Information Paper prepared for the Essential Services Commission of SA

Estimates of the long run marginal cost of supplying electricity to small customers in 2005

Electricity Supply Industry Planning Council

31 August 2004

Table of Contents

List of Tables and Figures

1 EXECUTIVE SUMMARY

1.1 Introduction

The Essential Services Commission of South Australia (ESCOSA) wrote to the Planning Council on 21 April 2004 seeking advice regarding the long run marginal cost (LRMC) of electricity supply for small customers during 2005. The Planning Council understands that the estimated LRMC will be used as one of the indicators that ESCOSA will consider in determining AGL's standing contract prices for the period 1 July 2005 to 30 June 2008.

This Information Paper has been prepared by the Planning Council to outline its estimate of the LRMC of supply and to describe the methodology and assumptions used in the analysis.

The estimated LRMC is a delivered energy cost which excludes transmission and distribution network charges and retailer margins and overheads which can amount to more than fifty percent of the final price paid by consumers. The estimates do, however, effectively include the cost of risk associated with exposure to the wholesale electricity market, as the LRMC represents the cost of physically supplying a load increment with the same characteristics as the existing small customer load including sufficient peak load and reserve plant to reliably meet their demand profile. A new market participant could, in principle, supply small customers with electricity at prices no greater than the LRMC, placing a cap on the energy price able to be sustained by incumbents operating in a competitive market.

The LRMC estimate will not necessarily align with either AGL's average cost over the next few years or the costs faced by a hypothetical prudent retailer in purchasing energy in the wholesale market and managing financial risks via the contracts market.

1.2 Methodology and assumptions

Calculation of the LRMC has two main elements:

- the cost of new entrant generation of several types in South Australia; and
- the load profile applicable to the small customer segment and hence the optimal mix of generation plant to reliably supply that load.

Candidate new entrant generators examined for this work were all gas fired and included both open cycle and combined cycle plant of several sizes. Information available to the Planning Council indicates that in some other States black coal fired generation may provide a lower cost for base load generation with a high capacity factor. The scope for such plant in meeting the South Australian small customer load is relatively small and, when coal transport costs are taken into account, any potential advantage is removed. At the other end of the scale it is possible that some demand side response may be able to meet extreme peak loads at a lower cost than open cycle gas turbines. The lack of demand side response in the market has, however, been noted by a number of reviews. Both ESCOSA and the Planning Council have work in progress related to demand side response.

The estimates of the long run marginal cost of supply are critically dependent upon the capital cost of plant installed, the cost of capital and the cost of gas. The capital cost of the plant includes the cost of the gas turbine, which is dependent on world market prices and exchange rates, and the site costs. High cost outcomes for these elements have been considered and are presented as sensitivities on the base case. The Planning Council has not considered low generation cost sensitivities as these are likely to be project specific and unique to individual proponents. Such opportunities might include, for example, the installation of refurbished generation plant or favourable access to a particular site or existing infrastructure.

The price estimates are based on generator new entrant price curves developed with the assistance of engineering consultants SKM. The key cost factors have also been tested with industry information available to the Planning Council, including a survey of generator capital and operating costs. The sensitivity labelled ‘New Entrant Curve 1’ represents costs considered able to be achieved by an efficient participant and therefore represents a base case estimate in a competitive market context.

To examine the potential impact on prices of various key generation cost components, the remaining eight new entrant price sensitivities all consider higher costs in one form or another. These are: (curve 2) higher initial capital cost; (curve 3) shorter plant life; (curve 4) 5% fuel price increase; (curve 5) 60c USD/AUD exchange rate; (curve 6) higher required IRR; (curve 7) higher required IRR and shorter plant life; (curve 8) higher required IRR and 3.5% fuel price increase; and (curve 9) higher required IRR and 60c USD/AUD exchange rate.

The projected 2005 load profile for small customers is based on 2003 load trace data provided by AGL, together with the Planning Council’s forecasts of growth of energy and peak demand between 2003 and 2005. There are necessarily some elements of uncertainty in these forecasts and a base case along with eight sensitivities are presented to show the range of outcomes possible, as described in the following table. Case 5 represents the base case load growth assumptions.

Assumptions used to forecast 2005 small customer load profiles

		Assumed ratio of small customer 50% PoE demand to large customer 50% PoE demand		
		57/43	60/40	63/37
Assumed small customer energy growth, 2003 to 2005	0.0%	Case 1	Case 2	Case 3
	2.0%	Case 4	Case 5	Case 6
	4.0%	Case 7	Case 8	Case 9

The load profile of the small customer segment in South Australia reflects the very “peaky” profile which is continuing to be driven by summer air-conditioning load. The load profile requires a large amount of plant to meet the peak load and poor utilisation of much of that plant. The optimal mix of plant determined by the Planning Council included around 49% of combined cycle plant operating at an average load factor of around 63%, complemented by some 51% of open cycle plant operating at an average load factor of only 1%.

Two sets of results are included for the small customer sector, one set including the hot water load and the other set excluding it. For comparative purposes, the Planning Council has also estimated the LRMC of supply for large customers in 2005. The large customer load profile was estimated by growing the 2003 state-wide load profile to its estimated 2005 level using forecasts reported in the *2004 Annual Planning Review*, then subtracting the Case 5 small customer load profile.

The resulting price estimates are delivered energy costs; they do not include transmission and distribution charges or other retailer costs. Two price estimates are reported for each scenario, one being the energy cost at the reference node, and the other allowing for transmission and distribution losses and certain pass through costs imposed on retailers by NEMMCO for market fees and ancillary services, the cost of meeting renewable energy obligations and the prudential costs associated with operating the market. The Planning Council has assumed these pass through costs total $1.50/MWh, as calculated by IES in previous work for the Commission.

2004-05 loss factors have been applied to arrive at delivered energy prices. Average losses are assumed to be 8.08% for small customers and 6.47% for large customers. The generator loss factor has been assumed to be 1.000. Depending upon the location chosen for a new generator, its loss factor could be higher or lower than unity and contribute to higher or lower delivered costs. In this work it is expected that an efficient new entrant gas plant would be located close to the regional reference node.

The pricing calculations assume that the small and large customer sectors operate as stand-alone markets and hence plant calculations reflect investment and utilisation solely for the small customer segment. An alternative approach, which has not been considered, would be to estimate the cost to supply one or the other sector and the total SA market, with the difference reflecting the incremental cost of supplying the other group of customers. Such an approach may result in lower cost estimates for one or the other sector as it would allow for diversity of demand across the two sectors and a reduction in the combined level of plant assumed necessary to support both market sectors. On the other hand, the estimates do assume the use of scale efficient plant.

The level of generation plant assumed necessary to supply each market sector includes plant necessary to supply a 10% PoE level of demand plus the required level of reserves in SA. Sixty per cent of this unused and reserve plant has been attributed to the small customer market and forty per cent to the large customer market. The cost of this reserve plant is therefore included in the final LRMC price estimates[1].

1.3 Summary of results

The following table summarises the Planning Council's 2005 LRMC estimates.

[1] Some 40 MW of demand side response has been assumed available within the large customer segment of the market, reducing the level of reserve plant required to support this group of customers. No demand side response has been assumed available within the small customer segment of the market.

Summary of LRMC estimates, $/MWh

	Large loads (>160 MWh)	2005 Small customer loads (< 160 MWh), excluding hot water load								
		Load growth scenario								
		Case 1	Case 2	Case 3	Case 4	Case 5 BASE CASE	Case 6	Case 7	Case 8	Case 9
New entrant curve 1 BASE CASE	57.64	66.06	67.30	68.44	65.49	66.84	68.03	64.91	66.40	67.70
New entrant curve 2	58.25	66.86	68.13	69.30	66.27	67.65	68.87	65.68	67.20	68.53
New entrant curve 3	59.23	68.14	69.45	70.66	67.53	68.95	70.20	66.90	68.46	69.83
New entrant curve 4	59.02	67.45	68.70	69.83	66.89	68.25	69.44	66.31	67.82	69.13
New entrant curve 5	61.90	71.67	73.12	74.45	70.99	72.54	73.92	70.29	71.99	73.48
New entrant curve 6	60.55	69.87	71.25	72.51	69.22	70.70	72.02	68.56	70.19	71.62
New entrant curve 7	62.21	72.08	73.54	74.90	71.38	72.94	74.34	70.67	72.36	73.86
New entrant curve 8	61.93	71.26	72.64	73.91	70.62	72.11	73.43	69.97	71.61	73.04
New entrant curve 9	65.38	76.22	77.83	79.32	75.44	77.15	78.69	74.66	76.51	78.16

The sensitivity that the Planning Council considers best represents a base case indicates an delivered energy cost of $66.84/MWh for the small customer market during 2005. This price is based on returns to capital proposed by our consultants SKM. The returns a market participant might require to invest will vary depending upon their perception of the risks. A delivered energy cost of $70.70/MWh would be required to meet a higher project rate of return[2]. These prices include network losses and pass through charges, but exclude the hot water load.

- If the hot water load is included in the small customer load profile, the estimated LRMC is approximately $1.50/MWh lower.
- The comparable cost for supply to large customers in 2005 is estimated to be $57.64/MWh to $60.55/MWh.
- Under the base case new entrant pricing model, the LRMC of supply for small customers (excluding the hot water load) varies between $64.91/MWh (-2.9%) and $68.44/MWh(+2.3%), depending on assumed growth of customer sales and the share of peak demand attributable to the small customer segment of the market.
- Under the base case load growth assumptions, the LRMC could be as high as $77.15/MWh (+15%) if a combination of high cost outcomes are assumed in the calculation of new entrant generation prices.

[2] The Planning Council's financial assumptions are set out below. The key assumption within the new entrant pricing model is the assumed project IRR, as the model solves for the $/MWh price necessary to achieve this rate of return from the perspective of the project as a whole. Interest, tax and dividend payments do not figure in this calculation.

	New entrant curves 1 to 5	New entrant curves 6 to 9
Project IRR (real)	9.1%	10.3%
Cost of debt (nominal)	7.8%	9.0%
Cost of equity (nominal)	11.8%	13.0%
Debt to equity ratio	50%	50%

2 INTRODUCTION

2.1 Purpose of this Information Paper

The Essential Services Commission of South Australia (ESCOSA) is conducting an Inquiry into electricity standing contract prices to apply to small customers for the period 1 July 2005 to 30 June 2008.

Standing contract prices apply by default to small customers that elect not to enter into a market-based contract with AGL or another electricity retailer operating in South Australia. Small customers are defined as those consuming up to 160 MWh of electricity annually. This group includes almost the entire residential sector of some 660,000 customers and almost 80% of the State's 90,000 business customers. Approximately 90% of small customers have not yet switched to a market contract and therefore pay the current standing contract price.

ESCOSA wrote to the Planning Council on 21 April 2004 seeking advice regarding the long run marginal cost (LRMC) of electricity supply for small customers in 2005. The Planning Council understands that the LRMC will be used as one of the indicators that ESCOSA will consider in determining standing contract prices for the period 1 July 2005 to 30 June 2008.

The Planning Council prepared the requested LRMC estimates during June and July 2004 following discussions with ESCOSA and AGL and presented a summary of the estimates to ESCOSA in a letter dated 2 August 2004. This Information Paper was subsequently prepared to outline in more detail the methodology and assumptions used to arrive at the LRMC estimates. The Planning Council understands that ESCOSA may publish the Information Paper and seek comments from interested parties as part of its Inquiry into standing contract prices.

2.2 Scope of costs covered by the LRMC

The LRMC estimate and related sensitivities presented in this Information Paper are delivered energy costs. They exclude network charges and retailer margins and overheads, which can amount to more than fifty percent of the final price paid by consumers. The estimates do, however, include the cost of risk associated with exposure to the wholesale electricity market, as the LRMC represents the cost of physically supplying a load increment with the same characteristics as the existing small customer load. A new market participant could, in principle, supply small customers with electricity at prices no greater than the LRMC, placing a cap on the energy price able to be sustained by incumbents operating in a competitive market. However, the LRMC will not necessarily align with either AGL's average energy cost over the next several years or the costs faced by a hypothetical prudent retailer purchasing energy in the wholesale market and managing related risks in the contract market. The LRMC may be higher or lower, depending on AGL's hedging decisions, prices available in the contract market, and actual generation costs[3].

[3] For example, the LRMC estimates are based on the cost of new gas-fired generation plant. Actual generation costs may be less than this due to the availability of existing coal-fired plant in both South Australia and across the interconnectors with Victoria.

The LRMC estimates are based on a 50% probability of exceedance (PoE)[4] load profile for small customers, as this load shape represents the most likely outcome in a statistical sense. That said, the LRMC, as it has been calculated by the Planning Council, includes the costs of providing and maintaining sufficient spare generation plant to meet an extreme 10% PoE demand level plus NEMMCO's minimum reserve requirement in South Australia.

Two types of LRMC estimate are presented in the Information Paper, one representing the cost of energy at the South Australian reference node, and the other allowing for transmission and distribution losses and certain mandatory pass through costs imposed on the wholesale price of electricity. LRMC estimates are also presented for the small customer group including and excluding the hot water load.

The customer demand profiles used in the Planning Council's analysis are assumed to cover all small customers in South Australia, not just AGL's small customers, and not just those currently on standing contracts. Customer transfers to AGL's market contracts or to other retailers operating in South Australia are not expected to alter the underlying shape of the demand profile of standing contract customers, or the cost of supplying energy to this group of customers, because under the NEM rules all small customers are deemed to have an identical load shape. If AGL's actual un-metered load shape is altered by small customer transfers, this may reflect larger customers being included within the un-metered load supplied by AGL. Time of use metering for these larger customers would avoid this impact.

2.3 Overview of methodology

Estimation of the LRMC of electricity supply has two key elements:

- the cost of new entrant generation, expressed as estimates of the $/MWh prices that must be achieved at various load factors to remain financially viable; and

- the load profile applicable to the small customer segment of the market and hence the optimal mix of plant to reliably supply that load.

The candidate new entrant generators examined for this work were all gas fired and included both open cycle and combined cycle plant of several sizes. The new entrant prices have been modelled in some detail with the assistance of consultants SKM and tested with industry information available to the Planning Council. Consistent with the competitive market in which the industry operates, these prices are considered to be achievable by an efficient participant.

The generator costs are critically dependent upon the capital cost of the plant installed, the cost of capital and the cost of gas. The capital cost of the plant includes the cost of the gas turbine, which is dependent on world market prices and exchange rates, and the site costs. High cost outcomes for these elements have been considered and are presented as sensitivities on the base case. Possible low cost sensitivities have not been considered, for example, the possibility

[4] Usual practice within the electricity industry is to present demand forecasts on a "probability of exceedance" basis due to the close correlation between electricity use and ambient temperatures and the inherent unpredictability of the weather beyond a few days. A 50% PoE demand forecast is considered to have a 50% probability of being exceeded and, as such, should be exceeded every second year on average. Similarly, a 10% PoE demand forecast should be exceeded in only one year out of every ten.

of purchasing cheaper plant such as refurbished second-hand gas turbines or favourable access to fuel supplies or a site for the plant. In a highly competitive market it will typically be the party best able to exploit such niche opportunities and financial advantages that actually becomes the new entrant. Similarly, demand side initiatives within the small customer sector, depending on their cost and feasibility, might also allow a lower LRMC of supply than estimated by the Planning Council[5].

The small customer load profile for 2005 is based on historic 2003 load trace data provided by AGL and the Planning Council's forecasts of energy and peak demand growth between 2003 and 2005. These profiles have been checked for reasonableness and compared with similar data obtained from ETSA Utilities. There are necessarily some elements of uncertainty in these forecasts and a base case along with eight sensitivities are presented to show the range of outcomes possible.

The load profile of the small customer segment reflects the very "peaky" nature of demand in South Australia, which is continuing to be driven by growth of the summer air-conditioning load. Such a load profile requires a large amount of plant to meet the potential peak demand and provide reserves, and a correspondingly poor utilisation of much of that plant. The optimal mix of plant identified by the Planning Council included around 49% of combined cycle plant operating at an average load factor of around 63%, complemented by some 51% of open cycle plant operating at an average load factor of only 1%.

In seeking to provide some perspective on the results, the Information Paper includes estimates of the LRMC of supply for the large customer segment of the market. The pricing calculations assume each market sector is a stand-alone market. An alternative approach, which has not been considered, would be to estimate the cost to supply one or the other sector and the total South Australian market, with the difference reflecting the incremental cost of supplying the other group of customers. Such an approach may result in lower cost estimates for one or the other sector as it would allow for diversity of demand across the two sectors and some reduction in the combined level of generation assumed necessary to support both market sectors.

[5] As discussed in *Section 5 Derivation of LRMC estimates* the estimates of the cost to supply large customers allow for the benefits, but not the costs, of existing committed levels of demand side management. None of this demand side capacity has been allowed for in estimating the cost to supply small customers.

3 LOAD FORECASTS

Estimating the LRMC of supply for small customers in 2005 requires the preparation of a forecast load profile for that year. This forecast has been prepared by applying an algorithm to adjust the 2003 load profile to reflect forecast peak demand and total energy consumption levels in 2005. The following section describes the historic load data used as the basis for forecasting the 2005 load profile. Subsequent sections then describe the 2005 peak demand and energy forecasts and the resulting 2005 load profile and related sensitivities.

3.1 Historic load data used in the analysis

For the purposes of undertaking this work the Planning Council accessed two sources of data showing historic half hourly demand for small customers:

- estimates for calendar year 2003 provided by ETSA Utilities, derived as the difference between ETSA Utilities' total load and the sum of all of ETSA Utilities' large (greater than 160 MWh) loads that have half hourly metering in place; and

- regression estimates of the small customer load for calendar years 2001 and 2003 provided by AGL.

Both of these data sets are only estimates of the actual small customer load profile and each has its advantages and disadvantages.

- The estimates obtained from ETSA Utilities have the obvious benefit of being based on metering data obtained from an independent source. However, the data includes electricity used by a number of large customers that do not have time of use metering, and it is measured at customer meters rather than the South Australian reference node. The data also includes a reasonably large number of readings that imply the small customer load is negative during some periods around midnight after the estimated hot water load profile is deducted[6].

- The second source of data was produced by AGL using an in-house regression model. The regression model estimates the total small customer load at the South Australian reference node as a function of total South Australian demand. AGL's estimated load profile is, in principle, the correct data series required for undertaking this work, and the estimated data does not give rise to the issue of negative levels of demand after the hot water load profile is deducted.

While the Planning Council's preference would normally be to base its forecasting work on independently metered data, the shortcomings noted above regarding the data obtained from ETSA Utilities required that the LRMC work be based on AGL's estimated data. AGL's

[6] The South Australian hot water load profile published on NEMMCO's web site has been used throughout this analysis. This is an estimated profile based on a sample of customers, as opposed to the actual metered profile for the entire hot water load. The issue of negative overnight loads during some periods may reflect inaccuracies or errors in either the meter data provided by ETSA Utilities or the estimated hot water load profile or both.

estimated load profiles have been examined carefully for overall reasonableness and compared with the data provided by ETSA Utilities. The results of this examination, and the underlying characteristics of the estimated small customer load profile, are summarised in the following charts and table. On the basis of this assessment, the Planning Council is satisfied that AGL's estimated load profile is a reasonably accurate representation of the small customer load profile.

Figure 3.1 compares average within-day small customer load profiles derived from the 2003 data provided by AGL with similar figures derived from the data provided by ETSA Utilities. The two sets of data display very similar daily average load profiles for business days and non-business days within each season. The unusual drop in demand around midnight in the ETSA Utilities data is clearly evident. This feature of the ETSA Utilities data results in negative load estimates after the hot water load profile is deducted and has precluded the use of this data in the LRMC analysis.

Figure 3-1 Comparison of AGL and ETSA Utilities small customer load data, 2003

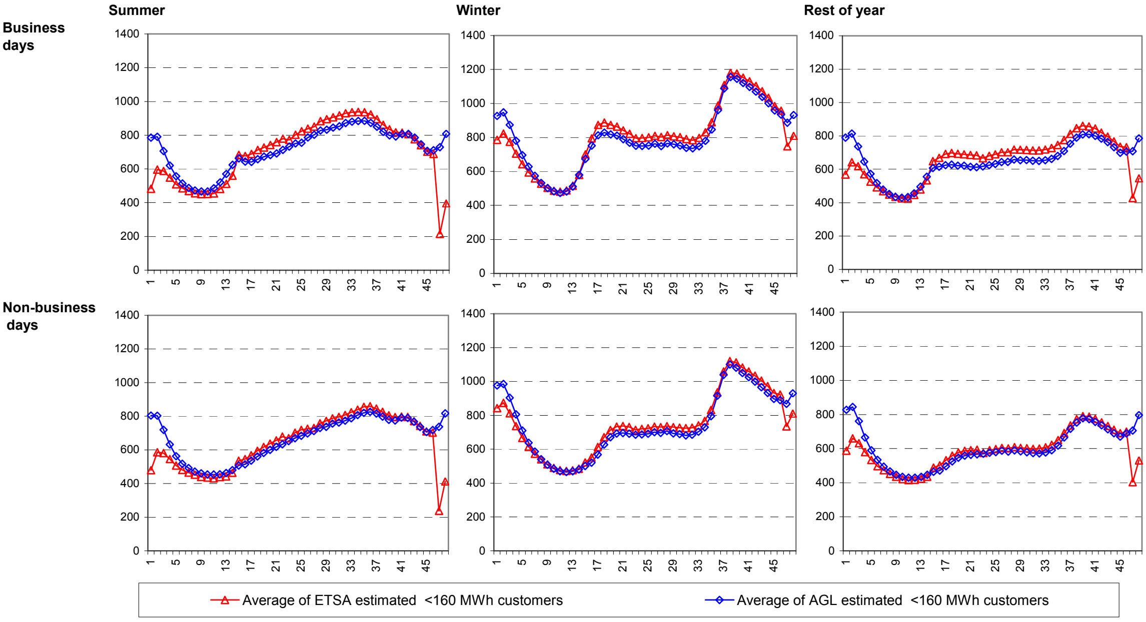


Table 3.1 compares several key summary measures derived from the AGL and ETSA Utilities estimated load data for 2003. The two data sets show a strong degree of similarity in terms of peak and average levels of demand and the total volume of energy, with only a very small difference in the annual load factor. This close agreement between the two sets of data, together with the similar within-day load profiles reported in *Figure 3.1*, provides reasonable assurance that the regression estimates supplied by AGL are a suitable base for forecasting the 2005 small customer load profile for use in the LRMC analysis.

Table 3-1 Summary measures of AGL and ETSA Utilities small customer load data, 2003

	Maximum demand MW	Average demand MW	Load factor	Total energy GWh
ETSA Utilities data	1,644	688	0.419	6,031
AGL data	1,647	688	0.418	6,028

3.2 2005 peak demand forecasts

The Planning Council published 10%, 50% and 90% PoE peak demand forecasts for the State as a whole in the *2004 Annual Planning Report*. Estimation of a 50% PoE load trace for small customers in 2005 requires that the State-wide 50% PoE peak demand forecast for that year be apportioned between the small customer group and the residual State load.

The historic small customer load profiles provided by AGL cover calendar years 2001 and 2003. South Australia experienced very close to a 10% PoE peak demand outcome in 2001 and a 90% PoE outcome in 2003. The following two figures show both the small customer load and the residual load on each of these occasions, and compare these peak day outcomes with the typical loads experienced on mild summer business days when the daily average temperature at Kent Town was 20^{o}C.

Figure 3-2 Peak day and base day load profiles, 2003

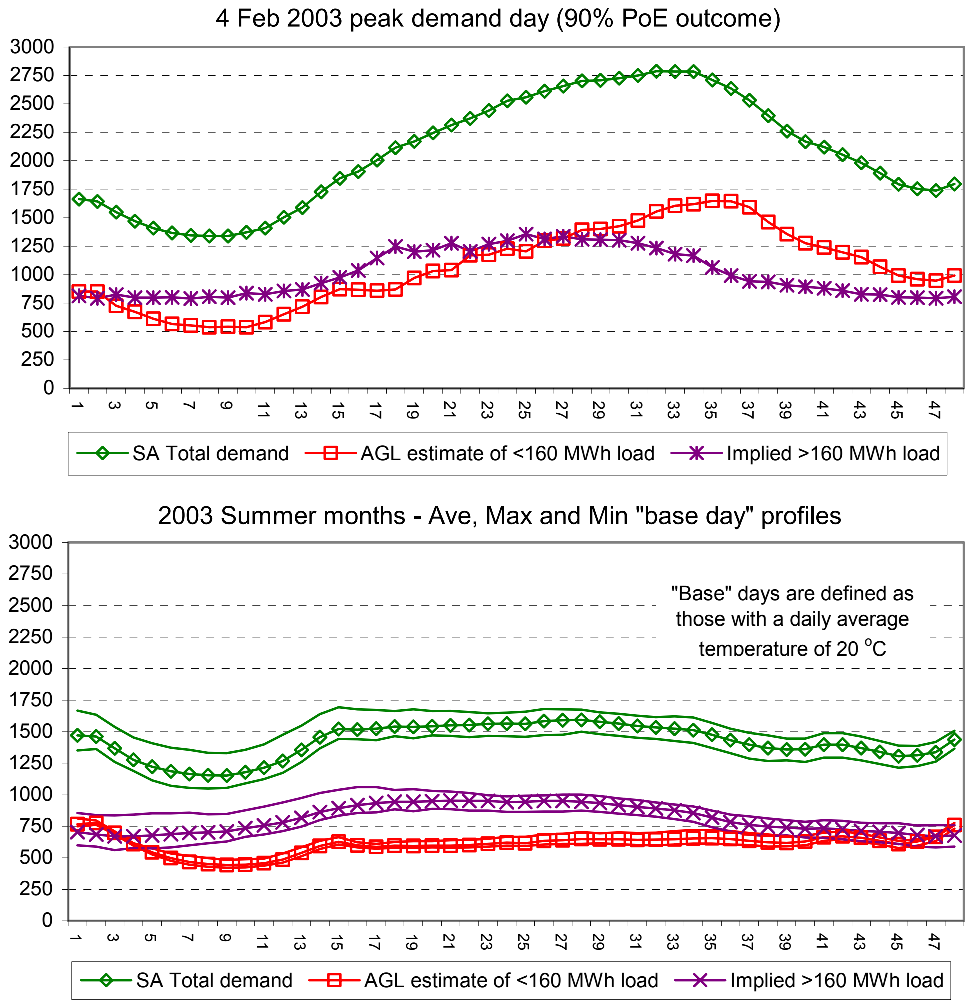
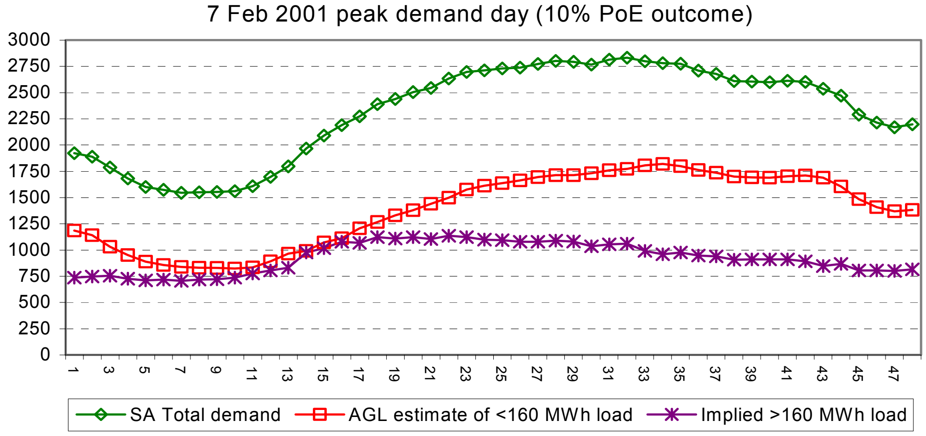
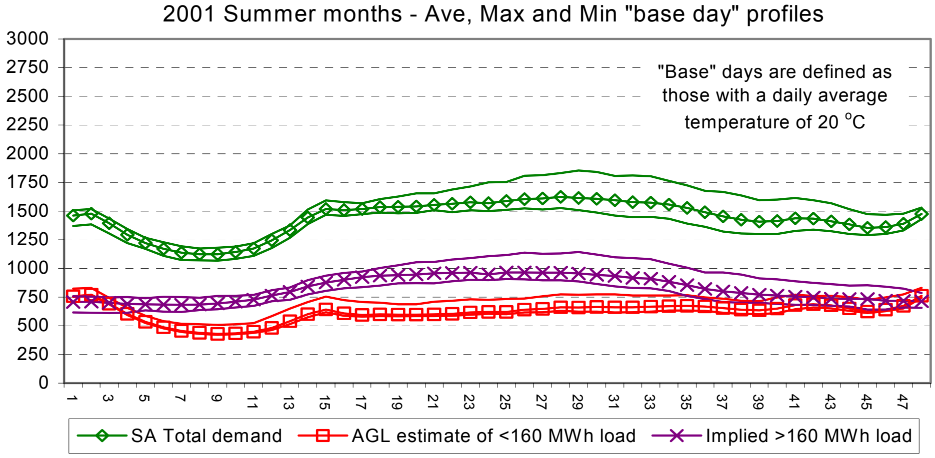


Figure 3-3 Peak day and base day load profiles, 2001





The small customer group's relative share of State-wide demand under differing temperature conditions is summarised in the following table. Two key observations are reported for each year – the level of demand on a mild 'base' day, and the level of demand on the peak day for that year. In each case the Planning Council has assumed a linear relationship between temperature and demand and interpolated the implied 50% PoE demand level for that year. These interpolated demand levels indicate that the small customer group would have contributed 60.6% of a 50% PoE demand outcome in 2001 and 57.8% in 2003.

Table 3-2 Relative shares of 50% PoE demand levels

	2001 demand levels MW (50% level interpolated)			2003 demand levels MW (50% level interpolated)		
	SA total load	< 160MWh loads	residual loads	SA total load	< 160MWh loads	residual loads
Base day 20 °C	1579	661	918	1534	643	890
90% day 29.5 °C				2787	1553	1234
50% day 32.5 °C	2638	1600	1039	3183	1840	1343
10% day 34.8 °C	2833	1773	1061			
Share of total load on a 50% day		60.6%			57.8%	

Based upon this analysis, the Planning Council has assumed that the small customer group would account for approximately 60% of a 50% PoE peak demand outcome during the 2005 summer, with the residual load accounting for 40% of peak demand. In recognition of the uncertainties in this assumption, the LRMC analysis also includes sensitivities which assume a 57%/43% split and a 63%/37% split between these two customer groups. These assumptions result in a base case 50% PoE peak demand forecast for small customers of 1,816 MW in 2005, with sensitivities of 1,725 MW and 1,906 MW, giving an overall spread of approximately 200 MW in the assumed 50% PoE peak demand level for the small customer group.

3.3 2005 energy forecasts

The load trace data provided by AGL indicates that total small customer energy consumption was 6,028 GWh in 2003. This figure is measured at the South Australian reference node and includes the hot water load. Estimation of a load trace for 2005 requires an assumption to be made about growth of energy consumption by small customers between 2003 and 2005.

The Planning Council has recently conducted an analysis of ETSA Utilities' sales growth by tariff category for ESCOSA as an input to the 2005-10 distribution network price determination which is currently underway[7]. The forecasts prepared for that work are on a consistent basis with the State-wide forecasts published recently in the *2004 Annual Planning Report* and provide a basis for projecting growth of AGL's 2003 small customer load estimates to the 2005 level. The following table reproduces the relevant sales forecasts from that work.

Table 3-3 Small customer sales forecasts, GWh

	Low voltage Residential	Controlled load	Low voltage Business single rate	Low voltage Business two rate	Total
2002-03	3,180.6	831.4	767.2	1,452.3	6,231.4
2003-04	3,223.5	830.2	775.8	1,479.2	6,308.8
2004-05	3,231.6	824.1	769.2	1,524.1	6,349.0
2005-06	3,266.8	824.9	769.6	1,585.0	6,446.2
estimate 2003(1)	3,202.1	830.8	771.5	1,465.8	6,270.1
estimate 2004	3,227.6	827.1	772.5	1,501.7	6,328.9
estimate 2005	3,249.2	824.5	769.4	1,554.5	6,397.6
% chg 2003 to 2005					2.0%

(1) Calendar year estimates have been calculated by averaging sales figures for the overlapping financial years.

The total sales estimates for 2003 and 2005 differ slightly in scope and definition from the small customer data provided by AGL, in that sales for each tariff category are measured at customer meters rather than the reference node and the two business tariff categories will include some customers with annual consumption above 160 MWh. Nevertheless, the Planning Council believes that the 2.0% growth rate between 2003 and 2005 estimated from these sales forecasts provides a sound basis for projecting forward the 2003 load data provided by AGL for the LRMC analysis.

---

7 The Planning Council understands that ESCOSA intends to publish and seek comment on the Planning Council's sales forecast report as part of the ETSA Utilities 2005-10 price determination.

In recognition of the uncertainties implicit in these forecasts, the LRMC results also include sensitivities which assume 0% and 4% growth of overall energy consumption for the small customer group. These assumptions result in a base case energy forecast for small customers of 6,149 GWh in 2005, with sensitivities of 6,028 GWh and 6,269 GWh, giving an overall spread of almost 250 GWh in the assumed level of energy consumption.

3.4 2005 load profile forecasts

A load growth model has been used to modify the 2003 small customer load profile to produce estimated load curves for 2005. This model preserves the inherent shape of a particular load profile while scaling it up or down to satisfy target values for the peak demand and total volume of energy. Preservation of the underlying load shape is an important feature of this work, as the load shape and resulting load factor are key determinants of the estimated LRMC[8]. South Australia’s peak level of demand under extreme temperatures has tended to grow more rapidly than the volume of energy in recent years, reflecting the increasing penetration of domestic air conditioning. This feature of demand growth is reflected in the load profile forecasts for 2005, with a corresponding reduction in the load factor.

As discussed in the previous sections, three values were identified for the 2005 peak demand forecast and three values selected for growth of energy consumption, giving nine different combinations to be considered in the LRMC analysis. These nine cases are summarised in the following table which cross tabulates the key peak demand and load growth assumptions. Case 5 best represents a base case or most likely outcome.

Table 3-4 Summary of load growth assumptions

		Assumed 50% PoE peak demand for less than 160MWh loads (ratio of small customer load to residual State load)		
		53/47	60/40	63/37
Assumed energy growth rate for less than 160MWh loads	0%	Case 1 Peak: 1,725 MW Energy: 6,028 GWh	Case 2 Peak: 1,816 MW Energy: 6,028 GWh	Case 3 Peak: 1,906MW Energy: 6,028 GWh
	2%	Case 4 Peak: 1,725 MW Energy: 6,149 GWh	Case 5 Peak: 1,816 MW Energy: 6,149 GWh	Case 6 Peak: 1,906 MW Energy: 6,149 GWh
	4%	Case 7 Peak: 1,725 MW Energy: 6,269 GWh	Case 8 Peak: 1,816 MW Energy: 6,269 GWh	Case 9 Peak: 1,906 MW Energy: 6,269 GWh

Projected 2005 load profiles based on these forecasts are summarised in the following chart and table. Profiles which exclude the hot water load have also been calculated by deducting the estimated South Australian water heating load published on NEMMCO’s website.

[8] The load factor is a common measure of the intensity of demand and is calculated as the ratio of the average level of demand to peak demand. A constant flat load will have a load factor of unity as the average equals the peak. Small domestic loads, where peak demand is driven mainly by temperatures and resulting air conditioner use, typically have a low load factor because the annual average level of demand is well below the peak experienced on very hot days.

Figure 3-4 Small customer load profiles, 2005

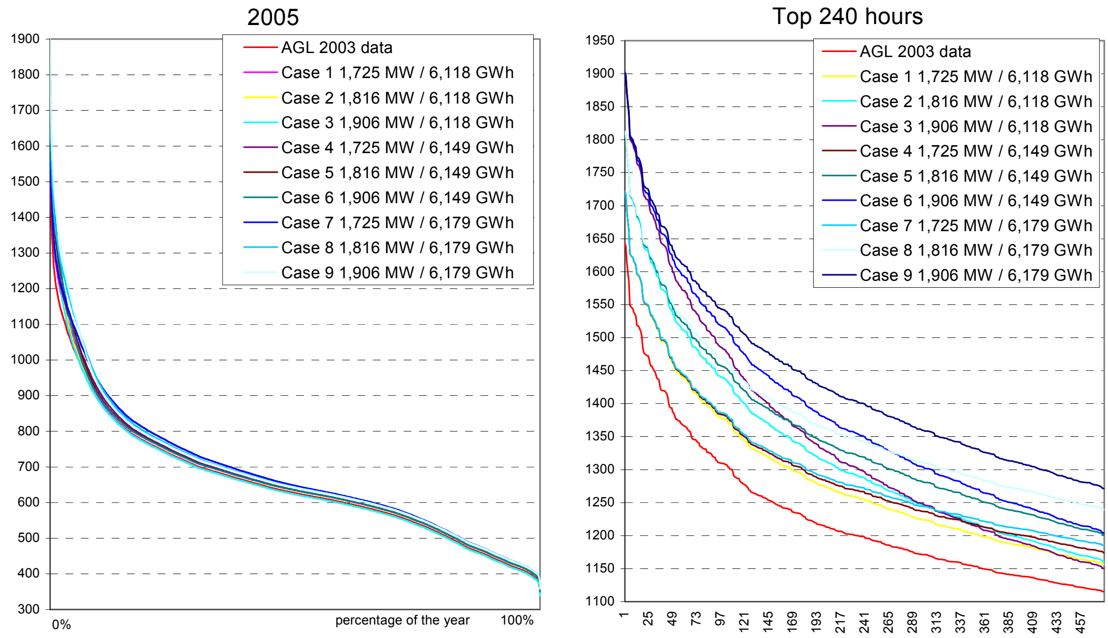


Table 3-5 Small customer load profiles, 2005

	Including hot water load			Excluding hot water load		
	Peak MW	Energy GWh	Load factor	Peak MW	Energy GWh	Load factor
AGL's 2003 data	1,647	6,028	0.418	1,643	5,744	0.399
Case 1	1,725	6,028	0.399	1,721	5,744	0.381
Case 2	1,816	6,028	0.379	1,812	5,744	0.362
Case 3	1,906	6,028	0.361	1,902	5,744	0.345
Case 4	1,725	6,149	0.407	1,721	5,865	0.389
Case 5 Base Case	1,816	6,149	0.387	1,812	5,865	0.369
Case 6	1,906	6,149	0.368	1,902	5,865	0.352
Case 7	1,725	6,269	0.415	1,721	5,985	0.397
Case 8	1,816	6,269	0.394	1,812	5,985	0.377
Case 9	1,906	6,269	0.376	1,902	5,985	0.359

A 2005 load profile for the residual State load has also been calculated to provide a basis for comparing the LRMC of supply for large and small customers. This profile was derived by deducting the base case small customer profile from a forecast of the State total profile for 2005. The forecast State total profile was based on the state-wide 50% PoE summer peak demand forecast reported in the *2004 Annual Planning Report* and energy growth of 2.8% between 2003 and 2005. This growth rate reflects the expected increase in ETSA Utilities total sales over this period. The resulting large customer load profile has a peak demand of 1,515 MW, total energy of 6,306 GWh and a load factor of 0.475.

4 NEW ENTRANT GENERATION PRICES

4.1 New entrant pricing model

The Planning Council, in conjunction with accounting firm PKF, has developed a detailed new entrant cost analysis model to evaluate the $/MWh price required by a new entrant generator such that the project is financially viable for a developer. Based on a cash flow approach, the model produces annual financial statements that are consolidated into a whole of life costing model. The model includes parameters such as:

- Plant cost information, including capital cost, construction period, interest during construction and fixed and variable operating costs;

- Performance information, including expected life of plant, heat rates, internal energy use, and fuel type, cost and price escalation;

- Outage information, including forced outage rates, routine maintenance timing and cost, time and cost of minor and major overhauls, spares; and

- Financial information, including interest rates, exchange rates, debt to equity ratio, dividend payment ratios, and the project's required internal rate of return.

The model calculates the total cost of financing and operating the plant over the specified life of the machine, and, from this information, calculates the wholesale market revenue, in $/MWh sent out, required to satisfy these costs and achieve the required internal rate of return. The model then varies the operational capacity factor of the plant to generate a curve which relates the $/MWh price required to remain financially viable in market segments equating to base load, intermediate or peaking duty. Different generation technologies are suited to different roles in the National Electricity Market, so by considering a range of different technologies, fuel sources and projects, a spectrum of alternative curves may be created that can then be used to assess the most efficient technology and project for a given target capacity factor.

4.2 Data sources

The Planning Council engaged engineering consultants Sinclair Knight Merz (SKM) to perform a review of recent market developments with respect to new entrant generation projects in Australia and across the world. This review included an examination of the major capital and equipment costs and a review of what could be expected to be reasonable financial market and investment parameters.

The Planning Council also performed an extensive media review of equipment cost and availability and typical project development costs. This included discussions with a number of existing South Australian generators regarding their assessment of the development costs of new entrant projects in Australia. This information was used to supplement and benchmark the data reported by SKM to produce the results presented in this paper.

4.3 Range of generation technologies considered

The SKM analysis provided cost information for a range of gas generation options and a potential black coal fired power station. While the information provided for the black coal station provide an interesting reference point, it has not been used in the final calculation of the cost of a new entrant in South Australia. Independent of greenhouse gas emission issues, black coal, while a viable option in other States, is not considered to be a viable technology for a new entrant in South Australia as the freight costs to import sufficient black coal are likely to reduce the cost advantage of the new entrant to a point where the project is no longer an attractive investment option in the State.

Specifically, the LRMC analysis has considered the following new generation plant options:

Large CCGT

- 390MW unit, single shaft CCGT (Frame 9FA, GT26, V94.3A, 701F technologies). The Frame 9FA has been selected as representative of the group and has been used as the basis for the LRMC calculations.
- Salt water cooling tower
- Evaporative inlet air cooling for the GT

Medium CCGT

- 200-250MW block, non-single shaft CCGT (Frame 9E, GT13E2, V94.2, 701D technologies). The GT13E2 has been selected as representative of the group and has been used as the basis for calculations.
- Salt water cooling tower
- Evaporative inlet air cooling for the GT

Small CCGT

- 125MW block, non-single shaft CCGT (2 x Frame 6B gas turbines + steam turbine).
- Salt water cooling tower
- Evaporative Inlet air cooling for the GT

SCGT

- 120MW – 160MW unit (Frame 9E, GT13E2, V94.2, 701D). The Frame 9E has been selected as representative of the group and has been used as the basis for calculations.

- Evaporative Inlet air cooling for the GT

Small SCGT

- Nominally 40MW unit (Frame 6B)
- Evaporative Inlet air cooling for the GT

The review by SKM covered the most likely range of current technologies that could be selected for potential new entrants, but did not include the use of renewable energy technologies. The major financial driver for renewable energy generation technologies in Australia is the Mandated Renewable Energy Target scheme that effectively subsidises these developments. While the current range of renewable energy technologies will contribute to the generation of electricity, they do not currently represent the most competitive new entrant source of supply.

Technologies such as hydrogen fuel cells and Integrated Coal Gasification Combined Cycle (ICGCC) have not been considered as they are, as yet, not commonly used compared to technologies such as conventional Rankine Cycle steam generation and open or closed cycle gas turbine technologies. As discussed in the *2004 Annual Planning Report*, gas is considered to be the most likely fuel for the development of new entrant generators in the State. The LRMC analysis has been based on two fuel prices: $3.50/GJ for generation projects with a target capacity factor greater than 10%; and $4.00/GJ for peaking plant. Higher gas prices are also considered as a sensitivity. Secondary fuels are called for on some natural gas fuelled stations where the owner cannot accept or manage the risk of fuel failure creating a market exposure or where the owner seeks cheaper gas delivery costs via a non-secure delivery arrangement. The addition of a secondary fuel capability can add to the cost of development but has not been considered in this analysis.

Environmental restrictions include greenhouse gas and NOx emissions from gas turbines, particularly where a station is to be located close to a metropolitan air-shed. Providing the appropriate technology is employed (Dry-low-NOx) and the generator emissions fall within the standards, it is anticipated that gas turbines can be installed within the metropolitan area. This analysis includes the costs of gas turbines which will comply with these standards. Gas turbine performance drops off with ambient temperature. Subject to the availability of water, inlet air-cooling is a low-cost performance enhancement to a gas turbine plant and has been assumed for the gas turbines used in this analysis.

4.4 Plant capital and operating costs

The following table summarises the key physical, capital and fuel cost parameters for each of the alternatives considered in the analysis.

Table 4-1 Plant characteristics and fuel and capital cost

	Fr9E (medium) SCGT	Fr6B (small) SCGT	2xFr6B (small) CCGT	GT13E2 (medium) CCGT	Fr9FA (large) CCGT
Gross output (MW)	125.7	42.4	130.0	245.6	396.6
Used in House (MW)	1.5	0.41	2.7	5.0	8.7
Net output (MW)	124.2	41.8	127.3	240.6	387.9
Net heat rate (GJ/MWh HHV)	12.12	12.89	8.33	7.88	7.36
Fuel Cost ($/GJ)	4.00	4.00	3.50	3.50	3.50
Forced Outage Rate	2%	2%	2%	2%	2%
Unplanned Maintenance Rate	3%	3%	3%	3%	3%
Planned Maintenance Rate	3%	3%	3%	3%	3%
Available Capacity Factor	93%	93%	93%	93%	93%
Approximate Capital Cost[9] ($M)	72	35	120	215	310
Project Life	25	25	25	25	25
Construction Time (yrs)	1.5	1.5	2.5	2.5	2.5

The cost of gas for high capacity factor generators such as the combined cycle machines is likely to be lower than that for peaking plant, reflecting the advantage of spreading fixed transport and connection costs over a broader utilisation base.

Assumed gas turbine maintenance cycles and costs are shown in the following table.

Table 4-2 Gas turbine maintenance periods and costs

Maintenance type	Duration (Hours)	Frequency	Cost ($M/100MW)
Off-line water wash	~ 8	3 months	
Boroscopic Combustion Inspection	~72	8,000 hours - base load or 400 starts – peakers	1
Hot Gas Path Inspection	~360	24,000 hours - base load 1,200 starts - peakers	2
Major Overhaul	~1080	6 years - base load 2,500 starts - peakers	6

For thermal plants an overhaul cycle for a mature unit is 4-6 years and assumed to cost $6M per 100MW capacity per overhaul. This cost, which can vary considerably depending on plant condition, is included in the major overhaul cost above.

Outage rates for gas turbines are estimated at 3% for unplanned outages and 3% for planned outages. Many unplanned outages are instrumentation failures or operator error. These have a downtime of generally less than one shift.

The EPC costs shown in *Table 4-1* exclude switchyard and electrical connection costs. These can be paid either upfront, or as an annual connection charge. Indicative capital costs for a 1½

[9] Costs exclude connection costs & switchyard, secondary fuel, IDC and any special site specific cost such as special noise treatment, difficult civil conditions etc. Also excludes land related costs and systems etc that the owner would provide to set-up the station for ongoing operation (eg maintenance management system, stores and layout areas, office fit out etc).

circuit breaker connection to a circuit about 1km away are assumed to be as per *Table 4-3*. Items such as the generator step-up transformer are included in the EPC costs.

Table 4-3 Indicative electrical connection costs

Voltage (kV)	Connection cost ($M)
220	$7
275	$8
330	$9
500	$15

Gas connection costs are dependent on the distance, gas inlet pressure (and the required discharge pressure for the particular gas turbine) and on how much expansion capability is to be built into the site. Based upon 20km of connection with 5000kPa minimum lateral inlet pressure, and a SCGT site capable of expansion to four units and a CCGT site capable of expansion to two units, indicative costs are $6m for small and medium CCGT units and $7m for a large CCGT. Gas connection costs are excluded from the new entrant calculations on the basis that expansion of existing stations represents a possible new entrant option. Specific costs have not been added for water infrastructure as they are highly project and site specific.

An allowance has been made for a minimum set of initial spares based on 2% of the EPC costs. Many developers don't purchase critical spares, relying on the manufacturers for rapid support and insurance. Generator rotors, stators and transformers are key areas of risk. For gas turbines, the timing of procurement of the hot section spares for the first overhaul is important. Based on advice from SKM, turbine items such as blades and combustion nozzles tend to be rotated and repaired through the machine three to five times, returning to 'spares' in between overhauls.

For a low capacity factor machine such as a gas turbine operating as a peaking generator, an overhaul cycle of approximately 15 years is likely and in the order of 80% of the variable costs would be as a result of the Combustion, and Hot Gas Path Inspections and the Major Overhauls in each cycle. These costs are included in the variable operating costs described in *Table 4-4*.

Operating and Maintenance cost estimates are shown in *Table 4-4*. Fuel handling and usage expenses have been dealt with separately, however labour related fuel costs are included. Other costs such as shared head-office costs unchanged by the existence of the plant and trading and marketing functions are not included.

Table 4-4 Variable and fixed O&M costs (including labour)

	Simple Cycle	Combined Cycle
Variable Opex	$2.97/MWh	$2.69/MWh
Small Size fixed opex (incl labour)	$11.0/kW/a[10]	$32.26/kW/a
Medium size fixed opex (incl labour)	$11.67/kW/a[11]	$21.92/kW/a
Large size fixed opex (incl labour)		$16.70/kW/a

The new entrant price analysis represents the development of a generic project close to a load centre. While the EPC costs have been critically examined, the cost of implementation and connection are considered to be more generic. The Planning Council anticipates that through aggressive procurement practices, for example by optimising site selection and using the advantages of an existing organisational structure, a project developer would be able to achieve lower overall costs.

Some potential proponents suggested a number of variations to other significant parameters:

- Some proponents with whom the Planning Council discussed project development costs require contingency allowances up to 10% of the project cost. The SKM information on contingency allowance is significantly lower, in the order of 3%.

- Another area of significant variation is the allowance for interest during construction (IDC). Proponent information included IDC allowances as high as 8.5%, while the SKM analysis varied between technologies based on the construction time but equated to an annual interest rate in line with the financial assumptions.

4.5 Financial parameters

In conjunction with SKM the Planning Council developed an abbreviated list of the key financial parameters for a new entrant project and an appropriate alternative scenario, as summarised in the following table.

Table 4-5 Financial parameters

Parameter	Base Case Assumptions	Alternative Assumptions
Inflation[12]	2.5%	2.5%
Exchange rate	1AUD= 0.72USD	1AUD= 0.72USD
Debt Equity Ratio	50%	70%
Risk free rate[13]	5.8%	5.7%
Debt premium	2.0%	3.3%
Market premium	6.0%	7.3%

[10] This assumes that the new entrant generator is part of a portfolio of generation and that full time dedicated personnel are not required. Where it necessary to have dedicated full time personnel, an additional component in the order of $30/kW/a would be necessary for a single unit station, reducing proportionately to the number of units at the site.

[11] Based on 2 x 120MW units. Higher costs may be expected for a single unit while stations with more than two units are likely to benefit from the economies of scale.

[12] With respect to projected inflation, the present difference between the 10 year govt bond rate and the 2015 Treasury Indexed Bond rate is 5.46 – 3.115 = 2.35%, which represents a potential market view of long term projected CPI.

[13] For comparison, risk free rate on the Australian 10 year Commonwealth bond rate is between 5.7% and 5.8%.

Parameter	Base Case Assumptions	Alternative Assumptions
Beta (equity)	1	1
Value of Imputation	0	0
Tax rate	30%	30%
Kd (cost of debt, nom)	7.8%	9.0%
Ke (cost of equity, nom)	11.8%	13.0%
WACC (post tax, nominal)	8.6%	8.3%
WACC (post tax, real)	6.0%	5.7%
WACC (pre-tax, nominal)	12.3%	11.9%
WACC (pre-tax, real)	9.6%	9.2%

In addition to the sensitivities on financial and fuel parameters, a number of other sensitivities have also been considered. These are:

- two exchange rate sensitivities were considered, these are 1AUD=0.72 USD and 1AUD=0.60 USD;
- a 5% gas price increase;
- 20 year economic life for the plant.

The following table shows a comparison of the estimates from SKM to identify the major components and costs for green field / brown field projects in this State. This information has then been compared with development proposals that have been provided to the Planning Council by South Australian participants. The results for the base case estimates are shown in *Table 4-6*.

Table 4-6 - New Entrant Cost Summary

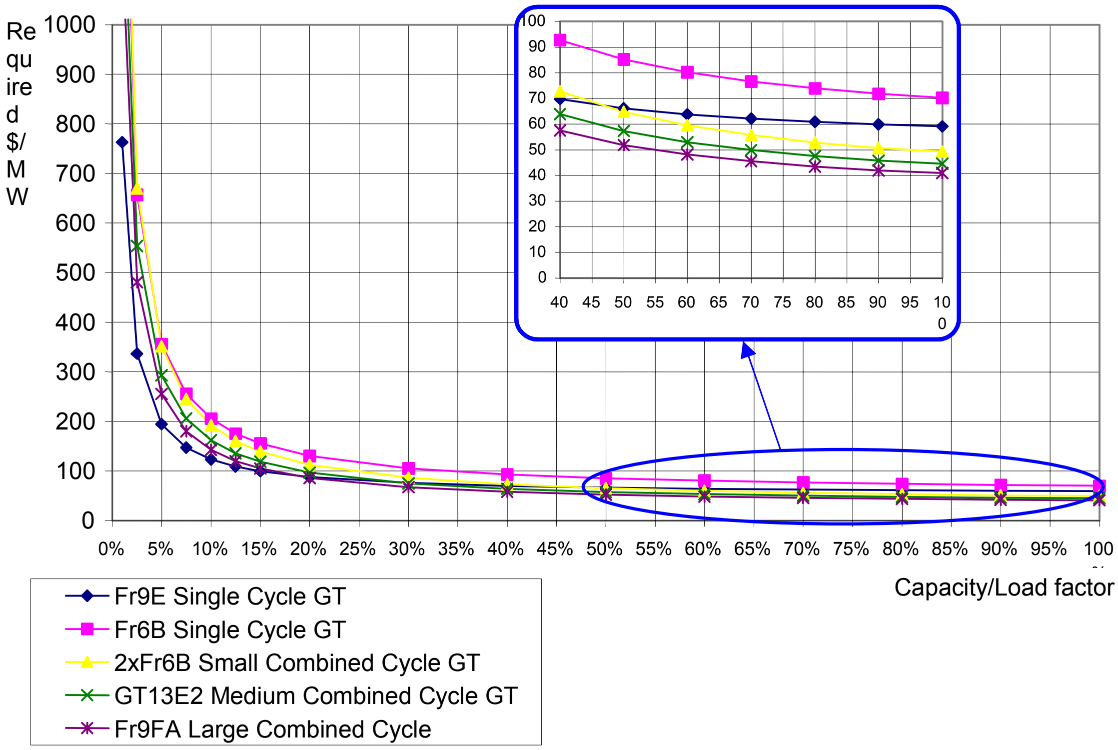
Project	Capacity (MW)	Capital Cost		Owners Costs[14]		Completed project cost[15]	
		SKM Estimate	Proponent Estimate	SKM Estimate	Proponent Estimate	SKM Estimate	Proponent Estimate
SCGT (Frame 9E)	125	$65M ($517/kW)	$65M-69M	$7M	$12M	$73.5M ($585/kW)	$81.8M ($650/kW)
Small SCGT (Frame 6B)	43	$44M ($1065/kW)	NA	$3M	NA	$48.2M ($1167/kW)	$78.8M (786/kW)
Small CCGT (2xFrame 6B)	125	$121M ($946/kW)	no comparable project	$12M	no comparable project	$134M ($1040/kW)	no comparable project
Medium CCGT (GT13E2)	245	$202M ($825/kW)	NA	$22M	~$24M	$223M ($917/kW)	Cockburn 2 WA $240M ($1024/kW)
							½ of Pelican Point $240M ($986/kW)
Large CCGT (Frame 9FA)	380	$286M ($721/kW)	NA	$31M	~$30M	$318M ($802/kW)	Swanbank E QLD $300M ($756/kW)

[14] Owners costs include, Engineering analysis, spares, start-up and testing fuel, legal fees and contract management establishment and negotiations and contingency allowance.
[15] These costs include interest during construction (IDC). IDC is not included in the capital cost entered into the Planning Council's new entrant model as the model calculates this cost.

4.6 Estimated new entrant price curves

Figure 4-1 shows the new entrant price curve estimated for each of the plant types considered for the LRMC analysis. Of the range of plant types considered, the Planning Council's analysis identified that the Frame 9FA large CCGT represented the most efficient plant choice at relatively high operating capacity factors. For low operating factors typically associated with peaking and reserve plant, the Frame 9E SCGT was identified as the most efficient choice.

Figure 4-1Gas generation plant new entrant price curves



The LRMC analysis has been based on a base case new entrant price curve for both the Frame 9FA CCGT and the Frame 9E SCGT, together with a number of sensitivity studies that consider alternative assumptions input into the new entrant pricing model. The following description of each of the sensitivities provides a guide to interpreting the final LRMC results.

- 'New Entrant Curve 1' represents generation costs considered able to be achieved by an efficient participant and therefore represents the Planning Council's "base case" estimates.

- A further eight sensitivities have been developed, all of which consider higher costs in one form or another. These are: (curve 2) higher initial capital cost; (curve 3) shorter plant life; (curve 4) 5% fuel increase; (curve 5) 60c USD/AUD exchange rate; (curve 6) higher required IRR; (curve 7) higher required IRR and shorter plant life; (curve 8) higher required IRR and 3.5% fuel price increase; and (curve 9) higher required IRR and 60c USD/AUD exchange rate.

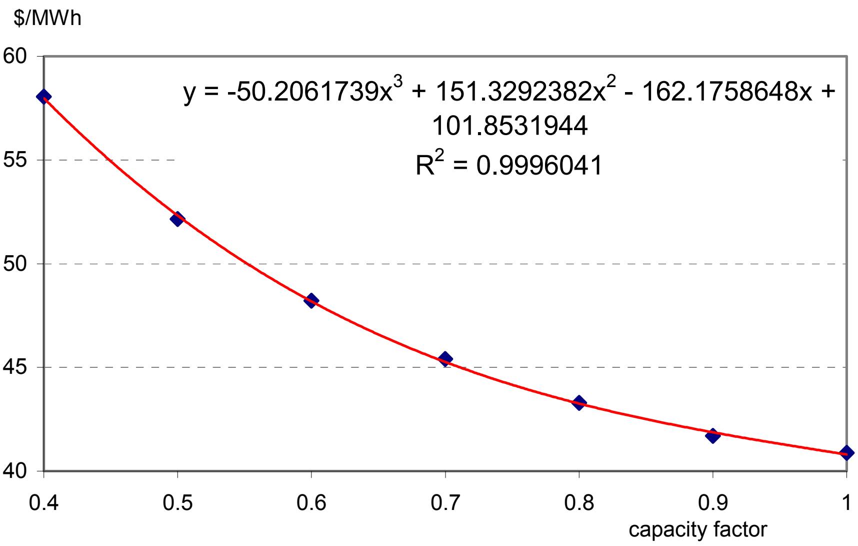
Table 4-7 below summarises the key input assumptions that were subjected to sensitivity analysis and used to produce the nine new entrant price curves for each type of plant.

Table 4-7 New entrant price curve sensitivities

	Plant life	Capital cost	Fuel price	Required IRR (real)	Cost of debt (nominal)
Frame 9A large CCGT					
New entrant curve 1 BASE CASE	25 yrs	$308m	$3.50/GJ	9.1%	7.8%
New entrant curve 2 higher capital cost	25 yrs	$316m	$3.50/GJ	9.1%	7.8%
New entrant curve 3 shorter life	20 yrs	$308m	$3.50/GJ	9.1%	7.8%
New entrant curve 4 higher fuel cost	25 yrs	$308m	$3.68/GJ	9.1%	7.8%
New entrant curve 5 0.60 exchange rate	25 yrs	$369m	$3.50/GJ	9.1%	7.8%
New entrant curve 6 higher IRR	25 yrs	$308m	$3.50/GJ	10.3%	9.0%
New entrant curve 7 higher IRR & shorter life	20 yrs	$308m	$3.50/GJ	10.3%	9.0%
New entrant curve 8 higher IRR & higher fuel cost	25 yrs	$308m	$3.68/GJ	10.3%	9.0%
New entrant curve 9 higher IRR & 0.60 exchg rate	25 yrs	$369m	$3.50/GJ	10.3%	9.0%
Frame 9E small SCGT					
New entrant curve 1 BASE CASE	25 yrs	$72m	$4.00/GJ	9.1%	7.8%
New entrant curve 2 higher capital cost	25 yrs	$74m	$4.00/GJ	9.1%	7.8%
New entrant curve 3 shorter life	20 yrs	$72m	$4.00/GJ	9.1%	7.8%
New entrant curve 4 higher fuel cost	25 yrs	$72m	$4.20/GJ	9.1%	7.8%
New entrant curve 5 0.60 exchange rate	25 yrs	$87m	$4.00/GJ	9.1%	7.8%
New entrant curve 6 higher IRR	25 yrs	$72m	$4.00/GJ	10.3%	9.0%
New entrant curve 7 higher IRR & shorter life	20 yrs	$72m	$4.00/GJ	10.3%	9.0%
New entrant curve 8 higher IRR & higher fuel cost	25 yrs	$72m	$4.20/GJ	10.3%	9.0%
New entrant curve 9 higher IRR & 0.60 exchg rate	25 yrs	$87m	$4.00/GJ	10.3%	9.0%

Each new entrant price curve sensitivity has been expressed as a regression relationship for use in the LRMC analysis. These equations relate the $/MWh prices required at different capacity factors, as demonstrated in the following chart which shows the estimated relationship for the Frame 9FA CCGT base case assumptions.

Figure 4-2 Frame 9FA CCGT new entrant price curve



The table below summarises the estimated regression equation for each plant type for each of the scenarios considered. These equations have been estimated using results from the Planning Council's new entrant pricing model over the likely operating range for each type of plant. The best statistical fit was found using a polynomial of order three for the Frame 9FA CCGT units, which takes the form of $y = ax^3 + bx^2 + cx + d$, and an exponential relationship of the form $y = ax^b$ for the Frame 9E SCGT units. In each case "y" refers to the required $/MWh price and "x" to the capacity factor. These equations are used in conjunction with the load curves identified in section 3 to estimate the LRMC of supply for small customers.

Table 4-8 New entrant curves – regression relationships

	Estimated regression relationships, Frame 9A CCGT
New entrant curve 1 Base Case	y = -50.2061739x3 + 151.3292382x2 - 162.1758648x + 101.8531944
New entrant curve 2	y = -51.4035180x3 + 154.9382199x2 - 166.0435228x + 103.6020189
New entrant curve 3	y = -53.7736614x3 + 161.7438475x2 - 173.0543766x + 106.6722517
New entrant curve 4	y = -50.2061739x3 + 151.3292382x2 - 162.1758648x + 103.1418145
New entrant curve 5	y = -58.5875823x3 + 176.5921101x2 - 189.2494703x + 114.0949663
New entrant curve 6	y = -60.9874104x3 + 178.4174506x2 - 186.9265039x + 111.5394374
New entrant curve 7	y = -64.2282965x3 + 188.1515108x2 - 197.3004640x + 116.1866378
New entrant curve 8	y = -60.9874104x3 + 178.4174506x2 - 186.9265039x + 112.8280575
New entrant curve 9	y = -71.3367354x3 + 208.6941941x2 - 218.6472005x + 125.6270472
	Estimated regression relationships, Frame 9E SCGT
New entrant curve 1 Base Case	y = 15.6567714x-0.8698406
New entrant curve 2	y = 15.8217211x-0.8724298
New entrant curve 3	y = 16.0578250x-0.8759268
New entrant curve 4	y = 16.0732152x-0.8646713
New entrant curve 5	y = 16.8374604x-0.8860264
New entrant curve 6	y = 16.3834421x-0.8816812
New entrant curve 7	y = 16.4573230x-0.8933286
New entrant curve 8	y = 16.7866736x-0.8768783
New entrant curve 9	y = 17.7495988x-0.8968862

5 DERIVATION OF LRMC ESTIMATES

5.1 Overview of calculations

Estimating the LRMC of supply for the small customer load has involved the following steps.

Forecasting the small customer load profile for 2005

Nine such forecasts have been considered, reflecting different assumptions about the 50% PoE peak demand and growth of total energy consumption, as described in section 3. Each load profile has been considered on the basis that the hot water heating load is either included or excluded. A separate profile for the residual state load has also been prepared to provide a basis for comparison of the cost to supply electricity to each group of customers.

Identification of the total amount of generation capacity required

For each load profile scenario, the total required plant capacity has been set so as to meet the 50% PoE peak demand plus a proportion of the reserve capacity necessary to meet the difference between the 50% and 10% PoE peak demand levels and satisfy South Australia's minimum reserve requirement of 265 MW. Sixty percent of this unused and reserve capacity has been attributed to the small customer group, with the remaining forty percent attributed to larger loads. These proportions reflect the relative contribution of each group to the overall State-wide 50% PoE demand level. Forty MW of demand side response has been assumed available within the large load category in determining the required amount of reserve plant capacity attributable to that group of customers.

Calculation of the cost to meet the forecast loads and provide reserve capacity

The Planning Council developed a spreadsheet model which incorporates the forecast load profiles and new entrant pricing equations outlined in section 4. This model identified the annual capacity factor of each type of generation plant in meeting its share of the forecast load, and used these capacity factors in conjunction with the new entrant pricing equations to estimate the $/MWh price and total annual revenue required for each type of plant to remain financially viable. The revenue requirement for each type of plant was then used to calculate the overall total and average revenue required to meet the entire load and provide the required level of reserves. This average $/MWh price was then adjusted for network losses and mandatory wholesale market pass through costs to provide an estimate of the LRMC of supply. An optimising algorithm was used to determine the optimal mix of base load and peaking/reserve plant such that the final $/MWh price was minimised.

Mandatory wholesale market passthrough costs have been set at $1.50/MWh, as calculated by IES in previous work undertaken for ESCOSA. This cost is imposed on retailers by NEMMCO and reflects market fees and ancillary service charges, the cost of meeting renewable energy obligations and prudential costs associated with operating the market.

2004-05 loss factors published by NEMMCO have been used in the calculations and have been assumed to total 8.08% for small customers and 6.47% for large customers. The generator loss factor has been assumed to be unity. Depending on the location of a new entrant generator, its loss factor could be higher of lower than this and contribute to higher or lower delivered costs. In this work it is expected than an efficient new entrant gas plant would be located close to the regional reference load.

This set of calculations has been repeated for each combination of the nine load growth scenarios and the nine generator new entrant price sensitivities, giving a total of 81 estimates of the LRMC covering a wide range of assumed operating conditions and pricing assumptions.

5.2 Summary of LRMC estimates

The sensitivity that the Planning Council considers best represents a base case or most likely outcome indicates a delivered energy cost of $66.84/MWh for the small customer segment of the market in 2005. This price includes network losses and pass through charges, but excludes the hot water load. If the hot water load is included in the load profile, the LRMC is approximately $1.50/MWh lower. The comparable cost for supply to large customers in 2005 is estimated at $57.64/MWh.

Under the base case new entrant pricing model, the LRMC of supply for small customers (excluding the hot water load) varies between $64.91/MWh and $68.44/MWh, depending on assumptions about growth of customer sales and the share of peak demand attributable to the small customer segment of the market.

Under the base case load growth assumptions, the LRMC could be as high as $77.15/MWh if a combination of high generation cost outcomes are assumed. The Planning Council has not considered low generation cost outcomes as these are likely to be project specific and unique to individual proponents. Such opportunities might include, for example, the installation of refurbished generation plant or favourable access to a particular site or existing infrastructure.

The table below summarises the Planning Council’s 2005 LRMC estimates. Additional detail is shown in *Table 5-2* on the following page.

Table 5-1 Summary of LRMC estimates, $/MWh

	Large loads (>160 MWh)	2005 small customer loads (< 160 MWh), excluding hot water load								
		Load growth scenario								
		Case 1	Case 2	Case 3	Case 4	Case 5 BASE CASE	Case 6	Case 7	Case 8	Case 9
New entrant curve 1 BASE CASE	57.64	66.06	67.30	68.44	65.49	66.84	68.03	64.91	66.40	67.70
New entrant curve 2	58.25	66.86	68.13	69.30	66.27	67.65	68.87	65.68	67.20	68.53
New entrant curve 3	59.23	68.14	69.45	70.66	67.53	68.95	70.20	66.90	68.46	69.83
New entrant curve 4	59.02	67.45	68.70	69.83	66.89	68.25	69.44	66.31	67.82	69.13
New entrant curve 5	61.90	71.67	73.12	74.45	70.99	72.54	73.92	70.29	71.99	73.48
New entrant curve 6	60.55	69.87	71.25	72.51	69.22	70.70	72.02	68.56	70.19	71.62
New entrant curve 7	62.21	72.08	73.54	74.90	71.38	72.94	74.34	70.67	72.36	73.86
New entrant curve 8	61.93	71.26	72.64	73.91	70.62	72.11	73.43	69.97	71.61	73.04
New entrant curve 9	65.38	76.22	77.83	79.32	75.44	77.15	78.69	74.66	76.51	78.16

Prices shown in this table include network losses and market pass-through charges.

Table 5-2 Derivation of LRMC estimates

	> 160 MWh loads	Less than 160 MWh loads - Including hot water, 2005									Less than 160 MWh loads - Excluding hot water, 2005								
		Case 1	Case 2	Case 3	Case 4	Case 5 BASE CASE	Case 6	Case 7	Case 8	Case 9	Case 1	Case 2	Case 3	Case 4	Case 5 BASE CASE	Case 6	Case 7	Case 8	Case 9
Summary load statistics																			
Peak demand MW	1515	1725	1816	1906	1725	1816	1906	1725	1816	1906	1721	1812	1902	1721	1812	1902	1721	1812	1902
Ave demand MW	720	688	688	688	702	702	702	716	716	716	656	656	656	669	669	669	683	683	683
Load factor	0.475	0.399	0.379	0.361	0.407	0.387	0.368	0.415	0.394	0.376	0.381	0.362	0.345	0.389	0.369	0.352	0.397	0.377	0.359
Energy reqt GWh	6306.3	6028.4	6028.4	6028.4	6149.0	6149.0	6149.0	6269.0	6269.0	6269.0	5744.1	5744.1	5744.1	5864.6	5864.6	5864.6	5984.6	5984.6	5984.6
Assumed capacity requirement																			
.. To cover 50% PoE demand	1515	1725	1816	1906	1725	1816	1906	1725	1816	1906	1721	1812	1902	1721	1812	1902	1721	1812	1902
.. Extra to cover 10% PoE demand	107.2	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8	160.8
.. Share of 265 MW reserves	106	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159	159
..less assumed DSP	-40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total capacity needed MW	1688	2045	2135	2226	2045	2136	2225	2045	2136	2226	2041	2132	2222	2041	2132	2222	2041	2132	2222
Plant duty																			
Assumed base load capacity MW	976	1045	1045	1045	1045	1045	1045	1045	1045	1045	1039	1039	1039	1039	1039	1039	1039	1039	1039
Base load plant - GWh supplied	6243.7	5956.6	5948.9	5946.4	6069.2	6053.3	6046.6	6182.8	6152.4	6134.7	5671.8	5664.1	5661.6	5784.5	5768.6	5761.8	5898.3	5868.8	5851.0
Load factor on plant	0.730	0.651	0.650	0.650	0.663	0.661	0.661	0.675	0.672	0.670	0.623	0.622	0.622	0.636	0.634	0.633	0.648	0.645	0.643
Reserve & peaking capacity MW	712	1000	1090	1181	1000	1091	1180	1000	1091	1181	1002	1093	1183	1002	1093	1183	1002	1093	1183
Reserve & peaking plant - GWh supplied	62.6	71.8	79.6	82.1	79.8	95.7	102.4	86.2	116.6	134.3	72.3	80.0	82.5	80.2	96.0	102.8	86.3	115.9	133.6
Load factor on plant	0.010	0.008	0.008	0.008	0.009	0.010	0.010	0.010	0.012	0.013	0.008	0.008	0.008	0.009	0.010	0.010	0.010	0.012	0.013
Total cost of supply $m																			
New entrant curve 1 BASE CASE	331.95	350.76	357.36	363.39	354.90	362.22	368.67	358.83	367.13	374.33	342.47	349.07	355.10	346.57	353.89	360.34	350.43	358.70	365.90
New entrant curve 2	335.56	355.02	361.78	367.97	359.17	366.65	373.25	363.09	371.56	378.91	346.73	353.48	359.67	350.82	358.30	364.91	354.69	363.11	370.47
New entrant curve 3	341.38	361.83	368.80	375.20	365.97	373.67	380.49	369.89	378.59	386.16	353.52	360.49	366.89	357.61	365.32	372.14	361.48	370.13	377.71
New entrant curve 4	340.13	358.54	365.15	371.16	362.87	370.23	376.67	366.97	375.35	382.58	349.88	356.49	362.51	354.17	361.52	367.98	358.21	366.55	373.79
New entrant curve 5	357.19	380.62	388.30	395.40	384.76	393.19	400.70	388.69	398.11	406.39	372.29	379.98	387.08	376.38	384.81	392.33	380.24	389.63	397.92
New entrant curve 6	349.19	371.05	378.37	385.11	375.20	383.24	390.40	379.13	388.16	396.07	362.71	370.03	376.77	366.81	374.86	382.02	370.68	379.67	387.59
New entrant curve 7	358.99	382.82	390.59	397.81	386.92	395.38	402.98	390.81	400.19	408.50	374.47	382.24	389.46	378.52	386.97	394.59	382.34	391.69	400.01
New entrant curve 8	357.37	378.83	386.15	392.88	383.16	391.25	398.40	387.27	396.39	404.33	370.12	377.45	384.17	374.41	382.49	389.65	378.45	387.52	395.47
New entrant curve 9	377.77	404.84	413.38	421.33	408.99	418.28	426.64	412.92	423.21	432.34	396.46	405.00	412.95	400.55	409.84	418.21	404.41	414.66	423.80
Average cost – delivered energy $/MWh																			
New entrant curve 1 BASE CASE	52.64	58.18	59.28	60.28	57.72	58.91	59.96	57.24	58.56	59.71	59.62	60.77	61.82	59.09	60.34	61.44	58.55	59.94	61.14
New entrant curve 2	53.21	58.89	60.01	61.04	58.41	59.63	60.70	57.92	59.27	60.44	60.36	61.54	62.62	59.82	61.10	62.22	59.27	60.67	61.90
New entrant curve 3	54.13	60.02	61.18	62.24	59.52	60.77	61.88	59.00	60.39	61.60	61.54	62.76	63.87	60.98	62.29	63.45	60.40	61.85	63.11
New entrant curve 4	53.93	59.47	60.57	61.57	59.01	60.21	61.26	58.54	59.87	61.03	60.91	62.06	63.11	60.39	61.64	62.75	59.85	61.25	62.46
New entrant curve 5	56.64	63.14	64.41	65.59	62.57	63.94	65.17	62.00	63.50	64.83	64.81	66.15	67.39	64.18	65.62	66.90	63.54	65.10	66.49
New entrant curve 6	55.37	61.55	62.76	63.88	61.02	62.33	63.49	60.48	61.92	63.18	63.14	64.42	65.59	62.55	63.92	65.14	61.94	63.44	64.76
New entrant curve 7	56.93	63.50	64.79	65.99	62.92	64.30	65.54	62.34	63.84	65.16	65.19	66.54	67.80	64.54	65.98	67.28	63.89	65.45	66.84
New entrant curve 8	56.67	62.84	64.06	65.17	62.31	63.63	64.79	61.78	63.23	64.50	64.44	65.71	66.88	63.84	65.22	66.44	63.24	64.75	66.08
New entrant curve 9	59.90	67.16	68.57	69.89	66.51	68.02	69.38	65.87	67.51	68.96	69.02	70.51	71.89	68.30	69.88	71.31	67.57	69.29	70.81
Ave cost after fees and losses $/MWh																			
New entrant curve 1 BASE CASE	57.64	64.51	65.69	66.77	64.00	65.29	66.42	63.48	64.92	66.16	66.06	67.30	68.44	65.49	66.84	68.03	64.91	66.40	67.70
New entrant curve 2	58.25	65.27	66.48	67.59	64.75	66.07	67.23	64.22	65.68	66.95	66.86	68.13	69.30	66.27	67.65	68.87	65.68	67.20	68.53
New entrant curve 3	59.23	66.49	67.74	68.89	65.95	67.30	68.50	65.39	66.89	68.20	68.14	69.45	70.66	67.53	68.95	70.20	66.90	68.46	69.83
New entrant curve 4	59.02	65.90	67.09	68.16	65.40	66.70	67.83	64.89	66.33	67.58	67.45	68.70	69.83	66.89	68.25	69.44	66.31	67.82	69.13
New entrant curve 5	61.90	69.86	71.24	72.51	69.25	70.73	72.05	68.63	70.26	71.68	71.67	73.12	74.45	70.99	72.54	73.92	70.29	71.99	73.48
New entrant curve 6	60.55	68.14	69.46	70.67	67.57	68.98	70.24	66.98	68.54	69.91	69.87	71.25	72.51	69.22	70.70	72.02	68.56	70.19	71.62
New entrant curve 7	62.21	70.25	71.65	72.94	69.63	71.12	72.45	69.00	70.62	72.05	72.08	73.54	74.90	71.38	72.94	74.34	70.67	72.36	73.86
New entrant curve 8	61.93	69.54	70.85	72.06	68.97	70.39	71.65	68.39	69.96	71.33	71.26	72.64	73.91	70.62	72.11	73.43	69.97	71.61	73.04
New entrant curve 9	65.38	74.20	75.73	77.16	73.51	75.14	76.61	72.81	74.58	76.16	76.22	77.83	79.32	75.44	77.15	78.69	74.66	76.51	78.16