Energy costs – annual review for 2011/12 and 2012/13

A FINAL REPORT PREPARED FOR IPART

June 2011

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1 Introduction

The Independent Pricing and Regulatory Tribunal (IPART) has determined regulated electricity tariffs to apply for the period between 1 July 2010 and 30 June 2013 for customers of the Standard Retailers operating in NSW who are supplied on standard contracts (**2010 Determination**). Frontier Economics advised IPART on the total energy cost allowance for 2010/11 to 2012/13 to be incorporated by IPART in its 2010 Determination.[1]

IPART's 2010 Determination provided for annual reviews of the total energy cost allowance for 2011/12 and 2012/13 for each Standard Retailer. IPART's 2010 determination also provided for a cost pass-through mechanism that allows the Standard Retailers to apply to pass through incremental and efficient costs associated with events that amount to regulatory and taxation change events.

1.1 Frontier Economics' engagement

Frontier Economics has now been engaged by IPART to provide advice on:

- the annual review of the total energy cost allowance for 2011/12 and 2012/13
- the assessment of cost pass-through applications for 2010/11 submitted by the Standard Retailers.

Frontier Economics' advice to IPART for the annual review of the total energy purchase cost allowance for 2011/12 and 2012/13 is to consist of estimates of:

- the long run marginal cost (LRMC) of generation to meet the regulated load of each of the Standard Retailers
- the market-based energy purchase costs to meet the regulated load of each of the Standard Retailers (using the conservative point on an efficient frontier curve)
- the volatility allowance associated with the market-based energy purchase cost for each Standard Retailer (using the conservative point on an efficient frontier)
- the cost allowances for complying with obligations under the LRET, SRES, GGAS and ESS.

1 Frontier Economics, *Energy purchase costs*, A Final Report prepared for IPART, March 2010. Available at:

http://www.ipart.nsw.gov.au/files/Consultant%20Report%20-%20Frontier%20Economics%20-%20Final%20Report%20-%20Energy%20Purchase%20Costs%20-%20March%202010%20-%20WEBSITE%20DOCUMENT.PDF

1.2 This final report

This final report sets out Frontier Economics' advice to IPART on the total energy cost allowance for 2011/12 and 2012/13, for the purposes of IPART's annual review.

This final report does not deal with Frontier Economics' advice to IPART on the cost pass-through applications from the Standard Retailers. Frontier Economics' advice to IPART on these applications is set out in a separate report by Frontier Economics.[2]

The modelling results set out in this final report are based on the modelling methodology and assumptions adopted by Frontier Economics for its modelling during the 2010 Determination, as set out in Frontier Economics' final report for the 2010 Determination (**Frontier Final Report for 2010**)[3] and Frontier Economics' modelling methodology and assumptions report for the 2010 Determination (**Frontier Assumptions Report for 2010**).[4] For this reason, for a detailed understanding of the modelling methodology and the modelling assumptions underpinning the results set out in this report, this report should be read in conjunction with the Frontier Final Report for 2010 and the Frontier Assumptions Report for 2010.

In keeping with the intention of the annual review, a number of modelling assumptions have been updated since the 2010 Determination in order to take account of changes to input costs since the 2010 Determination or the availability of better information since the 2010 Determination. Where input assumptions have been updated since the 2010 Determination, the updated assumptions are set out in this report.

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2 Frontier Economics, *Cost pass-through application for LRET and SRES*, A Final Report prepared for IPART, June 2011.

3 Frontier Economics, *Energy purchase costs*, A Final Report prepared for IPART, March 2010.

4 Frontier Economics, *Modelling methodology and assumptions*, A Report for IPART, August 2009. Available at:

http://www.ipart.nsw.gov.au/files/Review%20of%20regulated%20electricity%20retail%20tariffs%20and%20charges%202010%20to%202013%20-%20Frontier%20Economics%20%20-%20electricity%20purchase%20cost%20allowance%20%20-%20methodology%20and%20assumptions%20report%20

Note that this modelling and assumptions report was updated by addenda also available on IPART's website.

1.2.1 What has changed since the draft report?

Prior to the release of this final report, Frontier Economics provided a draft report to IPART.[5] This draft report was released by IPART for public consultation.

This final report updates Frontier Economics' advice to IPART on the total energy cost allowance for 2011/12 and 2012/13. Since the release of Frontier Economics' draft report, IPART have updated the following key input assumptions:

- the weighted average cost of capital (WACC) for generation has been revised from 8.0% to 7.8%
- the rate of inflation from 2009/10 to 2010/11 has been revised from 2.7% to 3.3%
- the rate of inflation from 2010/11 to 2011/12 has been revised from 3.0% to 3.3%[6]
- the transmission loss factors applicable to each Standard Retailer (which have been used only to calculate the cost of complying with the LRET and the SRES).

These updated input assumptions have resulted in Frontier Economics updating its estimates of the following:

- **The long run marginal cost (LRMC) of generation to meet the regulated load of each of the Standard Retailers**. The LRMC is updated to reflect the updated WACC for generation and the updated inflation rate.[7] The updated loss factors are not used as inputs into Frontier Economics' LRMC modelling. Frontier Economics' updated advice on the LRMC of generation to meet the regulated load is set out in Section 4.

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5 Frontier Economics, *Energy costs – annual review for 2011/12 and 2012/13*, A Draft Report prepared for IPART, April 2011 (**Frontier Annual Review Draft Report**).

6 The rate of inflation for all years after 2011/12 has remained unchanged at 3.0%.

7 As discussed in the Frontier Annual Review Draft Report and in Section 3.1 of this report, where Frontier Economics converted cost input assumptions from the ACIL Report for the QCA into 2010/11 dollars, Frontier Economics used the inflation rate of 2.5% adopted by ACIL Tasman in that report. The only cost input assumptions used in Frontier Economics' LRMC modelling that were not taken from the ACIL Report for the QCA were new entrant coal costs and the carbon price.

For coal costs, Frontier Economics used IPART's assumed rate of inflation to convert new entrant coal costs into 2010/11 dollars. However, the change in IPART's assumed rate of inflation does not result in a change in these new entrant coal costs – the impact of the revised inflation rate is within the rounding error for these costs.

The carbon price is not used in Frontier Economics' modelling of the LRMC of generation to meet the regulated load because it is assumed that a carbon price will not be introduced until 2013/14.

- **The cost allowances for complying with obligations under the LRET, SRES, GGAS and ESS**. These cost allowances are updated to reflect the updated WACC, the updated inflation rate and the updated loss factors. The LRMC of meeting the LRET and GGAS is updated to reflect the updated WACC for generation and the updated inflation rate (just as the LRMC of generation to meet the regulated load is updated to account for these changes). The real STC cost is also updated to reflect the updated inflation rate. The cost of complying with the LRET and the SRES (measured at the regional reference node) is updated to reflect updated transmission loss factors. Frontier Economics' updated advice on the cost allowances for the LRET, SRES, GGAS and ESS is set out in Section 6.
- **The volatility premium**. The volatility allowance is updated to reflect the updated WACC for generation. Frontier Economics' updated advice on the volatility allowance is set out in Section 5.5.

The updated input assumptions have not required Frontier Economics to update its estimates of the market-based energy purchase cost. Neither the WACC for generation nor the loss factors are an input into Frontier Economics' modelling of the market-based energy purchase cost. Similarly, none of the cost input assumptions used in Frontier Economics' modelling of the market-based energy purchase need to be updated to reflect the updated inflation rate.[8] For this reason, Frontier Economics' advice on the market-based energy purchase cost, set out in Sections 5.1 to 5.3 is unchanged from the Frontier Annual Review Draft Report.

1.3 Structure of this report

This report is structured as follows:

- Section 2 provides a brief overview of the two approaches used by Frontier Economics to estimate the energy purchase cost allowance, and the modelling methodologies used under these two approaches
- Section 3 sets out the input assumptions that have been updated since the 2010 Determination for use in the modelling for this annual review
- Section 4 sets out the results of Frontier Economics' modelling of the LRMC of supplying the Standard Retailers' regulated load

8 As discussed in the Frontier Annual Review Draft Report and in Section 3.1 of this report, where Frontier Economics converted cost input assumptions from the ACIL Report for the QCA into 2010/11 dollars, Frontier Economics used the inflation rate of 2.5% adopted by ACIL Tasman in that report. All cost input assumptions used in Frontier Economics' market modelling were taken from the ACIL Report for the QCA. In contrast to Frontier Economics' LRMC modelling, there is not new entrant coal plant and no carbon price in Frontier Economics' market modelling for 2011/12 and 2012/13.

- Section 5 sets out the results of Frontier Economics' modelling of the market-based energy purchase cost of supplying the Standard Retailer's regulated load
- Section 6 sets out Frontier Economics' advice on the allowance for the costs of complying with the LRET, the SRES, the GGAS and the ESS
- Section 7 provides a summary of Frontier Economics' advice.

More detail on input assumptions used by Frontier Economics is provided in a spreadsheet released with this report.

2 Overview of modelling approach

As discussed in Section 1.1, Frontier Economics' advice to IPART for this annual review is to consider two approaches to the energy purchase cost allowance:

- the LRMC of generating plant to supply the Standard Retailers' regulated load
- the market-based energy purchase cost to supply the Standard Retailers' regulated load

This section provides a brief overview of the modelling approach used by Frontier Economics to estimate the LRMC to supply the Standard Retailers' regulated load and the market-based energy purchase cost to supply the Standard Retailers' regulated load.

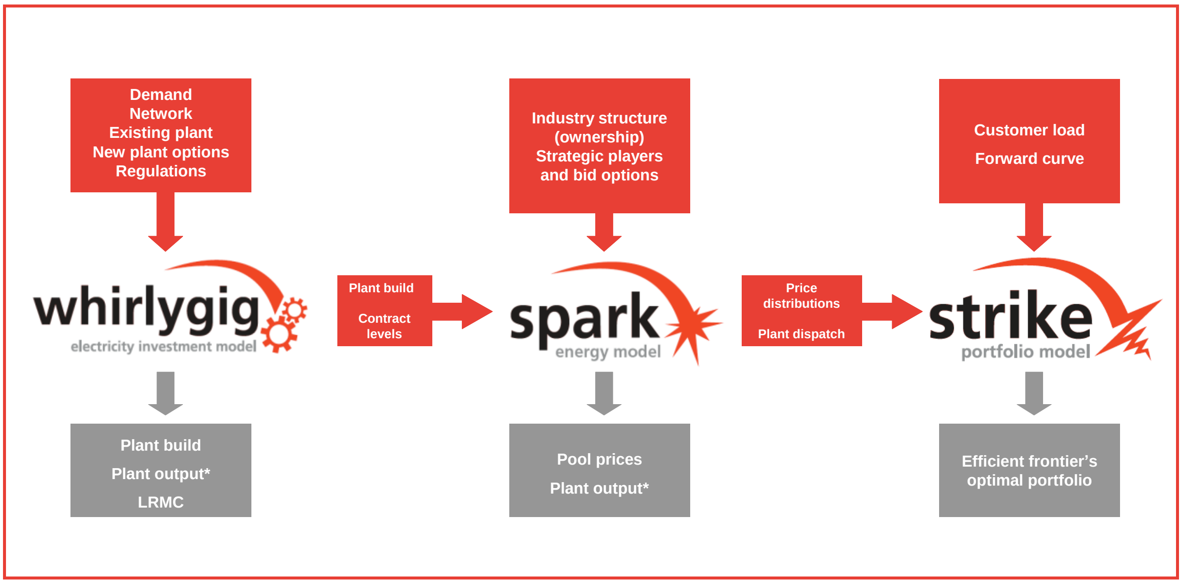
2.1 Frontier Economics' energy market models

For the purposes of estimating energy costs, Frontier Economics adopts a three-staged modelling approach, which makes use of three inter-related electricity market models: *WHIRLYGIG, SPARK* and *STRIKE*. These models were used in Frontier Economics' advice for the 2010 Determination. The key features of these models are as follows:

- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load. *WHIRLYGIG* provides an estimate of LRMC, including the cost of any plant required to meet modelled regulatory obligations
- *SPARK* uses game theoretic techniques to identify optimal and sustainable bidding behaviour by generators in the electricity market. *SPARK* determines the optimal pattern of bidding by having regard to the reactions by generators to discrete changes in bidding behaviour by other generators. The model determines profit outcomes from all possible actions (and reactions to these actions) and finds equilibrium bidding outcomes based on game theoretic techniques. An equilibrium is a point at which no generator has any incentive to deviate. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes
- *STRIKE* uses portfolio theory to identify the optimal portfolio of available electricity purchasing options (spot purchases, derivatives and physical products) to meet a given load. *STRIKE* provides a range of efficient purchasing outcomes for different levels of risk where risk relates to the levels of variation of expected purchase costs

The relationship between Frontier Economics' three electricity market models is summarised in Figure 1.

Figure 1: Frontier's energy modelling framework



* *Plant output from WHIRLYGIG and SPARK differs due to different assumptions about bidding behaviour.*

As discussed, there are essentially two aspects to Frontier Economics' analysis for this annual review: an estimate of LRMC and an estimate of market-based energy purchase costs.

To estimate LRMC, Frontier Economics uses *WHIRLYGIG*, which identifies the least cost mix of existing plant and new plant options to meet electricity demand. Frontier Economics uses *WHIRLYGIG* in two different ways:

- Frontier Economics estimates the LRMC of serving the Standard Retailers' regulated load using a stand-alone LRMC approach (which assumes that there is no existing plant to meet the regulated load). Under this approach, the load used to estimate LRMC is the Standard Retailers' regulated load, and the LRMC is the cost of serving an incremental increase to this load shape with a hypothetical new least-cost generation system.
- Frontier Economics estimates the LRMC of meeting the LRET and GGAS using the incremental LRMC approach (which assumes that the existing mix of generation plant, regions and interconnectors in the NEM is in place). Under this approach, the load used to estimate the LRMC is the system load in each region, and the LRMC of meeting the LRET or the GGAS is the marginal cost of an incremental increase in the relevant target.

To estimate the market-based energy purchase costs, Frontier Economics uses *STRIKE*, which identifies the least cost portfolio of electricity purchasing options for each level of risk. An important input into the estimation of energy purchase costs is a forecast of future spot prices. In order to forecast spot prices, Frontier Economics uses *SPARK*, which applies game theoretic techniques to forecast spot price outcomes.

3 Input assumptions

IPART's 2010 Determination outlines those input assumptions that IPART will review as part of its annual review process. Since IPART completed the 2010 Determination, a number of sources of new information regarding key modelling assumptions have become available.

In considering the appropriateness of these sources of modelling assumptions, Frontier Economics' advice to IPART has been guided by the same objectives as were adopted for the 2010 Determination:

- To the extent possible, Frontier Economics has adopted input assumptions that are publicly available. This increases the transparency of Frontier's modelling results
- To the extent possible, Frontier Economics has adopted input assumptions that are more likely to be used reasonably broadly across the industry. Adopting input assumptions from these sources is likely to better facilitate the comparison of Frontier Economics' modelling results with forecasts or modelling from other sources
- To the extent possible, Frontier Economics has used the most recent input assumptions available at the time the modelling is undertaken (within the constraint of using publicly available and industry standard assumptions)

One possible source of input assumptions for this annual review is the information released by AEMO as part of the 2010 National Transmission Network Development Plan (NTNDP). As part of the NTNDP, AEMO has released consultant reports on cost and technical information relevant to the NEM. These reports on cost and technical information are intended to replace the similar reports on cost and technical information that were prepared for the Inter-Regional Planning Committee (IRPC). Given that ACIL Tasman's 2009 report to the IRPC[9] was relied on as a source of input assumptions for the 2010 Determination, it might be expected that the equivalent report for the NTNDP, also by ACIL Tasman, would provide a useful source of updated input assumptions. However, the NTNDP considers the development of the NEM over the next 20 years by considering a set of five scenarios, each of which reflect "different combinations of the principal energy sector and national transmission network development drivers".[10] AEMO makes clear that none of these five scenarios is a base case but neither does each scenario have an equal probability

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9 ACIL Tasman, *Fuel resource, new entrant and generation costs in the NEM*, Final Report, Prepared for the Inter-Regional Planning Committee, April 2009 (**ACIL 2009 Report**).

10 AEMO, *National Transmission Network Development Plan*, 2010, page 22.

of occurring.[11] What this means is that no single NTNDP scenario – and therefore no single set of input assumptions – can be considered an effort to best reflect likely future outcomes in the market. Yet, for the purposes of this annual review, the input assumptions adopted should reflect a view of the most likely future outcomes.

IPART have reviewed and considered the available sources of information on input assumptions and have decided to update input assumptions by relying, to a large extent, on the following sources:

- AEMO, *Electricity Statement of Opportunities for the National Electricity Market*, 2010 (**AEMO 2010 ESOO**). This is the source for system demand forecasts used in Frontier Economics' modelling. This updates the 2009 ESOO which was relied on for the 2010 Determination.
- ACIL Tasman, *Calculation of energy costs for 2011-12 BRCI*, Draft Report, Prepared for the Queensland Competition Authority, December 2010 (**ACIL Report for the QCA**).[12] ACIL Tasman note in this report that, to a large extent, the input assumptions from the ACIL 2009 Report continue to be relevant and, for this reason, have been adopted in the ACIL Report for the QCA.

  As well as relying on the report itself, Frontier Economics has, in some cases, used input assumptions from spreadsheets accompanying the ACIL Report for the QCA that were provided to IPART by ACIL Tasman.

  It is considered that the use of this data will provide a set of modelling input assumptions that reflect an approach that is more consistent with the original 2010 Determination than would the use of the NTNDP data.

This section sets out the updated modelling assumptions that Frontier Economics has used in its modelling for this annual review. Modelling assumptions that are not explicitly discussed in this section have not been updated since the 2010 Determination.

A detailed set of input assumptions is set out in the assumptions spreadsheets released with this final report.

3.1 Inflation rate

Frontier Economics' advice to IPART in this final report is provided in 2010/11 dollars. Where it has been necessary to convert costs or prices into 2010/11 dollars, Frontier Economics has used the following inflation rates, as advised by IPART:

11 AEMO, *National Transmission Network Development Plan*, 2010, page 23.

12 At the time of writing, ACIL Tasman's final report to the QCA is not publicly available.

- 3.3% from 2009/10 to 2010/11 and from 2010/11 to 2011/12
- 3.0% for each year thereafter

The exception to this has been where converting input assumptions from the ACIL Report for the QCA into 2010/11 dollars. In this case, the inflation rate of 2.5% adopted by ACIL Tasman in that report has been used.

3.2 Discount rate

WHIRLYGIG optimises the total system costs of meeting demand over the entire modelling period. Total system costs are calculated as a net present cost in a specified base year using an assumed discount rate. The objective to be minimised by the model is the net present cost.

Frontier has assumed a pre-tax, real discount rate of 7.8% to discount future values for the optimisation process. This is consistent with IPART's advice for this annual review on the appropriate discount rate for the purposes of electricity generation assets.

3.3 System demand forecasts

System demand forecasts are used as an input to *WHIRLYGIG* under the incremental LRMC approach and are used as an input to *SPARK*.

Frontier Economics has used energy and maximum demand projections for each NEM region based on the AEMO 2010 ESOO. Frontier Economics has used the medium growth, 50% POE projections from the AEMO 2010 ESOO for the purposes of determining the energy and maximum demand projections. However, Frontier Economics has also used the medium growth, 10% POE projections for summer and winter for the purpose of modelling reserve constraints. These 10% POE projections are assumed to be 100% co-incident, implying that maximum demand occurs in each NEM region at the same time. This assumption of co-incidence is made to ensure consistency with AEMO's reported regional reserve margins in the reserve constraints.

3.4 Existing NEM generation plant

Frontier Economics has used the latest information available from AEMO's website[13] on existing and committed scheduled and semi scheduled generation plant in each region of the NEM. This provides both the identity of existing and

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13 AEMO, Tables of Existing and Committed Scheduled and Semi Scheduled Generation – by Region. Available from:

http://www.aemo.com.au/data/gendata.shtml committed generation plant and the summer and winter capacity of these generation plant.

In addition, Frontier Economics' models require key technical and cost information for existing generation plant.

The required technical information for existing generation plant includes the following:

- Expected outage rates – Frontier Economics has used the same information on outage rates as was used for the 2010 Determination (sourced from NEMMCo)
- Heat rate – Frontier Economics has used the information on the heat rate for existing generators that is set out in the ACIL Report for the QCA
- Emissions intensity – Frontier Economics has used the information on emissions intensity for existing generators that is set out in the spreadsheets accompanying the ACIL Report for the QCA that were provided to IPART by ACIL Tasman
- Auxiliary power – Frontier Economics has used the information on use of auxiliary power for existing generators that is set out in the ACIL Report for the QCA

The required cost information for existing generation plant is the following:

- Variable operating and maintenance costs – Frontier Economics has used the information on variable operating and maintenance costs for existing generators that is set out the ACIL Report for the QCA. Frontier Economics has assumed that variable operating and maintenance costs remain flat in real terms at these levels over time (which is consistent with the spreadsheet provided to IPART by ACIL Tasman)
- Fuel costs – Frontier Economics has used the information on fuel costs for existing generators that is set out the ACIL Report for the QCA. Where the fuel costs for existing generators are not stated in the ACIL Report for the QCA, Frontier has used the information on fuel costs for existing generators that is set out in the more detailed accompanying spreadsheet that was provided to IPART by ACIL Tasman

In addition to these assumptions on cost and technical information, Frontier Economics' modelling also requires information on ownership of existing generation plant. Since the 2010 Determination, the following changes have occurred, or have been announced by government:

- The NSW Energy Reform Strategy, which has resulted in the transfer of bidding control of Eraring and Shoalhaven power stations to Origin Energy and of Mt Piper and Wallerawang power stations to TRUenergy

- The Queensland Government has announced that it will restructure the three Government-owned generators in Queensland (CS Energy, Stanwell and Tarong Energy) into two Government-owned generators. The ownership of the generation assets following this re-structuring has already been set out by the Government[14]

3.5 New generation plant

Frontier Economics has used the ACIL Report for the QCA as the basis for input assumptions for new entrant generation plant.

The technologies that will be available as options over the modelling period are, therefore, black coal, brown coal, CCGT, OCGT, wind, hydro and biomass. Frontier Economics has not included geothermal as an option over the modelling period because Frontier Economics considers it unrealistic that geothermal will be available to any significant degree over the modelling period at the capital cost in the ACIL Report for the QCA (which is around $5,000/kW). At this capital cost, and taking account of the other geothermal assumptions in the ACIL Report for the QCA (particularly availability), geothermal will be lower cost than any other generation technology in the NEM once a carbon price is introduced, and will be built in preference to coal-fired generation, gas-fired generation and all other renewable technologies. It is Frontier Economics' opinion that the cost and availability of geothermal over the modelling period make it unlikely that investment in geothermal over this period will dominate investment in all other generation technologies.

As with the existing generation technologies, for each of the new entrant generation technologies Frontier Economics' models require key technical and cost information.

The required technical information for new entrant generation plant includes the following:

- Expected outage rates – Frontier Economics has used the same information on outage rates as was used for the 2010 Determination (sourced from NEMMCo)
- Heat rate – Frontier Economics has used the information on the heat rate for new entrant generators that is set out in the ACIL Report for the QCA
- Emissions intensity – information on emissions intensity for new entrant generators is not set out in the ACIL Report for the QCA. Therefore, Frontier Economics has assumed that the emissions intensity for a new plant

14 Statement from the Finance Minister, *Power station allocations*, 10 March 2011.

will be the same as the emissions intensity of the most recently built plant of the same technology

- Auxiliary power – Frontier Economics has used the information on use of auxiliary power for new entrant generators that is set out in the ACIL Report for the QCA.

The required cost information for new entrant generation plant is the following:

- Capital costs – Frontier Economics has used the information on capital costs for new entrant generations that is set out in the ACIL Report for the QCA. However, rather than using the learning curve for capital costs implied by the ACIL Report for the QCA, Frontier Economics has applied the same information on learning curves as was used for the 2010 Determination, and applied these learning curves to the capital cost for 2010/11 from the ACIL Report for the QCA
- Fixed operating and maintenance costs – Frontier Economics has used the information on fixed operating and maintenance costs for new entrant generators that is set out in the ACIL Report for the QCA. Frontier Economics has assumed that fixed operating and maintenance costs remain flat in real terms at these levels over time (which is consistent with the spreadsheet provided to IPART by ACIL Tasman)
- Variable operating and maintenance costs – Frontier Economics has used the information on variable operating and maintenance costs for new entrant generators that is set out in the ACIL Report for the QCA. Frontier Economics has assumed that variable operating and maintenance costs remain flat in real terms at these levels over time (which is consistent with the spreadsheet provided to IPART by ACIL Tasman)
- Gas costs – Frontier Economics has used the information on new entrant gas costs that is set out in the ACIL Report for the QCA
- Biomass costs – Frontier Economics has used the information on new entrant biomass costs that is set out in the ACIL Report for the QCA.
- Coal costs – neither the ACIL Report for the QCA nor the spreadsheet provided to IPART by ACIL Tasman provide new entrant coal costs. The ACIL Report for the QCA does contain a set of coal prices that ACIL uses in its LRMC modelling. However, these coal prices are simply an average of the coal prices to the existing coal-fired generators in the relevant region.

  Adopting the coal prices used by ACIL Tasman in its LRMC modelling would represent a significantly different approach to that adopted for the 2010 Determination. For the 2010 Determination, new entrant coal prices were taken from the ACIL 2009 Report, which provides, for each relevant NTNDP Zone in the NEM, forecasts of future coal prices that are based on an assessment of coal supplies and costs in those individual NTNDP Zones.

These are not simply the average coal prices faced by existing generators in those NTNDP Zones.

Similarly, adopting the coal prices used by ACIL Tasman in its LRMC modelling would represent a significantly different approach to that adopted for new entrant gas prices. For this annual review, new entrant gas prices are taken from the ACIL Report for the QCA which provides forecasts of future gas prices in each State in the NEM that are derived from modelling of gas supply and gas demand in these States, not the average gas prices faced by existing generators.

ACIL Tasman's rationale for basing its LRMC modelling on coal prices that are an average of coal prices into existing coal-fired generators is that existing coal sources will be available to new build coal-fired generators. However, even if new entrant coal-fired generators source coal from the same mines as existing coal-fired generators, it is unclear why the coal price for new entrant generators would be the same as the coal price for existing generators.

Having considered these issues, IPART have decided that the coal prices used by ACIL Tasman in their LRMC modelling for the QCA are inappropriate for the purposes of this annual review. For this reason, and in the absence of other appropriate sources for new entrant coal prices, IPART have decided that, for the purpose of this annual review, the new entrant coal price should be determined by escalating the new entrant coal prices from the ACIL 2009 Report in line with average increases in mining cost indices over the previous ten years.[15] This implies an annual increase in coal prices of 3.7% in nominal terms.

- Maximum capacity factors – Frontier Economics has used the information on maximum capacity factors that is set out in the ACIL Report for the QCA.

3.6 Carbon price

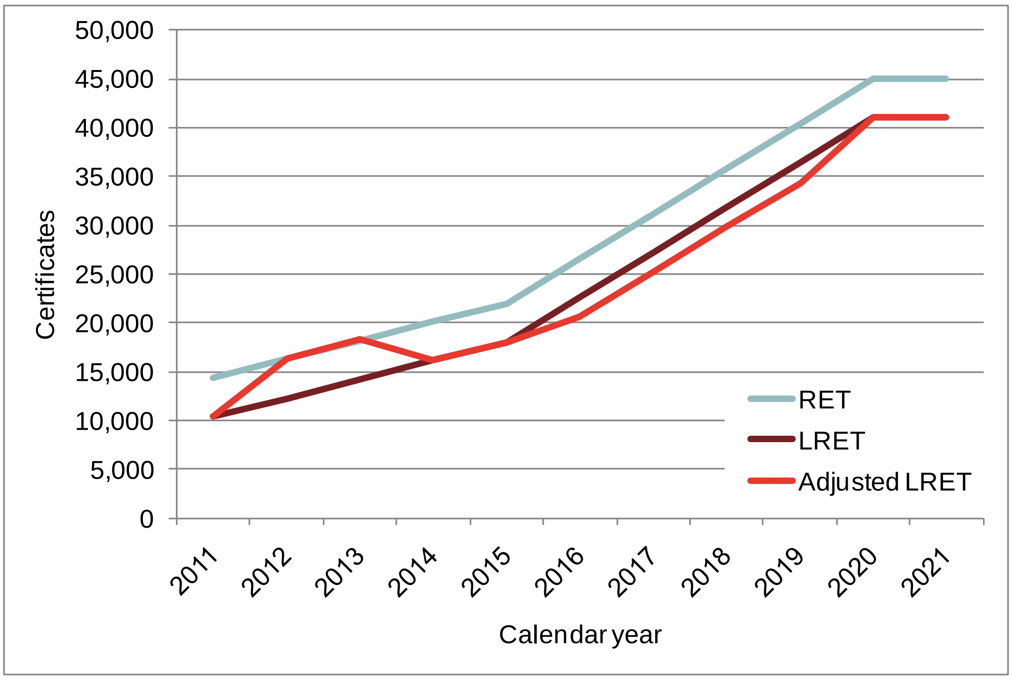
There is continued uncertainty about carbon pricing in Australia. IPART have decided that, for the purpose of this annual review, it will be assumed that a carbon price will be introduced from the beginning of 2013/14, and that the carbon price each year from 2013/14 will be the same carbon price assumed for the 2010 Determination (which was based on Commonwealth Treasury estimates).

15 The index for open cut mining and the index for underground mining, both from the ABS' Producer Price Index, have been used to determine an average increase in mining costs over the previous ten years. The two indices have been given an equal weight.

3.7 LRET target

Since the 2010 Determination, the RET scheme has been split into the Large-scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES). As part of this process the RET target has been amended to come up with the LRET target and the adjusted LRET target (which accounts for the surplus of RECs available at the end of 2010). Figure 2 shows the RET target, the LRET target and the adjusted LRET target. The adjusted LRET target has been used in Frontier's modelling for this annual review.

Figure 2: LRET target



Source: ORER, Frontier Economics.

4 Long run marginal cost

The LRMC of generating plant is typically determined on the basis of the least economic cost mix of plant to meet the required load to a particular security standard.

This section sets out the results of the LRMC modelling of generating plant to serve the regulated load of the Standard Retailers, including:

- a brief re-statement of Frontier Economics' approach to estimating the LRMC of the Standard Retailers' regulated load
- the results of the LRMC modelling
- a comparison between the LRMC estimated for this final report and the LRMC estimated for the 2010 Determination
- an overview of investment and dispatch outcomes from the LRMC modelling

4.1 Approach to estimating the LRMC

As discussed in the Frontier Final Report for 2010, there are two broad approaches to estimating the LRMC:

- Stand-alone LRMC – this approach assumes that there is currently no plant available to serve the required load. This approach effectively builds, and prices, a whole new least-cost generation system to meet the required load. This approach has the effect of re-pricing all existing capacity at efficient levels.
- Incremental LRMC – this approach assumes that the existing mix of generation plant in the system is in place and that the required load can be served using both existing generation plant and new generation plant. Under this approach, new generation plant is only built if it is required as part of a least-cost generation system to meet the required load. This approach prices load on the basis of the least cost way of adding to the existing stock of plant

Frontier Economics estimates the LRMC of serving the Standard Retailers' regulated load using the stand-alone LRMC approach. Under this approach, the load used to estimate LRMC is the Standard Retailers' regulated load, and the LRMC is the cost of serving an incremental increase to this load shape with a hypothetical new least-cost generation system.[16]

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16 In effect, the LRMC is calculated by adding to the regulated load an increment that is the same shape as the regulated load. This ensures that the LRMC reflects the fixed and variable costs associated with the mix of plant that is efficient, given the shape of the regulated load.

4.2 LRMC results

Results for the stand alone LRMC approach are set out in Table 1, for both the draft report and this final report.

Table 1: Stand-alone LRMC results ($2010/11)

Financial Year	Draft Report LRMC ($/MWh)	Final Report LRMC ($/MWh)
Country Energy		
2011/12	$63.06	$62.60
2012/13	$63.26	$62.80
EnergyAustralia		
2011/12	$67.09	$66.59
2012/13	$66.57	$66.08
Integral Energy		
2011/12	$70.38	$69.86
2012/13	$70.60	$70.08

Source: Frontier Economics

Note: the differences between the results from the draft report and final report are a result of the revised WACC.

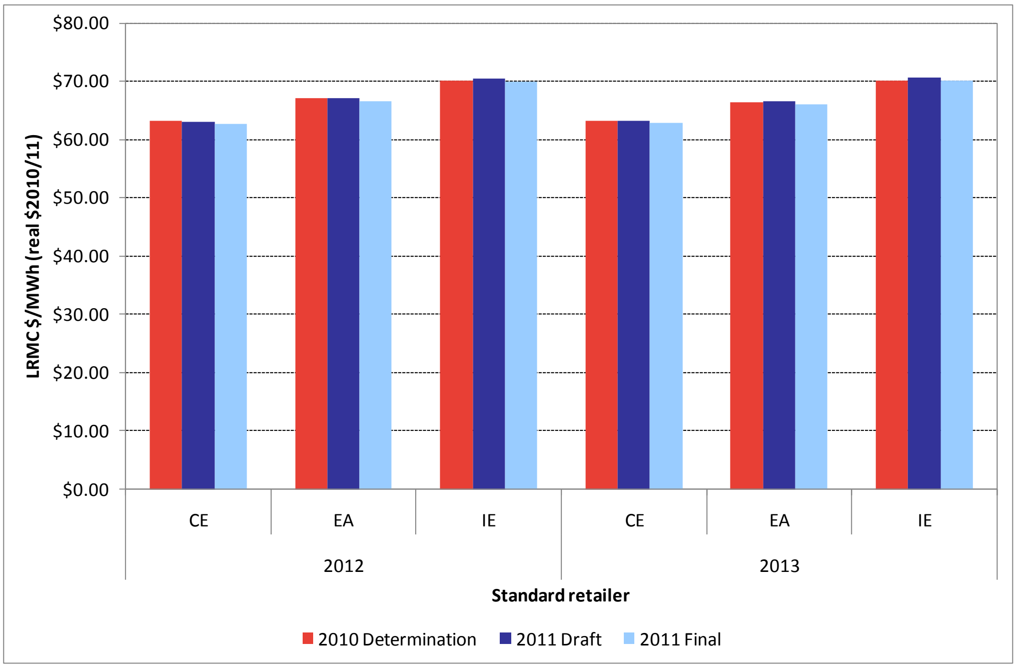
For both 2011/12 and 2012/13 the LRMC for the three businesses is in the range of around $60-$70/MWh. There is little change in the LRMC from 2011/12 to 2012/13. This is consistent with the assumed input costs being relatively constant in real terms. The change in LRMC from 2011/12 to 2012/13 is certainly less than for the base case from the 2010 Determination. This is because the modelling for this draft report assumes that a carbon price is not introduced until 2013/14, while the base case from the 2010 Determination assumed a carbon price commencing in 2011/12 and increasing in 2012/13.

For all years the LRMC determined for the businesses is highest for Integral Energy and lowest for Country Energy. This is consistent with the 2010 Determination and reflective of the load shapes of the businesses. Integral Energy's regulated load is relatively peaky due to it containing the majority of western Sydney's temperature-sensitive load. Conversely, Country Energy's regulated load is more geographically diverse leading to an overall flatter load. EnergyAustralia's regulated load lies in the middle of these two businesses.

4.3 Differences relative to the 2010 Determination

Results for the stand-alone LRMC approach from this draft report are compared with the equivalent results (from the no carbon scenario) from the 2010 Determination and the draft report in Figure 3. As can be seen, there is very little change in the LRMC results from the 2010 Determination to this annual review. This reflects the fact that most of the key cost input assumptions have not changed significantly since the 2010 Determination: the regulated load shape has not been updated as part of this annual review and updates to input assumptions for cost and technical details for new entrant generation plant have been relatively minor. That the LRMC has moved slightly higher for some retailers, but slightly lower for other retailers, is explained by the different movements in cost inputs for different generation technologies and the different investment and dispatch outcomes for each retailer (as discussed further in the next section).

Figure 3: Stand-alone LRMC results compared to 2010 Determination ($2010/11)



Source: Frontier Economics

4.4 Investment and dispatch outcomes

This section provides the investment and dispatch outcomes associated with the stand-alone LRMC modelling, for each Standard Retailer and each of 2011/12 and 2012/13.

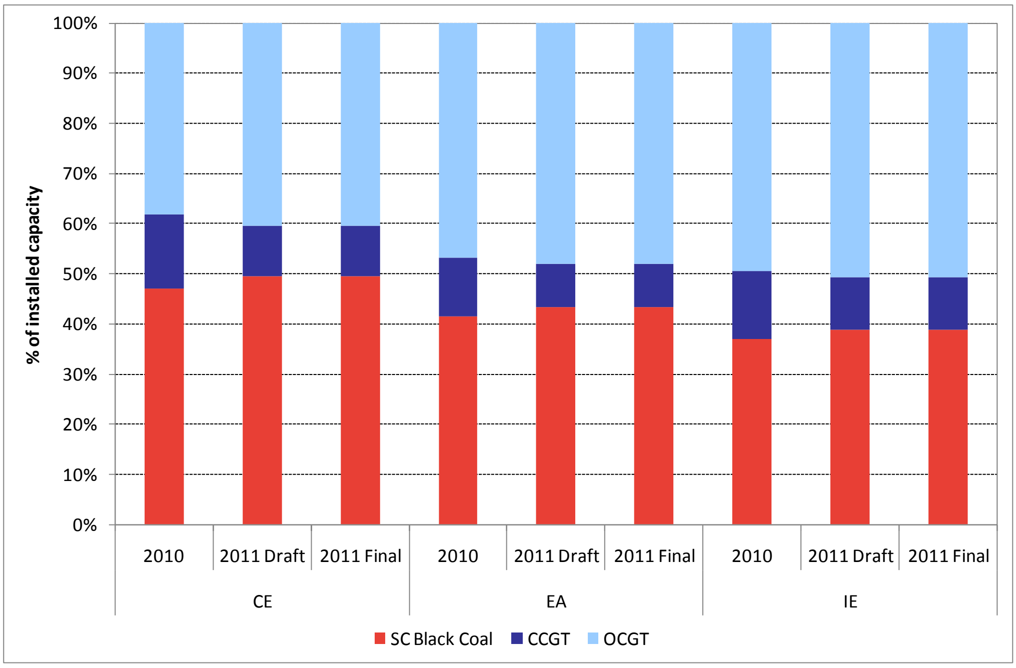
As discussed in the Frontier Final Report for 2010, in considering the investment and dispatch outcomes associated with the stand-alone LRMC modelling, it is important to note that under this approach the system that is built to serve the Standard Retailers' regulated load is optimised each year. This is important because in cases where the regulated load is falling over time, if the system is not optimised each year the resulting LRMC would reflect excess capacity in the later years of the Determination, and may not include a capital cost component. Because the system is optimised each year, changes in patterns of investment and dispatch from year to year are more pronounced than would be expected in the actual system where investments require long lead times and, once committed, plant will remain in the system until it is retired. These investment constraints are reflected in Frontier Economics' modelling under the market-based approach.

Figure 4 provides investment outcomes for each Standard Retailer in 2011/12. These results are similar to the results from the 2010 Determination (from the no carbon scenario). The investment mix across the Standard Retailers in 2011/12 is roughly 40-50% coal, 10-15% CCGT and the residual capacity is OCGT. Compared to the results from the 2010 Determination, the investment mix for this annual review results in slightly more investment in coal-fired generation plant, because the slight changes in cost input assumptions for this annual review have coal becoming relatively cheaper compared to gas.

Figure 5 provides dispatch outcomes for each Standard Retailer in 2011/12. The dispatch results reflect the investment outcomes, and again are little changed from the 2010 Determination. Compared to the results from the 2010 Determination, output from coal-fired generation plant has increased slightly because the slight changes in cost input assumptions for this annual review have coal becoming relatively cheaper compared to gas.

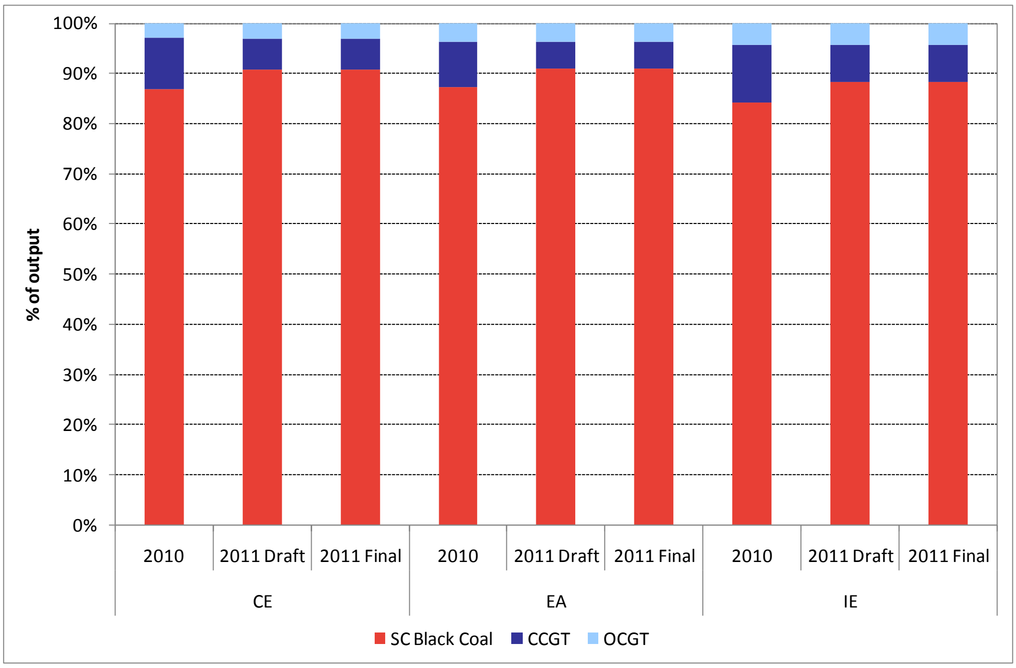
The patterns of investment and dispatch across the Standard Retailers reflect the load shape of the retailers. Peakier regulated loads, such as those of Integral Energy and EnergyAustralia, result in greater investment in OCGT plant. Flatter loads, such as Country Energy's, result in relatively less investment in OCGT plant.

Figure 4: Investment outcomes – stand-alone LRMC



Source: Frontier Economics

Figure 5: Dispatch outcomes – stand-alone LRMC



Source: Frontier Economics

4.5 Response to submissions

Both AGL and TRUenergy note in their submissions that they consider that cost input assumptions developed as part of the NTNDP process should be used in preference to cost input assumptions from the ACIL Report for the QCA. Based on some initial LRMC modelling, Frontier Economics estimates that the effect of adopting input assumption developed as part of the NTNDP in preference to cost input assumptions from the ACIL Report for the QCA would be to increase the stand-alone LRMC by around $7 to $8/MWh for each of the Standard Retailers.

5 Market-based energy purchase cost

Market-based energy purchase costs are the costs that retailers face in buying energy from the wholesale market, including the hedging contracts that retailers enter into to manage their risk. The estimation of market-based energy purchase costs can be separated into two broad steps:

- forecasting spot and contract prices
- based on these forecast prices, and the regulated load that the Standard Retailers supply, determining an efficient hedging strategy and the cost and risk associated with that hedging strategy

This section sets out the results of Frontier Economics' approach to estimating market-based energy purchase costs for the Standard Retailers, including:

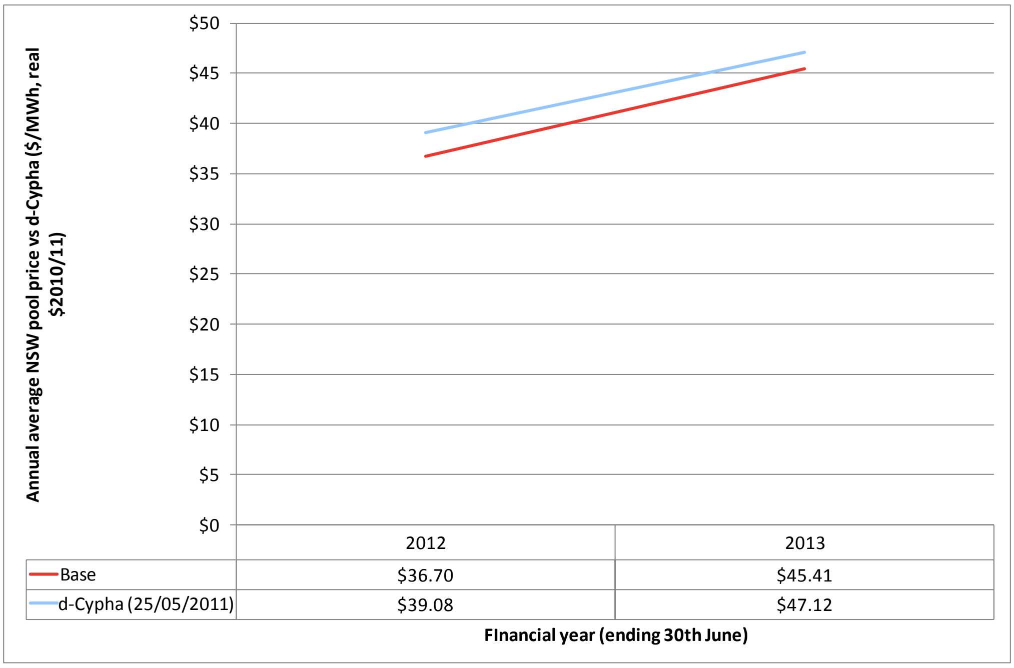
- a brief re-statement of Frontier Economics' approach to estimating market-based energy purchase costs
- the results of Frontier Economics' modelling of spot prices and of the market-based energy purchase cost
- a comparison between the results from this draft report and the results from the 2010 Determination
- the results of Frontier Economics' modelling of the volatility allowance

5.1 Spot and contract price forecasts

As discussed in the Frontier Final Report for 2010, Frontier Economics uses *SPARK* to forecast spot electricity prices. Like all electricity market models, *SPARK* reflects the dispatch operations and price-setting process that occurs in the NEM. Unlike other models, however, generator bidding behaviour is a modelling output from *SPARK*, rather than an input assumption. That is, *SPARK* calculates a set of optimal (i.e. sustainable) generator bids for all representative market conditions. As the market conditions change, so does the optimal set of bids. *SPARK* finds the optimal set using standard game theoretic techniques.

Price forecast results for the NSW region from *SPARK* are presented in Figure 6.

Figure 6: NSW annual average price forecast ($2010/11)



Source: Frontier Economics

For the purpose of comparison, Figure 6 also shows the d-cyphaTrade forward prices for flat annual swaps in NSW as of May 25. The d-cyphaTrade prices provide an indication of the market view on future contract prices (and, by association, pool prices).

It is clear from Figure 6 that Frontier Economics' spot price forecasts are close to the current d-cyphaTrade prices. Adjusting for the fact that Frontier Economics' forecasts are spot price forecasts (by applying Frontier Economics' assumption of a 5% contract premium) Frontier Economics' market-based price forecasts are around $0.50 below the equivalent d-cyphaTrade price for 2011/12 and are around $0.50 higher than the equivalent d-cyphaTrade price for 2012/13. Also, for 2012/13, it is likely that the d-cyphaTrade price incorporates some expectation of a carbon price being in place by that time, while Frontier Economics' prices are modelled on the assumption that a carbon price will not be introduced until 2013/14.

5.2 Market-based energy purchase costs

As discussed in the Frontier Final Report for 2010, Frontier Economics uses *STRIKE* to determine the efficient mix of hedging products that retailers would enter into over the period of the determination, and the energy costs and risks associated with each of these efficient mixes.

This section presents the results of Frontier Economics' *STRIKE* modelling. Results are presented as follows:

- efficient frontiers for 2011/12 and 2012/13 for each Standard Retailer
- market-based energy purchase costs for 2011/12 and 2012/13 for each Standard Retailer

Consistent with the approach adopted for the 2010 Determination, the efficient frontiers (and therefore the market-based energy purchase costs) for each Standard Retailer have been calculated by using *STRIKE* to optimise over three sets of load-price shapes that capture the volatility of prices and load, and the correlation between the two. That is, *STRIKE* finds an optimal contracting position taking into account the possibility of three alternate versions of the future.

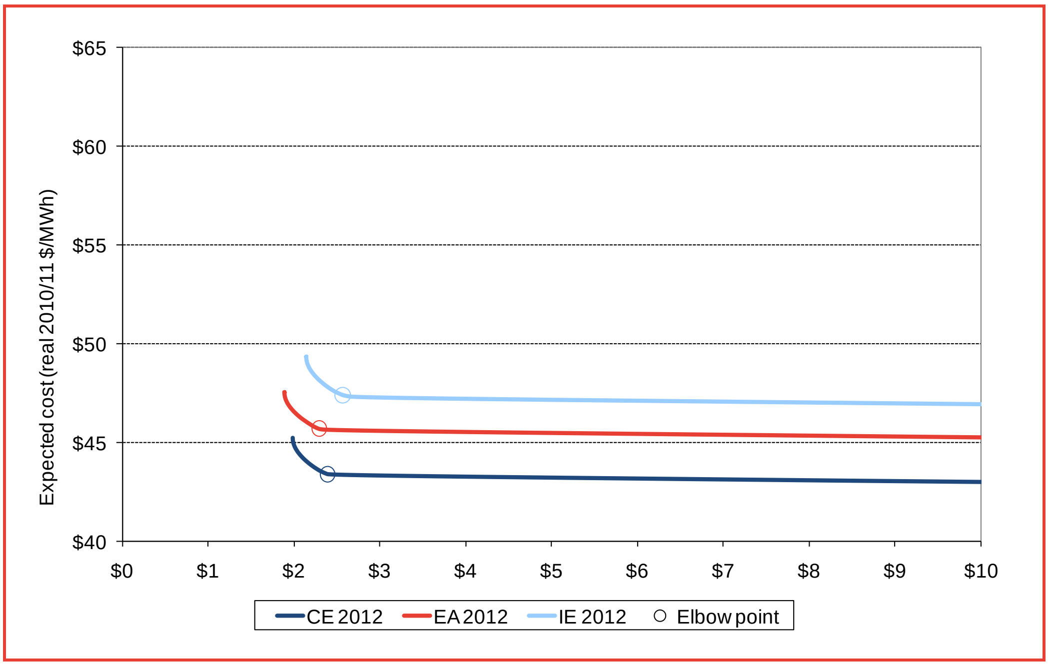
5.2.1 Efficient frontiers

For the financial years 2011/12 and 2012/13 and for each Standard Retailer, the efficient frontier of contracting options has been calculated. This frontier is a representation of the expected purchase cost and the associated risk (as measured by standard deviation) of a set of contracts that minimise risk whilst maximising return (minimising purchase cost). Each point on the efficient frontier is associated with a specific mix and quantity of contracts.

Figure 7 and Figure 8 show the efficient frontiers for each year, for each business. The vertical axes of these figures represent the expected annual average energy purchase cost (in $/MWh) for the efficient (lowest cost) mix of energy purchasing options at a given level of risk. The horizontal axes of these figures represent risk as the standard deviation of the energy purchase costs (in $/MWh) for each level of efficient costs. These cost efficient frontiers slope downwards to the right, indicating that the least risky position is also associated with the highest energy cost. This result is intuitively obvious – that is, more price insurance costs more money.

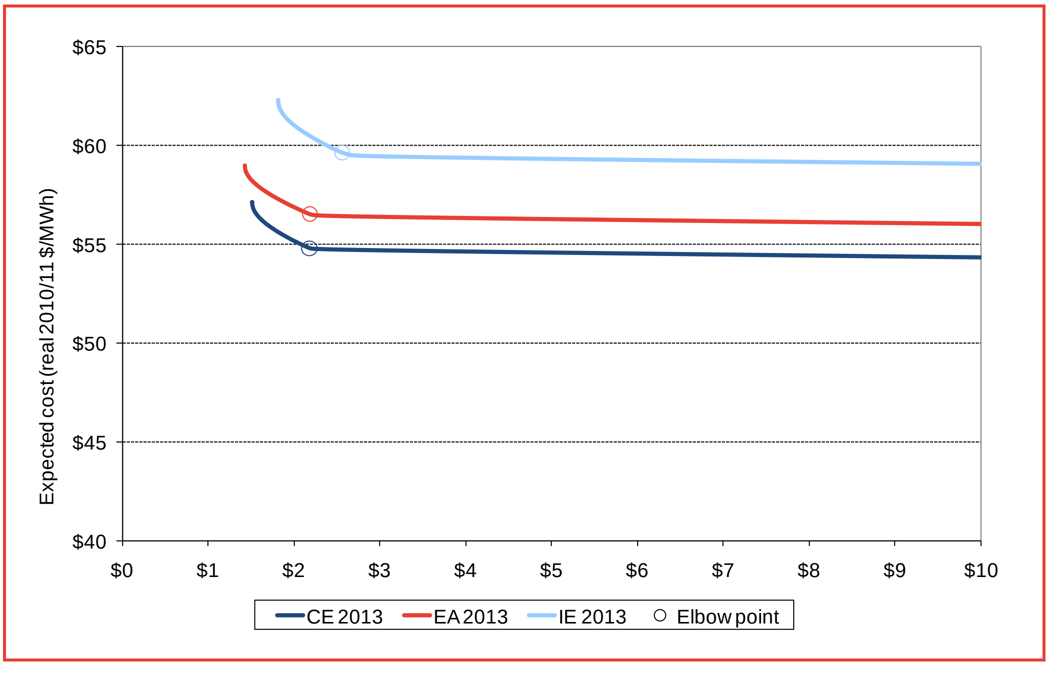
On each frontier an elbow point has been defined. The elbow point denotes the point on the frontier where the rate of change in the slope of the frontier is maximised (i.e. second order derivative of the frontier). This elbow point indicates the position on the frontier where costs are lowest for a given increase in risk. The least risky position (i.e. most conservative) is the point furthest to the left of the efficient frontier.

Figure 7: Efficient frontiers – 2011/12 ($2010/11)



Source: Frontier Economics

Figure 8: Efficient frontiers – 2012/13 ($2010/11)



Source: Frontier Economics

5.2.2 Market-based energy purchase costs

Consistent with the approach from the 2010 Determination, market-based energy purchase costs are based on the conservative points on the efficient frontiers.

The market-based energy purchase costs presented are comprised solely of the pool purchase cost of the Standard Retailers' regulated load and the premiums and difference payments made on the optimal set of contracts as determined by *STRIKE*. These are summarised in Table 2. The costs presented correspond to the conservative point on the efficient frontier for each business.

Table 2: Market-based energy purchase cost results ($2010/11)

Financial Year	EPC ($/MWh)
Country Energy	
2011/12	$45.23
2012/13	$57.12
EnergyAustralia	
2011/12	$47.52
2012/13	$58.97
Integral Energy	
2011/12	$49.36
2012/13	$62.34

Source: Frontier Economics

In 2011/12 the market-based energy purchase costs are in the order of $45/MWh to $50/MWh at the conservative point. This is consistent with a spot price in the order of $37/MWh, a 5 per cent contract premium and the effect of the load shape of each business on purchasing cost. The same ranking between the businesses as seen in the LRMC results – Integral Energy most expensive, followed by EnergyAustralia and then Country Energy as the cheapest – is maintained. This reflects the relative peakiness of the load shapes of the three businesses.

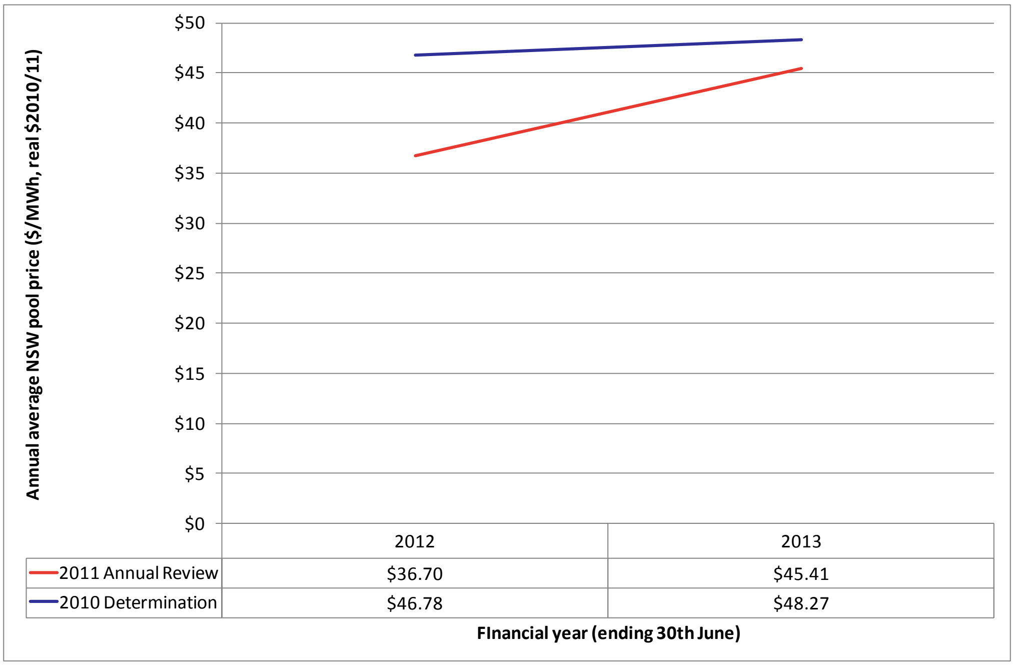
In 2012/13 the market-based energy purchase costs for each Standard Retailer increase in the order of $12/MWh. This is due to the forecast increase in spot prices (and therefore contract prices) for 2012/13. The market-based energy purchases costs in 2012/13 – ranging from around $57/MWh to $63/MWh – are consistent with a spot price in the order of $45/MWh, a 5 per cent contract premium and the effect of the load shape of each business on purchasing costs.

5.3 Differences relative to the 2010 Determination

5.3.1 Differences in price forecasts

Price forecast results from this final report are compared with the equivalent results (from the no carbon scenario) from the 2010 Determination in Figure 9. As can be seen in Figure 9, the wholesale price forecasts for this final report are lower than the prices forecast for the no carbon scenario of the 2010 Determination, particularly in 2011/12.

Figure 9: NSW annual average price forecast ($2010/11)



Source: Frontier Economics

There are four main changes in input assumptions used for this final report that drive this outcome:

- the assumed NSW peak demand level is lower
- the market is arguably more competitive due to Delta Electricity being effectively split following the NSW Energy Reform

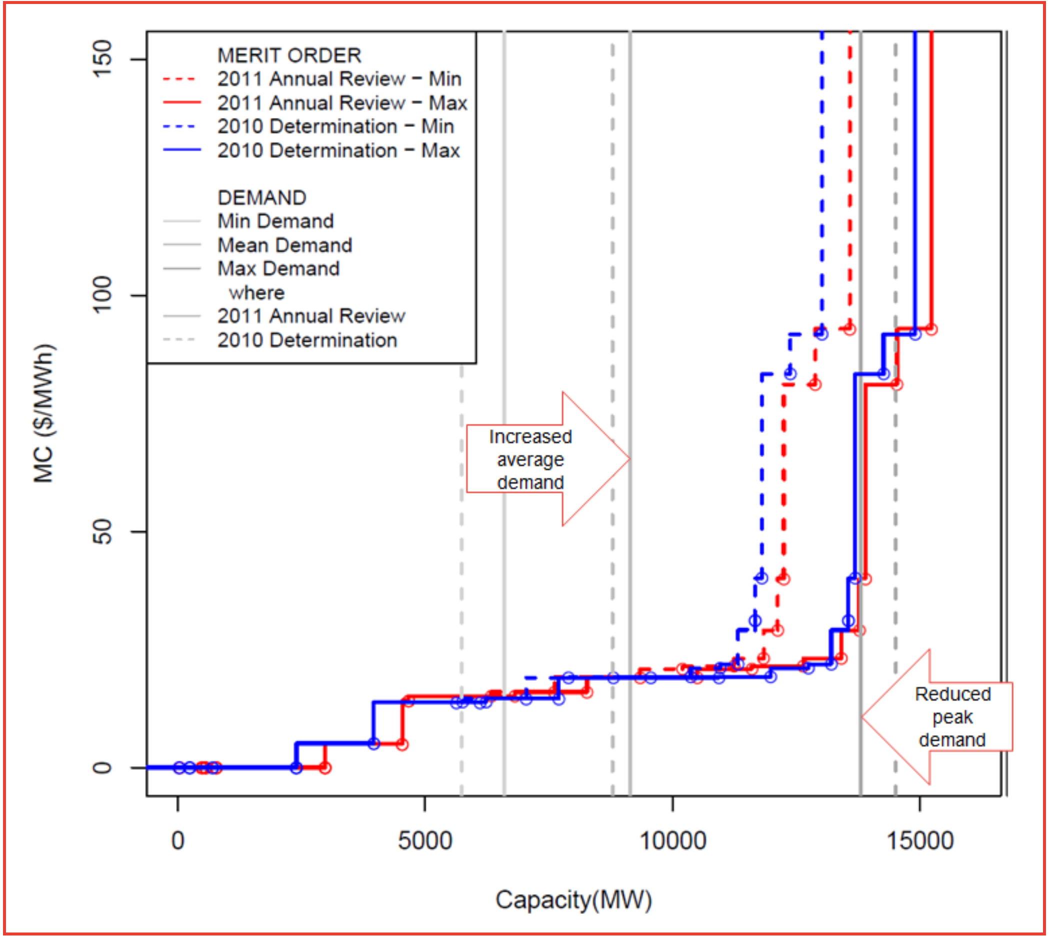
- there is slightly more capacity in NSW due to recently committed plant and upgrades
- assumed gas prices for existing gas-fired generators in the southern States are generally lower in the ACIL Report for the QCA than in the ACIL 2009 Report

By far the most important driver is the reduction in assumed peak demand levels. In the 2010 Determination, IPART decided that the high growth scenario from the AEMO 2009 ESOO was the most appropriate forecast of system demand. This decision was based on the observation that the forecasts for the AEMO 2009 ESOO were unduly pessimistic regarding the impact of the global financial crisis such that the medium growth scenario from the AEMO 2009 ESOO was likely to understate demand levels. The high growth scenario provided what was considered to be the best forecast of 2010/11 demand levels. However the demand in later years then grew at a relatively rapid rate. For the purpose of this draft report, IPART has decided that the medium growth scenario from the AEMO 2010 ESOO is the best available forecast as it best represents what is most likely to occur, a view that Frontier Economics supports. This being the case, the demand modelled has a higher energy and average demand level, due to the AEMO 2010 ESOO reflecting more current information regarding the impact of the GFC, and lower peak demand levels, as the growth in peak demand is lower under the medium growth rate. Annual prices are driven more by peak demand levels than by average levels resulting in lower forecast prices.

Figure 10 and Figure 11 show the supply demand balance curves from the modelling undertaken for this final report, compared to those for the 2010 Determination (no carbon scenario). Supply is represented by the modelled NSW SRMC merit order supply, where the 2011 Annual Review is shown in red and the 2010 Determination in blue. The curves are shown for both the maximum and minimum capacity offered into the market; *SPARK* models capacity bidding within these ranges. Three levels of assumed demand are also shown as vertical lines – minimum, mean and maximum. The 2011 Annual Review numbers are shown as solid lines and the 2010 Determination are displayed as dotted lines.

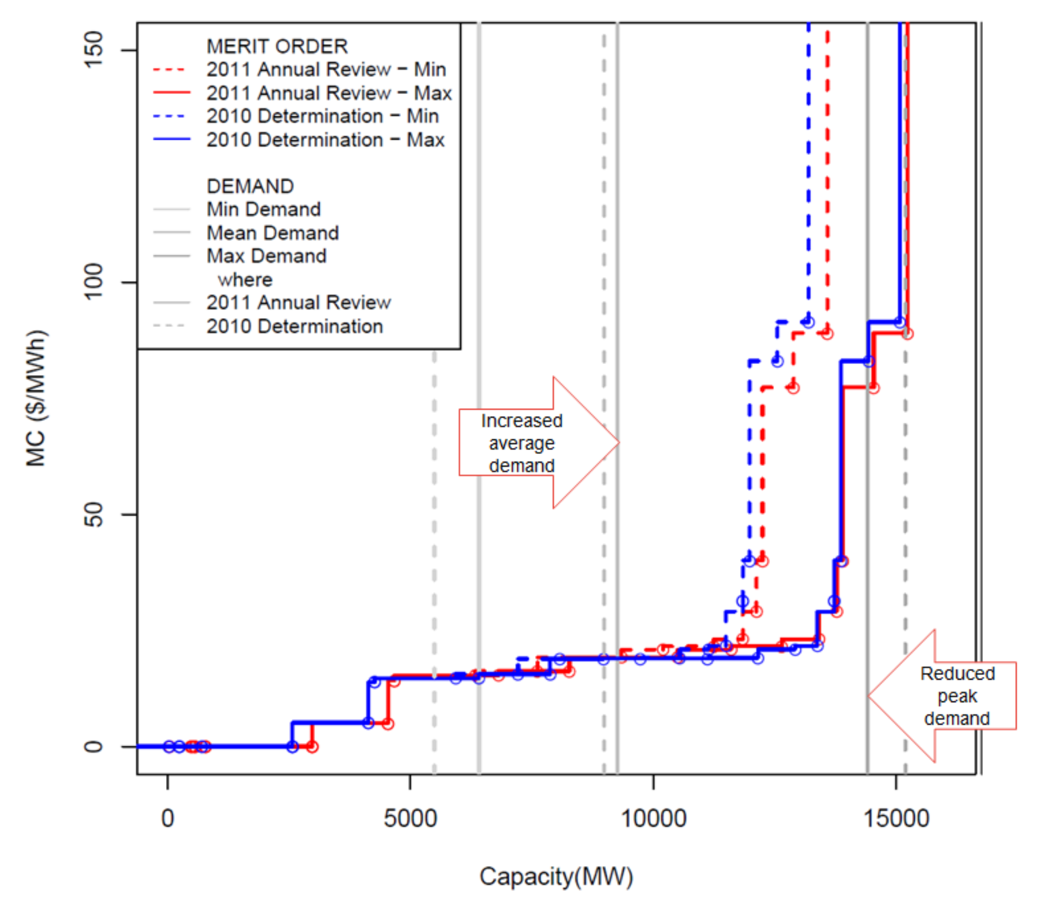
The supply demand balance curves demonstrate the key assumption changes that have led to lower estimates of pool prices in for this draft report – NSW peak demand is significantly lower and NSW supply is higher. The lower forecast pool prices are entirely consistent with the change in assumptions in the model.

Figure 10: NSW supply demand balance 2011/12



Source: Frontier Economics

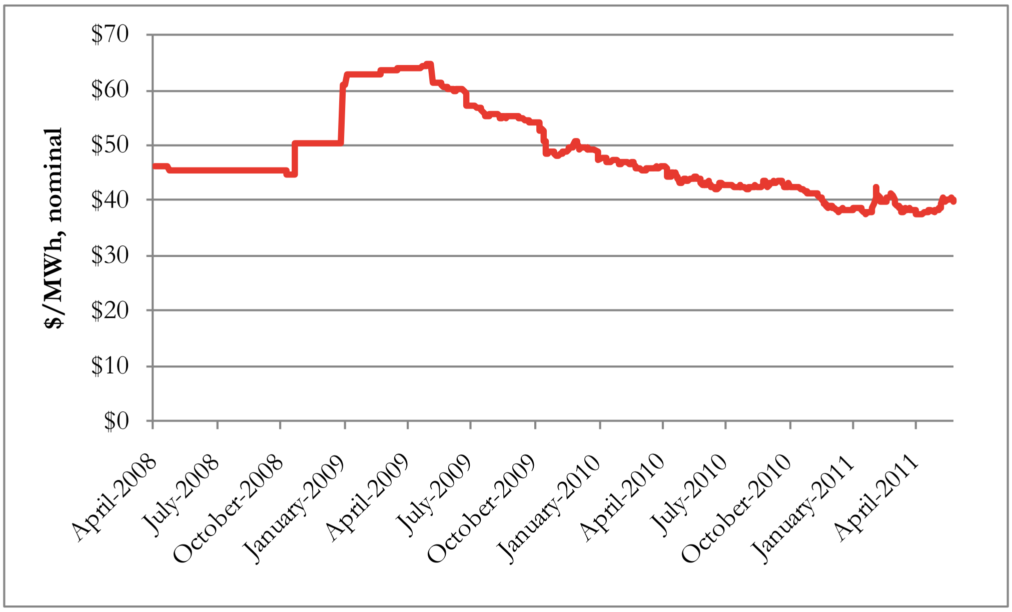
Figure 11: NSW supply demand balance 2012/13



Source: Frontier Economics

Just as Frontier Economics' wholesale spot price forecasts for 2011/12 have fallen since the 2010 Determination, dcypha-Trade NSW flat swap forward prices for 2011/12 have also come down over the same period. Figure 12 shows a time series for dcypha-Trade NSW flat swap forward prices for 2011/12, over the period from April 2008 to 25 May 2011. During the period when the 2010 Determination was being carried out (late 2009 and early 2010), dcypha-Trade prices were between $45 and $50. As of 25 March 2011, dcypha-Trade prices had fallen to around $40. While it is difficult to draw firm conclusions about what is driving changes in dcypha-Trade prices, Frontier Economics expects that, among other things, these prices have been responding to the same factors discussed above: changing expectations about demand, changes in generation plant and costs, and changes in industry structure.

Figure 12: dcypha-Trade NSW flat swap forward prices for 2011/12 (nominal)

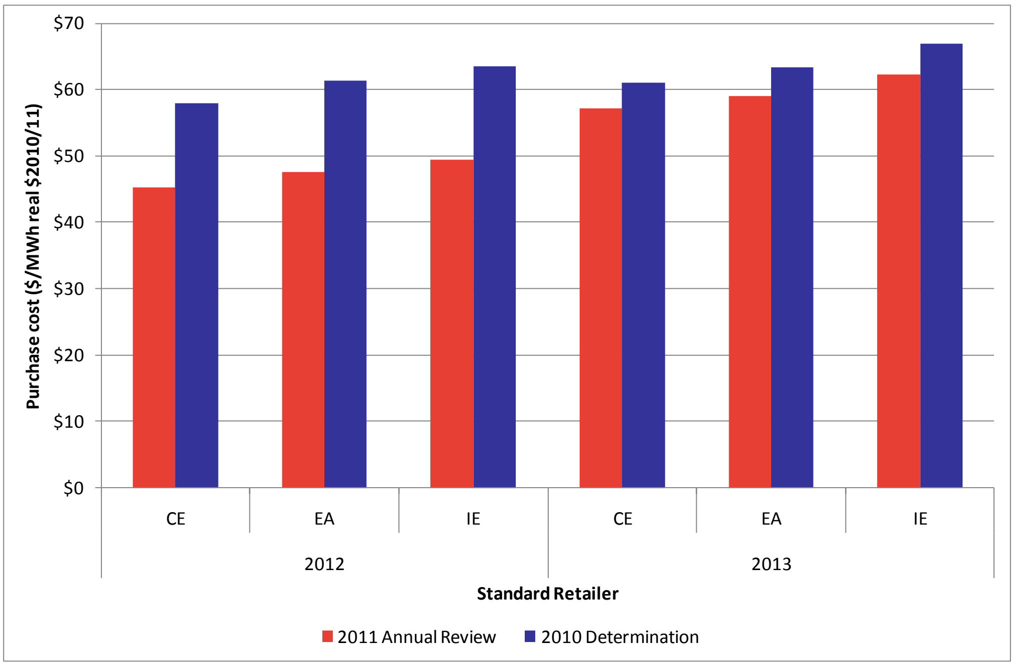


Source: dcypha-Trade

5.3.2 Differences in market-based energy purchase costs

Results for the market-based energy purchase costs from this final report are compared with the equivalent results (from the no carbon scenario) from the 2010 Determination in Figure 13. In contrast to the LRMC results from this final report, the market-based energy purchase costs from this final report have changed materially since the 2010 Determination. For both 2011/12 and 2012/13 the market-based energy purchase costs from this final report are lower than the equivalent market-based energy purchase costs from the 2010 Determination: for 2011/12 the purchase cost is now around $12/MWh to $14/MWh lower and for 2012/13 the purchase cost is now around $3/MWh to $4/MWh lower. These changes are a direct result of the updated spot price forecasts discussed above, which are in turn driven by changes in assumed peak demand.

Figure 13: Market-based energy purchase cost results compared to 2010 Determination ($2010/11)



Source: Frontier Economics

5.4 Response to submissions

Contract premium

AGL notes in its submission that Frontier Economics has not provided stakeholders with any detail in respect of the contract prices used in its modelling.

For clarity, Frontier Economics noted in its draft report that it used a 5% contract premium (relative to spot prices) to determine contract prices. Frontier Economics also noted that it used a 5% contract premium in its reporting for the 2010 Determination.

Movements in Frontier Economics' forecasts

AGL notes in its submission that Frontier Economics' forecasts of spot prices have moved significantly between the 2010 Determination and this annual review. AGL comments that it assumes that one of the benefits of modelled prices is that prices remain stable over time and that the fact that Frontier Economics' prices have changed between the 2010 Determination and this annual review call into question the validity of using modelled prices.

Frontier Economics does not consider that prices remaining stable over time would be a benefit of modelled prices. Indeed, Frontier Economics considers that if modelled prices did remain stable over time despite significant changes in the market, *this* would call into question the validity of using modelled prices.

Comparisons between Frontier Economics' forecasts and historic spot prices

AGL notes in its submission that Frontier Economics' forecast spot price for 2011/12 is different from historic spot prices between 2000/01 and 2009/10. In particular, AGL notes that Frontier Economics' forecast spot price for 2011/12 is 17% below the historic spot price in 2009/10.

In Frontier Economics' view, historic spot prices do not provide a particularly useful predictor of future spot prices. Indeed, the very variability of historic spot prices seen in AGL's analysis clearly supports the point that prices in the electricity market vary over time in response to changes in demand and supply. It is for this reason that both retailers and IPART have supported reviewing the energy purchase cost allowance as part of these annual reviews.

Frontier Economics considers that a more useful comparison is between Frontier Economics' forecast spot prices for 2011/12 and forward contract prices for 2011/12. This is why Frontier Economics has always provided IPART with a comparison of its forecast spot prices with the relevant dcypha-Trade contract prices.

Comparisons between Frontier Economics' forecasts and dcypha-Trade contract prices

AGL and TRUenergy both note in their submissions that Frontier Economics' forecast spot prices should be compared with average market prices over a two year period rather than a market price at a point in time. AGL and TRUenergy both state that the reason for this is that retailers hedge their load over time.

Frontier Economics recognises that retailers may well purchase contracts over time, but economic decisions are made on the basis of current value, not historic costs.

5.5 Volatility allowance

As discussed, even hedging the Standard Retailer's load consistent with the conservative point on the efficient frontiers will leave an element of risk in the Standard Retailers' portfolios. The volatility allowance is intended to compensate for this residual risk.

Consistent with the approach in the 2010 Determination, the volatility allowance is calculated based on the cost of holding working capital to fund cashflow shortfalls that could arise at times which the actual market-based energy purchase cost is below the expected market-based energy purchase cost. The working capital requirement is based on the standard deviation associated with the conservative point of each retailer's frontier. More specifically, Frontier Economics has estimated the difference between the expected market-based energy purchase cost and the expected purchase cost plus 3.5 standard deviations from the expected value.[17] We then estimate the cost of holding sufficient working capital, applying a WACC of 7.8%, to fund a shortfall of this magnitude.

5.5.1 Volatility allowance results

The volatility allowances calculated using this framework are set out in Table 3, for both the draft report and this final report. The differences in the volatility allowances between the Standard Retailers and the years are consistent with the risk associated with the conservative point on the relevant efficient frontier.

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17 The amount of working capital allowed for each year was calculated as 3.5 times the standard deviation in energy costs. If energy costs were normally distributed, energy costs would only ever exceed 3.5 standard deviations above the expected cost about 1 in every 3000 years, or 99.97% confidence level. However, the energy cost distributions are slightly skewed, with a marginally higher probability of high cost outcomes compared to a normal distribution. Allowing for this, a conservative estimate of the confidence level associated with a 3.5 standard deviation working capital allowance would be 1 in every 200 years, or 99.5%. The working capital cost was therefore calculated as 3.5 times the standard deviation (at the conservative point of the frontier) times the annual cost of capital (WACC). For example, if the standard deviation was $3/MWh, the amount of working capital allowed each year would be 3.5 x $3/MWh = $10.50/MWh. Assuming a WACC of 10%, the annual cost of holding the working capital would be $10.50 x 10% = $1.05/MWh.

Table 3: Volatility allowance results ($2010/11)

Financial Year	Draft Report Volatility premium ($/MWh)	Final Report Volatility premium ($/MWh)
Country Energy		
2011/12	$0.56	$0.54
2012/13	$0.42	$0.41
EnergyAustralia		
2011/12	$0.53	$0.52
2012/13	$0.40	$0.39
Integral Energy		
2011/12	$0.60	$0.59
2012/13	$0.51	$0.50

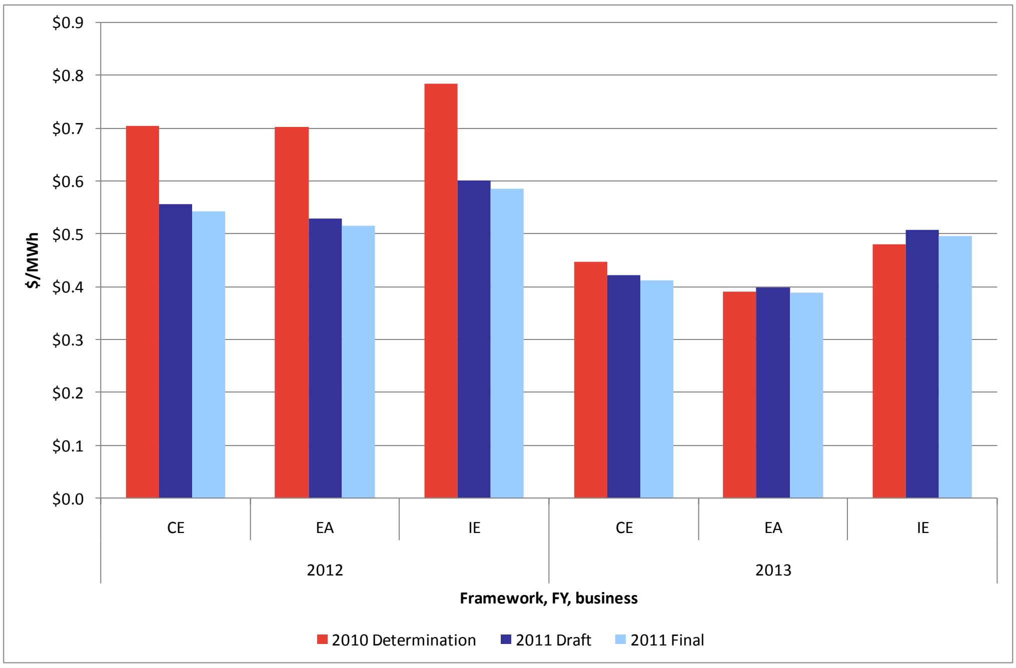
Source: Frontier Economics

Note: the differences between the results from the draft report and final report are a result of the revised WACC.

5.5.2 Differences relative to the 2010 Determination

Results for the volatility allowance from this final report are compared with the equivalent results (from the no carbon scenario) from the 2010 Determination in Figure 14. For the most part, the volatility allowances from this final report are lower than the volatility allowance from the 2010 Determination. In part this is because the spot price forecasts and resulting market-based energy purchase costs for this final report are lower than from the 2010 Determination. However, because the risk associated with the conservative point depends on the correlation between spot prices and the Standard Retailer's load, a lower average spot price will not necessarily lead to lower risk at the conservative point on the efficient frontier. This is evident for EnergyAustralia and Integral Energy in 2012/13. For these retailers, even though the expected energy purchase cost at the conservative point is lower, the risk associated with the conservative point is slightly increased, resulting in a slight increase in the volatility allowance.

Figure 14: Volatility allowance results compared to 2010 Determination ($2010/11)



Source: Frontier Economics

5.5.3 Response to submissions

TRUenergy notes in its submission that it has little confidence in Frontier Economics' calculation of the volatility premium because the volatility premium is lower in 2012/13 than in 2011/12 despite there being a very similar incidence of high prices in 2012/13 and 2011/12.

Importantly, the volatility premium is not determined solely by the incidence of high prices. The volatility premium is determined by the distribution of the Standard Retailers' energy purchase costs, where these energy purchase costs account for pool prices as well as contract payments. So, while the incidence of high prices will have an effect on the volatility premium, so will the correlation between demand and prices and the extent to which exposure to spot prices can effectively be managed by entering into hedge contracts.

6 LRET, SRES, GGAS and the ESS

In addition to reviewing the energy purchase cost allowance for 2011/12 and 2012/13, Frontier Economics scope of work also includes reviewing estimates for a range of other energy-related costs that Standard Retailers will face over the period of the determination.

This section considers the costs that Standard Retailers will face in 2011/12 and 2012/13 as a result of the following related schemes:

- the LRET
- the SRES
- the GGAS
- the ESS

Where the 2010 Determination considered the cost associated with the expanded RET, with the splitting of the expanded RET into the LRET and the SRES this annual review considers both the cost to the Standard Retailers of complying with the LRET and the cost to the Standard Retailers of complying with the SRES.

6.1 LRET

The LRET is essentially a continuation of the RET. The LRET places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the generation of additional renewable electricity from large-scale generators. Liable entities support additional renewable generation through the purchase of Large-scale Generation Certificates (LGCs). The number of LGCs to be purchased by liable entities each year is determined by the Renewable Power Percentage (RPP), which is set each year by the Office of the Renewable Energy Regulator (ORER). LGCs are created by eligible generation from renewable energy power stations.

The key difference between the RET and the LRET is that small-scale installations such as solar water heaters, air sourced heat pumps and small generation units, which were eligible to create certificates under the RET, are not eligible to create LGCs under the LRET. Instead, these small-scale installations are eligible to create certificates under the SRES.

6.1.1 Approach to estimating costs of complying with the LRET

In order to calculate the cost to a Standard Retailer of complying with the LRET, it is necessary to determine the RPP for the Standard Retailer (which determines the number of LGCs that must be purchased) and the cost of obtaining each LGC.

Renewable Power Percentage

The RPP establishes the rate of liability under the LRET and is used by liable entities to determine how many LGCs they need to surrender to discharge their liability each year.

The RPP is set to achieve the renewable energy targets specified in the legislation. ORER is responsible for setting the RPP for each year. The RPP for 2011 has been set at 5.62 per cent.

The *Renewable Energy (Electricity) Act 2000* states that where the RPP for a year has not been determined it should be calculated as the RPP for the previous year multiplied by the required GWh's of renewable energy for the current year divided by the required GWh's of renewable energy for the previous year. This calculation increases the RPP in line with increases in the renewable energy target but does not decrease the RPP to account for any growth in demand. As a result, this calculation is likely to overestimate the RPP for a given year.

Frontier Economics has used the published RPP for 2011 and the renewable energy target in 2012 and 2013 to calculate the RPP for 2012 and 2013. These values have then been averaged to arrive at the financial year RPPs set out in Table 4.

Table 4: Renewable Power Percentages

Year	RPP (% of liable acquisitions)
2010/11	5.80%
2011/12	7.22%
2012/13	9.34%

Source: ORER, Frontier Economics.

Cost of obtaining LGCs

The cost to a retailer of obtaining LGCs can be determined either based on the resource costs associated with creating LGCs or the price at which LGCs are traded.

As discussed in the Frontier Final Report for 2010, Frontier Economics estimated the cost of RECs on the basis of the LRMC of meeting the expanded

RET. Frontier Economics considers that an LRMC approach remains appropriate for the LRET for the purpose of this final report.

As discussed in the Frontier Final Report for 2010, the LRMC of meeting the LRET is calculated as an output from Frontier Economics' least-economic cost modelling of the power system, using *WHIRLYGIG*. The LRMC of meeting the LRET in any year is effectively the marginal cost of an incremental increase in the LRET target in that year, where the incremental increase in the LRET target can be met by incremental generation by eligible (large scale) generators at any point in the modelling period (subject to the ability to bank and borrow under the scheme). As discussed in the Frontier Final Report for 2010, modelling the LRMC of the LRET in this way accounts for the interaction between the energy market and the market for LGCs, including the impact that a price on carbon will have on the incremental cost of creating an LGC.

Adopting this approach, and using the updated input assumptions adopted for this annual review, provides the estimated LRMC of an LGC as set out in Table 5. Table 5 provides the estimated LRMC of an LGC for both the draft report and this final report. These results compare with a current spot price for LGC's of close to $40.

Table 5: LRMC of the LRET ($2010/11)

Year	Draft Report LGC 'price' ($/certificate)	Final Report LGC 'price' ($/certificate)
2010/11	$35.71	$35.18
2011/12	$37.14	$36.59
2012/13	$38.63	$38.05

Source: Frontier Economics

Note: the differences between the results from the draft report and final report are a result of the revised WACC and the impact of the revised inflation rate on the assumed carbon price.

6.1.2 Cost of complying with the LRET

Based on the RPPs set out in Table 4 and the LRMC of the LRET set out in Table 5, the cost of complying with the LRET is set out in Table 6.[18] Table 6

18 Note that, unlike the 2010 Determination, the cost of complying with the LRET estimated for the purposes of this annual review provides different costs (in $/MWh) for different retailers. The reason is that, since the 2010 Determination, Frontier Economics has received more detailed information on the transmission loss factors applicable to each Standard Retailer. As a result, rather

provides the estimated LRMC of an LGC for both the draft report and this final report.

Table 6: Cost of complying with the LRET ($2010/11)

Financial Year	Draft Report Cost of complying with LRET ($/MWh)	Final Report Cost of complying with LRET ($/MWh)
Country Energy		
2011/12	$2.62	$2.65
2012/13	$3.52	$3.56
EnergyAustralia		
2011/12	$2.67	$2.63
2012/13	$3.59	$3.53
Integral Energy		
2011/12	$2.67	$2.64
2012/13	$3.60	$3.56

Source: Frontier Economics

Note: the differences between the results from the draft report and final report are a result of the updated estimates of the LRMC of the LRET and updated transmission loss factors applicable to each Standard Retailer.

6.1.3 Comparison to 2010 Determination

The estimated cost of complying with the LRET has increased since the 2010 Determination, as seen in Table 7. This increase is accounted for by two factors:

- An increase in the LRMC of the LRET. The updated input assumptions used for this annual review result in an estimate of the LRMC of meeting the LRET that is higher than the estimate from the 2010 Determination of the LRMC of meeting the RET.

than using a single estimate of the transmission loss factor when converting the cost of complying with the LRET (which is calculated relative to purchases at the connection point between the transmission and distribution networks) to a price in $/MWh at the regional reference node, Frontier Economics has used these individual estimates of the transmission loss factor. The effects of this on the resulting cost in $/MWh are minor.

The LRMC of meeting the LRET is essentially an estimate of the 'subsidy' that is required for renewable generation to displace thermal generation. As a result, the LRMC of meeting the LRET is affected not only by changes to the target and the cost of renewable technologies, but also by broader market factors such as the cost of thermal technologies (including carbon) and system demand forecasts.

The increase in the LRMC of the LRET that is observed for this annual review occurs because the changes in input assumptions mean that it is now least cost for the marginal LGC to be created earlier in the modelling period (in 2014/15 rather than 2015/16) and to displace thermal plant that is lower cost (at least in part because of a lower carbon price). This means that a higher 'subsidy', in present value terms, is required in order to create the marginal LGC.

- An increase in the RPP for 2012/13. As a result of the increase in the adjusted LRET target during calendar years 2012 and 2013, the RPP for 2012/13 is estimated to be significantly higher under the LRET than it was under the RET. This implies a higher cost of complying with the LRET in 2012/13.

Table 7: Cost of complying with the LRET, compared to 2010 Determination ($2010/11)

Financial Year	Cost of complying with LRET – 2010 Determination ($/MWh)	Cost of complying with LRET – annual review ($/MWh)
Country Energy		
2011/12	$2.22	$2.65
2012/13	$2.62	$3.56
EnergyAustralia		
2011/12	$2.22	$2.63
2012/13	$2.62	$3.53
Integral Energy		
2011/12	$2.22	$2.64
2012/13	$2.62	$3.56

Source: Frontier Economics

6.1.4 Response to submissions

Modelling approach

AGL notes in its submission that it appears that Frontier Economics have used a stand-alone single-year LRMC approach in estimating the LRMC of serving the Standard Retailers' regulated load but have used an incremental multi-year LRMC approach in estimating the LRMC of the LRET.

TRUenergy comments that it is unclear why Frontier Economics have used a stand-alone LRMC approach in estimating the LRMC of serving the Standard Retailers' regulated load but have used an incremental LRMC approach in estimating the LRMC of the LRET. TRUenergy comment that the LRMC of the LRET could have been modelled in the stand-alone LRMC approach.

It is indeed the case that Frontier Economics models the LRMC of serving the Standard Retailers' regulated load using a stand-alone single-year LRMC approach. The reasons for this are discussed in the Frontier Assumptions Report for 2010. In short, the reason for the stand-alone single-year LRMC approach is that this approach provides the most effective way of accounting for the capital costs associated with meeting the regulated load in each year.

It is also the case that Frontier Economics models the LRMC of the LRET using an incremental multi-year LRMC approach. This is discussed in the Frontier Final Report for 2010. In short, the reason for the incremental multi-year LRMC approach is that this approach provides the most effective way of accounting for increases in the LRET target over time, the interaction between the LRET market and the energy market and the fact that investment decisions in renewable plant (and all other plant) are made with regard to outcomes over a number of years.

Alternative approach

TRUenergy notes in its submission that the cost of LGCs could be estimated by estimating the 'bundled' LRMC of new entrant wind (which TRUenergy considers is around \$117/MWh) and deducting from this an estimate of expected wholesale electricity prices. According to TRUenergy, this would imply a cost of LGCs in the order of \$50 to \$70.

Implicit in TRUenergy's calculation is that expected wholesale electricity prices are in the range of \$47 to \$67. The fact that TRUenergy's proposed approach requires an assumption on the level of wholesale electricity prices that is significantly higher than current spot and forward prices, but still results in an estimate of the cost of LGCs that is significantly higher than current LGC prices, suggests that TRUenergy's proposed approach does not reflect the way that the market thinks about the price of LGCs. The explanation is simple: investors in new entrant wind do not just consider the wholesale prices that they will receive today, but also the wholesale prices that they will receive over the life of their investment. Where wholesale prices are expected to increase over time (due, for instance, to a carbon price), the LGC cost required to make profitable an investment in new entrant wind will be lower. The reason Frontier Economics models the LRMC of the LRET using a multi-year approach is precisely to take account of the fact that these decisions are made with regard to outcomes over a number of years.

Carbon price assumption

TRUenergy notes in its submission that adopting a zero carbon price assumption in estimating the LRMC of the LRET would lead to modelling outcomes that are far more consistent with market outcomes. Based on some initial modelling, Frontier Economics estimates that the effect of adopting a zero carbon price assumption in estimating the LRMC of the LRET would be to increase the estimate of the LRMC of the LRET by around $20 (per certificate) and to increase the cost of complying with the LRET by close to $1.50/MWh for each Standard Retailer.

6.2 SRES

The SRES places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the costs of creating small-scale technology certificates (STCs). The number of STCs to be purchased by liable entities each year is determined by the Small-scale Technology Percentage (STP), which is set each year by ORER. STCs are created by eligible small-scale installations based on the amount of renewable electricity produced or non-renewable energy displaced by the installation.

Owners of STCs can sell STCs either through the open market (with a price determined by supply and demand) or through the STC Clearing House (with a fixed price of $40 per STC). The STC Clearing House works on a surplus/deficit system so that sellers of STCs will have their trade cleared (and receive their fixed price of $40 per STC) on a first-come first-served basis. The STC Clearing House effectively provides a floor to the STC price: as long as a seller of STCs can access the fixed price of $40, the seller would only sell on the open market at a price below $40 to the extent that doing so would reduce the expected holding cost of the STC.

6.2.1 Approach to estimating costs of complying with the SRES

In order to calculate the cost to a Standard Retailer of complying with the SRES, it is necessary to determine the STP for the Standard Retailer (which determines the number of STCs that must be purchased) and the cost of obtaining each STC.

Small-scale Technology Percentage

The STP establishes the rate of liability under the SRES and is used by liable entities to determine how many STCs they need to surrender to discharge their liability each year.

The STP is determined by ORER and is calculated as the percentage required in order to remove STCs from the STC Market for the current year liability. The STP is calculated in advance based on:

- the estimated number of STCs that will be created for the year
- the estimated amount of electricity that will be acquired for the year
- the estimated number of all partial exemptions expected to be claimed for the year

The STP is to be published for each compliance year by March 31 of that year. ORER must also publish a non-binding estimate of the STP for the two subsequent compliance years by March 31. The STPs published by ORER for 2011, 2012 and 2013 are set out in Table 8.

Table 8: Small-scale Technology Percentages

Year	STP (% of liable acquisitions)
2011	14.80%
2012 (estimate)	16.75%
2013 (estimate)	10.62%

Source: ORER.

Cost of STCs

The cost of STCs exchanged through the STC Clearing House is fixed at $40 (in nominal terms). While retailers may be able to purchase STCs on the open market at a discount to this $40, any discount would reflect the benefit to the seller of the STC of receiving payment for the STC at an earlier date. In effect, the retailer would achieve the discount by taking on this holding cost itself (that is, by acquiring the STC at an earlier date). For this reason, in estimating the cost to retailers of the SRES, Frontier Economics has adopted an STC cost of $40.

In real terms, and using IPART's forecast inflation rate of 3.0%, this nominal $40 results in the real STC costs set out in Table 9. Table 9 provides the real STC costs for both the draft report and this final report.

Table 9: STC costs ($2010/11)

Calendar Year	Draft Report STC cost	Final Report STC cost
2011	$39.41	$39.36
2012	$38.27	$38.10
2013	$37.15	$36.99

Source: Frontier Economics

Note: the differences between the results from the draft report and final report are a result of the revised rate of inflation used to convert the STC cost of $40, which is a nominal amount, into an amount in $2010/11.

6.2.2 Cost of complying with the SRES

In broad terms, the cost to a Standard Retailer of complying with the SRES is the STP multiplied by the cost of STCs.

However, this is complicated by the fact that liable entities' obligation to surrender STCs under the SRES occurs on a quarterly basis and varies over the course of a calendar year. Determining financial year costs (in order to line up with IPART's 2010 Determination, which is on a financial year basis) therefore requires that the cost of complying with SRES is calculated on a quarterly basis and then aggregated to a financial year basis.

Liable entities' quarterly obligations to surrender STCs in calendar year n are determined as follows:

$$Q1 = 35\% * STP_n * (REA_{n-1} - PEC_{n-1})$$

$$Q2 = 25\% * STP_n * (REA_{n-1} - PEC_{n-1})$$

$$Q3 = 25\% * STP_n * (REA_{n-1} - PEC_{n-1})$$

$$Q4 = STP_n * (REA_n - PEC_n) - (Q1 + Q2 + Q3)$$

Where:

STP_n is the STP for year n

REA_n is the retailer's relevant acquisitions of electricity in year n

PEC_n is the retailer's PECs in MWh in year n

Applying this methodology, and using the real STC costs set out in Table 9, the cost each quarter of these quarterly obligations can be determined in real terms. These quarterly costs can then be summed across financial years to provide financial year costs of complying with the SRES.

Frontier Economics has applied this approach for each of the Standard Retailers. The value of REA for each Standard Retailer and each calendar year is based on the forecast regulated load for that Standard Retailer for each calendar year (as measured at the connection point between the distribution network and the transmission network).[19] The value of PEC for each Standard Retailer and each calendar year has been set at zero, on the basis that retail customers are not eligible for PECs.

Using this approach and these inputs, the cost of complying with the SRES is set out in Table 10. Table 10 provides the cost of complying with the SRES for both the draft report and this final report.

Table 10: Cost of complying with the SRES ($2010/11)

Financial Year	Draft Report Cost of complying with SRES ($/MWh)	Final Report Cost of complying with SRES ($/MWh)
Country Energy		
2011/12	$6.01	$6.15
2012/13	$4.79	$4.90
EnergyAustralia		
2011/12	$6.07	$6.05
2012/13	$4.77	$4.74
Integral Energy		
2011/12	$6.08	$6.08
2012/13	$4.84	$4.84

Source: Frontier Economics

Note: the differences between the results from the draft report and final report are a result of the revised rate of inflation used to convert the STC cost of $40, which is a nominal amount, into an amount in $2010/11 and updated transmission loss factors applicable to each Standard Retailer.

19 Frontier Economics has used the regulated load provided by the Standard Retailers for the 2010 Determination.

6.3 GGAS

The Greenhouse Gas Abatement Scheme (GGAS) is designed to reduce the greenhouse gas emissions associated with the production and use of electricity.

Under the GGAS, electricity retailers, and certain other parties, are required to meet emissions benchmarks based on the size of their share of the electricity market. The GGAS establishes annual emissions benchmarks for these scheme participants, which participants are required to meet by obtaining and surrendering NSW Greenhouse Gas Abatement Certificates (NGACs). If participants fail to meet their targets through the surrender of NGACs, a penalty is imposed.

6.3.1 Approach to estimating costs of complying with the GGAS

In order to calculate the cost to a standard retailer of complying with the GGAS, it is necessary to determine the emissions target for a standard retailer (or the number of NGACs a standard retailer needs to surrender) and the cost of obtaining NGACs to meet the emissions target.

In the 2010 Determination, Frontier Economics estimated the cost of obtaining NGACs based on the LRMC of meeting the GGAS target. As discussed in the Frontier Final Report for 2010, Frontier Economics estimated the LRMC of meeting the GGAS target at zero. The reason for this was a combination of the number of NGACs that had been created but not surrendered, and the expected transition of the scheme within the context of the CPRS. Largely as a result of these two factors, Frontier Economics estimated that the GGAS target could be met without requiring any increase in economic cost.

For the purposes of this annual review, Frontier Economics has again estimated that the LRMC of meeting the GGAS target is zero. This occurs even taking into account the fact that the introduction of a carbon price is assumed to occur in July 2013 (rather than July 2011 for the 2010 Determination). Ultimately, the reasons for this are the same: the existing surplus of NGACs (which has increased further since the 2010 Determination), and the forecast ongoing production of NGACs, is more than enough to meet the GGAS target.

6.3.2 Cost of complying with the GGAS

Based on the LRMC of the GGAS being zero for 2011/12 and 2012/13, Standard Retailers will not face an additional cost of complying with the GGAS in these years.

6.3.3 Response to submissions

Modelling assumptions

AGL note in their submission that two assumptions relevant to the LRMC of the GGAS are unclear:

- the current NGAC supply-demand assumptions
- any assumptions about compensation of NGAC holders by the Commonwealth Government.

Frontier Economics includes an assumption about the current GGAS surplus in its LRMC modelling. As of the end of calendar year 2009 the GGAS surplus certificates stood at approximately 19.5m permits.[20] The GGAS surplus used by Frontier Economics in its modelling is 19.5m permits. Frontier Economics also conducted modelling using a surplus of 15.0m permits and confirmed that the marginal cost of the scheme was still zero even with this lower assumed surplus.

Frontier Economics does not make any assumption about the ongoing creation of NGACs. Rather, ongoing creation of NGACs by generators is a modelling outcome: *WHIRLYGIG* models least cost dispatch of each generator in the market, which implies a level of ongoing creation of NGACs by eligible generators.

Frontier Economics also does not make any assumption about compensation of NGAC holders by the Commonwealth Government. However, Frontier Economics does consider that the expectation that compensation may be available for NGAC holders could account for the current positive market price for NGACs.

Market price for NGACs

AGL and Origin note in their submissions that there is no certainty about the introduction of a carbon price and that, therefore, the LRMC of the GGAS should be modelled without a carbon price. Origin notes that Frontier Economics' modelling, which finds that the LRMC of the GGAS is zero for 2011/12 and 2012/13 is inconsistent with recently observed market prices for NGACs, which have been in the range of $5.00 to $7.50.

TRUenergy also notes in its submission that current market prices for NGACs are around $5.00 and that it is not aware of any retailer that was able to purchase a material quantity of NGACs in 2010/11 for zero consideration.

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20 See http://www.greenhousegas.nsw.gov.au/documents/SchRep09.pdf

Frontier Economics does model the LRMC of the GGAS on the assumption that a carbon price will be introduced in 2013/14, and this assumption does interact with the modelled LRMC of both the GGAS and the LRET.

If the current market price for NGACs was used to estimate the cost of complying with GGAS (as opposed to estimating the cost of complying with GGAS on the basis of the LRMC of the GGAS), the estimated cost would be around $1/MWh for each of the Standard Retailers.

6.4 ESS

The Energy Saving Scheme (ESS) is designed to increase opportunities to improve energy efficiency by rewarding companies that undertake eligible projects that either reduce electricity consumption or improve the efficiency of energy use.

Under the ESS, electricity retailers, and certain other parties, are required to meet individual energy savings targets based on the size of their share of the electricity market. The ESS establishes annual energy savings targets for these scheme participants, which participants are required to meet by obtaining and surrendering Energy Savings Certificates (ESCs). If participants fail to meet their targets through the surrender of ESCs, a penalty is imposed.

6.4.1 Approach to estimating costs of complying with the ESS

In order to calculate the cost to a standard retailer of complying with the ESS, it is necessary to determine the energy savings target for a standard retailer (or the number of ESCs that a standard retailer needs to surrender) and the cost of obtaining ESCs to meet the energy savings target.

Energy savings target

The ESS target is defined as a proportion of total annual NSW electricity sales to be saved through the take-up of energy efficiency projects.

The ESS target is allocated each year to electricity retailers in proportion to their liable electricity sales. Liable electricity sales are defined as total annual NSW electricity sales less sales to exempt emission-intensive trade-exposed activities. Taking this into account, the ESS target defined as a proportion of total annual NSW electricity sales and as a proportion of total annual liable sales is set out in Table 11.

Table 11: ESS target

Calendar year	Effective scheme target (% of annual NSW electricity sales)	Retailer compliance obligation (% of annual liable electricity sales)
2009 (from 1 July)	0.4 %	0.5 %
2010	1.2 %	1.5 %
2011	2.0 %	2.5 %
2012	2.8 %	3.5 %
2013	3.6 %	4.5 %
2014 – 2020	4.0 %	5.0 %

Source: ESS web site. Available at: http://www.ess.nsw.gov.au/participants/participants.asp

Cost of obtaining ESCs

Consistent with the approach adopted for the 2010 Determination, Frontier Economics has adopted the penalty price of the ESS as a proxy for the cost of obtaining ESCs. The penalty price will act as a cap on the price of ESCs. The penalty price of the scheme for 2011 is $25.52/MWh,[21] which is equivalent to an after-tax price of $36.46/MWh.

6.4.2 Cost of complying with the ESS

Based on the energy savings targets set out in Table 11 and the ESS penalty price of $36.46/MWh, the cost of complying with the ESS is set out in Table 12.

Table 12: Cost of complying with the ESS ($2010/11)

Year	Cost of complying with ESS ($/MWh)
2011/12	$1.09
2012/13	$1.46

Source: Frontier Economics

21 The penalty price escalates with CPI.

6.4.3 Comparison to 2010 Determination

The estimated cost of complying with the ESS has increased very slightly since the 2010 Determination, as seen in Table 13. This increase is accounted for by the increase in the penalty price in real terms since the 2010 Determination.

Table 13: Cost of complying with the ESS, compared with 2010 Determination ($2010/11)

Year	Cost of complying with ESS – 2010 Determination ($/MWh)	Cost of complying with ESS – annual review ($/MWh)
2011/12	$1.08	$1.09
2012/13	$1.44	$1.46

Source: Frontier Economics

7 Summary of advice

For this annual review, Frontier Economics has calculated the cost to an efficient standard retailer of supplying the Standard Retailers' regulated load using two approaches:

- Stand alone LRMC – estimates the resource costs associated with a hypothetical generation system to supply the Standard Retailers' regulated load.
- Market-based energy purchase cost – estimates the purchase costs of energy to meet the Standard Retailers' regulated load, including a volatility allowance.

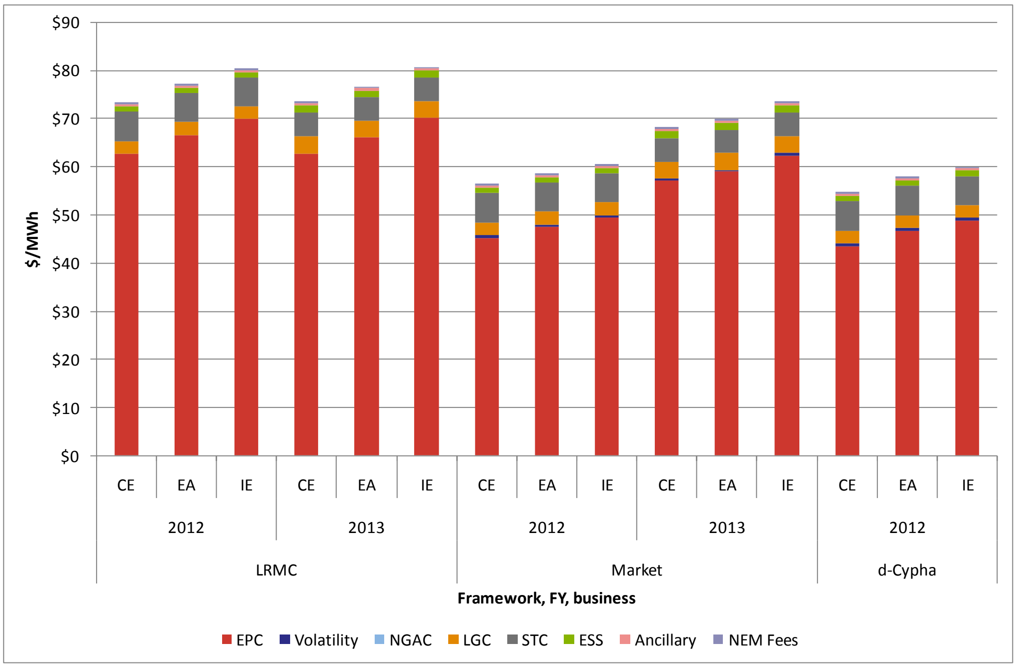
For this annual review, Frontier Economics has also estimated a number of other costs, including:

- LRET costs
- SRES costs
- GGAS costs
- ESS costs

Ancillary services costs and market fees, which also form part of the total energy cost that the Standard Retailers face, have not been updated as part of this annual review.

Combining each of the LRMC and the market-based energy purchase cost with the other costs enables the determination of the total energy purchase cost allowance (excluding losses). Consistent with the terms of reference for the 2010 Determination, the total energy purchase cost allowance will be based on the market-based energy purchase cost, with the LRMC providing a floor to the energy purchase cost allowance. Given this, Figure 15 provides a comparison of each of the LRMC and the market-based energy purchase cost, combined with the other costs set out above. As seen in Figure 15, for each of the Standard Retailers, and for each financial year, the LRMC is above the market-based energy purchase cost. As a result, the LRMC provides the basis for setting the energy purchase cost allowance. Full results are set out in Table 14 and Table 15.

Figure 15: Total energy purchase cost allowance (excluding losses) ($2010/11)



Source: Frontier Economics

Table 14: Total energy purchase cost with LRMC ($2010/11)

	LRMC	Volatility	GGAS	LRET	SRES	ESS	Ancillary	NEM Fees	Total
Country Energy									
2011/12	$62.60	$0.00	$0.00	$2.65	$6.15	$1.09	$0.44	$0.38	$73.31
2012/13	$62.80	$0.00	$0.00	$3.56	$4.90	$1.46	$0.44	$0.38	$73.54
EnergyAustralia									
2011/12	$66.59	$0.00	$0.00	$2.63	$6.05	$1.09	$0.44	$0.38	$77.18
2012/13	$66.08	$0.00	$0.00	$3.53	$4.74	$1.46	$0.44	$0.38	$76.63
Integral Energy									
2011/12	$69.86	$0.00	$0.00	$2.64	$6.08	$1.09	$0.44	$0.38	$80.49
2012/13	$70.08	$0.00	$0.00	$3.56	$4.84	$1.46	$0.44	$0.38	$80.76

Source: Frontier Economics

Table 15: Total energy purchase cost with market-based energy purchase cost ($2010/11)

	EPC	Volatility	GGAS	LRET	SRES	ESS	Ancillary	NEM Fees	Total
Country Energy									
2011/12	$45.23	$0.54	$0.00	$2.65	$6.15	$1.09	$0.44	$0.38	$56.48
2012/13	$57.12	$0.41	$0.00	$3.56	$4.90	$1.46	$0.44	$0.38	$68.28
EnergyAustralia									
2011/12	$47.52	$0.52	$0.00	$2.63	$6.05	$1.09	$0.44	$0.38	$58.62
2012/13	$58.97	$0.39	$0.00	$3.53	$4.74	$1.46	$0.44	$0.38	$69.91
Integral Energy									
2011/12	$49.36	$0.59	$0.00	$2.64	$6.08	$1.09	$0.44	$0.38	$60.58
2012/13	$62.34	$0.50	$0.00	$3.56	$4.84	$1.46	$0.44	$0.38	$73.51

Source: Frontier Economics

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