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ENERGYAUSTRALIA

RESPONSE TO THE QCA'S ISSUES PAPER – PUBLIC VERSION

APRIL 2007

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1 EXECUTIVE SUMMARY

EnergyAustralia welcomes the opportunity to make the following submission in response to the Minister for Mines and Energy's delegation to the Queensland Competition Authority (QCA) in accordance with the Electricity and Other Legislation Amendment Act 2006 (EOLA) and the QCA's Interim Consultation Notice.

EnergyAustralia believes it is critical that any annual decision made by the QCA on the Benchmark Retail Cost Index (BRCI, or 'the index') is consistent with the principle of maintaining headroom in Queensland's retail electricity market as stated in the Minister's certificate of delegation. Any erosion of that headroom will hinder the complete and successful evolution of full retail contestability in Queensland.

With the maintenance of headroom as an over-riding principle in the Minister's delegation, it is incumbent on the QCA to recognise recent movements in the contract market for wholesale electricity as well as the fundamental drivers behind these movements. We believe these costs can be recognised within the (currently draft) EOLA framework and will expand on this in section 5 of our submission.

The cost of energy

EnergyAustralia appreciates that the QCA is required to assess the Long Run Marginal Cost (LRMC) of energy. LRMC is, however, an artificial construct that bears little relevance to the market-based costs facing retailers on a day-to-day basis. Without reference to the true market costs faced by retailers, considering LRMC on its own risks misstating the real costs faced by a retailer and in turn jeopardise the Minister's intent and direction to maintain headroom.

Network costs

EnergyAustralia believes it is important for the QCA to assess network costs on a basis consistent with the direction in the Minister's drafting instructions. In doing so, the QCA will need to smooth Ergon's Annual Aggregate Revenue Requirement whilst maintaining net present value (NPV).

In the absence of a final Decision by the AER regarding Powerlink's revenue application for 2007-08, EnergyAustralia believes it is reasonable to determine the BRCI having regard to the AER's draft Decision on the matter. At the time of the next

BRCI review, for 2008-09, the BRCI base should be retrospectively adjusted for the AER's final Decision.

Retail costs

EnergyAustralia believes it is reasonable for the QCA to draw on the work performed in other jurisdictions to develop a reasonable operating cost allowance for an efficient hypothetical retailer. EnergyAustralia has engaged KPMG to review the costs of an efficient "Mass Market New Entrant" (MMNE) for the NSW Regulated Retail Price Review. We believe that the definition of a MMNE used in the NSW review and the "efficient hypothetical retailer" defined in the Minister's draft instructions are sufficiently similar to allow the QCA to rely on KPMG's results.

With the introduction of FRC in Queensland, retailers are expected to face additional costs associated with changed billing systems, call centre training, etcetera. EnergyAustralia believes it is reasonable to include these costs into the BRCI calculation as they are genuine costs faced by retailers and have been factored into other jurisdictional decisions where markets have transitioned to FRC.

Retail margin

The existing retail margin can be determined with reference to both the current notified price, less reasonable costs of supply. A stable margin is one which does not move materially (in revenue terms, ± 5 per cent) over time.

EnergyAustralia recognises the requirement to present the retail margin in cents per kilowatt hour. This amount should be determined initially in respect of a 'percentage of sales' so as to avoid degradation of real return as the revenue / cost base increases over time.

The Minister's delegation clearly emphasises the policy intent to maintain headroom. It is not entirely clear, however, at what point in time "headroom" is assessed in order to be maintained. EnergyAustralia argues that the best point in time to assess headroom for maintenance is at 1 July 2006 – the last price change date. This level of headroom is sufficient to encourage retail market entry and in turn deliver the real benefits of competition.

Other relevant costs

Although not specifically canvassed in the draft Queensland Pricing Regulations, EnergyAustralia believes it is appropriate for the QCA to have regard to the hedging, risk management and transaction costs associated with contracting on the wholesale market. EnergyAustralia believes this is the most critical cost the QCA must recognise and accommodate in their Decision. It is of particular relevance in light of the short- to medium- term contract prices which have soared in an environment of tightening supply which, in turn, is a function of the worsening drought conditions faced in south east Queensland.

With a mandate to maintain headroom, and an obvious current erosion of this headroom as the cost of purchasing wholesale energy escalates, we feel it incumbent on the QCA to recognise these real cost imposts in its Pricing Decision. EnergyAustralia believes that the EOLA provides an avenue for the inclusion of hedging, risk management and transaction costs by allowing the pricing entity to include “any other relevant costs”.

2 THE COST OF ENERGY

2.1.1 Relevance of LRMC

The 'LRMC of a new entrant generator' is a theoretical construct not readily observable in the market. Theoretically, LRMC will equate to hedge costs in the very long term. However, for the purpose of understanding the cost of energy purchases that a retailer is exposed to in the short- to medium-term, one must turn to the hedge market. Within the one year horizon of the QCA's first BRCI decision, hedge costs are clearly independent of LRMC.

When purchasing wholesale electricity, retailers are not faced with the long run marginal cost of electricity generation. The actual exposure of a retailer is a function of hedge costs & pool costs, which will generally come at a premium (that is, an 'additional' cost) to LRMC.

EnergyAustralia recognises that the QCA is obliged to assess LRMC for the purposes of assessing the energy cost component of the BRCI. Notwithstanding, we believe this is a base cost only; reference must also be drawn to the contract market to ensure that all true costs facing retailers are captured in the index. We believe that provision can be made for this cost under "any other relevant costs" in the EOLA and explain this approach in further detail in Section 5.

2.1.2 Definition of LRMC

There are two main approaches to modelling the LRMC of electricity generation: stand-alone load and incremental load¹. In its work for the Independent Pricing and Regulatory Tribunal (IPART), Frontier Economics lend their support to the former as it is in better keeping with NSW Minister's Terms of Reference for the 2007-10 Regulated Retail Price Review.

It is not obvious from either the drafting directions or the current draft Pricing Regulations which approach is best aligned to the Queensland Minister's intended framework. In the absence of explicit direction, EnergyAustralia advocates a 'stand-alone' approach. This should simplify the manner in which future LRMC calculations are struck and better enable consistent comparisons with prior year BRCI reviews.

¹ *Energy Costs, Public Final Report*, Frontier Economics, April 2007, p 12.

2.1.3 LRM annual change

EnergyAustralia expects that the LRM of energy generation will change from 2006-07 to 2007-08. The basis of this expectation is our observed increases in construction costs. However, it will not be clear the actual extent of the yearly increase in LRM until a thorough assessment is performed. EnergyAustralia recognises that the timeframe for consultation is tight but that this should not preclude an LRM assessment being made by an appropriately-qualified technical consultant. This assessment should, by definition, deliver the optimal combination of generating plant for a given load and other inputs. We believe that reference to the most current work performed by ACIL Tasman² is appropriate to determine the modelling assumptions underpinning the LRM analysis.

2.1.4 The 13 per cent Gas Scheme

The 13% Gas Scheme aims to boost the Queensland state's gas industry and reduce greenhouse gas emissions.

Earlier we recommended the stand-alone approach to determining LRM. In assessing the impact of the 13% Gas Scheme, we believe it is more appropriate to adopt an incremental approach. This is consistent with the approach adopted by IPART as part of the NSW Regulated Retail Price Review.

Under the stand-alone approach, the LRM model will naturally construct gas generators as part of the efficient suite of generation. This newer, gas-fired electricity produces a lower rate of greenhouse gas emissions than the current stock of older generating plant. No incremental cost to meet the 13% Gas Scheme would arise under the stand-alone approach as the efficient combination of generating plant would, by virtue of meeting load requirements, already satisfy the Schemes requirement. Consequently, no additional compensation would be required for meeting the scheme. This outcome is inconsistent with the cost burdens faced by retailers who, in practice, buy electricity from the NEM which is dominated by older, less efficient gas-fired generation. For this reason it is important to recognise the LRM of satisfying the 13% Gas Scheme on an incremental basis.

2.1.5 Other schemes

The level of mix of renewable generation should be consistent with the current obligations on retailers, including the Commonwealth Mandatory Renewable Energy Target (MRET) and any other new scheme affecting electricity retailing in

² ACIL Tasman, *Report on NEM generator costs (Part 2) - A report to IRPC and NEMMCO*, February 2005.

Queensland. A step-change in costs should also be recognised with the introduction of any new scheme affecting Queensland's retail electricity market.

2.1.6 Ancillary Services

In its delegation, the Minister also recognised that retailers must pay ancillary service charges to cover the costs associated with the physical safety and co-ordination of the National Grid. Ancillary services include:

- automatic generation control;
- governor control;
- load shedding;
- rapid generating unit loading;
- reactive power;
- rapid generating unit unloading; and
- system restart.

These costs are in some way related to the cost of energy. EnergyAustralia believes that, in recognising ancillary service costs, the QCA should have regard to the future charges an efficient retailer would be expected to incur. To determine future charges, the QCA should consider historical movements in ancillary service costs.

2.1.7 Other NEMMCO-related charges

EnergyAustralia believes the BRCI should capture all costs associated with the provision of retailing services, including other NEMMCO-related costs. In addition to ancillary services, noted above, an allowance should be made for general participant fees and full retail contestability fees.

EnergyAustralia expects these costs to increase in excess of CPI. In determining an appropriate provision for NEMMCO-related costs, we direct the QCA's attention to NEMMCO's draft 2007 Statement of Corporate Intent and Budget, where expected rises in fee revenue incorporate marked increases in labour costs and expanded responsibilities in their operation of the NEM.

3 NETWORK COSTS

3.1.1 Powerlink

According to the AER's timetable, it will finalise its decision on Powerlink's revenue application for 2007 to 2012 in April 2007. The QCA intends to release a draft Decision on the BRCI on 8 May 2007. Based on their proposed timetables, the QCA should be able to incorporate the AER's final decision into its draft Determination.

In the absence of a timely Decision from the AER, EnergyAustralia believes it would be reasonable for the QCA to base its BRCI Decision on the AER's draft Decision. In the following year (2008-09) the BRCI could be retrospectively updated to accommodate the AER's final Decision.

3.1.2 Energex

The QCA is currently reviewing Energex's application for the pass through of costs associated with Full Retail Contestability. Energex's application seeks an increase in costs of around 3% which will have a material effect on Energex network prices if included, as sought, in their 2007-08 revenue allowance.

The QCA recently made a final Decision on Energex's application for the pass through of costs associated with additional capital expenditure. The Decision meant that Energex's (smoothed) revenue would grow by 12.7% p.a. (in nominal terms) for the next three years.

Together, the financial effect of these additional costs as allowed to be recovered in Energex's network revenue need to be factored into the BRCI calculation. It would be appropriate to use the actual revised AARR used to set network prices (that is, the smoothed revenue allowance granted in the final Decision).

In the absence of a final Decision on Energex's FRC cost pass through claim, it would be appropriate for the QCA to base the BRCI for 2007-08 on its draft Decision and retrospectively correct the index as part of the 2008-09 BRCI review.

3.1.3 Ergon

In 'smoothing' Ergon Energy's AARR, it may be appropriate to update the WACC discount rate from the final Decision to reflect only changes in prevailing interest rates. It should also be made clear that the recalculation is only for the purposes of determining the BRCI and in no way constitutes a change in Ergon's actual AARR.

There are no obvious implications' stemming from the Minister's required treatment of Ergon's AARR in the BRCI calculation for Energex.

4 RETAIL COSTS

4.1.1 Defining an efficient hypothetical retailer

Important in determining the extent of costs faced by an efficient hypothetical retailer is to define what an efficient hypothetical retailer is. EnergyAustralia believes it is not unreasonable to assume the following key characteristics of an efficient hypothetical retailer:

- Area of operation, Queensland for customers using less than 100 MWh per annum;
- Electricity only retailer;
- Stand alone business, without vertical integration; and
- Mass market operator, with a customer base in excess of 250,000 to achieve reasonable economies of scale.

These assumptions are consistent with the criteria set out in Section 94 of the EOLA Bill 2006 and will facilitate a reasonably simple and transparent determination of retail costs.

In order to determine an efficient retailer's retail cost base, EnergyAustralia submits that the QCA consider a benchmarked cost build-up approach. A 'bottom-up' approach will better enable the QCA to adhere to its delegated requirement to consider retail cost functions such as "billing, customer call centres, credit management, energy trading, corporate overheads and information technology systems." It will also help the pricing entity maintain a consistent base of benchmarking by ensuring that all sub-components of the retail cost are accounted for, and that any new, changed or removed functions are transparently addressed.

The bottom up analysis we propose would entail:

- defining the electricity retailing function and the scope of an efficient hypothetical retailer's business;
- identifying the activities that are likely to be involved in undertaking the function;
- identifying the types of resources involved in undertaking those activities; and
- identifying the quantum of resources and unit costs that are likely to be consumed.

In its submission to IPART's Issues paper on the 2007-10 Regulated Retail Price Review, EnergyAustralia defined the following key retail business functions and cost drivers:

Activity	Cost Drivers	Benchmark
Billing, data validation	Number of bills issued, which in turn is a function of the billing cycle (monthly or quarterly), plus reminder notices	Cost per bill
Collection	Number of customers and billing frequency	Cost per receipt
Customer transfer	Number of customers and transfer rates	Cost per transfer
Bad debt expense	Size of business	Electricity market experience based on revenue
Customer Information System	Size of business	Benchmark costs based on IT Utilities survey
Call centre costs	Number of customers and the number of calls customers make to their retailer	Benchmark costs built up from call centre statistics
Management (pricing, Risk management, Settlements, Regulatory)	Size / scale of the business	Benchmarking staffing costs and occupancy costs, minor amounts for licensing and ombudsman
Energy trading	Size of business	Salary and occupancy costs
Public relations	Size of business, with an allowance for mass marketing budget	Salary and occupancy costs plus advertising budget

In an attachment to this submission, EnergyAustralia has provided the results of a retail benchmarking activity performed by KPMG. The commonality in retailer definitions should allow the QCA to meaningfully rely on the KPMG benchmarking study as the basis (or at least starting point) for its own retail cost analysis.

4.1.2 Comparison to incumbents

The retail functions of an efficient retailer and incumbent would broadly be the same. Differences, however, arise in the magnitude of the costs faced by these retailers.

For example, the incumbents enjoy synergies from vertical integration with generators that are not available to the efficient hypothetical retailer. This may, to a large extent, protect the incumbent from large and volatile movements in both the spot and contract market. It is therefore important for the QCA to appreciate those costs faced by an efficient, stand alone retailer over and above the costs faced by the incumbents.

4.1.3 Full retail contestability

The QCA needs to develop two BRCI for this, their first, review in order to determine the change in BRCI from 2006-07 to 2007-08. EnergyAustralia believes a obvious uplift in costs relating to full retail contestability should be evident in the retail cost element of the change in BRCI. Preparing a retail business for full retail contestability requires fundamental changes to business processes. These changes come at a significant cost³ and should be recognised in the 2007-08 BRCI.

4.1.4 Retail margin

The existing retail margin can be determined with reference to both the current notified price, less reasonable costs of supply. A stable margin is one which does not move materially (in revenue terms, ± 5 per cent) over time.

EnergyAustralia recognises the requirement to present the retail margin in cents per kilowatt hour. This amount should be determined initially in relation to 'percentage of sales' so as to avoid degradation of real return as the revenue / cost base increases over time.

The Minister's delegation clearly emphasises the policy intent to maintain headroom. It is not entirely clear, however, at what point in time "headroom" is assessed in order to be maintained. EnergyAustralia argues that the best point in time to assess headroom for maintenance is at 1 July 2006 – the last price change date. This level of headroom is sufficient to encourage retail market entry and in turn deliver the benefits of real competition.

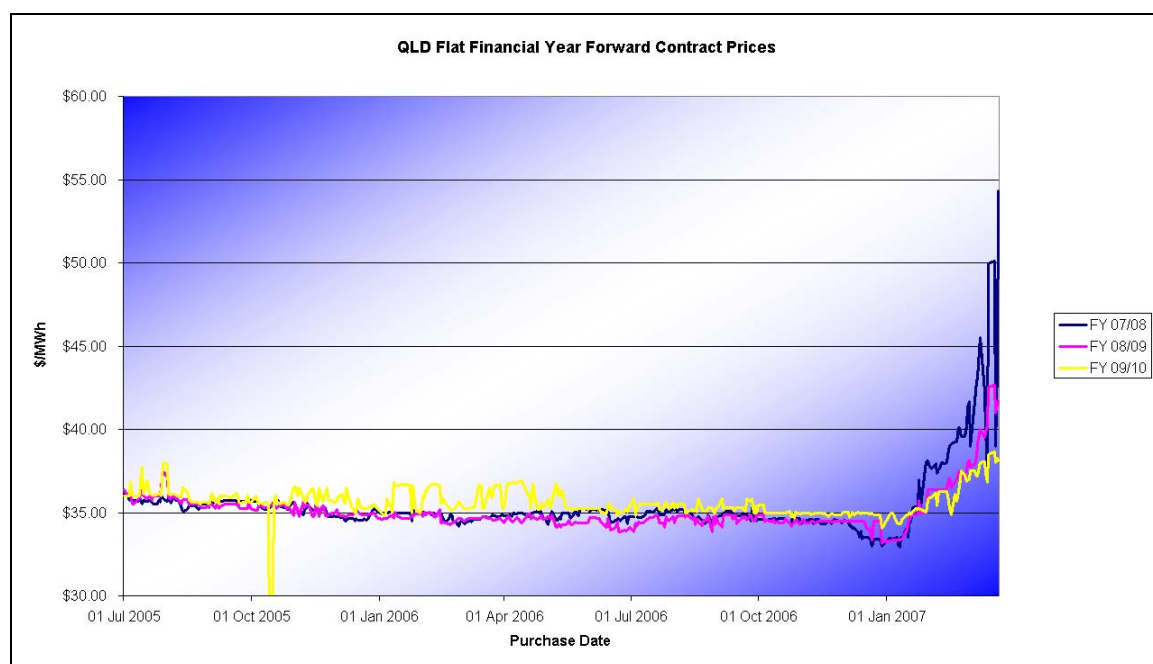
³ For example, IPART provided EnergyAustralia with a retail cost allowance of \$25.6M (or ~\$5 per standard retail customer) with the commencement of FRC in NSW.

5 OTHER RELEVANT COSTS

Although not specifically canvassed in the draft Queensland Pricing Regulations, EnergyAustralia believes it is appropriate for the QCA to have regard to the hedging, risk management and transaction costs associated with contracting on the wholesale market. EnergyAustralia believes this is the most critical cost the QCA must recognise and accommodate in their Decision.

Since January 2007 forward contract prices have been sharply rising and have reached unprecedented levels. In EnergyAustralia's considered opinion these movements reflect fundamental changes in the underlying medium term cost structure of the NEM and Queensland specifically.

Queensland's water shortages have reduced Queensland supply and consequently NEM wholesalers are reviewing the fundamental level at which they are selling firm contracts. Accordingly there is less and less liquidity and the prospect of further rationing of both physical supply and contracts suggests that there will not be any precipitous sell-off in the near term from current market levels.



The graph above highlights the movement in Queensland flat forward contract prices for financial years 07/08, 08/09 and 09/10. Prior to January 2007 Queensland flat forward contracts traded at around \$35/MWh, however since then they have risen exponentially and the 2007/08 contract is now trading above \$55/MWh reflecting the impact that water shortages are now having on generators in Queensland and the Snowy Mountains. These prices represent an increase of 57% since the movement began.

The Queensland drought has so far affected Tarong Energy and CS Energy with both companies advising NEMMCO of significant reductions in output. Tarong will be reduced to 30% of full capacity for at least the next 15 months and the CS Energy Swanbank output will be curtailed for at least the next 12 months causing both Queensland and NSW forward contracts to rise sharply.

The market is now revaluing the scarcity of energy due to water, plant reliability and contract shortfall, consequently Queensland contract prices for financial year 07/08 have risen by \$20/MWh to \$55/MWh since mid-January 2007.

We believe that the emergence of a water scarcity premium in energy market prices is predicated on fundamental changes to the medium-term structure of the NEM and Queensland markets. These reflect significant price movements and structural changes that have evolved recently and highlight the risk that retailers bear on behalf of customers in supporting predetermined tariffs. It is vital that these recent developments be considered in any review the Authority may perform of Queensland Retail electricity tariffs.

With a mandate to maintain headroom, and an obvious current erosion of this headroom as the cost of purchasing wholesale energy escalates, we feel it incumbent on the QCA to recognise this real cost impost in its Pricing Decision. We believe that the EOLA provides an avenue for the inclusion of hedging, risk management and transaction costs by allowing the pricing entity (QCA) to include "any other relevant costs".

**6 APPENDIX A – KPMG REPORT
FOR ENERGY AUSTRALIA ON
BENCHMARKING RETAIL
OPERATING COSTS AND
MARGINS**



EnergyAustralia

**Benchmarking Retail
Operating Costs and Margins**

September 2006

This report contains 57 pages

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1 Introduction

The Independent Pricing and Regulatory Tribunal (“IPART”) is currently engaged in a process to determine regulated electricity retail tariffs for the period 2007 to 2010. As part of this process, IPART recently published an Issues Paper which calls for submissions from interested parties on the issues involved in setting the tariffs.¹

EnergyAustralia (“EA”) has engaged KPMG to benchmark the:

- operating costs of a mass market new entrant (or “MMNE”); and
- retail margins a MMNE might reasonably expect to earn.

1.1 Outline of approach

To undertake this assignment we have:

- reviewed IPART’s Issues Paper;
- defined the entity for which we are benchmarking operating costs and margins;
- benchmarked operating costs and margins by reference to a range of evidence; and
- examined the findings and commented on how to interpret them.

1.2 Outline of report

This report provides the output of our analysis. In particular:

- section 2 outlines how we have approached the task;
- section 3 outlines how we have benchmarked retail operating costs;
- section 4 outlines how we have benchmarked retail margins; and
- section 5 provides our findings and comments.

There are three appendices:

- appendix A summarises our Terms of Reference;
- appendix B describes how we have benchmarked retail operating costs; and
- appendix C describes other regulatory decisions in respect of operating costs and margins.

¹ IPART, Review of Regulated Retail Tariffs and Charges for Electricity 2007 to 2010, July 2006.

1.3 Disclaimer

Inherent Limitations

This report has been prepared as outlined in section 2. The procedures outlined in this report constitute neither an audit nor a comprehensive review of operations.

No warranty of completeness, accuracy or reliability is given in relation to the statements and representations made by, and the information and documentation provided by, EnergyAustralia consulted as part of the process.

KPMG have indicated within this report the sources of the information provided. We have not sought to independently verify those sources unless otherwise noted within the report.

In the course of our work, projections have been prepared on the basis of assumptions and methodology which have been described in our report. It is possible that some of the assumptions underlying our projections may not materialise. Nevertheless, we have applied our professional judgement in making these assumptions, such that they constitute an understandable basis for estimates and projections. Beyond this, to the extent that certain assumptions do not materialise, then it must be appreciated that our estimates and projections of achievable results will vary.

KPMG is under no obligation in any circumstance to update this report, in either oral or written form, for events occurring after the report has been issued in final form.

The findings in this report have been formed on the above basis.

Third Party Reliance

This report is solely for the purpose set out in section 1 of this report and for EnergyAustralia's information which includes the use of this information in EnergyAustralia's response to the IPART Issues Paper. It is not however, to be used for any other purpose or distributed to any other party without KPMG's prior written consent.

This report has been prepared at the request of EnergyAustralia in accordance with the terms of KPMG's engagement letter/contract dated 26 July 2006. Other than our responsibility to EnergyAustralia, neither KPMG nor any member or employee of KPMG undertakes responsibility arising in any way from reliance placed by a third party on this report. Any reliance placed is that party's sole responsibility.

2 Approach

This section outlines our approach to benchmarking the retail operating costs and margins of a MMNE. In particular, it summarises the relevant parts of IPART's Issues Paper and describes how we have defined the relevant terms and the task.

2.1 IPART's Issues Paper

The Issues Paper raises and seeks comment on a number of matters relevant to the regulation of retail electricity tariffs. These include:

- policy changes impacting on the review;
- the form of regulation;
- costs to be recovered by regulated tariffs; and
- miscellaneous charges.

IPART considers that the 'costs' regulated tariffs ought to recover include the following:

- retail margin;
- retail operating costs; and
- costs of supply including:
 - energy;
 - network charges;
 - green energy;
 - hedging , risk management and transaction costs; and
 - costs of new schemes that may be imposed.

In identifying the range of costs that regulated tariffs ought to recover, IPART seeks comment from interested parties on retail operating costs and margins (the two areas this report addresses). More specifically, IPART has sought comment on the appropriate:

...level of mass market new entrant retail operating costs for inclusion in regulated tariffs.²

...mass market new entrant retail margin to be included in regulated retail tariffs.³

² Ibid., page 20.

³ Ibid., page 21.

2.2 Definitions

IPART is required by the NSW Minister of Energy's Terms of Reference to set regulated tariffs, in part, according to the operating costs and margins of a mass market new entrant (or "MMNE").

A mass market new entrant

The Minister of Energy's Terms of Reference does not define what it means by a "mass market new entrant" other than to state that a "new market entrant that is of sufficient size to achieve economies of scale". Moreover, IPART does not explain how it interprets the term either, although at one point it uses the term "competitive" mass market retailer.⁴

This raises a number of questions that may be relevant to benchmarking operating costs and margins for a MMNE including:

- the market definition;
- the size and type of retailer;
- whether a "new entrant" implies extra costs (eg. associated with getting into the market);
- whether a "new entrant" implies a retailer that is not vertically integrated; and
- whether the task is to determine the margins a MMNE would expect to earn in a market that did not have price regulation.

These questions are important because they go to interpreting both the objectives of the Terms of Reference and the evidence benchmarking produces, which inevitably requires considerable judgment.

The objectives of the Terms of Reference appear to require new entrants to be able to compete on a 'level playing field' with regulated tariffs. The Terms of Reference states that IPART:

...must consider the Government's policy aim of reducing customers' reliance of regulated prices and the effect of its determination on competition in the retail electricity market.⁵

It also states that the determination should ensure that all retail charges are at cost reflective levels for all small retail customers by 30 June 2010.

In our view, a MMNE would have two key features. It would:

- retail electricity to a large customer base and to a broad range of customers; and

⁴ Ibid., page 21.

⁵ Ibid., page 30.

- would employ best practice operations, systems and financial structures that would enable it to compete effectively with reasonably set regulated tariffs and earn returns that justify the risks associated with entering into the market.

Table 2.1 outlines our definition of a MMNE.

Table 2.1: Defining a Mass Market New Entrant (MMNE)

Definition	Comment
Area of operation	Assumed to be NSW for customers using less than 160 MWh per year, reflecting IPART's jurisdiction to regulate prices.
Electricity retailer only	Reflecting IPART's price determination of electricity tariffs.
Stand alone business	Assumed to be a stand alone, non-vertically integrated retailer. This will require the retailer to purchase all energy sold either via hedging contracts or via the spot market.
Customer numbers	A retailer would need to maintain a customer base of at least 250,000 customers to warrant the investment in systems necessary to handle a mass market. We assume (for simplicity) that the MMNE is able to achieve this scale of operation immediately on commencement of operations (see below).
Customer types	To operate in a mass market, the retailer should be in a position to accept all customer types including: <ul style="list-style-type: none"> - all metering types; - a range of customer types including small commercial and residential (including those from a relatively broad socioeconomic range); and - all payment types (direct debit, cheque and cash, and those requiring reminder notices and with payment difficulties).
Call centre contacts	When establishing costs for operating the call centre, we consider that it will be driven by the number of customers, the complexity of tariffs and billing information, and externalities such as market information, government policy etc. We have therefore assumed that the MMNE will operate in a similar manner to that currently experienced in the market place.
Billing intervals	Billing intervals should accommodate mostly quarterly read and bill cycles and a portion of monthly read and bill.
Handling of data	Data to be processed should include customer data for customers with time of use metering and customers with accumulation metering types.

Section 5 discusses in some detail the implications of our definition in commenting on our findings. In most cases, these implications go to how to interpret the benchmarks. This is primarily because although the available benchmarks are typically consistent with what we are seeking to quantify, they often lack the precision necessary to enable use without the exercise of judgement.

A couple of comments are worth reiterating here.

The benchmark entity described as a “mass market new entrant” is in some ways a hypothetical construct, involving a number of simplifying assumptions, which are potentially significant. For example, we have assumed that the MMNE has 250,000 customers and has attained these customers immediately. In practice, the new entrant is unlikely to enter, in the first instance, as a mass player and it is likely to take a number of years to develop such a customer base. If it is to compete in the mass market it will, however, need to have the systems in place to do so and the capability of dealing with the complexities of having a diverse customer base

(notwithstanding that in the short term at least its customer base is likely to be less diverse). It will have the operating costs to match.

In benchmarking the operating costs of a MMNE we have excluded customer acquisition costs (which are of more of a capital cost in nature) but not the cost of having such a capability. Acquisition costs are relevant to the analysis, but we account for them in the appropriate net margin, which our benchmarking of net margins implicitly captures. We have also excluded incumbent retailer costs, because a MMNE would not bear these costs.

So our assumptions, while somewhat simplistic, are nevertheless consistent with the underlying assumption regarding a MMNE that is able to exploit economies of scale.

Retail margins

IPART's Issues Paper defines the retail margin (or profit margin) as the reward to investors for committing capital to a business. This implies that it is the difference between the tariffs charged to a group of customers, and the costs incurred in selling energy to those customers.

IPART identifies a range of factors that will influence the retail margin including the level of risk associated with:

- energy purchasing costs;
- customer default and 'typical' bad debt expense; and
- competition from electricity substitutes (eg. gas, solid fuels etc).

IPART also identifies hedging, risk management and transaction costs and the forecasting risk that retailers will face in the absence of ETEF as potentially relevant to the estimation of the retail margin.

In principle, the margin should compensate a MMNE for the market risks associated with the underlying assets, and all the business risks should be compensated for in the operating cost allowances made for such a business. In practice, however, delineating risks and the compensation for them on this conceptual basis is typically problematic. This means that, in practice, it is always likely to be difficult to separate entirely the allowance for risks incorporated into:

- the operating cost allowances generally;
- the allowance for the costs of managing certain 'business' risks (eg. hedging costs)⁶; or
- the allowance for the market risk associated with the underlying assets.

⁶ Although we have included energy trading transaction costs in our operating benchmarks, it would not be unreasonable to account for these costs within the energy cost allowance as an alternative.

For the purposes of this exercise we have established operating cost benchmarks consistent with the available market information. Therefore:

- IPART will account for the costs of acquiring electricity elsewhere, but that the transaction costs associated with doing so are reflected in our benchmarks;
- our operating cost estimates reflect those ‘business’ risks that are readily quantifiable (this includes an allowance for ‘typical’ bad debts); and
- market risks (and presumably any other risks not captured above) are reflected in the margins it would be reasonable to expect a MMNE to earn.

For the purposes of this report we have used the following definitions of margins:

- *margin*: generally refers to the difference between the revenue and costs of a business. It is possible to express margins at a number of levels of a business’s Income Statement (see below).
- *gross margin*: is the difference between revenues and the direct costs⁷ of production of a business. In this case, we assume it means revenues less all electricity (commodity) costs and other pass through costs (eg. network charges).
- *net margin*: is the difference between the gross margin and the indirect costs⁸ of production of a business. In this case, we assume it means all operating costs, excluding interest and taxes.⁹

In addition, this report also uses EBITDA (“Earnings before interest tax depreciation and amortisation”) and EBIT (“Earnings before interest and tax”) margins because the market often expresses margins in these ways. The latter is broadly consistent with our definition of net margin. In practice, because of the nature of the retail electricity business, the differences between EBITDA and EBIT margins are typically relatively modest.

Unless otherwise indicated, this report expresses all these margins as a percentage of revenue.

⁷ Direct costs: generally refers to costs that are caused by the production of a particular product or service and may therefore be directly attributed to, or readily identified with, a particular product, service or contract (for example, raw materials used to produce a good).

⁸ Indirect costs: generally refers to the costs of doing business that are not directly related to a particular product, service or contract. It should be noted that determining what direct or indirect costs are in particular circumstances or for particular purposes can require a considerable degree of judgment, and estimating some margins is therefore subject to the same uncertainties.

⁹ As the net margin estimates the return on capital it implicitly includes the costs associated with the return on capital employed to acquire customers.

3 Retail operating costs

There are two main ways to benchmark the operating costs a MMNE could expect to incur:

- undertake a bottom-up, cost build-up exercise; and
- undertake a top-down review of operating costs by reference to the decisions by regulators and the available market evidence.

For the purposes of this exercise we focus on the bottom-up approach and cross check the results of this approach against regulatory decisions that have estimated retail operating costs.¹⁰

3.1 Our approach

This section summarises the bottom-up approach, which we describe in further detail in Appendix B. Our approach involves:

- defining the electricity retailing function and the scope of a MMNE's business;
- identifying the activities that are likely to be involved in undertaking the function;
- identifying the types of resources involved in undertaking those activities; and
- identifying the quantum of resources and unit costs that are likely to be consumed.

To do this, we identify and rely on the best available market information and benchmarks in respect of both the quantum and unit cost of the required resources.

3.2 Electricity retailing

Electricity retailers provide consumers with ways to buy electricity. From the customer's perspective the electricity retailers' offer has three key components:

- a price charged for access to electricity and for the amount of electricity consumed;
- a method by which customers pay; and
- typically, certainty in regard to the prices customers pay for a certain period.

Electricity retailers seek to add value by providing these services at a price and in a manner that meets customers' needs. It involves the following key functions:

- sales and marketing (eg. to generate revenues by winning and retaining customers);

¹⁰ There is relatively little detailed information on operating costs per customer available from the capital markets.

- billing and revenue collection (eg. to generate cash inflow);¹¹
- customer service (eg. to manage customer communication); and
- risk management (eg. minimise energy costs by managing purchase risk).

The first function is a profit centre, while the last three functions are principally cost centres.¹²

The retailers' costs are primarily either fixed or customer-related. A retailer's fixed costs are primarily a function of the information technology systems required. A retailer's customer related costs are primarily a function of processing the needs of each customer (i.e. having the information available to bill the customer, sending bills, collecting revenues etc).

Electricity retailing to a mass market is a high volume business that involves significant fixed costs (eg. a CIS system for a mass market retailer is likely to cost approximately \$15-20 million).

3.3 Defining the operating costs of a mass market new entrant

Due to the significance of systems needed to establish and maintain a MMNE retailer operation and the nature of the associated costs, we have formed the view that a MMNE would need to be serving at least 250,000 customers to justify the necessary investment. Appendix B.1.3 explains our reasoning.

A cost tree in Appendix B.2 sets out the key activities of a MMNE. We have then determined the drivers of costs for those activities and how we expect a MMNE retailer to operate based on benchmarks and observations which appendix B discusses.

Table 3.1 below defines the activities, comments on the key cost drivers and identifies the benchmarks we use.

¹¹ Sometimes the metering and or meter reading function are also included.

¹² Energy trading can also be a profit centre, but that is a function that can and usually is undertaken separately to energy retailing (ie. it is similar to the distinction between stock broking and proprietary trading).

Table 3.1: Summary of cost drivers for the benchmarks used in the operating costs of a MMNE

Activity	Comments on cost drivers	Benchmark
Billing, data validation	Driven by number of bills issued, which in turn is a function of the billing cycle (monthly or quarterly), plus reminder notices	Cost per bill
Collection	Driven by number of customers and billing frequency	Cost per receipt
Customer transfer	Driven by the number of customers and transfer rates	Cost per transfer
Bad debt expense	Driven by size of business	Electricity market experience based on revenue
Customer Information System	Driven by the size of the business. We have assumed a 250,000 customer base	Benchmark costs based on IT Utilities surveys
Call centre costs	Driven by the number of customers and the number of calls customers make to their retailer	Benchmark costs built up from call centre statistics
Management Pricing Risk management Settlements Regulatory	Driven by size/scale of the business. We have assumed a size of business for a MMNE that requires the management infrastructure defined in this benchmarking exercise	Benchmark staffing costs and occupancy costs, plus minor amounts for licensing, and ombudsman.
Energy trading	Driven by size of business	Salary and occupancy costs
Public relations	Driven by size of business, with an allowance for mass marketing budget	Salary and occupancy costs plus an advertising budget based on regulatory precedents

3.4 Results

Application of the benchmarks against the MMNE assumed in this report produce the operating costs Table 3.2 summarises.

Table 3.2: Summary of results - operating costs of a MMNE as defined above

	Section in appendix	2005/06 Benchmark		
		Lower bound benchmark (\$m)	Upper bound benchmark (\$m)	%
Billing and customer collection (including CIS/ITS)	B.3.1	10.04	10.19	46-50
Call centre costs	B.3.2	2.05	2.05	9-10
Full time equivalent employee costs and overheads	B.3.3	8.57	9.77	41-44
Total		20.70	22.00	100%

The total retail operating cost for the MMNE ranges from \$20.7m to \$22.0m, resulting in a per customer cost of about \$83 to \$88 for 2005/06.

4 Retail margins

There are two main ways to benchmark the margin a MMNE might reasonably expect to earn:

- undertake a bottom-up cost build-up to determine the asset base and a benchmark return on that asset base to determine what that calculation implies for margins; and
- undertake a top-down review of margins by reference to the decisions by regulators and the available market evidence.

For the purposes of this exercise, and for the reasons we illustrate, we use the latter approach.

4.1 Recent regulated electricity retail tariff decisions

The decisions by regulators might provide some evidence of what a MMNE might expect to earn.

We have summarised below the results of regulatory decisions on retail margins. Appendix C provides further details on these decisions.

Table 4.1: Jurisdictional decisions - margins

	Jurisdictional Benchmarking	
	Year	Net margin %
SA Electricity ¹³	2005	5%
NSW Electricity	2004	2%
Victoria Electricity	2003	5%
SA Electricity	2003	5%
Tasmania Electricity	2003	3%
ACT Electricity	2003	5%
NSW Electricity	2002	1.5 to 2.5%
Victoria Electricity	2001	2.5 to 5%
NSW Electricity	2000	1.5 to 2.5%
Tasmania Electricity	1999	1.5%

It is perhaps unsurprising that there has been more competitive activity in those markets where regulated margins are higher. For example, there has been a considerable degree of competitive activity and some new entry into the Victorian and South Australian markets. According to AGL, annual customer churn rates for Victorian and South Australian gas and electricity are all at least 20%, whereas for NSW gas and electricity the churn rates are 4% and 9% respectively.¹⁴ In addition, new entry into the NSW market has been modest.

¹³ See page 53.

¹⁴ AGL, 2006 Full Year Financial Results', 16 August 2006, page 17. The SA figures include retentions whereas the others do not and the Government also subsidised customer switching.

This suggests that the regulated retail prices in Victoria and SA have been sufficient to encourage switching and new entry. This does not necessarily mean, however, that the allowed margins are the primary reasons for this. For example, lower than expected wholesale electricity prices would appear to be partly responsible for some of this competitive activity.¹⁵ Our discussions with market participants have confirmed this view.

This view would appear to accord with the market evidence.

In the capital markets one of the most commonly used measures of the relative cost of acquiring retail businesses is the cost per customer.^{16,17} Most major transactions, many of which occurred some years ago, appear to have valued customers in the \$400 to \$850 range (with the higher end mainly for customers for whom dual fuel offers are an option). More recently, somewhat higher valuations would appear to be the norm.

For example:

- ABM Amro values AGL's retail business at approximately \$925/customer;¹⁸
- Morgan Stanley values Origin's retail gas business at \$900 per customer and its retail electricity business at \$980 per customer.¹⁹

Goldman Sachs JBWere also recently stated that it expected ENERGEX's retail business to sell for about \$600 million, which works out to be approximately \$750 per electricity customer.²⁰

To justify these valuations the market would appear to be expecting these customers to generate margins above those indicated by most regulated margins.

For example, net margins of 3% on an electricity bill of \$1000 per annum imply that the retailer is earning (before interest and tax) about \$30. The above valuations would suggest that at \$900 per customer the market is prepared to pay about 30 times these earnings (ie. it would take the

¹⁵ For example, Victorian electricity prices in the 2004/05-2005/06 appear to have been lower than expected around the time the regulated price path was set. The Age, "Transfield gets Loy Yang smoking" 16 August 2006. It states "Transfield Services' purchase of a 9.3 per cent stake in Victoria's biggest generator, Loy Yang A, for \$115 million earlier this month shows how generation asset values have risen in recent times." And "The reason the price has crept up is that for the first time in a while, power prices are actually tracking in the right direction as far as generators are concerned. In 2003-04, average Victorian power prices bottomed at \$25.38 per megawatt-hour. A year on they climbed to \$27.62, then last year to \$32.47. For the first month of the current financial year they have averaged \$46.39. By contrast, in October 2003 the expectations were for prices of around \$33 and \$35 in 2004-05 and 2005-06 respectively. See ESAA, Market Report, Week 40, October 2003. This also appears to have encouraged the Government to seek further reductions in retail prices over the regulated period. See Power Industry News, 'Vic Price Boast', Edition 494, 5 June 2006, page 18.

¹⁶ Australian Financial Review, 'Australian Energy poised', 6 August 2003, page 27.

¹⁷ Australian Financial Review, 'AGL needs up to \$500m equity for Pulse', 1 July 2002, page 16. See also the Allen Consulting Group, Review of the Gas Code: Commentary on Economic Issues, Report to BHP Billiton, August 2003. The paper provides a summary of Australian retail energy business transactions.

¹⁸ ABN Amro, Australian Gas Light' 28 February 2006, page 5.

¹⁹ Morgan Stanley, 'Origin Energy Limited', 21 February 2006, page 5.

²⁰ Australian Financial Review, Alinta-AGL deal to power activity, 23 August 2006, page 33. Although it also has about 50,00 LPG gas customers as well.

same number of years to recover the cost of paying this much to acquire a customer).²¹ At a net margin of 5%, the market is prepared to pay 18 times these earnings.

It seems unlikely that this is the case. For instance, ABN Amro suggests that it values AGL's retail business on an expectation that it earns an EBITDA of approximately \$100 per customer, and that the market is willing to pay 9 times EBITDA to acquire this performance. Moreover, AGL's most recent results suggest it is earning a gross margin of \$184 per electricity mass market customer.²² As section 4.2 illustrates, these figures are consistent with net margins above those implicit in regulated tariffs.

The evidence suggests that the margins within regulated retail electricity tariffs are likely to be at the low end of those necessary to encourage new entry, particularly for a MMNE.

4.2 Market evidence

There are a number of sources of market evidence on expected retail margins including:

- independent experts' reports; and
- brokers' reports (which often refer to company results).

Similar sources of information also available in relation to international data.

The key advantage of this evidence is that it provides the most direct indication of what the market expects from the performance of energy retailers. The key disadvantage of this type of evidence is that it often relates to the market's expectations of the performance of a particular business, or of the market in particular circumstances. In other words, often the information relates to retailers that are:

- part of a larger diversified utility business;
- undertaking a number of activities in addition to energy retailing (sometimes within the business unit containing energy retailing);
- much larger than a MMNE could reasonably expect to be (who are often large players in the lower margin, higher volume commercial and industrial markets as well);
- diversified across a number of regions (and/or countries) and fuels (eg. including LPG) within the energy retail business; and
- vertically integrated in the electricity (and possibly gas) sector.

²¹ This evidence also explains why estimating margins according to bottom-up approach can be problematic. Much of the value of retail businesses would appear to lie in the more intangible assets of the business (ie. its customer base), rather than in the underlying physical assets.

²² AGL, 2006 Full Year Financial Results: 12 months ended 30 June 2006, page 15. It reports a gross mass margin of \$263.4 million over 1.428 million accounts.

These caveats by definition draw into question whether the information provided from these sources is relevant for a MMNE. For example, a MMNE might require a higher margin than the incumbents to justify the risk of entry.

In addition, the information provided by brokers is often incomplete or may not be consistent with the benchmarks we estimate.²³

As a result, it does not obviate the need to exercise judgement when interpreting the evidence. That said, we are of the view that the market evidence is likely to provide the best available indication of the *sustainable* margin a MMNE might reasonably expect to earn, which might justify the decision to enter a market. We have focussed on evidence that goes to sustainability.

On balance, the evidence set out in the following sections suggests that a MMNE into a competitive retail electricity market might reasonably expect net margins in the order of 5-8%.

4.2.1 Independent Experts' reports

Independent experts' reports are usually prepared in the context of demergers and certain takeovers, where a Scheme of Arrangement is required. There have been two recent independent experts reports produced that are worth noting:

- Grant Samuel's report in respect of the (original) AGL demerger proposal; and
- BDO Kendalls's report in respect of the takeover of Australian Energy Ltd.

The AGL demerger

In October 2005 AGL proposed a demerger of its infrastructure and energy businesses (which has since been replaced by another transaction between it and Alinta, which achieves a similar outcome). Facilitating a demerger requires a Scheme of Arrangement. The Scheme requires an independent expert's report confirming that it is in shareholders' interests. The AGL Board retained Grant Samuel for this purpose.

Grant Samuel's report notes that:

- AGL Energy (would have been) a large listed Australian energy company with operations predominantly in eastern Australia encompassing:
 - energy generation and production assets; and
 - the marketing and retailing of energy.
- AGL Energy will continue its full service (ie. vertically integrated) energy model; and
- AGL Energy will be Australia's largest energy retailer with 2.8 million energy customer accounts (of which more than one million are dual fuel accounts).²⁴

²³ For example, it is not always obvious whether the margins contain an allocation of corporate overheads or not in instances where the retailer is part of a larger business.

²⁴ After the new merger with Alinta's retail business, the figure is likely to be closer to 3.5 million customers.

Its estimates of AGL Energy’s Pro Forma Financial Performance suggested margins for the year ended 30 June 2005 of:

- 8.5% EBITDA margin; and
- 6.2% EBIT margin.

This covers both aspects of AGL Energy’s business so is a less relevant indicator of retail margins (although it is similar to its retail business results).

Australian Energy Ltd

In December 2005, Australian Energy Limited, trading as Powerdirect, announced that Ergon Energy proposed to acquire all outstanding shares and options in the company, via a Scheme of Arrangement.

Powerdirect focuses on selling electricity to small and medium sized businesses in the NEM (eg. petrol stations, retail outlets, residential apartments, commercial office buildings and water authorities). It has over 40,000 customers in Victoria, representing 73.5% of total volume sold. It is not vertically integrated and is not a mass market retailer.

Its consolidated statements of financial performance for the 12 months to June 2004 and June 2005 respectively, indicate the following margins.

Table 4.2: Australian Energy Ltd - margins²⁵

	30 June 2004	30 June 2005
Gross margin	15.6%	13.9%
EBITDA margin	5.4%	4.5%
EBIT margin	5.1%	4.3%
Net margin (after interest and tax)	4.9%	4.1%

4.2.2 Company and brokers’ reports

We have reviewed company reports and a sample of the recent brokers’ reports available to us.²⁶ The information focuses on the two listed major retailers in Australia (ie. AGL and Origin).

On the 16 August 2006 AGL announced its full year results. It included for the retail business an increase in EBIT to sales margin to 7.7% from 6.6% (and a 2006 EBITDA of 8%).²⁷ The result was based on gross margins of 13.2% for its electricity business.

An earlier report by ABN Amro expected an EBIT margin of 7% for the full year for AGL, broadly in line with the previous calendar period.²⁸ It also argues that “retail margins are showing signs of being sustainable”.

²⁵ KPMG has estimated the EBITDA and EBIT margins from the available data.

²⁶ KPMG has access to two on-line sources of broker’s reports: Thomson and Onesource.

²⁷ AGL, 2006 Full Year Financial Results, 16 August 2006, page 4. It is not obvious whether this is before or after an allocation of corporate overheads.

Origin Energy

Origin's final results for 2006 suggest that it earned an EBIT margin in its Australian natural gas and electricity retail business (ie. excluding LPG) of 7.8% compared with 7.2% in 2005. This is \$110 per customer.²⁹ The LPG business made a lower margin (ie. about 4.5%). The gross margin for the electricity business was 17.3%.

CitiGroup states in relation to Origin Energy that its medium term expectations for the retail business remain for a stabilised EBIT margin around the 6% level.³⁰

Morgan Stanley values Origin Energy on a future EBITDA/sales margin for its retail business in the 8.2-8.4% range.³¹ This suggests an EBIT margin of 6.8-7.0%.³²

Meanwhile, JP Morgan estimates gross margins for Origin Energy's retail electricity business in 2006 and 2007 of 16.3% and 16.1% respectively.³³

4.2.3 International evidence

We have also reviewed some of the available information in respect of the United Kingdom and New Zealand. A key advantage of this information is that these are two national retail electricity markets that have fully deregulated retail prices. They therefore provide evidence on the margins that retailers would expect to earn in such a market. A key disadvantage is that there are likely to be several factors influencing the margins retailers might expect to earn in these countries.

For example, the UK market displays a high degree of vertical and horizontal (ie. dual fuel) integration, while the NZ is highly vertically integrated. These features may reduce the required margins for the relevant retailers (see section 5.2 below). The UK is also typically assumed to have a lower cost of capital. New Zealand has a generally less volatile electricity market due to its dependence on hydroelectric power, but one that nevertheless produces occasional but severe imbalances in periods of extreme weather (ie. drought).

Nevertheless, this evidence provides another set of comparables.

New Zealand

Contact Energy is one of New Zealand's major retailers (one of two that competes across the country) and is highly vertically integrated. Its retail performance in recent times has been highly volatile, but generally compensated for by its generation business. For example, in the year to June 2005, Contact retail business made an EBITF (before financial instruments as well,

²⁸ ABN Amro, Australian Gas Light, 'Solid result, but what happens next', 28 February 2006, page 2.

²⁹ Origin Energy, Directors' Review of Results for the full year ended 30 June 2006, 30 August 2006, page 17. These figures appear to be after an allocation of corporate costs.

³⁰ CitiGroup, Origin Energy Limited, 'No Contact', 28 June 2006, page 12. This includes the LPG business.

³¹ Morgan Stanley, Origin Energy Ltd., '2006 Interim Result and Merger with Contact', 21 February 2006, page 5.

³² Origin's interim results for 2006 resulted in EBITDA and EBIT margins from the retail segment falling from 9.8% to 8.8% and 8.4% to 7.4% respectively.

³³ JP Morgan, Origin Energy, 'Upstream costs moderate growth outlook', 29 August 2005, page 3.

but after an allocation of corporate costs) of 14.9%. In the year to June 2006, however, the same margin was -11.1%. However, generation business margins increased substantially.³⁴

CitiGroup assumes that retail EBIT margins for Contact Energy in New Zealand would fall to an average of 7.5% over the next few years.³⁵ On CitiGroup's analysis, this would be consistent with a gross margin of about 13.6%.

United Kingdom

There has been considerable volatility in the UK market in recent times due to upward pressure on wholesale electricity prices, which has led to significant upward pressure on retail prices.

The company that has been most exposed to this uncertainty is Centrica. It has approximately 16.5 million domestic energy customers, but has relatively little vertical integration particularly in electricity (see below). Its retail energy division has recently been making significant losses.

In March 2006, Moody's changed its outlook in respect of Centrica to negative despite its recent announcement to increase its tariffs by 22%. The change in outlook highlighted the risk of Centrica losing a lot of customers because of weaknesses in its hedging arrangements and thus its retail franchise. Moody's stated that its reassessment:

...underlines Centrica's current disadvantage over its UK peers from its short generation position and its gas-biased and thus costly fuel mix. As a result, Centrica's residential energy margins are further impacted by the necessity to purchase, at current high prices, power to meet its requirements. Moody's assumes that further acquisitions of power generating capacity (including power purchase agreements) are inevitable, but that such will come at a high price in the present environment, similarly to any upstream gas assets.³⁶

We understand that by June this year Centrica had lost over 400,000 customers in the first half.

Recent brokers' reports have suggested as follows:

We assume a long-term average (LTA) EBIT margin of 5.7% for this division;³⁷

The key value drivers in our Base Case valuation are (1) Sustainable retail margins of 6%.³⁸

Our revised valuation for Centrica is set out below. We are now assuming that stickier customers will mean 8% margins could be sustainable in the energy retail business.³⁹

³⁴ Contact Energy Limited, Management Discussion of Audited Consolidated Financial Results for the 12 months Ended 30 June 2006, pages 4-6.

³⁵ CitiGroup, Origin Energy Limited, 'No Contact', 28 June 2006, page 4.

³⁶ Moody's Investor Services, 'Moody's Changes Outlook on Centrica's Ratings to Negative', 16 March 2006.

³⁷ ABM Amro, 'British Gas Services – upping the ante', 27 June 2006, page 2.

³⁸ Morgan Stanley, 'Centrica – Recovery Fully Priced', 27 July 2006, page 3. This appears to relate purely to the UK retail energy business. It noted, however, that Centrica has never achieved these margins.

³⁹ Deutsche Bank, 'Centrica', 23 February 2006, page 4. This appears to be a Profit After Tax margin but appears to include the benefit of some generation assets within that business.

5 Findings and commentary

Our key findings are as follows:

- Our benchmarking in section 3 suggests that a reasonable retail operating costs for a MMNE are likely to be in the range of \$83-88 per customer; and
- Our benchmarking in section 4 suggests that an appropriate retail net margin for a MMNE is likely to be in the range of 5-8%.

Moreover, a margin at the upper end of this range is likely to be more consistent with meeting the Minister of Energy's primary objective of having cost reflective tariffs and encouraging a MMNE, particularly in light of what we believe is the most appropriate interpretation of the evidence. In other words, we believe there is a strong case for using a margin at the high end of this range.

There are a number of issues relevant to interpreting the evidence. These fall into three groups:

- qualifications (on what the benchmarks cover);
- potential issues with the NSW market; and
- other issues in setting appropriate regulated retail tariffs.

5.1 Qualifications

The benchmark entity a "mass market new entrant" is in some ways a hypothetical entity, involving a number of simplifying assumptions, which are potentially significant.

The scale of the business

We have assumed that a MMNE would need about 250,000 customers to achieve economies of scale. This would justify the investment in information systems and processes that would enable ongoing growth (eg. to 1 million customers and beyond).

What this means, however, is that in the first instance at least (see below), the relatively high fixed costs associated with operating a mass market retail business will be spread across relatively few customers (meaning higher average costs per customer). It may, however, have somewhat lower costs by virtue of having a more attractive customer base.

Time to reach the required scale

We have also assumed that a MMNE attains this scale immediately. This is, by definition, a simplistic assumption. In the event that a MMNE entered the market with the intention of competing broadly across it, then its average costs per customer would be significantly higher in the shorter term than those indicated in this report.

It is more likely, however, that any new entrant would commence operations:

- in a particular niche of the market targeting higher margin customers (and have systems to match);
- with the benefit of already competing in gas (and thus focus on dual fuel customers); and/or
- with the benefit of some generation capacity.

After securing a position, it may then attempt to grow into a truly mass market player.

It is also worth noting however that we are unaware of any instances where a stand alone retail business has entered the mass market and gained a substantial market share (at least compared to the incumbents). Making an assessment in regard to how long this process would take (even if it did happen) is therefore extremely difficult. Victoria Electricity retail business has recently grown to about 115,000 customers since 2002.⁴⁰

Our assumptions, while somewhat simplistic, are nevertheless consistent with the underlying assumption regarding a mass market entrant that is able to exploit economies of scale.

5.2 Potential NSW market issues

NSW is clearly the largest retail energy market in Australia and it is likely that a party with aspirations in the broader Australian mass market would enter the NSW market. That said, there are good reasons to assume that mass market new entry is likely to entail considerable risk. The key reasons are that:

- the two most likely entrants (Origin and TRUenergy) currently have limited market presence;
- there is limited vertical integration or capacity to vertically integrate (which the evidence suggests is particularly important, as we highlight below);
- the nation's largest retailer (AGL) already has a dominant position in the retail gas market and is therefore in a strong position to offer dual fuel to the incumbent's electricity customers. Origin and TRUenergy are less well placed;
- the remaining players in the retail electricity market are government owned, which may create a perception amongst privately owned competitors that there is a risk that the incumbents may make less commercial decisions. Some stakeholders have made this point in the context of the Energy Reform Implementation Group's consultation process;⁴¹ and

⁴⁰ This includes growing from 28,000 customers since March 2005. It has also recently made its first positive contribution to the company's first quarter result. See <http://www.infratil.com/1/6222.htm>. Its owner already has a significant retail business in New Zealand.

⁴¹ Power Industry News, Edition 506, 28 August 2006, page 7.

- the market is likely to perceive a risk of the Government changing its position (eg. perhaps in response to other issues, such as petrol prices).

Vertical integration

There is a considerable body of evidence to suggest that vertical integration provides value to electricity retailers (ie. there has been considerable vertical integration in competitive retail electricity markets).

It is possible to draw inferences about the value of vertical integration by examining the differences between:

- merchant generators (or Independent Power Producers – IPPs - who typically sell their output on short term contracts – 3 years – or via spot markets); and
- contracted generators (i.e. those with long term contracts often called Power Purchase Agreements – PPAs).

The comparison between the two types of generators is instructive because the long term contracts held by the contracted generator can effectively be regarded as a proxy for the natural hedge obtained through vertical integration. By contrast, a merchant generator bears wholesale market price risk, except over the short term. These two types of generators therefore provide a useful proxy for the type of valuation differences the market attaches to the management of this risk.⁴²

The UK provides the best available market evidence.

- In its valuation of International Power’s business, Morgan Stanley disaggregates the earnings from these two types of assets. It states:

We view the contracted earnings stream as stable and predictable... In our opinion this is worth a multiple in line with stable, regulated utilities. We apply a 15X PE multiple to gain a fair value for the contracted assets. Merchant assets should be valued differently. We believe the best way is to consider peak merchant earnings and apply a very different, much lower multiple to these. We apply a multiple of 8X to derive a fair value for the merchant assets.⁴³

In effect, Morgan Stanley values the earnings from a merchant generator at almost half the value of those from a contracted generator. Consistent with the above, Morgan Stanley took similar issues into account in August 2004 when International Power undertook the business transforming acquisition of the non-US assets of Edison Mission Energy (which included Loy Yang B). The assets acquired were almost entirely contracted. As a result, Morgan

⁴² Observed differences in the valuations of these two types of generators would, however, probably overstate the benefits of achieving vertical integration in a competitive market context. This is because the vertically integrated retailer does not have the same degree of control over its market as the contracted generator, but it has greater control than a merchant generator.

⁴³ Morgan Stanley Equity Research, ‘International Power: Further to go’, 7 March 2006.

Stanley altered its benchmark assumptions in respect of International Power's cost of capital. For example, it altered its benchmark gearing ratio from 30% to 60%.⁴⁴

Morgan Stanley also applies different discount rates when valuing pure merchant generators. For example, in respect of International Power, Morgan Stanley applies a "group" weighted average cost of capital of 7.9%. By contrast, in the cases of Drax and British Energy it uses discount rates of 8.75% and 10% respectively.⁴⁵ It notes that Drax is a "higher risk investment than a typical utility because it is not vertically integrated."⁴⁶ It derives its higher cost of capital than for International Power partly by using a gearing ratio of approximately 20%.

- ABN Amro adopts a similar approach in valuing International Power. It states that:

IPR's risk profile has changed significantly and it is not as exposed to merchant activities as it once was. Stable PPA assets now comprise 52% of IPR's EV vs 37% in January 2004. As a result, we view IPR's cash flows as more stable, warranting a lower WACC of 7% vs market consensus of 8%.⁴⁷

It assumes IPR's benchmark gearing ratio is 50%, based on an assumed gearing of 70% for contracted assets and 30% for merchant assets. These assumptions imply a cost of capital range of about 8% to 6.2% for merchant and contracted generation assets respectively.

A similar trend to vertical integration is evident in Australia. Credit Rating agency, Fitch, recently stated that:

Integrated utilities want to strengthen the quality of their internal hedges by combining generation and retail operations through further acquisitions. The resulting combination of size, synergies and the increased degree of vertical integration is placing pressure on disaggregated entities such as state government-owned generators and retailers to consider structural ownership changes to better manage industry risks.⁴⁸

A MMNE is likely to require a higher margin if it is not vertically integrated.

5.3 Other issues in setting appropriate regulated retail tariffs

There are a couple of other points worth making in relation to what the benchmarks cover. These include:

- the costs to incumbents; and
- benchmarking to set cost reflective regulated retail electricity tariffs.

⁴⁴ This is consistent with the actions of International Power which used 80% debt to fund the contracted assets.

⁴⁵ Morgan Stanley Equity Research, 'Drax: Confirming positive outlook', 8 March 2006 and Morgan Stanley Equity Research, 'British Energy – Key Takeaways from Q3 – We still prefer Drax', 24 February 2006. Morgan Stanley uses a higher discount rate for British Energy in part because of its higher operating leverage (ie. higher fixed costs).

⁴⁶ Morgan Stanley Equity Research, 'Drax: Discounting US\$43 Long-term Oil Price – May Be Conservative', 18 January 2006, page 18.

⁴⁷ ABN Amro, 'International Power: Switching the Focus', 13 October 2005, page 1.

⁴⁸ Fitch Ratings, Australian Utilities: What's the Mix for 2006?, 3 February 2006, page 1.

The costs of incumbents

Benchmarking the costs of a MMNE, by definition, excludes additional costs (and/or obligations) that might be borne by incumbents but not by the MMNE. There are a variety of costs that it would be reasonable to expect incumbent retailers to incur that our benchmarks do not cover. These costs are likely to include the following:

- the cost of existing legacy systems;
- the costs of a “retailer of last resort” facility (which would include additional costs for being able to quickly take over a substantial customer base and establish energy contracts to suit their demand); and
- the costs/obligations of meeting other requirement (eg. in respect of vulnerable customers).

This is unlikely to impede the ability of a new entrant to compete in the shorter term; indeed, it may help. It is, however, likely to distort the basis of competition if regulated tariffs are set too low, by focussing it more on the customers who are in a better position to avoid these costs (eg. miscellaneous charges).

Benchmarking to set regulated retail electricity tariffs

To set cost reflective regulated retail tariffs it is also important to ensure that you are valuing the benefits regulated tariffs provide compared to the competitive alternative. In other words, if regulated tariffs are to be set at competitively neutral levels, then it is crucial that the comparison is ‘like with like’. Regulators should therefore be estimating the cost of providing product features or benefits that regulated tariffs provide.

There are several areas of service differential between regulated and market offers.⁴⁹ These potentially include:

- the flexible term associated with regulated tariffs;
- the reversion opportunity associated with regulated tariffs; and
- the way regulators charge for miscellaneous services.

On the first point:

- market tariffs typically involve a fixed price for a fixed term, sometimes with fees for early termination. Indeed, the fixed nature of the contract is its most fundamental attribute. Terms are typically 2-3 years and termination fees are up to \$125. Alternatively, some retailers embed the risk and cost of early termination in higher unit prices. Many similar products (eg. telecoms, insurance, home loans) have similar features; and

⁴⁹ We are aware that some years ago IPART concluded that there may be no service differential between competitive and standard offer contracts, but that was in the context of a review carried out under a different Terms of Reference. Moreover, further evidence has come to light since that time as indicated above.

- regulated tariffs, by contrast, typically involve a fixed price for a flexible term, with no fees for early termination. This is analogous to fixing the interest rate on your home loan while retaining the ability to switch, at no cost, to another supplier if interest rates fall.

Regulated tariffs therefore provide customers with an *option* to stay on fixed prices for as long as prices are set, but to move for free onto a market contract in the intervening period. A customer on a market contract does not have this luxury. Moreover, a competitive market is unlikely to provide this option, at least not for free.

The regulated offer, however, means that there is no cost to the customer of making *no decision* on choosing their supplier. In other words, in the event that both regulated and market offers are similar, the regulated customer retains the option and its value.

Reversion policies can compound this problem (eg. the option to leave the regulated tariff is reinforced by a further free option to return). The Minister of Energy's Terms of Reference highlights the reversion policy and the optionality it creates.

Paul Joskow, an eminent energy economist, has noted the existence of options in the regulated retail tariffs of US Electricity Service Providers and their importance. He states that:

...allowing customers that choose to take service from an ESP to return to a regulated tariff when wholesale prices are high without being charged an appropriate price for this option, seriously undermines the development of retail competition because it effectively provides a subsidised option for retail customers who switch back and forth and a very unstable customer base for ESPs.⁵⁰

Options are often quite valuable to customers, particularly when they face making decisions which involve considerable uncertainty. The retail energy purchase decision involves considerable uncertainty because the choice is quite new, the product is quite complex and customers are unlikely to devote much time to making a decision on their retailer.

To set regulated tariffs at cost reflective or competitively neutral levels, it is important that the margin incorporated into them accounts for the additional benefits they provide.

It is possible that IPART could deal with the risks and costs of service differentials in other parts of its analysis.⁵¹ However, it is not obvious that this can be done solely by reference to the evidence. For example, the evidence on which regulators rely often draws on work by other regulators, partly because the market evidence is incomplete. In addition, the market evidence tends to rely on the margins for market players who are vertically integrated in their other markets (and are better placed to manage such risks).

Despite the greater switching rates and entry into some other Australian energy markets, regulators in those jurisdictions also have yet to conclude that the markets are competitive enough to warrant deregulating, even for the majority of domestic customers in those markets.

⁵⁰ P., Joskow, *The Difficult Transition to Competitive Electricity Markets in the US*, AEI-Brookings Joint Centre for Regulatory Studies, July 2003, page 35.

⁵¹ For example, by referring to the market evidence on what a MMNE needs to compete in other markets with similar service differentials, or by adjusting forecasting and hedging costs.

The value of the additional benefits regulated tariffs provide should be taken into account when setting a regulated retail margin, if the Minister of Energy's primary objective is to be met.

A EnergyAustralia's terms of reference

EnergyAustralia has engaged KPMG to estimate an appropriate allowance for retail margins and operating costs to be considered by IPART when setting regulated retail tariffs.

Operating costs

We have been asked to consider the fixed and variable costs associated with (but not limited to):

- customer service;
- finance;
- information systems;
- marketing and advertising;
- customer acquisition and retention costs; and
- legal and regulatory compliance

We have been asked to consider benchmarks in other jurisdictions and internationally to the extent they may be relevant in the context of NSW regulated retail electricity tariffs.

Retail margins

We have been asked to consider an appropriate margin for a MMNE retailer, providing an appropriate return on investment having regard to the levels of:

- working capital;
- tangible and intangible assets;
- depreciation and amortisation;
- bad debts;
- competition from electricity substitutes; and
- purchase risk.

We have been asked to have regard to the effect of margin on the level of competition in a mass market.

B Operating cost benchmarking

This appendix explains our approach to the development of the calculations which support our benchmark of the operating costs of a MMNE. Our:

- assumptions on the relevant business volumes are explained in section B.1.2;
- cost tree which establishes the methodology of calculating the relevant operating costs is set out in section B.2; and
- data, sources and benchmarks and explanations are set out in section B.3.

B.1 Business assumptions

B.1.1 Base year

The results presented in this report are expressed in real 2005/06 Australian dollars.

Where international benchmarks are quoted, we have converted these to Australian dollars using an exchange rate relevant to the year in which the benchmark is quoted.

Where we have used benchmarks from financial years prior to 2005/06, we have inflated them to 2005/06 dollars using the weighted average CPI for 8 capital cities⁵² as quoted by the Australian Bureau of Statistics.

B.1.2 Volume assumptions

To establish costs for a MMNE we have had to make assumptions about the size of the business that it is servicing and other issues which impact on the environment that the business operates in. Those input assumptions are set out below.

It is worth noting that some of the costs are step variable and so extrapolating them to a different sized business, or a business operating under different conditions, could be problematic.

B.1.3 Size of business

We have used the following key input assumptions in our calculations.

⁵² We understand that this inflator is consistent with that used by IPART in regulatory determinations in NSW.

Table B - 1: Volume assumptions applied in our calculations of retail operating costs for a MMNE

Input	Assumption
Customer numbers	250,000
Billing intervals	245,000 customers billed quarterly 5,000 customers billed monthly
Reminder notices	30% to 40%
Call centre use	Average of 2 calls per customer per year for retailer interaction
Time of use metering	Installed for all of the monthly billed customers

We have chosen a size of business that warrants systems suitable to support the delivery of energy retailing to a mass market. Retailers who operate in a mass market must have systems of sufficient size to be able to handle the volumes of data and customer information in a timely manner to meet the industry code requirements and commercial customer service.

We note that there are few instances of smaller retailers serving a mass market. We do observe that:

- ACTEWAGL serves 150,000 customers, but is supported by AGL and is likely to extract some economies of scale from that affiliation;
- Aurora Energy operates in Tasmania and serves some 250,000 customers and has recently developed a custom built customer information system; and
- Victoria Electricity retail business has recently grown to about 115,000 customers since 2002.⁵³ Its recent annual report provided no indication of any pending major IT investment.

Other energy retailing businesses are either smaller (not operating in the mass market) or operate with large customer bases of approximately 500,000 customers or more.

We have chosen a customer base of 250,000 as representative of the scale necessary to achieve the economies of scale associated with having a commercial customer information and billing system, automated business to business communication systems and energy trading systems. We base our estimate on our observations of Australian energy retailers, and in particular the size of the customer base and the systems employed.

B.1.4 Pro-forma financials

Some of the benchmarks used in this report relate to data acquired from survey respondents which is classified into groups based on revenue values. Therefore, in determining the size of a MMNE, we have constructed a value for revenue and other expenses which are consistent with the volumes assumed in B.1.3 above, and average market parameters consistent with those for NSW electricity customers. Our assumptions are explained below.

⁵³ This includes growing from 28,000 customers since March 2005. It has also recently made its first positive contribution to the company's first quarter result. See <http://www.infratil.com/1/6222.htm>. Its owner already owns a significant retail business in New Zealand.

Table B - 2: Financial assumptions for a MMNE retailer

Item	Assumption	\$m
Revenue	Customers	250,000
	Average annual charge	\$3,400 for monthly billed
	Average annual charge	\$950 for quarterly billed
Energy	35% of revenue	88.0
Network charges	42% of revenue	105.0
Other costs	3% of revenue	7.5

The percentages for energy, network charges and other costs are consistent with EnergyAustralia’s experience for the year ended to June 2006, however the cost benchmarking is not sensitive to these inputs as they only serve to assist in any calculation of working capital requirements.

In the first instance, a MMNE is likely to focus on more profitable customers, which are generally larger users. However, with a customer base of 250,000 it is likely to have a broad range of customers, which will mean its customer base is close to the average customer. The incumbents are also likely to respond with competitive behaviour of their own in the most attractive customer segments.

Therefore, we consider that these outcomes listed in the assumptions above are not unreasonable for the NSW market.

B.2 Cost tree

To benchmarks the costs associated with our MMNE we have created a cost tree based on the activities that we consider it will need to undertake. An overview of the cost tree is set out below.

Figure B-1: Conceptual Model and Information Requirements - Retailer Costs to Serve

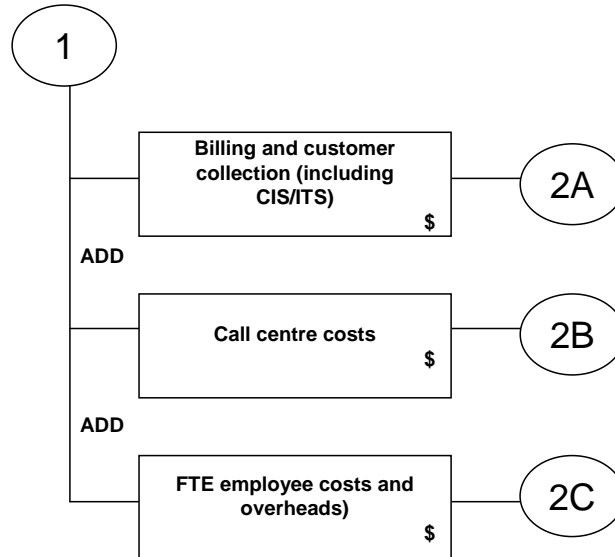


Figure B-2: Conceptual Model and Information Requirements - Billing and Customer Collection

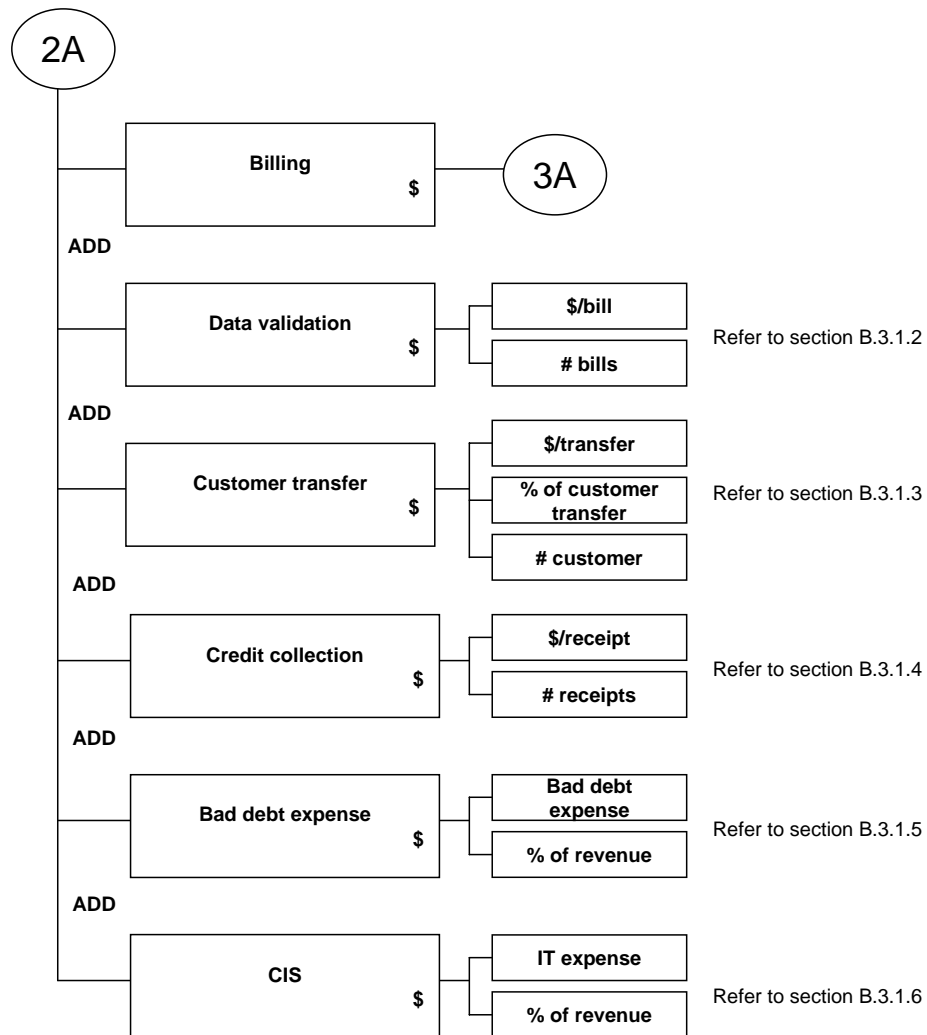


Figure B-3: Conceptual Model and Information Requirements - Billing

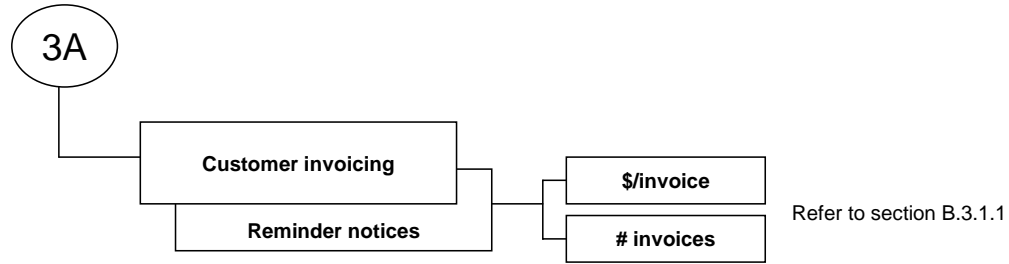


Figure B-4: Conceptual Model and Information Requirements - Call Centre

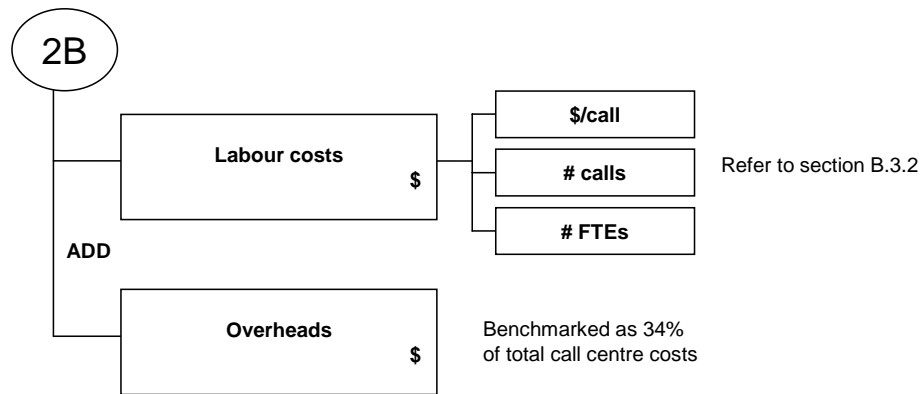


Figure B-5: Conceptual Model and Information Requirements - FTE Employee Costs and Overheads

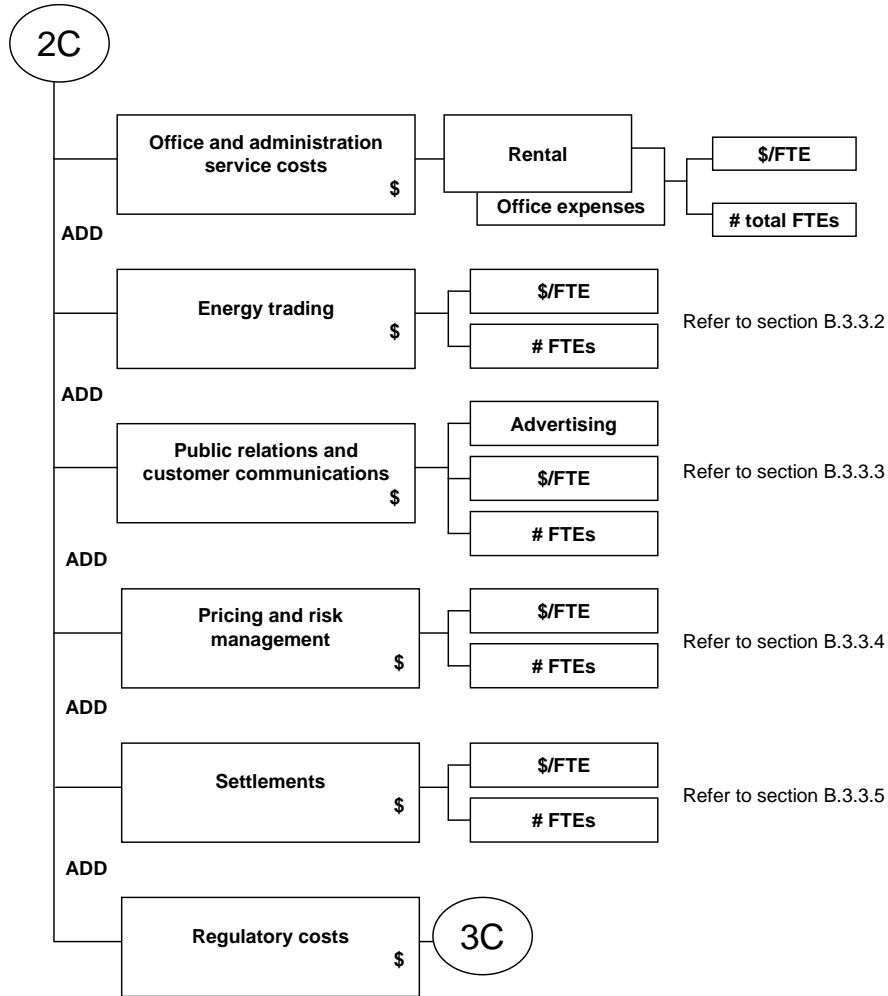
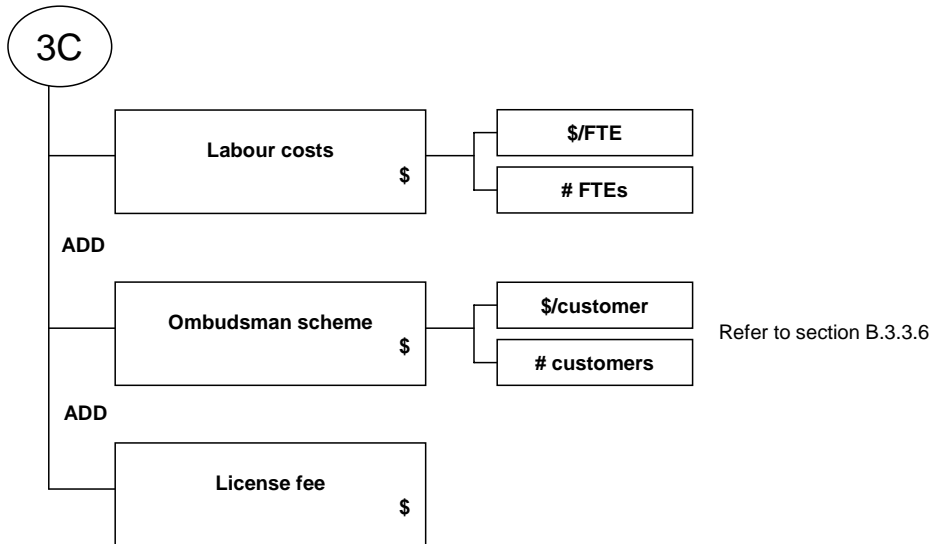


Figure B-6: Conceptual Model and Information Requirements - Regulatory Costs



B.3 Data, benchmarks and calculations

B.3.1 Billing and customer collection

B.3.1.1 Billing

The billing function relates to the preparation and distribution of bills to customers. The number of bills issued which in turn is a function of the number of customers and frequency of billing drives the cost of this function.

We have applied a cost of \$0.73 per bill or reminder for the MMNE.⁵⁴

As a further validation, the 2002 KPMG Benchmarking Study reported a tenth percentile cost of \$0.36 per bill and a first quartile cost of \$1.94 for the utilities and telecom industry⁵⁵. The processes captured in this benchmark include the developing procedures for customer billing, maintaining customer account records, and issuing credit notes and refunds. This is a very broad range and reflects the scale of operations in the population involved in the survey. We expect that the lower end of the range refers to simple single tariff billing statements whilst the upper end is likely to include detailed billing statements and variable tariffs for telecommunications. The detailed results of the survey respondents are not known, however, the range validates the Australia Post survey benchmarks applied.

We have arrived at our cost based on the assumption that the MMNE will be despatching all customer bills by mail. We acknowledge that electronic billing will help reduce this cost. However it is in our opinion that it is rather early at this stage for this to be significant.

We have made an allowance for the issue of reminder notices to customers which will add to billing costs. The Office of Regulator General, Victoria estimated that approximately 40% of customers need reminder notices.

We acknowledge that the number of reminder notices will very much depend on the ability of a MMNE's customers to pay their bills promptly. We expect a MMNE to be rigorous in managing its payment and credit terms, and it may therefore be able to reduce the need for the sending out of reminder notices to its customers. The uptake of direct debit as a payment method is also becoming increasingly popular, further contributing to the reduction of reminder notices. On this basis, we have suggested a lower bound benchmark of 30%, consistent with the experience of some electricity retailers in NSW.⁵⁶

⁵⁴ Includes recent industry estimates based on work undertaken for Australia Post for mass market issuing of paper bills to customers.

⁵⁵ Industry-specific comparisons for Customer Invoicing, 2002 KPMG Benchmarking Study

⁵⁶ Experience as advised by EnergyAustralia as indicative of the NSW market.

Table B - 3: Total customers and bills

Number of bills for the MMNE		2005/06 Benchmark	
		Customers	Bills
Customer billed quarterly	(#)	245,000	980,000
Customers billed monthly		5,000	60,000
Total bills			1,040,000

Table B - 4: Billing costs

Billing costs		2005/06 Benchmark	
		Low	High
Bills issued	(#)	1,040,000	1,040,000
Percentage of reminder notices		30%	40%
Reminder notices – quarterly		294,000	392,000
Reminder notices - monthly		18,000	24,000
Total bills and reminders	(#)	1,352,000	1,456,000
Cost per bill	(\$/bill)	0.73	0.73
Benchmark cost	(\$m)	0.99	1.06

B.3.1.2 Data validation

Data validation refers to the process of checking the accuracy, validity and completeness of data used in the billing process. It will involve the investigation and correction of errors in records.

In a 2001 gross margin review for the Queensland Treasury⁵⁷, we calculated that data validation costs to be in the order of \$0.81 per bill. It was the Office of the Regulator General’s view that one third of the data validation costs should be allocated to the retail business where the distributor was responsible for meter reading.⁵⁸

We have inflated this number to \$0.93 per bill to represent 2005/06 dollars, and applied one third of this cost at \$0.31 per bill as the benchmark for data validation cost for the MMNE.

⁵⁷ A commercial gross margin for Queensland Retailers, June 2001, KPMG Consulting.

⁵⁸ 2001 Price Review, Cost allocation, September 2001, Office of the Regulatory General, page 3.

Table B - 5: Data validation costs

Data validation costs		2005/06 Benchmark	
		Low	High
Bills issued	(#)	1,040,000	1,040,000
Data validation cost per bill	(\$/bill)	0.31	0.31
Benchmark cost	(\$m)	0.32	0.32

B.3.1.3 Customer transfer

Customer transfer costs are those incurred due to customers moving premises and switching to other retailers, or to a market contract with the first-tier retailer.

In a 2001 KPMG Consulting report to the ORG Victoria⁵⁹, the customer transfer cost was set at \$12 per transfer. We understand that the ORG accepted this cost. We have adjusted this number for inflation to arrive at \$14.32 per transfer for 2005/06. Rather than applying the CPI to our original cost, we have proceeded with escalating this figure by the Labour Price Index for Sydney. The basis for doing this is the cost reflects a labour-intensive activity and inflating it using the CPI might underestimate the results as labour rates in Sydney have a tendency to increase at a relatively higher rate.

We have assumed that householders move premises once in every five years, resulting in a customer transfer rate of 20% per annum. The ORG report in 2001 estimated householders move once in every seven years, but we have acknowledged that householders are now more mobile and relocate more frequently as evidenced in a recent social study⁶⁰. This is also compounded by demographic trends such as:

- the ‘sea change’ which sees the major shift of population to the coastal areas especially over the next decade as the baby boomers retire;
- people in their twenties who have been priced out of the housing market due to the property boom and therefore rent, further increasing their mobility.

In relation to business customers, we have estimated that businesses change premises (or ownership) once in every five years on average.⁶¹

We expect that customer contestability will increase in the future and customers will have greater flexibility in determining their choice of retailers and thereby increasing future transfer rates. We have allocated a further 3 and 5 percentage points to account for this for the lower and upper bound benchmark respectively, bringing the final transfer rate to 23% and 25%.

⁵⁹ Ibid, page 43

⁶⁰ “Changing homes is a moving thing” by Hugh Mackay, Sydney Morning Herald, January 11, 2003

⁶¹ Based on our previous work in energy retailing in another Australian jurisdiction, 2006.

Table B - 6: Customer transfer costs

Customer transfer costs		2005/06 Benchmark	
		Low	High
Customers	(#)	250,000	250,000
Transfer rate	(%)	23%	25%
Customer transfers per annum	(#)	57,500	62,500
Cost per transfer	(\$/transfer)	\$14.32	\$14.32
Benchmark cost	(\$m)	0.82	0.90

B.3.1.4 Credit collection

This function relates to all activities related to the collection and receipting of payments made on the bills issued, and is therefore largely driven by the number of bills raised.

The 2002 KPMG Benchmarking Study reported a first and third quartile cost of USD 0.29 and USD 5.63 respectively for the utilities and telecom industry.⁶² These figures were converted to Australian Dollars and then escalated by CPI, resulting in a credit collection cost per customer of \$0.57 and \$11.13.

The large range reflects a combination of highly efficient and less efficient companies in the coordination of the accounts receivable system. The higher end represents study participants utilising the physical settlement of bills. The processing of cheques sent by mail or cash paid over-the-counter undoubtedly will require more time and cost than when performed electronically through EFTPOS or internet banking.

We note that the NSW market is supplied a variety of payment options including higher cost and low cost transaction options such as cheques by mail, payment through Australia Post, credit card, BPay, POSTBillPay direct debit and regular payment option plans. We would expect a MMNE to offer payment systems which are efficient to the MMNE, but still comply with the industry standards required of a licensed retailer. We would not expect a MMNE to offer expensive payment options without passing the cost of that option onto the customer.

We have applied the World Class finance benchmark median cost of \$2.73 per receipt to our MMNE on the assumption that there would be a mixture in the methods of payment made by its customers, and that some but perhaps not all of the less attractive options would be offered to attract the mass market.

⁶² Industry-specific comparisons for Accounts Receivable, 2002 World Class Finance Benchmark Results.

Table B - 7: Total receipts

Number of receipts for the MMNE		2005/06 Benchmark	
		Customers	Bills
Customer billed quarterly	(#)	245,000	980,000
Customers billed monthly		5,000	60,000
Total receipts			1,040,000

Table B - 8: Credit collection costs

Credit collection costs		2005/06 Benchmark	
		Low	High
Total receipts	(#)	1,040,000	1,040,000
Cost per receipt	(\$/receipt)	\$2.73	\$2.73
Benchmark cost	(\$m)	2.84	2.84

B.3.1.5 Bad debt expense

We have defined bad debt expense as the net write-off of accounts after recoveries. It does not include costs associated with reminder and disconnection notices. Reminder notices are covered in the billing process, and disconnection notices and disconnection actions are generally charged to and recovered directly from the relevant customers. It is also worth noting that a reminder notice does not necessarily suggest that the customer is a credit risk. Reminder notices are system produced and may occur at the same time or shortly before the receipt is processed.

The 2002 KPMG Benchmarking Study provided a benchmark for the bad debts incurred by companies in a variety of different industries.⁶³ At the first quartile, the percentage of bad debt write-offs to sales is 0.060%. This is relatively low and reflects industries other than electricity retailing which is more highly regulated with regard to the provision of an essential service. The 2002 KPMG Benchmarking Study quotes a median for bad debt expense as 0.327%.

Our analysis of electricity (or energy) retailers as outlined in the following table suggests that the bad debt expense rates experienced in Australia is coincidentally in the order of 0.327% for the 2004/05 year. Based on this, we estimate a bad debt expense of 0.327% in line with the industry standards for mass market retailers.

⁶³ Comparisons for Percentage of Bad Debt Write-off to Sales, 2002 World Class Finance Benchmarks.

Table B - 9: Comparison of bad debt for electricity retailers and distributors

Retailer/Distributor	2004/05 Data		
	Revenue (\$m)	Bad debt (\$'000)	Percentage
Citipower/Powercor	941	1,212	0.13
Origin Energy	4,931	16,107	0.33
AGL	4,915	20,400	0.42
Integral Energy	1,369	6,353	0.46
Energy Australia	2,836	9,100	0.32
Average of above data			0.327%

The above data was extracted from Annual Financial Statements for the 2004/05 financial year.

Table B - 10: Bad debt expense

Bad debt expense		2005/06 Benchmark	
		Low	High
Total sales or revenue	(\$m)	250	250
Percentage of bad debt		0.33%	0.33%
Benchmark cost	(\$m)	0.82	0.82

B.3.1.6 Customer information system costs

We have defined CIS as the systems necessary for an MMNE to undertake its retailing business activities which includes:

- trading and settlements;
- customer relationship management systems (including call centre requirements);
- data warehousing;
- forecasting and marketing software;
- maintenance of hardware;
- IT personnel costs and overheads; and
- IT training and license fees.

Further, CIS and ITS costs also include annual personal computer costs for the corporate and administration functions, trading, settlements, regulatory, marketing or pricing, and the CIS requirements of the call centre (as described above).

A 2004/05 KPMG Utilities IT benchmarking survey⁶⁴ showed that the average adjusted IT operating expenditure as a percentage of corporate revenue was 1.7%. The term ‘adjusted’ refers to the exclusion of costs which had not been taken at a corporate level. Examples of these are the depreciation of IT assets and occupation overheads.

Table B - 11: Customer information system cost

CIS cost		2005/06 Benchmark	
		Low	High
Total sales or revenue	(\$m)	250	250
Percentage of IT operating expenditure		1.7%	1.7%
Benchmark cost	(\$m)	4.25	4.25

We note that in NSW and Victoria in particular, there is an increase in the roll out of time of use metering amongst smaller consumers. This has the potential to impact on costs in the future due to the increased amount of data handled, tariff complexity and data validation costs.

NSW (and Victoria) is early in the process of increasing the penetration of time of use metering. As a result, there is a significant degree of uncertainty over what the CIS cost impacts might be and how they might impact on the non-incumbent retailers. In part, this will depend on how they respond to the roll out of interval meters.

We have not therefore costed this factor into the benchmarks, but note that these costs are likely to show an upward trend over time.

B.3.1.7 Total for billing and customer collection

The total cost for billing and customer collection is summarised below.

Table B - 12: Total benchmark cost for billing and customer collection

Benchmarks		2005/06 Benchmark	
		Low	High
Billing		0.99	1.06
Data validation		0.32	0.32
Customer transfer		0.82	0.90
Credit collection		2.84	2.84
Bad debt expense		0.82	0.82
CIS		4.25	4.25
Total for Billing and customer collection (including CIS/ITS)	(\$m)	10.04	10.19

⁶⁴ The study into IT costs of Australian and New Zealand utilities had 12 participants and covered the period of January 2005 to July 2005. The information used was for financial year ending 2004.

B.3.2 Call centre

A MMNE will require a contact centre to administer incoming customer product support or information inquiries. This is a principle activity of a mass market retailer where the services are delivered through a third party supply network rather than a “shop front” interface.

We benchmark the costs of operating a call centre by examining the number of calls attended to by the call centre. The number of calls is likely to be a function of:

- certain aspects of the retailer’s communications, e.g. a clear and concise invoice design will reduce customer confusion and therefore, the number of calls made by customers; and
- industry activities or campaigns, e.g. the push by the government for more flexibility in energy choices might result in the rolling out of more energy plans, thereby increasing the number of calls asking for more information.

Publicly available information shows that in South Australia energy retailers received a total of 1.396 million calls in 2002/03 from 0.740 million customers.⁶⁵ This suggests that a customer makes approximately 1.9 calls per annum. In Victoria we found find that a total of 2.278 million customers made 4.715 million calls to customer centres in the same year, or an average of 2.1 calls per customer.⁶⁶

We have chosen to use the figures for 2002/03 because we consider that the data collected during this time is more accurate than the available data for subsequent years. As contestability in the electricity market expands, it has become increasingly difficult for call centres to disclose data on the origin of callers, especially so when the electricity retailer operates a national call centre servicing retailing operations in multiple states.

We have estimated that a MMNE’s call centre would receive an average of 2 calls per customer in a year. Further, we have assumed that call centre agents can respond to 80 calls per day (12 calls per hour for 6.5 hours). The number of full-time equivalent (FTE) agents required to handle this volume determines the labour cost for the call centre.

We have applied the following ratios of contact centre staff as recommended in an ACA research⁶⁷ paper. This suggests that the call centre would need approximately 28 FTEs⁶⁸ for its operations, resulting in a call centre labour cost of \$1.35m.

The ACA research benchmark also suggests that labour costs comprise 66% of total call centre costs (including the CIS). Hence, the total call centre cost for the MMNE is \$2.05m.

⁶⁵ http://www.escosa.sa.gov.au/webdata/resources/files/050401-R-SCONRRRetailTemp03_04.pdf

⁶⁶ http://www.esc.vic.gov.au/NR/rdonlyres/D8B79DE7-D3E9-4B4B-AE86-77F6F6FC70CB/0/NationalTemplate2004_05.pdf

⁶⁷ ACA research, 2002/03 and 2003/04 National regulatory requirements – Comparative summary for retailers to small electricity customers in Queensland, Office of Energy

⁶⁸ A total of 1 managers (\$150,000), 3 team leaders (\$65,000), 22 agents (\$42,000) and 2 support staff (\$42,000). All salaries for contact centres as benchmarked by Hays Salary Survey 2006. These salaries are at the higher end of the range consistent with the assumption that the MMNE will have a large contact centre to serve a mass market.

Figure B-7: Call centre staff ratio



We are aware that certain technologies applied by call centres could affect the call centre costs to callers. For example, interactive voice response (IVR) allows the caller to select an option from a voice menu to connect customers to their desired service promptly. It is not unreasonable to assume that automated features have increasingly been used at contact centres these days. Our benchmarks reflect the current state of automation⁶⁹ but note that this may change somewhat over time with improved technology, and with changes in the level of customer acceptance.

Table B - 13: Call centre costs

Call centre costs		2005/06 Benchmark	
		Low	High
Labour costs	(\$m)	1.35	1.35
Percentage of labour cost to total call centre cost	(%)	0.66	0.66
Total for call centre cost	(\$m)	2.05	2.05

B.3.3 Full time equivalent employee costs and overheads

Corporate and administrative overheads are:

- salary and wages costs associated with the management and administration of the business entity; and
- leasing and maintenance costs related to the provision of setting in which the retailer trades.

We have grouped the various staff into several key groups, namely:

⁶⁹ Our benchmarks were collected in 2003, and reflect the current levels of automation employed in call centres. Costs may change as more interactive systems are developed and as technology improves in communication management however the impact is not likely to be significant in the immediate future.

- corporate and administrative;
- energy trading;
- public relations and customer communication;
- pricing and risk management;
- settlements; and
- regulation and compliance.

We have identified the number of FTE employees required for each corporate and administrative role and their respective average salaries as suggested by the 2006 Hays Salary Survey. All quoted numbers are for Sydney, NSW. They are representative of the total package value including superannuation.⁷⁰

In our suggested staff structure, we have not made an allowance for IT or call centre staff for data validation and customer transfer activities. These are accounted separately in sections B.3.1.6 and B.3.2. The last column on the right of the table provides a reference to the specific section of this report for a more detailed discussion.

Table B - 14: Staff breakdown

Position	Lower bound FTE	Upper bound FTE	Salary per FTE (\$m)	Reference
Corporate and administrative roles				
CEO/Managing Director	1	1	0.450 ⁷¹	
Personal assistant	1	1	0.062	
Company secretary	1	1	0.057	
Board of director (number engaged in corporate governance, not FTE positions)	4	5	0.068 ⁷²	
Legal counsel	1	2	0.100	
Corporate and strategic planning	1	2	0.100	
Human resources manager	1	1	0.110	
Human resources officers	1	1	0.065	
Payroll	1	1	0.058	
Chief financial officer	1	1	0.250	
Corporate risk management	1	1	0.140	
Finance manager	1	1	0.160	
Finance, admin. and business services officers	2	2	0.080	

⁷⁰ Except for personal assistant and secretary where salaries were representative of the cash component only, but lifted by 15% to reflect superannuation and other costs. The package also includes bonuses and other benefits.

⁷¹ We have used the remuneration package for Envestra Limited as a guide and scale according to the size of the MMNE. Source: Envestra Limited's annual report 2005. We have then adjusted the rate to reflect a Sydney package as compared to an Adelaide package with reference to the differential for CFO as quoted by Hays Salary Survey.

Position	Lower bound FTE	Upper bound FTE	Salary per FTE (\$m)	Reference
Tax manager	1	1	0.140	
Treasury officers	1	1	0.086	
Administrative staff and reception	2	2	0.044	
Subtotal for corporate and administrative roles	21	24		Section B.3.3.1
Energy trading				
Manager, trading	1	1		
Senior traders	1	2	0.140 ⁷²	
Energy traders	0	1		
Market analysts	1	1		
Subtotal for energy trading	3	5		Section B.3.3.2
Public relations and customer communication				
Marketing professionals	1	1	0.096	
Public relations manager	1	1		
Customer relations officers	2	2		
Subtotal for public relations and customer communications	4	4		Section B.3.3.3
Pricing and risk management				
Pricing manager	1	1		
Data analysts (pricing)	2	2	0.120	
Risk manager	1	1		
Risk analysts	1	1		
Subtotal for pricing and risk management	5	5		Section B.3.3.4
Settlements				
Settlements manager	1	1	0.100	
Settlements analysts	2	2		
Subtotal for settlements	3	3		Section B.3.3.5
Regulation and compliance				
Regulatory manager	1	1		
Compliance manager	1	1	0.135	
Regulatory analysts	1	1		
Compliance analysts	1	1		
Subtotal for regulation and compliance	4	4		Section B.3.3.6
Total staff and total incremental staff	40	45		

B.3.3.1 Office and administration service costs

The extent of investment needed for office infrastructure is a function of the number of people in the workforce.

⁷² Based on KPMG's previous work for an electricity distributor and retailer, 2006.

The breakdown in the above table suggests that the MMNE would have 40 to 45 FTEs, including a board of directors. We have based this structure on our knowledge of the corporate and administrative function of other retail businesses.

The annual cost of \$22,283 per FTE is derived from:

- office leasing costs of \$17,910 per annum. We estimated that an FTE would require approximately 30 square meters of working space, and multiplied this by the average Sydney CBD corporate office rates for May 2006 of \$597 per square meter⁷³; and
- a suggested loading factor of 30 percent for the expenses incurred for utilities, maintenance and taxes.

We have estimated a sum of \$0.565m to \$0.600⁷⁴ for the following additional office expenses:

- postage and freight;
- printing and stationery;
- telephone and facsimile;
- travel;
- consultancy expenditures; and
- sponsorship and corporate entertainment costs.

Table B - 15: Corporate and administrative staff

Corporate and administrative personnel		2005/06 Benchmark	
		Low	High
FTE	(#)	21	24
Total	(\$m)	2.19	2.46

This table represents the corporate and admin staff identified in table B-14 above. The labour and on-costs associated with other staff involved in billing, energy trading etc. are covered in the respective area.

⁷³ Office rents and occupancy costs, CB Richard Ellis Global Market Rents, May 2006

⁷⁴ Based on previous work for an Australian distributor and retailer, 2006.

Table B - 16: Office and administration service costs

Office and administration service costs		2005/06 Benchmark	
		Low	High
FTE (from table B14 above)	(#)	40	45
Rental and utilities costs per person	(\$m)	0.022	0.022
Subtotal – rent and utilities	(\$m)	0.88	1.00
Office expenses, travel, consultants, postage and freight	(\$m)	0.57	0.60
Total rent, utilities and office expenditure	(\$m)	1.45	1.60
Add Salaries and wages for Corporate admin from Table B-15 above	(\$m)	2.19	2.46
Total	(\$m)	3.64	4.06

B.3.3.2 Energy trading

The energy trading function of a MMNE is responsible for managing the risks of its exposures in the physical and financial markets.

We base our estimates upon similar engagements undertaken in the past.⁷⁵ We consider that an energy trading room for a MMNE would have the staff shown in Table B-17 below.

We estimated that a small energy trading function would require 2 to 3 FTEs with a cost of \$0.420 million per annum. This cost could increase to \$0.700 million for a larger trading room with a 24-hour operation and require 5 to 7 staff.

The MMNE would likely need a trading function of significant size to cope with its customer base and to implement appropriate strategies, particularly with increased trading risk following greater contestability and the removal of ETEF.

Table B - 17: Energy trading costs

Energy trading costs		2005/06 Benchmark	
		Low	High
FTE	(#)	3	5
Total	(\$m)	0.42	0.70

B.3.3.3 Public relations and customer communications

Customer communication costs include those associated with informing customers of:

- available payment options;

⁷⁵ Based on previous work for an Australian distributor and retailer, 2006.

- their rights under an applicable retail code or customer charter;
- the availability of franchise (price regulated) green power options;
- the connection and disconnection process applying to the franchise market; and
- the cost of ensuring that the franchise retailer’s brand is sufficiently distinguished from any related business (such as distribution), thus meeting ring fencing obligations.

As part of the review of franchise gross margin for a retail electricity business in another jurisdiction, we have estimated this cost to be in the vicinity of \$2.5 to \$3.0 million. It is reasonable to draw a comparison between this retailer and the MMNE as both of them have a customer base across a similar geographical region, and would use the same media to communicate with these customers. For example, we observe that another retail electricity business regularly advertises in one or two major newspapers in New South Wales as retailers appear to view this as one of the most effective way of communicating with the target market.

It is also our experience that advertising and marketing costs are not likely to vary much with volumes, especially for a large retailer approaching its customer base with a mass market advertising campaign.

Table B - 18: Advertising and marketing

Advertising and marketing		2005/06 Benchmark	
		Low	High
Benchmark cost	(\$m)	2.50	3.00

Further, there are also the costs from salaries and wages attributed to this group. Table B-19 below outlines the total cost.

Table B - 19: Public relations and customer communication costs

Public relations and customer communication costs		2005/06 Benchmark	
		Low	High
FTE	(#)	4	4
Salaries and wages	(\$m)	0.38	0.38
Advertising and Marketing	(\$m)	2.50	3.00
Total	(\$m)	2.88	3.38

B.3.3.4 Pricing and risk management

The pricing and risk management team is required to mitigate the risks brought by the exposure to the volatility of prices and volumes. Specifically its roles are to:

- develop franchise tariffs consistent with the imposed regulatory constraints;

- identify risks to the business generated by different tariff categories;
- analyse market data to advise management on emerging issues and business impacts; and
- assess the impact of customer switching on appropriate tariff structures for residual franchise electricity customers.

We suggest a team as outlined below.

Table B - 20: Pricing and risk management staff

Pricing and risk management		
FTE	(#)	5
Total	(\$m)	0.6

B.3.3.5 Settlements

The suggested number of FTEs and labour costs associated with the settlements function is summarised in Table B-21 below. This function entails energy trading, settlements, reconciliations, verification and contracting.

Table B - 21: Settlements staff

Settlements		
FTE	(#)	3
Total	(\$m)	0.3

B.3.3.6 Regulatory costs

Regulatory costs are those incurred in complying with regulatory requirements. We have included in the regulatory costs of a MMNE the following:

- costs of retail license;
- costs of participation in the energy ombudsman scheme; and
- costs of regulatory and compliance personnel.

License fee

The retail license fee is estimated to be \$0.0523m per annum based on IPART published data⁷⁶.

⁷⁶ Based on annual electricity license fees for 2003/04 as published by IPART, and escalated to 2005/06 dollars. License fee comprises of a fixed component of \$10,000 plus \$4,000 for every 1 percent of market share (in 2003/04 dollars).

Participation in the energy ombudsman scheme

The NSW electricity industry ombudsman is the Energy and Water Ombudsman of NSW (EWON). EWON deals with disputes and complaints arising under any other standard form customer contract.

In developing a per customer benchmark ombudsman cost incurred by the MMNE, we have examined similar rates from the Energy and Water Ombudsman Scheme of Victoria (EWOV) and the Electricity Industry Ombudsman of South Australia (EIOSA). Table B-22 shows our calculations.

Table B - 22: Comparison between costs of ombudsman schemes

Scheme	Financial year	Operating costs	Customers covered	Number of customers	Cost per customer
EWOV	2005	4.77	Electricity, gas and water	6.0m ⁷⁷	\$0.80
	2004	4.46			\$0.74
EIOSA	2005	0.85	Electricity and gas	1.1m ⁷⁸	\$0.77
	2004	0.77			\$0.70
EWON	2005	3.80	Electricity, gas and water	6.90m ⁷⁹	\$0.55
	2004	3.58			\$0.52

The table shows that per unit ombudsman cost range from \$0.52 to \$0.80. It is worth noting that we have assumed that a household or business which is simultaneously an electricity, gas and water customer is considered three customers consistent with the opportunity for the customer to contact the ombudsman.

Based on the above, we have estimated the ombudsman scheme costs at \$0.52 per customer per annum representing the NSW experience, which is at the lower end of the range of the three states examined. We expect that the MMNE will have new systems and attempt to secure slightly better than the average customer, which should result in slightly lower than average interaction with an ombudsman. We have therefore have chosen the lower “2004” NSW benchmark in our calculations, however the difference is not particularly material to the final figures. This results in a benchmark scheme cost of \$0.13m for 2005/06.

It is likely a MMNE would also have customer relations personnel who are responsible for dispute resolution internally before forwarding the necessary cases to EWON. We have accounted for this additional FTE cost as part of public relations and communications.

⁷⁷ Total of 2.3m electricity customers, 2.2m water customers (assuming 0.1m of electricity customers not connected to mains water supply) and 1.5m gas customers. Source: ESC – “Final report to Minister – Special investigation: Review of effectiveness of retail competition and consumer safety in gas and electricity”, 2004. Electricity and gas customer numbers for Victoria were derived from rates of consumer switching.

⁷⁸ Total of 0.75m electricity customers and 0.36m gas customers. Source: KPMG industry knowledge.

⁷⁹ NSW and ACT have a total of 4.262m electricity and gas customers. 6.905m customers for NSW is derived by subtracting 4.262m by 0.257m customers in ACT, and added to an estimated 2.9m water customers in NSW. We have estimated that there are 2.9m water customers. Source: ESAA Report 2005 and ActewAGL Annual Report 2005.

Regulatory and compliance personnel

The final component of regulatory costs is the wages and salaries of regulatory and compliance personnel dealing with regulatory reporting and licence compliance issues, regulatory submissions, and industry monitoring. Table B-23 shows this cost.

Table B - 23: Regulatory and compliance staff

Regulatory and compliance personnel		
FTE	(#)	4
Total	(\$m)	\$0.54

Total regulatory cost

The total regulatory cost for the MMNE is the sum of the three components discussed previously. It is estimated that this figure will be approximately \$0.75m.

Table B - 24: Regulatory costs

Regulatory costs		2005/06 Benchmark	
		Low	High
Total customers	(#)	250,000	250,000
Ombudsman cost per customer	(\$)	0.52	0.52
Subtotal	(\$m)	0.13	0.13
License costs		0.05	0.05
Regulatory and compliance personnel		0.54	0.54
Total	(\$m)	0.72	0.72

B.3.3.7 Total for FTE employee costs and overheads

The total cost relating to employee and overheads are detailed below.

Table B - 25: Total benchmark cost for employee costs and overheads

Area		2005/06 Benchmark	
		Low	High
Office and administration service costs		3.64	4.06
Energy trading costs		0.42	0.70
Customer communications		2.88	3.38
Pricing and risk management		0.60	0.60
Settlements		0.30	0.30
Regulatory costs		0.72	0.72
Total	(\$m)	8.57	9.77

B.4 Summary

The retail operating cost for a MMNE consists of all the cost-to-serve components discussed in this appendix and summarised in Table B-26 below. We have suggested a lower and upper range for the retail operating cost of a MMNE. These benchmarks were derived by identifying the key activities required of an efficient MMNE operating in New South Wales. We have where possible used the most recent cost benchmarks and escalated accordingly.

It is important to note that implicit in our cost estimates are some assumptions that we have made relating to the operations of a MMNE, as set out in the body of this report. If different assumptions are applied then it should be appreciated that different results may be produced.

Table B - 26: Summary of retail operating cost

	2005/06 Benchmark			
	Section	Lower bound benchmark (\$m)	Upper bound benchmark (\$m)	%
Billing and customer collection (including CIS/ITS)	B.3.1	10.04	10.19	46-50
Call centre costs	B.3.2	2.05	2.05	9-10
Full time equivalent employee costs and overheads	B.3.3	8.57	9.77	41-44
Total		20.70	22.00	100%

The total retail operating cost for the MMNE ranges from \$20.7m to \$22.0m, resulting in a per customer cost of \$82.65 to \$88.01 for 2005/06.

B.5 Comparative analysis

We have summarised the results of recent regulatory decisions on the establishment of retail operating costs in Table B-27 below. Appendix C provides further details on these decisions.

Table B - 27: Summary of retail operating cost

Energy market	Jurisdictional Benchmarking		
	Year	Operating costs per customer	Customer base '000
SA Electricity	2005	84	700
NSW Electricity	2004	70	Various
Victoria Electricity	2003	90	Various
SA Electricity	2003	82	700
Tasmania Electricity	2003	77	250
ACT Electricity	2003	85	150
NSW Electricity	2002	45 – 75	Various
SA Electricity	2002	80	700
Victoria Electricity	2001	50 – 80	Various
NSW Electricity	2000	40 – 60	Various

The table needs to be read in the context of the introduction of retail contestability. The lower retail operating costs per customer in the earlier years do not reflect the costs of systems required to manage energy customers in a contestable market. Contestability increases complexity of data management and information transfer between retailer and distributor, whilst maintaining customer privacy.

The number of customers in the energy market evaluated also influences the cost per customer. The range of costs in NSW and Victoria recognise the value of fixed costs and their application against a range of business sizes operating in those markets.

Considering the above, and examining the operating costs allowed for each customer we observe that regulators tend towards a range of \$80 to \$90 for energy retailers with less than 500,000 customers.

We note in our assumptions that a MMNE retailer will need to be of sufficient size to justify an investment in systems with capacity to enter the mass market, and have assumed a customer base of 250,000 to represent this size.

The Independent Competition and Regulatory Commission (“ICRC”) in the ACT states that the retailer operating costs sufficient to cover the costs of a business the size of ACTEWAGL are in the order of \$85 per customer in 2003.⁸⁰ This would be over \$90 per customer in 2005/06 dollars. The ICRC notes that this is at the upper end of the range due to the diseconomies of scale as compared to Victorian and NSW or SA retailers with typically more than 500-600,000 customers.⁸¹ Therefore, we would expect that a MMNE retailer would experience operating costs at the higher end of the range due to the size of its customer base.

⁸⁰ ICRC, Investigation into Retail Prices for Non-contestable Electricity Customers in the ACT, May 2003, page 22.

⁸¹ We observe that a recent market presentation by AGL on the AGL/Alinta merger suggests AGL is currently experiencing operating costs of \$91 per customer, but is expecting to reduce this significantly (perhaps to \$68 per customer) with the amalgamation of systems and an operating cost efficiency project to commence in the near future. AGL, A new AGL scheme booklet release (revised), 29 August 2006, page 26.

C Recent regulated electricity retail tariff decisions

The table below describes recent net and gross margins (where applicable) and retail operating cost decisions by regulators in Australian and overseas jurisdictions for electricity retailers.

Table C - 1: Recent regulatory precedent for franchise electricity retailers- retail operating costs, net margin and RGM

Jurisdiction, Regulator and Retailer(s)	Operating cost \$ per customer	Net margin % of turnover	Gross margin % of turnover	Date	Source	Notes
South Australia (ESCOSA) AGLRE	\$84 ⁸²		10% ⁸³	2005	ESCOSA	The Essential Services Commission of South Australian ("ESCOSA") decided upon a retail operating cost of \$84 in December 2004 dollars, increasing by CPI + 2% thereafter. In addition, a margin of 10% on wholesale and retail operating costs, rather than a net or gross margin. The 10% retail margin applied by ESCOSA is the return on the combined wholesale electricity and retail operating costs of AGL SA, rather than a percentage return on sales. ESCOSA noted that this margin equated to around 5% of total costs given that network costs (on which no return was granted), comprise around 50% of retailer costs.
NSW (IPART) EnergyAustralia, Country Energy, Integral Energy, Australian Inland Energy	\$70 ⁸⁴	2% ⁸⁵		2004	IPART	IPART adopted a different approach than in previous years by setting target delivered tariffs for customers consuming less than 160MWh per annum, rather than benchmarking retailer margins. IPART introduced the concept of 'N' and 'R' components of delivered energy costs (network and retail costs). The decision referred to here affected the 'R' component only. The retail operating cost was considered largely fixed.
Victoria (ESC/Department of Infrastructure) Origin, AGL, TXU	\$90 ⁸⁶	5%		2003	Charles River Associates	CRA suggested that \$90 per customer was consistent with retailers' views on the retail operating costs. There is no evidence that DOI accepted this view in the CPI-X tariff path adopted for 2004-07, and this retail operating cost figure was not granted by the ESC.

⁸² ESCOSA, 'Final report – Inquiry into electricity retail price path', 2005, page 53.

⁸³ Ibid., page 57.

⁸⁴ IPART, 'NSW electricity regulated retail tariffs 2004/05 to 2006/07- Final report and determination', 2004, page 10. <http://www.ipart.nsw.gov.au/files/Det04-1.pdf>

⁸⁵ Ibid., page 9.

⁸⁶ Charles River Associates, 'Electricity and gas standing offers and deemed contracts (2004-07)', 2003, page 25.

Jurisdiction, Regulator and Retailer(s)	Operating cost \$ per customer	Net margin % of turnover	Gross margin % of turnover	Date	Source	Notes
South Australia (ESCOSA) AGLRE	\$82 ⁸⁷	5% ⁸⁸		2003	ESCOSA	
Tasmania (OTTER) Aurora Energy	\$76.67 ⁸⁹	3% ⁹⁰		2003	OTTER	Retail operating cost is expressed in May 2003 dollars.
ACT (ICRC) ActewAGL	\$85 ⁹¹		5%	2003	ICRC	The ICRC noted that ActewAGL could not take advantage of scale economies that might be available to other interstate retailers.
NSW (IPART) EnergyAustralia, Integral Energy, North Power, Advance Energy, Great Southern Energy, Australian Inland Energy	\$45 - \$75 ⁹²	1.5% - 2.5% ⁹³		2002	IPART	
South Australia (SAIIR) AGLRE	\$80 ⁹⁴			2002	SAIIR/ES COSA	
Victoria (ORG) Citipower, United Energy, Solaris, Powercor, TXU	\$50 - \$80 ⁹⁵	2.5% - 5% ⁹⁶		2001	ESC/ORG	

⁸⁷ ESCOSA, 'Electricity industry guideline no. 10 – Electricity retail price justification', December 2003, page 10.

⁸⁸ Ibid., page 10.

⁸⁹ Office of the Tasmanian Energy Regulator, 'Investigation of prices for electricity distribution services and retail tariffs', 2003, page 155

⁹⁰ Ibid., page 168.

⁹¹ Independent Competition and Regulatory Commission, Report 5 of 2003 - 'Investigation into retail prices for non-contestable electricity customers in the ACT', May 2003, page 21

⁹² IPART, 'Mid-term review of regulated retail prices for electricity to 2004', June 2002, page 5.

⁹³ Ibid., page 5.

⁹⁴ South Australian Independent Industry Regulator, 'Electricity retail price justification: Final report', September 2002, page 15

⁹⁵ Office of the Regulator General, 'Special investigation – Electricity retailer's proposed price increases – Final report', 2001, page 33.

⁹⁶ Ibid., page 33.

Jurisdiction, Regulator and Retailer(s)	Operating cost \$ per customer	Net margin % of turnover	Gross margin % of turnover	Date	Source	Notes
NSW (IPART) EnergyAustralia, Integral Energy, North Power, Advance Energy, Great Southern Energy, Australian Inland Energy	\$40 - \$60 ⁹⁷	1.5%-2.5% ⁹⁸		2000	IPART	
Tasmania (OTTER) Aurora		1.5% ⁹⁹		1999		The regulator made reference to the low risk facing Aurora's retailing activities, and assumed annual productivity gains of 5%.

⁹⁷ IPART, 'Regulated Retail Prices for Electricity to 2004', 2000

⁹⁸ Ibid.

⁹⁹ OTTER, 'Investigation into electricity pricing – final report', 1999, page 169.