wholesale price. The CEMOS modelling suite allows projection of generation market offer prices and was used to quantify the impact of the implementation of the functionalities on wholesale market offer prices as well as on production costs.

Future potential for technology and service innovation is not directly discussed in this report. The impact of smart metering infrastructure on the wholesale market is expressed in changes in the magnitude and timing of consumer demand for electricity. In and of themselves such changes would not necessarily create the potential for technology innovation in the wholesale market, though they would not hinder that potential either. The addition of carbon pricing, however, does create the potential for innovation in generation technology.

1.5. SCENARIOS, CASES AND ANALYSES CONSIDERED

1.5.1. Scenarios

The Terms of Reference for the study specified four scenarios under which the costs and benefits of smart metering infrastructure were to be assessed:

- Scenario 1: Distributor led;
- Scenario 2: Retailer led;
- Scenario 3: Non-smart-metering infrastructure for direct load control (DLC); assumed to be distributor led; and
- Scenario 4: Smart metering infrastructure with centralised communications; assumed to be retailer led.

For the purposes of Stream 5, no distinction was made between the impact that Scenarios 1, 2 and 4 would have on the wholesale market. Results for all three of those scenarios are assumed to be the same and are simply referred to as the impacts of smart metering infrastructure. Because it concerns an entirely different technology, Scenario 3 was modelled separately.

⁶ The NEM spot prices are expressed in the 5-minute bids and half-hourly prices posted in the pool price which governs the prices to be paid for all physical energy purchased. In WA, spot prices are expressed in the prices for short-term electricity market (STEM) purchases, which are used to balance participants' contract positions. The NT does not have a wholesale electricity pricing function.

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1.5.2. Analyses

Because the assessment of smart metering infrastructure needed to consider different levels of functionality, different incremental functional analyses were undertaken, as follow: The following cases and analyses were constructed to assess the impacts of the additional functionalities being considered in Phase 2:

- Business-as-Usual (BAU), which assumes the market continues as it operates today, and was used simply for reference.
- (Carbon Price) Base Case, which introduces a carbon price that affects wholesale production costs (and therefore prices) of generation plants that use fossil fuels. Because the introduction of a cap and trade scheme to set prices for carbon had been endorsed by both political parties at the time the study was commenced,⁷ the Base Case is assumed to constitute the baseline of wholesale market operations from which smart metering and non-smart-metering infrastructure benefits are calculated.
- Base functionality, which assesses the impact of the basic functionality of the smart metering infrastructure as defined by the Smart Meter Working Group (SMWG) for the SMCBA against the Base Case.
- Base plus incremental functionalities, in which each of the individual incremental functionalities is added to the base functionality and assessed against the Base Case. Because two levels of incremental functionality were considered – smart-metering based DLC in new and replacement applications and smart-metering based DLC in new, replacement and existing applications – two separate analyses were undertaken.
- Alternative DLC functionality (SMWG Scenario 3), which assesses the impact of the non-smart metering DLC functionality.

⁷ At the time the study was commenced, carbon prices as a result of the cap and trade scheme that had been endorsed by both political parties were expected to be introduced in 2012. Based on that, the carbon prices used in the study start in 2012 at A\$15/tonne and rise to A\$40/tonne by 2030. Subsequently, the target date for the introduction of carbon pricing was brought forward to 2010. This change is not reflected in this report as it took place after the analyses had been completed. The assumed carbon process were used to both (a) change the production costs of existing and candidate generation plants, and (b) represent the economic value of any change in carbon emissions.

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1.5.3. Cases

Significant uncertainty surrounds the per-customer impact and take-up of several of the base and incremental functionalities including:

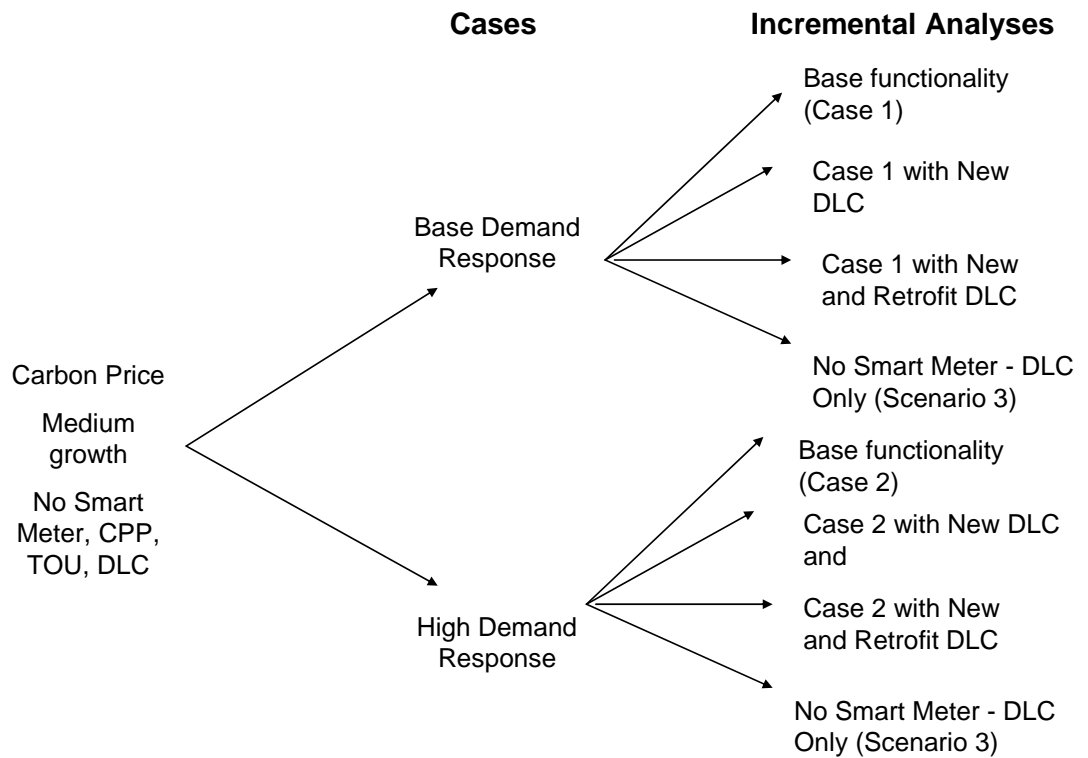
- The level of demand reduction and energy consumption reduction and shifting that will result from the introduction of time-of-use (TOU) and dynamic pricing arrangements such as critical peak pricing (CPP), and
- The extent to which such pricing arrangements will be offered by retailers and taken up by consumers.

As a result, two demand response cases⁸ were undertaken to assess the potential benefits of two different levels of take-up of the pricing and DLC programs by customers. For each of these scenarios, there are base case and incremental functionalities and different assumptions regarding associated conservation (as compared to peak-period demand reduction) effects.

Figure 2 provides an overview of the cases and incremental analyses. Table 1 summarises the key assumptions for each case and incremental analysis. Table 2 provides information on the change in peak demand and total energy consumption of each incremental analysis that was created by the output of Streams 3 and 4, and that served as a key input to the modelling of the wholesale market impacts of smart metering and DLC.

⁸ The high and low take-up levels were developed with input from KPMG (based on information provided by the retailers as part of the Stream 3 analysis), NERA (based on information developed in the assessment of the consumer perspective in Stream 4), and CRA.

Figure 2: Overview of the modelling cases and incremental functional analyses



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Table 1: Summary of case and incremental analysis take-up rates and impacts (residential customers)

	TOU only	TOU plus CPP	DLC	Conservation impact
Base demand response (Case 1)				
Base functionality (Case 1)	35%	7.5%	N/A	N/A
Case 1 with New DLC (functionalities 15, 16A, 16B)	30%	7.5%	7.5%	N/A
Case 1 with New and Retrofit DLC (functionality 16C)	30%	7.5%	7.5%	N/A
Scenario 3 – no smart meter DLC only	N/A	N/A	10%	N/A
High demand response (Case 2)				
Base functionality (Case 2)	35%	15%	N/A	3%
Case 2 with New DLC (functionalities 15, 16A, 16B)	30%	15%	15%	7%
Case 2 with New and Retrofit DLC (functionality 16C)	30%	15%	15%	7%
Scenario 3 – no smart meter DLC only	N/A	N/A	20%	N/A

Note: Duration for direct load control is assumed to be 6 hours on the basis of advice from ETSA Utilities.

Table 2: Changes in the 2050 load duration curve (% peak and energy reduction) assumed in Stream 5 for each DR case and incremental analysis

	% Energy	% Peak	% Energy	% Peak	% Energy	% Peak	% Energy	% Peak
Base Demand Response								
	Base Functionality (Case 1)		New DLC (16 A&B)		New & Retrofit DLC (16C)		Scenario 3 (No smart meter DLC Only)	
QLD	-0.030%	-0.733%	-0.039%	-1.482%	-0.039%	-1.482%	-0.014%	-0.912%
NSW	-0.018%	-0.440%	-0.028%	-1.035%	-0.028%	-1.035%	-0.013%	-0.772%
VIC	-0.026%	-0.582%	-0.035%	-1.159%	-0.035%	-1.159%	-0.012%	-0.694%
SA	-0.037%	-0.922%	-0.059%	-1.959%	-0.059%	-1.959%	-0.029%	-1.210%
TAS	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
WA	-0.010%	-1.147%	-0.024%	-2.003%	-0.024%	-2.003%	-0.020%	-1.022%
NT	0.000%	-0.215%	-0.009%	-0.771%	-0.009%	-0.771%	-0.012%	-0.724%

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	% Energy	% Peak	% Energy	% Peak	% Energy	% Peak	% Energy	% Peak
High Demand Response								
	Base Functionality (Case 2)		New DLC (16 A&B)		New & Retrofit DLC (16C)		Scenario 3 (No smart meter DLC Only)	
QLD	-0.403%	-1.263%	-0.969%	-3.043%	-0.969%	-3.043%	-0.027%	-1.825%
NSW	-0.243%	-0.972%	-0.590%	-2.466%	-0.590%	-2.466%	-0.026%	-1.544%
VIC	-0.291%	-1.015%	-0.697%	-2.423%	-0.697%	-2.423%	-0.025%	-1.388%
SA	-0.449%	-1.749%	-1.059%	-4.232%	-1.059%	-4.232%	-0.058%	-2.420%
TAS	-0.457%	-0.965%	-1.099%	-1.704%	-1.099%	-1.704%	0.000%	0.000%
WA	-0.402%	-1.940%	-1.000%	-3.974%	-1.000%	-3.974%	-0.040%	-2.044%
NT	-0.243%	-0.560%	-0.616%	-1.868%	-0.616%	-1.868%	-0.025%	-1.447%

Source: CRA calculations

In addition, it is not clear how quickly and to what extent the generation investment community will explicitly take into account the projected impacts of smart metering infrastructure on peak demand and energy consumption in its investment decisions. Investment decisions are generally made with regard to the identification of investment being needed in documents like the SOO and predictions of future spot and contract market prices. The likelihood of the introduction of smart metering affecting these inputs to investment decisions is likely to be a function of two factors:

- How large the impacts are. If the impacts are very small relative to the overall load it is less likely that they will be material in the load forecasts that underpin the SOO, and therefore taken into account in investors' decisions regarding the type or size of generation investments that are to be undertaken, or its timing.
- How firm the impacts are, which in turn will depend in part on the how the impacts are produced. Technology induced load changes – and particularly those that are not subject to intervention by the end user – are likely to be considered more firm than others. For example, controlled loads such as DLC are inherently firm, while behavioural responses are not. Demand reduction that is the product of behavioural responses – such as end-user response to TOU or CPP price signals – is less likely to be considered firm until a track record has been established that demonstrates that this response is repeatable and consistent (or at least predictable based on a set of measurable independent variables). Even then, only that proportion of the load that receives the price signal that has been observed to respond will be considered firm. These factors will have an impact on both (a) how quickly these impacts are included in the load forecasts that underpin the SOO, and (b) the extent to which they are credited by investors before they are included in the SOO.

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Based on these considerations, we have assumed a “fixed” generation plan, which assumes that the generation system develops without consideration of the projected impacts of the smart metering infrastructure (that is, that investment decisions remain the same as in the No Smart Meter Case)⁹.

It is important to note, however, that the decision to assume that the introduction of smart metering infrastructure does not change the timing, size or type of generation plant that will be built over the analysis timeframe does not necessarily mean that the benefits of smart metering infrastructure have been undercounted. Reductions in peak demand due to smart metering will reduce the risk of unserved energy. Because this reduction is valued in the modelling at VOLL (which is set at approximately the cost of an open cycle gas turbine), the modelling approximates the value that would be obtained if smart metering was assumed to defer generation investment.

1.6. FINDINGS

The key findings of the modelling undertaken in Phase 2 of Stream 5 are as follows:

- **The DR projected to occur in each of the four functional analyses delivers incremental benefits as compared to the carbon price base case** – The NPV of the benefits for the base smart meter functionality and the New DLC, New & Retrofit DLC and Scenario 3 DLC functionalities are all positive in both the Base and High Demand Response cases. NPVs range as shown in Table 9 below:

Table 3: NPV (\$m 2007-2030) of the four DR functionalities

Functionality	NPV (\$m 2007-2030)	
	Base Demand Response	High Demand Response
Base smart meter functionality	195	547
New DLC	279	1,027
New & Retrofit DLC	323	1,079
Scenario 3 – No Smart Meter, DLC only	236	395

⁹ In the Stream 2 report, *Cost Benefit Analysis of Smart Metering and Direct Load Control, Stream 2: Network Benefits and Recurrent Costs, Phase 2 Report*, a somewhat different view was taken with regard to potential demand response benefits that could result for DBs. In that analysis, it was assumed that, within specified conditions, the impacts of non-firm demand response would be taken into account in network augmentation decisions. This view rests on the facts that (a) in some cases, the DB will actively be pursuing augmentation alternatives, and (b) DBs are subject to regulation, and therefore their investments can be directed to take account of demand response. In addition, the analysis of network demand response benefits included factors that sought to account for the fact that not all the demand response would actually be taken up. Further detail is presented in Section 14 of the Stream 2 Phase 2 report.

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Further, incremental benefits accrue in each of the individual component of benefits, namely, operating costs, offer costs, USE costs and CO₂ costs. The High Demand Response case provides significantly higher benefits, including, for example, a twenty- to forty-fold increase in CO₂ emissions reductions under the three smart meter analyses, as compared to that provided by the base smart meter functionality in the Base Demand Response Case (Case 1). This is primarily a function of the assumption that the High Demand Response case engenders a conservation effect of 3% to 7% of total energy consumption (see Table 1). This level of energy conservation adds significantly to the CO₂ and operating cost reduction impacts of the High Demand Response case.

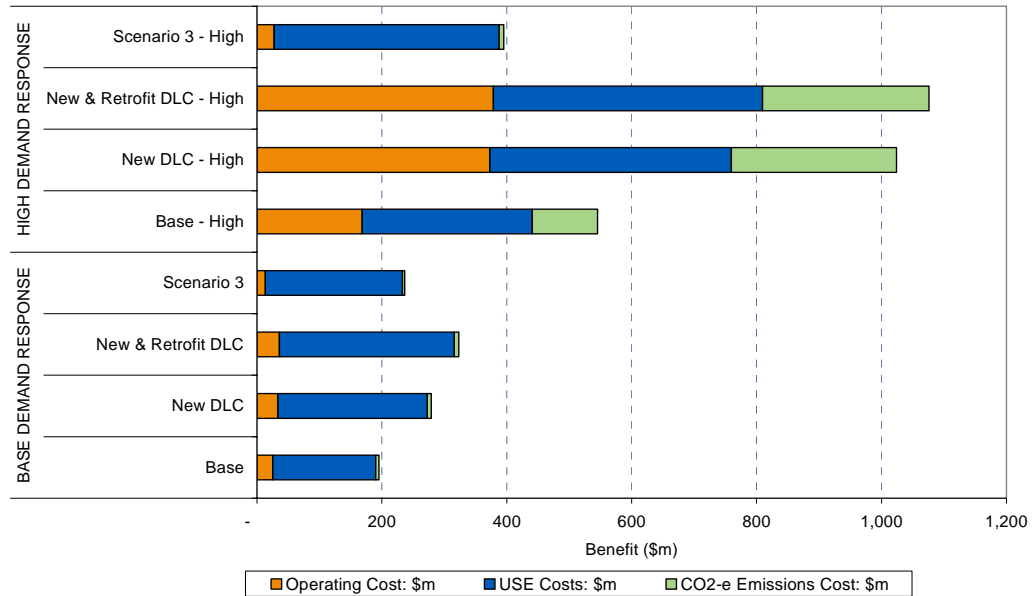
- **Total benefits are higher in each functional analysis if wholesale market prices based on Market Offer Costs rather than Operating Costs are considered** – This is not unexpected as the Market Offers capture any “mark up” that generators, as profit-maximising entities, can put in their bids over and above their costs. This suggests that the addition of DR – whether through smart meter infrastructure or non-smart meter DLC – is likely to (a) make wholesale electricity markets more competitive, and (b) deliver additional bill savings to consumers (though this will come as a result of reduced income to electricity generators and possibly retailers)¹⁰.

Figure 3 compares the magnitude and composition of the benefits of each of the four DR incremental analyses across the Base and High Demand Response cases when based on operating costs as compared to market offer costs.

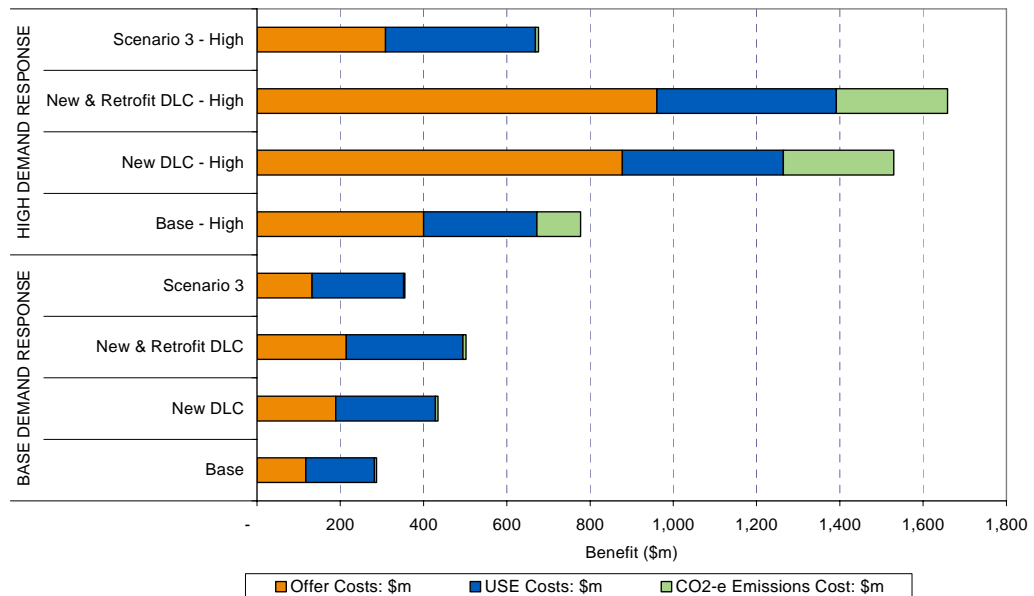
¹⁰ These reductions in wholesale market costs will be seen in the first instance by retailers. Although retailers could be expected to seek to retain as much of these wholesale cost reductions as possible, the workings of the competitive market will serve to deliver a significant proportion of the savings to end-use customers.

Figure 3: Level and composition of benefits based on operating vs. market offer costs

Benefits based on operating costs



Benefits based on market offer costs



- **The incremental smart meter DLC functionalities add a material level of benefit to the base smart meter functionality in both the Base and High Demand Response cases** – In the Base Demand Response case the increment is from about 43% to 65% (using operating costs) and 50% to 74% (using offer costs). In the High Demand Response case the incremental benefit increases drastically to 88% to 97% (using operating costs) and 97% to 113% (using offer costs). The increase in the High Demand Response case is again a result of the significant level of energy conservation impact assumed in this case.
- **The incremental benefit of the additional functionalities is most significant in terms of operating cost and CO₂ emissions reductions** – The additional functionalities provide significantly higher levels of opex savings and emissions reductions as compared to the basic smart meter functionality in both the Base and High Demand Response cases. However, their incremental impacts are much more significant in the High Demand Response case. This is the logical consequence of the energy conservation impacts associated with the incremental functionalities in the High DR case.
- **The New and Retrofit DLC functionality provides only marginally higher benefits than the New DLC functionality** – This seems surprising when first considered, but can be explained by the fact that over the course of the study timeframe virtually all air conditioning equipment will be replaced. As a result, the New (only) scenario, over time, winds up including all of the units that are represented in the New and Retrofit scenario. The only difference between the two is the value of the DLC provided by the retrofitted units over their remaining useful from the time of the initial smart meter DLC installation.
- **All of the smart meter and DLC functionalities exert downward pressure on both the average wholesale market price and the wholesale price pertaining in super-peak periods** – This is true in both the Base and High Demand Response cases. As would be expected, the High Demand Response case shows a significantly higher impact on both average and super-peak prices. This is simply the impact of the higher take-up assumed in the High Demand Response case. However there is also a greater increase in the price reduction provided by the incremental functionalities in the High Demand Response case as compared to that produced by them in the Base Demand Response case. This is a reflection of both the higher take-up and the greater conservation effect assumed in the High Demand Response case.

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- **The non-smart-meter DLC functionality (SMWG Scenario 3) provides a lower level of benefit than the smart meter DLC functionalities in each benefit category** – This reflects the fact that the non-smart-meter DLC functionality does not include either the price signal impacts or the conservation impacts present in the smart meter functionalities. Correspondingly, the non-smart meter DLC option lags the smart meter options most significantly where those price signals add benefits – particularly opex savings, market offer cost reductions and CO₂ emissions reductions. By contrast, non-smart-meter DLC benefits remain relatively similar to those provided by the base smart meter functionality in both the Base and High Demand Response Cases with regard to USE benefits and reductions in super-peak prices. It must be kept in mind, however, that the non-smart meter DLC option also has a different cost structure than the smart meter DLC options, and therefore may be more cost-effective, despite providing a smaller total magnitude of benefit¹¹.
- **Benefits at the jurisdictional level, in general, show the same pattern as seen at the national level** – All of the smart meter and non-smart-meter functionalities provide incremental DR-related benefits in each jurisdiction. Absolute benefits tend to be highest in NSW and Queensland. In addition, the value of the energy conservation impacts assumed to accrue due to the additional smart meter functionalities in the High Demand Response case are seen to result in similarly higher benefits at the jurisdictional level as was the case at the national level. The value of the High Demand Response case as compared to the Base Demand response case is most pronounced in South Australia and Western Australia.

¹¹ The relative cost-effectiveness of the various options, based on all applicable costs and benefits assessed in the various Stream reports, is discussed in NERA's *Smart Meter Cost Benefit Analysis: Phase 2 Overview Report*.

2. BACKGROUND AND PURPOSE

2.1. BACKGROUND

In February 2006, the Council of Australian Governments (COAG) committed to the progressive national roll-out of smart electricity meters from 2007 where benefits outweigh costs for residential users and in accordance with an implementation plan that has regard to costs and benefits and takes account of different market circumstances in each State and Territory. COAG identified the benefits of smart electricity meters as including the ability to allow the introduction of innovative, time-differentiated pricing and other means to enable users to better manage their demand for peak power.

In response to this decision, the Ministerial Council on Energy (MCE) Standing Committee of Officials (SCO) undertook initial work and released an information paper setting out MCE's policy direction on the smart meter roll-out in January 2007.

A Smart Meter Stakeholder Working Group (SMSWG) was established including representation from consumers, networks, retailers, metering service providers, NEMMCO, AEMC and AER. The group met for a series of workshops in February 2007, and developed a paper setting out key stakeholder positions, including areas where further work is required.

At its meeting in April 2007 COAG endorsed a staged approach for the national mandated roll-out of electricity smart meters to areas where benefits outweigh costs, as indicated by the results of the cost-benefit analysis which will be completed by or about the end of 2007.

The following milestones defined by COAG set out the key timelines for this consultancy:

- By September 2007, MCE will agree to a national minimum functionality for smart meters, including open communication protocols to support competition. Replacement criteria for existing meters will also be agreed to minimise costs of unnecessary replacements.
- By end 2007, MCE will finalise the cost-benefit analysis.
- By March 2008, MCE will also agree to any specific areas where replacement and roll-out may be exempt or delayed, on the basis of local factors which are demonstrated to reduce net benefits for consumers, as informed by the results of the cost-benefit analysis.
- By March 2008, MCE will agree necessary changes in the National Electricity Rules to require new and replacement meters to comply with the agreed minimum functionality and enable the national roll-out to commence.

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- During 2008, MCE will implement the necessary rule changes to mandate the roll-out of smart meters, consistent with the outcomes of the cost benefit analysis.
- By end 2008, replacement of existing meters with smart meters will have commenced.

2.2. PURPOSE

In June 2007, the Department of Industry, Tourism and Resources (now the Department of Resources, Energy and Tourism) issued a Request for Quotation (RFQ) for a set of studies designed to assess the costs and benefits of a mandatory roll-out of that functionality at the jurisdictional and national levels. The work was to be conducted in three phases:

- **Pre-work:** A pre-work phase was to define the agreed scenarios and base cases to be provided as input to the consultancy.
- **Phase 1 – National Functionality:** The objective of Phase 1 was to define the national minimum functionality.
- **Phase 2 – Regional and Detailed Analysis:** The objective of this work is to identify and quantify the costs and benefits of the roll-out of smart metering infrastructure from the perspective of specific stakeholder groups including consumers, networks, retailers, and the wider economy and market. This assessment has been undertaken at the jurisdictional and national levels.

The consultancy work to address Phases 1 and 2 was organised into five separate but interrelated streams. The objective of Stream 5, which is the subject of this report, was to assess the economic impacts of the national minimum functionality for smart metering infrastructure, two alternative levels of functionality, and an alternative means for providing the potential for demand response without smart metering, on the wholesale electricity market throughout Australia over the 2007 – 2030 timeframe. The specific impacts addressed, as specified in the Stream 5 Terms of Reference, included:

- Market price impacts;
- Generation investment;
- Greenhouse reductions – including modelling of changes to dispatch and inter-regional transmission losses over the interconnectors, and accounting for the specific emissions intensities of generation deferred;
- Reliability and service levels; and
- Future potential for technology and service innovation.

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2.3. ORGANISATION OF THE REPORT

The remainder of this report is organised as follows:

- Section 3 summarises the methodological and modelling approach that was used to assess the economic impacts of smart metering infrastructure and an alternative demand management scenario on the wholesale electricity market; and
- Section 4 presents the results of that analysis.

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3. METHODOLOGY AND APPROACH

3.1. OVERVIEW OF ISSUES TO BE ADDRESSED

The introduction of smart meters for small volume customers would provide functionality that could be used to assess customers' load profiles and seek to alter them through the use of price signals, education/awareness building and dedicated programs, including financial incentives.¹² Smart metering infrastructure would provide the means for sending price signals that could change how much electricity these consumers use and when they use it. It could also provide the means for actually controlling the operation of customers' end-use equipment within limits contractually agreed between the customer and one or more parts of the electricity value chain in ways that provide benefits to all parties to the transaction.¹³

There are four interrelated ways in which changes in the load profile of electricity demand that could result from the deployment and use of smart metering infrastructure (or alternative dedicated demand management systems) could affect the economics of the wholesale electricity market. These involve a complex range of issues from changes to short-term wholesale electricity market prices to longer term changes in generation investment, as discussed below:

- **Long term investment, wholesale electricity price and greenhouse gas (GHG) emission impacts:** Changes in load shape that persist over time can change the timing at which new plant is needed and the type of plant that is needed. Such deferral of plant additions or change in the mix of generation infrastructure can alter the total cost of supplying electricity, and the overall carbon intensity of the electricity generation system.¹⁴ The change in the total cost of supplying electricity will include the change in investment cost, changes in fixed maintenance and operating costs, and changes in variable operating and maintenance costs over time, including changes in fuel costs. Changes in the amount of different fuels used will also change the amount of carbon associated with meeting aggregate electricity needs, and therefore the cost of carbon emissions, assuming a price has been placed on such emissions.

¹² Financial incentives can be thought of as a type of price signal.

¹³ Control of specific end-use equipment can also be provided by technologies that do not rely on smart metering infrastructure. The costs and benefits of such an approach are also addressed in the MCE Smart Meter Cost Benefit Analysis. The economic impacts of such an approach on the wholesale electricity market are addressed in this report. Benefits accruing to networks, retailers and consumers are addressed in the Phase 2 Reports for Streams 2, 3 and 4 respectively. The costs of such an approach are addressed in the Stream 6 Phase 2 Report.

¹⁴ The potential for new generation technologies such as base-load clean coal plants whose market potential may be enhanced by a less peaky load shape is an example of how the introduction of smart metering infrastructure can have an impact on "future potential for technology innovation".

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- **Wholesale electricity price and greenhouse gas (GHG) emission impacts:** Changes in load shape and level – even where they do not persist over time – can change the amount of coal, natural gas and other fuels that are used to generate electricity, thereby changing the cost of production of the electricity consumed. Changes in the operating levels of these plants can also produce changes in variable maintenance and other variable operating costs. These changes occur any time the load shape changes from what it otherwise would have been.
- **Impacts on the level of competition in the wholesale market:** A change in load shape can also contribute to a change in the competitiveness of the wholesale market in certain time periods. For example, demand reductions can reduce the exercise of market power that can occur during periods of peak demand during which competition in the generation market is more limited (because very few generating units remain to be dispatched). If competition intensifies during peak periods, generators are likely to bid more competitively, which would result in lower wholesale market prices and should lead to lower price outcomes in the retail market as well.
- **Reliability impacts:** A change in load shape and/or level may also change the system reserve margin. Where reserve margins are enhanced due to reductions in peak demand relative to available generating capacity, system reliability will be improved because there is a lower probability of running out of capacity due to a loss of any particular generator or interconnector. While such impacts are most likely to occur during periods of high system demand, they can also occur at times of lower demand if available generating capacity is reduced, for example during periods of drought that limit hydro availability or during periods when generation plant is not available due to scheduled maintenance.

3.2. OVERVIEW OF APPROACH

Fundamentally, the approach employed conceptualises the impact of smart metering infrastructure and a dedicated demand response non-smart-meter alternative on the wholesale electricity market in terms of a change in wholesale market load profile. The implications of the change in terms of generation mix, fixed and variable operating and maintenance costs, generation system reliability (in the form of unserved energy) and carbon emissions are then calculated via a wholesale market analysis model.

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More specifically, the impact of the introduction of smart metering has been modelled as the change in the shape of regional (i.e. jurisdictional) load curves, which would result from consumers shifting peak load to off-peak hours, and/or changing their consumption level for some or all hours. These changes in end-use consumption are the result of the price signals that are made possible by smart meters, and that are assumed to be visible to at least some consumers, and/or the capability of smart meter infrastructure or the non-smart-meter DLC alternative to communicate with and control the operation of end-use equipment within customers' facilities.¹⁵

The impacts were assessed over the period 2007 to 2030 for all Australian states and territories. This includes the National Electricity Market (the NEM), the Western Australian SWIS, and the Northern Territory power grid. The NEM is modelled as an imperfectly competitive market where generators bid in their capacity as per the NEM market rules and can have parts of their capacity offered above their short-run marginal costs (SRMC). New entrant generators in the NEM are modelled as "price takers", i.e., these generators enter the market only if they can earn enough revenue to recover their fixed capital and O&M costs over and above their SRMC. WA and NT are modelled as least-cost perfectly competitive systems where all generators act as price takers.

The four types of impacts discussed in the previous section were modelled at two levels of detail. Chronological modelling for every hour of the year was undertaken in Phase 1 for the first 5 years of the study period to provide as accurate an estimate as possible of the impacts of the DR induced by smart meter and non-smart meter DLC functionalities. The findings of that Phase 1 analysis suggested that the difference in dispatch results between the chronological approach and the use of 40 blocks of time to characterise the load over the year was less than 1%.¹⁶ Based on this finding and the considerable improvement in analytic efficiency and flexibility offered by the 40-block approach, it was decided that the 40-block approach was sufficiently accurate and more appropriate for use in this study.¹⁷

15 Such control would only be exercised with the consent of the customer, generally for a consideration and under contractual limits to the frequency, duration and in some cases the timing of such control.

16 CRA International, *Economic Impact of Smart Metering and Direct Load Control*, Stream 5 Phase 1 Final Report, Section 3.5, September, 2007. Relevant results have been reproduced in section 3.9 of this report.

17 The accuracy of the use of the 40 block model was also checked using the short-term half-hourly dispatch model as part of our analysis of demand response benefits for the International Energy Agency (IEA): CRA International, *Valuation of demand side resources in Australia*, prepared for the International Energy Agency, December 2006. Section 5.6 of that report (Short-term Simulation to Assess the Accuracy of the Long-term Analysis) compares the performance of the short- and long-term models. See http://www.demandresponseresources.com/Portals/0/Australia/Australia_CRA%20Report%20on%20Demand%20Response%20Dec%202006.pdf

3.3. OVERVIEW OF METHODOLOGY

CRA's proprietary modelling tool, CEMOS, has been used in other applications for modelling wholesale market behaviour and outcomes, including the impact of demand response programmes and greenhouse gas pricing and policies. As discussed in the previous section, the model provides the ability to model generator behaviour and probabilistic system reliability using either a detailed half-hourly or a high-level load block-based investment and dispatch model. CEMOS has been set up for all Australian states and territories, including the interconnected NEM regions, the Western Australian SWIS and the Northern Territory power grid.

The discussion of the methodology and modelling implementation plan is structured as follows:

- The basic approach taken to modelling the benefits of DR;
- The analytic framework that was used;
- The detailed functionalities of the CEMOS models used for the analysis; and
- The modelling process itself.

3.4. BASIC APPROACH TO MODELLING THE BENEFITS OF DR

There are two basic approaches to assessing the impact of DR on a wholesale electricity system:

1. Modify the forecasted load exogenously to reflect the impact of the deployment of DR resources, and use a resource planning model to calculate the system cost to meet the modified load and load shape. In general, this approach is straightforward and easy to execute, but relies on the accuracy and comprehensiveness of the exogenous assessment of the impact of DR to provide the optimal modification of the load shape. This can be a problem in studies that are seeking to optimise DR and supply-side resources, but is less problematic when assessing the impact of a single or specified set of DR resources on a given generation system.
2. Model the economic, merit order dispatch of DR and supply-side options (generators) to meet load. While this is more complex, it can provide a more accurate estimate of the cost-effectiveness of demand-side resources as generation alternatives. The approach requires that the DR resources can be described in terms that are similar to the characteristics of generation plant. However, this additional complexity may not be warranted if the volume of DR options is inconsequential (e.g. < 50 MW system-wide over several years) to generation investment decisions, or the cost/nature of DR is such that the selection of DR resources ahead of supply resources is a trivial task.

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The first approach above was chosen for this study because the specific objective of this Stream was to determine the potential benefits of the DR impacts of smart meter and non-smart meter communication and control technologies, and did not require an assessment of the cost-effectiveness of those technologies relative to supply-side resources. More specifically, explicit data on the cost of smart meters and attribution of those costs to load reduction in different time periods is not required in this study as the wholesale market benefits are only one component of the overall benefits of smart meter deployment, and the decision as to whether to deploy the smart meters will not be made solely on their cost-effectiveness in reducing wholesale market costs.¹⁸ By contrast, the second approach would endogenously optimise the penetration of smart-meters in terms of their wholesale market benefits alone. As such, the results of the second approach would likely (a) be very sensitive to the cost assumptions made; (b) be less transparent and less intuitively understandable given the complex interactions that can exist between DR and generator resources over time, and (c) most importantly, not be reflective of the nature of the policy decision that is involved regarding whether or not smart meters are cost beneficial.

3.5. HOW BENEFITS ARE ALLOCATED IN CEMOS

In assessing the jurisdictional benefits of DR, there are two choices regarding how the benefits of the impacts of DR on the wholesale market could be allocated. On the one hand, they could be allocated to the end-users whose changed behaviours created the DR impact. On the other hand, they could be allocated to the area of the generation system those impacts affect. In jurisdictions where all end-user DR impacts affect only the wholesale (i.e., generation) market of that jurisdiction, these two choices devolve to the same outcome. This is the case in Western Australia and the Northern Territory.

By contrast, in the NEM – where interconnection largely networks the generation systems of Queensland, NSW, the ACT, Victoria, South Australia and Tasmania – a change in demand in one jurisdiction can change the level of energy generation in another jurisdiction. For example, energy conservation in South Australia is likely to reduce generation and carbon emissions from generators in Victoria. Similarly, a reduction in peak demand in Victoria is likely to increase reserve margins (and therefore reduce the likelihood of unserved energy) in NSW.

¹⁸ This is not to say that the costs of the smart meters have not been considered. All transitional costs associated with the installation of smart metering have been quantified in Stream 6. Recurring costs associated with operation of the smart meter functionality have been identified in Streams 2, 3 and 4, depending on whether these costs are incurred by networks, retailers or consumers respectively. All costs and all benefits that are assessed in Phase 2 are then brought together in the Phase 2 Overview Report. As such, the task in Stream 5 was simply to assess the benefits of smart meter and non-smart meter DR functionality with regard to the wholesale electricity market and greenhouse gas emissions.

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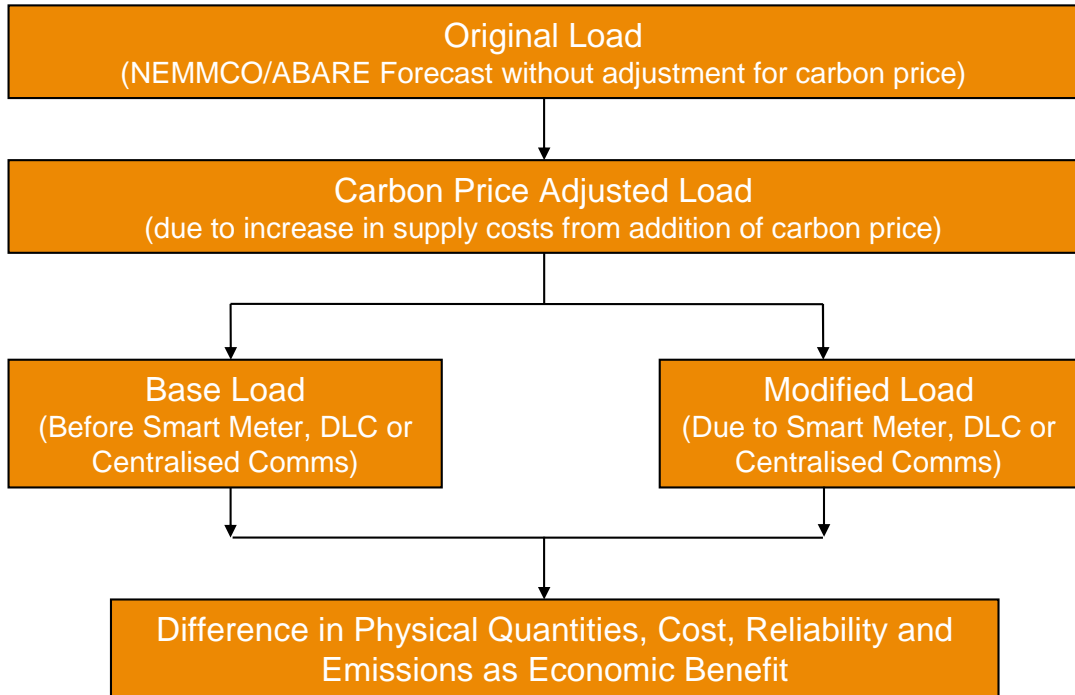
Because CEMOS is a model of the NEM, it associates the impacts of DR with the jurisdiction in which those impacts are experienced by the generation system, and the jurisdictional benefits reported in section 4 follow this convention. In some cases, this may seem unfair as the jurisdiction that is producing the DR is not getting “credit” for the benefits. However, such allocation is consistent with the nature of a system, and trying to assign certain benefits to here the demand reductions originate are likely to misrepresent the nature of those benefits. Reliability benefits are a good example of this problem: demand reductions at times when a jurisdiction’s load exceeds its native capacity will not increase reliability within the jurisdiction. Other benefits – such as carbon emission reductions – are essentially global in any case.

As a result, some care should be exercised in interpreting the benefits reported on a jurisdictional level for the NEM states.

3.6. ANALYTIC FRAMEWORK EMPLOYED

Figure 4 provides an overview of the analytic framework that was used in the study.

Figure 4: Overview of analytic approach



3.6.1. Original load – business as usual with no carbon price

This assumes the market continues as it operates today without any significant policy intervention that may alter the investment and dispatch profile in future. This has been implemented with the assumption that no carbon taxes or prices are introduced and all current state-based renewable and gas schemes continue.¹⁹ The BAU case is used as a benchmark to compare dispatch and price, and to get insight into the impact of the carbon price on smart meter benefits. Because its purpose was to determine the impact of carbon prices on the benefits of smart metering infrastructure, the BAU case was only run for the basic smart metering infrastructure functionality.

¹⁹

At the time the study was commenced it was not clear whether the state-based schemes would continue or not. See also the next footnote.

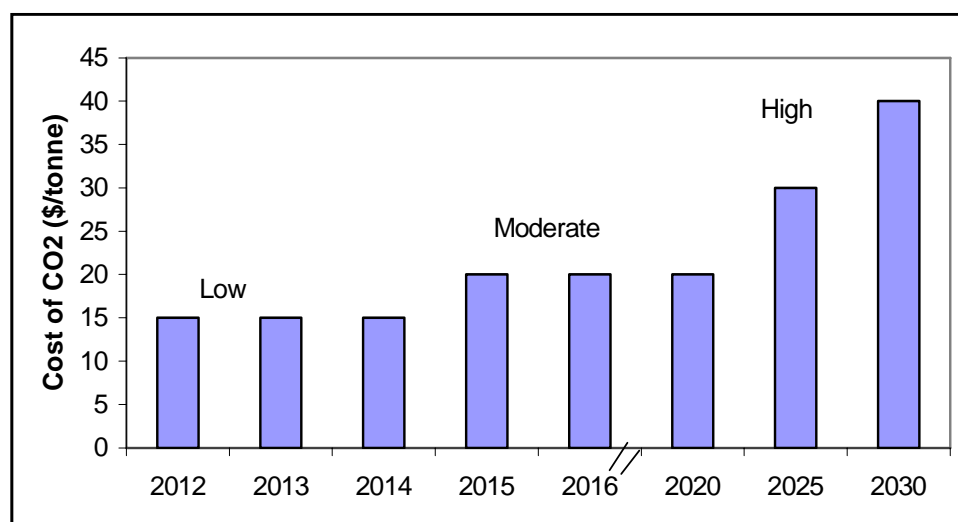
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3.6.2. Carbon price adjusted load

This case adds a price for carbon to fuel costs that is proportional to the emission intensity of the generator. This was done because at the time the project was commenced both political parties had stated their intention of introducing a carbon price, most likely through a cap and trade market mechanism.

We have assumed that a price case of \$15/tonne of CO₂ is introduced in 2012 and ramps up to \$40/tonne by 2030. It has also been assumed that the current state-based renewable and gas schemes are discontinued from 2012.²⁰ Figure 5 shows the carbon price path that has been assumed. The rationale for the selection of the CO₂ price path follows the figure.

Figure 5: Carbon price path assumed in the modelling



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At the time the study was commenced, carbon prices as a result of the cap and trade scheme that had been endorsed by both political parties were expected to be introduced in 2012. Subsequently, the target date for the introduction of carbon pricing was brought forward to 2010. This change is not reflected in this report as it took place after the analyses had been completed. Similarly, at the time the study was commenced the Government of the day had announced that the then-existing federal Mandatory Renewable Energy Target (MRET) would be discontinued once the carbon trading scheme was introduced. The Government also requested that the States discontinue their renewable and gas schemes. Subsequently, the new federal Government has announced that the MRET will be extended and expanded from the initial target of 9,500 GWh by 2010 to 45,000 GWh by 2020. This change is not reflected in this report but is likely to have only a second-order impact on study results because of the fixed capacity analysis framework. Under the fixed capacity assumption, an expanded MRET simply changes the nature of the generation sector in both the non-smart-meter and smart meter cases. USE benefits would likely be largely the same under the MRET and no MRET cases, and operating and emissions reductions would be likely to be similar as the renewable energy generators are likely to operate as must-run resources, therefore ensuring that non-renewable generation will be backed down when smart-meter- or non-smart-meter DLC- induced changes in load occur. This is likely to be gas-fired generation in either the no-MRET case (as is reflected in the results of this study), or the MRET case. As a result, it is unlikely that results under a new MRET regime will differ materially from those in the no-MRET regime modelled in the present study.

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A price of \$15-20/tonne of CO₂ forms the lower end of cost of carbon that is generally assumed to be required in order to induce some switching of existing generation from carbon-intensive fuels such as coal towards cleaner forms of generation such as gas. For instance, the more expensive end of coal generation costs in Australia are around \$20/MWh at a CO₂ intensity of 1 tonne/MWh, and the low end of baseload efficient gas generation cost is around \$30/MWh with a CO₂ intensity of 0.33 tonne/MWh. Therefore, every MWh switched from the most expensive existing coal generation to the least expensive gas option costs $[(30-20)/(1-0.33)] \sim \$15/\text{tonne of CO}_2$. Such reduction potential however is limited as most of the baseload coal generation in Australia has a short-run marginal cost well below \$20/MWh, and a significant proportion of baseload gas generation costs are over \$30/MWh.

Therefore, the cost of carbon will need to be higher than \$15/MWh to induce higher levels of switching from existing coal to existing gas and renewables. A moderate increase from \$15/tonne to \$20/tonne is assumed in the medium term (2015-2020).

Over time, new entrant cleaner technologies will also need to recover their capital costs over and above their short-run marginal cost, which implies that the cost of carbon will need to rise further. For instance, the long-run marginal cost of a new entrant closed cycle gas turbine (CCGT) has been estimated at over \$40/MWh. In order for a new entrant CCGT to be competitive with an existing coal plant with a SRMC of \$15/MWh, a carbon tax well in excess of \$30/tonne of CO₂ will be needed. A CO₂ cost in excess of \$30/tonne will also be needed to make clean coal technologies such as carbon capture and storage technologies competitive with conventional coal technologies. A cost of carbon of \$40/tonne, which would add approximately \$32/MWh to the cost of conventional coal generation in the long-run, would allow cleaner forms of generation to compete with conventional coal.

The transition from short-term the switch from existing coal to existing gas or renewable (which starts at \$15/tonne in the short term) to the substitution of existing coal generation by new entrant cleaner technologies (that occurs at \$40/tonne in the longer term) will require the cost of carbon to rise gradually over the years as existing carbon-intensive generation is phased out by cleaner forms of gas, clean coal and renewable generation. A rising trajectory of carbon prices has been advocated in the economic theory²¹. We have followed theory in this regard by assuming that the cost of carbon continues to rise beyond 2020 from \$20/tonne to \$40/tonne by 2030.

21 William Nordhaus, one of the leading economists in the arena of climate change, has suggested that the optimal carbon tax trajectory would start with a tax of about \$17 per ton, rising to \$84 in 2050 and \$270 in 2100. Another noted economist Paul Portney proposed starting with a \$5-per-ton tax on carbon and raising it by \$5 per ton every other year. A study published by McKinsey in December 2006 for the European Commission predicts a stepped increase in CO₂ price from the current level of €20/tonne of CO₂ to €30/tonne by 2015 and further to €35/tonne by 2020. (McKinsey & Company, *Report on International Competitiveness*, December 2006, see Figure2-5 on 'Potential European CO₂ Prices').

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Long-run elasticity of demand as estimated by NIEIR has been used to adjust demand for an increase in system cost due to the introduction of a cost for carbon. Wholesale electricity cost increases over the years as the cost of CO₂ increases, as shown in Figure 5 above. An adjustment based on the increased cost of electricity due to carbon prices and the NIEIR elasticity factor is applied to the energy projections for all jurisdictions for all years. In 2030, the adjustment amounts to approximately 2% of total Australian electricity requirement. It is important to note that this carbon-cost related energy forecast adjustment was made prior to consideration of the load shape and magnitude impacts of smart metering infrastructure and non-smart-metering DLC.²² As a result, the smart-meter related impacts that are discussed elsewhere in this report are incremental to the carbon price impacts. Table 4 shows the difference in total system cost for the BAU and carbon price cases, and how that difference and the NIEIR elasticity factor were used to adjust the energy projected for three target years. The same approach was applied to the energy projections for all jurisdictions for all years.

Table 4: Demand reduction in response to cost of carbon

Year	Total BAU Energy (GWh)	Total Australia Wholesale Cost (\$m)			Elasticity	Reduction in Projected Energy (GWh) *	Total Carbon Price Base Case Energy (GWh)
		BAU	Base With Carbon Prices	Wholesale Market Cost Increase			
2015	246,121	4,200	4,203	0.05%	0.2	0.01%	246,108
2025	321,429	4,986	5,310	6.51%	0.2	0.65%	319,336
2030	358,988	5,483	6,613	20.61%	0.2	2.06%	351,590

* Calculated as (Cost increase * Elasticity * Retail price share of energy cost). Retail share of energy cost has been assumed to be 50%. Hence, a 0.05% wholesale market cost increase leads to, $0.05 \times 0.2 \times 0.5 = 0.01\%$ demand reduction

3.6.3. Analyses undertaken to assess the impacts of the smart meter functionalities and non-smart-meter DLC

The following analyses were undertaken to assess the impacts of the functionalities being considered in Phase 2:

- Base functionality, which assesses the impact of the base functionality of the smart metering infrastructure as defined by the Smart Meter Working Group (SMWG) for the SMCBA against the Carbon Price Base Case.

22

At the time the study was commenced there was a general consensus that some form of carbon pricing would be implemented in the 2010 – 2012 timeframe. As a result, the SMWG directed that the modelling be undertaken assuming that this occurs. Modelling results, therefore, include the impacts of both the introduction of smart meters and the introduction of a carbon price, but the effects attributed to smart meters do not include the effects of the carbon prices.

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- Base plus incremental functionalities, in which each of the individual incremental functionalities is added to the base functionality and assessed against the Base Case. Because two levels of incremental functionality were considered – smart-metering based DLC in new and replacement applications and smart-metering based DLC in new, replacement and existing applications – two separate analyses were undertaken.
- Alternative DLC functionality (SMWG Scenario 3), which assesses the impact of the non-smart-metering DLC functionality.

Significant uncertainty surrounds the per-customer impact and take-up of several of the base and incremental functionalities including:

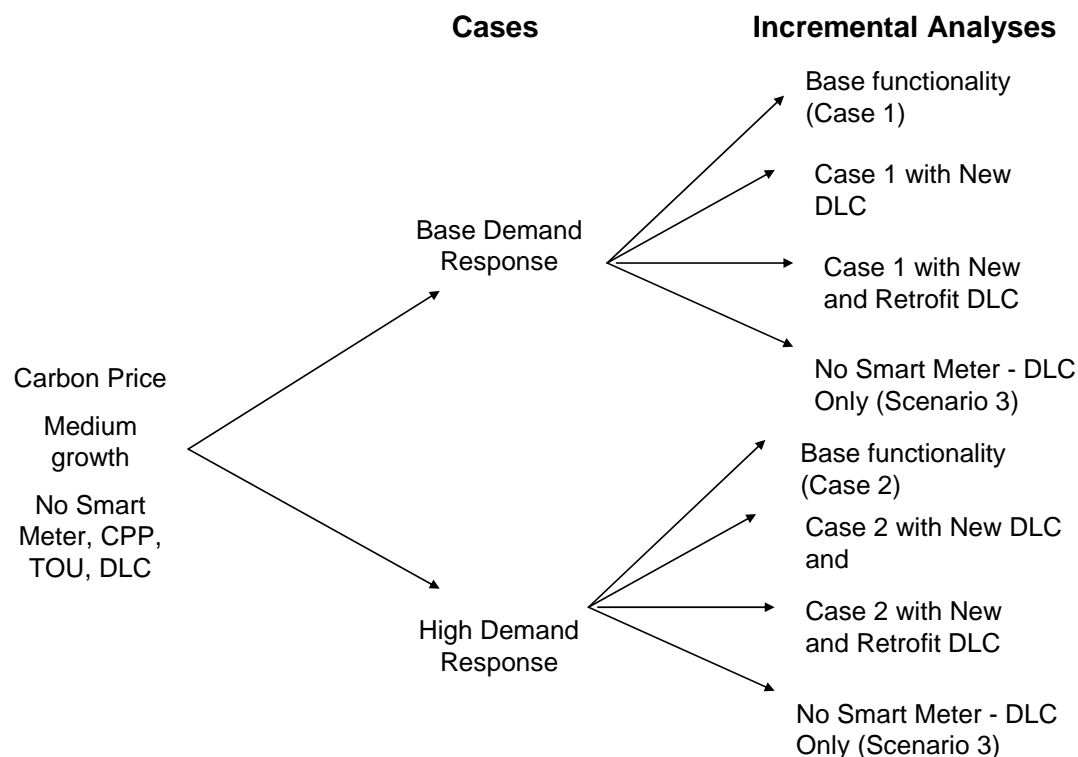
- The level of demand reduction and energy consumption reduction and shifting that will result from the introduction of time-of-use (TOU) and dynamic pricing arrangements such as critical peak pricing (CPP), and
- The extent to which such pricing arrangements will be offered by retailers and taken up by consumers.

As a result, two demand response cases²³ were undertaken to assess the potential benefits of two different levels of take-up of the pricing and DLC programs by customers. For each of these scenarios, there are base case and incremental functionalities and different assumption on conservation effects.

Figure 6 provides an overview of the cases and incremental analyses and Table 7, which is presented on page 34, summarises the key take-up and impact assumptions for each case and the associated incremental functionality analyses.

²³ The high and low take-up levels were developed with input from KPMG (based on information provided by the retailers as part of the Stream 3 analysis), NERA (based on information developed in the assessment of the consumer perspective in Stream 4), and CRA.

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Figure 6: Overview of the modelling scenarios

In addition, it is not clear how quickly and to what extent the generation investment community will explicitly take into account the projected impacts of smart metering infrastructure on peak demand and energy consumption in its investment decisions. Investment decisions are generally made with regard to the identification of investment being needed in documents like the SOO and predictions of future spot and contract market prices. The likelihood of the introduction of smart metering affecting these inputs to investment decisions is likely to be a function of two factors:

- How large the impacts are. If the impacts are very small relative to the overall load it is less likely that they will be material in the load forecasts that underpin the SOO, and therefore taken into account in investors' decisions regarding the type or size of generation investments that are to be undertaken, or its timing. While the peak demand reductions that result from the analysis of the impact of smart-metering infrastructure and non-smart-metering DLC are small in percentage terms, in absolute terms they can comprise 200 to 300 MW depending on the functionality and jurisdiction. Although these are not small numbers it must be noted that this level of demand is still well within the band of statistical uncertainty of system peak within these jurisdictions, and therefore it is quite possible that they could be significantly or totally discounted in generation capacity investment decisions. It is also important to note that the projected peak demand reduction attributable to the smart-metering infrastructure and non-smart-metering DLC is itself uncertain.

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If the level of DR were greater it would be worth considering the possibility that DR deployment would change the nature and timing of generation investments as compared to the Base Case. In such a case – referred to as a Re-optimised Capacity scenario – capex benefits would be expected to be non-trivial, but unserved energy benefits might decrease as the generation, now with less reserve capacity, might be more vulnerable to supply interruptions.

- How firm the impacts are, which in turn will depend in part on the how the impacts are produced. Technology induced load changes – and particularly those that are not subject to intervention by the end user – are likely to be considered more firm than others. For example, controlled loads such as DLC are inherently firm, whereas behavioural responses are not. Demand reduction that is the product of behavioural responses – such as end-user response to TOU or CPP price signals – is less likely to be considered firm until a track record has been established that demonstrates that this response is repeatable and consistent (or at least predictable based on a set of measurable independent variables). Even then, only that proportion of the load that receives the price signal that has been observed to respond will be considered firm. These factors will have an impact on both (a) how quickly these impacts are included in the load forecasts that underpin the SOO, and (b) the extent to which they are credited by investors before they are included in the SOO.

Based on these considerations, we have assumed a “fixed” generation plan, which postulates that the generation system develops without consideration of the projected impacts of the smart metering infrastructure (that is, that investment decisions remain the same as in the No Smart Meter Case).²⁴

It is important to note, however, that the decision to assume that the introduction of smart metering infrastructure does not change the timing, size or type of generation plant that will be built over the analysis timeframe does not necessarily mean that the benefits of smart metering infrastructure have been underestimated. Reductions in peak demand due to smart metering will reduce the risk of unserved energy. Because this reduction is valued in the modelling at VOLL (which is set at approximately the cost of an open cycle gas turbine), the modelling approximates the value that would be obtained if smart metering was assumed to defer generation investment.

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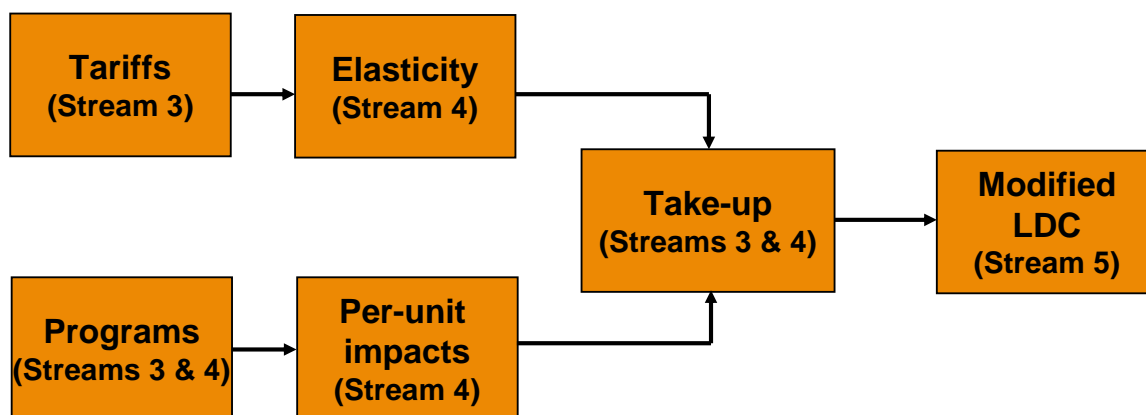
In the Stream 2 report, *Cost Benefit Analysis of Smart Metering and Direct Load Control, Stream 2: Network Benefits and Recurrent Costs, Phase 2 Report*, a somewhat different view was taken with regard to potential demand response benefits that could result for DBs. In that analysis, it was assumed that, within specified conditions, the impacts of non-firm demand response would be taken into account in network augmentation decisions. This view rests on the facts that (a) in some cases, the DB will actively be pursuing augmentation alternatives, and (b) DBs are subject to regulation, and therefore their investments can be directed to take account of demand response. In addition, the analysis of network demand response benefits included factors that sought to account for the fact that not all the demand response would actually be taken up. Further detail is presented in Section 14 of the Stream 2 Phase 2 report.,

Although the smart metering infrastructure does not provide any capacity deferral or avoidance benefits in the Fixed Capacity scenario used in this Phase 2 analysis, other benefits such as operating cost reductions and unserved energy reductions do occur.²⁵

3.6.4. Development of the DR-modified load duration curves that were modelled

Modified load duration curves were developed for each of the modelling scenarios described above for each region based on the likely response of end-use customers to the enhanced price signals and technological interventions made possible by the various smart meter and non-smart meter DR functionalities. Figure 7 shows the factors that influence how the load duration curve is modified in each scenario, and the Streams within the overall smart meter cost benefit analysis from which the information on these influences was drawn.

Figure 7: Inputs to modifying the load duration curve



The following subsections provide information on the tariffs that were developed in Stream 3, the take-up of those tariffs and the DLC program options as developed in Streams 3 and 4, and the resulting impacts on the load duration curve for each scenario, as summarised in the percentage reduction in peak demand and energy consumption.

The elasticity factors used can be found in the Stream 4 report. Details of the non-smart meter DLC program are also provided in the Stream 4 report.

²⁵ The dynamic interaction between the various components of the economic impacts of DR is discussed in Section 4.2 below.

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Tariff assumptions

The tariffs developed in Stream 3 are shown in Table 5 and Table 6.

Table 5: Tariff assumptions (c/kWh, excl GST and carbon) – residential (2007 dollars)

State	Flat Tariff	TOU tariffs				CPP	
		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	\$0.02470	\$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.

Source: KPMG, Stream 3 Report

Table 6: Tariff assumptions (c/kWh, excl GST and carbon) – small commercial (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

Source: KPMG, Stream 3 Report

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Tariff and program take-up assumptions

Take-up, as developed in Streams 3 and 4, is shown in Table 7.

Table 7: Summary of case and incremental analyses take-up and impact assumptions (residential customers)

	TOU only	TOU plus CPP	DLC	Conservation impact
Base demand response (Case 1)				
Base functionality (Case 1)	35%	7.5%	N/A	N/A
Case 1 with New DLC (functionalities 15, 16A, 16B)	30%	7.5%	7.5%	N/A
Case 1 with New and Retrofit DLC (functionality 16C)	30%	7.5%	7.5%	N/A
Scenario 3 – no smart meter DLC only	N/A	N/A	10%	N/A
High demand response (Case 2)				
Base functionality (Case 2)	35%	15%	N/A	3%
Case 2 with New DLC (functionalities 15, 16A, 16B)	30%	15%	15%	7%
Case 2 with New and Retrofit DLC (functionality 16C)	30%	15%	15%	7%
Scenario 3 – no smart meter DLC only	N/A	N/A	20%	N/A

Note: Duration for direct load control has been assumed to be 6 hours on the basis of ETSA Utilities' experience.

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

The take-up rates assumed in the Stream 3 report for the small business sector were as follows for all scenarios:

- TOU tariff: 40%
- CPP: NIL
- Flat tariff: 60%.

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Impacts on the load duration curves of the DR scenarios

NERA, through its work on Stream 4, Consumer Benefits, has provided an estimate of the half-hourly load impacts in that result from the installation of smart meters in two timeframes:

- 2014/15 to 2024/25, during which short-run elasticity factors are assumed to apply; and
- Beyond 2024/25, during which long-run elasticity measures are assumed to apply.

These estimates are based on an assumption that in the short term consumers will respond to the price signals delivered by smart meters primarily by voluntary, behavioural changes, which will be limited in their aggregate impact. In the longer term, however, consumers would be expected to respond to price signals that persisted over time by altering the type of capital equipment they purchase, for example by choosing equipment that maximises the use of electricity during peak periods, or that includes control logic that allows or enables usage to be reduced during periods of high prices.

From this half-hourly data the average demand reduction for peak- and off-peak periods (which were defined in load blocks) were calculated. Table 8 below summarises the resulting impacts on the load duration curve for each incremental analysis in each of the two demand response cases, in terms of the percentage reduction in peak demand and energy consumption that takes place. A modified load shape was developed for each incremental analysis using these percentage reductions.

Table 8: Changes in the 2050 load duration curve (% peak and energy reduction) assumed in Stream 5 for each DR case and incremental analysis

	% Energy	% Peak	% Energy	% Peak	% Energy	% Peak	% Energy	% Peak
Base Demand Response								
	Base Functionality (Case 1)		New DLC (16 A&B)		New & Retrofit DLC (16C)		Scenario 3 (No smart meter DLC Only)	
QLD	-0.030%	-0.733%	-0.039%	-1.482%	-0.039%	-1.482%	-0.014%	-0.912%
NSW	-0.018%	-0.440%	-0.028%	-1.035%	-0.028%	-1.035%	-0.013%	-0.772%
VIC	-0.026%	-0.582%	-0.035%	-1.159%	-0.035%	-1.159%	-0.012%	-0.694%
SA	-0.037%	-0.922%	-0.059%	-1.959%	-0.059%	-1.959%	-0.029%	-1.210%
TAS	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
WA	-0.010%	-1.147%	-0.024%	-2.003%	-0.024%	-2.003%	-0.020%	-1.022%
NT	0.000%	-0.215%	-0.009%	-0.771%	-0.009%	-0.771%	-0.012%	-0.724%

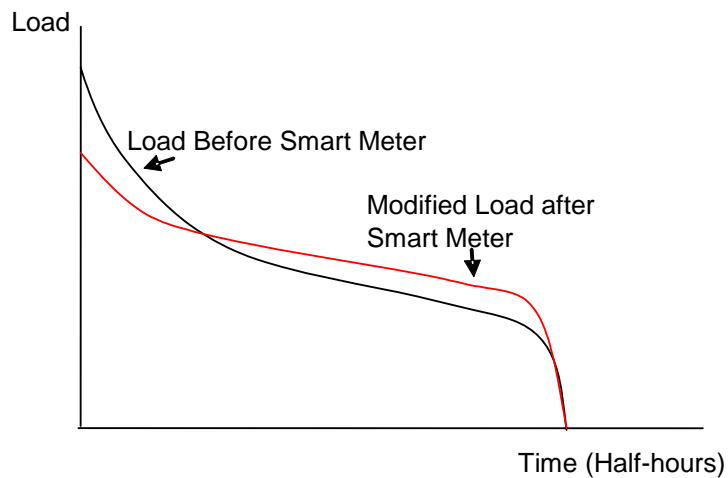
High Demand Response								
	Base Functionality (Case 2)		New DLC (16 A&B)		New & Retrofit DLC (16C)		Scenario 3 (No smart meter DLC Only)	
QLD	-0.403%	-1.263%	-0.969%	-3.043%	-0.969%	-3.043%	-0.027%	-1.825%
NSW	-0.243%	-0.972%	-0.590%	-2.466%	-0.590%	-2.466%	-0.026%	-1.544%
VIC	-0.291%	-1.015%	-0.697%	-2.423%	-0.697%	-2.423%	-0.025%	-1.388%
SA	-0.449%	-1.749%	-1.059%	-4.232%	-1.059%	-4.232%	-0.058%	-2.420%
TAS	-0.457%	-0.965%	-1.099%	-1.704%	-1.099%	-1.704%	0.000%	0.000%
WA	-0.402%	-1.940%	-1.000%	-3.974%	-1.000%	-3.974%	-0.040%	-2.044%
NT	-0.243%	-0.560%	-0.616%	-1.868%	-0.616%	-1.868%	-0.025%	-1.447%

Source: NERA Stream 4 Report

3.6.5. Modelling the impact of the DR-modified load duration curves

Modelling of the impact of these changes in load profile were undertaken in terms of the difference in wholesale market outcomes between the load curve before (i.e., under the Carbon Price Base Case conditions without the smart meter programme) and after the smart metering (or non-smart-meter DLC) infrastructure is deployed. Figure 8 shows a set of illustrative load duration curves representing the before and after smart meter roll-out cases that served as inputs to the market modelling. Such before and after load data was developed for each incremental analysis in each state for each year of the study timeframe.

Figure 8: Modified load duration curve



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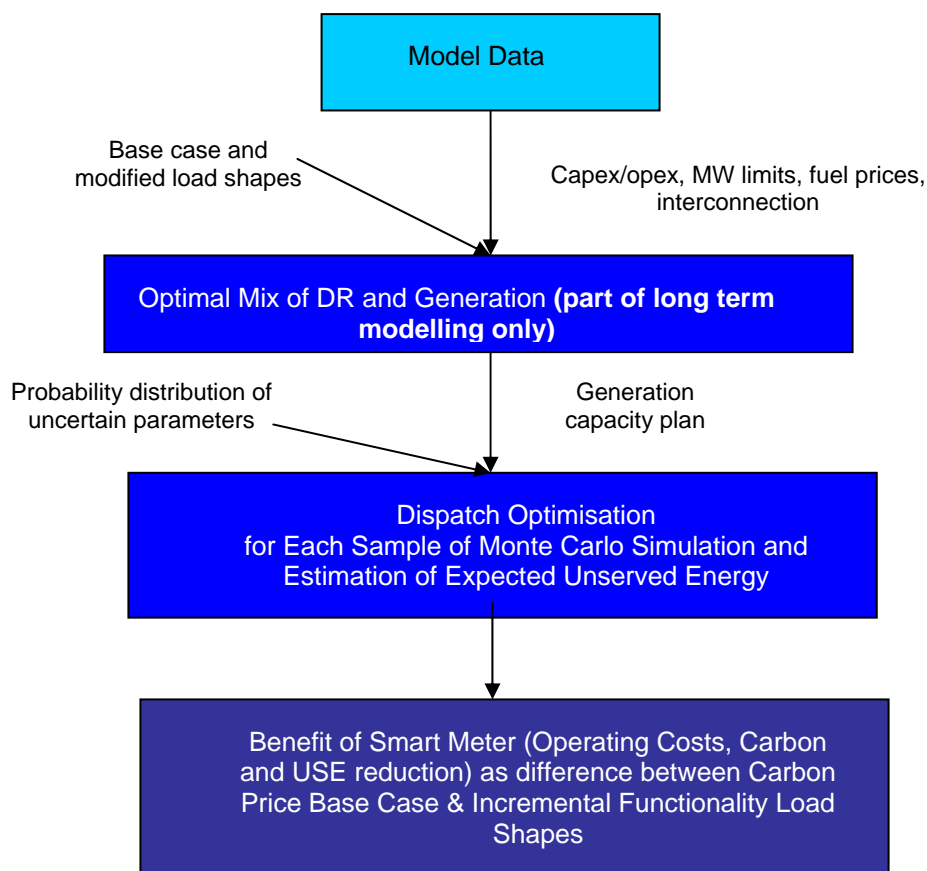
Once the modified load duration curves were developed, they were subjected to modelling runs in CEMOS that included:

- Developing generator bids for the NEM states and cost-based bids for SWIS and NT regions for each generator over 2007-2030 for both Carbon Price Base Case conditions (i.e., no smart meters) and the various smart metering and non-smart-metering DLC functionalities;
- Optimising dispatch over the 2007-2030 timeframe for both load forecast conditions;
- Performing Monte Carlo simulation using random samples of the probability distributions of generator outages, load levels and fuel costs for each year for both load forecast conditions. In this step, only dispatch was re-optimised; the capacity plan developed in the activity above was not changed. Expected dispatch, price, cost and USE outcomes were then developed using the average across the samples for both load forecast conditions. Each such run optimises dispatch of the generators to meet demand for each of the randomly generated generator outage patterns/samples. Expected dispatch cost, unserved energy (USE) costs, and carbon cost/emission estimates were developed using the average across all samples;
- The difference between capital, operating, USE and CO₂ costs was then calculated across the following runs:
 - a) “Carbon Price Base Case (i.e., no smart meter)” and “Base functionality” scenarios to provide the gross benefit of the base functionality;
 - b) “Carbon Price Base Case (i.e., no smart meter)” and each of the incremental functionality analyses (i.e. “New DLC functionality 16A&B”, “New and Retrofit DLC functionality 16C” and “Scenario 3 No Smart Meter – DLC Only”) to provide the gross benefit of the base functionality in combination with each of the three incremental functionalities tested; and
 - c) A “second difference” between (b) and (a) above, to provide the *incremental benefit* of each of the various smart metering and non-smart-metering DLC functionalities on its own.

Using the results from the above activity for the Carbon-Prices Base Case and each of the various smart metering and non-smart-metering DLC functionalities, the difference in prices, system fuel cost, USE and carbon emissions were calculated to assess the impacts of smart meter and DLC deployment.

Figure 9 provides an overview of the modelling approach we have employed.

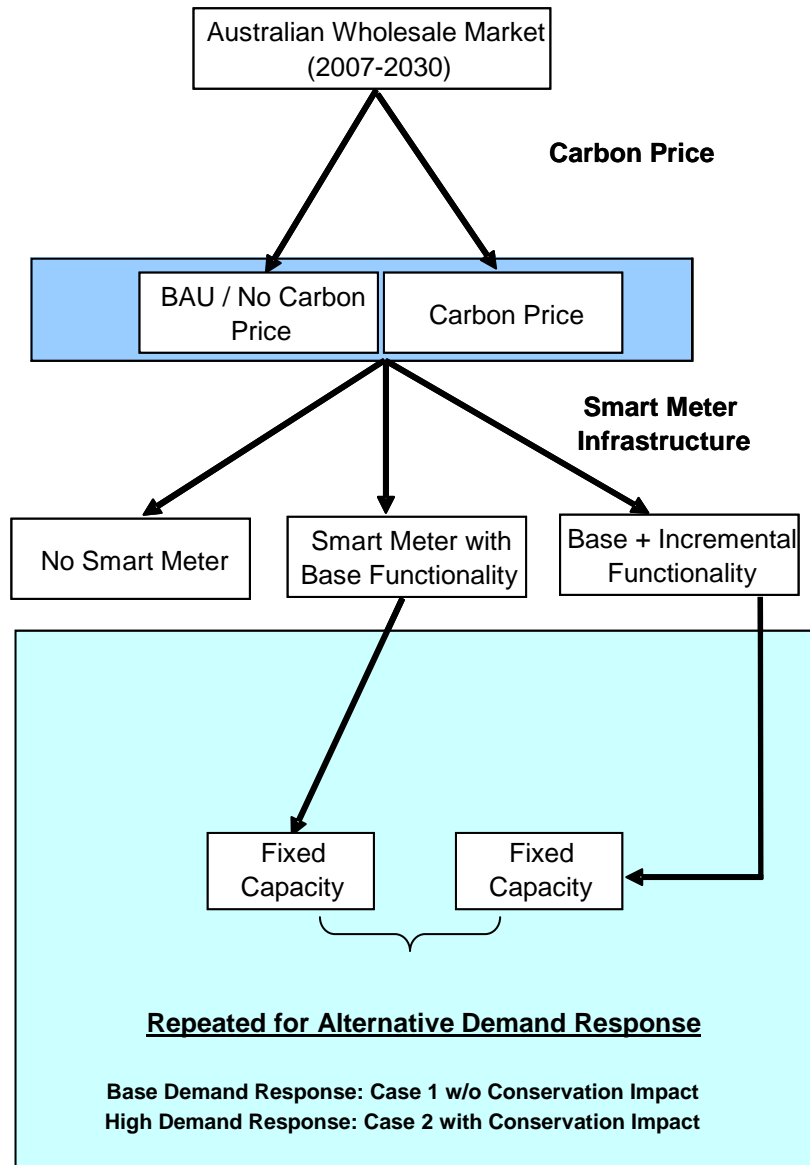
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Figure 9: Analytic framework

As Figure 10 illustrates, the benefit of each functionality is a function of, among other things:

- Policies such as the introduction of a carbon price;
- The nature of the smart meter infrastructure assumed to be included in place in the base and additional functionalities; and
- The per-unit impacts and take-up of the pricing and DLC options, which were reflected in our analysis in the Base and High Demand Response cases.

Figure 10: Economic impact assessment: scenarios developed for phase 2



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3.7. CEMOS FOR LONG-TERM NEM SIMULATION

3.7.1. Overview of CEMOS

CEMOS provides a comprehensive tool, and comprises the following models:

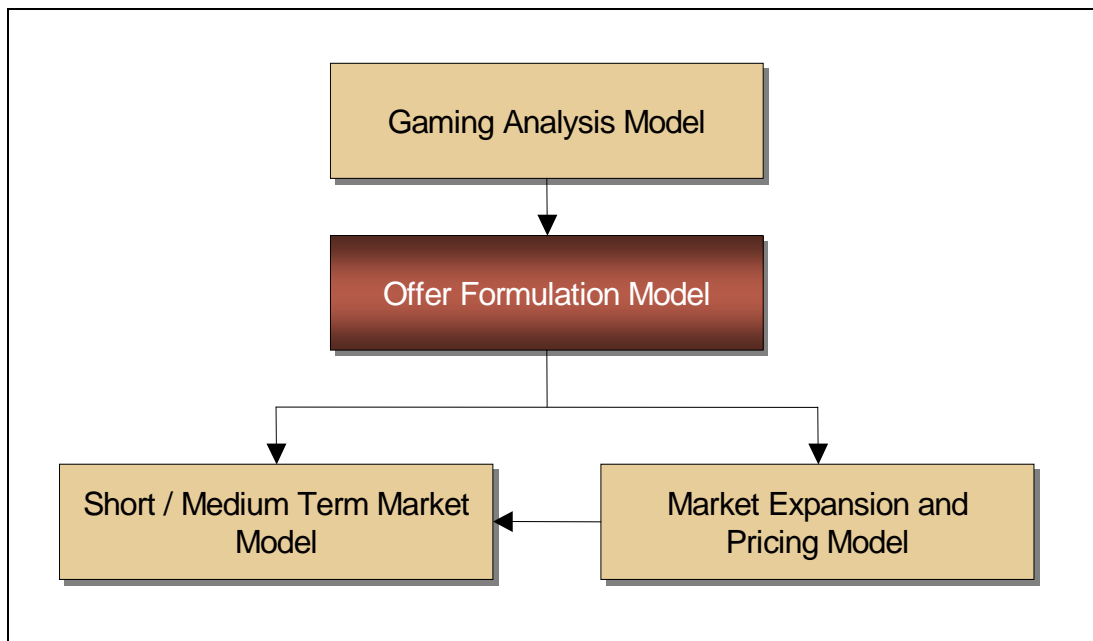
- PEPPY: Long-term market expansion;
- STEMM: Short-term simulation; and
- CONE: Strategic generator bidding.

All three modules were used in the analysis conducted in this study. Specifically:

- CONE and STEMM were used to model short-term bidding and half-hourly dispatch over 2007-2011;
- CONE and PEPPY were used to model long-term bidding and dispatch over 2007-2030; and
- The PEPPY Monte Carlo engine was used to sample multiple generator outage and load states to estimate USE, price, and revenue distribution over 2007-2030.

Figure 11 shows the broad CEMOS functionality.

Figure 11: Overview of CEMOS functionality



Short term (daily/weekly) simulation (STEMM)

STEMM is a short term (daily / weekly) unit commitment model. It provides a framework to develop insights about the implications of the interactions between the engineering characteristics of the existing, committed and candidate gas- and oil-fired generation units; the shape of the daily load curves; and generator's short-term gaming behaviour and bidding strategies. STEMM's key features include:

- Detailed consideration of generating unit start-up and shutdown, and ramping for energy and ancillary services;
- Replicating, where possible, the market-clearing process of the system;
- Chronological load profile;
- Transmission; and
- Ancillary services.

Longer term (several years) simulation (PEPPY)

PEPPY optimises electricity market investment and operation over several years, taking into account the physical realities of the electrical power system. It provides a framework to develop insights about the implications of the longer-term market drivers including future entry, longer-term effects of market power, effects of longer-term gas supply constraints, etc. The key features include:

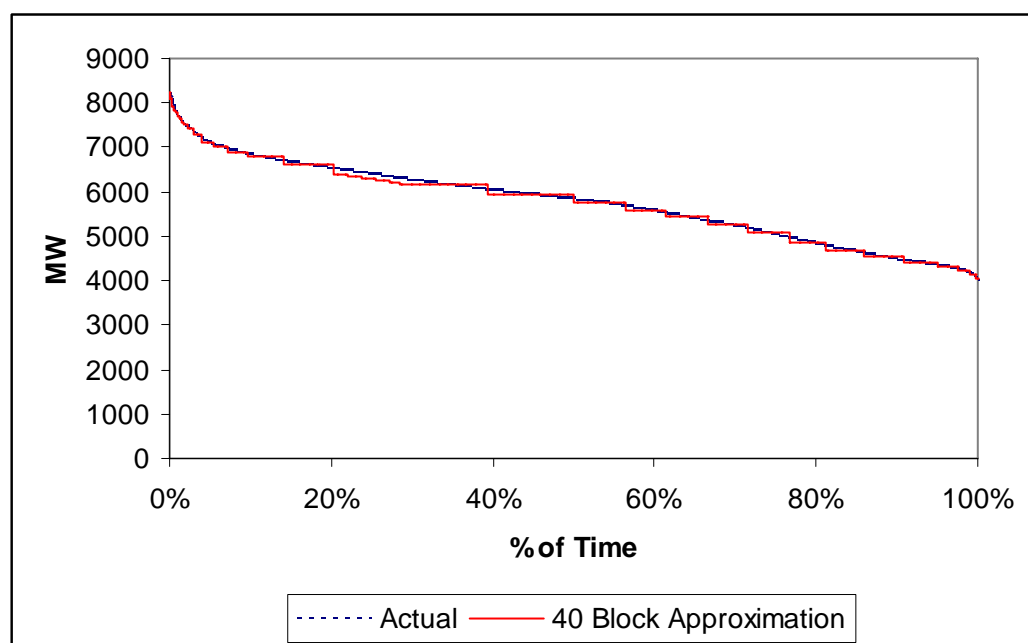
- Detailed consideration of fuel contracts, load growth and its temporal/spatial distribution, and new entrant capex;
- Replicating, where possible, the market-clearing process of the system;
- Load duration curves;
- Transmission; and
- Ancillary Services.

The key difference between PEPPY and STEMM is in the representation of demand. PEPPY uses annual load duration curves (LDC) to approximate demand. Instead of using 8,760 hourly loads, the year is characterised by forty blocks of varying duration (but totalling 8,760 hours). The duration of each block is selected to provide maximum 'fit' between the block structure and the actual load duration curve.

To illustrate, Figure 12 shows the actual load duration curve for Queensland in 2005, and its approximation using 40 load blocks. As the figure shows, the approximation is reasonably good, with less than 0.8% deviation for the entire year and less than 0.1% deviation from actual load for the top 1% of load. More precisely, in this case, 13 out of a total of 40 blocks were used to model the top 1% of the load.²⁶ Therefore, although the fact that PEPPY uses a relatively small number of load blocks to characterise the system over the course of an entire year inevitably implies that the estimate has some degree of crudeness, experience with the model indicates that even where fewer than 20 load blocks are used²⁷, the method can provide a reasonable representation of energy dispatch.

Barring minor inaccuracies around the edge of the blocks²⁸, our experience in prior studies including the Phase 1 analysis indicates that the estimate of GWh dispatch provided by PEPPY will closely match that provided by STEMM.

Figure 12: Actual QLD load duration curve (2005) and its approximation using 40 blocks



²⁶ The number of load blocks devoted to different parts of the load duration curve is determined by the slope of the curve and the degree of resolution desired on different portions of the load duration curve. Because this study focuses to a great extent on peak demand impacts, it is reasonable to devote a relatively high percentage of the total blocks on the top end of the load duration curve.

²⁷ Forty (40) blocks were used in both the Phase 1 and Phase 2 analyses of this study, however.

²⁸ That is, if the block size was such that a unit just fell short of being dispatched, or was over-dispatched. In such cases, the units of generation would have been slightly higher or lower if we had modelled loads in hourly resolution.

Gaming behaviour (short and long term)

CONE is a model for analysing market power and competition in an electricity market with few competing firms or companies. There are two variants of the model: Unconstrained and Transmission Constrained – we refer to the latter as Transmission-constrained Cournot-Nash Equilibrium (T-CONE) model. T-CONE models the strategic interaction among generating companies for a range of demand conditions (e.g. peak and off-peak demand across different seasons) taking into account their short-run marginal costs, availability, energy limits and contract positions.

Each company is assumed to maximise its own profit by adjusting its generation while considering the generation from all other companies, and the responsiveness of demand to price. This is known as a Cournot game, the solution to which comprises generation levels where each company has no incentive to adjust its supply because doing so would reduce its profit. Key features of the gaming module include:

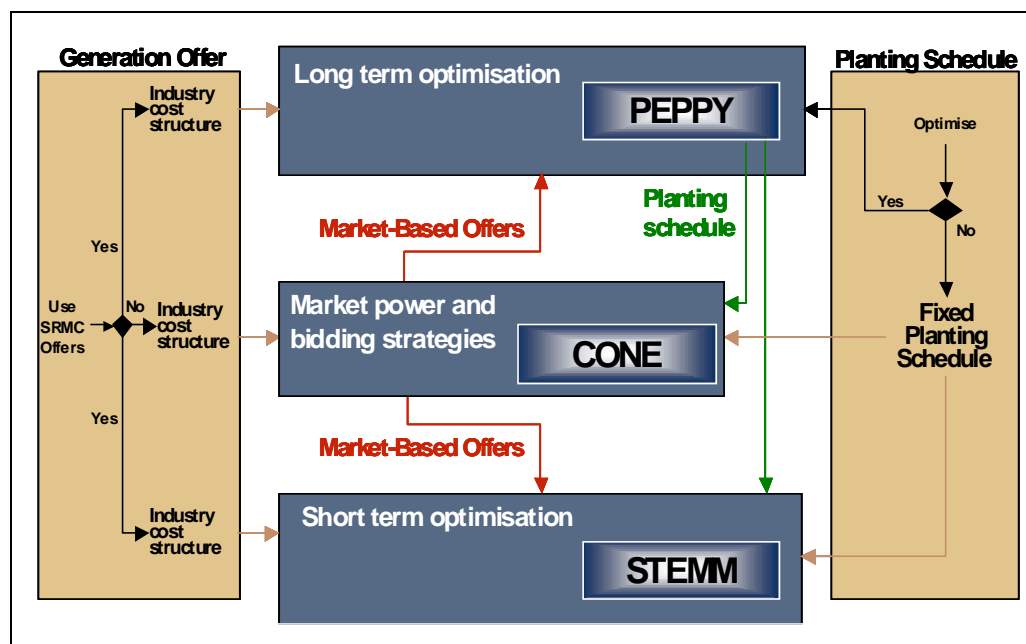
- Strategic interaction among competing suppliers;
- Oligopolistic market behaviour;
- Cournot-Nash equilibrium solution used as a basis;
- Bidding strategy can be built around the Cournot solution;
- Recognises short- and long-term demand elasticity;
- Recognises peak/off-peak temporal load behaviour; and
- Generator offers, however, can also have an alternative basis.

3.7.2. Interaction among the CEMOS modules

A key advantage of the CEMOS package is the complete integration of the different modules. Figure 13 shows how the results from each model can be used as input to another model.

Both PEPPY and STEMM can use the offers created by CONE. These offers are used instead of the SRMC of the generators. Both STEMM and CONE can use the capacity plan created by PEPPY. This allows for the optimal new entry determined by PEPPY to be used in these other models.

Figure 13: Interaction among CEMOS modules



3.7.3. Modelling uncertainties

CEMOS has been used for analysis of uncertainties around:

- Demand growth and level;
- Unforeseen outages of generators; and
- Hydrology.

The modelling approaches that we have employed in CEMOS for specific applications include:

- Scenarios – Scenario analysis provides a simple, transparent, and widely used way of capturing uncertainties in key system and other parameters. We have used it for modelling hydrological uncertainties among other things in long-term analyses.
- Stochastic programming (SP) – We have used SP to model uncertain growth in demand. We have adopted this approach in modelling the three load-growth and three temperature scenarios of the NEM in a single stochastic linear program (LP). SP provides a powerful and intuitive means of modelling parameter uncertainties, but is difficult to formulate/implement when there are multiple sources of uncertainties that are correlated.

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- Monte Carlo Simulation – Easy to implement and intuitively appealing, Monte Carlo is the best approach for multiple sources of uncertainties. However, it is also computationally very demanding because the number of samples can be very high.
- Statistical approximation of probability distribution – In special cases, the nature of the probability distribution allows an approximation of the function to be directly included in the optimisation, as happens to be the case with random outage of generators. We have used this approach to approximate a Loss of Load Probability (LOLP) constraint in the LP together with a deterministic reserve margin constraint.

3.8. CALIBRATION OF CEMOS FOR THE NEM

In order to produce spot price forecasts, CEMOS relies on parameters such as a very short-term elasticity of demand and the contract level of power stations for which no accurate estimate is available. This is due to either quality data not being available, as in the case of the elasticity, or the data being difficult to obtain because it is commercial in confidence, as is the case for generation contracts. Since these parameters have profound impact on modelling outcomes, a pragmatic way to establish a working model is to find out if the model can reproduce reasonable market outcomes within a plausible range of elasticity values that have been reported in the literature, and prevailing views on contract levels in the market.

Calibration then refers to the process by which we explore the impact of alternative levels of elasticity and contract values, and compare the outcomes with observed market values. The basic hypothesis is that the market is generally heavily contracted for baseload generation and less so for mid-merit and peaking generators, and that low elasticity is associated with peak-period volatility.

Within these broad guiding principles, the calibration process we use involves drawing up an n -dimensional grid of the combinations of potential values of the n parameters being estimated. Then, for each combination in the grid, a series of Cournot results is produced and assessed for its goodness of fit with the observed market data including observed generation data. The basic premise is that if the model can reliably and reasonably accurately reproduce observed market outcomes, including generation levels, prices, market share, etc using plausible values of elasticity and contract levels (following the broad principles of how these vary with loading condition and generator types), then the model can be used with confidence to produce outcomes going forward for the same inputs on elasticity and contract values.

The contractual obligations of electricity generators (both in respect of their retailer customers and their fuel supplies) form important assumptions in modelling generator behaviour and profitability. As noted before, power stations that are highly contracted have an incentive to compete more vigorously by submitting wholesale market bids at their short-run marginal cost (SRMC). Conversely, power stations that have few contracts tend to place more “strategic” bids that are higher than their SRMC.

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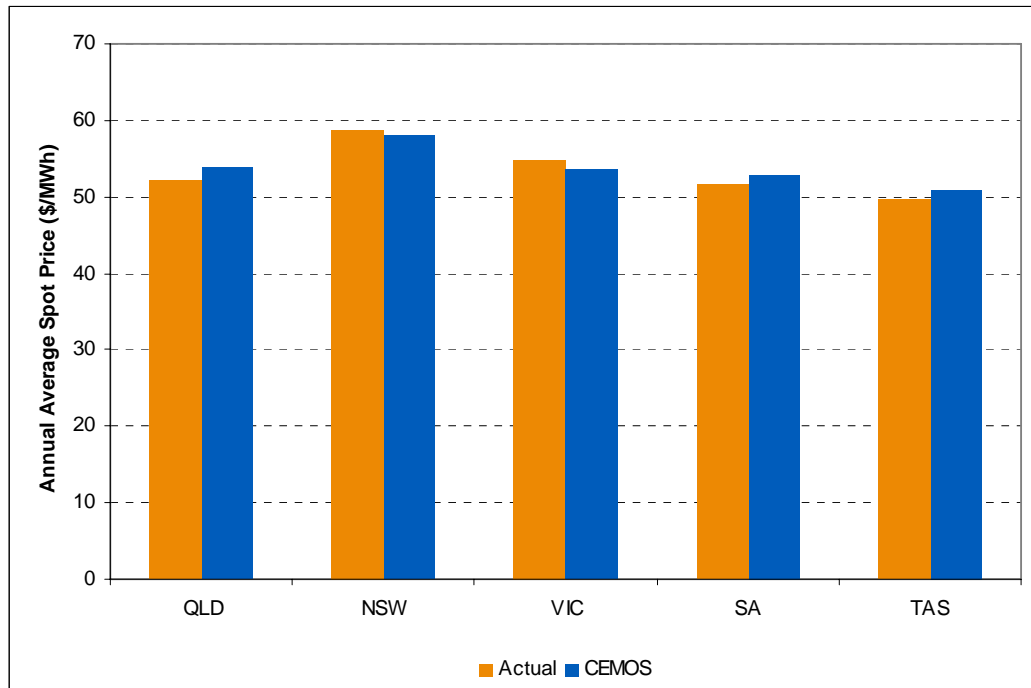
To derive spot prices for 2007 onwards CEMOS was calibrated based on the combination of (pseudo-) elasticity estimates and assumed (pseudo-) contract coverage (PCL) levels that yield the best fit to the observed price duration curves.²⁹ Other important indicators assessed included the total GWh generated in each of the four seasons.

During 2006/07 electricity spot prices in the NEM were exceptionally high. For the purpose of deriving longer-term price projections, we have therefore estimated demand function parameters using the average of 2005/06 and 2006/07 spot market prices. The use of this weighted average of the two prices essentially reflects a judgement call that the high price levels that have been observed recently in the NEM will not prevail over a longer timeframe.

As shown in the figures below, CEMOS has been calibrated to historical 2006/07 market outcomes. These outcomes can be replicated to a reasonable degree of accuracy, including the distribution of peak/off-peak prices, assuming relatively aggressive bidding strategies. The top load blocks (e.g., the top 13 blocks representing the 1% of peak load) are typically associated with aggressive bidding employed by the generators and adequately capture the volatility in pool prices. The results of the calibration are shown in Figure 14 and Figure 15, which compare actual prices from 2006/07 with the model results from CEMOS.

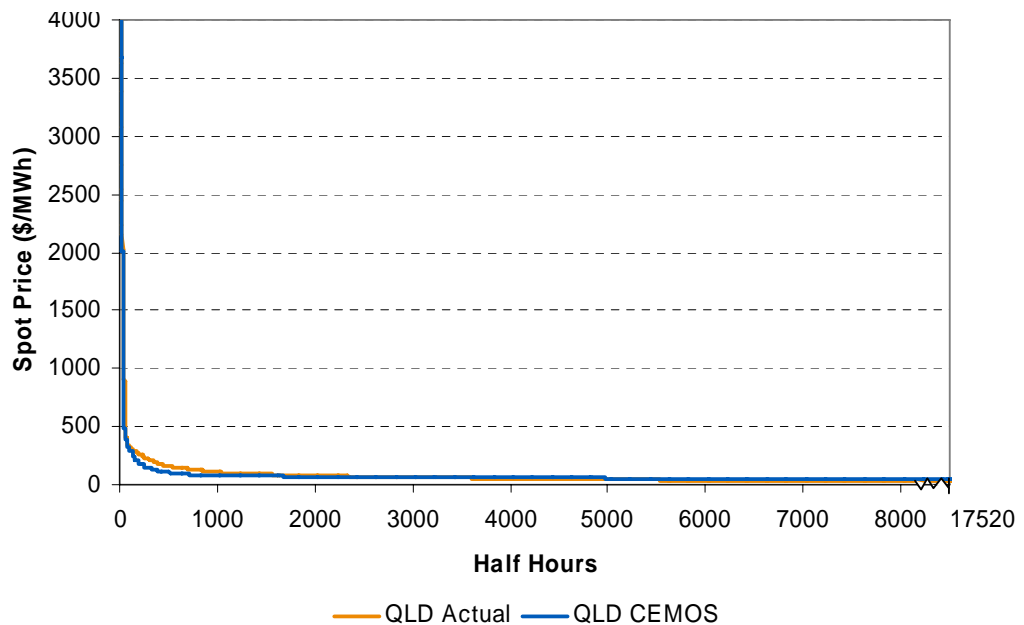
²⁹ These are termed “pseudo-values” because they are estimated from market data with the implication that market participants behave as if they were playing a Cournot game with these parameters. See J. Tipping, E. G. Read, D. Chattopadhyay and D.C. McNickle “Can the shoe be made to fit? – Cournot modelling of Australian electricity prices” *Operations Research Society of New Zealand Proceedings*, 2005. Also, J. Tipping, E.G. Read and D. Chattopadhyay, “Incorporating Bottom-up Structures into Top-Down Models of Electricity Market”, *Proceedings of International Association of Energy Economics*, 2007.

Figure 14: Average prices 2006/07 (\$/MWh)



Source: NEMMCO actual data and CEMOS modelled data.

Figure 15: CEMOS vs actual NEM spot price duration curve for Queensland



Source: NEMMCO actual data and CEMOS modelled data.

Notes: The price duration curve describes how frequently (in number of half-hours in the year) certain price outcomes occur.

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3.9. KEY SUPPLY-SIDE MODELLING ASSUMPTIONS

CEMOS has been set up for all Australian regions for the 2006-2050 timeframe as a result of its use in several studies that CRA has conducted. It has also been calibrated against NEM outcomes. CEMOS' database uses publicly available data including:

- Generation and transmission capacity, peak and energy demand growth till 2016
 - National Electricity Market Management Company, *Statement of Opportunities*, 2006, NEMMCO, October 2006.
 - Independent Market Operator, *Statement of Opportunities Report for the South West Interconnected System*, IMO West Australia, July, 2006.
 - Northern Territory Utilities Commission, *Annual Power System Review*, December 2006.
- Demand projections beyond 2016:
 - Australian Bureau of Agricultural and Resource Economics, *Australian Energy – National and State Projections to 2030*, 2006.
 - Energy Supply Association of Australia, *Energy and the Australian Economy*, Stage 1 Report, 2006. This study modified the ABARE projections to deduct non-grid generation.
- Generator outage statistics
 - Energy Supply Association of Australia, *Energy and the Australian Economy*, Stage 1 Report, 2006.
- Short-term DR statistics by NEM state from IRPC studies:
 - Inter-regional Planning Committee, *SNI Stage 1 Study*, 2001.
- Transmission expansion plan (for the NEM³⁰) from ANTS up to 2016
 - NEMMCO, 2007 ANTS Consultation: Issues Paper”, 2007.
 - Also CEMOS simulations using ABARE demand beyond 2016 to develop any further economic transmission expansion;
- ACIL Tasman report prepared for NEMMCO for fuel price projections and generation short-run marginal costs:

30 SWIS and NT systems are modelled as single region systems.

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- ACIL Tasman, *Fuel Resource, New Entry and Generation Cost in the NEM*, Report prepared for the NEMMCO, 2007.
- Numerous international sources for new generation technology capital costs that were extensively discussed to reach consensus with NGF/esaa³¹; and
- Maximum long-term technology potential data especially for renewable resources from multiple resources including studies by Hydro Tasmania³².

Generating the Monte Carlo samples requires establishing distributions around the relevant parameters. The following assumptions, which were also used in a study CRA conducted for the IEA³³, were used:

- Demand growth – the SOO high demand, low economic growth scenarios were used to provide a range of demand growth possibilities;
- Load distribution – SOO demand distributions for 10%, 50% and 90% POE scenarios were used as the basis for sampling;
- Fuel prices – the key fuel of interest is gas; a range of 1% to 4% per annum price increases were used with a mean-reverting gas price as the basis for sampling; and
- Random outage of generators – the forced outage probabilities that have been developed by the esaa for generic technology types (e.g. black coal, brown coal by size) were used.

As discussed before, CONE-STEMM was used for short-term modelling, and CONE-PEPPY-Monte Carlo was used for long-term modelling. The Business-as-Usual, Carbon Price Base Case and Smart Meter load scenarios were run to obtain a baseline estimate of smart meter impacts.

As part of the Phase 1 analysis, we investigated the potential increase in accuracy that could be obtained by using half-hourly dispatch modelling capabilities of STEMM instead of the 40-block approximation used in the PEPPY model. We therefore compared the Carbon Price Base Case and Smart Meter outcomes from both models. As noted in the Phase 1 report:

³¹ CRA International, *Analysis of Greenhouse Gas Policies for the Australian Electricity Sector*, December, 2006. Submitted to the National Generators Forum.

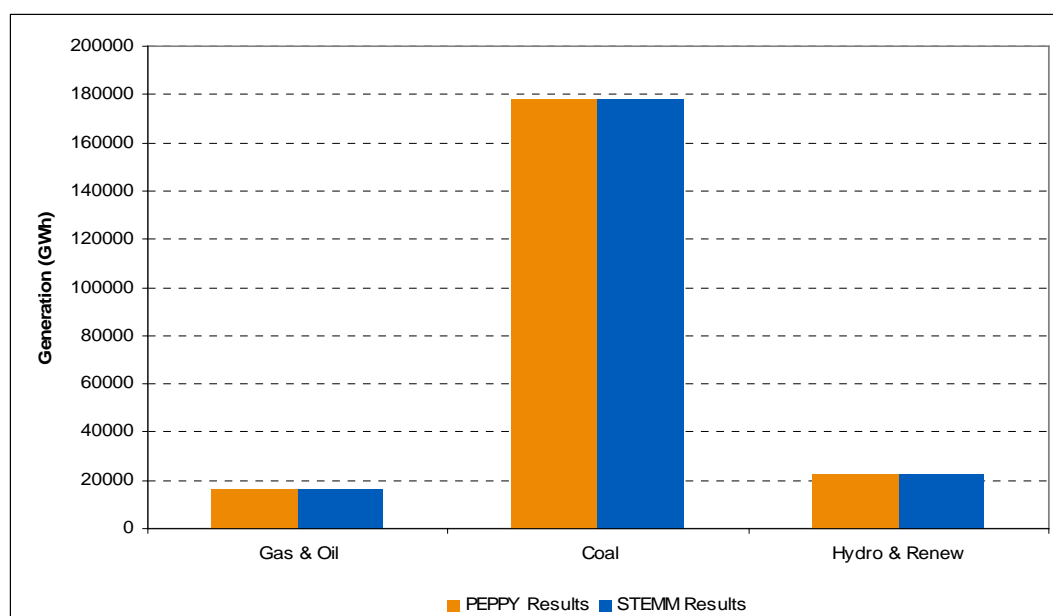
³² *Ibid.*

³³ The Appendix of the CRA report for IEA includes the full set of data/assumption used. *Ibid.*

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The difference between two STEMM run results provided an estimate of short-term price/cost impacts and the long-term modelling provided a distribution of price/cost/USE impacts. These runs also enabled estimation of the accuracy of PEPPY estimates by comparing PEPPY results with those from STEMM for 2008-2012. We have undertaken similar comparisons as part of the IEA study and found PEPPY's accuracy to be acceptable (variation below 1% for fuel cost estimate). Our present analysis using updated input assumptions since the IEA study also reveals that the PEPPY and STEMM dispatch outcomes align very closely and the differences are below 1%, as shown in Figure 16.

Figure 16: Dispatch by fuel type: comparison of long-term (PEPPY) and short-term (STEMM) model results



Our base case assumptions also include the following:

- Real 2006/07 dollars for all costs including fuel and O&M costs, capital costs and VoLL;
- Discount rate used is pre-tax real 9.2% as per the estimate of ACIL Tasman 2007³⁴;
- New entry technology choices include clean coal technologies; nuclear technology has not been included in the set of new electricity generation technology options;

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The 9.2% discount rate used here differs from the 8% used in NERA's Stream 1 Overview Report. We believe the 9.2% used here reflects the return expected in the higher-risk, competitive parts of the electricity value chain, and is therefore appropriate for characterising value from an investment decision perspective.

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- Capital costs for new entrant plant are based on ACIL Tasman 2007 estimates; and
- Generators are assumed to be contracted between 75% and 85% of their least cost dispatch across the regions for all years. These levels of contract cover are estimated as part of the calibration of the model against historical outcomes.

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4. ESTIMATION OF THE DR BENEFITS OF SMART METER INFRASTRUCTURE AND NON-SMART METER DLC

4.1. APPROACHES FOR OBTAINING DR THAT WERE ASSESSED

The Phase 2 Stream 5 research considered the economic benefits that would be expected to accrue in the wholesale electricity market from the demand response impacts of the basic smart metering functionality being considered in this study, two sets of incremental functionality and the deployment of direct load control (DLC) via a non-smart meter based communications and control system. A brief description of the various functionalities whose DR impacts were assessed follows.

- **Base smart metering infrastructure functionality** – This was represented by the national minimum functional specification of smart metering infrastructure that was developed in Phase 1.³⁵ At this most basic level, the loadshape impacts of smart metering infrastructure rest on its ability to support innovative, time-differentiated pricing because it allows measurement of consumption over very short time periods.
- **Incremental functionalities to enable cycling or constraining off of end-use appliances** – Two sets of incremental functionality that add the ability to cycle or constrain off appliances such as larger air conditioners (larger split and all ducted systems), pool pumps, clothes dryers, etc to the national minimum specification were modelled. Both include an in-home display (IHD) and an interface to a home area network (HAN) that allows the smart metering infrastructure to communicate with and control the end-use equipment.
 - One version of this incremental functionality (constructed from functionalities 15, 16a and 16b as investigated in Phase 1) is applicable only to new and replacement equipment, as it communicates with the end-use equipment via dedicated switches built into the appliances themselves;³⁶ while
 - The other version of this functionality (constructed from functionality 16c as investigated in Phase 1) is applicable to both new and existing equipment installations because it communicates via existing controls of the equipment, such as the remote controls that are used with split air-conditioning systems.³⁷

³⁵ A complete description of the smart metering infrastructure minimum functional specification that was modelled in Phase 2 can be found in NERA's *Smart Meter Cost Benefit Analysis: Phase 2 Overview Report*.

³⁶ The switches would either be added on to the appliances or come as OEM equipment with new appliances.

³⁷ The retrofit applications were limited to more recent vintage air-conditioners which operate or can operate via remote controls.

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As a result, the eligible population for the second version of the incremental functionality is significantly larger than that for the first, at least in the early years of the analysis timeframe.³⁸

Both versions of the incremental smart meter functionality include universal provisions of in-home displays,³⁹ which can be used to provide customers with information about a wide range of energy and price related topics, including current electricity price; current and period to date electricity consumption, cost and carbon emission rates; instantaneous impact of individual appliances on consumption and cost rates; energy saving tips, and feedback on the impact of energy use profiles on a daily basis.⁴⁰ These capabilities, supplemented by educational efforts and possibly financial incentives, were assumed to provide the basis for these functionalities providing enhanced peak demand reductions and energy conservation impacts.

- **Non-Smart-Meter DLC** – Direct control of end-use equipment can be undertaken through communication and control systems that do not include a smart meter. Dedicated communications and control system such as the ripple control technology that which has been used for decades in New South Wales and Queensland to control the operation of electric water heaters can also cycle or constrain off other end-use equipment.

Although the control capability provided by smart-metering infrastructure and dedicated communication and control systems can be used to operate a wide range of end-use appliances, the Stream 5 modelling, consistent with assumptions made in Streams 2 and 3, considered their application only to air-conditioning and pool pumps.

4.2. COMPONENTS OF THE BENEFITS AND TRADE-OFFS BETWEEN THEM

Although the overall impact of a reduction in demand can be stated simply as a reduction in wholesale market cost, there are important underlying dynamics among the *components* of that cost that are worth discussing before we present the model results. As will be seen, trade-offs can occur among the component benefits, each of which is described below.

38 Over time, all existing end-use equipment will be replaced, thereby allowing the technology applicable to new and replacement applications to characterise essentially the entire population.

39 The analysis assumed that IHDs would be distributed universally. If that were not the case, the benefit would be proportional to the percentage of customers in whose premises the devices had been installed.

40 IHDs, like remote reading, allow customers to receive feedback on their consumption from the previous day. Therefore the demand response benefits of remote reading have also been assumed for IHDs.

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- **Capex benefits** result from the deferral of the need for generation capacity additions, or changes in the timing and mix of generation plant required over the study time frame due to the availability of DR. Where the magnitude of DR is sufficient, it will substitute for generation capacity. However, as the magnitude of DR achieved in the DR scenarios considered in the Phase 2 analysis did not exceed 4.2%⁴¹ in any jurisdiction and included a significant proportion of behaviourally based (as compared to technology based) load reductions, it was assumed that the nature and timing of capacity additions would remain the same as in the Carbon Price Base Case, and therefore no capex benefits would accrue. Further discussion of the rationale for and implications of the decision to model the generation system on a “fixed capacity” basis and not consider capex deferral benefits is presented in section 3.6.3 following Figure 6.
- **Opex benefits** result when generation from peaking power stations reduces due to the reduction in energy consumption by end-use customers during peak, shoulder or off-peak periods. Opex savings depend on the relative marginal operating costs of the generation system at different times of day (and season), so that even where only part of the energy requirement shifts to off-peak, the lower cost of generation during off-peak can reduce total operating costs. In some cases, operating costs can vary enough that shifts in the time at which energy is consumed can produce opex savings even if end-use energy consumption increases.
- **USE benefits** occur in those cases where the total system capacity remains unchanged by the DR, but peak demand is reduced as a result of the availability of DR.⁴² This measure essentially reflects a lower overall risk of “running out” of capacity (i.e. a lower risk of outages developing due to demand outstripping available capacity).
- **CO₂ costs and emissions benefits** may or may not arise depending on a range of factors including the cost of carbon, the cost of alternative generation technologies, fuel costs and how these costs relate to the nature of demand reduction. If the underlying impact of DR is an overall conservation effect including off-peak demand reduction, there is likely to be an overall reduction in carbon emissions. This is the case for the incremental DR functionalities in the High Demand Response scenario, where the addition of the IHD and energy conservation messaging is assumed to produce a material conservation effect. On the other hand, if the impact of the DR is primarily or only to shift significant amounts of energy from peak to off-peak periods, carbon emissions may increase. This would be the case in most Australian jurisdictions at present because most off-peak generation is conventional coal, while on-peak generation includes a significantly higher proportion of gas and hydro generation. Such a shift, therefore, would tend to increase the carbon intensity of the wholesale electricity market. This result pertains at least in part even if there is a cost

41 For South Australia in the High Demand Response scenario. All other regions and scenarios are well below 4%.

42 USE benefits can also accrue when total system capacity reduces but peak demand is reduced more.

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of carbon in place. Although the cost of carbon will naturally discourage any carbon-intensive fuel, a time-of-use (TOU) price signal may dampen or entirely counteract the impact of the carbon price. If the cost of carbon is very high, however, it may encourage investment in cleaner forms of base-load investment. In such a case, net carbon emissions will reduce. Therefore, the net carbon emission outcome is a function of the cost of carbon and cost of cleaner technologies, and also has a time component: lower carbon prices and TOU pricing may result in carbon emission increases. As carbon prices increase, however, and new plant is needed, new generation technologies may produce lower net emissions. In terms of the scenarios undertaken in this analysis, the outcomes were as follow:

- BAU scenario: Carbon levels increase in the absence of any price being put on carbon.
 - Carbon price base case: Carbon reduces in comparison to the BAU case as a result of the significant increase in investment in gas plant that occurs when carbon costs are introduced.
 - Smart meter functionality analyses: Carbon reduces in all the smart meter functionality analyses⁴³ because the smart meters, at base or incremental functionality levels, induce a further reduction in load, and carbon emissions levels fall as a result in comparison to the carbon price base case.
- **Wholesale spot price changes** result from each of the impacts discussed above. Because DR can decrease fuel costs, carbon costs and USE costs – which are components of the wholesale spot price – DR can reduce average and peak period wholesale spot market prices.
 - **Generation offer costs** represent another measure of benefits that are closely related to opex. In a wholesale electricity market such as the Australian NEM, generators offer their capacity at prices that reflect a range of commercial realities including actual O&M costs, return on capital requirements, contract level, and the state of competition in the market. Analysis of actual generator bids in the NEM suggests that most, if not all, generators bid a small part of their capacity (something in the 15% to 25% range) at prices significantly above their operating costs.

⁴³ While carbon emissions in the “with smart meter” functionality analyses still increase from today’s levels, they do so more slowly than in the BAU or the carbon price base case.

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Due to the market-clearing price mechanism of the NEM, when these prices are accepted they set the price for all wholesale electricity in that bid period. It is also the case that there is more opportunity for generators to be successful with such a strategy in those periods during which there is not sufficient capacity to create competitive pricing pressure. The sum of cleared generation offers (i.e. prices quoted for the part of generation used to meet a specific demand) is therefore an alternative measure to the opex – and one that better captures the impact that such a change in load can have on wholesale market spot price. This can also be seen as a measure of the extent to which a reduction in peak load can lead to a higher level of competitive pricing in the market. As will be seen in the results below, the value of the reduction in offer costs tends to be greater than the reduction in opex in all scenarios. This difference – while it does affect the level of actual prices in the wholesale electricity market – represents a wealth transfer between generators and retailers/customers.

Although the amount of capacity that is likely to be bid into the wholesale market at prices significantly higher than SRMC is small for most generators – in the range of 15% to 25% of their total capacity – the revenue earned on these bids, if cleared, can be disproportionately high. For example, if a baseload generator with operating costs of \$10/MWh can bid even 5% of its capacity during peak hours at \$10,000/MWh it will result in a wide divergence between offer and operating costs. It is precisely the potential for DR to reduce the occurrence of such bidding behaviour that produces the observed difference in operating cost and offer cost benefits. It should also be noted, however, that because the remainder of the generator's capacity will almost certainly be operating under some form of hedge contract, the difference between the offer cost and the hedge strike price will be passed back through the contract market arrangements. As a result, the change in the generator's profitability due to the offer price is a function of the proportion of capacity that is unhedged and bid at the offer cost and the difference between the offer cost and operating costs.

As noted earlier, we do not assume any exercise of market power in WA and NT, i.e., all generators act as price takers in these two jurisdictions, and therefore reduction in offer costs equal reduction in opex for WA and NT.

4.3. RESULTS

4.3.1. National results

Table 9 below shows the benefits at the national level associated with both demand response cases and each of the incremental functionality analyses including base functionality, additional functionalities for New DLC (functionalities 15, 16a and 16b), New and Retrofit DLC (functionality 16c) and the 'No Smart Meter – DLC Only' Scenario 3. Incremental benefits of the two additional functionalities for 'New DLC' and 'New and Retrofit DLC' are also shown in Table 9. All scenarios presented below are based on wholesale market prices that include a price for carbon.

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Table 9: Benefit (2030) of DR impacts of smart meter base and incremental functionalities and non-smart meter DLC as compared to the carbon price base case

	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only (Case 2)
Benefit								
Operating Cost: \$m (NPV 2007-2030)	25	34	36	13	170	375	381	27
<i>% reduction vs Carbon Price Base Case</i>	0.05%	0.07%	0.07%	0.03%	0.33%	0.72%	0.73%	0.05%
Offer costs: \$m (NPV 2007-2030)	117	189	215	132	400	878	960	309
<i>% reduction vs Carbon Price Base Case</i>	0.20%	0.32%	0.37%	0.23%	0.66%	1.46%	1.59%	0.51%
USE Costs: \$m (NPV 2007-2030)	165	239	280	220	272	387	431	360
<i>% reduction vs Carbon Price Base Case</i>	30.40%	44.12%	51.68%	40.58%	50.23%	71.35%	79.54%	66.48%
CO2-e Emissions Cost: \$m (NPV 2007-2030)	5	6	7	3	105	265	267	8
<i>% reduction vs Carbon Price Base Case</i>	0.02%	0.02%	0.03%	0.01%	0.37%	0.94%	0.95%	0.03%
Average Spot Price: \$/MWh (2007-2030)	2	3	3	2	4	6	6	4
<i>% reduction vs Carbon Price Base Case</i>	2.90%	4.33%	4.93%	3.37%	5.41%	8.73%	9.38%	5.99%
Super Peak Price: \$/MWh (2007-2030)	150	228	260	182	261	414	449	326
<i>% reduction vs Carbon Price Base Case</i>	13.75%	20.91%	23.86%	16.68%	23.93%	37.92%	41.16%	29.85%
CO2-e Emissions: '000 tons cumulative through 2030	678	894	952	473	14,499	36,256	36,442	1,018
<i>% reduction vs Carbon Price Base Case</i>	0.01%	0.02%	0.02%	0.01%	0.31%	0.79%	0.79%	0.02%
Total Operating Cost Benefits: \$m (NPV 2007-2030) (operating cost, USE cost, emission cost)	195	279	323	236	547	1,027	1,079	395

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	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only (Case 2)
Incremental Benefit of Smart Meter Functionalities								
Operating Cost: \$m (NPV 2007-2030)		8	10			206	211	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.02%	0.02%			0.40%	0.41%	
Offer costs: \$m (NPV 2007-2030)		72	97			477	560	
<i>incremental % reduction vs Carbon Price Base</i>		0.12%	0.17%			0.78%	0.91%	
USE Costs: \$m (NPV 2007-2030)		74	115			114	159	
<i>incremental % reduction vs Carbon Price Base</i>		13.72%	21.28%			21.12%	29.31%	
CO2-e Emissions Cost: \$m (NPV 2007-2030)		1	2			160	162	
<i>incremental % reduction vs Carbon Price Base</i>		0.00%	0.01%			0.57%	0.57%	
Average Spot Price: \$/MWh (2007-2030)		1	1			2	3	
<i>incremental % reduction vs Carbon Price Base</i>		1.43%	2.03%			3.32%	3.97%	
Super Peak Price: \$/MWh (2007-2030)		78	110			153	188	
<i>incremental % reduction vs Carbon Price Base</i>		7.16%	10.11%			13.99%	17.23%	
CO2-e Emissions: '000 tons cumulative through 2030		217	275			21,757	21,943	
<i>incremental % reduction vs Carbon Price Base</i>		0.00%	0.01%			0.47%	0.48%	

Note:

* Super-Peak corresponds to the top 13 blocks, which equates to approximately 100 hours.

** Sum of all cleared generation offers.

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Key observations from the results shown in Table 9⁴⁴ above include the following:

- **The DR projected to occur in each of the four functional analyses delivers incremental benefits as compared to the carbon price base case** – The NPV of the benefits for the base smart meter functionality and the New DLC, New & Retrofit DLC and Scenario 3 DLC functionalities are all positive in both the Base and High Demand Response cases. NPVs range as shown in Table 10 below:

Table 10: NPV (\$m 2007-2030) of the four DR functionalities

Functionality	NPV (\$m 2007-2030)	
	Base Demand Response	High Demand Response
Base smart meter functionality	195	547
New DLC	279	1,027
New & Retrofit DLC	323	1,079
Scenario 3 – No Smart Meter, DLC only	236	395

Further, as was also shown in Table 9, incremental benefits accrue in each of the individual component of benefits, namely, operating costs, offer costs, USE costs and CO₂ costs. The High Demand Response case provides significantly higher benefits, including, for example, a twenty- to forty-fold increase in CO₂ emissions reductions under the three smart meter analyses, as compared to that provided by the base smart meter functionality in the Base Demand Response case (Case 1). This is primarily a function of the assumption that the High Demand Response case engenders a conservation effect of 3% to 7% of total energy consumption. This level of energy conservation adds significantly to the CO₂ and operating cost reduction impacts of the High Demand Response case.

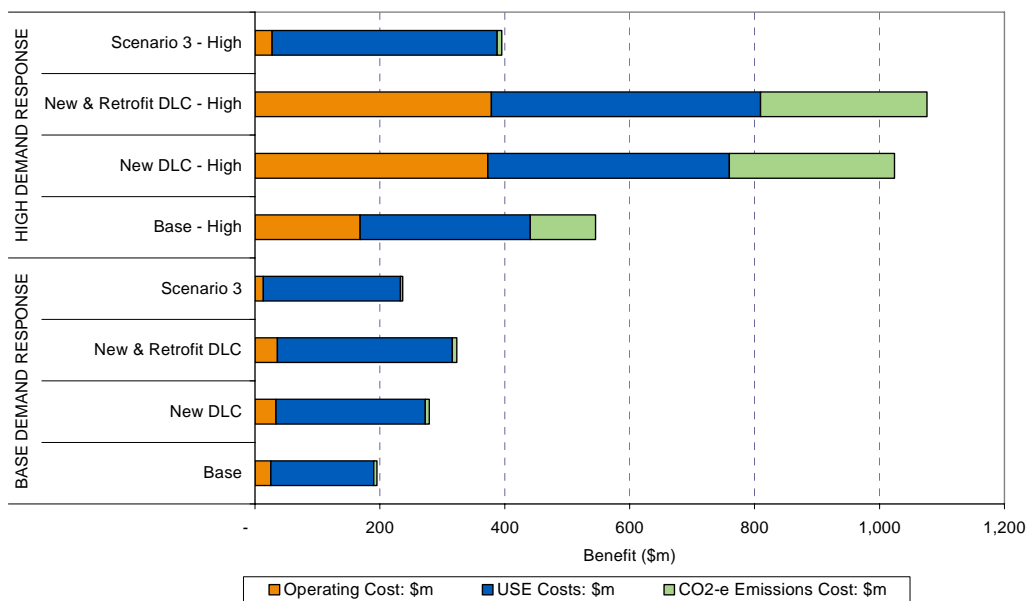
⁴⁴ Jurisdictional results are discussed in section 4.3.3, and jurisdictional versions of Table 9 appear in Appendix A. Care should be taken in interpreting these results at the jurisdictional level for the NEM states, as discussed in section 3.5.

- Total benefits are higher in each functional analysis if wholesale market prices based on Market Offer Costs rather than Operating Costs are considered** – This is not unexpected as the Market Offers capture any "mark up" that generators, as profit-maximising entities, can put in their bids over and above their costs. This suggests that the addition of DR – whether through smart meter infrastructure or non-smart meter DLC – is likely (a) to make wholesale electricity markets more competitive, and (b) to deliver additional bill savings to consumers (though this will come as a result of reduced income to electricity generators and possibly retailers).⁴⁵

Figure 17 compares the magnitude and composition of the benefits of each of the four DR scenarios across the Base and High Demand Response cases when based on operating costs as compared to market offer costs.

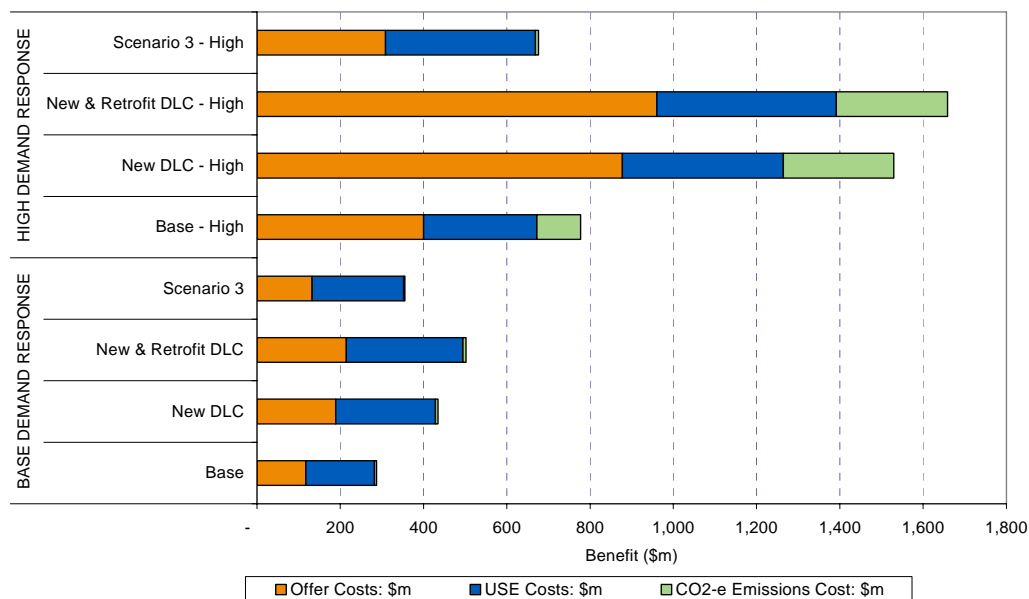
Figure 17: Level and composition of benefits based on operating vs. market offer costs

Benefits based on operating costs



⁴⁵ See also discussion in next to last paragraph of section 4.2. These reductions in wholesale market costs will be seen in the first instance by retailers. Although retailers could be expected to seek to retain as much of these wholesale cost reductions as possible, the workings of the competitive market will serve to deliver a significant proportion of the savings to end-use customers.

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Benefits based on market offer costs

- The incremental smart meter DLC functionalities add a material level of benefit to the base smart meter functionality in both the Base and High Demand Response cases** – In the Base Demand Response case the increment is from about 43% to 65% (using operating costs) and 50% to 74% (using offer costs). In the High Demand Response case the incremental benefit increases drastically to 88% to 97% (using operating costs) and 97% to 113% (using offer costs). The increase in the High Demand Response case is again a result of the significant level of energy conservation impact assumed in this case.
- The incremental benefit of the additional functionalities is most significant in terms of operating cost and CO₂ emissions reductions** – The additional functionalities provide significantly higher levels of opex savings and emissions reductions as compared to the basic smart meter functionality in both the Base and High Demand Response cases. However, their incremental impacts are much more significant in the High Demand Response case. This is the logical consequence of the energy conservation impacts associated with the incremental functionalities in the High DR case.
- The New and Retrofit DLC functionality provides only marginally higher benefits than the New DLC functionality** – This seems surprising when first considered, but can be explained by the fact that over the course of the study timeframe virtually all air conditioning equipment will be replaced. As a result, the New (only) functionality, over time, winds up including all of the units that are represented in the New and Retrofit functionality. The only difference between the two is the value of the DLC provided by the retrofitted units over their remaining useful life from the time of the initial smart-meter DLC installation.

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- **All of the smart meter and DLC functionalities exert downward pressure on wholesale market prices, both the average wholesale market price and the price pertaining in super-peak periods** – This is true in both the Base and High Demand Response cases. As would be expected, the High Demand Response case shows a significantly higher impact on both average and super-peak prices. This is a result of the higher take-up assumed in the High Demand Response case. However, there is also a greater increase in the price reduction provided by the incremental functionalities in the High Demand Response case as compared to that produced by them in the Base Demand Response case. This is a reflection of both the higher take-up and the greater conservation effect assumed in the High Demand Response case.
- **The non-smart-meter DLC functionality (SMWG Scenario 3) provides a lower level of benefit than the smart meter DLC functionalities in each benefit category** – This reflects the fact that the non-smart-meter DLC functionality does not include either the price signal impacts or the conservation impacts present in the smart meter functionalities. Correspondingly, the non-smart meter DLC option lags the smart meter options most significantly where those price signals add benefits – particularly opex savings, market offer cost reductions and CO₂ emissions reductions. By contrast, non-smart-meter DLC benefits remain relatively similar to those provided by the base smart meter functionality in both the Base and High Demand Response Cases with regard to USE benefits and reductions in super-peak prices. It must be kept in mind, however, that the non-smart meter DLC option also has a different cost structure than the smart meter DLC options, and therefore may be more cost-effective, despite providing a smaller total magnitude of benefit.⁴⁶
- **The composition of the benefits of the smart meter functionality options differ significantly from the composition of the benefits of the non-smart-meter DLC** – As shown in Table 11 below, this is particularly true in the High Demand Response case where benefits are based on operating costs. This is the result of the significant level of energy conservation assumed in the smart meter cases, and its impact on operating and emissions costs.

⁴⁶ The relative cost-effectiveness of the various options, based on all applicable costs and benefits assessed in the various Stream reports, is discussed in NERA's *Smart Meter Cost Benefit Analysis: Phase 2 Overview Report*.

Table 11: Composition of DR benefits (in 2030) of smart meter and non-smart meter functionalities

	Base DR Take-up				High DR Take-up			
	Base	New DLC	Retrofit DLC	Scenario 3	Base	New DLC	Retrofit DLC	Scenario 3
Operating Costs								
Total Operating Cost	13%	12%	11%	6%	31%	37%	35%	7%
USE Costs	84%	85%	87%	93%	50%	38%	40%	91%
CO ₂ -e Emissions Cost	3%	2%	2%	1%	19%	26%	25%	2%
Market Offer Costs								
Offer costs	44%	46%	45%	39%	51%	57%	58%	46%
USE Costs	55%	53%	54%	60%	35%	25%	26%	53%
CO ₂ -e Emissions Cost	2%	1%	1%	1%	14%	17%	16%	1%

4.3.2. Carbon emissions

Carbon emissions do not steadily decrease over the study period. As shown in Table 12 below, emissions actually increase (i.e., emissions reductions are negative) for several of the smart meter functionalities in various years until 2009/2010. Positive reductions occur for the subsequent years. This trend is an outcome of complex interactions as follows:

- Lower carbon prices in the initial years do not provide sufficient incentive to switch generation away from coal. Demand response yields a slightly flatter load curve, thereby encouraging more coal-based generation, and therefore carbon emissions increase during the initial years. In all cases where emissions increase in these years it is the result of the fact that the DR enabled by the price signals that are made possible by smart meters (i.e., CPP and TOU) have flattened the load curve to the point where, even with the carbon price, coal generation increases (at least as a percentage of total send out) as compared to gas. This is a reflection of the fact that at high duty cycles, coal is still able to compete with gas based on the total cost of production of each.
- Later, as carbon price reaches a higher level and there is entry of more efficient and/or cleaner forms of generation, there is a positive emissions reduction that becomes progressively more significant over the years.
- In addition, the conservation impact that is posited as part of the High Demand Response case reduces the overall energy requirement for all periods including off-peak hours, and thereby produces further and substantial levels of carbon emissions reductions.

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Table 12: Emissions reductions (000s tonnes)

	Base Demand Response				High Demand Response			
	Base	New DLC	Retrofit DLC	Scenario 3	Base	New DLC	Retrofit DLC	Scenario 3
2007	-2	3	1	2	6	4	-2	-1
2008	-1	-1	-3	2	-3	-2	-3	-7
2009	-4	0	-5	-4	-2	0	-4	2
2010	-7	18	6	16	40	69	66	12
2011	15	8	-3	6	87	198	198	22
2012	0	8	7	18	193	525	541	43
2013	15	7	17	30	477	1,018	1,033	52
2014	22	28	31	10	412	973	988	35
2015	31	35	44	24	628	1,638	1,663	47
2016	33	43	51	24	596	1,708	1,731	51
2017 - 19 (annual)	56	66	72	16	737	1,726	1,732	38
2020 - 25 (annual)	34	49	51	32	1,113	2,768	2,770	69
2026 - 30 (annual)	38	53	54	35	1,029	2,528	2,527	72
Cumulative (2007-2030)	678	894	952	473	14,469	36,187	36,372	1,014

4.3.3. Jurisdictional results

Table 13 provides an overview of the DR benefits provided by four smart meter and non-smart-meter functionalities by jurisdictional.

Table 13: Overview of smart meter and non-smart meter DR benefits in 2030, by jurisdiction

	Base Demand Response				High Demand Response			
	Base	New DLC	Retrofit DLC	Scenario 3	Base	New DLC	Retrofit DLC	Scenario 3
<i>New South Wales (including ACT)</i>								
Operating cost benefits (NPV \$m)	7	9	9	1	26	57	58	3
Market offer cost benefits (NPV \$m)	22	32	36	19	59	142	158	44
USE costs (NPV \$m)	136	196	234	183	229	324	364	303
CO ₂ -e emissions cost benefits (NPV \$m)	2	3	3	0	14	34	34	0

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	Base Demand Response				High Demand Response			
	Base	New DLC	Retrofit DLC	Scenario 3	Base	New DLC	Retrofit DLC	Scenario 3
CO ₂ -e Emissions: '000 tons	343	417	436	-16	1,953	4,470	4,511	74
Total Operating Cost Benefits (operating cost, USE cost, emission cost)	145	208	246	184	269	414	456	306
Queensland								
Operating cost benefits (NPV \$m)	8	11	13	5	53	126	128	11
Market offer cost benefits (NPV \$m)	60	98	112	69	162	363	403	153
USE costs (NPV \$m)	15	23	25	20	23	34	38	33
CO ₂ -e emissions cost benefits (NPV \$m)	3	4	4	1	32	80	81	2
CO ₂ -e Emissions: '000 tons	457	545	580	158	4,561	11,341	11,390	298
Total Operating Cost Benefits (operating cost, USE cost, emission cost)	27	38	42	27	108	241	246	46
Victoria								
Operating cost benefits (NPV \$m)	5	6	6	1	22	51	52	3
Market offer cost benefits (NPV \$m)	11	15	16	7	39	90	94	14
USE costs (NPV \$m)	11	15	16	13	15	19	20	18
CO ₂ -e emissions cost benefits (NPV \$m)	-1	-1	-1	1	33	101	101	2
CO ₂ -e Emissions: '000 tons	-163	-144	-155	142	4,729	13,943	13,990	247
Total Operating Cost Benefits (operating cost, USE cost, emission cost)	15	20	21	15	70	171	173	22
South Australia								
Operating cost benefits (NPV \$m)	3	5	5	3	41	72	73	7
Market offer cost benefits (NPV \$m)	17	31	34	26	71	134	145	52
USE costs (NPV \$m)	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2
CO ₂ -e emissions cost benefits (NPV \$m)	0.2	0.2	0.4	1.1	16.3	27.4	27.7	2.3
CO ₂ -e Emissions: '000 tons	52	57	75	139	1,993	3,341	3,381	290
Total Operating Cost Benefits (operating cost, USE cost, emission cost)	3	5	6	4	57	99	101	9
Tasmania								
Operating cost benefits (NPV \$m)					1	3	3	0
Market offer cost benefits (NPV \$m)					27	49	55	21
USE costs (NPV \$m)					0.0	0.0	0.0	0.0
CO ₂ -e emissions benefits (NPV \$m)					0.2	0.5	0.5	0.0
CO ₂ -e Emissions: '000 tons					29	69	69	3

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	Base Demand Response				High Demand Response			
	Base	New DLC	Retrofit DLC	Scenario 3	Base	New DLC	Retrofit DLC	Scenario 3
Total Operating Cost Benefits (operating cost, USE cost, emission cost)					2	3	3	0
Western Australian*								
Operating cost benefits (NPV \$m)	1	3	3	2	25	60	61	4
Market offer cost benefits (NPV \$m)	1	3	3	2	25	60	61	4
USE costs (NPV \$m)	3	5	5	4	5	9	9	7
CO ₂ -e emissions cost benefits (NPV \$m)	0	0.1	0.2	0.4	8.7	21.8	21.9	0.7
CO ₂ -e Emissions: '000 tons	-11	17	14	48	1,186	2,972	2,980	99
Total Operating Cost Benefits (operating cost, USE cost, emission cost)	4	8	8	6	39	91	92	12
Northern Territory*								
Operating cost benefits (NPV \$m)	0	0	0	0	3	7	7	0
Market offer cost benefits (NPV \$m)	0	0	0	0	3	7	7	0
USE costs (NPV \$m)	0	0	0	0	0	0	0	0
CO ₂ -e emissions cost benefits (NPV \$m)	0	0	0	0	0.4	0.9	0.9	0
CO ₂ -e Emissions: '000 tons	0	2	2	3	47	119	120	6
Total Operating Cost Benefits (operating cost, USE cost, emission cost)	0	0	0	0	3	8	8	0

* We do not assume any exercise of market power in WA and NT, i.e., all generators act as price takers in these two jurisdictions, and therefore reduction in offer costs equal reduction in opex for WA and NT.

Key observations and comments that can be made with regard to Table 13 include:

- **Benefits at the jurisdictional level, in general, show the same pattern as seen at the national level** – All of the smart meter and non-smart-meter functionalities provide incremental DR-related benefits in each jurisdiction. Absolute benefits tend to be highest in New South Wales and Queensland. In addition, the value of the energy conservation impacts assumed to accrue due to the additional smart meter functionalities in the High Demand Response case are seen to result in similarly higher benefits at the jurisdictional level as was the case at the national level. The value of the High Demand Response case as compared to the Base Demand response case is most pronounced in South Australia and Western Australia.

- **Market offer benefits have not been calculated with regard to the Northern Territory or Western Australia** – Because the Northern Territory does not have a competitive wholesale electricity market, there are no bids and consequently DR will not have an impact of market offers prices. Although Western Australia does have a competitive wholesale market whose operations include bidding into a short term electricity market, competition has only been introduced for larger customers (those with annual consumption greater than 50 MWh) and generator bids do not play the same role in that market as they do in the NEM. In Western Australia most contracting is bilateral, and the STEM is used primarily for balancing.
- **The value of DR in Western Australia's Reserve Capacity Mechanism has not been calculated** – The Western Australia wholesale electricity market requires retailers to contract for capacity that will provide a 10% reserve margin for the aggregate diversified demand of their customers, and sets a benchmark value for the value of that capacity. Unlike the NEM, this provides a known (maximum) market value for DR. This value has not been used in calculating the potential value of DR in Western Australia in this analysis, however, and therefore the value of DR in WA provided here may be conservative.

APPENDIX A: DETAILS OF JURISDICTIONAL BENEFITS

Details of the DR impacts of smart meter base and incremental functionalities and non-smart meter DLC as compared to the carbon price base case at the jurisdictional level are presented in Table 14 through Table 20 below. As discussed in section 3.5, care should be taken in interpreting jurisdictional-level results for the NEM states.

Tables 21 through 23 provide boundary projections of the peak demand reductions expected to occur in each jurisdiction, as follows:

- Base smart meter functionality in the base demand response case;
- New & retrofit DLC functionality in the high demand response case; and
- Scenario 3 (non-smart-meter DLC) in the high demand response case.

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Table 14: Benefit (2030) of DR impacts for NSW (including ACT)

	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Benefit								
Operating Cost: \$m (NPV 2007-2030)	7	9	9	1	26	57	58	3
<i>% reduction vs Carbon Price Base Case</i>	0.05%	0.06%	0.06%	0.01%	0.16%	0.36%	0.36%	0.02%
Offer costs: \$m (NPV 2007-2030)	22	32	36	19	59	142	158	44
<i>% reduction vs Carbon Price Base Case</i>	0.12%	0.18%	0.20%	0.11%	0.33%	0.79%	0.88%	0.25%
USE Costs: \$m (NPV 2007-2030)	136	196	234	183	229	324	364	303
<i>% reduction vs Carbon Price Base Case</i>	30.00%	43.34%	51.68%	40.41%	50.52%	71.54%	80.34%	66.88%
CO2-e Emissions Cost: \$m (NPV 2007-2030)	2	3	3	0	14	34	34	0
<i>% reduction vs Carbon Price Base Case</i>	0.02%	0.03%	0.03%	0.00%	0.16%	0.38%	0.38%	0.00%
Average Spot Price: \$/MWh (2007-2030)	3	5	5	4	6	9	10	7
<i>% reduction vs Carbon Price Base Case</i>	4.78%	7.07%	8.11%	5.58%	8.62%	13.87%	15.03%	9.93%
Super Peak Price: \$/MWh (2007-2030)	250	377	433	305	431	680	745	547
<i>% reduction vs Carbon Price Base Case</i>	14.54%	21.90%	25.19%	17.76%	25.05%	39.54%	43.29%	31.80%
CO2-e Emissions: '000 tons cumulative through 2030	343	417	436	-16	1,953	4,470	4,511	74
<i>% reduction vs Carbon Price Base Case</i>	0.02%	0.03%	0.03%	0.00%	0.14%	0.31%	0.31%	0.01%
Total Operating Cost Benefits: \$m (NPV 2007-2030) (operating cost, USE cost, emission cost)	145	208	246	184	269	415	456	306

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	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Incremental Benefit of Smart Meter Functionalities								
Operating Cost: \$m (NPV 2007-2030)		2	2			31	32	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.20%	0.20%	
Offer costs: \$m (NPV 2007-2030)		10	14			83	99	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.06%	0.08%			0.46%	0.55%	
USE Costs: \$m (NPV 2007-2030)		60	98			95	135	
<i>incremental % reduction vs Carbon Price Base Case</i>		13.35%	21.68%			21.02%	29.82%	
CO2-e Emissions Cost: \$m (NPV 2007-2030)		1	1			19	20	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.22%	0.22%	
Average Spot Price: \$/MWh (2007-2030)		2	2			3	4	
<i>incremental % reduction vs Carbon Price Base Case</i>		2.28%	3.33%			5.24%	6.41%	
Super Peak Price: \$/MWh (2007-2030)		126	183			249	314	
<i>incremental % reduction vs Carbon Price Base Case</i>		7.35%	10.65%			14.49%	18.24%	
CO2-e Emissions: '000 tons cumulative through 2030		74	93			2517	2558	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.17%	0.18%	

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Table 15: Benefit (2030) of DR impacts for QLD

	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Benefit								
Operating Cost: \$m (NPV 2007-2030)	8	11	13	5	53	126	128	11
<i>% reduction vs Carbon Price Base Case</i>	0.05%	0.07%	0.08%	0.03%	0.34%	0.81%	0.82%	0.07%
Offer costs: \$m (NPV 2007-2030)	60	98	112	69	162	363	403	153
<i>% reduction vs Carbon Price Base Case</i>	0.32%	0.52%	0.59%	0.37%	0.86%	1.91%	2.13%	0.81%
USE Costs: \$m (NPV 2007-2030)	15	23	25	20	23	34	38	33
<i>% reduction vs Carbon Price Base Case</i>	30.31%	45.77%	50.11%	40.65%	46.13%	68.63%	75.46%	65.40%
CO2-e Emissions Cost: \$m (NPV 2007-2030)	3	4	4	1	32	80	81	2
<i>% reduction vs Carbon Price Base Case</i>	0.04%	0.05%	0.06%	0.02%	0.41%	1.02%	1.03%	0.03%
Average Spot Price: \$/MWh (2007-2030)	3	5	5	4	6	9	10	6
<i>% reduction vs Carbon Price Base Case</i>	4.78%	7.07%	8.10%	5.56%	8.60%	13.75%	14.91%	9.90%
Super Peak Price: \$/MWh (2007-2030)	242	365	419	295	416	653	715	529
<i>% reduction vs Carbon Price Base Case</i>	14.53%	21.90%	25.18%	17.73%	25.00%	39.22%	42.96%	31.77%
CO2-e Emissions: '000 tons cumulative through 2030	457	545	580	158	4,561	11,341	11,390	298
<i>% reduction vs Carbon Price Base Case</i>	0.04%	0.04%	0.05%	0.01%	0.36%	0.89%	0.90%	0.02%
Total Operating Cost Benefits: \$m (NPV 2007-2030) (operating cost, USE cost, emission cost)	26	38	42	26	108	240	247	46

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	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Incremental Benefit of Smart Meter Functionalities								
Operating Cost: \$m (NPV 2007-2030)		3	4			73	75	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.02%	0.03%			0.47%	0.48%	
Offer costs: \$m (NPV 2007-2030)		39	53			200	241	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.20%	0.28%			1.06%	1.27%	
USE Costs: \$m (NPV 2007-2030)		8	10			11	15	
<i>incremental % reduction vs Carbon Price Base Case</i>		15.47%	19.80%			22.50%	29.33%	
CO2-e Emissions Cost: \$m (NPV 2007-2030)		1	1			48	48	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.61%	0.62%	
Average Spot Price: \$/MWh (2007-2030)		1	2			3	4	
<i>incremental % reduction vs Carbon Price Base Case</i>		2.29%	3.32%			5.15%	6.30%	
Super Peak Price: \$/MWh (2007-2030)		123	177			237	299	
<i>incremental % reduction vs Carbon Price Base Case</i>		7.37%	10.65%			14.22%	17.96%	
CO2-e Emissions: '000 tons cumulative through 2030		89	123			6781	6829	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.53%	0.54%	

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Table 16: Benefit (2030) of DR impacts for VIC

	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Benefit								
Operating Cost: \$m (NPV 2007-2030)	5	6	6	1	22	51	52	3
<i>% reduction vs Carbon Price Base Case</i>	0.08%	0.10%	0.10%	0.02%	0.37%	0.88%	0.89%	0.04%
Offer costs: \$m (NPV 2007-2030)	11	15	16	7	39	90	94	14
<i>% reduction vs Carbon Price Base Case</i>	0.15%	0.20%	0.21%	0.09%	0.53%	1.22%	1.26%	0.19%
USE Costs: \$m (NPV 2007-2030)	11	15	16	13	15	19	20	18
<i>% reduction vs Carbon Price Base Case</i>	48.26%	65.67%	68.84%	55.06%	66.94%	85.19%	87.98%	77.51%
CO2-e Emissions Cost: \$m (NPV 2007-2030)	-1	-1	-1	1	33	101	101	2
<i>% reduction vs Carbon Price Base Case</i>	-0.01%	-0.01%	-0.01%	0.01%	0.38%	1.18%	1.18%	0.02%
Average Spot Price: \$/MWh (2007-2030)	3	4	5	3	5	8	9	6
<i>% reduction vs Carbon Price Base Case</i>	4.66%	6.97%	7.98%	5.48%	8.48%	13.65%	14.80%	9.82%
Super Peak Price: \$/MWh (2007-2030)	231	353	405	285	401	636	696	512
<i>% reduction vs Carbon Price Base Case</i>	14.60%	22.32%	25.61%	17.99%	25.33%	40.21%	44.01%	32.37%
CO2-e Emissions: '000 tons cumulative through 2030	-163	-144	-155	142	4,729	13,943	13,990	247
<i>% reduction vs Carbon Price Base Case</i>	-0.01%	-0.01%	-0.01%	0.01%	0.33%	0.97%	0.98%	0.02%
Total Operating Cost Benefits: \$m (NPV 2007-2030) (operating cost, USE cost, emission cost)	15	20	21	15	70	171	173	23

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	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Incremental Benefit of Smart Meter Functionalities								
Operating Cost: \$m (NPV 2007-2030)		1	1			30	30	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.02%	0.02%			0.51%	0.52%	
Offer costs: \$m (NPV 2007-2030)		4	5			51	55	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.05%	0.07%			0.69%	0.74%	
USE Costs: \$m (NPV 2007-2030)		4	5			4	5	
<i>incremental % reduction vs Carbon Price Base Case</i>		17.41%	20.58%			18.26%	21.05%	
CO2-e Emissions Cost: \$m (NPV 2007-2030)		0	0			68	68	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.00%	0.00%			0.79%	0.80%	
Average Spot Price: \$/MWh (2007-2030)		1	2			3	4	
<i>incremental % reduction vs Carbon Price Base Case</i>		2.31%	3.32%			5.17%	6.32%	
Super Peak Price: \$/MWh (2007-2030)		122	174			235	295	
<i>incremental % reduction vs Carbon Price Base Case</i>		7.72%	11.01%			14.88%	18.67%	
CO2-e Emissions: '000 tons cumulative through 2030		19	8			9,214	9,260	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.00%	0.00%			0.64%	0.65%	

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Table 17: Benefit (2030) of DR impacts for SA

	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Benefit								
Operating Cost: \$m (NPV 2007-2030)	3	5	5	3	41	72	73	7
<i>% reduction vs Carbon Price Base Case</i>	0.12%	0.20%	0.20%	0.13%	1.57%	2.77%	2.82%	0.26%
Offer costs: \$m (NPV 2007-2030)	17	31	34	26	71	134	145	52
<i>% reduction vs Carbon Price Base Case</i>	0.52%	0.93%	1.03%	0.79%	2.14%	4.02%	4.33%	1.56%
USE Costs: \$m (NPV 2007-2030)	0	0	0	0	0	0	0	0
<i>% reduction vs Carbon Price Base Case</i>	14.60%	25.76%	27.99%	53.65%	24.32%	35.50%	50.80%	91.76%
CO2-e Emissions Cost: \$m (NPV 2007-2030)	0	0	0	1	16	27	28	2
<i>% reduction vs Carbon Price Base Case</i>	0.04%	0.04%	0.08%	0.21%	3.07%	5.14%	5.21%	0.43%
Average Spot Price: \$/MWh (2007-2030)	0	0	0	0	1	1	1	1
<i>% reduction vs Carbon Price Base Case</i>	0.34%	0.64%	0.72%	0.74%	1.11%	2.09%	2.26%	1.23%
Super Peak Price: \$/MWh (2007-2030)	13	26	29	31	27	46	52	52
<i>% reduction vs Carbon Price Base Case</i>	2.63%	5.42%	5.99%	6.38%	5.48%	9.33%	10.72%	10.60%
CO2-e Emissions: '000 tons cumulative through 2030	52	57	75	139	1,993	3,341	3,381	290
<i>% reduction vs Carbon Price Base Case</i>	0.06%	0.06%	0.08%	0.15%	2.14%	3.59%	3.64%	0.31%
Total Operating Cost Benefits: \$m (NPV 2007-2030) (operating cost, USE cost, emission cost)	3	5	5	4	57	99	101	9

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	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Incremental Benefit of Smart Meter Functionalities								
Operating Cost: \$m (NPV 2007-2030)		2	2			31	32	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.07%	0.07%			1.20%	1.25%	
Offer costs: \$m (NPV 2007-2030)		14	17			63	73	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.41%	0.51%			1.88%	2.19%	
USE Costs: \$m (NPV 2007-2030)		0	0			0	0	
<i>incremental % reduction vs Carbon Price Base Case</i>		11.17%	13.39%			11.18%	26.48%	
CO2-e Emissions Cost: \$m (NPV 2007-2030)		0	0			11	11	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.00%	0.04%			2.08%	2.14%	
Average Spot Price: \$/MWh (2007-2030)		0	0			0	1	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.30%	0.38%			0.98%	1.14%	
Super Peak Price: \$/MWh (2007-2030)		14	16			19	26	
<i>incremental % reduction vs Carbon Price Base Case</i>		2.79%	3.36%			3.85%	5.24%	
CO2-e Emissions: '000 tons cumulative through 2030		6	23			1,348	1,388	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.02%			1.45%	1.49%	

Table 18: Benefit (2030) of DR impacts for TAS

	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Benefit								
Operating Cost: \$m (NPV 2007-2030)					1	3	3	0
<i>% reduction vs Carbon Price Base Case</i>					0.08%	0.17%	0.17%	0.01%
Offer costs: \$m (NPV 2007-2030)					27	49	55	21
<i>% reduction vs Carbon Price Base Case</i>					1.41%	2.55%	2.83%	1.10%
USE Costs: \$m (NPV 2007-2030)					0	0	0	0
<i>% reduction vs Carbon Price Base Case</i>					0%	0%	0%	0%
CO2-e Emissions Cost: \$m (NPV 2007-2030)					0	1	1	0
<i>% reduction vs Carbon Price Base Case</i>					2.33%	4.99%	5.03%	0.22%
Average Spot Price: \$/MWh (2007-2030)					5	7	8	4
<i>% reduction vs Carbon Price Base Case</i>					8.26%	12.50%	13.01%	7.12%
Super Peak Price: \$/MWh (2007-2030)					336	514	538	346
<i>% reduction vs Carbon Price Base Case</i>					27.85%	42.56%	44.57%	28.64%
CO2-e Emissions: '000 tons cumulative through 2030					29	69	69	3
<i>% reduction vs Carbon Price Base Case</i>					1.81%	4.25%	4.29%	0.21%
Total Operating Cost Benefits: \$m (NPV 2007-2030) (operating cost, USE cost, emission cost)					1	4	4	0

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	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Incremental Benefit of Smart Meter Functionalities								
Operating Cost: \$m (NPV 2007-2030)						1	1	
<i>incremental % reduction vs Carbon Price Base Case</i>						0.08%	0.08%	
Offer costs: \$m (NPV 2007-2030)						22	27	
<i>incremental % reduction vs Carbon Price Base Case</i>						1.13%	1.41%	
USE Costs: \$m (NPV 2007-2030)						0	0	
<i>incremental % reduction vs Carbon Price Base Case</i>						0%	0%	
CO2-e Emissions Cost: \$m (NPV 2007-2030)						0	0	
<i>incremental % reduction vs Carbon Price Base Case</i>						2.66%	2.70%	
Average Spot Price: \$/MWh (2007-2030)						3	3	
<i>incremental % reduction vs Carbon Price Base Case</i>						4.24%	4.75%	
Super Peak Price: \$/MWh (2007-2030)						178	202	
<i>incremental % reduction vs Carbon Price Base Case</i>						14.71%	16.72%	
CO2-e Emissions: '000 tons cumulative through 2030						39	40	
<i>incremental % reduction vs Carbon Price Base Case</i>						2.44%	2.48%	

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Table 19: Benefit (2030) of DR impacts for WA

	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Benefit								
Operating Cost: \$m (NPV 2007-2030)	1	3	3	2	25	60	61	4
<i>% reduction vs Carbon Price Base Case</i>	0.02%	0.03%	0.04%	0.03%	0.33%	0.80%	0.81%	0.05%
Offer costs: \$m (NPV 2007-2030)	1	3	3	2	25	60	61	4
<i>% reduction vs Carbon Price Base Case</i>	0.02%	0.03%	0.04%	0.03%	0.33%	0.80%	0.81%	0.05%
USE Costs: \$m (NPV 2007-2030)	3	5	5	4	5	9	9	7
<i>% reduction vs Carbon Price Base Case</i>	17.07%	30.63%	32.87%	24.62%	31.60%	55.48%	58.22%	42.74%
CO2-e Emissions Cost: \$m (NPV 2007-2030)	0	0	0	0	9	22	22	1
<i>% reduction vs Carbon Price Base Case</i>	0.00%	0.00%	0.01%	0.02%	0.40%	1.01%	1.02%	0.03%
Average Spot Price: \$/MWh (2007-2030)	0	1	1	1	1	2	2	1
<i>% reduction vs Carbon Price Base Case</i>	0.89%	1.57%	1.64%	1.18%	1.65%	3.33%	3.42%	2.18%
Super Peak Price: \$/MWh (2007-2030)	38	63	66	48	62	124	127	91
<i>% reduction vs Carbon Price Base Case</i>	14.27%	24.05%	25.04%	18.37%	23.71%	47.25%	48.42%	34.59%
CO2-e Emissions: '000 tons cumulative through 2030	-11	17	14	48	1,186	2,972	2,980	99
<i>% reduction vs Carbon Price Base Case</i>	0.00%	0.00%	0.00%	0.01%	0.34%	0.86%	0.86%	0.03%
Total Operating Cost Benefits: \$m (NPV 2007-2030) (operating cost, USE cost, emission cost)	4	8	8	6	39	91	92	12

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	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Incremental Benefit of Smart Meter Functionalities								
Operating Cost: \$m (NPV 2007-2030)		1	1			35	36	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.02%			0.47%	0.48%	
Offer costs: \$m (NPV 2007-2030)		1	1			35	36	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.02%			0.47%	0.48%	
USE Costs: \$m (NPV 2007-2030)		2	3			4	4	
<i>incremental % reduction vs Carbon Price Base Case</i>		13.56%	15.80%			23.88%	26.62%	
CO2-e Emissions Cost: \$m (NPV 2007-2030)		0	0			13	13	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.61%	0.61%	
Average Spot Price: \$/MWh (2007-2030)		0	0			1	1	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.68%	0.74%			1.68%	1.77%	
Super Peak Price: \$/MWh (2007-2030)		26	28			62	65	
<i>incremental % reduction vs Carbon Price Base Case</i>		9.79%	10.78%			23.54%	24.71%	
CO2-e Emissions: '000 tons cumulative through 2030		28	25			1,786	1,794	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.52%	0.52%	

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Table 20: Benefit (2030) of DR impacts for NT

	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Benefit								
Operating Cost: \$m (NPV 2007-2030)	0	0	0	0	3	7	7	0
<i>% reduction vs Carbon Price Base Case</i>	0.00%	0.01%	0.01%	0.01%	0.14%	0.35%	0.35%	0.02%
Offer costs: \$m (NPV 2007-2030)	0	0	0	0	3	7	7	0
<i>% reduction vs Carbon Price Base Case</i>	0.00%	0.01%	0.01%	0.01%	0.14%	0.35%	0.35%	0.02%
USE Costs: \$m (NPV 2007-2030)	0	0	0	0	0	0	0	0
<i>% reduction vs Carbon Price Base Case</i>	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CO2-e Emissions Cost: \$m (NPV 2007-2030)	0	0	0	0	0	1	1	0
<i>% reduction vs Carbon Price Base Case</i>	0.00%	0.01%	0.01%	0.01%	0.24%	0.61%	0.61%	0.03%
Average Spot Price: \$/MWh (2007-2030)	0	0	0	0	0	0	0	0
<i>% reduction vs Carbon Price Base Case</i>	0.00%	0.01%	0.01%	0.01%	0.02%	0.16%	0.16%	0.04%
Super Peak Price: \$/MWh (2007-2030)	0	1	1	1	2	3	4	3
<i>% reduction vs Carbon Price Base Case</i>	0.01%	0.55%	0.56%	0.56%	1.02%	2.21%	2.36%	2.19%
CO2-e Emissions: '000 tons cumulative through 2030	0	2	2	3	47	119	120	6
<i>% reduction vs Carbon Price Base Case</i>	0.00%	0.01%	0.01%	0.01%	0.20%	0.50%	0.51%	0.02%
Total Operating Cost Benefits: \$m (NPV 2007-2030) (operating cost, USE cost, emission cost)	0	0	0	0	3	8	8	0

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	Base Demand Response				High Demand Response			
	Base Functionality (Case 1)	New DLC Case 1 (15, 16 A&B)	New & Retrofit DLC Case 1 (16C)	Scenario 3 – No Smart Meter DLC Only (Case 1)	Base Functionality (Case 2)	New DLC Case 2 (15, 16 A&B)	New & Retrofit DLC Case 2 (16C)	Scenario 3 No Smart Meter DLC Only
Incremental Benefit of Smart Meter Functionalities								
Operating Cost: \$m (NPV 2007-2030)		0	0			4	4	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.21%	0.21%	
Offer costs: \$m (NPV 2007-2030)		0	0			4	4	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.21%	0.21%	
USE Costs: \$m (NPV 2007-2030)		0	0			0	0	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.00%	0.00%			0.00%	0.00%	
CO2-e Emissions Cost: \$m (NPV 2007-2030)		0	0			1	1	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.37%	0.37%	
Average Spot Price: \$/MWh (2007-2030)		0	0			0	0	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.14%	0.14%	
Super Peak Price: \$/MWh (2007-2030)		1	1			2	2	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.54%	0.56%			1.19%	1.33%	
CO2-e Emissions: '000 tons cumulative through 2030		2	2			72	73	
<i>incremental % reduction vs Carbon Price Base Case</i>		0.01%	0.01%			0.30%	0.31%	

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Table 21: Peak demand reductions by jurisdiction (MW) for base smart meter functionality, base demand response case

	QLD	NSW (incl. ACT)	VIC	SA	TAS	WA	NT
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.2	0.2	0.4	0.1	0.0	0.1	0.0
2010	1.7	1.8	4.3	0.7	0.1	2.3	0.0
2011	6.4	6.8	17.0	2.6	0.4	12.9	0.1
2012	23.4	24.7	36.2	9.5	1.6	24.7	0.2
2013	44.2	46.3	57.9	17.6	3.0	37.9	0.4
2014	66.2	68.8	62.0	25.9	4.5	50.2	0.6
2015	85.0	88.0	61.7	32.8	5.7	51.9	0.8
2016	90.3	92.7	62.9	34.4	6.0	53.0	0.8
2020	112.0	100.7	72.1	37.3	7.1	64.2	0.9
2025	124.1	106.8	80.1	38.9	7.4	70.6	0.9
2030	138.1	113.9	88.8	41.0	8.0	77.7	1.0

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Table 22: Peak demand reductions by jurisdiction (MW) for new & retrofit DLC functionality, high demand response case

	QLD	NSW (incl. ACT)	VIC	SA	TAS	WA	NT
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.8	1.0	1.5	0.4	0.1	0.4	0.0
2010	6.7	9.0	16.7	3.1	0.5	7.6	0.1
2011	24.7	33.0	66.1	11.3	2.0	42.6	0.4
2012	94.5	125.8	147.4	42.9	7.7	85.1	1.7
2013	177.9	234.7	235.5	79.3	14.3	130.4	3.1
2014	266.4	347.5	252.0	116.5	21.5	172.7	4.7
2015	347.5	448.8	254.9	149.7	28.0	180.9	6.1
2016	368.9	471.4	259.9	156.9	29.3	184.8	6.3
2020	437.3	505.3	287.9	167.3	34.2	214.1	6.9
2025	504.9	549.6	324.4	177.4	37.1	242.7	7.6
2030	576.0	591.2	362.5	188.4	40.5	269.9	8.3

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Table 23: Peak demand reductions by jurisdiction (MW) for Scenario 3 (no smart meter, DLC only), high demand response case

	QLD	NSW (incl. ACT)	VIC	SA	TAS	WA	NT
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	7.8	9.9	6.1	3.7	0.0	3.7	0.2
2010	64.1	80.4	49.2	29.9	0.0	30.1	1.3
2011	131.9	163.2	100.1	60.4	0.0	61.5	2.8
2012	195.1	237.9	146.2	87.7	0.0	90.3	4.1
2013	209.4	251.8	154.9	92.4	0.0	96.2	4.4
2014	215.2	255.3	157.3	93.4	0.0	98.1	4.5
2015	221.2	258.9	159.8	94.3	0.0	100.1	4.6
2016	227.3	262.4	162.2	95.2	0.0	102.1	4.7
2020	252.0	276.2	171.8	98.5	0.0	110.0	5.1
2025	299.4	304.1	190.6	103.9	0.0	125.1	5.8
2030	347.9	326.0	207.9	108.0	0.0	139.4	6.4