The Allen Consulting Group

Final Report
Energy Wholesale Price Study

13 September 2004

Report to Essential Service Commission of South Australia

The Allen Consulting Group

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Chapter 1

Executive Summary

The Allen Consulting Group has been asked by the Essential Services Commission of South Australia (the Commission) to provide a detailed assessment of the efficient and prudent wholesale energy cost that should be built into South Australian electricity retail standing contract prices, for the three and a half year period starting January 2005.

Submissions have argued that a prudent retailer should seek to purchase energy at the best possible price while appropriately managing risk. Our conclusion, agreed with the Commission and the Australian Gaslight Company (AGL), is that a prudent retailer serving the standing customer load in South Australia would seek primarily to minimise risk by contracting to levels that cover at least expected demand under medium growth assumptions.

We analysed risk by:

- agreeing with the Commission and AGL five scenarios for future load and pool prices, with associated weights;
- calculating risk as the load weighted variance in cost due to a contract portfolio under- or over-hedging the five scenarios on a half-hourly basis;
- using a prudent hedging strategy of finding a portfolio of contracts that minimises risk; and
- hence calculating the wholesale energy cost for peak and off-peak each quarter.

We built a spreadsheet based model for the above calculation, taking as input:

- historical pool prices from 2001-02 to 2003-04 and a model for the 50 highest price events in summer 2001;
- load forecasts from AGL and the Electricity Supply Industry Planning Council (ESIPC) for AGL's expected customer load;
- new entrant prices from ESIPC;
- information from AGL about its existing contract portfolio; and
- forward contract prices from broker traded contracts.

We analysed three cases for future contract prices:

A. contracts priced at current forward prices;

B. as in case A plus a premium for uncertainty which is equivalent to buying an option to lock in future contract prices); and

C. as in case A plus a premium rising to new entrant price levels.

Wholesale energy costs for these three cases are shown in Table 1.1 and Figure 1.1. Prices in the first half of 2005 appear higher but are not. They are load weighted prices averaged over half a year, compared to other prices that are averaged over a full year, so the high cost of the January quarter is most pronounced.

Table 1.1

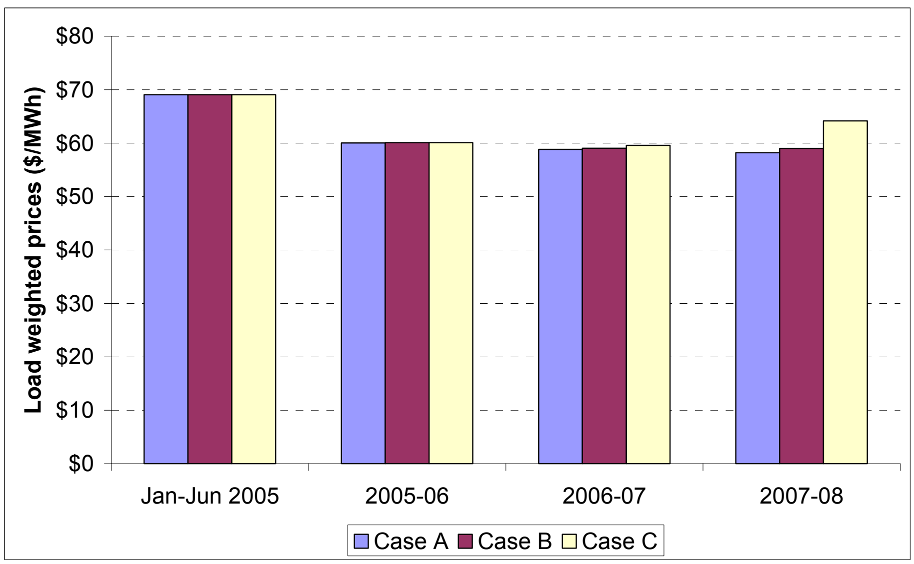
LOAD-WEIGHTED COSTS FOR CONTRACT CASES ($ PER MWH)

	Jan-Jun 2005	2005-06	2006-07	2007-08
Contract Case A	$69.08	$60.02	$58.84	$58.18
Contract Case B	$69.08	$60.11	$59.04	$59.00
Contract Case C	$69.08	$60.11	$59.56	$64.17

Source: ACG modelling of optimal portfolio

Figure 1.1

LOAD-WEIGHTED PRICES FOR CONTRACT CASES ($ PER MWH)



Source: ACG modelling

The wholesale cost of electrical energy at the customer meter has to include allowance for add-on costs and line losses. The sum of all the relevant costs and changes that make up the wholesale cost of electrical energy at the meter for standing contract customers is shown in the following table.

Table 1.2

WHOLESALE COST AT THE CUSTOMER METER — BASED ON CONTRACT CASE B ($ PER MWH)

	Jan-Jun 2005	FY 2005-06	FY 2006-07	FY 2007-08
Energy hedging cost	$69.08	$60.11	$59.04	$59.00
Pass through costs				
NEMMCO fees	$0.39	$0.40	$0.41	$0.42
Ancillary services	$0.75	$0.60	$0.62	$0.63
Bank guarantee	$0.10	$0.10	$0.10	$0.10
Embedded generation[1]	$0.47	$0.51	$0.55	$0.59
MRET	$0.70	$0.83	$1.10	$1.39
Total before losses	$71.49	$62.55	$61.82	$62.13
Line losses	$5.81	$5.08	$5.02	$5.04
Energy costs at meter	$77.30	$67.63	$66.84	$67.17
Energy cost at meter (Dec 2004 prices)*	$76.82	$65.98	$63.61	$62.38

Source: ACG modelling, assuming an annual inflation rate of 2.5%

Further analysis has been provided to the Commission on a confidential basis, so as not to prejudice AGL's commercial negotiations in respect of future contracting.

[1] The Commission is considering whether embedded generation should be included.

Chapter 2

Introduction and background

2.1 Background to the study

On 1 January 2003, the South Australian electricity retail market became fully contestable. Protection for small customers (less than 160 MWh per year) exists under section 36AA of the *Electricity Act 1996*. Section 36AA requires as a licence condition that the incumbent retailer, The Australian Gaslight Company (AGL), must offer a standing contract price and standing contract terms and conditions to small customers who have not previously contracted with another retailer.

AGL is therefore bound to purchase energy in the wholesale electricity market and sell it to standing contract customers at the standing contract price.

The Essential Services Commission of South Australia (the Commission) has received a Notice of Inquiry from the Minister for Energy under Part 7 of the *Essential Services Act 2002*, requiring the Commission investigate AGL's standing contract price proposal that will apply from 1 July 2005 for a period of no less than three years.

The Terms of Reference of the Inquiry require the Commission to have regard to, among other matters:

- the electricity entity's justification for its proposed charges, presented as part of the proposal;
- the wholesale electricity contracts and hedging strategies that would be utilised by a prudent electricity entity in providing the standing contracts to each of the residential and business customer classes in South Australia; and
- the electricity entity's actual underlying wholesale electricity contracts, hedging strategies and other arrangements for securing electricity for supply in South Australia, as well as the method for allocating these costs between large and small customers and within the small customer class

2.2 Scope of work

We have been asked to provide the Commission with a detailed assessment of the efficient and prudent wholesale energy cost that should be built into South Australian electricity retail standing contract prices, for the three and a half year period starting January 2005.

This requires us to research, provide supporting information, and develop a credible model, for estimating the wholesale electricity purchase cost for the prescribed class of customers.[2] The model and overall approach is consistent with IPART's comments on the Commission's previous approach to this task.[3]

- In particular, we were required to provide a detailed modelling of the wholesale electricity price for the prescribed class of customers, from 1 July 2005 onwards, for the standing contract retailer.
- We were required to demonstrate ways in which reliable information regarding contracts is sourced, and to indicate any assumptions.

In addition, we have considered:

- the popular belief that there has been a significant downward trend in forward contract price curves – and hence any consequential change in future standing contract prices that should apply;
- any residual impact of all the vesting contracts applicable to small customers terminating on a single day (31 December 2002), such that AGL SA may have faced an unfavourable "cliff edge" position in terms of their bargaining power with the generators following that period, and the ongoing effect of this, if any, on their subsequent energy bargaining;
- the forward contract (both for caps and swaps) price used as an input;
- the timing of purchase of swap contracts and the assumed level of cover;
- the appropriate risk management approach that would be used by a prudent retailer in the current environment;
- nature of, and changes to, the load profile over the period;
- level of, and changes to, the loss factors; and
- level of, and changes to, the other market related charges, such as NEMMCO fees and ancillary service charges, etc.

We have determined the quarterly average peak and off-peak wholesale energy cost based on contracts and hedging cost, and the final wholesale energy cost after including additional costs of NEM operation, MRET, insurance and network losses.

[2] 'prescribed class of customers' those customers which may be prescribed under Electricity Regulations, for the purpose of section 35A of the Electricity Act (considered to be those customers consuming less than 160 MWh/pa of electricity).

[3] Independent Pricing and Regulatory Tribunal of NSW, *South Australia 2004 Electricity Standing Contract Price Review of ESCOSA Methodology, Report to the Premier of South Australia*, March 2004, p. 1.

2.3 Standing contract customer load

Small customers (below 160 MWh per annum) consume around 55% of the total energy traded in the South Australian electricity market.[4] The majority of small customers are supplied by AGL, most under standing contracts and some under competitive market contracts. AGL purchases wholesale energy for all its small customers as a whole. That is, AGL does not purchase separately wholesale energy for its standing contract and its competitive market contract customers.

The number of small customers being supplied by AGL is slowly declining as customers transfer to competitive market contracts with new entrant retailers.

AGL forecasts its total small customer half-hourly electricity load for years in advance to determine the quantities of energy it must purchase in the wholesale market to supply these small customers. The shape and magnitude of AGL's small customer load depends on how many customers it retains in total, their consumption profile, economic conditions that affect load growth, and weather patterns.

To assist us with this study, the Electricity Supply Industry Planning Council has also developed half-hourly forecasts for both total state-wide load and entire small customer load.

2.4 The spot market

Each retailer, including AGL, must purchase the energy to supply their customers from the National Electricity Market (NEM) at the spot price set be the National Electricity Market Management Company (NEMMCO).

For every half-hour trading interval in the NEM, generators make offers to NEMMCO to supply the spot market with defined amounts of electricity at particular offer prices. From all offers submitted, NEMMCO selects the generating units and production levels required to produce electricity sufficient to meet forecast demand in the most cost-efficient way and issues dispatch instructions to the generators for every five-minute dispatch interval. A separate pool price is determined for each of the five regions in the NEM.

The dispatch price for each five-minute dispatch interval is set by the offer price of the last increment of generation necessary to meet demand. Six dispatch prices are averaged for each half-hour trading interval to determine the *spot price* of electricity for the trading interval.

The movement in the spot price can be volatile, reflecting:

- the non-storable characteristic of electricity — electricity demand and generation has to be kept in balance at all times to maintain power system security;
- the step shape of the generation supply curve;
- the price inelastic nature of electricity demand in the short term; and

[4] ESIPC, *2004 Annual Planning Report*, p. 14.

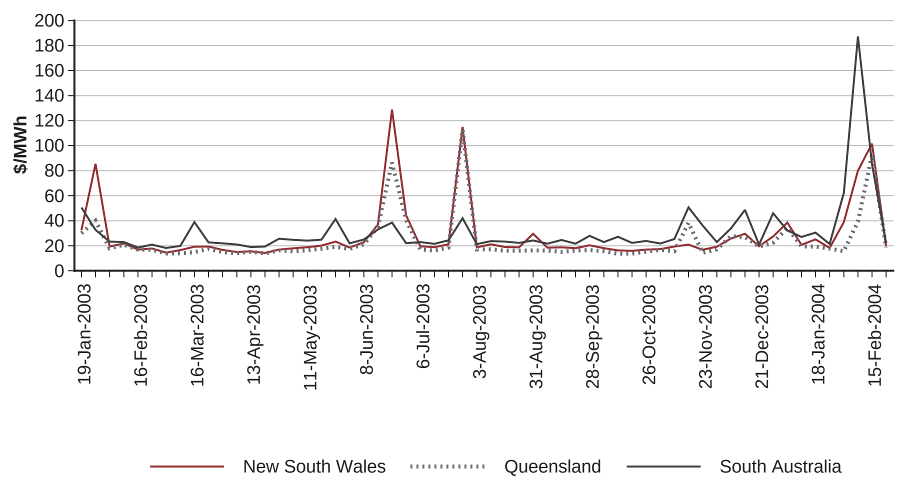
- bidding behaviour of generators, which is influenced by their contracted positions.

The electricity spot price between January 2003 and February 2004 by region is illustrated in the figure below. The figure highlights the strong seasonal trends and volatile movements in the spot price, even when averaged on a daily basis.

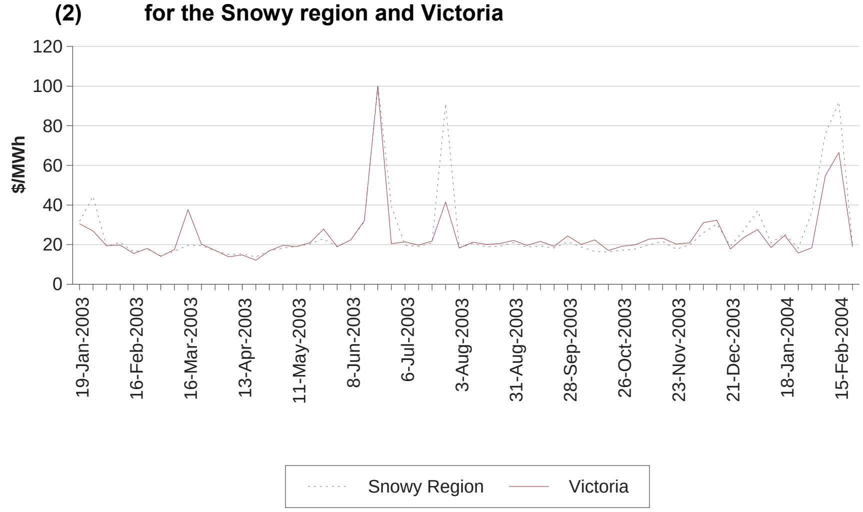
Figure 2.1

THE DAILY AVERAGE SPOT PRICE OF ELECTRICITY BY REGION

(1) for New South Wales, Queensland and South Australia



(2) for the Snowy region and Victoria



Source: NEMMCO. Accessed from http://www.nemmco.com.au/data/tables.htm

The half hourly spot price of electricity is published by NEMMCO.

2.5 The hedge contract market

Retailers of electricity supply their customers under fixed price contracts but pay NEMMCO the floating half-hourly pool price for the electricity their customers consume. They, therefore, need a mechanism to lock in a fixed price for the electricity they supply to their customers.

Hedge contracts are financial instruments used by electricity retailers and generators to manage their risk exposure, in view of uncertainty in the amount of energy they expect to supply to, or purchase from, the spot market and spot price uncertainty. These contracts include:

- bilateral hedge agreements that are traded directly between NEM participants; and
- over-the-counter electricity contracts that are traded through market facilitators and exchanges.

Hedge contracts are typically agreements between electricity generators and retailers that have the effect of stabilising and smoothing the price for a given amount of electricity that is traded through the spot market at an agreed *strike price*. The contract counter-parties will settle their hedge contracts with difference payments that reflect the extent to which the actual spot price has varied from the strike price.

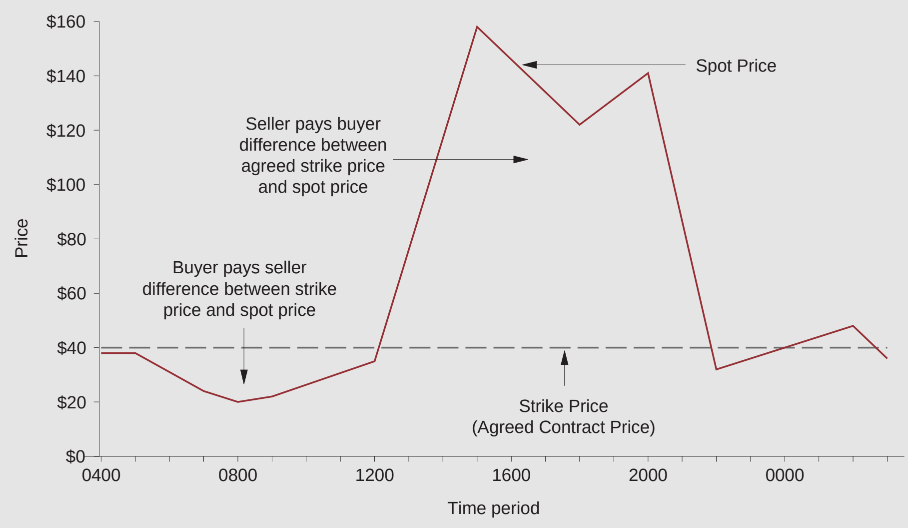
The two main types of hedge contracts are swaps and caps.

Swaps

The most commonly traded financial hedge is the electricity swap. This is simply a fixed for floating arrangement whereby the floating pool price is swapped for a fixed dollar per MWh amount, which is applied against an agreed MWh quantity. The swaps have half hourly settlements to reflect the half hourly nature of the pool price and difference payments are made by the counterparties throughout the life of the swap contract according to NEMMCO settlement dates.

Figure 2.2

SWAP CONTRACTS IN THE NEM



The two parties have agreed to set a price (the strike price) of $40/MWh. The figure above shows the strike price and the actual spot price over a hypothetical day's trading.

- under the hedging agreement entered into:
- when the spot price is less than the strike price, the market customer pays the difference in these prices to the generator. In this case, when the spot price is $17, the market customers pays the generator $23/MWh.;
- when the spot price is greater than the strike price, the generator pays the market customer the extra required to purchase electricity from the pool. In this case, when the spot price increases to $145/MWh, the generators pay the market customer the $105/MWh difference.

Source: Reproduced with permission of the National Electricity Market Management Company Limited. National Electricity Market Management Company Limited, *An introduction to Australia's national electricity market,* June 2003, p. 29.

A swap market exists to hedge periods from one month out to 5 years. Generally it is possible to trade monthly for the proximate 1-6 months, quarterly for the proximate four quarters, half-year for the proximate 2-3 half years. Generally it is only possible to trade whole year contracts after two years out. It is also possible to trade other periods, for example, single days or weeks but these periods are not liquid and are usually dealt bilaterally as the need arises.

In common with many commodities, liquidity has sometimes been patchy in the Australian electricity contract market. The fact that the majority of trading is transacted for hedging purposes means that sometimes few retailers are prepared to deal at high prices when generators are keen to sell, and vice-versa at times of low prices. Coupled with bouts of credit indigestion from time to time, this has caused periods of illiquidity. Since the Enron collapse, however, liquidity has steadily improved to the extent that more than twice as many deals are being transacted now than before that event. In fact, anecdotal evidence points to the fact that liquidity is now the best in the markets history. This can only continue to improve as new players enter.

Market participants include generators, retailers and some financial institutions that may trade speculatively. Trades can take place either directly between counterparties, which is the method generally used for large, or shaped, transactions or through a number of brokers who post anonymous bids and offers on their screens, allowing participants to reveal their identity only when a trade is transacted and only to the deal counterparty. Some of these brokers use the trade information gathered throughout the day to post closing market prices for forward contracts each day.

Electricity prices are generally averaged into peak and off-peak periods for trading purposes. Peak hours cover period ending 07.30 to period ending 22.00 on business days while off-peak covers all other times. Contracts that cover every period during the day are referred to as ‘flat’ (sometimes ‘base load’) contracts.

Caps

Half-hourly settled caps are the most popular method used by retailers to hedge the risk of high demand leading to spikes in the pool price. Whenever the half-hourly pool price is higher than the strike price of the cap, the cap seller must pay the buyer the difference between strike price and pool price for an agreed MWh quantity. The retailer still pays up to the strike price. The most popular strike prices are $200 and $300 per MWh.

These contracts are effectively insurance products. Caps are mainly sold by physical generators who price them based on the cost of their generation and how readily available it will be in the event it is needed in a hurry to meet a pool price spike. Cap prices have generally traded far above their historical pay-outs but, for retailers, the risks of being caught short during a high-priced event usually outweighs the high premium paid.

Futures swap contracts

Since September 2002, the Sydney Futures Exchange (SFE) has listed peak and base load electricity futures for the Victorian, New South Wales, South Australian and Queensland regions of the NEM for March, June, September and December quarters up to 15 quarters out. These are, in effect, exchange traded swaps with settlement occurring at the end of the quarter. The SFE have recently launched options on electricity futures. The take-up of futures trading has been slow with many market participants baulking at the prospect of paying up-front margins and the possibility of margin calls in the future.

The futures market also offers participants to ability to execute 'Exchange for Physical' transactions whereby counterparties can switch the swap position for a futures position via the SFE and the futures clearing house and largely neutralise their credit risk.

According to data from Australian Financial Market Association (AFMA)[5], over-the-counter (OTC) electricity derivatives turnover increased by around 40 per cent in 2002/03 from the year before, which was affected by a post Enron crash downturn in activity. Over the past four years growth has averaged around 15 per cent per annum. Futures trading has also increased over this time as more participants add futures to their list of permissible trading instruments. In 2002/3 over 265 million megawatt hours was traded over the counter. At an average price of around \$35/MWh this represents over \$9 billion worth of electricity. Generators report the largest proportion of trading (50%), followed by retailers (29%) and intermediaries (9%).The vast majority of OTC trades were vanilla swaps.

The Sydney Futures Exchange reports trading of over 15,000 contracts in the first year of listing, representing more than 26.7 million MWh and over \$1 billion in value and looks set for a similar performance in its second year.

2.6 The effective wholesale price of electricity

So the NEMMCO spot price is not, by itself, the wholesale purchase price for electricity. The wholesale price for electricity varies for each retailer as it is also determined by (1) the shape of the retailer's actual half-hourly load, (2) the extent to which the retailer enters into hedge contracts outside the spot market; (3) the strike price of these hedge contracts; and (4) other costs of participating in the NEM and buying energy — NEM fees, bank guarantees, ancillary services, embedded generation and Mandatory Renewable Energy Target (MRET) certificates[6].

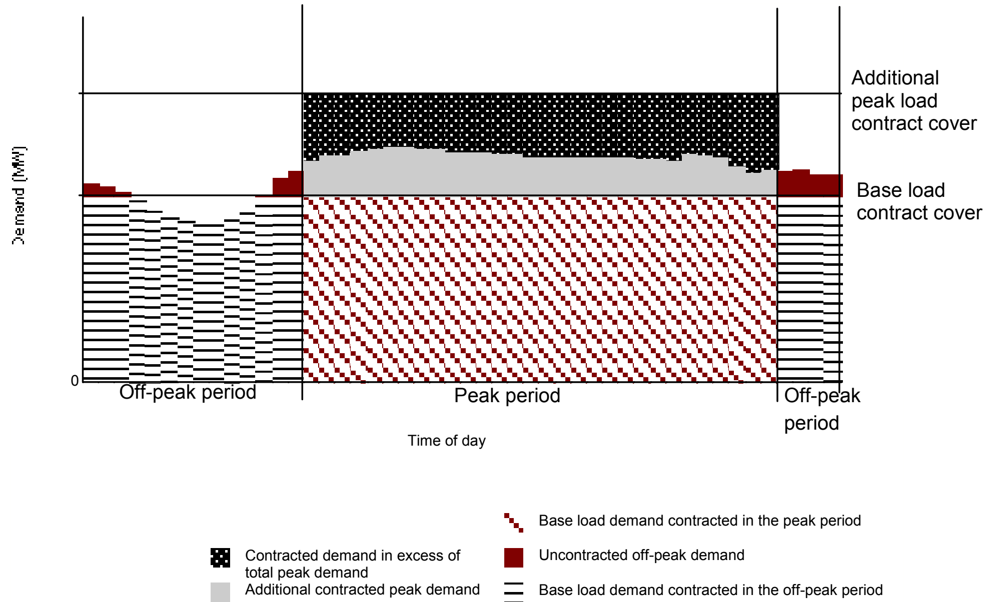
An efficient and prudent retailer would use a combination of different types of financial contracts to manage its spot price risk exposure. The mix will depend on the shape of the load, the expected prices for spot and contracts, and the risk preference of the retailer, as shown in the following example in Figure 2.3.

[5] AFMA, *2003 Australian Financial Markets – Comprehensive Report*, p. 95.

[6] The Commonwealth Governments mandatory renewable energy targets scheme requires that retailers cover a specified percentage of energy sales from renewable energy sources by purchasing 'Renewable Energy Certificates' (RECs), or pay a financial penalty. The MRET percentages are rising each year so that 9,500 GWh of sales are covered by renewable energy sources in 2010.

Figure 2.3

CONTRACTS AND SPOT RATE EXPOSURE



Source: The Allen Consulting Group

The hedge contract strike price for electricity is an 'agreed' future price for wholesale electricity. It reflects the expected future spot price of electricity at a time the contract is created given expectations of the overall supply and demand balance and the operational conditions that may affect that balance. In particular, the contract strike price incorporates judgements about the nature and likelihood of future market scenarios. Market participants enter into hedge contracts for both long and short-term periods.

Estimating the combination of hedge contracts that an efficient and prudent retailer would use to manage its spot price risk exposure given its expected load, and the associated contract strike prices is the key to determining average wholesale energy prices.

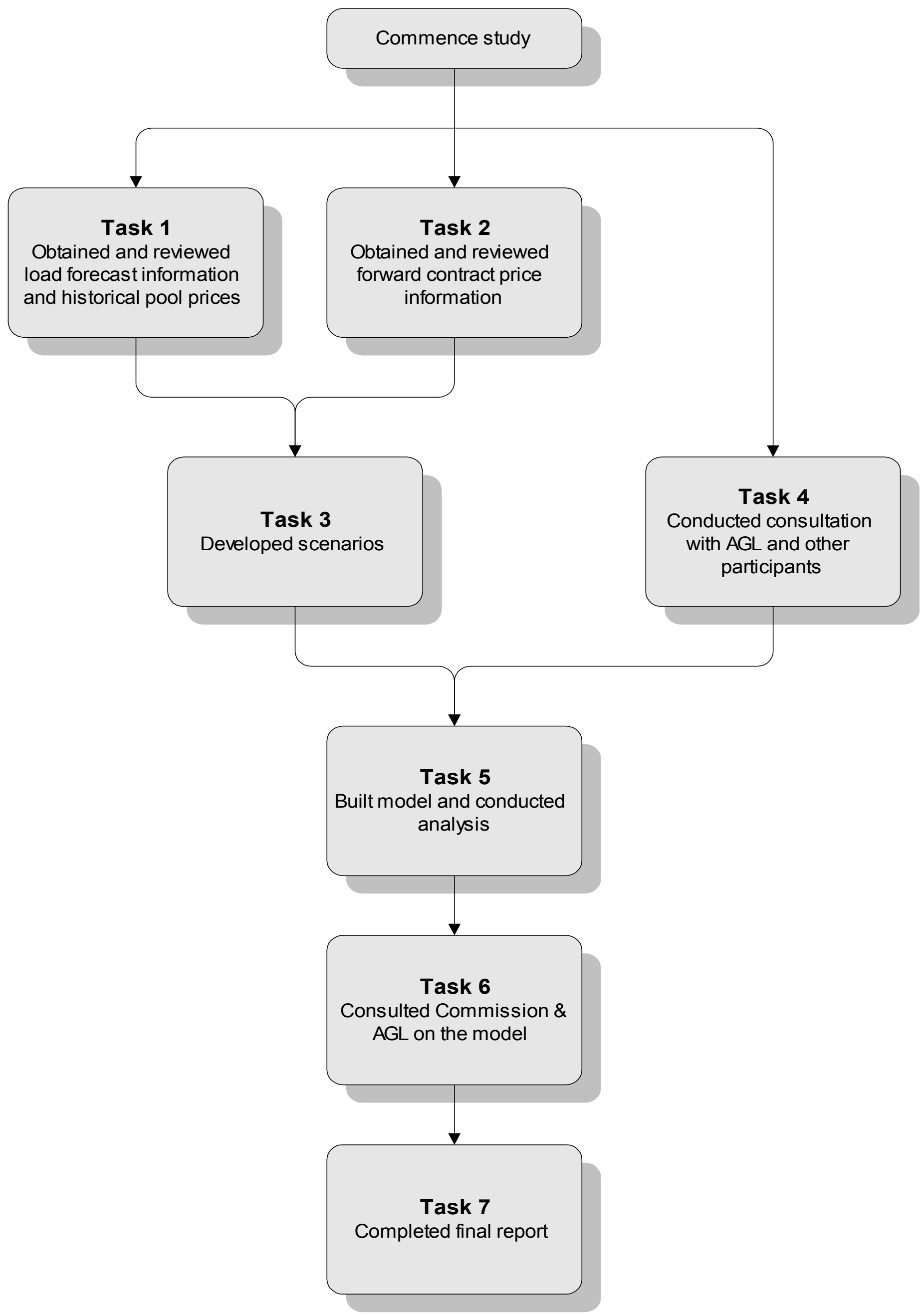
Chapter 3

Our approach

We conducted the study in 7 principal tasks as shown in Figure 3.1 and explained below.

Figure 3.1

THE 7 TASKS OF THE STUDY



3.1 Task 1 - Obtained and reviewed load forecast and pool price information

We:

- obtained from AGL half-hourly load forecasts for all AGL's South Australian customers below 160 MWh for the three and a half years from January 2005 - these forecasts took account of expected load growth and customer transfers away from AGL;
- obtained from the ESIPC half-hourly load forecasts for South Australian customers below 160 MWh and for the South Australian load as a whole for the three years from 1 July 2005;
- reviewed the AGL forecasts in the light of the ESIPC forecasts to confirm their robustness;
- considered which half-hourly load data should be used, and separated this into peak and off-peak load by month;
- analysed a half-hourly **low** case load profile for the three and a half years from January 2005, in which AGL assumptions about customer movements are incorporated into the ESIPC load forecast for **low economic growth case** coupled with the load expectations of **a year with mild weather**.
- analysed a half-hourly **high** case load profile for the three and a half years from January 2005 in which AGL assumptions about customer movements are incorporated into the ESIPC load forecast for **high economic growth** scenario and the expected load profile of **a hot weather year**;
- obtained historical pool price information for South Australia for 2001-02 till 2003-04;
- developed a composite pool price data set with the same price duration curve as the three year historical price data, separated into peak and off-peak by month;
- developed a regression model of the 50 highest prices in summer 2001, adjusted for the change in Value of Lost Load (VOLL) — the wholesale price cap applied by NEMMCO; and
- sorted load and price data into descending order, for peak and off-peak by month, to constitute higher risk cases in which prices are highest when load is highest, and prices are lowest when load is lowest.

3.2 Task 2 - Obtained and reviewed forward contract price information

We:

- received from AGL details of AGL's existing contracts entered into in order to hedge this small customer load;

- obtained market prices for forward swap and cap contracts from a number of sources including Next Generation Energy Solutions (NGeS)[7] and Tradition Financial Services (TFS)[8]; and
- obtained closing electricity futures contracts prices from the Sydney Futures Exchange;
- obtained the AFMA closing curve.

3.3 Task 3 - Developed scenarios for load forecasts and pool prices

We identified the main factors that affect AGL's costs of supplying customers for any given mix of spot and contract purchases. In addition to contract levels and prices, relevant factors are:

- shape of the load, for peak and off-peak periods by month;
- distribution of pool prices, for peak and off-peak periods by month; and
- synchronisation between customer load and pool price. This is important as the risk to a retailer is highest if pool prices are high when customer load is high (as the retailer may be under-hedged and hence paying high pool prices) and pool prices are low when customer load is low (as the retailer may be over-hedged and paying out to the counterparty).

We identified five scenarios that represent a wide range of possible future outcomes in the market, and agreed these with the Commission and with AGL. We also discussed associated weightings for the scenarios, to use in assessing risk.

3.4 Task 4 - Consulted with AGL and other participants

We consulted energy trading staff from AGL and other market participants to gather information relating to:

- the approach to managing risk that an efficient and prudent retailer acting as the standing contract retailer should bear in the South Australian market (that is, assumptions about what amount should be contracted, the timing of such contracting, and what amount should be exposed to spot prices);
- the expected decline in the number of standing contract customers given that AGL and new entrant retailers are offering competitive contracts to small customers in South Australia;
- future supply, especially in relation to new generators and interconnectors, and demand, and how future contract prices currently factor in future expectations;
- the unbundling of contracts for a prescribed class of customers;
- types of contracts that various suppliers are likely to enter into with the standing contract retailer; and

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7 <http://www.nges.com.au/>

8 < http://www.tfsbrokers.com>

- the popular belief that there has been a significant downward trend in forward contract price curves – and hence any consequential change in future standing contract prices that should apply;
- any residual impact of all the vesting contracts applicable to small customers terminating on a single day (31 December 2002), such that AGL SA may have faced an unfavourable "cliff edge" position in terms of their bargaining power with the generators following that period, and the ongoing effect of this, if any, on their subsequent energy bargaining.

We took account of the responses provided by AGL and market participants as we refined our scenarios, built our model, and conducted our analysis.

3.5 Task 5 – Developed model of a 'prudent retailer'

In undertaking this project, we were asked to determine the approach that would be undertaken by a 'prudent retailer' in covering the South Australian standing contract load. Much of our discussions with AGL and other market participants revolved around this topic.

Our discussions identified the following factors that characterise a prudent retailer:

- range of possible scenarios considered when assessing risk;
- approach to meeting objectives of minimising cost and minimising risk;
- contracting strategy for minimising risk; and
- price paid for portfolio of contracts.

We have developed a model of the above factors that:

- takes as input the scenarios for customer load and pool prices, and associated weights, from task 3;
- calculates risk as the load weighted variance due to under- or over-hedging for the range of scenarios on a half-hourly basis;
- use a prudent hedging strategy of finding a portfolio of contracts that minimises risk; and
- hence calculates the wholesale energy cost for peak and off-peak each quarter.

The model enables the Commission to analyse how the future wholesale electricity price depends on expectations about the market in the future. Our model explicitly takes into account variations in expected load and pool prices by calculating risk across the scenarios, which reduces the sensitivity to forecasts. However, different views about quarterly swap (peak and off-peak) and cap contract prices are analysed as different cases, to assist the Commission in reaching a conclusion about allowable contract prices.

We calculate final wholesale energy cost after including the following additional costs of participating in the NEM and purchasing energy:

- NEM operations – all fees and charges that NEMMCO recovers from retailers;

- NEM prudential requirements – the costs associated with providing unconditional payment undertakings and the like;
- network loss factors – as published by NEMMCO which affect the delivered wholesale price of energy to customers;
- embedded generation – AGL advised that during the privatisation of South Australia's electricity market, it inherited contracts for embedded generation that had previously been carried by the Electricity Trust of South Australia (ETSA). These contracts represent energy purchase prices above current market prices. AGL has calculated the extra cost of these contracts as a separate amount to be added to their energy hedging costs. The Commission has advised that it will be investigating the issue of embedded generation.
- MRET uplift – we applied the relevant percentages to AGL's sales to contract load customers to calculate the quantity of RECs required. There are forward curves for RECs also, which we have used to obtain prices for the years relevant to the study. The MRET revenue requirement (quantity of RECs multiplied by prices) was averaged over sales to calculate the dollar per MW hour cost of the scheme.

3.6 Task 6 - Consulted the Commission and AGL on the model

We held workshops with the Commission in Adelaide and a meeting with AGL in Melbourne to describe the operation of our model and to seek feedback and comment.

Based on these discussions and our analysis, we prepared a draft report and discussed it with Commission staff.

3.7 Task 7 - Completed final report

We have completed our final report using further information from AGL and feedback from Commission staff.

Chapter 4

Framework for analysis

4.1 What is a prudent retailer?

Submissions to the Commission have argued that a prudent retailer should seek to purchase energy at the best possible price while appropriately managing risk. However the statement does not provide much guidance about the trade-off between risk and cost of energy purchase. Hence we have designed our model to be able to take account of both risk and cost.

We believe that retailers are essentially in the business of collecting a margin through aggregating smaller demands to leverage wholesale purchases. It can be argued that a prudent retailer should seek primarily to minimise risks, with some, but a lesser, regard to cost. Some may say that customers are then effectively insuring the retailer against risk. This is true to an extent, although it is unlikely that any hedging strategy can remove all risk. AGL is in the position of having to supply the standing contract customers with electricity at a predetermined price, so it would seem reasonable that the Commission have a high degree of confidence that AGL can achieve a hedge cost at the effective wholesale price on which the pre-determined tariff has been set. Therefore, we have undertaken our analysis on the basis that a prudent retailer will seek primarily to minimise risk.

AGL advised that its risk management policy requires a high level of hedge cover, although we have not seen any written policies. AGL has advised that a prudent retailer would seek to contract to levels that cover at least 100% of expected demand under assumptions of medium growth and 50% probability of exceedance.

Accordingly, we have modelled a prudent retailer as minimising risk and contracting to cover at least average demand with swaps in each quarter, and with caps to cover at least 100% of the difference between average and peak load for load growth assuming medium economic growth with 50% probability of exceedance.

4.2 AGL's position in the market

The size and position of the standing contract retailer in the market is also a significant consideration in assessing prudency of approaches.

A small retailer in a liquid market has lower risk and potential higher return than a large retailer in a less liquid market. Smaller retailers have some flexibility in the contract strategies they employ and with whom they contract. A small retailer may even decide that purchasing swap contracts at prices much higher than historical pool prices is unnecessary and elect to take this position to the pool.

However, AGL has an obligation to supply standing contract customers at a predetermined price and is the dominant retailer in the South Australian market. AGL has much less flexibility than a smaller retailer or a retailer who competitively develops a portfolio of customers. It has the majority of the load in South Australia and the rest of the market is aware of this fact.

Several participants argued that AGL's contracting strategy has a direct influence on contract prices and the future direction of pool prices. If AGL elects not to purchase many hedge contracts then generators are under-contracted and have an incentive to offer higher prices in the spot market to gain compensatory revenues. To the extent that AGL buys hedge contracts, generators no longer have the same incentive to see higher pool prices and the pool outcome is lower. Therefore, market participants expect that AGL will operate a conservative hedging policy, buying contract cover well in advance—commencing hedging from 2 to 3 years in advance, with all required cover in place at least 6 months prior to the relevant period—and buying sufficient quantities of swaps and caps to ensure that its risks as South Australia's largest retailer are adequately covered. The high degree of peakiness evident in South Australian demand, especially due to domestic (and therefore small customer) usage, would also mitigate against having a large amount of pool price exposure.

We have obtained historical and current forward hedging contract closing prices from some of the prominent brokers acting in this market as well as closing prices for electricity futures and the AFMA price curve for comparison. The broker closing prices have the benefit of being based on actual trades and real bids and offers for contracts in the market. These forward prices reflect the market's belief of where the average spot price will be for that future period, taking into account all that is known about future supply/demand dynamics.

In order to establish a range of prices at which AGL may contract in the future, we have used the latest closing prices for forward contracts and the opinions of market participants with regards to possible movements in these prices.

Previous studies have used only the AFMA closing curve to determine forward prices. This curve on its own, however, has limited usefulness because it is based upon the expectations of a small number of contributors, rather than actual market trades. These contributors state where they think the curve is, so an 'adjustment factor' has been used in the past in an attempt to reconcile this curve to actual market prices (adding an arbitrary $5 per MWh in 2002 and $3 per MWh in 2003).

Some market participants have argued for a 'liquidity premium' to be added to market forward prices. They argue that large transactions are not dealt at these prices, but at levels that reflect the desire of a generator to make an adequate return on their investment. They further argue that generators are less sensitive to the price they obtain for residual capacity, so will be prepared to take lower prices which then show up in the forward curves. This argument also claims that more distant market prices of contracts are most suspect as very little market trading takes place in such contracts. No market participant was prepared to put a definite figure on the size of such a premium. However, our examination of AGL's large scale hedge contracts indicated that AGL bought contracts at, or very close to, the prevailing forward contract market prices at the time the contracts were made.

Other participants have argued that there is no need for such a premium. They argue that liquidity and price transparency would be greatly increased if market participants traded more often and in smaller quantities, rather than having infrequent, lumpy transactions that characterise the market at present and obscure market prices. They also argue that if published forward market prices are lower than actual hedge contract prices, a significant arbitrage opportunity would exist and the market would move quickly to bring the prices into line with one another.

Given the proximity of financial year 2005-06, it may be valid to use current market prices to determine the cost of the further hedging that needs to be achieved for this period. As we look further into the future however, contract prices are less certain. Also, the market is less liquid, so the forward curve may not be an adequate indicator of prices for larger volumes that AGL might need. We have therefore analysed cases that include premiums to account for some increases in contract prices, perhaps due to changes in the view about the market or supply/demand imbalances. It is also possible that contract prices could remain the same or even fall, in the future.

4.3 Load forecast scenarios

The cost in dollars per MWh of purchasing wholesale energy to meet the small customer load depends more on the shape of the load than on the size.

AGL provided a half-hourly forecast of small customer load for all of its small customers, that is, both standing contract and market contract customers for the three and a half years from 1 January 2005. AGL advised that it does not distinguish between such customers when purchasing electricity but that AGL's forecast implicitly includes AGL's projection of the small customers that will transfer away from AGL to other retailers.

ESIPC provided half-hourly forecasts for all small customers in South Australia for the three years from 1 July 2005, without distinguishing between retailers and hence with no analysis of customer movements between retailers. Forecasts were provided with different assumptions about economic growth (low, medium and high) and weather effects (90%, 50% and 10% probability of exceedance).

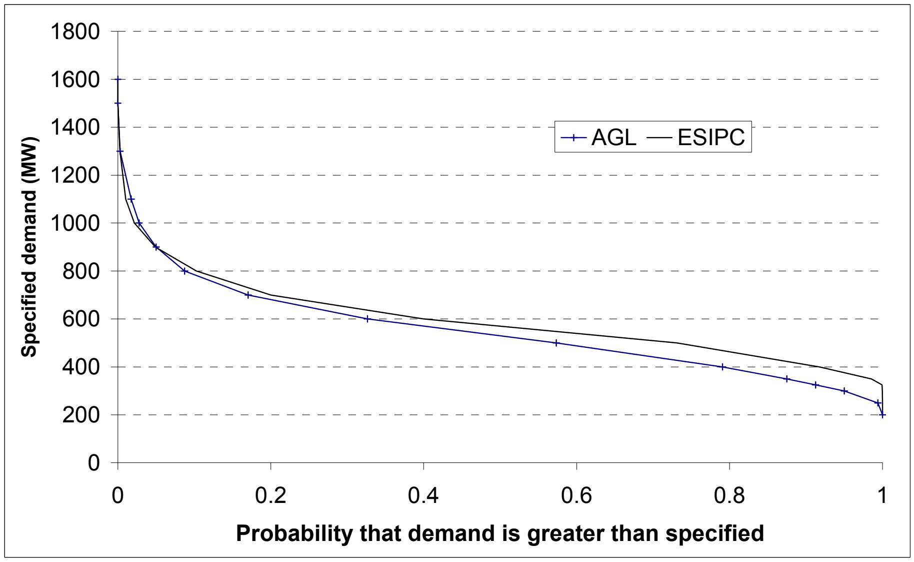
The AGL and ESIPC forecasts had different shapes, with AGL's having more high load peaks and more low load dips compared to the average load than ESIPC as shown in Figure 4.1.

A load profile with more high loads and low loads is generally more expensive to purchase as it has inherently higher risk associated with:

- prices being high when load is high and the retailer is under-hedged; and
- prices being low when load is low and the retailer over-hedged.

Figure 4.1

COMPARISON OF AGL AND ESIPC LOAD PROFILES TAKING ACCOUNT OF CUSTOMER LOSSES FOR 2005-06



Source: AGL base case and ESIPC medium, 50% probability of exceedance

AGL has advised that its load profile is based on 2001 calendar year, with some correction for weather as 2001 may have more extreme events than usual. However it has not provided detail on this correction. ESIPC has based its load profile on financial year 2003-03, which was the most recent available data. Neither AGL nor ESIPC have adequately explained which is the more appropriate load profile.

We are currently using AGL's load profile, on the grounds that AGL expects to have to meet the cost of serving this load. We have however used high and low demand growth scenarios based on the ESIPC load profiles for different growth and weather assumptions, less AGL's advised estimate of expected customer movements.

4.4 Future pool price scenarios

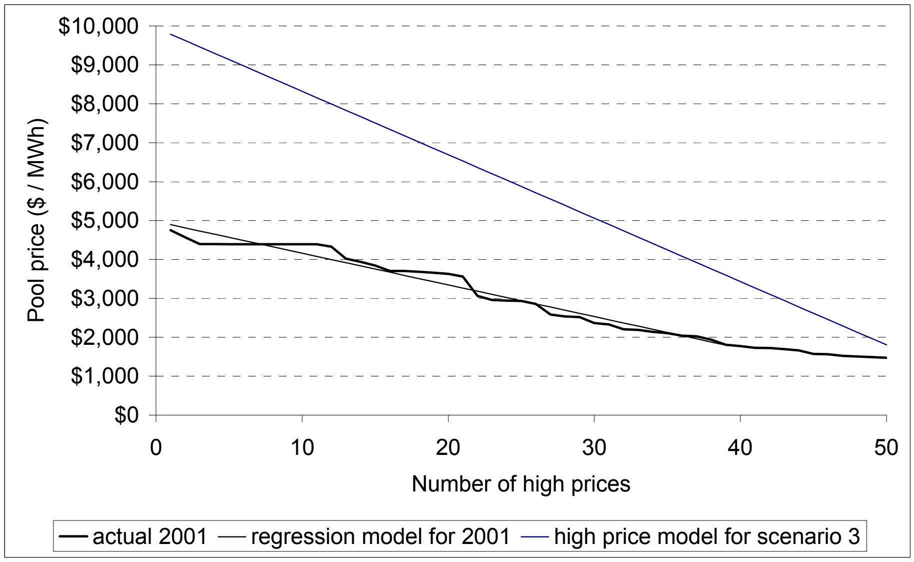
The cost of purchasing also depends on the shape, and to some extent the level, of future pool prices. It is important to understand that our model does not use average pool prices to calculate cost directly or as a guide to future contract prices. Instead it uses the distribution of pool prices to calculate the cost of being under or over-hedged when pool prices are high or low respectively.

We have used the previous three years of historical pool prices to derive a statistical distribution of pool prices.

However, pool prices over this period have averaged $32.27 per MWh, well below the long run marginal cost (LRMC) for a new entrant generator. So we have considered scenarios in which pool prices average the LRMC for a new entrant generator (see section 4.5) and in which they average a value between historical and new entrant. These scenarios have been modelled by including a number of high priced events, which are the most risky for a retailer. We analysed high prices in January and February 2001, which was a high priced season, and found that the 50 highest prices could be described well by a straight line as shown in Figure 4.2.

Figure 4.2

DISTRIBUTION OF HIGH PRICES IN 2001



Source: historical pool prices, ACG analysis

We used the same distribution to add 50 high prices in high priced scenarios, but doubled the prices to take account of the change in Value of Lost Load (VOLL) — the wholesale price cap applied by NEMMCO — from $5,000 per MWh in 2001 to $10,000 per MWh in the study period.

We have also considered scenarios in which pool prices are correlated with customer load: in just January and February when loads and prices are highest; and across the whole year.

4.5 Considering long run marginal cost of generation

Some submissions have argued that the allowable price for future contracts should be new entrant price, appropriately calculated to serve the small customer load.[9]

[9] TXU, Letter to the Commission from Peter Carruthers, 30 July 2004, pp. 6-7.

> As discussed above, if a multi-year price path is to be implemented, it will need to ensure that it recovers the average energy infrastructure costs required by the industry over time. Once this point is accepted, the question of what a suitable long-term average level of pricing to use in the price path energy costing needs to be considered. Such a price level will need to be able to fund existing and future infrastructure. This will need to include investments in generation, and the fuel supply infrastructure required to reliably support such generation.
>
> Over the life of an infrastructure asset, the investment needs to recover its costs on average. Sometimes the contract market may deliver higher returns than this average, and sometimes lower, however over the medium term, the average cost must be recovered if the project is to be viable. On this basis, we recommend that the annualized cost recovery required by new entrant plant be used as the basis for establishing what the medium term price of wholesale energy should be.
>
> This approach is not without precedent. It very much mirrors the Long Run Marginal Cost ("LRMC") based approach, which was adopted by IPART in NSW. Even in the last SA price review, this approach was used to estimate the cost of Cap contracts in SA.

The ESIPC has provided the Commission with a report on new entrant price for a mix of base load and peaking generation to meet the mix of small customer load. We have used these prices as an input to pool price scenarios that average new entrant levels, and in calculating new entrant price premiums for contracts.

The ESIPC report considered a mix of base load and peaking plant that would be needed to supply small customer load. The LRMC of generation is the cost, including capital appropriately amortised over the long run, of meeting the next increment of customer load. However, given the difficulty of deciding whether the next increment of small customer load should be met by base load or peaking plant, it is appropriate to use the combination proposed by ESIPC. In effect, the LRMC is the load-weighted price of meeting the next increment of small customer load.

In using the LRMC, we have needed to use time weighted averages, both for pool price scenarios and for contract pricing.

Table 5.2 of the draft ESIPC report dated 31 August 2004 derives the LRMC from 9 cases and 9 new entrant curves. For simplicity, we have used the base case (ESIPC case 5 and new entrant curve 1). This comprises:

- average load weighted cost of $60.34 per MWh to meet small customer load excluding hot water ($58.91 per MWh if hot water load included)
- base load CCGT running at 63.4% capacity factor; and
- peaking plant running at 1.0% capacity factor.

Table 4-8 (and figure 4-2) of the ESIPC report gives a regression equation for estimating the time weighted average price for the busload component, as a function of capacity factor. At the level of 63.4%, the energy cost is $47.07 per MWh. This has been used as the target average price for new entrant pool price scenarios, and the new entrant flat price for swaps.

Table 4-8 of the ESIPC report also gives a regression equation for estimating the time weighted average price for the peaking component, as a function of capacity factor. We used this equation to estimate the price for caps offered by a new entrant peaking plant, assuming that it sells 100% of its capacity as caps. This will, in fact, over-estimate the price for caps, as it includes all operation and maintenance costs, and does not take into account any pool revenue from running to back up swaps. At 100% capacity factor, the cost is $15.66.

AGL argued that average South Australian transmission loss factors should be added to new entrant costs to produce a price at the regional reference node. We do not agree, as the new entrant price ceiling applies at the regional reference node. In any event, the next increment of capacity is likely to be built very close to the regional reference node, so the specific transmission loss factor is close to one.

Chapter 5

Scenarios, results and findings

5.1 Scenarios

We have analysed the potential future in terms of five possible scenarios — one in which pool prices are at historical levels and load is at forecast levels; two in which pool prices are varied from historical levels; and two more in which load is varied from forecast levels:

Scenario 1 AGL load forecast and pool prices reflect the historical averages over the preceding three years (2001-02 to 2003-04). Demand and pool price are synchronised in January and February.

Scenario 2 AGL load forecast with historical pool prices. However in this scenario we also assume that pool prices are perfectly synchronised with customer load, in that pool prices are highest when load is highest, and lowest when load is lowest.

Scenario 3 AGL load forecast with pool prices averaging at new entrant levels due to 50 high price events in February following a similar pattern to 2001 but with prices doubled because VOLL is now $10,000 per MWh rather than $5,000 per MWh. Demand and pool price are synchronised in January and February.

Scenario 4 ESIPC load forecast for 90% POE and low economic growth, adjusted by AGL for its expectation of customer loss to other retailers, and historical pool prices. Demand and pool price are synchronised in January and February.

Scenario 5 ESIPC load forecast for 10% POE and high economic growth, adjusted by AGL for its expectation of customer loss to other retailers, and historical pool prices plus half the number of high price events as in scenario 3, resulting in pool prices at half new entrant levels. Demand and pool price are synchronised in January and February.

Scenario 2 accounts for the risks arising from AGL facing high pool prices when under-hedged and low prices when over-hedged. Scenario 3 accounts for the possibility of future pool prices going as high as new entrant levels of $47 per MWh as the market prices in a need for new investment in generation, even though pool prices over the preceding three years have averaged only $32.27 per MWh.

Scenarios 4 and 5 take into account the possibility that actual load will differ from AGL's forecast load due to weather factors, and also account for the possibility of greater customer transfers away from or to AGL than predicted.

Synchronising demand and pool price represents the highest risk outcome for reasons discussed previously, namely that the retailer may be under-hedged when prices are high and over-hedged when prices are low.

5.2 Scenario weightings

The above scenarios represent a possible range of future conditions. They can be used to analyse risk by assigning weights to the scenarios based on the probability of each scenario coming to pass. The weights could also take into account the effect each outcome would have on the financial returns to AGL. For instance, many high demand/high price events would cause a large financial loss to AGL were it not adequately hedged against this event, while being over-hedged and facing low pool prices would have less severe financial repercussions.

We had suggested weights of 20% for each of the 5 nominated scenarios. AGL has disagreed, saying:

> AGL was asked at short notice to give a view on the relative weightings of the 5 "hedging" scenarios. Scenarios 3 and 5 are likely to cause the largest financial impact to AGL, and based on a limited understanding of the model achieved at yesterday's meeting have been slightly more highly weighted. It is proposed that the weightings be: Scenario 1: 10% (Allens suggested that this scenario would be altered slightly to include price and demand correlation for Jan and Feb) Scenario 2: 20% Scenario 3: 25% Scenario 4: 20% Scenario 5: 25%.
>
> AGL email of 1 Sep 2004

The Commission has given consideration to the issue of what weights to use, and proposes using those suggested by AGL.

With these agreed weights for each of these scenarios in the model, we can calculate the risk as the probability weighted sum of variances between the cost of purchasing at the single best expected price and the different cost of purchasing under different scenarios. This is the same approach taken in financial portfolio theory.

We can also calculate the expected cost of hedging the load as the probability weighted sum of costs under each scenario.

5.3 Guidelines for contract cover

The previous chapter discussed various ways to approach the topic of establishing hedge cover and the adequate level of such cover required.

In order to establish an adequate amount of cover we have put parameters on the level of hedging the model will require to construct its portfolio. We have assumed that swap cover will be purchased to at least the level of the average load in each quarter and that the balance between this amount and the maximum quarterly demand under the base case forecast will be hedged using caps.

5.4 Contract prices

AGL has existing hedge contracts for a proportion of its small customer load and it will need to purchase additional contracts over the coming weeks and months to build its portfolio to its required level.

The Commission's Terms of Reference require it to take into account AGL's actual costs, but it has also asked whether AGL has acted prudently in purchasing existing contracts. We have considered separately:

- the already committed cost of hedging the proportion of load already covered; and
- the cost of hedging the remaining forecast load in the future.

As we calculate the cost of hedging on a quarterly basis, for both peak and off-peak demand, we have broken the value of swap and cap contracts down into peak and off-peak prices to reflect the cost of hedging each quarter. We have also assumed that swap quantities are uniform across each quarter, peak and off-peak. Swap contracts are not necessarily written this way, but it provides the most convenient way to describe and compare contracts.

Cost of hedging the load already covered

AGL has provided information about its existing contracts in terms of quarterly peak and off-peak flat quantities and prices. We have compared these prices with what was available in the market at the time the contracts were written. Our advice to the Commission is that AGL acted prudently when purchasing these hedges and therefore it is reasonable to use these historical prices when assessing the total cost of AGL's hedging requirements.

Cost of hedging the load yet to be covered

It is not possible to be definite about the prices for hedging load yet to be covered. We have taken this uncertainty into account by analysing three cases for future contract prices. In each case, we have used our model to construct an optimal portfolio by buying new contracts at specified prices, while taking into account existing contracts and prices, and the above policy for level of contract cover.

Case A Contracts can be bought at current forward prices, as shown in Table 5.1.

Case B Prices as in case A plus a risk premium. In the electricity market, as in other financial markets, it is possible for participants to hedge against the possibility of adverse moves in future contract prices by purchasing an option. An option gives the buyer the right, but not the obligation, to lock in a particular price at a certain time in the future. In this way a retailer who would not want contract prices to rise may buy a call option allowing him to purchase contracts at today's prices at some future time. If contract prices rise they will exercise their right to buy at the strike price. However, if prices have fallen they will elect not to exercise their option and buy contracts at the prevailing, lower, price. The premium paid for such an option represents the market's best estimate of the risk of future contract price moves. In establishing the risk premium in this contract price case we have calculated the cost of buying a call option to cover half of the remaining hedge quantity at present contract prices. The reason for allowing cover for only half the load is that if we allowed a premium to cover the full load then any possibility of having to pay higher prices would be annulled but a windfall profit would accrue if contract prices fell in the future.

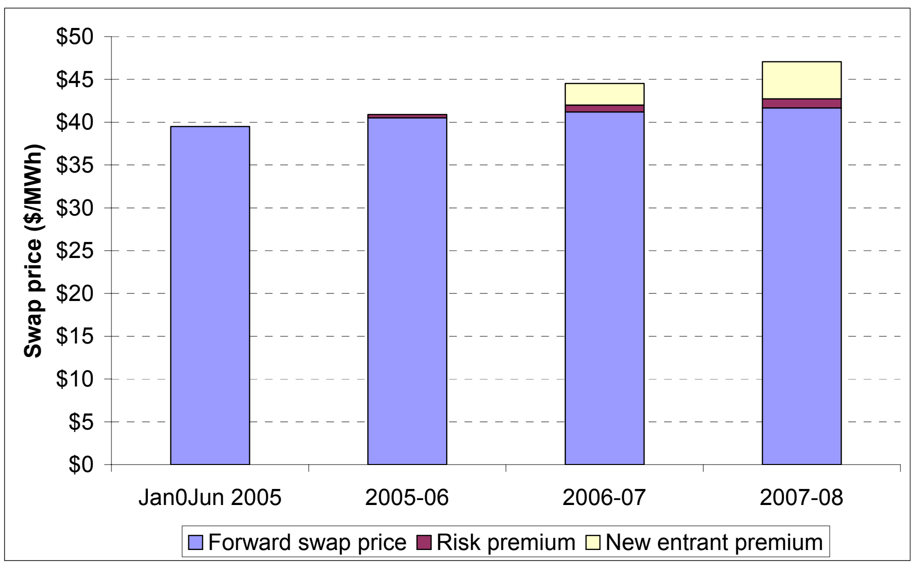
Case C Prices as in case A, plus a premium rising from $0 in 2005-06 to new entrant levels by 2007-08. This latter price level should facilitate a liquid contract market, as contracts could be sold by parties considering entry into the market even if not currently generating

Table 5.1
FORWARD CONTRACT PRICES AS AT AUGUST 2004

Year	Forward swap price ($/MWh)	Forward cap price ($/MWh)
2005	$39.50	$9.50
2006	$40.50	$9.50
2007	$41.20	$9.50
2008	$41.66	$9.50

Source: NGeS, AFMA

Figure 5.1
FORWARD CONTRACT PRICES ($/MWH)



Source: Table, ACG analysis

As discussed in Chapter 4, most submissions have argued that current forward prices do not represent an appropriate price level for AGL's further hedging requirements. However, we expect that sufficient volumes could be traded within the range implied by cases A, B and C to meet AGL's requirements to at least 2006-07. The Commission will need to form a view about where in the range to choose.

5.5 Results

Table 5.2 and Figure 5.2 show the expected load weighted prices calculated from our modelling of optimal portfolios, for each of the contract cases and for each of the years.

Prices in the first half of 2005 appear higher but are not. They are load weighted prices averaged over half a year, compared to other prices that are averaged over a full year, so the high cost of the January quarter is most pronounced. The load-weighted price falls over time as current higher priced swap contracts could be replaced with lower priced contracts. Price fall considerably in 2007-08 as caps terminate and are replaced with lower priced caps. Case B is more expensive by approximately the amount of risk premium assumed to be added to forward prices. However differences are small in 2005-06 and 2006-07 as AGL does not need to purchase much additional contract cover. Contract Case C has contract premiums rising to new entrant level in 2007-08, and the total costs rise accordingly.

Table 5.2

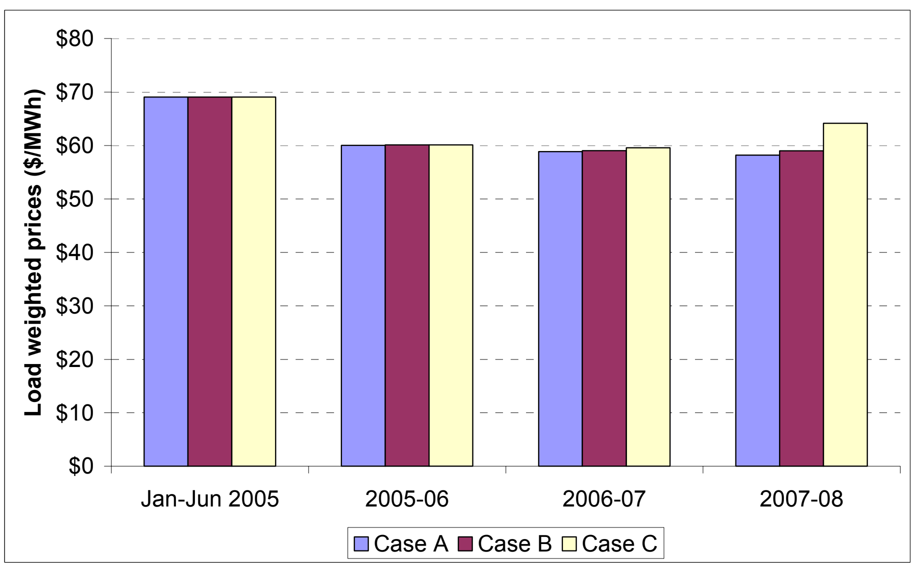
LOAD-WEIGHTEDCOSTS FOR CONTRACT CASES ($ PER MWH)

	Jan-Jun 2005	2005-06	2006-07	2007-08
Contract Case A	$69.08	$60.02	$58.84	$58.18
Contract Case B	$69.08	$60.11	$59.04	$59.00
Contract Case C	$69.08	$60.11	$59.56	$64.17

Source: ACG modelling of optimal portfolio

Figure 5.2

LOAD-WEIGHTED COSTS FOR CONTRACT CASES ($ PER MWH)



Source: ACG modelling

Further analysis has been provided to the Commission on a confidential basis, so as not to prejudice AGL's commercial negotiations in respect of future contracting.

Additional charges

In order to arrive at a total cost of energy at the meter it is necessary to add on pass through costs to the modeled energy price. These costs comprise the following:

- NEMMCO fees and charges, ancillary services, bank guarantee fees and the premium attributable to the use of embedded generation — AGL has provided figures, which will need to be audited.
- Mandatory Renewable Energy Target compliance — Every year AGL, like all electricity retailers, must purchase an increasing percentage of their power sales from renewable sources. Generators of such power create Renewable Energy Certificates, or RECs, which are then purchased by retailers and surrendered to the Office of the Renewable Energy Regulator to meet their obligations. After consultation with the ORER we have established the likely percentage of energy sales that will attract a REC obligation over the course of the financial years 2005-06 to 2007-08. Contracts for the sale of RECs have dealt in the market in a similar manner to electricity derivative contracts and closing price curves are also available to allow us to see current market prices. Like electricity contracts it is likely that a REC obligation would be purchased over time so we have calculated the cost of the REC liability by using the average of the last 12 months forward prices for the certificates. The breakdown is shown in Table 5.3.

Table 5.3
REC REQUIREMENTS

Year	% required	$ cost per REC	$ per MWh equivalent
Jan-Jun 2005	1.63	43.06	0.70
2005-06	1.90	43.84	0.83
2006-07	2.43	45.26	1.10
2007-08	2.98	46.61	1.39

- Loss Factor — ETSA Utilities has advised that the loss factor for transmission and distribution losses is 1.0812. The loss factor should be used to multiply the energy price at the reference node to give prices at the customer meter. ETSA Utilities advised that there were no grounds for knowing the how this figure might change over time, so we have included it as a constant in our analysis.

Because our model has already calculated the costs associated with being over- or under-hedged and the costs associated with the potential for increases and decreases in the number of AGL's small customers, we see no necessity for further cost add-ons.

Total wholesale cost of electricity at the customer meter

The sum of all the relevant costs and changes that make up the wholesale cost of electrical energy at the meter for standing contract customers is shown in Table 5.4.

Table 5.4

WHOLESALE COST AT THE CUSTOMER METER — FOR CONTRACT CASE B ($ PER MWH)

	Jan-Jun 2005	FY 2005-06	FY 2006-07	FY 2007-08
Energy hedging cost	$69.08	$60.11	$59.04	$59.00
Pass through costs				
NEMMCO fees	$0.39	$0.40	$0.41	$0.42
Ancillary services	$0.75	$0.60	$0.62	$0.63
Bank guarantee	$0.10	$0.10	$0.10	$0.10
Embedded generation[10]	$0.47	$0.51	$0.55	$0.59
MRET	$0.70	$0.83	$1.10	$1.39
Total before losses	$71.49	$62.55	$61.82	$62.13
Line losses	$5.81	$5.08	$5.02	$5.04
Energy costs at meter	$77.30	$67.63	$66.84	$67.17
Energy cost at meter (Dec 2004 prices)	$76.82	$65.98	$63.61	$62.38

Source: ACG modelling, assuming an annual inflation rate of 2.5%

Table 5.4 also shows prices in real (December 2004) terms, assuming an inflation rate of 2.5%.

[10] The Commission is considering whether embedded generation should be included.