Independent Pricing and Regulatory Tribunal

Review of regulated retail tariffs and charges for electricity 2010-2013

Electricity — Final Report
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Foreword

Today we are releasing our final decision on retail electricity prices for the three years from 2010/11 to 2012/13. Electricity prices will increase substantially as a result of this decision. Prices will increase by between 20% (for Integral Energy) and 42% (for Country Energy) if the Commonwealth Government's Carbon Pollution Reduction Scheme (CPRS) is not introduced. If the CPRS is introduced from 2011/12 as planned, the price increases over the next 3 years will total 46% to 64%. The price increases on 1 July 2010 will be between around 7% and 13%.

These price increases are similar to the ones that we presented in our draft report which was released in December 2009. The main reasons for these increases are higher network prices which have recently been determined by the Australian Energy Regulator and the proposed introduction of the Carbon Pollution Reduction Scheme.

Since the release of our draft determination we have received many submissions from individual customers. These customers submitted that they will find it difficult to pay substantially more for electricity. In particular, pensioners and others on low incomes stated that higher electricity prices will be a problem for them.

We do not welcome these price increases or the adverse effects that they will have for many electricity customers. We have, however, carefully considered all the advice that has been provided to us in submissions and made our own investigations. We believe that the price increases are the minimum required to ensure that prices will reflect efficient costs, that the NSW retail electricity market will remain adequately competitive and that the retailers will be able to finance their operations. We were required to consider these issues by our terms of reference.

The Commonwealth and NSW Governments are introducing policies to assist those who are particularly likely to be adversely affected by higher electricity prices. The NSW Government is implementing a customer assistance program and the Commonwealth Government has announced a compensation package to assist middle and low income households to adjust to the higher prices that will result from the introduction of the CPRS. However, it is important for governments to continue to examine their policies to ensure that they remain effective. This includes ensuring that the competitive electricity market works as effectively as possible to provide benefits to customers, including those on low incomes.

We are therefore making a number of recommendations to the NSW Government.

First, we recommend that the Government should extend the NSW energy rebate to all Commonwealth Health Care Card Holders. At present most health card holders receive the rebate but some (eg, those receiving unemployment allowances) do not. These people can pay a high proportion of their incomes on electricity costs.

Secondly, the Government should consider whether an increase in the amount of the NSW energy rebate is required. This rebate was increased substantially in 2009 (and will increase in future years according to changes in the Consumer Price Index). However, further increases maybe justified because electricity prices will increase in excess of the CPI over the next few years.

Thirdly, we are recommending that the Government should require retailers to disclose specified information about their tariffs to customers. We also consider that the Government should provide a service, which would be accessible over the internet or by telephone that enables customers to make accurate comparisons between the tariffs that the retailers offer. These recommendations will enable customers to easily compare the tariff offers that are available in the competitive market.

Finally, we recommend that the standard retailers should be required to publish their regulated tariffs no later than 5 days after the day on which IPART approves them.

It has been a complex and difficult task to make this determination. We have been considerably assisted in doing so by those who have made submissions to us or who have participated in our public inquiry process.

James Cox
Acting Chairman
Chief Executive Officer

1 Introduction and executive summary

The Independent Pricing and Regulatory Tribunal of NSW (IPART) has made a new determination on the regulated electricity tariffs for small retail customers in NSW to apply from 1 July 2010. These regulated tariffs will apply only to customers of the Standard Retail Suppliers in NSW (EnergyAustralia, Integral Energy and Country Energy) who are supplied on standard contracts. These customers currently represent around 66% of all small retail customers in NSW, and around 25% of the state's total electricity demand.

This report explains the determination and the decisions and analysis that underlie it. The determination will take effect from 1 July 2010.

1.1 Why are we making this determination?

Although the market for retail electricity has been fully open to competition for the past 7 years, small retail customers have had the option to remain on a standard contract and regulated tariff with the Standard Retailer in their supply area. This regulation is intended to provide protection for small retail customers while competition is developing. The NSW Government (along with other Australian governments) has agreed to phase out retail electricity price regulation completely where it can be demonstrated that effective competition exists.[1]

However, the Government committed to retaining the option of regulated retail electricity tariffs at least until 2013, with the Minster for Energy asking us to make a new determination for the period 1 July 2010 to 30 June 2013.

1.2 What is the scope of the determination?

Electricity retailers play a buffering role between the supply and demand sides of the market. They buy wholesale electricity from generators through the national electricity market, paying either the spot market price or a contract price. They also pay significant charges to transport electricity along the transmission and distribution networks to their retail customers. In most cases, they sell electricity to these customers at a set bundled price. For retailers to be viable, this price must cover their payments to generators and network businesses, as well as the costs of

1 Council of Australian Governments' Meeting, *Communique*, 10 February 2006, Appendix A to Attachment B, p 8.

running their own business. These costs include retail costs, and the costs of managing the risks associated with this business.

Retail electricity tariffs are structured to recover these costs. They comprise 2 components – network charges (N) and retail charges (R). A customer's total electricity bill is the sum of these components (N + R). Both the N and the R components include fixed charges (which are the same for all customers on a particular tariff) and variable charges (which depend on how much electricity the customer uses). Therefore, a customer's total bill also reflects their electricity consumption.

The network charges or N component of all retail tariffs – both regulated and market-based – are regulated by the Australian Energy Regulator (AER). Under this determination these charges are passed directly through to customers in retail tariffs. The retail charges or R component for customers supplied on standard form contracts are regulated in NSW. IPART is responsible for this regulation.

1.3 What factors will influence retail electricity prices over this period?

During the course of the 2010 determination period, 2 factors will drive substantial increases in retail electricity prices for all NSW customers, including those on regulated tariffs. These are:

- **Increased network charges.** Under the AER's 2009 network determination, the N component of retail tariffs will increase significantly over the next 3 years (see Table 1.6). The increases will allow NSW network service providers to increase investment in infrastructure and improve network security and reliability of supply in line with new licence conditions imposed by the NSW Government.
- **Increased costs associated with the introduction of the Federal Government's proposed Carbon Pollution Reduction Scheme (CPRS).** This scheme is designed to enable Australia to meet its national emissions reduction targets. It aims to ensure that the cost of carbon pollution is taken into account in investment and production decisions. This will affect the pattern of competitiveness across the economy, the relative prices of goods and services, and the consumption choices of households and individuals. If implemented it will lead to significant increases in the price of electricity because much of Australia's electricity generation involves high carbon emissions. The CPRS is proposed to commence on 1 July 2011 – the second year of the determination period – with an emissions reduction target of 5% below 2000 levels by 2020, and a one-year cap on the price of carbon of $10 per tonne. However, this is not certain, as the Federal Government's *Carbon Pollution Reduction Scheme Bill 2009* [No. 2] (Cth) was defeated in the Senate on 2 December 2009 (the CPRS Bill). The Federal Government reintroduced the bill into Parliament in early 2010 but at the time of making this determination, it had not passed into legislation.

In making our final determination, we have explicitly accounted for the impact of both these factors on regulated retail tariffs. We have also addressed the risks and uncertainties associated with the passage of the CPRS legislation.

We have assumed that the CPRS will commence as currently proposed in the Federal Government's *Carbon Pollution Reduction Scheme Bill 2010.* We have modelled the impact of the CPRS on electricity prices using the Commonwealth Treasury's forecast estimate of the market-based carbon price in 2012/13,[2] and have also indicated the price impacts if the CPRS does not proceed. We have provided for periodic reviews of this modelling throughout the determination period, so we can adjust regulated tariffs if these assumptions prove to be incorrect.

We have also taken account of the uncertainties and risks associated with other possible policy and market developments during the determination period, including the planned sale of the NSW Standard Retailers and trading rights to the state-owned generators.

1.4 Overview of price outcomes under the final determination

Under the final determination, average regulated retail tariffs increase by a substantial percentage in each year of the determination period. As Table 1.1 shows prices increase over the next three years will be between 46% (for Integral Energy customers) and 64% (for Country Energy customers) if the CPRS is introduced from 2011/12 as planned. If the CPRS is not introduced, prices will increase by between 20% (for Integral Energy customers) and 42% (for Country Energy customers). Regardless of the CPRS, the average price increases on 1 July 2010 will be from around 7% to 13%. While the 2010/11 price increases are final, the increases shown for 2011/12 and 2012/13 on this table (and throughout this report) are indicative only: it is not possible to show precise increases, due to uncertainties about the impact of the CPRS and other cost drivers. The prices will be finalised in May each year before the 1 July price change.[3]

Table 1.1 Indicative average increase in regulated retail tariffs under the final determination (nominal, %)

	2010/11	2011/12	2012/13	Cumulative total With CPRS	Cumulative total No CPRS
EnergyAustralia	10	16	25	60	36
Integral Energy	7	14	20	46	20
Country Energy	13	17	24	64	42

Note: Cumulative total includes the compound effect of each year's individual price increase. Totals may not add due to rounding.

2 Commonwealth Treasury's carbon price forecast as at October 2008 (adjusted to reflect financial years in $2009/10). Commonwealth Treasury, *Australia's Low Pollution Future: The Economics of Climate Change Mitigation*, October 2008.

3 There could be an additional price change on 1 January 2013 as a result of any special review of carbon prices.

These price increases are similar to the price increases that we announced in our draft determination, released in December 2009. We received over 100 responses from stakeholders highlighting the difficulties that they will face in paying substantially more for electricity. In particular, people on low incomes (including pensioners) are concerned about the affordability of electricity.

Table 1.2 shows the contribution of the various cost drivers to the cumulative average increase in regulated retail tariffs over the determination period. It indicates that the predominant reasons for this increase are the impact of network charges and the CPRS on the costs of supplying small customers. By 2013, retail prices will increase by between 16% and 35% because of increased network charges, and by between 22% and 26% if the CPRS is introduced as planned. More than 90% of the total cumulative price increase over the period is driven by these 2 factors.

Again, the contributions shown on the table indicate our best estimates of price changes. However, to accommodate uncertainties about the impact of the CPRS and other cost drivers, we will undertake periodic reviews of specific cost components during the determination period, to ensure that regulated retail tariffs recover the efficient cost of supplying small retail customers. In particular, we will ensure that neither customers nor the retailers are unfairly affected if the CPRS is not introduced during the determination period, or is introduced in a different form.

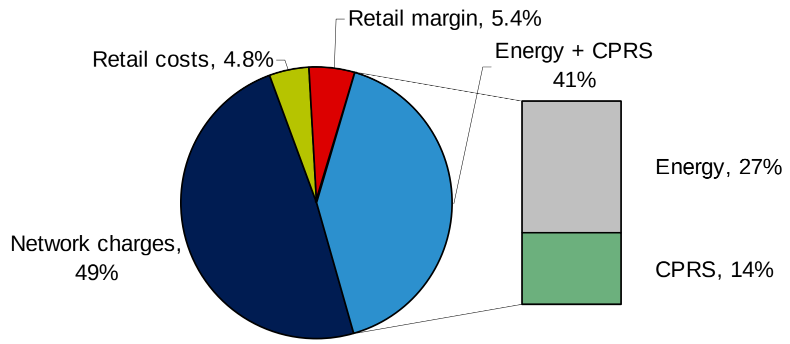
Table 1.2 Indicative cumulative increases in regulated electricity prices under the final determination, and their causes, 2010/11 to 2012/13 (nominal, %)

	EnergyAustralia	Integral Energy	Country Energy
Increases in network charges (as determined by the AER)	31	16	35
Increases in wholesale energy costs (if the CPRS is not introduced)	1	1	3
Increases in retail costs and margin	3	2	3
Total increases if CPRS not introduced	**36**	**20**	**42**
Additional increases in wholesale energy costs if the CPRS is introduced	24	26	22
Total increases if CPRS is introduced	**60**	**46**	**64**

Note: Columns may not add due to rounding.

Figure 1.1 shows the composition of a typical regulated customer's electricity bill in 2012/13 under the determination with the impact of the CPRS. It indicates that network charges (N) will account for around half of the total bill. The retail component (R), which accounts for the other half, comprises energy costs, retail costs and a retail margin. The energy costs make up the majority of this component and account for more than 40% of the total bill. Around one-third of the energy cost allowance in 2012/13 is due to the cost of carbon emissions under the CPRS.

Figure 1.1 Composition of a typical NSW electricity retail bill under final determination, 2012/13



Note: Figure shows composition of a typical bill averaged across the 3 NSW Standard Retailers for a customer consuming 7000kWh per annum.

Table 1.3 illustrates the increases in typical bills for residential customers in each standard supply area. It shows that by the end of the determination period, if the CPRS is introduced a typical customer supplied on a standard contract by EnergyAustralia, Integral Energy and Country Energy will be paying an additional $754, $575 and $918 a year (respectively) for electricity. If the CPRS is not introduced they will increase by $448, $246 and $601 a year (respectively).

Table 1.3 Indicative annual bill for typical residential customers in each standard supply area (nominal $)

	2009/10	2010/11	2011/12	2012/13	Cumulative increase With CPRS	Cumulative increase No CPRS
EnergyAustralia	1,257	1,383	1,605	2,012	754	448
Integral Energy	1,258	1,343	1,535	1,835	577	246
Country Energy	1,446	1,629	1,908	2,363	918	601

Note: Bills exclude GST. Forecast inflation is 2.4%, 2.7% and 2.7% for 2010/11, 2011/12, 2012/13, respectively. Calculations may not add due to rounding. Calculated using 7000 kWh per annum multiplied by the average price derived from the N+ R values. The Commonwealth Government's CPRS compensation is not included in this analysis as it will be a transfer payment to cover the overall costs of the CPRS and will not directly offset higher electricity costs.

Table 1.4 illustrates the increases in typical bills for business customers in each standard supply area. It shows that by the end of the determination period, if the CPRS is introduced a typical business customer supplied on a standard contract by EnergyAustralia, Integral Energy and Country Energy will be paying an additional $2,421, $1,660 and $3,070, respectively, each year for their electricity. If the CPRS is not introduced they will increase by $1,433, $706 and $2,012 a year (respectively).

Table 1.4 Indicative annual bill for typical business customers in each standard supply area (nominal $)

	2009/10	2010/11	2011/12	2012/13	Cumulative increase With CPRS	Cumulative increase No CPRS
EnergyAustralia	4,035	4,438	5,148	6,456	2,421	1,433
Integral Energy	3,620	3,863	4,415	5,280	1,660	706
Country Energy	4,834	5,448	6,379	7,904	3,070	2,012

Note: Bills exclude GST. Forecast inflation is 2.4%, 2.7% and 2.7% for 2010/11, 2011/12, 2012/13, respectively. Calculations may not add due to rounding. Calculated using 20,000 kWh per annum. EnergyAustralia customers are on the General Supply All Time LV tariff, Integral Energy customers are on the General Supply tariff and Country Energy customers are on the 5740 Business tariff. Prices increase at the average N+R rate.

Table 1.5 identifies the causes of the increases in typical residential bills in each year (between now and 2012/13 if the CPRS is introduced). It shows that while network charges increase in each year of the determination period, there is:

- No increase in energy costs due to the CPRS in the first year.
- A moderate increase in the second year as a result of the introduction of the CPRS (when a $10/tonne cap on the carbon price is in place).
- A larger CPRS impact in 2012/13. This is the result of a higher carbon price (we have used the Commonwealth Treasury's estimated carbon price of $26/tonne[4]) and a higher 'pass through rate'[5] (see Section 6.2.4 for more detail).

In 2010/11 and 2011/12 the energy purchase costs are calculated using the long run marginal cost (LRMC) of generation approach. The stand-alone LRMC is the cost of a theoretical system that is built in each year to meet each of the Standard Retailers' forecast regulated load at minimum cost. Under the LRMC modelling the introduction of a carbon price in 2011/12 leads to an increase in the proportion of gas fired generation plant that has lower emissions intensity and (hence lower carbon cost).

4 Commonwealth Treasury's carbon price forecast as at October 2008 (adjusted to reflect financial years in $2009/10). Commonwealth Treasury, *Australia's Low Pollution Future: The Economics of Climate Change Mitigation*, October 2008.

5 The carbon 'pass through' rate refers to the extent to which the cost of carbon is passed through by generators into wholesale electricity prices. The higher the pass through rate the more the costs of carbon are passed through into wholesale electricity prices.

In 2012/13, a market based estimate of the energy purchase cost is used. The market based estimate reflects the current mix of generation and dispatch in the NEM (which is predominantly coal fired generation with a high emissions intensity and hence high carbon costs), as well as the bidding behaviour of generators in response to the CPRS. The estimated pass through of carbon costs into wholesale prices is significantly higher in 2012/13 under the market based estimate as a result of these factors. The terms of reference require that we set the energy purchase cost as the higher of the market based costs and the LRMC (See Chapter 6 for more information on the pass through rates under the LRMC and market based approaches).

Table 1.5 Increases in annual bills for typical residential customers under the final determination, and their causes (nominal, $)

	2010/11	2011/12	2012/13	Cumulative total
EnergyAustralia				
Network charge increases (as determined by the AER)	106	132	157	**395**
Energy cost increases due to CPRS*	0	60	230	**290**
LRMC basis	*0*	*60*	-	
Market basis	-	-	*230*	
Energy cost increases due to factors other than CPRS	7	13	-7	**13**
Retail cost and margin increases	13	16	27	**56**
Total	**126**	**221**	**407**	**754**
Integral Energy				
Network charge increases (as determined by the AER)	79	98	28	**205**
Energy cost increases due to CPRS*	0	60	253	**313**
LRMC basis	*0*	*60*	-	
Market basis	-	-	*253*	
Energy cost increases due to factors other than CPRS	-6	20	0	**14**
Retail cost and margin increases	11	14	20	**45**
Total	84	192	300	**577**
Country Energy				
Network charge increases (as determined by the AER)	145	178	183	**507**
Energy cost increases due to CPRS*	0	62	237	**299**
LRMC basis	*0*	*62*	-	
Market basis	-	-	*237*	
Energy cost increases due to factors other than CPRS	21	19	6	**46**
Retail cost and margin increases	18	19	29	**66**
Total	**183**	**279**	**456**	**918**

Note: Forecast inflation is 2.4%, 2.7% and 2.7% for 2010/11, 2011/12, 2012/13, respectively. Columns and rows may not add due to rounding. Calculated using 7000 kWh per annum multiplied by the average price derived from the N+ R values.

* Chapter 6 explains of the effect of the CPRS on the energy cost allowances, including the change from the LRMC to market based modelling in 2012/13. Tables 6.3 and 6.4 illustrate the impact in each year of the CPRS on the LRMC. Tables 6.6 and 6.7 illustrate the impact in each year of the CPRS on the market based energy purchase cost.

We recognise that these price increases are large and will be felt by customers, particularly low-income households. Further, they follow large price increases in July 2009. We note that the NSW Government has introduced a $272 million customer assistance package, and the Federal Government has indicated that it will offer compensation to assist households with the cost impacts flowing from the CPRS. We also note that the State and Federal Governments provide incentives for households to reduce their energy consumption and the Standard Retailers offer advice on reducing consumption. However, even with targeted assistance from governments and efforts to reduce consumption by customers, households will be paying considerably more for electricity in the coming 3 years.

The Minister for Energy requested that IPART further consider the Commonwealth Government's CPRS compensation arrangements in our assessment of customer impacts.[6] We have taken the publicly available information and included it in our analysis in Chapter 11. The CPRS compensation package will provide a transfer payment to low and middle income households to compensate them for the increased cost of living arising from the CPRS. As a result of this determination, households will spend more on electricity and our analysis suggests that after the transfer payments are taken into account, households will continue to spend a greater proportion of their income on electricity.

Over the 2010 to 2013 period, we expect the competitiveness of the NSW retail market will continue to develop. This may help to lessen the impact of the regulated tariff increases on electricity prices in general, by encouraging retailers to compete for customers. To encourage stronger competition, we have recommended the NSW Government take steps to ensure consumers have access to transparent tariff information and can easily compare retailers' offers (see section 1.10 and Chapter 3). The Minister for Energy indicated in his submission that he has instructed Industry & Investment NSW to work with IPART to further develop this proposal with the objective of increasing transparency as well as flexibility in the types of services available to customers. We recognise that these enhancements will require regulatory changes.

1.5 Differences between draft and final determinations

We released our draft determination in December 2009 and by February 2010 we had received over 100 submissions. Most of these submissions were from individuals and raised concerns about the affordability of electricity. Submissions from industry stakeholders addressed a range of issues, but mainly focused on the energy purchase cost allowance and retail operating cost allowance.

We carefully considered all the submissions received in making our final decision. Appendix B summarises our consideration of the main issues raised.

6 Minister for Energy submission (John Robertson, MLC), February 2010, p 1.

Our final determination is very similar to our draft determination. The price increases if the CPRS is introduced are now slightly higher than they were in the draft report, with EnergyAustralia's average price change for the three years increasing from 58% to 60%, Integral's increasing from 44% to 46% and Country Energy's increasing from 62% to 64%.

The slight increases from the draft determination result from 3 changes:

- While the overall energy cost allowance is similar, the LRMC estimate fell slightly and the RET allowance increased as a result of the WACC changing from 8.2% to 8.0% for generation and a change to the amortisation of capital costs.
- The retail cost allowances increased on average by $5.10 per customer per year reflecting new customer transfer data from AEMO and revised customer numbers forecasts.
- We have updated our inflation forecast by 0.2% to 2.7% for 2011/12 and 2012/13.

We have amended our recommendation to Government regarding the online comparator service to include a phone service, recognising that some groups of customers, including the elderly, may not be readily able to use an online tool. We are also reiterating our recommendations from May 2009 that the Government consider extending the Energy Rebate to all Commonwealth Health Care Card holders and that it should consider further increases in the Energy Rebate.

We also note that on 26 February 2010 the Commonwealth Government announced changes to the Renewable Energy Target (RET). Because consultation is yet to commence and the legislation has not been introduced into Parliament, we have not incorporated the announced changes to the RET into regulated retail tariffs from 1 July 2010. We envisage, however, that any amendments to the RET would, once finalised, be eligible for pass through (subject to the materiality threshold being met).

1.6 Our approach to the final determination

The terms of reference for this determination are similar to those for the 2007 determination. They require us to use an approach that results in prices that recover an efficient Standard Retailer's costs in meeting the forecast demand for the regulated customers it is obliged to serve, including energy purchase costs, retailer operating costs and a retail margin. They also require us to make decisions that are consistent with the Government's policy aim of reducing customers' reliance on regulated prices and to maintain the aims and approach of the 2007 determination.

Therefore, we used the 2007 determination as the starting point for our considerations, and augmented this approach for the 2010 determination to reflect changes in the terms of reference and developments in the market. This approach included:

1. Considering the terms of reference and developing assessment criteria for our analysis and decision-making based closely on these terms of reference.
2. Considering the effectiveness of retail market competition in NSW to decide whether there is a need for any additional regulatory mechanisms to promote competition.
3. Analysing the specific risks retailers will face over the determination and identifying how best to address each risk in the determination.
4. Considering the form of regulation to be used in determining regulated retail tariffs.
5. Analysing the costs that an efficient Standard Retailer will incur in supplying small retail customers on regulated tariffs over the determination period, taking into account electricity purchase costs, retail operating costs and retail margin, and the risks associated with forecasting these costs over the determination period.
6. Taking account of the above considerations and analysis to make decisions on:
   - the form of regulation
   - the value of the regulated retail price controls within this form of regulation, and
   - the regulated retail charges.

As for the 2007 determination and consistent with our draft determination, we have developed a regulatory package that allows the Standard Retailers to pass through network charges in retail bills, and sets allowances that will recover their efficient energy and retail costs and an appropriate retail margin. The package also specifies that the Standard Retailers will set regulated tariffs in compliance with a weighted average price cap, and provides for additional review mechanisms to address some of the specific risks and uncertainties the retailers will face over this determination period. We have sought to ensure that all relevant risks and uncertainties are addressed within the package, and that each is addressed only once.

1.7 Network charges

In April 2009, the AER released its determinations for NSW network charges for the period 2009/10 to 2013/14. However, the NSW network businesses successfully appealed the AER's final decision. Table 1.6 presents the increases in network charges including the results of the appeal. These are the same as those included in the draft determination.

Table 1.6 Average price increases (%) allowed for NSW network charges, 2010/11 – 2012/13 (including the price increases from the WACC appeal) ($2009/10)

Distribution network business	2010/11	2011/12	2012/13
EnergyAustralia	16	16	16
Integral Energy	12	12	1
Country Energy	16	16	14

Like previous determinations, this determination provides for each Standard Retailer's regulated network charges to be passed through in the retail bill. As noted above, the increases in these charges account for 16% to 35% of the total cumulative increase in regulated retail tariffs under the final determination. In 2012/13, these charges will account for around half a typical residential customer's total electricity bill.

1.8 Total energy cost allowance

As directed in the terms of reference, we set the energy purchase cost allowance as the greater of the estimate of the LRMC of generation and the market-based purchase cost (including an allowance for volatility). For the first 2 years of the determination period, the energy purchase cost allowance reflects the LRMC of generation. In the final year, it reflects the market-based cost.

We note that both the LRMC of generation and the market-based cost vary over time. For example, in March 2009 we undertook an annual review of the market-based electricity purchase cost allowance included in the 2007 determination. We decided to increase regulated retail tariffs for 2009/10, partly to reflect our finding that market-based costs had increased materially since our 2007 review. However, we note that since that decision, market-based costs have fallen again, mainly due to reduced demand for electricity. At the same time, the estimated LRMC of generation has substantially increased – largely due to increased capital and fuel costs.

In making our final decision on the energy purchase cost allowance for each year of the 2010 determination period, we used the forecasts of regulated load submitted by the Standard Retailers (and analysed by Frontier Economics) and:

- Modelled the estimated LRMC of generation on a stand-alone basis, which effectively builds and prices a new least-cost generation system to meet the regulated load. Where possible we used publicly available information, preferably commissioned by the Australian Energy Market Operator (AEMO). The resulting LRMC estimates are higher than those for the 2007 determination, reflecting higher capital and fuel costs.

- Estimated the market-based purchase cost by modelling simulated forward data and also considered publicly observable information, namely d-Cypha data. Consistent with the 2007 determination, we used a point-in-time estimate and the conservative point on the 'efficient frontier curve'. We also included an allowance to account for the residual costs of managing the volatility of electricity costs in the national electricity market. (Note this volatility allowance is not required in the LRMC.)
- Adopted a carbon-inclusive approach for both the LRMC and market-based cost modelling. We used the Commonwealth Treasury's forecast carbon price and the relevant emissions intensity to determine the carbon cost for each generation type.[7] This was incorporated into the short run marginal cost (SRMC) of thermal generation plant which is used in both the LRMC and market based modelling. Therefore, the energy cost allowances factor in the cost to generators of complying with the proposed CPRS. However, we have also reported the energy cost estimates if the CPRS is not introduced.
- Provided for annual reviews of the energy purchase cost allowance during the determination period and a special one-off review of the market-based cost allowance for a 1 January 2013 price change (if necessary). This is to manage the risks and uncertainties associated with our decision to determine an energy cost allowance inclusive of the forecast impact of the CPRS (discussed in section 1.11 below).

We also calculated other costs associated with buying and selling electricity – including the costs of complying with the national Renewable Energy Target and other state-based 'green' schemes, market fees and energy losses.

The overall energy cost allowances in our final report are very similar to those set out in our draft report. However, we updated the WACC to reflect market parameters (nominal risk free rate, inflation adjustment and debt margin) as at 8 February 2010. As a result, the WACC for generation fell 20 basis points to 8.0%. Additionally, SFG amended its amortisation methodology. The LRMC estimates fell slightly, but this was offset by an increased RET allowance. The volatility allowance also changed marginally as a result of the revised WACC.

Table 1.7 sets out the resulting carbon-inclusive total energy cost allowances (including the costs of complying with green schemes, NEM fees and energy losses) in each year of the determination period.

7 We used the carbon price estimate that the Commonwealth Treasury produced in its 2008 White Paper.

Table 1.7 Final decision on total energy cost allowances (2009/10 $/MWh), including CPRS

	Current allowance (2009/10)	2010/11 LRMC	2011/12 LRMC	2012/13 Market-based cost[a]
EnergyAustralia	75.3	74.5	82.5	109.8
Integral Energy	80.6	77.9	86.7	117.9
Country Energy	71.5	72.7	81.9	111.9

a Includes allowance for volatility of market-based prices of $0.6 – $0.8 per MWh.

1.9 Retail cost allowance

We set the retail cost allowance based on historic actual cost data provided by the Standard Retailers and information from other retailers. We tested the reasonableness of this allowance by benchmarking it against other recent regulatory decisions on retail costs.

We opted to use the Standard Retailers' historic costs rather than their forecast costs because we did not agree with some retailers' view that the costs of serving customers would increase significantly over the 2010 determination period. We converted our decisions on each Standard Retailer's total retail cost allowance into an allowance per customer using its forecast total number of small customers in NSW.

In the draft determination, we adjusted EnergyAustralia and Country Energy's forecasts so that their forecast number of negotiated customers was consistent with historic trends. However, since then:

1. We have considered more recent customer transfer information from AEMO. Transfer rates in NSW have increased from 11% in 2008/09 to 13% in calendar year 2009. These rates are used in the analysis of customer acquisition costs. As a result, the customer acquisition costs have increased by around $4 to $36.80.
2. The Standard Retailers submitted new forecasts of customer numbers. For EnergyAustralia, the revised forecasts were still below our forecasts included in the draft determination. However, given that the AEMO transfer data suggests that more customers are transferring, we consider that EnergyAustralia's revised forecasts are reasonable. For Integral Energy, we did not adjust their original forecasts in our draft determination because they were in line with historical trends. Because their revised forecasts of higher customer numbers are not consistent with the trend in AEMO churn data, we have rejected their revised forecasts and maintained their original forecasts. Given the trend in the AEMO churn data, we now consider that Country Energy's customer number forecasts are reasonable and have used them. As a result of the adopting EnergyAustralia and Country Energy's forecast customer numbers, the retail operating costs increase by around $1.10 each year.

Table 1.8 shows our final decisions on the retail cost allowance per customer, and compares them to the current retail cost allowances (ie, the 2009/10 allowances provided for in the 2007 determination). The total retail cost allowance is on average $5.10 per customer each year higher than the allowance set out in the draft determination.

Table 1.8 Final decisions on retail cost allowance ($2009/10, $/customer)

	Current allowance (2009/10)	2010/11	2011/12	2012/13
Retail operating costs	82.6	75.3	77.2	79.2
Customer acquisition and retention costs	32.7	36.8	36.8	36.8
Late payment fee deduction		-2.3	-2.3	-2.3
Retail cost allowance	**115.3**	**109.8**	**111.7**	**113.7**

Note: The retail cost allowance of $115.3 per customer under the 2007 determination includes a $5 deduction for double counting. Columns may not add due to rounding.

The table shows that the annual retail cost allowances under the determination are lower than the current allowance. The retail operating costs are lower because the Standard Retailers' actual retail operating costs over the last years were less than those allowed for in the 2007 determination. In addition, all marketing costs are included in customer acquisition and retention costs, rather than in retail operating costs as they were previously.

In addition, we have confirmed that the Standard Retailers included the costs associated with customers not paying their bills on time in their retail cost data. As the late payment fee covers part of those costs, we have deducted a portion of the estimated revenue from this fee from the retail cost allowance.

1.10 Retail margin allowance

We set the retail margin allowance based on an EBITDA margin of 5.4% on each Standard Retailer's network and retail components, consistent with our draft determination. This is slightly higher than the 5% margin we allowed for in the 2007 determination, reflecting updated analysis of the systematic risks associated with electricity retailing for the 2010 determination.

The WACC that we have used in the final decision for electricity retail businesses is 9.1%, which is 30 basis points higher than in the draft determination. This reflects updated market based parameters (including the nominal risk free rate, inflation adjustment and debt margin) and a reduction in the assumed level of debt from 40% to 30% of the asset base. An increase in the retail WACC marginally decreases the expected returns estimate and marginally increases the bottom-up estimate. On balance the midpoint remained at 5.4% and we maintained our decision to adopt that mid-point.

1.11 Form of regulation

Consistent with the draft determination, we decided to use the same basic form of regulation as the 2007 determination. This means the Standard Retailers will set their regulated retail tariffs in accordance with a weighted average price cap. In general, we are confident that a weighted average price cap is sufficient to ensure the Standard Retailers set cost-reflective tariffs, given the restrictions on introducing new regulated tariffs, the small number of existing regulated tariffs, and the competitiveness of the market. However, we decided to continue with 2 additional conditions on Country Energy, due to its larger number of regulated tariffs and the lower level of competition in its supply area. To ensure that it sets regulated tariffs at cost-reflective levels, Country Energy must:

- demonstrate that its regulated tariffs are moving towards cost-reflective levels if it proposes to increase individual tariffs above the average annual price change plus an additional 5%
- obtain our approval if it proposes to remove a regulated tariff and transfer customers on that tariff to another and the price applying to the 2 tariffs (including level and structure) is not the same.

We consider that effective competition in the retail electricity market is crucial to deliver long-term benefits to customers. While there are relatively low barriers to entering this market, there is some evidence that a lack of information and knowledge of the market is leading to poor customer outcomes. Therefore, we consider better information that makes it easier for small retail customers to compare tariff offerings is needed to facilitate better outcomes and encourage competition. This is particularly the case given the large increases in price that will occur in the coming years. In the draft report we recommended that the NSW Government introduce tariff disclosure requirements in a common format for all licensed retailers and provide a government-endorsed web-based comparator service. These recommendations were supported by stakeholders during the consultation process. Following this consultation we decided to amend this recommendation to include a phone based comparator service to provide information to groups of customers that are less likely to use an on-line service, including aged pensioners.

We also decided that ‘normal changes’ in regulated retail tariffs will continue to occur on 1 July in line with the 2007 determination. However, we consider that the annual price compliance process should be brought forward to facilitate the development of the competitive market. We are working with the Australian Energy Regulator to facilitate this. To this end, we have recommended that the NSW Government consider amending the *Electricity Supply (General) Regulation 2001* to require Standard Retailers to publish their regulated prices and miscellaneous charges on their website within 5 calendar days of IPART approving them.

1.12 Periodic reviews of energy cost allowances and cost-pass-through mechanism

Given the uncertainties within the market and the volatile nature of electricity prices, setting electricity prices 3 years in advance is a difficult task. To ensure that regulated prices reflect current market conditions and obligations, we have provided for 3 types of reviews during the determination period:

1. **Annual reviews of the total energy cost allowance.** These reviews will be undertaken in time for a 1 July price change. They will update a range of input assumptions, including carbon price assumptions. Given that the 1 July price change accounts for network price changes and will occur regardless of this periodic review, there is no materiality threshold. We will consider both modelled results and publicly available information that we consider to be appropriate.
2. **A special one-off review of the market-based energy purchase cost.** This review will be undertaken in time for a possible price change on 1 January 2013. It will be limited to the market-based energy purchase cost allowance, and will update the carbon price input assumption only. It is specifically intended to manage the risks and uncertainties surrounding the level and volatility of carbon prices and their impact on wholesale electricity prices after the $10/tonne carbon price cap is removed. Only cost increases that exceed a materiality threshold will result in price changes.
3. **A cost-pass-through review**. This review is intended to manage the risks associated with regulatory or taxation changes that result in material increases in the retailers' costs. It can be initiated by the Standard Retailers or IPART after an eligible regulatory or taxation change event occurs, and has a materiality threshold.

We consider that the combination of these mechanisms addresses the major non-systematic risks retailers will face within the determination period. Specifically, it will accommodate uncertainties arising from the passage of the CPRS legislation, and about the eventual timing and form of this scheme. These mechanisms will also ensure that customers will not pay costs associated with the CPRS if it is not implemented during the determination period.

Additionally, we will consider the changes that the Commonwealth Government announced to the RET on 26 February 2010 under the cost pass through mechanism. Because public consultation is yet to occur on the proposed amendments and there is not sufficient detail to properly model the impact, we have not incorporated the announced changes to the RET into regulated retail tariffs from 1 July 2010. Considering amendments to the scheme under a cost pass through arrangement will allow the costs to be assessed on better information and will allow a consultative process. (See Chapter 10 for more detail on the cost pass through mechanism).

The periodic reviews also address the uncertainties arising from the NSW Government's planned energy reform strategy, including the planned privatisation of the Standard Retailers and the sale of trading rights to the state-owned generators. This is scheduled to take place in 2010, after the release of our final determination. Since we will not know the new ownership structure until after the sale is complete, we based our modelling on the current ownership structure. We will update this modelling to reflect changes in the ownership structure as part of our annual periodic review of the total energy cost allowance.

1.13 Non-tariff fees and charges

Consistent with our draft determination, we used the same approach to setting the late payment fee, security deposits and the dishonoured bank cheque fee as we used for the 2007 determination. As a result, the late payment fee will increase by 50 cents to $7.50. The other non-tariff fees and charges remain consistent with the 2007 determination.

1.14 Key dates for the review

We received the terms of reference for this review on 19 June 2009 and were required to issue a draft report within 6 months and a final report 3 months after the draft report. This is a more compressed timetable than for the 2007 review, so we maximised public consultation within the timeframe available. Specifically, we undertook extensive work and consultation on methodology papers and the draft report and draft determination. Together with our consultants, we relied on publicly available information to ensure that stakeholders could engage on the maximum amount of information.

Table 1.9 outlines the timetable for our review.

Table 1.9 Key dates for this review

Key tasks	Time
Receive terms of reference	19 June 2009
Release issues paper	3 July 2009
Receive stakeholder submissions on issues paper	3 August 2009
Release draft methodology paper and invite stakeholder submissions	19 August 2009
Hold public forum on methodology paper	1 September 2009
Receive stakeholder submissions on methodology paper	18 September 2009
Release IPART's draft report and determination and expert reports and invite stakeholder submissions	15 December 2009
Hold public hearing on draft report	2 February 2010
Receive stakeholder submissions on draft report	4 February 2010
Release IPART's final report and determination	**18 March 2010**

1.15 Recommendations to Government

1 That the NSW Government introduce retailer price disclosure requirements for all licensed retailer's main negotiated contract offerings. Retailers should be required to publish a fact sheet for each of its offers on its website, which includes:

– tariff information, being energy consumption (cents per kWh) and supply charge (cents per day)

– discount information

– any discounts, benefits, and fees and charges. 47

2 That the NSW Government implement an online pricing comparator tool to allow consumer and private pricing comparator services to access up to date pricing information. In a given area, the comparator tool should present each of the underlying regulated and negotiated tariffs for the main offerings of retailers:

– on a cents per kilowatt hour basis for consumption

– on a cents per day basis for the supply charge,

with discounts, other benefits, green content and fees and charges also being provided within 24 hours of the prices/ conditions being implemented.

The price comparisons should also be made available through a phone service. 47

3 That the NSW Government consider amending the *Electricity Supply (General) Regulation 2001* to require Standard Retailers to publish their regulated prices and miscellaneous charges on their website within 5 calendar days of obtaining IPART approval. 74

4 That the NSW Government consider specifying in the terms of reference for any future review of regulated retail tariffs and charges (ie, price review post- 2012/13) that the energy purchase cost allowance be based on each Standard Retailers’ net system load profile (NSLP). 84

5 That the NSW Government consider expanding the eligibility for its Energy Rebate to all Commonwealth Health Care Card holders. 182

6 That the NSW Government consider increasing the Energy Rebate. 182

7 That the NSW Government amends the Electricity Supply Act to allow the Standard Retailers to charge a fee for dishonoured non-cheque payments. 195

1.16 What does the rest of this report cover?

The rest of this report is structured as follows:

- Chapter 2 discusses the terms of reference, and explains how we have set and applied our assessment criteria in decision making.
- Chapter 3 discusses our assessment of the effectiveness of retail market competition in NSW. It also sets out our recommendation to the NSW Government about increasing the transparency of retail tariffs, and making it easier for customers to compare retail offerings, to promote competition.
- Chapter 4 summarises our approach to addressing the risks and uncertainties within the determination period, and indicates where within the regulatory package each risk is addressed.
- Chapter 5 discusses our approach to regulating tariffs, including the weighted average price cap and other regulatory mechanisms.
- Chapter 6 focuses on the total energy cost allowance, and explains how we set this allowance by estimating retailers' energy purchase costs and other associated costs, including those related to renewable energy and other green schemes, loss factors and NEM fees.
- Chapter 7 discusses how we set the retail operating cost allowance and explains our estimates of retail operating costs and customer acquisition and retention costs.
- Chapter 8 explains how we set the retail margin allowance.
- Chapter 9 presents the total cost allowances for each Standard Retailer and the resulting regulated retail price controls (R values).
- Chapter 10 details the scope, frequency and other characteristics of the periodic reviews and the cost-pass-through mechanism.
- Chapter 11 analyses the impacts of the determination on small customers.
- Chapter 12 sets out our decisions on regulated non-tariff charges, specifically the late payment fee, dishonoured cheque fee and security deposits.

Appendicies A to I provide additional background information:

- Appendix A Terms of Reference
- Appendix B IPART consideration of main issues raised in submissions
- Appendix C Energy Industry Background
- Appendix D Additional information on the competitiveness of the electricity market
- Appendix E Parameters of the Weighted Average Cost of Capital (WACC)
- Appendix F Additional information on the relationship between electricity consumption and the GDP

- Appendix G Retail operating costs benchmarking data
- Appendix H List of submissions to the review
- Appendix I Additional analysis of customer impacts.

2 Terms of Reference and context for the determination

To guide our analysis and decision-making for this determination, we have carefully considered the terms of reference provided by the Minister for Energy and developed a set of assessment criteria based on the terms of reference and the principles for good regulatory practice. We consider they are also appropriate for the context for the determination, particularly the additional risks and uncertainties involved in forecasting costs.

The sections below explain the terms of reference, and the context for the determination, and set out the assessment criteria that we used in making this final determination.

2.1 Terms of reference

In accordance with his powers under the *Electricity Supply Act 1995,* the Minister for Energy provided terms of reference for our review and determination. These terms of reference specify the matters we must take into account and objectives we should aim to achieve in making the determination. They also set out some requirements related to how we make the determination.

The terms of reference indicate that in making the 2010 determination, we should ensure the aims and approach of the 2007 determination are preserved – and note that these were to promote retail competition by ensuring that regulated tariffs fully reflect the efficient costs of meeting each Standard Retailer's obligations to its regulated customers. They also indicate that the 2010 determination should:

- be consistent with the Government's policy aim of reducing customers' reliance on regulated prices
- result in regulated tariffs that recover the efficient cost of supplying small retail customers, including customers who revert from negotiated tariffs.

In addition, the terms of reference note the importance of preserving the financial viability of Standard Retailers, to ensure the reliable provision of electricity in NSW. They also specify that the efficient cost of supplying small retail customers should be calculated by determining 3 distinct cost components: an energy purchase cost allowance, a retail operating cost allowance, and a retail margin allowance.

2.1.1 Determining the energy purchase cost allowance

In relation to the energy purchase cost allowance, the terms of reference specify that we should:

- use a transparent and predictable methodology to set the allowance at a level that would allow a Standard Retailer to recover the efficient costs of managing the risks associated with purchasing electricity from the National Electricity Market (including the proposed Carbon Pollution Reduction Scheme)
- have regard to the efficient costs of meeting Standard Retailers' other obligations in relation to energy purchases, including those of complying with greenhouse and energy efficiency schemes (including present and future schemes)
- ensure that the allowance for each year is not lower than the least-cost mix of generating plant
- allow for a periodic review of the energy purchase cost allowance including the costs of greenhouse schemes and energy efficiency schemes.

2.1.2 Determining the retail operating cost allowance and retail margin

In relation to the retail operating cost allowance, the terms of reference indicate that these costs include those associated with customer service, finance, IT systems and regulation. They also specify that we should:

- determine this allowance based on the efficient operating costs of a Standard Retailer in NSW and other information on efficient operating costs for retailers
- include customer acquisition costs in the allowance, to ensure that regulated retail tariffs are set at a level that encourages competition.

In relation to the retail margin allowance, the terms of reference specify that we should determine an appropriate allowance giving consideration to any risks arising from supplying regulated customers that are not compensated for through the other allowances.

A copy of the terms of reference is provided in Appendix A.

2.2 Contextual factors

Since the 2007 determination, there have been a number of policy, market and regulatory developments that will affect the electricity market and retail electricity prices over the 2010 determination period. Some of these developments will place significant upward pressure on electricity prices. Some create uncertainties when forecasting the costs Standard Retailers' will incur over the 2010 determination period, and so add to the risks in supplying customers on regulated tariffs.

The major developments include:

- the Federal Government's climate change mitigation strategy, including the planned introduction of the Carbon Pollution Reduction Scheme (CPRS) and the expansion of the Renewable Energy Target (RET)
- NSW Government's planned reforms and restructuring of the energy sector and the changes to the planned phase-out of the Electricity Tariff Equalisation Fund
- the Australian Energy Regulator's final determinations on electricity network tariffs.

The sections below briefly explain these developments, and how they are likely to affect electricity prices over the next years and their implications for the 2010 determination.

2.2.1 The planned introduction of the Carbon Pollution Reduction Scheme

The proposed CPRS will place a price on carbon emissions and set a medium-term national target for emissions reduction. Electricity generators will be required to purchase permits for each tonne of greenhouse gas they emit. This will push up the price of wholesale electricity, and thus the Standard Retailers' costs.

The CPRS also has other implications for the 2010 determination because there is significant uncertainty about its final design, when it will be implemented, and how it will affect electricity wholesale costs and retail prices over the coming years. The Federal Government's *Carbon Pollution Reduction Scheme Bill 2009* [No. 2] (Cth) (the CPRS) being defeated in the Senate on 2 December 2009. However, the Federal Government reintroduced the Bill into Parliament in February 2010. Further, there is speculation about the impact of the CPRS on electricity prices in 2012/13. Therefore, there is significant uncertainty about the CPRS and how it will affect electricity wholesale costs and retail prices over the coming years.

This uncertainty, together with the volatility in the wholesale price of electricity purchased through the National Electricity Market (NEM) over the last few years, will make it more difficult than usual to accurately estimate Standard Retailers' annual energy purchase costs over the determination period.

2.2.2 The expansion of the national Renewable Energy Target

Another important element of the national climate change mitigation strategy is the expansion to the Renewable Energy Target (RET). This target is for 12,500 GWh of Australia's electricity to come from new renewable sources by 2010, rising to 45,000 GWh by 2020.[8] This is much higher than the previous target, which was for

8 http://www.orer.gov.au/legislation/index.html

9,500 GWh of electricity to come from new renewable sources each year from 2010-2020[9].

We have modelled the costs of meeting an efficient Standard Retailer's obligations under the expanded RET and provide for the recovery of these costs through the regulatory package.

We have not incorporated the changes announced by the Commonwealth Government to the RET in February 2010 into regulated retail tariffs from 1 July 2010.[10] The announced changes are for the existing scheme to be split into two parts; including a small scale Renewable Energy Scheme (SRES) and a large scale Renewable Energy Target (LRET).[11] Given the absence of detail in relation to retailers' obligations under the enhanced scheme we have not been able to properly model the impact. Our cost pass through mechanism is capable of incorporating the efficient and incremental costs (subject to a materiality threshold) resulting from changes to the RET once the legislation has been enacted. (Refer section 10.4.5 for detail on the review and approval process for the cost pass through mechanism.)

2.2.3 NSW Government's planned energy sector reforms

The NSW Government is reforming the energy sector. The strategy includes (among other things) transferring the Standard Retailers' operations to the private sector, and contracting the right to sell electricity produced by state-owned generators to the private sector.

The Government has released a series of strategy documents outlining the options and planned approach for this industry reform and restructure.[12] On 1 November 2008, the Premier announced that the NSW Government would proceed with a revised electricity reform strategy which consists of:

- keeping electricity transmission, distribution and generation assets in public ownership
- transferring the electricity retailing operations of EnergyAustralia, Integral Energy and Country Energy to the private sector
- contracting the right to sell electricity produced by state-owned generators to the private sector (the Gentrader model)

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9 The RET scheme expands on the existing Renewable Energy Target (MRET) and absorbs existing and proposed State and Territory renewable energy schemes into a single national scheme.

10 Australian Government – Department of Climate Change, *Fact Sheet: Enhanced Renewable Energy Target*, February 2010.

11 Australian Government – Department of Climate Change, *Fact Sheet: Enhanced Renewable Energy Target*, February 2010.

12 NSW Government, *NSW Energy Reform Strategy: Defining an Industry Framework*, March 2009; NSW Government, *NSW Energy Reform Strategy: International Market Testing Update*, May 2009.

- selling a number of potential development sites for new power stations.[13]

On 5 March 2009, the Government released a strategy document outlining options for the reform of the energy sector in NSW.[14] This paper noted that the primary objective of the energy reform process is to optimise the conditions to ensure private sector investment in generation capacity in NSW is adequate, economic and timely.[15]

On 10 September 2009, the NSW Government released a paper outlining its approach to transactions and market structure. That document specified that[16]:

- There will be 5 Gentrader contracts, ensuring a new generation entrant in the market and therefore increased wholesale competition.
- The 3 retailers (EnergyAustralia, Integral Energy and Country Energy) will be offered in their current configurations, but that EnergyAustralia's gas business may be offered separately, given interest from potential bidders.
- The retail brands will be offered for sale with the retail businesses of EnergyAustralia, Integral Energy and Country Energy.
- Development sites will be offered on an individual basis (separate from the retailers and Gentrader contracts).
- All Gentrader contracts, retail businesses and development sites will be offered to bidders in a simultaneous trade sale process. If the trade sale process does not deliver the Government's objectives, the Government retains the discretion to offer particular assets as part of an Initial Public Offering.

On 18 February 2009, the NSW Treasurer announced that due diligence for the NSW retail electricity and Gentrader transactions will commence towards the middle of 2010, with the transactions to be completed later in 2010.[17]

Until the sale process is finalised, there will be uncertainty about the final structure of the electricity market. This uncertainty affects our review and determination, as the competitiveness of the retail market is one of the key factors we consider in deciding how prescriptive the regulatory control formula should be. In addition, the generation ownership structure affects the Standard Retailers' electricity purchase costs by influencing the bidding behaviour in the NSW market (as captured in the modelling of the market based electricity purchase cost allowances[18]).

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13 NSW Government, *Media Release - Rees delivers to secure the State's energy supply*, 1 November 2008.

14 NSW Government, *NSW Energy Reform Strategy: Defining an Industry Framework*, March 2009.

15 NSW Government, *NSW Energy Reform Strategy: Defining an Industry Framework*, March 2009, p 1.

16 NSW Government, *NSWs Energy Reform Strategy: Delivering the Strategy: approach to transactions and market structure*, 10 September 2009, pp 3-5.

17 http://www.treasury.nsw.gov.au/__data/assets/pdf_file/0003/17733/100218_energy_reform_update.pdf

18 The ownership structure impacts on Frontier Economics' *SPARK* model.

However, we consider the regulatory package for the 2010 period has been developed in a manner that accommodates this uncertainty. For example, the ownership structure is addressed in the annual reviews of electricity purchase allowances.

2.2.4 Changes to the planned phase-out of the Electricity Tariff Equalisation Fund

The NSW Government established the Electricity Tariff Equalisation Fund (ETEF) in 2001 to manage the risks Standard Retailers face in purchasing wholesale electricity for their regulated load. The retailers contribute to and/or withdraw from the fund based on differences between the actual price they pay for wholesale electricity and the cost of this electricity assumed in setting regulated retail tariffs.

At the time of the 2007 determination, the Government planned to phase out the ETEF by June 2010. However, in February 2009, it amended the ETEF Payment Rules to change this plan. More recently, it announced that the fund would be extended until 30 June 2011. The current plan is to gradually phase out the ETEF from 1 July 2010 to 30 June 2011, with a reduction of 20% per quarter over the period.[19]

The phasing out the ETEF affects the 2010 determination to the extent that it impacts on the bidding behaviour and hence the prices in the electricity market.

2.2.5 Australian Energy Regulator’s recent determination on network tariffs

Around half of Standard Retailers’ costs in supplying small retail customers are due to the distribution network and transmission network fees they are charged by the network service providers.

The AER’s Determination on **distribution network charges** provides for the NSW distribution network service providers (DNSPs) to increase the charges they levy on all electricity retailers, including the Standard Retailers, by levels significantly higher than the change in CPI.[20] The NSW distribution and transmission businesses successfully appealed certain aspects in relation to the weighted average cost of capital included in the AER’s April decision. Table 2.1 illustrates the revised average price increases.

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19 NSW Government, *New South Wales Energy Reform Strategy: Delivering the Strategy: approach to transactions and market structure*, 10 September 2009, p 43.

20 AER, *Final Decision – NSW distribution Determination 2009/10 to 2013/14*, April 2009, p xlvii.

Table 2.1 Real average price increases (%) for NSW distributors 2010/11 – 2012/13 (including the price increases from the WACC appeal)

NSW DNSPs	2010/11	2011/12	2012/13
EnergyAustralia	16	16	16
Integral Energy	12	12	1
Country Energy	16	16	14

The AER noted that its decisions reflect the need for significant increases in investment on the electricity networks. This investment is necessary to improve the network security and reliability of supply to meet new licence conditions imposed by the NSW Government.[21]

IPART has previously allowed the applicable network charges to be passed through to regulated retail charges and sees no reason to depart from this approach. Therefore, the network price increases will increase the total retail bill significantly.

2.3 Final assessment criteria

Our final assessment criteria derived from the terms of reference are that the 2010 review and determination on regulated retail electricity tariffs should:

1. Protect small retail customers by:
   a) resulting in prices that recover the efficient cost of supplying small retail customers on regulated tariffs over the determination period
   b) facilitating the development of effective retail competition.
2. Ensure that the package of regulatory measures covers all the efficient costs and relevant risks Standard Retailers are likely to face without double counting.
3. Facilitate reliable provision of electricity by setting prices that would allow an efficient retailer to be financially viable.
4 Be consistent with the aim of reducing customers' reliance on regulated retail tariffs.
5. Preserve the aims and approach of the 2007 determination while recognising the differences between the 2007 and 2010 terms of reference.
6. Provide advice to the Government regarding the impact of the determination on small retail customers.
7. Be consistent with principles of regulatory best practice by:
   a) ensuring that where possible, decisions are made by parties in the best position to make those decisions (avoid micro-management)
   b) being practical, pragmatic and feasible
   c) being simple and understandable

21 AER, *Final Decision - NSW distribution Determination 2009/10 – 2013/14*, April 2009, p xi.

d) being targeted at the regulatory objectives
e) being proportionate with the problem
f) being internally consistent
g) promoting regulatory certainty
h) being as transparent as possible.

We consider these criteria encapsulate the objectives included in the Government's terms of reference, as well as the principles of regulatory best practice. They are not intended to specifically address the contextual factors for the determination; however, the criteria ensure we take the particular risks and uncertainties arising from these factors into account.

We considered submissions that discussed the weightings of objectives from the terms of reference. Specifically, a number of retailers considered that we should give greater weight to facilitating the development of effective retail competition and reducing reliance on regulated retail tariffs. A number of retailers considered that choosing values above the mid-point in the range was appropriate and promoted these objectives.

The Minister for Energy stated[22]:

> I seek confirmation from IPART that in accordance with the Terms of Reference that the final increases to regulated tariffs and charges will be no more than required to ensure the ongoing financial viability of the NSW standard electricity retailers.

As previously mentioned, we had a strong response from individual stakeholders throughout our consultation process. Together with consumer groups including PIAC, EWON, COTA and the CPSA, they raised concerns about the ongoing affordability of electricity, particularly for low income households. Many called for lower price increases.

Ultimately, we carefully applied the terms of reference.

22 Minister for Energy submission (John Robertson, MLC), February 2010, p 1.

3 Effectiveness of retail competition

One of our main considerations in making our final decision on the most appropriate form of regulation for the 2010 determination period is the level of competition in the retail electricity market for each standard supply region. If competition is effective, the Standard Retailers are less likely to be able to set their regulated tariffs significantly above cost-reflective levels. This means that regulation can be more light-handed, as competition will provide customers with choices and limit regulated prices to efficient levels.

We examined the current level of competition, and considered the likely effect of the 2010 determination on competition in each market. This involved identifying the competitive constraints that currently exist, and the constraints that may emerge or subside over the course of the determination period. The section below provides an overview of findings. The subsequent sections summarise our findings on the key factors we considered, including:

- the definition of effective competition
- the definition of the market, including the existence of sub-markets defined along consumption, income, and residential/business lines
- the market structure, including the number of retailers contesting the market, market concentration and barriers to entry
- market conduct, including retailer marketing activity and market information and retailer offers to customers, and
- customer behaviour and outcomes, including customer awareness of full retail contestability, the exercise of customer choice and customer switching behaviour.

It is important to note that our purpose in reviewing retail competition as part of this review is **not** to determine whether it is sufficiently effective for regulation to be phased out. This is the responsibility of the Australian Energy Market Commission (AEMC), which is scheduled to review the NSW retail electricity market in 2011.[23] The NSW Government has already committed to maintaining retail price regulation at least until 2013. We are considering the effectiveness of competition only to help us decide what form of regulation is appropriate from 2010 to 2013 and to review what happened in the 2007 determination.

23 Under the Australian Energy Market Agreement, the AEMC is responsible for reviewing and publicly reporting on the effectiveness of retail competition in all jurisdictions participating in the NEM, for the purpose of removing retail price regulation where competition is effective.

3.1 Overview of final findings

We found that since the 2007 review, the Standard Retailers have continued to lose market share to second-tier retailers. However, Country Energy has retained a more substantial market share in its standard supply area than the other Standard Retailers. EnergyAustralia and Country Energy ceased their marketing activity to small customers in NSW for a period from the end of 2007, and transferred some customers back onto the regulated tariff at the conclusion of their negotiated contracts. Some second-tier retailers have also reported that they have decreased their marketing activity since 2007.

Following large regulated price increases on 1 July 2009, marketing efforts have expanded. Customer switching rates have increased over the second half of 2009 and the proportion of customers on the regulated rates in each of the standard supply areas is declining.

We also found that the market has become less transparent over the 2007 determination period. It is difficult for customers to access tariff information for comparison purposes. In addition, some retailers have moved away from the practice of marketing retail offerings based on a discount relative to regulated tariffs. This is likely to have increased the search costs for customers looking for more competitive offers in the market place. The lack of transparency has also affected the accuracy of pricing comparator services offered by private firms. We consider that if the lack of transparency in the market persists, it may be more difficult to determine that the market is competitive for the purpose of removing retail price regulation.

For customers who have entered the competitive market, outcomes have not been uniformly beneficial. Although a substantial number of customers have continued to enter into negotiated contracts with second-tier retailers at discounted rates compared to the regulated tariffs, some are likely to be paying rates higher than the regulated tariffs. With regard to service offerings, there has been a large increase in the GreenPower or renewable energy content products available to customers, which has increased the level of product diversity to customers.

On balance, our analysis of the available data suggests the competitiveness of the market has not changed significantly since 2007. However, the regulated tariffs will be set at cost reflective levels in each year of the 2010 determination. This is distinct from the 2007 determination, where regulated tariffs were targeted to reach fully cost reflective levels in 2009/10. As mentioned, since 1 July when prices reached cost reflective levels, the level of activity in the market has increased. We also note that Country Energy's continuing tariff rationalisation should bring all individual regulated tariffs[24] in its standard supply area closer to cost-reflective levels, which should allow other retailers to more easily compete with Country Energy in this area. If the government accepts our recommendations on information disclosure requirements and a price comparator service, customer outcomes may also improve.

24 As opposed to average regulated tariffs.

The NSW Government's planned reforms of the state's energy sector (see section 3.4.3) may also affect competition going forward. This reform will most likely lead to a more concentrated electricity retail market, and this would affect some measures of the competitiveness of the market. However, it should also result in a less concentrated electricity wholesale sector in NSW, which should put downward pressure on wholesale costs. But at this stage, it is not possible to determine the competitiveness of the post-sale retail market.

These findings are consistent with our draft determination.

3.2 What is effective competition?

In an effectively competitive market, the scope for participants to exercise market power (eg, by raising prices above the efficient cost level, restricting services, or reducing service quality to increase profits) is restricted by the action of competitors in the market, or by the actions of potential competitors yet to enter the market. Sufficient rivalry or the potential threat of rivalry between businesses should result in goods and services being delivered to consumers at least cost, and lead to product and process improvement tailored to the demand of consumers.

The AEMC recently reviewed the effectiveness of competition in the Victoria and SA electricity markets. These markets were determined to be sufficiently competitive for the purposes of removing retail regulation.[25] As noted above, the AEMC's purpose in reviewing these markets was different to our purpose in reviewing competition in the NSW market. Nevertheless, comparing key indicators across Victoria, South Australia and NSW is useful to gauge the level of competitiveness in the NSW market. This comparison suggests that while the NSW market's performance against several indicators is similar to that of the Victorian and SA markets at the time they were deemed to be competitive, its performance is lower for some key indicators. In particular:

- Switching rates[26] in NSW (13%)[27] are lower than those in Victoria (26%) and SA (17%).
- The proportion of Standard Retailers' customers (in their standard supply areas) on negotiated contracts is much lower in NSW (9%) than in either Victoria or SA (50% and 39% respectively).
- The proportion of all customers on negotiated tariffs in NSW (34%) is also substantially lower than in Victoria (60%) and SA (66%).[28]

25 The South Australian government decided to maintain retail price regulation.

26 Switching rates is defined as the number of people that have switched retailers in a year as a proportion of all NSW customers in that year.

27 Calendar year 2009. The numbers of transferred consumers reported in these statistics represent the number of completed change requests in MSATS for a change of retailer or to create a new second tier connection point. Data Source: AEMO, *Retail transfer statistical data* http://www.aemo.com.au/data/retail_transfers.html, accessed 23 February 2009

3.3 Definition of the market

We consider there are 3 relevant markets for the retail supply of electricity to customers consuming less than 160 MWh per annum in NSW. These are:

- EnergyAustralia's standard supply area which includes Sydney, the Central Coast and Hunter regions
- Integral's Energy's standard supply area which includes South Western Sydney, the Illawarra and South Coast
- Country Energy's standard supply, which covers the rest of NSW.

In reaching this view, we took into account that the relevant market needs to be defined with reference to the most important sources of competition for a retailer or set of retailers. We also took into account the functional, product, geographic and time dimensions of the relevant market. In addition, we considered whether there are separate sub-markets defined along customer characteristics such as income, consumption, and residential or business status within NSW. Our analysis and findings on these matters is provided in Appendix D.

One of our most significant findings was that, for the purposes of this review, there are no separate sub-markets defined along consumption and income characteristics in NSW. We based this finding on information we obtained from the Standard Retailers and other stakeholders and information from our most recent household surveys in the Sydney and Wollongong (2006) and the Hunter, Gosford and Wyong region (2008). While the available information was limited, it does not suggest that certain customer groups such as low-consumption or low-income customers are denied the opportunity to access the competitive market.

For example, information provided by Integral Energy shows that low-income households and pensioners tend to be over-represented among the customers moving from its regulated tariffs to a negotiated contract with another retailer. It considers this is likely to be because these customer groups are more likely to be at home when door-to-door selling occurs. Data provided by the Standard Retailers on customers receiving the pensioner rebate by contract type supports this view.[29] It shows that in all regions, the proportion of customers receiving the pensioner rebate being supplied on a negotiated contract within their standard supply area is higher than the proportion that remain on the regulated tariff (Figure 3.1). Overall, we

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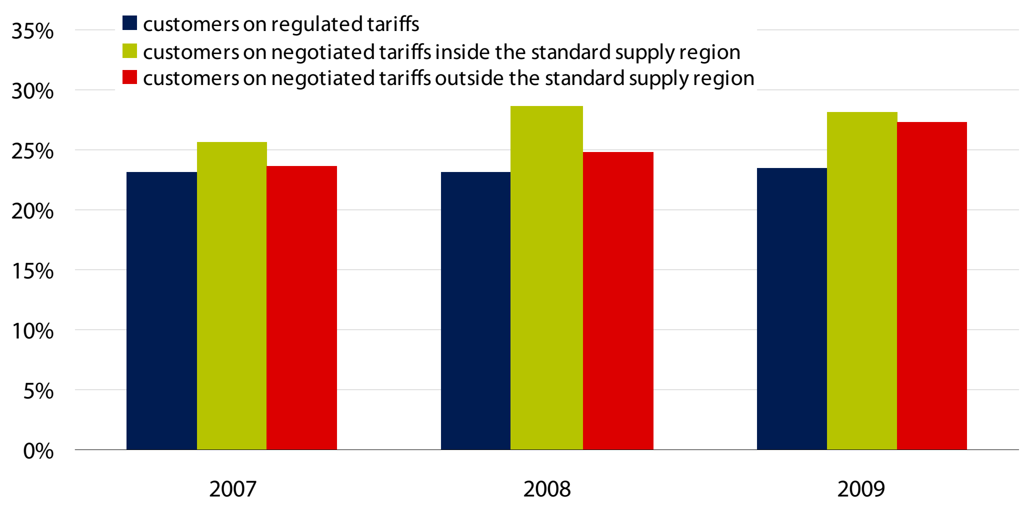
28 AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, First Final Report* 19 September, 2008, pp xi - xii, 22, AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria*, *First Final Report,* 19 December 2007, pp ix, 9, 38-39, 90; ESCOSA, *2007/08 Annual performance report energy retail market*, November 2008, p c, Information returns submitted by standard retailers, July 2009.

29 The statistics include customers who hold a Pensioner Concession Card issued by Centrelink or a Pensioner Concession Card issued by the Commonwealth Department of Veterans' Affairs for customers receiving a War Widows or War Widowers Pension or a Disability Pension at the 'totally and permanently incapacitated' (TPI) rate or 'extreme disablement adjustment' (EDA) rate.

consider that this indicates that lower socio economic customers have access to negotiated contracts.

However, we note that customers with a history of bad debt are less likely to be offered negotiated contracts. Some retailers submitted that they do not offer negotiated contracts to customers who have previously defaulted on payments, or have a bad credit rating. Financial hardship is likely to be one of the main causes of a bad debt history. Therefore, some submissions were concerned that people who would benefit the most from that discounted market offers were least able to access them.[30]

Figure 3.1 Proportion of the Standard's Retailers' residential customers in NSW receiving the pensioner rebate by contract type



Data source: Information provided by standard retailers, July 2009 and February 2010.

The structure of the market will affect the scope for effective competition within it. In assessing the implications of market structure for effectiveness of retail competition, we had regard to the number of electricity retailers operating in the 3 relevant markets in NSW, the current and future concentration of these markets, and barriers to entering these markets.

30 R Craggs submission, February 2010, p 2.

3.3.1 Number of retailers contesting the NSW market

There are currently 26 electricity retailer licence holders in NSW[31] and 12 of these currently supply the small retail market.[32] This is comparable to the number of active retailers in other jurisdictions where full retail contestability has been introduced.

The retailer licence holders participate in the NSW markets to differing degrees. They can be categorised into 3 groups:

- The Standard Retailers, which are obliged to supply and must offer a regulated tariff in their standard supply area. These businesses also act as second-tier retailers outside their standard supply areas and can offer negotiated contracts to customers within their own supply area.
- Mass market second-tier retailers, which are the non-incumbent retailers that aim over time to establish a large customer base.
- Niche second-tier retailers, which focus on specific customer classes or offer specific products and are likely to remain on a smaller scale.

3.3.2 Current market concentration

The more concentrated the market, the greater the potential for firms to exercise market power. Therefore, a market with a considerable number of firms may still not exhibit effective competition if it is concentrated in the hands of a small number of firms.

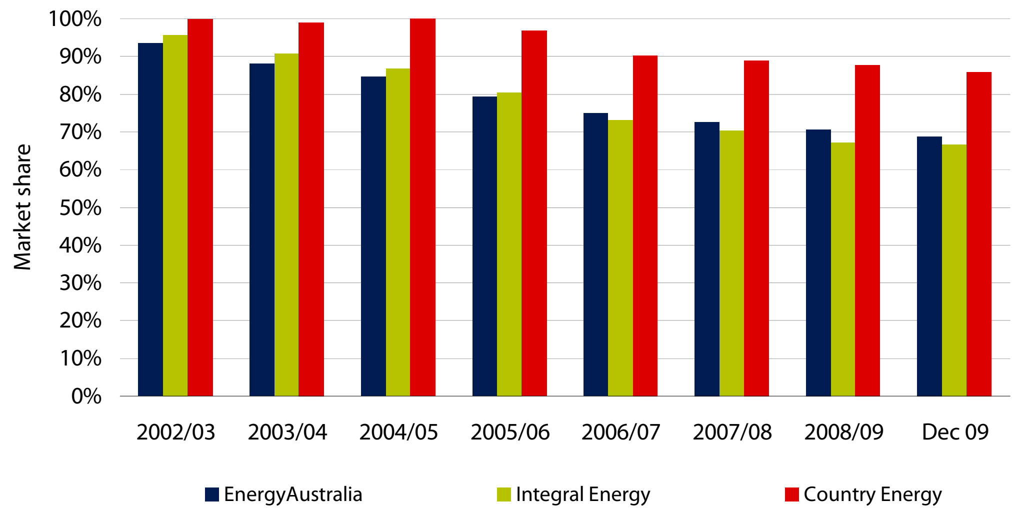
In each of the 3 NSW markets, the Standard Retailers have steadily lost market share to second-tier retailers over the period since full retail contestability began (Figure 3.2). Since the start of the 2007 determination period, they have lost between 3-6% of the market in their supply areas (although Country Energy has retained a higher market share than the other Standard Retailers). As of 31 December 2009, Integral Energy's market share in its supply area was 67%, while EnergyAustralia's was 69% and Country Energy's was 86%. Since the draft report, the overall market share of the Standard Retailer's in their standard supply areas has fallen by 1%, despite gaining around 45,000 additional customers from Jackgreen[33].

31 IPART, *Current Licence Holders*, accessed 23 February 2009, http://www.ipart.nsw.gov.au/electricity/licensing_further_information_1.asp

32 Several of the 26 retailers only supply large customers, and others are licensed but are not yet actively participating in the market.

33 Jackgreen has exited the electricity market since the draft determination. Jackgreen's customers were automatically reverted to the Standard Retailers are the Retailer of last resort arrangements. John Robertson MLC, *NSW Government keeps the lights on for Jackgreen customers* in *Media Release,* 19 December 2009. http://www.industry.nsw.gov.au/__data/assets/pdf_file/0011/313103/nsw-govt-keeps lights-on-for-jackgreen-customers.pdf, accessed 23 February 2009.

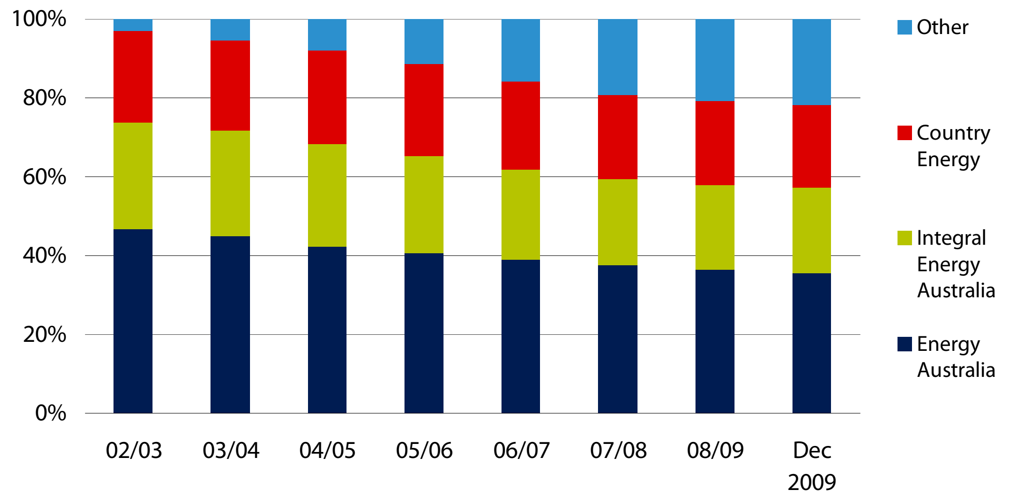
Figure 3.2 Standard Retailers' small customer retail market share in their standard supply area



Data source: Information provided by standard retailers, July 2009 and February 2010.

EnergyAustralia and Integral Energy have also lost market share on an aggregate state-wide basis. Among the new[34] retailers, the incumbent retailers of other states (Origin Energy, AGL and TRUenergy) have been the most successful in increasing their NSW market share over time. (AGL is also the dominant gas supplier in NSW.)

Figure 3.3 Aggregate market shares in NSW small customer retail market



Data source: Information provided by standard retailers, July 2009 and February 2010.

34 New retailers are retailers that do not have a standard supply area in NSW. These are retailers other than EnergyAustralia, Integral Energy and Country Energy.

3.3.3 Future market concentration

We also considered the possible concentration of the market after implementation of the NSW Government's *Energy Reform Strategy* (outlined in Appendix D). This strategy includes the sale of the 3 Standard Retailers, as well significant changes in the wholesale energy sector.

Given that the outcomes of the sale process are not yet know, it is not possible to determine what the concentration of NSW small retail market will be after the sale. We considered some speculative scenarios which suggested there is potential for the market to become considerably more concentrated (see Appendix D). If this proves to be the case, it is not clear what the effect on the NSW market's competitiveness would be. However, we note that the strategy requires specified objectives to be met in the sale process, including that it deliver a competitive retail and wholesale electricity market in NSW.[35] It is the role of the ACCC to assess any future mergers against section 50 of the *Trade Practice Act 1974* which prohibits mergers that would have the effect, or be likely to have the effect, of substantially lessening competition in a market.

3.3.4 Barriers to market entry

Barriers to entry are the characteristics of a market that may make it difficult or less attractive for firms to enter or exit (excluding obstacles that are part of the normal process of entering any market). Generally, a competitive market does not have significant barriers to entry, which helps ensure that the behaviour of market participants is disciplined by the actual or threatened entry of new firms. Where a market does have barriers to entry, there may be more opportunity for participants to exercise market power, reducing the extent to which competitive pricing and product differentiation occurs.

In line with the approach taken in the 2007 determination, we considered whether any of the following barriers to entry limit the potential for competition in the NSW retail electricity markets:

- regulated tariffs that are set at less than cost-reflective levels
- the number of regulated tariffs and geographic factors in the Country Energy standard supply area
- sunk costs[36] and legal or regulatory barriers
- advantages for incumbent retailers.

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35 NSW Government, *NSW Energy Reform Strategy, Delivery of the strategy: approaches to transactions and market structure*, September 2009, p 1.

36 Sunk costs are costs which cannot be recovered by firms when exiting a market. Sunk costs arise because some activities require specialised or firm-specific assets that cannot easily be diverted to other uses. As these assets cannot easily be sold, the existence of sunk costs creates risk for firms entering the market.

Our findings on each of these considerations are summarised below.

Regulated tariffs set at less than cost-reflective levels

In submissions to this review, several retailers contended that the largest barrier to entry was the fact that during the 2007 determination period, regulated tariffs were set below the efficient cost of retailing electricity.[37] They argued this has limited their capacity to offer negotiated tariffs that include sufficient discounts compared to the regulated tariffs.[38]

After considering these retailers views, and considering evidence about changes in marketing activity over the 2007 determination period (discussed below), we don't necessarily agree that the level of regulated tariffs during the 2007 determination period was a barrier to entry. (See Appendix D for more information.) As a result of the price increases from 1 July 2009, we consider that regulated tariffs reached fully cost reflective levels (as was required under the terms of reference for that review). Since the 1 July 2009 price increase, market activity has increased, for example:

- Marketing campaigns have expanded.
- A number of retailers are offering discounts of 5% to 8% below the regulated price.[39]
- Switch rates have increased.
- The proportion of customers on the regulated tariff has fallen.

However, some retailers submitted that even after the 1 July 2009 increases regulated tariffs are not as yet at cost reflectivity levels.[40]

Number of regulated tariffs and geographic factors in the Country Energy supply area

In our 2007 review, we found that Country Energy's large number of regulated tariffs - many of which were not cost reflective – was a potential barrier to entry in the market defined by its supply area. Therefore, the 2007 determination allowed Country Energy sufficient pricing discretion to rationalise its tariff structure. Since July 2004, it reduced its number of discrete regulated tariffs from 358 to 188, and moved around half of these to cost-reflective levels. Country Energy considers that 1 more phase of tariff rationalisation is needed to move all its regulated tariffs to cost-reflective levels. In our view, these changes (and the retailer's plans for continued tariff rationalisation) indicate that Country Energy's regulated tariffs are less likely to be a barrier to entry over the 2010 determination period.

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37 ERAA submission, August 2009, p 2; AGL submission, August 2009, pp 20-21; Origin Energy submission, August 2009, p 9.

38 Country Energy submission, August 2009, p 10.

39 Some retailers are offering discounts on a customers' total bill, while others are offering discounts on the usage component only.

40 TRUenergy submission, February 2010, p 1, Country Energy submission, February 2010, p 6, Integral Energy submission, February 2010, p 1-2.

Other characteristics of the Country Energy supply area may also act as a barrier to entry and prevent the level of competition in this market reaching the same level in other NSW markets over the medium term. For example, the low population density and size of the area make it prohibitively expensive for door-to-door marketers to reach many customers. However, other forms of marketing, such as telemarketing and internet marketing, may reduce the extent to which these factors act as barriers to entry in this market. We note that Country Energy considers that customers in its standard supply area will increasingly self-select competitive offers through telemarketing, direct mail, general advertising, and websites that compare relative service offerings.[41]

Sunk costs and regulatory differences

Potentially, sunk costs or the costs associated with legal or regulatory differences between jurisdictions can act as barriers to entry. However, the number of retailers that have already entered the NSW markets – and the fact that they have acquired a significant number of small customers, particularly in the Integral Energy and EnergyAustralia supply areas – suggests that these costs are unlikely to be material barriers to entry.

This view is consistent with the AEMC's findings that regulatory costs associated with cross-jurisdictional regulatory differences and prudential and working capital requirements were not a material barrier to entry or expansion in the SA retail market.[42] In addition, we note that the AEMC is currently reviewing the role of hedging contracts in potentially reducing the prudential costs of NEM participants[43]. This may reduce the prudential obligations and working capital requirements of the retailers.

Advantages for incumbent retailers

In the 2007 review, we found that the Standard Retailers' access to Electricity Tariff Equalisation Fund (ETEF) could act as a barrier to entry of the NSW retail market, to the extent that the ETEF offsets price for wholesale electricity below market-based prices. However, we consider this barrier has been removed over the 2007 determination period by setting the energy purchase cost allowance in line with market-based costs. For the 2010 determination, this allowance will be set at the greater of the market-based cost or the long run marginal cost. Further, the ETEF is scheduled to be phased out by 30 June 2010.[44] Therefore, we consider that access to the ETEF no longer affords the Standard Retailers any advantage.

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41 Country Energy submission, August 2009, p 11.

42 AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, First Final Report*, 19 September 2008, p 177.

43 The AEMC is currently in the draft report stages of this review.

44 NSW Government, *NSW Energy Reform Strategy, Delivery of the strategy: approaches to transactions and market structure*, September 2009, p 43.

3.4 Retailer conduct

The conduct of retailers within a market affects the level of competition. For example, an effective retail market requires retailers to actively market their products and services, and to provide information to the market so customers are aware of the offers available, and can compare them to identify those that best meet their needs and preferences.

3.4.1 Retailer marketing activity

Electricity is perceived as a homogenous product, and for many small customers their electricity bills represent a low percentage of their total household expenditure.[45] This means the search and transaction costs associated with actively seeking and switching to the most suitable energy product may outweigh the benefits.[46] To overcome this, retailers need to actively market their products and services.

Over the first 2 years of the 2007 determination period, retailer marketing activity appears to have declined across NSW. Some retailers significantly reduced their number of marketing contacts, and others ceased all marketing activity. Both EnergyAustralia and Country Energy declined to offer negotiated contracts within or outside their standard supply areas for extended periods. According to EWON and EnergyAustralia, some customers were forced to stay with or return to their Standard Retailer when second-tier retailers cancelled negotiated contracts or withdrew negotiated contract offers.[47]

We consider that the decision by EnergyAustralia and Country Energy not to offer negotiated contracts may be partly explained by the Government's decision to extend the ETEF arrangements over the 2007 determination period and the level of regulated tariffs. Given the uncertainties in the energy market and the volatility of wholesale prices, these retailers may have preferred to have customers on regulated tariffs in order to access the risk management benefits provided by the ETEF arrangements.[48]

However, the decline in the Standard Retailers' marketing activity may also have been partly due to the Standard Retailers finding it unnecessary to undertake defensive marketing strategies to retain customers. This may indicate a lack of competitive pressure from second-tier retailers. For example, TRUenergy has stated

45 We note that this may not be the case for low-income households.

46 AEMC, *Review of the Effectiveness of Competition in the Electricity and Gas Retail Markets in South Australia, First Final Report,* 19 September 2008, p 15.

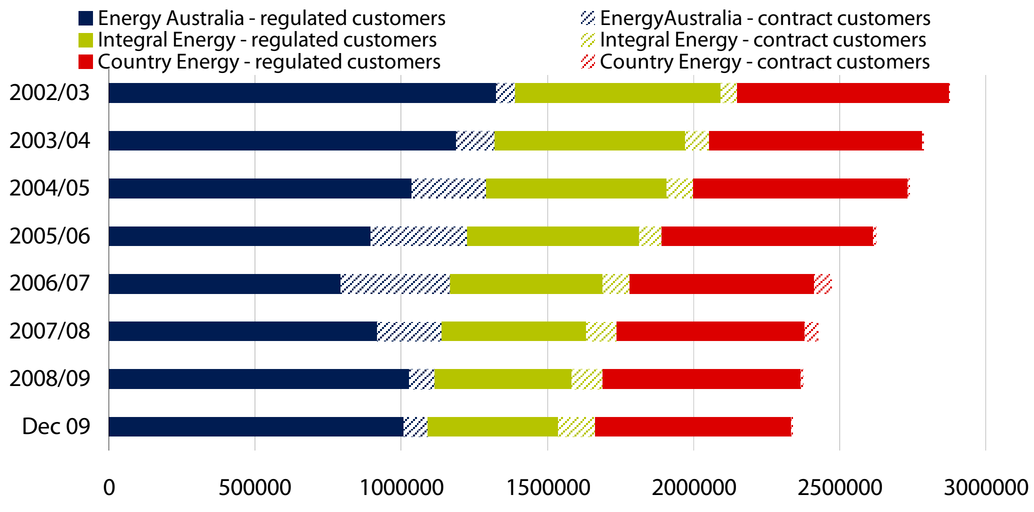
47 EWON submission, August 2009, p 2; EnergyAustralia submission, August 2009, p 8.

48 Only electricity supplied as part of the Standard Retailers' regulated load is subject to the ETEF arrangements, while all retailers are required to contract for electricity supplied under negotiated contracts. Therefore, the arrangements reduce the risks associated with purchasing wholesale electricity to supply regulated customers relative to customers on negotiated contracts.

that they have taken a passive position in the market, reflecting its assessment that regulated electricity tariffs in NSW are currently below cost reflective levels.[49]

As noted above, the Standard Retailers' loss of market share to second-tier retailers was relatively small (between 3% and 6%) in 2007 and 2008, and was no higher than in years when they undertook more marketing. We note that most of the growth in the numbers of customers being supplied on the regulated tariffs of EnergyAustralia and Country Energy which can be seen in Figure 3.4 was due to the retailers' own customers switching from negotiated contracts, rather than customers of second-tier retailers reverting back to the regulated tariff.

Figure 3.4 Standard Retailers' small customer numbers within their standard supply regions by contract type



Data source: Information provided by standard retailers, July 2009 and February 2010.

49 TRUenergy submission, February 2010, p 1.

Retail offers

Retailers principally compete on the basis of price discounts (and a range of non-price incentives). In the NSW retail market, retailers have typically used regulated retail tariffs as the benchmark product, and offered price discounts relative to this benchmark. In 2006/07, we observed that discounts of up to 10% off the regulated tariff were available in the metropolitan market.[50]

During 2007/08 and 2008/09 the size of such discounts generally fell to around 4% to 5%,[51] and several retailers are currently offering discounts of 5% to 8% on the regulated price.[52] However, some retailers have stopped linking their discounts to regulated prices. For example, several second-tier retailers have set their own 'benchmark tariffs' and offer customers a discount relative to these rates when they enter into negotiated contracts. Because these rates are not linked to the regulated tariff, they may change more frequently than regulated tariffs. Further, the level of retailers' benchmark tariffs is often difficult to ascertain – for example, they are not always published on the retailer's website. In our view, offering discounts on this basis can be confusing for consumers. It can mean that they enter into a negotiated contract mistakenly believing that they are being offered a discount on regulated tariffs and are subsequently charged more than the regulated tariff (see section 4.6).

Survey information from South Australia shows that 66% of customers rely on the retailer or a retailer's representative for their main source of information about energy offers, and are unlikely to undertake their own investigations.[53] This suggests that many customers are unaware that they may be paying more than the regulated price. EWON has reported that customers can also be unsure how to obtain further information when they are weighing up whether to sign up for a retail offer. They can be confused about the terms and conditions, the product/s on offer, what the real cost to them is, and how to compare this offer to their present contract or to offers from other providers.[54]

For offers that rely on product differentiation, GreenPower or renewable energy content offers are attracting the most non-price competition in the market. By varying the GreenPower content of the electricity, retailers are able to offer a larger number of products to suit their customers' needs. One retailer is currently still offering 'lifestyle benefits' with its free magazine subscription.

50 IPART, *Promoting retail competition and investment in the NSW electricity industry*, June 2007, p 38.

51 EnergyAustralia submission, August 2009, p 9.

52 Some retailers are offering discounts on a customer's total bill, while others are offering discounts on the usage component only.

53 AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, First Final Report*, 19 September, 2008, p 25.

54 EWON submission, October 2009, p 1.

Market information

An effective retail market requires that customers have sufficient information to make an informed choice. As noted above, most customers are unlikely to undertake their own investigation of alternative energy offers. In our view, a major contributor to this is the lack of readily available transparent price information. There is no requirement in NSW that retailers publish individual tariffs being offered to customers. When prices change, retailers are required only to publish the average variation in rates for each customer class.

PIAC submitted that information about electricity prices on retailers' websites often fails to adequately inform consumers of the price they would pay if they accepted an advertised offer. They found that:

- Some retailers are publishing the level of discount being offered without providing the reference rates.
- Some retailers require potential customers to initiate a 'sign up process' before providing the tariff details, and may request a large amount of personal information as part of this process (including name, data of birth, address, phone number, email address and drivers licence number).[55]

The deficiency of information provided on retailers' websites is significant as the internet is an increasingly important source of information for customers. The AEMC's review of competition in South Australia found that 12% of customers used this source when deciding to change their energy supply arrangements (making it second most common source of information for these customers, after the retailers themselves). It also found that 46% of customers actively seeking information about energy offers used the internet.[56]

We consider that the lack of transparent information in the NSW market increases the search costs for customers. Together with other transaction costs such as termination fees, these costs may exceed the benefits of finding a better offer, which makes customers less inclined to assess alternative offers and so reduces pressure on retailers to engage in competitive behaviour. EWON refers to Ofgem's Energy Supply Probe, which states that customer switching activities may not exert as much constraint on suppliers' prices as it could as customers may be switching on the basis of poor or partial information.[57]

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55 PIAC submission, September 2009.

56 AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, First Final Report,* 19 September, 2008, p 25.

57 EWON submission, February 2010, p 2.

In other jurisdictions, State governments require the Retailers to provide tariff information on their websites, and provide price comparator services that reduce these search costs.[58] However, in NSW, only price comparator services provided by private firms are available. The prices these services quote are not necessarily accurate and up to date, as the services are not endorsed by all retailers. CHOICE submitted that sourcing accurate tariff information is difficult as there is no requirement for retailers to publish their rates.[59] In addition, EWON submitted that some comparator services mistakenly assume that a retailer's own 'benchmark tariffs' are the regulated tariffs, and so incorrectly compute the savings provided by its retail offers.

EWON argued that when customers are signing up for a 3-year negotiated contract with fees such as contract termination penalties, it is critical that the information they are basing their decisions on is accurate.[60] We agree with EWON. We also consider the lack of transparent information and reliable, easy to use price comparator services is a considerable impediment to the further development of effective competition in NSW. To ensure that competition continues to develop and customers have ready access to accurate, up to date information on which to make informed choices, we believe the Government should introduce requirements for retailers to publish information on their tariffs, and provide a price comparator service.[61]

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58 In Victoria, each retailer must publish a standing offer for each region in which they are supplying in the Victorian Government Gazette and provide these tariffs to the Essential Services Commission 1 month prior to the date of effect. Retailers must publish their standing offer tariffs on their websites and a selection of its market offers in a form which is easy for customers to understand, and that should enable comparison between retailers' offers. The Essential Services Commission publishes all of the standard offers and a selection of market offer contracts for each of the retailers on a cent per kilowatt hour basis, and allows customers to compare the annual savings between different offers.
South Australia and Queensland requires that retailers publish a fact sheet, which includes the estimated annual cost of the market contract for a customers at different consumption levels, and other key features. These factsheets must be published on the retailer website. There is no requirement to publish the underlying tariffs. The Essential Services Commission of South Australia and the Queensland Competition Authority publish the annual bill information on their price comparator sites.

59 CHOICE submission, October 2009, p 3.

60 EWON submission, October 2009, p 3.

61 A government endorsed pricing comparator service would not be in competition with commercial services which facilitate customer switches. Its purpose is to provide an accurate source of information.

These recommendations have been supported by EWON, PIAC, Country Energy, the NSW Business Chamber, and a number of individual submissions.[62] Origin Energy submitted that it has no issues with additional price disclosure requirements.[63] The submission from the Minister for Energy agrees with the objective of increasing transparency and flexibility in the types of services available to customers.[64]

The Ministerial Council on Energy (MCE) is currently developing a national energy customer framework (NECF). We understand that the NECF will cover retailer price disclosure and price comparator requirements. Integral Energy and TRUenergy consider that interim arrangements should not proceed in NSW in advance of the national arrangements.[65] However, EWON considers that the lack of certainty surrounding the implementation dates of NECF necessitates the adoption of IPART's recommendation in the meantime.[66] We agree that in an environment of increasing prices and increasing market activity it is critical that consumers have access to accurate tariff information in order to make more informed choices about their energy arrangements. Given that one of the main private comparator services, CHOICE Switch, has recently suspended its operations, we consider that these recommendations should be adopted as soon as possible. However, we recognise that implementing a comparator service will take some time.

Country Energy and Origin Energy considered that modelling the NSW disclosure requirements and comparator services on existing states schemes is likely to minimise compliance costs on retailers.[67] We agree with these retailers.

We note EnergyAustralia's objection to ranking offers as comparisons can fail to value some elements of the offers, including:

- Discounts to the customer outside the first 12 months of the contract.
- Non monetary incentives.[68]

We agree that there is no need for a government comparator service to rank offerings. Rather, it is to provide accurate, readily accessible information.

We also recognise that internet access and use is limited among some demographics.[69] Therefore, in line with COTA's proposal we consider that any published information on the internet must also be available in hard copy by request

62 Country Energy submission, February 2010, p 6; NSW Business Chamber submission, February 2010, p 5; R Craggs submission, February 2010, p 1.

63 Origin Energy submission, February 2010, p 4.

64 Minister for Energy submission (John Robertson MLC), February 2010, p 2.

65 TRUenergy submission, February 2010, p 3, Integral Energy, February 2010, p 9.

66 EWON submission, February 2010, p 3.

67 Country Energy submission, February, 2010, p 6, Origin Energy submissions, February, p 4.

68 EnergyAustralia submission, February 2010, p 41.

69 COTA submission, February 2010, p 3, EMS Australia submission, February 2010, p 1, K Rollins submission, January 2010, p 4.

for those customers who do not have access to the internet.[70] We also note that the Government has an Energy Information phone line which may be able to give customer advice on market offers. Although IPART could, if requested by the Government, administer the on-line price comparator service, we do not think that we are well placed to administer a phone service.

Recommendation

1 That the NSW Government introduce retailer price disclosure requirements for all licensed retailer's main negotiated contract offerings. Retailers should be required to publish a fact sheet for each of its offers on its website, which includes:

   – tariff information, being energy consumption (cents per kWh) and supply charge (cents per day)

   – discount information

   – any discounts, benefits, and fees and charges.

2 That the NSW Government implement an online pricing comparator tool to allow consumer and private pricing comparator services to access up to date pricing information. In a given area, the comparator tool should present each of the underlying regulated and negotiated tariffs for the main offerings of retailers:

   – on a cents per kilowatt hour basis for consumption

   – on a cents per day basis for the supply charge,

   with discounts, other benefits, green content and fees and charges also being provided within 24 hours of the prices/ conditions being implemented.

   The price comparisons should also be made available through a phone service.

3.5 Consumer behaviour and outcomes

For competition to be effective, a market needs to be characterised by informed and active consumers willing and able to respond to offers for the supply of electricity, at prices and on terms and conditions that best meet their needs. Where enough consumers respond to price or quality differences by switching to products that better suit their needs, retailers will be encouraged to respond to these signals or risk losing customers and market share. Where this is not the case, retailers may develop a degree of market power that may lead to poorer price and service outcomes for customers.

There is some evidence that this kind of market power currently exists in the NSW market. For example, as discussed above, several second-tier retailers have begun setting their own 'benchmark tariffs' and offering customers a discount relative to these tariffs rather than regulated tariffs, without necessarily publishing their

70 In addition, COTA has suggested that any customer website is attached to a telephone line accessible by the Telephone Interpreter Service (TIS) for those customers who do not speak English and TT for hearing and speech impaired customers.

benchmark tariffs. Combined with the lack of transparent, easy to access information for comparing different tariffs (also discussed above) this means customers may enter into a negotiated contract and end up paying more than they would on the regulated tariff.

Given this evidence, it is not clear that competition is necessarily leading to uniformly better outcomes for consumers. This is of particular concern given that low-income households and pensioners are proportionately more likely to be offered and accept negotiated contracts (see section 3.3).

3.5.1 Customer awareness

The results of IPART's household surveys in 2006 and 2008 indicate there is a very high degree of awareness of full retail contestability. However, while most customers are aware they can choose their own retailer, other evidence suggests many are confused about the relationship between the regulated tariffs and the negotiated prices, and the role of the regulator in setting these prices. For example, EWON submitted that it is receiving complaints about marketers creating confusion about the different roles of distributors and retailers, and over the proposed sale of the Standard Retailers to encourage customers to sign a negotiated contract.[71]

3.5.2 Exercise of customers' choice

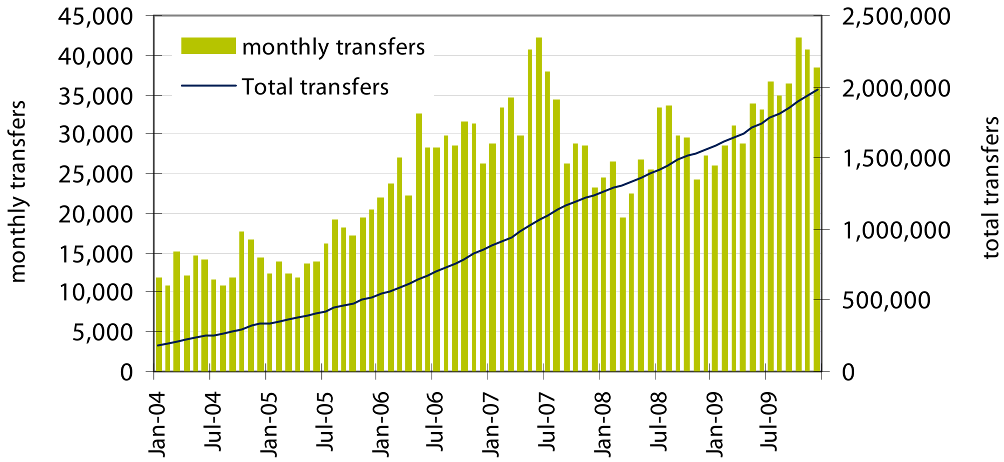
Retailers will not be exposed to competitive pressure unless customers participate in the competitive process by switching, or are prepared to switch retailers. Consumers preparedness to switch retailers will inhibit retailers from increasing individual tariffs above efficient costs.

Figure 3.5 shows the number of all customers in NSW who have switched retailers since the beginning of 2004. In 2009, 13% of all customers in NSW transferred to a different retailer. However, these switching statistics include large customers. In addition, they are not broken down by standard supply area, so are of limited use in examining the effectiveness of the each individual market.

Figure 3.6 shows that in 2008/09 around one-quarter of all customers who switched retailers were small customers reverting back onto a regulated tariff.

71 EWON submission, February 2010, pp 2, 3.

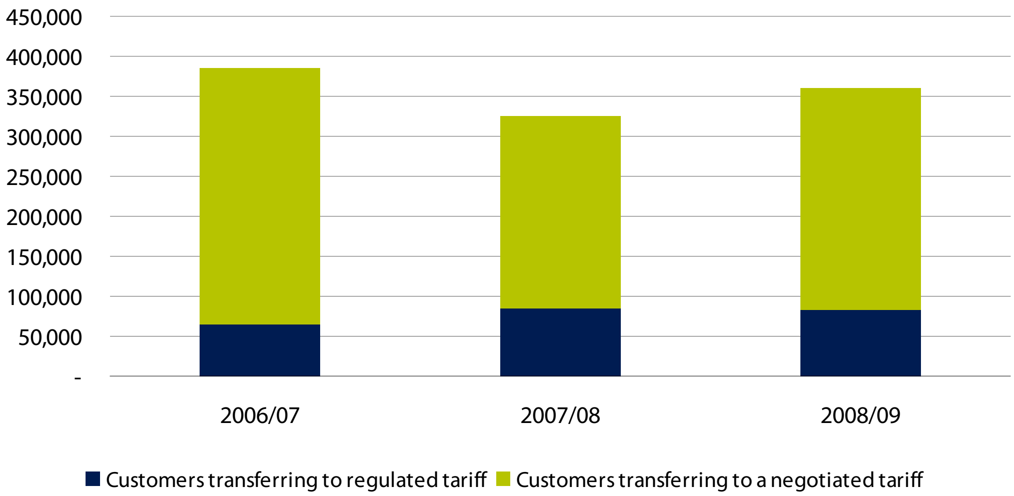
Figure 3.5 Number of all customers in NSW switching retailers, January 2004 – December 2009



Note: These numbers exclude small customers moving from a regulated tariff to a negotiated contract with their Standard Retailer.

Data source: NEMMCO, AEMO.

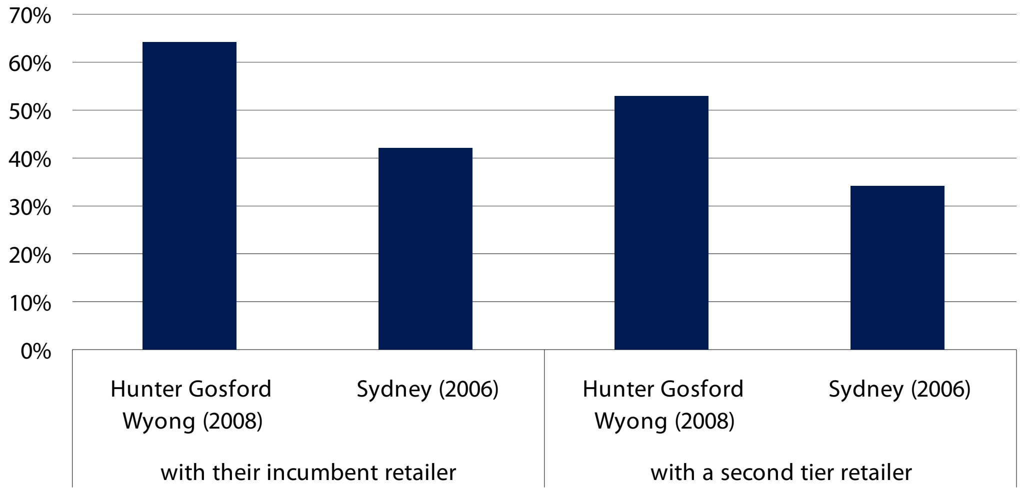
Figure 3.6 Number of all customers in NSW transferring between retailers by contract type, 2006/07 – 2008/09



Data source: Information provided by standard retailers, September and October 2009.

While small customers are unlikely to seek out competitive market offers (discussed above), they appear to be willing to participate in the competitive market if approached directly by a retailer. Figure 3.7 shows that a large proportion of the respondents to our 2006 and 2008 household surveys have switched onto a negotiated contract at least once after being approached since full retail contestability was introduced.

Figure 3.7 IPART household survey findings on proportion of customers who have switched to a negotiated contract after being approached



Data source: IPART household surveys.

The Standard Retailers' data suggests that between 2006/07 and 2008/09, 8% to 12% of small customers switched retailers after being approached by a door to door marketer. This is lower than the proportion suggested by our household survey results. This may reflect the fact that some households approached by door to door marketers are already locked into a negotiated contract. The 2008 Hunter, Gosford and Wyong survey found that of those households who had switched, 84% had switched only once, and 1% to 2% had switched more than twice.[72]

One individual considered that there may be reluctance by some consumers to take up negotiated contracts due to the risks associated with these contracts, stating:

> … the average small customers knows that entering unregulated market contracts comes with risks ... and customers face steep early termination fees if they move house or otherwise exist a contract before the terms of the contract expires.[73]

However, overall significant numbers of small customers in NSW have responded to competitive offers and exercised choice between available offers when approached by retailers and given sufficient incentive. Approximately 34% of these customers were on negotiated contracts as of December 2009, and 63% of these were on negotiated contracts with second-tier retailers. However, we note the proportion of small customers on negotiated contracts in NSW is substantially lower than in South Australia (66% as at June 2008) and Queensland (45% as at March 2009).[74]

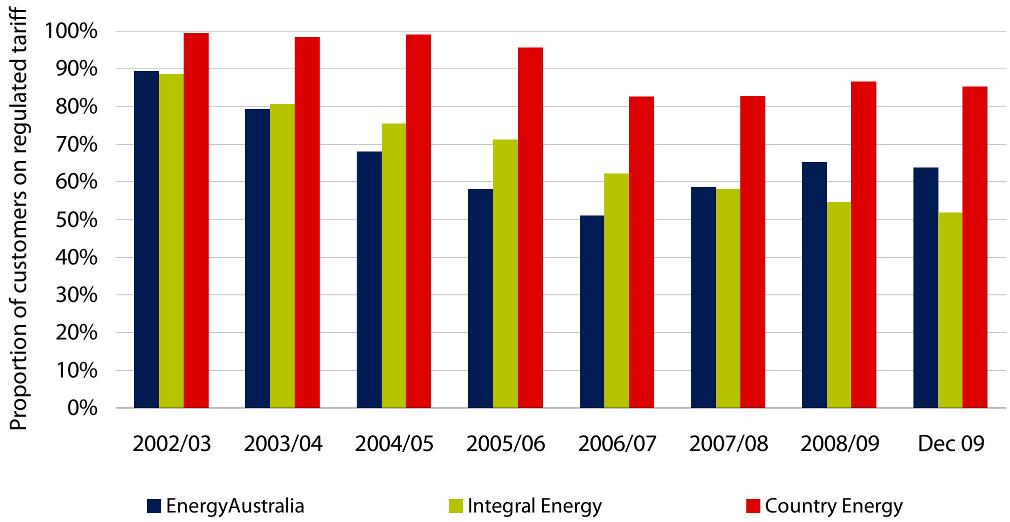
72 IPART, *Residential energy and water use in the Hunter, Gosford and Wyong, Results from the 2008 household survey*, December 2008, p 94.

73 K Rollins submission, January 2010, p 2.

74 Queensland Competition Authority, *Market and non market customers March quarter 2009*, http://www.qca.org.au/files/ER-FRC-QCA-CustStats-MarQTR-0709.pdf.

Figure 3.8 shows the proportion of small customers on regulated tariff since full retail contestability. It shows that between 2007 and mid- 2009, this proportion increased in the EnergyAustralia and Country Energy standard supply areas. One reason for this may be that the Standard Retailers in these areas stopped offering negotiated contracts for much of this period, as discussed in section 3.5.1. Since July 2009, there has been a decline in the proportion of EnergyAustralia and Country Energy customers being supplied on the regulated tariff. We note that since July 2009, EnergyAustralia has offered negotiated contracts to customers outside of their standard supply region.

Figure 3.8 Percentage of small customers in NSW on the regulated tariff



Data source: Information provided by standard retailers, July 2009 and February 2010.

3.5.3 Satisfaction with negotiated contracts

Our 2006 and 2008 household surveys found that almost 70% of households that had entered into a negotiated contract did so because they thought it would lead to lower electricity bills. However, the 2008 survey found that only 33% felt that their bills had gone down and 18% felt that their bills had increased.[75]

Nevertheless, these surveys found that of households on negotiated contracts:

- 60% indicated that they were satisfied with the contract
- 33% said they didn't care either way
- 7% said they were unsatisfied.[76]

75 IPART, *Residential energy and water use in the Hunter, Gosford and Wyong,* December 2008, p 96.
76 *Ibid*, p 97.

4 Analysis of risks retailers face over the determination period

Like all regulated businesses, the Standard Retailers face risks in supplying small customers on regulated tariffs. The revenue they generate from this activity is constrained by our determination, and to make this determination we have make assumptions about the factors that will influence their costs over the determination period – such as their forecast regulated load profile and the forecast level and volatility of wholesale electricity prices over this period. There is always a risk that these assumptions will prove to be inaccurate and, as a consequence, that the Standard Retailers significantly over or under recover their efficient costs for the determination period.

Some of this risk is systematic risk – that is, it arises from the retailers' exposure to overall economic conditions. For example, this includes the risk that small customers' demand for electricity will fall when the economic conditions worsen. However, some is non-systematic risk – it arises from events not related to overall economic conditions that may specifically influence the retailers' costs and/or regulated load. These events may be unforeseen, such as major changes in weather patterns, generation capacity, or regulatory requirements. Or they may be foreseen but uncertain, such as the proposed introduction of the CPRS, and the proposed reforms of the NSW energy industry.

In line with our terms of reference for this determination, we have analysed all the potential risks retailers face over the 2010 determination period, to determine how best to address each relevant risk. We have also ensured that the determination addresses each of these risks, and that the retailers are compensated only once for each risk that is allocated to them.

The sections below outline the approach we used to analyse the risks and summarises the results of this analysis, including how we have addressed each risk.

4.1 Approach for analysing the risks

To analyse the risks faced by Standard Retailers over the 2010 determination period and determine how best to address each of these risks, we:

1. Explicitly identified and described each risk related to forecasting the cost allowances.

2. Identified the cause of each risk including whether it is systematic or non-systematic and characterised its likely impact on retailers and customers.
3. Determined the most appropriate cost allowance or other regulatory mechanism for addressing each risk, taking into account the general principles of risk allocation, the impacts on regulatory certainty, the incentives created for retailers, the implications for administrative costs, and the expert advice and stakeholder comments we received.
4. Ensured that there is no double counting – that is, that retailers are compensated for each risk allocated to them once only, and are not compensated for risks allocated to consumers.

This approach is consistent with the draft determination but slightly different from the one we proposed in our draft methodology paper. When preparing the methodology paper we were expecting that changes to the energy purchase cost allowance arising from the annual reviews would be subject to a materiality threshold. We therefore proposed to distinguish between 'normal variations' that typically occur within a predictable range and 'step changes' that are significant changes outside the range of normal variations. However, in light of our draft decision not to impose a materiality threshold for the annual review of the total energy costs allowance, we now consider this distinction is no longer necessary.

We consider this approach is consistent with the terms of reference for the 2010 determination.

4.2 Summary of the results of this analysis

In general, we decided that it is appropriate to allocate all systematic risks to the Standard Retailers and compensate them for these risks through the retail margin allowance. We took account of these risks in determining the appropriate level for this margin (see Chapter 8).

We also decided it is appropriate to address some of the non-systematic risk in setting the allowances for total energy costs or retail costs, and some by including additional regulatory mechanisms such as periodic cost reviews or a cost-pass-through mechanism in the regulatory package. In general, we decided to allocate the non-systematic risks that stem from proposed regulatory, market or policy developments (such as the CPRS) to consumers, and address these risks through periodic cost reviews. This will ensure that neither the retailers nor consumers are unfairly affected if these developments do not go ahead as proposed, or developments mean that our forecasts need to be updated.

Table 4.1 summarises our analysis and decisions on the risks we have considered in making the final determination. Our decisions are also discussed in more detail within the chapters that follow.

Table 4.1 Key risks considered in making the final determination

Risk	Description	Comments	IPART's final decision on addressing the risk
Variation in load profile of regulated customer base	The actual load profile is different to that assumed in setting the regulated retail tariff.	Could be either a cost or benefit for retailers Some systematic risks due to changes in economic conditions Some non-systematic risks due to changes in weather patterns or technology, or generation availability, etc	Allocate systematic risk to retailers and address through the retail margin Allocate non-systematic risk to retailers and address by: ▾ Using forecasts of regulated load that reflect historic volatility in calculating the LRMC of generation and the market-based electricity purchase cost. Three load shapes (10, 50 and 90 Probability Of Exceedance) were used for each business ▾ Ensuring the market-based electricity purchase cost allowance (including the volatility allowance) captures the correlation between load and price volatility
Variation in wholesale electricity spot and contract price	The actual wholesale electricity spot and contract price outcomes are different to that assumed in setting regulated retail tariffs.	Could be either a cost or benefit for retailers Some systematic risk due to changes in economic conditions Some non-systematic risk due to changes in total system demand, generator availability, weather, gas prices, etc Some non-systematic risk due to market, policy and regulatory developments	Allocate systematic risk to retailers and address through the retail margin Allocate non-systematic risk due to changes in demand, generation availability etc to retailers and address by: ▾ Estimating market–based electricity purchase cost based on modelled half hourly pool prices that reflect historic and likely future volatility and contracts calculated at a premium to pool price ▾ Capturing the correlation between load and price volatility in the market based electricity purchase cost allowance

Risk	Description	Comments	IPART's final decision on addressing the risk
			Allocate non-systematic risk due to market, policy and regulatory developments to customers and address by providing for annual review of total energy cost allowance
Change in load profile of regulated customer base arising from change to threshold for eligibility	The forecast load profile changes significantly due to government raising or lowering the threshold for eligibility for regulated retail tariffs from current 160 MWh per annum	Could be either a cost of benefit for retailers Non-systematic risk due to unforeseen regulatory or taxation change event	Allocate to customers and address by providing for a cost-pass-through mechanism (subject to a materiality threshold)
Change in volatility of wholesale electricity spot and/or contract price	The volatility of prices changes significantly – but the average price does not change	Could be a cost to retailers, as increase in volatility without a change in the average price is likely to increase retailers' short-term working capital requirements Non-systematic risk due to changes in total system demand, generator availability, weather, gas prices, etc	Allocate to customers and address by providing for annual review of total energy cost allowance (including the volatility allowance in the market-based cost)
Material increase in customer defaults and bad debts	Significant change in bad debt and default rate among regulated customers	Some bad debt/default is normal part of doing business, but significant increase in rate would be a cost to retailers Could be a systematic risk, due to changes in economic conditions Could also be a non-systematic risk due to a significant rise in electricity prices as a result of CPRS and other developments	Allocate systematic risk to retailers in setting the margin Allocate normal business risk to retailers and address in setting retail operating cost allowance

Risk	Description	Comments	IPART's final decision on addressing the risk
Change in industry structure	The industry structure differs from that assumed in the determination as a result of NSW Energy Reform Strategy	Could cost or benefit retailers by affecting wholesale electricity costs (including by changing behaviour of market participants), and retail operating costs Non-systematic risk due to market, policy, regulatory developments	Assume current ownership and structure in setting energy cost allowance for 2010/11 (because the sale process will not be finalised) Allocate risk of change to customers and address by providing for annual reviews of energy cost allowance, including updating modelling inputs related to ownership and structure for the market-based purchase cost The retail operating costs would not be reviewed unless a regulatory or taxation change event occurred
General business risk	Economic risk (unexpected changes in interest rates, exchange rates); credit risk; operational risk (equipment failure, fraud); liquidity risk (inability to pay bills)	Could be a cost or benefit to retailers Mainly a systematic risk due to changes in economic conditions	Allocate systematic risk to retailers and address through the retail margin Allocate any non-systematic risk to retailers and address in setting the retail operating cost allowance
Change in regulations, legislation or taxation	Government imposed changes in regulatory, legislative or taxation environment (including changes to the design of the CPRS or RET) that were unanticipated at the time of making the determination	Could be a cost or benefit to retailers Non-systematic risk due to a unforeseen regulatory or taxation change event	Allocate risk that such an event leads to material change in retailers' costs to customers and address by providing for a cost-pass-through mechanism, subject to a materiality threshold
Change in the price of carbon	Updated forecasts of the 2013 price of carbon differs from that assumed in setting regulated retail tariffs	Cost be a cost or benefit to retailers Non-systematic risk due to market, policy and regulatory developments	Allocate to customers and address by providing for a special review of the carbon price in time for potential price change on 1 January 2013 (subject to a materiality threshold)

5 The form of regulation

The form of regulation can be defined as the rules and methodologies used to set, monitor and adjust the price of regulated services over a regulatory period. In considering which form of regulation to use for the 2010 determination period, we took the form of regulation for the 2007 period as our starting point. We assessed whether this approach needs to be changed or enhanced to better address the terms of reference for the 2010 determination or take account of the likely level of competition over this period and other contextual factors. Based on this assessment, we made final decisions on:

- which retail electricity tariffs will be regulated
- the main form of regulation to be used in setting and adjusting these tariffs
- whether to impose constraints in addition to this form of regulation
- key dates for adjusting regulated retail tariffs during the determination period.

The sections below provide an overview of these final decisions and discuss each decision in more detail.[77]

5.1 Overview of final decisions on form of regulation

Our final decision is to continue to regulate all existing regulated retail tariffs for small customers who have not entered a negotiated electricity supply contract, or who have returned from a negotiated contract to a regulated retail tariff. We will also continue **not** to regulate the green premium paid by customers on regulated tariffs who opt for a proportion of their electricity to come from renewable or 'green' energy sources.

In relation to the form of regulation, our final decision is to continue allowing the Standard Retailers to set regulated tariffs subject to a weighted average price cap (WAPC). We consider this form of regulation sufficient to ensure individual regulated tariffs are not set significantly above or below the cost-reflective level, given the level of competition in the NSW retail market (see Chapter 3), the small number of regulated retail tariffs in the 2 metropolitan markets and our final decisions on other elements of the regulatory package. We also consider a WAPC

[77] Chapter 12 addresses the other element of regulated services, specifically non-tariff charges (or miscellaneous charges), including our decisions on the maximum allowable non-tariff charges included in the *Electricity Supply Act 1995*.

provides the flexibility retailers need to rebalance and restructure their regulated tariffs so as to achieve cost-reflectivity and promote competition, in line with our terms of reference and assessment criteria.

In relation to constraints in addition to the WAPC, our final decisions are:

- not to impose additional price limits on the retail component of this price cap, or on the change in individual customer bills
- to allow the Standard Retailers to rationalise their regulated retail tariffs, and remove obsolete tariffs, provided they continue to offer at least one regulated tariff to small retail customers
- not to allow Standard Retailers to introduce new regulated tariffs, except where there are exceptional circumstances and they have obtained IPART approval.

However, given our finding that the level of competition in Country Energy's supply area continues to be lower than in the 2 metropolitan markets, we consider additional consumer protection measures are needed in that area. Our final decisions are to:

- continue to subject Country Energy to the 'threshold price increase test' if it proposes to increase an individual regulated tariff by more than the average maximum change allowed under the WAPC + 5%
- continue to require Country Energy to obtain IPART's approval if it proposes to remove a regulated tariff and transfer customers on that tariff to another regulated tariff with a different price structure and/or level.

In relation to the date on which regulated retail tariffs will change during the determination period, our final decisions are to maintain a 1 July price change for 'normal changes', but to bring forward the annual price compliance process to facilitate the development of the competitive market. To this end, we have made a final decision to recommend that the NSW Government consider amending the *Electricity Supply (General) Regulation 2001* to require Standard Retailers to publish their regulated retail tariffs and non-tariff charges (miscellaneous charges) on their website within 5 calendar days of IPART approving them.

These decisions are consistent with those set out in our draft report and were made after careful consideration of the issues raised in submissions. Appendix B provides a summary of submissions and our response to the submissions.

Please note that we have also decided to maintain the cost-pass-through mechanism that allows the Standard Retailers to pass through to customers material increases or decreases in costs associated with defined regulatory and taxation change events. Our final decisions on this mechanism are discussed in Chapter 10.

5.2 Tariffs to be regulated

IPART's final decisions are that:

- All existing regulated retail tariffs for small customers who have not entered into a negotiated electricity supply contract, or who have returned from a negotiated contract to a regulated retail tariff, will continue to be regulated.
- The green premium paid by customers on regulated tariffs who opt for a proportion of their electricity to come from renewable or 'green' energy sources will remain unregulated.

The terms of reference require IPART to determine regulated retail tariffs and regulated retail charges to apply to small retail customers in each standard retail supplier's supply district in New South Wales for the period from 1 July 2010 to 30 June 2013. However, they do not provide guidance on which tariffs or components of tariffs should be regulated. We could, for example, continue with the existing regulated tariffs. Alternatively, we could establish a limited number of new regulated tariffs and require all customers to actively choose to move to the new regulated tariff or a negotiated contact (the 'opt-in' model).[78]

In deciding which tariffs or components of tariffs should be regulated for the 2010 determination period, we considered the benefits of moving to an 'opt-in' regulated retail tariff model. We have previously noted that an 'opt-in' model has several benefits, including that it:

- ensures that **all** regulated tariffs are cost reflective[79]
- reduces the number and variety of regulated tariffs (which improves transparency and makes it easier to compare these tariffs with competitive offers), and
- reduces customers' reliance on regulated tariffs.

In its submission on our draft report Origin Energy noted these benefits.[80]

However, an opt-in model also has potential disadvantages. First, unless there is a high level of awareness among customers on regulated tariffs about their current electricity supply arrangements, and the alternative arrangements available in the competitive market, this model could lead to poorer customer outcomes. In addition, as Chapter 3 discussed, the transparent, easy to understand market information customers need to make informed decisions under this model is not currently available.

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78 Under this option, the Standard Retailers would have discretion over whether they continued to offer the existing tariffs and at what level.

79 Previously there were a significant number of tariffs that were not set at cost reflective levels, particularly in Country Energy's standard supply area. The Standard Retailers have broadly addressed this issue over the 2007 – 2010 Determination.

80 Origin Energy submission, February 2010, p 4.

Second, the opt-in model is not consistent with the approach of the 2007 determination, and so to that extent would not be consistent with our terms of reference for the 2010 determination. It would also necessitate changes to the broader regulatory framework, including changes to the Standard Retailers' licences and the use of standard form customer contracts. While the planned phase-out of the ETEF would reduce some of the potential complications associated with the opt-in approach, changes to the broader regulatory framework would still be required.

Stakeholders expressed mixed views on an opt-in model. Several submitted that this model would reduce customers' reliance on regulated tariffs and be an appropriate transition to a deregulated retail energy market.[81] For these reasons Origin Energy questioned our draft decision to continue to regulate all existing regulated retail tariffs for small customers.[82] However, EnergyAustralia, Country Energy and PIAC noted the risks and complications outlined above, and therefore were not in favour of adopting this model.[83] PIAC noted low levels of customer interest in actively choosing an energy supplier and submitted concerns over the level of transparent market information available to customers to assist them making a decision.[84]

On balance, we consider that the benefits of the opt-in approach are likely to be outweighed by the administrative and customer costs. Consistent with our draft decision, our final decision is therefore to continue to regulate all existing regulated retail tariffs for small customers who have not chosen to enter a negotiated electricity supply contract, or who have returned from a negotiated contract to a regulated retail tariff.

In relation to our final decision not to regulate the green premium, we note that this decision is consistent with the 2004 and 2007 determinations. We consider that as the green premium is paid only by customers who voluntarily choose to have it added to the regulated tariff, it is not appropriate or necessary to regulate it. We note that stakeholders who commented on this issue supported the voluntary green premium remaining unregulated[85] and supported our draft decision on this matter.[86]

5.3 Main form of regulation

IPART's final decision is to continue regulating retail tariffs using a weighted average price cap (WAPC) that allows the Standard Retailers to set individual regulated tariffs subject to this cap.

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81 Origin Energy submission, August 2009, p 12 and TRUenergy submission, August 2009, p 4.

82 Origin Energy submission, February 2010, p 4.

83 EnergyAustralia submission, August 2009, p 12; Country Energy submission, August 2009, p 13 and PIAC submission, August 2009, p 3.

84 PIAC submission, February 2010, p 3.

85 For example, EnergyAustralia submission, August 2009, p 12; AGL submission, August 2009, p 23.

86 Origin Energy submission, February 2010, p 4; Country Energy submission, February 2010, p 7, EnergyAustralia submission, February 2010, p 42.

Under a WAPC approach, IPART determines the maximum average percentage by which each Standard Retailer can increase its regulated tariffs (weighted by the relevant quantity) in each year of the determination period. The Standard Retailer can then adjust the level and structure of individual regulated tariffs as it sees fit, provided that on average, these tariffs do not increase by more than the maximum percentage. This is a more light-handed approach than IPART determining the level and structure of individual tariffs, and is consistent with the approach we used in the 2007 determination.

We consider that continuing to use a WAPC form of regulation is consistent with our terms of reference and assessment criteria for the 2010 determination. In our view:

- A WAPC facilitates the setting of individual tariffs to reflect the underlying costs of supply by providing retailers with flexibility to adjust these tariffs in response to changes in their cost base. This flexibility also facilitates the rationalisation of regulated tariffs, which is important for encouraging the development of effective retail competition. We note that several stakeholders, including all 3 Standard Retailers, expressed support for a WAPC on these grounds.[87]
- When combined with other elements of our final regulatory package, a WAPC is sufficient to protect small customers from the risk that Standard Retailers will set some individual tariffs significantly above the efficient cost of supply.
- A WAPC preserves the approach used to regulate retail tariffs under the 2007 determination.

In their response to the draft decision retailers supported the continuation of the WAPC noting the flexibility it provides to restructure and rebalance tariffs.[88] However a number of stakeholders including the Toronto Assistance Centre expressed concern that the WAPC provides retailers with too much flexibility, allowing them to impose pricing structures that it considers are unfair and inequitable, particularly the structure of the regulated time-of-use tariffs.[89]

In reaching our view that a WAPC provides sufficient customer protection, we considered our findings in relation to the effectiveness of competition in the NSW retail electricity markets. As Chapter 3 discussed, the overall competitiveness of the market has not changed significantly since we made our 2007 determination. We have found no evidence of certain customers being segmented and charged prices

87 EnergyAustralia submission, August 2009, p 14; Integral Energy submission, August 2009, p 4; Country Energy submission, August 2009, p 14; AGL submission, August 2009, p 24; and Origin Energy submission, August 2009, p 13.

88 Origin Energy submission, February 2010, p 4; EnergyAustralia submission, February 2010, p 42; County Energy submission, February 2010, p 7; Integral Energy submission, February 2010, p 9.

89 Toronto Assistance Centre submission, February 2010, pp 3-4.

significantly above the efficient costs of supply.[90] Importantly, we consider that our 2010 determination will facilitate an increasingly competitive market. In addition, we note that the NSW Government's *Reform Strategy* is intended to deliver a competitive retail and wholesale electricity market in NSW.[91]

We also note that in the metropolitan area, the vast majority of regulated customers are on the Standard Retailers' main regulated residential or business tariff. For example:

- around 87% of EnergyAustralia's regulated residential customers are on the *Domestic All Time* tariff
- over 99% of Integral Energy's regulated residential customers are on the *Domestic* tariff.

This means there is very little scope for these retailers to segment customers, including those who may be less likely to receive competitive offers, and increase individual tariffs by significantly more than the average maximum increase allowed under the WAPC. In addition, as we have decided to maintain the existing constraints on introducing new regulated tariffs (see section 5.5.2), this will not change over the 2010 period.

The situation in Country Energy's supply area is different. Only 47% of its regulated residential customers are on its main regulated tariff (the *Urban Domestic* tariff). However, Country Energy still has over 180 individual regulated tariffs, and only half of these are at cost-reflective levels.[92] While Country Energy has restructured its regulated tariffs such that an increasing number of residential customers face the same tariff level, the large number of separate regulated tariffs provides Country Energy with scope to alter the level of these individual tariffs in the future. Therefore, we consider that additional price limits on Country Energy are required to ensure customers are adequately protected over this period (see section 5.6).

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90 Retailers noted that a WAPC has not allowed the Standard Retailers to segment customers and charge prices that significantly exceed the cost of supply. Retailers note the limited number of regulated retail tariffs combined with competitive pressures ensure that retailers are unable to segment the market to target 'vulnerable' customers. Integral Energy submission, August 2009, p 4.

91 NSW Government, *NSW Energy Reform Strategy – Delivering the Strategy: approach to transactions and market structure*, September 2009, p 1.

92 Country Energy submitted that over 75% of residential customers are connected to the Country Energy regulated tariff. Country Energy submission, February 2010, p 7. We note that Country Energy plans to further rationalise regulated tariffs and move all tariffs to cost-reflective levels over the 2010 determination period.

We note PIAC's view that it is important to ensure the regulatory framework is sufficiently robust to deal with any risk of reduced competition over the determination period.[93] In light of the small number of regulated tariffs in the metropolitan areas, limits on the introduction of new tariffs (Section 5.5.2.), a developing competitive retail market and the additional price limits imposed on Country Energy, we are satisfied that the WAPC form of regulation is sufficiently robust to manage this risk.

5.4 How the WAPC will be calculated

IPART's final decision is to calculate the WAPC on the following basis:

- the N values (which relate to network costs) are based on actual network charges imposed by the distribution network service providers and approved by the AER
- the R values (which relate to retail costs) are based on the efficient Standard Retailer cost allowances determined by IPART (see Chapter 9)
- the quantities used to weight prices are:
  - for fixed components, actual customer numbers as at 31 December in the previous year, and
  - for variable components, estimated consumption (in MWh) over the previous 12 months.

This final decision is consistent with our draft decision and is consistent with the 2007 determination. It also involves the same formula for calculating the WAPC (see Box 5.1). The decision allows the Standard Retailers to fully recover the efficient costs allowed for in the 2010 determination (ie, the total energy cost, retail cost and retail margin allowances). It also allows them to fully recover the **actual** costs they incur in paying network fees and levies (as determined by the AER).

93 PIAC submission, August 2009, p 3.

Box 5.1 The Weighted Average Price Cap

$$\sum_{i=1}^{n}\sum_{j=1}^{m} P_{ij}^{t}.q_{ij}^{t-1} \leq \sum_{i=1}^{n}\sum_{j=1}^{m} C_{ij}^{t}.q_{ij}^{t-1} + PT^{t}$$

where:

- i=1,2…n and j=1,2,…m (ie, the retailer has n regulated tariffs which have up to m components, such as a fixed component and variable components).
- P_{ij}^{t} is the price proposed by the retailer for each component of tariff i
- q_{ij}^{t-1} is the relevant quantity (eg, customer numbers or consumption in MWh)
- $C_{ij}^{t} = N_{ij}^{t} + R_{ij}^{t}$, that is, the regulated price control set by IPART
- PT^{t} is the cost pass-through amount allowed or required by IPART.

Each year of the determination period, the WAPC will be calculated using:

1. the relevant R values determined by IPART as part of this determination
2. the N values, which are equivalent to the actual network charges incurred by the retailer
3. the relevant quantities, including consumption figures and customer numbers for each tariff.

In addition, the final decision provides the Standard Retailers with flexibility in how both the retail and network costs are recovered. This is because the WAPC limits the tariff revenue the retailers can recover (for a given demand), but allows them to set the level and structure of individual tariffs. This is in contrast to the approach in jurisdictions such as South Australia where the respective network tariffs are simply 'bolted on' to the approved retailer cost allowance (similar to the 'target tariff' approach used under our 2004 determination).

We considered Country Energy's proposal that some retail costs be removed from the retail cost allowances – such as those arising from the CPRS, the National Energy Renewable Target and NEM fees – and that a new 'G' component be included in the WAPC formula. The aim of this proposal was to enable the Standard Retailers to recover the actual green-related costs they incurred in the previous year, to manage the uncertainty about these costs in the coming 3 years.[94] However, in our view this proposal is not consistent with the terms of reference and assessment criteria for the 2010 determination. In particular, it would be a significant departure from the approach used in the 2007 determination, and would not necessarily result in prices that reflect the efficient costs of supply.

94 At present, these costs are in the Total Energy Cost Allowance. Under this proposal the WAPC cap would be based on a build-up of an 'N + R + G' with N being a pass through of network costs as above, R reflecting forecast energy costs (carbon and green **exclusive**), retail operating costs, retail margin and energy losses and G reflecting **actual** green related (CPRS, RET and ESS) and AEMO costs incurred. Country Energy submission, August 2009, p 5.

One of the central elements of the 2007 approach is that the R values are set ex-ante, based on our estimate of the **efficient** forecast retailing costs the Standard Retailers will incur. This is intended to provide incentives for the retailers to manage all the costs they can influence to achieve efficiency savings. We consider there are other ways to manage the uncertainties involved in forecasting the impact of the CPRS on retailers' energy costs without adopting a rate of return style of regulation that would involve passing through retailers' actual costs and reducing their incentives for efficiency savings.

In addition, as discussed in Chapter 6, we consider that once the CPRS is implemented it will become increasingly difficult to separate its effect on wholesale electricity prices from the other factors that affect these prices. Thus, Country Energy's proposal will become impractical, and will create a risk that green costs are 'double counted'.

We also expect that once the CPRS is implemented the retailers will be able to manage their carbon-inclusive energy purchase costs in a way similar to their current approach for managing energy purchase costs. For example, they will consider the likely carbon price and its impact on wholesale energy markets and then try to manage the risk of volatility in carbon prices (and the resulting impact on wholesale prices) by purchasing a suite of financial instruments (such as over-the-counter contracts with generators and carbon-inclusive futures)[95] or entering into risk management instruments with other counter-parties (such as financial institutions).

5.5 Additional constraints on all Standard Retailers

We have made several final decisions in relation to imposing constraints in addition to the WAPC that apply to all NSW Standard Retailers. These include decisions:

- not to impose additional price limits on the retail component of the WAPC or individual customer bills
- to impose a constraint on establishing new regulated tariffs unless there are exceptional circumstances, and
- to provide the Standard Retailers with flexibility to rationalise their regulated tariffs and remove obsolete tariffs.

5.5.1 No additional price limits

IPART's final decision is not to impose additional constraints on the change in the retail component of the WAPC, or in individual customer bills.

This final decision is consistent with our draft decision and with the 2007 determination. In our view, it is also consistent with the terms of reference and assessment criteria for the 2010 determination. In particular, we note that the imposition of additional price constraints could interfere with retailers' ability to set

95 Such as through the Sydney Futures Exchange.

regulated tariffs at cost-reflective levels in each year of the determination period, and their ability to rationalise regulated retail tariffs.[96]

During our consultations, retailers expressed support for continuing not to impose additional price constraints.[97] Country Energy noted that this would allow it to rationalise those tariffs that are currently below cost reflective levels.[98]

A significant number of submissions noted concerns about the financial impacts of our draft decision for those residents and businesses already struggling with affordability.[99] NCOSS noted that those on low incomes suffer the most when prices rise.[100] EWON noted the need to manage the impact of any price increase on customers who are already struggling to meet their financial commitments.[101] However, they did not propose that this be achieved by introducing additional price constraints on the retail component or individual customer bills. We agree that additional price limits are not the most effective way of addressing affordability concerns as price constraints would affect the prices of all customers, whether they are vulnerable or not. We consider that the impact of the determination on specific customer groups could be better addressed through other, more targeted mechanisms. In its response to the draft decision EWON noted our position.[102]

We also consider that customer information campaigns and price comparator services that are designed to improve the ability of customers to participate in the competitive market may provide some protection against prices that are significantly above costs. As discussed in Chapter 3, these non-regulatory mechanisms can supplement the regulatory framework and may assist to reduce customers' reliance on regulated tariffs in both the metropolitan and non-metropolitan markets.

5.5.2 Constraint on introducing new regulated tariffs

IPART's final decision is that Standard Retailers may not establish new regulated retail tariffs during the determination period; however, they may apply to IPART for approval to do so in exceptional circumstances – such as a mandated or network-business-instigated roll-out of smart meters that renders their existing regulated time-of-use tariffs obsolete.

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96 Price constraints would limit tariff rationalisation by constraining the retailers' ability to raise under-recovering or obsolete regulated tariffs to the level of current, cost-reflective tariffs, making it more difficult to move customers onto current tariffs and abolish obsolete tariffs.

97 For example, see TRUenergy submission, August 2009, p 5; Origin Energy submission, August 2009, p 14 and Country Energy submission, August 2009, p 15; Country Energy submission, February 2010, p 7; EnergyAustralia submission, February 2010, p 42.

98 Country Energy submission, February 2010, p 7.

99 NSW Farmers Association submission, February 2010 ,p 2; NSW Business Chamber submission, February 2010, p 1; COTA submission, February 2010 p 1, Ron Craggs submission, February 2010, pp 2-3; MJ Christie submission, January 2010, p 1, Andrews G submission, January 2010, p 1.

100 NCOSS submission, August 2009, p 1.

101 EWON submission, August 2009, p 1.

102 EWON submission, February 2010, p 4.

This final decision is consistent with our draft decision and is consistent with the 2007 determination. It is intended to limit the proliferation of new regulated retail tariffs, thereby reducing customers' reliance on regulated tariffs and facilitating the development of competition. This is consistent with the terms of reference and our assessment criteria for the 2010 determination.

We considered the concerns retailers' raised in relation to the constraint on introducing new regulated tariffs. For example, EnergyAustralia and Integral Energy submitted this constraint limits their flexibility to introduce pricing initiatives in response to changing circumstances, including where distribution businesses introduce time-related tariffs.[103] Origin Energy submitted that existing regulated tariffs might be inconsistent with time-related tariffs following the planned roll-out of smart metres by some of the NSW distribution businesses.[104]

We note that a government-mandated roll-out of smart metering is possible over the 2010 determination period.[105] However, we also note that many regulated retail customers are already supplied on time-of-use regulated retail tariffs. For example, EnergyAustralia already supplies 14% of its regulated domestic customers on time-of-use tariffs and 37% of its regulated business customers on these tariffs (Table 5.1). We note some stakeholders' concern regarding customers being moved onto regulated time-of-use tariffs, however this is largely a network distribution issue over which retailers have no control.[106]

Table 5.1 Number of regulated customers on time-of-use tariffs, 2009/10

	Number of regulated customers on time-of-use tariffs	Proportion of that customer type on time-of-use tariffs (%)
Integral Energy	**352**	**0.1%**
Domestic	5	0.0%
Business	347	0.6%
EnergyAustralia	**167,825**	**16.3%**
Domestic	122,087	13.5%
Business	45,738	37.1%
Country Energy	**12,131**	**1.8%**
Domestic	4,080	0.7%
Business	8,051	10.2%

Data source: Information returns submitted by standard retailers, July 2009.

103 EnergyAustralia submission, August 2009, p 13.
104 Origin Energy submission, August 2009, p 13.
105 Smart meters enable time related network and retail tariffs that are more reflective of network and energy costs at different times. All things being equal, retail bills for customers with lower than average peak time consumption are likely to reduce under time–related retail tariffs, whereas, retail bills for customers with higher than average peak consumption are likely to increase.
106 Toronto Assistance Centre submission, February 2010, pp 3-4.

We are not aware of any reason why these existing regulated time-related tariffs would not be suitable after any mandated roll-out of smart meters. In addition, we note that if the Standard Retailers want to offer innovative time-related retail tariffs in response to a smart meter installation program, they are free to do so in the competitive market. Further, if changes in network tariffs **did** render existing time-related regulated retail tariffs obsolete, our final decision provides for Standard Retailers to apply for IPART approval to introduce new regulated tariffs.

We note that the same provision existed under the 2007 determination; however, none of the Standard Retailers found it necessary to use it. Retailers did not provide comment on our draft decision.

One individual however supported the introduction of a regulated 'hardship' tariff that offers customers in financial distress a 'safety net' rather than being require to rely on "ex-post remedial measures".[107] We considered the introduction of a hardship tariff as part of the 2007 review and considered that it was not consistent with the terms of reference for that review which required tariffs to be at cost reflective levels by 2010 and would have required the costs associated with a new hardship tariff to be recovered through increases in other tariffs. We consider that a regulated hardship tariff is also not consistent with the 2010 terms of reference and we remain concerned that a hardship tariff may provide a way to segment customers, potentially allowing retailers to place less 'desirable' customers on a particular tariff.[108] Therefore, we maintain our view that the best way to address affordability concerns is through direct and transparent government payments or retailer hardship programmes. IPART's regulatory framework does not prevent Standard Retailers from providing rebates to customers in financial hardship; however, we do not consider it appropriate to recover these costs from other regulated customers.

5.5.3 Constraint on rationalising and removing regulated tariffs

IPART's final decision is that the Standard Retailers may rationalise their regulated retail tariffs, and remove obsolete regulated tariffs, provided they continue to offer at least 1 regulated tariff to small customers.

This final decision is consistent with our draft decision and is consistent with the 2007 determination. We consider that this decision to allow Standard Retailers to rationalise their regulated retail tariffs, and remove obsolete regulated tariffs, provided they continue to offer at least one regulated tariff to small customers is consistent with the terms of reference and assessment criteria for the 2010 determination. It provides the Standard Retailers with flexibility to rationalise their regulated retail tariffs and remove those that are obsolete, while also ensuring that all small customers have access to a regulated tariff.

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107 Ron Craggs submission, February 2010, pp 2-3.

108 Segmenting customers involves dividing a customer base into groups of individuals depending on their characteristics such as income, credit history etc.

As Chapter 3 discussed, the rationalisation of regulated tariffs is important to promote the continued development of competition, as a high number of regulated tariffs can act as a barrier for retailers considering entering the NSW retail market. We note that all stakeholders who commented on this issue supported continuing to allow the Standard Retailers to rationalise regulated tariffs[109] and supported our draft decision.[110]

5.6 Additional constraints on Country Energy

We have also made two final decisions on constraints in addition to the WAPC that apply only to Country Energy. These include decisions to subject Country Energy to additional constraints in relation to:

- increasing individual regulated tariffs above a defined threshold level
- removing individual regulated tariffs and transferring customers from one tariff to another tariff.

We consider that both additional constraints are necessary to ensure that individual regulated tariffs are not set above the efficient cost of supply in Country Energy's supply area. As discussed above, our assessment of retail competition in NSW found that the level of competition in this market is lower in than in the metropolitan markets served by EnergyAustralia and Integral Energy. Therefore, Country Energy is likely to face less pressure from competitors to keep individual regulated tariffs at cost-reflective levels than the other Standard Retailers.

In addition, Country Energy still has around 180 regulated tariffs and less than half its regulated customers are on its main regulated tariff (recognising that more than three-quarters of customers face a tariff with the same **rate** as the main regulated tariff).[111] In contrast, the other Standard Retailers have a very small number of regulated tariffs, and the vast majority of their regulated customers are on their main regulated residential or business tariff. This means Country Energy has much more scope to raise individual regulated tariffs by more than the maximum average increase allowed under the WAPC.

5.6.1 Additional constraint on increasing individual regulated tariffs above a threshold level

IPART's final decision is to continue to subject Country Energy to a 'threshold price increase test' that requires it to obtain IPART approval if it proposes to increase an individual regulated tariff by more than the maximum average change allowed under the WAPC plus an additional 5%.

109 EnergyAustralia submission, August 2009, p 13; Country Energy submission, August 2009, p 14.

110 EnergyAustralia submission, February 2010, p 42; Country Energy submission, February 2010, p 7.

111 Country Energy submission, February 2010, p 7.

This final decision is consistent with draft decision and the 2007 determination. In our view, it is also consistent with our assessment criteria and terms of reference for the 2010 determination.

We considered the arguments submitted by Country Energy and other retailers against imposing additional constraints such as the threshold price increase test for the 2010 determination period. These arguments included that:

- additional constraints are not necessary, as any prices above cost-reflective levels will be corrected by the competitive market[112]
- the threshold test adds to Country Energy's administrative costs[113]
- targeted hardship programs are more effective in assisting customers suffering hardship than price constraints,[114] and affordability concerns should be addressed through direct and transparent government transfers[115]
- additional constraints for Country Energy only delay the transition of its regulated tariffs to cost-reflective levels[116]
- Country Energy intends to complete its tariff rationalisation programme by 2010/11 and therefore the threshold test will not be necessary.[117]

We do not agree with these arguments. As noted above, our assessment indicates that Country Energy is under less competitive pressure than the other Standard Retailers. In addition, we note that during the 2007 determination period, Country Energy managed to achieve significant tariff reform despite being subject to additional constraints, including the threshold test – reducing the number of its individual regulated retail tariff from over 380 to around 180. This clearly indicates that the threshold test does **not** delay the transition of Country Energy's tariffs to cost-reflective levels.

Further, we consider that any additional administrative costs imposed by the threshold price increase test are small. Like the other Standard Retailers, Country Energy is required to submit all its annual proposed tariff increases to IPART for approval, as part of the annual retail tariff price compliance process.[118] Therefore, it can seek approval for increases above the threshold level as part of this process.

While we agree that targeted hardship programs are more effective in assisting customers suffering hardship than price constraints, we point out that the threshold price increase test is not designed to assist customers with affordability issues. As

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112 Country Energy submission, August 2009, p 15.
113 Country Energy submission, August 2009, p 14.
114 Country Energy submission, August 2009, p 16.
115 TRUenergy submission, August 2009, p 5.
116 TRUenergy submission, August 2009, p 5; Origin Energy submission, August 2009, p 14.
117 Country Energy submission, February 2010, p 7.
118 The retail price compliance check involves checking that proposed retail prices for the upcoming financial year comply with the weighted average price cap, based on the network tariffs approved by the AER and the retail cost blocks set out in IPART's Determination.

indicated above, it is designed to provide additional protection to customers by ensuring that regulated tariffs are not set significantly higher than the cost-reflective level where competition is not sufficiently developed.

We note that Country Energy also proposed that if the threshold price test is continued, the threshold level should increase from 5% to 10% higher than the average maximum increase allowed under the WAPC.[119] We have decided to maintain the threshold at 5%. We consider this threshold remains appropriate given the number of regulated tariffs and lower level of competition in Country Energy's supply area, as discussed above.

We note Country Energy's intention to complete its rationalisation of regulated retail tariffs by 2010/11. However, there is no requirement for them to do so. For this reason we consider that the threshold price test needs to be in place for the entire regulatory period given the significant number of regulated retail tariffs. However, we do not consider that the threshold test will restrict Country Energy's ability to further rebalance its tariffs and reduce the number of regulated retail tariffs.

The formula for the threshold price test is shown in Box 5.2.

Box 5.2 Threshold price increase test for Country Energy

$$\frac{\sum_{j=1}^{m} P_{ij}^{t} . q_{ij}^{t-1}}{\sum_{j=1}^{m} P_{ij}^{t-1} . q_{ij}^{t-1}} \leq \frac{\sum_{i=1}^{n} \sum_{j=1}^{m} C_{ij}^{t} . q_{ij}^{t-1} + PT^{t}}{\sum_{i=1}^{n} \sum_{j=1}^{m} C_{ij}^{t-1} . q_{ij}^{t-1} + PT^{t-1}} + 0.05$$

The definitions for these variables are provided in Box 5.1.

5.6.2 Additional constraint related to removing individual regulated tariffs

IPART's final decision is to continue to require Country Energy to obtain IPART approval if it proposes to remove an individual regulated tariff and transfer customers from that tariff to another tariff with a different structure and/or level.

This final decision is consistent with our draft decision and our 2007 determination. It is intended to ensure that Country Energy can not circumvent the threshold price increase test discussed above by removing a regulated tariff and transferring customers from that tariff onto another that is significantly different to the one being removed.

119 Country Energy submission, August 2009, p 16.

As noted above, several stakeholders submitted that additional price controls for Country Energy are undesirable, as they delay the transition of Country Energy's tariffs to cost-reflective levels.[120] We disagree with this view, for the same reasons as outlined above.

Country Energy submitted that the additional constraint on removing regulated tariffs imposes a regulatory burden which is unnecessary, given that the progressive transition of its regulated tariffs to cost-reflective levels has reduced any incentive for it to circumvent the threshold test.[121] However, we disagree with the argument that this imposes a regulatory burden. Like the threshold price increase test, Country Energy can apply for approval to remove regulated tariffs as part of the annual retail tariff price compliance process. Therefore, any regulatory burden imposed by this additional constraint is likely to be small. In addition, although we recognise that Country Energy has made significant progress in rationalising its regulated tariffs, only around half of these tariffs are currently at cost-reflective levels. Therefore, we do not accept that it has made sufficient progress to render the additional constraint on removing regulated tariffs unnecessary at this time.

5.7 Key dates for adjusting regulated retail tariffs during the determination period

We have made final decisions on the date on which regulated retail tariffs will change during the determination period, and the dates on which the Standard Retailers will be required to lodge their annual pricing proposals and publish the approved price changes.

5.7.1 Final decision on date for price changes

IPART's final decision is that 'normal changes' in regulated retail tariffs will continue to occur on 1 July. These changes include those due to:

- annual changes in the N values as a result of AER's 2009 determination on network fees
- annual changes in the R values as a result of IPART's 2010 determination on retail tariffs
- additional changes in the R values as a result of the 2012 and 2013 annual reviews of the total cost allowances provided for in the 2010 determination.

This final decision is consistent with our draft decision and the 2007 determination, which also provides for price changes to occur on 1 July.

120 TRUenergy submission, August 2009, p 5; Origin Energy submission, August 2009, p 14.
121 Country Energy submission, August 2009, p 14.

We note that retailers generally supported maintaining a 1 July price change date to ensure consistency with the date for network price changes, and to avoid the complications that would arise as a result of inconsistency between these price change dates – such as having to set higher prices to make up for any network costs not recovered because the retail price change occurred after the network price change.[122] Retailers reiterated these views in their submissions in response to our draft decision.[123]

In contrast, the consumer groups supported the staggered adjustment of regulated retail prices. They noted that a 1 July price change date means that all price increases correspond with customers' winter bill which is typically higher than their other quarterly bills. Therefore, changing the price change date to another date, or providing for changes in the R component to occur on a different date to changes in the N component would make it easier for customers to manage the increases in their bills. For example, PIAC proposed that retail price changes occur either on 1 January, or at the start of any quarter other than the July quarter.[124] In its response to our draft decision EWON noted the importance of addressing affordability concerns though direct and transparent government payments or retailer hardship programmes if the price changes are not staggered.[125]

Country Energy also supported providing for more frequent, smaller price changes as this would allow for more frequent periodic reviews of the total cost allowance, and assist customers manage the impact of retail price increases.[126]

We considered the advantages and disadvantages of providing for price changes related to the N and R components of regulated tariffs to occur on different dates. We accept that this approach would help to minimise the size of any one price increase, and thus minimise 'price shocks' for customers. However, in our view this would not necessarily help in managing the overall affordability issue some customers will face. We consider that affordability concerns should be addressed through direct and transparent government payments or retailer hardship programs.

In addition, we note the annual network costs and annual retail costs to be recovered through regulated tariffs are both calculated over the period 1 July to 30 June. Therefore, delaying the timing of price changes related to either of these components to stagger the overall impact on customers would create undesirable risks and complications. This is because it would necessitate calculating the correct 'catch up' amount to recover either the N or R related revenue foregone as a result of this staggered timing.

122 Origin Energy submission, August 2009, p 15.
123 EnergyAustralia submission, February 2010, p 42.
124 PIAC submission, August 2009, p 4.
125 EWON submission, February 2010, p 4.
126 Country Energy submission, August 2009, p 16.

It would also result in a higher number of price changes during the determination period, which may create customer confusion. We note there is already the potential for more than one price increase per year. This is because we have made final decisions to include a cost-pass-through mechanism in the regulatory package to allow retailers to recover material cost increases due to regulatory or taxation change events as soon as they obtain approval for this (not only on 1 July, as under the 2007 determination). We have also made a final decision to provide for a special review of the energy purchase cost allowance in time for a possible 1 January price change in 2013. (These decisions are discussed in Chapter 10.)

5.7.2 Dates for lodging annual pricing proposals and publishing price changes

IPART's final decision is to require the Standard Retailers to lodge their annual pricing proposals by 15 May, for approval by 1 June.

Recommendation

3 That the NSW Government consider amending the *Electricity Supply (General) Regulation 2001* to require Standard Retailers to publish their regulated prices and miscellaneous charges on their website within 5 calendar days of obtaining IPART approval.

While our final decision maintains the current 1 July price change, we have decided to bring forward the key dates in the annual regulated retail tariff compliance process so that Standard Retailers have time to notify their customers of the price changes ahead of 1 July each year.

We note that this decision is in line Integral Energy's proposal that the Standard Retailers be required to lodge their proposals 2 weeks earlier than currently required, and that IPART also approve applications earlier than currently required, to give the retailers more time to notify customers of price changes.[127] We see merit in this proposal, and have decided to adopt it. We have also decided to bring forward the release of our final report on our annual reviews of the total energy cost allowance to 30 April each year to allow retailers to lodge their annual pricing proposal by 15 May (see Chapter 10 for more information). We note EnergyAustralia's concern that the AER's network pricing approval process may not be completed until 2 June each year.[128] We have asked the AER to make best endeavours to complete the network compliance assessment as early as possible to assist us in approving regulated retail tariffs by 1 June. However, in some instances Standard Retailers may need to submit their annual pricing proposal using draft network prices if the AER has not completed its pricing approval process prior to 15 May. We will complete our compliance assessment once final network tariffs have been approved by the AER.

127 Integral Energy submission, August 2009, p 4.

128 EnergyAustralia submission, February 2010, p 42.

As for the 2007 determination, we have made a final decision to recommend that the NSW Government consider amending the *Electricity Supply (General) Regulation 2001* to require Standard Retailers to publish their regulated prices and miscellaneous charges on their website within 5 calendar days of obtaining our approval for these prices. We consider that this will facilitate the development of competition and the reduction of customers' reliance on regulated retail tariffs by assisting customers in making purchasing decisions, and assisting competing retailers in developing alternative products for the market.

6 Total energy cost allowance

To supply their customers, electricity retailers must purchase wholesale electricity through the National Electricity Market (NEM). This energy cost is the largest cost component of the retail cost base and represents around 40% of their total cost base.

In line with our terms of reference, we determined an energy purchase cost allowance for each Standard Retailer for each year of the 2010 determination period. This allowance reflects our estimate of the costs an efficient Standard Retailer would incur in purchasing energy from the NEM over the determination period, and managing the risks associated with this.

We also determined a number of costs directly associated with purchasing electricity on the NEM including those of:

- complying with the expanded national Renewable Energy Target (RET)[129]
- meeting obligations under existing NSW environmental schemes, including the NSW Greenhouse Gas Abatement Scheme (GGAS) and the Energy Efficiency Scheme (EES)
- NEM fees and ancillary services
- energy losses, as published by the Australian Energy Market Operator (AEMO).[130]

We calculated the energy purchase cost allowance and each of the associated costs based on each Standard Retailer's forecast regulated load over the determination period. The sum of the energy purchase cost allowance and the associated costs is the total energy cost allowance for each Standard Retailer.

The section below provides an overview of our final decisions on the total energy cost allowance and its components for each Standard Retailer. The following sections discuss how we reached these decisions.

[129] We have not incorporated the changes announced by the Commonwealth Government to the RET in February 2010 into the total energy cost allowance. The announced changes are for the existing scheme to be split into two parts; including a small scale SRES and a large scale LRET. (See Section 6.3.1 for more detail.)

[130] These losses occur in transporting the purchased electricity along the transmission and distribution networks.

6.1 Overview of final decisions on total energy cost allowance

IPART's final decision is that the total energy cost allowance for each Standard Retailer for each year in the determination period is as shown in Table 6.1.

Table 6.1 Final decisions on total energy cost allowance (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
EnergyAustralia				
Energy purchase cost allowance	63.7	66.3	73.0	97.9
RET	1.7[a]	1.8	2.2	2.5
GGAS/ESS	3.6	0.7	1.1	1.4
NEM fees and ancillary services	0.7	0.8	0.8	0.8
Energy losses	4.8	4.9	5.4	7.2
Total energy cost allowance	**75.3**	**74.5**	**82.5**	**109.8**
Integral Energy				
Energy purchase cost Allowance	67.0	68.4	75.8	103.8
RET	1.7[a]	1.8	2.2	2.5
GGAS/ESS	3.7	0.7	1.1	1.4
NEM fees and ancillary services	0.7	0.8	0.8	0.8
Energy losses	6.7	6.2	6.9	9.4
Total energy cost allowance	**80.6**	**77.9**	**86.7**	**117.9**
Country Energy				
Energy purchase cost allowance	56.6	61.7	69.1	95.2
RET	1.7[a]	1.8	2.2	2.5
GGAS/ESS	4.0	0.7	1.1	1.4
NEM fees and ancillary services	0.7	0.8	0.8	0.8
Energy losses	7.8	7.8	8.7	11.9
Total energy cost allowance	**71.5**	**72.7**	**81.9**	**111.9**

a Excluding costs associated with the NSW Renewable Energy Target Scheme (NRET).

Note: The Energy Purchase Cost Allowance has been calculated as the higher of the carbon-inclusive LRMC and market-based energy purchase cost per MWh of forecast regulated load. Totals may not add due to rounding. In addition, the total energy cost allowance in 2009/10 may not add due to the exclusion of NRET costs.

In making these final decisions, we were guided by expert advice from our consultant Frontier Economics. We used the methodology set out in our draft methodology paper.[131] This methodology is consistent with the explicit guidance provided in the terms of reference for calculating the energy purchase cost allowance. This guidance included (among other things) that the energy purchase cost allowance must:

- be set at a level that takes account of the impact of the national Carbon Pollution Reduction Scheme (CPRS)
- not be lower than the least-cost mix of generating plant required to meet each Standard Retailer's forecast regulated load.

These decisions were made after careful consideration of the issues raised in submissions. Appendix B provides a summary of submissions and our response to the submissions.

We are satisfied that our final decisions on the energy purchase cost allowance and the other components of the total energy cost allowance, when combined with our decisions to conduct periodic reviews of these allowances within the determination period, are consistent with the requirements of the terms of reference and our assessment criteria for the 2010 determination. Our final decisions on the periodic reviews of the energy cost allowances are discussed in Chapter 10.[132]

6.2 Energy purchase cost allowance

IPART's final decisions on the energy purchase cost allowance for each Standard Retailer for each year in the determination period are as shown in Table 6.2.

Table 6.2 Final decisions on the energy purchase cost allowance (2009/10 $/ MWh)

	2009/10	2010/11	2011/12	2012/13
EnergyAustralia	63.7	66.3	73.0	97.9
Integral Energy	67.0	68.4	75.8	103.8
Country Energy	56.6	61.7	69.1	95.2

To reach these final decisions we followed the methodology for calculating the energy purchase cost allowance detailed in our draft methodology paper. As this paper indicated, this methodology generally involved the same steps and

131 IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013 – Draft Methodology Paper*, August 2009.

132 We have made a final decision to conduct an annual review of the total energy cost allowance. As part of this annual review we will update the energy purchase cost allowance, the cost allowances associated with 'green' schemes and energy losses. The annual review will **not** update the allowance for NEM fees and charges. We have also made a final decision to conduct a one-off special review in 2012/13 of the market based energy purchase cost allowance by updating the carbon price only. This review provides for a potential price change on 1 January 2013.

calculations as the approach we used in making the 2007 determination and conducting annual reviews in 2008 and 2009.

However, the methodology differed from this approach in two important ways. First, as noted above, the terms of reference for the 2010 determination require us to take account of the costs associated with the introduction of the CPRS (proposed for 1 July 2011). As Chapter 2 discussed, this scheme will place a price on carbon emissions, adding to the cost of electricity generation and therefore will increase the cost of wholesale electricity in the NEM. Therefore, we had to decide whether to calculate the energy purchase cost allowance based on assumptions about the carbon-inclusive price of wholesale electricity (in which the costs of carbon are included in the costs of generation), or to calculate the incremental cost of carbon separately and add this to the energy purchase cost allowance (a carbon-exclusive approach). However, regardless of which approach is used, these costs will be included in the total energy cost allowance (and thus recovered through regulated tariffs) in line with the Terms of Reference.[133]

Second, the terms of reference for the 2007 determination required us to consider the Long Run Marginal Cost (LRMC) of generation and the market-based energy purchase cost, and set an appropriate energy purchase cost allowance with regard to both these costs. However, as noted above, the terms of reference for the 2010 determination are slightly different. They explicitly state that we are to set the energy purchase cost allowance **no lower** than the least-cost mix of generating plant (including plant required to meet any regulatory obligation). We interpret this to mean the LRMC of generation. Therefore, we estimated the LRMC of generation and market-based energy purchase cost in each year of the determination period, and set the energy purchase cost allowance for each year in line with the higher of these costs.

The sections below discuss:

- How we took account of CPRS in setting the energy purchase cost allowance
- How we chose between the LRMC and the market-based purchase cost in setting annual energy purchase cost allowances
- How we considered the Standard Retailers' forecasts of regulated load
- How we calculated the LRMC of generation
- How we calculated the market-based energy purchase cost
- The resulting energy purchase cost allowances.

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133 However, to accommodate uncertainties about the impact of the CPRS we have also provided for periodic reviews of this modelling throughout the determination period, so we can adjust regulated tariffs if these assumptions prove to be incorrect. In particular, we will ensure that neither customers nor the retailers are unfairly affected if the CPRS is not introduced during the determination period, or is introduced in a different form.

6.2.1 How we took account of the CPRS in setting the energy purchase costs allowance

As Chapter 2 discussed, the proposed CPRS will place a price on carbon emissions and set a medium-term national target for emissions reduction, which will push up the cost of electricity generation, wholesale electricity prices, and thus push up the retail price of electricity. This is intended to send price signals to electricity consumers about the environmental impact of their consumption, and thereby reduce overall consumption and the associated carbon pollution.

However, at the time of writing, there is still uncertainty about whether and when the CPRS will be implemented and, if it is implemented, the extent of its effect on electricity wholesale prices over the coming years. This uncertainty raised some questions about the approach for calculating the costs associated with the CPRS in this decision:

- We had to decide whether to calculate these costs using a carbon-inclusive approach, under which the costs of carbon are factored into the price of wholesale electricity, or a carbon-exclusive approach, in which the 'black' wholesale price of electricity is calculated and the costs of carbon are added on as a separate component. This was largely a practical matter, as regardless of which approach is used, these costs will be included in the energy purchase cost allowance (and thus recovered through regulated tariffs).
- We also had to decide how to manage the significant risk of forecasting error in these calculations – that is, the risk that the forecast carbon prices we assumed in calculating these costs will prove to be incorrect, and the risk that the CPRS will be implemented at a different time or in a different form than currently proposed or will not be implemented at all during the 2010 determination period.

Frontier Economics considered both a carbon-inclusive and carbon-exclusive approach in its *Modelling methodology and assumptions report*[134]. It recommended that we use a carbon-inclusive approach in calculating both the LRMC and the market-based purchase cost. Stakeholders expressed a variety of views, but there was no consensus on which approach was preferred. For example:

- Origin Energy has supported a carbon inclusive approach[135]
- AGL has supported a carbon inclusive approach for the market based estimates but a carbon exclusive approach for the LRMC of generation[136]
- EnergyAustralia has favoured setting a 'black' energy purchase cost allowance only; that is, only including the impacts of the CPRS in regulated retail prices when the scheme is finalised.[137]

134 Frontier Economics, *Modelling methodology and assumptions: A report for IPART,* August 2009.
135 Origin Energy submission, September 2009, p 13; Origin Energy submission, February 2010, p 1.
136 AGL submission, September 2009, p 10; AGL submission, February 2010, p 13.
137 EnergyAustralia submission, February 2010, p 6.

After considering the different advice and comments we received on this issue, we decided to accept Frontier Economics' advice. This is consistent with our draft decision. We consider that using a carbon-inclusive approach for the 2010 determination will help to avoid making assumptions about the extent to which generators will pass through carbon costs into the wholesale market (pass through rates)[138], avoid double counting of costs and facilitate internally consistent decisions. We also believe that in the medium to longer term, generators will treat the costs of carbon emissions just like other costs they incur in generating electricity. This will make it very difficult to separate the 'black' and the 'green' elements of wholesale energy costs. Therefore, using a carbon-inclusive approach now will simplify our task in the future, should the Government decide to continue regulating retail tariffs beyond 2013.

In relation to AGL's proposal to set a carbon exclusive LRMC we note that the terms of reference require us to set the LRMC of generation consistent with the least cost mix of generating plant to efficiently meet each Standard Retailers' forecast regulated load. Setting a carbon exclusive or 'black' LRMC and then adding a 'carbon component' that reflects a different generation and dispatch mix would not be consistent with the LRMC of generation in the presence of the CPRS. This is because the LRMC of generation is a theoretical framework in which investment is able to respond immediately to the carbon price, which leads to a change in the proportion of gas fired plant over the determination period. The 'carbon component' under the LRMC estimate is therefore less than under the market based estimate. While we recognise that the carbon cost that will be passed through to retailers will be a function of the existing generation build, it is important to note that the LRMC of generation is necessarily a theoretical framework and is not intended to necessarily reflect retailers' actual purchase costs in the NEM.

We instructed Frontier Economics on the assumptions for carbon prices (and related matters) it should use in modelling the carbon-inclusive LRMC and market-based purchase cost.[139] These assumptions were in line with the proposed cap for the carbon price in 2011/12 and the Commonwealth Treasury's forecast of carbon prices in 2012/13. This methodology is consistent with the draft decision.

In relation to the question of managing the risks of forecasting error, our final decisions are to provide for an annual review of the total energy cost allowance and a one-off special review of the market-based energy purchase cost in 2012/13 to manage these risks. These reviews will ensure that customers will not pay a regulated retail tariff that incorporates the cost of carbon emissions if the CPRS is not

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138 Under Frontier Economics' carbon inclusive modelling of the energy purchase costs, pass through rates are an output of the modelling rather than an input assumption.

139 Frontier has incorporated the carbon cost into the SRMC of thermal generation plant which is used in both the LRMC and market based modelling. The carbon cost of each generation plant is determined by taking the Commonwealth Treasury's October 2008 carbon price forecast (adjusted to reflect financial years in $2009/10, providing a price of $26 tonne/$CO_2$) and multiplying by the emissions intensity of the generation plant. http://www.treasury.gov.au/lowpollutionfuture/spreadsheets/report_charts/Chapter%206/Chart%206.3%20-%20%20Australian%20emission%20price.xls

implemented, or implemented in a different form during the 2010 determination period. (See Chapter 10 for more detail on these reviews.)

6.2.2 How we chose between the LRMC and market-based energy purchase cost in setting the annual energy purchase cost allowances

For the 2007 determination, we considered both the LRMC and market-based purchase cost. We concluded that the market-based cost better addressed the specific cost elements and risks the terms of reference required us to take into account in making that determination. We also considered that the market-based approach was better understood and supported by stakeholders. Therefore, we decided to set the energy purchase cost allowance in line with the market-based cost in each year of the determination period (at that time, this cost was slightly higher than the LRMC in each year).

We note that the LRMC is a forward looking concept that provides an indication of the efficient cost of generation required to meet the regulated load. However, in the short term, it may not reflect the efficient cost of managing the risks and costs associated with purchasing electricity from the NEM.[140]

The terms of reference require us to set a market based allowance unless it is lower than the LRMC. We asked Frontier Economics to calculate and recommend the efficient energy purchase costs for each Standard Retailer in each year of the determination period using both a LRMC and a market-based approach. We then set each retailer's energy purchase cost allowance in line with Frontier Economics' advice, using the higher of the LRMC and market-based cost in each year. This is consistent with our draft decision. Retailers supported setting the EPCA as the higher of the LRMC and market based estimates.[141]

6.2.3 How we considered the Standard Retailers' forecasts of regulated load

The terms of reference for this review require us to set an energy purchase cost allowance for each year of the determination period to efficiently meet each Standard Retailer's forecast regulated load.

The Standard Retailers provided forecasts of regulated load over the 2010 determination period. This was provided on a half hourly basis for each financial year of the determination.

140 The LRMC of generation under a standalone approach assumes that there is currently no generation plant available to serve the required load. This approach theoretically builds, and prices, a whole new generation system that is least-cost.

141 AGL submission, February 2010, p 2; EnergyAustralia submission, February 2010, p 3.

Frontier Economics examined the load forecast in detail and undertook an independent analysis of the reasonableness of these forecasts. This analysis involved comparing the load factor and volatility of each Standard Retailers' forecasts against historical ETEF data adjusting for any embedded generation.

The load profiles that were submitted to us by the Standard Retailers following this process ensured that the load forecasts:

- were based on historic ETEF data, accounting for the treatment of embedded generation in that data, such that the load profiles reflect trends in peak demand and load factors
- were correlated to both system demand and prices in a way that is consistent with correlations observed historically
- were appropriate to use in determining the EPCA as it would ensure that the cost of energy included the cost of load volatility.

The Standard Retailers' forecasts of regulated load over the 2010 determination period were used in determining the LRMC of generation and the market based estimate as is required by the terms of reference.

A number of stakeholders including AGL and Origin Energy have expressed concern over the accuracy and transparency of the regulated load forecasts provided by the Standard Retailers.[142] In particular, stakeholders noted that:

- The EPCA set out in the draft report imply load shapes with a lower cost to serve than the cost of energy based on the Net System Load Profile (NSLP)[143] and did not match their expectations based on publicly available ETEF information.[144]
- The relativities between each Standard Retailers' cost to serve are not consistent with stakeholders' expectations.[145]
- The assumptions, methodology for establishing the forecasts and the outcomes of the forecasts are not transparent to stakeholders.[146]

In its draft methodology paper, IPART sought comment on the costs and benefits of using the net system load profiles (NSLPs) as proxy for, or in addition to the retailers' forecasts of their regulated load. Our intention was to make greater use of publicly available data in forming key assumptions, and to make the decisions and the information they are based on as transparent as possible.

142 Origin Energy submission, February 2010, p 1; AGL submission, February 2010, p 11.
143 The NSLPs are publicly available data used to settle the wholesale energy consumption for all customers with accumulation meters, whether they are on a negotiated or regulated tariff.
144 AGL submission, February 2010, p 11; Origin Energy submission, February 2010, p 2.
145 Origin Energy submission, February 2010, p 2.
146 Origin Energy submission, February 2010, p 2.

We have previously recognised that using the NSLPs as the basis for the load profiles would have some potential benefits. For example, because the NSLPs are publicly available, stakeholders would be able to interrogate it to ensure its veracity, subject to adding in the controlled load profile. In addition, we would be able to release detailed information about the modelling the data is used in, increasing the transparency of our analysis and use of expert advice.

However, the terms of reference require us to set an energy purchase cost allowance for each year of the determination period to efficiently meet each Standard Retailer's forecast regulated load. Given that the forecasts submitted by the Standard Retailers were consistent with historical trends observed in ETEF data we consider that in any case they are appropriate to use in determining the EPCA for each year of the determination.

We recognise stakeholders' concern that the regulated load forecasts are not publicly available given they represent commercially sensitive information to the Standard Retailers. Consistent with stakeholders' requests,[147] we have released the energy cost modelling based on the NSLP for each Standard Retailer. This will assist stakeholders' in verifying Frontier Economics' modelling of the EPCA and is intended to provide confidence to stakeholders in the process.

Recommendation

4 That the NSW Government consider specifying in the terms of reference for any future review of regulated retail tariffs and charges (ie, price review post- 2012/13) that the energy purchase cost allowance be based on each Standard Retailers' net system load profile (NSLP).

6.2.4 How we calculated the LRMC of generation

We engaged Frontier Economics to advise us on the LRMC of generation in each year of the 2010 determination period. We asked it to use the same methodology to calculate this cost as it used for the 2007 review, but to update the assumptions and inputs for the methodology to take account of changes in the terms of reference, the retailers' forecast regulated load, and the policy and regulatory environment.

Frontier Economics calculated the LRMC using its *WHIRLYGIG* model, which is designed to identify the least-cost mix of existing generation plant and new generation plant options to meet the regulated load in NSW. This calculation was made on a standalone basis, rather than an incremental one, in line with the approach used for the 2007 review and for the same reasons. This means that Frontier Economics calculated the LRMC by theoretically building and pricing a whole new generation system to supply each Standard Retailer's regulated load for the least cost (without taking account of the current mix of generation plant in the

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147 Origin Energy submission, February 2010, p 7.

NEM). We note that among stakeholders who commented on this approach, most supported using a standalone approach.[148]

Frontier Economics explained its methodology and key assumptions for calculating the LRMC in its *Modelling methodology and assumptions report*[149]. We published this report on our website and asked stakeholders to comment. Several stakeholders commented on some of the key assumptions and Frontier Economics responded to their comments in its draft report,[150] and in its final report.[151] It also provided a 2nd addendum to its *Modelling methodology and assumptions report* that sets out updated modelling assumptions.[152] (Both these reports are also published on our website.)

In relation to the assumption on the discount rate, we instructed Frontier Economics to use a pre-tax real discount rate of 8.0% in its modelling. This rate is lower than the discount rate of 8.2% proposed in our draft methodology paper and set out in our draft report. However, it reflects updated market parameters rather than changes to other underlying parameters such as the level of gearing and the equity beta. We considered stakeholder comments on the discount rate and its underlying parameters, and consider a discount rate of 8.0% appropriate. (Appendix E discusses this issue in more detail.)

Frontier Economics noted that since it calculated the LRMC for the 2007 review, there have been significant increases in input costs and therefore its calculation of the LRMC for the 2010 determination period is higher. For example, the capital cost inputs are more than 30% higher than the inputs for the 2007 review.[153] The results of Frontier Economics' calculation of the LRMC are shown in Table 6.3.

This table shows that the LRMC of generation to meet the Standard Retailers' regulated load in 2010/11 is between $62 and $68 per MWh. This is lower than the LRMC of generation set out in our draft report reflecting the lower WACC assumption of 8.0% and the updated amortisation methodology[154] (See Frontier Economics' final report and accompanying spreadsheet for more information on the updated amortisation methodology). However, this is higher than the LRMC of generation estimated for 2009/10 as part of the 2007 determination when it was between $47 and $57 per MWh ($2009/10). Table 6.3 also shows that the LRMC

148 As noted in section 6.2.1 AGL supported a stand alone approach to setting the 'black' LRMC, but an incremental approach to setting the 'CPRS component'.

149 Frontier Economics, *Modelling methodology and assumptions: A report for IPART,* August 2009.

150 Frontier Economics, *Energy Purchase Costs – A draft report prepared for IPART*, December 2009.

151 Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010 – see www.ipart.nsw.gov.au

152 Frontier Economics, *Modelling methodology and assumptions 2nd addendum,* March 2010 – see www.ipart.nsw.gov.au

153 Frontier Economics' draft and final reports provide detail on the changes to capital costs of generation and fuel costs since the 2007 determination.

154 Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010, p 9.

increases in 2011/12 and again in 2012/13. This reflects the assumptions about the proposed introduction of the CPRS and the price of carbon in those years.[155]

Table 6.3 Frontier Economics' advice on the LRMC of generation to meet each Standard Retailers regulated load for the 2010 determination (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
EnergyAustralia	55.3	66.3	73.0	84.9
Integral Energy	57.3	68.4	75.8	88.2
Country Energy	46.9	61.7	69.1	81.7

Source: Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010.

The differences in the LRMC of generation for each Standard Retailer reflect the different peakiness of the forecast regulated loads.[156]

Frontier Economics also calculated the LRMC of generation under the CPRS15 scenario. (See Frontier Economics' final report for more information on its view of the impact of the CPRS15 on the market-based cost, and how this compares to the impact on the LRMC of generation.)

As a comparison, Table 6.4 shows Frontier Economics' calculation of the LRMC of generation under a no CPRS scenario (ie, excluding the forecast impact of the CPRS). A comparison of Tables 6.3 and 6.4 suggests that the impact of the proposed CPRS on the LRMC of generation will be around $8/MWh in 2011/12 and around $20/MWh in 2012/13. The impact of increasing the carbon price from $10 per tonne to $26 per tonne in 2012/13 is dampened by a lower carbon 'pass through rate' in 2012/13, the result of more gas fired generation being part of the theoretical least cost generation mix.[157] (See Frontier Economics' final report for more information on its view of the impact of the CPRS on the LRMC of generation, and how this compares to the impact on the market-based cost.)

As noted in section 6.2.1 we do not consider AGL's proposal to set a carbon exclusive LRMC of generation to be consistent with the terms of reference.[158]

155 The stand alone LRMC of generation is a theoretical system in which investment is able to respond immediately to the carbon price. As it constructs a least cost mix of generation in each year, the introduction of a carbon price leads to a significant increase in the proportion of gas fired generation plant over the determination period.

156 Each retail supply area in NSW has a different load profile. Integral Energy has the peakiest load profile, reflecting its more extreme weather events and Country Energy has the flattest load profile, reflecting its geographic diversity and the resulting variability in weather across its region. Peakier loads are more expensive to meet as the load requires more expensive gas fired generation.

157 The carbon 'pass through' rate refers to the extent to which the cost of carbon is passed through by generators into wholesale electricity prices. The higher the pass through rate the more the costs of carbon are passed through into wholesale electricity prices.

158 AGL proposed to set a carbon exclusive LRMC of generation and determine a separate carbon component that reflects the actual generation and dispatch mix of the NEM. AGL submission, September 2009, p 10; AGL submission, February 2010, p 13.

Table 6.4 Frontier Economics' advice on the LRMC of generation to meet each Standard Retailers regulated load for the 2010 determination, excluding the forecast impact of the CPRS (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
EnergyAustralia	55.3	66.3	65.4	64.7
Integral Energy	57.3	68.4	68.3	68.2
Country Energy	46.9	61.7	61.6	61.5

Source: Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010.

6.2.5 How we calculated the market-based energy purchase cost

For the 2007 determination, we focussed on developing a methodology for calculating the efficient market-based energy purchase cost that was relatively easy to understand, predictable and internally consistent, and which addressed any risks not accounted for in other parts of the regulatory framework. We engaged Frontier Economics to assist us in this and then apply the methodology to calculate the market-based cost for 2007/08 to 2009/10. The resulting methodology involved calculating an 'efficient frontier' for each Standard Retailer in each year of the determination period. These efficient frontiers essentially represented the expected cost and associated risk (as measured by standard deviation) of purchasing wholesale electricity from the NEM using a set of contracts that minimise risk while maximising return (and so minimise the purchase cost).

For the 2010 determination, we engaged Frontier Economics to calculate the market-based purchase cost using the same methodology, but to update the methodology to take account of changes in the terms of reference, the retailers' forecast regulated load, and the policy and regulatory environment.

As for the LRMC of generation, Frontier Economics explained its revised methodology and key assumptions for calculating the market-based cost in its *Modelling methodology and assumptions report.* We published this report and received several stakeholder comments on aspects of the methodology. Frontier Economics responded to stakeholder comments in its draft report[159] and in its final report.[160] It also provided an addendum to its *Modelling methodology and assumptions report* that sets out the updated modelling assumptions used in its final report.[161]

159 Frontier Economics, *Energy Purchase Costs – A draft report prepared for IPART*, December 2009 – see www.ipart.nsw.gov.au

160 Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010 – see www.ipart.nsw.gov.au

161 Frontier Economics, *Modelling methodology and assumptions addendum,* March 2010 – see www.ipart.nsw.gov.au

Frontier Economics' methodology involved using its portfolio optimisation model (*STRIKE*) to estimate optimal combinations of contract cover and spot price exposure for given levels of risk for each Standard Retailer, and then calculating efficient frontier curves. It also involved using game theoretic techniques (through its SPARK model) to forecast spot price outcomes in the NEM. However, for Frontier Economics to apply these modelling techniques, we had to make a series of decisions. These include:

- to use modelled forward price data in determining the market based estimate for 2010/11, recognising that as part of the annual review of the total energy cost allowance in 2011 and 2012 we will consider modelled price outcomes as well as publicly available electricity forward price market data
- in modelling this data:
  - to assume that growth in electricity demand in the NEM will be consistent with the high growth scenario in the AEMO's 2009 Statement of Opportunities, but recognising that this scenario may still understate the likely level of electricity demand in the NEM in 2010/11, and
  - to assume cost input assumptions consistent with those used in our draft report
- to use a point in time estimate rather than a rolling average of contract prices
- to base the market-based cost on the conservative point on the efficient frontier curve
- to include a volatility allowance in the market-based cost.

The sections below discuss each of these decisions, and set out Frontier Economics' calculation of the market-based purchase cost.

Using modelled forward price data

There are several possible sources of forward price data, including modelled or simulated data, publicly available market data (such as d-Cypha data or the AFMA curve) and retailers' actual forward costs. We asked Frontier Economics to provide advice on these alternatives, and considered stakeholder comments. We decided to accept Frontier Economics' advice to use modelled forward price data in determining the market based estimate for 2010/11 and the indicative price path for 2011/12 and 2012/13, recognising that the market based estimate will be revised in 2011 and 2012 as part of the periodic review of the total energy cost allowance. This decision is consistent with our draft determination and the approach used for the 2007 determination.

Retailers supported the use of market data as the source of forward price data into the portfolio optimisation model. Retailers noted that:

- Retailers cannot purchase contracts at a theoretical modelled price, but must purchase from the market and pay the market price.[162]
- The contract price at which sellers and buyers transact on an exchange traded or bilateral basis is an 'efficient' price.[163]
- Publicly available market data (such as d-Cypha data or the AFMA curve) and the expectations they reflect are transparent and do not require detailed consideration of modelled input assumptions.[164]

We note that the use of publicly available market data has some potential advantages, particularly in terms of transparency. We also recognise that observed market prices reflect the expectations of a wide range of market participants, each taking into account the information available to them.

However, there are also a number of complications in using publicly available market data as the source of forward prices (and therefore the basis of the EPCA) for this determination. Frontier Economics advice was that:

- There is insufficient liquidity in forward contract markets in the later years of the determination period, particularly 2012/13, to support its use for this review.[165] While a number of submissions acknowledge this point,[166] AGL notes that there is likely to be sufficient liquidity in forward contract markets for each coming financial year.[167] (See Chapter 10 for more detail on the annual review.)
- While publicly available data on forward prices such as d-Cypha data are carbon-inclusive, uncertainty about the implementation of the CPRS means that the data for the later years may not fully reflect the costs of the CPRS (ie, they may be discounted due to this uncertainty). A number of submissions acknowledge this point.[168]

We consider publicly available forward price data an important source of information in determining the market based estimate of the EPCA. However we agree with Frontier Economics' view and note that the observable forward price market data is highly variable and may not fully reflect the costs of the CPRS. Therefore while our preference is for greater reliance on publicly available market data, given the uncertainties in the market including uncertainty surrounding the proposed CPRS, it is difficult for us to rely solely on observable forward price market

162 AGL submission, February 2010, p 6; Country Energy submission, September 2009, p 18.
163 AGL submission, February 2010, p 6.
164 AGL submission, February 2010, pp 6 -7; Integral Energy submission, February 2010, p 3.
165 Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010, p 59-60.
166 Delta Electricity submission, August 2009, pp 1-2; AGL submission, February 2010, p 16.
167 AGL submission, February 2010, p 16.
168 AGL submission, February 2010, p 16.

data at this time, or to say in what circumstances this data would be relied upon relative to modelled price outcomes.

We note that one of the advantages of modelled forward price data is that they represent an alternative source of information, particularly, where there is not sufficient liquidity in the market to rely on market prices, or where there is uncertainty as to a change in the physical, commercial or regulatory environment affecting energy markets. In this situation, market prices will reflect this uncertainty and it may not be appropriate to set the EPCA (and therefore regulated prices) on this basis. In addition, modelled prices provide an opportunity to understand the impacts on energy markets of changes to the physical, commercial or regulatory environment. This can be important to the process of setting the EPCA particularly when a change to a retailers' operating environment triggers a cost pass through review.[169]

To enhance the transparency of our decisions, we have released Frontier Economics' spot price forecasts (the outcomes of its SPARK modelling). These price forecasts are reported on an aggregate basis (that is, an average spot price for each year of the determination). They are also provided in a spreadsheet on a half-hourly basis for each year of the 2010 to 2013 determination.[170] As well as the spot and contract price forecasts, we have also released two calculations of the market based energy purchase costs including a:

- Forward looking example, based on a hypothetical load shape that is a weighted average of Standard Retailers' forecast regulated load shapes and Frontier Economics' spot and contract price forecasts.
- Backward looking example based on the actual NSLP for each Standard Retailer using historic NSLP and NSW price data for calendar year 2008.

In addition, to address the risk that wholesale energy prices differ materially from the modelled data used in calculating the market-based cost, we have made a final decision to provide for an annual review of the total energy cost allowance.

The annual review of the total energy cost allowance will:

- use the same methodologies to calculate the LRMC of generation and market based estimate as were used in making this determination
- update a limited number of key input assumptions for the LRMC and market based estimates
- compare the modelled price outcomes against publicly available forward price market data and consider the reasons for any material deviation

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[169] For example, if we purely relied on market data it would be difficult to determine the impact of a regulatory change event on the EPCA for each Standard Retailer. Market prices vary over time reflecting the expectations of market participants, each taking into account the information available to them. Therefore, it would not be straightforward to isolate the impact on the market prices and therefore the incremental impact of a regulatory change event on the EPCA.

[170] www.ipart.nsw.gov.au

- make a draft decision on the most appropriate source of forward price data to be used in the portfolio optimisation modelling
- make a draft decision on the energy purchase cost allowance and consult on our draft decision, before issuing a final decision (see Chapter 10 for more detail on the annual review).

We considered Country Energy's proposal to use retailers' actual forward costs.[171] However, we consider that this approach may weaken the incentives of retailers to behave efficiently. In addition, if we did use this data, we would need to conduct an 'efficiency test' of retailers' actual forward costs, which would involve an independent assessment of an appropriate hedging strategy and its costs (ie, essentially the same process involved in simulating forward price data). We would also need to allocate retailers' actual forward costs between their regulated customers and negotiated customers, which would not be straightforward. There may also be transparency issues as the retailers are unlikely to agree to the disclosure of confidential contracting information. Therefore, we consider the use of retailers' actual data has no significant advantages. This view is consistent with our draft decision and Frontier Economics' advice.[172]

Assuming growth in electricity demand in the NEM will be consistent with the high growth scenario in the 2009 SOO

As noted above, we decided on using simulated forward price data to calculate the market-based cost. However, Frontier Economics' model for simulating this data requires certain inputs, including the forecast rate of growth in electricity demand in the NEM over the determination period. For previous reviews, Frontier Economics has advised us to use assumptions consistent with the medium growth rate scenario in the relevant Statement of Opportunities (SOO) produced by AEMO. However, for the 2010 determination, Frontier Economics considered that because the 2009 SOO was developed in March 2009 it reflects a more pessimistic view about economic growth than is generally held now. Therefore, it advised us to use the high growth scenario in this statement, and we accepted this advice.[173]

Stakeholder submissions on the draft report noted that the high growth scenario in the 2009 SOO may underestimate likely growth in demand given the revised expectations of domestic economic growth over the determination period.[174] Integral Energy proposed that the market based modelling be revised to take account of the stronger than expected economic recovery.[175]

171 Country Energy submission, September 2009, p 3, Country Energy submission, February 2010, p 3.

172 Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010, pp 35-36.

173 Note that the high growth scenario in the 2009 SOO for 2010/11 is lower than the medium growth scenario in the 2008 SOO which was used as part of the 2009 annual review. Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, December 2009, pp 16-17.

174 Integral Energy submission, February 2010, p 2-3; AGL submission, February 2010, p 7.

175 Integral Energy submission, February 2010, p 3.

We recognise that the current market expectations of domestic economic growth and therefore energy demand over the determination period, and particularly in 2010/11 may be more positive than at the time that the demand forecasting was undertaken for the AEMO 2009 SOO. We also recognise that for 2010/11 the high growth scenario in the 2009 SOO is lower than the medium growth scenario in the 2008 SOO which was used as part of our 2009 annual review.

Frontier Economics' analysis demonstrates that the market based modelling is sensitive to the energy demand assumption. Frontier Economics' final report provides forecasts of annual average NSW pool prices over the determination period based on the medium energy scenario in the 2008 SOO. This analysis highlights this sensitivity, showing that for 2010/11 the pool price forecasts under the 2008 SOO are broadly similar to the d-Cypha flat swap price.[176] This suggests that the low outcomes of the market based modelling for 2010/11 relative to current d-Cypha data reflect the unusually low forecasts of demand in the 2009 SOO.

While we recognise that the 2009 SOO may underestimate likely growth in demand given the revised expectations of domestic economic growth over the determination period, we consider it the most appropriate source of information regarding energy demand forecasts. We have previously noted that developing independent forecasts would be a very complex task due to the number of factors that can affect demand over the forecast period and the Transmission Network Service Providers (TNSPs) and AEMO put considerable work into their forecasts.[177] Therefore, we do not consider there to be advantages in undertaking our own energy demand forecasting and revising the market based modelling to take account of these forecasts, particularly given that:

- We are committed to using to the extent possible publicly available data regarding input assumptions, and undertaking our own forecasts is unlikely to be as transparent as the AEMO process.
- Developing independent forecasts would be a very complex task that would be difficult to undertake in the timeframe for this review.
- The market based allowance is significantly below the LRMC of generation in 2010/11 under both the 2008 and 2009 SOO, and therefore does not determine the EPCA in that year.
- We have made a final decision to undertake an annual review of the total energy cost allowance, and consider it unlikely that the unusual circumstances stemming from the global financial crisis would be repeated during this determination period.

However, we consider that were it not for the unusual economic conditions, we would ordinarily consider the SOO medium forecasts to be appropriate. We will consider this issue as part of the annual reviews of the total energy cost allowance.

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176 Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010, p 72.

177 IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013 – Draft Methodology Paper*, August 2009, p 24.

Assuming cost input assumptions consistent with our draft report

In addition to forecasts of energy demand, Frontier Economics' modelling of forward prices also requires assumptions in relation to the fuel costs of thermal and renewable plant.

We have made a final decision to continue to use the costs assumptions sourced from the ACIL 2009 report for AEMO as well as Concept Economics. This is consistent with our draft report. However, as noted in section 6.2.4 we have updated the WACC and the amortisation methodology which are used to amortise the fixed capital costs of thermal plant. This has a small impact on the LRMC modelling only.[178] (Refer Frontier Economics' final report and accompanying spreadsheets for further detail on these assumptions.)

Stakeholders submitted that there is updated information on the costs of renewable plant.[179] While we recognise that some updated information may be available we have previously emphasised our preference to base the assumptions on publicly available data where possible.[180] We consider an expert report commissioned by AEMO to be the most appropriate source of independent input data and as part of the annual review of the total energy costs, intend to rely on this. Stakeholders have supported the use of AEMO commissioned reports (such as the current ACIL 2009 report) as the source of input data.[181] Therefore, while we recognise that there may be updated information on capital and fuel costs available we have made a decision to continue to rely on expert reports commissioned by AEMO, or if unavailable or not sufficient another report that we consider represents standard industry practice or we commission.

Using a point in time estimate

Estimating the market-based energy purchase cost requires a decision about whether the price of hedging contracts should be based on a point in time estimate or a rolling average of contract prices over a period of time.

The use of a point in time estimate received significant discussion in stakeholders' submissions throughout the review including in response to our draft report.[182] In broad terms, retailers submitted that this approach does not reflect the volatility in contract prices over time, and the approach taken by prudent retailers to manage this risk.

178 The updated WACC assumption also leads to marginal changes in the volatility allowance.

179 EnergyAustralia submission, February 2010, p 10; Origin Energy submission, February 2010, p 9.

180 IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013 – Draft Methodology Paper*, August 2009, p 21.

181 Origin Energy submission, February 2010, p 1.

182 AGL submission, February 2010, p 8; Origin Energy submission, February 2010, p 1.

We note that the volatility in contract prices over time will be smoothed by taking a rolling average of contract prices and using this rolling average price as the basis for determining the energy purchase cost allowance (as regulators in Queensland and the ACT have done). While a rolling average approach may be practical when the energy purchase cost allowance is based on publicly-available contract prices, it is less practical when the energy purchase cost allowance is based on simulated forward prices. The reason is that simulated forward prices are not likely to be volatile unless key assumptions are altered in light of new market information. Using a rolling average approach under a simulated forward price would therefore require Frontier Economics to conduct its forward price modelling using a range of input assumptions over the last, say 24 months, as opposed to using the most up to date information. We not only consider this to be highly impractical, we maintain our view that this is unlikely to be consistent with setting prices based on the efficient cost of supplying small retail customers as is required in the Terms of Reference. It is also not consistent with the approach taken in the 2007 determination.

We note that in an efficient and competitive market (with low barriers to entry), wholesale energy prices as well as REC prices would reflect the most up to date information available. This suggests that the prices the Standard Retailers could charge would be constrained by other retailers (or potential retailers) to the market value of the inputs required to serve customers at that point in time. In a competitive market the historical or actual costs of retailers are only relevant for determining the profitability of its operations from serving customers at prices that reflect current market values. That is, in a competitive market historical costs rarely form the basis of current and future prices.[183]

Consistent with the advice from Frontier Economics we have decided to use a point in time estimate of forward prices.

Basing the market-based cost on the conservative point on the efficient frontier curve

As noted above, the output of Frontier Economics' modelling was efficient frontier curves for the market-based energy purchase cost of each Standard Retailer in each year. One end of the curve represents the highest estimate for an efficient retailers' purchase cost per MWh, with the lowest corresponding risk, while the other represents the lowest estimate of this cost produced by the model but with significant residual risk. We needed to decide which point on the curve provides the most appropriate basis for determining the market-based energy purchase cost for the 2010 determination, given our terms of reference and the context for this review.

183 As AGL notes, historical costs are compared to market values to determine the profit and loss statements of retailers. AGL submission, February 2010, p 10.

For the 2007 determination, we carefully considered this question and concluded that using the conservative point was a realistic and prudent decision. We also considered it was preferable to err on the side of overestimating rather than underestimating the market-based purchase cost. We considered this conclusion remained valid for the 2010 determination and made a draft decision to base the calculation of the market-based energy purchase cost on the conservative point on the efficient frontier curve. Given that stakeholders did not comment on this aspect of our draft report, we have made a final decision consistent with our draft decision.

Including a volatility allowance

For the 2007 determination, Frontier Economics advised us to include a volatility allowance when calculating the market-based purchase cost to compensate retailers for the additional cost associated with the volatile nature of wholesale electricity prices on the NEM. This volatility means that retailers are not always able to manage variations in the cost of purchasing load at the pool price on a half hour basis through their contract portfolio (including swaps and caps). Therefore, they need additional working capital to cover the residual risk associated with the portfolio. We accepted this advice as we considered a volatility allowance was an efficient and therefore reasonable way to address this residual risk.

For the same reason, we instructed Frontier Economics to include a volatility allowance for the 2010 determination, and to calculate this allowance using the same approach as it used for the 2007 review, but with updated data. This approach is based on the standard deviation of the conservative point of each retailer's efficient frontier.[184]

Table 6.5 shows Frontier Economics' calculation of the volatility allowance for each Standard Retailer in each year of the determination period. These are broadly consistent with the allowances set out in our draft report, however there are minor changes reflecting our updated WACC assumption (refer Appendix E).

Table 6.5 Frontier Economics' advice on the volatility allowance for the 2010 determination (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
EnergyAustralia	1.0	0.4	0.8	0.6
Integral Energy	1.2	0.4	0.9	0.8
Country Energy	0.8	0.4	0.7	0.7

Source: Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010.

184 The amount of working capital allowed for each year was calculated as 3.5 times the standard deviation in energy costs (at the conservative point of the frontier) times the cost of capital (WACC).

We note that these allowances are less than those included in the 2007 determination, and retailers expressed concern over this point.[185] We note that this reflects a more accurate calculation of the volatility allowance that was made possible by the improved data available in the current determination on the correlation between the Standard Retailers' regulated load, the system load and pool prices.[186]

We also note that the volatility allowance is not intended as the only compensation to retailers for the cost of managing risks in the energy market. The volatility in regulated load has been explicitly accounted for in the regulated load forecasts submitted by the Standard Retailers and explicitly accounted for in Frontier Economics' modelling of the market-based energy purchase cost. (Refer Frontier Economics' final report for more detail on the 'implicit method' of accounting for load volatility.) As a result, there is no need to include an additional allowance to account for load volatility (and this would result in double-counting of the cost of managing load volatility). Further, the volatility allowance is required in the market-based cost only (not the LRMC of generation), and whenever the market-based cost is referred to in this report, it includes the volatility allowance.

We note Origin Energy's concern that the volatility allowance assumes that the actual market price will equally vary above and below the expected market based energy cost.[187] Frontier Economics has advised that the modelling does not assume that there is an equal chance of the energy costs being above or below the expected cost given the correlation between load and prices. (Refer Frontier Economics final report and accompany spreadsheet for more information on the distribution of forecast market prices in Frontier Economics' modelling.)

Frontier Economics' calculation of the market-based energy purchase cost

Frontier Economics calculated the market-based purchase cost per MWh for each Standard Retailer for each year in the determination period, taking account of our decisions and its calculation of the volatility allowance as discussed above. Table 6.6 shows the resulting calculations.[188] These calculations are almost consistent with Frontier Economics' advice set out in our draft report, with the small change reflecting the impact of the updated WACC on the volatility allowance.[189]

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185 AGL submission, February 2010, p 11.

186 Frontier Economics, *Energy Purchase Costs – A draft report prepared for IPART*, December 2009, pp 19-20; Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010, p 68.

187 Origin Energy submission, February 2010, p 8.

188 Please note that the volatility allowance is required as part of the market-based cost only (not the LRMC of generation). Whenever the market-based cost is referred to in this report, this cost includes the allowance for volatility.

189 The only change to Frontier Economics' advice on the market based energy cost is for Country Energy in 2012/13 which decreased by $0.10 compared to the draft report.

Table 6.6 Frontier Economics' advice on the market-based energy purchase cost for the 2010 determination (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
EnergyAustralia	63.7	44.2	71.6	97.9
Integral Energy	67.0	45.9	74.1	103.8
Country Energy	56.6	42.3	68.1	95.2

Source: Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010.

As the Table 6.6 shows, the calculated market-based energy purchase cost in 2010/11 is lower than in 2009/10, reflecting lower levels of energy demand in the NEM and therefore easing of the supply-demand balance. However, the market-based cost increases significantly in 2011/12 and 2012/13, reflecting increases in electricity demand and the introduction of the CPRS in 2011/12. In 2012/13, the market based energy purchase cost is around $100 per MWh.

Frontier Economics also calculated the market based cost under the CPRS15 scenario. (See Frontier Economics' final report for more information on its view of the impact of the CPRS15 on the market-based cost, and how this compares to the impact on the LRMC of generation.)

As a comparison, Table 6.7 shows Frontier Economics' calculation of the market-based cost under a no CPRS scenario (ie, excluding the forecast impact of the CPRS). A comparison of Table 6.6 and 6.7 suggests that the impact of the proposed CPRS on the market based cost will be around $11 to $12/MWh in 2011/12 and around $36 to $38/MWh in 2012/13; significantly more than the impact of the CPRS on the LRMC of generation in 2012/13 (around $20/MWh).

Table 6.7 Frontier Economics' advice on the market-based energy purchase cost for the 2010 determination, excluding the forecast impact of the CPRS (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
EnergyAustralia	63.7	44.1	60.3	62.0
Integral Energy	67.0	45.8	62.5	65.6
Country Energy	56.6	42.2	57.1	59.8

Source: Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010.

The higher impact of the CPRS on the market-based cost reflects the higher carbon 'pass through' rate[190] under a market-based approach. This is due to 2 factors.

[190] The carbon 'pass through' rate refers to the extent to which the cost of carbon is passed through by generators into wholesale electricity prices. The higher the pass through rate the more the costs of carbon are passed through into wholesale electricity prices. The extent to which generators 'pass through' their costs will depend on a range of factors, including the emissions intensity of the marginal plant (before and after the introduction of the CPRS), the existing mix of generation technologies in each NEM region, and the competitiveness or market dynamics of the NEM.

The first is the relative difference in the mix of investment and dispatch (and higher resultant emissions intensity) in the market-based approach relative to the LRMC approach to calculating energy purchase costs. The stand alone LRMC of generation is a theoretical system in which investment is able to respond immediately to the carbon price. As it constructs a least cost mix of generation in each year, the introduction of a carbon price leads to a significant change in the proportion of gas fired generation plant over the determination period. Gas fired generation plant has a lower emissions intensity and therefore contributes to a lower carbon 'pass through' rate overall.

In contrast, the market based approach reflects the actual mix of investment and dispatch in the NEM where there is a lower proportion of gas-fired generation plant, contributing to a higher average emissions intensity and therefore a higher carbon 'pass through' rate overall. In short, under the market based approach investment is not able to respond immediately to the carbon price. However, over time new investment is likely to enter the market. This is likely to lower the average emissions intensity of the NEM.

The second factor is the strategic behaviour of market participants following the introduction of the CPRS. As our methodology paper noted, one of the key challenges in estimating the market-based cost for this determination is predicting how generators' bidding behaviour in the NEM will change in response to the CPRS, and how these behavioural changes will affect prices in the spot and contract markets. Frontier Economics' analysis suggests that in the early years of the CPRS, the effect of the carbon price in changing the relative costs of supply of different generators will change the incentives of generators so that at various times they will have an incentive to behave more strategically. This can amplify the effect that the carbon price has on electricity prices. However, the effect of the carbon price on generators' incentives will change over time with a change in the carbon price and with the commissioning of new non-strategic generation plant as a result of the CPRS and the expanded RET. This is likely to dampen the ability of generators to bid strategically. (See Frontier Economics' final report for more information on its view of the impact of the CPRS on the market-based cost, and how this compares to the impact on the LRMC of generation.)

6.2.6 The resulting energy purchase cost allowances

After considering Frontier Economics' advice on the LRMC of generation and the market-based purchase cost as well as stakeholder comments on this advice, we decided to accept Frontier Economics' advice on both costs. Therefore, as section 6.1 discussed, we set the energy purchase cost allowance for each Standard Retailer in each year in line with Frontier Economics' advice on the LRMC **or** the market-based cost, depending on which is higher.

Table 6.8 compares Frontier Economics' advice on these costs, and highlights which cost is higher in each year (in bold). As the table shows, the LRMC of generation is significantly higher than the market-based energy purchase cost in 2010/11 and slightly higher in 2011/12 (although the estimates are closer than those set out in our draft report). Therefore, our final decisions on the energy purchase cost allowance for these years are a reflection of the LRMC of generation. However, in 2012/13, the market-based cost is higher, so our final decision for this year is a reflection of the market-based cost.

Table 6.8 Frontier Economics' advice on the LRMC of generation compared to its advice on the market-based energy purchase cost for the 2010 determination (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
LRMC				
EnergyAustralia	55.3	**66.3**	**73.0**	84.9
Integral Energy	57.3	**68.4**	**75.8**	88.2
Country Energy	46.9	**61.7**	**69.1**	81.7
Market-based energy purchase cost				
EnergyAustralia	63.7	44.2	71.6	**97.9**
Integral Energy	67.0	45.9	74.1	**103.8**
Country Energy	56.6	42.3	68.1	**95.2**

Source: Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010.

Table 6.9 shows that the impact of the CPRS on the energy purchase cost allowance is around $7 to $8/MWh in 2011/12 and $35 to $38/MWh in 2012/13. This increase is due to both the increase in the carbon price from $10 per tonne in 2011/12 to $26 per tonne in 2012/13 and the switch from the LRMC of generation to the market based modelling approach.

As discussed above, the differences between the LRMC of generation and the market-based energy purchase cost in 2012/13 are largely due to the different way in which the impact of the CPRS affects each calculation, reflecting the different generation and dispatch mix under each approach (and resulting emissions intensity), and the bidding behaviour of generators in response to the CPRS. The energy purchase cost allowance under the market based approach in 2012/13 incorporates the higher carbon price of $26 per tonne and a higher carbon pass through rate. As a consequence, it is higher than the LRMC approach in this year. (See Frontier Economics' final report for more information on its view of the pass through rates under the LRMC and market based approaches).

However, the increases in the market-based energy purchase cost over the determination are due not only to the impact of the CPRS, but also to the forecast growth in electricity demand in the NEM in these years. As discussed earlier, forecast demand is relatively low in 2010/11 but increases in 2011/12 and 2012/13.

Notwithstanding these differences, we consider that our final decisions on the energy purchase cost allowances (Table 6.2 and Table 6.9) are appropriate inputs to our final determination on regulated retail tariffs.

Table 6.9 Final decisions on the energy purchase cost allowance (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
Energy purchase cost (excluding forecast impact of CPRS)				
EnergyAustralia	63.7	66.3	65.4	62.0
Integral Energy	67.0	68.4	68.3	65.6
Country Energy	56.6	61.7	61.6	59.8
Forecast impact of CPRS				
EnergyAustralia	-	-	7.6	35.9
Integral Energy	-	-	7.5	38.1
Country Energy	-	-	7.6	35.4
Final decision on energy purchase cost allowance				
EnergyAustralia	63.7	66.3	73.0	97.9
Integral Energy	67.0	68.4	75.8	103.8
Country Energy	56.6	61.7	69.1	95.2

Note: The forecast impact of the CPRS in 2011/12 is determined by calculating the difference between tables 6.3 and 6.4, while the forecast impact of the CPRS in 2012/13 is determined by calculating the difference between tables 6.6 and 6.7.

6.3 Allowance for costs of complying with obligations under the expanded RET, GGAS and ESS

IPART's final decisions on the costs of complying with the national Renewable Energy Target and NSW greenhouse and energy efficiency schemes are as shown in Table 6.10.

Table 6.10 Final decisions on cost allowances for complying with RET, GGAS and ESS (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
RET	1.7	1.8	2.2	2.5
GGAS	3.6 – 4.0	0.0	-	-
ESS	-	0.7	1.1	1.4

Note: The GGAS will terminate in July 2011 following the commencement of the CPRS.

In line with our terms of reference, we have calculated allowances for the efficient costs the Standard Retailers will incur in meeting their obligations under present and future national and state renewable energy, greenhouse gas and energy efficiency schemes. However, this allowance does not incorporate the changes announced by the Commonwealth Government to the RET in February 2010.[191] Note that this allowance doesn't include the costs of the CPRS – as discussed above these costs are implicitly included in the energy purchase cost allowance.

We have also made a final decision to review these green cost allowances as part of the annual review of the total energy cost allowance (see Chapter 10).

6.3.1 Expanded Renewable Energy Target (RET)

As part of the national climate change mitigation strategy, the Federal Government expanded the Renewable Energy Target (RET).[192] The target is now for 20% of Australia's electricity to come from renewable sources by 2020.[193] This is higher than the previous target.

The expanded RET scheme will affect Standard Retailers' energy purchase costs. Under the RET scheme they are legally obliged to create or purchase an increasing number of Renewable Energy Certificates (RECs) each year in line with their annual target. Failure to meet these obligations attracts penalties. As a result of the higher RET, their annual targets are also higher.

We engaged Frontier Economics to provide advice on the costs of complying with the RET scheme over the 2010 determination period. It calculated this cost by estimating the cost of 1 REC (for 1 MWh of renewable generation) over this period based on the LRMC of meeting the overall national target.[194] It found that this cost was between $29.70 and $32.10 per REC.[195]

This cost is broadly similar to the REC cost included in the 2007 determination, despite the higher targets. The primary reason for this is that the calculation of the REC cost for the 2010 period takes into account the presence of the CPRS. By increasing electricity prices, the CPRS will reduce the marginal cost of a REC by

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191 Australian Government – Department of Climate Change, *Fact Sheet: Enhanced Renewable Energy Target*, February 2010.

192 The RET scheme expands on the existing Renewable Energy Target (MRET) and absorbs existing and proposed State and Territory renewable energy schemes into a single national scheme.

193 http://www.climatechange.gov.au/en/government/initiatives/renewable-target.aspx

194 The LRMC of meeting the RET is calculated as an output from Frontier Economics' total cost optimisation model. The RET is imposed as a 'constraint' on the model, and Frontier Economics noted that the total cost optimisation model it uses to estimate the LRMC of generation for supplying retailers' regulated load optimises over the thermal (non-renewable) and renewable markets concurrently. This means it accounts for any interaction between the wholesale pool price and the Renewable Energy Certificate (REC) price. This ensures that the costs associated with the RET are not double-counted.

195 Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010, p 87.

reducing the subsidy renewable generators need to cover their total costs. This effect also occurs in 2010/11 (prior to the introduction of the CPRS), as the RET scheme allows 'banking' and to some extent 'borrowing' of RECs. Therefore, the discounted future value of certificates influences today's price.

However, this cost is higher than the forecast REC price of $16 to $18 set out in our draft report. Frontier Economics' has advised that this change arose as a result of updating the WACC and amortisation methodology used in the treatment of fixed costs of thermal and renewable plant. As discussed in section 6.2.4 updating these assumptions has led to small downward revisions of the LRMC of generation for meeting each of the Standard Retailers' regulated loads over the determination period. As Frontier Economics' total cost model optimises over the thermal and renewable markets concurrently and accounts for any interaction between the wholesale market and the market for RECs, these changes result in an increase in the LRMC of meeting the overall renewable national target.[196] However, the small movements in the forecast thermal or 'black' costs of generation over the determination period can lead to larger movements in the forecast REC price, particularly given that:

- the REC market is only a small layer of the total energy generated in the NEM, and
- the modelling is conducted over a 10 year period and accounts for banking and borrowing of RECs. (Refer Frontier Economics' final report for more information on its estimations of the cost of complying with the RET).

Frontier Economics' calculated REC cost is slightly lower than the observed market price for RECs (around $32 to $35) at the time it conducted its analysis.[197]

Stakeholders provided significant comment on Frontier Economics' draft advice that the LRMC of meeting the RET was around $16 to $18 over the determination period, noting that the forecasts:

- were significantly lower than current market price for RECs[198]
- would not bridge the gap between the LRMC of a renewable wind farm and the expected energy from the sale of energy into the NEM.[199]

Retailers offered a number of comments as to why Frontier Economics' REC price forecasts were below current market expectations:

- the assumption for the capital costs of wind generation underestimate current wind capital costs by around 25%[200]

196 The higher the market price for electricity, the lower the REC 'subsidy' needs to be.
197 The analysis was conducted in February 2010.
198 AGL submission, February 2010, pp 14-15; Origin Energy submission, February 2010, p 9; EnergyAustralia submission, February 2010, p 14; Integral Energy, submission, February 2010, p 4; Country Energy confidential submission, February 2010, p 5.
199 AGL submission, February 2010, p 15; EnergyAustralia submission, p 10.
200 Origin Energy submission, February 2010, p 9.

- that an assumption for wind's dispatch profile may not be appropriate[201]
- that the timing and availability of large scale geothermal may not be realistic.[202]

Country Energy also submitted that the renewable power percentages (RPP) used in the modelling to calculate the costs of meeting the RET obligations may below its expectations,[203] and therefore the RET allowance is understated.[204]

Frontier Economics has responded to these comments in detail in its final report. As discussed in section 6.2.5 we have made a decision to continue to use the cost input assumptions sourced from the ACIL 2009 report for AEMO as well as Concept Economics.[205] This is consistent with our draft report. However, the WACC and amortisation methodology have been updated and this does impact on the treatment of fixed costs for both thermal and renewable plant.

We considered EnergyAustralia's proposal to determine the RET allowance assuming that the CPRS does not exist over the determination period. However, this proposal does not resolve the difficulty surrounding the CPRS uncertainty. Modelling a carbon-exclusive price would result in a REC price forecast for 2010/11 that is based on the certain absence of the CRPS. Under this assumption the REC price would be significantly higher than REC prices under a carbon inclusive price given the relationship between wholesale energy prices and REC prices. In addition, this REC price for 2010/11 would be inconsistent with the forecast wholesale market prices for 2011/12 and 2012/13. We note that the total energy cost allowance and therefore regulated retail tariffs allow an efficient retailer to remain financially viable given that the LRMC of generation in 2010/11 is significantly higher than the Frontier Economics' market based estimates and current d-Cypha market data.

We remain of the view that Frontier Economics' cost based methodology is consistent with the terms of reference which require us to have regard to the efficient costs of meeting the RET obligations. We note that the majority of stakeholders that did comment on this aspect of the review supported this methodology in their response to our draft methodology and assumptions report.[206]

201 Origin Energy submission, February 2010, p 9.

202 EnergyAustralia submission, February 2010, p 9.

203 The renewable power percentages establish the rate of liability under the RET and is the mechanism that liable parties use to determine how many RECs need to be surrendered to discharge their liability each year.

204 Country Energy submission, February 2010, p 9.

205 We consider an expert report commissioned by AEMO to be the most appropriate source of independent input data and intend to rely on this. However if this is unavailable or not sufficient, we will consider another report that we consider represents standard industry practice or we commission.

206 Origin Energy submission, September 2009, p 14; AGL submission, September 2009, p 18.

We have reviewed Frontier Economics' calculation of the estimated REC cost over the 2010 period and its explanation for the change in the forecast REC price from its draft advice. We consider that this explanation is reasonable and note that its final advice is only slightly below observed market prices prior to the Commonwealth Government's proposed changes to the scheme. We would expect the modelled price of RECs to sit below the current market price (prior to the Commonwealth announcement) given that:

- The modelling assumes the CPRS will commence on 1 July 2011, where is there is considerable market uncertainty about the implementation of the CPRS and whether REC prices will fall as a result.[207]
- The LRMC modelling represents the least cost build of plant and therefore assumes that the market is perfectly competitive ie, there is no strategic behaviour from market participants.

Therefore, we accepted Frontier Economics advice, and consider that the resulting allowances for meeting the cost of complying with the RET scheme (Table 6.10) are appropriate inputs to our final determination.

We do recognise that on 26 February 2010 the Commonwealth Government announced changes to be made to the RET from 2011; in particular, that the existing scheme will be split into two parts:

- the small scale Renewable Energy Scheme (SRES) under which households and small businesses will receive $40 for each REC created by small scale technologies like solar panels and solar hot water heaters; and
- the large scale Renewable Energy Target (LRET) under which a target of 41,000 GWh for 2020 has been set to achieve a level of large scale renewable electricity generation above what was expected under the existing RET.[208]

Combined the new LRET and SRES are intended to deliver more renewable energy than the existing 45,000 GWh target in 2020, with the degree to which the 20% target is exceeded depending on the update of small scale technologies by households and small businesses.[209]

Retailers will be obligated to purchase RECs from both the SRES and LRET however, the details have not been finalised. The Commonwealth Government intends to release an industry consultation paper and following consultation with stakeholders legislate changes in the Winter Sittings of Parliament.[210]

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207 The higher the market price for electricity, the lower the REC 'subsidy' needs to be.

208 Australian Government – Department of Climate Change, *Fact Sheet: Enhanced Renewable Energy Target*, February 2010.

209 Australian Government – Department of Climate Change, *Fact Sheet: Enhanced Renewable Energy Target*, February 2010.

210 Australian Government – Department of Climate Change, *Fact Sheet: Enhanced Renewable Energy Target*, February 2010.

However given the absence of detail in relation to retailers' obligations, we have been unable to estimate the costs of complying with the enhanced RET and therefore incorporate the changes to the RET into regulated retail tariffs from 1 July. Our regulatory package is designed to accommodate changes to the efficient cost of supplying regulated retail customers stemming from changes to retailers' regulatory and/or taxation obligations. Therefore, our cost pass through mechanism is capable of incorporating the efficient and incremental costs resulting from changes to the scheme once the legislation has been enacted, subject to a materiality threshold. (Refer section 10.4 for our final decisions on the cost pass through mechanism.)

6.3.2 Greenhouse Gas Abatement Scheme

The NSW Greenhouse Gas Abatement Scheme (GGAS) is designed to reduce the greenhouse gas emissions associated with the production and use of electricity. The scheme establishes emissions benchmarks for the scheme participants (which include electricity retailers). They must meet these benchmarks by obtaining and surrendering NSW Greenhouse Gas Abatement Certificates (NGACs) based on the size of their share of the electricity market.

The NSW Government has announced that the GGAS will be discontinued once the CPRS is introduced. As the proposed date for this introduction is 1 July 2011, we engaged Frontier Economics to provide advice on the costs of complying with the GGAS in 2010/11. Frontier Economics estimated the cost of 1 NGAC by estimating the LRMC of meeting the GGAS target.[211] It found that this cost is zero in 2010/11, as a result of the planned introduction of the CPRS and a surplus of NGACs. Frontier Economics' final report notes that these factors are consistent with observed falling NGAC prices.[212]

Stakeholders provided significant comment on Frontier Economics' draft advice that the LRMC of meeting the GGAS target was zero, noting that the forecasts did not take into account:

- The Commonwealth Government's transitional compensation package offered to holders of NGACs. Stakeholders submitted that the compensation package effectively creates a price floor as holders of NGACs will not be prepared to sell at a price below their likely compensation.[213]
- That holders of NGACs would not prepared to sell them for zero given the associated transaction costs.[214]
- There have been changes to the GGAS rules which have an effect on supply and demand for NGACs.[215]

211 As with the RET, the LRMC of the GGAS target is calculated as an output from Frontier's total cost optimisation model.

212 Frontier Economics, *Energy Purchase Costs – A final report prepared for IPART*, March 2010, p 94.

213 EnergyAustralia submission, February 2010, p 26; AGL submission, February 2010, p 15.

214 AGL submission, February 2010, p 15.

- The potential for delayed introduction to the CPRS which may result in a tighter NGAC market.[216]

Frontier Economics has responded to these comments in detail in its final report.

We recognise retailers' comments that the Commonwealth Government's transitional compensation package creates a value for surplus NGACs that is above zero. However, our methodology considers the resource cost of meeting the scheme, rather than the financial or commercial value of NGACs. Frontier Economics' advice is that the incremental resource cost of meeting the GGAS is zero.

We remain of the view that our methodology is consistent with the terms of reference which require us to have regard to the efficient costs of meeting the GGAS obligations, and is consistent with our approach to estimating the costs of meeting the RET. Given the inter-relationship between the schemes we consider a consistent approach to be important. We note that the majority of stakeholders that did comment on this aspect of the review supported this methodology in their response to our draft methodology and assumptions report.[217]

We have reviewed Frontier Economics' advice and accepted this advice, and consider that the resulting zero allowance for the cost of complying with the GGAS in 2010/11 (Table 6.10) is an appropriate input to our final determination.

While we note that current observed prices for NGACs are above zero, under our final decision the total energy cost allowance and therefore regulated retail tariffs allow an efficient retailer to remain financially viable given that the LRMC of generation in 2010/11 is significantly higher than the Frontier Economics' market based estimates and current d-Cypha market data.

6.3.3 Energy Savings Scheme

The NSW Energy Savings Scheme (ESS) was introduced on 1 July 2009. This scheme establishes legislated annual energy savings targets for electricity retailers (and other participants). To meet their target, the Standard Retailers must surrender an appropriate number of Energy Savings Certificates (ESCs). ESCs may be created from recognised energy savings activities that either reduce electricity consumption or improve the efficiency of energy use.

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215 EnergyAustralia submission, February 2010, p 28; Country Energy submission, February 2010, p 10.

216 Origin Energy submission, February 2010, p10; EnergyAustralia submission, February 2010, p 28.

217 Origin Energy submission, September 2009, p 14; AGL submission, September 2009, p 19.

We engaged Frontier Economics to provide advice on the Standard Retailers' costs of complying with the ESS over the 2010 determination period. Frontier Economics noted that in the absence of any barriers to the take-up of cost-saving energy efficiency projects, these projects should be adopted without a scheme such as the ESS – that is, the efficiency projects are cost savings in themselves.[218] Therefore, the purpose of the ESS is to overcome existing barriers.

Given this, Frontier Economics' draft advice was that it did not consider it appropriate to use the same approach to calculating the cost of complying with the ESS as it used for the RET scheme and GGAS – that is, by estimating the LRMC of ESCs. It noted that in line with the purpose of the ESS, the price of ESCs will likely be driven by the cost of overcoming the barriers to the take-up of energy efficiency projects, and that this cost is more difficult to estimate than the cost of subsidising energy efficiency projects. In addition, the absence of historic ESC prices means that using a market-based approach to calculate this cost is also difficult. Therefore, Frontier Economics recommended adopting the penalty price of the ESS ($24.50/MWh, equivalent to an after-tax price of $35.00/MWh) as a proxy for the price of ESCs.

Stakeholders that commented on this aspect of our draft decision supported this approach to setting the ESS allowance.[219] Frontier Economics' final advice is consistent with its draft advice. We reviewed the reasons underlying Frontier Economics recommendation and consider this to be a reasonable and pragmatic approach. Therefore, we accepted this recommendation and set the allowances for the cost of comply with the ESS accordingly. We consider that these allowances (Table 6.10) are appropriate inputs to our final determination.

6.4 Market fees and ancillary fees

IPART's final decisions on the cost allowances for market fees and ancillary fees imposed under the National Electricity Rules are as shown in Table 6.11.

Table 6.11 Final decisions on cost allowances for market fees and ancillary charges (2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
NEM fees	0.4	0.4	0.4	0.4
Ancillary services	0.3	0.4	0.4	0.4
Total	**0.7**	**0.8**	**0.8**	**0.8**

218 Frontier Economics, *Energy Purchase Costs – A draft report prepared for IPART*, December 2009, p 84.

219 EnergyAustralia submission, February 2010, p 29.

In line with our terms of reference, we have calculated allowances for the costs of market fees and ancillary service fees as imposed by AEMO under the National Electricity Rules. We have also made a final decision **not** to review the allowance for these fees as part of the annual review of the total energy cost allowance (discussed in Chapter 10).

6.4.1 NEM market fees

AEMO (formerly NEMMCO) imposes fees on retailers to recover the costs of operating the market. NEM fees are levied on retailers on a per MWh basis according to their electricity purchases.

Consistent with our approach for the 2007 determination we engaged Frontier Economics to provide advice on an allowance for market fees as imposed under the National Electricity Rules. Frontier Economics noted that as these fees are based on the budgeted revenue requirements of AEMO and these requirements are relatively stable, the fees are relatively easy to predict. As it did for the 2007 determination, it used the simple linear trend in AEMO's revenue requirements to estimate these fees. On this basis, it advised that an appropriate allowance for NEM fees is $0.37/MWh. This is similar to the allowance included in the 2007 determination.

Stakeholders did not comment on this aspect of our draft decision. Given that market fees are a relatively small component of costs and are also relatively predictable, and that stakeholders did not provide any further information, we have accepted Frontier Economics' advice which is consistent with its draft advice. We consider that the resulting allowances for NEM fees (Table 6.11) are appropriate inputs to our final determination.

6.4.2 Ancillary charges

Ancillary service charges cover ancillary services purchased by AEMO to ensure the power system remains in a secure state. Consistent with our approach for the 2007 determination, we engaged Frontier Economics to provide advice on an allowance for ancillary charges as imposed under the National Electricity Rules.

Frontier Economics noted that ancillary service costs are more difficult to estimate than NEM fees, as they depend on the cost of services that AEMO sources on a competitive basis. However, while these charges are required on an ad-hoc basis, they are reasonably constant over time, with a few notable outliers.

Consistent with its approach in 2007, Frontier Economics forecast ancillary service costs using a simple time-series regression model that included 2 structural breaks. On this basis, it advised that an appropriate allowance for ancillary fees is $0.43/MWh.

Stakeholders did not comment on this aspect of our draft decision. We note that ancillary service charges are a relatively small component of costs and that Frontier Economics' model for estimating these costs is sufficiently robust.[220] Given that stakeholders did not provide any further information, we have accepted Frontier Economics' final advice which is consistent with its draft advice. We consider that the resulting allowances (Table 6.11) are appropriate inputs to our final determination.

6.5 Energy losses

IPART's final decisions on the cost allowance for each Standard Retailer's energy losses over the determination are as shown in Table 6.12.

Table 6.12 Relevant energy loss factors and final decisions on cost allowances for energy losses (% and 2009/10 $/MWh)

	2009/10	2010/11	2011/12	2012/13
EnergyAustralia				
%	6.76	7.06	7.06	7.06
$ / MWh	4.8	4.9	5.4	7.2
Integral Energy				
%	9.13	8.63	8.63	8.63
$ / MWh	6.7	6.2	6.9	9.4
Country Energy				
%	12.32	11.93	11.93	11.93
$ / MWh	7.8	7.8	8.7	11.9

In line with our terms of reference, we have included allowances for the costs Standard Retailers incur because some of the energy they purchase on the NEM is lost as it moves via the transmission and distribution networks to their customers' premises. Retailers charge their customers based on the energy consumption recorded at the customer's meter, but must pay for the energy sent out from the generator. Therefore, they incur costs equivalent to the total energy they purchase minus the total energy they bill customers for.

220 The model explains 42% of the variance in the past and the dummy and the constant were both significant at the 0.1% level. While it is arguable that this is not a high R-squared value (ie, does not sufficiently explain movements in ancillary service charges), we consider that given the significant outliers in historic ancillary service charges, Frontier Economics' model is sufficiently robust. We also note that there are no more accurate alternative techniques for forecasting ancillary fees.

To calculate these costs, we used the appropriate total loss factor (including both transmission and distribution losses) for each Standard Retailer as approved by AEMO and published on its website. We applied this factor to the sum of our final decisions on the energy purchase cost allowance and the other cost allowances discussed above to derive the cost of each retailers' energy losses over the determination period.[221] The loss factors are consistent with those used in our draft report.

For previous determinations, we have used the most recent published loss factors to set prices for the entire determination period (as there is no accurate way to forecast energy losses), without making any adjustment within the period when AEMO releases updated loss factors. However, as we have made a final decision to conduct an annual review of the total energy cost allowance over the 2010 determination period (discussed in Chapter 10), we consider it is sensible to update the cost allowances for energy losses as part of this review to reflect the most recent loss factors published by AEMO.

221 Note these decisions were made based on each Standard Retailers' forecast regulated load which represents the forecast level of consumption by their regulated customers, not their forecast level of energy purchases from the NEM. Therefore, the final decisions need to be inflated by the appropriate loss factors to provide the total energy cost allowance. This is achieved by including allowances for energy losses.

7 Retail cost allowance

In supplying their customers, electricity retailers perform a range of retail functions including billing, marketing, providing advisory services, promoting and advertising their services, and handling customer inquiries. The terms of reference for the 2010 determination require us to set an allowance to recover the efficient costs a Standard Retailer is likely to incur in providing these functions for small customers on regulated tariffs. In doing so, we are required to:

- take account of information from the NSW Standard Retailers and other available information on retailers' efficient operating costs (rather than consider the efficient costs of a mass market new entrant, as required for the 2007 determination)
- include customer acquisition costs to ensure regulated retail tariffs are set at a level which encourages competition.

The section below set out our final decisions on the retail cost allowance for each Standard Retailer for each year in the determination period. We then discuss our approach and decisions in more detail.

7.1 Overview of final decision on retail cost allowance

IPART's final decision is that the retail cost allowance for all Standard Retailers in each year in the determination period is as shown in Table 7.1.

Table 7.1 Final decision on retail cost allowance ($2009/10, $/customer)

	2009/10	2010/11	2011/12	2012/13
All Standard Retailers				
Retail operating costs	82.6	75.3	77.2	79.2
Customer acquisition and retention costs	32.7	36.8	36.8	36.8
Late payment fee deduction		-2.3	-2.3	-2.3
Retail cost allowance	**115.3**	109.8	111.7	113.7

Note: The retail cost allowance of $115.3 per customer under the 2007 determination includes a $5 deduction for double counting. Columns may not add due to rounding.

We consider our final decision reflects a Standard Retailer's efficient retail costs. After considering all further available information, we have increased the retail cost allowance by an average of $5.10 per customer per year because we:

- Updated retail operating costs to incorporate the Standard Retailers' customer number forecasts over the determination period following updated information. This change increased ROC by an average of about $1.10 per customer per year.
- Updated customer acquisition and retention costs to reflect the latest AEMO small customer transfer data for NSW. The updated data increased our switch rate to 13% and CARC by around $4 per customer per year.

However, we note that both the retail operating cost and the customer acquisition and retention cost components remain lower than those included in the 2007 determination. We reiterate that there are several reasons for this, including that for the 2010 determination, we:

- Estimated retail operating costs based on the Standard Retailers' actual retail operating costs, and some of these costs were slightly less than the costs included in the 2007 determination.
- Estimated the costs of retaining customers and winning customers, consistent with the requirement in our terms of reference for the retail cost allowance to reflect a Standard Retailer's costs (rather than assuming that all customers needed to be acquired, as we did for the 2007 determination). On a per customer basis, customer acquisition **and** retention costs are lower because, in general, retention costs are lower than acquisition costs.

7.2 How we set the retail cost allowance

As the terms of reference do not define a Standard Retailer, we adopted the following definition for the purpose of making the 2010 determination:

- an incumbent retailer that has achieved economies of scale (ie, has efficient costs)
- a standalone retailer in NSW that is not vertically integrated into electricity distribution in NSW
- serves retail customers, including small retail customers, in NSW and other jurisdictions across the NEM
- can offer retail customers standard form and negotiated customer supply contracts
- has an existing customer base to defend.

In line with this definition and the requirements in the terms of reference, we estimated the efficient level of a Standard Retailer's retail costs by analysing 2 cost components: retail operating costs (ROC) and customer acquisition and retention costs (CARC). For each of these components, we undertook bottom-up analysis to estimate the efficient level of costs a Standard Retailer will incur per customer over the 2010 period.

We then deducted an amount from ROC to account for some of the costs associated with late bill payments, as these costs are recovered through the late payment fee. This deduction is consistent with the terms of reference for this determination, which emphasise the need for cost allowances to be based on efficient costs without double counting (see Chapter 12).

Finally, we undertook benchmarking analysis to compare our combined ROC and CARC estimate (after the deduction for double counting) to other regulatory decisions on retail costs and other relevant information. This benchmarking indicated that this combined ROC and CARC estimate was consistent with past regulatory decisions on retail costs, so we set the retail cost allowance in line with this estimate.

7.3 Bottom-up analysis of ROC and CARC

To estimate the efficient ROC and CARC per customer using bottom-up analysis, we had to make decisions about a range of factors and assumptions including:

- the appropriateness of the Standard Retailers cost information
- the scope of activities and associated costs to include in each cost component
- the forecast number of customers for each Standard Retailer over the determination period
- whether to estimate the efficient ROC and CARC based on the Standard Retailers' historic costs, forecast costs or some combination of these, and
- as this analysis resulted in a range for the ROC and CARC, what point within this range to use as the basis for setting each cost allowance.

After considering submissions on our draft report, the sections below discuss our decisions on each of these matters, and the resulting ROC and CARC allowances for the purpose of making the 2010 determination.

7.3.1 Standard Retailers' cost information

Some stakeholders questioned whether the retail cost allowance based on the Standard Retailers' cost information would be biased downwards because they have integrated retail and distribution businesses (ie, they are stapled retailers in NSW) and may enjoy economies of scope that are inconsistent with our definition of a Standard Retailer (see Section 7.2).[222]

We note that submissions did not specify or quantify the economies of scope that stapled retail/distribution businesses achieve. However, on balance, we consider the Standard Retailers' cost information appropriate to use in setting the retail cost allowance because:

- Our benchmarking analysis shows that our retail cost allowance based on the Standard Retailers' information is comparable to the cost information reported by publicly listed businesses that are standalone in NSW. In particular, we note that our 2010/11 allowance of $109.80 per customer is above AGL's reported retail costs of $94 per customer[223] – currently a standalone business in NSW competing against the stapled incumbents. It is also above Origin Energy's latest cost to serve of $63 per customer (this figure does not appear to include CARC)[224].
- Standalone businesses in NSW may adopt business structures that achieve similar or greater cost advantages to those enjoyed by the Standard Retailers. For example, standalone retailers in NSW could achieve some economies of scope either outside of NSW or through complementary activities such as generation. Market evidence suggests that other retailers, for example, AGL, TRUenergy and Origin Energy seek out such opportunities.

7.3.2 Scope of activities and costs included in estimating ROC and CARC

We decided to include the following cost items in estimating the efficient level of ROC:

- call centre costs
- customer information costs
- corporate overhead costs
- administrative costs associated with regulatory compliance
- billing and revenue collection costs
- bad and doubtful debt.

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222 EnergyAustralia submission, February 2010, p 30; Origin Energy submission, February 2010, p 13; AGL submission, February 2010, p 18.

223 AGL Energy Limited, *2009 Full year results*, August 2009, p 56.

224 Origin Energy Limited, *2010 Half year results*, February 2010, p 45.

Note that we have accounted for amortisation and depreciation costs in the retail margin (see Chapter 8). Also note that we have included all marketing costs in estimating CARC. This is different from our approach for the 2007 determination, when we included the marketing costs in estimating ROC. This change reflects the difference in the terms of reference for the 2010 determination, which required us to consider a Standard Retailer's efficient costs in setting the retail cost allowance, rather those of a mass market new entrant.

We have included the costs related to the following activities in estimating the efficient level of CARC:

- acquiring new customers from another retailer onto a negotiated or standard contract
- transferring existing customers from a standard contract onto a negotiated contract
- retaining all existing customers, which includes the cost of transferring existing customers from a negotiated contract onto a standard contract.

EnergyAustralia considered our CARC allowance in the draft report too low because it did not cover the costs of "save" activity.[225] Save activity relates to acquisition costs retailers incur for customers they solicit from another retailer that do not become billable customers because they end up accepting counter offers from their existing retailer during the transfer process.[226] We believe that retailers are able to recoup the acquisition costs associated with these customers (ie, costs of save activity) through termination fees and that the application of termination fees are at the discretion of the retailer. Therefore, we do not consider it appropriate to include save activity in our CARC allowance.

7.3.3 Forecast customer numbers for each Standard Retailer

Because the ROC and CARC allowances are set on a per customer basis, our bottom-up analysis is sensitive to the assumptions we use about each Standard Retailer's customer numbers over the determination period. In calculating ROC and CARC, we use the Standard Retailers' total regulated and negotiated customers in NSW.

To assist us in deciding on reasonable assumptions, we asked each Standard Retailer to provide its forecast customer numbers for the 2010 determination period, as well as its actual customer numbers for the period 2002/03 to 2008/09. Each Standard Retailer's forecast reflected a decline in its customers, in line with its expectations about the impact of increasing competition in the NSW retail electricity market over the next years.

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225 EnergyAustralia submission, February 2010, p 32.

226 These are post-cooling off customers, but pre transfer customers – ie, they never become a billable customers.

We accept that as retail competition continues to develop, the Standard Retailers' customer numbers will decline over this period. In addition, we accept that this means the Standard Retailers will need to recover their **fixed** retail costs from a smaller customer base, and therefore the allowance for these costs will need to increase on a per customer basis to ensure they remain financially viable.[227] This is consistent with our terms of reference for the 2010 determination.

However, in the draft report, we stated that we were not convinced that all the Standard Retailers' forecasts were based on reasonable assumptions about the **level** of decline in their customer numbers. In particular, we adjusted EnergyAustralia's and Country Energy's forecast customer losses in line with past experiences. This adjustment was important because the relationship between lower customer numbers and higher retail cost allowances provides an incentive for the Standard Retailers to argue for lower customer numbers. We note that Integral Energy had forecast its customer numbers to decrease in each year of the determination period in line with recent past experience.

Some stakeholders considered our customer number forecasts unachievable, because they were based on historical trends from a period that was not demonstrating signs of a competitive market.[228] Country Energy was of the view that customer numbers will decline at greater rates over the determination period than historical trends due to increased competition in NSW. It asked that we use forecast customer numbers in setting the retail cost allowance.[229] EnergyAustralia also requested that the retail cost allowance be recalculated, however using its revised customer number forecasts that were submitted to us since the draft report.[230]

We note that EnergyAustralia's revised customer numbers indicate that its original forecasts of customer losses were overstated. In addition, we analysed 6 more months of AEMO data that became available since the draft report. These data indicate that customer transfers in NSW have recently increased.[231] Therefore, we have updated the retail cost allowance from our draft report to incorporate EnergyAustralia's revised customer numbers.

In addition, we have accepted Country Energy's revised forecasts as they are also consistent with the updated customer transfers from the AEMO. However, we have not accepted Integral Energy's revised forecasts because they predict lower rates of customer losses, which appears to contradict the latest AEMO data. Therefore, we have applied Integral Energy's initial customer number forecasts to our analysis.

227 But the Standard Retailers' variable retail costs should fall in line with the fall in their customer numbers.
228 Origin Energy submission, February 2010, p 12.
229 Country Energy submission, February 2010, pp 10-11.
230 EnergyAustralia submission, February 2010, p 30.
231 The NSW switch rate was 11% in 2008/09 and increased to 13% for calendar year 2009.

7.3.4 Should ROC and CARC be estimated based on Standard Retailers' historic costs and/or forecast costs?

The Standard Retailers also provided information on their actual retail costs (including both ROC and CARC) for the period 2002/03 to 2008/09 and forecast retail costs for 2009/10 and the 2010 period. We considered this information on a per customer basis and decided that it was more appropriate to base our analysis on the Standard Retailers' actual historical costs.

In their submissions, the retailers argued that a retail cost allowance based on historical costs reflected historical processes rather than forecast requirements and therefore cannot be considered cost reflective going forward.[232] In particular, some retailers claimed that we discounted suggestions that retailers will face increasing costs due to compliance obligations over the determination period, including costs associated with our proposed pricing comparator.

When basing the retail allowance on the Standard Retailers' historic costs, we considered the appropriateness of their forecast costs. In particular, we considered the explanations the retailers provided us as to why retail operating costs were expected to increase over the 2010 determination, which included:

- developing and implementing systems for managing obligations under climate change mitigation policies such as the CPRS, RET, ESS and the NSW Feed-in Tariff Scheme[233]
- conducting the retail component of smart metering technology trials and potentially rolling out of this technology[234]
- developing and implementing systems and processes to meet new or changed obligations under the National Energy Consumer Framework (NECF),[235] and
- increasing bad and doubtful debt.[236]

Our use of historical costs to set the retail cost allowance does not mean that we consider business activities over the determination period to be completely consistent with recent or past activities.[237] We reiterate that we consider the allowance covers the costs associated with changes to existing regulatory obligations expected over the determination period, such as the ESS and expanded RET. With respect to

232 EnergyAustralia submission, February 2010, p 30; Integral Energy submission, February 2010, p 6; Country Energy submission, February 2010, p 11; Origin Energy submission, February 2010, p 12, AGL submission, February 2010, p 18.
233 Country Energy submission, September 2009, p 29; AGL submission, September 2009, p 27; Origin Energy submission, September 2009, p 26.
234 Country Energy submission, September 2009, p 29; AGL submission, September 2009, p 27; Origin Energy submission, September 2009, p 26.
235 Country Energy submission, September 2009, p 29; Origin Energy submission, September 2009, p 26.
236 EnergyAustralia submission, September 2009, p 19; Country Energy submission, September 2009, p 29; AGL submission, September 2009, p 27; Origin Energy submission, September 2009, p 29.
237 Integral Energy submission, February 2010, p 6.

compliance costs associated with new regulatory obligations, such as the proposed obligations under the NECF, we consider that they are best catered for through the cost pass-through mechanism, when the materiality of such costs is known with greater certainty. (Chapter 10 discusses our decisions on the cost-pass-through mechanism.)

In relation to the CPRS, it has still not been made clear what specific regulatory obligations the Standard Retailers face under this scheme, given that they are not directly responsible for carbon emissions.[238] Therefore, we consider it unlikely that the CPRS will impose new regulatory administration costs on the Standard Retailers. We also reiterate that the CPRS will primarily affect Standard Retailers' energy purchase costs, and we have accounted for this in setting the energy purchase cost allowance. (Note that the costs of meeting obligations under GGAS, the ESS and RET are also included in the total energy cost allowance, as discussed in Chapter 6.)

Origin Energy submitted that a retail allowance based on historical costs does not cover the costs of trading or procuring wholesale energy costs in a non-ETEF environment.[239] We note that on average about a third of Standard Retailers' customer bases already comprise negotiated customers. We also note that ETEF is planned to be phased out over the determination period and not removed at the start of the period, and that managing ETEF is not costless but involves administrative costs that would be included in historical costs. Origin Energy did not provide any specific estimate regarding trading costs in a non-ETEF environment – or what proportion of retail costs this may represent.

AGL considered a real reduction in retail costs from the current allowance was not warranted in light of higher incidences of bad and doubtful debt over the determination period.[240] We note that the various government customer assistance and compensation packages (discussed in Chapter 11) should help manage some of the risk of increasing debt associated with the price increases allowed under the 2010 determination. We also note that the Standard Retailers did not report any material difference between the average historic and forecast per customer costs for bad and doubtful debt in their information returns. Therefore, we believe our retail cost allowance provides for an appropriate level for bad and doubtful debt.

In forming this view, we also considered the information Country Energy provided on benchmarking the cost of bad debt.[241] This information was based on analysis undertaken by the Utilities Industry Workgroup in Melbourne, and suggested an appropriate benchmark for this cost is 0.62% of sales. We note our decision on ROC includes bad debt costs in line with this percentage benchmark.

238 Origin Energy submission, February 2010, p 12.
239 Origin Energy submission, February 2010, p 11.
240 AGL submission, February 2010, p 17.
241 Country Energy submission, September 2009, p 29.

Finally, we consider the proposed pricing comparator to impose little additional compliance costs on the Standard Retailers, as we have recommended this service not be administered by the Standard Retailers. We also note that our retail cost allowance should cover any additional costs incurred with this service, as it is benchmarked against allowances in other jurisdictions that already require retailers to publish their rates on their websites and submit their prices to pricing comparator administrators.

We also decided to estimate CARC based on the Standard Retailers' actual historic costs. However, EnergyAustralia believed that CARC would not remain unchanged in real terms over the determination period. It considered the cost of outsourcing sales staff - a significant portion of acquisition costs - will increase in real terms over the determination period and outstrip potential productivity improvements because of increased competition for these resources from other industries.[242]

Although we used historic costs in setting our CARC allowance, it is based on a $213 unit acquisition cost which is broadly consistent with unit acquisition costs forecast by the Standard Retailers over the determination period. We also note that our allowance for customer acquisition costs is one of the highest in all jurisdictions.

On balance, we decided it was more consistent with our terms of reference to estimate CARC per customer for the 2010 determination period based on the Standard Retailers' actual historic costs. In addition, we consider there is likely to be potential for productivity improvements over the determination period in this area, and the resulting savings should be sufficient to offset any real increase in CARC that may materialise over the determination period.

7.3.5 What point within the estimated cost range should the allowances of ROC and CARC be based?

Our bottom-up analysis produced a range of per customer costs for ROC and CARC separately (ie, from the lowest estimated cost and highest estimated cost among all 3 Standard Retailers). We decided to use the mid-point in each cost range as the basis for the allowances for each of these costs.

The retailers argued that our decision to use the midpoint of the range of retail costs neglected the comparatively low levels of competition in NSW, which in itself is indicative of a lack of cost reflective retail tariffs.[243] They considered the high end of the range of retail costs provided a return more commensurate with a standalone retailer's costs and have a positive effect on competition, thus better satisfying our efficiency and competition criteria.

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242 EnergyAustralia submission, February 2010, p 31.

243 TRUenergy submission, February 2010, p 2; AGL submission, February 2010, pp 17-18; Origin Energy submission, February 2010, p 13.

We reiterate that the midpoint of the range identified for retail costs was not an arbitrary choice[244], especially with regulated tariffs reaching full cost reflective levels in 2009/10. We acknowledge that choosing a lower point may have reflected efficient costs (although we also note that this is not necessarily the case —for example, a Standard Retailer might achieve lower costs by not allowing for any system investment, which would not be efficient). In addition, we acknowledge that choosing a higher point may better facilitate competition and provide a more conservative allowance to cover increases in costs. However, in an environment of cost reflective tariffs, the midpoint represents a measured choice that balanced our efficiency and competition criteria.

We also note the Minister's submission that final increases to regulated tariffs be no more than required to ensure the ongoing financial viability of the NSW Standard Retailers.[245] Our efficient retail cost allowance was not just based on our bottom-up analysis, but also on our benchmarking analysis. The high end of the range for retail costs identified through our bottom-up analysis of about $125 per customer was not considered efficient because it was substantially higher than the midpoint of our benchmark range of $93 per customer. Our 2010/11 retail cost allowance of $109.80 per customer provided a more reasonable estimate that was still above the midpoint of our benchmark range and therefore balanced both efficiency and competition concerns.

7.3.6 Results of our bottom-up analysis of ROC

The results of our bottom-up analysis of ROC per customer for all Standard Retailers in each year of the determination period are shown in Table 7.2. To obtain these results we estimated the range for the variable and fixed components of these costs in each year of the determination period, then summed these components to give the range for ROC in each year. We determined the mid-point of this range, and then set the ROC allowance for each year in line with this point. As the table indicates, we found that:

- The range for the variable component of ROC is $14 to $20 in each year of the determination period.
- The range of the fixed component of ROC is $47 to $70 in the first year of the determination period, increasing to $50 to $75 in the last year. This is based on the Standard Retailers' average historic fixed costs plus an annual adjustment of 3.3% in real terms to account for declining customer numbers.[246]

244 TRUenergy submission, February 2010, p 2.

245 Minister for Energy submission (John Robertson MLC), February 2010, p 1.

246 We assumed that 75% of retail operating costs is fixed. This assumption is supported by information provided by the Standard Retailers which showed the contribution of fixed costs to total ROC ranged from 76% to 77% and variable costs from 23% to 24%. This is consistent with the proportion assumed in the retail margin analysis.

In 2010/11, the mid-point on the ROC range is $75.30 per customer. This is very similar to the 2009/10 allowance for ROC under the 2007 determination of $76.60 per customer (after it has been adjusted to remove marketing costs, consistent with the cost items included in estimating ROC for the 2010 determination).[247]

We note that fixed costs increase by 3.3% per year over the determination period instead of the 2.4% included in the draft report. This change reflects the update to customer number forecasts and has increased ROC over the determination period by an average of about $1.10 per customer per year.

Table 7.2 Bottom-up range analysis of ROC ($2009/10, $/customer)

	Year	Range of variable component	Range of fixed component	Range of ROC	Mid point
Base year	**2002/03 to 2008/09**	**14 to 20**	**45 to 68**	**59 to 88**	
2010 determination period	2010/11	14 to 20	47 to 70	60 to 90	75.3
	2011/12	14 to 20	48 to 73	62 to 93	77.2
	2012/13	14 to 20	50 to 75	63 to 95	79.2

7.3.7 Results of our bottom-up analysis of CARC

The results of our bottom-up analysis of CARC per customer indicate that the level of these costs is between $28 and $45 with a mid-point of $36.80. This is based on the Standard Retailers' average historic CARC over the period 2002/03 to 2008/09 (in 2009/10 dollars). We consider this range to be reasonable, and note that it includes:

- A midpoint of about $6 per customer for retention costs. This is comparable to the equivalent costs allowed for in the ROC for the 2007 determination.
- A midpoint cost of $28 per customer for the acquisition of new customers. This is based on a midpoint cost of $213 to acquire a new customer, which is broadly comparable to the $218 in 2009/10 dollars that we allowed for in the 2007 determination.
- A midpoint cost of $2 per customer for transferring existing customers onto negotiated contracts. This is based on a cost range of $138 to $167 per existing customer transferred between standard and negotiated contracts. There was no specific allowance for this cost in the 2007 determination. However, given that the range of estimates provided by the Standard Retailers was quite narrow it appears to be reasonable.

247 Our allowance for ROC in the 2007 determination is $82.60 per customer in 2009/10 dollars. Marketing costs averaged over the period 2002/03 to 2008/09 are estimated to be about $6 per customer across all Standard Retailers. Therefore, our 2007 allowance for ROC net of marketing costs in 2009/10 dollars is estimated to be $76.60 per customer.

The approach we used for this analysis was simpler than proposed in our Draft Methodology Paper due to data limitations.[248] We calculated the total CARC allowance per customer by adding together the average historic costs of each Standard Retailer's acquisition, transfer, and retention activities. This involved:

- Estimating the per customer cost for transferring new customers from another retailer and for transferring existing customers from a standard to a negotiated contract using the following expensing method:
  - estimating the total cost incurred per customer for each of these transactions
  - estimating the number of new customers acquired from other retailers and the number of existing customers transferring to negotiated contracts so that these activities were expensed as they occur.[249]
- Calculating the CARC allowance for retaining existing customers by subtracting the marketing costs from ROC and spreading marketing costs over the total small retail customer base, recognising that marketing targets existing and new customers.[250]

In applying this approach, we assumed a 13% churn rate for small retail customers transferring between retailers, based on the AEMO small retail customer transfer statistics in NSW over 2009.[251] We used this churn rate to estimate the number of new residential and business customers acquired each year by each Standard Retailer. The rate is higher than that indicated by customer transfer data provided by the Standard Retailers. However, some stakeholders consider historic churn rates in NSW to be too low and expect them to increase as tariffs increase.[252]

We reiterate that, on balance, we decided to use AEMO's transfer data because it is transparent and objective. We also consider our switch rate a reasonable forward estimate, given that switch rates are not the only indicator of competition. We note that we have increased the switch rate from 11% to 13% since the release of the draft report to reflect updated AEMO data on transfer activity in NSW. The updated switch rate increased CARC by $4 per customer per year from the draft report.

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248 Several retailers noted the analytic and data complexity of our proposed approach and expressed concern that the relevant data may not be available and/or may not be adequate for this level of detailed analysis. See AGL submission, September 2009, p 28; Origin Energy submission, September 2009, p 30.

249 We note that this approach has been adopted by QCA to estimate customer acquisition costs for a Standard Retailer since the 2008/09 Benchmark Retail Cost Index.

250 We note that this approach differs to that proposed in our draft methodology. It addresses concerns raised in submissions (for example by EnergyAustralia) about the generic nature of retention costs. It also addresses AGL's concerns that marketing costs were to be amortised rather than expensed.

251 The numbers of transferred consumers reported in these statistics represent the number of completed change requests in MSATS for a change of retailer or to create a new second tier connection point. Data Source: AEMO, Retail transfer statistical data http://www.aemo.com.au/data/retail_transfers.html, accessed February 2010

252 AGL submission, February 2010, p 19; Origin Energy submission, February 2010, p 12; TRUenergy submission, February 2010, p 2.

We also derived an 'internal' churn rate specific to each Standard Retailer for transfers of existing customers onto negotiated contracts (ie, transfers within the same retailer). This involved:

- applying the 13% 'external' churn rate to each Standard Retailer's year on year change in total negotiated customers to obtain an estimate of how many negotiated customers are won from other retailers each year
- assuming that the residual number of customers represents the number of internal transfers each year onto negotiated contracts
- dividing the number of internal transfers by the Standard Retailer's total small customer numbers to obtain a proxy for the internal churn rate.

We note that because this internal churn rate is a proxy, it may not capture all the transfers onto negotiated contracts that occur over the year within the same retailer, such as contract renewals. However, apart from the external churn rate, all the data used in our derivation of internal churn rates are based entirely on the customer numbers provided by the Standard Retailers themselves. On this basis, we consider the internal churn rates to be reasonable proxies.

In estimating the CARC, we considered each Standard Retailer's actual historic data on their customer acquisition, transfer and retention costs and customer numbers. In one case, a Standard Retailer did not provide information on the cost of transferring an existing customer from a standard to a negotiated contract. In this case, we used the 2009/10 QCA allowance for this ($106),[253] as this was the only publicly available estimate of this cost.[254]

7.4 Benchmarking retail costs

We compared our combined bottom-up estimate of ROC and CARC (minus the deduction for double counting, as discussed in section 7.2) with the retail cost allowances set in past determinations in NSW and other jurisdictions. We also compared this estimate with other relevant information, including information disclosed by publicly listed businesses. As these comparisons confirmed that this estimate is reasonable, we set the retail cost allowances for the 2010 determination in line with it.

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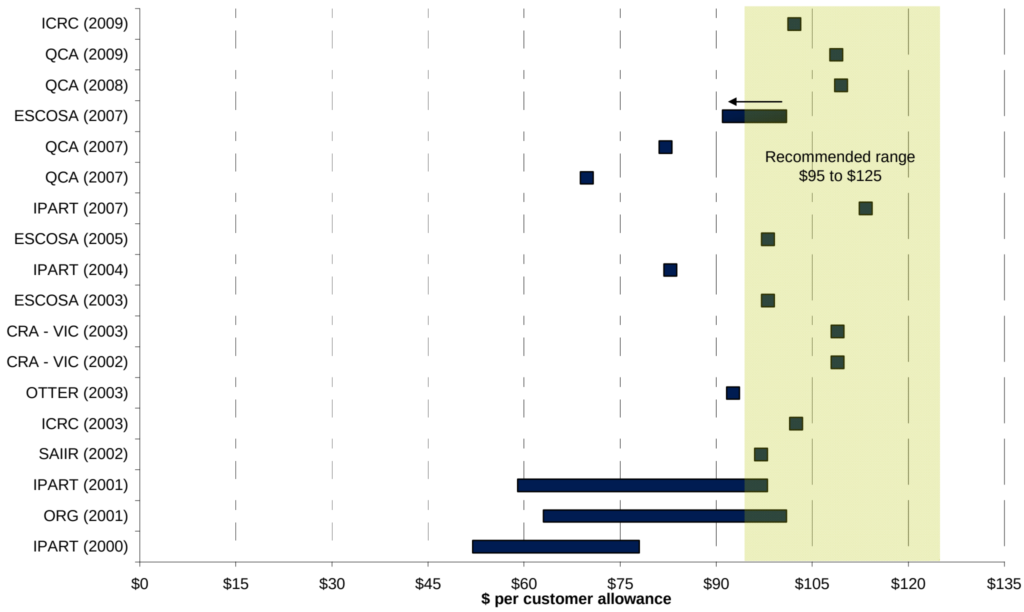
253 Note that the QCA escalated the customer acquisition costs established for 2007/08 (the base year) to 2009/10 values based on a weighted average of price (40%) and wage (60%) inflation in 2007/08 and 2008/09. See CRA report prepared for the QCA, *Calculation of the Benchmark Retail Cost Index 2009-10*, June 2009, p 87.

254 We note that the QCA allowance was deduced from the AEMC findings on customer acquisition costs in their review of the competitiveness of the South Australian electricity and gas markets. See AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia - First Final Report Appendices*, December 2008, pp 189-190.

We considered stakeholders' concern that benchmarking be conducted on a consistent basis.[255] We found that there are many variations in the way regulators calculate and allow for customer acquisition costs. Some do not explicitly include an allowance for customer acquisition costs in retail costs. If they do, they tend to estimate these costs on different bases. In addition, while most regulatory decisions on retail cost allowance include a general allowance for marketing costs in recognition of retailers' need to defend their existing customer base, this allowance is generally not disclosed.

Given the above, we decided to benchmark our combined ROC and CARC estimate against past regulatory allowances for retail costs (rather than the subcomponents of these allowances). This benchmarking is shown in Figure 7.1. We are satisfied that these past regulatory allowances included comparable cost items to our combined ROC and CARC estimate. (See Appendix G for more information on the past regulatory allowances for retail costs we considered.)

Figure 7.1 IPART's combined ROC and CARC estimate[a] compared to past regulatory allowances for retail costs ($2009/10, $/customer)



a We have combined our range estimate for ROC in the first year of the 2010 determination of $60 to $90 per customer (see Table 7.2) with our bottom-up midpoint estimate of CARC of $36.80 per customer (see Table 7.1). We have also removed the $2.30 per customer late payment fee deduction from the ROC range to provide a proper representation of our final decision.

Note: We have converted our 2007 retail cost allowance in this benchmarking exercise in 2009/10 dollars using the actual quarter on quarter to June CPI for each year. This contrasts the CPI methodology outlined in our 2007 determination. Therefore, the 2007 allowance is $114.3 per customer, which comprises $81.7 retail operating cost, $38.1 customer acquisition cost, and $5.40 deduction for double counting. ESCOSA's 2007 allowance decreases over the determination period.

255 Origin Energy submission, September 2009, p 27; AGL submission, September 2009, p 27; EnergyAustralia submission, August 2009, p 35.

As this figure shows the range for our combined ROC and CARC estimate is $95 to $125 per customer, and the past regulatory decisions on the retail cost allowance were either within this range or lower than this range. In particular, we note our final decision to set the retail cost allowance for 2010/11 at $109.80 per customer is very similar to the 2009/10 retail cost allowances set by the QCA ($110 per customer) and the ICRC ($103 per customer). The QCA allowance provides a more valid comparison, as it includes an allowance for customer acquisition costs similar in components to ours.[256]

We also note that ESCOSA's retail cost allowance under its 2007 determination includes both customer acquisition and retention costs and is lower than our final decision.[257] In making its decision, ESCOSA did not compensate retailers for their declining customer bases, and factored in a 4.1% real annual reduction in retail operating costs due to efficiency gains. As a result, the annual retail cost allowance under this decision decreases from about $101 per customer in January 2008 to $91 per customer in December 2010.[258] In addition, we note that the QCA has not allowed a real increase in the retail cost allowance since about 2007/08,[259] while the ICRC has not allowed a real increase in this allowance since 2003/04.[260]

We also benchmarked our combined ROC and CARC estimate against publicly available information on the retail costs of AGL and Origin Energy (both of whom are privately owned incumbent retailers in other jurisdictions and second tier retailers in NSW). In particular, we note that our final decision on the retail cost allowance for 2010/11 ($109.80 per customer) is above AGL's and Origin Energy's most recently reported cost to serve ($94 and $63 per customer respectively).[261]

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256 The QCA provided an allowance of $20 per customer for acquiring new customers and a $6.50 per customer for defending a customer base and transferring existing customers to negotiated contracts. In comparison, our bottom-up estimate for acquiring new customers is about $28 per customer across the Standard Retailers, while the combined retention and customer transfer estimate is about $8.80 per customer.

257 Note that in particular we refer to ESCOSA's October to December 2010 allowance in 2009/10 dollars. See ESCOSA, *2007 Review of retail electricity path: Final inquiry report and price determination*, November 2007, p A-59.

258 ESCOSA, *2007 Review of retail electricity path: Final inquiry report and price determination*, November 2007, p A-59.

259 The QCA have generally used an escalation factor based on a 40/60 weighting of CPI and wage inflation as measured by the wage price index (WPI). See QCA, *Final Decision 2009-10 Benchmark Retail Cost Index*, June 2009.

260 The ICRC's cost incurred in providing retail services are based on an estimate of $85 per customer in 2003/04. In subsequent years, the figure has been adjusted for movements in the CPI. See ICRC, *Final Decision Retail Prices for Non-contestable Electricity Customers 2009–2010*, June 2009, p 40.

261 AGL and Origin Energy's costs to serve are for their retail electricity and gas businesses. We have converted AGL 2008/09 costs to serve in 2009/10 dollars. See AGL Energy Limited, 2009 Full year results, August 2009, p 56; Origin Energy Limited, 2010 Half year results, February 2010, p 45.

AGL and Origin Energy submitted that caution is required when comparing the Standard Retailers' retail costs with the retail operating cost information disclosed by publicly listed businesses – due to variations in reporting requirements, information disclosure requirements and general cost allocation techniques.[262] However, our examination of these retailers' reported retail costs suggest they are reasonably comparable to the costs we considered in setting the retail cost allowance. AGL's reported cost to serve of $94 per customer includes costs to grow and retain customers. It is uncertain whether corporate overheads are included in that cost estimate, but if they are not then they would add about $17 per customer to AGL's cost to serve, increasing its retail costs to about $111 per customer. Origin Energy's reported cost to serve of $63 per customer is somewhat low, but appears to not include CARC, which would add about $36 per customer.

Finally, we consider that AGL and Origin Energy's retail costs are unlikely to increase in real terms over the 2010 determination period. In particular, while AGL's cost to serve increased by 21.2% in 2008/09 due to process and billing issues associated with its new customer service and billing platform (Project Phoenix), it expects to reap the first full-year of productivity benefits from this platform by 2010/11.[263] Holding all else constant, we interpret this to mean that AGL's costs to serve should at fall back to levels comparable to its 2007/08 costs of $79 per customer over the 2010 determination period. We also note that Origin Energy's 2009 costs to serve decreased by 6% due to operational efficiencies and improved productivity.[264] In our view, this suggests the retail cost allowance in our final decision is reasonable.

Some retailers questioned the appropriateness of some of our benchmarks in the draft report, and noted that they needed to be adjusted upwards for the final determination.[265] In particular, they noted that:

- the ICRC's 2009/10 allowance does not include customer acquisition costs and should reflect this
- ESCOSA's 2008 to 2010 allowance did not compensate for declining customer numbers
- while the QCA's 2009/10 allowance is comparable to our allowance, its recently released 2010/11 allowance suggests our allowance is too low
- AGL and Origin Energy's publicly reported retail costs include economies of scale materially larger than the Standard Retailers and they should be adjusted to reflect this.

262 AGL submission, September 2009, p 26; Origin Energy submission, September 2009, p 27.
263 Macquarie Research Equities, *AGL Energy – FY09 Surprises to the upside*, 21 August 2009, p 2.
264 Origin Energy Limited, 2010 Half year results, February 2010, p 43.
265 Integral Energy submission, February 2010, p 7-8; EnergyAustralia submission, February 2010, p 32; AGL submission, February 2010, p 18.

With respect to the points made about the ICRC's and ESCOSA's allowances, we reiterate that we have taken these matters into consideration. We also note that our retail cost allowance is above the midpoint of the benchmark range of $93 per customer, which balances out some of the discrepancies inherent in any benchmarking analysis.

Since the release of our draft report, the QCA has released its proposed 2010/11 retail cost allowance of $129.62 per customer, which is significantly higher than its previous allowance of about $110 per customer. However, we note that the increase in its allowance stems from significantly higher switch rates used to calculate customer acquisition costs. The QCA did not increase its retail operating cost allowance in real terms, nor did it increase unit acquisition costs in real terms.[266] In addition, we note that the QCA's unit cost estimate for customers switching retailers of $186.69 is lower than the $213 unit cost underpinning our CARC allowance.

Finally, we do not consider AGL and Origin Energy to have significant scale economies additional to the Standard Retailers due to differences in the number of customers they serve. We refer to Frontier Economics' advice on this issue in the 2007 determination that a retailer's average cost curve is flat over a wide range of customer numbers, and efficient scale is reached at levels much lower than the Standard Retailers' customer bases.[267] Our benchmarking confirms this advice.

[266] Origin Energy submission, February 2010, p 14.
[267] Frontier Economics, *Mass market new entrant retail costs and retail margin*, March 2007, pp 7-8.

8 Retail margin allowance

As Chapter 4 discussed, the Standard Retailers face a range of risks over the 2010 determination period. Some of these are systematic risks associated with supplying electricity to small customers on regulated tariffs. These systematic risks include:

- The risk of variation in their regulated load profile due to changes in economic conditions that affect the demand for electricity. This may mean their actual regulated load profile is different to that assumed in setting regulated tariffs (but still within the normal range).
- The risk of variation in wholesale electricity spot and contract prices due to changes in economic conditions and demand. This may mean their actual energy purchase costs are different to those assumed in setting regulated tariffs (but still within the normal range).
- General business risk due to changes in economic conditions. This may mean that their actual costs and revenues are different to those assumed in setting regulated tariffs due to factors such as unexpected changes in interest rates or exchange rates, equipment failures, or fraud.

We consider it appropriate to compensate the Standard Retailers for the systematic risks they face through the retail margin allowance, and have set an appropriate retail margin that takes account of these risks.

We recognised that the Standard Retailers also face non-systematic risks – for example, those arising from uncertainties about the impact of the CPRS and other foreseen but uncertain market and policy developments over the period. We have addressed these non-systematic risks in setting the total energy cost allowance and other regulatory mechanisms within the regulatory package. We have addressed also the non-systematic risks from unforeseen regulatory and taxation change events through other mechanisms (see Chapters 6 and 10).

The sections below provide an overview of our final decisions on the retail margin allowance, and explain the approach we used to set this margin and each of the key steps in this approach.

8.1 Overview of final decisions on retail margin

IPART's final decisions are that the appropriate retail margin to include in regulated retail tariffs is 5.4% of EBITDA, and that this margin should be:

- expressed as a fixed percentage of each Standard Retailer's total costs in supplying small customers on regulated tariffs (retail and network)
- calculated in dollar terms for the purpose of setting the value of the regulated retail price controls (R values), and recalculated at each annual cost review so the dollar amount remains consistent with 5.4% of total costs as other cost elements are updated.

Our decision on the appropriate retail margin is consistent with the mid-point of the reasonable range for this margin recommended by our expert consultant, SFG. Our decision to set the retail margin as a fixed percentage of total costs, and recalculate the margin in dollar terms within the determination period is consistent with our terms of reference, which stress the need for prices to reflect the efficient costs of supply in each year of this period.

Our decision to set the retail margin allowance relative to the retailers' EBITDA (earnings before interest, tax, depreciation and amortisation) is consistent with the approach we used for the 2007 determination. We consider this to be more appropriate than a margin based on EBIT (earnings before interest and tax), as the retail operating cost allowance does not include depreciation and amortisation costs. All references to the retail margin in this report are based on EBITDA unless otherwise stated.

We note that our final decision on the appropriate retail margin is the same as our draft decision. However, we updated the WACC, increasing it by 30 basis points to 9.1%, reflecting updated market parameters and reduced the assumed level of debt from 40% to 30% of the asset base. Further, SFG's final analysis includes our final energy cost and cost of capital estimates (see section 8.6 below and Appendix E). These revisions marginally reduced the estimated margin from the expected returns approach and marginally increased the estimated margin from the bottom-up analysis, but SFG's overall estimates were unchanged. In making this final decision we have considered SFG's analysis and recommendations set out in its final report (which has been released together with this final decision)[268]. We also considered stakeholder comments on our draft report, including arguments for adopting a margin towards the upper end of the reasonable range, however, we considered that our draft decision provided retailers with an appropriate retail margin allowance.

268 SFG, *Estimation of the regulated profit margin for electricity retailers in New South Wales*, March 2010, available from www.ipart.nsw.gov.au

8.2 Approach for setting the retail margin

As set out in our draft decision[269], we used the same approach to set the retail margin as we used for the 2007 determination. However, we have updated this approach to take into account recent developments that affect the analysis of retail margin and more information.

We engaged SFG to provide expert advice on the feasible range for the retail margin over the 2010 determination period. We asked it to derive this range by using 3 alternative approaches for estimating the margin (as it did for the 2007 determination):

- expected returns
- benchmarking
- bottom-up.

We then selected an appropriate retail margin from within this range, and made a decision on whether to set the margin as a fixed percentage or a fixed dollar amount over the determination period.

We instructed SFG to base its cost assumptions for all of the above approaches on the carbon-inclusive energy cost allowances adopted for this final decision (see Chapter 6). We also instructed SFG to use a discount rate of 9.1% in assuming the cost of capital for the expected returns and benchmarking approaches.

A number of stakeholders provided technical comments on SFG's approaches in their submissions. These are addresses in SFG's final report, which is available on our website.[270]

8.3 Estimated range provided by the expected returns approach

The expected returns approach estimates the expected cashflows that a retailer will earn from small customers and the systematic risk associated with these cashflows, and then determines a retail margin that will compensate investors for this systematic risk. Its basic principal is that the retail margin should be set at a level that achieves a balance between the systematic risk to the net cashflows to the electricity retailers and the systematic risk assumed when estimating the cost of capital for those same electricity retailers.

269 IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013 – Draft Report and Draft Determination, December* 2009.

270 SFG, *Estimation of the regulated profit margin for electricity retailers in New South Wales*, March 2010.

SFG's estimated range for the retail margin using the expected returns approach was 3.4% to 4.8%, with a mid-point of 4.1%. This range is slightly lower than the range used in the draft decision. The range has fallen because of the revised energy cost and cost of capital estimates. SFG's approach is unchanged. This is lower than the estimated range it derived for the 2007 determination, which was 4.3% to 6.4%.[271] This is mainly because for the 2010 determination, SFG assumed that the Standard Retailers' non-volume-related costs are 15% to 25% of their total costs (rather than 20% to 30% as previously assumed). SFG based this assumption on information provided by the Standard Retailers for the 2010 review, which indicated that these costs comprise less than 20% of total costs. SFG took a conservative approach, and adopted a range of 15% to 25% for its calculations. Had it used the previous range of 20% to 30%, the resulting range for the retail margin would have been 4.3% to 6.0%.[272]

As for the 2007 determination, SFG assumed a one-for-one relationship between growth in GDP and growth in demand for electricity from small retail customers. In the 2007 review, we questioned whether this relationship really is one-for-one. However, we accepted Frontier Economics' recommendation to assume this relationship in estimating the range for the retail margin, as there was insufficient evidence to show there was not a one-for-one relationship.[273]

For the 2010 review, we undertook further analysis on this issue, and also asked SFG to provide advice on the relationship. Our analysis was not conclusive, and also found there is insufficient evidence to depart from the assumption of a one-for-one relationship between GDP and electricity sales to small retail customers. (This analysis is summarised at Appendix F.) SFG undertook a review of literature and empirical studies on this issue, and reached the same finding as we did. SFG's analysis is attached to its report.[274]

As indicated above, we asked SFG to estimate the range for the retail margin using the energy cost allowances, which include the forecast impact of the CPRS. However, for the expected returns approach we also asked it to estimate the margin using energy costs which exclude the forecast impact of the CPRS, for comparison. Excluding the forecast impact of the CPRS resulted in a higher range for the retail margin, as it decreases the proportion of volume-related costs and lowers the overall cost base. The estimates are provided in SFG's report for information purposes.[275]

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271 Frontier Economics and SFG, *Mass market new entrant retail costs and retail margin*, March 2007, p 58.

272 SFG, *Estimation of the regulated profit margin for electricity retailers in New South Wales*, December 2009, p 15.

273 IPART, *Promoting retail competition and investment in the NSW electricity industry's – Regulated electricity retail tariffs and charges for small customers 2007 to 2010 - Final Report and Final Determination,* June 2007, p 110.

274 SFG, *The association between changes in electricity demand and GDP growth*, attached to SFG's March 2010 report.

275 Ibid, p 20.

We note that during our consultations, a number of stakeholders submitted that the expected returns approach should reflect the costs of a mass market new entrant rather than a Standard Retailer.[276] For example, Country Energy argued that the capital requirements of a mass market new entrant are different to a Standard Retailer's as the latter currently has access to the ETEF to manage some of the risks associated with purchasing wholesale electricity to supply its regulated load.[277] However, to comply with our terms of reference, we have set the retail margin allowance (and the other cost allowances) in line with the costs of an efficient Standard Retailer.

In addition, Origin Energy submitted that the assumptions on growth in demand for electricity need to take into account factors which will affect demand in the future, such as energy efficiency programs and interval metering.[278] We are satisfied that SFG took account of all appropriate factors, including those noted by Origin Energy. Further information on the growth assumptions used and how they were derived is provided in SFG's report.[279]

8.4 Estimated range provided by the benchmarking approach

The benchmarking approach examines the reported margins of comparable listed firms to establish a range of the retail margin. The underlying assumption of this approach is that the retail margin for an electricity retail business should be broadly consistent with those for other comparable retail businesses. SFG's estimated range for the retail margin using the benchmarking approach was 6.4% to 6.9%, with a mid-point of 6.7%. This range is unchanged from the draft decision.

In identifying comparable listed firms for this approach, SFG used an expansive interpretation of the term 'comparable'. This enabled it to examine data from a large number of retailers in Australia, the United States and the United Kingdom – in total, over 300 retail firms across 6 sub-industries. In taking this expansive view, SFG recognised the tradeoffs between examining data from a large number of comparable firms versus ensuring these firms face the same risks and growth prospects as an electricity retailer in NSW. In SFG's opinion, it was important to consider data from a large number of comparable firms as it improves the statistical reliability of its estimates.[280]

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276 Country Energy submission, August 2009, p 21; Jackgreen submission, August 2009, p 1; and Origin Energy submission, August 2009, p 24.

277 Country Energy submission, August 2009, p 21.

278 Origin Energy submission, September 2009, pp 33-34.

279 SFG, *Estimation of the regulated profit margin for electricity retailers in New South Wales*, March 2010, p 13.

280 SFG, *Estimation of the regulated profit margin for electricity retailers in New South Wales*, March 2010, pp 25-27.

SFG also compared its estimated range for the retail margin using the benchmarking approach with the profit margins of retail energy businesses in Australia, including the 3 NSW Standard Retailers. It found that these profit margins were consistent with its estimated range of 6.4% to 6.9%.[281]

In addition, SFG compared its estimated range for the retail margin in light of recent regulatory decisions. It found that in Queensland, South Australia and the ACT, regulators have adopted a retail margin of 5%. SFG noted that this margin is lower than the range it derived using the benchmarking approach, and approximately equivalent to the lower end of the feasible range it derived using all 3 approaches. However, it also noted that the extent to which they had considered the risks retailers face in adopting this margin (as IPART is required to do) was not clear.[282] (Our consideration of this issue is discussed in section 8.7 below.)

Some stakeholders raised concerns about the benchmarking approach. In particular, EnergyAustralia questioned its usefulness, given that a large number of assumptions and/or adjustments need to be made so that companies can be compared on a like-for-like basis. It argued that non-energy retailers and overseas regulated retailers are not comparable businesses for benchmarking the appropriate retail margin. It also argued that benchmarking should only be used as a "prudence check".[283]

We considered stakeholder criticisms of the benchmarking approach and remain of the view that the estimated range provided by this approach is an important component in setting the retail margin. The strength of the benchmarking approach is that it provides an estimated range that reflects the profit margins observed in the market. This means it can be used to assess whether the estimates provided by the other theoretical approaches are realistic and consistent with market data.

We also support SFG's decision to adopt an expansive interpretation of the term comparable to obtain a large sample of comparable retail firms. In our view, this larger sample size makes SFG's results more rigorous and reliable than those provided in 2007, which were based on a more limited sample size.

8.5 Estimated range provided by the bottom-up approach

The bottom-up approach starts from an assumed investment base and cost estimates, then determines the earnings and revenue which would allow the retailer to earn an expected return equal to its estimated cost of capital. SFG's estimate of the range for the retail margin using this approach was 4.5% to 6.3%, with a mid-point of 5.4%. This range is slightly higher than the range used in the draft decision reflecting the revisions to both the energy cost and cost of capital estimates.

281 Ibid, p 29-30.
282 Ibid, p 10.
283 EnergyAustralia submission, September 2009, pp 23-24.

As SFG explained in its final report, it has revised its bottom-up approach since the 2007 review. For that review, it relied on data provided in the Standard Retailers' submissions to apply this approach. For the 2010 review, it used its own methodologies and collected its own data, and had regard to the information in retailers' submissions. (More detailed information on these methodologies, including the approach used to estimate the asset base and the margins under alternative asset base estimates, is provided in SFG's final report.)[284]

We note that some stakeholders expressed strong support for basing the retail margin on the estimates provided by the bottom-up approach. For example, Country Energy submitted that this approach is most consistent with the role of the retail margin, which is to compensate retailers for the opportunity cost of the capital an efficient and prudent retailer requires.[285] However, it also argued that an allowance for customer acquisition costs should be included in the retail margin. It noted that ESCOSA accepted the principle that customer acquisition costs were part of both retail margin and retail cost estimates.[286]

Origin Energy submitted that recent market transactions need to be carefully considered in deciding on the assumed investment base, as recent prices paid reflect complex valuations.[287] Country Energy also suggested asset categories that should be included in this base.[288]

We acknowledge that the estimated range for the retail margin derived with a bottom-up approach depends on the key assumptions used in this approach. We note that SFG's report provides a detailed explanation of its approach and how the estimates vary under different asset base valuations.

As for the expected returns approach, we asked SFG to apply the bottom-up approach using energy costs allowances that both include and exclude the forecast impact of the CPRS. The results are presented in SFG's report for information.[289]

8.6 Cost of capital assumptions used in the expected returns and bottom-up approaches

As for the discount rate used in estimating the LRMC of generation (see Chapter 6), we determined the appropriate discount rate for the purpose of estimating the retail margin, and instructed SFG to use this rate in its analysis.

[284] SFG, *Estimation of the regulated profit margin for electricity retailers in New South Wales*, March 2010, pp 30-45.
[285] Country Energy submission, September 2009, p 32.
[286] Country Energy submission, September 2009, p 33.
[287] Origin Energy submission, September 2009, p 34.
[288] Country Energy submission, September 2009, p 33.
[289] SFG, *Estimation of the regulated profit margin for electricity retailers in New South Wales*, March 2010, pp 43-44.

We found that a discount rate 9.1% is appropriate for this purpose, after considering a range of parameters. In our view, the 2 key parameters in relation to the cost of capital for electricity retailers are the equity beta and the gearing level. Our analysis indicates that relative to other businesses we regulate, electricity retailing is significantly riskier. Electricity retailing also seems to be more risky than generation. In particular, electricity retailers tend to have a lower asset base and higher revenue volatility. Therefore, for our final decision, we decided to adopt:

- a lower target gearing level of 30%
- an equity beta of 0.9 to 1.1, to reflect our view that the equity beta of electricity retailers is likely to be higher than our normal industry range of 0.8 to 1.0.

In the draft decision we adopted a gearing level of 40% and an equity beta of 0.9 to 1.1. We have further considered these issues, including examining information submitted by stakeholders and we decided to reduce the gearing level but to maintain the draft decision on equity beta for this final decision. Other changes to the discount rate reflect updates to the market-based parameters (the nominal risk free rate, inflation and debt margin) using data as of 8 February 2010.

In reaching these decisions we considered data on Australian and overseas electricity businesses, professional valuations, stakeholder submissions and regulatory decisions. We note that it is difficult to obtain data for electricity retailers or generators as stand-alone entities. We also considered advice provided by SFG.[290] SFG's recommended a gearing level of 35% for electricity retail (and 50% for generation) and an equity beta of 1.0 for both. Our final decision is consistent with this advice.

We note that several stakeholders submitted that the cost of capital estimates set out in our draft decision were too low and do not reflect the cost of capital for electricity retailers.[291] Other stakeholders made technical comments.[292] Appendix E outlines our consideration of stakeholder comments, and provides detail on the key market parameters underlying our final decision on the appropriate discount rate.

8.7 Selecting an appropriate margin within the feasible range

The total range for the retail margin provided by the 3 approaches discussed above is 3.4% to 6.9% of a retailer's total electricity sales (EBITDA).[293] SFG's recommended reasonable range is 4.8% to 6.0%.[294]

290 SFG, *Equity beta and gearing estimates for electricity retail and generation businesses - draft report for IPART*, 14 July 2009.

291 EnergyAustralia submission, February 2010, p 37; and AGL submission, February 2010, p 22.

292 Origin submission, February 2010, pp 15-16; and Country Energy submission, February 2010, p 11.

293 Lower and upper bound estimates for all 3 approaches over the 3-year period.

294 SFG calculate this as the average of the upper and lower bounds of the EBITDA margins ranges for the three individual forecast years.

While it could be argued that any value chosen within this range is reasonable, we consider the best way to select the appropriate retail margin is to weight the estimates provided by each approach equally. Therefore, we took the mid-point value from the range provided by each approach: 4.1% (expected returns approach); 6.7% (benchmarking approach); and 5.4% (bottom-up approach) and attached a weighting of one-third to each of these values which provided a retail margin of 5.4%. This value is consistent with the mid-point of the reasonable range recommended by SFG.

This decision is consistent with the draft decision. While the reasonable ranges for the expected returns and bottom-up approaches changed slightly as a result of revisions to the energy cost and cost of capital estimates, the mid-point of the reasonable range remained at 5.4%.

Stakeholders have expressed mixed views on the appropriate retail margin. While a number of the retailers argued it should reflect the top of the feasible range,[295] NCOSS noted that increasing tariffs to provide for a higher retail margin to facilitate competition is not in the long-term interest of the majority of customers who have not moved to a market contract.[296]

We note that we might have used our regulatory discretion to adopt any value within the reasonable range identified by SFG. However, we consider that this approach is not as robust as the one we used. In particular, if we chose a point which varies greatly from the mid-point of this range, it would increase the risk that the retail margin allowance differs from the margin an efficient Standard Retailer requires, as required by our terms of reference.

We note that our final decision on the appropriate retail margin is slightly higher than other recent regulatory decisions on retail margin, and our decision on the margin for the 2007 determination (5%). However, we consider that our final decision of 5.4% is broadly consistent with these other decisions.

We consider that our final decision reflects an appropriate retail margin because it provides the Standard Retailers with a retail margin consistent with the margin an efficient retailer would require. This should encourage competition, while also ensuring retail prices reflect efficient costs.

[295] TRUenergy submission, August 2009, p 8; and EnergyAustralia submission, February 2010, p 37.

[296] NCOSS submission, August 2009, p 6.

8.8 Setting the retail margin as a fixed percentage amount

We have decided to set the retail margin as a fixed percentage of each retailer's total costs (retail and network) for the determination period. We calculated this percentage in dollar terms for the purpose of setting the value of the regulated retail price controls (R values), and will update this calculation at each annual cost review to reflect updates in the total costs. This will ensure that the dollar amount remains consistent with 5.4% of total costs in each year of the determination period. This decision is consistent with our draft decision.

This differs from the approach we used for the 2007 determination, when the retail margin was determined as 5% of total costs, but included in the R values as a fixed real dollar amount for each year. There was no provision for this amount to be reviewed or updated during the determination period. This meant that retailers' actual margins could have been more or less than 5%, depending on the movement in retail and network costs throughout the determination period.

Stakeholders have expressed support for the revised approach, as it ensures the margin remains consistent with the determination as other cost elements are revised during the determination period.[297]

[297] EnergyAustralia submissions, September 2009, p 22 and February 2010, p 34; Integral Energy submission, September 2009, p 5; Country Energy submission, September 2009, p 34; and Jackgreen submission, September 2009, p 1.

9 Regulated retail price controls

After making our final decisions on the total energy cost allowance, the retail cost allowance and the retail margin allowance (discussed in Chapters 6 to 8), we converted these allowances into the regulated price controls (or R values) for each Standard Retailer. The retailers must use these R values (and the N values) to calculate the maximum annual amount by which they can increase their regulated retail tariffs under the WAPC form of regulation.

As discussed in Chapter 5, the R values within the WAPC are set to allow each Standard Retailer to fully recover the total efficient costs that we have allowed in the 2010 determination. There are separate R values for the fixed and variable components of regulated tariffs. The fixed R values are expressed as $ per customer, while the variable R values are expressed as $ per MWh.

The section below sets out our final decisions on the R values for each Standard Retailer for each year in the determination period. The subsequent sections summarise our decisions on each Standard Retailer's efficient cost allowances and discuss how we calculated the R values for the final determination.

Please note that the N values in the WAPC are set to allow each Standard Retailer to fully recover the actual costs it incurs in paying the network fees and levies. These network fees are determined by the AER and are not affected by our 2010 determination. Therefore, this chapter focuses only on the R values.

9.1 Overview of final decision on the R values

IPART's final decision is to set the regulated retail price controls (R values) as shown in Table 9.1 below.

Table 9.1 Final decision on R values for the 2010 determination period ($2009/10)

Description	2009/10	2010/11	2011/12	2012/13
EnergyAustralia				
Fixed retail costs - $ per customer	94.6	91.6	93.0	94.5
Variable retail costs - $ per MWh	86.4	87.0	96.4	126.4
Integral Energy				
Fixed retail costs - $ per customer	94.6	91.6	93.0	94.5
Variable retail costs - $ per MWh	92.0	90.1	100.1	133.2
Country Energy				
Fixed retail costs - $ per customer	94.6	91.6	93.0	94.5
Variable retail costs - $ per MWh	83.7	87.1	98.0	131.0

9.2 Efficient cost allowances

As Chapters 6 to 8 discussed, we have set allowances that reflect the total energy costs and retail costs an efficient Standard Retailer is likely to incur in supplying customers on regulated tariffs and an appropriate retail margin for such a retailer for each year of the determination period. Table 9.2 summarises our final decisions on these allowances, and compares our final decisions with the allowances for 2009/10 under the 2007 determination.

Table 9.2 Final decisions on the efficient cost allowances for each Standard Retailer compared with 2009/10 allowances ($2009/10)

Description	2009/10[a]	2010/11	2011/12	2012/13
	2007 determination	2010 determination		
EnergyAustralia				
Electricity purchase cost ($/MWh)	63.7	66.3	73.0	97.9
Green costs ($/MWh)	6.0[a]	2.5	3.2	3.9
NEM fees ($/MWh)	0.7	0.8	0.8	0.8
Energy losses *($/MWh)*	4.8	4.9	5.4	7.2
Total energy cost allowance ($/MWh)	***75.3***	***74.5***	***82.5***	***109.8***
Retail operating costs ($/customer)	82.6	75.3	77.2	79.2
Customer acquisition and retention costs ($/customer)	32.7	36.8	36.8	36.8
Adjustment for double counting ($/customer)		-2.3	-2.3	-2.3
Total retail cost allowance ($/customer)	***115.3***	***109.8***	***111.7***	***113.7***
Retail margin allowance (%)	***5.0***	***5.4***	***5.4***	***5.4***
Integral Energy				
Electricity purchase costs ($/MWh)	67.0	68.4	75.8	103.8
Green costs ($/MWh)	6.1[a]	2.5	3.2	3.9
NEM fees ($/MWh)	0.7	0.8	0.8	0.8
Energy losses ($/MWh)	6.7	6.2	6.9	9.4
Total energy cost allowance ($/MWh)	***80.6***	***77.9***	***86.7***	***117.9***
Retail operating costs ($/customer)	82.6	75.3	77.2	79.2
Customer acquisition and retention costs ($/customer)	32.7	36.8	36.8	36.8
Adjustment for double counting ($/customer)		-2.3	-2.3	-2.3
Total retail cost allowance ($/customer)	***115.3***	***109.8***	***111.7***	***113.7***
Retail margin allowance (%)	***5.0***	***5.4***	***5.4***	***5.4***
Country Energy				
Electricity purchase costs ($/MWh)	56.6	61.7	69.1	95.2
Green costs ($/MWh)	6.3[a]	2.5	3.2	3.9
NEM fees ($/MWh)	0.7	0.8	0.8	0.8
Energy losses ($/MWh)	7.8	7.8	8.7	11.9
Total energy cost allowance ($/MWh)	***71.5***	***72.7***	***81.9***	***111.9***
Retail operating costs ($/customer)	82.6	75.3	77.2	79.2
Customer acquisition and retention costs ($/customer)	32.7	36.8	36.8	36.8
Adjustment for double counting ($/customer)		-2.3	-2.3	-2.3
Total retail cost allowance ($/customer)	***115.3***	***109.8***	***111.7***	***113.7***
Retail margin allowance (%)	***5.0***	***5.4***	***5.4***	***5.4***

a Including costs associated with the NSW Renewable Energy Target Scheme (NRET).

Note: Columns may not add due to rounding. The adjustment for double counting is made from the retail cost allowance. The margin is calculated on an EBITDA basis (including both the network and retail components).

9.3 How we set the R values for the final determination

To set the R values for each retailer and each year, we disaggregated each of the efficient cost allowances into their fixed and variable cost components, and calculated the cost per unit for each group of components.

The fixed cost components account for 100% of customer acquisition and retention costs and 75% of retail operating costs (after the adjustment for double counting of late payment costs). These costs are expressed in terms of dollars per customer, and are the same for all 3 retailers. Therefore, we set a single fixed R value per year that is common to all 3 retailers.

The variable cost components include 100% of total energy costs, 25% of retail operating costs (after the adjustment for double counting of late payment costs), and 100% of the retail margin. These costs are expressed in terms of dollars per MWh. These costs vary for each retailer (because the total energy cost allowance and the dollar value of the margin vary by retailer).

In our draft determination we signalled that we were considering setting a single variable R value for each Standard Retailer instead of the three variable R values for each Standard Retailer (single rate/time of use, controlled load A and controlled load B) because it reduced complexity and reduced the potential for errors. The Standard Retailers supported the use of a single variable R value approach.[298] We are using a single variable R value model.

For stakeholders who want a more detailed understanding of how we set the R values, we have made a model containing dummy values available on our website.

9.4 Using the R values in the WAPC

As explained in Chapter 5, for each year of the determination, the R values are an input to the WAPC. The WAPC will be calculated using:

1. the relevant R values set as we explained in section 9.3 determined by IPART under this determination
2. the N values, which are equivalent to the actual network charges incurred by the retailer
3. the relevant quantities, including consumption figures and customer numbers for each tariff.

298 EnergyAustralia submission, February 2010, p 43; Country Energy submission, February 2010, p 12; Integral Energy submission, February 2010, p 10.

10 Periodic cost reviews and cost pass-through mechanism

As previously discussed, one of the objectives for the 2010 determination is to ensure the regulatory package addresses all the relevant risks Standard Retailers are likely to face during this period without double counting. Based on our review of each identified risk (see Chapter 4), we consider that some specific risks are best addressed through periodic cost reviews within the determination period, or through a carefully defined cost-pass-through mechanism.

These include the non-systematic risks stemming from the uncertainty about developments in the market, policy and regulatory environment that could affect the level and volatility of wholesale electricity prices. The uncertainty creates a higher than usual risk that the assumptions we used in calculating the total energy cost allowance (discussed in Chapter 6) will prove to be incorrect. For example, these risks include that:

- carbon prices will differ from the forecasts we used in calculating the LRMC of generation and the market-based cost of purchasing electricity
- the CPRS will be introduced at a time or in a form that differs from the assumptions we used, or will not be introduced at all
- the structure of the NSW energy industry will change as a result of the NSW Government's *Energy Reform Strategy.*

These specific risks also include the risk of material change in the Standard Retailers' costs due to unforeseen regulation or taxation change events that are outside retailers' control.

Given the above, we have made final decisions to include periodic reviews of the total energy cost allowance and a cost-pass-through mechanism in the regulatory package. We have also made final decisions on the scope, frequency, timing and other details of these reviews and cost pass through mechanism. The sections below provide an overview of our final decisions then discuss these decisions in more detail.

10.1 Overview of final decisions on periodic reviews and the cost-pass-through mechanism

Our final decisions are that the regulatory package for the 2010 determination period will include:

- An annual review of the total energy cost allowance except for NEM fees and ancillary charges. This review is to be consulted on in March/April 2011 and 2012 for a price change on 1 July. It involves updating a limited number of key input assumptions, selected to manage the non-systematic risks identified above. It has no materiality threshold.
- A one-off special review of the market-based energy purchase cost for 2012/13. This review is to be held in September/October 2012 for a potential price change on 1 January 2013. It involves updating the carbon price input only, and has a materiality threshold of 5% of the energy purchase cost allowance for 2012/13. This review is intended to manage the risks associated with forecasting the market price of carbon. Therefore, if the CPRS is not implemented, or is not implemented as a cap and trade scheme, or the cap on the carbon price is extended beyond 2011/12 it will not take place.
- A cost-pass-through mechanism that will enable Standard Retailers to pass through the incremental, efficient costs associated with defined regulatory or taxation change events. It will be triggered by an eligible regulatory or taxation event occurring, and must be initiated by IPART or a Standard Retailer within 90 days of the event. It has a materiality threshold of 0.25% of the Standard Retailers' regulated revenue for the previous year[299] per event. The costs to be passed through are subject to IPART approval and, if approved, may lead to price changes other than on 1 July (ie, not only on 1 July as under 2007 determination).

Both periodic reviews and the cost-pass-through mechanism are symmetrical, meaning they provide for regulated retail tariffs to be adjusted to reflect both increases and decreases in the Standard Retailers' efficient costs.

We decided not to conduct periodic reviews of the retail operating cost allowance or the retail margin during the 2010 determination period. In our view, such reviews would reduce incentives for the Standard Retailers to seek efficiency gains in their operations. They would also be inconsistent with the principles of regulatory best practice, as periodic reviews of all 3 major cost components would result in a high level of regulatory uncertainty for businesses and customers, and increase the costs of undertaking the periodic reviews and implementing any required changes. However, as part of the annual review of the total energy cost allowance, we will recalculate the retail margin in dollar terms (so that it continues to reflect our final decision, which is expressed as a fixed percentage of each Standard Retailers' total costs).

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299 As used in assessing compliance for the annual price change and including the network use of system component of retail tariffs.

Table 10.1 Final decisions on annual review of the Total Energy Cost Allowance, special review and cost pass through mechanism

	Cost Pass Through	Annual review of the Total Energy Cost Allowance	Special review of market based allowance
Scope	Limited to regulatory and taxation events. We will assess efficient and incremental costs associated with any eligible event.	Review the Total Energy Cost Allowance including: ▼ Energy Purchase Cost Allowance including a review of the LRMC and market based cost allowances (including volatility allowance) ▼ green costs including RET, GGAS and ESS and energy losses. NEM fees and charges will **not** be reviewed. In updating the EPCA we will: ▼ use the same methodologies to calculate the LRMC and market based estimate as were used in making this determination ▼ update a limited number of key input assumptions for the LRMC and market based estimates ▼ compare the modelled price outcomes against publicly available electricity forward price market data which we regard as appropriate and consider the reasons for any material deviation ▼ make a draft decision on the most appropriate source of forward price data to be used in the portfolio optimisation modelling, and undertake consultation prior to issuing a final decision. In updating the cost allowances for complying with MRET, GGAS and ESS we will: ▼ use the same methodologies to calculate the cost of meeting the green obligations as were used in making this determination ▼ update a limited number of key input assumptions ▼ make a draft decision and undertake consultation prior to issuing a final decision.	Review the Market based allowance (including volatility allowance) only by updating the carbon price input.
Frequency	When eligible regulatory and/or taxation event occurs.	Annual review of the 2011/12 and 2012/13 energy cost allowance.	One-off review.

	Cost Pass Through	Annual review of the Total Energy Cost Allowance	Special review of market based allowance
Timing	Application within 90 days of eligible event and we will endeavour to assess application within 60 days. Price change no longer limited to 1 July.	Annual review in March/April 2011 and 2012 year for 1 July price change in those years.	Special review in September/October 2012 for a 1 January 2013 price change date.
Trigger	Regulatory and/or taxation change event.	No trigger - set timetable for review.	No trigger – set timetable for the review unless list of exclusions apply (such as CPRS not being implemented).
Materiality	0.25% of regulated N + R revenue.	No materiality threshold for annual reviews.	5% of the energy purchase cost allowance.
Symmetry	Cost increases and decreases passed through.	Cost increases and decreases passed through.	Cost increases and decreases passed through.

10.2 Annual review of the total energy cost allowance

IPART's final decision is that we will conduct an annual review of the total energy cost allowance for 2011/12 and 2012/13 for each Standard Retailer, and that this review will:

- include:
  - the energy purchase cost allowance, including the LRMC of generation and the market-based cost (which includes a volatility allowance)
  - the cost allowances for complying with obligations under the RET, GGAS and ESS (other 'green costs')
  - the cost allowance for energy losses
- use the same methodologies to calculate the energy purchase cost and other green cost allowances as were used in making the determination, and update the following input assumptions only:
  - capital costs of generation (as set out in an expert report commissioned by AEMO, or if unavailable or not sufficient another report that we consider represents standard industry practice or we commission)
  - fuel and other operating costs of generation (taking into account the operating characteristics of generation)
  - growth in electricity demand in the NEM (taking account of AEMO's most recent Statement of Opportunities)
  - industry ownership structure and generation availability / capacity
  - carbon prices
  - targets set by any green energy scheme
  - market parameters of the WACC including the risk free rates and debt margin
- compare the modelled price outcomes against publicly available electricity forward price market data which we regard as appropriate and consider the reasons for any material deviation
- make a draft decision on the most appropriate source of forward price data to be used in the portfolio optimisation modelling, and undertake consultation prior to issuing a final decision
- use the same methodology to calculate the cost allowance for energy losses as were used in making the determination, and update the network distribution and transmission loss factors only
- be initiated by IPART in time for a price change on 1 July
- have no materiality threshold
- be symmetrical in that it will adjust for increases and decreases in the total energy cost allowance

- be subject to a consultation and approval process under which IPART will:
  - issue a draft report by 17 March in each year
  - invite public submissions and allow 4 weeks for responses
  - issue a final report by 30 April
  - reset the R values in the WAPC to reflect the updated energy cost allowance and the recalculated the retail margin in dollar terms.

We consider these annual reviews are the most appropriate way to manage the risks associated with changes in the level and volatility of wholesale electricity prices over the determination period, including changes due to the impact of the CPRS. They are also necessary to ensure that regulated retail tariffs reflect the efficient costs of supplying small customers throughout this period. In addition, they are consistent with our terms of reference, which require us to allow for a periodic review of the energy purchase cost allowance and the allowances for complying with 'green' schemes. Stakeholders were broadly supportive of our draft decision to conduct annual reviews of the total energy cost allowance given the uncertainty in setting prices over the determination period.[300] However, retailers provided a number of specific comments on the annual reviews which are discussed further below.

The sections below discuss each element of our final decision on the annual reviews of the total energy cost allowance, including their scope, methodology, timing, materiality threshold, symmetry and process.

10.2.1 Scope of the annual reviews

The scope of the annual reviews of the total energy cost allowance will include updating our final decisions on:

- The energy purchase cost allowance. Both the LRMC of generation and the market-based cost calculations (including the volatility allowance) will be updated, so we can reset the allowance in line with the higher of the LRMC and the market-based cost in line with our approach in making the determination, discussed in section 6.2.2.
- The cost allowances for complying with MRET, GGAS and ESS.
- The cost allowance for energy losses.

This final decision is consistent with our draft decision. We consider this scope meets the requirements in our terms of reference. The scope of the annual reviews was supported by the majority of stakeholders.[301] However, AGL submitted that we

[300] Country Energy submission, February 2010, p 12; AGL submission, February 2010, p 2; Origin Energy, February 2010, p 5.

[301] Origin Energy submission, September 2009, p 23; AGL submission, August 2009, p 28; Country Energy submission, February 2010, p 12, p 1; Origin Energy, February 2010, p 5.

should not review the LRMC as part of the annual review given the need for certainty in the price path.[302]

In considering AGL's proposition we noted that the LRMC of generation is sensitive to changes in capital and fuel costs which fluctuate from year to year. It will also be sensitive to any changes in the assumed carbon price which will alter the investment and dispatch mix of the theoretical system. Given the potential for change in the LRMC over the determination period and that the terms of reference require us to set the EPCA as the higher of the LRMC and market based estimates, we consider that this requires updating the LRMC each year as part of the annual review.

The annual review will not include the cost allowances for NEM fees and ancillary fees as these costs are relatively stable over time. Our final decision on the cost pass through mechanism allows Standard Retailers to pass through incremental and efficient costs associated with regulatory change events including unforseen AEMO charges (refer section 10.4).

10.2.2 Methodology for the annual reviews

In conducting the annual reviews, we will use a methodology consistent with that used in making our decision on the energy purchase cost allowance, to increase regulatory certainty. This was supported by stakeholders.[303]

In updating the EPCA we will:

- use the same methodologies to calculate the LRMC and market based estimate as were used in making this determination, including:
  - determining the LRMC of generation on a standalone basis, as discussed in section 6.2.3
  - determining the market-based cost by modelling the efficient frontier of this cost, using simulated forward prices, and including an allowance for volatility, as discussed in section 6.2.4[304]
  - using a point in time estimate
- update a limited number of key input assumptions for the LRMC and market based estimates
- compare the modelled price outcomes against publicly available electricity forward price market data which we regard as appropriate and consider the reasons for any material deviation

302 AGL submission, February 2010, p 15.

303 Origin Energy submission, September 2009, p 23.

304 In contrast to Country Energy's proposal we will not consider Standard Retailers' actual costs as part of this review process. We consider that determining the market based energy purchase cost based on Standard Retailers' actual costs has a number of disadvantages (refer section 6.2.4).

- make a draft decision on the most appropriate source of forward price data to be used in the portfolio optimisation modelling
- base the market-based cost on the conservative point on the efficient frontier as discussed in section 6.2.4
- issue a draft report and undertake consultation prior to issuing a final decision.

In updating the cost allowances for complying with MRET, GGAS and ESS we will:

- use the same methodologies to calculate the allowances for meeting the green obligations as were used in making this determination
- update a limited number of key input assumptions
- make a draft decision and undertake consultation prior to issuing a final decision.

Stakeholders provided a number of comments on our methodology including the source of the input assumptions for the annual reviews:

- AGL submitted that the capital and fuel costs assumptions should only be updated with an expert report commissioned by AEMO, namely the ACIL Tasman Report.[305]
- AGL submitted that as part of the annual review the LRMC should be calculated on a carbon exclusive basis.
- Retailers submitted that greater use should be made of publicly available data as part of the annual review such as d-Cypha data rather than modelled forward price data[306]. AGL submits that there will be sufficient liquidity at the beginning of each relevant financial year.[307]
- Country Energy submitted that consideration should be given to actual contract prices purchased by Standard Retailers.[308]

In making our final decisions we have considered stakeholder comments. (See Appendix B.)

We have made a decision to update a limited set of key input assumptions. We consider these assumptions are the main drivers of the wholesale energy cost estimates, and all have an element of uncertainty over the 3-year determination period. We will not be reviewing the regulated load forecasts given that the roll off of ETEF will remove the source of data used to generate the retailers' regulated load, and therefore reviewing the load annually will be timely, costly and difficult to verify. This final decision is consistent with our draft decision.

305 AGL submission, February 2010, p 16.
306 AGL submission, February 2010, p 16; Origin Energy, February 2010, p 1.
307 AGL submission, February 2010, p 16.
308 Country Energy confidential submission, February 2010, p 5.

As part of updating the limited set of key input assumptions (such as capital and fuel costs) we consider an expert report commissioned by AEMO to be the most appropriate source of independent input data and intend to rely on this where possible. However if this is unavailable or does not have sufficient information to undertake the annual review, then we will rely on other report(s) IPART considers to represent independent industry expertise or a report we commission.

As noted in Chapter 6, we have decided to determine the LRMC of generation on a carbon inclusive stand alone basis. We do not consider AGL's proposition that we determine the LRMC on a carbon exclusive basis and add an allowance for the CPRS based on a different assumed pass through rate to be consistent with the terms of reference (refer Chapter 6 for more detail). We will maintain this methodology for determining the LRMC of generation as part of the annual reviews.

As noted in Chapter 6, we recognise that there is likely to be liquidity in the forward contract market in the nearer term (for example, one year ahead), and we consider publicly available forward price data an important source of information in setting the EPCA as part of the annual review. Stakeholders have sought greater clarity over the use of publicly available market data as part of the annual review. While our preference is for greater reliance on publicly available market data, given the uncertainties in the market including uncertainty surrounding the proposed CPRS, it is difficult for us to rely solely on market data at this time, or to say in what circumstances market data would be relied upon relative to modelled price outcomes.

We have decided to include in the annual review process a step in which we will compare the modelled price outcomes against publicly available forward price market data we consider appropriate and give consideration to the reasons for any material deviation. We will then make a draft decision on the most appropriate source of forward price data to be used in the portfolio optimisation modelling. We will however maintain our use of a point in time approach regardless of the source of the forward price data. We will then issue our draft report, and undertake consultation prior to issuing a final report.

In relation to Country Energy's proposal we maintain our view that using retailers' actual forward costs as part of the annual review of the EPCA does not necessarily represent efficient costs and does not provide any significant advantages (see Chapter 6 for more detail).

10.2.3 Timing, frequency and trigger for the annual reviews

We will initiate an annual review of the total energy cost allowance in 2011 and 2012, and conduct this review between March and April to allow for a 1 July price change. This is consistent with our draft decision.

We considered stakeholders comments on the timing, frequency and trigger for periodic reviews. Some retailers put the view that there needs to be more flexibility than there is in the 2007 determination, due to the uncertain impact of the CPRS and the potential for significant and rapid movements in carbon costs and wholesale energy prices. For example:

- Some retailers, including Integral Energy, preferred a retailer-initiated model that would allow them to apply for a periodic review and potential price change whenever certain criteria are met.[309]
- Origin Energy supported an annual review for the first 2 years of the determination period with an additional 6-monthly review in the final year (allowing for a 1 July 2012 and a 1 January 2013 price change).[310]

However, EnergyAustralia and PIAC supported maintaining the existing arrangements which include an annual review with 1 July price change.[311]

We are not convinced there is a strong case for moving to a retailer-initiated model, particularly in the first 2 years of the determination period when the risks and uncertainties associated with forecasting the energy purchase cost allowance are similar to those during the 2007 period. We also consider that such a model would reduce the incentive for retailers to manage their energy costs, add to regulatory costs and provide less regulatory certainty to stakeholders.

In our view, scheduled annual reviews are sufficient in the first 2 years of the determination period to manage the risks of change in the level or volatility of wholesale electricity prices due to market developments. However, as Section 10.3 discusses, we have decided to introduce a one-off special review of the market-based energy purchase in 2012/13.

10.2.4 Materiality threshold

As part of the 2007 determination, we choose to incorporate a materiality threshold of 10% in the annual review of the market-based energy purchase cost allowance. This meant that an annual review would only result in a price change if the review found that market-based purchase costs had changed by more than 10%. While some stakeholders supported maintaining this threshold,[312] others argued that it is too restrictive. For example, Integral put the view that with such a threshold, a Standard Retailer's retail margin would be virtually eliminated before an annual review results in a price change.[313]

309 Integral Energy submission, September 2009, p 3.
310 Origin Energy submission, September 2009, p 23.
311 EnergyAustralia submission, September 2009, p 18 and PIAC submission, August 2009, p 4.
312 EnergyAustralia submission, August 2009, p 33; PIAC submission, August 2009, p 4.
313 Integral Energy submission, September 2009, p 3.

For the 2010 determination period, we have decided there will be no materiality threshold for the annual reviews of the total energy cost allowance. This is consistent with our draft decision.

We consider that the primary purpose of this review is to help ensure that regulated retail tariffs remain at cost reflective levels throughout the determination period and promote retail market competition. For example, we note that if the materiality threshold did lead to significant falls in the retail margin, this could create barriers for potential 2nd tier retailers wishing to enter the NSW market. It could also create a situation where the total energy cost allowance, and consequently regulated retail prices, have to be revised significantly upwards (or downwards) in one year because the previous year's annual review found that these costs had changed by just less than the threshold level. Such movements would result in unacceptable impacts on customer bills.

We recognise however that the absence of materiality threshold means that the energy cost allowances for 2011/12 and 2012/13 outlined in this report are likely to be revised as part of the annual reviews. We consider that given the greater forecasting risk and the terms of reference for the 2010 determination, it is more important to ensure that the total energy cost allowance is maintained at a cost-reflective level throughout the determination period. In addition, we note that any additional administrative costs as a result of removing the materiality threshold from the annual reviews will be minimal, as we are already committed to a 1 July price change in each year of the period to enable network charges to be passed through to customers.

10.2.5 Symmetry

As under the 2007 determination, the annual reviews will be symmetrical, in that the selected input assumptions will be updated to reflect both increases and decreases in costs, and both increases and decreases in the total energy cost allowance will be reflected in regulated retail tariffs. This is consistent with our draft decision and the AEMC's final report.[314]

10.2.6 Process for conducting the annual reviews

Our final decision on the review process and timetable for the annual reviews of the total energy cost allowance is consistent with our draft decision and similar to those for periodic reviews in the 2007 determination.

314 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, p 65.

We will:

- review and update the relevant cost components of the total energy cost allowance (as discussed in sections 10.2.1 and 10.2.2 above) for each Standard Retailer for the remaining year(s) of the determination period
- make a draft decision on the revised total energy cost allowance for each Standard Retailer for these years, and recalculate the retail margin in dollar terms (so it remains constant in as a percentage of each retailer's total costs)
- make a draft decision on the new R values for each Standard Retailer to apply from 1 July in those year(s)
- issue a draft report by 17 March which sets out our findings and draft decisions
- invite public submissions and allow 4 weeks for responses
- consider all responses, make final decisions, and issue a final report and determination by 30 April.

Standard Retailers will then be required to submit their annual pricing proposals on 15 May, which we will assess by 1 June (rather than 26 June as under the current determination).

AGL submitted that prior to issuing a draft report IPART should:

- Release an initial report which could contain modelling assumptions and the resulting energy cost allowances.
- Conduct a round of consultation including a public workshop.[315]

While we appreciate AGL's desire for greater consultation as part of the annual review, we have limited the scope of the reviews and 'locked in' the methodology consistent with that used in making our decision on the energy purchase cost allowance. This is to provide regulatory certainty and to reduce the administrative costs to IPART and stakeholders. We consider issuing a draft report followed by stakeholder consultation, prior to issuing a final report to provide sufficient consultation.

10.3 One-off special review of the energy purchase cost allowance for 2012/13

IPART's final decision is that we will conduct a one-off special review of the energy purchase cost allowance in time for a potential 1 January 2013 price change, and that this review will:

  - include the market-based energy purchase cost only (including the volatility allowance)
  - use the same methodology as was used to determine the market-based cost in making the 2010 determination, but update the input assumption about the

315 AGL Energy submission, February 2010, p 16.

carbon price only (leaving all other input assumptions constant at the levels included in the 2012 annual review)

– result in a price change only if the revised market-based cost is found to be more than 5% higher or lower than the energy purchase cost allowance that was determined at the 2012 annual review

– follow a process and timetable that includes IPART:

  o issuing a draft report by 17 September 2012

  o inviting public submissions and allowing four weeks for responses

  o issuing a final report by 30 October 2012

  o resetting the R values based on the revised energy purchase cost and the recalculated retail margin in dollar terms

– not be conducted if the CPRS does not come into operation on or before 1 July 2012, the CPRS is introduced in a form other than a cap and trade scheme, or we consider that there has been no significant change between any carbon price caps applying in 2011/12 and 2012/13.

If the CPRS is introduced as currently proposed, 2012/13 will be the first year in which carbon prices are effectively set by the market. We recognise that this means forecasting retailers' energy purchase costs for this year is significantly more difficult than for the first 2 years of the determination period. We note that the AEMC recently expressed a similar view.[316] In addition, several stakeholders submitted that the risk stemming from the CPRS and its impact on wholesale energy prices is highest in 2012/13 and that an additional periodic review may be crucial in this year.[317]

We also note the AEMC's view that the CPRS is likely to introduce significant uncertainty and volatility to energy costs in 2012/13.[318] However, we question:

▼ the expected volatility of carbon prices

▼ the extent to which retailers will be exposed to carbon-related volatility in wholesale energy prices, and

▼ why retailers can't manage this volatility through access to risk management instruments, particularly as we expect the market for risk management instruments to develop if the CPRS legislation is enacted.

316 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, p 57.

317 Origin Energy submission, September 2009, p 23.

318 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, p 54.

In making our final determination, we considered the potential impact of the CPRS on wholesale energy prices in 2012/13 and the risks this creates for Standard Retailers in the context of fixed regulated retail prices. We also considered how these risks should be managed, and the extent to which the regulatory package for the 2010 determination period should be designed to manage this risk, taking account of the associated complications and costs that this might involve.[319]

We concluded that although it may be appropriate to have an additional mechanism in place to ensure that regulated prices are responsive to unexpected changes in costs in 2012/13, this mechanism must be carefully designed to ensure that it does not:

- reduce the retailers' incentives to manage these risks themselves
- reduce the retailers' incentives to operate efficiently, or
- interfere with the commercial operations and governance arrangements in the NEM.

Our final decision is to allow for a special review of the energy purchase cost allowance in 2012/13 that is designed to review the impact of carbon prices on the market-based cost calculated as part of the 2012 annual review. We consider that this mechanism balances the risks and uncertainties within the electricity market stemming from the CPRS with the need to impose disciplines on Standard Retailers to act efficiently. This decision is consistent with our draft decision.

Stakeholders were broadly supportive of our draft decision to conduct a one-off review of the EPCA in 2012/13.[320] However, retailers provided several specific comments on the annual reviews which are discussed further below (also see Appendix B for a summary of submissions and our responses to the submissions).

10.3.1 Scope of the special review

As indicated above, the special review of the energy purchase cost allowance should have a narrower scope than the annual reviews. We consider that this ensures the review better targets the specific risk it is designed to manage – the uncertainty and potential volatility of market-based carbon prices during 2012/13 and the impact these prices have on wholesale electricity prices. It also ensures that the direct administrative costs of undertaking the special review do not outweigh the benefits.

Therefore, this special review will include only the market-based energy purchase cost (which includes a volatility allowance). We will not review the LRMC of generation, given our view that this theoretical framework may not reflect retailers' exposure to carbon price volatility, at least in the short-term (see section 6.2.2).

319 For example, more regular reviews may reduce the incentives retailers have to manage their costs and creates administrative costs for Standard Retailers, IPART and other stakeholders.

320 EnergyAustralia, February 2010, p 38; Origin Energy, February 2010, p 5.

We will use the same methodology as we used to calculate the market-based cost in making the 2010 determination. However, we will update the carbon price assumption only – all other input assumptions will be held constant with the levels used for the 2012 annual review.

As part of our draft report, we noted that we had not made a decision on the source we will use to update the carbon price input assumption. We noted that there are likely to be a range of potential sources of information on market-based carbon prices in 2012, and that this decision is best made at the time of the special review. In their submissions on our draft report, AGL and Origin Energy requested further information on how the carbon price will be derived.[321] Given the level of uncertainty associated with the carbon scheme we do not consider that it is appropriate (nor in the best interest of stakeholders) to 'lock in' the carbon price input source as we have done with other cost inputs (such as our preference for relying on an AEMO commissioned report for capital and fuel cost assumptions). For example, the appropriate source of carbon price information may depend on the final details of the scheme including whether it is part of an international scheme with international trade in permits and the timing of the scheme including whether a liquid market for trading forward contracts, options and hedges will develop prior to our review. For these reasons we have made a decision not to specify the source of information on market-based carbon prices in 2012.

10.3.2 Frequency and timing of the special review

The special review is a one-off review that we will undertake in late 2012 to facilitate a 1 January 2013 price change, if necessary. However, as this review is specifically intended to manage any additional risk stemming from changes in market-based carbon prices in 2012/13, it will not take place if:

- the CPRS does not come into operation on or before 1 July 2012
- the CPRS is not implemented in the form of a cap and trade scheme, or
- we consider that there has been no significant change between any carbon price caps applying in 2011/12 and 2012/13.

10.3.3 Materiality threshold

We have decided that a materiality threshold of 5% of the market-based energy purchase cost will apply for the special review. This is consistent with our draft report. This means that the review will not result in a price change on 1 January 2013 unless the market-based purchase cost is found:

- to have changed by more than 5% compared to the energy purchase cost allowance that was determined at the 2012 annual review

321 AGL submission, February 2010, p 16; Origin Energy, February 2010, p 5.

- to be higher than the finding on the LMRC of generation at the 2012 annual review.

Integral Energy submits that the one-off review should not be subject to a materiality threshold consistent with the annual reviews of the total energy cost allowance. Integral Energy submits that some inconvenience to customers is necessary to avoid any erosion of the retail margin.[322]

In making a decision to implement a materiality threshold for the one-off review we noted that this review is different from the annual reviews of the total energy cost allowance in that:

- It is primarily designed to manage the risk of volatility in the carbon price and any significant impact on wholesale electricity prices and the volatility of these prices. Therefore, the risk it is targeting is different to the annual review.
- For the annual reviews with 1 July price changes the additional administrative costs of no materiality threshold are minimal as IPART is already committed to changing regulated retail prices for the N values and the existing R values.

We also consider that the 'costs' of changing regulated retail prices for small changes in energy purchase costs extend beyond inconvenience to customers and include the administrative costs of changing regulated retail prices (on both Standard Retailers, and other retailers whose prices are linked to the regulated tariff and IPART).

We also note that consistent with our draft decision we have included a materiality threshold on the cost pass through mechanism given that price changes could occur outside of 1 July. The intention being that the cost-pass through mechanism should address only large cost shocks rather than becoming a cost-plus regulatory regime in recognition of the principle of materiality, and the objective of regulatory efficiency, including minimising administrative costs. This is consistent with the AEMC's final recommendations on reviewing the energy cost component of retail tariffs.[323]

We therefore consider this materiality threshold is appropriate to avoid changes in regulated retail prices (that would not otherwise occur) for small changes in energy purchase costs, and to maintain the incentives for the Standard Retailers to act efficiently. In addition, we consider that any potential detrimental impacts of having a materiality threshold (eg, on retailers' margins and the cost-reflectivity of regulated retail tariffs) is lower than those for the annual reviews, as the review period is only 6 months.

322 Integral Energy submission, February 2010, p 10.

323 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, p 65.

10.3.4 Symmetry

Like the annual reviews, the special review will be symmetrical, in that the carbon price assumption will be updated with both material increases and decreases in the market based allowance reflected in the new R values. This is consistent with our draft decision.

10.3.5 Process and timetable for the special review

The process and timetable for the special review of the energy purchase cost allowance are consistent with those for the annual reviews. In particular, starting in September 2012, we will:

- review and update the market-based purchase cost, and determine whether the change in this cost meets the materiality threshold and whether it is higher than the 2012 LRMC of generation
- make draft decisions on the revised energy purchase cost allowance and the R values to apply from 1 January 2013
- issue a draft report by 17 September 2012 which sets out our findings and draft decisions
- invite public submissions on the draft report and allow for 4 weeks for responses
- consider all submissions we receive and make our final decisions on the energy purchase cost allowance and R values from 1 January 2013
- issue a final report and determination by 30 October 2012.

If we set new R values, Standard Retailers will then be required to submit their annual pricing proposals on 15 November, and we will assess these proposals by 1 December 2012. This is consistent with our draft decision.

10.4 Cost-pass-through mechanism

IPART's final decision is to establish a cost-pass-through mechanism that:

- allows the Standard Retailers to pass through incremental and efficient costs associated with events that comply with the following definition:
  - regulatory change events, including:
    - changed obligations in relation to green energy schemes
    - changed obligations in relation to Government-imposed hardship policies
    - unforseen AEMO charges (such as a reserve trader or direction event)
    - a retailer of last resort (ROLR) event
  - certain taxation change events, excluding:
    - income tax and capital gains tax

    - stamp duty
    - penalties, charges, fees and interest on late payments, or deficiencies in payments, relating to any tax
    - any tax that replaces or is similar to any of the taxes referred to above, and includes any licence fee payable by retailers
    - AEMO pool fees

– allows a Standard Retailer or IPART to initiate a cost-pass-through review within 90 days of an eligible regulatory or taxation change event occurring

– requires that to initiate such a review, a Standard Retailer must apply to IPART, identifying the eligible change event and setting out the associated incremental and efficient cost increases it proposes to pass through

– includes a materiality threshold of 0.25% of the Standard Retailers' previous year's proposed regulated retail revenue in NSW (including the network use of system component of retail tariffs) with the threshold defined on a per event basis

– is symmetrical in that cost increases and decreases can be passed through on average to regulated retail tariffs in NSW

– is subject to a review and approval process that includes IPART:

o checking that the event is consistent with the defined regulatory and/or taxation change events

o checking that the costs the retailer proposes to pass through are incurred as a direct result of the event and are incremental (ie, ensuring they are not already included in the cost allowances for the 2010 determination)

o assessing whether the proposed costs represent an efficient or reasonable response to the event (including considering whether the retailer has failed to take any action that could have reduced the costs incurred)

o determining the total costs associated with the regulatory and/or taxation event that the retailer can pass through in each year

o issuing a draft report and inviting stakeholder comments within 30 business days of receiving a Standard Retailer's application and issuing a final report within a further 30 business days (unless IPART notifies stakeholders of an alternative timeframe)

o resetting the R values and the recalculated retail margin in dollar terms

– provides for a price change on a date agreed by IPART once it has approved the total costs to be passed through and the costs incurred.

In making this final decision, we note that the scope of the cost-pass-through mechanism for the 2010 determination is substantially the same as the one included in the 2007 determination. In particular, it defines regulatory and taxation change events in the same way, has the same materiality threshold, and continues to be symmetrical. However, to provide for greater flexibility in its operation, we have changed the frequency, timing and trigger for a cost-pass-through review so that the Standard Retailers can initiate a review any time within 90 days of a relevant event occurring, and can change their prices on a date agreed by IPART after their application is approved. In the absence of a set date for a cost pass through review, we have also specified a timeframe for the decision making process.

We have been unable to estimate the costs of complying with the enhanced RET given the absence of detail in relation to retailers' obligations under the scheme. Therefore the RET allowance and regulated retail tariffs from 1 July do not reflect the announced changes to the scheme.[324] Our cost pass through mechanism is capable of incorporating the efficient and incremental costs (subject to a materiality threshold) resulting from changes to the RET once the legislation has been enacted. (Refer section 10.4.5 for detail on the review and approval process for the cost pass through mechanism.)

10.4.1 Scope of the cost-pass-through mechanism

Like the current cost-pass-through mechanism, our final decision allows the Standard Retailers to pass through material, unforseen changes in costs associated with a clearly defined set of regulatory or taxation change events. We consider that a clear definition is important, to provide greater certainty for retailers and customers about how and why regulated retail prices might change during the determination period. It is also important to reduce the potential for disputes over whether a particular event can trigger a cost-pass-through review, which could result in significant administrative costs for both retailers and IPART.

324 On 26 February 2010 the Commonwealth Government announced changes to be made to the RET from 2011; in particular, that the existing scheme will be split into two parts; the small scale Renewable Energy Scheme (SRES) under which households and small businesses will receive $40 for each REC created by small scale technologies like solar panels and solar hot water heaters; and the large scale Renewable Energy Target (LRET) under which a target of 41,000 GWh for 2020 has been set to achieve a level of large scale renewable electricity generation above what was expected under the existing RET. Australian Government – Department of Climate Change, *Fact Sheet: Enhanced Renewable Energy Target*, February 2010.

The set of events included in the definition are the same as those included for the 2007 determination. Most stakeholders supported retaining this definition,[325] however:

- Country Energy proposes that we establish a regulatory package that allows the retailers to pass through their actual costs in complying with 'green' schemes over the determination period rather than only those associated with additional obligations under these schemes (as part of its proposed N + R + G framework).[326]
- Country Energy also submits that the cost pass through mechanism should be extended to include unforseen and material changes in the EPCA.[327]
- EnergyAustralia submits that the definition of Regulatory Change Event excludes the introduction or amendment of any green energy scheme.[328]
- EnergyAustralia proposes that to deal with the uncertainty about the final design and implementation date for the CPRS, we set the total energy cost allowance without regard to the costs associated with this scheme. We could then estimate these costs if the CPRS legislation is enacted and incorporate them into regulated retail tariffs via the cost-pass-through mechanism.[329]
- EnergyAustralia submits that the definition of Regulatory Change Event and Taxation change event exclude events that may occur between the release of the final determination and its publication in the NSW Government Gazette.[330]

We considered these proposals. In relation to Country Energy's proposal we concluded that such an approach is inconsistent with our view of the cost-pass-through mechanism's purpose. This purpose is not to reduce the risk associated with changes in certain of the retailers' costs over the determination period. Rather, it is to manage the financial risk associated with material and unforseen changes in costs due to defined *regulatory or taxation change events*. The retailers always face the risk of unanticipated changes in their costs, and to some extent, managing this risk is a normal part of their business. However, as they have no ability to control costs imposed by unforeseen changes in regulation or taxation laws, it is appropriate that they be allowed to pass through these costs.

As we have previously noted, like their other energy costs, the costs of complying with existing and foreseen future green schemes are within retailers' control, and they have some ability to manage these green costs. Therefore, it is important that the regulatory package creates incentives for them to do so. Allowing them to pass through all their incurred costs would reduce this incentive. We consider that this would not be consistent with the terms of reference and assessment criteria for the 2010 determination.

325 EnergyAustralia submission, August 2009, p 16; AGL submission, August 2009, p 25.
326 Country Energy submission, August 2009, p 16.
327 Country Energy submission, February 2010, p 12.
328 EnergyAustralia confidential submission, February 2010, p 3.
329 EnergyAustralia submission, August 2009, p 16.
330 EnergyAustralia submission, February 2010, p 38.

Given the potential for change in Standard Retailer's green energy obligations over the determination period, we do consider that the definition of Regulatory Change Event should include the introduction or amendment of green energy obligations, and this has been reflected in the definition of Regulatory Change Event in the final determination.

In relation to EnergyAustralia's proposal for setting a carbon exclusive EPCA, we consider that setting the energy purchase cost allowance without regard to the costs associated with the proposed CPRS would be inconsistent with our terms of reference for this review. The terms of reference require us to set this allowance at a level that reflects the efficient costs of purchasing electricity on the NEM, including the costs associated the CPRS. Therefore, we have chosen to set the energy purchase cost allowance by estimating this cost on a carbon-inclusive basis (as discussed in Chapter 6), and addressing the risk of forecasting error due to uncertainty about the CPRS and its impact on electricity prices through the periodic reviews of this allowance, as discussed in sections 10.2 and 10.3 above. We consider this approach will adequately manage these risks.

In recognition of the risk of a Regulatory Change Event and/or Taxation Change Event occurring between the release of the final determination and its publication in the NSW Government Gazette we have altered the final determination to eliminate this risk.

10.4.2 Frequency, timing and trigger for the cost-pass-through mechanism

To introduce greater flexibility into operation of the cost-pass-through mechanism, both the Standard Retailers and IPART are able to initiate a cost-pass-through review within 90 days of an eligible change event occurring. This is consistent with our draft decision.

To initiate such a review, the Standard Retailers will each need to apply to IPART, providing evidence that an eligible event has occurred and will increase its costs, and setting out the incremental, efficient costs it proposes to pass through. Once we have assessed and approved a Standard Retailer's application and proposed cost pass through, and if it has begun to incur the relevant cost(s), it can implement the associated price change on any date – not only on 1 July as under the current determination. However, we consider it unlikely that any regulatory or taxation change will have immediate cost impacts and therefore 1 July price changes may be appropriate in some circumstances.[331] (See section 10.4.5 below for further detail on our approval process.)

[331] For example, any change to RET legislation may not have immediate cost impacts and therefore 1 July price changes (as under the current determination) may be appropriate.

We consider this greater flexibility is appropriate, given that the eligible events are beyond the retailers' control and may be significant. We also consider it is consistent with the terms of reference for the 2010 determination, which require that regulated prices reflect the efficient cost of supply and facilitate retail market competition. In addition, it is consistent with stakeholders' comments on the timing and initiation of cost-pass-through reviews and resulting price changes.[332] Further, it is consistent with other comparable regulatory frameworks, including the requirements in the National Electricity Rules for distribution network service providers. Stakeholders supported this decision for a retailer and IPART initiated review.[333]

10.4.3 Materiality threshold

As for the 2007 determination, the cost-pass-through mechanism includes a materiality threshold defined on a per event basis and equal to 0.25% of the Standard Retailer's previous year's proposed regulated retail revenue in NSW (including the network use of system component of retail tariffs). This is consistent with our draft decision.

We consider that this threshold is appropriate to limit the pass through of costs to those that have a material impact on the retailers' financial position and to maintain the incentives for them to act efficiently.

Several stakeholders submitted that this materiality threshold should be removed or at least reduced,[334] while other stakeholders supported retaining the threshold at the current level.[335] Country Energy and Origin Energy submitted that, if the threshold is retained, it should be on a cumulative rather than a per event basis, to account for the possibility of a large number of smaller events, such as smart metering trials, that may not result in material cost changes individually but exceed the threshold when considered collectively.[336]

We note that making cost-pass-through applications involves administrative costs for retailers, which may reduce their incentive to seek the pass through of immaterial costs. However, the strength of this incentive is unclear. In addition, a Standard Retailer is unlikely to consider the costs such applications impose on the regulator and other stakeholders. Therefore, we consider a materiality threshold is necessary to help ensure that the pass-through amount is sufficient to outweigh the administrative costs of making, reviewing and approving a cost-pass-through application, in line with regulatory best practice.

332 Integral Energy submission, August 2009, p 6.
333 Country Energy submission, February 2010, p12; EnergyAustralia submission, February 2010, p 38.
334 EnergyAustralia submission, August 2009, p 16.
335 PIAC submission, August 2009, p 4.
336 Country Energy submission, August 2009, p 16; Origin Energy submission, August 2009, p 15.

We also note that including a materiality threshold is consistent with other regulatory frameworks including the requirements in the National Electricity Rules for distribution network service providers. In regulating network tariffs, the AER includes a cost-pass-through materiality threshold of 1% of the distributor's maximum allowed revenue.[337] This is higher than the materiality threshold we have included in the cost-pass-through mechanism for retailers. As we noted in relation to the 2007 determination, we consider a lower threshold is appropriate for retailers, as they are more sensitive to variations in cash flows than the network businesses. However, we consider a materiality threshold of 0.25% adequately balances the trade-offs between the need to reduce the financial risks to retailers stemming from regulatory and taxation events and the need to avoid a cost plus form of regulation, including consideration of the administrative costs involved in assessing applications.

10.4.4 Symmetry

As for the 2007 determination, the cost-pass-through mechanism is symmetrical, in that it provides for both cost increases and decreases to be passed through to regulated retail tariffs. This is consistent with our draft decision.

Stakeholder expressed a range of views on this issue. Some supported maintaining a symmetrical mechanism,[338] while others argued that the competitive market will ensure that an 'over-estimation' of costs and prices will be competed away.[339] This implies that the risks of adjusting prices up or down are not symmetrical, as prices set too far above costs will be eroded by competition.

The terms of reference emphasise that this determination should protect small retail customers by resulting in prices that are based on the efficient cost of supply in each year of the determination period. We consider that to meet this requirement, the cost-pass-through mechanism must be symmetrical. For example, if there were a material decrease in retailers' costs due to a regulatory change event and this was not passed through to regulated tariffs, this might result in these tariffs over-recovering the efficient costs of supply. We also note that a symmetrical pass-through-mechanism is also consistent with the AEMC's recommendation in its recent review of energy market frameworks.[340]

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337 AEMC, *Rule Determination – National Electricity Amendment (Easement Land Tax Pass Through) Rule 2008*, 27 November 2008. http://www.aemc.gov.au/Media/docs/Final%20Rule%20Determination-c63193d2-f610-4175 973c-92a5f56547a7-0.PDF

338 Country Energy submission, August 2009, p 20.

339 TRUenergy submission, August 2009, p 7.

340 AEMC, Review *of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, p 65. The AEMC recommends a symmetrical adjustment of prices, noting that regardless of whether unnecessarily high prices would be competed away or not; there is no detriment to competition to have a symmetrical mechanism that lowers prices.

10.4.5 Review and approval process for the cost-pass-through mechanism

As noted above, the cost-pass-through mechanism is intended to allow retailers to pass-through efficient, incremental costs that are a direct result of an eligible pass-through event. To ensure that this is the case, IPART will review all applications to pass through such costs, and retailers' will be able to pass through approved costs only.

We will undertake this review and release a draft report within 30 business days of receiving a cost-pass-through application, and invite stakeholder comment. Then we will consider all comments we receive, make our final decision and release a final report within a further 30 business days. We consider that 60 business days will be sufficient to provide for consultation on our review process. This timetable is consistent with other comparable regulatory frameworks including the National Electricity Rules which require the AER to make a decision within 60 business days of receiving a cost-pass-through application.

11 Impact of the determination on customers

In line with our terms of reference, we have analysed the likely impact of our final determination on small customers. Electricity prices will increase substantially as a result of this decision. Prices will increase from between 46% (for Integral Energy) and 64% (for Country Energy) if the Commonwealth Government's Carbon Pollution Reduction Scheme (CPRS) is introduced from 2011/12 as planned. If the CPRS is not introduced price increases over the next three years will total 20% to 42%. The price increases on 1 July 2010 will be from 7% to 13%.

As requested by the Minister for Energy we have included in our analysis the proposed Commonwealth compensation package in assessing the impacts on households.[341]

The section below provides an overview of the high-level impacts of our determination. The subsequent sections look more closely at the impacts of the determination on customers with different levels of consumption and households with different characteristics, and the factors and policies which may help to mitigate these impacts for some customer groups, including the proposed CPRS compensation.

11.1 Overview of high-level impacts

Table 11.1 shows the cumulative total increase in the Standard Retailers' average regulated retail electricity tariffs as a result of our determination.

Table 11.1 Cumulative bill increases 2010/11 - 2012/13

	With CPRS (%)	Without CPRS (%)
EnergyAustralia	60	36
Integral Energy	46	20
Country Energy	64	42

[341] Minister for Energy submission (John Robertson MLC), February 2010, p 1.

Since the release of our draft determination we have received many submissions from individual customers. These stakeholders submitted that they will find it difficult to pay substantially more for electricity. In particular pensioners and others on low incomes stated that higher electricity prices will be a problem for them. Tables 11.2 (which includes the impact of the proposed CPRS) and 11.3 (if the CPRS is not introduced) show the annual increases in each Standard Retailer's average regulated tariffs under the determination, and compares these to the annual increases in average regulated tariffs over the previous 7 years.

Table 11.2 Increases in average regulated retail tariffs under past determinations and the 2010 determination with CPRS (% nominal)

	2003/04	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**Cumulative**[a]
Energy Australia	2.6	6.3	4.1	2.7	6.9	7.7	22.0	10.0	16.0	25.4	155.4
Integral Energy	-1.1	10.4	3.3	3.6	8.1	6.1	20.9	6.7	14.3	19.6	138.8
Country Energy	3.0	5.8	5.9	7.6	9.5	3.7	20.2	12.7	17.1	23.9	169.1
CPI[b]	3.1	2.4	2.4	3.2	2.9	3.4	3.1	2.4	2.7	2.7	32.0

a Cumulative calculation is from 2003/04-2012/13.

b June quarter on quarter CPI index for 2003/04 to 2009/10, 2010/11 to 2012/13 CPI numbers are IPART's forecasts

Note: The nominal increases for 2010/11to 2012/13 depend on actual rate of inflation and increases in network charges.

Table 11.3 Increases in average regulated retail tariffs under past determinations and the 2010 determination without CPRS (% nominal)

	2003/04	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**Cumulativea**
Energy Australia	2.6	6.3	4.1	2.7	6.9	7.7	22.0	10.0	11.4	10.6	116.5
Integral Energy	-1.1	10.4	3.3	3.6	8.1	6.1	20.9	6.7	9.6	2.2	95.7
Country Energy	3.0	5.8	5.9	7.6	9.5	3.7	20.2	12.7	13.1	11.1	133.0
CPI[b]	3.1	2.4	2.4	3.2	2.9	3.4	3.1	2.4	2.7	2.7	32.0

a Cumulative calculation is from 2003/04 to 2012/13.

b June quarter on quarter CPI index for 2003/04 to 2009/10. 2010/11 to 2012/13 CPI numbers are IPART's forecasts

Note: The nominal increases for 2010/11 to 2012/13 depend on actual rate of inflation and increases in network charges.

Table 11.2 shows that the annual increases in regulated tariffs under the determination get progressively higher over the determination period. This pattern reflects the significant increases to network charges in each year of the period, and the impact of the proposed CPRS to be introduced in the second year, with a cap on carbon prices in this year and without a cap in the final year. If CPRS is introduced the annual increases in the final 2 years of the determination period are higher than those experienced by NSW customers in the past, with the exception of the increases allowed in 2009/10.[342] Table 11.3 shows that if the CPRS is not introduced, the largest price increases (11% to 13%) occur in the second year of the determination.

Looking over a longer time period, the tables indicate that including the increases under the determination, regulated retail electricity prices in NSW will generally more than double over the 10 years between 2002/03 and 2012/13. This partly reflects the fact that regulated prices have gradually transitioned to cost-reflective levels over the years to 2009/10. It also reflects the increasing costs associated with significant network investments necessary to cope with increasing demand and improve the reliability of supply.

These tables also shows that the annual increases in regulated electricity prices in NSW under the determination are significantly higher than the forecast CPI for those years. The increases may also contribute to a rise in the CPI for those years – as was the case in 2009/10, when utility price increases were cited as one of the factors that led to the CPI increase in the first quarter of that year.[343] However, as electricity currently has a weighting of only 1.63 out of 100 in calculating the CPI, its direct impact on general inflation is unlikely to be significant.[344] Increases in electricity prices will also affect businesses' costs but the effect of this on the CPI is likely to be small and difficult to estimate. Electricity costs are generally a small component of business costs. Furthermore, the extent and timing of the pass though of these costs into prices is uncertain and will partly depend on economic conditions.

It's important to note that electricity bills typically account for a relatively small percentage of household expenditure. For example, a typical NSW household currently spends between $24 and $32 on electricity per week. Under the determination, this household's expenditure would be between $37 and $52 in 2012/13 if the CPRS is implemented and between $32 and $45 if the CPRS is not implemented.[345]

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342 The large increases in 2009/10 were driven by increases in network charges under the AER's 2009 determination, and higher than usual increases in wholesale electricity prices due to market uncertainty about policy and industry developments, the impact of drought on generation capacity and higher than forecast demand.

343 Australian Bureau of Statistics, *6401.0 - Consumer Price Index, Australia, September 2009*, http://www.abs.gov.au/ausstats/abs@.nsf/mf/6401.0.

344 This weighting is line with the percentage of household expenditure on electricity (based on the ABS's most recent 2003/04 household expenditure survey). In comparison, items such as housing (excluding utilities), food and transport which account for much higher percentages of household expenditure each have a weighting of around 13 to 16 out of 100. We note that the basket of goods will be reweighted in 2010/11, which may resulting in a higher weighting.
Source: ABS, *6430 - Consumer Price Index 15th Series Weighting Pattern* http://www.ausstats.abs.gov.au/Ausstats/subscriber.nsf/0/5424C607D189A7B5CA257097000636B0/$File/6430.0%2015th%20series%20weighting%20pattern.xls

345 GST inclusive.

The actual impact on individual households will depend strongly on their current consumption level, and the degree to which they can reduce this level in response to higher prices. We note that both the State and Federal Governments have policies directed towards reducing electricity consumption. In addition, the Standard Retailers currently offer advice to customers on how to reduce consumption. But while efforts to reduce consumption will mitigate the impacts of the regulated retail tariff increases under the determination, small customers will still pay considerably more for electricity in the coming years.

In addition, our analysis of the impact of the determination on households with different consumption, income and other characteristics suggests that some low-income households – such as sole parent families and large families – are likely to be more adversely affected than other households. This is due to their higher average levels of electricity consumption, and the fact that they are not currently eligible for the NSW Energy Rebate (see section 11.4.1 below). The NSW Government could address this by expanding the eligibility criteria for this rebate, but this would involve a cost and would not necessarily assist some large families.

As noted above, the determination also applies to businesses that consume less than 160 MWh per year. A typical small business consuming 40 MWh of electricity per year currently spends between $150 and $200 on electricity per week. Under our determination if the CPRS is implemented, this will rise to around $290 per week for EnergyAustralia's business customers, $220 per week for Integral Energy's business customers, and $320 per week for business customers in the Country Energy standard supply area. If the CPRS is not implemented, business bills are likely to be $245 per week, for EnergyAustralia's business customers, $180 per week for Integral Energy's business customers, and $280 per week for business customers in the Country Energy standard supply area.

11.2 Impact on customers with different levels of consumption

Although it is not possible to forecast precisely how the determination will affect individual regulated tariffs (see Box 11.1), we have analysed the impact on typical customer bills.

For each Standard Retailer, we took a 2009/10 annual electricity bill for typical residential and business small customers with different levels of consumption. We applied the average increase in regulated tariffs allowed under the determination. The analysis uses each retailers' standard all time tariff, however we note that some customers are on time of use tariffs. For the same level of consumption, the annual bills for customers on time of use tariff can vary significantly depending on when they use their electricity.

Tables 11.4 to 11.6 summarise the results of this analysis. For each consumption level, they show the total annual bill for 2009/10 and each year of the determination period, with and without the impact of the proposed CPRS. The bills for the first year of the determination will be the same regardless of whether the CPRS is introduced because it is not planned to commence until 2011/12. These amounts are expressed in nominal terms, based on current forecast inflation.[346] However, we stress that these results are indicative only – customers' actual bills may differ depending on a range of factors, including the level and structure of the regulated tariff they are supplied on and the actual rate of inflation. If the CPRS scheme is implemented, many households will be eligible for compensation though the compensation is not linked to electricity usage but rather household type and disposable income levels (see section 11.1.3).

Note that controlled load tariffs apply to particular appliances (usually hot water systems) that are permanently wired and separately metered from other appliances, and the network controls the times those appliances operate. These tariffs are lower than other tariffs. Our household surveys indicate that households that do not have their hot water system separately metered on a controlled load tariff will pay around $200 **more** on their annual electricity bills in 2010/11 compared to households with a separately metered hot water system.[347]

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[346] Forecast inflation is 2.4%, 2.7% and 2.7% for 2010/11, 2011/12, 2012/13, respectively.

[347] Of the 58% of Sydney, Illawarra and Blue Mountains households that have electric hot water systems, 62% are on controlled load tariffs. Source: IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra,* November 2007, Appendix A, p 5 of 53. Of the 75% Gosford, Hunter, and Wyong households that have electric hot water systems, 85% have access to the controlled load tariff. Source: IPART.

Box 11.1 Difficulties of forecasting the impact of the determination

It is not possible to forecast precisely how individual regulated tariffs will change under the determination because the determination uses a WAPC form of regulation. This means it limits the average increase in regulated tariffs, but allows each Standard Retailer to set the level and structure of its individual regulated tariffs. Therefore, we cannot forecast exactly how individual regulated tariffs will change.

However, the majority of EnergyAustralia's and Integral Energy's residential customers are supplied on 1 or 2 regulated tariffs. Therefore, the vast majority of their customers on standard supply contracts should face increases to their bills in line with or close to the regulated average increase. As Chapter 3 discussed, Country Energy has a much higher number of regulated tariffs, and some of these are obsolete tariffs that are still set below cost-reflective levels. Nevertheless, many of its regulated customers should face price increases similar to the average regulated increase. But those supplied on the obsolete tariffs are likely to face higher increases, as Country Energy continues to transition these tariffs to cost-reflective levels.

The WAPC also means that the retailers can apply different percentage increases to the fixed and variable charges of a particular tariff. This will impact on customers' bills differently depending on their consumption characteristics. For example, if the retailer applies a larger percentage increase to the fixed charges compared to the variable charges of the tariff, smaller electricity users will face slightly higher increases to their bills compared to large electricity users. This is because the fixed tariff component makes up a higher proportion of their overall bill.

Table 11.4 EnergyAustralia – Indicative increases in annual bills for typical customers under determination ($/customer, nominal, incl GST)

Description	2009/10 bill ($)	2010/11 bill ($)	2011/12 bill ($)		2012/13 bill ($)	
			With CPRS	*Without CPRS*	*With CPRS*	*Without CPRS*
Residential						
Low usage (3,000 kWh per year)	671	739	857	823	1,074	910
Medium usage - no controlled load (5,600 kWh per year)	1,118	1,229	1,426	1,370	1,788	1,515
High usage with controlled load (11,000 kWh per year)	2,013	2,215	2,570	2,468	3,221	2,730
Business						
20 MWh per year	4,438	4,882	5,664	5,440	7,101	6,018
40 MWh per year	9,432	10,376	12,037	11,561	15,091	12,790
80 MWh per year	19,420	21,364	24,784	23,804	31,072	26,334

Note: The 11,000 kWh bill comprises 2,000 kWh on off-peak 1. The increases are expressed in nominal terms, therefore they include expected changes in inflation over the period. The bills are typical for EnergyAustralia residential customers on the Domestic All Time tariff. Non-residential customers are on the General Supply All Time LV tariff.

Table 11.5 Integral Energy – Indicative increases in annual bills for typical customers under determination ($/customer, nominal, incl GST)

Description	2009/10 bill ($)	2010/11 bill ($)	2011/12 bill ($)		2012/13 bill ($)	
			With CPRS	*Without CPRS*	*With CPRS*	*Without CPRS*
Residential						
Low usage (3,000 kWh per year)	778	831	949	910	1,135	930
Medium usage - no controlled load (5,600 kWh per year)	1,286	1,372	1,569	1,503	1,876	1,537
High usage with controlled load (11,000 kWh per year)	2,136	2,279	2,605	2,497	3,115	2,552
Business						
20 MWh per year	3,982	4,249	4,857	4,655	5,807	4,759
40 MWh per year	7,883	8,411	9,614	9,215	11,496	9,420
80 MWh per year	15,684	16,735	19,128	18,335	22,873	18,743

Note: The 11,000 kWh bill comprises 2,000 kWh on off-peak 1. The increases are expressed in nominal terms, therefore they include expected changes in inflation over the period. The bills are typical for Integral Energy residential customers on the Domestic tariff. Non-residential customers are on the General Supply tariff.

Table 11.6 Country Energy – Indicative increases in annual bills for typical customers under determination ($/customer, nominal, incl GST)

Description	2009/10 bill ($)	2010/11 bill ($)	2011/12 bill ($)		2012/13 bill ($)	
			With CPRS	*Without CPRS*	*With CPRS*	*Without CPRS*
Residential						
Low usage (3,000 kWh per year)	942	1,062	1,243	1,200	1,540	1,333
Medium usage - no controlled load (5,600 kWh per year)	1,503	1,694	1,984	1,915	2,457	2,128
High usage with controlled load (11,000 kWh per year)	2,426	2,735	3,202	3,092	3,967	3,435
Business						
20 MWh per year	5,317	5,993	7,018	6,776	8,694	7,529
40 MWh per year	10,261	11,565	13,542	13,075	16,776	14,528
80 MWh per year	20,148	22,708	26,591	25,674	32,941	28,526

Note: The 11,000 kWh bill comprises 2,000 kWh on 5701 Residential – Controlled Load 1. The increases are expressed in nominal terms, therefore they include expected changes in inflation over the period. The bills are typical for Country Energy residential customers on 5700 Residential tariff. Non residential customers are on 5740 Business tariff.

11.3 Impact on households if the CPRS is implemented

The impact of the CPRS on households' electricity bills is substantial as shown in Tables 11.4 to 11.6. For example, for a residential bill (5,600 kWh consumption per year), CPRS accounts for around $50 of the annual electricity price increase in 2011/12 and between $185 and $205 of the annual price increase in 2012/13. However, the actual impact on individual households if the CPRS is implemented also depends on the extent to which households are compensated by the Commonwealth Government's proposed compensation arrangements.

The proposed Commonwealth Government compensation is not provided on an "offset" basis for individual expenditure items, rather, it will be made available through lump sum government payments and income tax concessions. This means it is not linked to electricity consumption levels – but rather it depends on household composition and income and is designed to compensate households for increases in their **total costs of living** due to the impact of the CPRS.

The Commonwealth Government's White Paper proposes a range of commitments to assist low and middle-income households in adjusting to the higher cost of living due to the CPRS, including higher electricity costs:[348]

- Pensioners, seniors, carers, people with disability, and low-income households will receive additional support, above indexation, to fully meet the expected overall increase in the cost of living.
- Middle-income households will receive additional support, above indexation, to help meet the expected overall increase in the cost of living. For middle-income families receiving Family Tax Benefit Part A, the Government will provide assistance to meet at least half of those costs.

Low and middle-income working households will also receive a tax cut to assist with the expected overall increase in the cost of living.[349]

Consequently under the proposed compensation arrangements low income households are likely to receive a proportionately higher level of assistance. For example, the white paper states that:

- around 89% of low-income households will receive assistance equal to 120% or more of the increase in their cost of living flowing from the CPRS

[348] We note that on the 24 November 2009, the Commonwealth Government announced that it would revise the structure of this household assistance package, as the appreciation of the Australian dollar meant the rise in the overall cost of living associated with the CPRS would be smaller than initially estimated. These revisions will reduce spending under this package by $0.91 billion over the forward estimates and by $5.76 billion to 2019/20. Commonwealth Government, *Details of proposed CPRS changes*, 24 November 2009, http://www.climatechange.gov.au/~/media/publications/cprs/CPRS_ESAS/091124oppnofferpdf.ashx

[349] Australian Government, *Australia's low pollution future, White Paper*, December 2008, xvii- xviii, http://www.climatechange.gov.au/publications/cprs/white-paper/~/media/publications/white-paper/V100eExecutiveSummary-pdf.ashx

- around 97% of middle-income households will receive some direct cash assistance, and around 60% of middle income households will receive assistance that will meet their cost of living increase.

Many high income customers will not receive any CPRS assistance, and therefore will incur the full electricity increases.[350]

The proposed assistance averages around $660 per eligible household in 2012/13 to offset the **total cost of living increases**, which includes increases to energy costs, road and transport costs, food costs and other goods and service. The proposed assistance is uniform across all states.[351] However, electricity price increases are likely to vary in each state, due to the different emissions intensity of the generation mix in each state, and varying rates of cost pass through.[352] By 2012/13 Commonwealth Treasury has forecast Australia-wide electricity price increases attributable to the CPRS of 19%.[353] This is less than the price increases due to the CPRS in NSW under our determination (between 22% and 26% by 2012/13). In dollar terms, this is likely to represent a difference of between $80 and $105 over 2011/12 and 2012/13 (cumulative) for a typical annual bill.

11.3.1 Impact on households with different characteristics

To help us to assess the impact of our pricing decisions on different households, we conduct periodic surveys of household water, electricity and gas consumption. Our most recent surveys were conducted in the Sydney, Illawarra and Blue Mountains area (2006) and in the Hunter, Gosford and Wyong area (2008).[354]

We used the electricity consumption data from those surveys and average income data for each household type to analyse the indicative impact of the determination on different households. We also used the electricity consumption data to analyse the impact on households with different numbers of occupants, and different numbers of large energy-using appliances (these results are presented in Appendix I).

350 See, Treasury, *Cameo analysis of household assistance package*, http://www.climatechange.gov.au/government/initiatives/cprs/who-affected/~/media/publications/cprs/CPRS_ESAS/091124%20Final%20cameos%20for%20publication.ashx

351 The Hon Peter Garrett AM MP, Minister for the Environment, Heritage and the Arts, *Media Release: One month and still waiting for Abbott to come clean on CPRS costs*, 30 December 2009, accessed 3 March 2010, http://www.environment.gov.au/minister/garrett/2009/mr20091230.html

352 Commonwealth Government, *Carbon Pollution Reduction Scheme: Australia's low pollution future*, 15 December 2008, pp 12-64, 13-18.

353 Senator Penny Wong, *Household Assistance under carbon pollution reduction scheme*, 25 November 2009, http://www.climatechange.gov.au/~/media/Files/minister/wong/2009/media-releases/November/mr20091125.ashx

354 IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra*, November 2007, http://www.ipart.nsw.gov.au/investigation_content.asp?industry=6&sector=17&inquiry=105, IPART, *Residential energy and water use in the Hunter, Gosford and Wyong*, December 2008, http://www.ipart.nsw.gov.au/investigation_content.asp?industry=6&sector=17&inquiry=146.

The results of this analysis are summarised in the sections below. However, we stress that they are indicative only, and will not be representative for all households in NSW. In particular:

- They are based on EnergyAustralia's average regulated tariffs in 2009/10 and EnergyAustralia's average tariff increases under the determination assuming CPRS is introduced.
- They reflect the consumption patterns in the particular areas we surveyed. The findings of these surveys indicate that location, as well as demographic factors, influence electricity consumption. For example, households in coastal areas tend to use heaters and air conditioners less than inland areas, which results in lower levels of consumption and hence lower bills.
- They assume that household consumption is constant throughout the determination period. However, actual consumption may decrease in response to large increases in prices, and a range of government incentives to purchase energy efficient appliances and reduce consumption (discussed in section 11.4.4).

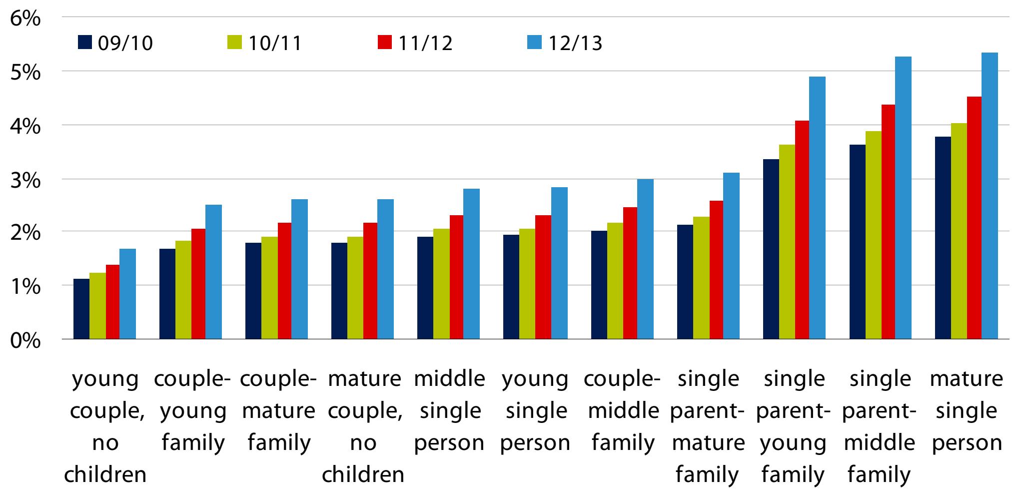
Our household survey data suggests that, on average, electricity bills (before the NSW energy rebate) currently account for between 1.1% and 3.8% of household income. The significance of electricity bills as a percentage of household income varies according to household type. For example, this percentage is lowest for households comprising young couples with no children and highest for those comprising mature single people.

Our analysis indicates that under the determination, electricity bills will account for between 1.7% and 5.6% of the household income by 2012/13, assuming consumption remains constant. If the proposed CPRS compensation is added to household income, electricity bills will account for between 1.7% and 5.3% of household income by 2012/03.[355]

For this analysis we have used the average level of income for each household category. Households that have a lower than average level of income for their household type will be affected more adversely than shown in the results in Figure 11.1, although some will receive proportionately more CPRS compensation. We have examined a selection of low income households in more detail in section 11.3.2.

[355] The proposed CPRS compensation was added to household income for this analysis.

Figure 11.1 Electricity bills as a percentage of average household income plus proposed CPRS compensation by household type (Sydney, no controlled load, incl GST, with CPRS)

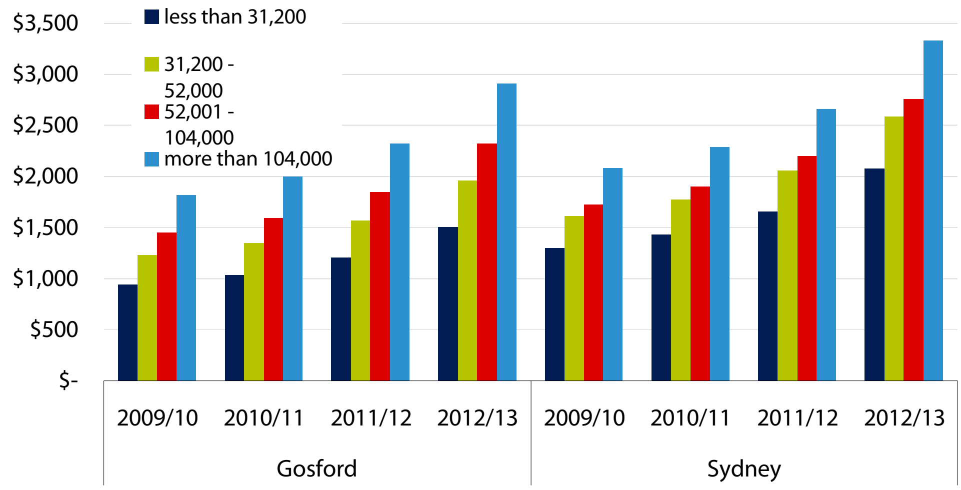


Note: The Commonwealth Government's Utilities Allowance ($522 pa) is included in average income data. Average income data has been inflated by forecast CPI for each year of the determination.

Data source: IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra,* November 2007, IPART, *Residential energy and water use in the Hunter, Gosford and Wyong,* December 2008, NATSEM Sydney income data.

A household's income can influence how much electricity it consumes, as well as its ability to pay electricity bills. Our household surveys found that households with lower incomes generally consume less electricity than those with higher incomes, and therefore also have lower bills. This can be seen in Figure 11.2, which shows the average bills for households with different annual incomes in 2009/10 and under the determination (assuming consumption remains constant). The figure also shows that in all income bands, the average bill for households in the Sydney, Illawarra, and Blue Mountains area tends to be higher than that for households in the Gosford, Wyong, and Hunter area. However, we note that there are both high and low electricity consumers within each income band.

Figure 11.2 Average annual electricity bills by annual household income before CPRS compensation (nominal $, no controlled load, incl GST, with CPRS)



Data source: IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra,* November 2007, IPART, *Residential energy and water use in the Hunter, Gosford and Wyong,* December 2008.

11.3.2 The effect of the determination on selected low income households

We also looked at electricity bills compared to disposable income for selected low income households. For this analysis, disposable income was defined as private income plus total government payments minus total tax paid.

Table 11.7 shows indicative household impacts for the final year of the determination if the CPRS is implemented. It shows that pensioners have significantly lower bills than single parent families. However, single aged pensioners have significantly lower levels of disposable income than single parent families and will receive a lower rate of CPRS compensation in dollar terms. Table 11.7 also shows that in each case Country Energy households will pay at least 25% and up to 60% more on their bills than EnergyAustralia or Integral Energy customers for the same level of consumption. Note that the proposed CPRS compensation added to households disposable incomes in Table 11.7 is compensation for the total cost of living increases, which includes increases to road and transport costs, food costs and other goods and services as well as to increases to energy bills.

Table 11.7 Indicative household impacts for selected low income families (2012/13)

	Annual bills ($)				Annual disposable income ($)	
	Energy Australia bill	Integral Energy bill	Country Energy bill	Energy Rebate (-)	Private income + transfer payments - tax	CPRS compensation
Single aged pensioner	1,734	1,650	2,388	130	18,287	455
Couple aged pensioners	2,097	1,819	2,855	130	28,230	686
Sole parent with two children (0% AWE)	2,621	2,617	3,340	-	30,165	709
Sole parent with two children (50% AWE)	2,621	2,617	3,340	-	48,286	759

Note: The Commonwealth Government's Utilities Allowance ($522 pa) is included in disposable income. Average income data has been inflated by forecast CPI for each year of the determination. Annual bills and CPRS compensation are shown in nominal dollars. The energy rebate and disposable incomes are shown in real $09/10.

Data source: IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra*, November 2007, IPART, *Residential energy and water use in the Hunter, Gosford and Wyong*, December 2008, NATSEM Sydney income data, Treasury, *Cameo analysis of household assistance package,* http://www.climatechange.gov.au/government/initiatives/

Figure 11.3 presents electricity bills as a proportion of disposable income. For this analysis the proposed CPRS compensation and Energy Rebate were added to the household's disposable income where applicable. Figure 11.3 shows that electricity bills currently account for 6% to 8% and 4% to 6% of disposable income for households comprising single and couple aged pensioners respectively. By 2012/13, this percentage will increase to between 8% to 11% of a single aged pensioner's disposable income,[356] and 6% to 9% of a couple aged pensioners' disposable income.[357]

For a sole parent with 2 children earning 50% of average weekly earnings, electricity bills will account for 5% to 6% of disposable income by 2012/13.[358] For a sole parent relying on government payments alone, electricity bills will be equal to 8% to 10% of their disposable income.

Some stakeholders were concerned that the price increases make electricity unaffordable for young people who were reliant on government payments, such as students and those on Newstart allowance.[359] They are currently not currently eligible to receive the Energy Rebate, and will receive a lower rate of CPRS compensation ($315) than other low income households. Our household surveys

356 Based on consumption of 5,646 kWh, IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra,* November 2007.

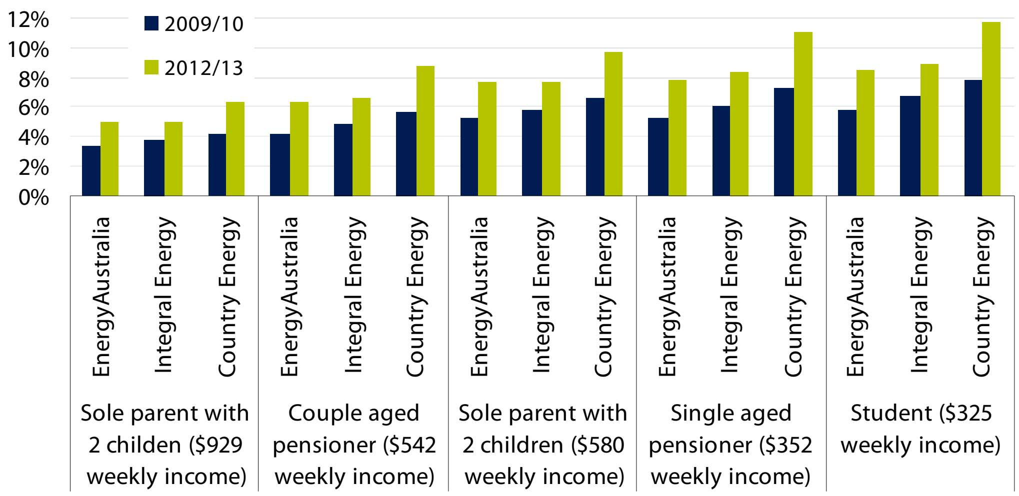
357 Based on consumption of 7,572 kWh, IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra,* November 2007.

358 Based on consumption of 6,585 kWh, IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra,* November 2007.

359 See IPART's Public Hearing transcript, 2 February, 2010, p 50 at 28.

show that low income single people tend to have relatively low electricity bills, but some students (particularly in the Country Energy area) will be paying significantly more of their disposable income on electricity than other groups. A student (living alone) relying on youth allowance and a small amount of private income currently spends between 6% to 8% of their income on electricity bills, increasing to between 8% and 12% by 2012/13. However, we note that students are often in share accommodation and therefore share the costs of energy bills. Others in university accommodation are likely to have their electricity costs included in their accommodation bills.

Figure 11.3 Electricity bills as a percentage of disposable income with CPRS compensation (selected households, Sydney consumption data, no controlled load, incl GST)



Note: The pensioner bill rebates have been applied to the single aged pensioner and couple aged pensioner bills. The Commonwealth Government's Utilities Allowance ($522 pa) is included in disposable income data. Disposable income is weekly disposable income for a household paying full rent. Incomes shown are for $2009/10. Average income data has been inflated by forecast CPI for each year of the determination.

Data source: IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra*, November 2007, IPART, *Residential energy and water use in the Hunter, Gosford and Wyong*, December 2008. NATSEM income data.

11.3.3 Impact on business customers

We received several submissions from businesses concerned about the impact of higher electricity prices. The NSW Farmers Association stated that electricity is around 2.5% of the average NSW dairy farm's input costs and 0.43% of broad acre operations. They estimate that under the determination, by 2012/13, a dairy operation will be paying an additional $10,000 per year and a broad acre operation will be paying an additional $2,680 a year. As primary producers they consider they will not be in a position to pass on input cost increases to their downstream customers which will affect their viability and domestic and international competitiveness.[360] The NSW Business Chamber submitted that businesses should be properly assisted for the costs they will face as a result of CPRS to minimise the impact on business viability and jobs (see section 11.4.5).[361]

11.4 Policies and other factors that may mitigate the impact of the determination on some customers

In addition to the proposed Commonwealth compensation package for CPRS there is a range of existing and proposed government polices likely to mitigate the impact of the determination on some households, especially disadvantaged and low income households. These include:

- the NSW Energy Rebate for concession card holders
- the NSW Energy Accounts Payable Assistance (EAPA) Scheme
- the proposed NSW Customer Assistance Program
- NSW and Commonwealth polices to reduce energy consumption and
- (potentially) increasing competition in the retail electricity market.

11.4.1 NSW Energy Rebate

In 2009/10, the NSW Government increased the annual Energy Rebate from $112 to $130, and indicated that the rebate will be indexed annually by CPI. Customers who hold the following concession cards are eligible for this rebate:

- Pensioner Concession Card issued by Centrelink.
- Pensioner Concession Card issued by the Commonwealth Department of Veterans' Affairs for customers receiving a War Widows or War Widowers Pension or a Disability Pension at the 'totally and permanently incapacitated' (TPI) rate or 'extreme disablement adjustment' (EDA) rate.
- Carer Allowance (child under 16) Commonwealth Government Health Care Card.
- Sickness Allowance Commonwealth Government Health Care Card.
- Special Benefit Commonwealth Government Health Care Card.[362]

EWON submitted that the NSW Government should extend the eligibility for the Energy Rebate to all Health Care Card (HCC holders), consistent with the Victoria, Tasmania, SA and WA.[363] COTA has requested that the Energy Rebate also be

360 NSW Farmers Association submission, February 2010, p 5.
361 NSW Business Chamber submission, February 2010, p 1.
362 NSW Industry and Investment, *Rebates*, http://www.industry.nsw.gov.au/energy/customers/rebates#Energy-Rebate, accessed 3 December 2009.
363 EWON submission, February 2010, p 4.

extended to Commonwealth Seniors Health Card holders.[364] An extension of eligibility for the Energy Rebate is supported by AGL.[365]

We have previously estimated the cost of expanding the eligibility for this rebate to all health care card holders would be around $40 million (although we note that robust data was not readily available for a more accurate estimate).[366]

We also note the growing disparity between CPI and energy price increases, especially over the course of the determination. As shown in Table 11.2, if the CPRS is implemented price increases are forecast to be

- 7% to 13% in 2010/11, compared to a CPI forecast of 2.4%.
- 14% to 17% in 2011/12, compared to a CPI forecast of 2.7%.
- 20% to 24% in 2012/13, compared to a CPI forecast of 2.7%.

Recommendations

5 That the NSW Government consider expanding the eligibility for its Energy Rebate to all Commonwealth Health Care Card holders.

6 That the NSW Government consider increasing the Energy Rebate.

11.4.2 NSW Energy Accounts Payment Assistance (EAPA) Scheme

The NSW EAPA scheme helps financially disadvantaged customers experiencing difficulty paying their electricity or gas bill because of a crisis or emergency situation, to ensure they can stay connected to essential services. The scheme provides customers with $30 vouchers, which are credited towards their electricity account. The vouchers are issued by a participating community welfare organisation (CWO) such as St Vincent de Paul, Salvation Army and Anglicare. Customers need to apply to a CWO, which will consider their claim and, if appropriate, provide assistance.[367]

From 1 July 2009, the NSW Government allocated an additional $55 million to this scheme over 5 years providing the maximum EAPA assistance available for individual customers to increase to $480 per year.

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364 COTA submission, February 2010, p 1.

365 AGL submission, February 2010, p 21.

366 IPART, *Market-based electricity purchase cost allowance - 2009 review Regulated electricity retail tariffs and charges for small customers 2007 to 2010,* May 2009, p 18.

367 NSW Industry and Investment, *Providing Help with bills,* http://www.industry.nsw.gov.au/energy/customers/help, accessed 3 December 2009.

11.4.3 NSW Customer Assistance Policy

On 20 May 2009, the NSW Minister for Energy announced the introduction of Customer Assistance Policy in response to increases in regulated retail electricity prices from 1 July 2009. This package includes $125 million over 5 years to implement a range of consumer protection measures, including:

- A Medical Energy Rebate, which was introduced from 1 January 2010. This provides financial assistance of $130 a year to eligible customers who are medically diagnosed with an inability to self-regulate body temperature.
- Strengthened regulatory obligations, which commenced from 1 March 2010. These require retailers to:
  - develop, implement and publish a customer hardship charter, and
  - offer a payment plan to all residential small retail customers who are scheduled to be disconnected for non-payment at least twice in the 12 months prior to disconnecting the customer.
- Funding, training and other support for financial counselling services to assist energy customers.

The Government is also finalising an Energy Hardship Guide, which is designed to provide a step by step reference guide to NSW government financial assistance measures, as well as regulatory consumer protection measures (such as payment plans, the role of the Energy and Water Ombudsman in resolving disputes between a customer and a retailer, and customer rights when a marketer knocks on the door or calls on the telephone).

11.4.4 Policies directed at reducing electricity consumption

The NSW and Commonwealth Governments have introduced a range of incentives for households and businesses to reduce their electricity consumption. Reducing consumption can mitigate the impact of rising electricity costs. For example, based on 2009/10 electricity prices, it is estimated that:

- switching from an electric hot water system to a gas, solar or heat pump hot water system can reduce a household's electricity bills by up $300 a year[368]
- installing the Low Income Household Refit Program's energy saving kit, which contains energy saving lights, a water-efficient shower head, a low flow tap restrictor, draught excluders and door snakes, can save around $95 in energy costs a year.[369]

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368 New South Wales Government, Department of Environment, Climate Change and Water, *NSW hot water system rebate*, http://www.environment.nsw.gov.au/rebates/ccfhws.htm

369 New South Wales Government, Department of Environment *Low Income Household Refit Program,* http://www.environment.nsw.gov.au/households/lowincome.htm

COTA considers that many older people in particular may benefit from these incentives as many older people may not have energy efficient appliances in their home. However, they note the importance of providing older people with information and advice regarding such incentives and offers. They consider that all relevant information should be available through a single information source, for example on the proposed online comparator website and phone service. We note that NSW government's Energy Hardship guide being developed as part of the Customer Assistance Policy may be a useful reference point for all of the assistance measures available in NSW.

Table 11.8 summarises the major government initiatives for reducing household and business energy consumption.

Table 11.8 Residential and business energy consumption reduction strategies

NSW Government	Commonwealth Government
NSW hot water system rebate ▼ $300 for a gas hot water system with a 5-star or higher energy rating	**Renewable Energy Bonus Scheme** ▼ rebate of $1,000 for solar hot water and $600 for heat pump hot water systems to replace an electric hot water system
Low income Household Refit Programs ▼ provides free energy assessments, power saver kits and advice to 220,000 low income households across NSW.	**Green Loans** ▼ a free Home Sustainability Assessment and report; and ▼ access to a Green Loans subsidy provided to participating financial institutions to cover up to four years interest for borrowing of up to $10,000, to implement changes recommended in the assessment report.
NSW Solar Bonus Scheme ▼ households with solar panels will be paid 60 cents per kilowatt hour for up to 7 years and an average household system would generate annually around 2500 kWh	**Small-scale renewable energy** ▼ households that install small-scale solar photovoltaic (PV) systems, small wind turbines and micro-hydro systems can create RECS for the equivalent to up to 15 years of operation under the RET scheme. The sale of these RECS provides an upfront capital subsidy to householders, businesses and community groups. From 2011, these projects will be supported under the Small-scale renewable energy scheme (SRES)
Energy Efficiency for Small Business Program ▼ a subsidised personalised energy assessment and action plan ▼ a 50% rebate of up to $5,000 for businesses that use $5,000-$20,000 a year in electricity and $2,000 for businesses that use less than $5,000 a year in electricity for businesses that use up to approximately $20,000 in electricity a year or have up to approximately 10 employees	

Source: New South Wales Government, Department of Environment, Climate Change and Water, *Residential Rebate Program*, *Low Income Household Refit Program* and Energy Efficiency for Small Business Program, http://www.environment.nsw.gov.au/rebates/index.htm, http://www.environment.nsw.gov.au/households/lowincome.htm, http://www.environment.nsw.gov.au/sustainbus/smallbusenergy.htm, NSW Industry and Investment, Solar bonus scheme for NSW, *http://www.industry.nsw.gov.au/energy/sustainable/renewable/solar/solar-scheme*, Australia Government, Department of Climate Change, *Small scale renewable energy systems under the RET scheme,* http://www.climatechange.gov.au/government/initiatives/renewable-target/need-ret/solar-ret.aspx, Department of the Environment, Water, Heritage and the Arts , *Green Loans, Solar Hot Water Rebate,* http://www.environment.gov.au/energyefficiency/solarhotwater/index.html http://www.environment.gov.au/greenloans/about/index.html, Department of climate change, *Fact sheet: enhanced renewable energy target,* http://www.climatechange.gov.au/en/government/initiatives/~/media/publications/renewable-energy/enhanced-ret-fs-pdf.ashx

Some submissions noted that government programs designed to reduce consumption will not mitigate the increases associated with the service availability charge (SAC) which applies to all customers regardless of their consumption levels.[370] Currently the SAC varies from $157 per year in EnergyAustralia's standard supply area, to $294 per year in Country Energy's standard supply area. If the SAC increases in line with the average tariff increases, these charges are likely to be $250 and $481 respectively for 2012/13.[371]

11.4.5 Commonwealth Government CPRS assistance

We have already considered the impact of the proposed CPRS compensation that will be available to some households (see section 11.3). However we also note that businesses will be assisted by Government following the introduction of the CPRS. The Government's Climate Change Action Fund will include a Small Business Capital Allowance to assist investment in energy efficiency enhancing equipment (eg, hot water, insulation, lighting, motor and drives, combined heat and power, heating, ventilation and air conditioning, and refrigeration equipment) that meets established energy saving criteria.

11.4.6 Increasing competition in the retail electricity market

Our analysis of the impact of the determination on customers was based on the average increase in regulated retail tariffs under this determination. However, as Chapter 3 discussed, a considerable proportion of small customers in NSW are supplied on negotiated contracts, so do not pay regulated tariffs.

Some retailers may be able to supply electricity at lower prices than the regulated tariffs. For example, discounts of 5% to 8% below the regulated price are currently being offered to small residential customers who take up negotiated contracts.[372] Increasing competition in the electricity market over the 2010 determination period has the potential to put downward pressure on electricity prices.

As Chapter 2 noted, we consider that NSW customers will be more inclined to enter the competitive market if there is transparent, easy to understand information available to help them assess alternative offers. Therefore, we have made recommendations to make retailers' competitive offers more transparent through information disclosure requirements in a common form and a pricing comparator service. Greater customer participation in the competitive market should increase the rivalry between retailers and result in lower prices for customers.

370 A. Goonan submission, January 2010.

371 Inclusive of GST.

372 Some retailers are offering discounts on a customers' total bill, while others are offering discounts on the usage component only.

12 Non-tariff charges

The *Electricity Supply Act 1995* indicates that the Standard Retailers are able to impose several miscellaneous or non-tariff charges on small customers they supply on regulated tariffs. The Act defines these 'regulated retail charges' as:

- a security deposit
- a late payment fee
- a fee for a dishonoured bank cheque.

In effect, this definition means that Standard Retailers can impose no other non-tariff charges (although they can pass through network miscellaneous charges).

To assist us in setting the maximum level of each non-tariff charge and any conditions associated with imposing these charges, we established a working group comprising representatives of retailers, community welfare organisations and the Energy and Water Ombudsman of NSW (EWON). The working group's role was to provide information and comment on options for the above non-tariff charges. Our decisions and considerations in relation to each charge are outlined below.

12.1 Security deposits

IPART's final decision is to maintain security deposits at the same level with the same conditions as under the 2007 determination. That is:

- The maximum level of security deposits will be either:
  - 1.5 times the Standard Retailer's average quarterly electricity account, or
  - 1.75 times the Standard Retailer's average 2-monthly electricity account, or
  - 2.5 times the Standard Retailer's average monthly electricity account.
- For residential customers, security deposits can be required prior to commencement of supply only if the customer:
  - has an outstanding debt owed to the Standard Retailer in relation to an electricity retail bill and the customer has refused and refuses to make an arrangement to pay that debt, or
  - has been responsible for the illegal use of electricity within the previous 2 years, or

- o does not have a satisfactory credit history in the reasonable opinion of the Standard Retailer, and has been offered a payment plan and has refused or failed to agree to this offer.

– Security deposits can be required from a residential customer within 12 months of commencement of supply if:

  - o the customer entered into a payment plan with the Standard Retailer at the start of the contract and subsequently cancelled that plan, and
  - o one or more of the circumstances in which a security deposit can be requested prior to commencement of supply exists.

– For business customers, security deposits can only be required prior to commencement of supply and only if the customer:

  - o does not have a satisfactory credit history in the reasonable opinion of Standard Retailer, or
  - o is a new business, or
  - o was responsible for the illegal use of electricity within the past 2 years.

This decision is consistent with our draft decision.

In making this decision, we took into account the various views expressed by stakeholders in relation to the level and conditions for security deposits. For example:

- Country Energy, EnergyAustralia, Integral Energy and AGL submitted that the current level and conditions surrounding security deposits continue to be appropriate.[373]
- Origin Energy suggested that the level of security deposits be reassessed.[374]
- TRUenergy argued that the maximum level for a security deposit should be fixed at 37.5% of the customer's annual consumption (consistent with 1.5 times the average quarterly bill). It noted that currently the maximum security deposits for customers on monthly and bimonthly billing represent only 29.2% and 20.8% of annual expenditure. TRUenergy also suggested that the conditions associated with security deposits are inappropriate, noting that other jurisdictions allow retailers to request a security deposit at any time (not just when supply is requested), and that the current provisions unfairly treat customers who move supply address compared those who do not.[375]

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373 Country Energy submission on Issues Paper, August 2009, p 24; EnergyAustralia submission on Issues Paper, August 2009, p 38; Integral Energy submission on Issues Paper, August 2009, p 9; AGL submission on Issues Paper, August 2009, p 32.

374 Origin Energy submission on Issues Paper, August 2009, p 26.

375 TRUenergy submission on Issues Paper, August 2009, pp 8-9.

- NCOSS and PIAC proposed that security deposits be abolished. PIAC also argued that these deposits are a punitive measure for households having difficulty paying bills due to financial hardship.[376] EWON and COTA both supported our draft decision.[377]

At the working group meeting, the Standard Retailers indicated that they currently charge less than the maximum allowable security deposit. We note that each retailer's website indicates that the level of the security deposit for residential customers is $180 to $200, and these levels have not increased since 2007.

In response to NCOSS and PIAC's argument, we consider that because energy retailers provide electricity in advance of payment, security deposits have a role as a defence against non-payment of bills and bad debts. We also note that security deposits or their equivalent are charged in Victoria, South Australia and Queensland. In addition, security deposits are included in the draft National Energy Retail Rules and Regulations (currently being developed by the Ministerial Council on Energy).[378]

In relation to the appropriate level for security deposits, we note that the second exposure draft of the National Energy Retail Rules and Regulations sets the maximum level of security deposits at 37.5% of the customer's or a comparable customer's estimated annual bill (equivalent to 1.5 times the average quarterly bill). However, the maximum levels for security deposits allowed under the 2007 determination are largely consistent with the current levels in South Australia and Queensland.

In relation to TRUenergy's comment about the conditions for imposing security deposits, we note that in South Australia and Queensland and in the draft National Energy Retail Rules and Regulations, a security deposit can only be levied at the time of application for supply. Previously, this was also the case in NSW. However, in making the 2007 determination, we relaxed this condition to allow a Standard Retailer to impose a security deposit on residential customers in limited circumstances within 12 months of commencement of supply. Only EnergyAustralia commented on this. It fully supported our draft decision and the continuation of the ability to require security deposits from customers in the first 12 months of supply commenting that prior to the introduction of this provision there had been an observable trend of customers avoiding paying a security deposit by entering into a payment plan and then cancelling the plan.[379]

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376 NCOSS submission on Issues Paper, September 2009, p 2; PIAC submission on Issues Paper, August 2009, p 4.

377 EWON submission on Draft Report and Draft Determination, February 2010, p 5 and COTA submission on Draft Report and Draft Determination, February 2010, p 4.

378 Ministerial Council on Energy Standing Committee of Officials, Second Exposure Draft of National Energy Retail Law, National Energy Retail Regulations, National Energy Rules, November 2009, Draft Rule 225 and Model Terms and Conditions for standard retail contracts, clause 13.1.

379 EnergyAustralia submission on Draft Report and Draft Determination, February 2010, p 39.

On balance, we decided to retain the current level and conditions for security deposits. We consider the current maximum levels for security deposits are appropriate, as they are based on multiples of an average bill and therefore are implicitly indexed. In addition, we don't consider that stakeholders have identified significant problems with the current conditions for imposing security deposits.

12.2 Late payment fees

IPART's final decisions are to:

- Increase the late payment fee to $7.50, exclusive of GST.
- Require Standard Retailers to waive the late payment fee for customers receiving the Energy Rebate, and maintain other conditions related to waiving this fee. That is, the late payment fee must be waived or not levied:
  - during a period in which there has been an agreed extension of time in which the customer may pay the bill
  - where a customer has made a billing-related complaint to EWON or other external dispute resolution body and the complaint is unresolved
  - during the period of an instalment arrangement entered into between a customer and the Standard Retailer
  - where the Standard Retailer is aware the customer has contacted a welfare agency for assistance
  - where all or part payment is by a voucher issued under the Energy Accounts Payment Assistance Scheme, or
  - where considered appropriate by the Energy and Water Ombudsman.
- Maintain the current conditions related to imposing a late payment fee. That is, that the late payment fee may only be levied:
  - on or after a date at least 5 business days after the due date, and
  - after the customer has been notified in advance that the late payment fee will be charged if the bill is not paid or alternative arrangements entered into, within 5 business days of the due date.

This decision is consistent with our draft decision.

Late payment of bills by customers imposes costs on retailers – for example, the costs of disconnection warnings, field visits, disconnection, mercantile agents and foregone interest. The late payment fee is intended to allow the Standard Retailers to recover these efficient costs.

In reaching our decisions on the late payment fee for the 2010 determination, we took account of stakeholder views on the appropriate level and conditions for this fee, and information on late payment fees in other jurisdictions. We also considered whether the costs associated with late payment are accounted for elsewhere in the regulatory package.

12.2.1 Stakeholder views on the late payment fee

Several retailers including EnergyAustralia submitted that the current $7 fee does not reflect the costs of late payment.[380] AGL also put the view that the $14 fee it charges customers on negotiated contracts for late payment is cost reflective, and that there should be greater national consistency in relation to the level of non-tariffs fees in general. Origin Energy also submitted that the fee should be increased for small business customers, and that the current $7 fee does not reflect the cashflow costs to a retailer stemming from late payment where the customer's bill is large.

The other Standard Retailers were less specific, but supported the need for a late payment fee. Integral Energy[381] did not seek a fee increase at present, but argued the fee should be adjusted for changes in CPI each year of the determination. Country Energy[382] noted that while it does not currently charge a late payment fee, it considers more flexibility is needed to ensure that retailers can charge 'fair and reasonable amounts' in relation to costs incurred.

However, community organisations put the view that the late payment fee itself or increases to this fee were inappropriate, particularly for customers who incur the fee because they are unable to pay their bill. For example:

- PIAC[383] indicated that it does not support continuation of late payment fees, particularly for households disconnected due to inability to pay. It cited the findings of its report 'Cut-Off II', which showed that 31% of households disconnected due to inability to pay were charged a late payment fee.
- NCOSS[384] did not support an increase to the late payment fee, noting that any increase would run counter to the objectives of the government's customer assistance policy. It also expressed support for retailers' current practice of waiving the fee if they consider the customer to be in hardship, but proposed more clearly established polices and procedures for this.

380 EnergyAustralia submission on Issues Paper, August 2009, p 38; TRUenergy submission on Issues Paper, August 2009, p 9; Origin Energy submission on Issues Paper, August 2009, p 26; AGL submission on Issues Paper, August 2009, p 32.

381 Integral Energy submission on Issues Paper, August 2009, p 9.

382 Country Energy submission on Issues Paper, August 2009, p 24.

383 PIAC submission on Issues Paper, August 2009, p 5.

384 NCOSS submission on Issues Paper, September 2009, p 3.

Community organisations also expressed concern at the working group meeting about a possible increase to the level of late payment fee, given the large increase in regulated tariffs in 2009, and expectations of further significant increases in the coming years. They noted that these conditions have consequences for the affordability of electricity and increase the likelihood that customers will struggle to pay their bills on time. In addition, they raised the option of extending the waiver of late payment fees to customers receiving the Energy Rebate.

EWON submitted that it was not aware of any developments which would provide grounds for changing the late payment fee, or other miscellaneous charges. EWON and COTA both supported our draft decision.[385]

12.2.2 Late payment fees charged in other jurisdictions

In Victoria and Queensland, retailers cannot levy late payment fees on customers on standard contracts.[386] In South Australia, the customer may be required to pay reasonable costs of recovering the amount owed and business customers may be charged interest.

The second draft of the National Energy Retail Rules and Regulations for the National Energy Customer Framework allows retailers to levy a late payment fee but does not indicate the level of this fee. It also requires retailers to waive the late payment fee for small customers who are hardship customers.

12.2.3 Whether costs associated with late payment are recovered elsewhere in the regulatory package

The Standard Retailers provided estimates of the cost of each late payment, which ranged from $13 to $14.50. We considered that 1 of these estimates was based on an inappropriately high interest rate and after adjusting for this, the cost estimates range between $11 and $14.50.

In addition, Country Energy advised us that it does not charge a late payment fee, and all of its costs associated with late payment were included in the retail operating cost information it provided to assist us in setting the retail cost allowance (discussed in Chapter 7). Integral Energy and EnergyAustralia both advised that they do charge a late payment fee, and that all their late payment costs except the cost of foregone interest were included in their retail operating costs information.

385 EWON submission on Draft Report and Draft Determination, February 2010, p 5 and COTA submission on Draft Report and Draft Determination, February 2010, p 4.

386 In Victoria, the Electricity Industry Act prohibits the energy retailers from charging small retail customers late fees, although the Energy Retail Code makes provision for a 'fair and reasonable' late fee to be charged. Queensland's standard retail contract under the Electricity Industry Code allows a late payment fee to be charged if permitted in the notified prices but at present no late fee has been notified.

We estimated that the costs of foregone interest make up only 12% to 20% of retailers' late payment costs. Therefore, to ensure that all late payment costs are accounted for only once in the regulatory package, in line with our terms of reference for the 2010 determination, we had to make an adjustment to either the level of the late payment fee, or the retail operating cost allowance.

In considering this issue, we noted that there were a range of options for making this adjustment. At one end of the range, we could remove the late payment fee altogether so that all late payment costs are recovered through the retail operating cost allowance. At the other end, we could significantly increase the late payment fee so it recovers all retailers' estimated late payment costs and none of these costs are recovered through the retail operating cost allowance.

12.2.4 Reasons for our decisions

In relation to the level of the late payment fee, we decided to increase this level in line with inflation, to maintain the current value of the late payment fee in real terms. We calculated that this required an increase of $0.50, based on the change in the CPI from the start of the 2007 determination period, when the fee was set at $7, and the forecast change to the middle of the 2010 period.

In relation to the conditions associated with imposing a late payment fee, we decided to extend the conditions related to waiving late payment fees so the Standard Retailers are required to waive these fees for all customers receiving the Energy Rebate, as suggested by community organisations. We consider that waiving late payment fees for these customers is a logical extension to the existing energy assistance measures for those on low and fixed incomes, who may have affordability issues. This, along with our other draft decisions on miscellaneous charges was supported by COTA and EWON.[387]

We understand that some retailers also have a policy of waiving late payment fees where a customer has been identified as in economic hardship. We support this as good practice. We also note that this is consistent with the proposed approach under the draft National Energy Customer Framework.

In relation to the adjustment needed to avoid double-counting of the costs associated with late payment, we decided not to make this adjustment to the late payment fee. Rather, we decided to make the adjustment in setting the retail cost allowance, as discussed in Chapter 7. This involved deducting 80% of the forecast revenue from late payment fees over the determination (or 80% of the notional revenue from these fees in the case of Country Energy, which does not charge late payment fees). This translated to a deduction of $2.30 per customer per year. We decided that this deduction should be applied to all the Standard Retailers including Country Energy who are able to charge a late fee but have made a business decision not to do so.

387 EWON submission on Draft Report and Draft Determination, February 2010, p 5 and COTA submission on Draft Report and Draft Determination, February 2010, p 4.

Integral Energy suggested that either the requirement to waive the late payment fee for recipients of the energy rebate should be removed and this left to the discretion of retailers or the $2.30 deduction from retail costs removed. It argued that the combined effect of the draft decisions on late payments would prevent any recovery of costs associated with late payment by customers receiving the Energy Rebate.[388] We consider this unnecessary as the deduction from retail operating costs was based on data from all standard retailers and neither EnergyAustralia or Country Energy currently charge recipients of the Energy Rebate a late payment fee and we expect that Integral Energy would already waive a proportion of these fees as some pensioners would fall within the existing requirements to waive late payment fees. Also, the $2.30 deduction represents only 80% of the revenue from late payment and allows for some additional revenue to be recovered from late payment fees.

We decided not to set the late payment fee at zero because in our view, this approach has the potential to lead to higher late payment costs. The absence of a late payment fee would reduce the incentive for small customers to pay their bills on time, and therefore could result in retailers having to send more reminder notices, experiencing longer delays between billing and payment, and foregoing more interest.

We decided not to set the late fee at around $11 to $14.50 (the range of costs estimates submitted by retailers) and remove all the costs associated with late payment from the retail operating cost allowance. This approach would mean that all retailers' late payment costs must be recovered from those customers who make late payments, rather than some being recovered through regulated tariffs as currently occurs. Therefore, it would necessitate a substantial increase in the level of the late payment fee. As NCOSS pointed out, such an increase would run counter to the objectives of the customer assistance policy and place further pressure on low-income households who are having difficulty paying their electricity account. We also note that none of the Standard Retailers argued for an increase in the late payment fee of this magnitude.[389]

Finally, we decided not to allow retailers to charge what they consider to be 'fair and reasonable', as Country Energy proposed and as allowed in some other jurisdictions. We consider that this approach would not address the potential for double counting of late payment costs, and would make it difficult for us to estimate any amount to be deducted from the retail cost allowance to address any double counting. We also consider that this approach would reduce the transparency and certainty of the late payment fee for customers.

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388 Integral Energy submission, February 2010, p 9.

389 Integral Energy's submission on the issues paper requested CPI changes and EnergyAustralia's submission did not specify the level of increase being sought.

12.3 Dishonoured cheque fee

IPART's final decision is to:

– Retain the level of the dishonoured cheque fee at 2 times the regular (GST-exclusive) fee charged by the bank or financial institution.

– Continue to provide that the Standard Retailers may only charge this fee where they actually incur a bank or financial institution fee for the dishonoured cheque.

Recommendation

7 That the NSW Government amends the Electricity Supply Act to allow the Standard Retailers to charge a fee for dishonoured non-cheque payments.

This decision and recommendation is consistent with our draft decision.

Stakeholder submissions and the working group did not raise any significant concerns about the current level of dishonoured cheque fee. In addition, we note that the average fee Standard Retailers' charge has decreased in real terms over the past 5 years, as it has remained fairly constant since 2004. Therefore, we consider it appropriate to maintain the current level and conditions for the dishonoured cheque fee, as set in the 2007 determination.

In their submissions, the 3 Standard Retailers argued that the Electricity Supply Act should be amended to enable them to levy a non-tariff charge for dishonoured non-cheque payments. As noted above, the Act currently defines regulated retail charges in a very specific way, so the Standard Retailers can only charge a fee for dishonoured payments made by cheque. However, they also incur costs when a customer defaults on a payment made by direct debit.

The Standard Retailers made the same point in the 2007 review, and we considered the point was valid. Therefore, we recommended that the Government amend the Electricity Supply Act to allow Standard Retailers to charge a fee for non-cheque dishonoured payments. The government did not respond to that recommendation.

We still consider the point valid, and note that information from Standard Retailers indicates that only a small and declining proportion of bills are now paid by cheque (around 3% on average in 2009, down from 4% in 2007). In contrast, a larger and increasing proportion of bills are paid by direct debit (19% on average in 2009, up from 16% in 2007). The annual value of financial institution charges to Standard Retailers for dishonoured cheques has been declining steadily, and for 2 of these retailers, the total annual charges for dishonoured direct debit payments are many times more than total financial institution charges for dishonoured cheques.

We consider that it is anomalous that retailers are able to charge a fee for dishonoured cheque payments, but are not able to charge a similar fee for dishonoured non-cheque payments. Therefore, we have decided to again recommend that the Government amend the Electricity Supply Act to remove this anomaly.

EnergyAustralia submitted that the determination should include clauses which would come into effect if and when amendments are made to the Electricity Supply Act and would allow standard retailers to charge twice the financial institution fee for a dishonoured direct debit.[390] However, we have not made provision for the fee to be introduced under the determination as we do not know whether the Government will accept our proposal and, if it did, the form of any amendment to the Act and therefore we have not formed a view on the appropriate level for such a fee. It is not necessarily appropriate to apply the same fee as for dishonoured cheques to non-cheque payments. We consider it appropriate that only incremental costs associated with dishonoured non-cheque payments be recovered through such a fee.

390 EnergyAustralia submission, February 2010, pp 39-40.

Appendices

A Terms of Reference

Terms of Reference for an investigation and report by the Independent Pricing and Regulatory Tribunal on regulated retail tariffs and regulated retail charges to apply between 1 July 2010 and 30 June 2013 under Division 5 of Part 4 of the *Electricity Supply Act 1995*.

A.1 Reference to IPART under section 43EA

The Minister refers to IPART for investigation and report under section 43EB of the Act:

> The determination of regulated retail tariffs and regulated retail charges to apply to small retail customers in each standard retail supplier's supply district in New South Wales for the period from 1 July 2010 to 30 June 2013.

A.1.1 Background

In accordance with its commitment to retain the offer of regulated retail tariffs at least until 2013, the Government has extended the current scheme for regulated retail tariffs and charges to apply to small retail customers supplied under a standard form contract. A regulatory amendment will be made for these purposes under section 43EJ of the *Electricity Supply Act 1995* to allow IPART to make a further determination of regulated retail tariffs and charges that will apply from 1 July 2010 to 30 June 2013.

Since January 2002, every electricity customer in NSW has had the option to negotiate a retail supply contract with any licensed retailer. Small retail customers who do not seek supply from the competitive market are deemed to receive electricity under a 'standard form' customer supply contract from their 'standard retail supplier'. Customers can also switch backwards and forwards between these alternatives. These arrangements were designed to encourage customers to test the market by providing an assurance that they can return to regulated retail tariffs. Approximately nine hundred thousand NSW customers have now moved on to negotiated tariffs.

While retail competition has delivered benefits for those participating in the market, the majority of residential and some small business customers have chosen to remain on standard form customer supply contracts which impose regulated retail tariffs and charges determined by IPART.

The NSW Government considers the reliable provision of electricity to be an essential service. It is therefore important that the financial viability of Standard Retail Suppliers is preserved, in order to ensure that they are able to continue to provide electricity to NSW customers. Network charges and energy purchase costs represent a significant proportion of the costs faced by retailers in the provision of electricity.

To promote retail competition and investment, regulated retail tariffs have been progressively moved toward fully cost-reflective levels over the course of the last three retail tariff determinations by IPART. The 2007 determination aimed to achieve regulated retail tariffs by 30 June 2010 that fully reflect the market-based costs of meeting each Standard Retail Supplier's obligations to their regulated customers.

This review should ensure the aims and approach of the 2007 determination are preserved. IPART's approach should result in prices that are based on the efficient cost of supplying small retail customers, including customers who revert from negotiated tariffs.

In carrying out the review, IPART should provide advice to the Government regarding the impact of the determination on small consumers.

A.1.2 Matters that must be taken into account

For the purposes of section 43EB(2) of the *Electricity Supply Act 1995*, in undertaking the review from 1 July 2010 to 30 June 2013, IPART should ensure its determination is consistent with the Government's policy aim of reducing customers' reliance on regulated prices. Regulated tariffs should reflect the efficient costs faced by a Standard Retailer Supplier meeting the forecast demand of the regulated customers they are obliged to serve.

IPART's determination for the period from 1 July 2010 to 30 June 2013 should:

- result in prices that recover the efficient costs of supplying small retail customers; and
- apply any change to regulated tariffs on 1 July 2010 and annually thereafter on 1 July or on a date determined by IPART.

These Terms of Reference refer to three distinct cost components for Standard Retail Suppliers:

- Energy Costs
- Retail Costs, and
- Retail Margin.

Energy Costs

Energy costs include energy purchases from the National Electricity Market (NEM), greenhouse and renewable energy costs, NEM fees and energy losses.

For energy purchases, IPART should determine a target Energy Purchase Cost Allowance for 30 June 2013 and an Energy Purchase Cost Allowance for each year of the determination. The Energy Purchase Cost Allowance should be set, using transparent and predictable methodology, at a level that would allow a Standard Retail Supplier to recover the efficient costs of managing the risks associated with purchasing electricity from the NEM (including the Carbon Pollution Reduction Scheme). Additionally, IPART should have regard to the efficient costs of meeting any obligations that Standard Retail Suppliers must comply with, including the costs of complying with greenhouse and energy efficiency schemes (including present and future State and Commonwealth schemes).

The Energy Purchase Cost Allowance for each year must not be lower than the least cost mix of generating plant (based on those plants earning an economic return on their market value), including any plant that would be required to meet any regulatory obligation, (using generation technology that is available in the NEM for the relevant year/period), to efficiently meet each Standard Retail Supplier's forecast regulated load.

IPART should allow for a periodic review of the Energy Purchase Cost Allowance, including the costs of complying with greenhouse and energy efficiency schemes.

IPART should allow for energy losses as published by the Australian Energy Market Operator (AEMO).

IPART should allow for market fees and ancillary fees as imposed by AEMO under the National Electricity Rules.

Retail Costs

Standard Retailers incur retail operating costs in supplying electricity customers, which include the costs associated with customer service (eg, operating call centres, billing and collecting revenue), finance, IT systems, and regulation (eg, licence fees).

IPART will determine an allowance for retail operating costs based on efficient costs. IPART will take into account NSW Standard Retailers' efficient costs and other available information on efficient operating costs for retailers.

IPART should also ensure regulated retail tariffs are set at a level which encourages competition in the retail electricity market by including customer acquisition costs in the retail cost allowance.

Retail Margin

IPART will determine an appropriate retail margin giving consideration to any risks not compensated elsewhere arising from supplying regulated customers.

A.1.3 Consultation

IPART should consult with stakeholders, conduct public hearings or workshops and consider submissions, within the timetable for the investigation and report. IPART must make its report available to the public.

A.1.4 Timing

IPART is to investigate and provide a report of its Draft Report and Draft Determination of regulated retail tariffs and charges within six months of receiving the terms of reference and a Final Report and determination within three months of releasing the Draft Determination. IPART is also to publish an Issues Paper and methodology paper within two months of receiving the terms of reference.

A.1.5 Definitions

Regulated retail tariff means a tariff for or in relation to the supply of electricity required to be charged to a small retail customer under a standard form customer supply contract, being a tariff specified in a determination in force under Division 5 of Part 4 of the *Electricity Supply Act 1995*.

Small retail customer means a customer that consumes electricity at less than 160MWh per year as prescribed in clause 7 of the *Electricity Supply (General) Regulation 2001*. A small retail customer is eligible for supply under a standard form customer supply contract.

Standard retail supplier means a retail supplier to whose retail supplier's licence is attached a standard retail supplier's endorsement. A standard retail supplier must impose tariffs and charges for or in relation to supplying electricity under a standard form customer supply contract in accordance with any relevant determination of IPART under Division 5 of the *Electricity Supply Act 1995*.

Standard form customer supply contract means a contract entered into under Division 3 of Part 4 of the *Electricity Supply Act 1995*.

B Key issues raised in submissions and IPART's response

We received over 100 submissions on our draft report. Submissions are available on our website. We have carefully considered all submissions. The following table presents an overview of key issues raised in submissions and our response. For our response on WACC please refer to Appendix E.

Table B.1 Key issues raised in submissions and IPART's response

Key issues raised in submissions	IPART's consideration
Form of regulation	
Origin Energy and Country Energy questioned the need to subject Country Energy to a 'threshold price increase test' that requires Country Energy to obtain IPART approval if it proposes to increase an individual regulated tariff by more than the maximum average change allowed under the WAPC plus an additional 5%.	Our assessment indicates that Country Energy is under less competitive pressure than the other Standard Retailers and has significantly more tariffs. Only 47% of its regulated residential customers are on its main regulated tariff (the *Urban Domestic* tariff). However, Country Energy still has over 180 individual regulated tariffs, and only half of these are at cost-reflective levels. While Country Energy has restructured its regulated tariffs such that an increasing number of residential customers face the same tariff level, the large number of separate regulated tariffs provides Country Energy with scope to alter the level of these individual tariffs in the future. Therefore, we consider that additional price limits on Country Energy are required to ensure customers are adequately protected over this period (see Chapter 5). However, we do not consider that the threshold test will restrict Country Energy's ability to further rebalance its tariffs or delay the transition of Country Energy's tariffs to cost-reflective levels.
Individual submission proposed that a low income tariff be introduced.	We considered the introduction of a hardship tariff as part of the 2007 review and considered that it was not consistent with terms of reference for that review which required tariffs to be at cost reflective levels by 2010 and would require the costs associated with a new hardship tariff to be recovered through increases in other tariffs. We consider that a regulated hardship tariff is also not consistent with the 2010 terms of reference and we remain concerned that a hardship tariff may provide a way to segment customers. We maintain our view that the best way to address affordability concerns is though direct and transparent government payments or retailer hardship programmes. Our regulatory framework does not prevent Standard Retailers from providing rebates to customers in financial hardship; however, we do not consider it appropriate to recover these costs from other regulated customers.
Council on the Ageing's (COTA) proposed that a comparator phone service should also be made available.	We recommend that a comparator phone service should be made available, as internet access and use is limited among some demographics (see Chapter 3).
EWON considered that the lack of certainty surrounding the implementation dates of NECF necessitates the adoption of IPART's recommendation in the meantime whereas some retailers (Integral Energy and TRUenergy) consider that interim arrangements should not proceed in NSW.	In an environment of increasing prices and increasing market activity it is critical that consumers have access to accurate tariff information as soon possible in order to make more informed choices. Given that one of the main private comparator services, CHOICE Switch, has recently exited the market, we consider that these recommendations should be adopted as soon as possible. However, we recognise that implementing a comparator service may take time. We agree with Country Energy and Origin Energy that modelling the NSW disclosure requirements and comparator services on existing states schemes is likely to minimise compliance costs on retailers, as they already have to provide this information in other states (see Chapter 7). Further, we expect that the NECF

Key issues raised in submissions	IPART's consideration
	arrangements will be broadly consistent with any State comparator service.
EnergyAustralia was concerned that the AER's network pricing approval process may not be completed until 2 June each year.	We have asked the AER to make best endeavours to complete the network compliance assessment as early as possible to assist us in approving regulated retail tariffs by 1 June. However, in some instances Standard Retailers may need to submit their annual pricing proposal using draft network prices if the AER has not completed its pricing approval process prior to 15 May. We will complete our compliance assessment once final network tariffs have been approved by the AER.
Energy cost allowance and periodic cost reviews	
Retailers expressed concern over transparency and accuracy of regulated load forecasts: ▼ AGL and Origin Energy sought release of further load data or an 'independent audit' of the retailers' load forecasts. ▼ The EPCA set out in the draft report did not match some retailers expectations based on publicly available ETEF information. ▼ The relativities between each Standard Retailers' cost to serve are not consistent with stakeholders' expectations.	The terms of reference for this review require us to set an energy purchase cost allowance for each year of the determination period to efficiently meet each Standard Retailer's forecast regulated load. However, we had Frontier Economics examine the load forecast in detail and undertake an independent analysis of the reasonableness of these forecasts. This analysis involved comparing the load factor and volatility of each Standard Retailers' forecasts against historical ETEF data including taking account of any embedded generation. The load profiles that were submitted to us by the Standard Retailers: 1. were based on historic ETEF data, accounting for the treatment of embedded generation in that data, such that the load profiles reflect trends in peak demand and load factors 2. were correlated to both system demand and prices in a way that is consistent with correlations observed historically 3. were appropriate to use in determining the EPCA as it would ensure that the cost of energy included the cost of load volatility (refer to Chapter 6). We recognise stakeholders' concern that the regulated load forecasts are not publicly available given they represent commercially sensitive information to the Standard Retailers. Consistent with stakeholders' requests, as part of this final report we have released modelling of the LRMC of generation and the market based estimates based on the NSLP for each Standard Retailer. This should assist stakeholders' in verifying Frontier Economics' modelling of the EPCA. (Refer Frontier Economics' final report as well as IPART's website for Frontier's modelling results). We are also recommending to the NSW Government that in any future review of regulated retail tariffs and charges (ie, price review post-2013) the terms of reference specify that the energy purchase cost allowance be based on each Standard Retailers' NSLP.
Some retailers argued that forecast regulated loads should be reviewed annually.	We will not be reviewing the regulated load forecasts as part of the annual review of the total energy cost allowance given that the removal of ETEF will remove the source of data used to generate the retailers' regulated load, and therefore reviewing the load annually will be timely, costly and difficult to verify (refer to Chapter 10).

Key issues raised in submissions	IPART's consideration
NEM demand forecasts (2009 SOO) used for market modelling are overly pessimistic about economic growth and electricity demand.	We recognise that the current market expectations of domestic economic growth and therefore energy demand over the determination period, and particularly in 2010/11 may be more positive than at the time that the demand forecasting was undertaken for the AEMO 2009 SOO. We also recognise that for 2010/11 the high growth scenario in the 2009 SOO is lower than the medium growth scenario in the 2008 SOO which was used as part of our 2009 annual review. Frontier Economics' analysis demonstrates that the market based modelling is sensitive to the energy demand assumption. Frontier Economics' final report provides forecasts of annual average NSW pool prices over the determination period based on the medium energy scenario in the 2008 SOO as a scenario. This analysis highlights this sensitivity, showing that for 2010/11 the pool price forecasts under the 2008 SOO are broadly similar to the d-Cypha flat swap price. This suggests that the low outcomes of the market based modelling for 2010/11 relative to current d-Cypha data reflect the unusually low forecasts of demand in the 2009 SOO. While we recognise that the 2009 SOO may underestimate likely growth in demand given the revised expectations of domestic economic growth over the determination period, we consider it the most appropriate source of information regarding energy demand forecasts. We have previously noted that developing independent forecasts would be a very complex task due to the number of factors that can affect demand over the forecast period and the Transmission Network Service Providers (TNSPs) and AEMO put considerable work into their forecasts. Therefore, we do not consider there to be advantages in undertaking our own energy demand forecasting and revising the market based modelling to take account of these forecasts. We will consider this issue as part of the annual reviews of the total energy cost allowance.
AGL submitted that we should not review the LRMC as part of the annual review given the need for certainty in the price path.	We noted that the LRMC of generation is sensitive to changes in capital and fuel costs which fluctuate from year to year. It will also be sensitive to any changes in the assumed carbon price which will alter the investment and dispatch mix of the theoretical system. Given the potential for change in the LRMC over the determination period and that the terms of reference require us to set the EPCA as the higher of the LRMC and market based estimates, we consider that this requires updating the LRMC each year as part of annual review.
AGL submitted that as part of the annual review the LRMC should be calculated on a carbon exclusive basis, with a separate carbon allowance determined using a 'relevant pass through rate' such as the NEM emissions intensity rather than the emissions intensity of the theoretical LRMC system.	We note that the terms of reference require us to set the LRMC of generation consistent with the least cost mix of generating plant to efficiently meet each Standard Retailers' forecast regulated load. Setting a carbon exclusive or 'black' LRMC and then adding a 'carbon component' that is calculated on an incremental basis such that it reflects the emission intensity of the entire NEM would not be consistent with the least cost theoretical system to meet the regulated load in the presence of the CPRS. This is because the LRMC of generation is a theoretical system in which investment is able to respond immediately to the carbon price, which leads to a change in the proportion of gas fired plant over the determination period. While we recognise that the carbon cost that will be passed through to retailers will be a function of the existing generation build, it is important to note that the LRMC of generation is a theoretical framework and is

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	not intended to necessarily reflect retailers' actual purchase costs in the NEM.
AGL submitted that the capital and fuel costs assumptions should only be updated with an expert report commissioned by AEMO, such as the ACIL Tasman Report.	As part of updating the limited set of key input assumptions (such as capital and fuel costs) we consider an expert report commissioned by AEMO to be the most appropriate source of independent input data and intend to rely on this where possible. However if this is unavailable or does not have sufficient information to undertake the annual review, then we will rely on other report(s) IPART considers to represent independent industry expertise or a report we commission.
Retailers supported the use of publicly available forward market prices such as d-cypha data as a source of contract prices.	We decided to use modelled forward price data in determining the market based estimate for 2010/11 and the indicative price path for 2011/12 and 2012/13, recognising that the market based estimate will be revised in 2011 and 2012 as part of the periodic review of the total energy cost allowance. We note that the use of publicly available market data has some potential advantages, particularly in terms of transparency. We also recognise that observed market prices reflect the expectations of a wide range of market participants, each taking into account the information available to them. However, there are also a number of complications in using publicly available market data as the source of forward prices: ▼ there is insufficient liquidity in forward contract markets in the later years of the determination period, particularly 2012/13, to support its use for this review ▼ while publicly available data on forward prices such as d-Cypha data are carbon-inclusive, uncertainty about the implementation of the CPRS means that the data for the later years may not fully reflect the costs of the CPRS (ie, they may be discounted due to this uncertainty). We consider publicly available forward price data an important source of information in determining the market based estimate of the EPCA. However, we note that the observable forward price market data is highly variable and may not fully reflect the costs of the CPRS. Therefore while our preference is for greater reliance on publicly available market data, given the uncertainties in the market including uncertainty surrounding the proposed CPRS, it is difficult for us to rely solely on observable forward price market data at this time, or to say in what circumstances this data would be relied upon relative to modelled price outcomes.
Retailers supported the use of d-cypha data as part of the annual reviews of the total energy cost allowance.	We recognise that there is likely to be liquidity in the forward contract market in the nearer term (for example, 1 year ahead), and we consider publicly available forward price data an important source of information in setting the EPCA as part of the annual review. Stakeholders have sought greater clarity over the use of publicly available market data as part of the annual review. While our preference is for greater reliance on publicly available market data, given the uncertainties in the market including uncertainty surrounding the proposed CPRS, it is difficult for us to rely solely on market data at this time, or to say in what circumstances market data would be relied upon relative to modelled price outcomes. We have decided to include in the annual review process a step in which we will compare the modelled price outcomes against publicly available market data and give consideration to the reasons for any material

Key issues raised in submissions	IPART's consideration
	deviation. We will then make a draft decision on the most appropriate source of forward price data to be used in the portfolio optimisation modelling. We will however maintain our use of a point in time approach regardless of the source of the forward price data. We will then issue our draft report, and undertake consultation prior to issuing a final report. (See Chapter 10 for more detail on the annual review of the total energy cost allowance.)
AGL submitted that prior to issuing a draft report for the annual review of the energy purchase cost allowance IPART should: ▾ Release an initial report which could contain modelling assumptions and the resulting energy cost allowances. ▾ Conduct a round of consultation including a public workshop.	We have limited the scope of the reviews and 'locked in' the methodology consistent with that used in making our decision on the energy purchase cost allowance. This is to provide regulatory certainty and to reduce the administrative costs to IPART and stakeholders. We consider issuing a draft report followed by stakeholder consultation, prior to issuing a final report to provide sufficient consultation.
Retailers support a 24 month rolling average of d-cypha prices rather than a point in time 'snapshot'.	We note that in an efficient and competitive market (with low barriers to entry), wholesale energy prices as well as REC prices would reflect the most up to date information available. This suggests that the prices the Standard Retailers could charge would be constrained by other retailers (or potential retailers) to the market value of the inputs required to serve customers at that point in time. In a competitive market the historical or actual costs of retailers are only relevant for determining the profitability of its operations from serving customers at prices that reflect current market values. That is, in a competitive market historical costs rarely form the basis of current and future prices. We have decided to use a point in time estimate of forward prices.
EnergyAustralia proposed that we should deal with the uncertainty about the final design and implementation date for the CPRS by setting the total energy cost allowance without regard to the costs associated with this scheme. We could then estimate these costs if the CPRS legislation is enacted and incorporate them into regulated retail tariffs via the cost-pass-through mechanism.	We consider that setting the energy purchase cost allowance without regard to the costs associated with the proposed CPRS would be inconsistent with our terms of reference for this review. The terms of reference require us to set this allowance at a level that reflects the efficient costs of purchasing electricity on the NEM, including the costs associated the CPRS. Therefore, we have chosen to set the energy purchase cost allowance by estimating this cost on a carbon-inclusive basis (as discussed in Chapter 6), and addressing the risk of forecasting error due to uncertainty about the CPRS and its impact on electricity prices through the periodic reviews of this allowances. We consider this approach will adequately manage these risks.
Integral Energy submitted that the one-off review of the market based energy purchase cost allowance should not be subject to a materiality threshold consistent with the annual reviews of the total energy	We consider the materiality threshold is appropriate to avoid changes in regulated retail prices for small changes in energy purchase costs, and to maintain the incentives for the Standard Retailers to act efficiently. In addition, we consider that any potential detrimental impacts of having a materiality threshold (eg, on retailers' margins and the cost-reflectivity of regulated retail tariffs) is lower than those for the annual reviews, as the

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cost allowance.	review period is only 6 months.
AGL and Origin Energy requested further information on how the carbon price will be derived.	Given the level of uncertainty associated with the carbon scheme we do not consider that it is appropriate (nor in the best interest of stakeholders) to 'lock in' the carbon price input source as we have done with other cost inputs (such as our preference for relying on an AEMO commissioned report for capital and fuel cost assumptions). For example, the appropriate source of carbon price information may depend on the final details and timing of the scheme. For these reasons we have made a decision not to specify the source of information on market-based carbon prices in 2012 (see Chapter 10 for more detail).
Country Energy proposed that we establish a regulatory package that allows the retailers to pass through their actual costs in complying with 'green' schemes and also submits that the cost pass through mechanism should be extended to include unforseen and material changes in the EPC.	The costs of complying with existing and foreseen future green schemes are within retailers' control, and they have some ability to manage these green costs. Therefore, it is important that the regulatory package creates incentives for them to do so. Allowing them to pass through all their incurred costs would reduce this incentive. We consider that this would not be consistent with the terms of reference. The purpose of the cost pass through is not to reduce the risk associated with changes in certain of the retailers' costs over the determination period. Rather, it is to manage the financial risk associated with material and unforseen changes in costs due to defined *regulatory or taxation change events*. The retailers always face the risk of unanticipated changes in their costs, and to some extent, managing this risk is a normal part of their business. However, as they have no ability to control costs imposed by unforeseen changes in regulation or taxation laws, it is appropriate that they be allowed to pass through these costs.
EnergyAustralia submitted that the definition of Regulatory Change Event excludes the introduction or amendment of any green energy scheme.	We do consider that the definition of Regulatory Change Event should include the introduction or amendment of green energy obligations, and this has been reflected in definition of Regulatory Change Event in the final determination.
EnergyAustralia submitted that the definition of regulatory change event should include events that may occur between the Final Determination being released, and the gazettal of the Final Determination.	In recognition of the risk of a Regulatory Change Event and/or Taxation Change Event occurring between the release of the final determination and its publication in the NSW Government Gazette we have altered the final determination to eliminate this risk.
Retailers submitted that the RET allowance in our draft report is too low and does not reflect: ▼ current market prices for RECs ▼ developments in the capital costs of wind farms ▼ the uncertainty surrounding whether the CPRS will be introduced or delayed.	Our final decision on the RET allowance is higher than the draft report, reflecting increases in Frontier Economics' final advice on forecast REC prices over the determination period (around \$30 -\$32). (Refer Chapter 6 for more detail on the changes to the REC forecasts.) We remain of the view that Frontier Economics' cost based methodology is consistent with the terms of reference which require us to have regard to the efficient costs of meeting the RET obligations. We note that the majority of stakeholders supported this methodology in their submissions in response to our draft methodology and assumptions report. We also note that Frontier Economics' calculated REC cost is only slightly lower than the observed market price for RECs (around \$32 to \$35) at the time it conducted its analysis

Key issues raised in submissions	IPART's consideration
	(prior to the Commonwealth Government's announced changes to the scheme). In providing their final advice to us on the costs of complying with the RET, we instructed Frontier Economics to continue to use the cost input assumptions sourced from the ACIL 2009 report for AEMO as well as Concept Economics. While we recognise that some updated information may be available we have previously emphasised our preference to base these assumptions on publicly available data where possible. We consider an expert report commissioned by AEMO to be the most appropriate source of independent input data and as part of the annual review of the total energy costs, intend to rely on this where possible. Stakeholders have supported the use of AEMO commissioned reports (such as the current ACIL 2009 report) as the source of input data. Therefore while we recognise that there may be some updated information available on the costs of renewable plant we have made a decision to continue to rely on the ACIL 2009 report.
EnergyAustralia submits that there is no ex-post compensation for green losses stemming from the delay of the CPRS. EnergyAustralia proposed determining the RET allowance using the assumption that the CPRS does not exist over the determination period (on a carbon exclusive basis).	We considered EnergyAustralia's proposal to determine the RET allowance assuming that the CPRS does not exist over the determination period. However as Frontier Economics has advised this proposal does not resolve the difficulty surrounding the CPRS uncertainty. Modelling a carbon-exclusive price would result in a REC price forecast for 2010/11 that is based on the certain absence of the CRPS. Under this assumption, the REC price would be significantly higher than REC prices under a carbon inclusive price given the relationship between wholesale energy prices and REC prices. In addition, this REC price for 2010/11 would be inconsistent with the forecast wholesale market prices for 2011/12 and 2012/13 set out in this report. We note that under our preferred approach the total energy cost allowance and therefore regulated retail tariffs would allow an efficient retailer to remain financially viable given that the LRMC of generation in 2010/11 is significantly higher than the Frontier Economics' market based estimates and current d-Cypha market data.
Stakeholders submitted that the GGAS allowance set out in the draft report is too low and does not take into account: ▾ The Commonwealth Government's transitional compensation package offered to holders of NGACs. ▾ That holders of NGACs would not prepared to sell them for zero given the associated transaction costs ▾ There have been changes to the GGAS rules which have an effect on supply and demand for NGACs	We recognise retailers' comments that the Commonwealth Government's transitional compensation package creates a value for surplus NGACs that is above zero. However, our methodology considers the resource cost of meeting the scheme, rather than the financial or commercial value of NGACs. Frontier Economics' advice is that the incremental resource cost of meeting the GGAS is zero. We remain of the view that our methodology is consistent with the terms of reference which require us to have regard to the efficient costs of meeting the GGAS obligations, and is consistent with our approach to estimating the costs of meeting the RET. Given the inter-relationship between the schemes we consider a consistent approach to be important. We note that the majority of stakeholders that commented on this issue in their submissions in response to our draft methodology and assumptions report supported this methodology. While we note that current observed prices for NGACs are above zero, under our final decision on the total energy cost allowance and therefore regulated retail tariffs would allow an efficient retailer to remain financially viable given that the LRMC of generation in 2010/11 is higher than the Frontier Economics' market based estimates and current d-Cypha market data.

Key issues raised in submissions	IPART's consideration
Retail cost	
Retailers submitted that Standard Retailers are stapled businesses and thus their costs are inappropriately low to represent the efficient costs of a standalone business.	We note that submissions did not specify or quantify the economies of scope that stapled retail/distribution businesses achieve. However, on balance, we consider the Standard Retailers' cost information appropriate to use in setting the retail cost allowance because: ▼ Our benchmarking analysis supports our retail cost allowance being based on the Standard Retailers' information, as it is comparable to the cost information reported by publicly listed businesses that are standalone in NSW. In particular, we note that our allowance of $109.80 per customer is above AGL's reported retail costs of $94 per customer – currently a standalone business in NSW competing against the stapled incumbents. It is also above Origin Energy's latest cost to serve of $63 per customer (this figure does not appear to include CARC)) (see Chapter 7). ▼ Standalone businesses in NSW can adopt business structures that achieve similar or greater cost advantages to those enjoyed by the Standard Retailers. For example, standalone retailers in NSW could achieve some economies of scope either outside of NSW or through complementary activities such as generation. Market evidence suggests that other retailers, for example, AGL, TRUenergy and Origin Energy seek out such opportunities.
Retailers submitted that historical costs reflect historical processes rather than forecast requirements and therefore cannot be considered cost reflective going forward.	Our use of historical costs to set the retail cost allowance does not mean that we consider business activities over the determination period to be completely consistent with recent or past activities. We reiterate that we consider the allowance covers the costs associated with changes to existing regulatory obligations expected over the determination period, such as the ESS and expanded RET. With respect to compliance costs associated with new regulatory obligations, such as the proposed obligations under the NECF, we consider that they are best catered for through the cost pass-through mechanism, when the materiality of such costs is known with greater certainty (see Chapter 10). In relation to the CPRS, it has still not been made clear what specific regulatory obligations the Standard Retailers face under this scheme, given that they are not directly responsible for carbon emissions. Therefore, we consider it unlikely that the CPRS will impose new regulatory administration costs on the Standard Retailers. We also reiterate that the CPRS will primarily affect Standard Retailers' energy purchase costs, and we have accounted for this in setting the energy purchase cost allowance. The costs of meeting obligations under GGAS, the ESS and RET are also included in the total energy cost allowance, as discussed in Chapter 6.
	Origin Energy submitted that a retail allowance based on historical costs does not cover the costs of trading or procuring wholesale energy costs in a non-ETEF environment. We note that on average about a third of Standard Retailers' customer bases already comprise negotiated customers. We also note that ETEF is planned

Key issues raised in submissions	IPART's consideration
	to be phased out over the determination period and not removed at the start of the period, and that managing ETEF is not costless but involves administrative costs that would be included in historical costs. Origin Energy did not provide any specific estimate regarding trading costs in a non-ETEF environment – or what proportion of retail costs this may represent. AGL considered a real reduction in retail costs from the current allowance was not warranted in light of higher incidences of bad and doubtful debt over the determination period. We note that the various government customer assistance and compensation packages (discussed in Chapter 11) should help manage some of the risk of increasing debt associated with the price increases allowed under the 2010 determination. We also note that the Standard Retailers did not report any material difference between the average historic and forecast per customer costs for bad and doubtful debt in their information returns. Therefore, we believe our retail cost allowance provides for an appropriate level for bad and doubtful debt.
Integral Energy claimed that we did not adequately support our decision to reject its specific forecast costs.	This issue is whether prices are set according to the standard retailers' individual operating costs, including depreciation and amortisation, or whether a consistent estimate of operating costs, depreciation and amortisation is applied for all three standard retailers. We have determined that we will adopt consistent cost and margin assumptions across the three standard retailers,
Standard Retailers submitted revised customer number forecasts underpinning the draft report underestimate the competitiveness of the market going forward.	In response to the draft report EnergyAustralia has revised its customer number forecasts. We note that EnergyAustralia's revised customer numbers indicate that its original forecasts of customer losses were overstated. We also reviewed the latest 6 month AEMO customer transfer data that is now available since the draft report. These data indicate that customer transfers in NSW have recently increased. Therefore, we have updated the retail cost allowance from our draft report to incorporate EnergyAustralia's revised customer numbers. In addition, we have accepted Country Energy's forecasts as they are also consistent with the updated customer transfers from the AEMO. However, we have not accepted Integral Energy's revised forecasts because they predict lower rates of customer losses, which appears to contradict the latest AEMO data. Therefore, we have applied Integral Energy's initial customer number forecasts to our analysis. Our decision has updated retail operating costs to incorporate the Standard Retailers' customer number forecasts over the determination period following updated information. This change increased ROC by about $1.10 per customer per year.
Retailers submitted that the midpoint of our cost range is an inappropriate reflection of retail costs and competitive state of the market.	We reiterate that the midpoint of the range identified for retail costs was not an arbitrary choice, especially with regulated tariffs reaching full cost reflective levels in 2009/10. We acknowledge that choosing a lower point may have reflected efficient costs (although we also note that this is not necessarily the case —for example, a Standard Retailer might achieve lower costs by not allowing for any system investment, which

Key issues raised in submissions	IPART's consideration
	would not be efficient). In addition, we acknowledge that choosing a higher point may facilitate competition and provide a more conservative allowance to cover increases in costs. However, in an environment of cost reflective tariffs, the midpoint represents a measured choice that balanced our efficiency and competition criteria. We also note the Minister's submission that final increases to regulated tariffs be no more than required to ensure the ongoing financial viability of the NSW Standard retailers. Our efficient retail cost allowance was not just based on our bottom-up analysis, but also on our benchmarking analysis. The high end of the range for retail costs identified through our bottom-up analysis of about \$125 per customer was not considered efficient because it was substantially higher than the midpoint of our benchmark range of \$93 per customer. Our retail cost allowance of \$109.80 per customer provided a more reasonable estimate that was still above the midpoint of our benchmark range and therefore balanced both efficiency and competition concerns.
Retailers submitted that the CARC allowance is too low as it is based on a historical switch rate that does not reflect future levels of competition.	We note that we have increased the switch rate from 11% to 13% since the release of the draft report to reflect updated AEMO data on transfer activity in NSW. The updated switch rate increased CARC by \$4 per customer per year from the draft report. We used AEMO's customer transfer data because it is transparent and objective. We also consider our switch rate a reasonable forward estimate, given that switch rates are not the only indicator of competition.
EnergyAustralia considered our CARC allowance too low as it excludes the costs of "save" activity.	Save activity refers to the acquisition costs retailers incur for customers that do not become billable customers, because they end up accepting counter offers from their existing retailer during the transfer process. We believe that retailers are able to recoup the acquisition costs associated with these customers (ie, costs of save activity) through termination fees and that the application of termination fees are at the discretion of the retailer. Therefore, we do not consider it appropriate to included save activity in our CARC allowance.
Some retailers questioned the appropriateness of some of our benchmarks in the draft report, and noted that they needed to be adjusted upwards for the final determination: ▾ the ICRC's 2009/10 allowance does not include customer acquisition costs and should reflect this ▾ ESCOSA's 2008 to 2010 allowance did not compensate for declining customer numbers ▾ while the QCA's 2009/10 allowance is comparable to our allowance, its recently released 2010/11 allowance suggests our allowance is too low.	With respect to the points made about the ICRC's and ESCOSA's allowances, we reiterate that we have taken these matters into account. We also note that our retail cost allowance is above the midpoint of the benchmark range of \$93 per customer, which balances out some of the discrepancies inherent in any benchmarking analysis. Since the release of our draft report, the QCA has released its proposed 2010/11 retail cost allowance of \$129.62 per customer, which is significantly higher than its previous allowance of about \$110 per customer. However, we note that the increase in its allowance stems from significantly higher switch rates used to calculate customer acquisition costs. The QCA did not increase its retail operating cost allowance in real terms, nor did it increase unit acquisition costs in real terms. In addition, we note that the QCA's unit cost estimate for customers switching retailers of \$186.69 is lower than the \$213 unit cost underpinning our CARC allowance.

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AGL and Origin Energy's publicly reported retail costs include economies of scale materially larger than the Standard Retailers and they should be adjusted to reflect this.	We do not consider AGL and Origin Energy to have significant scale economies additional to the Standard Retailers due to differences in the number of customers they serve. We refer to Frontier Economics' advice on this issue in the 2007 determination that a retailer's average cost curve is flat over a wide range of customer numbers, and efficient scale is reached at levels much lower than the Standard Retailers' customer bases. Our benchmarking confirms this advice.
Retail margin	
Stakeholder submitted that we should adopt a margin towards the upper end of the reasonable range.	Our decision on the appropriate retail margin is consistent with the mid-point of the reasonable range for this margin recommended by our expert consultant, SFG. Our decision to set the retail margin as a fixed percentage of total costs, and recalculate the margin in dollar terms within the determination period is consistent with terms of reference, which stress the need for prices to reflect the efficient costs of supply in each year of this period.
Several stakeholders submitted that the cost of capital estimates set out in our draft decision were too low and do not reflect the cost of capital for electricity retailers.	We revised the WACC, increasing it by 30 basis points to 9.1%, reflecting updated market parameters and reduced the assumed level of debt from 40% to 30% of the asset base. (See Chapter 6 and Appendix E).
Origin Energy submitted that the use of an EBIT retail margin was appropriate because "customers of various sizes and billing revenue actually face different retail margins (EBIT) when the fixed cost of depreciation is removed.	We have decided to adopt consistent cost and margin assumptions across the three standard retailers, so whether the margin is presented as an EBITDA margin or an EBIT margin will not determine the final regulated tariff.
Integral Energy submitted that the assumed depreciation charges were too low.	The reliance upon average depreciation figures means that depreciation charges for Integral Energy are projected to be higher than the average. However, these depreciation charges result from information technology investments, made with the intention to improve efficiency, and thereby reduce overall costs. In other words, there is presumably a trade-off between increased investment, and the associated increases in depreciation charges, and lower operating costs in other areas. Were depreciation allowances to be estimated on a firm-specific basis, all other operating costs should be estimated on a firm-specific basis, due to this trade-off. Alternatively, additional investment could be made with the intention to grow the business, rather than reduce the costs of running that business. In that event, we would need to allow for higher customer numbers and volumes over the three-year explicit forecast period, and higher long-term growth than currently assumed. Integral Energy also submitted that it was appropriate to use an estimate of depreciation charges which were 2.2% of revenues; consistent with the broader class of listed retailers relied upon in our benchmarking analysis. SFG's report states that the appropriate profit margin for comparison is the EBIT margin because listed retailers are more capital-intensive than electricity retailers. Relying upon the average of estimates for depreciation and

Key issues raised in submissions	IPART's consideration
	amortisation projections for the standard retailers, depreciation and amortisation represent approximately 0.9% of the total operating costs for standard retailers, compared to approximately 2.4% for the broader class of retailers. SFG notes that "the observed profit margins of retail energy businesses are not materially different from the observed profit margins of the broader class of retailers" clearly refers to the comparability of the EBIT margin.
AGL expressed concern that the margin derived from the expected returns analysis was understated, because the valuation multiples implied by this analysis were less than observed in transactions.	AGL is correct in stating that the margin from the expected returns analysis implies lower valuation multiples than observed in transactions, especially if the more recent transactions from 2006 – 2007 are given more than equal weight, as was done in SFG's bottom-up analysis. However, they are essentially stating that the expected returns approach should not be given weight in the final determination, because it implied the lowest margins and valuation of the three approaches used. SFG's overall conclusions were framed on the basis of applying equal weight to the three techniques, to estimate retail margin in the absence of evidence that any one of these techniques was more reliable than the other.
Origin Energy expressed three concerns regarding the bottom up approach: ▾ that there is a circularity involved in that the purchase price is a function of expectations for profit margin ▾ that there is a limited set of transactions for analysis and ▾ that the five transactions from 1999 – 2002 may not be relevant. AGL made the same point with respect to the earlier transactions, with the addition that the lowest valuation multiple should be dropped as an outlier.	We acknowledge that acquisition prices reflect expectations for future profit margins. But we also note that the expected cash flows underpinning those transactions are likely to extend well beyond the period when energy prices are no longer regulated. Hence, acquisition prices will incorporate expectations of margins the buyer and seller would expect to prevail in a competitive market. We do not have information to suggest that a positive or negative bias exists, based upon publicly-available information. With only ten data points rather than 1,000, there is a heightened risk that SFG's sample is not representative of the population of energy retail transactions which would have occurred over this time. SFG believe it is reasonable to place some reliance on the set of ten transactions rather than ignore this data entirely – we agree with this. We re-state that the five transactions from 2006 – 2007 have been given twice as much weight by SFG in their valuation estimates as the five transactions from 1999 – 2002. Given that there is only ten transactions in SFG's sample, we think it unreasonable to place zero weight on five of those transactions, which only occurred 8 – 11 years ago.
Impacts on customers	
Stakeholders submitted that they will find it difficult to pay substantially more for electricity. In particular pensioners and others on low incomes stated that higher electricity prices will be a problem for them.	We recognise that these price increases are large and will be felt by customers, particularly low-income households. Further, they follow large price increases in July 2009. We note that the NSW Government has introduced a $272 million customer assistance package, and the Federal Government has indicated that it will offer compensation to assist households with the cost impacts flowing from the CPRS. We also note that the State and Federal Governments provide incentives for households to reduce their energy consumption and the Standard Retailers offer advice on reducing consumption. However, even with targeted assistance from

Key issues raised in submissions	IPART's consideration
	governments and efforts to reduce consumption by customers, households will be paying considerably more for electricity in the coming 3 years. We recommend that the Government should extend the NSW energy rebate to all Commonwealth Card Holders. At present most health card holders receive the rebate but some (eg, unemployment allowances) do not. These people can pay a high proportion of their incomes on electricity costs. We also recommend that the Government should consider whether an increase in the amount of the NSW energy rebate is required. This rebate was increased substantially in 2009 (and will increase in future years according to changes in the Consumer Price Index). However, further increases maybe justified because electricity prices will increase in excess of the CPI over the next few years (see Chapter 11).
EWON submitted that the NSW Government should extend the eligibility for the Energy Rebate to all Health Care Card (HCC holders), consistent with the Victoria, Tasmania, SA and WA. COTA has requested that the Energy Rebate also be extended to Commonwealth Seniors Health Card holders.	We have recommended that the NSW Government expanding the eligibility for its Energy Rebate to all Commonwealth Health Care Card holders.
The Minister for Energy requested that we consider the impact of the CPRS compensation package in our customer impact analysis.	The assistance is not provided on an "offset" basis for individual expenditure items, rather, it will be made available through income tax concessions and lump sum payments (see Chapter 11). This means it is not linked to electricity consumption levels – but rather it depends on household composition and income and is designed to compensation households for increases in their **total costs of living** due to the impact of the CPRS. The proposed assistance averages around $660 per household in 2012/13 to offset the **total cost of living increases**, which includes increases to energy costs, road and transport costs, food costs and other goods and services, and is uniform across all states.
Miscellaneous charges	
EnergyAustralia submitted that the determination should include clauses which would come into effect if and when amendments are made to the Electricity Supply Act and would allow standard retailers to charge twice the financial institution fee for a dishonoured direct debit.	We have not made provision for the fee to be introduced under the determination as we do not know whether the Government will accept our proposal and, if it did, the form of any amendment to the Act and therefore we have not formed a view on the appropriate level for such a fee. It is not necessarily appropriate to apply the same fee as for dishonoured cheques to non-cheque payments. We consider it appropriate that only incremental costs associated with dishonoured non-cheque payments be recovered through such a fee (see Chapter 12).

Key issues raised in submissions	IPART's consideration
Integral Energy suggested that either the requirement to waive the late payment fee for recipients of the energy rebate should be removed and this left to the discretion of retailers or the $2.30 deduction from retail costs removed.	We consider this unnecessary as the deduction from retail operating costs was based on data from all standard retailers and neither EnergyAustralia or Country Energy currently charge recipients of the Energy Rebate a late payment fee and we expect that Integral Energy would already waive a proportion of these fees as some pensioners would fall within the existing requirements to waive late payment fees. Also the $2.30 deduction represents only 80% of the revenue from late payment and allows for some additional revenue to be recovered from late payment fees
Some retailers consider the late payment fee is below the cost reflective level.	The late payment fee was set by adjusting the current late payment fee by CPI forecast to the mid term of the determination. We decided an adjustment for double counting of costs of late payment should be made to the retail operating cost allowances and that some of the costs of late payment should continue be recovered through regulated tariffs (see Chapter 12).

C Background and regulation of electricity

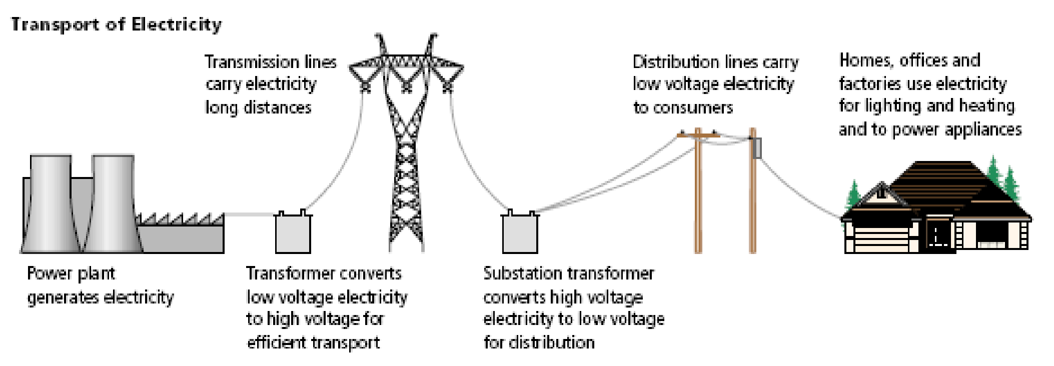
This appendix gives an overview of the electricity supply chain, what is regulated by this determination, and the components of regulated retail prices.

The energy reform process introduced in the 1990s by the Council of Australian Governments involved restructuring the traditionally vertically integrated energy industry so that consumers could benefit from competition where possible. Within the national framework for competition, State governments have also pursued their own reform policies and regulatory arrangements in retail energy markets.

C.1 Structure of the electricity industry

Traditionally the electricity industry in NSW was made up of large vertically integrated companies that controlled most parts of the supply chain, including generation, transportation and retail of electricity (see Figure C.1).

Figure C.1 The Electricity Supply Chain



Source: NEMMCO, *An introduction to Australia's national electricity market*, June 2005, p 3.

As part of the process of industry reform, these vertically integrated companies were broken into segments so that customers could benefit from competition in the areas that could be contestable – generation and retail. Legislation was introduced to regulate the areas that relied on monopoly owned infrastructure – transmission and distribution (now regulated via the National Electricity Rules) – to ensure that access to necessary infrastructure was made available on reasonable terms and conditions.

Initially, parts of the retail market remained a monopoly and were regulated. However, over the past few years, the NSW Government has progressively introduced retail competition into the electricity market. Large consumption electricity customers have been able to choose their retailer since 1 July 1998. Competition, or contestability, for other customers was introduced in stages, with all customers able to choose their electricity retailer from 1 January 2002.

As discussed in Chapter 2, the NSW Government is undertaking reform of the electricity sector, including the sale of the NSW Standard Retailers and the trading rights to the state owned generators.

C.2 Regulation of retail prices in NSW

We have been asked to continue to regulate retail prices for small retail customers (defined as customers that use less than 160 MWh of electricity per year, equivalent to an annual bill of approximately $35,000) who do not choose to enter the competitive electricity market by signing a negotiated contract. These customers remain on a standard electricity supply contract. This determination regulates the prices of electricity for small retail customers on standard electricity supply contracts.

Each area in NSW has a nominated Standard Retail Supplier. The *Electricity Supply Act 1995* (the Act) requires Standard Retail Suppliers to make supply available on the tariffs and charges set by a determination of IPART. Standard Retail Suppliers and new entrant retailers may also offer customers competitive or negotiated contracts. These contracts are not regulated by IPART and the prices charged under them are negotiated between retailer and customer.

There are 3 Standard Retail Suppliers in NSW for which IPART determines regulated retail tariffs. Each is Government-owned and is also involved in the distribution of electricity in NSW. The Standard Retail Suppliers and the areas in which they are required to offer regulated tariffs are:

- EnergyAustralia – Sydney, Central Coast and Hunter regions.
- Integral Energy – Western Sydney, Blue Mountains, Southern Highlands, Illawarra and Shoalhaven regions.
- Country Energy – remainder of NSW.

C.3 How tariffs are structured

There are 2 main components of retail electricity tariffs – network charges and retail charges. Network charges (N) are governed by the Australian Energy Regulator's 2009 network determination and are passed through directly into the retail tariffs.[391] This determination sets the retail component (R) of the charge. Within both components there are fixed (that do not vary with electricity usage) and variable charges (that depend on the amount of electricity used). A customer's total bill is the sum of the network and retail components.

The components of the tariffs are explained in more detail in the table below.

Table C.1 Components of regulated retail tariffs

Component of target	Elements of each component	Nature of the elements	Factors that affect the value of each element
N component	Applicable network tariff	May be a combination of a fixed network charge ($/customer), variable network charges (c/kWh) and any other charge (eg, maximum demand/capacity charge)	Network tariffs are set outside the retail determination and differ between regions and customers with different characteristics (eg, business/residential). The same network tariff applies to a customer irrespective of its retailer.
R component	'Fixed R'	Fixed retail charge expressed in $ per customer per year	Fixed R is set by the retail determination at the same level for every customer in NSW. Fixed R is set to enable retailers to recover retail costs that do not vary with electricity usage.
	'Variable R'	Variable retail charge expressed in cents per kWh	Variable R is set by the retail determination and is different for: - each retailer - different types of supply. Variable R is set to enable retailers to recover retail costs that do vary with electricity usage

391 The Australian Energy Regulator issued final network determinations for the period 2009/10 2013/14 in April 2009. The determinations provide for significant increases in network charges, above any change in the CPI. Further, in November 2009, the NSW distribution and transmission service providers successfully appealed the AER's determination, specifically relating to the weighted average cost of capital. This appeal further increased the network price increases over the regulatory period.

D More detail on our analysis of the level of retail competition in NSW

Chapter 3 outlined our analysis and findings on the level of retail competition in NSW. This appendix provides additional detail on some areas of this analysis.

D.1 Level of competition

As Chapter 3 noted, although we recognise that the AEMC's purpose in reviewing the SA and Victorian small customer retail markets was different to our purpose in reviewing competition in the NSW market, comparing key indicators across these states provides a means to gauge the level of competitiveness in the NSW market.

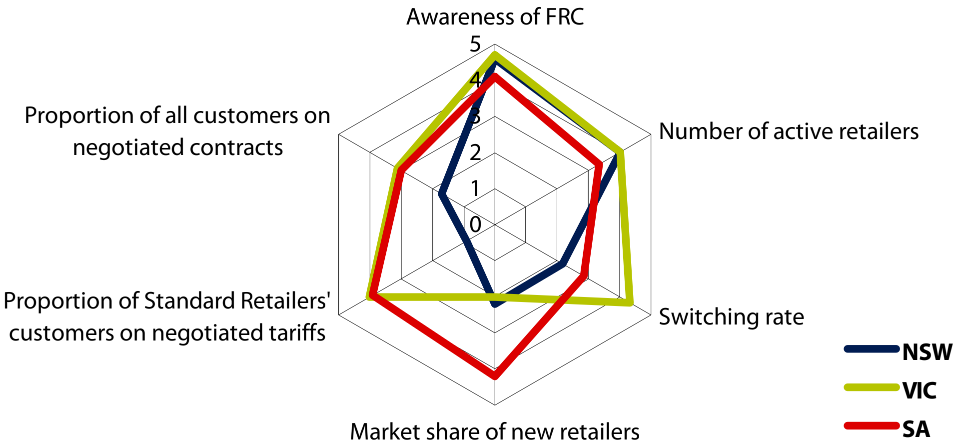
We compared the key indicators of competition in the NSW market with the equivalent indicators in the Victorian and SA markets at the point in time that they were deemed to be competitive for the purpose of removing retail price regulation.[392] The results of this comparison are illustrated in Figure D.1, and include that:

- Residential customer awareness of full retail contestability in NSW (92%) is about the same as in Victoria (94%) and higher than in SA (82%).
- The number of second-tier retailers in NSW (12) is the same as in Victoria and higher than in SA (10).
- Switching rates in NSW (13%) are lower than those in Victoria (26%) and SA (17%).
- The market share of new retailers in NSW (22%) is similar to that in Victoria (20%) and lower than in SA (42%).
- The proportion of the Standard Retailers' customers (in their standard supply areas) that are on negotiated contracts is much lower in NSW (9%) than in either Victoria or SA (50% and 39% respectively). The proportion of all customers on negotiated tariffs in NSW (34%) is also substantially lower than in Victoria (62%) and SA (60%).[393]

392 The Victorian review was completed in 2007, and the SA review was completed in 2008. We note that since these reviews, the Victorian market has been deregulated, and the statistics cited below may have changed.

393 AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, First Final Report* 19 September, 2008, pp xi-xii, 20, 22, AEMC, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria*, *First Final Report*, 19 December 2007, pp ix, 9, 31, 38-39, 90, ESCOSA, *2007/08 Annual performance report energy retail market*, November 2008, p c, Information returns submitted by standard retailers, July 2009.

Figure D.1 Comparison of NSW competition indicators with other jurisdictions at the time the AEMC considered them to be competitive for the purpose of removing price regulation



Indicator	0	5
Awareness of full retail contestability	0%	100%
Number of retailers active	0	15+
Switching rate negotiated contract	0%	30% +
Market share of new retailers	0%	50% +
Proportion of Standard Retailers' customers on negotiated contracts	0%	60% +
Proportion of all customers on negotiated contracts	0%	100%

Data source: Information returns submitted b y standard retailers, July 2009, *AEMC Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia, First Final Report* 19 September, 2008, *AEMC Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria*, *First Final Report,* 19 December 2007.

D.2 Definition of the market in NSW

In reaching our view of the definition of the NSW retail market, we took into account a range of factors, including the functional, product, geographic and time dimensions of the relevant market, and whether or not there were sub markets based on customers' characteristics. The sections below provide more information on our considerations of these factors.

D.2.1 Functional dimension

In our view, the functional market relevant to this review is the retail electricity market. While there may be some efficiencies associated with a retailer holding generation or distribution assets, the electricity retail function is both economically separable and economically distinct.

D.2.2 Product dimension

We consider that the product market relevant to this review is electricity only. We examined whether the product market should include the broader energy market, which includes the retail supply of gas. However, we concluded that gas and electricity are not reasonable substitutes for each other over the period of the determination. The costs associated with switching from electricity to gas prevent these sources of energy being sufficiently interchangeable to be considered reasonable substitutes over the next 3 years. Further, customers may be able to use gas for a limited selection of activities such as cooking and heating, but they cannot switch to gas for all their power needs. Therefore, we do not consider the retail supply of gas to form part of the relevant market.

D.2.3 Geographic dimension

We have considered the geographic areas in which retailers currently operate and provide customers with practical offers for the retail supply of electricity. In our view, defining the market as the NEM would be too broad and would include products and sellers that do not constrain the ability of retailers licensed in NSW to exercise market power.

As outlined above, for the purposes of our review, we consider that there are 3 relevant markets for the retail supply of electricity in NSW corresponding to the standard supply regions for each of the Standard Retailers. In forming this view, we note that we set the weighted average price cap for each Standard Retailer to reflect the costs that it incurs. These costs differ across these retailers, due to:

- their unique load profiles, which result in different energy purchase costs
- their distinct network charges, as determined by the AER.

This means that the tariffs in each of the standard supply areas are different and so the price that a retailer charges in 1 region does not constrain the pricing strategies of a different retailer in another region. Further, it is theoretically possible to have a highly competitive market in 1 standard supply area while there could be no effective competition in another.

D.2.4 Time dimension

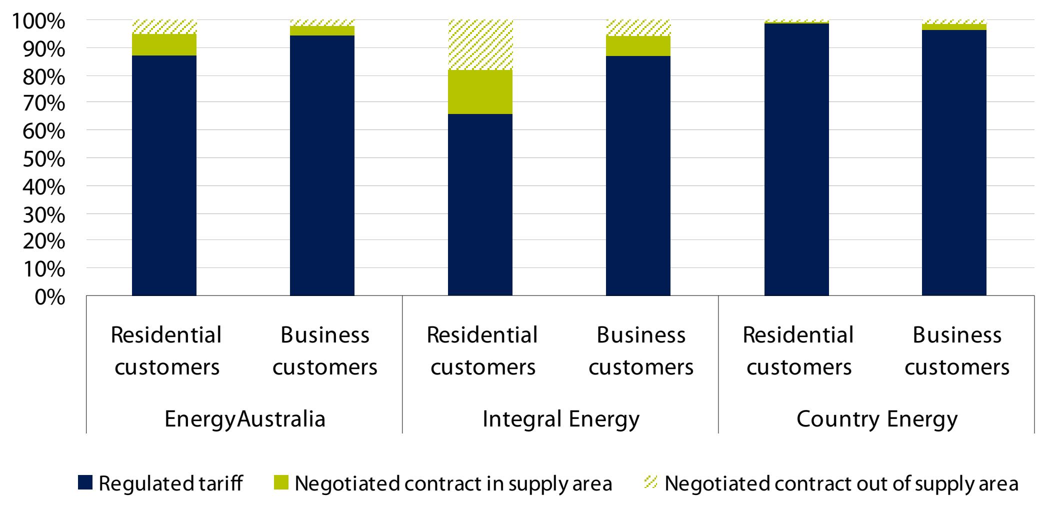
We consider that the time period relevant to this review is the period of the determination (the 3 years from 1 July 2010 to 30 June 2013).

D.2.5 Sub markets

In each standard supply region, the regulated tariff a small customer can be supplied on depends only on whether they are a business or residential customer, and the type of meter that they have. Small customers are not differentiated by other characteristics – for example, pensioners not charged particular tariffs for pensioners.

Figure D.2 compares the extent to which small residential and business customers are being supplied on negotiated contract by their Standard Retailer. In both the EnergyAustralia and Integral Energy regions, a smaller proportion of the Standard Retailers' business customers are supplied on negotiated contracts than residential customers. In the Country Energy region, a similar but very low proportion of Country Energy's residential and business customers are supplied on negotiated contracts (2% and 3% respectively).

Figure D.2 Standard Retailers' small residential and business customers in NSW by contract type (2008/09)



Data source: Information returns submitted b y standard retailers, July 2009.

We requested information from stakeholders to help understand whether there are certain customer groups, such as low-income or vulnerable customers, that do not have the opportunity to access the competitive market, and therefore constitute sub-markets within these markets. PIAC expressed concern that some vulnerable customer groups may have difficulty in participating in energy retail markets. However, the retailers agree that the market is generally characterised by generic market-wide products and campaigns, rather than targeting specific customer groups.[394] While we have limited information for assessing the existence of sub-groups, we can observe that:

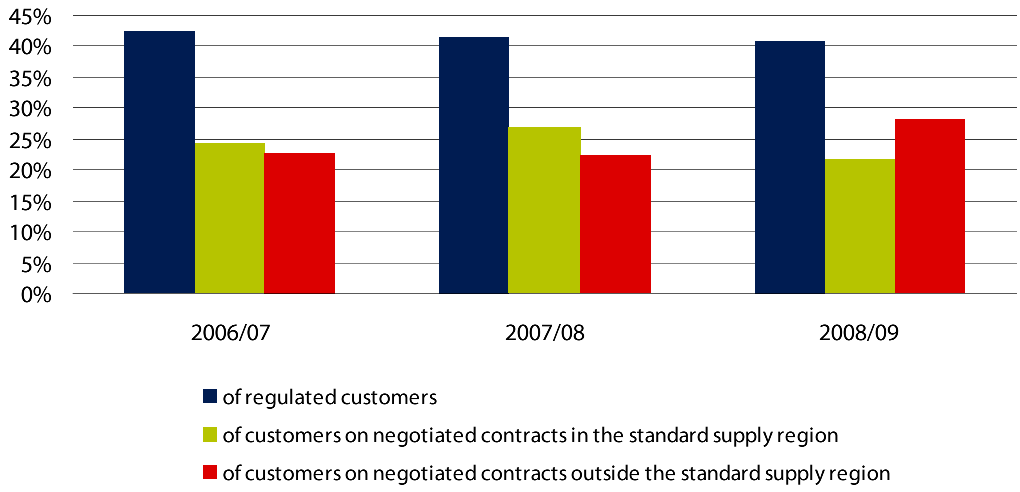
- Some retailers do not offer negotiated contracts to customers who are not credit-worthy (eg, customers with a poor bill payment history and credit rating).
- Consumers that have a greater propensity to purchase green-based power, based on their locality, are particularly targeted by some retailers.
- Some retailers do not actively market to customers who consume less than 5 MWh per annum (approximately 38% of the residential market[395]). This is reflected in the breakdown of customers by consumption, which shows that the proportion of customers consuming less than 5 MWh per annum on regulated tariffs is substantially higher than the proportion on negotiated contracts (Figure D.3). Further, the proportion of customers consuming more than 15 MWh per annum on regulated tariffs is lower than the proportion on negotiated contacts (Figure D.4). These data suggest it is likely that retailers are more active in marketing to customers with higher levels of consumption. However, it does not appear that customers with lower consumption levels are being excluded from entering a negotiated contract with retailers.

However, analysis provided by Integral Energy shows that low-income households, pensioners, and people with poor credit ratings tend to be over represented among those who move away from its regulated tariffs to negotiated contracts with another retailer. It considers that this is likely to be because these groups are more likely to be at home in the afternoon when door-to-door selling occurs.

394 PIAC submission, August 2009, p 3; TRUenergy submission, August 2009, p 2; EnergyAustralia submission, August 2009, pp 8-9; Origin Energy submission, August 2009, p 10; AGL submission, August 2009, p 21; Country Energy submission, August 2009, p 9; Integral Energy submission, August 2009, p 2.

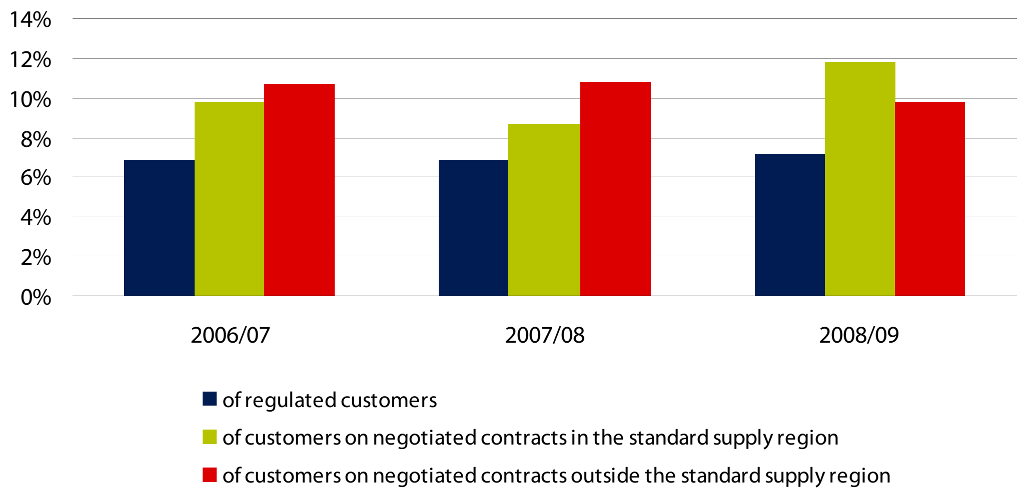
395 Information returns submitted b y standard retailers, July 2009.

Figure D.3 Proportion of Standard Retailers' residential customers in NSW consuming less than 5 MWh per annum by contract type



Data source: Information returns submitted by standard retailers, July 2009.

Figure D.4 Proportion of Standard Retailers' residential customers in NSW consuming more than 15 MWh per annum by contract type



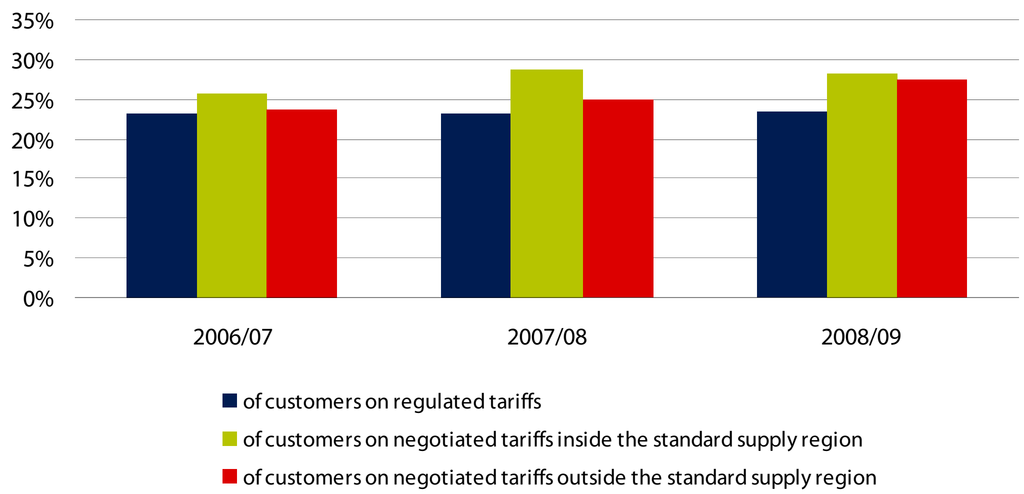
Data source: Information returns submitted by standard retailers, July 2009.

Integral Energy's view is supported by data provided by the Standard Retailers on customers receiving the pensioner rebate by contract type.[396] We consider that these customers are a suitable proxy for low socioeconomic customers. Figure D.5 shows that in all regions, the proportion of customers receiving the pensioner rebate being supplied on a negotiated contract within each standard supply area is higher than the proportion of customers receiving the pensioner rebate that remain on the regulated tariff. Overall, we consider that this indicates that lower socioeconomic customers have access to negotiated contracts.

In addition, we note that our 2008 household survey in the Hunter, Gosford and Wyong region found that only 1% of customers surveyed indicated that they had been refused a negotiated contract.[397]

Based on the information provided by the Standard Retailers, and the results from the 2008 household surveys, we consider that for the purposes of this review there are not separate sub-markets defined along consumption and income characteristics.

Figure D.5 Proportion of the Standard's Retailers' residential customers in NSW receiving the pensioner rebate by contract type



Data source: Information returns submitted by standard retailers, September and October 2009.

[396] The statistics include customers who hold a Pensioner Concession Card issued by Centrelink or a Pensioner Concession Card issued by the Commonwealth Department of Veterans' Affairs for customers receiving a War Widows or War Widowers Pension or a Disability Pension at the 'totally and permanently incapacitated' (TPI) rate or 'extreme disablement adjustment' (EDA) rate.

[397] IPART, *Residential energy and water use in the Hunter, Gosford and Wyong*, December 2008, p 95.

D.3 Market concentration arising from the *NSW Energy Reform Strategy*

As part of our analysis of the concentration of the NSW retail market, we considered how the proposed sale of the Standard Retailers as part of *NSW Energy Reform Strategy* might affect this concentration. This strategy includes the sale of the 3 Standard Retailers, as well significant changes in the wholesale energy sector. However, the strategy requires specified objectives to be met in the sale process. If they are not met in the initial phase, the Government will float Integral Energy in an initial public offering.[398]

Box D.1 Objectives of the NSW energy reform process

- Deliver a competitive retail and wholesale electricity market in NSW to increase the potential for the sector to respond dynamically and innovatively to market forces and opportunities;
- Create an industry and commercial framework to encourage private investment into the NSW electricity sector and reduce the need for future public sector investment in retail and generation;
- Ensure NSW homes and businesses continue to be supplied with reliable electricity; and
- Place NSW in a stronger financial position by optimising the sales value of public assets and reducing the Government's exposure to electricity market risk and reducing the State's public sector debt.

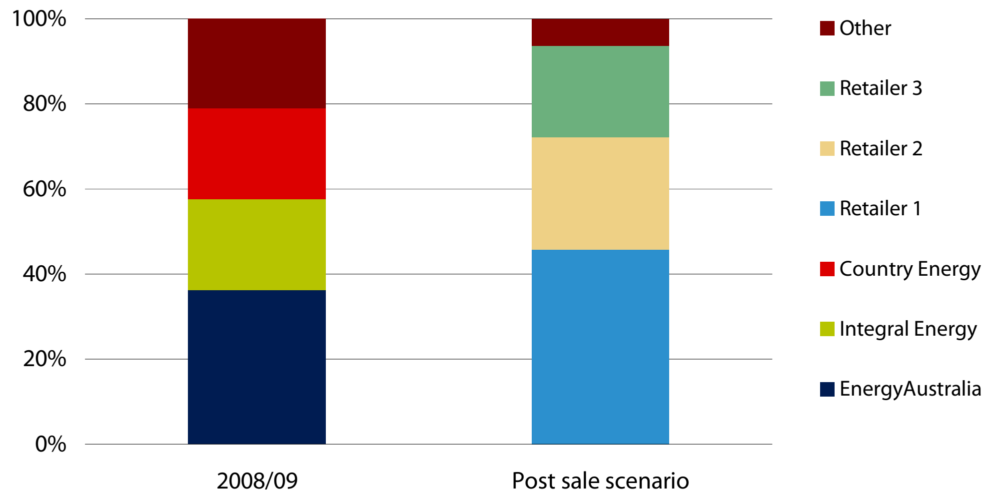
Data source: NSW Government, *NSW Energy Reform Strategy*, *Delivering the strategy: approach to transactions and market structure*, September 2009, p 1.

For illustrative purposes, Figure D.6 provides 1 speculative state-wide market concentration scenario following this sale. It gives an indication of what the retail market could possibly look like after the sale. It assumes that 2 of the large second-tier retailers in NSW buy EnergyAustralia and Country Energy. A new entrant acquires Integral Energy in line with the objectives and phased sale process.

Under this scenario, the combined market share of the remaining new retailers would be only 6%, so the NSW market would be markedly more concentrated. We note that if the market is defined based on the standard supply regions consistent with our analysis, the resulting market structure would be even more concentrated.

[398] NSW Government, *NSW Energy Reform Strategy, Delivering the strategy: approach to transactions and market structure*, September 2009, p 47.

Figure D.6 Potential future market share of small retail market in NSW (after sale of Standard Retailers)



Data source: Information returns submitted by standard retailers, July 2009.

It is not clear whether a more concentrated market will impact upon the competitiveness of the market. In submissions to this review, stakeholders expressed mixed opinions on this. For example, PIAC considered that if the major second-tier retailers acquire the Standard Retailers, the remaining second-tier retailers are unlikely to have the capacity to provide similar levels of competitive pressure.[399] However, Origin Energy put the view that despite changes in market share, competitors will remain and new entrants will become active if the current limitations of the retail price regulation are resolved and investment in the market is attractive.[400] Further, the ACCC will to assess any future mergers against section 50 of the *Trade Practice Act 1974* which prohibits mergers that would have the effect, or be likely to have the effect, of substantially lessening competition in a market.

D.3.1 Barriers to market entry

Regulated tariffs set at less than cost-reflective levels

In Chapter 3, we noted that several retailers submitted that the most significant barrier to market entry over the 2007 determination period was that the level of regulated tariffs during this period was below the efficient cost of supply. Our considerations in relation to this view are provided below.

399 PIAC submission, August 2009, p 3.

400 Origin Energy submission, August 2009, p 10.

Under the 2007 determination, 2009/2010 was targeted as the year in which tariffs would reach fully cost reflective levels, based on our assessment of these costs for a 'hypothetical retailer'. The tariff path in the preceding years was transitional to cost reflectivity. In making this determination, we considered that a straight line transitioning approach was more appropriate than allowing for full cost recovering in every year for a number of reasons, including:

- the terms of reference required us to ensure that tariffs recovered the hypothetical retailer costs by 30 June 2010, and a straight line transition path met this requirement while recognising that there are benefits for customers in providing a stable and smooth tariff path
- this approach is simple, understandable, practical and pragmatic, whereas tariffs that followed the hypothetical retailer's costs would have resulted in substantial increases in tariffs in the first 2 years of the determination period and tariff reductions in the final year.[401]

However, we also considered that the costs of efficient mass market new entrants could be lower than our assessment of a 'hypothetical retailer' costs. Mass market new entrants may engage in trading strategies that are low cost and higher risk (but also efficient) compared to our 'hypothetical retailer'. In addition, in determining the energy cost allowance, we ignored the potential portfolio benefits that retailers could achieve in a market not limited to the regulated load.[402]

For these reasons, we don't agree with retailers' view that under-recovering regulated tariffs necessarily limited their capacity to offer sufficient discounts relative to these tariffs. In relation to the contention that changes in retailers' marketing activity over the 2007 determination period – such as some ceasing to offer discounts off regulated tariffs – provides evidence to support this view, we note the reason for these changes is not clear. It may be that competitive prices do not provide a sufficient margin. On the other hand, it may be that retailers have been able to maintain higher prices due to a lack of market information and customer inertia.

As Chapter 3 discussed, since electricity supply is perceived as a homogenous service, customers are unlikely to actively seek more competitive offers. Due to the absence of easily accessible pricing information in the marketplace, customers that are interested in seeking more competitive offers may incur high search costs, outweighing the benefits from switching. If retailers believe that electricity is sufficiently inelastic they may charge higher prices in the short term to increase their overall revenue.

But regardless of whether or not under-recovering regulated tariffs were a barrier to entry, we note that from July 1, 2009 these tariffs (on average) have increased to what is considered a cost-reflective level.

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401 IPART, *Promoting retail competition and investment in the NSW electricity industry,* June 2007, pp 118-119.

402 IPART, *Promoting retail competition and investment in the NSW electricity industry,* June 2007, p 113.

In addition, we note that 1 of the objectives of the NSW energy reform strategy is a more competitive wholesale market, which should facilitate efficient wholesale costs. Given that wholesale energy costs are the main cost and source of risk faced by retailers in supplying customers, reforms in the generation market are likely to be a positive influence on the retail market by addressing some of the barriers to entry, namely the ability of retailers to obtain reasonably price hedging contracts.

E Weighted Average Cost of Capital (WACC)

The rate of return or return on capital is used as a discount rate assumption in the modelling of the energy costs and retail margin. There are several approaches for calculating the rate of return. Our preferred approach is to use the weighted average cost of capital (WACC) to determine an appropriate range for the rate of return. A point estimate of the WACC is selected from this range. The WACC for a business is the expected cost of its various classes of capital (debt and equity), weighted to take into account the relative share of debt and equity in the total capital structure. In making this determination, we have made 2 decisions on the WACC:

- the first was on an appropriate WACC for electricity generation, which we used to determine the discount rate to be used in modelling the LRMC of generation (discussed in Chapter 6)
- the second was on the appropriate WACC for electricity retailing, which we used to determine the discount rate to be used in the bottom-up analyses of the retail margin (discussed in Chapter 8).

As with previous determinations, we used a real pre-tax WACC.

In making each of our decisions, we considered and made decisions on a number of input parameters to determine the appropriate range for the WACC. We then made a decision on the appropriate point within the range.

Our decisions for each of the WACC parameters are discussed below. This appendix also discusses the issues raised by stakeholders in regard to the WACC in their responses to the methodology paper and draft decision.

E.1 Overview of final decision on the WACC for generation and retailing

IPART's final decision is to use the WACC for electricity generation and retail shown in Table E.1.

Table E.1 final decision of generation and retailing WACC

WACC parameters	Electricity generation		Electricity retail	
	Draft Decision	Final Decision	Draft Decision	Final Decision
Nominal risk free rate[a]	5.4%	5.5%	5.4%	5.5%
Inflation adjustment[a]	2.7%	3.0%	2.7%	3.0%
Market risk premium	5.5 – 6.5%	5.5 – 6.5%	5.5 - 6.5%	5.5 - 6.5%
Debt margin[a]	1.9 - 3.6%	2.0 - 3.7%	1.9 - 3.6%	2.0 - 3.7%
Debt to total assets	50%	50%	40%	30%
Dividend imputation factor (gamma)	0.5 – 0.3	0.5 – 0.3	0.5 – 0.3	0.5 – 0.3
Tax rate	30%	30%	30%	30%
Equity beta	0.9 - 1.1	0.9 - 1.1	0.9 - 1.1	0.9 - 1.1
Cost of equity (nominal post tax)	10.4 - 12.6%	10.5 - 12.7%	10.4 - 12.6%	10.5 - 12.7%
Cost of debt (nominal pre-tax)	7.4 - 9.1%	7.5 - 9.3%	7.4 - 9.1%	7.5 - 9.3%
WACC range (real pre-tax)	6.9 - 9.6%	6.8 - 9.4%	7.4 - 10.3%	7.7 - 10.8%
WACC (real pre-tax) mid-point	8.2%	8.0%	8.8%	9.1%

a Reflects market data sampled over the 20 trading days to 8 February 2010.

Compared to the draft decision, the WACC for generation is 20 basis points lower (8.0% compared to 8.2%) and the WACC for retail is 30 basis points higher (9.1% compared to 8.8%). The key changes are:

- We have updated the market-based parameters (nominal risk free rate, inflation adjustment and debt margin) to reflect the current data on 8 February 2010. This has reduced the WACC.
- In the case of retail, we have reduced the assumed level of debt from 40% to 30% of the asset base. This increases the WACC for retail.

We have received and considered submissions on the WACC from EnergyAustralia, Country Energy, Origin Energy and AGL. EnergyAustralia engaged PwC[403] to respond to our methodology paper. AGL sought advice from KPMG[404] on our draft decision on WACC.

403 PwC, Advice to EnergyAustralia regarding discount rate assumption made in IPART review of regulated retail tariff charges, October 2009 ('the PwC advice').

404 KPMG, *Weighted average cost of capital – IPART review of regulated retail tariffs for electricity – 1 July 2010 to 30 June 2013*, February 2010 ('the KPMG advice').

Stakeholders including Origin Energy and AGL have submitted that we should select a point above the midpoint of our range of values in selecting a point estimate of the WACC. For example, PwC submits:

> Given the high degree of uncertainty associated with estimating the WACC of a benchmark electricity retail business, IPART's choice of a WACC based on the mid-point parameter estimates is unusual.[405]

Similarly, KPMG considers that adjustments are required for factors such as the post-global financial crisis (GFC) environment, uncertainty surrounding carbon reduction policies and NSW energy reform.

Our final decision selects the midpoint of our range. We consider that regulatory certainty is enhanced by the use of the midpoint value and parameter uncertainty should be addressed at the parameter level. We have further considered the level of uncertainty in estimating parameters due to the limited reliable evidence available. As discussed in the sections that follow, we have adjusted our valuation of some parameters in light of this uncertainty.

In relation to KPMG's advice, we consider that our valuations of the WACC are commensurate with prevailing market conditions and reasonably reflect the post-GFC environment. In particular, we note that low-rated corporate bond yields have not yet returned to pre-GFC levels in the Australian market, unlike those in the US and UK markets. In the US and UK markets, the difference between the AAA and BBB bonds has largely returned to pre-GFC levels. We consider that the Australian market data used to set the debt margin appropriately recognises the costs of debt funding in the post-GFC environment. Consistent with financial theory, we have not addressed business-specific risk, such as the risk of the introduction of carbon reduction policies, in our WACC valuation. We have addressed this risk in our assessment of the wholesale prices and the mechanisms for adjusting retail prices.

We also consider that it is inappropriate to recognise the effect of NSW energy reform in our WACC valuation. We consider that while there may be some uncertainty during the transition to this reform, removing government interest in these assets will 'level the playing field' for private companies in the industry.

We recognise the uncertainties in regard to the implementation and impact of the CPRS. However, rather than adjusting the WACC we have made changes to the regulatory framework in this decision, compared to the 2007 decision[406], that improve the responsiveness of the regulatory regime and, in particular, will ensure the prompt pass through of the impact of the CPRS or other policies.

In the past, we have adopted values above and below the midpoint of the WACC to have regard to the impact of our decision on customers or the government agency concerned or to recognise factors related to business-specific risks which are not

405 PwC advice, pp 1, 2.

406 IPART, *Regulated electricity retail tariffs and charges for small customers 2007 to 2010 – Final Decision*, June 2007.

addressed elsewhere in our decisions. However, we do not consider that this situation warrants any such adjustments as business-specific risks are addressed elsewhere in this determination.

We consider that if there are adjustments made for factors such as the post-GFC environment, carbon policies and the NSW energy reform, further, adjustments would then need to be reversed when the influence of the factor is removed. This would lead to increased regulatory risk for customers and regulated entities.

In addition, KPMG proposed that IPART take into account the Australia Energy Regulator's (AER) assessment of the WACC parameters in its final decision for electricity transmission and distribution network service providers. We are undertaking a review of AER's WACC decision; however the review will not be completed until April 2010. Until we make that final decision, we will continue with our existing methodology.

The sections below discuss our decisions on the input parameters for our electricity retail and generation WACC values, and our considerations of stakeholder comments on these parameters.

Nominal risk free rate and inflation

IPART's decision is to use:

– a nominal risk free rate of 5.5% based on the 20-day average as at 8 February 2010

– an inflation adjustment of 3.0% based on the 20-day average of market swap data to 8 February 2010.

We estimated the nominal risk free rate from the 20-day average of the yield on nominal Commonwealth Government bonds. We used swap market data to derive the inflation adjustment.

EnergyAustralia has submitted advice from PwC that queries our draft position on the inflation forecast. PwC consider that our value of 2.7% appears to be relatively high given recent reductions in market forecasts of inflation[407]. PwC proposes that IPART's inflation forecast be investigated further using longer-term market forecasting sources.

KPMG's advice supported our approach to setting the inflation adjustment.[408]

We have considered the PwC advice and note that PwC has presented evidence limited to short-term views of inflation. Our approach estimates a 10-year view of inflation. Our approach is consistent with other parameters in the WACC. This issue is discussed in more detail in *Final Decision – Adjusting for Expected Inflation in Deriving the Cost of Capital*, May 2009.

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407 PwC advice, p 2.

408 KPMG advice, pp 21, 22.

E.1.1 Debt margin

IPART's final decision is to adopt a debt margin range of 2.0% to 3.7% based on market observations as at 8 February 2010.

The debt margin represents the cost of debt a company has to pay above the nominal risk free rate. The debt margin is related to current market interest rates on corporate bonds, the maturity of debt, the assumed capital structure and the credit rating.

IPART received 4 submissions on the debt margin.

PwC advises that a stand alone electricity retail business is unable to attain a credit rating[409]. PwC consider that without a credit rating, a retailer would need to obtain shorter term debt (around 3-5 years) directly from banks. The shorter term to maturity may result in higher re-financing risk and debt margin.

Origin Energy notes that IPART's draft decision has indicated that the debt margin for electricity retail and generation could be closer to the upper bound of the range. Origin Energy considers that the Bloomberg data presented in our discussion paper on the WACC suggests that the debt margin is in the higher end of the range.[410]

KPMG has proposed the following ranges for the debt margin[411]:

- 3.6% to 4.3% for electricity generation, assuming a gearing level of 50%
- 3.0% to 3.7% for electricity retail, assuming a gearing level of 30%.

KPMG considered several debt margin pricing indicators other than the Bloomberg fair value yield curves, such as bank debt transactions, corporate bond yields and US private placement debt[412]. KPMG noted the limitations on the available data and considered other available proxies to arrive at its proposed range.

Country Energy considers that it is unlikely that a BBB rated retailer would be able to issue 10-year debt at 190 basis points over the risk free rate. Country Energy considers that the debt margin is more likely to be in the range of 2.5% to 4.0%[413]. Country Energy has not provided any supporting evidence.

In past WACC decisions, we used a set methodology to determine the debt margin. This ensures that the regulatory environment created by our WACC decisions is as predictable and transparent as possible.

409 PwC advice, p 5, 6.
410 Origin Energy submission, February 2010, p 16.
411 KPMG advice, p 40.
412 KPMG advice, p 32.
413 Country Energy's response to review of regulated retail tariffs and charges for electricity 2010-2013 - Draft report and draft determination, February 2010, p 11.

For our final decision we based the debt margin range on 20-day averages of the 7-year Bloomberg fair value curve and a portfolio of BBB+ and BBB rated Australian corporate bonds[414] without any further adjustments. The final decision on debt margin is based on our traditional universe of securities including 12.5 basis points for debt raising costs. In the recent draft decisions on State Water and Country Energy (Broken Hill Water) we excluded a short-dated bond from its sample of proxies as it may be causing a downward bias in its range of values. This decision also excludes the short-dated Coles bond.

In relation to PwC's comments, that retailers are seeking financing from banks directly instead of through corporate bonds, we note that:

> Participants such as AGL Energy, Origin and TRUenergy are all rated in the BBB+/- range.[415]

We consider that this indicates that some, if not all, retailers may be able to access corporate bond markets in Australia or overseas. While the thin volumes on the local bond market are of concern, we are also concerned about the assumptions required to estimate the cost of funds through direct financing or off-shore bond markets. However we will continue to monitor the case of these alternatives.

With regards to Origin Energy's comments, we note that the data in IPART's discussion paper presented 8-year BBB fair value yield curve sourced from Bloomberg. The Bloomberg fair value yield curve[416] is only one of the inputs IPART considers when setting the range for the debt margin.

We have considered KPMG's comments and decided to continue to use our debt margin methodology without making any explicit adjustments reflecting temporary increases in funding costs. We noted that corporate bond yields have not returned to pre-GFC levels, unlike those in the US and UK markets, that this is reflected in the estimated range. In the US and UK markets, the difference between the AAA and BBB bonds has largely returned to pre-GFC levels.

E.1.2 Equity beta

IPART's decision is to adopt an equity beta of 0.9 to 1.1 for electricity retailers and generators.

The equity beta value is a business specific parameter that measures the extent to which the return of a particular security varies in line with the overall return of the market. It represents the systematic or market wide risk of an asset that cannot be avoided by holding it as part of a diversified portfolio. It is important to note that the equity beta does not take into account business specific or non-systematic risks.

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414 These bonds include Coles, GPT, Snowy Hydro and Santos.
415 KPMG advice, p 31.
416 The 7-year Bloomberg FV curve is now used.

For the equity beta, we have separately considered the systematic risks involved in providing electricity retail and generation services.

IPART received 4 submissions on the equity beta.

EnergyAustralia has submitted advice from PwC that IPART's asset beta of 0.65 is likely to understate the systematic risk of a stand-alone electricity retailing business and proposed that the asset beta should be at least 0.75[417].

Origin Energy submits that IPART's draft report considered evidence from ACIL Tasman who valued the equity beta at 1.75.[418] Origin Energy queries why ACIL Tasman's value has not been included in IPART's range of equity beta values. Origin Energy submits that the evidence from ACIL Tasman should either be regarded as a useful data point or reasonably dismissed.[419]

KPMG estimated the beta by using the Bloomberg data on Australian and overseas companies and proposed the equity beta range of 0.9 to 1.4 for electricity generation and 1.0 to 1.2 for electricity retail businesses[420]. KPMG have based these ranges on:

- observed beta values of proxies in the Australian and New Zealand market
- observed beta values of overseas independent power producers (IPP) beta values ascribed by independent valuers for overseas IPPs.

Country Energy submits that electricity retailers would have an equity beta "above 1.0 at a minimum"[421] however Country Energy has not provided any supporting evidence.

We have recognised the uncertainties and concluded that an equity beta in the range of 0.9 to 1.1 is appropriate for electricity generation and retail activities. This is consistent with the asset beta of approximately 0.75 for retail and approximately 0.65 for generation. Advice from SFG supports our view. SFG suggests that the appropriate beta for electricity generation and retail businesses is 1.0.[422]

In addition to considering the evidence presented by stakeholders, we have updated our own analysis of the of equity betas of proxy companies, professional valuations and other regulatory decisions on the equity beta for electricity businesses. We have not been able to draw any reliable conclusions from empirical evidence derived from observes betas in the Australian market due to the considerable limitations in the availability of relevant proxies in the Australian market.

417 PwC advice, pp 4, 5.
418 ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM, prepared for the Inter-Regional Planning Committee*, April 2009.
419 Origin Energy submission, February 2010, p 16.
420 KPMG advice, p 55.
421 Country Energy submission, February 2010, p 11.
422 SFG, *Equity beta and gearing estimates for electricity retail and generation businesses – draft report prepared for IPART*, 14 July 2009, p 10.

Tables E.3 to E.4 summarise our analysis of evidence used by professional valuers and in other regulatory decisions.

Table E.2 Beta, gearing levels and debt margin used in professional valuations

Region	Valuer	Industry	Equity beta	Asset beta	Debt funding	Debt Margin
Australia	ACIL Tasman[a]	Generation	1.75	0.8	60%	2.00%
NZ	Macquarie[b]	Generation	0.75	0.6	20%	2.27%
NZ	Macquarie[c]	Generation	0.75	0.6	20%	2.27%
NZ	Macquarie[d]	Generation	0.75	0.6	20%	2.27%
Europe	Credit Agricole[e]	Generation	1	N/A	170%	N/A
Italy	Credit Agricole[e]	Generation	1.3	N/A	98%	N/A
Australia	Grant Samuel[f]	Retail and generation	Energy fuel: 0.9 – 1.0 Energy conversion and marketing: 0.8 – 0.9	N/A	20% to 25%	1.40%
Australia	RBS[g]	Retail and generation	0.86	0.78	25%	2.00%

a ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM, prepared for the Inter- Regional Planning Committee*, April 2009, p 22.

b Macquarie Research, *Mighty River Power - Performance evaluation*, October 2009, p 5.

c Macquarie Research, *Genesis Energy*, October 2009, p 5.

d Macquarie Research, *Meridian Energy*, October 2009, p 5.

e IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity – Draft Report and Draft Determination*, December 2009, p 195.

f Grant Samuel, valuation report for Origin Energy, Appendix 4.

g RBS Research, AGL Energy, February 2010, p 4.

Table E.3 Regulatory decisions on equity beta and gearing for generation and retail businesses

Region	Regulator	Industry	Equity beta value	Asset beta	Gearing
Australia	IPART[a]	Retail	0.8 to 1.2	0.6 - 0.8	30% - 40%
Ireland	CER[b]	Generation	1.22	0.55	55%
Singapore	EMA[c]	Vesting contracts for generation	1.2 (approx)	0.89	46%

a IPART, *Regulated electricity retail tariffs and charges for small customers 2007 to 2010 – Final Decision*, June 2007, p 158.

b CER, *Direction to ESB power generation on allowable costs 2006/07 by the Commission for Energy Regulator*, September 2005, p 50.

c EMA, *LRMC parameters for setting vesting price for 1 January 2007 to 31 December 2008*, December 2006, pp 8, 9.

Regarding PwC's submission, we consider that there are insufficient relevant proxies to conclude that the asset beta should be valued at 0.75. This is because the values reported form a wide range (0.33 to 1.25) and do not centre on any particular value.

In response to Origin Energy's request to consider ACIL Tasman's adopted equity beta, we note that ACIL has used (relative to IPART's assumptions):

- a higher gamma (0.5)
- a lower debt margin (200 bps)
- a higher gearing (60%).

ACIL Tasman's higher equity beta is partly a result of a higher gearing assumption.

We consider that the upper bound of the range of values recommended by KPMG is not supported by the evidence it presented. KPMG provides the equity betas for the comparable Australian and New Zealand companies[423]. The equity betas for these companies show a wide range of variation. We consider that the wide range makes it difficult to draw sensible conclusions. KPMG also provides the equity beta estimates of the overseas companies[424]. In making our decisions, we place less weight on the overseas data because they are less relevant to the Australian market. However, we have considered KPMG's research on equity betas applied in the broker reports[425], and conducted a similar analysis shown in Table E.4. Our equity beta has a lower bound than KPMG's recommendations.

Further, we consider that there is insufficient evidence to make the distinction between the electricity generation and retail businesses. We have therefore maintained the same range of equity beta values for electricity generation as for retail businesses.

We consider that:

- There are insufficient relevant proxies in the Australian market to reliably derive an estimate of the equity beta empirically.
- The asset beta in the recommended WACC values is similar to the level recommended by PwC.[426]
- The AER proposes to adopt an equity beta of 0.8 and gearing of 60% in future decisions made under the National Electricity Rules. The recommended equity beta of 0.8 to 1.0 places the systematic risk arising from generation and retail activities at a higher level than that faced by a regulated monopoly network business.

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423 KPMG advice, p 50.
424 KPMG advice, pp 51, 52.
425 KPMG advice, p 53.
426 PwC recommend an asset beta of 0.75. The midpoint asset beta implied by our decisions for gearing and equity beta is approximately 0.65 for electricity generation and approximately 0.75 for electricity retail.

We consider that, given the assumed gearing levels, a range of 0.9 to 1.1 accurately captures the systematic risks involved in providing electricity retail and generation services in Australia.

E.1.3 Market risk premium

IPART's decision is to adopt an MRP range of 5.5% to 6.5%.

The market risk premium (MRP) is the expected return over the risk free rate that investors would require for investing in a well diversified portfolio of risky assets.

Consistent with our draft report, we use an MRP of 5.5% to 6.5% which is based on long term historical averages.

We received a submission on the MRP conducted by KPMG from AGL. The advice from KPMG recommends a higher MRP range of 6% to 7% due to the impact of the GFC, which resulted in wider credit spreads and higher risk premium[427]. Due to this reason, AER has increased its mid-point MRP from 6% to 6.5%.

We acknowledged that post-GFC businesses may have to offer a higher return on equity to attract equity finance. However, we are not convinced whether the forward looking long term MRP can be reliably estimated. Our standard approach is to use long term historical estimates. As we mentioned in the draft report, we expect to make a final decision on the impact of the AER's WACC decision on our own WACC estimate in April 2010. Currently, we use a MRP estimate which is based on long term historical time series. In theory, this estimate should account for short and medium term variations from the mean, in particular when a range rather than a point estimate is used.

Table E.4 Current estimates of MRP

From	To	Market risk premium
1883	Aug 2009	6.1%
1937	Aug 2009	5.7%
1958	Aug 2009	6.1%
1980	Aug 2009	5.7%
1988	Aug 2009	4.7%

Source: Bloomberg, Secretariat's own calculation.

427 KPMG advice, p 46.

E.1.4 Gearing

IPART's decision is to use a gearing level of:

- 50% for electricity generation; and
- 30% for electricity retail.

Gearing refers to the capital structure of an entity measured as the proportion of total assets that are funded by debt. Gearing is used to weigh the costs of debt and equity in estimating the WACC. Gearing is also used to determine the credit rating and debt premium and to re-lever asset betas into equity betas.

It is a common regulatory practice to benchmark a regulated business's capital structure by reference to gearing levels of businesses operating in similar industries rather than using the regulated business's actual capital structure. In doing this, the regulator is aiming to approximate the optimal capital structure of the business. However, in this case, IPART is not setting the WACC for a regulated business. For the purpose of this final decision, IPART is estimating the WACC for businesses operating in competitive generation and retail markets. The WACC is then used to build-up benchmark generation and retail costs.

In our final report, our final decision is to use:

- a gearing ratio of 50% for generation; and
- a gearing ratio of 30% for retail.

IPART received 4 submissions on the gearing level.

Origin Energy notes that our draft decision presented evidence that the gearing ratio should be lower than 40% and consider that this in itself should substantiate reconsideration of the gearing ratio currently used.[428]

PwC advises that a stand alone retail electricity business is likely to be unrated and proposes a gearing ratio of 10% to 20%[429].

The KPMG advice from AGL supports the gearing levels of:

- 50% to 60% for electricity generation
- 30% to 40% for a standalone electricity retailer.[430]

KPMG advocates the gearing levels towards the lower end of these ranges in the current post-GFC environment.

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428 Origin Energy submission, August 2009 p 16.
429 PwC advice, p 5.
430 KPMG advice p 3.

Country Energy submits that it supports the assumption of 40% for the level of gearing.[431]

Our analysis in Table E.2 and Table E.3 indicates that a wide range of gearing estimates have been used by market practitioners and other regulators. It also supports the gearing level of 0.5 for electricity generation and 0.3 for electricity retail.

Advice from SFG is consistent with our analysis[432]. SFG has examined 81 exchange-listed utility companies from US, UK and Australia and noted that the appropriate gearing levels are 50% and 35% for electricity generation and retail, respectively.

For the final decision on WACC, we revised the gearing levels for retail businesses downwards. We consider that the evidence received in response to the draft decision indicates that the level of gearing adopted in the draft decision may slightly overstate the level of gearing adopted by the benchmark energy retail and generation firm.

E.1.5 Tax rate and dividend imputation factor (gamma)

IPART's final decision is to use:

- the statutory tax rate (30%), and
- a gamma range of 0.5 to 0.3.

Under the Australian dividend imputation system, investors receive a tax credit (franking credit) for the company tax they have paid. This ensures that the investor is not taxed twice on their investment returns (ie, once at the company level and once on the personal tax level).

The value of the imputation tax credits is represented in the CAPM by 'gamma'. The rationale behind this, including the value of gamma in the CAPM, is that if investors are receiving a tax credit from their investment, they would accept an investment with a lower return than if there were no tax credits attached to this investment. The gamma is an important input in the CAPM, as a high value (valued at or approaching one) would reduce the cost of capital considerably.

AGL's submission from KPMG advocates the gamma should lie in the range of 0% to 50% and prefer to adopt a value of zero at the bottom end of the range[433]. However, KPMG does not consider our gamma proposal to be unreasonable.

Our standard parameter range of 0.5 to 0.3 for gamma is consistent with our regulatory approach, which promotes stability to the regulatory regime.

431 Country Energy submission, February 2010, p 11.

432 SFG, Equity beta and gearing estimates for electricity retail and generation businesses – draft report prepared for IPART, 14 July 2009, p 10.

433 KPMG advice, p 4.

F The relationship between the growth in electricity consumption for small retail customers and the growth in GDP

A substantial issue for the 2007 determination was the link between Gross Domestic Product (GDP) and energy sales. In 2007, IPART considered there was some doubt as to whether the relationship between the growth in electricity consumption for small retail customers and the growth in GDP was one-for-one. However, we accepted Frontier Economics' conclusion that there was insufficient evidence to reject a one-for-one relationship and adopted that value for the 2007 decision.[434]

For this review, we have completed further analysis on this issue in addition to asking SFG to provide advice on the relationship. Our analysis, while not conclusive, indicates that there is insufficient evidence to depart from the assumption of a one-for-one relationship between GDP and electricity sales to small retail customers. Our findings support the results of SFG's literature review and empirical results which are presented as an attachment to its final report.[435] The following sets out our exploratory analysis of this issue.

F.1 Why is this issue important?

The basic principal of the expected returns approach is that the retail margin should be set at a level to compensate electricity retailers for bearing the systematic risk of their net cash flows. Systematic risk is the result of exposure to overall economic or market conditions. Therefore, the expected returns approach to estimating the retail margin relies upon an estimate of how electricity volumes would be expected to change in economic conditions, represented by GDP, which are above or below expectations.

For the 2007 review, SFG (and Frontier Economics) used the following empirical model to represent the association between GDP growth and electricity volumes:

- % Change in volume in year t = Intercept + Beta1 x %Change in GDP in year t + Beta2 x %Change in GDP in year t-1 + Beta3 x %Change in GDP in year t-2 + Gamma x % Change in volume in year t-1 + Theta x %Change in price in year t

[434] IPART, *Promoting retail competition and investment in the NSW electricity industry's – Regulated electricity retail tariffs and charges for small customers 2007 to 2010 - Final Report and Final Determination,* June 2007, p 110.

[435] SFG, *The association between changes in electricity demand and GDP growth*, March 2010, attached to SFG's final report.

The variables:

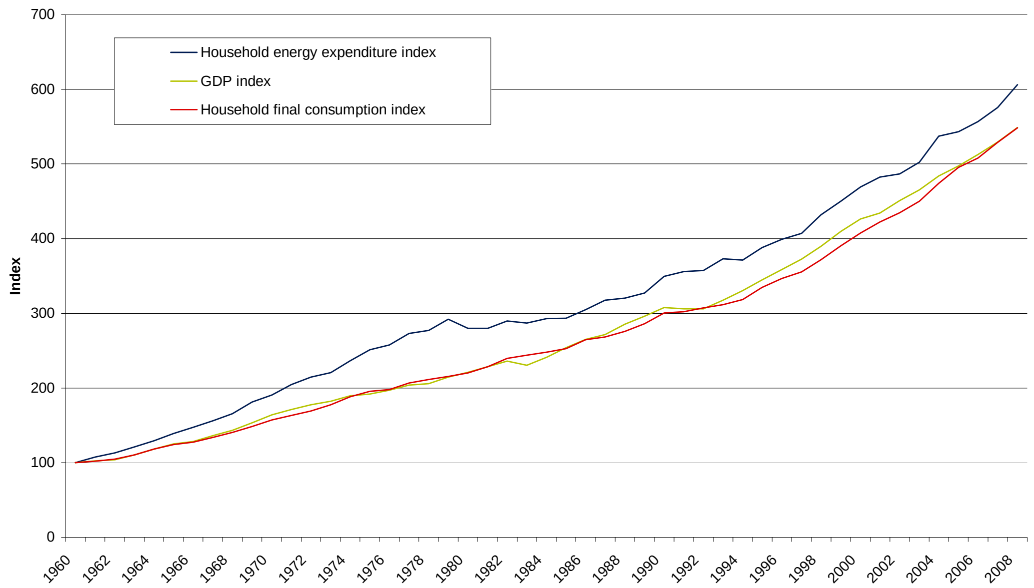
- % Change in volume in year (in year t and t-1); % Change in GDP (in year t, t-1 and t-2); and % Change in price were compiled on an annual basis.
- The coefficients - Intercept, Beta1, Beta2, Beta3, Gamma and Theta - were estimated using ordinary least squares regression.

By using this model, SFG and Frontier Economics recommended a one-for-one relationship between GDP and electricity sales to small retail customers. The following analysis reassesses this relationship. It uses ABS household expenditure data from the Australian System of National Accounts (ABS catalogue number 5204.0) and the Household Expenditure Survey (HES) (ABS catalogue number 6530.0).

F.2 Trends in the household budget share of energy expenditure

According to the System of National Accounts data, total energy (electricity, gas and other fuels) expenditure per year across all Australian households has grown from $2.09 billion in 1959/60 to $12.66 billion in 2007/08. This translates to an average yearly growth rate of about 3.9%, which compares to an average yearly growth of 3.6% in both household final consumption expenditure (HFCE) and GDP (see Figure F.1).

Figure F.1 Total household expenditure on energy against GDP for Australia 1960 to 2008



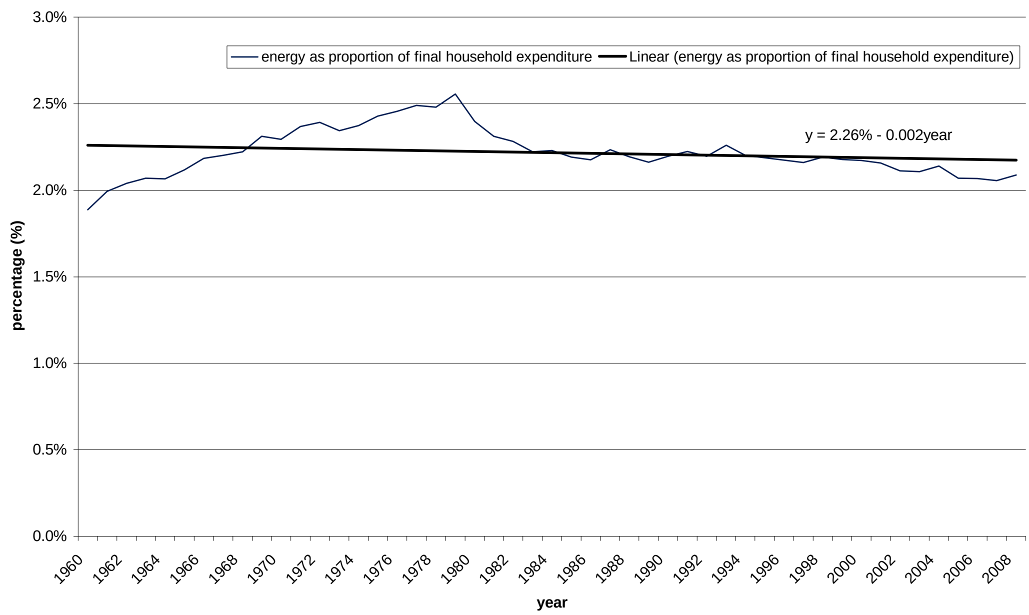
Note: Energy expenditure comprises electricity, gas and other fuels.

Data source: ABS, 5204.0 Australian System of National Accounts, Table 42. Household Final Consumption Expenditure (HFCE).

The higher growth in energy expenditure relative to GDP over the 49-year period appears to be driven by the growth encountered in the 1960s and early 1970s. From 1980 onwards there is a distinctly different picture. The yearly growth in GDP is 3.3%, which clearly outpaces that in household energy expenditure of 2.6%.

Over the period 1960 to 2008, total energy expenditure as a proportion of household final consumption expenditure (HFCE) averaged 2.2% (see Figure F.2). The trend line in Figure F.2 indicates that energy as a proportion of HFCE has declined by 0.002 percentage points per year since 1960. On the surface, this suggests that there may be less than a one-for-one relationship between income and energy expenditure to small retail customers, and especially so since around 1980.

Figure F.2 Energy as a share of total household final consumption expenditure for Australia 1959 to 2009



Note: Energy expenditure comprises electricity, gas and other fuels.

Data source: ABS, 5204.0 Australian System of National Accounts, Table 42, Household Final Consumption Expenditure (HFCE).

The relationship between energy expenditure and household expenditure is corroborated by data from the ABS's HES, which dates back to 1984. Weekly expenditure on energy (ie, domestic fuel and power) has averaged 2.7% of total expenditure on goods and services since 1984, and 2.2% of mean gross weekly household income (Table F.1).

Table F.1 Average weekly household income and expenditure for Australia adjusted for the consumer price index[a]

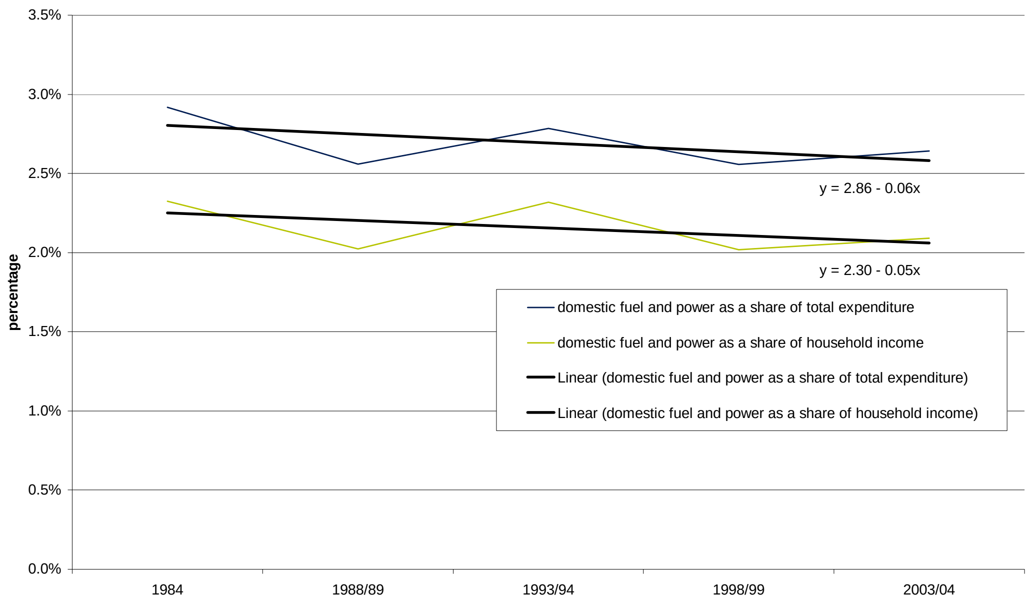
	Domestic fuel and power ($)	Total expenditure on goods and services ($)	Mean gross household income ($)	Domestic fuel and power as a share of total expenditure (%)	Domestic fuel and power as a share of household income (%)
1984**[a]**	16.00	548.24	687.88	2.9	2.3
1988/89	13.90	543.03	687.01	2.6	2.0
1993/94	15.20	545.64	655.19	2.8	2.3
1998/99	14.71	575.28	728.40	2.6	2.0
2003/04	16.44	622.40	786.34	2.6	2.1

a The HES data is converted into constant dollars using the Consumer Price Index (base year 1989-90). Yearly CPI indexes were calculated by averaging quarterly CPI indexes. The 1984 survey refers to the calendar year. All subsequent surveys relate to financial years.

Data source: ABS, 6530.0 Household Expenditure Survey, Summary of Results, Table 1. HOUSEHOLD EXPENDITURE, 1984 to 2003–04; ABS, 6401.0 Consumer Price Index, Australia., TABLES 1 and 2. CPI: All Groups, Index Numbers and Percentage Changes.

Figure F.3 shows how these proportions have fluctuated over time. On average, weekly spending on energy still increases less than proportionately in terms of both total household expenditure and income – with energy expenditure declining by about 0.06 percentage points as a proportion of total expenditure and 0.05 percentage points as a proportion of weekly income per survey period. If these downward trends are spread evenly across the survey period (ie, 5 years), they would represent a decline in the budget share of energy of about 0.01 percentage points per year.

Figure F.3 Energy expenditure as a share of average weekly household expenditure and mean average gross income for Australia, real prices



Note: Energy refers to domestic fuel and power, which includes gas heating, fire wood, as well as electricity.

Data source: ABS, 6530.0 Household Expenditure Survey, Summary of Results, Table 1. HOUSEHOLD EXPENDITURE, 1984 to 2003–04; ABS, 6401.0 Consumer Price Index, Australia., TABLES 1 and 2. CPI: All Groups, Index Numbers and Percentage Changes.

While the downward trend in the budget share of energy may imply that there is less than a one-for-one relationship between income and energy expenditure to small retail customers, an important question to ask is whether this relationship is statistically significant. We undertook some statistical analysis to answer this question which is set out in the following sections. All modelling results are presented in full in section F.5.

F.3 Modelling the association between household energy expenditure and total household expenditure and GDP

We began by modelling the trend in energy expenditure as a share of total household expenditure over the period 1960 to 2008 as depicted in Figure F.2. The empirical relationship is:

Energy exp/total exp = 2.3% -0.002 x %time period (adj-R^2 = 1%).

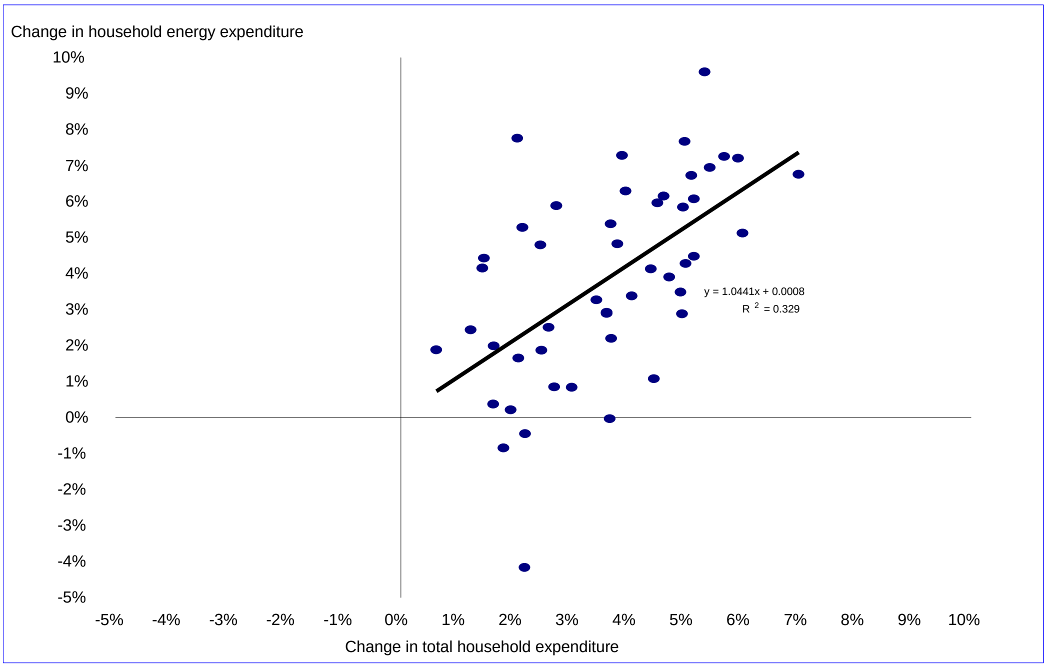
While the coefficient suggests a downward trend over time of 0.002 percentage points, the relationship is not statistically significant. The trend in the budget share of energy is insignificantly different from zero with a p-value of 0.2. This means that if we reject the proposition that the proportion of energy expenditure is constant over time, we have a 20% chance of getting it wrong.

The data is also consistent with household energy expenditure keeping pace with total household expenditure if the association between percentage changes in energy expenditure and total expenditure is modelled. The empirical relationship over the period 1961 to 2008 is illustrated in Figure F.4 and given by:

> % Change in energy expenditure = 0.1% + 1.04 x % Change in total expenditure (adj-R^2 = 31%).

The estimated coefficient indicates that for every 1% increase in total expenditure, energy expenditure increases by 1.04%. Further, the coefficient is insignificantly different from one (p-value = 0.83).

Figure F.4 The association between changes in energy expenditure and total household expenditure for Australia 1961 to 2008



Note: Energy refers to domestic fuel and power, which includes gas heating, fire wood, as well as electricity.

Data source: ABS, 5204.0 Australian System of National Accounts, Table 42, Household Final Consumption Expenditure (HFCE).

Finally, the association between percentage changes in household energy consumption and percentage changes in GDP was modelled to assess the relationship between household energy expenditure and income. The empirical relationship is:

> % Change in energy expenditure = 1.2% + 0.70 x % Change in GDP (adj-R^2 = 21%).

The coefficient of 0.70 on the percentage change in GDP is significantly lower than one (p-value = 0.04), which does not point to a one-for-one relationship. However, once lagged GDP is incorporated into the analysis the sum of the coefficients on GDP increases to 0.89 and 1.28, both of which are insignificantly different from one. Further, these models appear to be more statistically robust as they both have greater explanatory power.

> % Change in energy expenditure = 0.5% + 0.64 x % Change in GDP + 0.25 x One year lagged % change in GDP (adj-R^2 = 22%).

> % Change in energy expenditure = -0.9% + 0.65 x % Change in GDP + 0.11 x One year lagged % change in GDP + 0.51 x Two year lagged % change in GDP (adj-R^2 = 33%).

The empirical models presented above suggest that we cannot reject the hypothesis that household energy consumption has a one-for-one relationship with GDP growth, and that the contemporaneous association between these two variables may merely be dampened by:

- imprecision with which the variables are measured (ie, there is some 'noise' in the GDP variable as it includes investment expenditure as well as consumption expenditure), and
- any delayed consumer response to economic conditions dampens the contemporaneous association.

F.3.1 A sub-sample analysis over different periods

On balance, the data over the period 1960 to 2008 appears to be consistent with household energy expenditure having approximately the same sensitivity to economic conditions. However, this 'neutral' result may be driven by the ratio in the budget share of energy peaking around 1980 (see Figure F.2). For completeness, we replicated the analysis presented above over 2 truncated data sets that straddle either side of the peak ratio in the budget share of energy. This was designed to test whether there is any structural break in the data set and thus a different relationship between energy expenditure and economic conditions over the 2 time periods.

We began by modelling the trend in energy expenditure as a share of total household expenditure over the sub-sample 1980 to 2008. The empirical relationship is:

> Energy exp/total exp = 2.3% -0.01 x % time period (adj-R^2 = 71%).

The budget share of energy has declined on average by 0.01 percentage points per year since 1980 and is significantly different from zero (p-value = 0.00). Therefore, the length of the time period seems to influence the statistical significance of the relationship between household energy expenditure and total expenditure - ie, the significance of the downward trend seems to be driven by the fact that 1980 marks the start of the decline in energy expenditure as a share of total household expenditure. This downward trend is greater by 0.006 percentage points per year than that observed over the whole sample period 1960 to 2008.

To balance the analysis the same model was run over the sub-sample 1960 to 1979. The empirical relationship is:

Energy exp/total exp = 1.9% +0.03 x % time period (adj-R^2 = 96%).

The budget share of energy this time increases on average by 0.03 percentage points per year. The coefficient of 0.03 percentage change in the budget share of energy is significantly different from zero (p-value = 0.00). Therefore, the upward trend in the budget share of energy and its statistical significance seems to be an artefact of the time period selected.

We then modelled the association between percentage changes in household energy consumption and percentage changes in total household consumption over the two sub-samples: 1963 to 1981 and 1982 to 2008. These sample ranges were set to accommodate the lagged models that follow.

First, over the period 1982 to 2008 the empirical relationship is:

% Change in energy expenditure = -0.2% + 0.93 x % Change in total expenditure (adj-R^2 = 36%).

The coefficient on the percentage change in total expenditure of 0.93 has changed little from the full sample estimate of 1.04, and is still insignificantly different from one (p-value = 0.87). Therefore, this result is insensitive to the change in time period and, more importantly, the decline in the budget share of energy noted above over the same period.

Over the period 1963 to 1981 the empirical relationship is:

% Change in energy expenditure = -0.1% + 1.19 x % Change in total expenditure (adj-R^2 = 36%).

The relationship is stronger over the period 1963 to 1981 with the coefficient on the percentage change in total expenditure increasing to 1.19. The estimated coefficient is also still insignificantly different from one (p-value = 0.97).

Therefore, a one-for-one association between the percentage change in energy expenditure and the percentage total consumption expenditure seems to exist on either side of the peak ratio in the budget share of energy.

Finally, we modelled the association between percentage changes in household energy consumption and percentage changes in GDP from 1982 onwards. The empirical relationship is:

% Change in energy expenditure = 1.5% + 0.43 x % Change in GDP (adj-R^2 = 10%).

% Change in energy expenditure = 1.0% + 0.41 x % Change in GDP + 0.17 x One year lagged % change in GDP (adj-R^2 = 8%).

% Change in energy expenditure = -0.5% + 0.50 x % Change in GDP + 0.11 x One year lagged % change in GDP + 0.45 x Two year lagged % change in GDP (adj-R^2 = 20%).

The results from these models provided mixed signals in terms of the relationship between energy expenditure and GDP. On the one hand, the coefficient of 0.43 on the percentage change in GDP is significantly lower than one (p-value = <0.01) and also lower than its contemporaneous counterpart of 0.70 over the full data set. Once lagged GDP is incorporated into the analysis the relationship appears to strengthen with the sum of the coefficients on GDP increasing to 0.58 and 1.05, but again these relationships are less pronounced than those modelled since 1960. Further, only the sum of the coefficients on the double lagged GDP model is insignificantly different from one (p-value 0.65).

On the other hand, an important observation is that the sum of coefficients on the percentage change in GDP for energy consumption is not too dissimilar to that for total household consumption (see modelling results – Table F.7). The implication of this result is that there is no evidence that energy consumption is more stable (or less elastic) than total consumption over the period 1982 to 2008. It is also important to note that the only model in which sum of the coefficients is insignificantly different from one (ie, the double lagged GDP model) has the greatest explanatory power (adj-R^2 = 20%).

Finally, we note that the relationship between energy expenditure and GDP is more stable and thus certain over the sub-sample 1963 to 1981. The sum of the coefficients on GDP in all models of energy consumption is insignificantly different from one (see modelling results - Table F.5). Therefore, over this sub-sample we cannot reject the hypothesis that household energy consumption has a one-for-one relationship with GDP growth.

F.4 Conclusion

This exploratory analysis demonstrates that there is sufficient uncertainty to make it difficult to move away from a position of an assumed one-for-one relationship between changes in GDP and changes in household electricity consumption. We note that this supports SFG modelling of the issue.

F.5 Modelling results

Table F.2 Energy consumption as a share of total consumption over time

Intercept	Time	p-value	Adjusted R^2	N	Year 1
1.9%	0.031%	0.00	96%	20	1960
2.3%	-0.007%	0.00	71%	29	1980
2.3%	-0.002%	0.20	1%	49	1960

Table F.3 % Change in energy consumption as a function of % change in total consumption

Intercept	% change in total consumption	p-value	Adjusted R^2	N	Year 1
-0.1%	1.19	0.97	31%	19	1963
-0.2%	0.93	0.87	36%	27	1982
0.1%	1.04	0.83	31%	48	1961

Table F.4 % Change in energy consumption as a function of % change in GDP (sub-sample 1982 - 2008)

Intercept	GDP	Lag1GDP	Lag2GDP	SumCoeff	p-value	Adjusted R^2	N	Year 1
1.5%	0.43			0.43	<0.01	10%	27	1982
1.0%	0.41	0.17		0.58	0.10	8%	27	1982
-0.5%	0.50	0.11	0.45	1.05	0.65	20%	27	1982

Table F.5 % Change in energy consumption as a function of % change in GDP (sub-sample 1963 - 1981)

Intercept	GDP	Lag1GDP	Lag2GDP	SumCoeff	p-value	Adjusted R^2	N	Year 1
1.4%	0.82			0.82	0.38	21%	19	1963
0.9%	0.77	0.17		0.94	0.55	17%	19	1963
-0.2%	0.73	0.04	0.45	1.22	0.94	20%	19	1963

Table F.6 % Change in energy consumption as a function of % change in GDP (whole sample 1963 - 2008)

Intercept	GDP	Lag1GDP	Lag2GDP	SumCoeff	p-value	Adjusted R^2	N	Year 1
1.2%	0.70			0.70	0.04	21%	46	1963
0.5%	0.64	0.25		0.89	0.47	22%	46	1963
-0.9%	0.65	0.11	0.51	1.28	0.23	33%	46	1963

Table F.7 % Change in total consumption as a function of % change in GDP (including up to two lags)

Intercept	GDP	Lag1GDP	Lag2GDP	SumCoeff	p-value	Adjusted R^2	N	Year 1
2.1%	0.35			0.35	<0.01	17%	27	1982
1.2%	0.31	0.31		0.62	<0.01	30%	27	1982
0.3%	0.37	0.27	0.28	0.92	0.56	41%	27	1982

G Benchmarking retail costs

Information on retail costs from other jurisdictions can provide useful information on the retail costs that a Standard Retailer would face. This appendix provides a summary of allowances for retail costs in recent regulatory decisions in Australia (Table G.1). Retail costs include both ROC and CARC allowances, where applicable.

Table G.1 Electricity retail costs in other regulatory decisions 2001/02 to 2009/10

Decision	Regulatory period	Retail cost per customer (nominal)	Retail cost per customer ($2009/10)[a]	Comments
IPART (2000)[b]	January 2001 to June 2004	$40-$60	$52-$78	IPART's cost allowance included an allowance for the costs of contestability. IPART recognised there are economies of scale in retailing, but noted that retailers reported similar costs per customer, irrespective of scale.
ORG (2001)[b]	2002	$50-$80	$63-$101	ORG noted that the most significant cost components are likely to be billing and revenue collection costs and call centre costs. ORG's cost allowance included an allowance of $5-$10 for the costs of FRC. ORG noted that the potential for larger NSW retailers to access economies of scale may justify a greater allowance for retail costs in Victoria than in NSW.
IPART (2001)[b]	August 2002 to June 2004	$45-$75	$59-$98	IPART's cost allowance included an allowance for the costs of contestability.
SAIIR (2002)[b]	2003	$80	$98	SAIIR's cost allowance included an allowance for the costs of FRC. SAIIR noted that AGL SA is larger than any of the Victorian retailers and larger in aggregate than any other electricity retailer. SAIIR suggested that AGL SA's costs should therefore be lower. AGL SA argued that since it was not a stapled retail/distribution business its costs would be higher.
ICRC (2003)[b]	July 2003 to June 2006	$85	$103	ICRC's cost allowance included an allowance for the costs of FRC. ICRC considered that diseconomies of scale justified an increased allowance for retail costs relative to Victoria and South Australia.

Decision	Regulatory period	Retail cost per customer (nominal)	Retail cost per customer ($2009/10)[a]	Comments
OTTER (2003)[b]	January 2004 to December 2006	$76	$94	OTTER's cost allowance did not include an allowance for the costs of FRC (as FRC had not been introduced in Tasmania). OTTER recognised the importance of economies of scale, but considered that a retailer in Tasmania should be able to achieve comparable costs to one in South Australia or the ACT.
CRA (2002)[b]	2003	$90	$110	CRA's cost allowance was based on Victorian retailers' reports of their retail costs for standing offer customers, as reported to ORG during its 2001 investigation of retail pricing.
CRA (2003)[b]	January 2004 to December 2007	$91	$110	CRA considered that its analysis from 2002 remained relevant, but adjusted this by CPI-1 (to allow for some productivity gain).
ESCOSA (2003)[b]	2004	$82	$99	ESCOSA considered that its analysis from 2002 remained relevant, but increased the $80 allowance to reflect inflation.
IPART (2004)[b]	July 2004 to June 2007	$70	$84	IPART based its allowance on estimates of retail operating costs provided by retailers. IPART noted that these estimates were lower than retail operating costs allowed for in other jurisdictions, but considered that the use of higher benchmark costs is inconsistent with determining efficient costs.
ESCOSA (2005)[b]	January 2005 to December 2007	$84	$99	ESCOSA undertook a review of AGL SA's retail costs and concluded that the results of the cost audit were sufficiently similar to its previous benchmarking exercises that there was no justification for replacing the benchmarked results. ESCOSA increased the $82 allowance to reflect inflation.
IPART (2007)	July 2007 to June 2010	$105	$114	Retail costs reflected an efficient mass market new entrant - which was judged to have similar scale to standard retailers and thus estimates were based on standard retailers cost data. IPART was not persuaded that retail costs should increase in real terms over the determination period due to likely productivity gains. ROC was $75 per customer, CARC $35 per customer, and there was a $5 deduction for double counting (in nominal dollars).
QCA (2007)	July 2006 to June 2007	$65	$71	Benchmarked on IPART's $75 per customer allowance in the 2007 determination - for a well established, standalone and efficient retail business. A $10 per customer deduction was made because FRC costs did not apply in

Decision	Regulatory period	Retail cost per customer (nominal)	Retail cost per customer ($2009/10)[a]	Comments
				Qld at the time.
QCA (2007)	July 2007 to June 2008	$80	$83	Retail operating costs were calculated by escalating the benchmark cost established in 2006/07 for wage and price inflation. FRC-related costs were also accounted for and so the benchmark used was $75 per customer. The uplift factor was 3.65%. Customer acquisition allowance based on a loss of scale methodology of $2.
ESCOSA (2007)	January 2008 to December 2010	$97-$87	$101-$91	ESCOSA factored a 4.1% real annual decrease in ROC over the determination period due to efficiency gains from project Phoenix - based on a 50:50 sharing ratio of the expected benefits between consumers and AGL. No explicit customer acquisition cost was provided.
QCA (2008)	July 2008 to June 2009	$108	$111	Retail operating costs were calculated by escalating the 2007/08 allowance for wage and price inflation. Uplift factor of 3.65%. QCA introduced a new two-step process to estimate customer acquisition and retention costs: estimating the costs and number of customers transferring or switching contracts. The allowance for this was $27 per customer.
QCA (2009)	July 2009 to June 2010	$110	$110	QCA estimates 2009/10 retail operating costs represents a 2.8% increase on the estimated costs for 2008/09. The escalation factor was based on a 40/60 weighting of CPI and wage inflation as measured by the wage price index (WPI). The allowance for CARC was $27 per customer.
ICRC (2009)	July 2007 to June 2010	$103	$103	Costs incurred in providing retail services are based on an estimate of $85 per customer in 2003/04. In all subsequent years, the figure has been adjusted for movements in the CPI. No explicit provision for customer acquisitions due to negative customer impacts.
QCA (2009)	July 2010 to June 2011	$130	$130	The QCA escalated its original ROC benchmark of $75 in 2006/07 by its 60/40 weight of CPI/WPI factors to arrive at its 2010/11 allowance of $85.42. CAC increased to $44.20 because of a significantly higher switch rate rather than any real increase permitted in unit customer acquisition costs.

a We have converted all allowances in this benchmarking exercise into 2009/10 dollars using the actual quarter on quarter to June CPI for each year.

b All estimates sourced from Frontier Economics, *Mass market new entrant retail costs and retail margin, Final Report*, March 2007, p 34. We have converted these allowances from 2006/07 dollars into 2009/10 dollars.

Sources: All per customer retail costs in nominal dollars are sourced from the following reports:

IPART, *Promoting retail competition and investment in the NSW electricity industry: Regulated electricity retail tariffs and charges for small customers 2007 to 2010*, June 2007.

ESCOSA, *2007 Review of retail electricity path: Final inquiry report and price determination*, November 2007.

QCA, *Remade Final Decision 2008-09 Benchmark Retail Cost Index*, June 2009.

QCA, *Final Decision 2009-10 Benchmark Retail Cost Index*, June 2009.

ICRC, *Final Decision Retail Prices for Non-contestable Electricity Customers 2009–2010*, June 2009.

ICRC, *Final Decision and Price Direction Retail Prices for Non-contestable Electricity Customers Report 4 of 2008*, June 2008.

ICRC, *Final Decision and Price Direction Retail Prices for Non-contestable Electricity Customers Report 7 of 2007*, June 2007.

QCA, *Draft Decision 2010-11 Benchmark Retail Cost Index*, December 2009, p 29-30.

H List of submissions

This appendix provides a list of submissions to our Draft Report and Determination released in December 2009 (see Table H.3), our Draft Methodology Paper released in August 2009 (see Table H.2), and our Issues Paper released in June 2009 (see Table H.1).

Table H.1 List of submissions to our Issues Paper - Review of regulated retail tariffs and charges for electricity 2010 - 2013 - July 2009

Submitter	Date received
AGL	03 August 2009
Country Energy	05 August 2009
Delta Electricity	03 August 2009
Energy and Water Ombudsman NSW (EWON)	05 August 2009
Energy Management Solutions Australia	03 August 2009
Energy Retailers Association of Australia	17 August 2009
EnergyAustralia	17 August 2009
Individual - (Anonymous)	23 July 2009
Individual - (Craig Black)	24 July 2009
Integral Energy	12 August 2009
Jackgreen International Pty Ltd	04 August 2009
NSW Council of Social Services (NCOSS)	29 July 2009
NCOSS	14 September 2009
Origin Energy	04 August 2009
Public Interest Advocacy Centre (PIAC)	05 August 2009
TRUenergy	05 August 2009

Table H.2 List of submissions to our Draft Methodology Paper - Review of regulated retail tariffs and charges for electricity 2010 - 2013 - August 2009

Submitter	Date received
AGL	22 September 2009
D-Cypha	18 September 2009
Choice	19 October 2009
Country Energy	24 September 2009
Energeia	03 September 2009
Energy and Water Ombudsman NSW (EWON)	19 October 2009
Energy Retailers Association of Australia	18 September 2009
EnergyAustralia	18 September 2009
Integral Energy	21 September 2009
Jackgreen International Pty Ltd	21 September 2009
Public Interest Advocacy Centre (PIAC)	29 September 2009
Origin Energy	24 September 2009
TRUenergy	18 September 2009

Table H.3 List of submissions to our Draft Report and Draft Determination - Review of regulated retail tariffs and charges for electricity 2010 - 2013 – December 2009

Submitter	Date received
AGL	8 February 2010
Combined Pensioners & Superannuants Association CPSA	8 February 2010
Council of the Ageing NSW (COTA)	8 February 2010
Country Energy	4 February 2010
Hon Duncan Gay MLC	2 February 2010
EnergyAustralia	4 February 2010
Energy Management Solutions	7 February 2010
Energy and Water Ombudsman NSW (EWON)	4 February 2010
Gloucester Shire Council	8 January 2010
Independent Member of Tamworth	4 February 2010
Integral Energy	1 February 2010
Manning Valley CPSA	4 February 2010
Member for Northern Tablelands	3 February 2010
Minister for Energy	3 February 2010
NSW Business Chamber	4 February 2010
NSW Farmers Association	5February 2010
NSW Independent Member for Dubbo	3 February 2010
Origin Energy	5 February 2010

Submitter	Date received
Penrith City Council	11 February 2010
Peter Besseling MP	22 December 2009
Public Interest Advocacy Centre (PIAC)	3 February 2010
Toronto Assistance Centre	2 February 2010
TRUenergy	5 February 2010
Individual (Susan Abouav)	30 November 2009
Individual (Ray Jaeger)	3 December 2009
Individual (Eileen de Lapp)	15 December 2009
Individual (Anonymous)	15 December 2009
Individual (Anonymous)	15 December 2009
Individual (Anonymous)	15 December 2009
Individual (Les Evans)	15 December 2009
Individual (Anonymous)	15 December 2009
Individual (Anonymous)	15 December 2009
Individual (Glen Tinker & Family)	15 December 2009
Individual (Troy Davis)	15 December 2009
Individual (Anonymous)	16 December 2009
Individual (Elizabeth Paul)	16 December 2009
Individual (Anonymous)	16 December 2009
Individual (Anonymous)	16 December 2009
Individual (Anonymous)	16 December 2009
Individual (Anonymous)	16 December 2009
Individual (Robert Carlos)	16 December 2009
Individual (Jenny Watson)	16 December 2009
Individual (Margaret Surace)	16 December 2009
Individual (Barry Withers)	16 December 2009
Individual (Penny Ferguson)	16 December 2009
Individual (Trevor Keayes)	16 December 2009
Individual (Anonymous)	17 December 2009
Individual (Anonymous)	17 December 2009
Individual (Phil Kotromanovic)	17 December 2009
Individual (Peter Herman)	18 December 2009
Individual (Pamela Brayley)	18 December 2009
Individual (Paul Johnson)	18 December 2009
Individual (Mike Austin)	19 December 2009
Individual (Greg Raffin)	21 December 2009
Individual (Mavis Ellison)	21 December 2009
Individual (John Richardson)	22 December 2009
Individual (Pamela Folpp)	23 December 2009
Individual (Anonymous)	24 December 2009
Individual (Roslyn Bird)	26 December 2009

Submitter	Date received
Individual (Frank Avis)	5 January 2010
Individual (Ian Belford)	6 January 2010
Individual (Cliff & Miriam Hill)	6 January 2010
Individual (David Marshall)	6 January 2010
Individual (Heather Chettle)	6 January 2010
Individual (R L Ray)	7 January 2010
Individual (P R Turner)	7 January 2010
Individual (Gary Moore)	7 January 2010
Individual (Rohan Hutchins)	7 January 2010
Individual (Linda Walsh)	8 January 2010
Individual (Doug & Una Rudd)	9 January 2010
Individual (Bob Griffin)	11 January 2010
Individual (Dorothy Goldspink)	13 January 2010
Individual (Elaine Lloyd)	13 January 2010
Individual (Richard & Judy Goder)	14 January 2010
Individual (Pat Robinson)	14 January 2010
Individual (June Shannon)	14 January 2010
Individual (Max & Beryl Bennett)	14 January 2010
Individual (Phillip Hawes)	15 January 2010
Individual (Ray & Muriel Ryan)	16 January 2010
Individual (Peter Lean)	16 January 2010
Individual (Cory Morrison)	16 January 2010
Individual (Pat McGee)	17 January 2010
Individual (James & Julie Chissell)	18 January 2010
Individual (John Hunter)	18 January 2010
Individual (Anthony Goonan)	18 January 2010
Individual (Robert Wornes)	19 January 2010
Individual (Maureen Lee)	20 January 2010
Individual (K Rollins)	20 January 2010
Individual (David Lee)	21 January 2010
Individual (David Wilcox)	21 January 2010
Individual (Gloria Andrews)	21 January 2010
Individual (Anonymous)	22 January 2010
Individual (M Christie)	22 January 2010
Individual (Gary Townsend)	22 January 2010
Individual (Gail Woods)	23 January 2010
Individual (Steve & Chris Young)	23 January 2010
Individual (Dayner Rauser)	24 January 2010
Individual (W & C Bachme)	25 January 2010
Individual (C C Mackenzie)	25 January 2010
Individual (Mrs M Avery)	25 January 2010

Submitter	Date received
Individual (Dalma Moore)	25 January 2010
Individual (Anonymous)	27 January 2010
Individual (Loraine Branz)	27 January 2010
Individual (Olive Guthrie)	27 January 2010
Individual (Mrs V J Cook)	29 January 2010
Individual (J Osborn)	29 January 2010
Individual (Paul Duncan)	1 February 2010
Individual (Bob Griffin)	2 February 2010
Individual (D Brydon)	3 February 2010
Individual (Graham & Jan Watkins)	3 February 2010
Individual (Joanne Whitehead)	3 February 2010
Individual (Ron Craggs)	3 February 2010
Individual (Peter Carruth)	3 February 2010
Individual (Ross Hamilton)	3 February 2010
Individual (Edward & Elizabeth McPaul)	3 February 2010
Individual (Graeme Davis)	6 February 2010
Individual (Anonymous)	11 February 2010

I More detail on our analysis of the impact of the final determination on small customers

Chapter 11 outlined our analysis and findings on the level of retail competition in NSW. This appendix provides additional detail on some areas of this analysis.

I.1 Impact on households with different characteristics

As mentioned in Chapter 11, IPART conducts periodic surveys of household electricity consumption to help us to assess the impact of our pricing decisions on different households. We used the electricity consumption data to analyse the impact on households with different numbers of occupants, and different numbers of large energy-using appliances.

The results of this analysis are summarised below. However, we stress that they are indicative only, and will not be representative for all households in NSW. In particular:

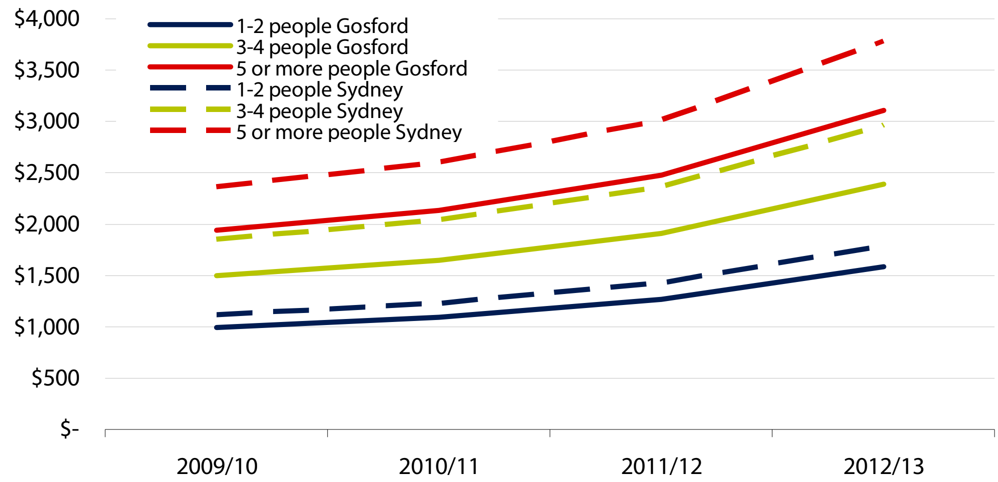
- They are based on EnergyAustralia's average regulated tariffs in 2009/10 and EnergyAustralia's average tariff increases under the determination.
- They reflect the consumption patterns in the particular areas we surveyed. The findings of these surveys indicate that location, as well as demographic factors, influence electricity consumption. For example, households in coastal areas tend to use heaters and air conditioners less than inland areas, which results in lower levels of consumption and hence lower bills.
- They assume that household consumption is constant throughout the determination period.
- They include the CPRS, but exclude the impact of the CPRS compensation package.

I.1.1 Impact on households with different number of occupants

Our household surveys found that the average electricity consumption increases on average with the number of household occupants. Therefore, regulated electricity price increases are likely to have a greater impact on larger households. To illustrate this, we analysed the impact of the determination on the average bills for households with different numbers of occupants. The results of this analysis, which are shown in Figure I.1, suggest that:

- In the Hunter, Gosford and Wyong area, the average annual electricity bill for households with 5 or more occupants was $1,942 in 2009/10, which is 96% higher than that for households with 1 or 2 occupants. This average annual bill will increase to $2,137 in 2010/11, and rise to $3,108 in 2012/13.
- In Sydney, Illawarra and the Blue Mountains areas, the average annual bill for households with 5 or more occupants was $2,363 in 2009/10 (111% higher than the average bill for households with 1 or 2 occupants). It will increase to $2,599 in 2010/11, and rise to $3,780 in 2012/13. This analysis suggests that large family households are likely to be more adversely affected than other households by the price increases under the determination.

Figure I.1 Average annual electricity bills by household size (nominal $, no controlled load, incl GST)



Data source: IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra*, November 2007, IPART, *Residential energy and water use in the Hunter, Gosford and Wyong*, December 2008.

I.1.2 Impact on households that use more large appliances

Our household surveys found that higher electricity consumption is associated with households that have more large energy-using appliances than others. To illustrate the likely impact of the determination on such households, we compared the annual average electricity bill of households with air conditioners to those of households without air conditioners.[436] The results of this analysis are shown in Figure I.2 and suggest that:

- In the Gosford Wyong Hunter area, the average annual bill for households with air conditioning was $1,266 in 2009/10, which is 26% higher than the average bill for households without air conditioning. Under the determination, this average

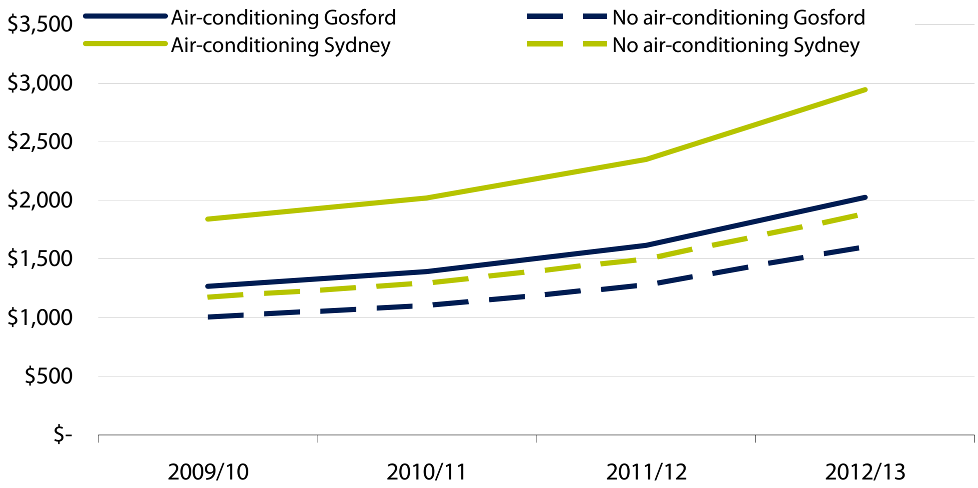
436 According our household surveys, around 71% of households in the Hunter, Gosford and Wyong area have an air conditioner, compared to 58% of households in the Sydney, Illawarra and Blue Mountains area.

bill for households with air conditioning will increase to $1,393 in 2010/11 and to $2,025 in 2012/13.

- In the Sydney Illawarra Blue Mountains area, the impact of air conditioning is likely to be more pronounced. The average annual bill for households with air conditioning was $1,839 in 2009/10, which is 56% higher than the average bill for households without air conditioning. This bill for households with air conditioning will increase to $2,023 in 2010/11 and to $2,942 in 2012/13.

Please note that these differences in household bills should not be interpreted as the incremental cost of having an air conditioner. Other household characteristics may contribute to both owning (and frequently using) air conditioning and consuming more electricity (eg, household income, dwelling type and the use of other appliances). In addition, where households use reverse-cycle air conditioning for heating and cooling, these appliances may contribute to lower consumption.[437]

Figure I.2 Average electricity bills for households with and without and air conditioning (nominal $, no controlled load, incl GST)



Data source: IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra,* November 2007, IPART, *Residential energy and water use in the Hunter, Gosford and Wyong,* December 2008.

[437] That is, reverse-cycle air conditioning units can be more efficient than other means of heating in winter. For example, EnergyAustralia estimates that the cost of heating with a reverse cycle air conditioner is $5 a week, compared to $12 a week for an electric convection heater or an oil filled column heater. Source: EnergyAustralia, *Winter Heating,* http://www.energyaustralia.com.au/energy/ea.nsf/AttachmentsByTitle/080624+-+Winter+heating/$FILE/4060_EA+Heating+V10.pdf

List of acronyms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CARC	Customer acquisition and retention costs
COTA	Council on the Aging
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
DNSP	Distribution Network Service Provider
EAPA	NSW Energy Accounts Payable Assistance Scheme
EBITDA	Earnings before interest, taxes, depreciation and amortisation
ETEF	Electricity Tariff Equalisation Fund
EPCA	Energy Purchase Cost Allowance
ESCO	Energy Savings Company
ESCOSA	Essential Services Commission of South Australia
ESS	Energy Savings Scheme
ESC	Energy Savings Certificates
EWON	Energy and Water Ombudsman NSW
GDP	Gross Domestic Product
GGAS	Greenhouse Gas Abatement Scheme
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
LRET	Large scale Renewable Energy Target
LRMC	Long Run Marginal Cost
MCE	Ministerial Council on Energy
MW	Megawatt

MWh	Megawatt Hour
NECF	National Energy Customer Framework
NCOSS	Council of Social Service of NSW
NEM	National Electricity Market
NGAC	NSW Greenhouse Gas Abatement Certificates
NSLP	Net System Load Profile
NSW	New South Wales
PIAC	Public Interest Advocacy Centre
POE	Probability of Exceedance
QCA	Queensland Competition Authority
REC	Renewable Energy Certificate
RET	Renewable Energy Target
ROC	Retail operating costs
ROLR	Retailer of Last Resort
SOO	Statement of Opportunities
SFG	Strategic Finance Group
SRMC	Short Run Marginal Cost
SRES	Small scale Renewable Energy Scheme
TNSP	Transmission Network Service Provider
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap