15 September 2008

Manager Companies
ASX Limited
20 Bridge Street
SYDNEY NSW 200

Dear Sir

INDEPENDENT EXPERT'S REPORT

Attached herewith for immediate release to the market is the Independent Expert's Report of Grant Samuel dated 15 September 2008.

The report will be available today on the Origin Energy website on: www.originenergy.com.au/media/newsroom.

Printed copies of the report may be requested by contacting our shareholder information line 1800 647 819.

Yours faithfully

Bill Hundy
Company Secretary

02 8345 5467 - bill.hundy@originenergy.com.au

GRANT SAMUEL

GRANT SAMUEL & ASSOCIATES

LEVEL 19 GOVERNOR MACQUARIE TOWER
1 FARRER PLACE SYDNEY NSW 2000
GPO BOX 4301 SYDNEY NSW 2001
T: +61 2 9324 4211 / F: +61 2 9324 4301
www.grantsamuel.com.au

15 September 2008

The Directors
Origin Energy Limited
Level 45, Australia Square
264-278 George Street
Sydney NSW 2000

Dear Directors

ConocoPhillips Proposal

1 Introduction

On 8 September 2008, Origin Energy Limited ("Origin") announced that it had entered conditional agreements with a wholly owned subsidiary of ConocoPhillips ("ConocoPhillips") to create an incorporated 50/50 joint venture ("JV") to develop Origin's coal seam gas ("CSG") assets and a gas liquefaction facility ("the ConocoPhillips Proposal"). The key features of the ConocoPhillips Proposal are:

- ConocoPhillips will subscribe for new partly paid shares in Origin Energy CSG Limited ("OECSG") which will comprise 50% of the enlarged share capital. OECSG will be the owner of all of Origin's CSG related assets and liabilities including contracts for gas supply to Origin and third parties ("the CSG Assets");
- the development of a four "train" liquefied natural gas ("LNG") facility. The next two years will be spent proving up reserves, developing further gas production capability, site selection, front end engineering and design and undertaking the necessary feasibility studies with a view to making a Final Investment Decision ("FID") to proceed with the first LNG train in the last quarter of calendar 2010;
- ConocoPhillips will make a series of payments to obtain its 50% interest in OECSG:
  - an upfront payment of US$5.0 billion payable upon the subscription agreement becoming unconditional ("the Initial Contribution");
  - additional contributions to the JV totalling A$1.15 billion to carry Origin's share of the budgeted development costs and operating costs up to FID for Train 1 ("Development Cost Contribution"). The approved expenditure budgets form part of the transaction documents; and
  - additional contingent payments of US$0.5 billion, payable upon FID for each of the planned four LNG trains ("Contingent Contributions"), to partly carry Origin's share of the construction costs.

  The Initial Contribution will be repatriated to Origin through a combination of a return of capital, repayment of intercompany loans and new interest free loans to Origin. Origin will not have to make any payments in relation to its 50% interest in the JV except to the extent additional capital is required (e.g. pre FID cost overruns, LNG train construction costs above US$1 billion each) but both parties will contribute to these on a 50/50 basis (with Origin's contribution by way of loan repayment); and
- each party will have two directors on the board of OECSG (with no casting votes). The steering committee will have an equal number of representatives from Origin and ConocoPhillips. Origin will be the "operator" of the upstream assets while ConocoPhillips will be the "operator" of the downstream assets (i.e. the LNG plant), all on a cost recovery basis.

  There are restrictions on transfer and pre emptive rights. A change of control event at Origin either through another entity acquiring more than 50.1% of Origin shares or through a change of management would give the right to ConocoPhillips to assume operatorship of the upstream assets and the CSG marketing but does not give a right to acquire Origin's equity interest in OECSG.

The ConocoPhillips Proposal is the culmination of a process commenced by Origin in June 2008 when it invited expressions of interest from a wide range of potential parties to participate in the monetisation of Origin's CSG Assets including, but not limited to, the associated potential development of an LNG plant ("the CSG Monetisation Process"). A CSG Monetisation Process in some form had been contemplated by Origin to enable it to optimally finance and manage the development of the CSG Assets. However, the process was accelerated as a result of the approach by BG Group plc ("BG Group") in late April 2008. Following a breakdown in negotiations in late May, Origin rejected BG Group's approach. Subsequently, BG Group announced on 24 June 2008 that it intended making a takeover offer for Origin. BG Group's offer of $15.37[1] cash per Origin share was made to Origin shareholders on 4 August 2008 and remains open for acceptance until 26 September 2008 ("the BG Offer"). The directors of Origin have rejected the BG Offer as inadequate. BG Group announced on 9 September 2008 that, in view of the ConocoPhillips Proposal, it now intends to let its offer lapse on the closing date.

The directors of Origin have engaged Grant Samuel & Associates Pty Limited ("Grant Samuel") to prepare an independent expert's report setting out its opinion as to whether the ConocoPhillips Proposal is in the best interests of Origin's shareholders and whether the BG Offer is fair and reasonable. A copy of the report is to accompany either an Explanatory Memorandum or a Supplementary Target's Statement to be sent to Origin shareholders.

2 Summary of Opinion

In Grant Samuel's opinion, the ConocoPhillips Proposal is in the best interests of shareholders.

Origin's CSG Assets have emerged as its most valuable set of assets and development of these assets is central to Origin's long term strategy. The scale of the CSG development, at least if Origin was also to participate in an LNG plant, would have been beyond the financial resources of Origin without substantial equity raisings. Realistically, it was always going to need a partner (or partners) to extract the maximum value from these assets. The ConocoPhillips Proposal:

- **crystallises a very substantial value for 50% of the CSG Assets;**
- **allows Origin to participate in both the exploitation of the CSG Assets and the LNG production opportunity through its retained 50% interest;**
- **provides Origin with approximately $6 billion in cash immediately and has a structure where Origin is not likely to need to subscribe any material amount of capital to cover development costs for some years;**
- **brings in a partner with outstanding credentials and the:**
  - **financial capacity to fund its share of the JV's development costs; and**
  - **technical skills and marketing capability to make a very material contribution towards the substantive task of developing and operating the proposed LNG plant.**

The terms of ConocoPhillips' 50% investment in the CSG Assets establishes a benchmark value for the CSG Assets. Having regard to the process undertaken, the structure and terms of the transaction and the implied values per GJ of reserve or resource, Grant Samuel is satisfied that the terms represent a fair arm's length value of a 50% interest in the CSG Assets. Grant Samuel has valued the aggregate consideration to be subscribed by ConocoPhillips for its 50% interest at $8.36-8.69 billion. It is reasonable to attribute the same value to Origin's 50%. There is nothing in the terms of the agreements that would diminish the value of Origin's 50% relative to ConocoPhillips' interest.

Grant Samuel has estimated the full underlying value of Origin's other assets, namely its retail and generation businesses, the conventional oil and gas assets and its 51.3% interest in Contact Energy Limited ("Contact Energy"). These businesses were primarily valued on the basis of discounted cash flow ("DCF") analysis and multiples of earnings. However, in the case of Contact Energy, only publicly available information was available.

[1] The offer was originally $15.50 but has been adjusted to reflect the payment of Origin's final dividend of 13 cents on 3 October 2008.

On the basis of this analysis, Grant Samuel has estimated the full underlying value of Origin, including a premium for control, to be in the range $28.55-30.71 per share. This value is substantially above the BG Offer of $15.37 per share. The ConocoPhillips Proposal therefore provides superior value to Origin shareholders. Accordingly, the BG Offer is neither fair nor reasonable.

The value range of $28.55-30.71 represents the full underlying value of Origin including a control premium. It is not an estimate of the market trading price of Origin shares. Grant Samuel expects that Origin shares would trade on the Australian Securities Exchange ("ASX") at prices below this level in the absence of a takeover offer or takeover speculation.

While the value of 50% of the CSG Assets has been crystallised, the ConocoPhillips Proposal means that shareholders will have an ongoing exposure to 50% of the CSG Assets, providing both upside potential and downside risk. The ConocoPhillips Proposal substantially enhances the prospects of successful development but there is, nevertheless, a risk that the ultimate development of CSG is less successful than currently expected.

Origin will have net cash of approximately $2.5 billion (excluding net borrowings of Contact Energy) after the repatriation of the Initial Contribution. Origin proposes to pay an additional 25 cent dividend and commence a $1.275 billion on market buyback after repatriation of the Initial Contribution. Even after these initiatives, Origin will have very substantial financial capacity to continue to meet its existing capital commitments and to develop its other business operations. Shareholders will also benefit from a substantial uplift in earnings per share and a higher dividend payout ratio.

3 Key Conclusions

- **Origin's CSG Assets are a major source of value**

  The market value of all CSG assets in Australia has undergone a dramatic shift over the past 12-18 months as:

  - the scale of the resource has become more apparent and ongoing drilling programs have proved up substantial increases in reserves and identified other resources, particularly in Queensland;
  - domestic demand for gas continues to grow, particularly through the development of gas fired power stations (primarily peaking plants but also for base load). The introduction of an emissions trading scheme will underpin the move toward gas as the major fuel source for electricity;
  - alternative sources of new domestic natural gas on the east coast have been limited, major existing conventional gas fields are maturing or in decline and the proposed PNG gas pipeline has been deferred;
  - oil prices have risen dramatically which has had a flow on effect to all energy prices globally; and
  - the scale of the CSG reserves and the rise in energy prices has opened up the potential for development of an LNG export industry from Queensland using CSG as the feedstock. There are a significant number of hurdles to overcome including:
    - confirmation of consistency of gas production;
    - location, technical design and permitting of the LNG plant;
    - completing drilling programs to prove up reserves to ensure a sufficient total volume to underwrite plant throughput;
    - resolving "ramp up" gas issues;
    - securing sufficient offtake arrangements recognising the "lean" nature of the gas; and
    - funding.

  However, notwithstanding the hurdles to overcome, there have been several recent transactions where major international energy companies have entered agreements that attribute very

substantial values to undeveloped CSG resources (and are premised on LNG plant development and sufficient export markets).

Origin has what can reasonably be regarded as the best portfolio of CSG assets in Australia:

- it has the largest 2P and 3P reserves position of CSG producers in Australia. Origin's reserves and resources represent the largest portfolio of uncontracted/uncommitted reserves position (circa 8,000PJ) and the only remaining portfolio of quality and significant scale available for supply to LNG projects;
- the assets are located in what are considered "sweet spots" for CSG. Origin's Spring Gully/Fairview fields in the Bowen basin and the Undulla Nose in the Walloons Fairway section of the Surat Basin are acknowledged by market participants to rank among the best CSG assets worldwide on key technical criteria such as gas content and recoverable reserves per well; and
- Origin's CSG interests are highly prospective for additional reserves and resources. Over 70% of Origin's 3P reserves and 85% of Origin's contingent resource totalling 20,830PJ are located in the relatively undeveloped north east Surat Basin. These fields are located on permits adjacent to or within close proximity to fields already well explored by other CSG participants such as Queensland Gas Company Limited ("QGC"), Arrow Energy Limited ("Arrow") and Santos Limited ("Santos").

- **The CSG Monetisation Process is a strategically sound initiative to develop the CSG Assets**

Origin's initial interest in CSG was as a source of gas to supply its growing downstream businesses, both gas retailing and gas fired electricity generation. CSG was a key part of Origin's strategy of being an integrated energy business with a focus on the fuel component as the greatest source of long term value creation. However, as the potential CSG volumes expanded, LNG options have become more evident. Origin has therefore also been exploring ways in which it can either:

- participate in LNG directly; or
- provide CSG in sufficient volumes to underpin a third party development of an LNG plant.

In either case, the underlying objective was to maximise the price for the gas by accessing export markets. The "net back" price received for gas as feedstock for LNG (which is driven by the oil price and the production/tolling costs) is substantially above current Australian domestic gas prices.

The development of the CSG Assets (other than as supply to LNG plants) is a significant project with estimated capital expenditure in excess of $2 billion over the next five years. As a domestic gas only project, this was considered manageable for Origin as the capital expenditure could be phased and offset by operating cash flows.

However, LNG introduces a different dimension. Direct participation in LNG substantially increases and brings forward the capital commitments and takes Origin into an activity where it has no existing operations or expertise. On the other hand, if it just supplies gas to others to facilitate their LNG projects, Origin has less control and certainty over the development and the gas pricing received may be less favourable.

Accordingly, Origin's preferred approach was to participate across the entire LNG value chain in order to benefit from vertical integration. Realistically, to participate directly in LNG, Origin was always going to need to bring in a partner (or partners) to share the financial burden, provide technical expertise and provide access to LNG export markets.

The ConocoPhillips Proposal provides an attractive outcome consistent with Origin's strategic objectives:

- it crystallises a value for 50% of the assets but allows Origin to retain a 50% exposure to the CSG Assets and participate in 50% of the LNG plant;
- it provides Origin with immediate cash of approximately $6 billion which will leave it in a net cash position of approximately $2.5 billion (excluding net borrowings of Contact Energy). Even after allowing for the proposed increase in dividends and the share buyback, Origin will

have substantial financial capacity to meet its existing capital commitments and develop its other business operations including downstream energy retailing and electricity generation.

ConocoPhillips will subscribe for all the capital necessary to cover the anticipated development costs up to FID for the first LNG train (up to $2.3 billion) and will subscribe US$1 billion of additional capital at the time of FID for each LNG train. Depending on how the project is financed, Origin is unlikely to need to subscribe for any material amount of capital in the joint venture until 2012 at the earliest; and

- ConocoPhillips is one of the world's leading integrated energy companies. It has the financial capacity to fund its share of equity commitments but, more importantly, it should be a strong partner that can make a major contribution to the development of CSG Assets in areas such as technical expertise in the development and operation of the LNG plant and marketing of LNG.

  ConocoPhillips is the leading CSG producer in the United States with 25 years of experience. It has extensive experience in the development and operation of LNG plants and has developed its own proprietary LNG process (in collaboration with Bechtel Corporation) which has been used on nine plants around the world. More particularly, ConocoPhillips:

  - has recent experience developing the greenfield LNG facility in Darwin; and
  - is a leader in "tight" gas to LNG (similar to "lean" CSG), having built the world's first tight gas LNG plant in Kenai, Alaska.

The ConocoPhillips Proposal is based on a four train LNG plant, much larger than any other planned development exploiting Queensland CSG. This plan is fundamental to maximising the value of Origin's CSG Assets and to supporting the value attributed under the ConocoPhillips Proposal. ConocoPhillips' participation as a 50% partner provides a high degree of confidence that the development will occur (and within time horizons and budgets).

- **Assuming the ConocoPhillips Proposal is implemented, the full underlying value of Origin is estimated to be in the range $25.5-27.4 billion, equivalent to $28.55-30.71 per share**

Origin has been valued in the range of $25.5-27.4 billion which corresponds to a value of $28.55-30.71 per share. The valuation represents the full underlying value of Origin assuming 100% of the company was available to be acquired and includes a premium for control. The value exceeds the price at which, based on current market conditions, Grant Samuel would expect Origin shares to trade on the ASX in the absence of a takeover offer.

The value for Origin is the aggregate of the estimated market value of Origin's business operations and other assets and trading liabilities. The valuation is summarised below:

Origin - Valuation Summary ($ millions)

	Report Section Reference	Value Range	
		Low	High
Business Operations			
CSG Assets	9.4	16,700	17,400
Conventional Oil and Gas	9.5	2,400	2,800
Downstream Energy	9.6	8,500	9,200
Head office costs (net of savings)	9.8	(250)	(225)
Total business operations		**27,350**	**29,175**
51.3% interest in Contact Energy	9.7	2,300	2,400
Other assets and liabilities	9.9	(705)	(700)
Net borrowings	9.10	(3,453)	(3,453)
Value of equity		**25,492**	**27,422**
Fully diluted shares on issue (millions)		892.9	892.9
Value per share		**$28.55**	**$30.71**

The valuation is after taking into account Origin's final dividend for the year ended 30 June 2008 (to be paid on 3 October 2008).

The value attributed to the CSG Assets is twice the estimated value of the ConocoPhillips Proposal which was calculated by discounting the future cash flow equivalents at an interest rate. The Contingent Contributions were risked by applying various probability factors (between 50% and 90%) to reflect that they are not certain.

The values of the Conventional Oil and Gas and Downstream Energy businesses were estimated having regard to two primary methodologies, DCF analysis and multiples of earnings. Regard was also had to rules of thumb such as price paid per mass market customer (for Retail) and price per MW (for Generation).

The valuation of the 51.3% interest in Contact Energy is based solely on publicly available information as Grant Samuel did not have access to any non public information such as internal Contact Energy forecasts.

- **The value range of $28.55-30.71 represents a very substantial increase over the BG Offer and the market price of Origin shares prior to the initial approach by BG Group in April 2008**

  Grant Samuel has estimated the full underlying value of Origin assuming the ConocoPhillips Proposal is implemented and compared that to the BG Offer.

  Grant Samuel believes this is the relevant test as the BG Offer involves a change of control. It is not appropriate to compare the BG Offer with the price at which Origin shares might trade if the ConocoPhillips Proposal is implemented because that is a portfolio value and shareholders will still have the opportunity to realise a control premium by participating in a future change of control event.

  The value range of $28.55-30.71 per share is substantially above the BG Offer of $15.37 per share. The ConocoPhillips Proposal therefore provides superior value to Origin shareholders. Accordingly, the BG Offer is neither fair nor reasonable.

  The value range of $28.55-30.71 per share also represents a very substantial increase over the level at which Origin shares were trading prior to the announcement of the approach by BG Group on 29 April 2008 of approximately $9-10 per share.

  However, while this difference is far greater than normally seen in a "control" valuation, the circumstances are unique and reflect the value that has been created through the CSG Monetisation Process. The market attributed some value to Origin's CSG Assets but there was both a rapidly changing environment (e.g. the Santos/Petronas transaction was not announced until after BG Group's initial approach) and value was constrained by the absence of specific plans or credible partners as well as the limited levels of published reserves (Origin released a substantial upgrade on 15 May 2008).

  The ConocoPhillips Proposal dramatically alters the picture. Apart from the value recognition through the transaction terms, it transforms the CSG Assets from an Origin shareholder's perspective from an "interesting play with potential" to one where there is a real project with:

  - a strong partner with outstanding technical capabilities fully committed to the project;
  - the project fully financed with very limited need for Origin to invest its own cash; and
  - a demonstrably high level of confidence in the provability of the vast majority of Origin's contingent resource by one of the world's most experienced CSG operators.

  In this respect, the CSG Assets are now very different assets to what they were in April 2008.

- **The value of Origin's CSG Assets is based on the agreed transaction price for the 50% interest**

The rapidly changing environment for CSG, its early stage of development and uncertainties about future gas prices would normally make valuation of Origin's CSG Assets extremely difficult.

However, the ConocoPhillips Proposal provides a clear arm's length benchmark value. The price paid by an independent third party conducted through a competitive tender process is the most reliable evidence of value, far more so than theoretical values based on long term cash flow projections for operations not yet in existence.

In Grant Samuel's opinion, it is appropriate to use this transaction as the basis for valuing Origin's CSG Assets for the purposes of this report. The reasons include:

- the ConocoPhillips Proposal is the culmination of the CSG Monetisation Process begun in June 2008. Expressions of interest were invited from a wide range of international and domestic energy companies. 22 expressions of interest were received in early July 2008, all from credible parties. Origin then reduced this to a short list of six, who were invited to conduct detailed due diligence and submit final offers. Five final offers were received. Each of the final round bidders were parties of undoubted substance and expertise. There is no evidence that:
  - the timing of the CSG Monetisation Process was inopportune;
  - the process was conducted unfairly or in a manner unlikely to yield the best price;
  - the timetable did not allow bidders sufficient time to conduct their analysis, undertake due diligence or organise funding; or
  - different structures (i.e. other than 50/50) would have produced superior values;
- the ConocoPhillips Proposal is a relatively straight forward transaction. There are no terms which transfer value between one 50% holding and the other. For example:
  - there are no abnormal "control" provisions or other terms which affect the value of the other 50%. Voting power and board representation are split 50/50. There are restrictions on transfer and pre-emptive rights but they are the same for both parties and not unusual in this type of transaction; and
  - the JV will cover all of Origin's CSG Assets and includes the LNG plant. Both parties have the same economic interests across the entire business. There are some minor differences where Origin is the operator of the CSG production activity and ConocoPhillips is the operator of the LNG plant but these are largely cost recovery exercises. Any future gas sales from the JV to Origin will be at market price.

  There is a potential cost to a bidder for Origin in some circumstance but this does not impact the value of the asset in Origin's hands; and
- the price parameters are not inconsistent with those seen in other recent CSG transactions. The values represent the following parameters:

CSG Assets - Implied Value Parameters ($ per GJ)

	NPV of 100% ($ millions)	Reserves/Resources[2] as at 30 June 2008		
		2P	3P	3P+2C
Initial Contribution plus Development Cost Contribution only	14,176	2.98	1.39	0.54
Low Value - all payments (but risked) - Delayed	**16,726**	**3.52**	**1.64**	**0.64**
High Value - all payments (but risked) - Base	**17,386**	**3.66**	**1.71**	**0.67**
All Contributions at face value	19,167	4.03	1.88	0.74

[2] Including 44PJe of 2P conventional reserves from the Denison Trough that will be an asset of the JV.

Values per GJ (particularly 2P and 3P) need to be treated with considerable caution as they are influenced by a wide range of factors including the location, the reserve maturation profile, the stage of development, the extent of additional resources and the scope and timing of any associated LNG facility. In fact, given the history of drilling programs, the maturation profiles and the nature of the resources, it is arguable that the recent prices being paid are premised more on the total resource (i.e. 3P + Contingent Resources) rather than just current levels of reserves (2P or 3P), so these multiples may be more relevant.

The recent Santos/Petronas transaction represented $1.32-1.65[3] per GJ on a 3P basis and $0.46-0.58[3] per GJ on a 3P+Contingent Resource basis. Adjusting for currency movements would shift the values to $1.51-1.89[3] per GJ and $0.53-0.66[3] per GJ respectively. On this basis, the value under the ConocoPhillips Proposal of $1.39-1.88[3] per GJ (3P) and $0.54-0.74[3] per GJ (3P+2C) is clearly not an "outlier".

One area of contention that has arisen is in relation to the Tri-Star reversion rights and their potential value impact. Those rights lie within the JV company and have therefore been taken into account in the pricing of the ConocoPhillips Proposal.

- **Grant Samuel has attributed a value of $8.36-8.69 billion to the ConocoPhillips Proposal, which values the CSG Assets at $16.7-17.4 billion**

Grant Samuel has attributed a value of $8.36-8.69 billion to the consideration for a 50% interest under the ConocoPhillips Proposal. The value was determined based on the following DCF analysis:

- the Initial Contribution of US$5.0 billion was converted at an exchange rate of A$1=US$0.83;
- the Development Costs Contribution of A$1.15 billion (Origin's carry) was spread over the period through to the end of 2010 in accordance with the expenditure budgets. The parties are committed to this expenditure program;
- the Contingent Contributions for Train 1 and Train 2 are assumed to be made in the last quarter of 2010 and third quarter of 2011 respectively. While the payments are not certain, it is not appropriate to ignore them as there are reasonable grounds for believing there is a very high likelihood of them occurring. Apart from the demonstrated capabilities of ConocoPhillips, and the financial commitment it will have already made, the terms of the agreements include incentives for ConocoPhillips to ensure FID is progressed. A probability factor of 80-90% has been applied;
- the Contingent Contributions for Train 3 and Train 4 are assumed to be made in 2013 and 2015. Probability factors of 50-65% have been applied to these payments as it is less certain at this stage that they will proceed although there are good reasons for believing it is highly likely (e.g. the ability to use other parties' gas to meet FID criteria for LNG trains);
- the low case also assumes a six month delay on the first two trains and a two year delay on Trains 3 and 4;
- future payments were converted at prevailing forward exchange rates; and
- cash flows were discounted at 7% per annum representing an interest rate for a ConocoPhillips credit exposure in A$ terms. Given the relatively flat yield curve a single rate was assumed. An interest rate is appropriate because, while the payments may or may not occur, they are not variable (and have been separately risked).

- **The Conventional Oil and Gas assets have been valued at $2.4-2.8 billion**

A value of $2.4-2.8 billion has been attributed to Origin's Conventional Oil and Gas assets. DCF analysis was the primary methodology used, but the values were also benchmarked to other metrics. The overall value range represents $14.31-16.57 million per MMBoe and $2.46-2.84 per PJe on a 2P basis.

[3] Low end equals base payment only. High end equals base payments plus contingent payments at face value (unrisked and undiscounted).

Individual DCF models were developed for the major assets (Cooper Basin, BassGas Gas Project, Otway Gas Project and Kupe Project). Production profiles, operating costs and capital costs were provided by the technical expert, Gaffney, Cline & Associates Pty Ltd, with three scenarios for each asset essentially based on 1P, 2P and 3P reserves. The following gas price scenarios were assumed:

East Coast Domestic Gas Price Estimates[4] ($ per GJ real 2008)

	Year end 30 June		
	2008 to 2010	**2011 to 2015**	**2016 onwards**
Gas Price Path A	$3.50	$4.50	$6.50
Gas Price Path B	$3.50	$5.50	$7.50

Source: Grant Samuel analysis

The West Texas Intermediate ("WTI") crude oil price was assumed to move from around US$103-107 per bbl in 2009 to around US$90-110 per bbl by 2016 (nominal dollars) and increase thereafter by inflation. Tapis crude was assumed to trade at a premium of US$3.50 per bbl to WTI. Condensates were assumed at parity to WTI and LPG is assumed to be 95% of WTI.

The after tax cash flows were discounted at 9.5-10.5%. The valuation range selected for each asset was generally focussed on the 2P reserves case. Exploration assets were valued at $10-83 million by Gaffney, Cline & Associates Pty Limited. Allowance was also made for capitalised divisional overheads.

- **The Downstream Energy business has been valued at $8.5-9.2 billion**

The Downstream Energy business comprises:

- Generation (including existing 100% owned power stations, 50% interests in cogeneration plants and 2,096MW of committed new capacity); and
- Retail (including Energy Retailing comprising mass market and commercial and industrial customers, Energy Trading and LPG).

The Generation assets have been valued at $2.05-2.20 billion. The value of existing and committed generation was largely based on DCF analysis with the after tax cash flows discounted at 9.0-10.0%. Revenues were generally based on contracted prices with alternative scenarios around terminal values. The value of the existing portfolio represents 6.6-7.2 times the forecast 2008/09 EBITDAF[5] generated by the model and $0.90-0.98 million per MW. The committed portfolio represents a higher value per MW ($1.43-1.46 million per MW) but this reflects the value through brownfield development and the favourable economics of the Darling Downs Power Station.

The Retail business (including LPG) has been valued at $6.05-6.55 million. The Energy Retailing operations are essentially a "margin" business. A range of scenarios were developed around different gas price paths, tariff caps, retail margins and churn rate. The after tax cash flows were discounted at 9.0-10%. The value range for Energy Retailing represents $1,307-1,399 per mass market customer. While at the higher end of comparable transactions it is not unreasonable and reflects the level of profitability generated by the Origin business compared to competitors.

Energy Trading is a trading business that manages the supply of energy fuel and energy and dispatches it within Origin or externally. The value is largely based on the DCF analysis of existing contracts in place (and reflecting the gas price scenario outlined above) for the term of those contracts. A small component of the value represents an assumption of ongoing profits from MDQ[6] contracts and REC[7] trading (16% of the net present value).

The value of LPG is also based on DCF analysis across a range of scenarios. The value range of $500-550 million represents $1,029-1,132 per tonne of LPG sold.

4 Gas prices are stated as ex well head.

5 Earnings before interest, tax, depreciation, amortisation and fair value adjustments.

6 Maximum Daily Quantity

7 Renewable Energy Certificates

Grant Samuel has also included an allowance of $400-450 million (approximately 5% of the aggregate business values) to reflect the value created through Origin's highly integrated energy business. This integration creates ongoing opportunities to capture value (or additional returns) across the business but particularly in Energy Trading which are not reflected in the individual business unit values. Examples include lower hedging costs (as a consequence of the natural hedge of the upstream gas and generation portfolio, geographical diversification and load diversification between customers), extensive market pricing knowledge and brownfield development options.

The prospective multiples implied by the value of $8.5-9.2 billion of around 12-13 times 2008/09 EBITDAF generated by the model reflects Downstream Energy's strategic position in the Australian energy market and the earnings to emerge from the committed new generation capacity. The range of activities, size of retail market shares and extent of integration in the business are important competitive advantages.

- **Origin's 51.3% interest in Contact Energy has been valued at $2.3-2.4 billion**

Origin owns 51.3% of Contact Energy, with the balance being listed on the New Zealand Stock Exchange. Origin has a controlling interest and it is therefore appropriate to include a control premium. However, the extent of that premium may need to be tempered by the fact that control is not unfettered and, if Origin was ever to realise its holding, acquirers are also likely to assume that they would not gain unfettered control as obtaining 100% may prove difficult.

The value range of $2.3-2.4 billion is based on a value of NZ$9.50-10.00 per Contact Energy share (converted at NZ$1.00=A$0.82). The value represents premiums of:

- 14-20% over the closing price on 5 September 2008;
- 1-7% over the closing price on 29 April 2008, the day BG Group first approached Origin; and
- 13-19% over the weighted average price for the period from 29 April 2008 to 5 September 2008.

These premiums are less than would normally be seen in takeovers (which are typically in the 20-35% range) but this reflects the anticipated difficulties of obtaining 100% and the limited level of synergies that would be likely to be available to an acquirer.

The value represents:

- 11.8-12.3 times EBITDAF for the year ended 30 June 2008; and
- 11.2-11.7 times broker median forecast EBITDAF for the year ending 30 June 2009.

Having regard to multiples implied by recent transactions and the share prices of listed comparable companies, Grant Samuel believes these multiples are reasonable for Contact Energy having regard to its strong growth prospects and market positioning. In particular, Contact Energy is a very strategic asset in the context of the New Zealand energy market. It operates a substantial diversified (by plant type, fuel type and geographic location) generation portfolio and has substantial retail market positions.

- **Under the ConocoPhillips Proposal, Origin shareholders will still have a substantial exposure to the CSG Assets**

Under the ConocoPhillips Proposal, Origin will retain a 50% interest in the CSG Assets including the planned LNG plant. Accordingly, shareholders will have an ongoing exposure to:

- upside opportunities. Any value attributed to CSG Assets in today's environment is inevitably discounted to take account of the risks and hurdles that remain. If the development is successfully executed and a functioning LNG plant is operating at full capacity, it is reasonable to expect that, over time, there will be a substantial increase in the value of Origin's 50% interest in the JV compared to the price under the ConocoPhillips Proposal (assuming gas prices are also at least in line with expectations). Successful development would also provide further opportunities for expansion in due course (e.g. for domestic gas or additional LNG trains). The CSG Assets include substantial prospective acreage on which there has been little drilling activity; and

- downside risk. Both the development and the ongoing operation of the JV have risks and exposures that could have a material adverse impact on returns from the investment and its value. These include:
  - notwithstanding the alignment of interests, the introduction of any partner into a business brings the potential for tensions within the relationship which could adversely affect value;
  - the hurdles to be passed in getting to FID for Train 1 including obtaining the appropriate site (and planning approvals), resolving technical issues (e.g. lean gas), ensuring production levels will be as expected, finalising ramp-up gas arrangements and securing off-take arrangements. There is no guarantee FID will be reached and no decision is expected until December 2010 at the earliest;
  - proving up sufficient gas for all four trains. This requires approximately 24,000PJ (including the already contracted volumes). At present, while Origin has a total resource of approximately 26,000PJ, it has less than 5,000PJ certified to a 2P reserve level;
  - exposure to costs overruns and delays on construction of the LNG facilities;
  - a significant exposure to the global oil price. A material and sustained fall would impact revenues (with minimal effect on costs);
  - dependence on continued growth in global demand for energy; and
  - exposure to a rise in the A$ against the US$ (except to the extent of any hedging).

  In short, there is potential for CSG to be less successful than currently envisaged. However, these risks are unavoidable in any project of this nature (and shareholders are currently exposed to 100% of them). The respective capabilities and track records of the two parties should give some comfort that controllable risks will be well managed. In any event, this does not detract from the fact that there is a market value that an arm's length party is prepared to pay today.

- **Shareholders will benefit from increased earnings per share and dividends**

  The ConocoPhillips Proposal will result in a significant uplift in earnings per share. Origin has estimated that, on an annualised basis, the increase is greater than 50%.

  In addition, it is proposed that dividends will be higher than they would have been in the absence of the ConocoPhillips Proposal. The directors of Origin have announced:

  - an immediate extra dividend of 25 cents per share fully franked; and
  - an increased target dividend payout ratio of at least 60%.

  However:

  - earnings per share are not a major driver of the share price in the short term because, while there is very substantial value in assets such as CSG, there will be no contributions to earnings for some years (except for interest benefits from the Initial Contribution); and
  - even after the increase in the dividend payout ratio, Origin's dividend yield will be relatively low.

4 Other Matters

This report is general financial product advice only and has been prepared without taking into account the objectives, financial situation or needs of individual shareholders in Origin. Because of that, before acting in relation to their investment, shareholders should consider the appropriateness of the advice having regard to their own objectives, financial situation or needs. Shareholders should read the Explanatory Memorandum or the Supplementary Target's Statement issued by Origin in relation to the ConocoPhillips Proposal.

The decision whether to accept or reject the BG Offer is a matter for individual shareholders, based on their own views as to value, their expectations about future market conditions and their particular circumstances including risk profile, liquidity preference, investment strategy, portfolio structure and tax

position. Shareholders who are in doubt as to the action they should take should consult their own professional adviser.

Similarly, it is a matter for individual shareholders as to whether to buy, hold or sell Origin shares. This is an investment decision independent of the ConocoPhillips Proposal or the BG Offer and is one on which Grant Samuel does not offer an opinion. Shareholders should consult their own professional adviser in this regard.

Grant Samuel has prepared a Financial Services Guide as required by the Corporations Act, 2001. The Financial Services Guide is included at the beginning of the full report.

This letter is a summary of Grant Samuel's opinion. The full report from which this summary has been extracted is attached and should be read in conjunction with this summary.

The opinion is made as at the date of this letter and reflects circumstances and conditions as at that date.

Yours faithfully
GRANT SAMUEL & ASSOCIATES PTY LIMITED

Grant Samuel & Associates

Financial Services Guide and Independent Expert's Report in relation to the ConocoPhillips Proposal

Grant Samuel & Associates Pty Limited
(ABN 28 050 036 372)

15 September 2008

GRANT SAMUEL & ASSOCIATES

LEVEL 19 GOVERNOR MACQUARIE TOWER
1 FARRER PLACE SYDNEY NSW 2000
GPO BOX 4301 SYDNEY NSW 2001
T: +61 2 9324 4211 / F: +61 2 9324 4301
www.grantsamuel.com.au

Financial Services Guide

Grant Samuel & Associates Pty Limited ("Grant Samuel") holds Australian Financial Services Licence No. 240985 authorising it to provide financial product advice on securities and interests in managed investments schemes to wholesale and retail clients.

The Corporations Act, 2001 requires Grant Samuel to provide this Financial Services Guide ("FSG") in connection with its provision of an independent expert's report ("Report") which is included in a document ("Disclosure Document") provided to members by the company or other entity ("Entity") for which Grant Samuel prepares the Report.

Grant Samuel does not accept instructions from retail clients. Grant Samuel provides no financial services directly to retail clients and receives no remuneration from retail clients for financial services. Grant Samuel does not provide any personal retail financial product advice to retail investors nor does it provide market-related advice to retail investors.

When providing Reports, Grant Samuel's client is the Entity to which it provides the Report. Grant Samuel receives its remuneration from the Entity. In respect of the Report for Origin Energy Limited ("Origin") in relation to ConocoPhillips Proposal ("the Origin Report"), Grant Samuel will receive a fixed fee of $2,750,000 plus reimbursement of out-of-pocket expenses for the preparation of the Report (as stated in Section 11.3 of the Origin Report).

No related body corporate of Grant Samuel, or any of the directors or employees of Grant Samuel or of any of those related bodies or any associate receives any remuneration or other benefit attributable to the preparation and provision of the Report.

Grant Samuel is required to be independent of the Entity in order to provide a Report. The guidelines for independence in the preparation of Reports are set out in Regulatory Guide 112 issued by the Australian Securities & Investments Commission on 30 October 2007. The following information in relation to the independence of Grant Samuel is stated in Section 11.3 of the Origin Report:

> *"Grant Samuel and its related entities do not have at the date of this report, and have not had within the previous two years, any shareholding in or other relationship with Origin or ConocoPhillips that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the ConocoPhillips Proposal. Grant Samuel advises that:*
>
> - *Grant Samuel prepared an independent expert's report dated 1 September 2003 for Oil Company of Australia Limited in relation to a takeover offer by Origin;*
> - *Grant Samuel prepared an independent expert's report dated 5 August 2003 on the compulsory acquisition of ordinary shares in Petroz NL by ConocoPhillips;*
> - *a related New Zealand company of Grant Samuel, Grant Samuel & Associates Limited, has prepared the following independent reports for Contact Energy:*
> - *an independent adviser's report dated 15 September 2004 in relation to a takeover offer by Origin following its acquisition of Edison's 51.2% shareholding in Contact;*
> - *an independent adviser's report dated 2 November 2001 on the merits of a takeover offer by Edison; and*
> - *an appraisal report dated 11 May 2001 in relation to the proposed restricted transfer as Edison sought to acquire further shares in Contact; and*
> - *Louise Watson, Managing Director of Symbol Strategic Communications which provides strategic communications services to Origin, is a member of the Grant Samuel Corporate Finance Advisory Board. The Grant Samuel Corporate Finance Advisory Board convenes quarterly, acts as a sounding board for and provides market positioning feedback to the corporate advisory activities of the Grant Samuel group of companies. Members of the Grant Samuel Corporate Finance Advisory Board have no involvement in the day to day operations of Grant Samuel or any of its related entities.*
>
> *Grant Samuel commenced analysis for the purposes of this report in May 2008 prior to the announcement of the ConocoPhillips Proposal. This work did not involve Grant Samuel participating in setting the terms of, or any negotiations leading to, the ConocoPhillips Proposal.*
>
> *Grant Samuel had no part in the formulation of the ConocoPhillips Proposal. Its only role has been the preparation of this report.*
>
> *Grant Samuel will receive a fixed fee of $2,750,000 for the preparation of this report. This fee is not contingent on the outcome of the ConocoPhillips Proposal. Grant Samuel's out of pocket expenses in relation to the preparation of the report will be reimbursed. Grant Samuel will receive no other benefit for the preparation of this report.*
>
> *Grant Samuel considers itself to be independent in terms of Regulatory Guide 112 issued by the ASIC on 30 October 2007."*

Grant Samuel has internal complaints-handling mechanisms and is a member of the Financial Industry Complaints Services' Complaints Handling Tribunal, No. F 4197.

Grant Samuel is only responsible for the Report and this FSG. Complaints or questions about the Disclosure Document should not be directed to Grant Samuel which is not responsible for that document. Grant Samuel will not respond in any way that might involve any provision of financial product advice to any retail investor.

Table of Contents

Appendices

1 Details of the Proposal

1.1 Background

On 8 September 2008, Origin Energy Limited ("Origin") announced that it had entered conditional agreements with a wholly owned subsidiary of ConocoPhillips ("ConocoPhillips") to create an incorporated 50/50 joint venture ("JV") to develop Origin's coal seam gas ("CSG") assets and a gas liquefaction plant ("the ConocoPhillips Proposal").

The ConocoPhillips Proposal is the culmination of a process commenced by Origin in June 2008 when it invited a wide range of parties to put forward expressions of interest to participate with Origin in the development of its CSG Assets including the associated potential development of a liquefied natural gas ("LNG") plant ("the CSG Monetisation Process"). This process evolved into a competitive tender and the ConocoPhillips Proposal was selected as the best of the final offers submitted on 29 August 2008.

The formal commencement of this process followed an approach to Origin by BG Group plc ("BG Group") on 29 April 2008, under which it initially proposed making a cash offer for Origin of $14.70 per share. Negotiations subsequently failed to reach agreement. On 24 June 2008, BG Group announced its intention to make a formal takeover offer for Origin at a price of $15.37[1] ("the BG Offer"). The BG Offer was made to shareholders on 4 August 2008 and remains open for acceptance until 26 September 2008. The directors of Origin have rejected the BG Offer as inadequate. BG Group announced on 9 September 2008 that in view of the ConocoPhillips Proposal it now intends to let its offer lapse on the closing date.

1.2 The ConocoPhillips Proposal

Overview

The ConocoPhillips Proposal has two key features:

- ConocoPhillips will invest cash into the JV to acquire its 50% interest. In addition to an upfront payment, the cash payments will cover all of the budgeted development costs up to the Final Investment Decision ("FID") for the first LNG production line (or "train"). Further cash contributions will partly cover the construction costs of each of the four planned trains; and
- the 50/50 split across the key components of the value chain is intended to ensure complete alignment between Origin and ConocoPhillips and establish an economic incentive for the parties to pursue full development of the JV's CSG reserves.

The JV will be structured as an incorporated JV with Origin Energy CSG Limited ("OECSG") being the joint venture entity. OECSG, which is currently a wholly owned subsidiary of Origin, will hold all of Origin's CSG assets including permits, wells, gathering systems, processing facilities and existing wholesale gas supply contracts comprising Origin's internal commitments (such as gas to be supplied to Darling Downs Power Station) and gas sales agreements with third parties totalling 2,200 PJ ("the CSG Assets").

Origin will remain as operator of the upstream CSG Assets (on a cost recovery basis) and will be responsible for the marketing of domestic gas including ramp up gas that may be produced in the development phase of the project. In this regard, the JV can require Origin to purchase up to 150PJ of ramp up gas during the period 1 January 2011 to 31 December 2014.

Under the ConocoPhillips Proposal, the JV will develop and manage an LNG plant with ConocoPhillips as operator. The long term objective of the JV will be to establish a four train LNG plant (with the first two trains planned for 3.5Mtpa each), with a target FID date for the first LNG train of December 2010. The parties have committed to an agreed budget for the JV of approximately A$2.3 billion which covers pre-first FID expenditures. The JV will be responsible

[1] Adjusted for the payment of Origin's final dividend of 13 cents on 3 October 2008.

for marketing and shipping the LNG volumes produced, with ConocoPhillips to lead these activities.

Consideration

The consideration for ConocoPhillips' investment in the JV includes fixed and contingent components:

- an upfront amount of US$5.0 billion will be paid by ConocoPhillips on completion ("the Initial Contribution"). On paying the Initial Contribution, ConocoPhillips will receive new partly paid shares in OECSG which will comprise 50% of the shares on issue of the enlarged share capital;
- additional contributions to the JV totalling A$2.3 billion to cover the development costs up to FID. Of this amount, $1.15 billion is contributed by ConocoPhillips to carry Origin's share of these development costs ("Development Cost Contribution"). These amounts will be payable by way of cash calls to fund the JV's budgeted expenditure on the development of the upstream and downstream assets for the period from completion until FID for the first LNG train, expected to be December 2010. To the extent that total expenditure exceeds A$2.3 billion, each partner will be required to contribute its 50% share; and
- four contingent sums of US$1.0 billion each to be contributed to the JV at the time of FID for each of the four planned LNG trains ("the Contingent Contributions") to partly cover the construction costs. Of this amount, US$500 million represents a carry of Origin's share of this contribution. The timing of FID for the first two trains is currently expected to be December 2010 and September 2011.

Governance and Transferability

The JV and the relationship of the parties are set out in a suite of agreements, the principal of which is a shareholder agreement between ConocoPhillips and Origin, which govern the ownership, operation, control and financing of OECSG. In terms of governance and control, the key elements are:

- each party will appoint two directors to the OECSG board;
- decisions are to be made by a majority of 75%; and
- ConocoPhillips will appoint a Project Director to be responsible for the management and administration of the JV and Origin will appoint the Chief Financial Officer to be responsible for the financial management. A steering committee including the Project Director, Chief Financial Officer and an equal number of representatives from Origin and ConocoPhillips will advise and support the Project Director as required.

The transaction agreements also provide for knowledge sharing between the parties and for interchange of personnel in each element of the supply chain. A detailed procedure for the development of the LNG plant is set out and a proposal must be submitted to the board of the JV for approval by 31 December 2010. The agreement also provides for where such requirement is not met, including extending the submission date by a further 12 months.

The agreement includes restrictions on transfers of shares in the JV. Where either shareholder wishes to transfer its interest in the JV, the following restrictions apply:

- a shareholder may only transfer a minimum of 10% of its interest and must hold at least 10% post transfer (other than where it sells all of its shares);
- a transferee of an interest of less than 25% must be capable of discharging financial obligations under the transaction agreements; and
- where the transferee is to acquire a 25% or greater interest, the transferee must be both technically competent and capable of discharging financial obligations under the transaction agreements. In addition, the transferring shareholder must ensure arrangements are put in place as to secondments and the transfers of operatorship that are acceptable to the other

shareholders prior to any transfer, otherwise the transferee must retain existing operatorships of the JV.

Where Origin disposes of its shares in the JV, it must assign the outstanding balance (if any) of the interest free loan to the acquirer of its shares in the JV. The same obligation applies to the debt owed by the acquirer of the shares to the JV until repaid in full.

The agreements also include normal pre-emptive rights which apply where one partner has received a bona fide third party offer for all or part of its interest in the JV, other than where a change of control occurs (as defined in the agreement). These include standard provisions requiring the seller to first offer the shares to the other partner at the same price.

There are also restrictions on either shareholder disposing of its interest (directly or indirectly held) in the JV to a third party which would effect a "change of control". A "change of control" occurs where a subsidiary of Origin or ConocoPhillips, which is a holding company for its respective interest in the JV, ceases to be a subsidiary. If that event occurs, the relevant JV shareholder will be required to offer its shares in the JV to the other JV shareholder(s) on a pro rata basis at a price determined by an independent valuer. A change of control resulting from the acquisition of securities which are traded on a relevant securities exchange will not be considered a change of control for this purpose. These rights are the same for both parties.

The agreement also sets out certain consequences that follow where a "control transaction" (as defined in the agreement) occurs in relation to Origin (but not ConocoPhillips). A "control transaction" includes where:

- Origin becomes a subsidiary of another entity;
- another entity acquires a relevant interest in more than 50% of Origin shares;
- Origin ceases to have a majority of its shares traded on a financial market, such as the Australian Securities Exchange ("ASX"), other than as a result of a trading halt under the ASX Listing Rules; or
- a transaction or transactions result in another entity acquiring more than 50% of Origin shares and gaining a right to control the composition of the Origin Board.

If any of these events occur, ConocoPhillips will have the right but not the obligation to step into Origin's role as operator of the upstream CSG assets, its CSG marketing role and as corporate services provider to the JV. In addition, ConocoPhillips will also have the right but not the obligation to require Origin to repay to the JV any amounts outstanding under the interest free loans. However, Origin will retain its equity interest in the JV, its right to appoint half the JV board and have a veto right in relation to decisions at the JV level and in relation to the approval of budgets. This right to take over operatorship excludes change of control events arising from certain restructuring events (e.g. such as a demerger), provided there is a substantial continuation of existing management, two thirds of non-executive directors remain on the Board and the company continues to have a majority of its ordinary shares traded on a financial market.

Conditions Precedent

The proposal is conditional on approval by the Treasurer under the Foreign Acquisitions and Takeovers Act 1975 and on an ordinary resolution of the shareholders of Origin to approve the entry into and completing of the ConocoPhillips Proposal (unless this second condition is waived or is deemed to be satisfied if the BG Offer lapses).

Post Implementation Fund Flows

The Initial Contribution will be repatriated to Origin through a combination of return of capital, repayment of intercompany loans and new interest free loans to Origin. The return of capital component will be a taxable amount to Origin. Origin will not have to make any payments in relation to its 50% interest except to the extent additional capital is required (e.g. pre FID cost overruns, LNG train construction costs above US$1 billion) for which both parties will contribute on a 50/50 basis. Contributions made by Origin to the JV will be applied toward repayment of the interest free loan, which it is expected would not occur before 2011.

Origin has announced that, following completion of the transaction, Origin intends to undertake a $1.5 billion capital management program which will comprise an immediate payment of an additional dividend of 25 cents per share fully franked (approximately $225 million) and an on-market buyback of shares of up to $1.275 billion.

1.3 Information on ConocoPhillips

ConocoPhillips is an international integrated energy company based in Houston, Texas in the United States with operations in nearly 40 countries in the petroleum, natural gas, chemicals and plastics industries.

ConocoPhillips has extensive oil and gas reserves and ranks sixth amongst the non-government controlled companies in terms of worldwide proved reserves and is the fifth largest refiner worldwide. In 2007, total year production was almost 700MMboe, with natural gas accounting for over half of this production. As at 31 December 2007, ConocoPhillips had total worldwide developed and undeveloped proved reserves of 10.6 billion Boe (excluding Syncrude), of which 51% comprised crude oil, 42% natural gas and 7% natural gas liquids.

ConocoPhillips has approximately 33,100 employees. In 2007, ConocoPhillips had revenues of US$187 billion, net income of US$12 billion and net operating cash flows of $US25 billion. As at 30 June 2008, ConocoPhillips had total assets of US$190 billion and net assets of US$97 billion. The company is listed on the New York Stock Exchange and as at 5 September 2008 had a market capitalisation of approximately US$115 billion.

ConocoPhillips has four principal business lines worldwide:

- **Exploration and Production:** which explores for, produces, transports and markets crude oil, natural gas and natural gas liquids worldwide. It holds a combined 68.5 million net developed and undeveloped acres in 23 countries and produced hydrocarbons in 16 countries, with proved reserves in three additional countries. Bitumen is also extracted from oil sands deposits in Canada and upgraded into synthetic crude oil;
- **Refining and Marketing**: which refines crude oil and other feedstocks into petroleum products and markets and transports them. It has operations in the United States, Europe and the Asia Pacific region, including interests in 12 United States refineries and five refineries outside the United States, with net crude oil processing capacity of nearly 2.7MMbpd globally. ConocoPhillips is the second largest refiner in the United States and the fifth largest non government controlled refiner internationally;
- **Midstream**: which gathers natural gas, processes it to extract natural gas liquids, and sells the remaining residue gas to electrical utilities, industrial users and marketing companies primarily in the United States and Trinidad. The Midstream business consists of a 50% interest in DCP Midstream, LLC (a 50/50 joint venture with Spectra Energy) and other assets located predominantly in North America. Approximately 40% of ConocoPhillips' total gas production comes from the Fruitland Coals fields in the San Juan Basin with interests in over 13,000 wells (of which nearly 10,000 wells are operated by ConocoPhillips), producing 1.25PJ per day and a drilling program of 350 new operated wells per annum; and
- **Chemicals:** ConocoPhillips has a 50/50 joint venture with Chevron Corporation (Chevron Phillips Chemical Company LLC) which produces a range of plastics: olefins and polyolefins and specialty products, including chemicals, catalysts and high performance polymers and compounds. Major production facilities are located in the United States, Puerto Rico, Belgium, China, Saudi Arabia, Singapore, South Korea and Qatar.

ConocoPhillips' other assets include a 20% ownership in LUKOIL, an international, integrated oil and natural gas company headquartered in Russia.

2 Scope of the Report

2.1 Purpose of the Report

There is no requirement for an independent expert's report pursuant to the Corporations Act, 2001 ("Corporations Act") or the ASX Listing Rules in relation to the ConocoPhillips Proposal. However, the directors of Origin have engaged Grant Samuel & Associates Pty Limited ("Grant Samuel") to prepare an independent expert's report setting out whether, in its opinion, the ConocoPhillips Proposal is in the best interests of Origin shareholders and to state reasons for that opinion. The report will also have regard to whether the BG Offer is fair and reasonable. A copy of the report will accompany either an Explanatory Memorandum to be sent to shareholders by Origin ("the Explanatory Memorandum") or a Supplementary Target's Statement to be sent to shareholders by Origin ("the Supplementary Target's Statement").

This report is general financial product advice only and has been prepared without taking into account the objectives, financial situation or needs of individual Origin shareholders. Accordingly, before acting in relation to their investment, shareholders should consider the appropriateness of the advice having regard to their own objectives, financial situation or needs. Shareholders should read the Explanatory Memorandum or Supplementary Target's Statement issued by Origin in relation to the ConocoPhillips Proposal.

It is a matter for individual shareholders as to whether to buy, hold or sell shares in Origin. This is an investment decision upon which Grant Samuel does not offer an opinion. Shareholders should consult their own professional adviser in this regard.

2.2 Basis of Evaluation

The term "in the best interests" arises under Part 3 of Schedule 8 to the Corporations Regulations which prescribes the information to be sent to shareholders in relation to schemes of arrangement pursuant to Section 411 of the Corporations Act. Schemes of arrangement pursuant to Section 411 can encompass a wide range of transactions. Accordingly, "in the best interests" must be capable of a broad interpretation to meet the particular circumstances of each transaction. However, there is no legal definition of the expression "in the best interests".

The Australian Securities & Investments Commission ("ASIC") has issued Regulatory Guide 111 which establishes guidelines in respect of independent expert's reports. ASIC Regulatory Guide 111 differentiates between the analysis required for control transactions and other transactions. In the context of control transactions (whether by takeover bid, by scheme of arrangement, by the issue of securities or by selective capital reduction or buyback), it comments on the meaning of "fair and reasonable" and continues earlier regulatory guidelines that created a distinction between "fair" and "reasonable". A proposal that, under takeover analysis, was "fair and reasonable" or "not fair but reasonable" would be in the best interests of shareholders. For most other transactions the expert is to weigh up the advantages and disadvantages of the proposal for shareholders. This involves a judgement on the part of the expert as to the overall commercial effect of the transaction, the circumstances that have led to the proposal and the alternatives available. The expert must weigh up the advantages and disadvantages of the proposal and form an overall view as to whether the shareholders are likely to be better off if the proposal is implemented than if it is not.

In Grant Samuel's opinion, the ConocoPhillips Proposal is not a control transaction and therefore the most appropriate basis on which to evaluate the ConocoPhillips Proposal is to assess the overall impact on the shareholders of Origin and to form a judgement as to whether the expected benefits outweigh any disadvantages and risks that might result.

In forming its opinion as to whether the ConocoPhillips Proposal is in the best interests of Origin shareholders, Grant Samuel has considered the following:

- whether the value effectively being paid by ConocoPhillips for its 50% interest in the JV represents fair market value;
- the strategic rationale for the ConocoPhillips Proposal;

- the impact on Origin's business and financial position;
- the impact on ownership and control of Origin;
- any other advantages and benefits arising from the ConocoPhillips Proposal;
- the costs, disadvantages and risks of the ConocoPhillips Proposal; and
- alternatives available to shareholders.

2.3 Sources of the Information

The following information was utilised and relied upon, without independent verification, in preparing this report:

Publicly Available Information

- the Replacement Bidder's Statement dated 30 July 2008 from BG Group;
- the Target's Statement dated 19 August 2008 by Origin in relation to the BG Offer ("the Target's Statement");
- annual results announcements for Origin and Contact Energy for the year ended 30 June 2008;
- annual reports of Origin and Contact Energy for the six years ended 30 June 2008;
- press releases, public announcements, media and analyst presentation material and other public filings by Origin and Contact Energy including information available on their websites;
- brokers' reports and recent press articles on Origin, Contact Energy and the energy sector;
- sharemarket data and related information on Australian and New Zealand listed companies engaged in the energy sector and on acquisitions of companies and businesses in this sector; and
- information relating to the Australian, New Zealand and international energy sectors including supply/demand forecasts and regulatory decisions and pronouncements (as appropriate).

Non Public Information provided by Origin

- management accounts for Origin for the period from 1 July 2004 to 30 June 2008;
- budget for Origin for the year ending 30 June 2009;
- detailed cash flow models including projections for Origin's Australian business operations;
- documentation in relation to the CSG Monetisation Process including summary material provided to bidders;
- bid documents and transaction documents for the ConocoPhillips Proposal; and
- other confidential documents, board papers, presentations and working papers.

In preparing this report, representatives of Grant Samuel visited the corporate and Brisbane offices of Origin. Grant Samuel has also held discussions with, and obtained information from, senior management of Origin and its advisers.

Grant Samuel was not given access to non public information (including financial and operational information) for Contact Energy and no discussions were held with the senior management of Contact Energy.

Grant Samuel has held no discussions with representatives of ConocoPhillips.

2.4 Limitations and Reliance on Information

Grant Samuel believes that its opinion must be considered as a whole and that selecting portions of the analysis or factors considered by it, without considering all factors and analyses together, could create a misleading view of the process underlying the opinion. The preparation of an opinion is a complex process and is not necessarily susceptible to partial analysis or summary.

Grant Samuel's opinion is based on economic, sharemarket, business trading, financial and other conditions and expectations prevailing at the date of this report. These conditions can change significantly over relatively short periods of time. If they did change materially, subsequent to the date of this report, the opinion could be different in these changed circumstances.

This report is also based upon financial and other information provided by Origin and its advisers. Grant Samuel has considered and relied upon this information. Origin has represented in writing to Grant Samuel that to its knowledge the information provided by it was complete and not incorrect or misleading in any material aspect. Grant Samuel has no reason to believe that any material facts have been withheld.

The information provided to Grant Samuel has been evaluated through analysis, inquiry and review to the extent that it considers necessary or appropriate for the purposes of forming an opinion as to whether ConocoPhillips Proposal is in the best interests of Origin shareholders. However, Grant Samuel does not warrant that its inquiries have identified or verified all of the matters that an audit, extensive examination or "due diligence" investigation might disclose. While Grant Samuel has made what it considers to be appropriate inquiries for the purposes of forming its opinion, "due diligence" of the type undertaken by companies and their advisers in relation to, for example, prospectuses or profit forecasts, is beyond the scope of an independent expert. In this context, Grant Samuel advises that:

- it was not given access to non public information (including financial and operational information) for Contact Energy; and
- it is not in a position nor is it practicable to undertake its own "due diligence" investigation of the type undertaken by accountants, lawyers or other advisers.

Accordingly, this report and the opinions expressed in it should be considered more in the nature of an overall review of the anticipated commercial and financial implications rather than a comprehensive audit or investigation of detailed matters.

An important part of the information used in forming an opinion of the kind expressed in this report is comprised of the opinions and judgement of management. This type of information was also evaluated through analysis, inquiry and review to the extent practical. However, such information is often not capable of external verification or validation.

Preparation of this report does not imply that Grant Samuel has audited in any way the management accounts or other records of Origin. It is understood that the accounting information that was provided was prepared in accordance with generally accepted accounting principles and in a manner consistent with the method of accounting in previous years (except where noted).

Gaffney, Cline & Associates Pty Ltd ("Gaffney Cline") was appointed as technical specialist to review the conventional oil and gas assets of Origin for Grant Samuel. Gaffney Cline's review included a review of the reserves, development plans, production schedules, operating costs, capital costs, potential reserve extensions and exploration activities. Gaffney Cline also prepared valuations of Origin's exploration interests. The report prepared by Gaffney Cline is attached to and forms part of this report.

The information provided by Origin to Grant Samuel included:

- the budget for Origin for the year ending 30 June 2009 ("2009 Budget") prepared by management and adopted by the directors of Origin;

- cash flow models for Origin's Australian business operations for the period commencing 1 July 2008. These models were prepared by Origin management and its financial advisers. The models were based on the 2007 Five Year Strategic Plan for Origin (which was prepared in November 2007) as adjusted by Origin management to allow for changes since the date of preparation as reflected in underlying asset models used within the business; and
- development plans for Origin's major conventional oil and gas assets.

Origin is responsible for the information contained in the 2009 Budget, the cash flow models and the development plans ("the forward looking information"). Grant Samuel has (together with Gaffney Cline in relation to the development plans) considered and, to the extent deemed appropriate, relied on this information for the purposes of their analysis. In the case of certain conventional oil and gas assets, Gaffney Cline has recommended that Grant Samuel adopt assumptions regarding production profiles, operating costs, capital costs and other matters that are different to those used in the forward looking information provided by Origin. In relation to the cash flow models Grant Samuel has made adjustments to reflect its judgement on certain matters and to ensure consistent application of assumptions. The major assumptions underlying the forward looking financial information were reviewed by Grant Samuel in the context of current economic, financial and other conditions. It should be noted that the forward looking financial information and the underlying assumptions have not been reviewed (nor is there a statutory or regulatory requirement for such a review) by an investigating accountant for reasonableness or accuracy of compilation and application of assumptions. However, the cash flow models were independently reviewed for Origin by a third party for mathematical accuracy.

Subject to these adjustments and limitations, Grant Samuel considers that, based on the inquiries it has undertaken and only for the purposes of its analysis for this report (which do not constitute, and are not as extensive as, an audit or accountant's examination), there are reasonable grounds to believe that the forward looking financial information has been prepared on a reasonable basis. In forming this view, Grant Samuel has taken the following factors, inter alia, into account that:

- the 2007 Strategic Plan was endorsed by the Directors of Origin;
- the 2009 Budget has been adopted by the Directors of Origin;
- Origin has sophisticated management and financial reporting processes. The prospective financial information has been prepared through a detailed budgeting process involving preparation of "ground up" forecasts by the management and is subject to ongoing analysis and revision to reflect the impact of actual performance or assessments of likely future performance;
- Origin has a history of meeting its annual budgets; and
- senior management of Origin (including management from the Australian operating businesses) were responsible for the development of the long term cash flow models in conjunction with Origin's financial advisers. Furthermore, the cash flow models were independently reviewed for Origin by a third party.

While Origin has made guidance statements that it is targeting an increase in underlying earnings per share of at least 10% in the year ending 30 June 2009, the directors of Origin have decided not to include the 2009 Budget or the longer term cash flow projections in the Target's Statement or in either the Explanatory Memorandum or the Supplementary Target's Statement (as applicable) and therefore neither the 2009 Budget nor the cash flow model have been disclosed in this report.

Grant Samuel has no reason to believe that the forward looking information reflects any material bias, either positive or negative. However, the achievability of the 2009 Budget and the cash flow models is not warranted or guaranteed by Grant Samuel. Future profits and cash flows are inherently uncertain. They are predictions by management of future events that cannot be assured and are necessarily based on assumptions, many of which are beyond the control of the company or its management. Actual results may be significantly more or less favourable.

As part of its analysis, Grant Samuel has reviewed the sensitivity of net present values to changes in key variables. The sensitivity analysis isolates a limited number of assumptions and shows the impact of the expressed variations to those assumptions. No opinion is expressed as to the probability or otherwise of those expressed variations occurring. Actual variations may be greater or less than those modelled. In addition to not representing best and worst outcomes, the sensitivity analysis does not, and does not purport to, show the impact of all possible variations to the business model. The actual performance of the business may be negatively or positively impacted by a range of factors including, but not limited to:

- changes to the assumptions other than those considered in the sensitivity analysis;
- greater or lesser variations to the assumptions considered in the sensitivity analysis than those modelled; and
- combinations of different assumptions may produce outcomes different to those modelled.

In forming its opinion, Grant Samuel has also assumed that:

- matters such as title, compliance with laws and regulations and contracts in place are in good standing and will remain so and that there are no material legal proceedings, other than as publicly disclosed;
- the information set out in the Target Statement and the Explanatory Memorandum or Supplementary Target's Statement sent by Origin to its shareholders is complete, accurate and fairly presented in all material respects;
- the publicly available information relied on by Grant Samuel in its analysis was accurate and not misleading;
- the ConocoPhillips Proposal will be implemented in accordance with its terms; and
- the legal mechanisms to implement the ConocoPhillips Proposal are correct and will be effective.

To the extent that there are legal issues relating to assets, properties, or business interests or issues relating to compliance with applicable laws, regulations, and policies, Grant Samuel assumes no responsibility and offers no legal opinion or interpretation on any issue.

3 Overview of the Australian Energy Industry

3.1 Overview

World energy consumption has increased by an average of 2.2% per annum since 1997[2]. Most of the world's energy requirements are met from five major energy sources (oil, coal, natural gas, nuclear and hydroelectricity) although renewable sources of energy are increasing in importance. Coal has experienced the highest rate of growth since 1997 (3.2% per annum) followed by natural gas (2.7% per annum). Oil is the leading energy source in all world regions except Asia Pacific where coal dominates and Europe/Eurasia where the leading fuel is natural gas.

Recent years have seen high and volatile world energy prices signifying shifting supply and demand conditions and changing geopolitical risks. Furthermore, the threat of climate change has moved to the top of the international policy agenda and is strong factor in energy market dynamics. High prices for fossil fuels combined with political interest in climate change (given the level of carbon emissions associated with oil and coal) has increased demand for natural gas as an energy fuel source and encouraged the rapid growth of renewable energy sources.

The Asia Pacific region accounts for over 34% of world energy consumption with average growth over the last 10 years of 4.4% per annum. Although the major fuel sources in the Asia Pacific region continue to be coal and oil, natural gas has experienced the fastest rates of growth albeit off a relatively low base. Chinese demand is the major driver in the Asia Pacific region accounting for nearly 50% of energy consumption in the region (and over 16% of world consumption). Chinese consumption has increased by around 6.8% per annum since 1996 accounting for around 40% of all world growth in that period.

Energy consumption in Australia has grown at an average rate of 1.7% per annum over the last ten years. The trends being experienced in Australia are consistent with international trends with growth in the consumption of natural gas and energy from renewable sources primarily at the expense of oil. Energy consumption in Australia is expected to continue to grow in the foreseeable future (by 1.6% per annum to 2030 but at a higher rate of 2.2% per annum in the shorter term to 2012) driven by a number of factors including general economic growth, population growth, growth in new housing, increasing installation and usage of air conditioners and other electrical appliances.

Since 2000 consumption of electricity on the east coast of Australia has grown at an average of 3.4% per annum (with Queensland having the highest rate of growth at 4% per annum) largely as a consequence of increased demand from the commercial and industrial segments. Electricity consumption is expected to continue to grow in the foreseeable future with Queensland to show the strongest growth. As electricity generation utilises approximately 35% of the natural gas produced in Australia, the consumption of gas is also expected to continue to grow.

The remainder of this section of the report provides an overview of the segments of the energy industry and the regulatory environment in Australia. A description of the New Zealand energy industry is set out in Section 8 on Contact Energy.

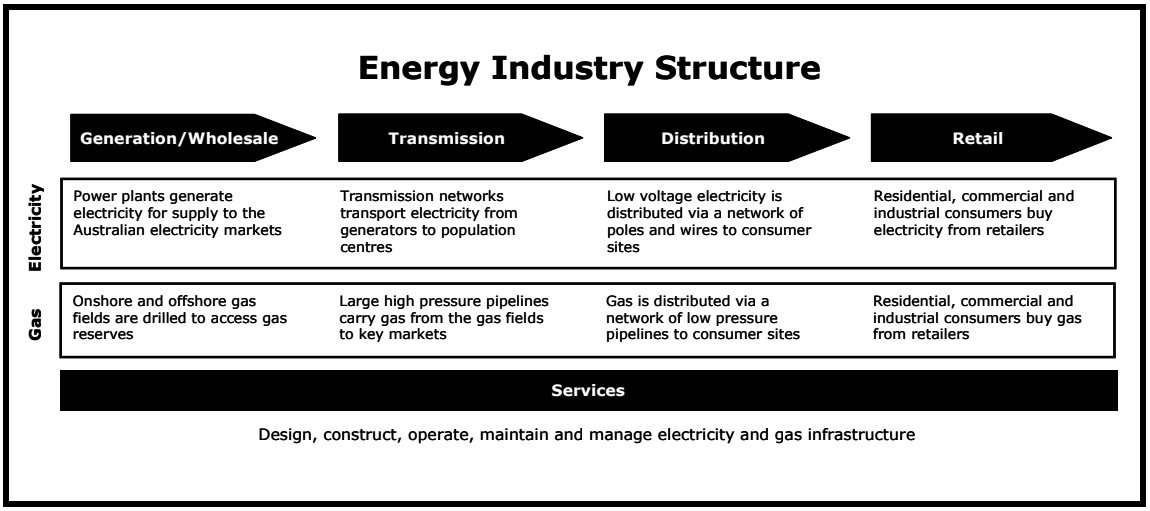
3.2 Segments and Services

In summary, the segments of, and services to, the energy industry can be depicted as follows:

---

[2] Information in this report on the energy industry is from a wide range of sources. The major sources of statistical data are:

- historical energy consumption data from *BP Statistical Review of World Energy June 2008* and forecast Australian energy consumption data from ABARE Research Report 07.24 *"Australian Energy: National and State Projections to 2029-30"*.
- historical Australian electricity consumption data from Australian Energy Regulator, *"State of the Energy Market 2007"* and forecast Australian electricity generation demand from National Electricity Market Management Company Limited *"Australia's National Electricity Market, Statement of Opportunities 2007"*.



Source: Grant Samuel

3.3 Regulatory Environment

Historically, Australia's energy sector comprised state based enterprises. It is only in recent decades that, as a consequence of economic and legislative changes, the energy sectors have become more integrated. However, as the management of energy resources, production and supply of energy and stability of energy markets are critical to the economy, the energy sector has historically been the subject of substantial regulation. The regulatory environment is currently undergoing reform.

On 30 June 2004, the Australian Government and each of the states and territories agreed to redesign the regulatory functions for the energy sector and establish two new national regulatory bodies: the Australian Energy Market Commission ("AEMC"), responsible for rule making and market development, and the Australian Energy Regulator ("AER"), responsible for monitoring and regulating electricity and gas transmission and distribution networks and retail markets[3].

The AER is part of the Australian Competition and Consumer Commission ("ACCC") and its formation has drawn on experienced regulatory personnel from both the ACCC and the state based regulators. Regulation of electricity and gas transmission networks was handed over to the AER during 2005, regulation of electricity distribution networks was handed over to the AER in January 2008 and legislation enabling regulation of gas distribution networks by the AER has yet to be enacted (except in relation to the Northern Territory). Western Australia has currently opted not to transfer regulatory responsibility for its energy markets to the AER. It is expected that the AER will be the sole regulator for the electricity and gas industries in the eastern and southern states and for the gas industry in the Northern Territory by 2010.

3.4 Electricity Sector

Generation and Wholesale

Electricity is generated by energy extracted from sources such as coal and gas combustion, nuclear fission, running water and wind. In 2006/07 93% of electricity in Australia was generated from fossil fuels (with heavy reliance (81%) upon coal) and 7% from renewable sources (including hydro, wind, biomass, biogas and solar). The most common forms of electricity generation in Australia are compared below:

[3] Energy sector reform is continuing and in April 2007 it was agreed to establish an industry funded National Energy Market Operator for both electricity and gas by 2009. The new body will replace certain functions of NEMMCO (i.e. National Electricity Market Management Company Limited) and the gas market operators and undertake a national transmission planning role.

Major Generation Types in Australia[4]

Type	Capital Cost	Operating Cost	Time Start	Carbon Intensity	Operator Control	Optimal Operation
Coal	High	Low	Slow	High	High	Base load
OCGT[5]	Low	High	Fast	Medium	High	Peaking/ Intermediate
CCGT[6]	Medium	Medium	Medium-Fast	Low	High	Base load
Hydro	High	Low	Fast	-	Medium	Dependent on water source
Wind	High	Low	Weather Dependent	-	Low	Suitable for standalone application

Source: AER and Origin

Base load generators are used to meet minimum levels of demand and operate continually at close to maximum capacity, intermediate generators generally switch off during periods of low demand and peaking plants generally operate for short periods only during periods of peak demand. Different types of generators are more suited to meeting base load than peak demand. For example, coal and CCGT generators have high initial investment costs, relatively low operating costs (due to the relatively low cost non renewable fuel sources) and take a long time (and cost) to start up (up to 48 hours) and therefore are more suited to operating continually at close to maximum capacity to meet minimum (or base) levels of demand. On the other hand, OCGT generators have low capital costs, higher operating costs and can be started relatively quickly (in around 20 minutes) and are more suited to meeting peak demand. Hydro generators can have the fastest start up times (e.g. five minutes) but availability and capacity is dependent on water resources. Wind generation has a high initial cost but is dependent on weather conditions.

Prior to industry reforms in the 1990s, the Australian electricity sector generally consisted of state owned, vertically integrated electricity enterprises. During the 1990's a number of states disaggregated these enterprises with a view to establishing competitive generation and retail sectors and regulated (price and access) monopoly transmission and distribution network assets. Generation assets in Victoria and South Australia are now fully privatised while private ownership of generation capacity exists to varying degrees in Queensland, New South Wales and Western Australia as a result of privatisations and the development of new generation capacity. The major non government owners of generation assets in Australia include AGL Energy Limited ("AGL Energy"), TRUenergy Limited ("TRUenergy") (which is owned by Hong Kong listed CLP Holdings Limited), Origin, Babcock & Brown Power ("BBP") and International Power plc ("International Power"). The New South Wales Government has announced plans for the potential privatisation of certain of its electricity generators including Eraring Energy, Macquarie Generation and the Delta Electricity.

Since the 1990's Victoria, New South Wales, the Australian Capital Territory, South Australia, Queensland and Tasmania progressively established an interconnected National Electricity Market ("NEM") which has resulted in the formation of a competitive wholesale spot market. The NEM has a total installed generation capacity (excluding wind) of in excess of 40,000MW. Energy in the NEM is primarily transacted through the wholesale spot market. As electricity must be produced on demand, the electricity spot market is volatile, with price spikes occurring during intraday peak demand, seasonal peaks, supply interruptions and due to extreme weather conditions. For example, in June 2007, electricity spot prices increased in all states as a result of drought conditions in Victoria and Queensland with prices increasing to over $5,000 per MWh on 42 occasions in that month. As a consequence, market participants manage price risk through bilateral contracts and derivative instruments and by increasing the level of vertical integration thereby taking advantage of a natural hedge.

Western Australia and the Northern Territory are not expected to join the NEM in the near future due to geographical and physical constraints. Two electricity markets have developed in Western Australia. The Western Australian Wholesale Electricity Market ("WEM") encompasses a region bounded by Kalbarri in the north of Western Australia, Kalgoorlie in the east and Albany in the south (i.e. including the major centres of Perth, Geraldton, Bunbury, Albany and Kalgoorlie). The electricity transmission and

4 Cogeneration is also common in Australia. However, it relates to the use of power plant to simultaneously generate electricity and heat typically for industrial purposes.

5 OCGT is open cycle gas turbine generation whereby compressed air produced by gas combusted in a chamber is used to directly drive the turbine without the use of steam.

6 CCGT is combined cycle gas turbine generation which is similar to OCGT but also harnesses the wasted heat in a boiler to produce steam which is subsequently used to drive an additional electric generator to produce electricity.

distribution systems that cover this area are interconnected and are known as the South West Interconnected System ("SWIS"). The SWIS has a total installed generation capacity of in excess of 4,000MW. The majority of energy traded within the SWIS is done via privately negotiated bilateral contracts with relatively little trading through the spot market. The SWIS market also features a "reserve capacity mechanism" under which retailers purchase capacity credits from the owners of generation capacity. This is designed to provide economic incentive for the construction of generation capacity.

In addition, an interconnected electricity grid has developed in the north west of Western Australia which has become known as the North West Interconnected System ("NWIS"). The NWIS was originally developed from a small number of resource company owned transmission systems and generators, with little coordination or optimisation and, in this regard, does not constitute a typical interconnected grid. There are also additional "island" generators that are owned by various resource companies. The NWIS has a total generation capacity of 412MW (approximately 824MW including "island" generators) and is operated by Horizon Power (a state government owned utility).

As Australia has considerable resources of low cost fuel for generation (i.e. coal and gas), prior to the 1990s governments in eastern Australia built substantial amounts of base load generation and therefore the eastern Australian electricity market has experienced relatively low electricity prices. The low prices were a disincentive to build additional generation capacity and, with demand for electricity increasing, the NEM is moving to a position of undercapacity (particularly to satisfy peak demand). Each state has different demand supply balances notwithstanding the interconnectivity of the NEM. Peak demand is expected to reach supply capacity in Queensland by 2009/10 (peak was, in fact, reached in 2007/08 due to drought conditions) and 2010/11 in Victoria and South Australia whereas this is not expected to occur in New South Wales until 2013/14. Across the NEM, an overall deficit to peak demand is expected to occur in 2011/12. Consequently, substantial new generation build (particularly peaking capacity) is required across the NEM with NEMMCO estimating that (excluding wind) generation capacity will need to increase by approximately 9,100MW (or around 1,000MW per annum) to almost 50,000MW by 2016/17. In comparison, it is expected that (other than in Queensland) base load capacity will be sufficient to meet demand over the next 10 years.

Announced committed projects are expected to contribute 6,230MW of both base and peak capacity over the next four years. These projects are predominantly gas fired generation. However, further build of new capacity will be required to meet forecast demand.

Transmission and Distribution

Electricity is transmitted via high voltage transmission lines to population centres where it is delivered to customers via local distribution networks. The transmission network of the NEM operates as a connected system (with high voltage interconnector cables running between states) whereas the transmission networks of the Northern Territory and Western Australia are isolated systems. In Australia, transmission lines are primarily owned by state government entities, except in Victoria where SP AusNet owns the electricity transmission network and South Australia where Spark Infrastructure Group ("Spark") leases and operates the electricity transmission network. In addition, three major interconnector cables are privately owned: DirectLink and Murraylink by APA Group and Basslink by CitiSpring Infrastructure Trust (a Singaporean listed investment trust). There is a greater proportion of private ownership of distribution networks with the major private owners being Diversified Utility and Energy Trusts ("DUET"), SP AusNet, Singapore Power International Pte Limited ("Singapore Power") (the 51% owner of SP AusNet) and Spark.

Electricity transmission lines and distribution networks are subject to substantial monitoring and economic regulation. Transmission line owners charge regulated tariffs to distributors, who in turn charge regulated tariffs to retailers and other wholesale electricity purchasers.

The regulatory regime provides for periodic reviews under which the regulator assesses the terms of network access proposed by the network operator and can approve or vary the terms. A "building block" approach is used by which tariffs in access arrangements are based on the estimated efficient costs of providing the services including operating and maintenance costs, depreciation and a return on assets calculated by reference to a weighted average cost of capital applied to a regulated asset base. This process determines an appropriate level of revenue for the asset, which is then used to fix transmission or distribution reference tariffs for the period. In this way, asset owners are incentivised to improve efficiency and thereby retain profits earned by outperforming the forecasts of costs and volumes on which

the regulatory tariffs were based. However, any change in demand or cost efficiency will be taken into account at the next regulatory review, potentially reducing the tariff.

Retailing

Retailers purchase electricity from the wholesale electricity markets and sell to residential, commercial and industrial customers. The retail tariff for electricity reflects the wholesale energy cost, transmission and distribution tariffs, the retailer's operating costs and a profit margin. As electricity is considered an essential service retail tariffs have historically been subject to a regulated cap reviewed at regular intervals. Although the approach differs between states, price regulation generally occurs when the state appoints an incumbent operator to contract with customers in a designated geographical area at standard terms and conditions, often at capped prices (e.g. based on benchmark costs) or with price oversight. Small consumers (residential and small business) would then be charged the standard tariff (which the retailer may set equal to or lower than the tariff cap) but larger consumers (commercial and industrial) would negotiate tariffs with the retailer.

Since 1995 the state and territory governments have progressively worked to establish a competitive national electricity market including the opening of the retail electricity market to competition (i.e. full retail contestability). The retail markets of New South Wales, the Australian Capital Territory, Victoria, South Australia and Queensland are now fully contestable (i.e. customers can choose which electricity retailer to use) and full retail contestability is being phased in in Tasmania. The Northern Territory and Western Australia have not yet implemented full retail contestability although the Northern Territory is planning for its introduction in 2010 and Western Australia is proposing a review of contestability in 2009. With the introduction of full retail contestability, the state governments are also moving towards removing retail price caps where effective competition (as assessed by AEMC) can be demonstrated. On this basis, price caps are to be removed in Victoria in 2008/09 and in South Australia in the near future.

State owned incumbent retailers still dominate the New South Wales and Tasmanian electricity retail markets while private retailers (including AGL Energy, Origin and TRUenergy) dominate the other states. Retail contestability has resulted in new segment entrants including established interstate electricity retailers, gas retailers branching into electricity retailing, generators seeking the benefits of vertical integration and new market players (e.g. Australian Power and Gas Company Limited ("APG")).

Vertical integration between electricity generators and retailers has evolved driven by the need for retailers and generators to manage the risk of price volatility in the electricity spot market. Integration provides a natural hedge against price volatility in the wholesale market by offsetting the complementary price risks faced by generators and retailers.

3.5 Gas Sector

Production and Wholesale

Australia has extensive reserves of natural gas. The two main types of natural gas used in Australia are conventional natural gas and coal seam methane gas ("CSG"). At January 2006 total proved and probable conventional gas reserves were around 40,200PJ with a contingent resource estimated to be around 97,800PJ. Current proved and probable CSG reserves are approximately 12,400PJ with a contingent resource estimated to be around 30,000PJ (although CSG resources are still being delineated).

All major gas producers/wholesalers supplying the Australian market are privately owned with Western Australia by far Australia's largest producer and exporter of natural gas. In the year ended 30 June 2008 total natural gas production was estimated to be 1,692PJ of which around 60% was consumed domestically with the balance exported to markets in Asia from Western Australia in the form of LNG. Domestic consumption of natural gas is forecast to continue to grow increasing from 19% of energy consumption to 24% by 2030 due to strong gas demand from electricity generation, the manufacturing and mining sectors and steady residential and business demand growth.

Wholesale gas prices are typically based on confidential fixed price contracts, normally including some adjustment for inflation or periodic price resets. Victoria operates a spot market in which approximately 5-10% of gas produced is traded. Wholesale gas supply and price are not subject to economic regulation.

The Australian natural gas production and wholesale sector is discussed in more detail in Section 5.2 of this report.

Transmission and Distribution

Large scale commercial gas usage in Australia commenced in the early 1970's and, as most Australian production fields are located in areas remote from major retail load centres, a high pressure pipeline infrastructure network was developed to bring gas to market. Gas distribution networks connect with the transmission system to distribute gas to the premises of residential, commercial and industrial customers. Large industrial users may connect directly to the high pressure transmission network.

Initially the major gas markets were supplied from single production basins via sole purpose monopoly pipelines. However, in the last 20 years, expenditure on pipeline infrastructure and the discovery of new gas reserves has seen the development of an integrated natural gas market in south east Australia and the extension of gas supply into Tasmania. Planning work is currently underway for a transmission pipeline to connect the transmission network in Queensland with those in the south east. The transmission network of the Northern Territory may eventually be connected to the eastern network via Queensland. Although Western Australia remains isolated from this integrated network, the development of its natural resources has led it to become the largest market for natural gas in Australia.

As a result of industry reforms over the last decade, all major gas transmission pipelines and the majority of gas distribution networks in Australia are now owned by the private sector. As transmission and distribution networks generally have natural monopoly characteristics, they are subject to a regulatory regime to ensure non discriminatory third party access. The major owners of Australian gas transmission pipelines include APA Group, Hastings Diversified Utilities Fund, DUET and Singapore Power. The major owners of Australian gas distribution networks include Singapore Power, DUET, APA Group and Envestra Limited ("Envestra").

The regulatory regime for natural gas transmission pipelines and distribution networks in Australia is detailed in the Gas Access Regime ("GAR") and is given effect by legislation in each state and territory enacting the National Third Party Access Code for Natural Gas Pipeline Systems ("Gas Code"). Regulatory responsibility for all gas transmission assets (except for Western Australia) was transferred to the AER in mid 2005. Legislation handing regulatory responsibility for gas distribution networks (except for Western Australia) to the AER during 2007 has yet to be enacted (except in relation to the Northern Territory).

Gas pipelines and networks can be "covered" or "uncovered" under the Gas Code according to the application of statutory criteria. Owners of covered pipelines must submit access arrangements (i.e. the provisions under which access to a pipeline can be granted) and periodic revisions to their arrangements for approval by regulators. Access arrangements generally include reference tariffs for the services to be offered and are approved for a period of time (typically five years) after which they are reviewed. In Queensland, however, pipeline tariffs have been derogated for a period and are not subject to review until the end of the derogation period applicable to the specific pipeline. Uncovered pipelines are free to determine prices and other terms and conditions on a commercial basis (subject to the general anti-competitive provisions of the Trade Practices Act, 1974).

Reference tariffs in access arrangements are based on a building blocks approach. Tariffs are based on estimated efficient costs of providing the services including operating and maintenance costs, depreciation and a return on assets calculated by reference to a weighted average cost of capital applied to a regulated asset base. Gas network owners are incentivised to improve cost efficiency and grow demand over each regulatory review period.

Retailing

Retailers purchase natural gas from suppliers (producers or wholesalers) and on sell it to residential, commercial and industrial customers. The retail price of gas represents the wholesale cost of gas, transmission and distribution tariffs, the retailer's operating costs and a profit margin. Retail tariffs have historically been subject to a regulated cap reviewed at regular intervals (usually annually). Although the approach differs between states, price regulation generally occurs when the state appoints an incumbent operator to contract with customers in a designated geographical area at standard terms and conditions, often at capped prices (e.g. based on benchmark costs) or with price oversight. Gas price regulation is generally considered more light handed than for electricity which may reflect that gas is often regarded as a fuel of choice rather than an essential service. In general, small consumers (residential and small

business) are charged the standard tariff (which the retailer may set equal to or lower than the tariff cap) however larger consumers (commercial and industrial) negotiate tariffs with the retailer.

In all states full retail contestability for gas has been implemented. To date no alternative retailer to the mass market has emerged in Western Australia although two state government owned retailers have applied for gas licences and are currently restricted from supplying gas to customers who consume less than 0.18 TJ per annum. The state governments are committed to the removal of retail price caps for gas where effective competition can be demonstrated. It has been determined that competition in both electricity and gas retailing in Victoria and South Australia is effective and it has been recommended that price regulation in Victoria cease from 1 January 2009 with the recommendation for South Australia due in 2008. Although no price cap structure has as yet been removed, it is expected that tariffs will increase over time to reflect increases in costs.

At April 2007 there were about 14 gas retailers (operating 30 licences) active in the mass market. In comparison, there were 21 electricity retailers to the mass market (operating 46 licences). The difference in activity reflects a range of factors including the market size, available profit margins and the barriers to entry created by finite pipeline capacity. Private retailers dominate the gas market in all states except Tasmania. The major retailers are private companies AGL Energy, Origin, TRUenergy, Simply Energy (owned by International Power) and Alinta (owned by BBP) and state owned entities EnergyAustralia, Integral Energy, Ergon Energy and Aurora Energy. Retail contestability for gas has resulted in new entrants in most markets including established interstate gas retailers, electricity retailers branching into gas retailing and new market players (e.g. APG). Although, investment in gas reserves provides a natural hedge against gas price rises and security of supply, there is little evidence of gas producers expanding into retailing. On the other hand, existing retailers such as AGL Energy and Origin have overtime acquired and/or developed significant gas reserves.

In recent years, there has been a trend for retailers to offer both electricity and gas (i.e. "dual fuel") accounts. This has been driven by cost saving opportunities through the sharing of billing, call centre, marketing and administrative overheads as well as the opportunity to attract and retain customers. There has been significant retail convergence in Victoria and South Australia where AGL Energy, Origin and TRUenergy jointly account for 90-95% of small electricity and gas customers. Convergence has created barriers to entry for new entrants who may need to offer a broader range of services or specialised product offerings (e.g. green products) to win customer share.

LPG

Liquefied petroleum gas ("LPG") is the generic name for mixtures of hydrocarbons (mainly propane and butane) which when lightly compressed change from a gaseous state to liquid. LPG burns readily in air and has energy content similar to petrol which makes it a good fuel for heating, cooking and automotive purposes. LPG occurs naturally in crude oil and natural gas production and is also produced in the oil refining process. There are two grades or blends of LPG and they are not interchangeable. One is for automotive use only (known as autogas) and the other is suitable for decanting into cylinders for domestic and recreational purposes. LPG is considered a clean fuel relative to petrol, coal and wood.

The Australian LPG industry began in the 1920s when LPG was shipped from the United States in cylinders with Australian production only beginning at the oil refineries in the 1950s. However, in the 1970s, with the development of the natural gas industry, LPG production increased with the majority of production exported. Subsequently, Australian domestic demand for LPG grew and today it is used as source of energy in areas where natural gas cannot be economically supplied (e.g. regional areas), for recreational purposes (e.g. barbeques, camping etc) and as an alternative automotive fuel.

During 2006/07 Australia produced 3,158Kt of LPG of which around 48% were exported mainly from Western Australia to Asia. Approximately 77% of production was naturally occurring (from Bass Strait, the Cooper Basin, Kwinana, the North West Shelf and the Surat Basin) with the balance from seven refineries (Bulwer Island and Lytton in Queensland, Clyde and Kurnell in New South Wales, Altona and Geelong in Victoria and Kwinana in Western Australia). Australian sales of LPG in 2006/07 were 2,147Kt of LPG of which approximately 58% was for automotive use. Due to the shortage of autogas in the eastern states and storage limitations (which means it is not cost effective for the Western Australian producers to ship LPG to the eastern states), Australia also imports LPG mainly from Saudi Arabia.

The marketing and distribution of LPG in Australia is a competitive market and there is no price or other

industry specific market regulation. The major distributors are Origin, Elgas Limited ("Elgas") (a joint venture between AGL Energy[7] and BOC Limited[8]) and Wesfarmers Kleenheat Gas Pty Limited ("Kleenheat") (a subsidiary of Wesfarmers Limited). Origin and Elgas operate nationally while Kleenheat primarily operates in Western Australia. In addition to price, competition is based on the ability to provide a reliable supply of LPG close to end markets. This requires an extensive distribution network (including import terminals, storage depots and regional depots) which creates significant barriers to entry.

LPG prices in Australia are closely linked to international prices as Australian producers have the option of exporting their production at world prices and because of the need to import autogas to meet the shortage in the eastern states. International prices for LPG sold in the Asia-Pacific region are based on the monthly Saudi Aramco Contract Price ("Saudi CP"). LPG producers and importers in Australia determine an Australian landed price based on the Saudi CP. Retail prices are based on this import cost plus distribution and marketing costs, overheads and wholesale and retail margins. Australian LPG and petrol prices move independently of each other as they are based on different international prices although, over time, LPG prices show a close correlation with crude oil prices. As such, LPG prices have risen substantially in recent years mirroring the increase in crude oil prices. In addition, demand for LPG tends to increase in the northern hemisphere winter which has a significant influence on price movements.

3.6 Climate Change Implications

The thermal power generation industry is a significant producer of carbon emissions. Accordingly, potential changes to regulations arising from government sponsored climate change initiatives will impact the energy industry.

In recent years, both the Australian and State governments have developed and implemented a number of energy sector and environmental initiatives to address the implications of climate change. These initiatives have led to the development of "green energy" markets which operate alongside the electricity markets. Existing government schemes include:

- **Mandatory Renewable Energy Target ("MRET")**: implemented by the Commonwealth Government in 2001 and requires wholesale purchasers of electricity to acquire renewable energy certificates ("RECs") from accredited renewable energy generators equal to a percentage of their annual electricity purchases. The scheme provides additional revenues for accredited renewable energy generators as retailers pay a market determined price for RECs to avoid paying penalties if they fail to meet their required renewable purchases. A separate market exists for the sale of RECs which can be sold separately from the underlying electricity. The scheme targets energy from renewable sources of 9,500GWh per annum by 2020. MRET has been retained and increased following the change of government at the November 2007 federal election (see below);
- **National Green Power Accreditation Scheme**: a voluntary renewable energy scheme developed by the New South Wales, Victoria, Queensland, South Australia and Australian Capital Territory governments to allow electricity retailers to purchase electricity from accredited green generators and charge higher prices to customers to reimburse the retailer for the cost of that green energy;
- **Greenhouse Gas Reduction Scheme**: implemented in New South Wales in 2003 and the Australian Capital Territory in 2005, this scheme imposes benchmarks on all electricity retailers and other liable parties to reduce the greenhouse gases from the production of electricity they supply or use. Retailers can offset the liability for their excess emissions with NSW Greenhouse Abatement Certificates ("NGACs"). These certificates are created for every tonne of carbon dioxide that is abated that would ordinarily have been produced. From a generator's perspective an ability to create NGACs represents an additional source of revenue. Parties who fail to meet their targets pay a penalty;
- **Queensland 13% Gas Scheme:** implemented in 2005 to ensure that 13% of Queensland's electricity requirements are sourced from gas fired generation. The target will increase to 15% in 2020. End users of electricity are obliged to purchase Gas Electricity Credits ("GECs") to cover

[7] AGL Energy has recently indicated its intention to sell its interest in Elgas.

[8] A subsidiary of Linde Group AG

13% of their energy usage. Gas fired generators located in Queensland are eligible to produce GECs provided they generate above an allocated baseline;

- **Low Emissions Technology Demonstration Fund ("LETDF"):** a $500 million fund established by the Commonwealth Government in 2005/06 to support the development of new energy technologies to deliver long term greenhouse gas emission reductions. The fund is to operate to 2020 and the initial round of funding was announced in 2007. Projects which received funding included a proposed 154MW solar concentrator power station in Victoria, a clean coal technology project and projects designed to capture and store carbon dioxide. Subsequent funding rounds expected in 2008/09 and 2012/13 subject to the outcomes of round one; and
- **Victorian Renewable Energy Target Scheme ("VRET**"): implemented by the Victorian Government in January 2007 and mandates that Victoria's consumption of electricity generated from renewable sources be increased to 10% by 2016. VRET imposes a legal liability on electricity retailers and wholesale buyers in Victoria to contribute to the generation of additional renewable energy and meet their obligations by acquiring renewable energy certificates ("VRECs"). Relevant entities are required to surrender VRECs in proportion to their acquisitions of electricity or pay penalties if they fail to meet their required renewable purchases. In 2006 the New South Wales Government proposed a renewable energy target scheme based on the VRET and legislation to that effect is currently with parliament.

The establishment of a national emissions trading scheme has been contemplated since 2004. Following the change of government at the November 2007 federal election, progress on the development of a national emissions trading scheme has accelerated and work has commenced to streamline the range of climate change related requirements facing business. In this regard, the new Commonwealth Government has commissioned the Garnaut Climate Change Review (the draft report was released on 4 July 2008 and a supplementary draft report released on 5 September 2008) ("the Garnaut Report") and on 16 July 2008 issued a Green Paper outlining its approach to the design of a national emissions trading scheme. Stakeholders have until 10 September 2008 to make submissions and it is expected that the Government will issue a White Paper reflecting its decisions and an exposure draft of legislation for the scheme by the end of 2008. In addition, in July 2008 the Council of Australian Governments Working Group on Climate Change and Water released design options for the Expanded National Renewable Energy Target Scheme based on a national mandatory renewable energy target of 20% by 2020.

The Commonwealth Government climate change position is based on commitments to reduce Australia's greenhouse gas emissions by 60% below 2000 levels by 2050, the need for the economy to adapt to climate change that cannot be avoided and to participate in the global response to climate change. Its major climate change initiatives that impact the energy sector are the introduction of:

- **a national emissions trading scheme (on a cap and trade basis) by 2010:** under such a scheme emitters will acquire a carbon pollution permit ("permit") for every tonne of greenhouse gas they emit and at the end of the year will need to surrender a permit for every tonne of emissions produced during that year. The number of permits issued by the Government in each year would be limited to the total carbon cap for the Australian economy. Firms would compete to purchase the number of permits they require. Those which value the permits most highly will be prepared to pay the most for them either at the permit auctions or on a secondary trading market. For other firms it will be cheaper to reduce emissions than to buy permits. Certain categories of business might receive some permits free (as a form of transitional assistance) to use or sell.

  The design of the scheme and key abatement targets will not be finalised until late 2008. This creates significant uncertainty for business. However, it is likely that a target reducing emissions by least 10% below 2000 levels by 2020 may be established. In a report for the Energy Supply Association of Australia, ACIL Tasman Pty Ltd ("ACIL Tasman") has estimated that a permit price starting at $20 per tonne of carbon in 2010 would need to rise rapidly to $45 and $55 per tonne to deliver reductions in emissions in the range of 10% to 20% over 2000 levels[9]. The Garnaut Report recommends a 10% reduction in emissions over 2000 levels and suggests that to achieve that target, permits would be sold at prices starting at $20 per tonne in 2010, rising each year at inflation plus 4%. Assuming inflation of 3% this implies a price for permits of $39 in 2020.

[9] ACIL Tasman Pty Ltd, *"The Impact of an ETS on the Energy Supply Industry"*, 23 July 2008.

- **a 20% mandatory renewable energy target by 2020:** this national renewable energy target scheme ("NRET") will ensure that at least 20% of Australia's electricity supply is generated from renewable sources by 2020 (i.e. an increase of approximately 45,000GWh-60,000GWh). It is proposed that the existing MRET and state based targets will be combined into a single scheme. The design of the NRET is expected to be finalised late 2008 and legislation enacted by mid 2009. It is expected that NRET will be phased out between 2020 and 2030 as emissions trading matures.

Both of these policy initiatives have substantial impacts on the energy sector. They will influence the level and type of new generation build, demand (and therefore prices) for fuel for generation purposes and the price of electricity and gas to end users.

Electricity generation accounted for around 35% of Australian carbon dioxide emissions in 2007. Consequently, an emissions trading scheme will impact the relative cost competitiveness of the different types of generation. Coal fired generators (in particular brown coal) have the highest carbon intensity (i.e. carbon output per unit of electricity generated), gas fired generators can produce half the carbon emissions of coal fired power stations and renewable generators produce no carbon emissions but typically have a higher build cost. As a result, gas fired generation is expected to be the major source of new capacity in the foreseeable future.

An emissions reduction target of between 10% and 20% is expected to result in the retirement or semi retirement (i.e. operation only in peak seasons of winter and summer) of existing coal fired generation plants as they become uneconomic as the cost of carbon increases[10]. This is expected to create additional demand for gas fired generation as, unless new renewable technologies (such as geothermal energy, clean coal, solar) are commercialised during the period, renewable energy sources are unlikely to be able to meet increased demand for energy (either base or peaking capacity).

The NRET will result in an increase in generation capacity from renewable sources (e.g. hydro and wind). However, as these energy sources are subject to environmental factors such as rainfall and wind, demand for additional peaking capacity is expected to increase and is likely to be satisfied by gas fired generation.

Consequently, it is expected that the demand for generation capacity from gas fired power stations in the NEM will increase above current estimates of 1,000MW per annum. This will increase the demand for gas for electricity generation purposes substantially.

[10] ACIL Tasman expects that between 2011 and 2020 the forced retirement of 6,645-10,425MW of base load coal generation capacity will result in total new build requirements of 13,700-16,500MW.

4 Profile of Origin Energy Limited

4.1 Background

Origin's history can be traced to Bitumen and Oil Refineries (Australia) Limited which was incorporated in 1946 to manufacture bitumen and petroleum by-products from imported crude oil. During the 1950's, it expanded its operations in the petrochemical industry and entered the gas market and quarrying activities. The acronym "Boral" gradually became widely attributed to the company and in 1964 it formally changed its name to Boral.

During the 1960's, Boral exited the petrochemical industry and expanded further into building materials by acquiring brick, masonry and pre-mixed concrete operations. In the 1970's and 1980's Boral increased its presence in building and construction materials both in Australia and internationally. It also acquired interests in the oil and gas industry and various manufacturing and engineering businesses.

By the early 1990's, Boral was a diversified company operating 48 separate businesses in 23 countries with approximately 80% of revenues from its Australian operations. As a consequence of difficult trading conditions in the early 1990's, Boral refocussed on its operations in building and construction materials and energy and sold a number of its non-core operations and rationalised or closed other operations. By 1997, Boral's operations had been reduced to 23 businesses and it concentrated on developing its energy business and further rationalising and strengthening its building and construction materials businesses.

In October 1999, Boral announced its intention to separate its building and construction materials business and its energy business into two industry specific companies. The demerger was implemented on 18 February 2000[11]. At the time of the demerger, Origin's operations were:

- **Exploration & Production:** exploration for and production of natural gas in Australia and New Zealand with 1,056PJe of 2P reserves (87% natural gas). In addition, through an 85.23% interest in ASX listed company Oil Company of Australia Limited ("OCA") it had interests in both conventional gas and CSG assets in central Queensland;
- **Networks:** an energy infrastructure asset management business providing services primarily to ASX listed company Envestra in which it held a 19.97% interest;
- **Generation:** development and operation of gas fired power stations and cogeneration projects around Australia with a proportional interest in 178MW of installed generation capacity and 92MW of committed generation capacity; and
- **Retail & Trading:** retailing of natural gas, LPG, electricity and related energy services to 1.2 million retail customers in Australia. It also supplied LPG in New Zealand and the South Pacific, wholesale traded LPG, electricity and natural gas in Australia and supplied autogas in Australia through a 50% joint venture with Caltex Australia Limited ("Vitalgas").

Since the demerger, Origin has focused on the competitive segments of the energy supply chain in Australia and New Zealand and on deepening the integration within its businesses. It has invested significantly in organic growth projects (e.g. the development of additional generation capacity and the acquisition of prospective natural gas resources), positioned itself to respond to the growing challenge of carbon emissions (e.g. the development of solar energy and geothermal energy technologies) and made a number of significant strategic acquisitions including:

- Powercor's retail electricity business, comprising 582,000 customers primarily in western Victoria, for $315 million in June 2001;
- a 50% interest in the South West Cogeneration Joint Venture in Western Australia for $68.5 million in July 2001;
- CitiPower's retail electricity business, comprising 260,000 retail customers and 4,000 commercial and industrial customers in Victoria, for $137 million in August 2002;
- Mount Stuart Power Station, a 288MW gas turbine peaking plant in Townsville, Queensland, for $93 million in December 2002;

[11] The demerger steps included the transfer of the building and construction materials business into a wholly owned subsidiary in which Boral shareholders received shares directly. The former parent company comprising the energy business was renamed Origin Energy Limited. The building and construction materials subsidiary changed its name to Boral and listed on the ASX on 21 February 2000.

- the remaining 14.77% of OCA for $74 million in September 2003;
- a 50% interest in the Kupe Gas Field in New Zealand for NZ$33 million in February 2004;
- a 50% interest in Rockgas (to bring Origin's interest to 100%), the largest distributor of LPG in New Zealand, for NZ$17.6 million in March 2004;
- Sun Retail, an electricity retailer with around 840,000 electricity customers predominantly in south east Queensland and 55,000 LPG customers, for $1.2 billion in February 2007; and
- Uranquinty Power Station, a 640MW gas fired peaking plant under construction in New South Wales, for $700 million in July 2008.

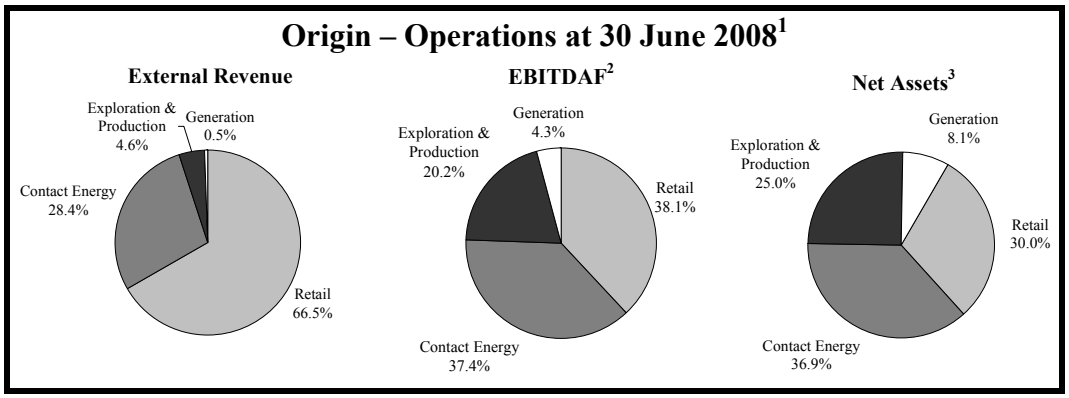
Since the demerger, Origin has also sold a small number of assets and businesses where they were underutilised or no longer central to Origin's integrated strategy (e.g. Rockgas was sold to Contact Energy for NZ$156 million in March 2007 and the Networks business was sold to APA Group for $556 million in June/July 2007).

Origin also expanded further in New Zealand by acquiring a 51.4% interest in Contact Energy Limited ("Contact Energy"), a New Zealand listed integrated generator and retailer, for $1.024 billion in October 2004. During early 2006, Origin pursued a merger with Contact Energy via a dual listed company structure but discussions were terminated in June 2006 when the parties were unable to agree on final terms. In addition, in February 2007 Origin rejected a nil premium merger proposal from AGL Energy, an ASX listed integrated energy company.

Today, Origin is the largest integrated energy company in Australia and New Zealand with approximately 5,400 employees (including around 1,000 Contact Energy employees and 500 contractors in Australia). Its operations comprise:

- **Exploration & Production:** exploration for and development and production of natural gas in Australia and New Zealand with 1,019PJe of 2P reserves of conventional oil and gas assets and 4,751PJ of 2P reserves of CSG. In addition, it has greenfield exploration activities in New Zealand, Kenya and Vietnam;
- **Generation:** development and operation of gas fired power stations and cogeneration projects around Australia with a proportional interest in 704MW of installed generation capacity and 2,096MW of committed generation capacity;
- **Retail:** supplies electricity, natural gas, LPG and related products to more than three million customers in Australia and the South Pacific and supplies autogas in Australia via the Vitalgas joint venture; and
- **Contact Energy:** New Zealand's second largest electricity generator (around 28% of generation capacity) and one of New Zealand's largest energy retailers (27% of retail electricity market, 40% of retail gas market and 50% of LPG market).

Origin's businesses and assets are described in more detail in Sections 5-8 of this report. The importance of each operation is shown in the following graphs:



Source: Origin and Grant Samuel analysis

Notes: (1) On a fully consolidated basis including equity accounted associates.
(2) Earnings before net interest, tax, depreciation, amortisation and fair value adjustments to financial instruments and significant items.
(3) Segment net assets excluding unallocated assets and liabilities.

4.2 Business Strategy

Origin operates in the competitive segments of the energy supply chain in Australia (i.e. energy fuel production, electricity generation and energy retailing) and does not operate in energy transmission and distribution preferring to contract with third parties for these services. It adopts a highly fuel integrated approach across its businesses seeking to maximise the natural hedge that exists. Origin takes a long term view focussing on developing strategies and investing to address the issues facing the energy sector from scarce resources and the threat of climate change.

Key initiatives of Origin's strategy include:

- focussed exploration for natural gas particularly near existing infrastructure and markets both to support Origin's demand for gas for generation and to increase the opportunity for external sale of gas;
- monetising its CSG resources by implementing the ConocoPhillips Proposal;
- maintaining a portfolio of gas supply contracts to complement Origin's physical gas resources, support its retail customer base and differentiate its gas supply costs from its retail peers;
- developing a competitive portfolio of gas based power generation assets to maximise the value of Origin's gas resources and take advantage of opportunities in the downstream electricity market;
- continuing to enhance skills in energy utilisation encompassing areas such as cogeneration, energy efficiency, appliance merchandising and the development of products and services that will add value for energy customers;
- limiting adverse impacts from fluctuations in wholesale electricity prices by increasing the natural hedge of power generation assets and derivatives trading activities;
- planning for and managing the implication of government regulation with regard to carbon emissions to reduce the potential impact on earnings;
- developing interests in renewable energy resources (e.g. investments in solar and geothermal technologies);
- continuing to be the largest retailer of "green energy" including from solar, wind and hydro sources;
- expanding the gas and electricity customer retail base to achieve scale advantages over energy retailing competitors;
- taking advantage of market opportunities (e.g. potential privatisation of New South Wales electricity assets); and
- pursuing improvements in systems and processes in order to improve customer service and profitability.

Origin's business strategy provides for the diversification of risk within each of its businesses as well as providing significant opportunities for growth. In this regard, Origin has built its position in CSG and conventional gas over the last decade primarily to provide an alternative fuel source for electricity generation and this investment is now also likely to lead to growth in earnings from external sales.

Origin's investment in Contact Energy is consistent with its strategy as Contact Energy operates a similar business strategy utilising the significant natural hedge that exists in being an integrated energy generator and retailer.

4.3 Financial Performance

The financial performance of Origin for the five years ended 30 June 2008 is summarised below:

Origin - Financial Performance[12] ($ millions)

	Year ended 30 June				
	2004 actual AGAAP	2005[13] actual AIFRS	2006 actual AIFRS	2007[14] actual AIFRS	2008 actual AIFRS
Sales revenue	**3,521.8**	**4,870.0**	**5,879.7**	**6,435.9**	**8,274.9**
EBITDAF[15]	**532.2**	**918.5**	**1,076.5**	**1,194.8**	**1,309.0**
Depreciation and amortisation	(203.0)	(262.2)	(296.6)	(329.6)	(344.6)
EBITF[16]	**329.2**	**656.3**	**779.8**	**865.2**	**964.4**
Changes in fair value of financial instruments:[17]					
- non-financing financial instruments	-	-	(20.2)	32.1	(76.6)
- financing financial instruments	-	-	7.5	20.2	(13.2)
	-	-	(12.7)	52.3	(89.8)
Net interest expense	(45.4)	(147.7)	(174.8)	(215.2)	(220.1)
Significant items	-	-	30.9	45.9	202.0
Operating profit before tax	**283.8**	**508.6**	**623.2**	**748.2**	**856.5**
Income tax expense	(76.9)	(137.2)	(169.1)	(156.6)[18]	(235.0)
Operating profit after tax	**206.9**	**371.4**	**454.1**	**591.6**	**621.5**
Outside equity interests	(2.0)	(70.2)	(122.2)	(134.7)	(104.8)
Profit after tax attributable to Origin shareholders	**204.9**	**301.2**	**331.9**	**456.9**	**516.7**
Statistics					
Basic earnings per share	*30.0¢*	*42.1¢*	*41.9¢*	*54.7¢*	*59.0¢*
Adjusted basic earnings per share[19]	*30.0¢*	*39.5¢*	*42.7¢*	*44.3¢*	*50.6¢*
Dividends per share	*13.0¢*	*15.0¢*	*18.0¢*	*21.0¢*	*25.0¢*
Dividend payout ratio[20]	*43%*	*38%*	*42%*	*47%*	*49%*
Amount franked	*100%*	*100%*	*100%*	*100%*	*100%*
Interest cover[21]	*7.2x*	*4.4x*	*4.5x*	*4.0x*	*4.4x*

Source: Origin and Grant Samuel analysis

Origin has grown substantially since 2003 following a number of strategic acquisitions and divestments including the acquisition of a 51.4% interest in Contact Energy in October 2004 and 100% of Sun Retail in February 2007 and the sale of Networks in June/July 2007. As Contact Energy is fully consolidated, Origin's net profit after tax reflects 100% of Contact Energy's earnings and outside equity interests are primarily the 48.6% of shares in Contact Energy held by public shareholders.

During this period earnings per share (before significant items) and dividends per share have

12 Financial statements for the years prior to 1 July 2005 were prepared in accordance with Australian generally accepted accounting principles ("AGAAP"). Origin adopted the Australian equivalent to International Financial Reporting Standards ("AIFRS") from 1 July 2005. With the exception of the application of the standard in relation to financial instruments, the result for the year ended 30 June 2005 was restated under AIFRS.

13 Contact Energy consolidated from 1 October 2004 (i.e. nine months contribution during 2004/05).

14 Including five months contribution from Sun Retail.

15 EBITDAF is earnings before net interest, tax, depreciation, amortisation, significant items and changes in the fair value of financial instruments. EBITDAF includes Origin's share of net profits of equity accounted investments.

16 EBITF is earnings before net interest, tax, significant items and changes in the fair value of financial instruments. EBITF includes Origin's share of net profits of equity accounted investments.

17 Changes in the fair value of financial instruments reflects gains and losses where the derivative financial instrument does not qualify as a hedge for accounting purposes. Hedges qualify for hedge accounting if changes in fair value or cash flow of the hedged item and the hedging instrument offset each other or if the hedge substantially offsets risk associated with the change in the fair value of the hedged item. There must also be sufficient certainty with respect of the occurrence of the risk.

18 Including a tax benefit of $56.9 million relating to the reduction in the New Zealand corporate tax rate from 33% to 30%.

19 Adjusted earnings per share calculated on Origin's underlying profit (i.e. before significant items including changes in fair value of financial instruments, asset sales and the reduction in the New Zealand corporate tax rate).

20 Calculated by reference to adjusted basic earnings per share.

21 Interest cover is EBITF divided by net interest.

grown at around 13% and 17.5% per annum respectively. Origin's payout ratio is relatively low at around 40-50% due to substantial reinvestment in the business.

Origin utilises derivative financial instruments to manage its exposure to electricity and oil price volatility and to interest and foreign exchange rate volatility. Changes in the fair value of financial instruments reflect the charge to the income statement for gains and losses where the financial instruments do not qualify as a hedge for accounting purposes. Relative to its peers, only a small proportion of Origin's financial instruments do not qualify for hedge accounting. In this regard, during the year ended 30 June 2007 wholesale electricity prices increased substantially resulting in a significant unrealised non cash gain of $3.2 billion, of which only 1.6% ($52 million) was recognised in the income statement.

Over the last five years, Origin has identified a number of significant or non-recurring items some of which have been reported as significant below operating earnings (i.e. after EBITF) while others have been recognised in EBITF. The items reported separately by Origin as significant below EBITF are summarised below:

Origin – Significant Items as Reported ($ millions)

	Year ended 30 June				
	2004 actual AGAAP	2005 actual AIFRS	2006 actual AIFRS	2007 actual AIFRS	2008 actual AIFRS
Gain on sale of Valley Power	-	-	30.9	-	-
Impairment of Cooper and Onshore Otway assets	-	-	-	(73.8)	-
Mount Stuart power purchase agreement termination	-	-	-	19.6	-
Gain on sale of Networks	-	-	-	113.7	224.9
Sun Retail one off costs	-	-	-	(13.6)	(11.5)
Gain on sale of Mokai geothermal assets	-	-	-	-	18.2
New Plymouth asbestos removal and related costs	-	-	-	-	(29.6)
Total	**-**	**-**	**30.9**	**45.9**	**202.0**

Source: Origin

Net interest expense increased significantly in 2005 (and interest cover decreased) following the debt funded acquisition of Contact Energy. Subsequently, higher interest rates and additional debt for the Sun Retail acquisition and development projects have resulted in an increase in interest expense although interest cover has been maintained at above 4 times.

Analysis of Origin's operational performance is made difficult at a consolidated level by recent acquisitions, divestments and other factors. In order to better analyse Origin's operational performance Grant Samuel has adjusted reported operating earnings (i.e. EBITDAF and EBITF) to exclude the divested Networks and Rockgas businesses, share of net profits of equity accounted investments, other income, goodwill and licence amortisation prior to the adoption of AIFRS and other non-recurring items recognised in EBITF as follows:

Origin – Adjusted Financial Performance ($ millions)					
	Year ended 30 June				
	2004 actual AGAAP	2005 actual AIFRS	2006 actual AIFRS	2007 actual AIFRS	2008 actual AIFRS
Sales revenue	**3,521.8**	**4,870.0**	**5,879.7**	**6,435.9**	**8,274.9**
Adjustments:					
Networks	(168.1)	(158.7)	(187.8)	(208.9)	-
Rockgas[22]	(19.4)	(78.9)	(84.2)	(83.8)	-
Adjusted sales revenue	**3,334.3**	**4,632.4**	**5,607.7**	**6,143.2**	**8,274.9**
EBITDAF	**532.2**	**918.5**	**1,076.5**	**1,194.8**	**1,309.0**
Adjustments:					
Networks[23]	(24.8)	(27.5)	(22.6)	(22.8)	-
Rockgas[22]	(3.4)	(15.1)	(13.4)	(11.2)	-
Share of profits of equity accounted investments[24]	(26.0)	(16.4)	(20.4)	(22.6)	(17.0)
Other income[25]	(10.3)	(18.5)	(31.5)	(7.5)	(35.1)
Non-recurring items not treated as significant:					
- impairment of Cooper Basin	16.2	-	-	-	-
- dual listing proposal costs	-	-	16.9	-	-
	16.2	-	16.9	-	-
Adjusted EBITDAF	**483.9**	**841.0**	**1,005.5**	**1,130.7**	**1,256.9**
Depreciation and amortisation	**(203.0)**	**(262.2)**	**(296.6)**	**(329.6)**	**(344.6)**
Adjustments:					
Goodwill and licence amortisation	37.2	-	-	-	-
Networks[26]	2.1	1.3	4.2	3.6	-
Rockgas[22]	1.4	5.0	6.1	4.9	-
Adjusted depreciation and amortisation	**(162.3)**	**(255.9)**	**(286.3)**	**(321.1)**	**(344.6)**
Adjusted EBITF	**321.6**	**585.1**	**719.2**	**809.6**	**912.3**
Statistics					
Adjusted sales revenue growth	*4.9%*	*38.9%*	*21.1%*	*9.5%*	*34.7%*
Adjusted EBITDAF growth	*7.5%*	*73.8%*	*19.6%*	*12.5%*	*11.2%*
Adjusted EBITF growth	*11.8%*	*81.9%*	*22.9%*	*12.6%*	*12.7%*
Adjusted EBITDAF margin	*14.5%*	*18.2%*	*17.9%*	*18.4%*	*15.2%*
Adjusted EBITF margin	*9.6%*	*12.6%*	*12.8%*	*13.2%*	*11.0%*

Source: Grant Samuel analysis

This analysis indicates that over the five year period sales revenue has grown at an average rate of around 25% per annum while operating earnings have increased at an average rate of around 29.5% per annum. Origin's overall profit margins increased with the acquisition of Contact Energy and have grown gradually over time until 2008 when the profit contribution from the lower margin retail business increased as a proportion of total earnings following the acquisition of Sun Retail.

This analysis of the performance of Origin's continuing operations can be further analysed by operating business as follows:

22 Relates to the period during which Rockgas was 100% owned by Origin (i.e. from March 2004 to April 2007).

23 Excluding share of profits of equity accounted investments but includes other income.

24 Including share of profits of equity accounted investments held by Networks.

25 Other income includes dividends received, gains and losses on sale of assets, net foreign exchange gains, government grants/subsidies and other income from non trading operations.

26 Including goodwill and licence amortisation relating to Networks.

Origin – Adjusted Financial Performance by Business ($ millions)					
	Year ended 30 June				
	2004 actual AGAAP	2005 actual AIFRS	2006 actual AIFRS	2007 actual AIFRS	2008 actual AIFRS
Adjusted sales revenue					
Exploration & Production	290.8	349.8	344.0	339.1	381.4
Generation	74.0	77.3	67.2	66.7	40.1
Retail	2,969.5	2,989.4	3,121.8	3,997.8	5,505.5
Contact Energy	-	1,215.8	2,074.7	1,739.6	2,347.9
Total	**3,334.3**	**4,632.4**	**5,607.7**	**6,143.2**	**8,274.9**
Adjusted EBITDAF					
Exploration & Production	211.1	218.5	188.8	254.4	258.3
Generation	46.4	43.4	42.7	66.5	40.5
Retail	226.4	235.5	271.0	336.7	479.3
Contact Energy	-	343.6	503.0	473.1	478.8
Total	**483.9**	**841.0**	**1,005.5**	**1,130.7**	**1,256.9**
Adjusted depreciation and amortisation					
Exploration & Production	(91.2)	(97.9)	(106.4)	(134.7)	(144.0)
Generation	(21.7)	(24.4)	(23.0)	(19.8)	(17.3)
Retail	(49.4)	(45.2)	(37.9)	(45.1)	(53.3)
Contact Energy	-	(88.4)	(119.0)	(121.5)	(130.0)
Total	**(162.3)**	**(255.9)**	**(286.3)**	**(321.1)**	**(344.6)**
Adjusted EBITF					
Exploration & Production	119.9	120.6	82.4	119.7	114.3
Generation	24.7	19.0	19.7	46.7	23.2
Retail	177.0	190.3	233.1	291.6	426.0
Contact Energy	-	255.2	384.0	351.6	348.8
Total	**321.6**	**585.1**	**719.2**	**809.6**	**912.3**

Source: Grant Samuel analysis

The adjusted financial performance reflects the full allocation of Origin's corporate overheads (e.g. shared services, corporate head office costs, listed company costs etc) to its Australian operating divisions.

The operating performance of each of Origin's businesses based on this analysis is discussed in detail in Sections 5-8 of this report.

Outlook

Origin has not publicly released earnings forecasts for the year ended 30 June 2009 or beyond. In order to provide an indication of the expected future financial performance of Origin, Grant Samuel has considered brokers' forecasts for Origin (see Appendix 2) as follows:

Origin – Financial Performance ($ millions)			
	Year end 30 June		
	2008 actual	Broker Consensus (Median)	
		2009	2010
Adjusted sales revenue	8,274.9	8,272.0	8,723.7
Adjusted EBITDAF	1,256.9	1,483.2	1,761.1
Adjusted EBITF	912.3	1,084.7	1,319.9
Underlying net profit after tax[27]	443.0	501.4	602.0
Adjusted earnings per share (cents)	50.6¢	57.3¢	68.0¢
Dividends per share (cents)	25.0¢	27.5¢	33.0¢

Source: Grant Samuel analysis (see Appendix 2).

On 28 August 2008, Origin advised that in 2009 it is targeting an increase in underlying earnings per share of at least 10%. The median consensus brokers' forecasts indicate a 13% increase in net profit after tax in 2009 which is consistent with that guidance.

[27] Before fair value adjustments and significant items.

4.4 Financial Position

The financial position of Origin as at 30 June 2008 is summarised below:

Origin - Financial Position ($ millions)		
	As at 30 June 2008	
	As Reported	Adjusted[28]
Debtors and prepayments	1,582.3	1,178.9
Inventories	147.6	130.8
Creditors and accruals	(1,659.0)	(1,224.9)
Net working capital	**70.9**	**84.8**
Property, plant and equipment (net)	6,402.9	3,252.6
Exploration and evaluation expenditure	61.3	61.3
Development expenditure	631.0	589.6
Goodwill	2,410.0	1,979.1
Other intangible assets (net)	53.5	50.3
Equity accounted investments	67.4	61.1
Investment in Contact Energy	-	1,395.4
Investment in Geodynamics	30.0	30.0
Other investments	3.3	1.0
Derivative financial instruments (net)	31.5	243.7
Defined benefit superannuation surplus	7.2	7.2
Other non current assets (net)	0.2	0.4
Acquired environmental certificate purchase obligations	(102.2)	(102.2)
Provision for income tax	(118.4)	(115.6)
Deferred income tax liabilities (net)	(714.9)	(247.2)
Non current provisions	(373.1)	(346.5)
Onerous contracts	(2.4)	(2.4)
Total funds employed	**8,458.2**	**6,942.6**
Cash and deposits	96.0	92.0
Bank loans, other loans and finance leases	(3,378.6)	(2,831.8)
Net borrowings	**(3,282.6)**	**(2,739.8)**
Net assets	**5,175.6**	**4,202.8**
Outside equity interests	(1,103.6)	(8.3)
Equity attributable to Origin shareholders	**4,072.0**	**4,194.5**
Adjusted net borrowings[29]	**(3,607.5)**	**(2,913.2)**
Adjusted net assets[30]	**4,972.0**	**3,940.3**
Statistics		
Shares on issue at period end (million)	*880.8*	*880.8*
Net assets per share	*$5.88*	*$4.77*
NTA[31] per share	*$3.08*	*$2.47*
Gearing[32]	*38.8%*	*39.5%*
Adjusted net assets per share	*$5.65*	*$4.47*
Adjusted NTA[33] per share	*$2.85*	*$2.17*
Adjusted gearing[34]	*42.0%*	*42.5%*

Source: Origin and Grant Samuel analysis

Origin's activities are capital intensive and its investment in property, plant and equipment is substantial, particularly in relation to its Exploration & Production and Generation businesses. Goodwill primarily relates to retail acquisitions (including Sun Retail) and the acquisition of Contact Energy.

Equity accounted investments include a 50% interest in the Bulwer Island Energy Partnership, a

28 Contact Energy recognised as an investment (i.e. not consolidated)

29 Excludes fair value adjustments to borrowings.

30 Excludes the impact of changes in fair value of hedging derivatives.

31 NTA is net tangible assets, which is calculated as net assets less goodwill and other intangible assets.

32 Gearing is net borrowings divided by net assets plus net borrowings.

33 Adjusted NTA is adjusted net tangible assets, which is calculated as adjusted net assets less goodwill and other intangible assets.

34 Adjusted gearing is adjusted net borrowings (adding back the fair value adjustment) divided by adjusted net assets (excluding the fair value of reserves) plus adjusted net borrowings.

50% interest in the Osborne cogeneration plant and a 50% interest in Vitalgas. Contact Energy also holds a 25% interest in Oakey Power Station and a 50% interest in Rockgas Timaru Limited ("Rockgas Timaru") which is part of Rockgas.

Origin uses a range of derivative financial instruments to manage its exposure to various price, interest rate and foreign exchange risks. Derivative financial instruments are recognised at fair value and, due to the volatility in energy markets and the size of Origin's operations can represent a substantial variable component of funds employed.

Origin operates a number of defined benefit superannuation plans for the benefit of its employees. The defined benefit superannuation surplus ($7.2 million) represents the excess of the fair value of plan assets over the present value of plan obligations.

The environmental certificate purchase obligations represent the long term commitments to acquire RECs, NGACs and GECs held by Sun Retail at acquisition in February 2007. This amount will reduce over the term of the commitments as the environmental certificates are acquired by Origin in the normal course of business.

Non current provisions for Origin (excluding Contact Energy) relate to restoration, rehabilitation and dismantling of sites ($328 million), employee benefits ($11 million) and other ($7.5 million). There is no provision at 30 June 2008 for the final dividend of 13.0 cents per share ($114.5 million) payable on 3 October 2008.

Outside equity interests in the reported balance sheet primarily represent the minority interests in Contact Energy.

At 30 June 2008 Origin (excluding Contact Energy) had committed credit facilities (including unsecured bank loans, unsecured other loans, unsecured capital markets borrowings and secured lease liabilities) totalling approximately $5.4 billion available on a consolidated basis of which approximately $1.8 billion was unutilised.

Analysis of Origin's financial position is distorted by movements in the fair value of derivative financial instruments. After adjusting for the fair value impact of financial instruments, net assets and NTA per share have decreased and gearing is within Origin's targeted range of 40-45%. Origin has a BBB+ (stable outlook) credit rating from Standard & Poor's and Fitch Ratings (subject to the CSG Monetisation Process).

At 30 June 2008, Origin had gross carried forward Australian income tax losses of approximately $328 million, all of which were recognised in the balance sheet. In addition, Origin had gross carried forward Australian capital losses of approximately $248 million. At 30 June 2008, Origin had $0.7 million of accumulated franking credits.

At 30 June 2008 Origin (as reported) had total capital expenditure commitments of approximately $2.0 billion of which $1.6 billion is payable during 2009. Excluding Contact Energy, Origin's capital expenditure commitments totalled $1.8 billion of which $1.5 billion is payable during 2009.

4.5 Cash Flow

Despite significant capital expenditure investment in recent years, Origin generates substantial operating cash. Recent capital expenditure includes substantial growth expenditure in relation to the exploration for and development and production of natural gas assets (30-50% of total capital expenditure). Operating cash flow, additional borrowings and proceeds from equity raisings have been used to meet strategic acquisitions (particularly the Contact Energy and Sun Retail acquisitions), increased interest payments and increased dividends (dividend per share has increased from 13.0 cents to 25.0 cents over the period).

Origin - Cash Flow ($ millions)					
	Year ended 30 June				
	2004 actual AGAAP	2005[35] actual AIFRS	2006 actual AIFRS	2007[36] actual AIFRS	2008 actual AIFRS
EBITDAF (as reported)	**532.2**	**918.5**	**1,076.5**	**1,194.8**	**1,309.0**
Changes in working capital and other adjustments	(82.3)	(40.2)	178.8	(22.1)	(133.1)
Capital expenditure (net)	(323.0)	(467.2)	(680.2)	(762.3)	(1,347.5)
Operating cash flow	**126.9**	**411.1**	**575.1**	**410.4**	**(171.6)**
Tax paid	2.2	(181.2)	(118.8)	(164.8)	(143.2)
Subvention paid	(4.0)	-	-	-	-
Net interest paid	(51.1)	(150.3)	(185.2)	(222.2)	(253.3)
Distributions received	12.2	20.0	21.2	22.1	15.5
Dividends paid	(34.2)	(108.5)	(163.1)	(183.2)	(232.2)
Business and investment acquisitions (net of cash)	(166.6)	(967.6)	(181.0)	(1,242.4)	(93.3)
Contact Energy borrowings assumed	-	(1,537.9)	-	-	-
Loans to equity accounted entities	(28.0)	(1.3)	59.0	2.7	-
Proceeds from disposal of assets and businesses	9.4	22.3	94.7	139.3	468.9
Proceeds from security issues (net)	4.8	611.4	4.0	486.1	190.3
Net cash generated (used)	**(128.4)**	**(1,882.0)**	**105.9**	**(752.0)**	**(218.9)**
Net borrowings – opening[37]	*(732.1)*	*(860.5)*	*(2,742.5)*	*(2,636.6)*	*(3,388.6)*
Net borrowings – closing[37]	*(860.5)*	*(2,742.5)*	*(2,636.6)*	*(3,388.6)*	*(3,607.5)*

Source: Origin and Grant Samuel analysis

4.6 Capital Structure and Ownership

As at 3 September 2008, Origin had the following securities on issue:

- 881,120,722 ordinary shares;
- 11,053,200 options over unissued ordinary shares; and
- 744,000 performance share rights over unissued ordinary shares.

At that date there were 105,974 registered shareholders with the top twenty shareholders accounting for approximately 63% of the ordinary shares on issue. The top twenty registered shareholders are principally institutional nominee or custodian companies. Origin has a significant retail investor base with approximately 86% of registered shareholders holding up to 5,000 shares although these shareholders represent only 16% of shares on issue. Origin shareholders are predominantly Australian based investors (over 97% of registered shareholders and 99% of securities on issue).

Origin has operated a dividend reinvestment plan since listing. It has a participation rate in recent years of around 20-25% of issued capital.

Origin has received the following current substantial shareholder notices:

Origin – Substantial Shareholders as at 3 September 2008			
Shareholder	**Date of Notice**	**Number of Shares**	**Percentage**
Commonwealth Bank of Australia	28 August 2008	44,054,709	5.00%
BG Group[38]	3 September 2008	1,156,005	0.13%

Source: Origin

Under the Senior Executive Option Plan each option on issue is exercisable into one ordinary share and has no dividend entitlement or voting right. Options become exercisable after the third anniversary of grant and before expiry date and are subject to performance hurdles being met. These hurdles vary by option tranche and are based on a comparison of Origin's total shareholder

35 Contact Energy consolidated from 1 October 2004 (i.e. nine months contribution during 2004/05).

36 Including five months contribution from Sun Retail.

37 From 30 June 2006 net borrowings are adjusted net borrowings (i.e. excluding the impact of fair value adjustments to borrowings).

38 BG Group's substantial shareholder notice has been given as a result of the commencement of its bid period.

return against that of other companies comprising the ASX 100 at the time of issuance. Employee options lapse if the executive resigns (after six months), on termination of employment for cause (immediately) or on the expiry date. The options outstanding are summarised below:

Origin – Options on Issue as at 3 September 2008

Issue Date	Expiry Date	Exercise Price	Issued Options	Exercisable Options
19 December 2003	19 December 2008	$4.15	1,454,000	1,454,000
6 August 2004	6 August 2009	$5.98	775,000	775,000
26 November 2004	26 November 2009	$5.72	1,463,200	1,463,200
20 May 2005	20 May 2010	$6.75	100,000	100,000
7 September 2005	7 September 2010	$7.21	2,568,000	2,568,000
11 September 2006	11 September 2011	$6.50	2,694,000	2,694,000
26 June 2007	26 June 2012	$8.97	50,000	50,000
28 September 2007	28 September 2012	$10.32	300,000	300,000
28 September 2007	28 December 2012	$10.32	1,649,000	-
Total			**11,053,200**	**9,404,200**

Source: Origin

Options issued to executives prior to July 2007 and those issued to the Managing Director in September 2007 may be exercised prior to the third anniversary of grant if a person acquires or gives notice of a proposal to make an acquisition of more than 20% of Origin provided that the performance hurdles have been achieved. BG Group's announcement on 30 April 2008 brought forward the first exercise date for these options and, as the performance hurdles have been met, the options have vested and become exercisable. The remaining options may be exercised prior to the third anniversary of grant in the event of a takeover which has become unconditional and a person acquires more than 20% of the issued shares in Origin, provided that the performance hurdles are achieved.

Origin also operates a Performance Share Rights Plan under which rights to acquire ordinary shares at a zero exercise price are granted to senior executives. The performance share rights are exercisable in a period between the third anniversary of grant and the expiry date and are subject to performance hurdles being met. Vested performance share rights lapse if the executive resigns (within six months), on termination of employment for cause (immediately) or on the expiry date. Unvested performance share rights lapse immediately upon resignation. As at 3 September 2008 744,000 performance share rights had been granted. BG Group's announcement on 30 April 2008 brought forward the first exercise date of the 100,000 Performance Share Rights issued to the Managing Director in September 2007 and, as the performance hurdles have been met, they have vested and are exercisable. The remaining Performance Share Rights will only vest prior to the third anniversary of grant in the event of a takeover which has become unconditional and results in a person acquiring more than 20% of the issued shares of Origin, provided the performance hurdles are achieved.

Origin also operates the following share plans:

- **Employee Share Plan**: where up to $1,000 in Origin shares may be awarded to employees (pro rata for part time employees) if Origin meets specified financial and safety targets. Shares awarded under the plan are issued or bought on market. Shares awarded must be held for at least three years or until the employee ceases employment. The relevant target for 30 June 2008 has been met and Origin expects to acquire and award shares to approximately 2,400 employees during September 2008;
- **Employee Share Plan New Zealand:** which enables employees who are resident in New Zealand to be awarded Origin shares when specified performance targets are met (similar to the Employee Share Plan). Shares are acquired by the trustee of the plan and cannot be sold for three years or until the employee ceases employment. If a takeover is made for Origin, the trustee may, after consultation with the relevant employee, accept or reject the offer. If accepted, the trustee holds the proceeds until the restrictive period expires; and
- **Non-Executive Directors Share Plan:** which requires Non-Executive Directors to sacrifice 25% of their annual fee for the acquisition on market of Origin shares until they hold at least 20,000 shares. The shares are held by the trustee of the plan until at least five years from acquisition or upon retirement or death.

4.7 Share Price Performance

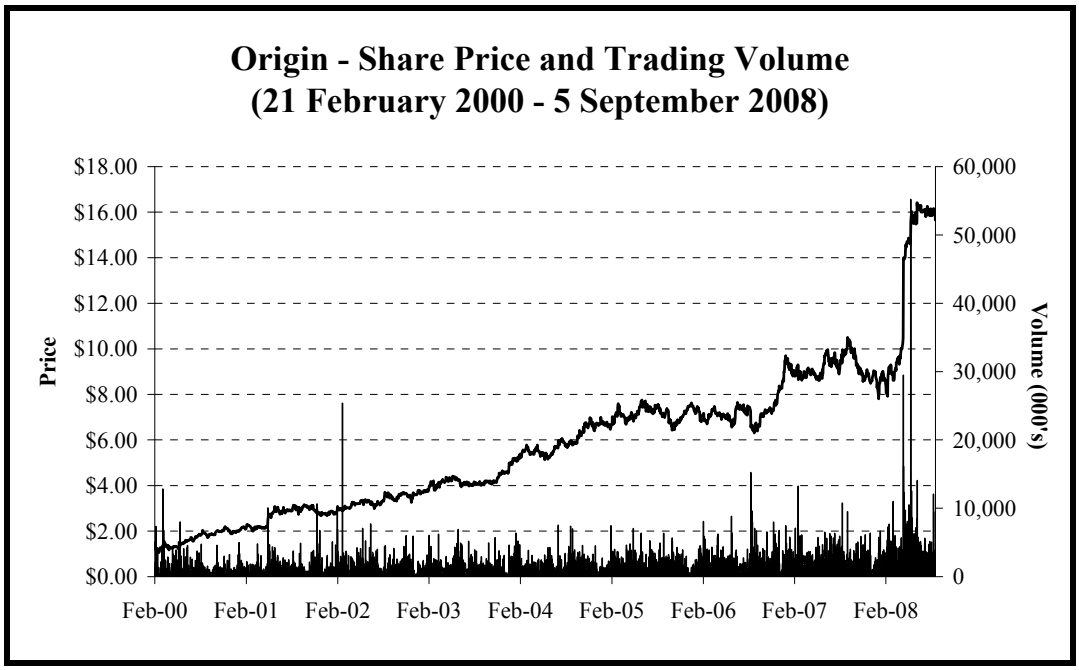
A summary of the price and trading history of Origin since the demerger is set out below:

Origin - Share Price History

	Share Price ($)			Average Weekly Volume (000's)	Average Weekly Transactions
	High	Low	Close		
Year ended 31 December					
2000 (from 21 February)	2.22	1.01	1.99	7,618	1,032
2001	3.19	1.94	2.74	7,769	1,242
2002	3.77	2.65	3.61	9,631	1,176
2003	4.66	3.51	4.62	8,355	1,288
2004	6.99	4.49	6.70	9,107	1,612
2005	7.85	6.40	7.51	10,528	2,628
2006	8.40	6.23	8.27	12,560	3,624
2007	10.76	8.23	8.85	14,960	7,304
Quarter ended					
31 March 2008	9.45	7.65	9.16	17,623	10,335
Month ended					
30 April 2008	14.60	9.02	13.95	20,725	11,284
31 May 2008	16.15	13.82	15.60	43,803	11,578
30 June 2008	16.49	15.35	16.12	29,945	12,040
31 July 2008	16.38	15.76	15.85	17,229	10,935
31 August 2008	16.27	15.60	16.15	16,726	10,354
30 September 2008 (to 5 September)	16.15	15.65	15.65	21,961	13,675

Source: IRESS

The following graph illustrates the movement in the Origin share price and trading volumes since the demerger:



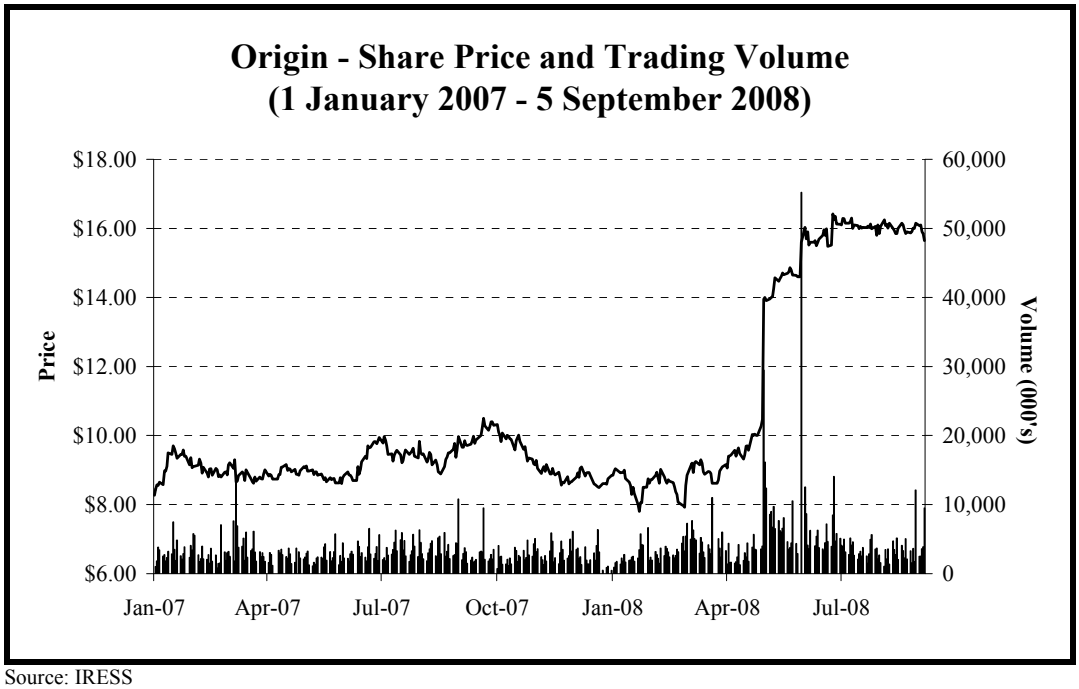
Source: IRESS

Following the demerger in February 2000, Origin's share price rose steadily from around $1.50 to a peak of $7.85 in July 2005 on the back of strong earnings growth particularly from strategic acquisitions. Following this period of price growth, the Origin share price plateaued to trade around $7.00 through to the last quarter of 2006.

From a low of $6.23 in September 2006, Origin's share price increased to a peak of $9.70 on 16 January 2007 following the announcement of the acquisition of Sun Retail in November 2006 and

the announcement on 4 January 2007 that Origin had received an unsolicited merger proposal from AGL Energy. Origin rejected the proposed nil premium merger on 23 February 2007 and its share price declined to below $9.00. Following AGL Energy's announcement on 7 March 2007 that it would not be pursuing a merger with Origin, the share price declined further to $8.65, albeit significantly above price levels during 2006.

During 2007 Origin shares traded broadly in the range of $8.50 to $10.00 at volume weighted average price of $9.18:



Source: IRESS

Origin's share price increased to almost $10.00 in early July 2007 following the announcement of two significant gas supply deals demonstrating Origin's ability to monetise its CSG reserves. These deals included supply of CSG to Origin's proposed gas fired power station near Braemar in the Darling Downs region of Queensland and a long term contract to supply CSG to Rio Tinto Limited's ("Rio Tinto") Yarwun alumina refinery at Gladstone in Queensland. In addition, the announcement of a 42% increase in 2P gas reserves to 3,471PJ (including an 80% increase in CSG reserves) on 31 July 2007 resulted in a 5% jump in the Origin share price on that day.

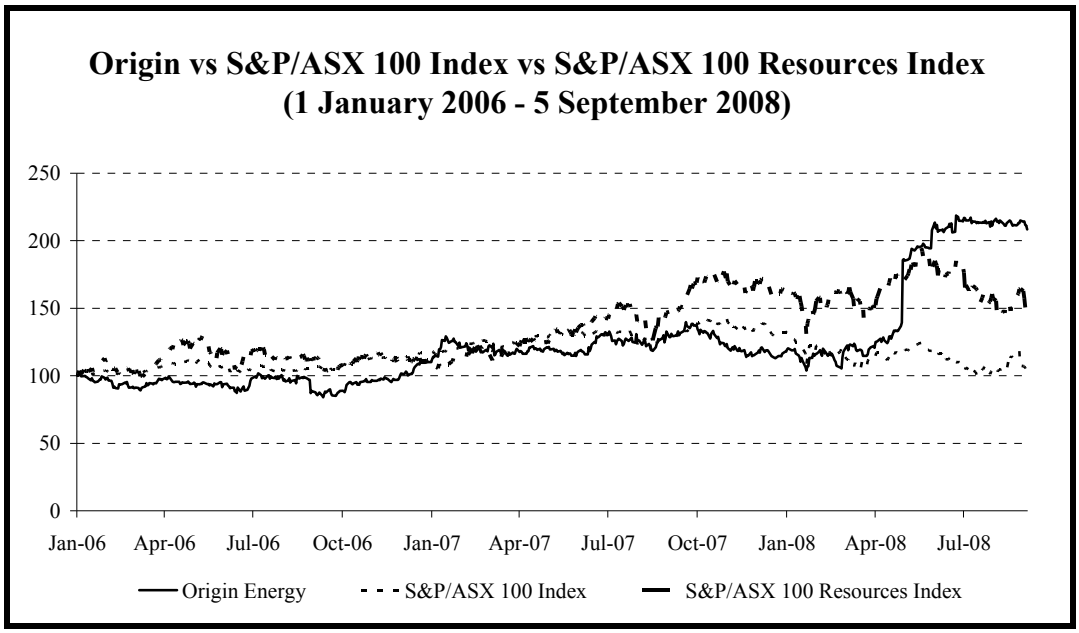
Origin's share price reached a high of $10.76 on 26 September 2007 following a better than expected 2007 earnings results. Notwithstanding increased oil and gas prices, Origin's share price drifted back below $9.00 in the absence of any further news on the monetisation of the CSG reserves and reflecting the general decline in international sharemarkets, delays in the Otway project and declines in New Zealand wholesale electricity prices which had adverse impact on Contact Energy's earnings.

Origin's share price strengthened during April 2008 to close at $10.47 on 29 April 2008, immediately prior to the announcement of BG Group's proposal to acquire all of the shares in Origin at $14.70 cash per share. Following the announcement, Origin shares immediately rose above $14.00 and traded at a weighted average price of $14.35 prior to Origin's rejection of the BG Group's revised offer of $15.50 cash per share on 30 May 3008. During this period, it became clear that Origin's reserves and resource of CSG were substantially greater than previously understood by investors. Consequently, following rejection of BG Group's offer, Origin's share price again rose and stayed at above $15.50. On 24 June 2008 BG Group announced its intention to make a takeover offer at $15.50 cash per share and the Origin share price rose above $16.00. Since then until 5 September 2008, Origin shares have traded in the range of $15.60 to $16.49 per share (at a weighted average price of $16.05) and closed at $15.65 on 5 September 2008.

Origin is in the top 20 companies on the ASX, a member of all major indices and has no limitations on free float. It is a reasonably liquid stock and average weekly volume over the twelve months to 29 April 2008 (immediately prior to the BG Group's initial proposal) representing approximately 1.7% of average shares on issue or annual turnover of around 91% of total average issued capital.

Origin's weighting in the S&P/ASX 100 Index, S&P/ASX 200 Energy Index and S&P/ASX 100 Resources index is approximately 1.48%, 16.3% and 4.54% respectively. Given its significant representation in the S&P/ASX 200 Energy Index, Origin has generally performed in line with that index since the demerger, albeit with periods of over and under performance.

However, although Origin remains a leading integrated Australian energy company, its relative performance is better judged today against the market generally and the resources sector specifically, given the increasing importance of its upstream activities to its earnings outlook. The following graph illustrates the performance of Origin shares since January 2006 relative to the S&P/ASX 100 Index and S&P/ASX 100 Resources Index:



Source: IRESS

During 2006 Origin underperformed both indices while during 2007 Origin generally traded around the market but below the S&P/ASX Resources Index, which may indicate that the market was yet to perceive Origin as a resource stock. Origin over performed both indices in the period to April 2008 and has since continued to over perform relative to the S&P/ASX 100 Index.

Despite the price rerating following the announcement of BG Group's initial proposal, Origin shares underperformed the S&P/ASX 100 Resources Index until 30 May 2008. Following the further substantial price rerating on 30 May 2008 subsequent to rejection of BG Group's revised offer, Origin marginally outperformed the resource index prior to the announcement of BG Group's takeover offer on 24 June 2008. From July until mid August 2008, Origin has outperformed both indices, particularly the S&P/ASX 100 Resource Index which underperformed relative to the market. However, since the release of its Target Statement on 19 August 2008 to 5 September 2008, Origin has underperformed both indices.

5 Profile of Exploration & Production

5.1 Overview

Origin has a portfolio of oil and gas production, development and exploration assets primarily located in Australia and New Zealand, but also in Kenya and Vietnam.

Historically, Origin's major oil and gas production assets were located in the Cooper and Eromanga Basins ("Cooper Basin") in Australia. The Cooper Basin has been the principal supplier of natural gas to New South Wales, South Australia and Queensland but is now in decline. Although brownfield exploration activities continue in the Cooper Basin it is generally accepted that it is unlikely that there are any substantial prospects remaining undeveloped. Origin's other conventional onshore Australian production interests are also reasonably mature.

Over the past decade, Origin has made a series of investments in new projects and brownfield exploration to offset the anticipated decline of the Cooper Basin and its other mature gas producing areas. In particular, Origin's onshore development and production activities have increasingly focussed on CSG. Origin is also a participant in a number of offshore projects that are in the process of commissioning or have recently commenced production (i.e. the BassGas and Otway Gas projects in Australia and the Kupe Gas project in New Zealand). During 2008 Origin invested $421 million in exploration and development. It is confident that these new projects will replace earnings from the maturing assets in the Cooper and Perth Basins.

More than 95% of Origin's proved and probable reserves of 5,770PJ are natural gas, of which approximately 85% are sourced from the Queensland CSG fields (4,751PJ). Proved and probable (2P) reserves increased by 66% in 2008 primarily from CSG (which grew by 92% in the year):

Origin – Proved and Probable Reserves by Region as at 30 June 2008

	Gas (PJ)	LPG (Kt)	Condensate (Kbbls)	Oils (Kbbls)	Total (PJe)
Queensland CSG	4,751	-	-	-	4,751
Cooper Basin	157	299	2,212	3,195	202
Bass Basin	130	399	4,964	349	179
Surat Basin/Denison Trough	75	54	395	247	81
Other onshore Australia	14	-	28	1,170	21
Otway Basin offshore	265	491	3,194	-	306
New Zealand	147	565	7,863	2,054	230
Total	**5,539**	**1,808**	**18,656**	**7,015**	**5,770**

Source: Origin

Origin's 3P reserves of CSG total 10,138PJ and it also has significant contingent and prospective CSG resources (15,869PJ and 17,947PJ) respectively.

Origin achieved record production, sales volumes and revenue in the year ended 30 June 2008. Its share of production by product in the five years ended 30 June 2008 is summarised below:

Origin – Production by Product

	2004	2005	2006	2007	2008
Natural gas and ethane (PJe)	66.4	65.6	63.2	71.7	87.6
Crude oil (Kbbls)	1,700.3	2,003.5	1,556.2	1,333.0	941.3
Condensate/Naphtha (Kbbls)	504.0	596.8	494.5	781.9	746.2
LPG (Kt)	42.8	58.5	52.8	67.2	66.4
Total (PJe)	**81.2**	**83.4**	**77.6**	**87.1**	**100.5**

Source: Origin

Origin's CSG and conventional gas assets are described in more detail in Sections 5.3 and 5.4 of this report.

5.2 Australian Natural Gas Sector

5.2.1 Overview

Natural gas is a clean burning fuel source produced during the break down of organic matter. The gas primarily comprises methane but may also contain hydrocarbons such as propane, butane and ethane. It has a range of uses in the industrial, commercial and domestic sectors.

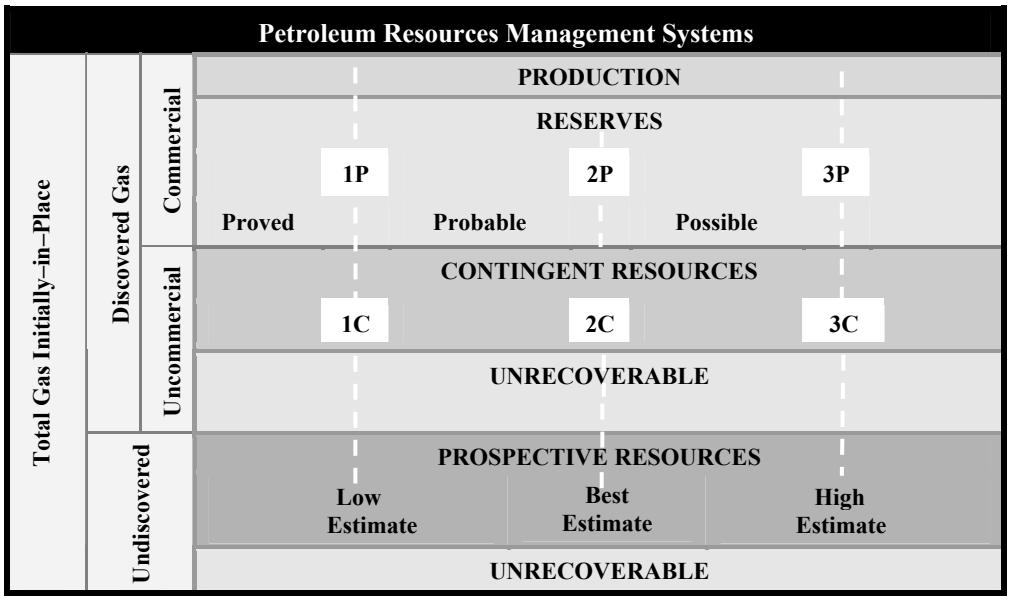
There are two main types of natural gas produced in Australia: conventional natural gas which is found in underground reservoirs trapped in rock (both onshore and offshore) sometimes in association with oil and CSG which is contained within coal seams. There are also a range of alternative renewable sources of gas including biogas (landfill and sewage gas) and biomass which includes wood, wood waste and sugarcane residue (bagasse).

Conventional natural gas is extracted by drilling into the gas reservoir (typically at a depth of 1,000 to 3,000 metres) and the gas usually flows under its own pressure to be collected and processed on the surface. In comparison, CSG is found in coal seams where it is held on the surface of the coal by a weak molecular bond known as adsorption. Pressure from water in the coal seam (which may also contain dissolved gas) keeps the gas adsorbed. Extraction of CSG involves the drilling of a series of wells into the coal seam (typically at a depth of 200 to 1,000 metres). Water held in the coal seam is pumped from the wells to reduce pressure and causes methane to desorb and begin to flow from the coal. This also facilitates the release of any methane dissolved in the water. The CSG is then collected and processed on the surface.

The first commercial conventional natural gas project was established in Roma in central southern Queensland in 1961. In comparison, the first commercial CSG project was established in late 1996. Renewable gas production in Australia is at an even earlier stage of commercialisation.

5.2.2 Resource Classification

Oil and gas resources are categorised according to the degree to which they are likely to be commercially recoverable. This includes judgments both as to the level of certainty of the volume of resource and the degree to which extraction is commercially viable. Certification of reserves is usually undertaken by external technical experts. The categorisation system is summarised in the following diagram:



Source: Society of Petroleum Engineers

Commercially viable resources (or reserves) are categorised as proved (1P), proved and probable (2P) or proved, probable and possible (3P). The benchmark for commercial contracts for conventional gas in Australia has traditionally been 2P, with 3P reserves being considered in assessing potential upside. In recent years this focus on 2P reserves has reduced where the producer has a portfolio of gas reserves available to meet contract obligations. Contingent resources are potentially recoverable but do not qualify as economically recoverable due to commercial (e.g. lack of market) or technical issues (such as reliance on technology under development or lack of detailed exploration information).

In determining the commerciality of extraction, consideration is given to the market price for gas. As prices increase, the amount of commercially viable resources may also increase. Ongoing production and exploration will also result in changes in the quantum and category of reserves and resources. This is referred to as the reserves maturation process.

The resource classification system applies to both conventional gas and CSG. However, as CSG fields are typically continuous accumulations, the reserves maturation process for CSG differs to conventional gas. The CSG maturation process is based on the initial identification of contingent resources and progresses to the booking of 3P, then 2P and 1P reserves as additional evidence accumulates. This evidence is a direct consequence of exploration and production which involves continual drilling of core holes, pilot wells and production wells across the resource which provides greater certainty about the extent and quality of the resource. In other words, the level of CSG reserves booked depends on the number of wells drilled and tested that have shown commercial flow rates.

Therefore, for CSG, 3P reserves (and in many cases, 2C resources) reflect the believed extent of the gas bearing coals rather than the probability that gas exists. Defining CSG 3P reserves as only having a 10% probability in areas surrounding existing production may be overly pessimistic. The areal extent and quality of the gas bearing coals may be well understood but the reserves may only be classified as 3P because of the lack of appraisal drilling.

The ultimate plateau production for a CSG project will depend on the available market, the costs of development, the production profile and ultimate recovery per well. As a result, CSG projects tend to expand capacity incrementally and 2P reserves grow over time (as contingent resources and 3P reserves are converted) until an economic plateau in production is reached.

5.2.3 Demand

Natural gas has a range of industrial, commercial and domestic applications. Reticulated natural gas was introduced in eastern state capital cities from 1969 replacing 'town gas' which was manufactured from coal and oil. The primary use for natural gas in Australia is electricity generation (35% of total consumption in 2007). Manufacturing was the second largest gas consumer (33%) while the residential sector (where gas is used for water heating, space heating and cooking) accounted for 11%. In Western Australia, a large proportion of gas produced is utilised to service the mining sector and for conversion to LNG for export.

Energy consumption in Australia has grown at an average rate of 1.7% per annum over the last ten years. Natural gas currently accounts for approximately 19% of total primary energy consumption in Australia, behind oil (35%) and coal (44%) which remain relatively cheap and abundant sources of fuel. Energy consumption is expected to continue to grow in the foreseeable future (by 1.6% per annum to 2030). In line with international trends, demand for gas is expected to grow at a faster rate than non renewable fuels, increasing to 24% total consumption over this period.

Increased demand from gas fired power generation projects in the eastern states accounts for a significant component of the forecast increase in gas consumption. Total gas fired electricity generation is expected to increase 156% from 38.5TWh per annum in 2006 to 98.6TWh in 2030. Key factors driving this demand include the increasing availability of gas (particularly with the continued exploration of CSG), the increasing relative cost of coal

(driven largely by continued demand from China) and government initiatives to reduce greenhouse gas emissions (including the proposed emission trading scheme which will place a cost on carbon dioxide emissions and provide significant incentives to convert to lower emission intensive fuels such as gas). The proposed NRET (which is effectively an expansion of the MRET) is likely to divert demand for base load electricity generation from gas to renewable resources (such as wind) with gas being used for peaking generation. However, current forecasts indicate that renewable generation will not be sufficient to meet the increased base load demand and gas fired generation is expected to be needed to meet this shortfall as well as to replace coal base load generation which becomes uneconomic over time. Furthermore, as wind generation is a less reliable base load generator, reliable peaking capacity (fuelled by gas) will be required.

The growth in gas demand differs from the west coast to the east coast. Western Australia is the largest consumer of natural gas (36% of total primary consumption in 2007) with demand forecast to increase by 85% to 760PJ per annum by 2030, driven by gas fired power generation, LNG exports and the mining sector. On the east coast, Victoria is expected to remain the largest consumer of gas followed by Queensland (13%) and New South Wales (12%). Queensland is forecast to experience the most rapid growth in gas consumption (other than NT which remains relatively small) increasing 130% to 340PJ per annum by 2030 underpinned by new gas fired generation (including Origin's 630MW Darling Downs Power Station due to be commissioned in 2010). Significant additional growth in demand for gas could result if one or more of the proposed LNG export projects in Queensland is successfully developed.

5.2.4 Reserves and Production

Australia has extensive natural gas reserves. Current proved and probable (2P) natural gas reserves are estimated at around 52,700PJ (including 12,400PJ of CSG) plus contingent resources estimated in excess of 128,000PJ (including 29,800PJ of CSG). However, Australia's natural gas reserves are not typically located in close proximity to the majority of users with gas supplies linked to end markets by transmission pipelines. Due to the relatively low domestic market price for gas in the eastern states, the absence of cross continental pipelines and the costs associated with transporting LNG, Australia's natural gas market operates as two separate regional markets: the west/north (Western Australia and Northern Territory) and the east/south (other states and territories).

Estimated 2P reserves, contingent resources and production by region are summarised below:

Australia - Natural Gas Reserves and Domestic Gas Production (PJ)

Region	2P Reserves[39]	Contingent Resources[40]	Domestic Production 12 months to June 2008
Conventional Gas			
West/North	31,622	93,530	361[41]
East/South	8,688	4,270	519
Total Conventional	**40,310**	**97,800**	**880**
Coal Seam Gas			
West/North	-	-	-
East/South			
- Surat-Bowen	11,633	29,660	127
- New South Wales	742	173	5
Total CSG	**12,375**	**29,833**	**132**
Total Natural Gas	**52,685**	**127,633**	**1,012**
Total East/South Gas	21,063	34,103	651

Source: Australian Energy Regulator, EnergyQuest Pty Ltd (August 2008) and Grant Samuel analysis

39 As at 30 June 2008.

40 As at January 2006 for conventional gas and 30 June 2008 for CSG.

41 In addition, an estimated 680PJ of natural gas was produced in the West/North region for export as LNG.

The west/north region (which includes the largest single gas resource located in the Carnarvon Basin off the northwest Australian coast) accounts for 60% of Australia's 2P natural gas reserves and 73% of contingent resources. At current rates of production, 2P reserves represent approximately 88 years of domestic supply (30 years including current levels of LNG exports). There are also significant contingent resources in the Carnarvon and Bonaparte Basins as well as the currently undeveloped Browse Basin. The bulk of the fields are located in major off-shore reservoirs. There are currently no CSG resources identified in the west/north region.

Eastern state reserves of conventional gas (e.g. Cooper-Eromanga Basin in South Australia/Queensland and the Gippsland Basin in Bass Strait) amount to only approximately 17 years of supply at current production levels although considerable potential remains to develop new reserves (e.g. Gippsland Basin, Otway Basin). The relatively low level of conventional gas resource and the fact that it is currently uneconomical to deliver Western Australian gas to the east coast have provided an incentive for further gas exploration and the development of CSG as an alternative form of natural gas fuel for the eastern states.

Australia's reserves of CSG are located in the east/south region with production focussed in the Bowen and Surat Basins in Queensland. These basins, which span central southern Queensland to central northern New South Wales account for approximately 11,600PJ of 2P reserves plus a further 29,700PJ of contingent resources. CSG deposits are typically described by geologically defined "fairways" and the major objective of exploration is to locate a highly productive area (or "sweet spot") which possesses attractive production characteristics. Queensland has a number of such sweet spots. In particular, fields in the Comet Ridge area of the Bowen Basin and the Undulla Nose of the Surat Basin are considered to be on par with some of the most attractive CSG fields globally.

CSG reserves now exceed conventional gas reserves on the east coast. Queensland accounts for the majority of 2P reserves (approximately 94%) and contingent resources (over 99%). Exploration for CSG in the Sydney Basin in New South Wales commenced in 1996 but accounted for only 4% of total CSG production in the twelve months to June 2008. While the area is rich in coal deposits and gas in place is estimated in the order of 97,000PJ, exploration has been limited and the degree to which these resources are commercially viable is yet to be assessed. Additional CSG resources have been identified in coal bearing fields across the eastern states including the Galilee, Ipswich and Maryborough Basins in Queensland as well as the Gunnedah and Gloucester Basins in New South Wales.

CSG production has grown significantly over the past several years from 13PJ in 2000 to 132PJ in the year to June 2008. CSG accounted for approximately 20% of east/south region natural gas production in the twelve months to June 2008 and is expected to increase significantly as a source of gas to eastern Australia.

5.2.5 Coal Seam Gas

Overview

Production of CSG commenced in North America in the 1920's and 1930's, however, large scale commercial production from dewatered coal seams did not start until the 1970's. Early exploration of CSG in Australia commenced in the Bowen Basin in Queensland in 1976. The first commercial production was established by Conoco Australia in February 1996 from the Dawson River field in the Bowen Basin with sales for the ammonium nitrate facility of Queensland Nitrates Pty Limited near Moura.

Commercial acceptance of CSG as a reliable fuel source did not occur until the early 2000's with major upstream producers such as Santos Limited ("Santos") and Origin acquiring and developing significant CSG reserves. The growing commercial credibility of CSG was evident with a number of major downstream users entering into long term CSG purchase agreements including BP plc (for the Bulwer Island Refinery in 1999), CS Energy and the Queensland Government (for gas fired power stations in 2002), Incitec-Pivot Limited

("Incitec-Pivot") (for its Gibson Island fertiliser plant in 2005) and Rio Tinto (for the Yarwun aluminium refinery in 2007). Market commentators estimate that currently around 80% of east coast 2P CSG reserves are contracted or committed under long term arrangements.

Production Parameters

Extraction of CSG involves the drilling of a series of wells into the coal seam. Water held in the coal seam is pumped from the wells to reduce pressure causing methane to desorb and begin to flow from the coal. The CSG is then collected and processed on the surface.

A single CSG field may comprise hundreds of wells (typically in a grid formation) to maximise the total extraction and flow. The production performance of coal seam gas wells depends on a number of factors, including:

- the extent of total gas content (which is in turn affected by factors such as coal rank and the depth and thickness of the seam);
- gas saturation of the coal (with higher saturation reducing the amount of dewatering required to promote desorption); and
- permeability (which affects the ability of the gas to flow through the seam to the well).

Operator expertise is also an important factor in determining productivity. Different drilling and well completion techniques can ultimately have very different impacts on flow rates. Advances in drilling and production as well as the shallow depth of the seams make CSG exploration a relatively low cost exercise compared to conventional gas (a typical well costs in the order of $1.0 million).

Water disposal and treatment is a significant issue and cost in CSG production. While evaporation ponds have historically been used for water handling they are no longer favoured due to environmental reasons. However, reverse osmosis treatment for the excess water reduces the environmental impacts and may lead to new revenue streams for CSG producers from marketing the purified water.

Market Participants

There are currently more than 20 companies actively involved in the exploration, development and production of CSG in Australia. This includes several major producers (with significant reserves and financial resources) and a large number of smaller "junior" and start-up explorers. The top three producers (Origin, Santos/Petroliam Nasional Berhad ("Petronas") and Queensland Gas Company Limited/BG Group ("QGC/BG Group") account for 71% of 2P reserves and 92% of contingent resources.

Australian CSG reserves and resources at 30 June 2008 are summarised below by market participant:

Australian CSG Reserves and Resources by Market Participant (PJ)					
Company	Production (12 months to 30 June 2008)	As at 30 June 2008			
		1P	2P	3P	Contingent Resources
Queensland					
Origin	39.4	1,375	4,751	10,138	15,869
QGC/BG Group	22.9	609	2,415	7,163	1,211
Santos/Petronas	27.1	324	1,573	4,511	10,492
Arrow/Shell	16.3	262	1,430	3,127	-
Sunshine	-	44	469	1,097	-
AGL	8.4	63	277	867	-
Other	12.4	122	718	1,659	2,088
	126.5	**2,799**	**11,633**	**28,562**	**29,660**
New South Wales					
Metgasco	-	-	264	1,419	-
AJ Lucas	-	11	124	261	121
Sydney Gas	2.6	30	41	54	-
AGL	2.7	30	41	54	-
Other	-	25	272	1,532	52
	5.3	**96**	**742**	**3,320**	**173**
Total	**131.8**	**2,895**	**12,375**	**31,882**	**29,833**

Source: EnergyQuest Pty Ltd (August 2008), Origin and Grant Samuel analysis

The last three years has seen considerable corporate activity as market participants seek to secure resources and increase scale. This follows from a general increase in interest in the sector driven by the decline of conventional gas resources on the east coast, the growing outlook for domestic gas demand (particularly on the back of emissions reduction initiatives) as well as global demand for LNG, particularly from Asia (see below).

The prospect for higher domestic gas prices (see Section 5.2.7) increases the viability of CSG resources which may have been marginal at historical gas prices. Furthermore, current international energy prices have stimulated interest from a number of major international oil and gas players to secure gas resource in connection with the development of projects to convert the CSG into LNG for export (see Section 5.2.6).

Notable recent corporate activity in the CSG sector includes:

- AGL Energy's acquisition of a 27.5% interest in QGC in March 2007 (subsequently diluted by the share issue to BG Group in February 2008);
- BG Group's alliance with QGC to develop a LNG plant using QGC's CSG resources as feedstock in February 2008. BG Group acquired a 20% interest in QGC's CSG assets (with a right to increase to 30%) and also acquired a 9.9% shareholding in QGC;
- BG Group's approach to Origin in April 2008 which resulted in the BG Offer in June 2008;
- Petronas and Santos' joint venture to develop a LNG plant in Gladstone using Santos' CSG resources as feedstock in May 2008. Petronas has acquired a 40% interest in certain of Santos' CSG resources;
- the alliance between Royal Dutch Shell plc ("Shell") and Arrow Energy Limited ("Arrow") to jointly develop Arrow's CSG assets in June 2008. Shell agreed to acquire 30% of Arrow's upstream CSG assets; and
- QGC's takeover offer for Sunshine Gas Limited ("Sunshine") in August 2008.

5.2.6 Proposed LNG Projects

LNG production involves the cooling of natural gas into liquid form. This reduces the volume of gas by a factor of approximately 600 times making it more economic to transport. LNG is transported in specially designed tankers for delivery to purpose built inbound terminals, where it is converted back into gas before being used for fuel.

Australia has two LNG operations: the North West Shelf Joint Venture located off the north west coast of Western Australia (which commenced export in 1991) and the Darwin LNG Project in the Northern Territory (which commenced export in 2006). In 2007 15.2Mt of LNG (9% of world LNG demand) was exported from Australia. The primary markets for LNG exports from Australia are Japan, China, Korea and Taiwan. Australian production of LNG is forecast to increase to 24Mt by 2011/12 and as much as 76Mt by 2030 (excluding any of the proposed Queensland CSG to LNG projects) although some industry commentators consider this forecast to be conservative.

The primary export markets for Australian LNG exports are Japan (79% of total in 2007), China (16%), South Korea (3%) and Taiwan (2%). With the exception of China, these countries have limited or no access to indigenous or piped gas. Asia is the largest importing region for LNG and Korea and Japan are the largest individual importers of LNG. LNG demand in existing Asian markets is expected to continue to grow and new markets (such as Singapore and Thailand) are expected to commence LNG importation from 2011.

High energy prices and the continued demand for LNG in Asia have prompted further investment in the LNG industry in Australia. A fifth LNG train at the North West Shelf Joint Venture (increasing capacity by 4.4Mt) is due for completion by the end of 2008. Construction is also underway at Woodside Petroleum Limited's ("Woodside") 4.8Mtpa Pluto LNG project located off the north coast of Western Australia and scheduled to be commissioned in late 2010. A number of other potential greenfield LNG projects have been proposed which would source gas from resources in western and northern Australia.

Until recently there has been insufficient surplus gas in the eastern states to support LNG production. The firming up of CSG reserves and identification of further resources in central Queensland has changed this situation. As a result, a number of parties have announced proposals to establish LNG export operations in Queensland. All of the major owners of CSG resources are sponsoring a project (including Origin through the ConocoPhillips Proposal). A summary of the proposed projects is set out below:

Potential East Coast CSG to LNG Projects

Project Sponsor	Origin	Arrow	Sunshine[42]	QGC	Santos	Impel
Partner	ConocoPhillips	Shell/LNG Ltd	Sojitz	BG Group	Petronas	na
Announced	Sept 2008	May 2007	Dec 2007	Feb 2008	July 2007	May 2008
Location	na	Fisherman's Landing	Fisherman's Landing	Curtis Island	Curtis Island	Curtis Island
Proposed Capacity	14Mtpa	1.3-1.5Mtpa	0.5Mtpa	3.0-4.0Mtpa	3.0-4.0Mtpa	2.1-3.9Mtpa
Number of trains	4	1	1	2	1	3
Annual Gas Requirement	840PJ	55PJ	30PJ	190PJ	170-220PJ	na
Estimated Cost	na	$0.4 billion	$0.5 billion	$8 billion	$5-7 billion	na
Final Investment Decision	2010	na	Late 2008	Early 2010	Late 2009	na
Target Commissioning	2014	2011	2012	2013	2014	2013

Source: Company announcements

[42] QGC announced an agreed takeover offer for Sunshine on 20 August 2008. It is has not yet been confirmed that the success of this offer means that Sunshine' proposed LNG plant will not proceed.

There are currently a number of hurdles to the development of LNG projects in Queensland:

- **project risk:** an LNG project will require significant capital investment and (skilled and unskilled) labour resources. There is currently a significant shortage of materials and labour resources as a result of high levels of activity in the mining and infrastructure sectors. Securing resources on a timely and economical basis for an LNG project will be a significant challenge. In addition, raising the necessary capital given recent capital markets volatility may also be difficult;
- **supply risk:** supply of CSG on the scale required to support LNG is currently unproven. It is estimated that a single 3-4Mtpa plant will require in the order of 200PJ of gas per annum (approximately 1.5 times total current CSG production). Moreover, around 33% of current 2P CSG reserves are subject to existing contracts or commitments (excluding gas earmarked for LNG projects). Accordingly, significant further exploration will be required in order to provide sufficient security of supply for the projects. Furthermore, due to development timeframes, drilling of wells needs to be undertaken in advance of commissioning. Therefore, in the period prior to commissioning, to the extent that well production may not be reduced by technical means (such as choking back or re-injection) 'ramp up' gas will be produced which may need to be stored or sold into the domestic market;
- **demand risk:** projects will be dependent on the ability to secure long term gas supply agreements for the LNG produced. In some cases, the announced partnership arrangement (e.g. QGC/BG Group and Arrow/Shell) envisage off take arrangements for 100% of production. Other projects will depend on the ability to market and sell the LNG. However, demand for LNG globally (and specifically in South East Asia) is expected to grow significantly;
- **regulatory risk:** the proposed national emissions trading scheme may increase the costs associated with producing LNG. This will potentially reduce the competitiveness (and therefore viability) of Australian LNG in comparison to international producers not subject to similar imposts; and
- **technical risk:** conversion of CSG to LNG has not been previously undertaken. A number of potential technical risks have been identified although none is expected to be a material hurdle to production. In particular, the calorific value of CSG (i.e. the amount of energy released on combustion) is lower than other liquid rich LNG sources. This may impact the price received or require 'spiking' of CSG with higher calorific additives or blending with conventional LNG, adding to delivered cost.

Current market expectations are that one or more of the proposed projects are likely to proceed.

5.2.7 Wholesale Gas Prices

Overview

Natural gas markets around the world have developed on a regional basis, resulting in prices being set in different ways and at different levels across the world. Only around 7.5% of natural gas production is traded internationally as LNG and most of that under long term contracts. Therefore, only a small proportion of LNG is available to respond to regional price movements. As a consequence, unlike oil, no global pricing benchmarks have developed for natural gas. Nevertheless, gas prices will typically range within the bounds of the cost of production (minimum price) and a price ceiling based on the available alternative fuel sources (maximum price). The actual gas price within this range will be determined by competitive pressures in the market.

Australian market prices for natural gas have historically been low in comparison to international prices. Major factors for the price differential include:

- the abundance of coal available as fuel for electricity generation and therefore comparatively low consumption of gas;
- Australia's geographic isolation from international markets; and
- Australia's extensive natural gas resources and therefore no need to import gas and be exposed to international pricing.

Gas is typically sold in Australia under confidential long term wholesale contracts based on negotiations between producers and downstream buyers. The price will depend on a number of factors including total contract volume, available reserves, length of contract, price escalations and flexibility. Publicly available gas pricing information is limited[43], however, market commentators indicate that historically[44]:

- west coast domestic gas contract prices have been just above $2.00 per GJ since 2004;
- east coast domestic gas contract prices have been around $3.00-3.50 per GJ since 2004; and
- spot gas prices in Victoria have moved up from around $3.00 per GJ in 2004 to $3.50 per GJ more recently (except in 2007 when demand for gas increased to meet the increase in gas fired electricity generation as a result of drought conditions)[45].

The first long term contracts for CSG in Australia were priced at around $2.00-2.50 per GJ, a discount to conventional gas. The discount took into account that CSG was unproven as a commercial fuel source, the limited certified CSG reserves at that time and the start up nature of many of the CSG producers. The entry of major producers such as Santos and Origin has added significant commercial credibility to CSG with a number of long term CSG supply agreements being entered into with major downstream energy buyers (including Rio Tinto, AGL Energy and Origin itself). As a result, the price differential has narrowed and recent asking prices for new CSG contracts have been at $3.00 per GJ and above.

Recent domestic pricing in Western Australia indicates a significant uplift in gas prices (even ignoring the interruption to supply from the June 2008 pipeline rupture at Varanus Island which supplies approximately 30% of domestic gas). Prices approaching $5.00-6.00 per GJ have been agreed in the last two years reflecting the impact of demand from LNG (i.e. the alternative for producers to export gas as LNG at higher prices than to sell to the domestic market), the cost of gas field development (both as a result of the resources boom and as the large gas accumulations are located offshore), competition from users seeking to secure gas supply and a relatively small domestic gas market.

Given the long term nature of the majority of existing contracts, there have been few recent specific price signals on the east coast. East coast gas contracts have traditionally included partial CPI escalation, however, recently contract parties have also exercised their rights under contract provisions for market resets and/or price reopens. The extent of such provisions in the east coast market is not clear but key industry participants (such as Santos) have recently indicated that a significant proportion of their sales volume will face price adjustments in the medium term. Furthermore, the proportion of gas sales volumes which are contracted are expected to increase to 2012 but decline rapidly around 2017 meaning that future gas contracts will be entered into in a new pricing environment.

Outlook for Domestic Gas Prices on the Australian East Coast

It is widely accepted that gas prices on the east coast will increase in real terms over the medium term. However, the timing and extent of any increase is uncertain and dependent on the interaction of a range of complex factors.

The major factors which indicate that gas prices on the east coast are likely to rise in the medium term include:

---

43 Quarterly production and reserves reports provide details of average gas prices received by industry players but those prices are distorted by factors such as the mix of gas sales (i.e. domestic, LNG and international) and the terms of existing contracts.

44 All gas prices quoted are ex well head prices.

45 However, even if a larger spot market for gas develops in Australia over time, the prices in such a market are generally considered to reflect market imbalances and not prices that would be agreed under longer term arrangements.

- **the continued growth in demand for energy:** as 35% of natural gas produced in Australia is used in electricity generation, the demand for natural gas is expected to continue to grow at least in line with the growth in consumption of electricity;
- **government initiatives to address climate change:** the electricity generation sector will need to make a large contribution if Australia is to make significant reductions in its carbon emissions. As natural gas has lower carbon intensity than coal, government climate change initiatives will further underpin the growth in demand for natural gas. However, the competitiveness of natural gas as a fuel source in comparison to coal will, in part, depend on the "price" of carbon emissions. The parameters of the national emissions trading scheme (and therefore the likely price of carbon) are still being determined. Forecasts for the cost of carbon fall in a wide range but market commentators generally agree that for the scheme to be effective in reducing emissions, carbon prices will need to be in excess of $20 per tonne post 2010. Market participants consider that the cost of carbon will significantly exceed that level in the medium term and use the European forward prices for carbon (currently around $50 per tonne) tends to support those views.

  The higher the price of carbon the more competitive gas will be as a fuel source relative to coal. However, as coal is a cheap and abundant fuel source, the transition to gas will take some time (particularly if the coal fired generators receive transitionary compensation on introduction of the emissions trading scheme). Therefore, in the short term, new generation capacity is likely to be predominantly gas fired and, in the longer term, gas is expected to replace coal as the base load fuel (although this is subject to the implications of government renewable generation targets). Some market commentators indicate that delivered prices could rise up to $6.50 per PJ before gas would be uncompetitive with black coal;
- **continued growth in demand for LNG in Asia:** the rate of growth in the consumption of energy in Asia has exceeded global growth for many years and this is expected to continue in the foreseeable future. Due to a lack of natural gas resources, Asia has for the last 30 years been the major importing region for LNG, primarily for power generation. Consequently, demand for LNG imports is also expected to continue to grow.

  Furthermore, LNG prices in Asia have historically been linked to oil prices (typically the Japanese custom cleared crude oil price) at close to parity. It is only in the recent high oil price environment that LNG prices have diverged from close to oil parity (although they have also risen). The divergence has occurred as a significant share of the LNG sold to Japan is based on provisional prices which will be recalculated when new price formulae are agreed. There is no reason to consider that new price formulae will not be at close to oil parity;
- **commercialisation of CSG on the east coast:** the substantial increase in east coast natural gas reserves as a consequence of the proving up of CSG as a source of gas has moved the region from a position of relatively limited gas supply (conventional gas reserves are estimated at 16 years based on current production levels) to one with significant resources surplus to domestic requirements. This situation, together with the high energy price environment and the continued demand for LNG in Asia, has lead to a number of proposals to establish LNG export operations in Gladstone in Queensland based on the central Queensland CSG resources. Market commentators estimate that the announced LNG projects and existing domestic contracts will require all current 3P CSG reserves, leaving future domestic gas demand (in the absence of further conventional gas discoveries) to be met from contingent resources. Commercialisation of the contingent resources will depend on higher gas prices.

  The export of LNG from Gladstone would significantly increase demand for CSG and, as has happened in Western Australia, is expected to place upward pressure on domestic gas prices generally as producers would have an alternative channel of selling gas to LNG plant operators which sell LNG at international prices. In this case, domestic gas prices are more likely to approach a LNG "net back" price (i.e. a

notional price of gas reached by taking the LNG price and "netting back" costs such as LNG production, transport and losses on conversion). LNG netback prices for CSG from central Queensland have been estimated by various producers at $4.80-8.00 per GJ (depending on the assumed oil price, LNG-oil price relationship and netback components), a significant premium to current east coast gas prices. Given the significant gas requirement and the need for security of supply, any LNG project will seek to tie up commitments from the major CSG producers. Additionally, those major CSG producers are becoming LNG producers (particularly as more industry consolidation occurs) and are more likely to achieve pricing outcomes approximating LNG netback prices. Smaller producers with limited access to infrastructure or CSG resources of scale are less likely to achieve these higher prices;

- **CSG is being reserved for LNG projects:** substantial amounts of CSG reserves and resources are currently being reserved by market participants (e.g. Santos, QGC) as feedstock for potential LNG projects rather than being made available to the domestic market. While conventional gas remains available to meet domestic demand this will have limited impact on east coast gas prices. However, to the extent that the most productive and economic CSG fields are reserved for LNG, the domestic gas market will over time become more reliant on higher cost, more marginal CSG fields. For such fields to be economic (and therefore developed) domestic gas prices would need to increase; and
- **available gas contract price data reflects historical capital and operating costs:** east coast contract prices typically quoted in the market are referenced to capital expenditure incurred over 20 years ago in relation to the development of the gas resources in Bass Strait. To that extent, those prices do not reflect the returns needed by producers on more recent capital expenditure. Furthermore, in recent years the resource sector has seen operating cost increases significantly above general inflation rates. These increased costs need to be factored into future expectations for gas prices.

On the other hand, there are a number of factors which may limit the extent to which gas prices on the east coast may increase:

- **growth in demand for electricity may moderate:** demand for electricity has the potential to fall below currently forecast levels as a result of an increased focus by consumers on energy efficiency as concerns about climate change increase and as the cost of energy increases (following the introduction of the proposed emissions trading scheme);
- **natural gas may be superseded as the low carbon intensity fuel for generation:** significant investment is currently being made in building wind generation capacity and developing and commercialising renewable generation technologies such as geothermal and solar. To the extent that renewable generation is developed, the demand for natural gas for generation may moderate. Furthermore, natural gas may be replaced as a fuel source for base load electricity generation and be directed primarily towards peaking capacity. In this case, although gas fired generation capacity and production will increase to support the intermittent nature of wind generation, gas demand will moderate as the level of gas consumed for peaking is lower than for base load generation;
- **there is no certainty that any of the proposed CSG to LNG projects will proceed:** there are significant risks associated with the development of a LNG plant (see Section 5.2.6) and there is no certainty that any of the proposed projects in Gladstone will proceed. If this occurred a substantial proportion of current CSG resources would be stranded without a market, particularly while conventional gas production is sufficient to meet domestic demand. This would place downward pressure on domestic gas prices and, for producers with no existing route to market, their CSG resources would become uneconomic until such times as the gas market supply/demand balance tightened;
- **the fragmented nature of the CSG sector:** there are currently a few major producers (holding large CSG reserves concentrated in the higher producing fields)

and a number of junior producers. The difficulties involved in aggregating the required amount of gas supply across a number of smaller producers for a LNG plant means that junior producers are unlikely to be able to access the LNG demand (unless an "open access" LNG plant is established) and are likely to supply their gas into the domestic market. This will reduce the degree to which the LNG netback will drive domestic pricing. However, as the CSG sector is rapidly consolidating, this is becoming a less important factor;

- **an increase in east coast gas prices will stimulate competition:** projects which are currently marginal (such as lower producing conventional gas basins) may become economical if there is a significant increase in gas prices on the east coast. These projects could add significantly to supply on the east coast and place downward pressure on prices.

  Furthermore, there is substantial potential for CSG production in other areas of Queensland and in New South Wales and a sustained rise in gas prices would stimulate new exploration as there are relatively low barriers to entry in the CSG sector (in that the cost of exploration is much lower than that for conventional gas and exploration and development of fields can be undertaken incrementally). This, together with the depth of the east coast domestic market and reasonable access to gas processing plants and pipelines, would enable junior producers to compete with major producers. Consequently, domestic gas pricing is likely to remain competitive; and

- **there will be significant gas production in advance of LNG plant commissioning:** given the magnitude of the annual gas requirement for a LNG plant, there will be significant drilling of CSG wells undertaken in advance of plant commissioning. To the extent that well production is not managed by technical means (such as choking back or re-injection) "ramp up" gas will need to be contracted, stored or sold into the domestic market. This will place some downward pressure on gas prices in the short to medium term.

In the absence of potential for LNG demand, sufficient factors exist to indicate higher prices will be obtained for natural gas in the east coast domestic market. Pricing outcomes are dependent on a range of factors but the growth in demand for energy and the introduction of an emissions trading scheme will put upward pressure on the current domestic gas prices of around $3.00-$3.50 per GJ in the medium term. The existence of a potential alternative source of demand for natural gas on the east coast will create further competitive pressure. If any of the Gladstone LNG projects proceed there will be further upward pressure on domestic prices to approximate LNG netback prices which many market commentators predict as likely to exceed $6.00 per GJ. In any event, as producers will hesitate to commit to new contracts in the expectation that LNG demand will eventuate, there will be upward pressure on prices as domestic users seek to secure supply. Any contracts that are negotiated in the near term (or until the new pricing environment is understood) may include market adjustment provisions so that the producer is able to share with the purchaser in increases in the market price for gas over the term of the contract.

5.3 Coal Seam Gas Assets

5.3.1 Overview

Origin holds the largest reserves and is the largest producer of CSG in Australia. It holds permits covering 17,000km^2 in the Bowen and Surat Basins in central southern Queensland and exploration interests covering approximately 18,800km^2 in the Galilee Basin in northern Queensland.

Origin began exploring for CSG in the mid 1990s as the conventional gas fields in the Cooper Basin matured. Origin (through OCA) acquired its first CSG interests in the Peat field in 1996 and entered into its first long term CSG supply agreement in 1999 with BP's Bulwer Island Refinery. Origin continued to build its CSG interests by accumulating exploration interests and acquiring CSG interests from Transfield CSM Pty Limited ("Transfield") and Tri-Star Petroleum Company ("Tri-Star") in 2002.

Origin's CSG interests comprise both wholly owned interests as well as joint venture interests with Santos/Tri-Star in the Bowen Basin and QGC/BG Group in the Surat Basin. Origin's interests are concentrated in areas generally considered to be sweet spots for CSG with attractive resource and production characteristics. Origin's CSG interests and operatorships are summarised below:

Origin – Summary of CSG Interests

Basin/Project Area	Interest	Status	Operator	Partner
Bowen Basin				
Spring Gully	96-99%	Production	Origin	Santos/Tri-Star
Peat	100%	Production	Origin	-
Fairview/Comet Ridge	23%	Production/Development	Santos	Santos
Membrance/Lonesome	100%	Exploration	Origin	-
Denison Trough	50%	Exploration	Santos/Origin	Santos
Denison Trough Mahalo Farmout	30%	Exploration	Santos	Santos/Comet Ridge
Surat Basin				
Talinga/Orana	100%	Development	Origin	-
Argyle/Kenya/Bellevue	29-41%	Production/Exploration	QGC	QGC/BG Group
Condabri/Gilbert Gully/Carinya	100%	Exploration	Origin	-
Combabula/Ramyard	93%	Exploration	Origin	Santos/Tri-Star
Other				
Galilee Basin	100%	Exploration	Origin	-

Source: Origin

5.3.2 Reserves and Resources

A summary of Origin's CSG reserves and resources as at 30 June 2007 and 2008 is set out below:

Origin - Equity Interest in CSG Reserves and Resources (PJ)

	30 June 2007	30 June 2008	Net Increase
Proved reserves (1P)	1,107	1,375	*24.2%*
Proved and probable reserves (2P)	2,470	4,751	*92.3%*
Proved, probable and possible reserves (3P)	4,578	10,138	*121.5%*
Contingent resources[46] (2C)		15,869	*na*
Prospective resources[46]		17,947	*na*

Source: Origin, NSAI

[46] The contingent resources assessment is over and above the 3P reserves. The prospective resources are additional to the contingent resources.

The reserves and resources have been certified by international petroleum consultant Netherland, Sewell and Associates, Inc. ("NSAI") based on technical, commercial and operational information provided by Origin. NSAI has been used by the majority of the Queensland CSG producers to determine reserves. The commercial information provided included a forward price scenario based on the monetisation of CSG through domestic markets including power generation opportunities, direct sales to end users and utilisation of Origin's wholesale and retail channels to market. It did not include any sales to LNG projects or other export market channels.

The equity interest does not include any allowance for state royalties and overriding royalty interests common in the petroleum industry. Therefore, Origin's equity interest may change from time to time in the future. Furthermore, some of Origin's CSG tenements are subject to reversion (see Section 5.3.8). The equity interests shown above make no allowance for reversion on the basis that Origin does not consider that reversion will occur under current development and production plans based on the commercial information provided to NSAI.

The increase in reserves and resources in 2008 reflects ongoing exploration, appraisal and development activity being undertaken by Origin and its partners and the increasing maturity of the CSG industry including greater confidence in CSG estimation techniques. Origin expects further conversion of resources to reserves as its drilling activities in these areas continues. Experience to date has been an extremely high conversion rate of 3P to 2P reserves. Around 77% of Origin's 2P and 3P reserves are in areas with a higher well density (the upper quartile) while contingent resources are located in areas with lower well density.

Origin's CSG 2P reserves have grown from 79.7PJ at 30 June 2000 to 4,751PJ at 30 June 2008 as a consequence of the acquisition of new acreage and reserves maturation through exploration and development activities. At 30 June 2008, approximately 22% of Origin's 3P reserves (2,200PJ) were subject to third party commitments or committed to Origin's generation and retail businesses. Its major commitments at 30 June 2008 include:

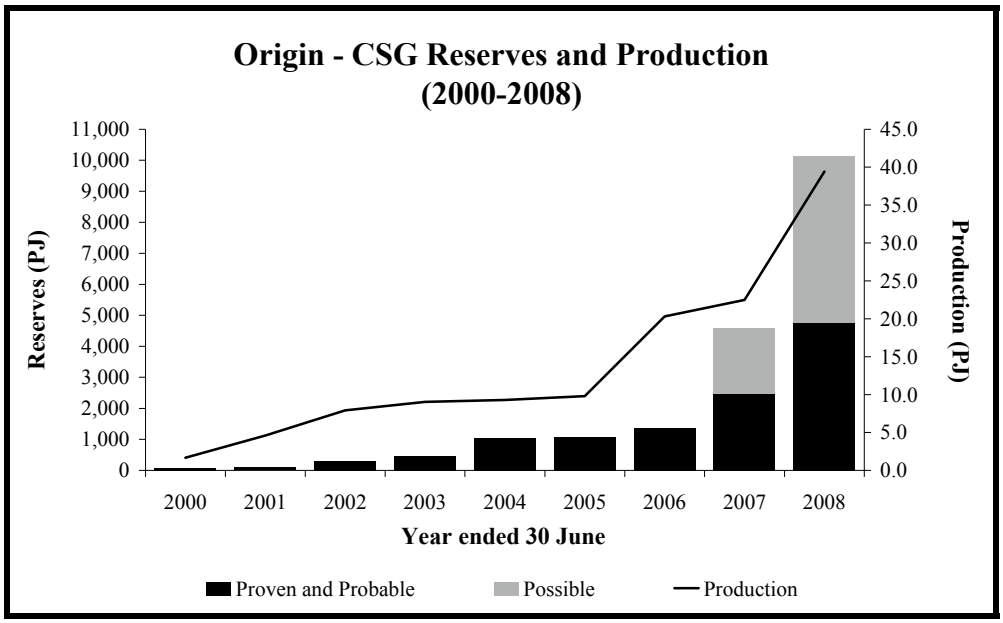
- 14.3PJ per annum (180PJ total) to Queensland Alumina Limited (ending 2021);
- 25PJ per annum (296PJ total) to AGL Energy (ending 2020);
- 472PJ over 21 years to Rio Tinto's Yarwun aluminium refinery (ending 2031);
- 7PJ per annum (92PJ total) to Incitec-Pivot (ending 2017); and
- 39.5PJ per annum (967PJ total) to Darling Downs Power Station (ending 2034).

Origin has also signed an agreement with the South West Queensland Gas Producers ("the SWQ Producers") for the swapping of between 155PJ and 202PJ of gas between Queensland and Moomba until mid 2012. The arrangement effectively enables Origin to deliver gas to New South Wales from its Queensland CSG projects. There is a limit to the volume that can be swapped under this arrangement and the 180 kilometre QSN Link pipeline is being developed to physically connect the Queensland CSG fields to the southern markets (due to be completed in 2009).

Origin's uncontracted reserves are available for sales to third parties or could be dedicated towards a LNG project.

5.3.3 Production

Historically, Origin's strategy has been to prove up reserves and develop production capacity in order to meet contracted demand as well as forecast growth in gas requirements from its generation and retail businesses. With increased confidence in the growth in demand for gas on the east coast, more speculative development has occurred. Origin is now the holder of the largest reserves of CSG and the largest producer of CSG in Australia. CSG production now exceeds Origin's share of conventional gas production from the Cooper Basin and represents approximately 40% of its total energy production.



Source: Origin

Total production of CSG during 2008 was 39.4PJ, an increase of 17PJ (75%) over the prior year. Production is planned to increase to around 120PJ per annum by 2011 to meet existing commitments. Most of Origin's current production (approximately 93%) derives from Origin's developed fields in the Bowen Basin. The Spring Gully and Fairview projects (both in the Bowen Basin) are expected to underpin the planned growth in production in the medium term. The Surat Basin remains relatively undeveloped (with production from the Talinga/Kenya field only commencing in 2007) and will be the focus of future exploration and development activities.

5.3.4 Technical Comparison

Origin's assets are concentrated in some of the more attractive CSG sweet spots in terms of the technical characteristics which determine the overall quantity and quality of the resources. The geology is very different between the Bowen and Surat basins. This has implications for exploration activities and production outcomes. A comparison of key technical characteristics of Origin's assets in these basins is shown in the table below:

Origin - Technical Comparison of Major CSG Producing Fields

	Bowen Basin	Surat Basin
Area	Comet Ridge	Undulla Nose/Walloons
Existing fields	Spring Gully Fairview	Talinga/Orana Argyle/Kenya/Bellevue
Average net coal	8 metres	20 metres
Average gas content	12 m^3 per tonne	8 m^3 per tonne
Well spacing	1,000 – 1,500 metres	750 metres
Area per well	1.0 – 2.25 km^2	0.56 km^2
Permeability	100 mD	500 mD
Time to peak	approx 2 – 5 years	approx 1– 2 years
Average peak production rate	~ 1,000 GJ per day	~ 2,000 GJ per day
Best sustained peak production rate	3,000 – 7,000 GJ per day	3,000 – 4,000 GJ per day
Estimated average well life	20 - 30 years	15 years

Source: Origin

The Bowen Basin consists of three main production regions: the northern Bowen Basin, the eastern margin and Comet Ridge. Origin's interests (specifically the Fairview and Spring Gully fields) are located in the highly productive southern part of the Comet Ridge area.

The three main coal seams in the Comet Ridge area tend to be more continuous, homogeneous and on average thicker than the individual seams which underlie Origin's Surat Basin assets. As a result several factors (including this geological consistency), wells can be spaced more widely. While this results in a longer dewatering period (that is, longer time to first gas) and slower ramp up of gas, the capital cost of developing the field is lower (due to the lower number of wells required) and economic production continues over a longer time period.

Origin's Surat Basin assets overlie the Walloon Coal Measures ("Walloons"), a body of rich gas bearing coals. The major assets (the Talinga/Orana and Argyle/Kenya/Bellevue fields) are concentrated in the highly productive Undulla Nose section of the Walloons Fairway. Origin also holds significant exploration interests in other areas of the Walloons. The geology in the Undulla Nose consists of a larger number of thinner seams with greater geological inconsistency than Comet Ridge (although with greater overall coal thickness). As a result, performance can differ significantly from well to well requiring a much higher well density and these wells tend to reach peak production more rapidly but with a reduced lifespan in comparison to Comet Ridge.

5.3.5 Bowen Basin Assets

The Bowen Basin (along with the Undulla Nose in the Surat Basin) includes the most attractive CSG fields in Australia which are considered comparable to the leading CSG fields in the world in terms of scale and productivity. The Bowen Basin is connected via lateral pipelines to the key markets at Gladstone. Origin's major interests in the Bowen Basin are:

Peat

The Peat field is located near the township of Wandoan in central Queensland. Origin acquired a 50% interest in the field (via OCA) in 1996 and increased this to 100% in 1998. Origin is also the operator. Following acquisition Origin carried out a comprehensive drilling and testing program which culminated in the signing of Australia's first major long term gas sale agreement for the supply of CSG to the BP Bulwer Island Refinery in Brisbane which runs until 2021. The field commenced full production in 2001 and produces around 4PJ of CSG per annum. Flow rates peaked in 2001 at 16TJ per day and production is expected to be maintained for some period, before slowly declining.

Spring Gully

The Spring Gully field (formerly known as Durham under Tri-Star's ownership) is located 90 kilometres north of Roma in central Queensland and comprises CSG processing facilities including two gas plants, gas gathering and export pipeline networks and water processing facilities. Origin holds an average 97.1% of the Spring Gully field (based on currently assessed 2P resources) across four PLs and one ATP and is also the operator. The remainder is held by Santos and Tri-Star. Origin first acquired interests (and operatorship) in the Spring Gully field in December 2001 through the acquisition of Transfield's CSG operations. Further interests were acquired in 2002 from Tri-Star, which are subject to reversionary rights.

Development of the field was commenced in 2004 and completed mid 2005. Initial production exceeded expectations and a new gas plant was commissioned in August 2007 at Strathblane which increased production capacity from 65TJ per day to 85TJ per day. Current operations comprise 108 wells and production has ramped up to 105TJ per day during the quarter ended June 2008.

A further expansion of Spring Gully is in progress. This will include 60 new development wells (of which 36 are already drilled), associated gas and water gathering systems, three new compressors at the Strathblane Gas Plant (now installed) and a new gas plant in the southern part of the field. The additional wells and plant are designed to increase production capacity to 150TJ per day and are scheduled to be operational by the first half of 2009.

Spring Gully is linked via a dedicated 89 kilometre pipeline to the Wallumbilla gas hub. Gas from Spring Gully is streamed into Origin's portfolio of gas supply contracts. Due to its pipeline access, Spring Gully may also supply future LNG projects at Gladstone.

A reverse osmosis water treatment plant has been built as part of this development to convert saline waste water into water for beneficial use. This plant was commissioned in December 2007 with capacity of 9ML per day and will be expanded to 12ML per day as water production increases. In addition, Spring Gully has an evaporation pond for brine disposal.

Fairview

The Fairview field is located north of Roma and to the north of the Spring Gully field. It is the oldest commercial Queensland CSG field, having produced the first contracted CSG in 1997 for Energex Limited. Some of the wells are believed to have been flowing for 15 years. Origin currently holds a 23.93% interest in the Fairview field (comprised of 10 PLs and three ATPs) which it acquired in 2002. The field is operated by Santos which acquired the balance of the interest in 2005.

Fairview is the second largest producing field in Origin's portfolio behind Spring Gully with current production of 72TJ per day. The average flow rate per well is approximately 1TJ per day, although some wells are producing in excess of 5TJ per day, consistent with some of the world's best producing fields. There are currently 87 producing wells at Fairview. Gas is collected for dehydration and compression at one of two compressor sites before being shipped through the Wallumbilla to Gladstone Pipeline (via a 26 kilometre lateral) or direct to the Wallumbilla gas hub (via a recently constructed 124 kilometre pipeline). A third compressor, due for commissioning in early 2009 is expected to increase capacity to 100TJ per day.

Significant exploration activities are planned to be undertaken over the next several years, with a targeted production of approximately 200TJ per day by 2012. Fairview is expected to be a major supply source for Santos' proposed LNG Project at Gladstone.

Water disposal has historically comprised creek discharge and reinjection, however, reverse osmosis units are currently under trial.

Other Bowen Interests

Origin has around a 23% interest in exploration acreage within the Comet Ridge area of the Bowen Basin and 50% of the Denison Trough operated by Santos and 100% of the Membrance/Lonesome fields which it operates.

5.3.6 Surat Basin Assets

Origin operates, or has interests in (through its joint ventures with QGC), a large component of the productive Walloon Fairway. Exploration and development is expected to increase significantly over the next few years with extensive drilling programs scheduled across Origin's interests. While overall estimated gas in place is substantial, the commerciality of extraction for the majority of Origin's Surat fields is yet to be tested, resulting in a relatively high proportion of 3P reserves. However, these interests are located adjacent to a number of commercially established producing fields.

The Walloons are located close to the Roma to Brisbane Pipeline. Origin is also constructing a gas pipeline that will connect the Walloons and Spring Gully to the Darling Downs Power Station.

Origin's major interests in the Surat Basin are:

Talinga/Orana

The Talinga/Orana gas fields are located in the Undulla Nose region of the Walloons. Origin secured an initial 50% interest and operatorship via OCA in December 2000 and increased its interest to 100% in February 2003.

Origin has operated pilot wells at Talinga since December 2001 and Orana since late 2006, with the former achieving its first gas sales in October 2007. The Orana production pilot has shown gas and water production sufficient to enable reserves booking. A development program of 100 wells as well as construction of gas and water processing facilities commenced in April 2008. Based on current estimates, peak development plateau is expected to be reached in 2014 with a target production of 90TJ per day for the initial phase. Production from Talinga/Orana will be streamed into Origin's gas supply contract portfolio.

Argyle/Kenya/Bellevue

The Argyle/Kenya/Bellevue fields are located to the southeast of the Talinga/Orana fields in the Undulla Nose region of the Walloons (referred to as the Central Fairway). Origin's interest ranges from 29.375% to 40.625%. Origin acquired its interests from Pangaea Oil and Gas Pty Ltd in February 2006. The fields are operated by QGC which sold a 20% interest in its CSG assets to BG Group in April 2008. The Argyle sequence was first drilled in 2000/01 followed by further wells at Argyle East in 2004.

Gas is presently processed at QGC's Berwyndale South gas plant before delivery to customers via a 14 kilometre lateral to the Roma to Brisbane Pipeline. The project was commissioned by the joint venture in June 2007. Current production is approximately 21TJ per day (100% interest) and is expected to increase as well production ramps up and gas processing is expanded. Investment in exploration and production has continued. It is currently proposed to increase production to 120TJ per day by 2010. Production from these fields is sold to a range of customers including Incitec-Pivot's fertiliser manufacturing facility at the Port of Brisbane.

Other Surat Interests

Origin holds a range of other exploration interests within the Undulla Nose and other parts of the Walloons in the Surat Basin. These include joint venture interests with Santos at Combabula and Roma North, as well as other wholly owned fields. These interests are at very early stages of exploration.

5.3.7 Galilee Basin

Origin obtained interests in exploration permits in the Galilee Basin in far north Queensland in late 2007. Total acreage is approximately 18,794km^2 across three ATPs. No exploration has been carried out and no reserves have been booked for these areas. Due to the early stage of development there is currently no pipeline connection from Galilee to gas markets. NSAI estimated total prospective resources of approximately 17,947PJ as at 30 June 2008. The Galilee Basin has drawn increasing interest as a potential source of CSG, with AGL Energy announcing a $37 million 'farm-in' agreement with Galilee Energy Limited (whose majority shareholder is ASX listed company Eastern Corporation Limited) in July 2008.

5.3.8 Reversion Rights

The CSG interests acquired from Tri-Star in 2002 are subject to reversion rights held by Tri-Star. These interests include permits in the Fairview field and the Spring Gully field and exploration permits in the Surat Basin and the Galilee Basin. Approximately one third of Origin's 3P CSG reserves at 30 June 2008 are subject to the reversion rights.

The reversion rights were granted at the time of acquisition. Deferred value sharing arrangements are common in the oil and gas industry, particularly in the United States. Although the CSG interests were acquired encumbered by these rights, it was considered acceptable so that Origin could derive the operational benefits from controlling 100% of the interests during the exploration and development phase.

Reversion will occur only if certain conditions are met. The conditions will be met when Origin has fully recovered from revenue its capital and operating expenditure plus an uplift factor (calculated monthly at a rate of 8% per annum on cumulative capital, operating and

overhead expenditure) together with the acquisition price and royalties. Whether the reversion rights are triggered is tested on a portfolio basis (i.e. reversion needs to be tested across the entire portfolio of interests acquired by Origin from Tri-Star not on a field by field basis).

Should reversion be triggered, Tri-Star would be entitled to 45% of Origin's interests that were acquired from Tri-Star and Origin's share in those interests would decrease to 55%. At that time, Tri-Star would be entitled to extract its share of any remaining CSG, would need to enter into its own contracts to sell that CSG and need to contribute its share of future capital, operating and abandonment costs. Origin would retain its 55% interest as well as control of operations and gas processing.

Origin has calculated that the theoretical maximum reversion of Origin's current 3P reserves is 14% and for 2C resources is 24% based on reserves and resources as at 30 June 2008. At current domestic gas prices and planned production Origin does not expect reversion to occur. If reversion does occur due to higher gas prices, Origin considers that the reduction in its share of 3P reserves will be outweighed by the increase in its 3P reserves that will have occurred because of those higher prices before reversion is triggered.

5.4 Conventional Oil and Gas Assets

5.4.1 Cooper Basin

The Cooper Basin is located in central Australia (straddling the South Australia and Queensland borders) and is Australia's largest onshore resource project. Gas was discovered in the Cooper Basin 1963 and commercial production commenced in 1969. It has been the principal supplier of natural gas to New South Wales, South Australia and Queensland. Santos operates the Cooper Basin.

The Cooper Basin comprises approximately 160 gas fields and 75 oil fields currently in production. These fields deliver oil and gas into production facilities at Moomba in South Australia and Ballera in Queensland through approximately 5,600 kilometres of pipelines.

Natural gas liquids are recovered via a refrigeration process in the Moomba plant and sent together with stabilised crude oil and condensate via pipeline to Port Bonython in South Australia. Ethane is sent to plastics manufacturer Qenos Pty Ltd ("Qenos") in Sydney via a dedicated pipeline. Sales gas is sent to Adelaide, Sydney, Mt Isa and Brisbane via pipeline. The Moomba facility includes substantial underground storage for processed sales gas and ethane. Following a leak, the Moonie to Brisbane Pipeline was closed in July 2007 and in April 2008 Santos announced that it would not reopen. Crude oil is currently being trucked to Dullingari or Moomba in South Australia or Lytton in Queensland. This is expected to cease with the commissioning of the new Jackson to Moomba pipeline that was completed in July 2008.

Ballera is approximately 90 kilometres east of the South Australia-Queensland border and about 950 kilometres north of Adelaide. It has a small underground storage system for processed sales gas. No crude oil is processed at Ballera. All crude oil is processed at Jackson and then transported to the Lytton terminal in Brisbane for distribution. Some natural gas liquids are recovered at Ballera with raw gas and condensate sent to Moomba via pipeline to allow additional recovery of liquids via the refrigeration process.

The majority of gas reserves at the Cooper Basin are contracted under long term take or pay contracts. The largest customer is AGL Energy which has two contracts for 505PJ of gas between 2003 and 2016 (equating to more than 50% of contracted reserves). Other customers include Origin, Xstrata plc and Qenos. The Cooper Basin also purchases small quantities of gas and liquids externally to meet contract arrangements.

Origin has various interests in fields across both the South Australian and Queensland sections of the Cooper Basin. Its aggregate share of reserves in the Cooper Basin is summarised below:

Origin – Share of Cooper Basin Reserves as at 30 June 2008		
	1P	**2P**
Gas (PJ)	67	157
Condensate/Naphtha (Kbbls)	833	2,212
Crude oil (Kbbls)	1,004	3,195
LPG (Kt)	116	299
Total (PJe)	**83**	**202**

Source: Origin

The Cooper Basin is now in decline as contract volumes commence to ramp down. Although Origin and the other participants in the Cooper Basin continue to undertake brownfield exploration activities in the area, Origin management consider it unlikely that there are any substantial prospects remaining undeveloped.

Origin's share of production of the Cooper Basin for the five years ended 30 June 2008 is summarised below:

Origin – Share of Cooper Basin Production					
	Year ended 30 June				
	2004	**2005**	**2006**	**2007**	**2008**
Gas (PJ)	33.6	30.6	25.6	23.0	19.6
Ethane (PJ)	0.8	1.3	1.6	1.6	1.3
Crude oil (Kbbls)	375.1	324.3	331.3	307.8	331.4
Condensate/Naphtha (Kbbls)	407.0	484.3	403.6	370.1	305.6
LPG (Kt)	34.0	48.6	43.6	40.9	37.1
Total (PJe)	**40.5**	**38.8**	**33.4**	**30.4**	**26.3**

Source: Origin

5.4.2 BassGas Project

The BassGas Project commercialises gas from the Yolla gas field in Bass Strait and is expected to meet around 10% of Victoria's demand for 15 years. The Yolla gas field was discovered in 1985 (with the Yolla 1 well) and is located approximately 120 kilometres from the coast of Tasmania and 150 kilometres from the coast of Victoria. Yolla 2 was drilled in 1998 and Yolla 3 and 4 development wells were drilled in 2004. The Yolla gas field contains recoverable reserves of approximately 323PJ of sales gas, 13MMbbls of condensate and 0.97Mt of LPG in the main reservoir with additional reserves possible in other unexplored parts of the field.

The BassGas Project was established in July 2001 and production began in June 2006 reaching design capacity in early 2007. Liquids production was lower than anticipated in the quarter ended 30 June 2008 due to capacity constraints in the onshore gas processing plant at Lang Lang and production from some areas was at lower condensate yields than the field average. The joint venture has invested $750 million to develop the project.

The Yolla platform is generally unmanned. An undersea pipeline transports the gas and liquids from the Yolla field and it intersects land near Kilcunda Beach. In total, 67 kilometres of onshore, underground gas pipelines have been installed with the first section (known as the "raw gas" pipeline) being 32 kilometres long and connecting the undersea pipeline to the Lang Lang gas processing plant. The Lang Lang plant has a capacity of 67TJ per day. Liquids are transported by road. The sales gas is transported in a 35 kilometre pipeline to the Victorian Principal Gas Transmission Pipeline near Pakenham. All of the gas production is acquired by Origin under long term gas contracts and sold throughout south east Australia by the Retail business. The processed condensate and LPG are transported by road to the Shell Refinery in Geelong.

Origin is the operator and holds a 42.5% interest in the BassGas Project. Origin's share of the reserves of the BassGas Project are summarised below:

Origin – Share of BassGas Project Reserves as at 30 June 2008		
	1P	**2P**
Gas (PJ)	100	130
Condensate/Naphtha (Kbbls)	3,807	4,964
Crude oil (Kbbls)	105	349
LPG (Kt)	306	399
Total (PJe)	**137**	**179**

Source: Origin

Yolla consists of four main reservoirs, of which two are currently producing. Since the start of production, observed liquid yields, particularly condensate, have been lower than forecast. Origin's share of production of the BassGas Project since commencement is summarised below:

Origin – Share of BassGas Project Production			
	Year ended 30 June		
	2006	**2007**	**2008**
Gas (PJ)	0.1	6.7	7.8
Condensate/Naphtha (Kbbls)	7.8	332.4	319.8
LPG (Kt)	-	16.4	18.6
Total (PJe)	**0.2**	**9.3**	**10.5**

Source: Origin

Production was restricted in the second half of 2008 by remedial work on the Yolla 3 well. Whilst Yolla will continue production from the Yolla 3 and 4 wells, it will be unable to maintain full production from the fourth quarter of 2009 without additional wells or on platform compression. Pumping and compression is required to manage declining reservoir pressure beyond 2011. Furthermore, it is unlikely that the reliability of Yolla can be maintained on an unmanned basis in the long term. Accordingly, the field development plan includes a "mid life extension plan" which canvasses two options:

- base option: drilling of Yolla 5 and 6 wells and conversion to manned operation in the first quarter of 2010 (contingent on rig availability), and on-platform export compression and pumping installed a year later; and
- defer option: drilling of Yolla 5 and 6 wells is deferred for two years.

Early commitment to the mid life extension plan (the base option) is Origin's preferred option as the economic value is eroded by deferral of drilling as production falls below the plateau in 2012. Origin expects a final investment decision to be made in December 2008. The budgeted capital cost of the extension plan is $230-260 million (100%).

There are a number of near field development options in Bass Basin, including a tieback to Yolla with host facilities or a second fixed platform.

5.4.3 Otway Gas Project

The Otway Gas Project involves the development of the Thylacine and Geographe gas fields located offshore from Victoria. Geographe is 55 kilometres and Thylacine is 70 kilometres south of Port Campbell. The project proposes to supply gas via either the SEAGas Pipeline to Adelaide or the South West Pipeline to Melbourne. The fields were discovered in 2001. A platform was installed on Thylacine in 2006 and four gas development wells were drilled during 2006. The Otway Gas Project commenced production in September 2007. The onshore gas processing plant was shut down in late September 2007 due to commissioning issues. Gas production resumed in February 2008 and commercial operations commenced in June 2008.

Gas is extracted using the remotely operated Thylacine platform and brought to shore via offshore and onshore pipelines to a gas processing plant located north of Port Campbell. Condensate and LPG will also be produced at the plant. The Thylacine and Geographe fields are expected to produce 885PJ of gas, 12.2MMbbls of condensate and 1.7 Mt of

LPG. Woodside is the operator of the Otway Gas Project. Origin has a 30.75% interest and purchases 48.5% of the sales gas for its Retail business. The balance of sales gas is sold by Woodside to TruEnergy. The condensate is sold to Shell whilst each joint venture party lifts their share of propane and autogas products and sells to a variety of wholesale and retail customers.

Origin's share of the reserves in the Otway Gas Project are summarised below:

Origin – Share of Otway Gas Project Reserves as at 30 June 2008

	1P	2P
Gas (PJ)	171	265
Condensate/Naphtha (Kbbls)	2,053	3,194
LPG (Kt)	312	491
Total (PJe)	**197**	**306**

Source: Origin

The field production and development strategy is based on three phases. Phase 1 has been completed. Significant capital expenditure overruns were experienced during Phase 1. The original Phase 1 development budget was $811 million but the latest reported estimated cost is approximately $977 million.

Phases 2 and 3 seek to extend the project to access to reserves not otherwise produced:

- Phase 2 involves the development of the Geographe field using three sub-sea wells tied in to pre-installed pipeline tees and Thylacine North using one sub-sea well tied back to the Thy-A platform. The estimated cost is at least $447 million (100%); and
- Phase 3 involves inlet compression at the onshore gas plant. The estimated cost is at least $73 million (100%).

There is considerable uncertainty as to the scope, costs and timing for Phases 2 and 3. Alternative development plans include implementing Phase 3 ahead of Phase 2 and a reduced number of Geographe wells. Origin expects the development concept will be finalised prior to 2009.

5.4.4 Other Onshore Australia

Origin's other Australian onshore interests are in the Surat Basin, Denison Trough, Perth Basin and the onshore Otway Basin.

The Surat Basin acreage is approximately 90 kilometres long and 70 kilometres wide and is centred around the township of Surat in Queensland. Drilling first commenced in the region of the Surat Basin currently held by Origin in 1966 with the first commercial discovery made in 1970. Gas production commenced from the Kincora production facility in 1977 via a 6 inch pipeline to Wallumbilla. The plant has a capacity of 25 TJ per day with current throughput averaging approximately 10TJ per day due to declining reserves and deliverability. There is also a storage facility at Newstead, with the potential to contain up to 8PJ storage gas to supplement field deliverability, with a peak deliverability of 15TJ per day. Origin holds various interests in the Surat Basin and is the exploration and production operator of a number of the ATPs and PLs comprising the basin.

The Denison Trough is located on the western limb of the Bowen Basin in the Springsure/Injune area north of Roma in Queensland. It is located 520 kilometres northwest of Brisbane and 230 kilometres north of Roma. The Denison Trough acreage is over 280 kilometres long and 63 kilometres wide. Origin has a 50% interest in the Denison Trough and is the production operator.

The Denison Trough gas fields were first discovered in the early 1960s. The emergence of the potential Queensland Alumina Limited demand in the early 1980s led to exploration and the discovery of a further six fields within the Denison Trough. In July 1989, Origin signed a 10 year gas purchase agreement to supply 13.1PJ of gas per annum to Queensland Alumina Limited in Gladstone. The agreement was replaced in 1996 with a 15 year

agreement for 14.3PJ per annum. As the Denison Trough is believed to contain CSG this interest will be an asset of the JV.

Origin's interests in the Perth Basin comprise:

- a 67% interest in the Beharra Springs gas fields, located 30 kilometres southeast of the township of Dongara and 2 kilometres north of the Beharra Springs Gas Plant. Origin is the operator of the field;
- a 50% interest in the Hovea/Eremia/Xyris gas fields; and
- a 49.189% interest in the Jingemia gas fields.

The Perth Basin oil fields have historically produced high margin liquids. However, the fields are mature and production levels are now in decline. During 2007 three new wells were successfully brought on line temporarily lifting production rates. However, by 30 June 2007, production had declined and the remaining reserves in the fields are 1.2MMbbls at 30 June 2008. Production at Beharra Springs declined significantly in the March 2008 quarter due to a shutdown resulting from a fire in December 2007.

In July 2008, Origin announced the sale of its exploration acreage, producing gas fields and associated processing facilities in South Australia's onshore Otway Basin for $2.175 million. Completion of this transaction is subject to regulatory approvals.

Origin's share of the reserves in the Surat Basin, Denison Trough, Perth Basin and onshore Otway Basin are summarised below:

Origin – Share of Other Onshore Australia Reserves as at 30 June 2008

	1P	2P
Gas (PJ)	47	89
Condensate/Naphtha (Kbbls)	250	423
Crude oil (Kbbls)	671	1,417
LPG (Kt)	32	54
Total (PJe)	**55**	**113**

Source: Origin

The production history of the Surat Basin, Denison Trough, Perth Basin and onshore Otway Basin for the four years ended 30 June 2008 is summarised below:

Origin – Share of Other Onshore Australia Production

	Year ended 30 June				
	2004	2005	2006	2007	2008
Surat Basin/Denison Trough					
Gas (PJ)	10.7	11.7	10.2	11.9	9.9
Crude oil (Kbbls)	77.9	29.2	22.3	27.8	37.8
Condensate/Naphtha (Kbbls)	54.2	73.5	59.9	59.7	52.4
LPG (Kt)	8.8	9.9	9.2	9.8	9.0
Onshore Otway Basin					
Gas (PJ)	7.5	7.6	3.6	2.0	0.6
Condensate/Naphtha (Kbbls)	38.9	34.5	14.8	10.0	5.9
Perth Basin					
Gas (PJ)	2.3	2.5	3.2	4.0	4.0
Crude oil (Kbbls)	1,247.3	1,650.0	1,202.6	997.4	568.4
Condensate/Naphtha (Kbbls)	3.9	4.5	8.4	9.7	7.9
Total (PJe)	**29.2**	**32.7**	**25.2**	**24.9**	**19.0**

Source: Origin

5.4.5 Kupe Gas Project

The Kupe gas field is located approximately 30 kilometres offshore southwest of Hawera in New Zealand's Taranaki Basin. The Kupe Gas Project was formed to extract gas and condensate from that field. Origin acquired a 50% interest in the Kupe Gas Project in early 2004 and is the project operator. The Kupe gas field was discovered in 1986 but remained undeveloped due to lack of a suitable market. Approved to proceed in June 2006, the Kupe Gas Project is expected to be operational in 2009 and will provide approximately 20PJ of gas, 90Kt of LPG and 1.7MMbbls of condensate per annum. The Kupe Gas Project will make a significant contribution to New Zealand's gas supply for 15-20 years.

Construction of the Kupe Gas Project is progressing to schedule with the offshore work (including the drilling of the development wells) completed in June 2008. Development is by way of a wellhead platform, pipeline to shore and onshore production station. Construction is proceeding on the onshore production station with first gas expected by mid 2009. It is anticipated that a further two or three wells will be drilled in a second development phase in 7 to 10 years with the exact timing dependent on field performance.

The gas from Kupe is to be acquired by Genesis with oil to be transported to New Plymouth for shipping to market and LPG is likely to be sold to Rockgas.

Origin's share of the reserves in the Kupe Gas Project are summarised below:

Origin – Share of Kupe Project Reserves as at 30 June 2008		
	1P	**2P**
Gas (PJ)	100	127
Condensate/Naphtha (Kbbls)	6,353	7,352
LPG (Kt)	457	531
Total (PJe)	**159**	**194**

Source: Origin

5.4.6 Other Assets

Halladale and Blackwatch

In February 2008, Origin acquired Woodside's interest in exploration permits covering the Halladale and Blackwatch gas and condensate fields in the offshore Otway Basin in Victoria (taking its interest to 100%). The fields are located four to five kilometres offshore and may potentially be accessed via extended reach drilling from onshore. This would provide an economic means of tying the field into either new or existing pipelines and plant infrastructure in the area. The fields are estimated to contain 55PJe recoverable gas and condensate contingent resource.

Onshore Taranaki Basin

In December 2007, Origin announced the acquisition of upstream assets in New Zealand from Swift Energy Company including the Rimu and Waihapa producing assets in the onshore Taranaki Basin and various exploration permits. These assets are expected to deliver operational synergies with the Kupe Gas Project and exploration opportunities. Origin's share of reserves in the onshore Taranaki Basin are summarised below:

Origin – Share of Onshore Taranaki Reserves as at 30 June 2008		
	1P	**2P**
Gas (PJ)	6	20
Condensate/Naphtha (Kbbls)	104	511
Crude oil (Kbbls)	118	2,054
LPG (Kt)	9	34
Total (PJe)	**7**	**36**

Source: Origin

5.4.7 Exploration

Origin's exploration strategy is to add gas reserves which can access existing infrastructure and local markets. The exploration portfolio includes ongoing brownfield exploration in the near field to Origin's existing activities and includes offshore and onshore acreage in the Otway and Perth basin, the offshore Bonaparte and Bass basins and the onshore Cooper, Surat and Bowen basins in Australia.

Origin also has interests in a number of greenfield exploration assets:

- **Northlands Basin in New Zealand:** a 50% equity interests in two permit areas in the Northland Basin in New Zealand for which Origin has incurred approximately NZ$8 million in capital expenditure to date;
- **Canterbury Basin in New Zealand:** a 100% equity interest in two permit areas in the Canterbury Basin in New Zealand for which Origin has incurred approximately NZ$8 million in capital expenditure to date;
- **Vietnam**: a 50% interest in a permit area in offshore Vietnam for which Origin has incurred approximately US$1.0 million in capital expenditure to date; and
- **Kenya:** a 75% interest in two permit areas in the Lamu Basin in Kenya for which approximately US$6 million (100%) in capital expenditure has been incurred to date.

5.5 Financial Performance

The adjusted financial performance of Exploration & Production for the five years ended 30 June 2008 is set out in Section 4.3 of this report and summarised below:

Exploration & Production – Adjusted Financial Performance ($ millions)

	Year ended 30 June				
	2004 actual AGAAP	2005 actual AIFRS	2006 actual AIFRS	2007 actual AIFRS	2008 actual AIFRS
Operating statistics					
2P CSG reserves (PJe)	*1,035*	*1,086*	*1,375*	*2,470*	*4,751*
2P conventional reserves (PJe)	*1,185*	*1,134*	*1,061*	*1,001*	*1,019*
Total 2P reserves (PJe)	*2,220*	*2,220*	*2,436*	*3,471*	*5,770*
Production volumes (PJe)	*81*	*83*	*78*	*87*	*101*
Sales volumes (PJe)	*85*	*87*	*84*	*93*	*101*
Adjusted external sales revenue	290.8	349.8	344.0	339.1	381.4
Internal sales revenue	54.5	64.6	90.9	145.1	145.6
Total adjusted sales revenue	**345.3**	**414.4**	**434.9**	**484.2**	**527.0**
Adjusted EBITDAF	**211.1**	**218.5**	**188.8**	**254.4**	**258.3**
Adjusted depreciation and amortisation	(91.2)	(97.9)	(106.4)	(134.7)	(144.0)
Adjusted EBITF	**119.9**	**120.6**	**82.4**	**119.7**	**114.3**
Capital expenditure					
- Stay in business	55.0	48.8	62.2	56.8	48.9
- Growth[47]	313.0	335.2	600.3	413.5	774.8
	368.0	**384.0**	**662.5**	**470.3**	**823.7**
Statistics					
Total adjusted sales revenue growth	*20.6%*	*20.0%*	*4.9%*	*11.3%*	*8.8%*
Adjusted sales per PJe (millions)	*$4.07*	*$4.79*	*$5.19*	*$5.23*	*$5.23*
Adjusted EBITDAF growth	*13.2%*	*3.5%*	*(13.6%)*	*34.7%*	*1.5%*
Adjusted EBITF growth	*15.9%*	*0.6%*	*(31.7%)*	*45.3%*	*(4.5%)*
Adjusted EBITDAF margin[48]	*61.1%*	*52.7%*	*43.4%*	*52.5%*	*49.0%*
Adjusted EBITF margin[48]	*34.7%*	*29.1%*	*18.9%*	*24.7%*	*21.7%*
Adjusted EBITDAF/ SIB[49] capital expenditure	*3.8x*	*4.5x*	*3.0x*	*4.5x*	*5.3x*

Source: Origin and Grant Samuel analysis

47 Including acquisitions and construction projects.

48 Calculated by reference to total adjusted sales revenue.

49 SIB = stay in business

The financial performance of Exploration & Production has been extracted from the consolidated financial statements of Origin and adjusted by Grant Samuel in Section 4.3 of this report to exclude significant and non recurring items (e.g. impairment of Cooper Basin in 2004 and 2007 and impairment of Onshore Otway assets in 2007), other income and (in 2004 only) amortisation of goodwill. Furthermore, as Exploration & Production sells a significant proportion of gas and LPG produced to Origin's Generation and Retail businesses, internal sales have been added back into total sales revenue in order to better analyse operating performance.

Major factors affecting the performance of Exploration & Production in the period include:

- on adoption of AIFRS from 2005 the accounting policy for exploration was changed from full capitalisation of exploration expenditure to a successful efforts basis which requires all exploration expenditure of a general nature and all unsuccessful exploration and appraisal drilling to be expensed. This resulted in a increase in exploration and evaluation expense and a decrease in amortisation expense from the 2004 year to 2005;
- an increase in the write off of capitalised development expenses decreased margins in 2006;
- depreciation and amortisation increased in 2006 and 2007 reflecting commencement of production from the Spring Gully field in 2006 and the BassGas Project in 2007, higher depletion charges in the Cooper and Surat Basins in 2006 and Perth Basin in 2007 and further growth in the production and asset base of Origin's CSG projects;
- CSG production volumes have increased significantly from 10.6PJ in 2004 (12% of energy production) to 39.4PJ in 2008 (39% of energy production). The increased CSG production and sales has offset declines in gas production and sales from the mature conventional basins although the CSG sales have been made under contracts made at prices below conventional gas;
- lower volumes of crude oil sales from 2006 have been offset by higher oil prices (increased from $49.94 per barrel in 2005 to $96.54 per barrel in 2008);
- the first full year contribution to earnings by the BassGas Project occurred during 2008. There were capacity constraints for production during the year but these issues have now been resolved; and
- the Otway Gas Project was completed and commenced production in June 2008 and is expected to contribute significantly to sales and earnings in future years.

Stay in business capital expenditure for the producing assets has been in the range of $50-60 million per annum. Growth capital expenditure relates to exploration and evaluation expenditure (including directly attributable overheads, general permit activity, geological and geophysical costs) which is capitalised where costs are expected to be recouped through successful development, as well as other development expenditure. The major items of development expenditure have been in relation to the development of the CSG reserves, the Otway Gas Project and the BassGas Project. Acquisitions made during the period include the acquisition of the remaining 14.77% of OCA in 2004 ($74 million) and the acquisition of an additional 5% interest in the BassGas Project ($55 million) and coal seam gas assets from Pangaea Oil and Gas Pty Ltd ($72 million) in 2006.

6 Profile of Generation

6.1 Operations

The Generation business encompasses 704MW of installed electricity generation capacity, 2,096MW of committed generation capacity and a further 1,508MW of permitted generation sites. It also includes a portfolio of renewable generation assets and investments.

Origin's existing electricity generation portfolio is located predominantly in eastern Australia and includes base, peaking and intermediate generation:

Origin - Generation Portfolio

Plant	State	Interest	Capacity[50] (MW)	Type	Fuel	Operation
Internally contracted						
Mount Stuart	Queensland	100%	288	OCGT	Jet fuel	Peaking
Quarantine	South Australia	100%	96	OCGT	Gas	Peaking
Ladbroke Grove	South Australia	100%	80	OCGT	Gas	Base/Peaking
Roma	Queensland	100%	74	OCGT	Gas	Peaking
Externally contracted						
Osborne	South Australia	50%	90	Cogeneration	Gas	Base load
Worsley	Western Australia	50%	60	Cogeneration	Gas	Base load
Bulwer Island	Queensland	50%	16	Cogeneration	Gas	Base load
Total capacity			**704**			

Source: Origin

The internally contracted generation assets are a peaking generation portfolio used to manage Retail's exposure to wholesale pool prices during periods of peak demand. The portfolio currently produces around 1% of the annual electricity demand and 10% of peak demand capacity of the Retail business.

Origin also has 50% interests in gas fired cogeneration plants which supply electricity and heat to third parties under long term contracts. Osborne Cogeneration Plant services Penrice Soda Products Pty Ltd and Flinders Operating Services Pty Ltd (owned by BBP) in South Australia, Worsley Cogeneration Plant services the Worsley Alumina Refinery and Verve Energy (previously Western Power) in Western Australia and the Bulwer Island Cogeneration Plant services the Bulwer Island Refinery in Queensland.

Origin's power stations are almost entirely fuelled by natural gas. Gas consumed by Generation is sourced from Origin's wholly owned conventional gas and CSG reserves, joint venture interests and contract portfolio. Mount Stuart Power Station runs on jet fuel sourced from Shells' import terminal in Townsville although there is a possibility of converting the fuel source to gas in the future. Bulwer Island Cogeneration Plant utilises gas from Origin's Peat CSG field, Worsley Cogeneration Plant sources gas externally from the North West Shelf and the Osborne Cogeneration Plant sources gas from Flinders Operating Services Pty Ltd (owned by BBP).

Origin currently benefits from long term wholesale electricity purchase contracts which were entered into at a time of lower prices due to excess industry generation capacity. Consequently, Origin has not focused on developing additional generation capacity and only produces around 1% of its annual energy requirements for electricity and 10% of its peak requirements. This compares to peers such as AGL Energy which supplies approximately 50% of its base load requirements and 55% of its peak load requirements and TRUenergy which produces substantially more electricity that it sells to retail customers. As the long term electricity contracts run off Origin's Retail business will become more exposed to fluctuations in wholesale electricity prices and the electricity demand of the Retail business presents a significant opportunity to support the development of additional generation capacity. Consequently, Origin has committed to developing additional internal gas fired generation capacity. This will improve the natural hedge against volatile wholesale electricity prices as well as provide flexibility of channel through which to monetise Origin's gas reserves.

[50] Origin's pro rata interest.

Origin has committed to construction contracts for 2,096MW of gas fired power generation capacity (quadrupling its capacity over the next few years to 2,800MW) and holds permitted sites for 1,508MW of additional capacity:

Origin – Committed and Permitted Capacity

Plant	State	Capacity (MW)	Type	Operation	Fuel	Cost ($ millions)	Year
Committed Capacity							
Quarantine (expansion)	South Australia	120	OCGT	Peaking	Gas	86	2008
Mount Stuart (expansion)	Queensland	126	OCGT	Peaking	Jet fuel	92	2009
Darling Downs	Queensland	630	CCGT	Base load	Gas	951[51]	2009
Uranquinty	New South Wales	640	OCGT	Peaking	Gas	700	2009
Mortlake	Victoria	550	OCGT	Peaking	Gas	640	2010
Cullerin Range	New South Wales	30	Wind	Intermittent	Wind	90	2009
Total committed capacity		**2,096**				**2,559**	
Permitted Sites							
Spring Gully	Queensland	1,000	CCGT	Base load	Gas	na	na
Mortlake (expansion)	Victoria	450	CCGT	Base load	Gas	na	na
Conroy's Gap	New South Wales	30	Wind	Intermittent	Wind	na	na
Snowy Plains	New South Wales	28	Wind	Intermittent	Wind	na	na
Total permitted sites		**1,508**					

Source: Origin

The committed new capacity is primarily peaking generation and is designed to meet approximately 40% of Origin's peak electricity requirements (which is estimated to be growing by 8-12% per annum).

Quarantine Power Station and Mount Stuart Power Station are being expanded by the addition of new turbines to meet expected increases in peak demand from Origin's Retail business in their regions. The Quarantine expansion will also be supplied by natural gas from Origin's Otway Gas Project while the Mount Stuart expansion will run on jet fuel. Origin holds development approval to convert the Quarantine Power Station to a base load power station which would create additional demand for gas. Furthermore, Mount Stuart Power Station (including the expansion) could also be converted to run on gas.

Origin's base load capacity will increase substantially with the commissioning of the Darling Downs Power Station at Braemer in Queensland. It will be Australia's largest CCGT plant and is due to be completed in early 2010. Darling Downs Power Station will produce electricity for Origin's expanded customer base in Queensland following the Sun Retail acquisition as well as contribute to meeting the base load shortfall in the Queensland market. It is expected to have one of the lowest costs in the NEM as it is to be fuelled by gas from Origin's Spring Gully CSG field, has a competitive site location and has relatively low construction and long term maintenance costs.

Origin acquired the partly constructed Uranquinty Power Station in southern New South Wales for an enterprise value of $700 million in July 2008. The four 160MW turbine plant is expected to be completed in 2008/09. At 30 June 2008 the capital expenditure remaining to complete construction and commission the power station was estimated to be $160 million. Uranquinty will operate as a merchant plant supplying electricity into the NEM. It will source gas under contracts with Esso/BHP from Bass Strait but Uranquinty's location provides flexibility to source gas from across the east coast.

Mortlake Power Station in Western Victoria represents the first 550MW stage of a total 1,000MW permitted gas fired peaking plant at Mortlake, Victoria. It is being built in response to the growing and future demand for electricity and is expected to be completed in 2010/11. Mortlake Power Station's two 275MW turbines will be fuelled by natural gas from the offshore Otway Gas Project (in which Origin is a joint venture partner) and is designed to allow an upgrade to a base load plant if electricity prices are high or excess gas is available.

[51] Including cost of pipeline from Spring Gully field.

Origin also holds permits for a 1,000MW CSG fired base load power station at Spring Gully near Roma in central Queensland. The power station would allow Origin to meet forecast demand for base load electricity generation capacity in Queensland beyond 2010. The co-location of the power station with its CSG reserves provides economic and environmental benefits for the overall Spring Gully project.

Darling Downs and Spring Gully base load plants are to be supplied directly from Origin's CSG reserves.

Collectively, Origin's committed and permitted capacity represents half of the new build requirement for the NEM to 2012. However, even allowing for all of this new capacity, Origin would account for only 9% of forecast generation capacity in the NEM by 2016/17.

As the major projects are implemented, the scale and complexity of Origin's generation business is increasing. In this regard, the Generation business is supported by:

- Origin's major projects group (which comprises over 180 personnel) which is responsible for developing, designing and implementing major capital projects which have been identified as strategically important to Origin's growth. This involves obtaining development approvals, delivering large capital projects on time and on budget, safety and community awareness and identifying and managing risks. The costs of the major projects group are either capitalised into a specific project or expensed and allocated to the relevant business; and
- Origin's Energy Trading business (see Section 7.1) which seeks to match the supply and demand for gas and electricity (both physically and with derivative instruments) to reduce risk and to optimise the financial return to Origin. As electricity demand varies considerably with variations in weather conditions there will be occasions when retail demand may not match existing or available contracts and therefore the Retail business will be exposed to spot prices in the NEM. In this case, Energy Trading may determine that Origin's financial position is better served by starting up appropriate peaking plants in the generation portfolio.

Future expansion of generation capacity will depend on the relative cost competitiveness of building capacity versus entering into long term supply contracts for electricity purchases.

Origin's substantial and growing portfolio of mainly gas generation assets positions it well for the introduction of carbon emissions trading. In addition, over the last decade Origin has developed a portfolio of renewable generation assets and investments including geothermal, wind and solar energy. The extent of its investment in renewable assets is growing in response to the setting of mandatory renewable energy targets. Origin has addressed a range of renewable energy generation sources rather than focussing in one area in order to provide future options for its generation business. In the long run, it is considered that geothermal energy generation will be the lowest cost renewable energy technology. However, as geothermal energy technology is still being developed in the Australian context, wind remains the lowest cost large scale renewable technology in the short to medium term.

Origin's renewable energy generation portfolio includes:

- **geothermal:** a 30% interest in a joint venture with ASX listed Geodynamics Limited ("Geodynamics") which is seeking to commercialise the geothermal potential of hot rocks in the Cooper Basin in South Australia. The aim is to use heat trapped five kilometres below the earth's surface to heat water pumped underground to create steam to generate electricity. Origin has made a total commitment of $150 million to project expenditure, of which $27 million has been invested to date. Geodynamics have currently drilled three wells – Habanero 1, Habanero 2 and Habanero 3. Habanero 3 was completed in early 2008 and is currently being evaluated. The joint venture is aiming to have a 1MW pilot plant in operation by the end of 2008 and a 50MW plant by 2012. In addition, Origin is a major shareholder in Geodynamics with a 6.86% shareholding. In committing to the development of geothermal energy technology in an Australian context Origin is leveraging the geothermal expertise which resides at its 51.3% subsidiary Contact Energy;
- **wind:** Origin holds an option over 590MW of wind farm development sites in New South Wales from wind generation developers Epuron, a subsidiary of German company Conergy AG. Under this option Origin has committed to the construction of the 30MW Cullerin Range Wind Farm west of Goulburn with the wind farm expected to be operational in early

2009. There are two other already permitted sites in New South Wales under the option (Conroy's Gap 30MW and Snowy Plains 30MW) and Origin also holds an option to develop a further 500MW of wind farm projects. Origin has also entered into a strategic relationship with Epuron. Cullerin Range is Origin's first owned wind farm. It has previously invested indirectly in wind farms by underwriting development by way of entering into offtake agreements (e.g. Pacific Hydro's development of wind farms at Codrington and Challicum Hills in Victoria). The Retail business currently contracts almost 200MW of wind generated electricity;

- **solar:** Origin has invested approximately $65 million in the development and commercialisation of the SLIVER® solar photovoltaic technology which it invested in conjunction with the Australian National University's Centre for Sustainable Energy Systems. SLIVER® solar panels use one-tenth of the silicon of conventional solar panels while matching their power, performance and efficiency. Origin has constructed a pilot plant in Adelaide in South Australia with a team of 50 people with the intention of proving the technology by manufacturing increasingly larger panels. It has currently started the early stages of planning for commercial production. A decision on progressing to commercial production is expected in the near future. Should commercial production of SLIVER® panels commence, Origin proposes to leverage the Retail business' position as a leading installer of domestic solar panels; and
- **geosequestration:** during 2007 Origin joined CO2CRC a collaborative research organisation exploring carbon dioxide capture and geological storage. If successful this technology may provide Origin with an alternative approach to reducing its greenhouse gas emissions.

6.2 Financial Performance

The adjusted financial performance of Generation for the five years ended 30 June 2008 is set out in Section 4.3 of this report and summarised below:

Generation – Adjusted Financial Performance ($ millions)

	Year ended 30 June				
	2004 actual AGAAP	2005 actual AIFRS	2006 actual AIFRS	2007 actual AIFRS	2008 actual AIFRS
Operating statistics					
Total generation capacity[52] (MW)	*878*	*878*	*870*	*870*	*870*
Total electricity sales[52] (GWh)	*1,830*	*1,763*	*1,620*	*1,620*	*1,550*
Adjusted generation capacity (MW)[53]	*670*	*670*	*670*	*662*	*662*
Adjusted electricity sales (GWh)[53]	*1,060*	*1,100*	*900*	*860*	*800*
Adjusted external sales revenue	74.0	77.3	67.2	66.7	40.1
Internal sales revenue	43.1	47.9	29.0	35.9	46.4
Total adjusted sales revenue	**117.1**	**125.2**	**96.2**	**102.6**	**86.5**
Adjusted EBITDAF	**46.4**	**43.4**	**42.7**	**66.5**	**40.5**
Adjusted depreciation and amortisation	(21.7)	(24.4)	(23.0)	(19.8)	(17.3)
Adjusted EBITF	**24.7**	**19.0**	**19.7**	**46.7**	**23.2**
Capital expenditure					
- Stay in business	5.0	2.1	5.7	4.8	7.5
- Growth[54]	8.0	5.5	11.7	84.2	488.1
	13.0	**7.6**	**17.4**	**89.0**	**495.6**
Statistics					
Total adjusted sales revenue growth	*20.3%*	*6.9%*	*(23.1%)*	*6.7%*	*(15.8)%*
Adjusted EBITDAF growth	*27.6%*	*(6.5%)*	*(1.6%)*	*55.7%*	*(39.1%)*
Adjusted EBITF growth	*51.2%*	*(23.1%)*	*3.7%*	*137.1%*	*(50.3%)*
Adjusted EBITDAF margin[55]	*39.6%*	*34.7%*	*44.4%*	*64.8%*	*46.9%*
Adjusted EBITF margin[55]	*21.1%*	*15.2%*	*20.5%*	*45.6%*	*26.9%*
Adjusted EBITDAF/ SIB[56] capital expenditure	*9.3x*	*20.7x*	*7.5x*	*13.9x*	*5.4x*

Source: Origin and Grant Samuel analysis

52 Generation capacity and electricity sales including 100% of equity accounted cogeneration plants.
53 Capacity and electricity sales excludes equity accounted cogeneration but includes Origin's 50% share of Worsley Cogeneration.
54 Including acquisitions and construction projects.
55 Calculated by reference to total adjusted sales revenue.
56 SIB = stay in business

The financial performance of Generation has been extracted from the consolidated financial statements of Origin and adjusted by Grant Samuel in Section 4.3 of this report to exclude share of profits from equity accounted investments (i.e. Osborne and Bulwer Island cogeneration interests), significant and non recurring items (e.g. termination payment in relation to the Mount Stuart power purchase agreement), other income and (in 2004 only) amortisation of goodwill. Furthermore, as Generation sells a significant proportion of electricity generated to Origin's Retail business, internal sales have been added back into total sales revenue in order to better analyse operating performance.

Major factors affecting the performance of Generation in the period include:

- disposal of its interest in the 8MW OneSteel Whyalla cogeneration plant in 2006;
- the termination of the Mount Stuart Power Station power purchase agreement at 31 December 2006. This had the effect of reducing external sales revenue and increasing internal sales revenue and decreasing depreciation expense (to reflect the effective life of the plant rather than the life of the power purchase agreement). The power station has been added to the internal generation portfolio and provides additional flexibility;
- the extension of Ladbroke Grove's useful life as a result of a major component overhaul in October 2006 has decreased depreciation expense;
- the level of plant availability from year to year (e.g. outages, refits); and
- the level of calls to dispatch on the peaking plants, particularly during 2007.

External sales represent Origin's 50% share of revenue from the Worsley cogeneration plant. Internal sales are made to the Retail business on the basis of a tolling agreement representing a fee for the capacity provided and costs incurred by the merchant power stations. Consequently, Generation's earnings reflect a return on investment rather than movements in electricity prices.

Stay in business capital expenditure for the existing generation portfolio is relatively low at around $5-10 million per annum. Growth capital expenditure has increased over time as Origin has focussed on developing new capacity to meet future electricity demand as well as a renewable generation portfolio. Expenditure in 2007 and 2008 primarily relates to the portfolio of committed gas fired generation projects. It also reflects the ongoing investment in renewable energy generation including the Geodynamics joint venture, wind farms and the SLIVER® technology. The investment in new generation capacity is expected to result in a substantial uplift in earnings for the Generation business from 2009.

7 Profile of Retail

7.1 Operations

Origin markets and retails electricity, natural gas and LPG predominantly in eastern Australia. In 2008 Origin sold 264PJe of energy including 32TWh of electricity, 127PJ of natural gas and 462Kt of LPG.

(i) Retail

Origin markets and sells gas and electricity in Victoria, Queensland, South Australia and New South Wales. It has approximately 2.7 million mass market (residential and small and medium enterprise customers) energy accounts comprising 1.8 million electricity accounts and 0.9 million gas accounts including 0.9 million dual fuel (i.e. gas and electricity) customers. It currently does not operate in the Western Australian, Northern Territory or Tasmanian retail markets. Origin is estimated to have an overall market share in the states in which it operates of 23% for electricity and 27% for gas. It has the second largest retail customer base in the Australian energy sector.

Origin has substantial market shares in Victoria and Queensland as a consequence of a number of acquisitions it has made in those states of electricity and gas retailers since 1999. These acquisitions include incumbent electricity retailers CitiPower and Powercor in Victoria and Sun Retail in Queensland and gas retailer Energy21 in Victoria. It also has a substantial market share in gas retailing in South Australia as it acquired the incumbent gas retailer (The South Australian Gas Company) in 1993. In comparison, Origin's market share for both electricity and gas retailing in New South Wales and electricity retailing in South Australia are relatively low as it entered each of these retail markets as a new entrant rather than by acquisition. Origin has a strong interest in participating in the proposed sale of the New South Wales electricity retailers.

The core retailing activities are complemented by a range of energy related services provided to its mass market customer base. Origin operates 30 branded shops (including 13 company operated shops, 6 agent shops and 5 authorised dealers) mostly in Victoria and South Australia which provide customers with a range of gas and electric appliances. It also offers customers gas and electrical repairs, installation and maintenance services and electricity and gas safety advice.

Origin has positioned itself as the leading Australian retailer of green energy products. Its *GreenEarth* product enables consumers to choose to purchase electricity generated from renewable sources such as wind and solar via Origin. Origin also operates a carbon exchange that provides consumers with an opportunity to calculate and offset their greenhouse gas emissions (i.e. consumers make payments to offset their emissions by Origin undertaking projects such as composting of waste and planting trees). Origin has signed more than 423,000 green energy customers which is estimated to represent a 30% share of green energy market customers.

Origin is also involved in two Solar Cities projects which aim to demonstrate and trial how the use of solar technologies, smart meters, energy efficiency initiatives and new approaches to electricity pricing can combine to provide a more sustainable energy future. Origin is the lead partner in the Adelaide Solar City consortium in South Australia and in 2007 became a partner in the Central Victorian Solar City. In addition, Origin has introduced an innovative solar hot water product to the market which allows customers to add solar panels to their existing gas or electricity systems.

Origin also markets electricity and gas to large wholesale customers (industrial and commercial). These customers have well known energy requirements (typically in excess of 750MWh per annum) and contract for periods of one to three years. Origin sells around 19TWh of electricity and 68PJ of gas per year to these wholesale customers. These services are delivered through state based account management and business development resources.

Origin continually reviews the adequacy of the information technology systems in its retail business and expects that an upgrade of certain systems will be required by 2010. It expects that it will derive operational efficiencies from the upgrade.

The electricity and gas sold by Retail is sourced from Origin's portfolio of external electricity and gas contracts, from the output of its gas reserves and generation assets and from electricity

purchasers from the NEM. The matching of the supply of energy to customer demand is managed by a specialist energy trading team (discussed below). The large customer base provides scale and geographic diversification advantages and a material channel to market for Origin's upstream gas and generation businesses.

(ii) Energy Trading

Origin operates a team of energy trading specialists to manage the purchases of energy to meet the demand of its generation and retailing businesses. This team seeks to match supply and demand (both physically and with derivative instruments) to reduce the overall risk and to optimise the financial return to Origin. In this regard, Energy Trading provides a range of services internally including:

- management of a portfolio of physical gas and electricity supply contracts;
- management of the generation and dispatch of electricity from the generation portfolio to the Retail business and NEM and, as required, purchasing electricity from the NEM;
- implementation and management of a portfolio of caps and swap contracts to hedge prices paid for peak and base load electricity requirements and peak gas requirements; and
- management of a carbon portfolio reflecting Origin's obligations under renewable energy targets.

Management of these portfolios reduces the risk of exposure to movements in wholesale electricity and gas prices. In the future, Origin's carbon portfolio will also reflect its obligations under the proposed carbon emissions trading scheme.

Origin has a number of long term gas and electricity purchase contracts. It has a portfolio of swaps and caps covering 176TWh of future electricity requirements which include medium term swaps and caps as well as 1,325MW of long term electricity cap contracts (including with Snowy Hydro and Braemar 1 and 2 power stations with varying terms out to more than 10 years). Many of these contracts were entered into at times when electricity prices were lower due to excess base load generation capacity. The effect of these long term contracts is to reduce to cost of electricity purchases below current (and expected future) market prices for electricity. This portfolio provides a significant financial benefit to Origin although it will run off over time.

(iii) LPG

Origin is a distributor and marketer of LPG in Australia and the South Pacific both to domestic and industrial customers. Origin has been marketing LPG in Australia since 1963. In 2008 (the first full year since the sale of the New Zealand LPG business Rockgas to Contact Energy and the acquisition of Sun Retail LPG) Origin sold approximately 462Kt of LPG to 358,000 customers.

Origin operates an extensive network across Australia including 86 depots and seven of the 14 LNG import terminals in Australia. It distributes LPG in Australia directly to LPG distributors and to commercial and retail customers through a branch network and a chain of regional distribution agents. LPG is the preferred energy source throughout the South Pacific and Origin operates a fleet of five ships and a network of owned outlets and distribution agents to service that market. It also sells a large range of LPG appliances across the South Pacific and (to a lesser extent) Australia. LPG is considering expanding into other markets with features similar to those in the South Pacific.

LPG is both imported and sourced from Origin's conventional oil and gas reserves, other Australian upstream producers and Australian oil refineries. LPG prices are based on international LPG market prices (which often move in line with oil prices) and therefore in recent times profitability of the LPG business (particularly in the South Pacific) has come under pressure to the extent that cost increases cannot be passed immediately through to customers.

LPG also supplies autogas in Australia through the Vitalgas joint venture with Caltex.

7.2 Financial Performance

The adjusted financial performance of Retail for the five years ended 30 June 2008 is set out in Section 4.3 of this report and summarised below:

Retail – Adjusted Financial Performance ($ millions)

	Year ended 30 June				
	2004 actual AGAAP	2005 actual AIFRS	2006 actual AIFRS	2007 actual AIFRS	2008 actual AIFRS
Operating statistics[57]					
Customer ('000s):					
- Electricity	*887*	*913*	*955*	*1,786*	*1,757*
- Gas	*967*	*900*	*880*	*889*	*896*
- LPG	*258*	*256*	*263*	*336*	*358*
Sales volumes:					
- Electricity (TWh)	*15.9*	*15.7*	*15.6*	*23.0*	*32.0*
- Gas (PJ)	*114*	*117*	*127*	*125*	*127*
- LPG (Kt)	*469*	*425*	*437*	*713*	*462*
- Total (PJe)	*194*	*194*	*205*	*227*	*264*
Adjusted sales revenue	**2,969.5**	**2,989.4**	**3,121.8**	**3,997.8**	**5,505.5**
Adjusted EBITDAF	**226.4**	**235.5**	**271.0**	**336.7**	**479.3**
Adjusted depreciation and amortisation	(49.4)	(45.2)	(37.9)	(45.1)	(53.3)
Adjusted EBITF	**177.0**	**190.3**	**233.1**	**291.6**	**426.0**
Capital expenditure[57]					
- Stay in business	24.5	32.1	40.0	47.9	41.6
- Growth[58]	44.2	31.9	46.7	1,272.6	74.0
	68.7	**64.0**	**86.7**	**1,320.5**	**115.6**
Statistics					
Adjusted sales revenue growth	4.7%	0.7%	4.4%	28.1%	37.7%
Adjusted sales per PJe[59] *(millions)*	*$15.31*	*$15.41*	*$15.24*	*$17.58*	*$20.85*
Adjusted EBITDAF growth	(0.4)%	4.0%	15.1%	24.2%	42.4%
Adjusted EBITF growth	5.4%	7.5%	22.5%	25.1%	46.1%
Adjusted EBITDAF margin	7.6%	7.9%	8.7%	8.4%	8.7%
Adjusted EBITF margin	6.0%	6.4%	7.5%	7.3%	7.7%
Adjusted EBITDAF/ SIB[60] *capital expenditure*	9.2x	7.3x	6.8x	7.0x	11.5x

Source: Origin and Grant Samuel analysis

The financial performance of Retail has been extracted from the consolidated financial statements of Origin and adjusted by Grant Samuel in Section 4.3 of this report to exclude share of profits from equity accounted investments (i.e. Rockgas prior to March 2004), significant and non recurring items (e.g. Sun Retail integration costs), changes in the fair value of financial instruments, other income and (in 2004 only) amortisation of goodwill.

Major factors affecting the performance of Retail in the period include:

- the acquisition of the Sun Retail electricity business in February 2007 (which added 841,000 electricity and 55,000 LPG customers) and the LPG retailer Speed-E-Gas during 2006 (which added 11,000 LPG customers);
- increased competition and customer churn as more of Origin's markets became fully contestable. In particular, the introduction of full gas retail contestability in South Australia (where Origin was the incumbent gas retailer) in July 2004 resulted in a net decline in gas customers over the period and, in 2008, overall customer churn was heightened by the introduction of contestability in Queensland (e.g. during 2008 Origin acquired over 482,000 new mass market customer accounts but had an overall net decline of 22,000 accounts).

57 Excluding Rockgas.

58 Including acquisitions and construction projects.

59 As the volume of electricity sold has increased as a proportion of energy sold, sales per PJe has increased as electricity prices per PJe are greater than gas prices.

60 SIB = stay in business

However, actual movements in electricity customers as a result of contestability is not clearly observable over the period due to Origin's entry as an electricity retailer in South Australia and New South Wales and the acquisition of Sun Retail; and

- variations in weather conditions from year to year which have impacted the overall volume of energy sold. Cold weather conditions in 2006 resulted in an increase in energy sales in that year while milder conditions in 2007 resulted in lower energy sales although this is not obvious due to the five months contribution from Sun Retail.

Despite increased churn and cost increases, Retail has experienced overall growth in sales and profitability over the period and increased stability in profit margins. This has been achieved by:

- the increased business flexibility derived from wider geographic and business coverage and increased scale from recent acquisitions and entry into new markets. Historically, Victoria has accounted for the majority of Origin's customers and earnings which created significant business risks in relation to adverse weather events and movement in customer numbers. The diversification achieved from the acquisition of Sun Retail in Queensland and entry into New South Wales has substantially reduced this business risk and earnings volatility;
- lower customer acquisition costs as a result of increased number of dual fuel accounts and increasingly steady cost to serve by customer;
- continued implementation of the integrated business risk processes to manage exposure to fluctuations in wholesale gas and electricity prices;
- the increase in tariffs (e.g. South Australian gas tariffs increased from July 2005, Victorian electricity tariffs increased from January 2008 and gas tariffs increased across all states during 2008); and
- active cost management programs as well as reductions in cost to serve following the termination of transitional agreement for Sun Retail in March 2008.

Despite the overall improvement in profitability, the earnings of the LPG business have been under pressure as the cost of LPG has increased mirroring recent oil price increases. These price increases have not been able to be passed on to customers immediately. However, active price management has been effective in managing margin compression.

Stay-in-business capital expenditure of around $40-50 million per annum is expected to continue although a regular IT systems upgrade is due in 2010. Growth capital expenditure has been around $45-55 million per annum except for the $1.24 billion acquisition of Sun Retail in 2007.

8 Profile of Contact Energy Limited

8.1 Background

Contact Energy commenced operations in February 1996 when the New Zealand Government separated the assets of the state owned monopoly generator Electricity Corporation of New Zealand ("ECNZ") into two state owned enterprises, Contact Energy and ECNZ. The 1998 enactment of the Electricity Reform Act ("the Reform Act") allowed Contact Energy to expand into energy retailing and it acquired eight retail electricity companies (with a total of 342,000 customers) and in April 1999 acquired Enerco New Zealand Limited's retail gas business (106,000 customers).

In May 1999 a 40% shareholding in Contact Energy was sold to Edison Mission Energy ("Edison"), a wholly owned subsidiary of the United States energy company Edison International, and the remaining 60% was sold through an initial public offering. Following listing, Contact Energy consolidated and grew its electricity and gas retailing operations and continued to develop its integrated business model. Edison increased its shareholding to 51.2% in the period 2000-2001 by way of additional share purchases. In October 2004, due to a change of strategy by its parent company, Edison sold its entire interest in Contact Energy to Origin.

Today, Contact Energy's operations encompass electricity generation and wholesaling and the retailing of electricity, natural gas and LPG. It is the second largest company by market capitalisation on the New Zealand Stock Exchange ("NZSX") and, prior to the announcement of BG Group's approach to Origin on 29 April 2008, had a market capitalisation of approximately NZ$5.4 billion.

8.2 New Zealand Energy Sector

Overview

In line with international trends total energy consumption in New Zealand has grown over the last ten years. However, as electricity generation is dominated by renewable fuel sources and hydrocarbon resources are limited, the trends in the types of energy consumed in New Zealand differ to international trends in that the consumption of natural gas is also declining with the consumption of oil and coal. Consumption of energy from renewable sources is growing in New Zealand and is supported strongly by government policy. Energy consumption is expected to continue to grow in the foreseeable future (e.g. electricity demand is expected to grow by around 2% per annum to 2025).

Historically, the energy sector was managed as part of the New Zealand Government. It is only since the 1980s that the energy sector has been subject to corporatisation and (in the 1990's) privatisation. However, today the energy sector in New Zealand remains dominated by state owned enterprises and subject to regulation.

Electricity Sector

Deregulation of the New Zealand electricity sector began in 1987 with the corporatisation of ECNZ. Corporatisation of the locally owned retail utilities followed in 1993 and in 1994 the national grid operator Transpower was separated from ECNZ. ECNZ was subsequently split into Contact Energy and three state owned enterprises: Meridian Energy Limited ("Meridian"), Mighty River Power Limited ("Mighty River Power") and Genesis Energy Limited ("Genesis").

For regulation purposes, the Reform Act divided the electricity sector into three operating segments: Generation/Retail, Transmission and Distribution. The Electricity Commission was established in March 2004 to assume responsibility for overseeing the electricity industry and for security of supply.

(i) Generation and Wholesale

Electricity demand has grown at around 2% per annum over the last ten years despite significant increases in wholesale electricity prices. Electricity generation totalled approximately 42,373GWh in 2007 from approximately 7,200MW of installed capacity. New Zealand generation is fuelled approximately 67% by renewable resources (hydro, geothermal, wind and biomass) but is dominated by hydro electricity:

Electricity Generation in New Zealand						
Generation Type	**Year ended 31 December**					
	2005		**2006**		**2007**	
Hydro	55%		55%		55%	
Gas	22%		22%		26%	
Geothermal	7%		8%		8%	
Coal	13%		12%		7%	
Wind	1%		1%		2%	
Other	2%		2%		2%	
	100%		100%		100%	
Electricity Generated (GWh)	**41,670**	***0%***	**41,995**	***+0.8%***	**42,374**	***+0.9%***

Source: Statistics New Zealand

The major generators are Meridian, Genesis, Mighty River Power, Contact Energy and TrustPower. All have a significant retail customer base which provides a hedge against the price received by the generator for electricity produced. Whilst TrustPower also owns generation assets it is a net retailer and relies heavily on hedge contracts with the other generators to manage its exposure to wholesale electricity prices.

Distributed generators which connect directly to local electricity networks supply around 5% of the electricity generated in New Zealand. These include small local hydro schemes, wind energy plants, small diesel and gas generators (including landfill gas), small geothermal power plants, cogeneration or combined cycle power plants and domestic or small commercial solar generation. TrustPower is the largest operator of distributed generation plants.

The uncertainty around future gas supplies and the increasing cost of new generation has placed upward pressure on average wholesale electricity prices and a narrowing of the gap between peak demand and supply. Market commentators have estimated that New Zealand is facing a shortfall in peak generation capacity of around 170MW by 2012 (after allowing for a reserve margin of 18% to maintain system equilibrium) and, in the absence of new capacity build, substantially more by 2025 (3,700MW has been mentioned). The supply of new generation capacity will be driven by the New Zealand Government's energy strategy which is targeting 90% generation from renewable sources by 2025 (refer later in this section for more detail). Generally projects and generation types with the lowest long run marginal cost will be the first to proceed but the ability to obtain necessary development consents will also be important.

The wholesale electricity market involves the sale and purchase of physical electricity at prices established half hourly at 244 different points of connection (nodes) to the national grid located across New Zealand. Generators offer electricity into the market and large users and retail electricity companies bid to purchase electricity. Subject to transmission constraints, generators offering the lowest prices get dispatched to meet the demand of the users and retail electricity companies. Prices therefore depend on supply by generators (which depend on hydrology, station availability, transmission constraints, etc) and demand by retailers (which depends on ambient temperature, seasonality, time of day, etc). As there is no maximum price, generators are at times able to achieve very high spot wholesale prices for their generation output. However, wholesale prices can often be low providing little revenue for base load generation, which cannot be easily "turned off" for short periods.

The wholesale electricity price is volatile primarily due to the reliance on hydro stations for electricity generation. Approximately 55% of electricity generated in New Zealand is from hydro stations, resulting in a strong correlation between water inflows into storage lakes and electricity prices. Due to New Zealand's small hydro storage reservoirs (national storage is 3,500GWh or less than 10% of annual electricity consumption) wholesale prices tend to be lower when storage is high with regular inflows and tend to rise during periods of lower than average storage levels and low inflows. Recent periods of high electricity wholesale prices during the winters of 2001, 2003, 2006 and 2008 have coincided with periods of low rainfall.

(ii) Transmission

Transpower owns and operates the high voltage electricity transmission system in New Zealand. It contracts with generators and distributors to connect to the national system. The main

transmission grid in the North Island comprises 220kV and 110kV lines connecting major load centres with generating stations. In the South Island the transmission grid consists of 220kV, 110kV and 66kV lines. More than 60% of New Zealand's electricity is produced in the South Island with 70% of electricity demand coming from the North Island. Transpower owns the 1,040MW high voltage direct current ("HVDC") link between the North and South Islands which is designed primarily to deliver electricity northward.

A supply constraint currently exists in the North Island as the HVDC link has been downgraded to operate at only 700MW. Transpower plans to upgrade the national grid by 2013 to remove or reduce geographical price differences by eliminating transmission constraints (e.g. by increasing the capacity of the HVDC link to 1,400MW). Transpower expects the upgrades to reduce transmission losses and increase the number of potential sites for new generation projects.

(iii) Distribution

There are 28 electricity distribution businesses providing local area lines networks through which electricity is transmitted from the transmission grid exit points to end users. Most of the distribution businesses were formed by the New Zealand Government in 1992 when the New Zealand Government corporatised the businesses under a number of ownership structures including local council owned, trust owned (with profit distributions being made back to the consumer or the community generally) and public ownership. The Commerce Commission regulates electricity distribution by setting thresholds (e.g. price paths and quality) against which it assesses the performance of the distributors annually. If one or more of the thresholds are breached the Commerce Commission can further investigate the business and, if required, control prices, revenue or quality.

(iv) Retailing

Electricity retailers acquire electricity and use distribution networks to deliver electricity to end users. The major costs of an electricity retailer comprise energy cost, distribution costs and metering costs. Retail tariffs are not subject to price regulation and vary across New Zealand according to geographic location, local distribution network charges and the impact of nodal electricity pricing.

Following a period of consolidation, the five largest electricity generators are also the largest electricity retailers:

Electricity Retailer - Market Shares as at April 2008

Company	Market Share
Genesis	28.8%
Contact Energy (*Contact* and *Empower* brands)	27.1%
Mighty River Power (*Mercury Energy* brand)	18.4%
Meridian	11.5%
TrustPower	11.5%
King Country Energy	1.0%
Bay of Plenty Energy	1.3%
Bosco Connect	0.4%

Source: Electricity Commission

A number of small low cost, low margin electricity retailers have entered the market since 1998 with the objective of attracting customers away from incumbent retailers rather than acquiring incumbent customer bases. The most successful were Empower and Energy Online each of which was later acquired by a larger electricity generator. Since then, the relative market positions of the large electricity retailers have been reasonably stable (although the market shares of Genesis and Mighty River Power have increased at the expense of Meridian and TrustPower). There continues to be price competition although recently retail prices have been rising and greater emphasis has been placed on customer retention and maintenance of retail margins.

Natural Gas Sector

The development of the natural gas sector in New Zealand was based around the discovery of the Kapuni field in 1959 and the Maui field in 1969. Unlike the electricity sector there is no legislation preventing ownership across each segment of the industry. Some industry participants

are active across more than one segment with Todd Corporation Limited ("Todd") participating in all segments. The New Zealand Government was directly involved in the development of the gas sector, however, since the 1980s the sector has largely been privatised although subject to some regulation, particularly in relation to the transmission and distribution of gas.

Although the New Zealand gas sector is small by global standards it plays a large role in the economy as natural gas is primarily used to generate electricity. The New Zealand Government conducted a review of the sector in 2002 which resulted in a gas governance policy (which has been refined over the period to 2008) and the establishment of the Gas Industry Company Limited, a co-regulatory body to deliver industry led solutions for sector reform (e.g. an effective open access regime for transmission and distribution pipelines).

(i) Production and Wholesale

At 1 January 2008 total proven and probable reserves in New Zealand were 2,195PJ and production during 2007 was 181PJ:

New Zealand - Natural Gas Reserves and Production (PJ)

Field	Reserves	Gas Production
Maui	490	55.4
Kapuni	239	24.8
Tariki/Ahuroa	22	4.0
McKee	54	7.7
Rimu/Kauri	54	3.2
Kaimiro/Ngatoro/Moturoa	31	1.7
Pohokura	1,064	69.8
Other	241	14.3
Total	**2,195**	**180.9**

Source: Ministry of Economic Development (June 2008)

Maui has historically been the largest producing field supplying approximately 75-80% of New Zealand's annual gas requirements. The Pohokura field is the first significant gas field developed since Maui. In recent years a number of gas fields have been developed (e.g. the Kupe field (which is operated by and owned 50% by Origin) was discovered in 1988, is estimated to have 254PJ of 2P reserves and is scheduled to enter production by mid 2009). While individually each of these fields are small in comparison to the original reserves of Maui, they extend the horizon of New Zealand's gas supply.

With the decline of the Maui field, the New Zealand energy market now faces significant uncertainty in relation to future gas availability and prices. Consequently, exploration levels have increased but the small size (in terms of available capital and resources) of the companies that hold exploration permits has impacted exploration success levels. The Taranaki Basin is considered to have high potential (estimated at 5,300PJ) for the discovery of new gas reserves, however, there is significant uncertainty as to economic viability of recovering the gas.

The price for Maui gas was set in 1975 based on an initial price adjusted annually by approximately half the rate of inflation for the preceding year. This adjustment mechanism led to a fall in the real price of gas year on year compared with other sources of energy thereby encouraging the consumption of Maui gas. However, the low Maui gas price has been the benchmark for gas prices in New Zealand and discouraged exploration and development of alternative supplies. With Maui gas reserves declining and no new major discoveries the medium term outlook is for tight supply and for gas prices to increase.

Major gas users (including Contact Energy and Genesis via their Gasbridge Joint Venture) have also been investigating the development of facilities to allow for the importation of LNG. This involves significant capital expenditure although the proposed Ahuroa gas storage facility would assist with the project feasibility. The threat of LNG importation is likely to assist with domestic gas price negotiations and any LNG investment decision is likely to be deferred until the latest possible time.

(ii) Transmission

Natural gas transmission systems only exist on the North Island as New Zealand's gas supplies are

dominated by reserves from the Taranaki Basin. The two main gas transmission pipelines are:

- the 313 kilometre Maui pipeline from Oaonui in Taranaki (where Maui gas comes onshore and is processed) to Rotowaro near Huntly. The pipeline is owned by Shell New Zealand Limited ("Shell"), OMV New Zealand Limited ("OMV") and Todd and operated by Vector Limited ("Vector"). In October 2005 an open access regime was implemented for the pipeline; and
- the Vector transmission network which comprises approximately 2,200 kilometres of pipelines taking gas from Taranaki as far north as Kamo, east to Gisborne, southeast to Hastings and south to Wellington under an open access system.

There are also a number of smaller transmission pipelines in the Taranaki area.

(iii) Distribution

There are extensive low pressure gas reticulation networks in most cities in the North Island. There are three main gas distribution companies Powerco Limited ("Powerco") (owned by Babcock & Brown Infrastructure) which operates in the Taranaki, Manawatu, Hawke's Bay, Horowhenua and Wellington areas, Vector which operates in the greater Auckland, Northland, Bay of Plenty and Gisborne areas and Wanganui Gas which operates around Wanganui. In addition, Nova Gas (a subsidiary of Todd) supplies gas through its own small network of pipelines in various areas.

In July 2005, the New Zealand Minister of Energy announced the decision to impose price control over the gas distribution services of Powerco and Vector. In its October 2007 draft authorisation the Commerce Commission proposed prices representing substantial reductions over current distribution prices. Gas retailers are expected to pass on the full amount of any reductions in distribution charges.

(iv) Retailing

Gas retailers purchase natural gas and on sell it to industrial, commercial and residential end use customers. In 2007 approximately 59% of natural gas produced in New Zealand was consumed by electricity generation and 15% by the petrochemical industry (for the production of methanol and ammonia-urea). The remaining 26% of gas produced was consumed in the retail market but only 3-4% was consumed by the residential market (the balance consumed by industry and commercial customers). Gas is considered an elective fuel source in the retail market and therefore pricing of gas plays a large role in the uptake of retail users. In recent years, as the price of gas has increased, the level of consumption in the residential and commercial segments has decreased.

Eight retailers sell gas to industrial and commercial customers: Contact Energy, Genesis, Mercury Energy (a subsidiary of Mighty River Power), Energy Direct NZ (a division of Wanganui Gas), On Gas (a subsidiary of Vector), Todd (via subsidiaries Auckland Gas Company, Nova Gas and Bay of Plenty Energy), EGas Group and Greymouth Petroleum Limited. Only five of these retailers supply gas to residential customers (i.e. Contact Energy, Genesis, Mercury Energy, Bay of Plenty Energy and Energy Direct NZ) and three of these retailers are also major electricity retailers to the residential market (i.e. Contact Energy, Genesis and Bay of Plenty Energy). Genesis and Contact Energy are considered the major gas retailers in New Zealand.

LPG Sector

LPG is widely used as a source of energy throughout New Zealand, particularly in the South Island. LPG occurs naturally in crude oil and natural gas production field and is also produced in the oil refining process. The New Zealand industry began in the 1920s when LPG was shipped from the United States in cylinders and, with the development of the natural gas industry in the 1970s, domestic production of LPG commenced. Consumption of LPG grew strongly in the 1980s and production peaked in the 1990s when New Zealand began to export LPG. However, with the decline of the Maui gas field, New Zealand has had to import LPG to meet demand. Imports are expected to reduce when the Kupe field starts producing LPG.

Approximately 180Kt of LPG is consumed annually in New Zealand for residential, commercial and automotive purposes and demand for LPG is estimated to be growing at over 7% per annum. Traditionally LPG has been supplied in cylinders distributed by trucks directly to the customer but

in recent years reticulation systems have been developed (e.g. in Christchurch, Queenstown, Wanaka and Dunedin on the South Island). The major suppliers of LPG are Rockgas (a subsidiary of Contact Energy), Nova LPG (a subsidiary of Todd) and BOC New Zealand Limited (a subsidiary of Linde Group AG). Rockgas is estimated to have a 50% share of the LPG distribution market.

Since 2003 the LPG price in New Zealand has increased significantly due to importation of LPG which is acquired in United States dollars on world markets at prices reflecting international supply and demand. While the price of LPG is not directly linked to the price of oil, when oil prices move LPG prices generally move due to the level of switching between the fuels and the similarity in factors affecting demand (e.g. increases in demand from China and India). Although the level of imports is expected to decrease as domestic production increases again as new gas fields commence production, LPG prices in New Zealand are expected to continue to reflect international pricing rather than domestic factors.

Climate Change Initiatives

In October 2007, the New Zealand Government announced the New Zealand Energy Strategy ("NZES") setting out a strategic direction for the New Zealand energy sector to address providing enough energy to meet the needs of a growing economy, maintaining security of supply and reducing greenhouse gas emissions.

For the electricity sector there are three major policy initiatives:

- introduction of a carbon emissions trading scheme from 1 January 2010 as the core price based measure for reducing greenhouse gas emissions and enhancing forest carbon sinks. The various sectors of the economy will be brought into the scheme in a staged transition with the electricity sector involved from commencement. The scheme will allow both sales of units to, and purchases from, international carbon trading markets to aid liquidity in the market and act as a safety value on price. The emissions trading scheme will result in increases in the cost of transport fuels, electricity and gas;
- a 10 year moratorium on the development of new base load fossil fuel thermal generation (except as required to maintain security of supply). This moratorium will require generators to adjust their plans for the type of new generation capacity developed to meet future demand; and
- a target of 90% renewable generation by 2025. The significant increase in projected base load geothermal production should meet the growth in projected demand for approximately 5 years by which time additional wind farms and further geothermal plants are likely to have come on stream. However, the goal of 90% of electricity sourced from renewable sources is generally considered ambitious particularly as existing legislation provides opportunities for organisations opposing wind or hydro investment to delay and/or prevent new projects proceeding.

With the policy environment directing investment towards renewable generation, it is expected that wholesale electricity prices will trend towards the long run marginal costs of wind generation resulting in upward pressure on retail prices for electricity. In addition, as over 50% of natural gas production is consumed by electricity generation, these policy initiatives have implications for the demand for gas. Although the impact is currently uncertain, increased wind farm production will necessitate additional flexible generation (such as hydro or thermal peaking plants) to address the variability of wind generation. Therefore, it is likely that, in the future, natural gas will be used less for base load generation and more for intermittent or peak generation.

8.3 Operations

Contact Energy is one of the largest energy retailing companies in New Zealand and the second largest generator of electricity. It operates a highly integrated business model employing approximately 1,000 people. Contact Energy's businesses are described below:

Electricity Generation

Contact Energy's generation portfolio is diverse in terms of plant type, fuel type and geographic location. This portfolio of 10 power stations provides approximately 25-30% of New Zealand's

electricity generation capacity. This diversity positions Contact Energy well to take advantage of revenue optimisation opportunities presented by changing fuel and weather scenarios:

Contact Energy – Existing Generation Assets				
Power Station	**Type**	**Operation**	**Capacity (MW)**	**% of Portfolio**
Thermal				
Otahuhu B	CCGT	Base/Intermediate	400	
Taranaki	CCGT	Base/Intermediate	377	
Te Rapa	Cogeneration	Base/Intermediate	44	
New Plymouth	OCGT	Peak/Intermediate	100[61]	
Otahuhu A	Reactive power	Reactive power	-	
			921	**47%**
Geothermal[62]				
Wairakei	Geothermal	Base	172	
Ohaaki	Geothermal	Base	65[63]	
Poihipi	Geothermal	Base	50	
			287	**15%**
Hydro[64]				
Clyde	Hydro	Base	432	
Roxburgh	Hydro	Base	320	
			752	**38%**
Total Capacity			**1,960**	**100%**

Source: Contact Energy reports

Contact Energy also has a portfolio of consented and/or planned generation capacity developments to meet future demand for electricity as well as addressing government climate change initiatives:

Contact Energy – Consented and/or Planned New Generation Assets		
Power Station	**Planned Capacity (MW)**	**Status**
Thermal		
Otahuhu C	-	400MW consented, unlikely to proceed in short term
Otahuhu A peaking	-	120MW consented, current status unclear
Stratford	-	500MW consented, current status unclear
Stratford peaking[65]	200	500MW consented, 200MW expected by 2010
	200	
Geothermal		
Tauhara binary	23	Production expected by 2010
Te Mihi	220	In planning stage, interim consents received
Tauhara (phase 2)	240	In planning stage
	483	
Hydro		
Hawea	17	Consented, investment decision pending
	17	
Wind		
Hauāuru mā raki	540	Resource consent called in
Waitahora	177	Resource consent applications filed
	717	
Total	**1,417**	

Source: Contact Energy reports

The New Zealand Government's initiative targeting renewable electricity generation has impacted Contact Energy's planned development of new thermal power stations. For example, investment decisions on the Otahuhu C Power Station have been deferred while Contact Energy expects that the Stratford peaking plant will proceed largely to support the increasing volumes of weather dependent wind generation. Contact Energy has redirected its development efforts towards renewable generation particularly wind and geothermal. In addition to the announced Hauāuru mā raki wind farm, Contact Energy is working on four potential wind farm sites across New Zealand

61 In December 2007 Contact Energy made the decision to permanently close New Plymouth Power Station due to the identification of asbestos in areas not previously noted. It has recently been decided to recommission a 100MW generator during the 2008 winter.

62 All of Contact Energy's geothermal plants are located near Lake Taupo in the central North Island and are low marginal cost plants suitable for base load operation.

63 The generation capacity at Ohaaki is 105MW but is currently restricted by steam supply and is operating at 65MW capacity.

64 Contact Energy's two hydro stations are located on the Clutha river catchment system in the South Island.

65 In parallel with the Stratford peaking units Contact Energy is to develop an underground gas storage facility in the nearly depleted Ahuroa gas field.

with the potential to generate up to 950MW per annum (e.g. it recently filed resource consent applications for the 177MW Waitahora wind farm near Dannevirke on the North Island).

Consumption of electricity by its retail electricity customer base significantly reduces the wholesale market risks of Contact Energy's generation portfolio (in 2007 Contact Energy's retail customers purchased approximately 69% of its electricity output). Although the retail customer base provides a relatively stable price and volume market there are still significant fluctuations in load demand due to the time of day and ambient temperature variations. Consequently, in periods of low wholesale prices Contact Energy may elect to reduce generation output from its thermal power stations if it is more cost effective to purchase electricity for its retail business than produce it. Contact Energy also enters into hedge contracts with other electricity retailers and large industrial customers which have the effect of fixing prices for periods of one to five years.

The operating statistics for Contact Energy's generation business since October 2003 are summarised below:

Electricity Generation – Operating Statistics

	Year ended 30 Sept 2004	Year ended 30 June			
		2005[66]	2006	2007	2008
Average wholesale price to Contact Energy (per MWh)	NZ$37.01	NZ$48.58	NZ$92.84	NZ$53.70	NZ$106.90
Thermal (GWh)	4,076	4,702	6,649	5,413	5,351
Geothermal (GWh)	1,752	1,765	1,820	1,968	2,180
Hydro (GWh)	4,315	3,982	3,065	3,639	3,504
Total generation (GWh)	**10,143**	**10,449**	**11,534**	**11,020**	**11,035**

Source: Contact Energy reports

Electricity Retailing

Contact Energy is the second largest electricity retailer in New Zealand with approximately 520,000 customers supplying electricity to commercial and residential customers under the *Contact* and *Empower* brands. Contact Energy has an estimated market share of 27% and this market share has been stable over the last five years.

Contact Energy's retail electricity prices have historically been higher than the state owned enterprises. However, this price differential has been closing as wholesale electricity prices have risen with the decline of the Maui gas field and the costs of new forms of generation increases.

The relatively benign competitive environment and medium term outlook for higher wholesale electricity prices suggests that retail electricity prices will increase above the rate of inflation. A further increase of 5-10% is expected from the introduction of the emissions trading scheme. Some commentators consider this increase is likely to exceed the actual cost to electricity generators (depending on their mix of generation) and may lead to retail margin expansion.

The operating statistics for Contact Energy's electricity retailing business since October 2003 are summarised below:

Electricity Retailing – Operating Statistics

	Year ended 30 Sept 2004	Year ended 30 June			
		2005[66]	2006	2007	2008
Average electricity cost Contact Energy (per MWh)	NZ$39.51	NZ$50.53	NZ$100.81	NZ$57.11	NZ$122.07
Retail sales (GWh)	7,415	7,213	7,361	7,564	7,800
Electricity customers	508,000	513,000	515,000	513,000	520,000

Source: Contact Energy reports

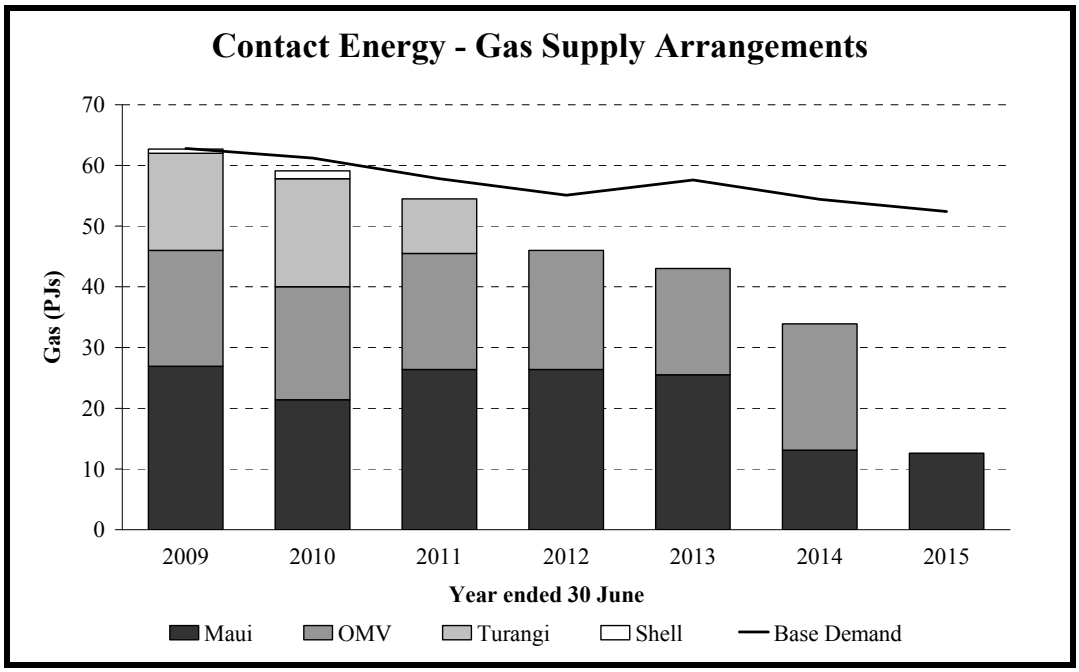
[66] Contact Energy changed its year end to 30 June during 2005 and therefore its financial results for 2005 are for nine months. However, the operating statistics are for the year ended 30 June 2005.

Gas Operations

Contact Energy acquires natural gas primarily for use in its thermal power stations and to supply its retail customer base. However, it also sells gas wholesale to other electricity generators and major customers. Contact Energy acquires gas from a number of sources including:

- rights to a significant portion of the remaining gas to be produced from the Maui field;
- arrangements to acquire approximately 19.3PJ per annum from OMV (sourced from the Pohukura field) for five years from 2006. Following completion of this arrangement OMV will supply an additional 32PJ from the Pohukura field until 31 December 2013; and
- arrangements to acquire approximately 20.4PJ per annum for the period to 31 December 2010 from Shell (probably sourced from the Pohokura field).

Notwithstanding these arrangements, Contact Energy is facing a shortfall in gas supply:



Source: Contact Energy announcement (August 2008).

In December 2007 Contact Energy acquired the right to own and develop the Ahuroa field as an underground gas storage facility (to mitigate the financial consequences of not using natural gas under "take or pay contracts" and when there are more cost effective fuel options than gas) and to purchase the remaining gas and LPG reserves in the Ahuroa reservoir.

Contact Energy currently retails gas to around 75,000 customers and is estimated to have a 36% market share by gas volume. The number of retail gas customers and the volume of gas supplied to those customers has reduced in recent years possibly due to the increase in tariffs to reflect the rising cost of gas.

On 30 April 2007, Contact Energy acquired Rockgas from Origin for NZ$156 million. Rockgas commenced supplying LPG in New Zealand in 1934 and is estimated to supply approximately 50% of the market. It services around 300 bulk industrial clients, 7,000 commercial accounts, 13,000 domestic customers and 300 automotive refuelling outlets throughout New Zealand. Rockgas has over 120 employees and operates a branch and franchise network and a chain of regional cylinder distribution agents. It has taken the lead in the development of LPG reticulation including in the Christchurch and Queenstown central business districts. Rockgas provides a platform for Contact Energy to offer electricity and gas products to an enlarged retail base.

The operating statistics for Contact Energy's gas operations (wholesaling, retailing and LPG) since October 2003 are summarised below:

Gas Operations – Operating Statistics					
	Year ended 30 Sept 2004	Year ended 30 June			
		2005[66]	2006	2007	2008
Natural Gas					
Sales to wholesale customers (PJ)	6.8	8.5	13.8	9.5	17.0
Sales to retail customers (PJ)	10.3	9.5	7.0	4.7	4.1
Used for generation (PJ)	33.5	38.9	54.0	43.2	42.0
Total gas used or sold (PJ)	**50.6**	**56.9**	**74.8**	**57.4**	**63.1**
Gas customers	90,000	85,000	79,000	75,000	75,000
LPG					
Sales to LPG customers (tonnes)	-	-	-	17,467	84,334
LPG customers (including franchisees)	-	-	-	49,000	52,500

Source: Contact Energy reports

Other Energy Assets

Contact Energy has interests in other energy assets as follows:

- a 25% interest in the 286MW natural gas or distillate fired open cycle peak load Oakey Power Station in Queensland. Contact Energy provides operating and maintenance services to the plant under a fifteen year contract which terminates in 2014;
- it leases the Whirinaki site to the New Zealand Government upon which it has constructed a 155MW diesel fired power station to provide reserve generation. Contact Energy is contracted to operate the power station;
- a 50% interest in the Gasbridge Joint Venture with Genesis. The purpose of the joint venture is to investigate and evaluate the potential for importation of LNG should domestic natural gas production not meet gas demand;
- a 50% interest in Rockgas Timaru, part of the Rockgas business. The other 50% is owned by a number of South Island council bodies; and
- an 8.5% interest in Liquigas Limited ("Liquigas"), a bulk distributor of LPG in New Zealand. The other shareholders in Liquigas are Vector (60.25%), BOC New Zealand Limited (18.75%) and Todd (12.5%).

8.4 Outlook

The New Zealand Government climate change initiatives and other industry dynamics impact Contact Energy in a number of ways:

- the emissions trading scheme will place significant costs on Contact Energy as a large generator of electricity from natural gas. However, it is expected that the increased costs will be passed on to end users;
- already consented generation thermal base load developments are unlikely to proceed in the short to medium term. However, proposed gas fired peaking plant developments may proceed in order to ensure security of supply;
- proposed geothermal developments are expected to proceed although they will attract emission charges (although relatively small); and
- a greater emphasis will need to be placed on wind farm developments.

As a net seller of electricity Contact Energy benefits from the high wholesale prices when hydroelectricity production is constrained by hydrology status. Consequently, while renewable generation is being developed Contact Energy is expected to benefit from higher wholesale electricity prices from the shortfall in supply. In the longer term the average wholesale price should be around the long run marginal cost of new generation (expected to be wind generation) although this cost is currently uncertain due to the long lead times and the impact of supply and demand dynamics and currency fluctuations on capital equipment pricing and availability. Nevertheless, wholesale electricity prices are expected to be higher than at present and, assuming that the increases will be passed through to the end users, Contact Energy's generation business is expected to benefit financially.

8.5 Financial Performance

The financial performance of Contact Energy for the year ended 30 September 2004, the nine months ended 30 June 2005 and the three years ended 30 June 2008 are summarised below:

Contact Energy - Financial Performance[67] (NZ$ millions)

	Year ended 30 Sept 2004 actual NZGAAP	9 months ended 30 June 2005[68] actual NZIFRS	Year ended 30 June 2006 actual NZIFRS	2007[69] actual NZIFRS	2008 actual NZIFRS
Generation					
Wholesale electricity	424.9	459.8	1,046.2	630.4	1,148.0
Steam	-	6.5	9.0	12.2	11.0
	424.9	466.3	1,055.2	642.6	1,159.0
Retail					
Retail electricity	975.0	728.4	1,080.5	1,170.2	1,244.3
Wholesale and retail gas	155.5	116.7	184.3	148.0	181.5
LPG	-	-	-	25.3	145.2
	1,130.5	845.1	1,264.8	1,343.5	1,571.0
Total sales revenue[70]	**1,555.4**	**1,311.4**	**2,320.0**	**1,986.1**	**2,730.0**
Adjusted EBITDAF[71]	**421.0**	**359.2**	**555.6**	**532.5**	**541.0**
Depreciation and amortisation[72]	(114.2)	(94.3)	(133.2)	(139.3)	(146.5)
Adjusted EBITF[71]	**306.8**	**264.9**	**422.4**	**393.2**	**394.5**
Changes in fair value of financial instruments	-	-	8.7	23.3	(1.9)
Other income	29.1	7.7	10.1	11.2	26.1[73]
Share of profits of equity accounted investments	0.6	0.5	4.4	0.7	2.8
Net interest expense	(86.0)	(59.5)	(67.6)	(62.7)	(69.9)
Goodwill amortisation	(11.8)	-	-	-	-
Significant items	1.7	-	24.7	-	(12.4)
Operating profit before tax	**240.4**	**213.6**	**402.7**	**365.7**	**339.2**
Income tax expense	(96.4)	(65.8)	(121.8)	(126.1)[74]	(102.1)
Profit after tax attributable to Contact Energy shareholders	**144.0**	**147.8**	**280.9**	**239.6**	**237.1**
Statistics					
Basic earnings per share[75]	*25.0¢*	*25.6¢*	*41.9¢*	*40.1¢*	*40.4¢*
Dividends per share[76]	*15.0¢*	*18.0¢*	*26.0¢*	*27.0¢*	*28.0¢*
Dividend payout ratio	*60%*	*70%*	*62%*	*67%*	*69%*
Imputed amount	*100%*	*100%*	*100%*	*100%*	*100%*
Sales revenue growth	*(15.8)%*			*(14.4%)*	*37.5%*
Adjusted EBITDAF growth	*23.7%*			*(4.1%)*	*1.7%*
Adjusted EBITF growth	*29.0%*			*(6.9%)*	*0.3 %*
Adjusted EBITDAF margin	*27.1%*	*27.4%*	*23.9%*	*26.8%*	*19.8%*
Adjusted EBITF margin	*19.7%*	*20.2%*	*18.2%*	*19.8%*	*14.5%*
Interest cover	*3.6x*	*4.5x*	*6.3x*	*6.3x*	*5.6x*

Source: Contact Energy reports and Grant Samuel analysis

67 Financial statements for the years prior to 1 July 2005 were prepared in accordance with New Zealand generally accepted accounting principles ("NZGAAP"). Contact Energy adopted the New Zealand equivalent to international financial reporting standards ("NZIFRS") from 1 July 2005. With the exception of the application of the standard in relation to financial instruments, the result for the 9 months ended 30 June 2005 was restated under NZIFRS.

68 During 2005 Contact Energy changed its year end to 30 June to align with Origin's year end. Therefore, the results for 2005 are for a nine month period only.

69 Including two months contribution from Rockgas following acquisition on 30 April 2007.

70 Before other income.

71 Reported EBITDAF and EBITF adjusted by Grant Samuel to exclude other income.

72 Excluding goodwill amortisation in 2004.

73 Including sale of fuel reserves at New Plymouth Power Station (NZ$9.6 million).

74 Including a tax expense of NZ$7.1 million relating to the reduction in New Zealand corporate tax rate from 33% to 30%.

75 Before fair value adjustments, gains on disposal of subsidiaries and the impact of the change in corporate tax rate.

76 Excluding special dividends. A special dividend of 10.0¢ per share was paid in 2004.

Since 2003 earnings per share (before significant items) has grown at around 14.5% per annum. Contact Energy has maintained its dividend payout ratio during this period in the range of 60-70% and therefore dividends per share have mirrored the growth in earnings.

Contact Energy's overall earnings performance highlights the value of the integrated business model and a balanced generation portfolio. Earnings for both of its businesses fluctuate from year to year depending on conditions in the electricity market including hydrology, power station availability, transmission constraints and demand (depending on temperature, seasonality etc). This makes it difficult to analyse the operating result on a consolidated basis. Notwithstanding this:

- Contact Energy's earnings have benefited over the last three years from increased electricity demand which has resulted in total generation of around 11,000GWh per annum of electricity during that period about 10% higher than prior to 2005 although the composition of generation by fuel type has fluctuated from year to year; and
- average wholesale electricity prices have been volatile with average prices moving by around 50% from year to year.

In 2008 drought conditions (placing pressure on hydro storage) and transmission constraints both in the lower North Island and the interisland HVDC link resulted in high wholesale electricity prices. This benefited Contact Energy's generation business but negatively impacted its retail business. Consequently, despite the first full year contribution from Rockgas, Contact Energy's profits were relatively flat and its margins tightened significantly. Contact Energy expects these market conditions to continue during 2009.

Contact Energy utilises derivative financial instruments to manage its exposure to electricity price volatility and to interest rate and foreign exchange rate volatility. Changes in the fair value of financial instruments reflects the charge to the income statement for unrealised gains and losses where the financial instruments do not qualify as a hedge for accounting purposes.

Share of profits of equity accounted investments relate to a 25% interest in Oakey Power Station and a 50% interest in Rockgas Timaru, part of the Rockgas business.

Over the period Contact Energy has reported a number of significant items as summarised:

Contact Energy – Significant Items (NZ$ millions)

	Year ended 30 Sept 2004 actual NZGAAP	9 months ended 30 June 2005 actual NZIFRS	Year ended 30 June		
			2006 actual NZIFRS	2007 actual NZIFRS	2008 actual NZIFRS
Close out of long term hedges	1.7	-	-	-	-
Gain on sale of Valley Power	-	-	33.4	-	-
Dual listing proposal costs	-	-	(8.7)	-	-
Gain on sale of Mokai geothermal assets	-	-	-	-	21.3
New Plymouth asbestos removal and related costs	-	-	-	-	(33.7)
Total	**1.7**	**-**	**24.7**	**-**	**(12.4)**

Source: Contact Energy reports

Outlook

Contact Energy is not directly a party to the ConocoPhillips Proposal and Grant Samuel has only had access to public information in relation to Contact Energy. In order to provide an indication of the expected future financial performance of Contact Energy, Grant Samuel has considered broker forecasts for Contact Energy (see Appendix 3) as follows:

Contact Energy – Financial Performance (NZ$ millions)			
	Year end 30 June		
	2008 actual	Broker Consensus (Median)	
		2009	2010
Sales revenue	2,730.0	2,634.6	2,616.1
Adjusted EBITDAF	541.0	570.0	624.9
Adjusted EBITF	394.5	410.0	456.1
Net profit after tax	237.1	244.0	263.8
Earnings per share[77] (NZ cents)	40.4¢	42.3¢	45.4¢
Dividends per share (NZ cents)	28.0¢	29.5¢	31.5¢

Source: Grant Samuel analysis (see Appendix 3).

On 26 August 2008, Contact Energy advised that in 2009 it does not expect to significantly outperform the result for the year ended 30 June 2008. The median consensus brokers forecasts indicate a 2.9% increase in net profit after tax in 2009 which is not materially out of line with that guidance.

8.6 Cash Flow

Contact Energy has generated substantial operating cash flow (both from earnings and from the release of working capital) in recent years notwithstanding increased capital expenditure on development projects. Operating cash flow has primarily been used to fund increased dividends and the acquisition of Rockgas:

Contact Energy – Cash Flow (NZ$ millions)					
	Year ended 30 Sept 2004 actual NZGAAP	9 months ended 30 June 2005 actual NZIFRS	Year ended 30 June		
			2006 actual NZIFRS	2007 actual NZIFRS	2008 actual NZIFRS
Adjusted EBITDAF	**421.0**	**359.2**	**555.5**	**532.5**	**541.0**
Changes in working capital and other adjustments	105.4	13.2	76.8	(7.9)	(12.4)
Capital expenditure	(64.6)	(68.9)	(133.8)	(145.1)	(228.7)[78]
Operating cash flow	**461.8**	**303.5**	**498.5**	**379.5**	**299.9**
Tax paid	(66.8)	(155.6)	(105.8)	(104.1)	(98.7)
Net interest paid	(83.1)	(56.8)	(70.0)	(58.0)	(69.9)
Dividends paid	(198.9)	(92.3)	(115.3)	(149.9)	(161.5)
Dividends received	-	-	0.3	2.8	1.9
Acquisitions of businesses and investments (net)	(10.7)	0.6	1.3	(162.5)	(27.3)
Proceeds from sale of businesses and assets	0.9	1.2	70.5	-	27.3
Net cash generated (used)	**103.2**	**0.6**	**279.5**	**(92.2)**	**(28.3)**
Net cash (borrowings) – opening	*(1,141.2)*	*(1,038.0)*	*(1,037.4)*	*(757.9)*	*(850.1)*
Net cash (borrowings) - closing	*(1,038.0)*	*(1,037.4)*	*(757.9)*	*(850.1)*	*(878.4)*

Source: Contact Energy reports and Grant Samuel analysis

[77] Before fair value adjustments and significant items.

[78] Including cost of removal of asbestos at New Plymouth Power Station ($11.1 million).

8.7 Financial Position

The financial position of Contact Energy as at 30 June 2008 is summarised below:

Contact Energy - Financial Position (NZ$ millions)	
	As at 30 June 2008
Debtors, prepayments and other assets	517.4
Inventories	21.1
Creditors, accruals and provisions	(542.7)
Net working capital	**(4.2)**
Property, plant and equipment (net)	4,381.6
Gas storage (cushion gas)	23.6
Goodwill and other intangibles (net)	214.6
Equity accounted investments	8.0
Investment in Liquigas	2.9
Other non current assets	5.3
Derivative financial instruments[79] (net)	(76.5)
Deferred income tax liabilities (net)	(718.5)
Provision for retirement of New Plymouth Power Station	(18.8)
Provisions (non current)	(33.6)
Other non current liabilities	(1.9)
Total funds employed	**3,782.5**
Cash and deposits	2.5
Bank and other loans and finance lease liabilities	(689.7)
Impact of foreign exchange hedging on borrowings	(191.2)
Net borrowings	(878.4)
Net assets attributable to Contact Energy shareholders	**2,904.1**
Statistics	
Shares on issue at period end (million)	*576.8*[80]
Net assets per share	*NZ$5.03*
NTA per share	*NZ$4.66*
Gearing	*23.2%*

Source: Contact Energy and Grant Samuel analysis

Contact Energy's activities are capital intensive and its investment in property, plant and equipment is substantial particularly with regard to the generation business. Gas storage (cushion gas) represents beneficial access to the natural gas and LPG reserves in the Ahuroa reservoir. The reserves (approximately 4PJ) together with future additional gas injections represent a long term investment to enable the field to be used for gas storage. Goodwill primarily reflects acquired retail customer bases.

Equity accounted investments include a 25% investment in Oakey Power Station and a 50% interest in Rockgas Timaru. Contact Energy owns 8.5% of Liquigas which was acquired with Rockgas and is reflected at fair value.

Contact Energy uses a range of derivative financial instruments to manage its exposure to various price, interest rate and foreign exchange risks. Derivative financial instrument are recognised at fair value and, due to the volatility in energy markets and the size of Contact Energy's operations, represent a substantial variable component of funds employed. At 30 June 2008 derivatives in relation to financing totalled ($180.6) million (net) and electricity price hedges totalled $87.1 million (net).

Provisions primarily relate to decommissioning/restoration in relation to power stations (NZ$31.1 million). The provision for retirement of New Plymouth Power Station reflects the financial impact of the decision to close the plant following discovery of asbestos in September 2007. The provision represents an estimate of the cost to decommission the plant including the removal of

[79] Excluding the impact of foreign exchange hedging on borrowings.

[80] Including restricted shares.

asbestos. There is no provision at 30 June 2008 for the final dividend of 17.0 cents per share (NZ$98.0 million) which is to be paid on 23 September 2008.

At 30 June 2008, Contact Energy had credit facilities totalling approximately NZ$1.6 billion of which NZ$880.9 million were utilised. Contact Energy has a BBB (stable outlook) credit rating from Standard & Poor's and BBB+ from Fitch Ratings.

At 30 June 2008, Contact Energy had no carried forward income tax losses. At 30 June 2008, Contact Energy had NZ$206.5 million of accumulated imputation credits (approximately NZ$0.36 per share) the majority of which appear to be surplus to requirements.

8.8 Capital Structure and Ownership

Contact Energy has the following securities on issue:

- 576,797,290 ordinary shares; and
- 830,785 options over unissued ordinary shares.

The ordinary shares are held by more than 85,000 registered shareholders. The top twenty shareholders account for around 70% of issued shares and, other than Origin, are principally institutional nominee or custodian companies holding shares on behalf of a wide range of shareholders. Origin holds 296,153,144 ordinary shares equal to 51.34% of the issued capital. Contact Energy has a significant retail investor base with approximately 95% of registered shareholders holding less than 5,000 shares although these shareholders represent less than 14% of shares on issue.

Of the ordinary shares on issue, 163,308 are issued pursuant to Contact Energy's employee long term incentive scheme for senior executives. These shares are not tradeable and are not listed or quoted on the NZSX. Under the terms of the Restricted Share Plan, shares are issued to a trustee (on behalf of the beneficial owner) which does not exercise any voting rights and dividends are forgone. The shares may be released from restriction three years after grant if performance hurdles are satisfied at three annual test dates. To the extent that shares have "vested" and hurdles are satisfied legal title will be transferred to the participant. The rights to restricted shares lapse if the performance hurdles are not met by the last test date, termination of employment (except for redundancy) or on death (subject to Board discretion). The shares may be released from restrictions and transferred to the participants if, between the grant date and a test date, a change of control of Contact Energy occurs.

Under the Share Option Plan each option on issue is exercisable into one ordinary share and has no dividend entitlement or voting right. Options become exercisable in a period three years following grant and are subject to performance hurdles being met at three annual test dates following vesting. If the hurdle is met at a test date, there is a two year two month exercise period. Options lapse if the performance hurdles are not met on the last test date, on termination of employment (except for redundancy), on death (subject to Board discretion) or on the expiry date. The options outstanding are summarised below:

Contact Energy – Options on Issue

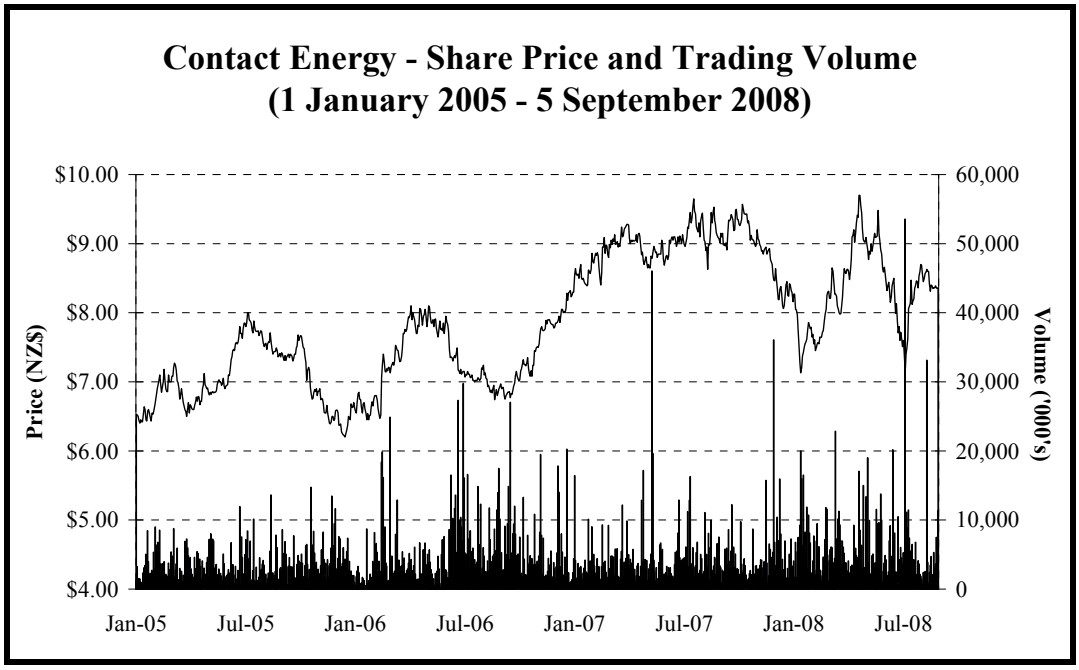
Issue Date	First Exercise Date	Expiry Date	Exercise Price	Issued Options	Exercisable Options
1 July 2006	1 October 2009	30 November 2011	NZ$7.35	330,706	-
20 November 2006	1 October 2009	30 November 2011	NZ$7.55	18,361	-
15 January 2007	1 October 2009	30 November 2011	NZ$8.28	13,413	-
1 October 2007	1 October 2010	30 November 2012	NZ$9.15	445,599	-
1 February 2008	1 October 2010	30 November 2012	NZ$7.63	22,706	-
Total				**830,785**	**-**

Source: Origin

Options may become exercisable if a change of control occurs. The Board may also permit options to be exercised where Contact Energy ceases to be listed on the NZSX or other circumstances occur where such early exercise is considered appropriate by the Board.

8.9 Share Price Performance

Contact Energy's unrestricted ordinary shares are quoted and listed on the NZSX. The share price performance of Contact Energy since 1 January 2005 is illustrated below:



Source: Bloomberg

Origin announced the acquisition of Edison's 51.2% interest in Contact Energy on 21 July 2004 at a price of NZ$5.67 per share. The price paid was a 4.5% discount to Contact Energy's market price of NZ$5.94 (although it should be noted that the share price had risen from around NZ$5.00 following the November 2003 announcement by Edison's parent of the potential sale of the interest in Contact Energy). Until Origin's follow on takeover offer closed on 26 October 2004, Contact Energy shares traded around NZ$6.00. Subsequently, the share price reached NZ$6.50 in January 2005.

During 2005 and 2006 Contact Energy shares traded in the range of NZ$6.20-8.30 (at a volume weighted price of NZ$7.19) and finished the 2006 year at NZ$8.30. During the first half of 2006, the share price was influenced by Origin and Contact Energy's ongoing discussions concerning a merger via a dual listed company structure. Discussions were terminated in June 2006 when the companies were unable to agree on final terms and the share price declined.

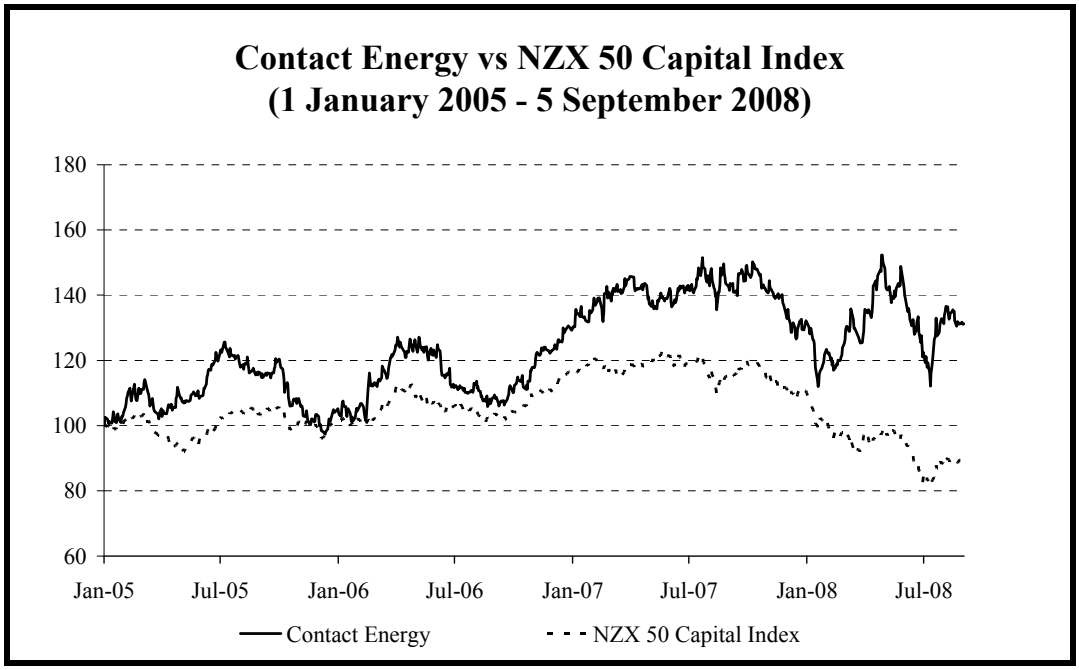
During 2007 Contact Energy shares traded higher in the range of NZ$6.70-9.70 (at a volume weighted price of NZ$8.98). These levels reflected market acceptance that the improvement in earnings and dividends under the integrated business model was sustainable notwithstanding highly variable trading conditions and the Rockgas acquisition. Post July 2007 the Contact Energy share price declined along with the market as the implications of the international credit crisis were absorbed. Contact Energy shares hit a low of NZ$6.91 on 22 January 2008.

The Contact Energy share price recovered from this low on the back of continued solid earnings performance and positive announcements regarding its generation development portfolio and participation in the acquisition of the Swift Energy oil and gas assets. The share price strengthened during April 2008 to close at NZ$9.39 on 29 April 2008, immediately prior to the announcement of BG Group's proposal to acquire all of the shares in Origin. Following that announcement, Contact Energy shares immediately rose to around NZ$9.70 but then declined to a low of around NZ$7.20 in mid July 2008. Since then the share price has risen and closed at NZ$8.36 on 5 September 2008.

Contact Energy is the second largest company by market capitalisation on the NZSX and a member of all major indices. However, it has a limited free float of 48.7% (given Origin's shareholding) but in reality its free float is probably less than that given institutional holdings.

Furthermore, Contact Energy is not a particularly liquid stock. Average weekly volume over the twelve months to 29 April 2008 (immediately prior to the BG Group's initial approach to Origin) represented approximately 0.4% of average shares on issue or annual turnover of around 22% of total average issued capital.

Contact Energy has a weighting of approximately 12.3% in the NZSX50 Capital Index and since January 2005, until recently, it has outperformed the index. Despite this outperformance, Contact Energy's share price has generally reflected movements in the wider market (e.g. the market has declined since July 2007 as has Contact Energy shares) although during the three months prior to BG Group's approach to Origin it significantly outperformed the market. Following the immediate reaction to the BG Group approach, Contact Energy declined in line with the market until mid July (albeit at a marginally faster rate) and has subsequently risen in line with the market:



Source: Bloomberg

9 Valuation of Origin Energy Limited

9.1 Summary

Origin has been valued in the range $25.5-27.4 billion which corresponds to a value of $28.55-30.71 per share. The valuation represents the estimated full underlying value of Origin assuming 100% of the company was available to be acquired and includes a premium for control. The value exceeds the price at which, based on current market conditions, Grant Samuel would expect Origin shares to trade on the ASX in the absence of the BG Offer or some similar change of control transaction.

The value for Origin is the aggregate of the estimated market value of Origin's operating business and other assets less external borrowings and non-trading liabilities. The valuation is summarised below:

Origin - Valuation Summary ($ millions)

	Report Section Reference	Value Range	
		Low	High
Business Operations			
CSG Assets	9.4	16,700	17,400
Conventional Oil and Gas	9.5	2,400	2,800
Downstream Energy	9.6	8,500	9,200
Head office costs (net of savings)	9.8	(250)	(225)
Total business operations		**27,350**	**29,175**
51.3% interest in Contact Energy	9.7	2,300	2,400
Other assets and liabilities	9.9	(705)	(700)
Net borrowings	9.10	(3,453)	(3,453)
Value of equity		**25,492**	**27,422**
Fully diluted shares on issue (millions)		892.9	892.9
Value per share		**$28.55**	**$30.71**

The value attributed to the various operating businesses is an overall judgement having regard to a number of valuation methodologies and parameters, including capitalisation of earnings or cash flows (multiples of EBITDA and EBIT), discounted cash flow ("DCF") analysis and other measures commonly used in the energy sector (including multiples of MW installed capacity, mass market customer accounts and value per GJ).

The value attributed to the CSG Assets is twice the estimated value of the ConocoPhillips Proposal which was calculated by discounting the future cash flow equivalents at an interest rate. The Contingent Contributions were risked by applying various probability factors (between 50% and 90%) to reflect that they are not certain. This approach was considered more appropriate than undertaking a separate DCF valuation of projected cash flows as the ConocoPhillips Proposal is an arm's length market price for the CSG Assets.

The DCF analysis for the remaining businesses was based on cash flow models and long term business plans provided by Origin. The financial models developed by Grant Samuel use as their starting point the balance sheet of Origin as at 30 June 2008 and project cash flows from 1 July 2008. Projected ungeared after tax cash flows were discounted to a net present value ("NPV") using nominal after tax discount rates appropriate for each business. Appendix 4 sets out a detailed analysis of the selection of the discount rates used in this report.

The earnings multiples and NTA multiples implied by the valuation of Origin's operating business and the value of the equity of Origin are summarised below:

Origin – Implied Valuation Parameters				
	Variable Source Section Reference	Variable ($ millions)	Value Range	
			Low	High
Multiple of EBITDAF				
Year ended 30 June 2008 (actual)	4.3	1,256.9	25.9	27.6
Year ending 30 June 2009 (broker median)	4.3	1,483.2	21.9	23.4
Year ending 30 June 2010 (broker median)	4.3	1,761.1	18.5	19.7
Multiple of EBITF				
Year ended 30 June 2008 (actual)	4.3	912.3	35.7	38.0
Year ending 30 June 2009 (broker median)	4.3	1,084.7	30.0	32.0
Year ending 30 June 2010 (broker median)	4.3	1,319.9	24.7	26.3
Multiple of net profit after tax				
Year ended 30 June 2008 (actual)	4.3	516.7	49.3	53.1
Year ending 30 June 2009 (broker median)	4.3	501.4	50.9	54.7
Year ending 30 June 2010 (broker median)	4.3	602.0	42.3	45.6
Multiple of NTA (at 30 June 2008)	4.4	2,712.1	9.4	10.1

The multiples implied by Grant Samuel's valuation range are presented for information purposes but are not meaningful primarily due to the substantial value for the CSG Assets for which earnings are yet to emerge. In addition, both Origin and Contact Energy also have substantial pipelines of generation developments (for 2096MW and 1,417MW respectively) for which earnings will emerge over 2009-2011. The ConocoPhillips Proposal has fundamentally transformed the value of Origin but the earnings from these assets will not emerge until beyond 2015.

The premia implied by the value range over the share price prevailing prior to the announcement of the BG Group approach on 29 April 2008 ($10.47) are in the range of 173-193% and over the share price on 5 September 2008 (the day before announcement of the ConocoPhillips Proposal) ($15.65) in the range of 82-96%. As with the implied earnings multiples, the implied premium are substantial as the ConocoPhillips Proposal transforms Origin in a way the market had not anticipated at that time.

9.2 Methodology

9.2.1 Overview

Grant Samuel's valuation of Origin has been estimated by aggregating the estimated market value of its operating businesses together with the realisable value of non-trading assets and deducting external borrowings and non-trading liabilities. The value of the operating businesses have been estimated on the basis of fair market value as a going concern, defined as the maximum price that could be realised in an open market over a reasonable period of time assuming that potential buyers have full information.

The valuation of Origin is appropriate for the acquisition of the company as a whole and, accordingly, incorporates a premium for control. The value is in excess of the level at which, under current market conditions, shares in Origin could be expected to trade on the sharemarket. Shares in a listed company normally trade at a discount of 15-25% to the underlying value of the company as a whole (but this discount does not always apply).

The most reliable evidence as to the value of a business is the price at which the business or a comparable business has been bought and sold in an arm's length transaction (and this methodology has been adopted in relation to the CSG Assets). In the absence of direct market evidence of value, estimates of value are made using methodologies that infer value from other available evidence. There are four primary valuation methodologies that are commonly used for valuing businesses:

- capitalisation of earnings or cash flows;
- discounting of projected cash flows;
- industry rules of thumb; and
- estimation of the aggregate proceeds from an orderly realisation of assets.

Each of these valuation methodologies has application in different circumstances. The primary criterion for determining which methodology is appropriate is the actual practice adopted by purchasers of the type of business involved.

Nevertheless, valuations are generally based on either or both discounted cash flow or multiples of earnings and Grant Samuel has had regard to both methodologies in the valuation of Origin. In addition, some weight has also been given to the implied multiples of reserves, of MW installed capacity, of mass market customer accounts and of tonnes of LPG which are metrics considered in the energy sector.

9.2.2 Discounted Cash Flow

Discounting of projected cash flows has a strong theoretical basis. It is the most commonly used method for valuation in a number of industries, including resources, and for the valuation of start-up projects where earnings during the first few years can be negative but it is also widely used in the valuation of established industrial businesses. Discounted cash flow valuations involve calculating the net present value of projected cash flows. This methodology is able to explicitly capture depleting resources, development projects and fixed term contracts (which are typical in the energy sector), the effect of a turnaround in the business, the ramp up to maturity or significant changes expected in capital expenditure patterns. The cash flows are discounted using a discount rate which reflects the risk associated with the cash flow stream.

Considerable judgement is required in estimating future cash flows and it is generally necessary to place great reliance on medium to long term projections prepared by management. The discount rate is also not an observable number and must be inferred from other data (usually only historical). None of this data is particularly reliable so estimates of the discount rate necessarily involve a substantial element of judgement. In addition, even where cash flow forecasts are available, the terminal or continuing value is usually a high proportion of value. Accordingly, the multiple used in assessing this terminal value becomes the critical determinant in the valuation (i.e. it is a "de facto" cash flow capitalisation valuation). The net present value is typically extremely sensitive to relatively small changes in underlying assumptions, few of which are capable of being predicted with accuracy, particularly beyond the first two or three years. The arbitrary assumptions that need to be made and the width of any value range mean the results are often not meaningful or reliable. Notwithstanding these limitations, discounted cash flow valuations are commonly used and can at least play a role in providing a check on alternative methodologies, not least because explicit and relatively detailed assumptions as to expected future performance need to be made.

Financial models for the operating businesses have been developed by Grant Samuel based on long term cash flow models developed by Origin in conjunction with its financial advisers. These models allow the key drivers of revenues, costs and capital expenditure to be modelled. The models are based on a large number of assumptions and are subject to significant uncertainty and contingencies, many of which are out side the control of Origin. A number of different scenarios have been developed and analysed to reflect the impact on value of various key assumptions relating to pricing, capital expenditure and other factors. The cash flow models are discussed in more detail in the following sections of this report.

9.2.3 Capitalisation of Earnings or Cash Flows

Capitalisation of earnings or cash flows is the most commonly used method for valuation of industrial businesses. This methodology is most appropriate for industrial businesses with a substantial operating history and a consistent earnings trend that is sufficiently stable to be indicative of ongoing earnings potential. This methodology is not particularly suitable for start-up businesses, businesses with an erratic earnings pattern or businesses that have unusual capital expenditure requirements. This methodology involves capitalising the earnings or cash flows of a business at a multiple that reflects the risks of the business and the stream of income that it generates. These multiples can be applied to a number of different earnings or cash flow measures including EBITDA, EBIT or net profit after tax. These are referred to respectively as EBITDA multiples, EBIT multiples and price earnings multiples. Price earnings multiples are commonly used in the context of the sharemarket. EBITDA and EBIT multiples are more commonly used in valuing whole businesses for acquisition purposes where gearing is in the control of the acquirer but are also used extensively in sharemarket analysis.

Where an ongoing business with relatively stable and predictable cash flows is being valued, Grant Samuel uses capitalised earnings or operating cash flows as a primary reference point.

Application of this valuation methodology involves:

- estimation of earnings or cash flow levels that a purchaser would utilise for valuation purposes having regard to historical and forecast operating results, non-recurring items of income and expenditure and known factors likely to impact on operating performance; and
- consideration of an appropriate capitalisation multiple having regard to the market rating of comparable businesses, the extent and nature of competition, the time period of earnings used, the quality of earnings, growth prospects and relative business risk.

The choice between parameters is usually not critical and should give a similar result. All are commonly used in the valuation of industrial businesses. EBITDA can be preferable to EBIT if depreciation or non-cash charges distort earnings or make comparisons between companies difficult. On the other hand, EBIT can better adjust for differences in relative capital expenditure intensity.

Determination of the appropriate earnings multiple is usually the most judgemental element of a valuation. Definitive or even indicative offers for a particular asset or business can provide the most reliable support for selection of an appropriate earnings multiple. In the absence of meaningful offers it is necessary to infer the appropriate multiple from other evidence.

The usual approach used by valuers is to determine the multiple that other buyers have been prepared to pay for similar businesses in the recent past. A pattern may emerge from transactions involving similar businesses with sales typically taking place at prices corresponding to earnings multiples within a particular range. This range will generally reflect the growth prospects and risks of those businesses. Mature, low growth businesses will, in the absence of other factors, attract lower multiples than those businesses with potential for significant growth in earnings.

An alternative approach in valuing businesses is to review the multiples at which shares in listed companies in the same industry sector trade on the sharemarket. This gives an indication of the price levels at which portfolio investors are prepared to invest in these businesses. However, share prices reflect trades in small parcels of shares (portfolio interests) rather than whole companies and it is necessary to adjust for this factor.

In interpreting and evaluating such data it is necessary to recognise that:

- multiples based on listed company share prices do not include a premium for control and are therefore often (but not always) less than multiples that would apply to acquisitions of similar companies. However, while the premium paid to obtain control in takeovers is observable (typically in the range 20-35%) it is inappropriate to simply

add a premium to listed multiples. The premium for control is an outcome of the valuation process, not a determinant of value. Premiums are paid for reasons that vary from case to case and may be substantial due to synergy or other benefits available to the acquirer. In other situations premiums may be minimal or even zero. There are transactions where no corporate buyer is prepared to pay a price in excess of the prices paid by sharemarket investors;

- acquisition multiples from comparable transactions are therefore usually seen as a better guide when valuing 100% of a business but the data tends to be less transparent and information on forecast earnings is often unavailable;
- the analysis will give a range of outcomes from which averages or medians can be determined but it is not appropriate to simply apply such measures to the company being valued. The most important part of valuation is to evaluate the attributes of the specific company being valued and to distinguish it from its peers so as to form a judgement as to where on the spectrum it appropriately belongs;
- acquisition multiples are a product of the economic and other circumstances at the time of the transaction. However, each transaction will be the product of a unique combination of factors, including:
  - economic factors (e.g. economic growth, inflation, interest rates) affecting the markets in which the company operates;
  - strategic attractions of the business - its particular strengths and weaknesses, market position of the business, strength of competition and barriers to entry;
  - the company's own performance and growth trajectory;
  - rationalisation or synergy benefits available to the acquirer;
  - the structural and regulatory framework;
  - investment and sharemarket conditions at the time; and
  - the number of competing buyers for a business;
- acquisitions and listed companies in different countries can be analysed for comparative purposes, but it is necessary to give consideration to differences in overall sharemarket levels and ratings between countries, economic factors (economic growth, inflation, interest rates) and market structures (competition etc) and the regulatory framework. It is not appropriate to adjust multiples in a mechanistic way for differences in interest rates or sharemarket levels;
- acquisition multiples are based on the target's earnings but the price paid normally reflects the fact that there were synergies available to the acquirer (at least if the acquirer is a "trade buyer" with existing businesses in the same or a related industry). If the target's earnings were adjusted for these synergies, the effective multiple paid by the acquirer would be lower than that calculated on the target's earnings; and
- while EBITDA multiples are commonly used benchmarks they are an incomplete measure of cash flow. The appropriate multiple is affected by, among other things, the level of capital expenditure (and working capital investment) relative to EBITDA. In this respect:
  - EBIT multiples can in some circumstances be a better guide because (assuming depreciation is a reasonable proxy for capital expenditure) they effectively adjust for relative capital intensity and present a better approximation of free cash flow. However, capital expenditure is lumpy and depreciation expense may not be a reliable guide. In addition, there can be differences between companies in the basis of calculation of depreciation; and
  - businesses that generate higher EBITDA margins than their peer group companies will, all other things being equal, warrant higher EBITDA multiples because free cash flow will, in relative terms, be higher (as capital expenditure is a smaller proportion of earnings).

The analysis of comparable transactions and sharemarket prices for comparable companies will not always lead to an obvious conclusion as to which multiple or range of multiples

will apply. There will often be a wide spread of multiples and the application of judgement becomes critical. Moreover, it is necessary to consider the particular attributes of the business being valued and decide whether it warrants a higher or lower multiple than the comparable companies. This assessment is essentially a judgement.

In determining values for Origin's business operations, Grant Samuel has considered EBITDAF and EBITF multiples for the Downstream Energy Business as they remove the impact of fair value adjustments (i.e. unrealised gains or losses) in relation to financial instruments.

9.2.4 Industry Rules of Thumb

Industry rules of thumb are commonly used in some industries. These are generally used as a "cross check" of the result determined by a capitalised earnings valuation or by discounting cash flows. While they are only used as a cross check in most cases, industry rules of thumb can be the primary basis on which buyers determine prices in some industries. In the case of the energy sector there are a number of rules of thumb adopted including multiples of reserves for oil and gas assets, multiples of regulated asset base for energy infrastructure businesses, multiples of MW installed capacity for electricity generation businesses, multiples of mass market customer accounts for energy retailing and multiples of annual LPG tonnes sold for LPG distribution businesses. However, it should be recognised that rules of thumb are usually relatively crude and prone to misinterpretation.

9.2.5 Net Assets/Realisation of Assets

Valuations based on an estimate of the aggregate proceeds from an orderly realisation of assets are commonly applied to businesses that are not going concerns. They effectively reflect liquidation values and typically attribute no value to any goodwill associated with ongoing trading. Such an approach is not appropriate in Origin's case.

9.3 Key Assumptions

There are a number of economic assumptions which apply across the valuations of Origin's businesses (excluding CSG):

- **East Coast Domestic Gas Prices**

The outlook for domestic gas prices on the east coast is subject to considerable uncertainty. While it is generally expected that gas prices will increase in the medium term, the quantum and timing of these increases will depend on a range of regulatory, economic and supply/demand factors. Moreover, the interaction of each of these factors in determining gas prices is difficult to assess. A detailed discussion of these factors is set out in Section 5.2.7.

Wholesale gas prices are a fundamental input in the valuation of all of Origin Energy's businesses. Grant Samuel has carefully considered the market commentary and expectations for domestic gas prices which also incorporates expectations for the cost of carbon and the implications of the proposed LNG projects. It is Grant Samuel's view that wholesale domestic gas prices will increase relatively strongly over the medium term. On that basis, two price paths have been developed as follows:

East Coast Domestic Gas Price (ex well head) Estimates ($ per GJ real 2008)

	Year end 30 June		
	2008 to 2010	2011 to 2015	2016 onwards
Gas Price Path A	$3.50	$4.50	$6.50
Gas Price Path B	$3.50	$5.50	$7.50

Source: Grant Samuel analysis

The gas price paths reflect Grant Samuel's judgement taking into consideration the range of available information regarding the various inputs to future gas prices. The price paths reflect a progression of real price increases resulting from the interplay of pricing pressures as a consequence of the introduction of an emissions trading scheme in 2010, the projected

dates for FID for the proposed LNG plants by the JV and others (2010-2011) and the estimated commissioning dates for the proposed LNG plants (around 2015).

It is generally accepted by market commentators that domestic gas prices in the medium term will move towards $6.00 per GJ irrespective of whether any of the proposed LNG plants proceed (due to increased demand for gas and the cost of carbon). However, it is reasonable to expect that (as four of the six proposed plants are backed by international LNG operators) at least one of the LNG plants will be commissioned and therefore domestic gas prices will be influenced to some degree by LNG netback prices. Accordingly, Grant Samuel's price paths include a moderate price path and a high price path. Future gas prices may exceed these price paths, particularly if more than one LNG plant is commissioned and the east coast gas market therefore reverts to a more finely balanced supply position.

- **Oil Prices**

  The West Texas Intermediate ("WTI") crude oil price is accepted as an international crude oil benchmark price. However, most crude oils and condensates produced in Australia are sold by reference to the Tapis crude oil benchmark in Asia. Historically, Tapis has traded at close to parity with WTI but, in recent years, has attracted an increasing premium over WTI.

  Although the price of crude oil has continued to achieve record highs during 2008, it has fallen more recently and prices around these lower levels are expected to prevail over the medium term. For the purposes of this report, WTI is assumed to move from levels of around US$103-107 per bbl in 2009 to around US$90-110 per bbl by 2016 (in nominal dollars) and thereafter to increase at the rate of inflation. The high end of these oil price paths is not out of line with the price of traded oil futures which are currently indicating US$107 per bbl (in nominal dollars) in 2016.

  Tapis has been assumed to trade at a premium of US$3.50 per bbl to WTI. This is broadly consistent with market commentators that expect the premium to continue but decline from current levels of over US$5.00 per bbl.

  Condensate prices are assumed to trade at parity with WTI and LPG prices are assumed to be 95% of WTI reflecting their historical relationships.

- **Inflation**

  Grant Samuel has assumed an inflation rate of 3% per annum. This is consistent with medium term expectations for inflation.

- **Taxation**

  Australian and New Zealand income tax rates are assumed to remain constant at 30%.

- **Discount Rates**

  The following discount rates have been applied to forecast nominal ungeared after tax cash flows:

  - energy fuel (i.e. Conventional Oil and Gas) 9.5-10.5%;
  - energy conversion and marketing (i.e. Generation and Retail) 9.0-10.0%

  Appendix 4 sets out a detailed analysis of the selection of these discount rates

Other operational and specific assumptions used in the DCF models in this report are set out in Appendix 5.

9.4 Value of the Coal Seam Gas Assets

9.4.1 Overview

Grant Samuel considers it appropriate to use the value to be contributed by ConocoPhillips for its 50% interest in the JV as the basis for valuing Origin's CSG Assets for the purposes of this report. Grant Samuel has assessed the value of the ConocoPhillips Proposal to be in the range of $8.36-8.69 billion for a 50% interest based on a DCF analysis of the cash flow equivalents arising under the ConocoPhillips Proposal. Risk factors were applied to the contingent payments for LNG Trains 1 and 2 and Trains 3 and 4. Allowance was also made for potential delays. On this basis, the CSG Assets have a total value of $16.7-17.4 billion.

9.4.2 Approach and Rationale

The rapidly changing environment for CSG, its early stage of development and the outstanding issues yet to be resolved would normally make reliable estimates of the value of Origin's CSG Assets extremely difficult.

Key value drivers such as future gas prices are subject to substantial uncertainty. Today's gas prices are well below levels that virtually all commentators and analysts expect them to be in the next 5-10 years but where they settle will be the result of a complex interplay of future demand for energy, future oil prices, coal prices and carbon prices and, in part, will be dependent on whether or not LNG plants are constructed in Queensland. Similarly, capital and operating costs for LNG plants are, at this stage, fairly broad estimates. It is then necessary to overlay a "risking" that takes account of the hurdles yet to be overcome.

However, the ConocoPhillips Proposal provides a clear arm's length benchmark that represents the maximum price that independent parties will pay for a 50% interest today. The sale price to an independent third party conducted through a competitive tender process is the most reliable evidence of value, far more so than the theoretical values based on long term cash flow projections for operations not yet in existence. It effectively consolidates all of the judgements about variables and risks into a single number.

In forming this view, Grant Samuel also considered the following factors:

Process

The ConocoPhillips Proposal is the culmination of the CSG Monetisation Process begun in June 2008. Expressions of interest were invited from a wide range of potential partners. In total, Origin approached 45 parties ranging from major international oil companies to financial investors. BG Group was also invited to participate in the process but declined. In any event, the process was well publicised and any seriously interested party would have been aware of it and able to become involved had it wished to do so. The invitation was also broadly based and not prescriptive as to ownership, structure or technology.

22 expressions of interest were received by early July 2008, all of them from credible parties. Origin then reduced this to a short list of six who were invited to conduct detailed due diligence and submit final offers. Five parties did so and all submitted final offers. Each of the final round bidders were companies of undoubted substance and expertise.

In Grant Samuel's opinion, the process was conducted on a basis likely to lead to a fair outcome. There is no evidence that:

- the timing of the CSG Monetisation Process was inopportune. While equities markets have fallen sharply since November 2007 and credit markets remain in turmoil, energy companies, particularly major oil and gas companies, have been enjoying very strong earnings and cash flows and continue to be well rated by the market. The general market conditions are unlikely to have a material impact on their appetite for investment. In addition, the potential of CSG has been widely discussed in the media and elsewhere and there is a broad recognition of the value potential. Participants in

the process do not "need to be convinced". The extent of market activity in the sector is also indicative of the extent of interest at the present time.

Origin has also now proved up sufficient reserves for at least two trains and the quality of information around other resources is such that there would be a substantial degree of comfort for bidders around production levels. While there are technical issues associated with the development, many of the bidders had experience in either managing CSG production fields or in building and managing LNG plants and appeared comfortable that there were solutions to any significant issues such as lean gas. It is not "new" technology where it might be better to wait. Other hurdles such as managing ramp up gas were also resolvable because of Origin's extensive downstream operations and in field technical solutions;

- the process was conducted unfairly or in a manner unlikely to yield the best price. Grant Samuel has been advised that all the final round bidders were treated equally. They were given the same level of information and had the same access to Origin management;
- the timetable did not allow all bidders sufficient time to conduct their analysis, undertake due diligence or organise funding. The timetable was relatively short for the conduct of a major asset sale, particularly one as complex as the CSG Assets and with as many uncertainties. However, Grant Samuel has been advised that none of the bidders raised the issue of timing as a significant issue. In any event, three final round bidders submitted board approved offers with minimal conditions; and
- different structures (i.e. other than 50/50) would have produced superior values. For example:
  - could better value have been realised through alternative structures such as a 49/51, 51/49 or 40/60 splits or through a three or four way split or different ownership interests in the gas production and LNG components?; or
  - were any proposed terms of the transaction put forward by Origin so draconian as to materially adversely impact value?

  While it is difficult to be certain and it is primarily a matter of judgement, Grant Samuel believes the 50/50 structure across the whole business is probably the most sensible one. A 50% interest is big enough to be meaningful but is also manageable for all parties. Neither party will dominate and their economic interests are fully aligned.

  In any event, Grant Samuel has been advised that the 50/50 "whole of business" model was put forward strongly by a number of potential bidders in their expressions of interest as being likely to be the most attractive to them.

Structure and Terms

The ConocoPhillips Proposal is a relatively straight forward transaction. There are no apparent terms and conditions which transfer value between one 50% holding and the other. For example:

- there are no abnormal "control" provisions or other terms which affect the value of the other 50%. Voting and board representation are split 50/50. The steering committee which will oversee the day to day activities will have equal representation from both parties. There are normal restrictions on transfer and pre emptive rights but they are the same for both parties; and
- the ConocoPhillips Proposal covers all of Origin's CSG Assets and includes the LNG plant. Both parties have the same economic interests across the entire business. There are some minor differences where Origin is the operator of the CSG production activity and ConocoPhillips is the operator of the LNG plant but these are largely cost recovery exercises.

In addition, it should be noted that Origin (and ConocoPhillips) will have capacity to sell down part of its interest (up to half of its interest) without triggering the pre-emptive rights (but subject to the buyer meeting certain criteria) and still maintain its 50% voting power and operatorship of the upstream assets.

There may be some debate about whether Origin's 50% is "worth" the same as ConocoPhillips' 50%. On one hand, it could be argued that ConocoPhillips paid a strategic premium to obtain an entry point into the industry in Queensland or that it would pay less for Origin's 50% because it would then lose access to Origin's deep knowledge of the assets. On the other hand:

- the implied value parameters (see below) are comparable to the Santos/Petronas transaction and do not suggest a premium has been paid;
- the resources industry is largely based on partial interests. Grant Samuel's experience is that transaction values usually represent a pro rata share of value and that different parcels (larger or small) are not attributed different (pro rata) value; and
- it might be argued that ConocoPhillips would pay more for an interest that would take it to 100% as this would give unfettered control over the assets (compared to shared control under the 50/50 structure).

On balance, Grant Samuel believes that as the two 50% interests are identical (except for operatorship of some segments), attributing the same value to each 50% interest is the most appropriate.

In any event, even if the value of Origin's 50% interest was discounted by, say, 20% the low end of the adjusted value range for Origin would still exceed $26.00.

Implied Value Parameters

Another test is whether or not the value is an "outlier". The parameters implied by the value range of $8.36-8.69 billion for 50% are shown below along with other bases of calculation:

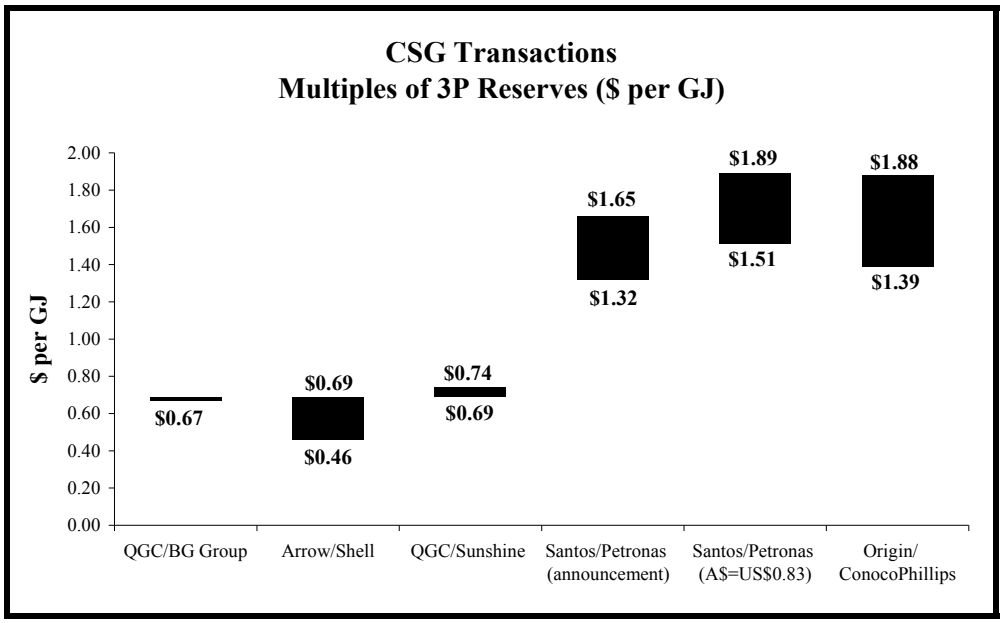
CSG Assets - Implied Value Parameters ($ per GJ)

	Reserves/Resources[81] as at 30 June 2008		
	2P	**3P**	**3P+2C**
Initial Contribution plus Development Cost Contribution only	2.98	1.39	0.54
Low Case - all payments (but risked and delayed)	**3.52**	**1.64**	**0.64**
High Case - all payments (but risked)	**3.66**	**1.71**	**0.67**
All Contributions at face value	4.03	1.88	0.74

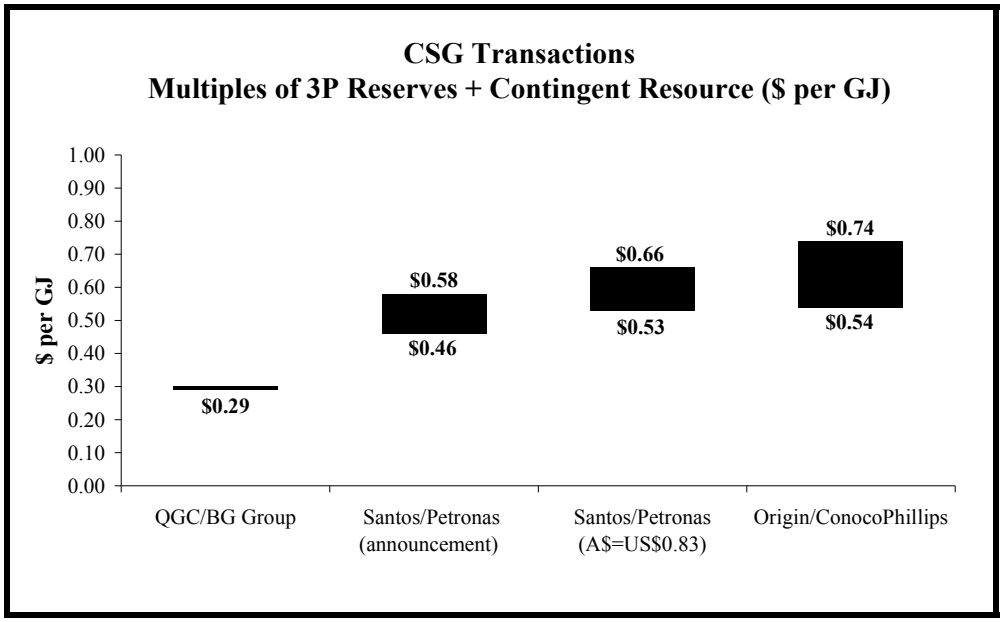
These parameters can be compared to those seen in other recent transactions, specifically:

- the takeover offer by QGC for Sunshine;
- the acquisition by Petronas of a 40% interest in Santos' Gladstone LNG project and associated reserves;
- the investment by Shell in 30% of the Australian CSG assets of Arrow; and
- the acquisition by BG Group of a 20% interest (with the right to go to 30%) in QGC's Walloons acreage, coupled with joint ventures for the pipeline and the LNG plant.

[81] Including 44PJe of 2P conventional reserves from the Denison Trough that will be an asset of the JV.



Source: Grant Samuel analysis



Source: Grant Samuel analysis

The low value for each transaction (other than the QGC/Sunshine transaction) is based on base payments only while the high value adds the face value of contingent payments (i.e. unrisked and undiscounted)[82].

The Santos/Petronas transaction has been shown on two bases. To a large degree, the assets are US$ assets (revenues and most construction costs will be denominated in US$) and the purchase price of the interest was expressed in US$. At the time of announcement, the exchange rate was A$1.00=US$0.95. In order to put it on a comparable basis with the ConocoPhillips Proposal (which is also largely priced in US$), it is appropriate to convert the transaction consideration at the current exchange rate. For this analysis, an exchange rate of A$1.00=US$0.83 was used.

[82] In the case of the QGC/Sunshine transaction the low and high values represent the scrip and cash and scrip consideration respectively. The multiples for the Arrow/Shell transaction are based on reserves at 30 June 2008 although the transaction was announced on 2 June 2008.

In general, it is necessary to be cautious in relying on these kinds of value parameters because they are relatively crude rules of thumb influenced by many factors including the location, the extent of additional resources and the scope and timing of any associated LNG project. In this case, there is further debate on exactly how some of the values in these transactions should be measured having regard to reserve maturation profiles, the status (progress) of the development and contingent payments (where they apply).

Normally 2P or 3P based measures are considered the better measures because of the greater reliability of the technical data. However, for CSG assets it is arguable that 3P+Contingent Resource is a more relevant basis despite the uncertain and contingent nature of such measurements. It appears that investors/acquirers are premising their purchase prices more on this basis than just 3P as current 3P reserves may be insufficient to provide the volumes necessary for the planned level of LNG plants. This approach reflects the nature of CSG assets, the drilling program strategies generally adopted (a progressive proving up as the need arises and, at least historically, generally only based on meeting domestic demand as it evolved over time) and the fact that there is often a reasonable amount of supporting data from nearby fields. The 3P+Contingent Resource basis also avoids the need to make reserve maturation adjustments to try to align the various transactions.

Another approach is to analyse the value in terms of the projected LNG development. In this analysis, it is assumed the fields contain the gas necessary to support the aggregate LNG production over the life of the plant (assumed to be approximately 20 years).

For example, in BG Group's Bidder's Statement, Wood Mackenzie Ltd ("Wood Mackenzie"), an international energy consultancy, calculated a value of $0.56 per GJ for the Santos/Petronas transaction on the basis of:

- a two train development of 3.5Mtpa with each requiring 5,509PJ; and
- including the contingent payments discounted at 12%.

Using the current exchange rate (A$1.00=US$0.83), the adjusted figure for the Santos/Petronas transaction is $0.64 per GJ. Wood Mackenzie also calculated a value of $0.72 per GJ for the Arrow/Shell transaction on a similar basis (i.e. assuming an LNG plant is completed).

Grant Samuel's value range for the ConocoPhillips Proposal (which includes the Contingent Contributions on a discounted and risked basis) is equivalent to $0.69-0.71 per GJ:

- assuming a four train development (of 3.5Mtpa each); and
- including 2,200PJ for gas contracts already in place for which reserves are also required.

Grant Samuel does not believe it is necessary or appropriate at this point in time to make any adjustments for perceived differences in the relative stages of development of the different projects.

In summary, the comparative analysis does not suggest that the ConocoPhillips Proposal is not fair value, either on the low side or the high side. In fact it is almost directly in line with the Santos/Petronas transaction, arguably the most relevant benchmark. In any event, it can be argued that Origin's CSG Assets may warrant a premium for a variety of reasons including:

- the scale of the resource which is the single largest portfolio in Australia and large enough to underpin several LNG trains;
- low levels of contracted gas, providing maximum capacity for LNG;
- geographic diversity of the fields;

- location of operated reserves in the best areas (higher well densities etc). Origin has prime acreage in two sweet spots – Spring Gully/Fairview and Undulla Nose (although Santos also has a significant presence in high quality areas);
- significant unexplored acreage in the Galilee Basin;
- the 2C resources which are predominantly in the Walloons Fairway, with well known characteristics; and
- Origin's strong ability to manage ramp up gas through its downstream business operations.

Reversion Rights

One area of contention that has arisen is in relation to the Tri-Star reversion rights and their potential value impact. Those interests lie within the JV company and have therefore been taken into account in the pricing of the ConocoPhillips Proposal. It should also be noted that if reversion does occur, Tri-Star will have an interest in the permits (i.e. rights to the remaining gas) but no other rights (such as participating in the JV). The JV could purchase the gas from Tri-Star for the LNG plant.

9.4.3 Valuation

Grant Samuel has estimated the value of the ConocoPhillips Proposal to be in the range of $8.36-8.69 billion for the 50% interest. This value is based on the low and high cases from a DCF analysis of the cash flows under the ConocoPhillips Proposal. While these cash flows are by way of subscription into OECSG rather than payment to Origin, the Initial Payment will be repatriated to Origin (through a combination of return of capital, repayment of intercompany loans and an interest free loan) and the subsequent payments, in so far as they save Origin from any such expenditure (without impacting its 50% equity ownership) or represent an increase in value of its interest on that date, can be considered as cash equivalents.

The analysis was undertaken on the following basis:

- the cash flows are discounted to a present value on 1 October 2008;
- the Initial Contribution is assumed to be repatriated on 1 October 2008. It has been converted at A$1.00=US$0.83;
- the Development Cost Contribution of A$1.15 billion (Origin's carry) was spread quarterly over the period to the end of 2010. The timing is based on the phasing of the approved budgets set out in the agreements. No risk factor has been applied to this amount as the parties have committed to the expenditure program. The aggregate budgets are approximately equal to the cap of A$2.3 billion;
- the Contingent Contributions payable upon FID for each LNG train have been risked. The low and high cases involve the following assumptions:

Contingent Contributions – Valuation Assumptions

	Low		High	
	FID Date	Probability Factor	FID Date	Probability Factor
Train 1	Jun 2011	80%	Dec 2010	90%
Train 2	Mar 2012	80%	Sep 2011	90%
Train 3	Sep 2015	50%	Sep 2013	65%
Train 4	Sep 2017	50%	Sep 2015	65%

The selection of probability factors is highly subjective. However, Grant Samuel believes that it is reasonable to assume a very high probability of Trains 1 and 2 proceeding to FID. The reasons include:

- the current market environment in terms of oil price and LNG demand and supply;
- the standing, experience and expertise of ConocoPhillips;
- the financial incentives for ConocoPhillips, having invested US$7 billion in cash up to that point;
- the scale and quality of Origin's resources which is highly likely to provide sufficient (uncontracted) CSG for two trains; and
- the incentives within the agreements between the parties which involve penalties if FID is unnecessarily delayed.

Lower probabilities apply to the subsequent two trains. Decisions are much further off with greater potential for slippage. It will require substantial further conversion of resources. However, there is still a reasonably strong likelihood of success as the existence of two existing trains materially improves the economics for subsequent trains and the JV will be able to access third party supplies of gas to meet FID criteria for LNG trains;

- future payments were converted at prevailing forward exchange rates; and
- the cash flows have been discounted at a rate of 7%. This rate represents an interest rate commensurate with a credit risk against ConocoPhillips. It reflects a margin of approximately 1.4% over Australian government bonds which Grant Samuel believes is reasonable having regard to ConocoPhillips' credit rating (A1 – Moodys, A – Standard & Poor's) and recent bond issues. A single rate has been used as the yield curve is relatively flat.

  Although the payments are uncertain, the quantum of the payments is fixed (i.e. they are not business cash flows). It is therefore not appropriate to discount them at a cost of equity capital or weighted average cost of capital (they have been separately adjusted for risk).

The resultant net present values are summarised below:

CSG Assets – NPV Outcomes ($ millions)		
	50% Interest	**100% Interest**
Initial Contribution plus Development Cost Contribution only	7,083	14,176
Low Case – all payments (but risked and delayed)	**8,364**	**16,726**
High Case – all payments (but risked)	**8,693**	**17,386**
All Contributions at Face Value	9,583	19,167

9.5 Value of Conventional Oil and Gas Assets

9.5.1 Overview

A value of $2.4-2.8 billion has been attributed to Origin's conventional oil and gas assets:

Conventional Oil and Gas Assets – Valuation Summary ($ millions)			
	Report Section Reference	Value Range	
		Low	High
Cooper Basin	9.5.3	500	550
BassGas Project	9.5.4	450	500
Otway Gas Project	9.5.5	600	660
Kupe Gas Project	9.5.6	660	730
Other producing and developing assets	9.5.7	350	390
Exploration assets	9.5.8	10	83
Other assets and liabilities	9.5.9	(175)	(140)
Total		**2,395**	**2,773**

The valuation of Origin's conventional oil and gas assets implies a value of $14.31-16.57 million per MMboe (2P) and $2.46-2.84 per PJe (2P). This is broadly consistent with listed conventional oil and gas companies that have a combination of producing and developing assets.

No earnings multiples analysis is presented as the financial information for Exploration & Production (as presented in Section 5.5) is for the combined CSG and conventional oil and gas assets and the resulting multiples would not be meaningful.

9.5.2 Approach

DCF analysis is the primary methodology that has been used to value Origin's interests in producing gas fields and development projects. This approach involves calculating the NPV of projected future cash flows. The cash flows are discounted using a discount rate that reflects the time value of money and the risks associated with the cash flow stream. Discounting projected cash flows is particularly appropriate for assets such as producing oil and gas fields where the resource is depleting and for development projects where significant capital expenditure is required before operating cash flows are generated. It is the most commonly used method for valuation in the oil and gas industry.

Gaffney Cline was commissioned as technical specialist to review production profiles, operating costs and capital costs adopted in the cash flow scenarios for Origin's major conventional oil and gas assets (i.e. Cooper Basin, BassGas Project, Otway Gas Project and Kupe Gas Project). Gaffney Cline also reviewed the reserve estimates for these assets.

DCF models for the major conventional oil and gas assets have been developed by Grant Samuel based on long term cash flow models prepared by Origin. Origin's models were reviewed and modified by Grant Samuel based on technical input data provided by Gaffney Cline and Grant Samuel's economic assumptions. The DCF models are long term commencing at 1 July 2008. Net present values are calculated on an ungeared after tax basis using nominal after tax discount rates of 9.5-10.5%. Appendix 4 sets out a detailed analysis of the selection of these discount rates. A corporate tax rate of 30% has been assumed. A range of scenarios was examined reflecting the implications of various forecasts of oil and gas prices, different production profiles and other factors. The key general assumptions underlying the DCF models for the four major assets (including gas and oil prices) are set out in Section 9.3. The specific assumptions for the major assets are set out in the remainder of Section 9.5.

The DCF analysis for the four major assets has been undertaken by reference to profile scenarios prepared by Gaffney Cline. These scenarios have been considered in light of the selected discount rates and price scenarios developed by Grant Samuel to the extent that sales volumes are (or become) uncontracted. The low price scenario is based on Gas Price Path A and the low crude oil, condensates and LPG case. The high price scenario is based

on Gas Price Path B and the high crude oil condensates and LPG case. Grant Samuel's assumptions for oil and gas prices are discussed in Section 9.3 of this report.

9.5.3 Cooper Basin

A value in the range $500-550 million has been attributed to Origin's interest in the Cooper Basin.

Gas production from the Cooper Basin commenced in 1969 and is sold under long term take or pay contracts. The largest contract, which is with AGL Energy, accounts for more than half of the total contracted volumes. These contracts are principally based on negotiated prices with provision for increases at the rate of inflation.

The Cooper Basin is in long term decline, and, given the long history of production, the production profile can be predicted with some confidence. Gaffney Cline provided separate profiles for the South Australian project and the south west Queensland project. Grant Samuel's valuation has been prepared having regard to DCF analysis of three scenarios prepared by Gaffney Cline. The scenarios were based around the 1P, 2P and 3P reserve profiles:

- **Scenario 1:** reflects Origin's share of production of proved reserves (1P) as at 30 June 2008 and that oil and gas production continues until 2020. Scenario 1 assumes $429 million (2008 dollars) of capital expenditure over this period including $48 million (2008 dollars) of exploration expenditure and abandonment costs of $31 million (2008 dollars).
- **Scenario 2:** reflects Origin's share of production of proved and probable reserves (2P) as at 30 June 2008 and 2.7PJe of prospective resources resulting from continued exploration. Gaffney Cline has applied an 80% chance of development factor to prospects identified by Origin in their five year exploration plan. The scenario assumes that oil and gas production continues until 2034. Scenario 2 assumes $494 million (2008 dollars) of capital expenditure over this period including $74 million (2008 dollars) of exploration expenditure and abandonment costs of $26 million (2008 dollars).
- **Scenario 3:** reflects Origin's share of production of proved, probable and possible reserves (3P) as at 30 June 2008 and 8PJe of prospective resources resulting from continued exploration (with an 80% chance of development factor). Gaffney Cline has also assumed that prospective resources will be recovered at a higher cost than experienced historically in the Cooper Basin. The scenario assumes that oil and gas production at the Cooper Basin continues until 2050. Scenario 3 assumes $518 million (2008 dollars) of capital expenditure over this period including $74 million (2008 dollars) of exploration expenditure and abandonment costs of $20 million (2008 dollars).

Operating costs for each scenario were estimated by Gaffney Cline having regard to forecast production rates and information provided by Origin.

The results of the NPV analysis are set out below:

Cooper Basin – NPV Outcomes ($ millions)

Case	Price Scenarios	Discount Rate	
		10.5%	9.5%
Scenario 1	Low	(81.5)	(83.9)
	High	(46.8)	(47.7)
Scenario 2	Low	207.2	218.2
	High	306.7	323.6
Scenario 3	Low	1,251.4	1,349.9
	High	1,551.4	1,675.1

The above table produces an extremely wide range of NPV outcomes. This reflects the significantly different production profiles represented by the three categories of reserves

and the range of associated probabilities of recovery. In particular, Scenario 3 assumes that production at the Cooper Basin continues for more than 30 years beyond Scenario 1. Furthermore, Scenario 1 includes exploration expenditure in the 2009 and 2010 financial years, with no incremental production above 1P reserves. It therefore represents an extremely unlikely scenario. Similarly, Scenario 3 represents an upside production profile based on reserves that have a low degree of certainty (10% confidence) and contingent and prospective resources that have an even lower likelihood of recovery. Whilst Scenario 2 reflects the production of Origin's 2P reserves, the value of the incremental production of contingent and prospective resources is exceeded by the additional exploration and operating costs to recover and produce the resources.

Given the inconclusive outcomes of the NPV analysis, Grant Samuel has also had regard to recent transaction evidence involving the Cooper Basin. In particular, Grant Samuel has considered the acquisition by Beach Petroleum Limited of Delhi Petroleum Group's equity of approximately 21% in the Cooper Basin for $574 million in September 2006. This implies $9.32 per Boe assuming 59MMboe at the acquisition date (after adjusting the acquisition price for the cash and transaction costs at acquisition). It also implies a value of around $410 million for Origin's interest in the Cooper Basin (assuming a 15% average interest). However, at the time of the offer, oil prices were considerably lower than current prices, averaging around US$70 per Bbl over the three months prior to announcement of the transaction which would suggest that the value would have increased. On the other hand, exchange rates were also lower at around A$1.00 = US$0.75.

Having regard to these factors, Grant Samuel has estimated the value of Origin's interest in the Cooper Basin at $500-550 million. This implies a multiple of $14.29-15.71 million per MMboe (2P) and of $2.48-2.72 per PJe (2P), which is reasonably consistent with the market evidence summarised in Appendix 7 to this report.

9.5.4 BassGas Project

A value in the range $450-500 million has been attributed to Origin's interest in the BassGas Project. The BassGas Project consists of the development of the Yolla gas field and future possible development of other fields in the vicinity that may utilise the Yolla platform. The Yolla gas field contains recoverable reserves of gas, condensate and LPG. Production from the BassGas Project commenced in June 2006.

Origin acquires all the natural gas production from the BassGas Project under long term gas contracts for its Retail business. The Shell Refinery in Geelong purchases the condensate and LPG.

Three scenarios were developed to assess the value of Origin's interest in the BassGas Project. They reflect possible production profiles over the expected field life. All three scenarios provided by Gaffney Cline include the costs for two additional platform development wells (Yolla 5 and Yolla 6) in the 2010 financial year. The inclusion of Yolla 6 assumes that the field is compartmentalised and that at least one additional well will be required (in addition to Yolla 5) to produce the reserves. The scenarios all include the costs for compression to be installed in the 2010 financial year and the installation of facilities for permanent platform manning in 2010. The scenarios used in the NPV analysis are as follows:

- **Scenario 1**: reflects Origin's proved reserves (1P) as at 30 June 2008. This scenario assumes that no additional fields are developed (other than Yolla 5 and Yolla 6) and tied into the BassGas Project. It assumes production of oil and gas continues until 2020. Scenario 1 assumes $221 million (2008 dollars) of capital expenditure over this period including abandonment costs of $68 million (2008 dollars).
- **Scenario 2**: reflects Origin's proved and probable reserves (2P) as at 30 June 2008. It assumes production of oil and gas continues until 2027. Scenario 2 assumes $210 million (2008 dollars) of capital expenditure over this period including abandonment costs of $80 million (2008 dollars).

- **Scenario 3**: reflects Origin's proved, probable and possible reserves (3P) as at 30 June 2008. It also includes estimated production from a further four development wells required to develop the Trefoil and White Ibis discovery as well as the Rockhopper and Silvereye prospects, over and above the wells included in Scenario 2. The timing of the development and production of the contingent and prospective resources was estimated having regard to the existing 3P reserves of Yolla and the capacity limitations of the Yolla facility. It assumes production of oil and gas continues until 2031. Scenario 3 assumes $344 million (2008 dollars) of capital expenditure over this period including $58 million (2008 dollars) of exploration expenditure and abandonment costs of $88 million (2008 dollars).

Operating costs for each scenario were estimated by Gaffney Cline having regard to forecast production rates and information provided by Origin.

The results of the NPV analysis are set out below:

BassGas Project – NPV Outcomes ($ millions)

Case	Price Scenarios	Discount Rate	
		10.5%	9.5%
Scenario 1	Low	305.2	320.4
	High	367.2	385.8
Scenario 2	Low	432.3	459.3
	High	504.1	535.1
Scenario 3	Low	490.6	520.6
	High	545.9	578.4

The above table encompasses a wide range of potential NPV outcomes, reflecting the range of reserve probabilities considered. Grant Samuel's valuation of Origin's interest in the BassGas Project focuses on Scenario 2. It takes into account the following factors:

- approximately 70.4PJ of gas production from the BassGas Project is acquired by Origin's Retail business under a long term contract. This contract does not reflect any uplift in gas market prices during the contract period;
- although it is currently producing at maximum capacity, it is unlikely that the BassGas Project can maintain full production from the third quarter of 2009 without additional wells or platform compression. Accordingly, significant capital expenditure is required to produce the reserves; and
- historically, there has been issues with the BassGas Project (delays and cost overruns). There is a risk that similar issues will occur during implementation of the extension plan.

9.5.5 Otway Gas Project

A value in the range $600-660 million has been attributed to Origin's interest in the Otway Gas Project. The Otway Gas Project consists of the development of a remotely operated wellhead platform on Thylacine (with provision for six wells) and a pipeline to an onshore gas processing plant north of Port Campbell. Gas, condensate and LPG are produced at the plant. The Otway Gas Project development plan involved a total of eight to ten development wells for Thylacine, Thylacine North and Geographe. Future opportunities involve development of the Geographe field using three subsea wells tied back into the pipeline and development of Thylacine North using a subsea completion tied back to the Thylacine platform.

Four development wells have been drilled on Thylacine and production commenced in September 2007. Following initial commissioning difficulties resulting in the shut down of the gas processing plant, production resumed in February 2008 and commercial operations commenced in June 2008. The design production rate for the fields is approximately 60PJ per annum.

Origin purchases 48.5% of the sales gas produced from the Otway Gas Project for its Retail business.

Three scenarios were developed to assess the value of Origin's interest in the Otway Gas Project. They reflect likely production profiles over the expected field life. All three scenarios provided by Gaffney Cline include three subsea Geographe development wells scheduled to be implemented in the 2011 financial year at a total estimated cost of $64 million per well (100% equity) (2008 dollars) and the compression project (scheduled in the fourth quarter of the 2014 financial year) at an estimated cost of $73 million (100% equity) (2008 dollars). The scenarios used in the analysis were as follows:

- **Scenario 1**: reflects Origin's proved reserves (1P) as at 30 June 2008. This scenario assumes that the cost of the three new Geographe subsea development wells and the compression project is 25% greater than in Scenario 2 to represent potential cost overruns. This scenario assumes the production of oil and gas continues until 2020. Scenario 1 assumes $252 million (2008 dollars) of capital expenditure over this period including abandonment costs of $72 million (2008 dollars).
- **Scenario 2:** reflects Origin's proved and probable reserves (2P) as at 30 June 2008. In this scenario, the facility reaches its design capacity of 60PJ per annum. The field production is forecast to come off plateau during 2018. In addition, one Thylacine North development well is included in 2011 as a subsea tieback to the Thylacine facility at an estimated cost of $193 million (100% equity) (2008 dollars). Total capital expenditure of $232 million (2008 dollars) is assumed over the production period including abandonment costs of $72 million (2008 dollars). This scenario assumes the production of oil and gas continues until 2031.
- **Scenario 3**: reflects Origin's proved, probable and possible reserves (3P) as at 30 June 2008 and includes two further development wells from the Razorback and Glenaire prospects (in addition to those included in Scenario 2). Gaffney Cline estimates that the Razorback and Glenaire prospects have a 60% and 40% chance of development respectively and a geologic chance of success of 25%. The development of these prospects are estimated by Gaffney Cline to realise lower recovery efficiency than the existing Thylacine/Geographe field. This is due to estimated development by subsea facility tie backs of the remote satellite accumulations, and deteriorating uptime performance of the unmanned Thylacine/Geographe facility. Production from the prospects is scheduled to maintain the production plateau when production from Thylacine/Geographe commences to decline. Total capital expenditure of $251 million (2008 dollars) is assumed over the production period including abandonment costs of $76 million (2008 dollars). This scenario assumes production of oil and gas continues until 2031.

Operating costs for each scenario were estimated by Gaffney Cline having regard to forecast production rates and information provided by Origin.

The results of the NPV analysis are set out below:

Otway Gas Project – NPV Outcomes ($ millions)

Case	Price Scenario	Discount Rate	
		10.5%	9.5%
Scenario 1	Low	416.5	433.3
	High	466.1	485.1
Scenario 2	Low	558.2	591.5
	High	628.5	666.6
Scenario 3	Low	711.5	768.4
	High	803.1	868.0

The above table encompasses a wide range of potential NPV outcomes. The range adopted by Grant Samuel's valuation is a subjective assessment having regard primarily to Scenario 2. This scenario includes some upside value from the Thylacine North development

project. The valuation reflects the considerable uncertainty as to the scope, costs and timing for Phases 2 and 3 of the Otway Gas Project. Given that significant capital expenditure overruns were experienced during Phase 1 of the development, there is a risk that cost overruns will also be experienced in the secondary phases of the project. Further, only small volumes have been produced to date.

9.5.6 Kupe Gas Project

A value in the range $660-730 million has been attributed to Origin's interest in the Kupe Gas Project in the Taranaki Basin in New Zealand. The Kupe Gas Project consists of an unmanned platform over the field supporting three wells, a subsea pipeline to an onshore gas processing plant, a gas processing plant that recovers condensate and LPG and a sales gas pipeline to the main gas distribution system. The offshore work was completed in June 2008 and construction is proceeding on the onshore production facility with production expected to commence in mid 2009.

It is anticipated that two or three additional wells will be drilled in a second development phase in 7-10 years with the exact timing dependent on field performance.

The gas production from the Kupe Gas Project is fully contracted to Genesis while the liquids production is uncontracted.

Three scenarios were developed to assess the value of Origin's interest in the Kupe Gas Project. They reflect likely production profiles over the expected field life. All three scenarios provided by Gaffney Cline are based on production of the three initial development wells for approximately seven years, followed by drilling of two additional wells in 2016 as part of the second development phase at an estimated cost of $53 million (100% equity) (nominal dollars) per well. They also assume that an onshore compression project occurs in 2019 at an estimated cost of $5 million (100% equity) (nominal dollars). The scenarios considered in the analysis were as follows:

- **Scenario 1**: reflects Origin's proved reserves (1P) as at 30 June 2008. The costs associated with the drilling of the additional two wells and the compression project above has been increased by 25% to allow for possible cost overruns. This scenario assumes production of oil and gas continues until 2021. Scenario 1 assumes $276 million (2008 dollars) of capital expenditure over this period including abandonment costs of $64 million (2008 dollars).
- **Scenario 2**: reflects Origin's proved and probable reserves (2P) as at 30 June 2008. This scenario assumes oil and gas production continues until 2024. Scenario 2 assumes $262 million (2008 dollars) of capital expenditure over this period including abandonment costs of $64 million (2008 dollars).
- **Scenario 3:** reflects Origin's proved, probable and possible reserves (3P) as at 30 June 2008 and includes production from the Momoho field (contingent resources) plus potential successful developments of the Denby D and Leith prospects (prospective resources). Gaffney Cline has assumed that Momoho has a 20% chance of development and that Denby D and Leith each have a 10% chance of development. The timing of production from the prospects was estimated by Gaffney Cline having regard to the existing production forecasts and facility constraints. This scenario assumes oil and gas production continues until 2027. Scenario 3 assumes $297 million (2008 dollars) of capital expenditure over this period including abandonment costs of $67 million (2008 dollars).

Operating costs for each scenario were estimated by Gaffney Cline having regard to forecast production rates and information provided by Origin.

The results of the NPV analysis are set out below:

Kupe Gas Project – NPV Outcomes ($ millions)			
Case	Price Scenarios	Discount Rate	
		10.5%	9.5%
Scenario 1	Low	535.9	559.9
	High	615.1	643.0
Scenario 2	Low	620.5	652.1
	High	708.6	745.2
Scenario 3	Low	824.7	872.6
	High	944.7	1,000.2

The valuation of Origin's interest in the Kupe Gas Project is a subjective assessment by Grant Samuel. The valuation reflects the current status of the project. Whilst the offshore work for the Kupe Gas Project (including the drilling of the development wells) was completed in June 2008, the onshore construction work is progressing. Accordingly, there are some development and production risks that remain associated with the project. Grant Samuel's valuation focuses on the NPV outcomes from Scenario 2.

9.5.7 Other Producing and Developing Assets

The aggregate value of Origin's other producing and developing assets has been estimated by Grant Samuel to be $350-390 million. These assets include Origin's interests in the Surat Basin, the Perth Basin, the onshore Otway Basin, the onshore Taranaki Basin and the Halladale and Blackwatch fields in the offshore Otway Basin[83]. The value range has been assessed with regard to the field profiles reflected in Origin's cash flow models and Grant Samuel's discount rates.

9.5.8 Exploration Assets

The value of Origin's greenfield exploration interests has been assessed by Gaffney Cline to be $10-83 million. A summary of this assessment is set out in Section 5 of the Gaffney Cline report attached as Appendix 8.

9.5.9 Other Assets and Liabilities

Other assets and liabilities of the Conventional Oil and Gas business have been valued as follows:

Conventional Oil and Gas Assets – Other Assets and Liabilities ($ millions)		
	Value Range	
	Low	High
Hedge book	(60)	(40)
Divisional overheads	(115)	(100)
Total	**(175)**	**(140)**

The value of Origin's hedge book (excluding hedging relating to the Kupe Gas Project) has been estimated as a liability of approximately $40-60 million on an after tax basis. Origin's oil price hedges in relation to the Kupe Gas Project have been incorporated into the estimate of the net cash flows.

Origin's Exploration & Production division incurs divisional costs that have not been allocated to the cash flow models for the individual conventional oil and gas assets. These costs have been estimated at approximately $15 million per annum and represent costs associated with maintaining divisional offices and executive staff. This cost estimate does not include any costs of exploration and research and development. The capitalised value of these costs, taking into account the life of the oil and gas operations, is estimated at $100-115 million.

[83] Excludes Denison Trough interests which are to be transferred to the JV.

9.6 Value of Downstream Energy Business

9.6.1 Overview

Grant Samuel estimates the value of Origin's Downstream Energy business to be in the range $8.5-9.2 billion. This value range represents the value attributed to Retail and Generation separately as well as an allowance for the extent of integration flexibility and options existing within the combined operations (and not otherwise reflected in the separate business valuations):

Downstream Energy Business – Valuation Summary ($ millions)

	Report Section Reference	Value Range	
		Low	High
Generation	9.6.3	2,050	2,200
Retail	9.6.4	6,050	6,550
		8,100	8,750
Integration allowance		400	450
Total		**8,500**	**9,200**

The values for the Retail and Generation businesses are set out in the following sections of the report. In determining this value, Grant Samuel had regard (as appropriate) to DCF analysis, multiples of EBITDAF, EBITDA and EBITF, price paid per MW, price paid per mass market customer and price paid per tonne of LPG.

The integration allowance equates to approximately 5% of the aggregate values of the Generation and Retail businesses. This represents Grant Samuel's assessment of the incremental value over and above the stand alone values of these businesses as a result of Origin's full integration across the value chain for a downstream energy business. This allowance is inherently subjective but there is clear evidence that Origin has been able to (and should be able to continue to do so in the future) generate additional revenue or save costs in conducting its business through the matching of its internal capabilities. This integration is reflected in:

- lower hedging costs as a result of the natural hedge created by Origin's upstream gas and generation portfolio, by geographical diversification (i.e. presence in all states throughout the NEM) and load diversification between customers (i.e. commercial and industrial customers have lower peak load requirements). Some of this saving is effectively already reflected in the DCF models for Retail;
- an ability to take advantage of higher gas or electricity prices by supplying gas to either the Generation or Retail businesses;
- Origin's extensive market knowledge of pricing through participation in various markets across the value chain which enables it to achieve favourable contracting outcomes for longer term energy supply or purchase agreements (as the case may be);
- the growing generation portfolio provides a strong negotiating position when entering into power purchase agreements and provides a competitive advantage in contracting the sale of electricity; and
- potential to capture value from lower build costs for future generation by leveraging existing permitted sites and infrastructure (e.g. pipelines, transmission, development approvals, communications). An example of this is the additional value reflected for the expansions of Quarantine Power Station and Mount Stuart Power Station. Origin has a portfolio of existing sites where such value adding expansions can be replicated. In fact, Origin is incurring additional costs today to build in the potential for this value in the future (e.g. Mortlake Power Station).

9.6.2 Overall Earnings Multiples

The overall value for the downstream energy business represents the following multiples of earnings:

Downstream Energy Business – Implied Valuation Parameters			
Parameter	**Variable ($ millions)[84]**	**Value Range**	
		Low	**High**
Value Range ($ millions)		**8,500**	**9,200**
Multiple of EBITDAF			
Year ended 30 June 2008 (adjusted actual)[84]	586.3	14.5	15.7
Year ended 30 June 2009 (model forecast)	722.1	11.8	12.7
Year ending 30 June 2010 (model forecast)	786.6	10.8	11.7
Multiple of EBITF			
Year ended 30 June 2008 (adjusted actual)[84]	510.9	16.6	18.0
Year ended 30 June 2009 (model forecast)	651.2	13.1	14.1
Year ending 30 June 2010 (model forecast)	705.9	12.0	13.0

The implied valuation parameters set out above have been compared to multiples implied by the share prices of listed Australian and New Zealand integrated energy companies and the prices at which transactions involving integrated energy business have been completed. The focus of this review has been on integrated energy businesses due to the natural hedge available where a business has both energy generation and retailing operations, although the degree to which this natural hedge is utilised depends on factors such as the proportion of electricity generated sold to the retail operations or into the spot market. The market evidence is analysed in Appendices 9 and 10 to this report and summarised below:

(i) Transaction Evidence

The following table sets out EBITDA and EBIT multiples implied by transactions involving the acquisition of integrated energy businesses in Australia and New Zealand since 2002:

Recent Transaction Evidence							
Date	**Target**	**Transaction**	**Consid-eration (millions)**	**EBITDA Multiple (times)**		**EBIT Multiple (times)**	
				Historical	**Forecast**	**Historical**	**Forecast**
May 07	King Country Energy	Acquisition of 10% by King Country Electric Power Trust	NZ$94	12.1	8.9	16.0	11.0
Oct 06	TrustPower	Acquisition of 23.77% by Infratil	NZ$1,944	12.6	11.4	14.8	13.3
Mar 05	Singapore Power's merchant energy business	Acquisition by CLP	A$2,128	11.7	na	na	na
Jul 04	Contact Energy	Acquisition of 51.2% by Origin	NZ$3,270	12.3	9.4	17.8	12.8
Apr 04	TXU's Australian assets	Acquisition by Singapore Power	A$5,100	9.2	8.6	na	na

Source: Grant Samuel analysis (see Appendix 9)

The following factors are relevant to consideration of these multiples:

- Origin's acquisition of the 51.2% interest in Contact Energy was at a 4.5% discount to the Contact Energy share price on the day prior to announcement. A number of factors may have influenced this discount:
  - the sale of the interest was part of a larger tender process involving Edison's parent company's international assets as part of a strategy to reduce debt and had been flagged in November 2003;

[84] 2008 earnings are based on adjusted financial performance set out in Section 4.3 of the report. Those earnings have been further adjusted to exclude head office costs allocated to the Downstream Energy Business (as head office costs are separately valued in Section 9.8 of the report) and to include Origin's 50% share of earnings from Bulwer Island Cogeneration Plant and Osborne Cogeneration Plant (which are equity accounted investments for segment reporting purposes). Forecast earnings are sourced from the Grant Samuel cash flow models.

- New Zealand investors were aware that there would be a follow on bid required under the New Zealand Takeovers Code if the interest was sold which is likely to have supported the rise in the Contact Energy share price from around NZ$5.00 in November 2003 to closer to NZ$6.00 in July 2004;
- there were limited potential acquirers for the interest within Edison's time frame; and
- the share price may not have been a good indicator of full underlying value as Contact Energy shares were not particularly liquid;

▪ the transactions involving King Country Energy and TrustPower are for minority interests; and

▪ the earnings multiples for the remaining transactions reflect a blend of energy businesses and assets. The merchant energy business acquired by CLP Holdings Limited in March 2005 was a subset of the assets of Singapore Power Limited acquired from TXU Corporation in April 2004. The merchant energy business included the fifth largest energy retailer in Australia, the 1,280MW Torrens Island Power Station in South Australia, a 33% interest in the SEAGas pipeline, an underground gas storage plant and a right to call on Ecogen Power to supply as much as 966MW of electricity. As the TXU assets acquired by Singapore Power Limited also included significant electricity and gas distribution and transmission networks in Victoria, the earnings multiples for that transaction reflect an even wider range of assets.

Although there is some transaction evidence involving generation assets or retailing businesses separately in Australia, the evidence is not meaningful for this analysis as multiples for such stand alone operations would not reflect the benefits of reduced earnings volatility implicit in the integrated business model.

(ii) Sharemarket Evidence

The following table sets out the implied EBITDAF, EBITDA and EBIT multiples for the listed integrated energy entities in Australia and New Zealand based on share prices as at 5 September 2008 (except for Contact Energy which is based on the share price as at 29 April 2008, the day prior to the announcement of the BG approach):

Sharemarket Ratings of Listed Integrated Energy Companies

Entity	Market Capitalisation (millions)	EBITDAF Multiple[85] (times)	EBITDA Multiple (times)			EBIT Multiple (times)		
		Historical	Historical	Forecast Year 1	Forecast Year 2	Historical	Forecast Year 1	Forecast Year 2
AGL Energy	A$6,486	12.9	23.8	8.6	7.9	35.4	10.8	10.0
Contact Energy	NZ$5,410	11.6	11.7	11.1	10.2	16.0	15.4	14.2
TrustPower	NZ$2,494	15.1	15.0	13.1	10.8	17.8	15.7	12.7

Source: Grant Samuel analysis (see Appendix 10)

The following factors are relevant to consideration of these multiples:

▪ the multiples are based on share prices and therefore do not include a premium for control. The Forecast Year 1 multiples represent the 2008/09 financial year;

▪ brokers do not forecast unrealised derivative gains and losses. Therefore, there is a disconnect between the historical and forecast EBITDA and EBIT multiples presented in the table. This is eliminated by calculating historical EBITDAF multiples which ignore the impact of unrealised derivatives gains and losses on earnings. In this regard, the historical multiples for AGL Energy in particular are overstated to the extent they reflect unrealised derivatives losses;

▪ AGL Energy's forecast earnings multiples are relatively low. This may, in part, be a result of its share price not fully reflecting the market value of its 24.9% interest in

[85] EBITDAF is EBITDA before changes in the fair value of financial instruments.

QGC. The forecast EBITDA multiples increase to 8.5-9.0 times if the QGC investment is allowed for at acquisition cost rather than at current market value; and

- the multiples for Contact Energy and TrustPower are high in comparison to AGL Energy reflecting the focus on renewable fuel sources in New Zealand as well as the limited free float and low liquidity of these companies.

Furthermore, based on the share price prior to the approach by BG Group, Origin itself was trading at prospective EBITDA and EBIT multiples of 9-10 times and 12-14 times respectively.

The prospective multiples implied by the value of $8.5-9.2 billion for the Downstream Energy business of around 12-13 times EBITDAF (model forecast) are above the (limited) transaction evidence and other listed entities (which exclude a premium for control). However, in Grant Samuel's opinion, they are appropriate as Origin's Downstream Energy is a strategic asset in the context of the Australian energy market and would be an attractive acquisition. It has a high level of integration which is an important competitive advantage. It:

- is highly integrated and effectively managed by Energy Trading to optimise returns to Origin across the value chain by matching its internal capabilities. Significant benefits are also derived from integration with Origin's upstream oil and gas activities;
- holds substantial market positions across the eastern states with estimated total retail market share in the states in which it operates of 23% for electricity and 27% for gas. Retail has established a leading position in green energy having developed a suite of green energy products for consumers;
- has a substantial pipeline of committed (2,096MW) and permitted (1,508MW) generation assets to meet the demands of the changing energy industry market dynamics (e.g. continued demand for electricity but increasing cost of carbon leading to increasing demand for gas fired generation); and
- is holding and developing a portfolio of options in renewable generation (e.g. geothermal, solar) to provide future business flexibility.

Furthermore, the multiples reflect:

- a significant value for committed new generation capacity (the earnings for which will have not fully emerged by 2009/10) and derivatives contracts and gas supply contracts managed by Energy Trading. Excluding the value attributed to committed generation capacity and the gas supply contracts, reduces the implied multiples 8.7-9.4 times 2009 EBITDAF and 9.6-10.5 times EBITF; and
- that the model forecasts in 2009/10 incorporate the run off of Origin's existing energy trading portfolio and does not assume that significant earnings are generated in Energy Trading beyond the existing book.

9.6.3 Generation

(i) Overview

Grant Samuel estimates the value of Origin's Generation business to be in the range $2,050-2,200 million:

Generation - Valuation Summary ($ millions)

Asset	Report Section Reference	Value Range	
		Low	High
Existing Generation		630	690
Committed Generation		780	850
	9.6.3 (ii)	1,410	1,540
Uranquinty Power Station	9.6.3 (iii)	540	540
Renewable Portfolio	9.6.3 (iv)	100	120
Total		**2,050**	**2,200**

For the purposes of this valuation the generation businesses comprise:

- **Existing Generation:**
  - Ladbroke Grove Power Station;
  - Quarantine Power Station;
  - Mount Stuart Power Station;
  - Roma Power Station;
  - Worsley Cogeneration Plant (50%);
  - Bulwer Island Cogeneration Plant (50%); and
  - Osborne Cogeneration Plant (50%).
- **Committed Generation:**
  - Quarantine Power Station Expansion;
  - Mount Stuart Power Station Expansion;
  - Mortlake Power Station; and
  - Darling Downs Power Station.
- **Uranquinty Power Station**
- **Renewable Portfolio:**
  - 30% interest in Geodynamics Joint Venture;
  - option over 590MW of wind farm development sites including proposed construction of Cullerin Range Wind Farm and two permitted sites at Conroy's Gap and Snowy Plains; and
  - the SLIVER® solar technology.

In determining this value, Grant Samuel has had regard to (as appropriate) DCF analysis, multiples of EBITDAF, EBITDA and EBIT and multiples of MW of installed capacity. The value is the aggregate of the values attributed by Grant Samuel to each of the assets. Values for individual assets have not been disclosed in this report for reasons of commercial sensitivity. Origin does not release financial information on an individual asset basis.

(ii) Existing and Committed Generation

Summary

Grant Samuel has estimated the value of Origin's existing and committed generation portfolio to be in the range of $1,410-1,540 million as follows:

Existing and Committed Generation Portfolio - Value Summary ($ millions)

Asset	Value Range	
	Low	High
Existing Generation (including Cogeneration)	630	690
Committed Generation	780	850
Total	**1,410**	**1,540**

The value ranges are the aggregate of the values attributed by Grant Samuel to each of the power stations. Grant Samuel has valued each asset having regard to DCF analysis and multiples of EBITDAF and EBITF and multiples of MW installed capacity. Values for individual power stations have not been disclosed in this report.

DCF Analysis

DCF models for each of Origin's generation assets have been developed by Grant Samuel based on long term cash flow models prepared by Origin. Grant Samuel has adjusted the

Origin cash flow models to reflect its judgement on certain matters (e.g. inflation) and to ensure consistent application of assumptions.

The DCF models are long term commencing at 1 July 2008 and extend for the remaining life of the power station or the cogeneration agreements. OCGT and CCGT generation plants receive revenue based on a tolling agreement consisting of a fee for the capacity provided (for OCGT plants) or electricity generated (for CCGT plants) as well as reimbursement of costs incurred. Cogeneration plants receive revenue and incur costs in accordance with the cogeneration agreement. Terminal values represent the disposal value for 100% owned plants calculated as proceeds from the sale at the end of the plant life after refurbishment and restoration. No extensions to operating agreements, decommissioning costs or sale proceeds are assumed for cogeneration plants.

Net present values are calculated on an ungeared after tax basis using nominal after tax discount rates of 9.0-10.0%. Appendix 4 sets out a detailed analysis of the selection of these discount rates. A corporate tax rate of 30% has been assumed. The key general and specific operational and asset assumptions underlying the DCF models are set out in Appendix 5.

Origin's 100% owned generation portfolio primarily services the Retail business and has limited ability to sell electricity into the NEM. Revenue is generally independent of electricity prices. Accordingly, it is not appropriate to develop scenarios based on a range of electricity prices. The cogeneration plants exist to service the relevant partners' plant for the period under the cogeneration agreement. Therefore, there are few operational levers by which to review the sensitivity of the NPV from the DCF models. However, disposal proceeds represent a significant proportion of the NPV outcomes (in the vicinity of 15%). In reality, disposal proceeds vary depending on a wide range of factors such as market dynamics, plant condition and refurbishment costs. Consequently, a number of scenarios in relation to disposal values have been developed and analysed to reflect the impact on NPV outcomes:

- **Scenario 1** – Base case scenario with pricing and future demand expectations as set out in Appendix 5. 100% owned assets are disposed at the end of plant life after refurbishment and allowance for asset age (roughly equivalent to 60% of new build cost);
- **Scenario 2** – Scenario 1 assuming disposal proceeds are equivalent to new build costs (i.e. no refurbishment costs or allowance for asset age); and
- **Scenario 3** – Scenario 1 with no terminal value (i.e. assuming no disposal proceeds after refurbishment).

The output of the NPV analysis is summarised below:

Existing and Committed Generation – NPV Outcomes ($ millions)

Scenario	Discount Rate		
	10.0%	9.5%	9.0%
Scenario 1	1,385.9	1,502.5	1,630.6
Scenario 2	1,513.2	1,645.0	1,788.2
Scenario 3	1,196.4	1,292.7	1,395.3

As discussed above, the results of the DCF analysis are subject to significant limitations and should always be treated with considerable caution. The NPV outcomes show a relatively wide range across the different scenarios, highlighting the sensitivity to changes in terminal value assumptions.

Assuming generation assets are sold at a price equivalent to new plant investment (with no allowance for asset age or refurbishment) is not realistic but so is assuming no value at the end of plant life. Given the forecasts assume continued investment in maintenance, it is possible that the plants could continue to be used to serve Origin's Retail business beyond the period of the projections. However, even in this situation, it is likely that substantial

refurbishment would be required. Therefore, the selected value range for existing and committed generation assets is towards Scenario 1.

Earnings Multiple Analysis (Existing Generation)

Earnings multiple analysis is only appropriate for the existing generation portfolio as the committed generation portfolio is under construction with earnings to emerge over the period 2009-2011. The value attributed to existing generation of $630-690 million implies the following multiples of earnings:

Existing Generation – Implied Earnings Multiples

Parameter	Variable ($ millions)[86]	Value Range	
		Low	High
Value Range for Existing Generation ($ millions)		**630**	**690**
Multiple of EBITDAF			
Year ended 30 June 2008 (adjusted actual) [86]	63.0	10.0	10.9
Year ended 30 June 2009 (model forecast)	95.2	6.6	7.2
Year ending 30 June 2010 (model forecast)	98.4	6.4	7.0
Multiple of EBITF			
Year ended 30 June 2008 (adjusted actual)[86]	40.9	15.4	16.9
Year ended 30 June 2009 (model forecast)	74.0	8.5	9.3
Year ending 30 June 2010 (model forecast)	76.4	8.3	9.0

The implied earnings multiples presented indicate a disconnection between the actual results in 2008 and the model projections. This results from different accounting treatments for the internal tolling arrangements between Origin's reported earnings and internal projections for Generation. For public segment reporting, the internal tolling fees paid to Generation are based on the historical cost of plants. In comparison, in the cash flow models the tolling fees are based on current costs and therefore, the earnings generated by the model are higher (with a commensurate negative impact on Retail) than the public segment reporting. If current costs are adopted in 2008, the EBITDAF and EBITF multiples implied by the valuation reduce to 7.6-8.3 and 10.3-11.3 times respectively[87].

There have been a large number of transactions involving electricity generation assets in recent years (see Appendix 9). However, the evidence for earnings multiples (particularly EBIT multiples) is limited and shows a wide range. Earnings multiples have risen in recent years with increased investor interest in the energy sector but may have moderated in more recent times due to conditions in credit markets. Generation assets based on non renewable fuel sources have generally been acquired for multiples of 9-11 times prospective EBITDA with higher multiples paid for renewable energy generation. In comparison, power generation entities are trading at prospective multiples in the range of 7-9 times EBITDA and 10-13 times EBIT. The low end of the multiple ranges primarily reflects the blended multiples of the integrated electricity generators and energy retailers with standalone generators towards the higher end.

Accordingly, the multiples implied by the valuation of Existing Generation are low in comparison to recent transaction evidence. However, in Grant Samuel's opinion they are reasonable as:

- Existing Generation includes cogeneration plants for which the agreements are not assumed to be renewed (i.e. the asset has a finite life reflecting the agreement duration) although they are currently relatively profitable operations for Origin;

86 2008 earnings are based on the adjusted financial performance for Generation set out in Section 4.3 of the report. These earnings have been further adjusted to exclude head office costs allocated to Generation (as head office costs are valued separately in Section 9.8 of the report) and to include Origin's 50% share of earnings from Bulwer Island Cogeneration Plant and Osborne Cogeneration Plant (which are equity accounted investments for segment reporting purposes). Forecast earnings are sourced from the Grant Samuel cash flow models.

87 An increase in Generation's reported segment earnings for this tolling arrangement there would lead to a reciprocal decrease in the segment earnings of Retail.

- many of the recent transactions reflect significant strategic acquisitions or involved recently constructed power stations;
- the existing 100% owned generation portfolio plays a strategic role in Origin's overall energy strategy but only earns a tolling revenue based on a return on investment. Consequently, the nature of its activities and its profitability may not be directly comparable to other power stations or generation portfolios;
- some of the strategic value of Origin's generation assets are captured in the values attributed to Energy Trading and the integration allowance; and
- the value range attributed is supported by the MW of installed capacity metric.

Capital Expenditure Incurred (Committed Generation)

The value attributed to Committed Generation of $780-850 million represents the present value of the committed plants less outstanding capital expenditure to complete construction. The value exceeds Origin's capital expenditure to 30 June 2008 by $380-450 million. In Grant Samuel's opinion, this is reasonable as:

- the expansion of the existing generation plants (i.e. Mount Stuart and Quarantine) involves significantly lower construction costs as the expansions leverage off existing infrastructure (e.g. pipeline, transmission, development approvals, communications). In other words, the internal rate of return on these plants is higher than a new stand alone power station; and
- the Darling Downs Power Station project reflects lower build costs (i.e. competitive site location and relatively low construction costs) and lower running costs (i.e. relatively low priced gas from the Spring Gully CSG field and maintenance costs). Although these cost advantages are partially offset by higher costs associated with running the plant at varying capacity levels as part of Origin's generation portfolio, the internal rate of return for this plant is higher than would be expected from a "standard" new stand alone power station.

The higher value of these three power stations is, in part, offset by a lower value attributed to Mortlake Power Station. This lower value is because the first stage of construction for this plant includes costs associated with infrastructure to support the expansion of the power station to 1000MW sometime in the future.

Multiples of MW of Installed Capacity

A common rule of thumb parameter used in the valuation of generation businesses is price paid per MW of installed capacity. In general, the price per MW capacity varies depending on the fuel source (gas/coal/diesel/renewable) and type of plant (peaking/base load/cogeneration).

The values attributed to Existing and Committed Generation imply the following multiples of MW installed capacity:

Existing and Committed Generation – Implied Multiples of MW

Asset	Installed Capacity	Value Range ($ millions)	$ millions per MW	
			Low	High
Existing Generation	704MW	630-690	$0.90	$0.98
Committed Generation[88]	1,426MW	780-850	$1.43	$1.46

The market parameters from recent transactions are summarised below:

[88] Multiples of MW for committed generation are calculated based on the present value on completion (i.e. capital expenditure is added back).

Selected Australian Transactions – Price per MW Installed Capacity			
Date	**Target**	**Transaction**	**Price per MW[89] ($ millions)**
Gas – Peaking			
Jul 08	Ecogen generation business	Acquisition of 73% by IFM	$0.24
Jul 08	Uranquinty Power Station	Acquisition by Origin	$1.09
Dec 07	Braemar Power Station	Acquisition of 15% by BBP	$0.99
Dec 07	Uranquinty Power Station	Acquisition of 30% by BBP	$0.96
Jan 07	Hallett Power Station	Acquisition by TRUenergy	$0.69
Nov 06	BBP	IPO	$0.82
Oct 05	Valley Power	Acquisition by Snowy Hydro	$0.89
Dec 02	Ecogen generation assets	Acquisition by Prime Infrastructure and Babcock & Brown	$0.25
Gas – Base Load			
Jan 07	Torrens Island Power Station	Acquisition by AGL Energy	$0.47
Gas – Cogeneration			
Sep 07	AlintaAGL's cogeneration business	Acquisition of 33% by BBP	$1.45
Jul 01	South West Cogeneration Joint Venture	Acquisition of 50% by Origin	$1.40

Source: Grant Samuel analysis (Appendix 9)

Price paid per MW varies by fuel source and type of generation. The price paid per MW for gas peaking plants (similar to Origin's existing OCGT portfolio) have increased substantially in recent years to be in the range of $1.0-1.1 million per MW. There is no meaningful evidence for gas fired base load generators but the price paid per MW for gas cogeneration capacity is higher at around $1.4-1.5 million reflecting higher capacity utilisation. Listed entities with predominantly gas fired generation are trading at multiples in the range of $0.9-1.0 million per MW installed capacity (see Appendix 9).

Origin's Existing Generation portfolio includes both gas fired peaking plants and cogeneration plants and the implied MW of installed capacity reflects the blended operating types. The value per MW for Existing Generation is in line with market parameters for gas peaking stations but this reflects various offsetting factors:

- the age of Origin's plants, which should result in lower values;
- the inclusion of cogeneration which is generally higher than other categories; and
- the impact of cogeneration contractual terms (e.g. pricing assumptions and contract duration).

The multiples per MW implied for Committed Generation are high in comparison to recent market evidence due to the additional value implicit in the plant expansions and Darling Downs Power Station (as discussed above).

(iii) Uranquinty Power Station

Uranquinty Power Station has been valued at $540 million. This reflects the price paid by Origin in July 2008 to acquire the plant less the capital expenditure to complete the plant. Origin acquired the partly constructed power station for $700 million on 4 July 2008 and the estimated capital expenditure remaining to complete construction and commission the plant is estimated to be $160 million.

The price per MW implied by the acquisition of Uranquinty Power Station is at the high end of recent transaction evidence at $1.09 million per MW. However, Uranquinty is a new power station and provides Origin with a range of strategic benefits in supporting its growing New South Wales electricity position and provides additional flexibility in the generation portfolio through geographical diversification.

[89] Represents gross consideration divided by MW of installed capacity on a proportional basis. In some transactions price per MW is based on broker estimates of the price paid for the generation asset acquired. Multiples presented in the table have been adjusted to allow for inflation since acquisition so that all multiples reflect current dollars. Unadjusted price per MW data is set out in Appendix 9.

(iv) Renewable Portfolio

A value of $100-120 million has been attributed to Origin's renewable energy portfolio comprising the 30% interest in the Geodynamics joint venture, the wholly owned SLIVER® solar technology business, the committed Cullerin Range Wind Farm and the option over a further 560MW of wind farm development sites (including two permitted sites). This value range reflects expenditure to 30 June 2008 by Origin.

9.6.4 Retail

(i) Overview

Grant Samuel estimates the value of Origin's Retail business to be in the range $6,050-6,550 million:

Retail – Valuation Summary ($ millions)

Asset	Report Section Reference	Value Range	
		Low	High
Energy Retailing	9.6.4 (ii)	3,550	3,800
Energy Trading	9.6.4 (iii)	2,000	2,200
LPG (including 50% of Vitalgas)	9.6.4 (iv)	500	550
Total		**6,050**	**6,550**

For the purposes of this valuation the Retail businesses are:

- **Energy Retailing**
- **Energy Trading**
- **LPG (including 50% interest in Vitalgas)**

The values for each of the businesses that comprise Retail are set out in the remainder of this section.

(ii) Energy Retailing

Summary

Grant Samuel has estimated the value of the Energy Retailing business to be in the range $3,550-3,800 million. In determining this value, Grant Samuel had regard to DCF analysis and multiples of mass market customers.

DCF Analysis

DCF models for Energy Retailing have been developed by Grant Samuel based on long term cash flow models prepared by Origin. Grant Samuel has adjusted the Origin cash flow models to reflect its judgement on certain matters (e.g. gas prices, inflation etc.) and to ensure consistent application of assumptions.

The DCF models are long term commencing at 1 July 2008 and extend for a period of 39 years. Energy Retailing receives revenue based on retail electricity and gas prices (which reflect a retailing margin and reimbursement of wholesale energy charges and network costs). The extent to which higher wholesale electricity costs can be passed through to consumers in any particular year is capped at levels based on Origin's historical experience.

Terminal values representing the value of cash flows in perpetuity have been calculated by capitalising net after tax cash flows based on a 3% perpetual growth assumption. Net present values are calculated on an ungeared after tax basis using nominal after tax discount rates of 9.0-10.0%. Appendix 4 sets out a detailed analysis of the selection of these discount rates. A corporate tax rate of 30% has been assumed. The key general and specific assumptions underlying the DCF models are set out in Appendix 5.

A number of different scenarios have been developed and analysed to reflect the impact on NPV of selected key assumptions, particularly in relation to pricing outcomes, gross margins and churn rates:

- **Scenario 1** – Base case scenario with Gas Price Path A and future demand expectations as set out in Appendix 5;
- **Scenario 2** – Scenario 1 with Gas Price Path B;
- **Scenario 3** – Scenario 1 with no electricity tariff cap;
- **Scenario 4** – Scenario 1 with a lower tariff cap (i.e. half the price increase allowed in any particular year compared with the base case);
- **Scenario 5** – Scenario 1 with 10% lower long term retail margins (i.e. 90% of base case retail margin);
- **Scenario 6** - Scenario 1 with 10% higher long term retail margins (i.e. 110% of base case margin);
- **Scenario 7** - Scenario 1 with 5% higher churn rate (i.e. base case churn plus 5%); and
- **Scenario 8** - Scenario 1 with 5% lower churn rate (i.e. base case churn less 5%).

The output of the NPV analysis is summarised below:

Energy Retailing – NPV Outcomes ($ millions)

Scenario	Discount Rate		
	10.0%	9.5%	9.0%
Scenario 1 – Gas Price Path A	3,257.0	3,569.0	3,938.7
Scenario 2 – Gas Price Path B	3,244.8	3,556.1	3,925.1
Scenario 3 – Scenario 1 no tariff caps	3,879.4	4,199.2	4,577.0
Scenario 4 – Scenario 1 lower tariff caps	1,924.1	2,207.7	2,548.3
Scenario 5 – Scenario 1 with 10% lower retail margin	2,709.9	2,964.7	3,266.9
Scenario 6 – Scenario 1 with 10% higher retail margin	3,804.0	4,173.2	4,610.6
Scenario 7 – Scenario 1 with 5% higher churn rate	3,130.3	3,249.3	3,783.8
Scenario 8 – Scenario 1 with 5% lower churn rate	3,383.6	3,708.6	4,093.7

As discussed above, NPV outcomes from DCF analyses are subject to significant limitations and should always be treated with considerable caution. In particular, the scenarios presented are static analyses only (i.e. involving changes in one assumption in each scenario) and do not reflect the impact of management responses to circumstances (i.e. management flexibility). The NPV outcomes above show a relatively wide range across the scenarios, highlighting the sensitivity to relatively small changes in assumptions. In particular, the analysis shows a high sensitivity to changes in retail margins.

The following factors are relevant to consideration of the NPV outcomes:

- in the absence of tariff caps, changes in wholesale electricity costs (as a result of changes in gas prices and carbon prices) do not have a significant effect on NPV as increased wholesale electricity costs are passed through to consumers;
- in the case of tariff caps, higher gas and carbon costs will result in a lower NPV due to retail margin compression (i.e. values presented for Scenario 2 are lower than for Scenario 1). However, at tariff caps consistent with historical experience, changes in gas prices result in only moderately lower NPV;
- a lower tariff price cap will have a significant influence on NPV (Scenario 4); and
- NPV is not overly sensitive to churn rates but is highly sensitive to changes in retail margin.

State governments are moving towards removing retail electricity tariff caps. However, under current cap arrangements, tariffs are intended to reflect wholesale costs consistent with a prudent retailer and Origin's experience is that moderate retail electricity tariff increases are usually allowed. Consequently, a moderate tariff cap or no tariff cap scenario

is appropriate. Under a moderate or no tariff cap scenario, values are not highly sensitive to changes in wholesale electricity costs resulting from changes in gas prices. Increased competition could potentially lower retail margins per customer but the assumed retail margins are relatively conservative relative to Origin's historical experience. Furthermore, although churn rates fluctuate widely as a result of a range of factors, NPV is not highly sensitive to churn rates. Therefore, the selected value range for Energy Retailing is between Scenarios 2 and 3.

Multiples of Mass Market Customers

A common rule of thumb parameter used in the valuation of mass market energy retail businesses is price paid per customer. Industry metrics of value per customer are not meaningful except in the case of pure retailers (i.e. the metrics calculated for the integrated energy companies reflect all of the entity's activities). While there are a number of acquisitions of pure retailers which provide meaningful values per customer, there are no listed entities which are solely retailers and, consequently, value per customer has not been presented for the listed entities.

Some caution is necessary in relying on this data as it is difficult to isolate the full effects of other activities (e.g. wholesale trading activities) to determine what adjustments may be necessary. The price paid per mass market customer implied by acquisitions of retailing businesses in Australia since 2002 are set out below:

Selected Australian Acquisitions – Price Per Mass Market Customer

Date	Target	Transaction	Price per Customer[90] $
Electricity Retailing – Australia			
Feb 07	Powerdirect Australia	Acquisition by AGL Energy	1,400[91]
Dec 06	Jackgreen	Acquisition of 8.89% by Babcock & Brown	870
Nov 06	Sun Retail	Acquisition by Origin	1,160
Dec 05	Australian Energy	Acquisition by Ergon Energy	2,390[92]
Mar 05	Singapore Power's merchant energy business	Acquisition by CLP Holdings	840-950[93]
Jul 02	CitiPower Retail	Acquisition by Origin	630
Jul 02	Pulse Energy	Acquisition by AGL	890[93]
Apr 01	Powercor Retail	Acquisition by Origin	497
Gas Retailing – Australia			
Sep 07	Alinta Retail	Acquisition of 33% by BBP	1,250
Nov 06	Sun Gas Retail	Acquisition by AGL Energy	1,120
Mar 05	Singapore Power's merchant energy business	Acquisition by CLP Holdings	890-1,000[93]
Jul 02	Pulse Energy	Acquisition by AGL	1,010[93]
Electricity and Gas Retailing – Australia			
May 07	Simply Energy	Acquisition of 50% by International Power	740
Mar 07	Victoria Electricity	Acquisition of 42% by Infratil	710
Apr 05	EnergyAustralia's business in Vic/SA	Acquisition of 50% by International Power	760
Mar 05	Singapore Power's merchant energy business	Acquisition by CLP Holdings	850-1000[93]
Jul 02	Pulse Energy	Acquisition by AGL	815

Source: Grant Samuel analysis (see Appendix 9)

90 Represents gross consideration divided by mass market customers. In some transactions price paid per customer is based on broker estimates of the price paid for the retail businesses acquired. Multiples presented in the table allow for inflation since acquisition so that all multiples reflect current dollars. Unadjusted price per customer is set out in Appendix 9.

91 Price per mass market customer as provided by AGL Energy.

92 Australian Energy Limited was focused on small to medium sized commercial customers and not mass market customers.

93 Multiples shown for electricity and gas customers are based on broker estimates as no split was provided by acquirer.

The following factors are relevant to consideration of price paid per mass market customer:

- the acquisition of an 8.89% interest in Jackgreen is not a control transaction;
- the price per electricity customer and price per gas customer data for the acquisition of Singapore Power's merchant energy business and Pulse Energy are based on estimates published by brokers and, consequently, should be treated with caution;
- since 2002 there has been an increase in the prices paid per mass market customer in Australia (after adjusting for inflation) reflecting cost synergies available to acquirers, diversification benefits (e.g. diversifying between states and size of customer accounts which reduces hedging requirements), integration benefits (e.g. creating a natural hedge against electricity price volatility), the scarcity of retail businesses available for acquisition (as most state retail businesses have been privatised) as well as strong economic growth expectations at the time;
- price per customer is generally lower for gas customers than electricity customers reflecting lower profit margins for gas retailing. However, this differential has reduced over time due to the increasing numbers of dual fuel accounts; and
- price per customer is higher for larger customers (i.e. small to medium enterprise and commercial and industrial customers) than for retail customers reflecting higher revenue per account and additional diversification benefits (as larger customers have lower peak load factors) that reduce hedging requirements. Therefore, the overall price per customer will be higher to the extent that the retailer's customer base also includes commercial customers.

The value attributed to Energy Retailing of $3,550-3,800 million implies a multiple in range of $1,307-1,399 per mass market customer. These multiples are towards the high end of recent transaction evidence for mass market energy retailing businesses ($1,200-1,400 for electricity retailing and $1,100-1,300 for gas retailing).

Origin's Energy Retailing business represents a blend of mass market electricity and gas retailing as well as a commercial and industrial business and the resulting overall mass market multiples of customers reflect the mix of those businesses. In any event, Origin's Energy Retailing is a substantial and strategic energy retailer in the Australian market. Its estimated market share in the states in which it operates is 23% for electricity and 27% for gas with 2.7 million mass market customers (including 0.9 million dual fuel customers).

(iii) Value of Energy Trading

Summary

Grant Samuel has estimated the value of the Energy Trading business to be $2,000-2,200 million. In determining this value, Grant Samuel had regard to DCF analysis.

DCF Analysis

DCF models for Energy Trading have been developed by Grant Samuel based on long term cash flow models prepared by Origin. Grant Samuel has adjusted the Origin cash flow to reflect its judgement on certain matters (i.e. gas prices, inflation etc.) and to ensure consistent application of assumptions.

The Energy Trading business procures energy fuel and energy and dispatches it to the appropriate Origin business or into the market. It seeks to optimise returns by utilising Origin's in house portfolio flexibility to meet the supply and demand requirements of the energy market on a daily basis. Its earnings capture the differential between wholesale energy prices (i.e. electricity, gas and carbon) or the prices of derivatives and the contracted derivative prices and long term supply contracts. In particular, there are a number of long term (out to ten years) electricity cap contracts and gas purchase contracts that are (even at today's energy prices) substantially in the money.

The DCF analysis reflects existing contracts for their remaining lives and does not capture any value for the trading function generally except for Maximum Daily Quantity contracts which support peak gas requirements and ongoing REC trading (although these represent

less than 16% of the NPV outcomes for Energy Trading). These limited ongoing trading activities are reflected in cash flows which extend to 2047 with a 3% perpetual growth assumption. Net present values are calculated on an ungeared after tax basis using nominal after tax discount rates of 9.0-10.0%. Appendix 4 sets out a detailed analysis of the selection of these discount rates. A corporate tax rate of 30% has been assumed. The key general and specific operational assumptions underlying the DCF models are set out in Appendix 5.

The scenarios used in the DCF analysis for Energy Trading are based on Gas Price Path A and Gas Price Path B as discussed in Section 9.3. Gas prices also influence electricity prices. The NPV analysis is summarised below:

Energy Trading – NPV Outcomes ($ millions)

Scenario	Discount Rate		
	10.0%	9.5%	9.0%
Scenario 1 – Gas Price Path A	1,845.3	1,929.0	2,020.8
Scenario 2 – Gas Price Path B	2,220.8	2,321.3	2,430.8

The values are highly sensitive to changes in gas prices and less sensitive to discount rates. In particular, there is substantial value leverage in the long term gas supply contracts, which were entered into at a time of lower gas prices. However, much of the NPV for Energy Trading (around 35%) relates to medium and long term electricity cap contracts which are not sensitive to changes in gas prices. The terminal values allowed for in the model represent less than 3% of NPV outcomes.

(iv) Value of LPG

Summary

Grant Samuel has estimated the value of LPG to be in the range of $500-550 million. In determining this value, Grant Samuel had regard to DCF analysis and multiples of tonnes of LPG.

DCF Analysis

DCF models for LPG have been developed by Grant Samuel based on long term cash flow models prepared by Origin. Grant Samuel has adjusted the Origin cash flow to reflect its judgement on certain matters (e.g. inflation) and to ensure consistent application of assumptions.

The DCF model is long term commencing at 1 July 2008 and extends for a period of 38 years. LPG price increases are assumed to 2012 with relatively constant margins, after which EBITDA is assumed to increase by inflation. The terminal value calculated represents the value of cash flows in perpetuity and has been calculated by capitalising net after tax cash flows based on a 3% perpetual growth assumption. Net present values are calculated on an ungeared after tax basis using nominal after tax discount rates of 9.0-10.0%. Appendix 4 sets out a detailed analysis of the selection of this discount rate. A corporate tax rate of 30% has been assumed. The key general and specific operational and asset assumptions underlying the DCF model are set out in Appendix 5.

LPG prices are based on international LPG prices, which generally move in line with world oil prices. However, there can be a delay in passing on higher LPG prices to some Origin customers which results in some margin compression. A number of different scenarios have been developed and analysed to reflect the impact on NPV of various pricing outcomes for LPG:

- **Scenario 1** – Base case scenario with pricing and future demand expectations as set out in Appendix 5 (i.e. constant margins);
- **Scenario 2** – Scenario 1 with 10% higher LPG prices and no delay in passing on cost increases;
- **Scenario 3** – Scenario 1 with 10% reduction in LPG prices; and

- **Scenario 4** – Scenario 2 with 5% margin compression (i.e. 95 % of base case margin reflecting a delay in the ability to pass cost increases through to customers).

LPG – NPV Outcomes ($ millions)			
Scenario	**Discount Rate**		
	10.0%	**9.5%**	**9.0%**
Scenario 1 – constant margins	511.3	558.8	614.6
Scenario 2 – higher LPG price, no margin compression	595.8	649.9	713.3
Scenario 3 – lower LPG price	426.7	467.7	515.9
Scenario 4 – higher LPG price, 5% margin compression	428.7	470.0	518.5

Scenarios 1, 2 and 3 assume that LPG prices are immediately passed on to consumers (i.e. no margin compression). While an increase in LPG prices is generally passed on to customers, there can be a short lag to a proportion of Origin's customer base, resulting in margin compression. Consequently, the NPV outcomes for Scenario 2 are unrealistic. Higher LPG prices and a lag in the ability to pass higher LPG prices through to consumers (resulting in a 5% margin compression) results in significantly lower values (Scenario 4). However, Origin's active price management has historically limited the extent of margin compression. Consequently, NPV outcomes consistent with the Scenario 1 are more realistic.

Multiples of Tonnes of LPG

The value attributed to the LPG business of $500-550 million implies a multiple in range of $1,029-1,132 per tonne of LPG sold. These multiples are towards the low end of recent transaction evidence for LPG businesses ($400-2,830 per tonne) (See Appendix 9). However, the price paid per tonne is typically higher for LPG cylinder businesses (e.g. Speed-E-Gas) than for bulk LPG businesses. Businesses operating across the LPG customer spectrum (e.g. Rockgas) have been acquired at multiples of tonnes sold within those extremes. Origin's LPG business encompasses retail and bulk LPG customers plus a wholesale LPG trading business and extensive South Pacific LPG businesses which warrant lower multiples. Therefore, the multiples implied by the value range represent the blended earnings of the business and are considered realistic.

(v) Earnings Multiple Analysis

In estimating a value for Origin's Retail business Grant Samuel has had regard to both EBITDA and EBIT multiples from an analysis of transactions involving comparable businesses and comparable listed entities.

Transaction Evidence

The table below sets out EBITDA and EBIT multiples implied by selected transactions involving the acquisition of energy retail and wholesale businesses (as opposed to integrated energy businesses) in Australia since 2002:

Recent Transaction Evidence – Energy Retailing								
Date	Target	Type[94]	Transaction	Consid-eration (millions)	EBITDA Multiple (times)		EBIT Multiple (times)	
					Historical	Forecast	Historical	Forecast
Electricity – Australia								
Feb 07	Powerdirect Australia	R	Acquisition by AGL Energy	A$1,200	na	14.6	na	15.0
Nov 06	Sun Retail	R	Acquisition by Origin	A$1,202	na	9.0	na	10.0
Dec 05	Australian Energy	G/R	Acquisition by Ergon Energy	A$99	19.6	12.6	20.5	na
Gas – Australia								
Nov 06	Sun Gas Retail	R	Acquisition by AGL Energy	A$75	11.5	9.0	na	na
Apr 06	AlintaAGL	G/R	Acquisition of 33% by AGL Energy	A$1,112	na	12.6	na	14.2
Electricity and Gas – Australia								
Mar 05	Singapore Power's merchant energy business	G/R	Acquisition by CLP Holdings	A$2,128	11.7	na	na	na
Apr 04	TXU's Australian assets	G/R/I	Acquisition by Singapore Power	A$5,100	9.2	8.6	na	na
Jul 02	Pulse Energy	R	Acquisition by AGL	A$880	7.8	7.4	8.4	8.4

Source: Grant Samuel analysis (see Appendix 9)

Further details on these transactions are set out in Appendix 9. The following factors are relevant to consideration of the transaction evidence:

- a number of the transactions involved the privatisation of energy retail businesses and the acquirers would have expected to lower the cost structures of the businesses. Consequently, the implied multiples for the acquisition would be below those presented in the table. For example, AGL Energy indicated that the price paid for Powerdirect Australia under its own cost structure was 9.8 times expected EBITDA for the year ending 30 June 2009;
- Australian Energy Limited was focussed on small to medium sized commercial customers and not mass market customers;
- the transactions involving generation, infrastructure and retail assets will have multiples that represent a blend of these businesses; and
- electricity retailers have generally been acquired at higher EBITDA multiples then gas retailers, possibly as margins for gas retailing are generally lower. Furthermore, the primary energy retailing customer relationships tend to be with electricity as it represents a larger portion of household income expenditure.

The above transaction evidence indicates that energy retailers have been acquired at multiples of 9-10 times EBITDA and potentially lower having regard to the improvements in cost structure and operational efficiency targeted (and expected) by acquirers.

There is limited evidence of the multiples of earnings paid for LPG distribution businesses in either Australia or New Zealand. The transaction evidence that is available is set out in Appendix 9. The best (and most relevant) evidence available relates to the acquisition of the Rockgas business (the largest LPG supplier in New Zealand) by Contact Energy from Origin in March 2007. This transaction implied prospective multiples of 7.5 times EBITDA and 7.9 times EBIT.

Sharemarket Evidence

The following table sets out the implied EBITDAF, EBITDA and EBIT multiples for a range of listed energy entities in Australia and New Zealand with significant energy retail

[94] R = Retail; G = Generation; I = Infrastructure

and wholesale activities based on share prices as at 5 September 2008 (except for Contact Energy which are based on sharemarket prices as at 29 April 2008, the day prior to the announcement of BG Group's approach):

Sharemarket Ratings of Selected Listed Energy Entities

Entities	Market Capitalisation (millions)	EBITDAF Multiple (times) Historical	EBITDA Multiple (times)			EBIT Multiple (times)		
			Historical	Forecast Year 1	Forecast Year 2	Historical	Forecast Year 1	Forecast Year 2
AGL Energy	A$6,486	12.9	23.8	8.6	7.9	35.4	10.8	10.0
BBP	A$113	9.4	7.8	9.5	8.4	12.0	16.8	13.9
Contact Energy	NZ$5,410	11.6	11.7	11.1	10.2	16.0	15.4	14.2
TrustPower	NZ$2,494	15.1	15.0	13.1	10.8	17.8	15.7	12.7

Source: Grant Samuel analysis (see Appendix 9)

A detailed analysis of these entities is set out in Appendix 9.

The following factors are relevant to consideration of these multiples:

- the multiples for the listed entities are based on share prices and therefore do not include a premium for control. All entities have 30 June year ends except TrustPower which has a 31 March year end;
- as a consequence of the application of AIFRS, historical earnings multiples of energy businesses are distorted by unrealised derivative gains and losses (particularly if material in size). Brokers do not forecast such profit impacts. Therefore, there is a disconnect between the historical and forecast EBITDA and EBIT multiples presented in the above analysis. This is eliminated by calculating historical EBITDAF multiples which ignore the impact of unrealised derivatives gains and losses on earnings. In this regard, historical EBITDA multiples for AGL Energy are overstated to the extent they reflect unrealised derivatives losses while historical EBITDA multiples for BBP are understated to the extent they reflect unrealised gains;
- all entities (except BBP) are integrated energy businesses. However, BBP operates a portfolio of generation assets and a stand alone energy retailing business (predominantly gas) in Western Australia. The sharemarket ratings for all of these entities represent a blend of their generation, retailing and other businesses. All (except BBP) source a significant portion of their electricity needs for their retailing operations internally;
- AGL Energy's forecast earnings multiples are relatively low. This may, in part, be a result of its share price not fully reflecting the market value of its 24.9% interest in QGC. The forecast EBITDA multiples increase to around 8.5-9.0 times if the QGC investment is allowed for at acquisition cost rather than at current market value;
- BBP's earnings multiples are distorted to the extent that its earnings exclude its proportional interest in Oakey Power Station and by asset sales in July and August 2008 and its market rating has been impacted by the recent turmoil in global credit markets; and
- the multiples for the New Zealand companies are high in comparison to the Australian entities reflecting the focus on renewable fuel sources in New Zealand. However, both of these companies also have a limited free float and are not particularly liquid.

The absence of pure energy retailers in the sharemarket evidence makes it difficult to derive useful guidance in assessing the value of the Retail business. However, due to the additional operational risk associated with being a stand alone energy retailer it is reasonable to assume that energy retailers would trade at multiples lower than integrated energy businesses.

Summary of Implied Multiples

The aggregate value attributed to the Retail business of $6,050-6,550 million implies the following multiples of earnings:

Retail – Implied Earnings Multiples			
Parameter	**Variable ($ millions)[95]**	**Value Range**	
		Low	**High**
Value Range ($ millions)		**6,050**	**6,550**
Multiple of EBITDAF			
Year ended 30 June 2008 (adjusted actual)[95]	523.3	11.6	12.5
Year ended 30 June 2009 (model forecast)[95]	596.4	10.1	11.0
Year ending 30 June 2010 (model forecast)[95]	610.6	9.9	10.7
Multiple of EBITF			
Year ended 30 June 2008 (adjusted actual)[95]	470.0	12.9	13.9
Year ended 30 June 2009 (model forecast)[95]	549.5	11.0	11.9
Year ending 30 June 2010 (model forecast)[95]	558.7	10.8	11.7

The multiples are high in comparison to available transaction evidence including energy retailers with substantial mass market businesses (9-10 times) forecast EBITDA (particularly having regard to Retail's already efficient operations). Grant Samuel considers this appropriate as the multiples reflect the blended earnings of Origin's retail business including substantial value for the Energy Trading business (specifically long term gas supply contracts). If the value attributed to these contracts is excluded, the forecast multiples implied for the remainder of the business decline to 8.3-9.0 times 2009 EBITDA. Retail is a substantial strategic retailing business which is holding significant operational flexibility within a highly fuel integrated energy business. While Origin's Generation business largely involves a set return on investment, Retail reflects the value of energy trading activities (including historical operating decisions that have resulted in a substantially "in the money" portfolio of energy contracts). Further it holds substantial market positions in each of its customer facing businesses and has developed a leading position in the area of green energy products.

9.7 Contact Energy Limited

9.7.1 Overview

Origin holds 296,153,144 ordinary shares in Contact Energy equal to 51.3% of the issued capital. For the purposes of this report, Origin's holding in Contact Energy has been valued in the range of $2,300-2,400 million which corresponds to a value of NZ$9.50-10.00 per share (based on an exchange rate of NZ$1.00 = A$0.82).

9.7.2 Approach

The value attributed to Contact Energy is an overall judgement having particular regard to the market trading price of Contact Energy shares and the multiples of EBITDAF, EBITDA, EBIT, net profit after tax implied by the value range compared to the multiples derived from an analysis of comparable listed entities and transactions involving comparable companies. In forming this view, Grant Samuel has had access only to public information on Contact Energy and therefore it was not possible to develop a reliable DCF model. Furthermore, as Contact Energy is an integrated energy company with generation and retailing activities, the rules of thumb commonly

[95] 2008 earnings are based on the adjusted financial performance for Retail set out in Section 4.3 of the report. These earnings have been further adjusted to exclude head office costs allocated to Retail (as head office costs are valued separately in Section 9.8 of the report). Forecast earnings are sourced from the Grant Samuel cash flow models. The growth in earnings in 2009 over 2008 reflects the growth in energy trading activities projected as a number of the committed new generation plants are commissioned. The lower growth in 2010 reflects the run off of Origin's existing portfolio of energy contracts.

used in the energy segments in which it operates (e.g. multiples of MW installed capacity and mass market customer accounts) cannot be meaningfully analysed.

As Origin has a 51.3% interest in, and management control of, Contact Energy, it is appropriate that the value includes a control premium. At the same time, it is necessary to recognise that Origin does not have unfettered control of Contact Energy and is not able to directly access its cash flows.

Origin could, of course, seek to buy out the minorities but it is unclear if institutional investors in Contact Energy will realise their interests at any price a bidder would pay and, therefore, an acquirer may not be able to obtain 100%. Both Edison and Origin have previously attempted to acquire the interests of Contact Energy's minority shareholders.

Edison made a takeover offer in October 2001 at NZ$3.85 cash per share (subsequently increased to NS$4.25 per share) for the 48.8% of Contact Energy that it did not already own. This offer was unsuccessful and Edison's shareholding remained at 51.2%. Origin's takeover offer following its acquisition of Edison's 51.2% interest (NZ$5.57 cash per share) resulted only in an increase of 0.2% in its interest in Contact Energy. Furthermore, during early 2006 Origin pursued a merger with Contact Energy via a dual listed company structure but discussions were terminated in June 2006 when the parties were unable to agree on terms.

This situation exists primarily because Contact Energy is the second largest company by market capitalisation on the NZSX and the New Zealand stock market has been contracting in size over the last decade. Contact Energy represents the largest and best positioned exposure for investors to the New Zealand energy market and has a history of growing dividends.

Accordingly, if Origin was to seek to sell its 51.3% interest, it is likely that acquirers would also anticipate that they would be unlikely to secure 100% control (e.g. through a follow on offer) and this may constrain the price they will be prepared to pay.

On the other hand:

- a 51.3% shareholding would provide capacity to control Contact Energy via an ability to pass any ordinary resolution in general meeting (and arguably, for practical purposes, special resolutions where the 51.3% holder could vote). In this regard, although Origin does not currently control the board (with three of the six board members including the Chairman, albeit with no casting vote) it has the ability to increase or change the composition of the board by way of ordinary resolution;
- a 51.3% shareholder should be able to obtain some degree of control over management. For example, the current chief executive is on secondment from Origin (a similar situation existed under Edison's ownership);
- Contact Energy has a relatively high dividend payout ratio (around 70%) providing the 51.3% shareholder has a reasonable cash flow; and
- for strategic reasons some potential acquirers may be more comfortable with a large local equity holding (e.g. in terms of managing potential issues over energy pricing).

9.7.3 Premium for Control

The premia for control compared to Contact Energy's share price over a range of different periods are set out below:

Contact Energy – Premium over Share Prices		
Period	**Share Price**	**Premium/(Discount) represented by Value Range**
Close of business:		
5 September 2008	NZ$8.36	13.6-19.6%
29 April 2008 (day prior to announcement of BG Group approach)	NZ$9.39	1.2-6.5%
Volume weighted average price:		
From 30 April 2008 to 5 September 2008	NZ$8.41	13.0-18.9%
1 month prior to 29 April 2008	NZ$8.77	8.3-14.0%
3 months prior to 29 April 2008	NZ$8.16	16.4-22.5%
6 months prior to 29 April 2008	NZ$8.20	15.9-22.0%
12 months prior to 29 April 2008	NZ$8.67	9.6-15.3%

Takeover premiums in the range 20-35% are typically observed in takeovers. However, the level of premium paid depends on the circumstances of the target company, the level of synergies available to the acquirer and other factors (such as the extent of competing bids). In the case of Origin's 51.3% interest in Contact Energy, Grant Samuel believes these premia are reasonable having regard to:

- the difficulties identified for any party attempting to obtain 100% of Contact Energy; and
- the level of synergies likely to be available. Synergies are a primary reason for payment of a control premium. It is unlikely that many synergies exist for a new 51.3% shareholder beyond those already derived by Origin (by improving operations and therefore profitability). A 51.3% shareholder can only access Contact Energy's free cash flow via dividend payments. In any event, as most likely acquirers would be overseas companies, the scope for savings (even in head office costs) is likely to be limited.

9.7.4 Earnings Multiple Analysis

The value of Origin's interest implies a value in the range of NZ$5.5-5.8 billion for 100% of Contact Energy and NZ$6.4-6.6 billion for the operating business of Contact Energy as follows:

Contact Energy – Summary of Implied Value (NZ$ millions)			
	Report Section Reference	**Value Range**	
		Low	**High**
Equity value per share		**NZ$9.50**	**NZ$10.00**
Shares on issue (millions)		576.8	576.8
Implied value of equity		**5,479.6**	**5,768.0**
Net borrowings at 30 June 2008 (including hedging impact)	8.7	(878.4)	(878.4)
Other assets and liabilities[96]		(7.9)	(7.9)
Implied value of business operations		**6,365.9**	**6,654.3**

The earnings multiples implied by the value attributed to Contact Energy's business operations and the value attributed to the equity of Contact Energy are summarised below:

[96] Other assets and liabilities include the carrying value at 30 June 2008 of 25% interest in Oakey Power Station and 50% interest in Rockgas Timaru (total of NZ$8.0 million) plus 8.5% interest in Liquigas (NZ$2.9 million) less provision for retirement of New Plymouth Power Station (NZ$18.8 million)

Contact Energy – Implied Valuation Parameters				
	Report Section Reference	Variable (NZ$ millions)	Value Range	
			Low	High
Multiple of EBITDAF				
Year ended 30 June 2008 (actual)	8.5	541.0	11.8	12.3
Year ending 30 June 2009 (broker median)	8.5	570.0	11.2	11.7
Year ending 30 June 2010 (broker median)	8.5	624.9	10.2	10.6
Multiple of EBITF				
Year ended 30 June 2008 (actual)	8.5	394.5	16.1	16.9
Year ending 30 June 2009 (broker median)	8.5	410.0	15.5	16.2
Year ending 30 June 2010 (broker median)	8.5	456.1	14.0	14.6
Multiple of Net Profit after Tax				
Year ended 30 June 2008 (actual)	8.5	237.1	23.1	24.3
Year ending 30 June 2009 (broker median)	8.5	244.0	22.5	23.6
Year ending 30 June 2010 (broker median)	8.5	263.8	20.8	21.9

The implied valuation parameters set out above have been compared to multiples implied by the share prices of listed Australian and New Zealand integrated energy companies and the prices at which transactions involving integrated energy businesses have been completed. The focus of this review has been on integrated energy businesses due to the natural hedge available where a business has both energy generation and retailing operations, although the degree to which this natural hedge is utilised depends on factors such as the proportion of electricity generated sold to the retail operations or into the spot market.

These multiples are high relative to the market evidence for integrated energy businesses previously discussed in Section 9.6.2 (although that evidence is relatively limited). In Grant Samuel's opinion, the implied multiples reflect the strong growth prospects and market positioning of Contact Energy. In particular, Contact Energy is a very strategic asset in the context of the New Zealand energy market. It operates a substantial diversified (by plant type, fuel type and geographic location) generation portfolio providing approximately 25-30% of New Zealand's electricity generation capacity and has substantial retail market positions (it is the second largest electricity retailer, has an estimated 36% share of the retail gas market and supplies LPG to approximately 50% of the market).

Other attractive attributes include that Contact Energy:

- has a significant pipeline of around 1,400MW of consented or planned generation assets to meet the New Zealand Government's climate change initiatives (i.e. wind, geothermal, hydro);
- is expected to be less affected by the costs associated with the introduction of an emission trading scheme in 2010 than a number of its peers. This portfolio creates significant opportunities for growth; and
- is a net generator (i.e. it produces more electricity than it sells to its customers) and therefore benefits from periods of high electricity prices.

9.8 Head Office Costs

Origin incurs head office costs of approximately $45 million per annum. These costs represent costs associated with running Origin's head office and include:

- the Origin executive office (such as costs associated with the offices of the Managing Director and Chief Financial Officer, company secretarial and legal, planning and development, corporate affairs, treasury, tax etc.);
- being a listed company (such as directors fees, annual reports and shareholder communications, share registry and listing fees and dividend processing);
- certain group shared services (such as human resources, information technology etc.) not fully recharged to the business operations during the year.

These head office costs are fully allocated to Origin's Australian operating businesses for the purposes of financial reporting. In comparison, the cash flow models upon which the valuation of Origin's businesses are primarily based reflect only divisional overheads (i.e. costs associated with the management of the businesses) and recharged corporate costs. They do not reflect the head office costs. Therefore, separate allowance has been made for head office costs.

Any acquirer of 100% of Origin would be able to save the costs associated with being a publicly listed company. Furthermore, an acquirer of Origin which has an existing presence in Australia would be able to eliminate some of the costs associated with the Origin executive office. It is estimated that approximately 50% of head office costs would be saved.

Grant Samuel has assumed residual head office costs of $22.5 million per annum for the purposes of the valuation (i.e. costs remaining after the savings available to the acquirer) which have been capitalised at a multiple of 10-11 times (say $225-250 million).

9.9 Other Assets and Liabilities

Origin's other assets and liabilities have been valued in the range $(700)-(705) million and include:

- Origin's 19,788,403 shares in Geodynamics;
- the defined benefit superannuation surplus;
- the provision for onerous leases;
- an allowance for Origin's obligations in relation to contaminated properties;
- cash receivable by Origin on exercise of all outstanding options;
- $(114.5) million representing the provision for the final dividend of 13 cents per share payable on 3 October 2008. Origin shares started trading ex dividend on 3 September 2008;
- transaction costs associated with the ConocoPhillips Proposal, the BG Offer and the CSG Monetisation Process. Origin has estimated the maximum cost in relation to these matters to be approximately $110 million (of which 5% are estimated not to be tax deductible with the balance deductible over five years). An amount of $86 million representing the tax effected present value of estimated transaction costs has been allowed by Grant Samuel; and
- tax to be incurred on the capital return from OECSG under the ConocoPhillips Proposal. Origin will incur tax on this return. Origin has estimated the excess amount to be $2,510 million. Grant Samuel has assumed tax at 30% on this amount less an allowance for Origin's income tax losses disclosed in its 30 June 2008 financial statements, giving a cash payment of $654 million.

Other assets and liabilities exclude the other assets and liabilities of Contact Energy which have been allowed for in the value of Contact Energy (see Section 9.7).

Origin has a number of other assets and liabilities on its balance sheet that have not been included in other assets and liabilities for the following reasons:

- acquired environmental certificate purchase obligations which represent long term commitments acquired with Sun Retail in February 2007. This amount is an accounting provision and amortises over time in the normal course of business and is therefore already valued in the Downstream Energy Business (see Section 9.6); and
- the provision for restoration and rehabilitation and dismantling of sites ($328 million) is an accounting provision based on the present value of the future estimated costs to decommission power stations, gas processing plants and LPG plants. The cash outlay required to decommission plants at the end of their useful lives is reflected in the cash flows used in the valuation of the conventional oil and gas assets, the power station portfolio and the LPG business.

9.10 Net Borrowings

Origin's net borrowings for valuation purposes are $3.45 billion. This amount is based on net borrowings at 30 June 2008 excluding the net borrowings of Contact Energy as Grant Samuel has separately valued Origin's interest in the equity of Contact Energy (see Section 9.7). Furthermore, net borrowings have been adjusted to reflect the AIFRS fair value adjustment at 30 June 2008 and the acquisition of Uranquinty Power Station in July 2008.

Origin – Net Borrowings for Valuation Purposes

	$ millions
Borrowings at 30 June 2008	(3,378.6)
Cash and deposits at 30 June 2008	96.0
Net borrowings as at 30 June 2008 (see Section 4.4)	**(3,282.6)**
AIFRS fair value adjustment at 30 June 2008	(324.9)
Adjusted net borrowings as at 30 June 2008 (see Section 4.4)	**(3,607.5)**
Contact Energy adjusted net borrowings as at 30 June 2008	694.3
Adjusted net borrowings as at 30 June 2008 (ex Contact Energy) (see Section 4.4)	**(2,913.2)**
Acquisition of Uranquinty Power Station on 4 July 2008	(540.0)
Net borrowings for valuation purposes	**(3,453.2)**

9.11 Franking Credits

Under Australia's dividend imputation system, domestic equity investors receive a taxation credit (franking credit) for tax paid by a company. The franking credit attaches to any dividends paid by a company and the franking credit offsets personal tax for Australian investors. To the extent that personal tax has been fully offset the individual will receive a refund of the balance of the franking credit. Franking credits therefore have value to the recipient.

However, in Grant Samuel's opinion, while acquirers are attracted by franking credits there is no clear evidence that they will actually pay extra for a company with them (at any rate the sharemarket evidence used by Grant Samuel in valuing the Origin businesses will already reflect the value impact of the existence of franking credits). Further, franking credits are not an asset of the company in the sense that they can be readily realised for a cash sum that is capable of being received by all shareholders. The value of franking credits can only be realised by shareholders themselves when they receive distributions. Importantly, the value of franking credits is dependent on the tax position of each individual shareholder. To some shareholders (e.g. overseas shareholders) they will have very little or no value. Similarly, if they are attached to a distribution which would otherwise take the form of a capital gain taxed at concessional rates there may be minimal net benefit.

Accordingly, while franking credits may have value to some shareholders they do not affect the underlying value of the company itself. No value has therefore been attributed to Origin's accumulated franking credit position in the context of the value of Origin as a whole.

10 Evaluation of the ConocoPhillips Proposal

10.1 Summary

In Grant Samuel's opinion, the ConocoPhillips Proposal is in the best interests of Origin shareholders. The reasons for Grant Samuel's opinion include the following:

- the value attributed by the ConocoPhillips Proposal for a 50% interest in the JV is a fair market value;
- the ConocoPhillips Proposal is a strategically sensible strategy for developing Origin's CSG Assets and maximising the return to Origin shareholders;
- there are a number of benefits for Origin and its shareholders including:
  - generation of a substantial net cash balance providing greatly enhanced financial flexibility;
  - the ability to undertake share buybacks which should be positive for the share price;
  - an additional fully franked dividend of 25 cents per share and a higher dividend payout ratio going forward; and
  - a significant uplift in earnings per share;
- there are risks attached to the 50% of the CSG Assets retained by Origin but Origin shareholders previously had a 100% exposure and, if anything, the risks are now significantly reduced; and
- the underlying value of Origin, including the value of its other business operations and assets is estimated to be in the range $28.55-30.71 per share (including a premium for control). This value is substantially above the BG Offer of $15.37 per share. The ConocoPhillips Proposal therefore provides superior value to Origin shareholders. Accordingly, the BG Offer is neither fair nor reasonable.

10.2 Strategic Rationale

Origin's initial interest in CSG was as a source of gas to supply its growing downstream energy businesses, both gas retailing and gas fired electricity generation. CSG was a key part of Origin's strategy of being an integrated energy business with a focus on the fuel component as being the greatest source of long term value creation. However, as the LNG options have become more evident, Origin has also been exploring ways in which it can either:

- participate in LNG directly; or
- provide CSG in sufficient volumes to underpin a third party development of a LNG plant.

In either case, the underlying objective was to maximise the price for the gas. The "net back" price received for gas as feedstock for LNG (which is driven by the oil price and the production/tolling costs) is substantially above current Australian domestic gas prices.

The development of the CSG Assets (excluding as supply to LNG plants) is a significant project with estimated capital expenditure in excess of $2 billion over the next five years. As a domestic gas only project, this was considered manageable for Origin as the capital expenditure can be phased and offset by operating cash flows.

However, LNG brings a different dimension. Direct participation in LNG substantially increases and brings forward the capital commitments and takes Origin into an area where it has no existing operations or expertise. On the other hand, if it just supplies gas to others to facilitate their LNG projects, Origin has less control and certainty over the development and the gas pricing received may be less favourable.

Realistically, to participate directly in LNG, Origin was always going to need to bring in a partner (or partners) to share the financial burden, provide technical expertise and provide access to LNG export markets.

The ConocoPhillips Proposal provides an attractive outcome consistent with Origin's strategic objectives:

- it crystallises a value for 50% of the assets but allows Origin to retain a 50% exposure to the CSG Assets and participate in 50% of the LNG plant;
- it provides Origin with immediate cash of approximately $6 billion underpinning future financial flexibility for developing the rest of its businesses;

  ConocoPhillips will subscribe all the capital necessary to cover the anticipated development costs up to FID for the first LNG train (up to $2.3 billion). Origin is unlikely to need to subscribe for any material amount of capital in the joint venture until 2012 at the earliest. Even then the requirement may not be large because ConocoPhillips provides US$1 billion at FID for each train (out of a total cost of approximately US$3.0-3.5 billion, and lower for subsequent trains) and there will be other financing options. In any event, there will be operating cash flows to offset the construction cost of Trains 2-4; and
- ConocoPhillips is one of the world's leading energy companies. It has a market capitalisation of approximately US$115 billion. Globally, it is the sixth largest holder of proven (non government controlled) oil reserves and operates in nearly 40 countries. It clearly has the financial capacity to fund its share of equity commitments but, more importantly, it should be a strong partner that can make a major contribution to the development of CSG Assets in areas such as technical expertise in relation to the development and operation of the LNG plant and in the marketing of LNG.

  ConocoPhillips has been involved in CSG production for over 25 years and is one of the largest CSG producers in the United States. It is the largest operator in the San Juan Basin, one of the more prolific CSG formations in the world, with almost 10,000 operated wells.

  ConocoPhillips is also one of the world's most experienced developers and operators of LNG facilities:

  - it developed its own proprietary technology (the Optimised Cascade℠ Process) in collaboration with Bechtel Group Inc. (beginning in 1969). This technology, which is particularly suited to CSG and has been nominated by QGC/BG Group and Santos/Petronas for their LNG projects. It has been used in approximately half of all greenfield LNG developments since 1996;
  - recent developments by ConocoPhillips were completed on time, on budget and exceeding design capacity;
  - ConocoPhillips developed and operates the Darwin LNG facility (first shipments were in 2006). It is proposed that the proposed LNG plant will be substantially the same as the Darwin facility (which incorporated a number of recent innovations and greenhouse gas reduction features); and
  - through its involvement in the LNG facility in Kenai, Alaska (which has operated since 1969), ConocoPhillips has extensive experience in lean gas to LNG production (which has similar issues to CSG).

10.3 Impact on Origin and its Shareholders

The ConocoPhillips Proposal provides Origin with immediate cash of approximately $6 billion. Origin's current net borrowings (including Uranquinty but excluding the net borrowings of the 51.3% owned Contact Energy) are approximately $3.5 billion. Accordingly, Origin will have net cash of over $2.5 billion immediately after the ConocoPhillips Proposal is implemented.

Origin has announced:

- an additional fully franked dividend of 25 cents per share; and
- commencement of an on market buyback of up to $1.275 billion.

It will also consider further capital management initiatives in future. However, at the very least,

even after the dividend and buyback, it provides Origin with very substantial financial capacity to pursue further development of its downstream gas retailing and electricity generation businesses (e.g. through acquisitions) and to fund its existing capital commitments (e.g. Darling Downs Power Station). The only downside is that for a period of time, Origin may have an inefficient capital structure.

Other benefits for Origin shareholders include:

- substantial uplift in earnings per share, over 50% on an annualised basis; and
- an increase in the dividend payout ratio to at least 60% of underlying earnings.

However, it should be recognised that:

- earnings per share are not a major driver of the share price in the short term because a major part of Origin's value is represented by assets such as the CSG Assets which will not generate significant earnings for some years; and
- the dividend yield will still be relatively low (based on the current share price).

A further issue for Origin shareholders is the impact of the ConocoPhillips Proposal on the prospects for a future takeover of Origin. The ConocoPhillips Proposal has no direct impact on the ability of any party to bid for Origin. However, the question arises as to whether there are any arrangements within the JV that would be a disincentive for a bidder for Origin or reduce their willingness to pay a full price for Origin.

Most importantly, in a change of control situation there is no right for ConocoPhillips to acquire Origin's 50% equity interest in the JV. Any bidder would therefore be able to retain this interest.

There are, however, some aspects that may adversely impact a bidder's willingness to make a full offer:

- ConocoPhillips will have the right to review the operatorship arrangements for the upstream gas assets (currently held by Origin). If this occurred, Origin loses some control over day to day upstream operations although it would still have its 50% membership of the board and negative control over decisions. Nevertheless, this may affect the "attractiveness" of the asset; and
- there may be a requirement to repay the interest free loan from the JV to Origin (part of the mechanism to repatriate the Initial Contributions to Origin). This could cause a loss to the bidder equal to 50% of the interest income on the amount repaid for the period from repayment until the time of which the funds would have otherwise been paid to meet future capital contributions.

These provisions were designed to give ConocoPhillips a right to review the situation and, depending on the identity of the bidder, protect its interest in the JV.

The impact, if any, on a bidder would depend on the timing of any offer and the identity of the bidder. If the bidder is a party of substance and there is no change in Origin management and in the running of its operations, it is reasonable to assume that ConocoPhillips may leave the operatorship untouched. Equally, ConocoPhillips is a very experienced upstream CSG operator so there should be limited loss of expertise or impact from a financial point of view. If the bidder is financially strong ConocoPhillips may be less inclined to force what is effectively early payment of future capital contributions.

Accordingly, it is difficult to gauge the overall effect, but Grant Samuel's judgement is that while it represents a potential disadvantage, it is not a major drawback of the ConocoPhillips Proposal.

In any event, it does not detract from the value of the 50% interest in the JV in Origin's hands.

10.4 Approach and Conclusion

In considering whether or not the ConocoPhillips Proposal is in the best interests of Origin shareholders Grant Samuel has adopted the following approach. The ConocoPhillips Proposal will be in the best interests of Origin's shareholders if it represents fair value for the 50% interest and if the full underlying value of Origin, assuming the ConocoPhillips Proposal is implemented (including its other assets and liabilities), exceeds the BG Offer of $15.37.

Grant Samuel believes this is the relevant comparison as the BG Offer involves a change of control. It is not appropriate to compare the BG Offer with the price at which Origin shares might trade if the ConocoPhillips Proposal is implemented because that is a portfolio value and shareholders will still have the opportunity to realise a control premium by participating in a future change of control event.

Assuming the ConocoPhillips Proposal is implemented, Grant Samuel has estimated the value of Origin to be in the range of $25.5-27.4 billion which corresponds to a value of $28.55-30.71 per share. The valuation represents the full underlying value of Origin assuming 100% of the company was available to be acquired and includes a premium for control. The valuation is set out in Section 9. The value exceeds the price at which, based on current market conditions, Grant Samuel would expect Origin shares to trade on the ASX in the absence of a takeover offer.

This value is substantially above the BG Offer of $15.37 per share. The ConocoPhillips Proposal therefore provides superior value to Origin shareholders. Accordingly, the BG Offer is neither fair nor reasonable.

The value range of $28.55-30.71 per share also represents a very substantial increase over the level at which Origin shares were trading prior to the announcement of the approach by BG Group on 29 April 2008 of approximately $9-10 per share.

However, while this difference is far greater than normally seen in a "control" valuation, the circumstances are unique and reflect the value that has been created through the CSG Monetisation Process. The market attributed some value to Origin's CSG Assets but there was both a rapidly changing environment (e.g. the Santos/Petronas transaction was not announced until after BG Group's initial approach) and value was constrained by the absence of specific plans or credible partners and the limited levels of published reserves (there was a substantial upgrade at 15 May 2008 announced on 30 May 2008).

The ConocoPhillips Proposal dramatically alters the picture. Apart from the value recognition through the transaction terms, it transforms the CSG Assets from an Origin shareholder's perspective from an "interesting play with potential" to one where there is a real project with:

- a strong partner with outstanding technical capabilities fully committed to the project;
- the project fully financed with very limited need for Origin to invest its own cash; and
- a demonstrably high level of confidence in the provability of the vast majority of Origin's contingent resource by one of the world's most experienced CSG operators.

In this respect, the CSG Assets are now very different assets to what they were in April 2008.

10.5 Other Considerations

Under the ConocoPhillips Proposal, Origin will retain a 50% interest in the CSG Assets including the potential LNG plant. Accordingly, shareholders will have an ongoing exposure to:

- upside opportunities. Any value attributed to CSG Assets in today's environment is inevitably discounted to take account of the risks and hurdles that remain. If the development is successfully executed and a functioning LNG plant is operating at full capacity, it is reasonable to expect that, over time, there will be a substantial increase in the value of Origin's 50% interest compared to the price under the ConocoPhillips Proposal (assuming gas prices are also at least in line with expectations). Successful development would also provide further opportunities for expansion in due course (e.g. for domestic gas or additional LNG trains). The CSG Assets include substantial prospective acreage on which there has been little drilling activity; and

- downside risk. Clearly both the development and the ongoing operation of the JV have risks and exposures that could have a material adverse impact on the returns from the investment and its value. These include:
  - notwithstanding the alignment of interests, the introduction of any partner into a business brings the potential for tensions within the relationship which could adversely affect value;
  - the hurdles to be passed in getting to FID for Train 1 including obtaining the appropriate site (and planning approvals), resolving technical issues (e.g. lean gas), ensuring production levels will be as expected, finalising ramp up gas management arrangements and securing offtake arrangements. There is no guarantee FID will be reached and no decision is expected until December 2010 at the earliest;
  - proving up sufficient gas for all four trains. This requires approximately 24,000PJ (including already contracted volumes). At present, while Origin has a total resource of approximately 26,000PJ, it has less than 5,000PJ certified to a 2P reserve level;
  - exposure to costs overruns on construction of the LNG facilities;
  - a significant exposure to the global oil price. A material and sustained fall would impact reserves (with minimal effect on costs);
  - dependence on continued growth in global demand for energy; and
  - exposure to movements in the A$/US$ exchange rate. LNG revenues will be denominated in US$. Accordingly, a rise in the A$ would diminish revenues (but not operating costs) which would impact Origin's returns from the JV, the value of its 50% interest and the value to Origin of the carry of Development Cost Contribution and the Contingent Contributions (except to the extent Origin hedges such exposures). There is also the partial natural hedge to the extent that the LNG plant construction costs are also denominated in US$. In this context, Grant Samuel's valuation is based on current exchange rates of A$1.00=US$0.83 (and forward rates for deferred payments).

In short, there is potential for CSG to be less successful than currently envisaged. However, these risks are unavoidable in any project of this nature (and shareholders are currently exposed to 100% of them). The respective capabilities and track records of the two parties should give some comfort that controllable risks will be well managed. In any event, this does not detract from the fact that there is a market value that an arm's length party is prepared to pay today.

10.6 Shareholder Decision

The decision whether to accept or reject the BG Offer is a matter for individual shareholders based on each shareholder's views as to value, their expectations about future market conditions and their particular circumstances including risk profile, liquidity preference, investment strategy, portfolio structure and tax position. In particular, taxation consequences may vary from shareholder to shareholder. Shareholders who are in doubt as to the action they should take should consult their own professional adviser.

Similarly, it is a matter for individual shareholders as to whether to buy, hold or sell Origin shares. This is an investment decision independent of the ConocoPhillips Proposal or the BG Offer and is one on which Grant Samuel does not offer an opinion. Shareholders should consult their own professional adviser in this regard.

11 Qualifications, Declarations and Consents

11.1 Qualifications

The Grant Samuel group of companies provide corporate advisory services (in relation to mergers and acquisitions, capital raisings, debt raisings, corporate restructurings and financial matters generally) and property advisory services, manages specialist funds and provides marketing and distribution services to fund managers. The primary activity of Grant Samuel & Associates Pty Limited is the preparation of corporate and business valuations and the provision of independent advice and expert's reports in connection with mergers and acquisitions, takeovers and capital reconstructions. Since inception in 1988, Grant Samuel and its related companies have prepared more than 405 public independent expert and appraisal reports.

The persons responsible for preparing this report on behalf of Grant Samuel are Caleena Stilwell BBus CA F Fin, Stephen Wilson MCom (Hons) CA (NZ) SF Fin and Stephen Cooper BCom (Hons) CA (SA) ACA ACMA. Each has a significant number of years of experience in relevant corporate advisory matters. Celeste Oakley BEc LLB CFA F Fin, Hannah Crawford BCom LLB CA F Fin, Melinda Snowden BEc LLB F Fin and Damien Elias BSc (Psychol.) (Hons) MCom assisted in the preparation of the report. Each of the above persons is an authorised representative of Grant Samuel pursuant to its Australian Financial Services Licence under Part 7.6 of the Corporations Act.

11.2 Disclaimers

It is not intended that this report should be used or relied upon for any purpose other than as an expression of Grant Samuel's opinion as to whether the ConocoPhillips Proposal is in the best interests of Origin shareholders. Grant Samuel expressly disclaims any liability to any Origin shareholder who relies or purports to rely on the report for any other purpose and to any other party who relies or purports to rely on the report for any purpose whatsoever.

This report has been prepared by Grant Samuel with care and diligence and the statements and opinions given by Grant Samuel in this report are given in good faith and in the belief on reasonable grounds that such statements and opinions are correct and not misleading. However, no responsibility is accepted by Grant Samuel or any of its officers or employees for errors or omissions however arising in the preparation of this report, provided that this shall not absolve Grant Samuel from liability arising from an opinion expressed recklessly or in bad faith.

Grant Samuel has had no involvement in the preparation of the Explanatory Memorandum or Supplementary Target's Statement to be issued by Origin and has not verified or approved any of the contents of the Explanatory Memorandum or Supplementary Target's Statement. Grant Samuel does not accept any responsibility for the contents of the Explanatory Memorandum or Supplementary Target's Statement (except for this report).

11.3 Independence

Grant Samuel and its related entities do not have at the date of this report, and have not had within the previous two years, any shareholding in or other relationship with Origin or ConocoPhillips that could reasonably be regarded as capable of affecting its ability to provide an unbiased opinion in relation to the ConocoPhillips Proposal. Grant Samuel advises that:

- Grant Samuel prepared an independent expert's report dated 1 September 2003 for Oil Company of Australia Limited in relation to a takeover offer by Origin;
- Grant Samuel prepared an independent expert's report dated 5 August 2003 on the compulsory acquisition of ordinary shares in Petroz NL by ConocoPhillips;
- a related New Zealand company of Grant Samuel, Grant Samuel & Associates Limited, has prepared the following independent reports for Contact Energy:
  - an independent adviser's report dated 15 September 2004 in relation to a takeover offer by Origin following its acquisition of Edison's 51.2% shareholding in Contact;
  - an independent adviser's report dated 2 November 2001 on the merits of a takeover offer by Edison; and

- an appraisal report dated 11 May 2001 in relation to the proposed restricted transfer as Edison sought to acquire further shares in Contact; and

- Louise Watson, Managing Director of Symbol Strategic Communications which provides strategic communications services to Origin, is a member of the Grant Samuel Corporate Finance Advisory Board. The Grant Samuel Corporate Finance Advisory Board convenes quarterly, acts as a sounding board for and provides market positioning feedback to the corporate advisory activities of the Grant Samuel group of companies. Members of the Grant Samuel Corporate Finance Advisory Board have no involvement in the day to day operations of Grant Samuel or any of its related entities.

Grant Samuel commenced analysis for the purposes of this report in May 2008 prior to the announcement of the BG Group Offer. This work did not involve Grant Samuel participating in setting the terms of, or any negotiations leading to, the ConocoPhillips Proposal.

Grant Samuel had no part in the formulation of the ConocoPhillips Proposal. Its only role has been the preparation of this report.

Grant Samuel will receive a fixed fee of $2,750,000 for the preparation of this report. This fee is not contingent on the outcome of the ConocoPhillips Proposal. Grant Samuel's out of pocket expenses in relation to the preparation of the report will be reimbursed. Grant Samuel will receive no other benefit for the preparation of this report.

Grant Samuel considers itself to be independent in terms of Regulatory Guide 112 issued by the ASIC on 30 October 2007.

11.4 Declarations

Origin has agreed that it will indemnify Grant Samuel and its employees and officers in respect of any liability suffered or incurred as a result of or in connection with the preparation of the report. This indemnity will not apply in respect of the proportion of any liability found by a court to be primarily caused by any conduct involving gross negligence or wilful misconduct by Grant Samuel. Origin has also agreed to indemnify Grant Samuel and its employees and officers for time spent and reasonable legal costs and expenses incurred in relation to any inquiry or proceeding initiated by any person. Where Grant Samuel or its employees and officers are found to have been grossly negligent or engaged in wilful misconduct Grant Samuel shall bear the proportion of such costs caused by its action. Any claims by Origin are limited to an amount equal to the fees paid to Grant Samuel.

Advance drafts of this report were provided to Origin and its advisers. Certain changes were made to the drafting of the report as a result of the circulation of the draft report. There was no alteration to the methodology, evaluation or conclusions as a result of issuing the drafts.

11.5 Consents

Grant Samuel consents to the issuing of this report in the form and context in which it is to be included in the Explanatory Memorandum or Supplementary Target's Statement to be sent to shareholders of Origin. Neither the whole nor any part of this report nor any reference thereto may be included in any other document without the prior written consent of Grant Samuel as to the form and context in which it appears.

11.6 Other

The accompanying letter dated 15 September 2008 and the Appendices form part of this report.

Grant Samuel has prepared a Financial Services Guide as required by the Corporations Act. The Financial Services Guide is set out at the beginning of this report.

GRANT SAMUEL & ASSOCIATES PTY LIMITED
15 September 2008

Grant Samuel & Associates

Appendix 1

Glossary of Technical Terms and Conversion Factors

The following terms used in this report have the meanings set out below:

Glossary of Technical Terms	
Abbreviation	**Description**
1P	Proved reserves
2C	Best estimate currently available for contingent resource
2P	Proved and probable reserves
3P	Proved, probable and possible reserves
Appraisal well	Well drilled to determine the size of an oil or gas discovery
ATP	Authority to prospect
Availability	The time a generation plant was available for use, after deducting planned and unplanned outage hours, compared with the total time under review
Base load plant	A generator which is typically operated at high levels of capacity utilisation to meet base electricity requirements
Cap	A contract that places a ceiling on the effective price the buyer will pay for electricity in the future
Capacity factor	A generation plant's output over a period compared with the expected maximum output from the plant in that period based on 100% availability at the manufacturer's operating specifications
CCGT	Closed cycle gas turbine
Churn	Mass market energy customers switching suppliers
Cogeneration	Producing two or more forms of energy from one fuel source.
Condensate	A light oil that separates during gas production processes due to changes in pressure and temperature
Contingent resources	Those quantities estimated to be potentially recoverable but not yet considered mature enough for commercial development
CSG	Coal seam gas
DA	Designated authority
Development well	A well drilled to enable production from a known oil or gas reservoir
Electricity measures	▪ Watt (W) - a measure of power when one ampere of current flows under one volt of pressure ▪ Kilowatt (kW) - one kW = 1,000 watts ▪ Megawatt (MW) - one MW = 1,000 kW or one million watts ▪ Gigawatt (GW) – one GW = 1,000 MW or one million kilowatts ▪ Terawatt (TW) – one TW = 1,000 GW or one million megawatts ▪ Kilowatt Hour (kWh) - standard unit of electrical energy representing consumption of one kilowatt over one hour ▪ Megawatt hour (MWh) – one MWh = 1,000 kilowatt hours or one million watt hours ▪ Gigawatt hour (GWh) - one GWh = 1,000 megawatt hours or one million kilowatt hours ▪ Terawatt hour (TWh) - one TWh = 1,000 gigawatt hours or one million megawatt hours
Exploration well	A well drilled to identify a new reservoir of oil or gas
Farm in	An agreement whereby a party acquires an interest in a permit by either fully or partially funding an agreed work program for the permit
Full retail contestability	Where homes and businesses are able to choose their own energy supplier
Gas measures	▪ Joule – primary measure of energy in the metric system ▪ Gigajoule (GJ) – a gigajoule equals one billion joules ▪ Terajoule (TJ) – a terajoule is equal to 1,000 gigajoules ▪ Petajoule (PJ) – a petajoule is equal to one million gigajoules ▪ Petajoules equivalent (PJe) – an energy measurement representing the equivalent energy in different products so the amount of energy contained in those products can be compared
Geothermal	Energy that is generated by converting hot water or steam from deep beneath the earth's surface into electricity
Greenfields exploration	Where Origin Energy holds exploration rights, but does not have a substantial producing interest

Glossary of Technical Terms	
Abbreviation	**Description**
Hedge contract	A financial instrument to manage the risk created by price volatility for a commodity (such as electricity or crude oil) on a spot market. Buyers and sellers of the commodity may enter into long or short term contracts at an agreed price
Hydrocarbons	Oil and gas, including condensate and gas liquids (LPG and ethane)
Hydrocarbon measures:	▪ Boe – barrel of oil equivalent ▪ Bbls – barrels = an international measure of oil production. 1 barrel = approx 159 litres ▪ Bpd – barrels of oil per day ▪ Btu – British thermal unit ▪ Kbbls – Kilo barrels = 1,000 barrels ▪ MMbbls – million barrels ▪ MMboe – million barrels of oil equivalent ▪ MMbpd – million barrels of oil per day ▪ MMBtu – million Btu ▪ Kt – Kilo tonnes = 1,000 tonnes ▪ Mt – Million tonnes ▪ Mtpa – Million tonnes per annum
LNG	Liquefied natural gas
Load factor	A measure of the output of a power plant compared to its maximum capacity
LPG	Liquefied petroleum gas
Md	Millidarcy = a measure of permeability
MDQ	Maximum daily quantity (a measure of peak gas requirements)
OCGT	Open cycle gas turbine
PL	Petroleum lease
Peaking plant	A generator that can be quickly started to operate during periods of high electricity demand and/or high prices in the electricity market
Photovoltaic	Photovoltaic cells convert sunlight into electricity
Prospective resources	Those volumes estimated as potentially recoverable from undiscovered accumulations
REC	Renewable energy certificate
Spot market	A wholesale market for commodities, such as electricity or crude oil, which allows matching of supply against demand
Swap	Agreement to exchange the NEM spot price in the future for an agreed fixed price

The conversion factors used in this report are the same as those adopted by Origin:

Conversion Factors	
Metric	**Description**
Crude oil	= 0.00583 PJ/Kbbls
Condensate	= 0.00541 PJ/Kbbls
LPG	= 0.0493 PJ/Kt
Ethane	= 0.0517 PJ/Kt
CSG	= 1.045 PJ/BCF
LNG	= 1.055 GJ/MMBtu

Appendix 2

Origin Energy Limited - Broker Consensus Forecasts

Origin Energy Limited ("Origin") has not publicly released earnings forecasts for the year ending 30 June 2009 or beyond. However, on 28 August 2008 Origin advised the market that in 2009 it is targeting an increase in underlying earnings per share of at least 10%. Underlying net profit after tax in 2008 was $443 million.

Accordingly, the prospective multiples implied by the valuation of Origin in the Grant Samuel report are based on median broker forecasts. These forecasts are sufficiently close to Origin's 2009 budget and internal projections to be useful for analytical purposes.

Set out below is a summary of forecasts prepared by brokers that follow Origin in the Australian stockmarket:

Origin – Broker Forecasts for the Two Years ending 30 June 2010 ($ millions)

Broker	Date	EBITDAF[1]			EBITF[2]			Net Profit after Tax		
		2008 actual	Forecast Year 1	Forecast Year 2	2008 actual	Forecast Year 1	Forecast Year 2	2008 actual	Forecast Year 1	Forecast Year 2
Broker 1	28 Aug 2008		1,449.6	1,598.9		1,037.6	1,122.9		497.0	537.0
Broker 2	28 Aug 2008		1,540.0	1,940.0		1,145.0	1,477.0		533.0	703.0
Broker 3	28 Aug 2008		1,427.6	1,630.9		1,073.6	1,231.9		487.0	564.0
Broker 4	28 Aug 2008		1,471.8	1,679.5		1,099.6	1,283.2		509.9	613.5
Broker 5	28 Aug 2008		1,485.7	1,842.7		1,092.7	1,356.5		501.5	590.5
Broker 6	29 Aug 2008		1,480.6	1,660.9		1,076.6	1,212.9		497.0	552.0
Broker 7	29 Aug 2008		1,578.1	1,876.6		1,040.6	1,384.0		501.2	677.9
Broker 8	29 Aug 2008		1,521.0	1,856.0		1,108.0	1,364.0		529.0	663.0
Minimum			*1,427.6*	*1,598.9*		*1,037.6*	*1,122.9*		*487.0*	*537.0*
Maximum			*1,578.1*	*1,892.7*		*1,145.0*	*1,477.0*		*533.0*	*703.0*
Median		***1,309.0***	***1,483.2***	***1,761.1***	***964.4***	***1,084.7***	***1,319.9***	***516.7***[3]	***501.4***	***602.0***
Average			*1,494.3*	*1,760.7*		*1,084.2*	*1,304.1*		*507.0*	*612.6*

Source: Brokers' reports, Grant Samuel analysis

When reviewing this data the following should be noted:

- the forecasts presented above represent the latest available broker forecasts for Origin;
- the brokers presented are those who have published research on Origin following the announcement of the result for the year ended 30 June 2008 on 28 August 2008;
- Grant Samuel is aware of four other brokers that follow Origin. The brokers have not released any research on Origin that includes earnings forecasts subsequent to Origin's announcement of its 2008 results on 28 August 2008;
- the broker forecasts are not prepared on a consistent basis, particularly in relation to the treatment of other income and share of net profit after tax from associates. Some brokers show these items separately and some do not. As the implied value of Origin's operating businesses excludes investments and interests in associates separately, other income and net profit after tax from associates should be excluded from the earnings parameters (except for net profit after tax). In the table above, Grant Samuel has attempted to present the broker earnings forecasts on a common basis by, in the four cases where share of net profit after tax from equity accounted associates was not separately presented by the broker, deducting the median share of forecast net profit after tax from associates from the presented EBITDAF and EBITF. As none of the brokers allow for other income, no adjustment has been made to EBITDAF and EBITF for other income; and
- as far as is possible to identify from a review of the brokers' reports, Grant Samuel believes that the earnings forecasts do not incorporate any one-off adjustments or non-recurring items.

---

1 EBITDAF is earnings before net interest, tax, depreciation, amortisation, investment income, significant and non-recurring items and changes in fair value of financial instruments.

2 EBITF is earnings before net interest, tax, investment income, significant and non-recurring items and changes in fair value of financial instruments

3 As reported. Underlying net profit after tax in 2008 was $443.0 million.

Appendix 3

Contact Energy Limited - Broker Consensus Forecasts

Contact Energy Limited ("Contact Energy") has not publicly released earnings forecasts for the year ending 30 June 2009 or beyond. Accordingly, the prospective multiples implied by the valuation of Contact Energy in the Grant Samuel report are based on median broker forecasts. The valuation of Contact Energy has been undertaken on the basis of only publicly available information and therefore Grant Samuel does not know if these forecasts are close to Contact Energy's 2009 budget and internal projections. However, on 26 August 2008 Contact Energy advised the market that in 2009 it does not expect to significantly outperform the result for the year ended 30 June 2008.

Set out below is a summary of forecasts prepared by brokers that follow Contact Energy in the New Zealand stockmarket:

Contact Energy – Broker Forecasts for the Two Years ending 30 June 2010 (NZ$ millions)

Broker	Date	EBITDAF[1]			EBITF[2]			Net Profit after Tax		
		2008 actual	Forecast Year 1	Forecast Year 2	2008 actual	Forecast Year 1	Forecast Year 2	2008 actual	Forecast Year 1	Forecast Year 2
Broker 1	27 Aug 2008		563.0	649.5		407.0	475.5		244.0	292.0
Broker 2	26 Aug 2008		570.0	616.0		410.0	434.0		249.0	259.0
Broker 3	27 Aug 2008		511.0	678.7		421.0	513.7		256.0	320.6
Broker 4	26 Aug 2008		543.9	614.0		384.3	441.3		224.1	244.0
Broker 5	26 Aug 2008		562.2	596.8		403.2	435.2		243.4	263.8
Broker 6	26 Aug 2008		588.5	647.8		420.9	470.8		231.9	267.8
Broker 7	26 Aug 2008		588.4	na		428.0	na		250.2	235.4
Minimum			*511.0*	*596.8*		*384.3*	*434.0*		*224.1*	*235.4*
Maximum			*588.5*	*678.7*		*420.9*	*513.7*		*256.0*	*320.6*
Median		***541.0***	***570.0***	***624.9***	***394.5***	***410.0***	***456.1***	***237.1***	***244.0***	***263.8***
Average			*567.4*	*626.5*		*408.5*	*461.8*		*242.6*	*268.9*

Source: Brokers' reports, Grant Samuel analysis

When reviewing this data the following should be noted:

- the forecasts presented above represent the latest available broker forecasts for Contact Energy;
- the brokers presented are those who have published research on Contact Energy following the announcement of the result for the year ended 30 June 2008 on 26 August 2008;
- the broker forecasts are not prepared on a consistent basis, particularly in relation to the treatment of other income, share of net profit after tax from associates and significant and non-recurring items. Some brokers show these items separately and some do not. As the implied value of Contact Energy's operating businesses excludes investments and interests in associates separately, other income and net profit after tax from associates should be excluded from the earnings parameters (except for net profit after tax). In the table above, Grant Samuel has attempted to present the broker earnings forecasts on a common basis by making the following adjustments based on analysing historical experience:
  - exclude an amount of NZ$15.0 million other income from revenue and EBITF; and
  - exclude an amount of NZ$3.0 million share of net profit of associates from EBITF; and
- as far as is possible to identify from a review of the brokers' reports, Grant Samuel believes that the earnings forecasts do not incorporate any one-off adjustments or non-recurring items.

[1] EBITDAF is earnings before net interest, tax, depreciation, amortisation, investment income, significant and non-recurring items and changes in fair value of financial instruments.

[2] EBITF is earnings before net interest, tax, investment income, significant and non-recurring items and changes in fair value of financial instruments

Appendix 4

Selection of Discount Rates

1 Overview

The following discount rates have been selected by Grant Samuel to apply to the forecast nominal ungeared after tax cash flows of the major business segments of Origin Energy Limited ("Origin"):

- energy fuel (i.e. Exploration & Production) 9.5-10.5%
- energy conversion and marketing (i.e. Generation and Retail) 9.0-10.0%

Different discount rates have been selected for each business segments because they have differing risk profiles.

Selection of the appropriate discount rate to apply to the forecast cash flows of any business enterprise is fundamentally a matter of judgement. The valuation of an asset or business involves judgements about the discount rates that may be utilised by potential acquirers of that asset. There is a body of theory which can be used to support that judgement. However, a mechanistic application of formulae derived from that theory can obscure the reality that there is no "correct" discount rate. Despite the growing acceptance and application of various theoretical models, it is Grant Samuel's experience that many companies rely on less sophisticated approaches. Many businesses use relatively arbitrary "hurdle rates" which do not vary significantly from investment to investment or change significantly over time despite interest rate movements. Valuation is an estimate of what real world buyers and sellers of assets would pay and must therefore reflect criteria that will be applied in practice even if they are not theoretically correct. Grant Samuel considers the rates adopted to be reasonable discount rates that acquirers would use irrespective of the outcome or shortcomings of applying any particular theoretical model.

The discount rate that Grant Samuel has adopted is reasonable relative to the rates derived from theoretical models. The discount rate represents an estimate of the weighted average cost of capital ("WACC") appropriate for these assets. Grant Samuel has calculated a WACC based on a weighted average of the cost of equity and the cost of debt. This is the relevant rate to apply to ungeared cash flows. There are three main elements to the determination of an appropriate WACC. These are:

- cost of equity;
- cost of debt; and
- debt/equity mix.

WACC is a commonly used basis but it should be recognised that it has shortcomings in that it:

- represents a simplification of what are usually much more complex financial structures; and
- assumes a constant degree of leverage which is seldom correct.

The cost of equity has principally been derived from application of the Capital Asset Pricing Model ("CAPM") methodology. The CAPM is probably the most widely accepted and used methodology for determining the cost of equity capital. There are more sophisticated multivariate models which utilise additional risk factors but these models have not achieved any significant degree of usage or acceptance in practice. However, while the theory underlying the CAPM is rigorous the practical application is subject to shortcomings and limitations and the results of applying the CAPM model should only be regarded as providing a general guide. There is a tendency to regard the rates calculated using CAPM as inviolate. To do so is to misunderstand the limitations of the model.

For example:

- the CAPM theory is based on expectations but uses historical data as a proxy. The future is not necessarily the same as the past;
- the measurement of historical data such as risk premia and beta factors is subject to very high levels of statistical error. Measurements vary widely depending on factors such as source, time period and sampling frequency;

- the measurement of beta is often based on comparisons with other companies. None of these companies is likely to be directly comparable to the entity for which the discount rate is being calculated and may operate in widely varying markets;
- parameters such as the debt/equity ratio and risk premium are based on subjective judgements; and
- there is not unanimous agreement as to how the model should adjust for factors such as taxation. The CAPM was developed in the context of a "classical" tax system. Australia's system of dividend imputation has a significant impact on the measurement of net returns to investors.

The cost of debt has been determined by reference to the pricing implied by the debt markets in Australia. The cost of debt represents an estimate of the expected future returns required by debt providers. In determining the appropriate cost of debt over this forecast period, regard was had to debt ratings of comparable companies.

Selection of an appropriate debt/equity mix is a matter of judgement. The debt/equity mix represents an appropriate level of gearing, stated in market value terms, for the business over the forecast period. The relevant proportions of debt and equity have been determined having regard to the financial gearing of the industry in general and comparable companies, and judgements as to the appropriate level of gearing considering the nature and quality of the cash flow stream.

The following sections set out the basis for Grant Samuel's determination of the discount rates for Origin's businesses and the factors which limit the accuracy and reliability of the estimates.

2 Definition and Limitations of the CAPM and WACC

The CAPM provides a theoretical basis for determining a discount rate that reflects the returns required by diversified investors in equities. The rate of return required by equity investors represents the cost of equity of a company and is therefore the relevant measure for estimating a company's weighted average cost of capital. CAPM is based on the assumption that investors require a premium for investing in equities rather than in risk free investments (such as government bonds). The premium is commonly known as the market risk premium and notionally represents the premium required to compensate for investment in the equity market in general.

The risks relating to a company or business may be divided into specific risks and systematic risks. Specific risks are risks that are specific to a particular company or business and are unrelated to movements in equity markets generally. While specific risks will result in actual returns varying from expected returns, it is assumed that diversified investors require no additional returns to compensate for specific risk, because the net effect of specific risks across a diversified portfolio will, on average, be zero. Portfolio investors can diversify away all specific risk.

However, investors cannot diversify away the systematic risk of a particular investment or business operation. Systematic risk is the risk that the return from an investment or business operation will vary with the market return in general. If the return on an investment was expected to be completely correlated with the return from the market in general, then the return required on the investment would be equal to the return required from the market in general (i.e. the risk free rate plus the market risk premium).

Systematic risk is affected by the following factors:

- financial leverage: additional debt will increase the impact of changes in returns on underlying assets and therefore increase systematic risk;
- cyclicality of revenue: projects and companies with cyclical revenues will generally be subject to greater systematic risk than those with non-cyclical revenues; and
- operating leverage: projects and companies with greater proportions of fixed costs in their cost structure will generally be subject to more systematic risk than those with lesser proportions of fixed costs.

CAPM postulates that the return required on an investment or asset can be estimated by applying to the market risk premium a measure of systematic risk described as the beta factor. The beta for an

investment reflects the covariance of the return from that investment with the return from the market as a whole. Covariance is a measure of relative volatility and correlation. The beta of an investment represents its systematic risk only. It is not a measure of the total risk of a particular investment. An investment with a beta of more than one is riskier than the market and an investment with a beta of less than one is less risky. The discount rate appropriate for an investment which involves zero systematic risk would be equal to the risk free rate.

The formula for deriving the cost of equity using CAPM is as follows:

$$Re = Rf + Beta\ (Rm - Rf)$$

where:

Re	=	the cost of equity capital;
Rf	=	the risk free rate;
Beta	=	the beta factor;
Rm	=	the expected market return; and
Rm - Rf	=	the market risk premium.

The beta for a company or business operation is normally estimated by observing the historical relationship between returns from the company or comparable companies and returns from the market in general. The market risk premium is estimated by reference to the actual long run premium earned on equity investments by comparison with the return on risk free investments.
The formula conventionally used to calculate a WACC under a classical tax system is as follows:

$$WACC = (Re \times E/V) + (Rd \times (1-t) \times D/V)$$

where:

E/V	=	the proportion of equity to total value (where V = D + E);
D/V	=	the proportion of debt to total value;
Re	=	the cost of equity capital;
Rd	=	the cost of debt capital; and
t	=	the corporate tax rate.

The models, while simple, are based on a sophisticated and rigorous theoretical analysis. Nevertheless, application of the theory is not straightforward and the discount rate calculated should be treated as no more than a general guide. The reliability of any estimate derived from the model is limited. Some of the issues are discussed below:

- **Risk Free Rate**

  Theoretically, the risk free rate used should be an estimate of the risk free rate in each future period (i.e. the one year spot rate in that year if annual cash flows are used). There is no official "risk free" rate but rates on government securities are typically used as an acceptable substitute. More importantly, forecast rates for each future period are not readily available. In practice, the long term Commonwealth Government Bond rate is used as a substitute in Australia and medium to long term Treasury Bond rates are used in the United States. It should be recognised that the yield to maturity of a long term bond is only an average rate and where the yield curve is strongly positive (i.e. longer term rates are significantly above short term rates) the adoption of a single long term bond rate has the effect of reducing the net present value where the major positive cash flows are in the initial years. The long term bond rate is therefore only an approximation.

  The ten year bond rate is a widely used and accepted benchmark for the risk free rate. Where the forecast period exceeds ten years, an issue arises as to the appropriate bond to use. While longer term bond rates are available, the ten year bond market is the deepest long term bond market in Australia and is a widely used and recognised benchmark. There is a very limited market for bonds of more than ten years. In the United States, there are deeper markets for longer term bonds. The 30 year bond rate is a widely used benchmark. However, long term rates accentuate the distortions of the yield curve on cash flows in early years. In any event, a single long term bond rate matching

the term of the cash flows is no more theoretically correct than using a ten year rate. More importantly, the ten year rate is the standard benchmark used in practice.
Where cash flows are less than ten years in duration the opposite issue arises. An argument could be made that shorter term, and therefore lower, bond rates should be used in determining the discount rate for there assets. While Grant Samuel believes this is a legitimate argument, an adjustment may give a misleading impression of precision for the whole methodology. In any event, the impact on valuation would usually be trivial.

In practice, Grant Samuel believes acquirers would use a common rate. The ten year bond rate can be regarded as an acceptable standard risk free rate for medium to long term cash flows, particularly given its wide use.

- **Market Risk Premium**

The market risk premium *(Rm - Rf)* represents the "extra" return that investors require to invest in equity securities as a whole over risk free investments. This is an "ex-ante" concept. It is the expected premium and as such it is not an observable phenomenon. The historical premium is therefore used as a proxy measure. The premium earned historically by equity investments is calculated over a time period of many years, typically at least 30 years. This long time frame is used on the basis that short term numbers are highly volatile and that a long term average return would be a fair indication of what most investors would expect to earn in the future from an investment in equities with a 5-10 year time frame.

In the United States it is generally believed that the premium is in the range of 5-6% but there are widely varying assessments (from 3% to 9%). Australian studies have been more limited but indicate that the long run average premium has been in the order of 6% using a geometric average (and is in the order of 8% using an arithmetic average) measured over more than 100 years of data[1]. Even an estimate based over a very long period such as 100 years is subject to significant statistical error. Given the volatility of equity market returns it is only possible to state that the "true" figure lies within a range of approximately 2-10% at a 95% confidence level (using the geometric average).

In addition, the market risk premium is not constant and changes over time. At various stages of the market cycle investors perceive that equities are more risky than at other times and will increase or decrease their expected premium. Indeed, until recently, arguments were being put that the risk premium is now lower than it has been historically. This view is reflected in the 2005 update of the Officer Study[2] which indicates that (based on the addition of 17 years of data to 2004) the long term arithmetic average has declined to 7.17% from 7.94%. However, volatility in equities markets since mid 2007 may impact the observed trend.

In the absence of controls over capital flows, differences in taxation and other regulatory and institutional differences, it is reasonable to assume that the market risk premium should be approximately equal across markets which exhibit similar risk characteristics after adjusting for the effects of expected inflation differentials. Accordingly, it is reasonable to assume similar market risk premiums for first world countries enjoying political economic stability, such as Australia, New Zealand, the United States, Japan, the United Kingdom and various western European countries.

In practice, market risk premiums of 5-7% are typically adopted in Australia.

- **Beta Factor**

The beta factor is a measure of the expected covariance (i.e. volatility and correlation of returns) between the return on an investment and the return from the market as a whole. The expected beta factor cannot be observed. The conventional practice is to calculate an historical beta from past share price data and use it as a proxy for the future but it must be recognised that the expected beta

---

1 See, for example, R.R. Officer in Ball, R., Brown, P., Finn, F. J. & Officer, R. R., "Share Market and Portfolio Theory: Readings and Australian Evidence" (second edition), University of Queensland Press, 1989 ("Officer Study") which was based on data for the period 1883 to 1987 and therefore was undertaken prior to the introduction of dividend imputation in Australia.

2 Gray, S. and Officer, R.R., "A Review of the Market Risk Premium and Commentary on Two Recent Papers: A Report prepared for the Energy Networks Association", August 2005.

is not necessarily the same as the historical beta. A company's relative risk does change over time.

The appropriate beta is the beta of the company being acquired rather than the beta of the acquirer (which may be in a different business with different risks). Betas for the particular subject company may be utilised. However, it is also appropriate (and may be necessary if the investment is not listed) to utilise betas for comparable companies and sector averages (particularly as those may be more reliable).

However, there are very significant measurement issues with betas which mean that only limited reliance can be placed on such statistics. Even measurement of historical betas is subject to considerable variation. There is no "correct" beta. For example:

- over the three years prior to BG Group's initial approach Origin's beta as measured by the Australian Graduate School of Management ("AGSM") has varied generally between 0.04 and 0.55 and in March 2008 was measured at 0.38; and
- the standard error of the AGSM's estimate of Origin's beta has generally been in the order of 0.2 to 0.3 meaning that for a beta of, say, 0.50 there is only a 67% confidence level that it falls somewhere in a range of roughly 0.20 to 0.80.

- **Debt/Equity Mix**

The tax deductibility of the cost of debt means that the higher the proportion of debt the lower the WACC, although this would be offset, at least in part, by an increase in the beta factor as leverage increases.

The debt/equity mix assumed in calculating the discount rate should be consistent with the level implicit in the measurement of the beta factor. Typically, the debt/equity mix changes over time and there is significant diversity in the levels of leverage across companies in a sector. There is a tendency to calculate leverage at a point in time whereas the leverage should represent the average over the period the beta was measured. This can be difficult to assess with a meaningful degree of accuracy.

The measured beta factors for listed companies are "equity" betas and reflect the financial leverage of the individual companies. It is possible to unleverage beta factors to derive asset betas and releverage betas to reflect a more appropriate or comparable financial structure. In Grant Samuel's view this technique is subject to considerable estimation error. Deleveraging and releveraging betas exacerbates the estimation errors in the original beta calculation and gives a misleading impression as to the precision of the methodology. Deleveraging and releveraging is also incorrectly calculated based on debt levels at a single point in time.

In addition, the actual debt and equity structures of most companies are typically relatively complex. It is necessary to simplify this for practical purposes in this kind of analysis.

Finally, it should be noted that, for this purpose, the relevant measure of the debt/equity mix is based on market values not book values.

- **Specific Risk**

The WACC is designed to be applied to "expected cash flows" which are effectively a weighted average of the likely scenarios. To the extent that a business is perceived as being particularly risky, this specific risk should be dealt with by adjusting the cash flow scenarios. This avoids the need to make arbitrary adjustments to the discount rate which can dramatically affect estimated values, particularly when the cash flows are of extended duration or much of the business value reflects future growth in cash flows. In addition, risk adjusting the cash flows requires a more disciplined analysis of the risks that the valuer is trying to reflect in the valuation.

However, it is also common in practice to allow for certain classes of specific risk (particularly sovereign and other country specific risks) in a different way by adjusting the discount rate applied to forecast cash flows.

3 Calculation of WACC

3.1 Cost of Equity Capital

The cost of equity capital has been estimated by reference to the CAPM. Grant Samuel has adopted the following cost of capital of for each of the business segments:

- energy fuel 11.2-11.8%
- energy conversion and marketing 10.6-11.2%

The assumptions, judgements and estimates upon which the costs of equity were based are as follows:

- **Risk-Free Rate**

  Grant Samuel has adopted a risk free rate of 5.8%. The risk free rate approximates the current yield to maturity on ten year Australian Government bonds. The forecast period for the cash flow models exceed ten years. However, ten year bonds are the accepted market benchmark and is typically used as a proxy for the long term risk free rate even where the forecast period exceeds ten years.

- **Market Risk Premium**

  Grant Samuel has consistently adopted a market risk premium of 6.0% for Australia and believes that, particularly in view of the general uncertainty, this continues to be a reasonable estimate. It is:

  - not statistically significantly different to the premium suggested by the historical data;
  - similar to that used by a wide variety of analysts and practitioners (typically in the range 5-7%); and
  - the same as that adopted by most regulatory authorities in Australia.

  Some research analysts and other valuers may use even lower premiums. Overall, Grant Samuel believes 6.0% to be a reasonable, if not conservative, estimate.

- **Beta Factor**

  Grant Samuel has adopted the following beta factors for the purposes of this report:

  - energy fuel 0.9-1.0
  - energy conversion and marketing 0.8-0.9

  Grant Samuel has considered the beta factors for a wide range of energy entities in determining an appropriate beta for each business segment. The betas have been calculated on two bases, relative to the entity's local index and relative to the Morgan Stanley Capital International Developed World Index ("MSCI"), an international equities market index that is widely used as a proxy for the global stockmarket as a whole.

  Energy Fuel

  Grant Samuel has adopted beta factors for the purposes of valuing Origin's upstream assets of 0.9-1.0.

  In Grant Samuel's view betas estimated by reference to the MSCI are generally more relevant than those estimated relative to home indices, because they represent a better measure of the systematic risk added to the portfolio of a diversified international investor as the result of investing in the resources sector.

  Grant Samuel has also considered betas estimated on the basis of share market data over various periods of time. Betas are, conceptually, estimates of the expected systematic risk added to a diversified portfolio by an investment (although they are estimated by reference to historical share market data). Estimates based on historical data do not necessarily reflect investor expectations.

A summary of betas for selected comparable listed Australian upstream energy companies is set out in the table below:

Equity Beta Factors for Selected Listed Australian Upstream Energy Companies

Company	Market Capital-isation[3] (millions)	Monthly Observations over 4 years			Weekly Observations over 2 years	
		AGSM[4]	Bloomberg[5]		Bloomberg	
			Local Index	MSCI[6]	Local Index	MSCI
Origin	**A$9,340.5**	**0.38**	**0.59**	**0.51**	**0.72**	**0.50**
Coal Seam Gas						
Queensland Gas Company	A$3,050	1.23	1.11	1.45	1.30	1.03
Arrow Energy	A$2,086	2.48	1.79	1.75	1.47	1.12
Eastern Star Gas	A$428	1.61	1.58	2.13	1.35	1.28
Molopo	A$228	2.06	1.48	1.97	1.06	0.96
Sydney Gas	A$137	1.28	1.16	1.32	1.08	0.96
Metgasco[7]	A$110	na[8]	na	na	1.54	1.53
Conventional Oil & Gas						
Woodside Petroleum	A$38,860	1.00	1.13	1.00	0.99	0.82
Santos	A$10,572	0.92	1.04	0.93	1.11	0.92
Oil Search	A$4,788	0.85	0.96	0.77	0.99	0.71
Australian Worldwide Exploration	A$1,403	0.41	0.68	0.48	1.05	0.89
Beach Petroleum	A$943	1.35	1.27	1.25	1.03	0.77
Nexus Energy	A$768	1.91	1.67	1.78	1.21	0.99
Karoon Gas	A$648	2.13	1.78	1.60	0.98	0.96
New Zealand Oil & Gas	A$479	-0.04	0.81	0.42	0.65	0.42

Source: AGSM, Bloomberg, IRESS

The beta estimates suggests that pure play Australian coal seam gas companies generally have betas of over 1.0 (indicating more systematic riskiness than the overall market). Whilst a number of the Australian conventional oil and gas companies have betas of greater than 1, the large companies such as Oil Search Limited, Santos Limited and Woodside Petroleum Limited have betas of closer to, or less than, 1.

In Grant Samuel's view, it is not clear that beta calculations based on share market data for the last four years provide reliable estimates of expected systematic riskiness. Over the last four years resource companies (including oil and gas companies) have generally significantly outperformed broader measures of equity market performance. This is largely the result of a substantial increase in prices in commodities (which is largely the result of the increasing impact of growing Chinese and other developing nation demand for commodities), supply shortages, significantly increased production costs and other factors. While there is little market consensus about likely long run future commodity prices, there has been a dramatic change in expectations of long run prices relative to those that prevailed (say) five years ago. In effect, there has been a shift in the market's view on the value of commodity and resource

3 Based on share prices as at 5 September 2008 except for Origin and Contact Energy which are based on share prices as at 29 April 2008 (the day prior to the announcement of the BG Group approach).

4 Beta factors are calculated by AGSM up to 30 June 2008, with the exception of Origin which is calculated up to 31 March 2008. Betas are measured over a period of 48 months using ordinary least squares regression or the Scholes-Williams technique where the stock is thinly traded.

5 Bloomberg's betas have been calculated up to 5 September 2008, with the exception of Origin and Contact Energy which are calculated up to 29 April 2008. Grant Samuel understands that betas estimated by Bloomberg are not calculated strictly in conformity with accepted theoretical approaches to the estimation of betas (i.e. they are based on regressing total returns rather than the excess return over the risk free rate). However, in Grant Samuel's view the Bloomberg beta estimates can still provide a useful insight into the systematic risks associated with companies and industries. The figures used are the Bloomberg "adjusted" betas.

6 MSCI is calculated using local currency so that there is no impact of currency changes in the performance of the index.

7 Metgasco was listed on 23 December 2004 and, accordingly, there is insufficient data to be able to calculate four year betas.

8 na = not available

companies. In the context of an overall risk in stock market value, the outperformance of resource companies (including oil and gas companies) results in the calculation of betas of over 1.

In Grant Samuel's view this is potentially misleading. To the extent that the outperformance of the resources sector (and the consequent high beta measurements) reflects a one-off (although gradual) paradigm shift, the calculated betas may reflect a specific risk factor rather than systematic risk. This view is supported by the recent performance of many major resource stocks, which have generally performed relatively strongly in the context of significant declines in overall markets. Prima facie, this relative performance (with resource stocks declining by less than the overall market) suggests betas of less than 1.

Moreover, the strong share price performance of major resource companies is not obviously consistent with high beta values and high discount rates. To the contrary, it would appear more likely that, at least implicitly, resource sector investors have factored in lower discount rates (implying lower betas) in their valuations of resource sector stocks.

In Grant Samuel's view, it is reasonable to adopt betas in the range 0.9-1.0 for Origin's energy fuel businesses. This range better reflects beta estimates over a longer period than the last four years and appears broadly consistent with the views of market participants.

Energy Conversion and Marketing

A summary of betas for selected comparable listed energy retail and generation entities is set out in the table below:

Equity Beta Factors for Selected Listed Energy Retail and Generation Entities

Entity	Market Capital-isation[3] (millions)	Monthly Observations over 4 years			Weekly Observations over 2 years	
		AGSM[4]	Bloomberg[5]		Bloomberg	
			Local Index	MSCI[6]	Local Index	MSCI
Origin	**A$9,340.5**	**0.38**	**0.59**	**0.51**	**0.72**	**0.50**
AGL Energy	A$6,486.3	na[8]	na	na	na	na
BBW	A$1,072.7	na	na	na	1.01	0.86
Energy Developments	A$444.1	0.84	0.72	0.68	0.72	0.67
TSI Fund	A$369.4	na	na	na	na	na
BBP	A$112.6	na	na	na	na	na
Viridis	A$134.7	na	na	na	0.62	0.55
Contact Energy	NZ$5,410.4	na	0.90	0.66	0.99	0.55
TrustPower	NZ$2,494.4	na	0.99	1.07	1.04	0.68

Source: AGSM, Bloomberg, IRESS

The evidence is limited but suggests moderate betas (in the range of 0.7 to 1.0) are appropriate for energy retail and generation entities. However, considerable caution is warranted in selecting a beta for Origin's retail and generation businesses:

- many of the entities involved in energy retail and generation are relatively recently listed (four within the last three years) and, accordingly, there is insufficient data to be able to calculate four year betas. Furthermore, AGL Energy and BBP were effectively listed in late 2006 and TSI Fund was listed in mid 2007. Consequently there are insufficient data points to calculate reliable betas for those entities. Nevertheless, their local index betas since listing are 0.64, 1.41 and 0.93 respectively;
- individual entity betas (for the same source/period) fall in a relatively wide range. For example, Bloomberg Two Year Local Index betas generally range from 0.62 (Viridis) to 1.04 (TrustPower);
- all of the data is subject to significant statistical error. For example, Origin's AGSM beta has a standard error of 0.24 (i.e. even at a 68% confidence level it lies somewhere between 0.14 and 0.62) and Energy Developments has a standard error of 0.35;

- for some entities there is a substantial difference between the beta measured by AGSM and the beta measured by using Bloomberg (Energy Developments). There are also variations depending on the index used (Local or MSCI); and
- BBP, BBW, TSI Fund, Energy Developments and Viridis are primarily energy conversion businesses with limited or no energy marketing operations. Similar to Origin, AGL Energy, Contact Energy and TrustPower are integrated energy conversion and marketing businesses. However, Contact Energy and TrustPower operate in New Zealand where electricity prices are relatively volatile.

Similar to Origin, BG Group is an integrated energy company (including exploration and production, LNG production, transmission and distribution and power generation activities) with a focus on natural gas. BG Group's Bloomberg Two and Four Year Local Index betas are 1.0 and 0.9 respectively.

Origin's energy conversion and marketing businesses are highly integrated, which creates a natural hedge against volatile electricity prices and additional electricity requirements purchased from the National Electricity Market are typically hedged. As a result, cash flows derived by its conversion and distribution businesses are not subject to significant cash flow volatility.

Having regard to the factors above, Grant Samuel has selected beta factors in the range 0.8-0.9 for Origin's energy creation and marketing businesses.

- **Cost of equity capital**

Using the CAPM formula and the estimates set out above, the cost of equity capital for each of the business segments can be calculated as follows:

Cost of Equity Capital Calculations

Business Segment	Low		High	
Formula	***Re***	***= Rf + Beta (Rm-Rf)***	***Re***	***= Rf + Beta (Rm-Rf)***
Energy Fuel	=	*5.8% + (0.9 x 6%)*	=	*5.8% + (1.0 x 6%)*
	=	*11.2%*	=	*11.8%*
Energy Conversion and Marketing	=	*5.8% + (0.8 x 6%)*	=	*5.8% + (0.9 x 6%)*
	=	*10.6%*	=	*11.2%*

3.2 Cost of Debt

A cost of debt of 7.4% has been adopted. These figures represent the expected future cost of borrowing over the duration of the cash flow model. Grant Samuel believes that this would be a reasonable estimate of an average interest rate, including margin, that would match the duration of the cash flows assuming that the operations were funded with a mixture of short term and long term debt. The costs of debt represent a margin of 1.6% over the risk free rate which allows for the margin over bank rates that Origin would expect to pay together with an allowance for the difference between bank rates and government bonds.

3.3 Debt/Equity Mix

The selection of the appropriate debt/equity ratio involves perhaps the most subjectivity of discount rate selection analysis. In determining an appropriate debt/equity mix, regard was had to gearing levels of selected comparable listed Australian entities and the nature and quality of the cash flow stream of the relevant businesses.

Gearing levels for selected listed entities in the Australian and New Zealand energy sectors over the past four years are set out below:

Gearing Levels for Selected Listed Energy Entities[9]						
	Net Debt/(Net Debt + Market Capitalisation)					
Entity	Financial Year Ended				Current[10]	4 Year Average
	2005	2006	2007	2008		
Origin	**31.3%**	**29.2%**	**25.3%**	**20.3%[11]**	**30.4%**	**26.5%**
Coal Seam Gas						
Queensland Gas Company	(19.5%)	10.3%	(13.5%)	(18.9%)	(30.0%)	(10.4%)
Arrow Energy	1.4%	(18.4%)	1.3%	2.2%	(2.5%)	(3.4%)
Eastern Star Gas	6.7%	(30.5%)	(0.8%)	(7.9%)	(10.7%)	(8.1%)
Molopo	(24.6%)	(24.6%)	(11.1%)	(6.1%)	(10.5%)	(16.6%)
Sydney Gas	18.8%	(15.1%)	(0.9%)	(4.9%)	(5.8%)	(0.5%)
Metgasco	(26.9%)	(6.9%)	(13.0%)	(8.2%)	(11.8%)	(13.7%)
Median	*(9.1%)*	*(16.8%)*	*(6.0%)*	*(7.0%)*	*(10.6%)*	*(9.3%)*
Minimum	*(26.9%)*	*(30.5%)*	*(13.5%)*	*(18.9%)*	*(30.0%)*	*(16.6%)*
Maximum	*18.8%*	*10.3%*	*1.3%*	*2.2%*	*(2.5%)*	*(0.5%)*
Conventional Oil & Gas						
Woodside Petroleum	2.2%	5.2%	4.0%	3.8%	4.1%	3.8%
Santos	16.2%	17.4%	16.6%	12.3%	15.4%	15.6%
Oil Search	(2.4%)	(18.7%)	(13.9%)	(5.8%)	(9.5%)	(10.2%)
Australian Worldwide Exploration	(2.6%)	(2.5%)	2.7%	(22.1%)	(27.4%)	(6.1%)
Beach Petroleum	(18.6%)	(3.9%)	14.9%	(11.5%)	(20.1%)	(4.8%)
Nexus Energy	(16.6%)	(18.1%)	(0.5%)	(0.4%)	(0.6%)	(8.9%)
Karoon Gas	(15.7%)	(15.4%)	(39.0%)	(61.5%)	(54.4%)	(32.9%)
New Zealand Oil & Gas	(33.1%)	(12.4%)	6.8%	(39.6%)	(48.1%)	(19.6%)
Median	*(9.1%)*	*(8.2%)*	*3.3%*	*(8.7%)*	*(14.8%)*	*(7.5%)*
Minimum	*(33.1%)*	*(18.7%)*	*(39.0%)*	*(61.5%)*	*(54.4%)*	*(32.9%)*
Maximum	*16.2%*	*17.4%*	*16.6%*	*12.3%*	*15.4%*	*15.6%*
Retail and Generation						
AGL Energy	na	na	24.8%	24.3%	23.8%	na
BBW	na	29.3%	40.6%	69.9%	74.3%	na
Energy Developments	21.9%	29.0%	34.6%	52.1%	48.0%	34.4%
TSI Fund	na	na	39.6%	69.5%	66.0%	na
BBP	na	na	49.5%	88.8%	96.3%	na
Viridis	na	137.7%	160.5%	67.6%	65.2%	na
Contact Energy	19.4%	13.3%	9.3%	16.0%	14.0%	14.5%
TrustPower	16.0%	13.7%	14.9%	18.3%	20.3%	15.7%
Median	*19.4%*	*29.0%*	*37.1%*	*59.9%*	*56.6%*	*15.7%*
Minimum	*16.0%*	*13.3%*	*9.3%*	*16.0%*	*14.0%*	*14.5%*
Maximum	*21.9%*	*137.7%*	*160.5%*	*88.8%*	*96.3%*	*34.4%*

Source: Entity Reports, IRESS, Bloomberg

The table shows a wide range of gearing levels. Moreover, these do not always bear any relationship to the betas of the individual companies. In some cases highly geared companies have equity betas towards the lower end of the range (e.g. Viridis). In this case the selection of gearing levels is highly judgemental. Further, the debt levels should actually be the weighted average measured over the same period as the beta factor rather than just at the current point in time.

Energy Fuel

Oil and gas companies either have cash reserves or relatively low gearing. Those companies with significant exploration activities and little if any production usually hold cash to fund those activities. Those companies (such as Santos and Woodside) which have substantial production

9 All of the companies have 30 June year ends except for TrustPower which has a 31 March year end and Woodside Petroleum, Santos and Oil Search which have 31 December year ends. For the companies with 31 December year ends the 30 June data is based on their half yearly reports.

10 Current gearing levels are based on the most recent balance sheet information and on sharemarket prices as at 5 September 2008 except for Origin and Contact Energy which are at 29 April 2008 (the day prior to the announcement of the BG Group approach). For Eastern Star Gas, Molopo, Sydney Gas, Metgasco, Nexus Energy and Karoon Gas, balance sheet information is sourced from the 30 June 2008 production reports.

11 Origin gearing at 30 June 2008 is low relative to historical levels as it reflects sharemarket prices post the BG Offer.

businesses and greater certainty of cash flow do utilise gearing. However, due to the volatility inherent in earnings (being dependent on international pricing), their gearing ratios tend to be less than 20%. As a substantial proportion of Origin's energy fuel operations involve already producing or near to producing assets and sale of that production into its Retail business, Grant Samuel has adopted a gearing ratio in the range of 20-25% for this business.

Energy Conversion and Marketing

Gearing ratios for integrated energy businesses (AGL Energy, Contact Energy and TrustPower) are significantly lower than those for predominantly electricity generators (BBP, BBW, TSI Fund, Energy Developments and Viridis). The gearing of BBP and (to a lesser extent} BBW have increased during 2008 as their market capitalisation have declined due to the implications of the turmoil in the global credit markets for refinancing existing borrowings.

Lower gearing is appropriate for integrated energy businesses, not least because they require a relatively high credit rating for energy trading activities with third parties (electricity derivatives etc). Further, Origin's target book gearing ratio of 40-45% equates to a market gearing ratio of approximately 25-30% based on Origin's share price immediately prior to the announcement of BG Group's initial approach. Having regard to this data, Grant Samuel has adopted a gearing ratio in the range of 20-25% for Origin's energy conversion and marketing businesses.

3.4 WACC

On the basis of the parameters outlined above and assuming a corporate tax rate of 30%, nominal WACC for Origin's business segments are calculated as follows:

WACC Calculations		
Business Segment	**Low**	**High**
Formula	***= (Re x E/V) + (Rd x (1-t) x D/V)***	***= (Re x E/V) + (Rd x (1-t) x D/V)***
Energy Fuel	= (11.2% x 75%) + (7.4% x 0.7 x 25%) = 9.7%	*= (11.8% x 80%) + (7.4% x 0.7 x 20%)* *= 10.5%*
Energy Conversion and Marketing	= (10.6% x 75%) + (7.4% x 0.7 x 25%) = 9.2%	*= (11.2% x 80%) + (7.4% x 0.7 x 20%)* *= 10.0%*

These are after tax discount rates to be applied to nominal ungeared after tax cash flows. However, it must be recognised that this is a very crude calculation based on statistics of limited reliability and involving a multitude of assumptions.

Having regard to these matters and the calculations and data set out above, Grant Samuel has concluded that reasonable discount rates for the purposes of the valuation of Origin are:

- energy fuel 9.5-10.5%
- energy conversion and marketing 9.0-10.0%

4 Dividend Imputation

The conventional WACC formula set out above was formulated under a "classical" tax system. The CAPM model is constructed to derive returns to investors after corporate taxes but before personal taxes. Under a classical tax system, interest expense is deductible to a company but dividends are not. Investors are also taxed on dividends received. Accordingly, there is a benefit to equity investors from increased gearing.

Under Australia's dividend imputation system, domestic equity investors now receive a taxation credit (franking credit) for any tax paid by a company. The franking credit attaches to any dividends paid out by a company and the franking credit offsets personal tax. To the extent the investor can utilise the franking credit to offset personal tax, then the corporate tax is not a real impost. It is best considered as a

withholding tax for personal taxes. It can therefore be argued that the benefit of dividend imputation should be added into any analysis of value.

There is no generally accepted method of allowing for dividend imputation. In fact, there is considerable debate within the academic community as to the appropriate adjustment or even whether any adjustment is required at all. Some suggest that it is appropriate to discount pre tax cash flows, with an increase in the discount rate to "gross up" the market risk premium for the benefit of franking credits that are on average received by shareholders. On this basis, the discount rate might increase by approximately 2% but it would be applied to pre tax cash flows. However, not all of the necessary conditions for this approach exist in practice:

- not all shareholders can use franking credits. In particular, foreign investors gain no benefit from franking credits. If foreign investors are the marginal price setters in the Australian market there should be no adjustment for dividend imputation;
- not all franking credits are distributed to shareholders; and
- capital gains tax operates on a different basis to income tax. Investors with high marginal personal tax rates will prefer cash to be retained and returns to be generated by way of a capital gain.

Other have proposed a different approach involving an adjustment to the tax rate in the discount rate by a factor reflecting the effective use or value of franking credits. If the credits can be used, the tax rate is reduced towards zero. The proponents of this approach have in the past suggested a factor of up to 50% as representing the appropriate adjustment (gamma). Alternatively, the tax charge in the forecast cash flows can be decreased to incorporate the expected value of franking credits distributed.

There is undoubtedly merit in the proposition that dividend imputation affects value. Over time dividend imputation will become factored into the determination of discount rates by corporations and investors. In Grant Samuel's view, however, the evidence gathered to date as to the value the market attributes to franking credits is insufficient to rely on for valuation purposes. More importantly, Grant Samuel does not believe that such adjustments are widely used by acquirers of assets at present. While acquirers are undoubtedly attracted by franking credits there is no clear evidence that they will actually pay extra for them or build it into values based on long term cash flows. The studies that measure the value attributed to franking credits are based on the immediate value of franking credits distributed and do not address the risk and other issues associated with the ability to utilise them over the longer term. Accordingly it is Grant Samuel's opinion that it is not appropriate to make any such adjustments in the valuation methodology. This is a conservative approach.

Appendix 5

DCF Model Assumptions

1 General Assumptions

The following general assumptions have been made in the DCF models developed to value Origin's business operations:

- inflation rate of 3.0% per annum;
- corporate tax rate of 30% for Australian and New Zealand assets. There is no change in taxation legislation that has a material impact on Origin's operations;
- no material changes to working capital from year to year throughout the forecast period; and
- no significant changes in legislation or in the policies or procedures of regulatory bodies.

2 Wholesale Gas Prices

- east coast domestic gas prices (ex well head) used in all cash flow models:

East Coast Domestic Gas Price Estimates ($/GJ real 2008)			
	Year end 30 June		
	2008 to 2010	2011 to 2015	2016 onwards
Gas Price Path A	$3.50	$4.50	$6.50
Gas Price Path B	$3.50	$5.50	$7.50

3 Wholesale Electricity Prices

- wholesale electricity prices are a function of:
  - the long run average nominal after tax return on the least cost generating option for supplying base load power in the market;
  - domestic wholesale gas price assumption plus $0.50 per GJ transportation cost;
  - operating costs based on fixed and variable costs for new CCGT build; and
  - electricity pool price increases equal to inflation.

  On this basis, real electricity prices in the Grant Samuel DCF models increase from around $50 per MWh to around $105 per MWh by 2020.

4 Conventional Oil and Gas Assets

- a discount rate range of 9.5-10.5% has been applied to the nominal after tax cash flows;
- the West Texas Intermediate ("WTI") crude oil price is assumed to decline from around US$103-107 per bbl in 2009 to around US$90-110 per bbl by 2016 (in nominal dollars) and thereafter to increase at the rate of inflation;
- Tapis crude has been assumed to trade at a premium of US$3.50 per bbl to WTI;
- condensates are assumed to trade at parity with WTI;
- LPG is assumed to be 95% of WTI; and
- prices and costs that are denominated in United States dollars and New Zealand dollars have been converted to Australian dollars at forward exchange rates.

The specific operational and asset assumptions for the Cooper Basin, BassGas Project, Otway Gas Project and Kupe Gas Project are set out in Sections 9.5.3-9.5.6 of the report.

5 Downstream Energy Business

5.1 General Assumptions

- a discount rate range of 9.0-10.0% has been applied to the nominal after tax cash flows.

5.2 Generation

- generation plants are assumed to earn revenue based on a long run nominal after tax return on new CCGT build (inclusive of a terminal value and tax shield on depreciation) representing a tolling arrangement between the Retail and Generation businesses, as well as reimbursement of costs incurred (i.e. gas, carbon and operating costs);
- reimbursement of costs incurred is based on an assumed level of costs for new build depending on factors such as fuel efficiency;
- gas fuel cost (except for Darling Downs Power Station) are based on wholesale domestic gas price paths (Section 2 above) plus a transportation cost of $0.50 per GJ;
- for Darling Downs Power Station gas costs are based the contract price and do not include transportation costs as the pipeline is owned by the power station;
- wholesale gas costs, costs of carbon and operating costs are assumed to be passed through in the price of electricity to the Retail business;
- running hours are based on Origin projections of NEM demand and prices;
- terminal values represent the inflation adjusted disposal value for plants calculated as proceeds from the sale at the end of plant life after refurbishment and allowance for asset age (equivalent to 60% of new build cost for OCGT/CCGT plants);
- remaining life of existing plants is 14-19 years;
- life of committed plants is 25-26 years;
- capital expenditure investment based on long term asset plans including remaining upfront capital expenditure as follows: Mortlake Power Station ($617 million in 2009-2011), Darling Downs Power Station ($648 million in 2009-2010), Quarantine expansion ($40 million in 2009) and Mount Stuart expansion ($67 million in 2009-2010) with plant commissioning occurring in the final year of expenditure;
- Darling Downs Power Station cost to build includes pipeline costs;
- maintenance expenditure (e.g. turbine repair and overhaul) required each year or at regular intervals for all generation plants in accordance with long term asset plans; and
- cogeneration plant revenue and costs based on cogeneration arrangement contracts.

5.3 Retail

- revenue for mass market retailing is based on retail tariffs in each state which represent a retailing margin and reimbursement of wholesale energy charges and network costs:
  - retail margins stabilise after price caps are removed in Victoria (January 2009) and South Australia and New South Wales (in 2010);
  - all states converge towards a common margin for electricity or gas by 2018, after which margins are assumed to increase by inflation;
  - wholesale energy charges represent the transfer price from Energy Trading; and
  - network costs to 2012 are based on the long term plan, after which they increase at 2.0% per annum;
- the extent to which higher wholesale electricity cost is passed through to consumers is assumed to be capped at a level based on Origin's historical experience. There is no cap on wholesale gas prices;
- market share in states where Origin has a presence is assumed to be constant. Origin gains a significant presence in New South Wales over the period to 2012 but does not enter Western Australia and Tasmania;
- beyond 2012, churn rates stabilise in all states at 22% for electricity and 17% for natural gas;
- 1% net increase in customer base per annum (after churn and growth);
- a constant energy consumption per customer in each state ranging from of 5.8MWh to 6.8MWh per annum;

- variable costs including costs associated with maintaining customers (e.g. billing, credit), acquiring customers (e.g. sales commissions) and losing customers (e.g. processing and collection) and are a function of customer numbers and inflation. Initial cost levels are consistent with Origin's historical experience;
- fixed costs (including overheads associated with commercial and industrial customers and Energy Trading) increase by inflation. Initial fixed costs are consistent with Origin's historical experience;
- maintenance costs and investment costs escalate at inflation and include:
  - growth capital expenditure for possible large scale overhauls to customer systems of approximately $100 million (real) every 10 years;
  - maintenance capital expenditure of $20 million (real) per annum;
- existing fixed assets and stay in business capital expenditure are depreciated on a straight line basis over five years, while growth capital expenditure is depreciated over ten years;
- per customer working capital requirements are based on Origin's historical experience and increase by inflation; and
- total volumes of electricity and gas for commercial and industrial customers increase by 1% per annum.

5.4 Energy Trading

- captures the difference between expected future wholesale energy prices (i.e. electricity, gas and carbon) or prices of related derivatives and contracted prices for derivatives and long term supply contracts. Wholesale gas and electricity as per Section 2 and 3 above.
- includes existing contracts for their remaining lives and does not capture any value for the trading function beyond the life of the contracts other than for Maximum Daily Quantity contracts and RECs. Existing contracts include:
  - long term electricity cap contracts with varying terms out to more than 10 years;
  - swap book;
  - cap book;
  - long term gas purchase contracts (e.g. Darling Downs Power Station, BassGas Project); and
  - medium and long term existing carbon contracts which extend up to 2020;
- ongoing trading activities related to Maximum Daily Quantity contracts and RECs. Cash flows extend to 2047 and incorporate a terminal value based on a constant growth model, with inflationary growth assumed into perpetuity;
- transfer price to Energy Retailing based on hedged market electricity or gas prices which reflect both "flat" energy charges (for base load requirements) and capacity charges (for peak load requirements):
  - capacity charges for electricity are based on long run average cap prices which are determined by reference to long range average nominal after tax return on new OCGT capacity peaking and increase by inflation;
  - capacity charges for gas are based on Maximum Daily Quantity prices and increase by inflation;
  - electricity costs also include a 10% charge for electricity lost in the system, REC charges and NEM costs; and
  - wholesale gas prices as per Section 2 above plus $0.50 per GJ transportation.

5.5 LPG

- sales volumes and Australian dollar sales prices increase by 6-7% per annum to 2012;
- EBITDA increases by 3% from 2012; and
- capital expenditure and working capital requirements based on long term plan.

Appendix 6

Market Evidence – Coal Seam Gas Transactions

Coal seam gas ("CSG") transactions in Australia since 2003 for which there is sufficient information to prepare meaningful market parameters are summarised below:

Recent Transaction Evidence – Coal Seam Gas

Date	Target	Transaction	Consid-eration[1] (millions)	Years in production	Certified Reserves[2] (PJ)		Reserves Multiple[3] (A$/GJ)	
					2P	3P	2P	3P
Aug 08	Sunshine Gas Limited[4]	Takeover by Queensland Gas Company Limited	813[5]	-	469	1,097	1.73	0.74
Jun 08	Arrow Energy Limited (Arrow CSG tenements)	Acquisition of 30% interest by Shell Exploration Company B.V.	435[6]– 644[7]	4.0	429[8]	938[8]	1.01[9] - 1.50[10]	0.46[9] - 0.69[10]
Jun 08	Roma Petroleum NL	Takeover by Queensland Gas Company Limited	48[11]	na[12]	na[13]	na	na	na
May 08	Santos Limited (Gladstone LNG project)	Acquisition of 40% interest by Petroliam Nasional Berhad	2,114[14] – 2,648[15]	10.0	538	1,600	3.93[9] - 4.92[10]	1.32[9] - 1.65[10]
Feb 08	Queensland Gas Company Limited (Walloons CSG interests)	Acquisition of 20% interest by BG Group plc[16]	415	2.0	263	623	1.58	0.67
Feb 07	Arrow Energy Limited (Arrow CSG tenements)	Farm-in agreement in relation to CSG interests in Queensland and NSW	225	na	na	na	na	na

1 Announced consideration for proportional interest acquired unless otherwise indicated.

2 Represents relevant proportional interest in stated certified reserves acquired as at date of announcement on a legal interests basis unless otherwise indicated.

3 Represents base consideration only divided by stated 2P and 3P reserves unless otherwise indicated.

4 Multiples shown are calculated by dividing the enterprise value (based on net cash of $81 million) by the cash and share consideration using the pre-announcement closing price of QGC shares. Using the QGC share only consideration the multiple would be $1.61 per GJ and $0.69 per GJ respectively for 2P and 3P reserves. The multiples based on an implied equity value using the cash and share consideration would be $1.91 per GJ and $0.82 per GJ for 2P and 3P reserves or $1.79 per GJ and $0.76 per GJ for 2P and 3P reserves using the share only consideration.

5 The implied enterprise value if 100% of the company had been acquired.

6 Base consideration.

7 Base consideration plus conditional payments of $139 million and $70 million.

8 At the time of the announcement of the transaction a 30% interest in Arrow's total stated reserves were was 237PJ of 2P reserves and 837PJ of 3P reserves. However, Arrow confirmed that prior to the announcement Shell had access to its well and reserve data. In July 2008 Arrow announced a significant upgrade to the reserves data shown in the table. The multiples calculated are based on these increased reserves. Using the stated reserves data as at the date of announcement, the transaction implies multiples of A$1.83 per GJ for 2P reserves and A$0.52 per GJ for 3P reserves.

9 Multiples calculated on base consideration only.

10 Multiples calculated on base consideration plus conditional payments.

11 The implied enterprise value if 100% of the company had been acquired.

12 Roma is also an oil producer. Its coal seam gas assets had not yet reached commercial development at the time of the takeover.

13 na = not available

14 Base consideration of US$2,008 million assuming an AUD/USD exchange rate of 0.95.

15 Base consideration of US$2,008 million plus conditional payment of US$500 million payable on FID for a second LNG train assuming an AUD/USD exchange rate of 0.95.

16 This acquisition was part of a broader alliance/joint venture transaction. The multiple shown is calculated based on the acquisition of the 20% interest in the QGC CSG interests only.

Recent Transaction Evidence – Coal Seam Gas								
Date	Target	Transaction	Consid-eration[1] (millions)	Years in production	Certified Reserves[2] (PJ)		Reserves Multiple[3] (A$/GJ)	
					2P	3P	2P	3P
Dec 06	Queensland Gas Company Limited	Acquisition of 27.5% equity interest by AGL Energy Limited	1,178[17]	0.5	932[18]	2,755[19]	1.26	0.43
Jul 06	Arrow Energy Limited	Acquisition of 19.9% equity interest by New Hope Corporation	243	2.0	498	2,778	0.49	0.09
Jun 06	BHP Billiton Limited (Moranbah gas project in Queensland)	50% acquisition by The Australian Gas Light Company	93	2.0	191	na	0.49	na
May 06	CH4 Gas Limited	Takeover by Arrow Energy Limited	145[20]	1.5	191	770	0.76	0.19
Feb 06	Pangaea Oil and Gas Pty Limited (Argyle CSG Project)	40.6% acquisition by Origin Energy Limited	70	-	117	260[21]	0.60	0.27
Sep 05	Arrow Energy Limited (ATP 683P and PL 198 interests of the Tipton West CSG project)	40% acquisition by Beach Petroleum Limited	35	-	50	811	0.71	0.04
Sep 05	Origin Energy Limited (Moura CSG field)	Acquisition by Anglo Coal (Moura) Limited and Mitsui Moura Investment Pty Limited	22	4.0	52	na	0.43	na
Jul 05	Tipperary Corporation (Fairview CSG field)	Takeover by Santos Limited	612[22]	7.0	830[23]	na	0.74	na
Jul 03	Oil Company of Australia Limited	Acquisition by Origin Energy Limited of 11.93% minority interests	549[24]	na	471[25,]	2,548	na[26]	na[26]

Source: Grant Samuel analysis[27]

The most common valuation metric for oil and gas businesses is the transaction value for the assets acquired as a multiple of the stated 2P and 3P reserves. This multiple is calculated based on publicly available information for the relevant asset which may be limited.

These multiples are a relatively imprecise valuation metric as the assets acquired and the transactions themselves may differ in material respects. The following limitations should be noted in relation to the reserves multiples in the context of the valuation of CSG assets:

17 Implied enterprise value if 100% of the company had been acquired.

18 Reserves data for 100% of AGL Energy as at 2 March 2007.

19 Reserves data for 100% of AGL Energy. Note that no increase to 3P reserves was announced on 2 March 2007 at the time increases to 1P and 2P reserves were announced.

20 The implied enterprise value if 100% of the company had been acquired.

21 Represents 3P reserves for ATP 620P only.

22 Enterprise value for Tipperary Corporation.

23 Reserves shown based on Tipperary stated 2P reserves of 787BCF (830PJ) as at 31 December 2004 (for its 75% interest) 830PJ. Joint venture party on the Fairview field Origin's reserves as at June 2004 of 1,009PJ (956BCF).

24 Implied enterprise value if 100% of the company had been acquired.

25 Reserves shown for coal seam gas assets only. Oil Company of Australia Limited also had a further 127PJ of 2P and 277PJ of 3P conventional gas reserves.

26 Multiple not calculated as assets acquired included non CSG assets. However, using the Origin offer price of $4.25 per share and using an average of values calculated by the independent expert for the non CSG assets implies multiples of $0.69 per GJ for 2P reserves and $0.13 per GJ for 3P reserves.

27 Grant Samuel analysis based on data obtained from IRESS, company announcements, transaction documentation and, in the absence of company published financial reports, brokers' reports.

- multiples are calculated on publically available information based on 2P reserves and 3P information as released by the company on or prior to the transaction date. The requirements for 2P certification are stringent (and 3P slightly less so), typically requiring a contract in place with a third party in order to demonstrate the commerciality of reserve. However, the price is not necessarily just reflective of the value of the existing (stated) 2P reserves as would be the case in a conventional gas asset. The buyer will have taken a view that some of the contingent resource will be converted to proven reserves over a longer timeframe. In some cases, the buyers view may have been formed through a non public due diligence process. The calculated multiple therefore may not recognise that the buyer will have put some value on any potential upside in 3P resources and/or additional exploration acreage (e.g. contingent resource). The resource potential of these assets is changing so rapidly (through exploration and drilling) such that on the basis of publicly available information it may be difficult to assess what the buyer is actually assuming the ultimate resource actually will be. Even where the reserves and resources have been recently updated by technical experts prior to the acquisition, an asset owner or potential buyer will not necessarily accept or factor in all that reported resource into its price, for example, if it had a different view on future gas market prices and therefore what resource may become economic at higher prices;
- this imprecision may be accentuated as certain transactions are based on more than just an interest in reserves acquired and the consideration price may structured to include payments for the assets which are contingent on future events (e.g. upgrades in reserves and resources). To the extent that the asset acquisition is part of a package of transactions (for example the Queensland Gas Limited ("QGC")/ AGL Energy Limited ("AGL Energy"), BG Group plc ("BG Group")/QGC deals or access to an LNG project) and some portion of value may not be directly attributed to the CSG assets acquired; and
- using the reserves multiple for valuation of an asset assumes the tenements to be acquired and those subject of the comparable transactions are similar, for example, at the same stage of development, have the same prospectivity for increases in reserves, and have a similar amount of contracted/uncontracted gas available. This is usually not the case.

Transactions in the CSG sector have shown a rapid step change in valuations since mid 2006. Prior to 2006, 2P reserves multiples averaged less than $0.50 per GJ with a number of smaller sized transactions for acquisitions of partial interests in relatively undeveloped assets. In May 2006 the merger of CH4 Limited ("CH4") and Arrow Energy Limited ("Arrow") indicated higher values could be realised in the fragmented CSG market and reflected the growing acceptance of CSG as a mainstream product.

This trend accelerated in late 2006/early 2007 due to a number of factors including growing demand for securing gas and upstream assets and the greater willingness of acquirers to attribute value (typically undisclosed) to 3P reserves. A key strategic imperative for gas and electricity retailers became to improve their internally owned upstream hedges. In addition, a growing expectation by the market that AGL Energy's and Petroliam Nasional Berhad's ("Petronas") Australia-PNG gas pipeline project was only marginally economic and would not proceed was confirmed by AGL Energy in August 2006 which withdrew additional potential gas to market of approximately 550PJ, in a market of tightening supply with declining Cooper Basin reserves. Competing proposals for a cornerstone shareholding in QGC by Santos Limited ("Santos") and AGL Energy and The Trust Company of the West between October 2006 and March 2007 resulted in another step change in reserve multiples to around $1.00 per GJ. The AGL Energy bid included a substantial gas supply offtake agreement which together with the ability of the QGC management to retain management control were factors in contributing to the AGL Energy offer being recommended by the QGC board.

By mid 2007 both Santos and LNG Limited (with Arrow as supplier) had announced proposed LNG exports projects based on CSG supply from Queensland (later followed by announcements by Sunshine Gas Limited ("Sunshine"), QGC and Impel Limited for additional projects). These projects implied expectations of domestic gas prices remaining low in the medium term and accelerated the need to prove up and secure additional reserves. The initial cash bid by BG Group for Origin Energy Limited ("Origin") in April 2008 indicated confidence for the technical feasibility of conversion of LNG into CSG, the attractiveness of the LNG export market in the context of a high oil price, a rapidly approaching carbon trading environment and buyer willingness to pay for reserve prospectivity. This announcement was followed by several landmark transactions in the sector further raising confidence in the concept even further and saw international groups such as BG Group, Petronas and Shell Exploration Company B.V. ("Shell") paying multiples closer to $2.00 per GJ to participate in these projects, setting new benchmarks. These deals have set new valuation metrics for all companies in the sector.

A brief summary of each transaction is set out below.

Sunshine Gas Limited / Queensland Gas Company Limited

On 20 August 2008 QGC and Sunshine announced an agreed merger. The merger is to be implemented by means of a takeover bid by QGC for all of the issued capital of Sunshine under which Sunshine shareholders would receive either five QGC shares for every eight Sunshine shares or cash of $1.65 per Sunshine share and two QGC shares for every seven Sunshine shares. Based on the last traded share price for QGC of $4.32 per share, the all scrip alternative represents a total consideration Sunshine at $837 million or $895 million for the cash and scrip alternative. At the date of the announcement QGC had entered into a pre-bid acceptance agreement with a Sunshine shareholder in respect of 15% of Sunshine's issued capital. The offer is expected to close 13 October 2008.

Sunshine is a Queensland based energy company focused on the exploration, development, and commercialisation of coal seam and conventional gas resources. Sunshine is yet to produce or sell any gas. Sunshine's interests include its 100% owned Lacerta CSG project near Roma in the Walloons part of the Surat basin with certified gas reserves of 469JP of 2P and 1,097PJ of 3P and is focused on developing the field for gas production. The addition of the Sunshine's CSG assets to QGC's reserves is expected to provide additional gas supplies for QGC's joint venture with BG Group for an LNG plant, potentially enabling additional production trains as well as the development of its planned gas fired power stations.

Sunshine also has secondary CSG exploration projects representing ~30,000 km^2 of CSG and conventional gas acreage at earlier stages of development which include Pegasus (100%), Atria (100%), Paranui (50%), Tilbrook (50%), Foxleigh (50%) and Cullin (50%). Conventional gas projects include: Redrock (100%) and Champagne Creek (50%). Oil projects include: Copper (100%), Alton (33%) and UK Operations (50%). In December 2007 Sunshine had entered a head of agreement for a joint venture with Sojitz Corporation and LNG Japan to evaluate the feasibility of a medium scale (0.5Mtpa train) LNG project in Gladstone which would use Sunshine's CSG as fuel.

Roma Petroleum NL / Queensland Gas Company Limited

On 10 June 2008 QGC and Roma Petroleum NL ("Roma') announced an agreed offer under which QGC would acquire all of the issued capital of Roma. Under the offer terms Roma shareholders would receive 10 cents cash and 0.0177 QGC shares for every one Roma share. At the date of the announcement QGC had entered into a pre-bid acceptance agreement with a Roma shareholder in respect of 19.16 % of Roma's issued capital. On 17 July 2008, QGC revised the cash component of the Offer to 11 cents per Roma share. The revised offer terms valued each Roma share at 20 cents. On 9 July 2008 Bow Energy Limited ("Bow") announced a competing takeover bid for shares in Roma offering 5 Bow shares for every 7 Roma shares. By 22 August 2008 QGC had obtained a substantial interest in Roma shares of 76.8% and the Board of Roma confirmed that they recommended shareholder accept the QGC offer and reject the Bow bid.

Roma is an oil production and exploration company, and was producing oil at a rate of about 270 barrels a day from its Mirage and Ventura oilfields. Roma also holds a significant interest in PL 171 which is located near the proposed pipeline for the Queensland Curtis Island LNG project being under taken by QGC and BG Group. The acreage covered by the permit is located in the northeast Surat basin in Queensland and is prospective for CSG. It is also close to QGC's CSG interests, ATP 651P, adjacent to ATP 574P. QGC's offer has been extended and is expected to close on 17 October 2008.

Arrow Energy Limited (Australian CSG assets) / Shell Exploration Company B.V.

On 2 June 2008 Shell and Arrow announced an alliance to jointly develop CSG projects in Australia, China, Indonesia, Vietnam and India. The alliance included the acquisition by Shell of a 30% interest in Arrow's Australian CSG tenements for up to $644 million and the acquisition of 10% of Arrow's international assets in Asia for up to $134 million. The consideration for the acquisition of the coal seam assets is to be made up of an up front payment of $435 million (including back costs from 1 January 2008) with $140 million payable upon final investment decision ("FID") for Arrow's Gladstone LNG project in Queensland. Under the transaction a further $70 million is payable by Shell when the project is producing 1Mpta which may only occur in 4 years time. The project is expected to have a capital cost of around $400 million and require around 2,300PJ of gas. The funding provided by the Shell deal will significantly underwrite Arrow's equity requirements for project financing and also added to the overall credibility of the project. FID is expected to occur in first quarter 2009.

In contrast to the Santos/Petronas deal, this transaction did not include Shell taking an interest in Arrow's LNG project. However, it included other broader alliance aspects such as the secondment of Shell personnel to Arrow, access to Shell's research capabilities as well as the right for Shell to negotiate an agreement for offtake of LNG produced gas from the CSG operations on market based terms with LNG sellers. The transaction excluded Arrow's downstream assets, (such as interests in Enertrade power generation assets and pipelines), corporate interests (including its holding in Liquefied Natural Gas Limited and Pure Energy Resources Limited) with Arrow remaining the operator of the upstream assets.

Arrow's Australian CSG tenements are situated in the Bowen and Surat Basins in Queensland, including four producing projects which supply industrial users and power generators. Arrow's Surat Basin interests comprised a 50% operator interest in Kogan North (a 50/50 joint venture with CS Energy), consisting of around 40 wells, a 60% operator interest in Tipton West (with Beach Petroleum Limited ("Beach")), consisting of 85 wells and 100% of the Daandine Prospect consisting of 21 producing wells. Moranbah, located in the Bowen Basin, a 50/50 joint venture with AGL Energy with 82 producing wells. Commercial gas production began in 2006 from its Kogan North fields and in the quarter ended March 2008 Arrow's total gas production was 4.2PJ per day.

Arrow's net CSG reserves at the date of the announcement comprised 791PJ of 2P reserves and 2,790 3P reserves of which approximately 70% represented Surat interests. Of these reserves approximately 61% of 2P and 89% of 3P were uncommitted/uncontracted. At the date of the announcement, Arrow had not commissioned a review of its contingent resources. However, management had previously stated 2P guidance target circa 2,000PJ by end 2008 and Arrow confirmed that Shell had reviewed its well and reserve data prior to signing the deal. Post announcement of the transaction in July 2008 Arrow announced a significant reserves increase to 1,430PJ of 2P reserves and 3,127PJ of 3P reserves.

Based on the initial cash payment and the upgraded reserves the transaction represented a 2P reserves multiple of $1.01 per GJ of 2P reserves and $0.46 per GJ of 3P reserves. Assuming inclusion of the contingent payments (unrisked and undiscounted), these multiples would be $1.50 per GJ and $0.69 per GJ respectively which are broadly in line with the QGC/BG Group asset acquisition. However, the transactions are arguably not directly comparable. While both companies have assets in the Surat Basin, there are differences between the assets of the companies such as average well deliverability with QGC fields producing substantially higher rates than that achieved by Arrow. Completion of the transaction is expected to occur in the September 2008 quarter and will result in Shell acquiring an interest in 429PJ of 2P reserves (i.e. a 30% interest in the upgraded reserves). Shell is a wholly owned subsidiary of Royal Dutch Shell Plc.

Santos Limited (Gladstone LNG Project) / Petroliam Nasional Berhad

On 29 May 2008, Petronas announced an agreement to acquire 40% of Santos Limited's Gladstone LNG project. The transaction was the acquisition by Petronas of an interest in an LNG project as well as reserves/resource and Petronas will have exposure to value from the transaction across the upstream and down stream elements. Under the agreement, a new 60/40 joint venture company is to be formed which would develop and operate the gas liquefaction facility at Gladstone Queensland, build and operate a 450 kilometre pipeline from jointly owned upstream CSG assets to the facility, and undertake marketing activities for the LNG output. Petronas will head marketing for the joint venture. Santos will operate the upstream assets. The consideration comprised a US$2,008 million cash payment (5% deposit, balance on completion, post FIRB and other regulatory approvals) with an additional payment of up to US$500 million on FID for a second LNG train. Under the transaction Santos will sell 538PJ (approximately one third) of 2P reserves, 1,600PJ of 3P reserves plus 2,969PJ of contingent 3C resource and less than 11% of its total oil and gas reserves to the joint venture. The interests sold were principally in the Denison, Greater Fairview and Greater Roma fields in the Bowen Basin. Santos owns 100% of the Roma fields and Origin is Santos' joint venture partner in the Santos operated Fairview field.

The project is to have an initial one train capacity of approximately 3 Mtpa which represented a gas requirement for circa 5,500PJ for a two train project or 2,500PJ for the first train (compared to the 4,569PJ of reserves and resource acquired) and therefore will require some conversion of resource into reserves to meed the second train gas requirements. Based on the initial cash payment only the reserves multiples for the transaction were $3.93 per PJ for 2P reserves, $1.32 per GJ for 3P reserves and $0.46 per GJ as a multiple of 3P reserves plus contingent resource. These multiples would increase to $4.92 per GJ and $1.65 per GJ and $0.58 per GJ respectively if the contingent payment of a further US$500 million is included (unrisked and undiscounted) which would be potentially received in 3 years time.

The transaction was the outcome of a global competitive tender process conducted by Santos for a partner for its LNG project which was at evaluation stage at the time of BG Group's initial approach to Origin on 29 April

2008. The reserves multiples achieved were high relative to prior transactions. This may reflect Santos' strong negotiating position based on its then leading asset position, some benefit from the increasing impetus to secure the significant volumes of gas required for LNG projects flowing from the announcement of the BG Group offer for Origin and confidence that 3P reserves and gas resources will be converted to commercial reserves over time (to meet the LNG project's gas requirements) and that project expansion is likely. An LNG project in partnership with Santos would also potentially have an advantage in managing ramp up gas. This could include through Santos' access to substantial gas storage facilities, its ability to manage gas supply on a portfolio basis including between conventional and CSG assets and its experience in shutting in wells for significant periods of time. In addition, as an existing LNG supplier into the international market, Petronas would have greater capacity to manage reserves risk/ gas deliverability within its overall LNG portfolio which would reduce contract risk which is dependent on proven reserves.

Petronas is a Malaysian Government owned company with over US$50 billion in revenue. Petronas has significant LNG experience as suppler and is the largest LNG supplier/producer in Asia and third largest in the world. This experience and marketing network as well as access to Petronas' experienced personnel is expected to de-risk the project. Globally Petronas operates LNG capacity of circa 30Mtpa.

Queensland Gas Company Limited / BG Group plc

On 3 February 2008 BG Group announced an $870 million alliance with QGC primarily directed to the development of an export LNG facility (the "joint venture"). This alliance was the fourth Queensland based export LNG to be announced since mid 2007 and the first significant investment by a major international energy market participant. This was BG Group's first investment in Australia which secured it a commercially proven source of gas with significant reserves.

Under the joint venture BG Group acquired 20% of QGC's existing Walloons CSG fields located in the Surat Basin for $415 million. QGC's interests to be acquired included ATP 620P (including the Kenya, Argyle, Codie and Lauren, PLA 247 (Bellevue) and ATP648P (Kenya east) fields which QGC operates with Origin as joint venture partner. BG Group has the right to acquire a further 10% share of QGC's interests for $207 million in cash upon the earlier to occur of FID approving the budget for the construction of an LNG facility and the certification of 7,000PJ of 2P reserves. Under the transaction BG Group would acquire a 9.9%[28] shareholding in QGC at a share price of $3.07 per share for $250 million and an entitlement to nominate a director for appointment to the QGC board (subject to QGC shareholder approval)[29]. Other elements of the alliance include: an agreement for the two companies to cooperate in the further exploration and development of onshore CSG tenements based on a $230 million exploration programme, the companies will develop and build a pipeline from the CSG acreage to the port facility in Gladstone to be owned 50% by BG Group and 50% by QGC; build an LNG production and export facility and port assets on the Queensland coast to be owned 70% by BG Group and 30% by QGC. BG Group and QGC have agreed to enter into certain joint marketing arrangements for the sale of gas to the LNG facility and into the domestic market. BG Group will purchase 100% of the planned resulting LNG produced from the project under a 20 year offtake agreement, expected to be 3-4Mtpa from 2013.

QGC engages in the exploration, evaluation, development, and production of CSG, holding 7,500 square kilometres of production and exploration permits in the Surat Basin. QGC commenced commercial production in 2006 from its Berwyndale South field. QGC supplies CSG from coal seams in the Surat Basin to domestic customers in south east Queensland. The estimated cost of the upstream development, the 380km pipeline to Gladstone and the liquefaction plant is A$8 billion and will require approximately 4,400PJ of gas over 20 years. As at the date of the announcement, QGC had stated reserves and resource of 1,317PJ of 2P, 3,116PJ of 3P and 4,139PJ of contingent resource and was the third largest holder of 3P reserves after Origin and Santos. Of its reserves, approximately 35% of 2P reserves (467PJ) and 73% of 3P reserves (2,266PJ) were uncontracted. The payment for the acquisition of the 20% interest in the CSG assets represented a multiple of $1.58 per GJ of 2P reserves, $0.67 per GJ of 3P reserves and $0.29 per GJ as a multiple of 3P reserves plus contingent resource.

---

[28] The arrangements entered into by QGC and BG Group in relation to the LNG project includes provisions to limit the dilution of BG Group's interest in QGC by giving BG Group a right to participate in any non-pro rata issue of QGC shares. In the context of the offers for Roma and Sunshine, QGC has an obligation to offer BG Group such number of QGC shares which will result in BG Group holding 8 per cent of the total number of QGC shares on issue immediately after the issue of QGC shares to Roma and Sunshine shareholders.

[29] As a condition of ACCC approval for its bid for Origin, in the event that the takeover was successful BG Group agreed to changes to certain aspects of the QGC alliance, including to the joint marketing arrangements and relinquishment of its QGC Board seat. BG Group announced on 9 September 2008 that it expects its bid for Origin to lapse.

BG Group is a global natural gas business operating in 25 countries and business segments exploration and production, LNG, transmission and distribution and power generation.

Arrow Energy NL / Energy Infrastructure Group AB

On 23 February 2007, Arrow announced it had entered into a letter of intent with Energy Infrastructure Group AB ("EIG") for a farmin to a portfolio of predominantly exploration CSG assets in the coastal Queensland and Clarence Moreton basin licences as well as Dundee and the Daandine Power Project for a consideration up to $225 million. With the exception of the Dundee pilot project and the entitlement to the Daandine Power Project, the tenements to be acquired in the farmin are greenfields requiring further exploration and the development of infrastructure to process and deliver gas. Under the agreement EIG was required to reimburse Arrows's expenses and spend $150 million to earn a 50% interest in a joint venture. In addition, EIG was also required to pay up to a further $75 million (increased in April 2007 to $115 million) by way of four milestone bonuses, the first three of which become payable for certification of 250PJ, 500PJ and 750PJ of gross 2P reserves on the portfolio assets (excluding PL 230). The earliest first payment is payable on 1 January 2009. EIG is a privately owned energy asset holding company based in Sweden with energy development subsidiaries active in the Asia-Pacific region.

Queensland Gas Company Limited / AGL Energy Limited

On 5 December 2006, AGL Energy reached agreement to acquire a 27.5% interest in QGC for $292 million at $1.44 per share. As part of the transaction, AGL Energy committed to cap its interest at 30% under a planed share buy back by QGC. The share acquisition (and other aspects of the related transactions) were subject to shareholder approval in March 2007 and formed part of a broader transaction which included a 20 year gas sale agreement at favourable prices for up to 740PJ, a 3 year gas market services development agreement for $22.5 million and Board appointments (the "AGL Energy Transaction"). The announcement of the AGL Energy Transaction was made during the currency of a takeover offer for QGC by Santos announced on 5 October 2006. In mid February 2007 Santos announced that it would improve the terms of its competing offer but on 21 February 2007 announced its offer would not proceed due to the Australian Competition and Consumer Commission ("ACCC") finding the proposal was anti-competitive. On 1 March 2007, QGC announced that it had received a conditional cash and scrip takeover offer from Trust Company of the West valued at $1.51 per share which it rejected and QGC announcing a 190.6PJ increase to its 2P reserves. On 2 March 2007 AGL Energy increased their offer to $1.60 per share or $324 million. QGC engages in the exploration, evaluation, development, and production of CSG, holding 7,500 square kilometres of production and exploration permits in the Surat Basin.

Arrow Energy NL / New Hope Corporation Limited

On 26 July 2006 New Hope Corporation Limited ("New Hope") acquired 19.9% of Arrow and 16 million listed options for a total consideration of $48.5 million. Arrow is involved in the exploration, appraisal, development and operation of CSG projects within Queensland and northern New South Wales. Arrows' major reserves include the Moranbah gas project (acquired through Arrow's merger with CH4) in Bowen Basin and the Kogan North Project in the Surat Basin. This acquisition provided New Hope with an expanded energy portfolio together with its existing domestic coal energy business, with both energy segments positioned near infrastructure allowing competitive transportation costs.

Moranbah Project (BHP Billiton Limited) / AGL Energy Limited

On 21 June 2006 AGL Energy acquired 50% of BHP Billiton Limited's Moranbah CSG project ("Moranbah Project") for $93.3 million. The Moranbah Project is located in the Bowen Basin and was a joint venture with CH4, producing approximately 16PJ in 2006. Contracts were in place with energy generators and suppliers Enertrade and Energex over Moranbah's production from 300PJ of its reserves until 2020. This acquisition continued AGL Energy's strategy of seeking upstream gas and electricity generation assets to avoid retail pricing pressures.

CH4 Gas Limited / Arrow Energy NL

On 4 May 2006 Arrow and CH4 announced an agreed merger. The merger was implemented by means of a takeover bid by Arrow for all of the issued capital of CH4 under which CH4 shareholders would receive 2.15 Arrow shares for every one CH4 share and two Arrow options with an exercise price of $0.75 and expiry date of 1 December 2006 for every five CH4 shares. The merger terms valued each CH4 share at $1.36. CH4 was a

Queensland based energy company focused on the exploration, development and commercialisation of CSG resources. It had a 50% share in the Moranbah Project which had 2P reserves of 149PJ and over 7,000 square kilometres of other tenements at earlier stages of development.

Argyle and Lauren CSG Project (Pangaea Oil and Gas Pty Limited) / Origin Energy Limited

On 1 February 2006 Origin entered into an agreement to acquire a 40.6% interest in the Argyle and Lauren CSG Project ("Argyle and Lauren") held by Pangaea Oil and Gas Pty Limited for $70 million. The assets acquired also included other tenements at earlier exploration stages and a pipeline licence to access the main gas trunkline, the Wallumbilla to Brisbane pipeline. The Argyle and Lauren project was a joint venture with operator QGC, was not yet at production stage and required development capital of $20 million before production could commence. Pangaea had contracted net sales to Incitec Pivot Limited, with sales scheduled to commence at 3PJ per annum from late 2007.

Tipton West Project (Arrow Energy Limited) / Beach Petroleum Limited

On 12 September 2005 Beach announced a farmin arrangement with Arrow in relation to its Tipton West CSG project ("Tipton") for $35 million. In return for funding Stage 1 of Arrow's Tipton project, Beach received a 40% interest in the upstream interests in ATP 683P and PL 198 held by Arrow. Tipton is located in the Surat Basin. Tipton was not at production stage with Beach's investment funding the gathering and water handling infrastructure with the target of starting production in late 2006.

Moura Project / Anglo Coal (Moura) Limited and Mitsui Moura Investment Pty Limited

On 7 September 2005 Origin announced that it had sold its interests in the Moura CSG project ("Moura") to Anglo Coal (Moura) Limited and Mitsui Moura Investment Pty Limited for $22 million. Moura is in the Bowen Basin and gas production first began in 2001.

Tipperary Corporation / Santos Limited

On 1 July 2005 Santos announced it would acquire Tipperary Corporation ("Tipperary") and 10% of Tipperary Oil and Gas Australia, a 90% subsidiary of Tipperary, for US$466 million. Tipperary was a US listed company whose principal asset was a 75% working interest in the Fairview CSG project, and approximately 4,000 square kilometres of exploration acreage in the Bowen Basin with joint venture partner Origin. Fairview is a high quality CSG field as measured by gas content, permeability, saturation, flow rate, and coal seam thickness. It also has lower production costs than its peer group. Fairview had been in commercial production since 1997.

Oil Company of Australia Limited / Origin Energy Limited

In July 2003, Origin made takeover offers for all the issued shares in Oil Company of Australia Limited ("OCA") that it did not already own. OCA shareholders were offered $4.25 in cash for each ordinary share in OCA representing a transaction value of $528 million. At the time of the announcement Origin had a relevant interest in 88.07% of the issued capital of OCA, including 2.9 million shares (2.47% of the issued capital of OCA) in respect of which Santos had agreed to accept the Origin offer pursuant to a pre-bid agreement with Origin. OCA had interests in conventional gas and CSG fields in Queensland.

Appendix 7

Market Evidence – Comparable Listed Oil and Gas Companies

The valuations of the coal seam gas ("CSG") and conventional oil and gas assets of Origin Energy Limited ("Origin") have been considered in the context of the sharemarket ratings of listed Australian oil and gas companies. In particular, those companies with exploration, development and production assets have been considered. While none of these entities is precisely comparable to Origin's activities, the sharemarket data provides some framework to assess valuation parameters for these activities.

Sharemarket Ratings of Selected Listed Oil and Gas Exploration and Production Companies

Entity	Market Capital-isation[1] (millions)	EBITDA Multiple[2] (times)			EBIT Multiple[3] (times)			Certified Reserves[4] (PJ)		Reserves Multiple[5] (A$/GJ)	
		Historical	Forecast Year 1	Forecast Year 2	Historical	Forecast Year 1	Forecast Year 2	2P	3P	2P	3P
CSG											
Queensland Gas Company	A$3,050	236.3	69.0	32.6	na[6]	130.4	41.9	2,415	7,163	1.0	0.3
Arrow	A$2,086	55.3	36.1	23.0	101.4	56.7	35.2	1,430	3,127	1.3	0.6
Eastern Star Gas	A$428	124.4	53.5	21.5	nmf[7]	87.6	54.3	120	845	3.2	0.5
Molopo	A$228	na	na	41.3	na	na	76.4	50	245	4.1	0.8
Sydney Gas	A$137	nmf	69.0	32.6	nmf	130.4	41.9	41	54	3.2	2.4
Metgasco	A$110	na	na	na	na	na	na	264	1,419	0.4	0.1
Conventional Oil and Gas											
Woodside	A$38,860	17.0	9.0	7.3	23.2	10.8	8.6	9,702	na	4.3	
Santos	A$10,572	6.6	5.5	5.4	13.1	8.8	8.8	1,573	na	6.5	
Oil Search	A$4,788	10.0	5.6	5.4	14.6	6.8	6.5	427	na	10.2[8]	
Beach	A$943	3.1	2.3	2.3	6.0	3.8	4.0	94	na	8.7	
Nexus Energy	A$768	na	22.4	8.5	na	23.6	10.4	337	na	2.0	
New Zealand Oil & Gas	A$479	1.6	2.7	2.4	1.8	3.2	3.2	350	na	1.0	

Source: Grant Samuel analysis[9]

Sunshine Gas Limited ("Sunshine") has been excluded from the analysis as on 20 August 2008 Queensland Gas Company Limited ("QGC") announced an agreed all scrip or cash and scrip takeover for the company. This takeover offer is discussed in Appendix 6.

The multiples shown above are based on sharemarket prices as at 5 September 2008 and do not reflect a premium for control.

All of the companies have a 30 June year end except for Woodside Petroleum Limited ("Woodside"), Santos Limited ("Santos") and Oil Search Limited ("Oil Search") which have 31 December year ends.

The Forecast Year 1 multiples represent the 2008/09 financial year. The data analysed for each company included the last two annual historical results plus the subsequent three forecast years. However, five of the companies (i.e. Eastern Star Gas Limited ("Eastern Star Gas"), Molopo Australia Limited ("Molopo"), Sydney

1 Implied equity value if 100% of the company or business had been acquired.

2 Represents gross capitalisation divided by EBITDA. EBITDA is earnings before net interest, tax, depreciation, amortisation, investment income and significant and non-recurring items.

3 Represents gross capitalisation divided by EBIT. EBIT is earnings before net interest, tax, investment income and significant and non-recurring items.

4 Represents relevant proportionate interest in stated reserves as at latest announcement.

5 Represents enterprise value divided by proportionate interest in stated reserves.

6 na = not available

7 nmf = not meaningful

8 Oil Search also has substantial resources (approximately 5,550PJ) which have not yet been certified as reserves.

9 Grant Samuel analysis based on data obtained from IRESS, company announcements, transaction documentation and, in the absence of company published financial forecasts, brokers' reports. Where company financial forecasts are not available, the median of the financial forecasts prepared by a range of brokers has generally been used to derive relevant forecast value parameters. The source, date and number of broker reports utilised for each transaction depends on analyst coverage, availability and corporate activity.

Gas Limited ("Sydney Gas"), Metgasco Limited ("Metgasco") and Nexus Energy Limited ("Nexus Energy")) have not yet released their 30 June 2008 annual results. For those companies, where available, brokers' estimates for 2008 have been used as the actual result for the year and brokers' estimates for 2009 and 2010 have been used as Forecast Year 1 and Year 2 respectively. As a consequence, the historical data represents the year ended 30 June 2008 for those companies with a 30 June year end (although for five companies this is sourced from brokers' forecasts). For the companies with 31 December year end, the historical data is for the year ended 31 December 2007.

Given the range of Origin's upstream gas activities, the selected companies encompass exploration, development and production companies involved in CSG and conventional oil and gas assets in Australia. The selected CSG focused companies include current producers of CSG as well as developers of assets. The selected conventional oil and gas companies are those which have significant earnings from production activities while at the same time having significant exploration and/or development of oil and gas assets activities.

The following should be noted in relation to the sharemarket ratings for CSG focused companies:

- the earnings multiples for the CSG companies are generally not meaningful as their market capitalisation reflects substantial value attributed to CSG reserves and resources which are under development and from which earnings are only just beginning to emerge;
- some of the CSG focused companies also hold conventional gas assets and/or have interests in electricity generation businesses as part of pursuing an integrated operator strategy (in order to gain access to net back electricity prices and consequently higher margins than available through domestic gas sales) (e.g. Arrow Energy Limited ("Arrow") and Eastern Star Gas);
- the portfolios of CSG assets owned by each of the companies differ across a range of factors which will impact relative valuation metrics. These factors include the stage of development of reserves and resources, the location of the interests, relative scale, quantum and quality of the assets and recoverable gas, the prospects for additional resources, access to markets (e.g. infrastructure), access to expertise or funding of joint venture partners, the extent to which the reserves are contracted or uncontracted (the attractiveness of contract terms) and the target market for the gas;
- the CSG industry within New South Wales is less developed than in Queensland and therefore has less explored (and less understood) geological structures. The reserves multiples for companies developing CSG assets in New South Wales (e.g. Molopo, Eastern Star Gas and Sydney Gas) are relatively high reflecting the low extent to which 2P reserves have been proven;
- Sydney Gas's high reserves multiple may reflect certainty associated with offtake arrangements with AGL Energy Limited ("AGL Energy") (10 year gas sales contract commencing in 2008) and with funding for commercialisation from an alliance with AJ Lucas Group Limited as well as a low level of share liquidity;
- in the last 12 months the market has ascribed higher multiples to companies with potential or planned access to LNG projects and potential for higher margins from LNG net back prices. Each of Arrow (with Shell), QGC (with BG Group) and Santos (with Petronas) have planned LNG projects; and
- while QGC also has potential for access to the LNG market (through the alliance with BG) and exposure to higher electricity linked gas margins, its multiples may reflect some uncertainty in relation to AGL Energy's intention regarding its 24.9% stake and the impact of QGC's takeover offer for Sunshine.

In relation to the conventional oil and gas companies the following should be noted:

- the major conventional oil and gas companies (i.e. Woodside, Santos and Oil Search) all have substantial international activities in addition to substantial Australian operations. In comparison, Origin's oil and gas activities outside of Australia and New Zealand are limited to some greenfield exploration activities. Furthermore, Woodside is a substantial producer of LNG;
- Woodside has substantial growth projects emerging by 2010 (Forecast Year 3) including a fifth train at the North West Shelf Venture and the first gas production from the Pluto LNG Project. Its market capitalisation reflects this growth but no earnings are yet reflected and therefore its EBITDA and reserves multiples are high relative to Santos and Oil Search; and
- Oil Search's multiple of 2P reserves is high. It also has substantial resources (approximately 5,550PJ) which have been certified as reserves to which the market is attributing a value which explains its high multiple of 2P reserves.

Appendix 8

Report by Gaffney, Cline & Associates Pty Ltd

Copy No. 1

INDEPENDENT TECHNICAL EXPERT'S REPORT ON ORIGIN ENERGY'S CONVENTIONAL OIL AND GAS ASSETS

Prepared for

GRANT SAMUEL & ASSOCIATES PTY LIMITED

SEPTEMBER 2008

The Americas

Four Oaks Place
Houston, Texas 77056
Tel: +1 713 850 9955
Fax: +1 713 850 9966
email: gcah@gaffney-cline.com

Europe, Africa, FSU and the Middle East

Bentley Hall, Blacknest
United Kingdom GU34 4PU
Tel: +44 1420 525366
Fax: +44 1420 525367
email: gcauk@gaffney-cline.com

Australia

Level 16, 275 Alfred Street
North Sydney NSW 2060
Tel: +61 2 9955 6157
Fax: +61 2 9955 0624
email: gcasyd@gaffney-cline.com

and at Caracas – Rio de Janeiro – Buenos Aires – Singapore – Moscow
www.gaffney-cline.com

TABLE OF CONTENTS

TABLE OF CONTENTS (cont'd)

Page No.

TABLE OF CONTENTS (cont'd)

Page No.

Tables

Figures

Appendices

Gaffney, Cline & Associates Pty Ltd
Technical and Management Advisers to the Petroleum Industry Internationally Since 1962

Level 16
275 Alfred Street
North Sydney NSW 2060
Australia

Telephone: +61 2 9955 6157
Facsimile: +61 2 9955 0624
Email: gcasyd@gaffney-cline.com
www.gaffney-cline.com

ACN 087 730 390
ABN 72 087 730 390

MDF/chw/0980/KK1242/08 **12 September 2008**

Grant Samuel & Associates Pty Limited
Level 19, Governor Macquarie Tower
1 Farrer Place
SYDNEY NSW 2000

Dear Sirs,

INDEPENDENT TECHNICAL EXPERT'S REPORT
ON ORIGIN ENERGY'S CONVENTIONAL OIL AND GAS ASSETS

Grant Samuel & Associates Pty Limited (Grant Samuel) has been appointed by Origin to prepare an Independent Expert's report. Gaffney, Cline & Associates Pty Ltd (GCA) has been commissioned by Origin as an Independent Technical Expert to assist Grant Samuel in its review and valuation of Origin's conventional petroleum assets. This report is submitted to Grant Samuel to provide input data for its assessment.

1. INTRODUCTION

Origin is a fully integrated energy company encompassing oil and gas exploration and production, gas, LPG and power retailing, and power generation. In accordance with its commission GCA has undertaken a technical evaluation of Origin's conventional oil and gas exploration and production assets. This report does not address Origin's retailing or power generation business, or its coal seam gas assets.

For each of Origin's major assets of discovered oil and gas GCA provided production, capex and opex profiles to Grant Samuel for its use in valuing the company. For each asset there were three sets of profiles: Low, Most Likely and High. The estimated value of discovered oil and gas and the associated facilities was estimated by Grant Samuel. For exploration areas considered prospective for conventional oil and gas GCA provided Grant Samuel with its estimated range of fair market value.

GCA was not commissioned to review or advise on current or future oil or gas prices or on future gas markets.

GCA is an independent energy consultancy specialising in petroleum evaluation and economic analysis. In the preparation of this report GCA has maintained, and continues to maintain, strict independence from Origin in accordance with the Valmin Code issued by the Australasian Institute of Mining and Metallurgy. The directors and employees of GCA have been, and continue to be, independent of Origin including the provision of the opinions expressed in this report. Furthermore, the directors of GCA have no interest in any assets or share capital of Origin or in the promotion of the company.

GCA has neither sought nor received any relevant third party authorizations that may be necessary for the information provided herein to be entered into the public domain.

In carrying out this review, GCA has relied upon information and data provided by Origin which comprised details of the petroleum assets, basic exploration and engineering data, interpretation and other technical reports, and cost data, supplemented by public domain data as was appropriate. No new mapping or detailed interpretation was carried out, but the data supplied were reviewed and audited with due diligence to provide appropriate confidence in its validity. GCA did not conduct site visits.

A glossary is attached as **Appendix I**.

All costs and prices are constant 2008 Australian dollars.

This report must only be used for the purpose for which it was intended.

2. OVERVIEW OF ASSETS

The locations of Origin's major petroleum assets are shown in **Figure 1**. The conventional assets are made up of the Cooper Basin which extends across the north eastern section of South Australia and the south western section of Queensland, Thylacine development in the Otway Basin offshore Victoria, the Bass Gas project in the Bass Basin between Victoria and Tasmania and the Kupe development in the Taranaki Basin offshore New Plymouth in New Zealand.

The Cooper Basin was, at one time, the sole source of gas to Adelaide and Sydney but the gas fields are now mature and gas production is declining. Gas is processed by plants at Moomba, in South Australia, and at Ballera in south west Queensland. Oil, condensate and LPG are piped to Pt. Bonython in South Australia where they are separated and shipped to markets.

The Bass Gas project development of the Yolla field commenced production in June 2006. The Yolla field is located between Tasmania and Victoria, 147 km off the southern Victorian coastline. The project produces gas and associated liquids through a single onshore and offshore pipeline to a gas and liquids processing plant at Lang Lang in Victoria. The plant produces gas, LPG and condensate products.

The Thylacine field is located in the Otway Basin 55 to 70 km offshore Port Campbell Victoria. After some early commissioning production the field started continuous production in February 2008. The development consists of a wellhead platform with four production wells, one deviated and three horizontal wells. The field produces gas and associated liquids through a 70 km offshore and onshore pipeline to an onshore gas processing plant.

A summary of Origin's Proved plus Probable (2P) reserves as at 30 June 2008 is shown in the following table.

TABLE 1

SUMMARY OF ORIGIN'S PROVED PLUS PROBABLE RESERVES
Reported by Origin as at 30 June 2008

	Sales Gas + Ethane PJ	LPG MMtonnes	Oil + Condensate MMbbl
Conventional oil and gas	787	1.8	25.7
CSG	4,751		
Total	5,537	1.8	25.7

Values in tables may not add due to rounding

Locations of Origin's Conventional Oil and Gas Assets

Project: KK1242 Sep '08	Checked:	Fig. 1

3. METHODOLOGY

Origin provided GCA with reserve estimates, prepared by Origin and by others, for its conventional oil and gas assets. Origin also provided extensive technical data supporting the reserve estimates. GCA reviewed the reserve estimates of all the major conventional oil and gas assets.

In reviewing the reserve estimates GCA has not reviewed sufficient information to undertake a detailed reserve estimation in accordance with the definitions and guidelines set out in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers and others. However GCA has reviewed sufficient information to opine on the reasonableness of the reserve estimates.

Origin also provided descriptions of each of the assets, historical and forecast capital and operating costs, a brief description of the status of each asset and future development plans. Information and maps were provided on exploration prospects and leads, both near existing developments and in greenfield areas.

Origin developed most likely production forecasts for each of its major assets along with associated capital and operating expenditures and made these available to GCA. Capital expenditures were broken down into six categories and opex into two, the forecasts also included the number of wells drilled.

GCA developed production, capex and opex profiles on an annual basis for each of the major petroleum assets. Major conventional oil and gas assets were considered to be: Cooper Basin, Bass Gas, Thylacine/Geographe and Kupe. All profiles were provided on a 100% interest basis. Summaries of the profiles are included in the report. Details are considered to be commercially sensitive and are not included.

Three sets of profiles were developed for each asset, a Low, Most Likely and High. In some cases the production matched the Proved reserves (1P), Proved plus Possible reserves (2P) and Proved plus Probable plus Possible reserves (3P) respectively but in some cases they did not. The profiles were developed to allow Grant Samuel to determine a value range and are not intended to be a production forecast for a particular reserve estimate.

For the conventional oil and gas assets, where Contingent Resources and/or Prospective Resources have been identified, incremental profiles were provided to Grant Samuel, along with the associated commercial or geological risk. This allowed the value of the Resources to be recognised while acknowledging that the development of the Resources is less certain than that of the Reserves.

Profiles for each of the assets extended from July 2008 to June 2050. Where an asset ceased production during this time abandonment costs were included in the profile.

Value associated with exploration prospects in proximity to developed conventional fields was captured by incorporating production and costs associated with possible successful development in one or more cases for the developed field.

A common method of assessing market value of greenfield exploration acreage is to consider recent transactions for assets that ideally lie within or adjacent to the licence area. Where an area contains well defined prospects which are to be drilled in the near term a method based on Expected Monetary Value (EMV) may be used. There was insufficient information available to use either of these methods and a market value was estimated based on expenditures to date, future commitments and Origin's efforts to obtain farminees.

GCA met with Origin on two occasions but did not conduct any site visits.

4. CONVENTIONAL OIL AND GAS

Origin's main conventional oil and gas assets consist of its interests in the Cooper Basin in South Australia and south west Queensland, the Bass Gas project on the Yolla field in Bass Strait, the Thylacine development in the Otway Basin offshore Victoria and the Kupe development in the Taranaki Basin offshore the North Island of New Zealand.

It also has smaller interests in conventional oil and gas assets in Western Australia, the onshore Otway Basin in Victoria, the Taranaki Basin in New Zealand and the Surat Basin and Denison Trough in Queensland.

4.1 Reserves

Origin provided GCA with summaries of conventional oil and gas reserves, estimated by Origin, as at 30 June 2008.

TABLE 2

SALES GAS AND ETHANE RESERVES (ORIGIN SHARE)
Reported by Origin as at 30 June 2008

Category Area / Asset	1P PJ	2P PJ	3P PJ
Cooper Basin	67	157	436
Bass Gas (Yolla)	100	130	147
Thylacine/Geographe	171	265	379
Kupe	100	127	154
Other Conventional Oil & Gas	53	109	249
TOTAL	491	787	1,364

TABLE 3

LPG RESERVES (ORIGIN SHARE)
Reported by Origin as at 30 June 2008

Category Area / Asset	1P MMtonnes	2P MMtonnes	3P MMtonnes
Cooper Basin	0.1	0.3	1.1
Bass Gas (Yolla)	0.3	0.4	0.5
Thylacine/Geographe	0.3	0.5	0.7
Kupe	0.5	0.5	0.7
Other Conventional Oil & Gas	-	0.1	0.2
TOTAL	1.2	1.8	3.1

TABLE 4

OIL AND CONDENSATE RESERVES (ORIGIN SHARE)
Reported by Origin as at 30 June 2008

Category Area / Asset	1P MMbbl	2P MMbbl	3P MMbbl
Cooper Basin	1.8	5.4	18.7
Bass Gas (Yolla)	3.9	5.3	6.3
Thylacine/Geographe	2.1	3.2	4.6
Kupe	6.4	7.4	9.8
Other Conventional Oil & Gas	1.1	4.4	12.2
TOTAL	15.3	25.7	51.6

4.2 Cooper Basin

The Cooper Basin extends across the north eastern section of South Australia and the south western section of Queensland. Both the Queensland and South Australian portions are operated by Santos. It is considered to be a mature oil and gas province. First discoveries were made in the mid 1960s and the basin has been in continuous production since 1969. Origin's share of gas production in the 12 months to year ending June 2008 (YEJ08) was 21 PJ. During the period between financial years YEJ03 – YEJ08 Origin's participation in Cooper Basin exploration activity has comprised an average of 25 wells per annum. Origin's share of gas reserve additions over this period has been 12 PJ.

Gas is processed at a large processing plant at Moomba in South Australia and a smaller plant at Ballera in south west Queensland. Gas from Moomba flows to South Australia and New South Wales whilst gas from Ballera flows to Eastern Queensland and Mt Isa. In addition raw gas can flow from Queensland to the Moomba gas processing plant. Ethane is separated in the Moomba plant and flows to Botany in New South Wales. Liquids (oil, condensate and LPG) are pumped to Pt. Bonython in South Australia where they are separated and stored before dispatch.

4.2.1 Main Fields

Approximately one-third of South Australia's Cooper Basin gas reserves are in the Moomba and Big Lake gas fields. The Tirrawarra Field contains some 80% of known oil reserves.

The Moomba field is located in the central part of the South Australian sector of the Cooper Basin. Moomba commenced production in 1969 and cumulative production has totalled approximately 1 Tcf of raw gas. The original wells were, initially, relatively high rate comprising flush production from the tight gas reservoirs. Production originates from reservoir depths of approximately 7,000-10,000 ft TVDSS and is therefore associated with high reservoir temperatures (up to 200 deg C).

There are multiple completion zones in Moomba and historical development has employed hydraulic fracturing campaigns (conventional and nitrified) in order to stimulate production rates. More recently, multi-stage "pin-point" fracturing techniques have been implemented via multi-well campaigns. The field has been operated as a swing producer with periods of flush production following downtime. The Moomba South and North gas fields are in a mature development phase. Approximately 178 development wells have been completed in Moomba, around twice as many as in the adjacent Big Lake field.

The Big Lake field is located to the south east of the Moomba South accumulations and was discovered by the Big Lake-1 well drilled in 1971. Subsequent production operations commenced in 1972. The field reached a peak production level of approximately 230 terajoules per day (TJ/d) in 1978.

The Tirrawarra Field is located some 50 km north of Moomba. Tirrawarra is part of a sub-set of Permian oil fields known as 'Unit Oil'. The Tirrawarra oil and gas field is now in late field life. First production commenced in 1983. The field has produced approximately 27 MMstb and 185 Bcf raw gas from approximately 70 development wells. The various reservoir zones include volatile oil in the Tirrawarra formation.

4.2.2 Geological Overview

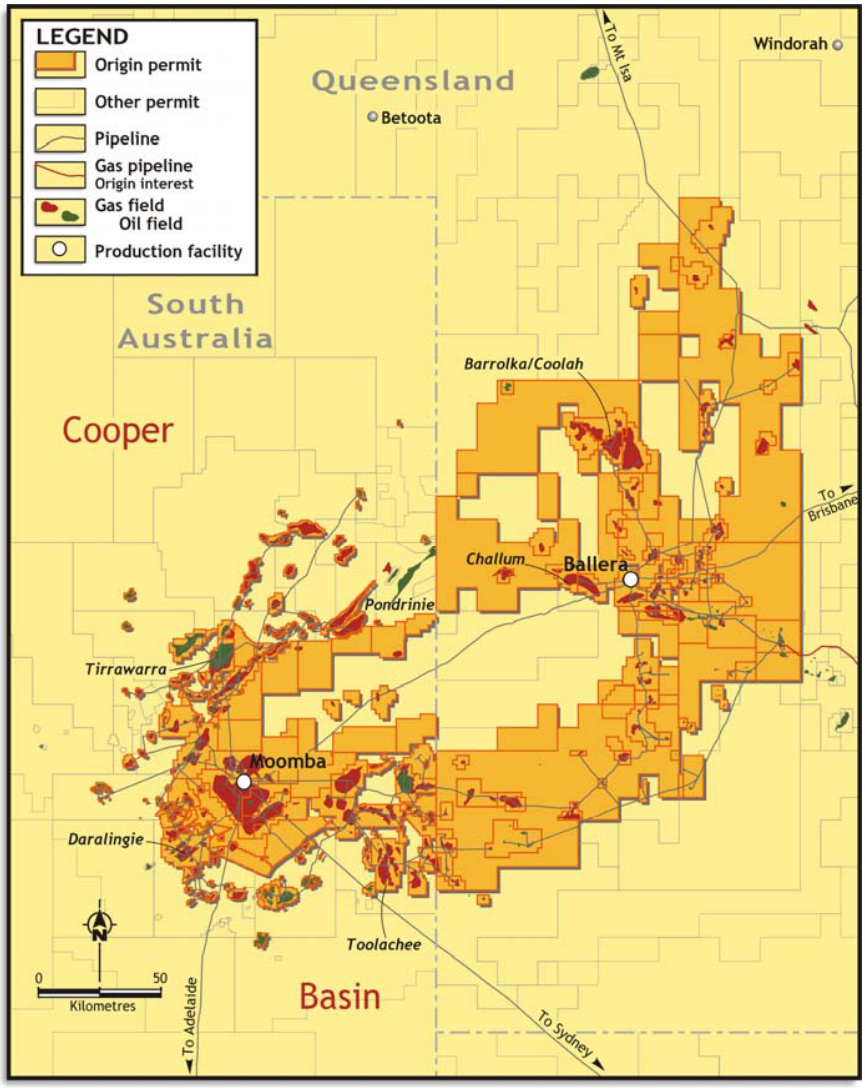
The Cooper Basin is a Late Carboniferous to Middle Triassic, non-marine sedimentary basin which underlies the desert region of north eastern South Australia and south west Queensland (**Figure 2**). Approximately one-third of the basin (35,000 $km^{2)}$ is in South Australia. The unconformity at its upper surface varies in depth from 970 to 2,800 m while the base of its deepest trough reaches approximately 4,400 m below sea level.

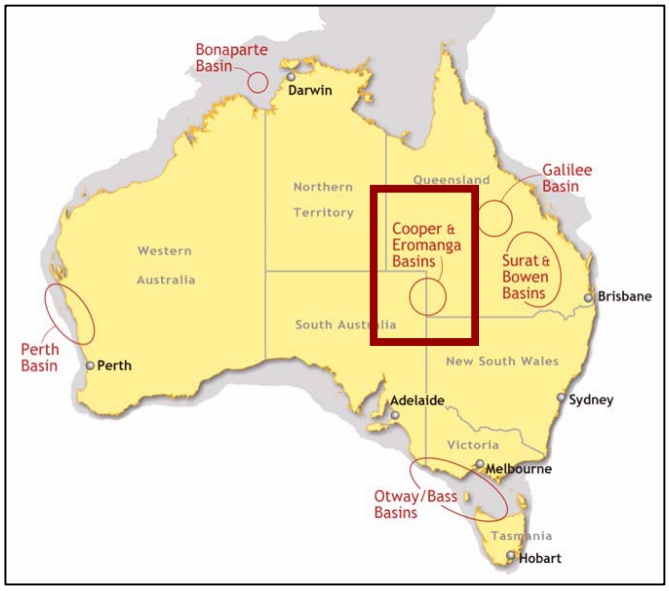
A stratigraphic summary of the Cooper Basin is illustrated by **Figure 3**.

Numerous oil and gas fields in the Cooper Basin point to the Permian containing effective source rocks. The Cooper Basin contains both light oil-condensate and waxy oil with depleted light hydrocarbon contents. The source of the oil is Permian coal and associated terrestrial organic matter. Oil and condensate are typically medium to light (30-60° API) and paraffinic, with low to high wax contents. Many of the hydrocarbon accumulations in the region comprise gas fields. Gas composition is closely related to maturity with depth, with drier gas occurring towards basin depo-centres, although with compositional control from the geology.

Reservoirs within the Patchawarra, Epsilon, Daralingie and Toolachee Formations consist of quartz, minor to trace amounts of altered feldspar and the authigenic components. Tirrawarra Sandstone and Merrimelia Formation reservoirs contain higher proportions of lithics, and range from quartzarenite to litharenite.

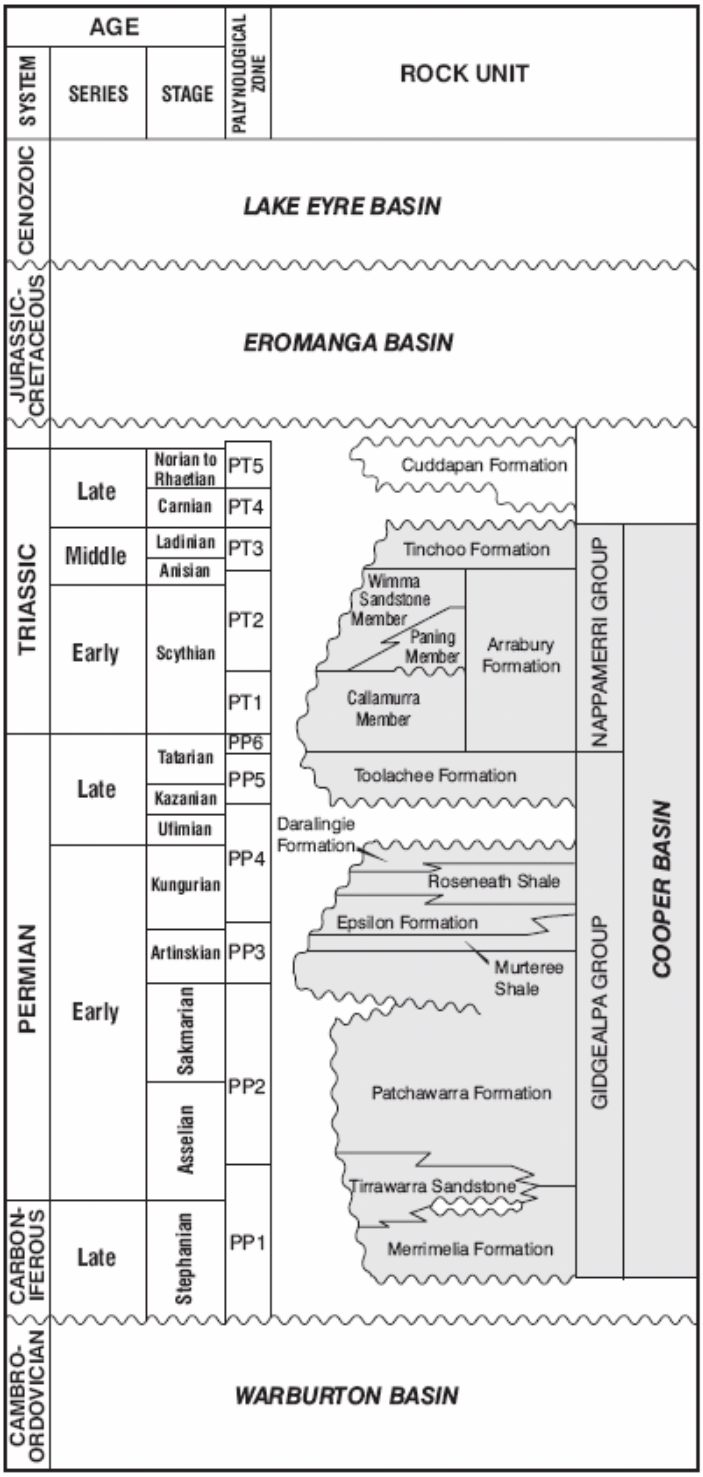
Regional seals are distinguished from intra-formational seals, both of which types lie in or on troughs separated by basement ridges. Although known to pinch out on ridges within the confines of the basin, the Cooper regional seals may also pinch out towards the basin margin. The principal regional seal comprises the Arrabury Formation which is thickest over gas-prone Nappamerri Trough.





Cooper Basin
Field Locations and Permit Boundaries

Project: KK1242 Sep '08	Checked:	Fig. 2



Cooper Basin Stratigraphic Summary

Project: KK1242 Sep '08	Checked:	Fig. 3

4.2.3 Exploration Potential

During the five year period from July 2003 to June 2008 Origin drilled 125 wells which resulted in an addition of 18.6 PJe net, 0.149 PJe net per well.

The modest net reserve additions, relative to the historical cumulative production from the Cooper Basin, reflect the maturity of the existing fields.

Origin has advised that the joint venture plans to continue exploration in the Basin. GCA considers that this will result in future discoveries and GCA has included production from future exploration in its High case valuation profiles, albeit at a higher finding cost than experienced historically.

Origin considers that there is considerable scope for unconventional gas potential in the Cooper Basin in the form of tight gas in Moomba and Big Lake fields, deep coal gas in Moomba and Coonatie and shale gas in Moomba and Big Lake. However any Reserves for these unconventional gas projects will already be booked at the individual field levels. GCA considers that any development of unconventional gas Resources is notional at this stage and has not included development of unconventional Resources in its profiles provided for valuation.

4.2.4 Reserves

The Cooper Basin reserves reported by Origin are shown in the following table.

TABLE 5

COOPER BASIN RESERVES (ORIGIN SHARE)
Reported by Origin as at 30 June 2008

Category	Sales Gas + Ethane PJ	LPG MMtonnes	Oil + Condensate MMbbl
Proved (1P)	67	0.1	1.8
Proved + Probable (2P)	157	0.3	5.4
Proved + Probable + Possible (3P)	436	1.1	18.7

The Origin reserves estimates represent their share of the gross assessment provided to joint venture parties by the Operator, Santos.

GCA has reviewed the reserves reported by Origin and finds the figures to be a reasonable estimate of the remaining recoverable hydrocarbons at this time.

4.2.5 Profiles provided to Grant Samuel

The Most Likely production profile provided to Grant Samuel for the Cooper Basin asset is shown in the following table.

TABLE 6

COOPER BASIN (ORIGIN SHARE)
MOST LIKELY PRODUCTION FORECAST

Year Ending 30 June	Sales Gas + Ethane PJ	LPG ktonnes	Oil & Cond. kbbl
2009	19.0	34	489
2010	18.5	35	514
2011	17.7	36	508
2012	16.6	35	614
2013	14.8	32	571
2014	12.0	26	501
2015	9.1	20	437
2016	7.6	16	366
2017	6.4	13	309
2018	5.4	11	245
2019+	31.8	50	1,032
TOTAL	**159**	**307**	**5,586**

Separate forecasts were made for the South Australian project and the south west Queensland project. **Table 6** is Origin's share of production from both projects. The production forecast includes Origin's reported Proved plus Probable reserves, as of 30 June 2008, plus 2.7 PJe Prospective Resources as a result of continued exploration. The volume of Prospective Resources included in the Most Likely case reflects GCA's view that future finding costs will be greater than those experienced in the past five years.

GCA's production forecast for the Low Case matched Origin's reported Proved Reserves, while the High Case included Origin's reported Proved plus Probable plus Possible reserves plus Prospective Resources of 8 PJe.

Individual profiles for the Reserves and Prospective Resources were provided to Grant Samuel.

GCA estimated capital and operating costs on an annual basis for each of the production profiles provided to Grant Samuel. The estimated costs were based on information provided by Origin and GCA's knowledge of costs in the Cooper Basin. Abandonment costs were included in each case.

TABLE 7

COOPER BASIN
GCA'S ESTIMATED REMAINING LIFE OF FIELD CAPEX AND OPEX
(Origin Share)
$ million

	Capex	Opex
Low	429	307
Most Likely	494	616
High	518	1,197

Notes: 1) High case includes costs for development and production of Prospective Resources
2) Life of field for all assets commences July 2008

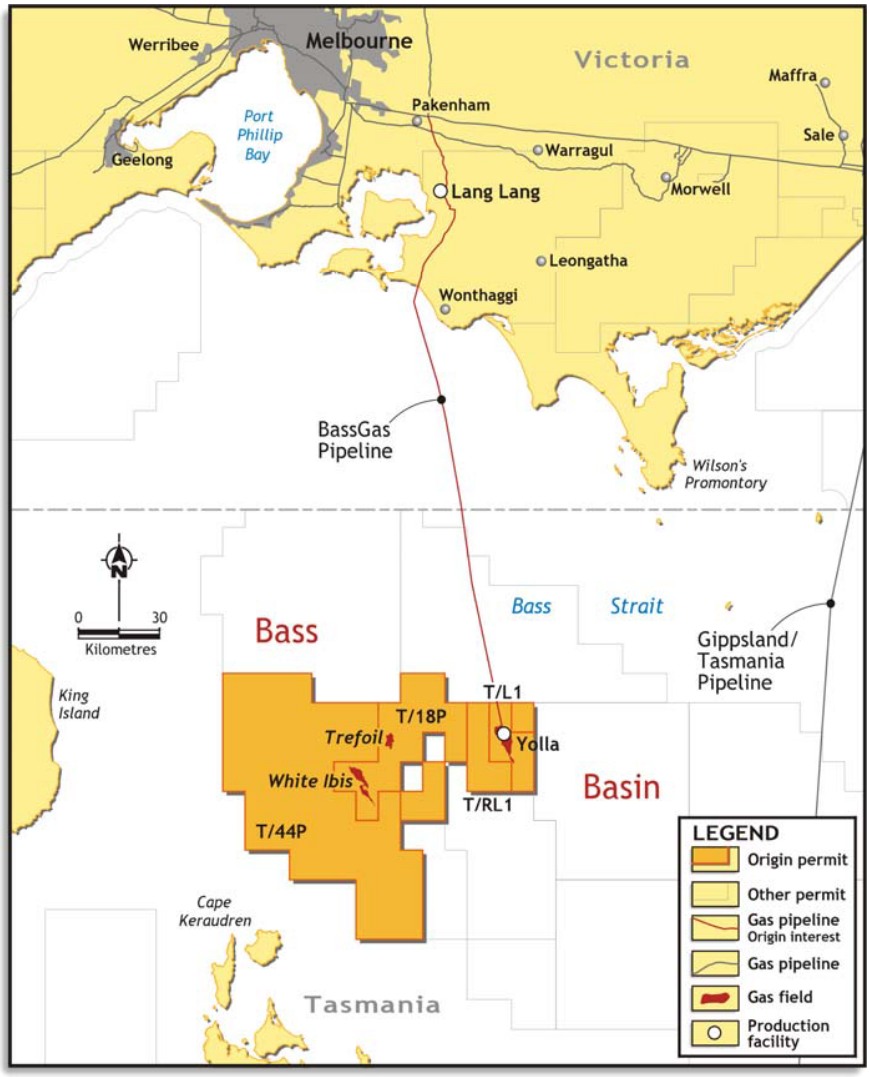
4.3 Bass Gas

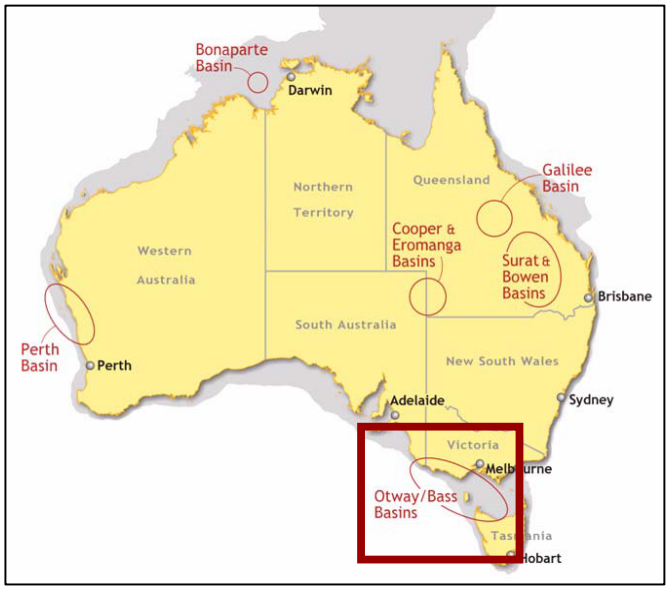
The Bass Gas project consists of the development of the Yolla field and future possible development of other fields in the vicinity that may be produced to the Yolla platform.

The Yolla Field, in the Bass Basin, is located 220 km south of Melbourne and 120 km north of Tasmania in water depth of approximately 80 m. Yolla is in permit T/L1 (**Figure 4**). Four wells have been drilled on the structure. To date the field has been developed with an unmanned platform with two production wells. The Yolla project comprises production wells, and an unmanned wellhead platform connected to the gas processing facility at Lang Lang. Water is removed prior to injection of raw gas into the offshore pipeline. Gas and gas liquids are separated into their sales components at the Lang Lang gas facility. Yolla 1, the discovery well, was drilled in 1985, Yolla 2 was drilled in 1998 and Yolla 3 and 4 development wells in 2004.

Production commenced from Yolla in June 2006. The project produces gas and associated liquids through a single onshore and offshore pipeline to a gas and liquids processing plant at Lang Lang in Victoria. The plant produces gas, LPG and condensate products.

Hydrocarbons in Yolla are contained in reservoirs in the Eastern View Coal Measures. The depositional environment varies from sandy embayment-tidal flat to delta front. There are five recognised hydrocarbon filled zones, three gas and two with both oil and gas legs.





Yolla Field Location and Permit Boundaries

Project: KK1242 Sep '08	Checked:	Fig. 4

4.3.1 Yolla Field

The Bass Basin is a north west to south east trending basin located almost entirely offshore between Victoria and Tasmania in Bass Strait. The basin covers an area of approximately 35,000 sq km. Sediments range in age from Lower Cretaceous to Recent. Petroleum accumulations are contained in reservoirs in structural fold related traps within the Lower Cretaceous to Upper Eocene fluvio-deltaic clastic rocks of the Eastern View Coal Measures.

The Yolla Field is a north west to south east trending tilted fault block. The east and north east flank is bound by a down to the east normal fault. The structure dips to the south west and plunges along a north west to south east axis. The south west down dip flank is affected by two down to the south west normal faults and there are several down to the south west normal faults within the mapped hydrocarbon column, although they do not appear to compartmentalise the field. See **Figure 5**.

Three of the five reservoir zones are within the tilted fault block while two shallower reservoirs are in sands draped over the fault block. Each reservoir appears to have independent fluid contacts

4.3.2 Seismic Interpretation and Depth Mapping

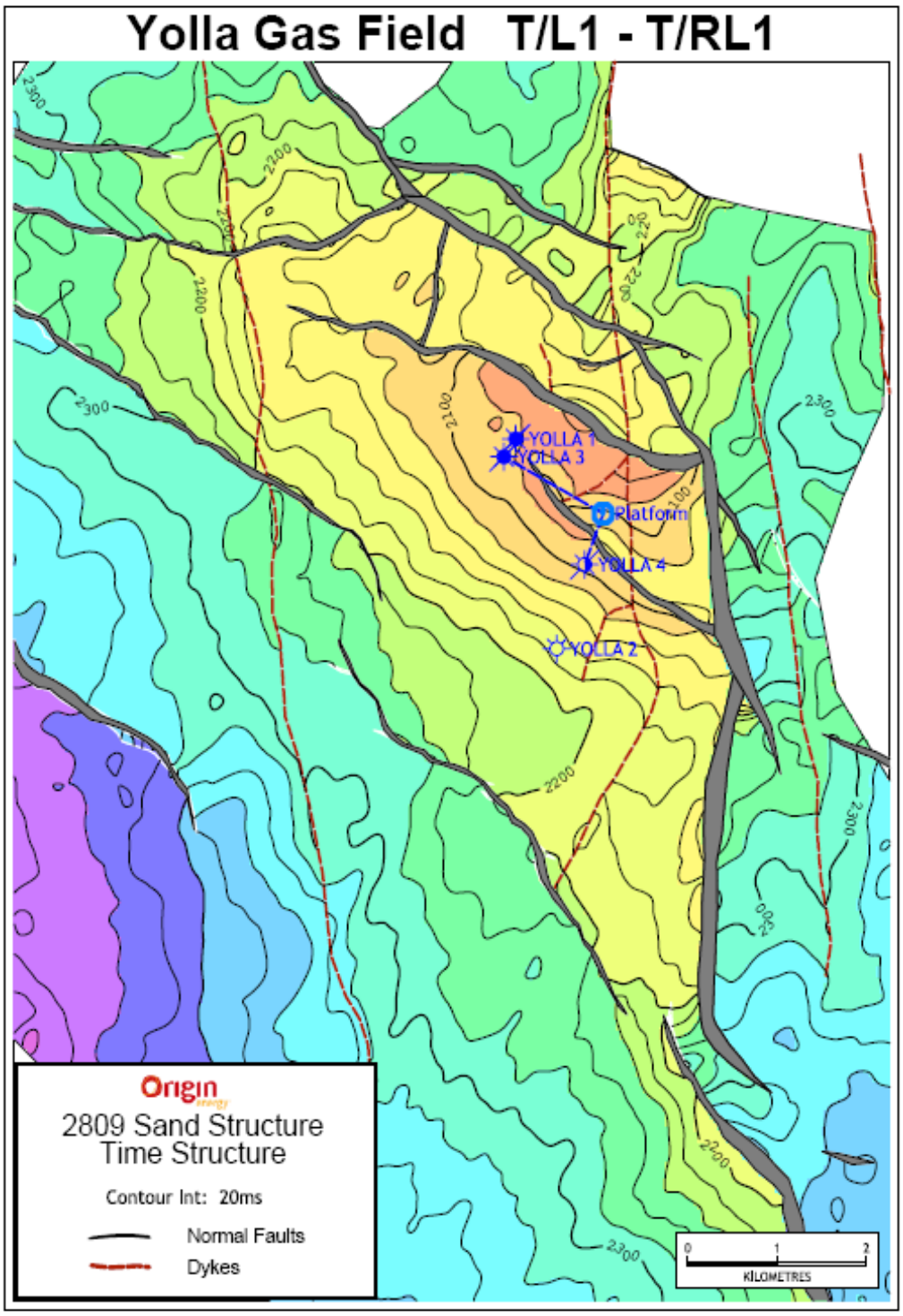
A 3D seismic survey was acquired over Yolla in 1994, this was used for mapping the field. Five horizons were mapped on the 3D volume. Origin used an interval velocity approach to depth conversion. Horizon Velocity Analysis (HVA) techniques were used to compute interval velocity grids. These were calibrated to wells. The 2809 sand was the only mappable target level within the lower reservoir package, while the Top Eastern View Coal Measures Formation was mappable. Depth maps for other zones were created by isopaching from these two main control surfaces.

Origin generated P90, P50 and P10 depth structure maps using an error grid that varied from 0 % at the wells to plus or minus 40 % on the flanks of the structure.

4.3.3 Modelling, Simulation and Volume Calculations

Surface grids generated from the HVA method were imported to Petrel where depth surfaces were generated for all the reservoir units. These surfaces formed the basis for a fine scale model with dimensions of 50 by 50 metres. The model had 326 sub layers 0.5 metres thick.

Multiple realisations of the model were run to provide P90, P50 and P10 estimates of GIIP. Volumes were also calculated probabilistically. GCA has reviewed the inputs to the Petrel Model and considers them to be reasonable.



Yolla Field
2809 Sand Structure
Time Structure

Project: KK1242 Sep '08	Checked:	Fig. 5

4.3.4 Reserves

The Yolla field reserves reported by Origin are shown in the following table.

TABLE 8

YOLLA FIELD RESERVES (Origin Share)
Reported by Origin as at 30 June 2008

Category	Sales gas + Ethane PJ	LPG MMtonnes	Oil + Condensate MMbbl
Proved (1P)	100	0.3	3.9
Proved + Probable (2P)	130	0.4	5.3
Proved + Probable + Possible (3P)	147	0.5	6.3

The Origin reserves estimates are based on the recoverable hydrocarbon products detailed in the "T/L1 -Yolla Field Reservoir Management Plan, Hydrocarbon in Place and Reserve Annual Review September 2007" adjusted for production from the field to 30 June 2008.

Origin's field production and development strategy is based on continued production from Yolla-3 and Yolla-4 with the next stage of development being to drill Yolla-5, with the provision to drill Yolla-6 if the field is compartmentalised. This will be followed by the installation of offshore compression.

GCA has reviewed the reserves reported by Origin and finds the estimates to be a reasonable estimate of the remaining recoverable gas and oil at this time.

However, the potential for field compartmentalisation is recognised by GCA following analysis of available production data and therefore Yolla-6 will likely be required to produce the reserves. GCA is of the opinion that there is evidence from the initial measured production and wellhead pressure declines that the two development wells were initially in reservoir communication. This occurred during the period to December 2006 when both produced from the zone 2809 sandstone.

Subsequently, with the switching of Yolla-4 to produce from the zone 2755 sandstone, a similar analysis indicates that Yolla-4 is likely only communicating with a fraction of the in-place volume modelled by Origin for this reservoir zone. GCA considers that there is potential for reservoir compartmentalisation to be realised through faulting and / or facies discontinuities.

4.3.5 Resources

Contingent

Two small undeveloped gas accumulations, White Ibis and Trefoil, have been discovered nearby to Yolla. Original Gas In-Place (OGIP) volumes estimated by Origin for these fields are shown in the following table.

TABLE 9

ESTIMATED GAS IN PLACE FOR WHITE IBIS AND TREFOIL FIELDS (Origin Share) Reported by Origin

Name	P90 / Low OGIP (Raw bcf)	P50 / Mid OGIP (Raw bcf)	P10 / High OGIP (Raw bcf)
White Ibis	16	23	32
Trefoil	98	162	368

Prospective

There are also a number of leads and prospects mapped in Origin held permits T/RL1, T/18P and T/44P in close proximity to Yolla, which are estimated to be small relative to the Yolla field. GCA did not review the base data in the volumetric determinations.

In order to recognise the potential upside value in GCA's High case the most significant prospect volumes (Mid case OGIP estimates > 100 bcf) were considered. Prospects with Chance of Success of less than 10% were excluded, as were leads due to their relative technical immaturity. Oil prospects were excluded as the Yolla field essentially comprises a gas production development. The two prospects that passed through this screening process were Rockhopper and Silvereye.

4.3.6 Profiles provided to Grant Samuel

The Most Likely production profile provided to Grant Samuel is shown in the following table.

TABLE 10

BASS GAS PROJECT (ORIGIN SHARE)
MOST LIKELY PRODUCTION FORECAST
RESERVES

Year Ending 30 June	Sales gas + Ethane. PJ	LPG ktonnes	Oil + Condensate. kbbl
2009	9.5	30	441
2010	9.5	26	416
2011	9.5	25	407
2012	9.7	32	514
2013	9.6	32	484
2014	9.6	32	462
2015	9.4	26	325
2016	9.2	29	371
2017	9.2	30	385
2018	9.3	29	344
2019+	35.8	105	1,180
TOTAL	**130**	**397**	**5,329**

GCA's Most Likely Reserves production profile matches Origin's reported Proved plus Probable reserves, as at 30 June 2008.

The Low case production matches Origin's estimated Proved reserves, as at 30 June 2008 while the High case has Yolla Proved plus Probable plus Possible reserves plus estimated production from Trefoil and White Ibis fields, and Rockhopper and Silvereye prospects. Production from Trefoil, While Ibis and Rockhopper was scheduled to fill the Yolla facility ullage when it becomes available.

In the High case the additional upside from the Contingent and Prospective Resources was considered by providing incremental profiles and the Chance of Development for the Contingent Resources and the GCoS for the Prospective Resources.

All three cases estimated by GCA include costs for two more platform development wells, Yolla-5 and Yolla-6 in 2009-10. Yolla-6 is included on the basis of GCA's expectation that the field is compartmentalised and at least one more well will be required, in addition to Yolla-5, to produce the reserves. All cases also include costs for compression to be installed in 2010 and installation of facilities for permanent platform manning in 2010.

In the Low and Most Likely cases no additional fields are tied into the Bass Gas development.

GCA's High case includes a further four development wells to develop the White Ibis and Trefoil discoveries as well as the Rockhopper and Silvereye prospects, over and above the GCA Most Likely case. Timing of development and production of Rockhopper and Silvereye (2023+) were estimated, taking into account the existing Yolla field's 3P production forecast, as well as Yolla facilities' capacity limitations.

GCA has estimated fixed and variable operating costs based on figures provided by Origin. GCA's estimated Origin's share of capital and operating costs over the life of the field for each of the three cases is shown in the following table.

TABLE 11

BASS GAS PROJECT
GCA'S ESTIMATED REMAINING LIFE OF FIELD CAPEX AND OPEX
(Origin Share) $million

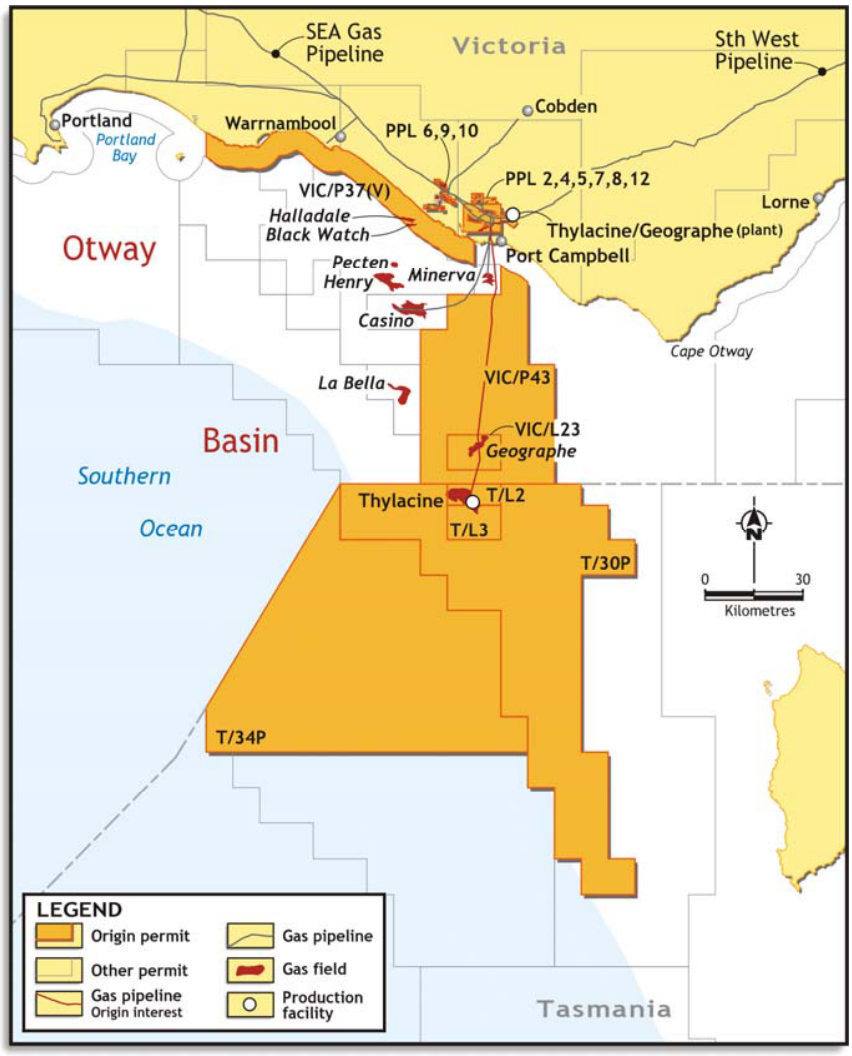
	Capex	Opex
Low	221	210
Most Likely	210	257
High	344	321

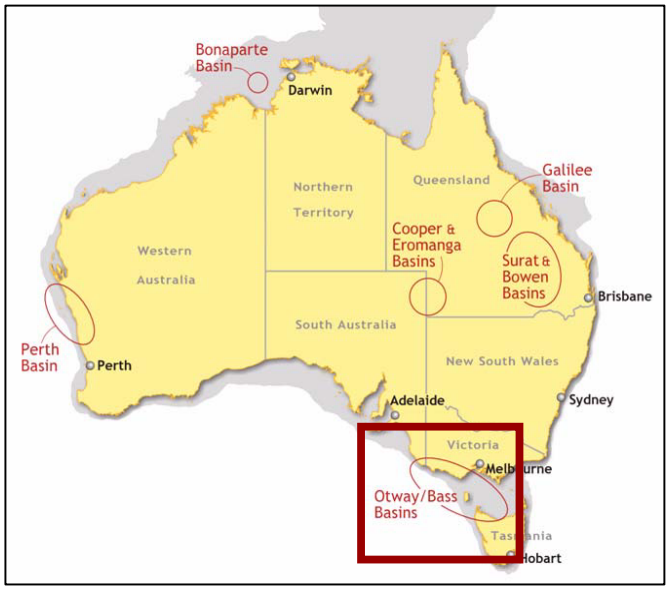
Note: Includes costs associated with Resource development and production

4.4 Thylacine and Geographe Development

The Thylacine and Geographe fields, **Figure 6**, are located about 15 km apart in the Otway Basin 55 to 70 km offshore of Port Campbell Victoria, in permits VIC/P43 (Thylacine) and T/30P (Geographe). The fields are in water depths of 101 m and 85 m respectively. The fields produce gas from Late Jurassic sandstone reservoirs, interpreted to have been deposited in deltaic to marginal marine settings.

Both fields were discovered in mid 2001 and production commenced from Thylacine in February 2008. The fields are being developed with a remotely operated wellhead platform on Thylacine, with provision for six wells, and a 70 km long pipeline to an onshore gas processing plant near the Iona gas plant, 6 km north of Port Campbell. The gas plant recovers LPG, and condensate and removes carbon dioxide. Four development wells have been drilled on Thylacine. The design production rate for the fields is some 60 PJ/annum.





Thylacine and Geographe Fields Locations and Permit Boundaries

Project: KK1242 Sep '08	Checked:	Fig. 6

The overall development plan calls for a total of eight to ten development wells for Thylacine, Thylacine North and Geographe. Future development plans call for development of the Geographe field using three subsea wells tied back into the pipeline and development of Thylacine North using a subsea completion tied back to the Thylacine platform.

4.4.1 Thylacine and Geographe Fields

Thylacine is a south east to north west trending faulted horst block. The crest of the structure is at the eastern end of the field. The structure plunges gently to the west. The reservoir depth ranges from 2,100 to 2,300 metres TVDSS. See **Figure 7**.

Geographe is a faulted anticline with an axis trending north east to south west. The reservoir depth ranges from 1,800 to 2,150 metres TVDSS.

Both fields are located in the Otway Basin which is a north west to south east striking, divergent margin, rift and drift basin. It is approximately 500 km long from Cape Jaffa in South Australia to north west Tasmania and forms part of the 4,000 km long Jurassic-Cretaceous Australian Southern Rift System. The basin is present both on and offshore South Australia and Victoria. The Tasmanian sector is wholly offshore.

4.4.2 Seismic Interpretation and Depth Mapping

The fields are covered by 3D seismic data that was acquired in 1999-2000. The data was reprocessed using Pre Stack Depth Migration methods after the discovery of Thylacine and Geographe fields. This reprocessing was completed in May 2002.

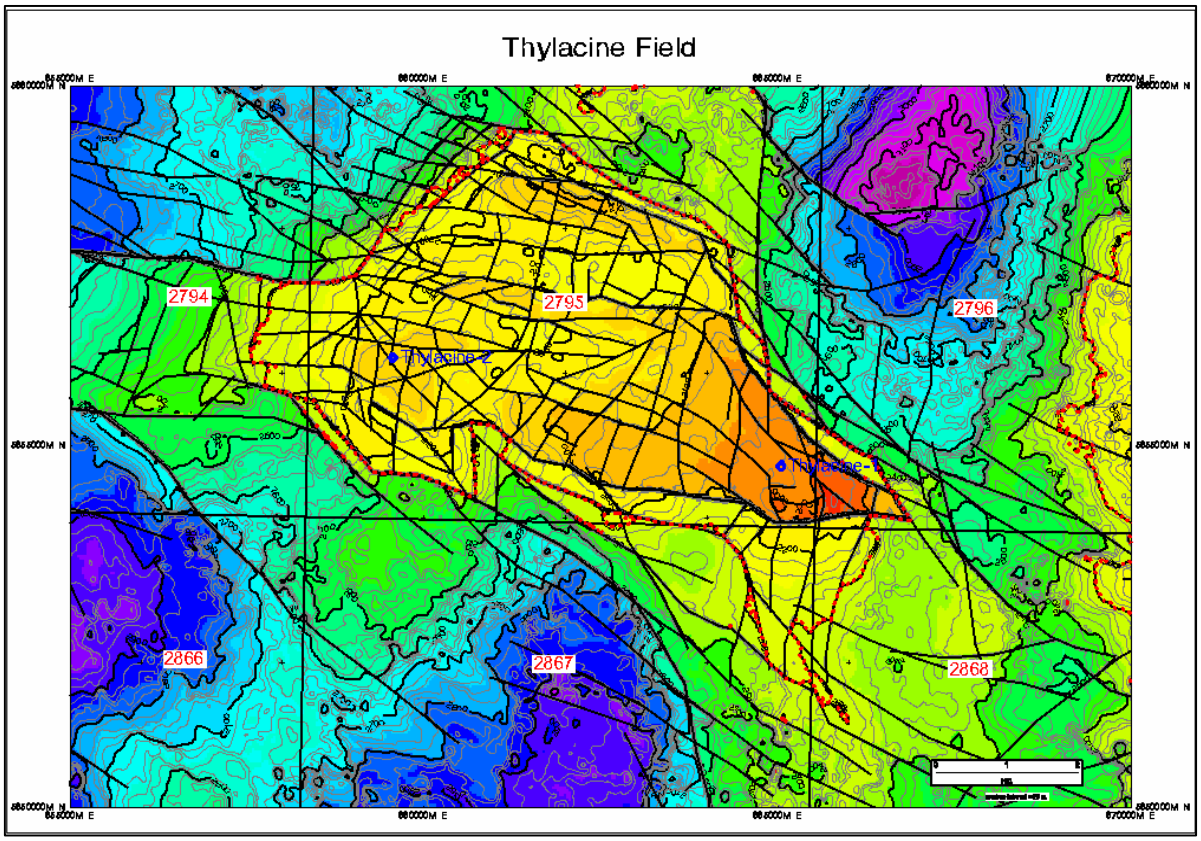
The operator, Woodside, explored several methods for converting picked horizons from time to depth. The preferred model was an average of three different seismically derived velocity data sets.

4.4.3 Modelling, Simulation and Volume Calculations

The basis for the geological models is discussed in the Operator's Field Development Plan document (2003). Petrel models generated from these have since been upgraded with the new well information and reserves estimates have been upgraded.

GCA has reviewed the Field Development Plan as well as the inputs to the models and has found them to be acceptable.

It is understood that these models are currently being revised with input from the development wells.



Thylacine Field
Depth Structure Map

Project: KK1242 Sep '08	Checked:	Fig. 7

4.4.4 Reserves

The Thylacine/Geographe field reserves reported by Origin are shown in the following table.

TABLE 12

THYLACINE / GEOGRAPHE
RESERVES (ORIGIN SHARE)
Reported by Origin as at 30 June 2008

Category	Sales Gas + Ethane PJ	LPG MMtonnes	Oil + Condensate MMbbl
Proved (1P)	171	0.3	2.1
Proved + Probable (2P)	265	0.5	3.2
Proved + Probable + Possible (3P)	379	0.7	4.6

Origin's reserves estimates are based on the Operator's (Woodside) "Final Field Development Plan, Thylacine and Geographe Fields, Offshore Otway Basin" (October 2003). Adjustments have been made to reflect results from drilling the four Thylacine development wells as well as initial cumulative production volumes and compositional sampling results from these wells. The sampling results led to negative revisions in the Condensate and LPG reserve estimates in line with the Operator's new assessments of product stream ratios relative to raw gas production volumes.

During Q3 2003, an independent reserves review of both fields was conducted by Malkewicz, Hueni and Associates (MHA). MHA did not calculate independent reserves figures, but conducted a review of the methodology and calculations of the Operator. During that review, risking of undrilled fault blocks was reviewed and adjusted, and continues to be carried by Origin.

The field production and development strategy is based on three main phases. Phase I comprises four Thylacine wells, a wellhead platform, subsea gas pipeline to shore, shore crossing near Port Campbell and gas processing plant adjacent to the Iona gas plant. This phase has been completed. Phase II will consist of the development of the Geographe Field with three subsea horizontal wells, expected in 2010. In addition, a separate single-well subsea tieback of Thylacine North is planned. Phase III comprises installation of onshore compressors.

Drilling of the four Thylacine development wells (one deviated and three horizontal wells) was completed in October 2006. Origin reported that all four wells came in structurally high to prognosis, and that less faulting (in N-S direction) is observed than in pre-drill expectations. Origin interpreted a significant change in the degree of likely structural compartmentalization.

Scope for geological facies-related compartmentalization still exists, and pressure data acquired during field appraisal clearly indicate that areal and vertical compartments exist, particularly in Unit 1. GCA is of the opinion that reservoir connectivity issues can only be fully understood with adequate dynamic field performance data following the acquisition of significant quantities of production and pressure response data.

Thylacine field first gas production, during facility commissioning, commenced in September 2007. Production subsequently remained shut-in until February 2008 whilst further commissioning work was completed. Only small reservoir fluid volumes have been withdrawn to date, relative to the in-place volumes. Origin's Thylacine reserve estimates, based primarily on static volumetric calculations and simulated reservoir performance forecasts, are therefore considered by GCA to remain a reasonable approach until adequate dynamic field data are available for interpretation.

Geographe reserves will not be updated until Phase II drilling data becomes available.

GCA has reviewed the reserves reported by Origin and finds the figures to be a reasonable estimate of the remaining recoverable gas and oil at this time, including recent results from the initial four development wells.

4.4.5 Resources

Origin provided information on a number of small prospects and leads in the vicinity of Thylacine and Geographe. GCA did not review the base data used for the volumetric determinations.

In order to recognise the technical basis for future potential value upside, the most significant prospect volumes (Mid case OGIP estimates > 100 bcf) were considered. Prospects with a Chance of Success of less than 10% were excluded as were leads due to their relative technical immaturity.

Two prospects, Razorback and Glenaire, were identified in the vicinity of Thylacine, with the potential to tie back to the Thylacine platform if exploration is successful.

4.4.6 Profiles provided to Grant Samuel

Production

The Most Likely production profile provided to Grant Samuel is shown in the following table.

TABLE 13

THYLACINE/GEOGRAPHE (Origin Share)
MOST LIKELY PRODUCTION FORECAST

Year Ending 30 June	Sales gas + Ethane. PJ	LPG ktonnes	Oil + Condensate. kbbl
2009	18.4	29	198
2010	18.2	29	194
2011	18.3	30	197
2012	18.4	34	246
2013	18.2	37	263
2014	18.2	36	251
2015	18.3	36	238
2016	18.4	35	230
2017	17.8	34	216
2018	15.1	28	179
2019+	85.0	160	991
TOTAL	**264.1**	**488**	**3,203**

The Most Likely case production profile produces the Proved plus Probable reserves, as at 30 June 2008, reported by Origin. The field plateau production rate is estimated to be approximately 60 PJ/annum (164 TJ/d) including down-time. The field production is forecast to come off plateau during 2018.

The Low case produces the estimated Proved reserves.

The High Case includes the estimated 3P reserves plus the estimated mean potentially recoverable resources from Razorback and Glenaire prospects. Chances Of Development (COD) of 60% and 40% respectively were estimated by GCA, in addition to a Geologic Chance of Success (GCOS) of 25%. However, the developments of these prospects were estimated to realise lower recovery efficiency than the existing Thylacine/Geographe field. This was due to estimated development by subsea facility tie-backs of the remote satellite accumulations, and deteriorating uptime performance of the unmanned Thylacine/Geographe facility. Profiles for development and production of the prospects were provided in separate profiles. Production from Razorback and Glenaire was scheduled to maintain the production plateau when production from Thylacine/Geographe commenced to decline.

Capex and Opex

GCA's estimated share of Origin's capital and operating costs over the life of the fields for each of the three cases is shown in the following table.

TABLE 14

THYLACINE/GEOGRAPHE
GCA'S ESTIMATED REMAINING LIFE OF FIELD CAPEX AND OPEX
(Origin's share) $ million

	Capex	Opex
Low	252	122
Most Likely	232	205
High	251	220

Significant capital expenditure over-runs were experienced during Thylacine Phase I development and commissioning periods. The original Phase I development budget was approximately $811 million, whilst the latest estimate reported by Origin is approximately $977 million (some 20.5% increase).

The further Field Development Plan capital expenditure estimates were reviewed by the Joint Venture in mid-2007. Phase II cost estimates approximately doubled since the previous estimate, while the Phase III estimate increased by 70%.

The Joint Venture is revisiting concept selection in an effort to focus on scope and cost reduction. Alternative development plans may include compression ahead of additional drilling and possible reduction in the number of Geographe wells. The partnership expects to finalise development concept revisions before the end of 2008.

In GCA's Most Likely case three new Geographe field subsea development wells are scheduled to be implemented in 2010/11 for an estimated cost of $64 million per well. The compression project, scheduled in Q4 2014, is estimated to cost $73 million. In addition, one Thylacine North development well is included in 2011 as a subsea tie-back to the Thylacine facility for an estimated cost of $193 million.

GCA's Low case includes three new Geographe subsea development wells and the compression project, as in the Most Likely case, but with costs increased by 25% over the Most Likely case to represent potential cost overruns. In the Low case development of Thylacine North is not included.

GCA's High case includes a further two development wells, over and above the GCA Most Likely case, to develop the Razorback and Glenaire prospects. Unit well, compression, and facility capital costs were estimated as per the Most Likely case. Timing of the development of the prospects and their production was scheduled to maintain the plateau production from the Thylacine/Geographe project.

In all cases abandonment costs were estimated to be $10 million per development well, $130 million for the unmanned platform and $29 million per subsea facility (excluding wells).

GCA has estimated fixed and variable operating costs based on data provided by Origin and forecast production rates.

4.5 Kupe

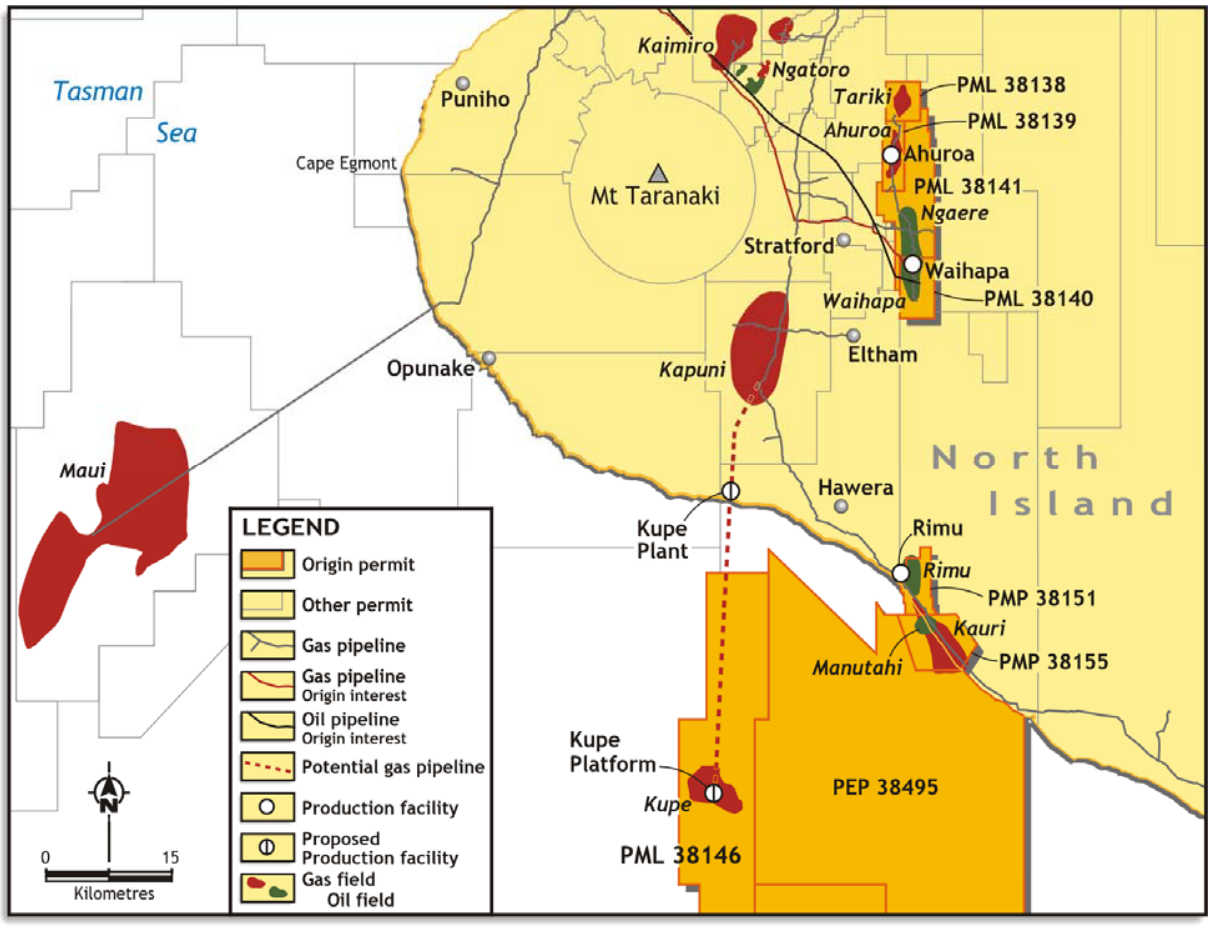
The Kupe Field is located in the southern offshore portion of the Taranaki Basin, approximately 30 km south of Hawera in 34 m of water in permit PML 38146. The field was discovered by the Kupe South-1 well drilled in 1986.

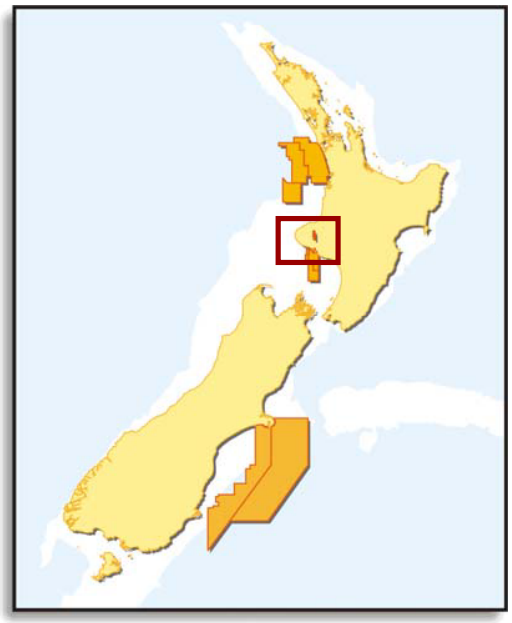
The Taranaki Basin is located onshore and offshore the west coast of the North Island of New Zealand (**Figure 8**). The Basin covers an area of over 100,000 sq km and is up to 9,000 m deep in places. Basin formation began in the Late Cretaceous and continued until the present. Hydrocarbons are found in sediments ranging from Palaeocene to Pliocene age.

The Kupe development consists of a normally unmanned wellhead platform over the field supporting three wells, a subsea pipeline to an onshore gas processing plant, a gas processing plant that recovers condensate and LPG and a sales gas pipeline to the main gas distribution trunkline system. The offshore work, including the drilling of the development wells, was completed in June 2008. Construction is still proceeding on the onshore works with production expected to commence mid 2009.

It is anticipated that a further two or three wells will be drilled in a second development phase in 7 to 10 years with the exact timing dependent on field performance.

Hydrocarbons in Kupe are contained in reservoirs in the Palaeocene Farewell Formation, a section of fluvial braided stream deposits. Three appraisal wells were drilled on Kupe: Kupe South-1, Kupe South-2, and Kupe South-3B. The Kupe-1 well was drilled just to the north of the OWC and encountered residual hydrocarbon shows.





Kupe Field
Location and Permit
Boundaries

Project: KK1242 Sep '08	Checked:	Fig. 8

4.5.1 Kupe Field

The Kupe Field is a north dipping nose structure which is sealed on the up-dip southern boundary by a north dipping NW-SE trending normal fault (**Figure 9).** The field is further compartmentalised by additional faults in a NW-SE trend as well as faults in a NE-SW trend. It has not yet been established whether these internal faults are sealing, although the recently drilled development wells Kupe South-6, -7ST1 and -8 should help in the understanding of field compartmentalisation.

4.5.2 Seismic Interpretation and Depth Mapping

The Kerry 3D seismic survey was acquired over the Kupe Field in 1996. The data was later reprocessed using Pre Stack Time Migration methods. Origin interpreted five horizons including the top and base of the reservoir section as inputs into the depth conversion process.

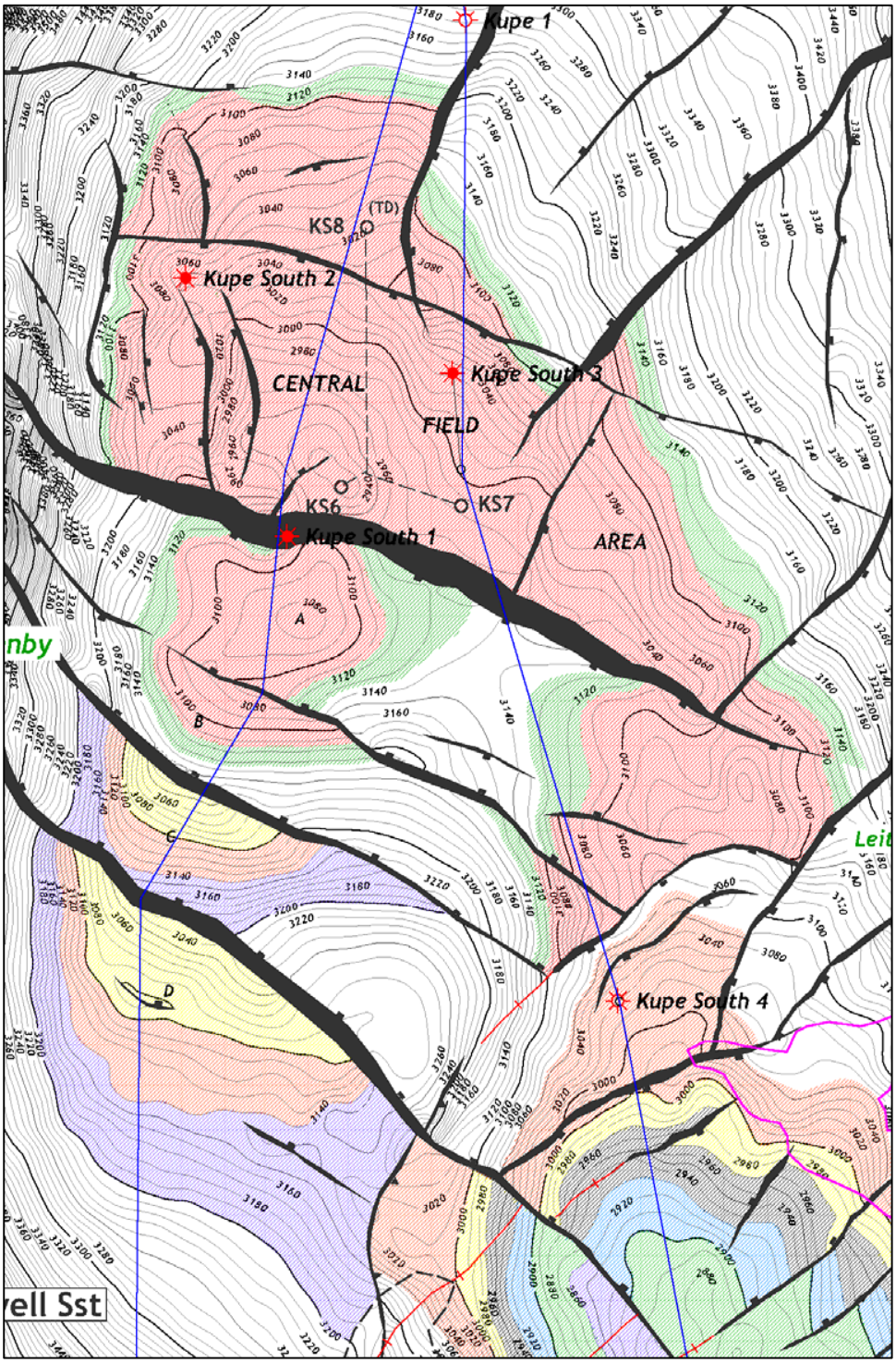
Several methods of depth conversion were tried including Horizon Velocity Analysis (HVA) using 2D gathers. Resource Investment Strategy Consultants (RISC) reviewed the seismic interpretations and depth mapping methodology and found them to be reasonable.

4.5.3 Modelling, Simulation and Volume Calculations

Two-way time and velocity grids generated from the HVA method were imported into Petrel where depth surfaces were generated of the top and base reservoir. These surfaces formed the basis for a fine scale model with dimensions of 50 by 50 m. The model had 300 sub layers 0.75 metres thick.

Multiple realisations of the model were run to provide P90, P50 and P10 estimates of GIIP. GCA has reviewed the inputs to the Petrel Model and accepts them to be reasonable.

The Petrel Model was up-scaled and exported to Eclipse for reservoir simulation.



Kupe Field
Depth Structure Map

Project: KK1242 Sep '08	Checked:	Fig9

4.5.4 Reserves

The Kupe reserves reported by Origin are shown in the following table.

TABLE 15

KUPE FIELD RESERVES (ORIGIN SHARE)
Reported by Origin as at 30 June 2008

Category	Sales Gas + Ethane PJ	LPG MMtonnes	Oil + Condensate MMbbl
Proved (1P)	100	0.5	6.4
Proved + Probable (2P)	127	0.5	7.4
Proved + Probable + Possible (3P)	154	0.7	9.8

The Origin reserves estimates are based on the evaluation presented by Origin in the "Kupe Central Field Area (CFA) Subsurface Development Plan" (April 2005).

The reserve estimate is based on the current (mainly static) understanding of the field. It is expected that the level of understanding of the reservoir will improve as additional well data, production data and pressure data are obtained and incorporated into dynamic field reservoir models for calibration purposes.

Pre-development reserves estimates were independently assessed by RISC Consultants for the joint venture in March 2006. The main reserves assessment difference was that RISC's Proved (1P) reserves were 26 bcf lower than the Operator's estimate at that time. This difference was mainly due to the exclusion by RISC of potential in-place volume contained in an un-penetrated northern fault block.

The northern fault block has recently been drilled by the KS-8 development well and encountered top reservoir close to the prognosis depth. Open-hole logs indicated similar reservoir fluid contacts to the Central Field Area (CFA). Origin has adjusted their reserves estimates in light of this new information. Subsequently, the KS-8 well was flow-tested and indicated poorer inflow performance than the KS-6 and KS-7ST1 development wells, but stable rates of some 33 MMscf/d gas and 3,800 bpd condensate. Carbon dioxide concentrations were slightly higher than anticipated, at around 15 mol%.

GCA has reviewed the reserves reported by Origin and finds the figures to be a reasonable estimate of the remaining recoverable gas and oil at this time, including recent results from the initial three development wells.

4.5.5 Resources

Contingent

The Momoho-1 exploration well has recently been drilled and Origin advised that the well discovered a small gas condensate pool within thin, good quality sandstones of the Palaeocene Farewell Formation. Preliminary Interpretation indicated that the well intersected a gross gas condensate column over the interval 2,896 to 2,921 mRT.

Origin indicated that potential exists for hydrocarbons to be trapped within a large closure on the north eastern, downthrown side of a central fault. Evaluation of this portion of the Momoho anticline will be considered at a future date by the Joint Venture once the full implications of Momoho-1 have been considered. Further studies will be undertaken to determine whether it may be possible to contemplate a development combining these existing and potential hydrocarbon accumulations. The Momoho-1 well will be plugged and abandoned upon the completion of the current evaluation programme.

Since the full implications of the well results have not yet been assessed by Origin, GCA has maintained its predrill estimated P50 ultimate recovery of 96 Bcf raw gas as its basis for valuation.

Prospective

Origin provided information on a number of small prospects and leads in the vicinity of Kupe. GCA did not review the base data used for the volumetric determinations.

In order to recognise potential upside value the most significant prospect volumes (Mid case Recoverable Gas volume estimates > 20 bcf) were considered. Prospects with Chance of Success of less than 10% and leads were excluded.

4.5.6 Profiles provided to Grant Samuel

The Most Likely production profile provided to Grant Samuel is shown in the following table.

TABLE 16

KUPE (ORIGIN SHARE)
MOST LIKELY PRODUCTION FORECAST

Year Ending 30 June	Sales gas + Ethane. PJ	LPG ktonnes	Oil + Condensate. kbbl
2009	2.5	11	239
2010	10	45	940
2011	10	45	873
2012	10	44	808
2013	10	43	742
2014	10	43	678
2015	10	42	614
2016	10	42	550
2017	10	41	487
2018	10	40	425
2019+	34.2	134	995
TOTAL	**127**	**531**	**7,352**

Production in the Most Likely case is consistent with the Proved plus Probable estimated reserves. The forecast is based on the three initial development wells producing in isolation for approximately seven years and then a further two wells being drilled as part of the second development phase. The production forecast is consistent with the current Origin "Kupe Central Field Area (CFA) Subsurface Development Plan" Proved plus Probable scenario.

The GCA Low case production forecast was based on Origin's Proved reserves.

GCA's High case production forecast was based on Origin's Proved plus Probable plus Possible reserves plus production contributions from the recently discovered Momoho field plus potential successful developments of the Denby D and Leith prospects. Separate profiles for the reserves and resources were provided to Grant Samuel. The costs and production associated with the inclusion of both Contingent and Prospective Resources were risked after allowing for the chance of both geologic and commercial success. Deferred timing of production from the prospects was estimated by taking into account existing Kupe production forecast and facilities limitations.

4.5.7 Capital and Operating Costs

GCA's estimated share of Origin's capital and operating costs over the life of the field is shown for each of the three cases in the following table.

TABLE 17

KUPE
GCA'S ESTIMATED REMAINING LIFE OF FIELD CAPEX AND OPEX
(Origin Share) $million

Category	Capex	Opex
Low	276	193
Most Likely	262	228
High	297	258

GCA'S Most Likely case includes two new development wells in 2016 with an estimated cost of $53 million per well. Onshore installation of compression is estimated to occur in 2019 at a nominal cost of $5 million.

GCA's Low case includes two new development wells and the compression project, as in the Most Likely case, but with costs increased by 25% to allow for possible cost overruns.

GCA's High case includes an additional three development wells to develop the Denby D, Leith, and Momoho prospects, over and above GCA's Most Likely case. Unit well, compression, and facility capital costs were the same as the Most Likely case. The cost of the subsea wells was estimated to be $69 million per well and the tie-back of the subsea facilities and pipeline was estimated to be $167 million.

In all cases abandonment costs were estimated to be $8 million per development well, $87 million for removal of the wellhead platform and $25 million per subsea facility (excluding wells).

Estimated operating costs for all cases were based on information provided by Origin, and forecast production rates.

4.6. Other Conventional Oil and Gas Assets

Origin has a number of additional smaller conventional oil and gas assets in its portfolio that have not been reviewed by GCA. GCA did not provide profiles for these smaller assets to Grant Samuel. The reserves for these assets are shown in the following tables.

4.6.1 Reserves

TABLE 18

SALES GAS AND ETHANE RESERVES OTHER AREAS (ORIGIN SHARE)
Reported by Origin as at 30 June 2008

Category Area / Asset	1P PJ	2P PJ	3P PJ
Onshore Australia	47	89	173
Onshore NZ	6	20	75
TOTAL	53	109	249

TABLE 19

LPG RESERVES OTHER AREAS (ORIGIN SHARE)
Reported by Origin as at 30 June 2008

Category Area / Asset	1P MMtonnes	2P MMtonnes	3P MMtonnes
Onshore Australia	-	0.1	0.1
Onshore NZ	-	-	0.1
TOTAL	-	0.1	0.2

TABLE 20

CONDENSATE AND OIL RESERVES OTHER AREAS (ORIGIN SHARE)
Reported by Origin as at 30 June 2008

Category Area / Asset	1P MMbbl	2P MMbbl	3P MMbbl
Onshore Australia	0.9	1.8	3.0
Onshore NZ	0.2	2.6	9.1
TOTAL	1.1	4.4	12.2

Origin's interests in the smaller conventional oil and gas assets are shown in **Appendix II.**

5. CONVENTIONAL OIL AND GAS GREENFIELDS EXPLORATION

Origin has exploration permits in Vietnam, Kenya and New Zealand. It has been actively seeking to farm down in all of them.

In the following tables currencies have been converted to Australian dollars using a rate of NZ$1 equals A$0.817 and US$1 equals A$1.04.

5.1 New Zealand

In New Zealand Origin has a 50% interest in two Northland Basin permits, PEP 38618 and PEP 38619 and a 100% interest in two Canterbury Basin permits, PEP 38262 and PEP 38264.

The Northland Basin is north of and contiguous with the Taranaki Basin and has a similar geological history. The basin covers an area of 50,000 sq km both on and offshore the west coast of the North Island. Sediment thickness ranges up to 9,000 m in some areas.

Both Northland permits have just entered year three of a five year term (**Table 21**). Combined expenditure (100%) to date is $13.075 million. There is a well commitment in each permit during year three.

TABLE 21

NORTHLAND REMAINING PHASE 2 EXPLORATION COMMITMENT (100%) - $million
Reported by Origin as at 30 June 2008

Permit	Activity	Year 3	Year 4	Year 5
PEP 38618	G&G Studies	-	-	-
	3D Seismic	-	-	150 km^2
	Wells	$49	-	1 Well
PEP 38619	G&G Studies	-	-	-
	3D Seismic	-	-	150 km^2
	Wells	$33	-	1 Well

The Canterbury basin is located on and offshore of the east coast of the South island. It covers an area of 55,000 sq km and has over 6,000 m of sediment. The basin is from Mid Cretaceous to recent in age.

Combined expenditure to date in the Canterbury permits is $6.5 million. Origin has announced that it intends to progress into year four of Permit 38262 that carries a commitment to drill an exploration well. Permit 38264 is currently in year two of a five year permit term (**Table 22**).

TABLE 22

CANTERBURY REMAINING PHASE 1 EXPLORATION COMMITMENT (100%) - $ million

Permit	Activity	Year 3	Year 4	Year 5
PEP38262	G&G Studies	-	$0.2	$0.2
	Wells	-	$41	-
PEP38264	G&G Studies	$0.2	$0.2	$0.2
	2D Seismic	$1.2	-	-
	Wells	-	$40.9	-

GCA is unaware of any significant Canterbury Basin transactions relevant to the deep water area Origin's permits are in, although there were four permits in the Great South Basin awarded to consortia led by ExxonMobil and OMV with commitments of over $980 million.

GCA is unaware of any significant recent transactions in the Northland area.

5.2 Kenya

Origin has a 75% interest in two exploration permits in the Lamu Basin offshore Kenya, L8 and L9.

The Lamu Basin lies both on and offshore of Kenya. The basin contains sediments ranging from Permian to recent in age. There are upwards of 12,000 m of sediment in parts of the basin.

Phase 1 of the contract has been extended to 21 January 2009, subject to completion of further specialist seismic work.

Phase 1 expenditure was approximately $6 million (split evenly between Blocks 8 and 9). The Phase 2 commitment is summarized in **Table 23**.

TABLE 23

KENYA PHASE 2 EXPLORATION COMMITMENT (100%) - $million

Block	Activity	Year 1	Year 2	Year 3	Year 4
Block 8	G&G Studies	$ 0.3	$0.3	$0.3	$0.3
	3D Seismic	-	$2.1	-	$ 2.1
	Wells	$46.9	-	$ 46.9	-
Block 9	G&G Studies	$0.3	$0.3	$0.3	$0.3
	3D Seismic	$2.1	-	$2.1	-
	Wells	-	$46.9	-	$46.9

In recent transactions in the Lamu Basin area, CNOOC acquired Blocks L2, L3 and L4 in the onshore part of the basin but are reportedly seeking farm-in partners or an acreage swap. Woodside is reportedly pulling out of Lamu Basin Blocks L5, L7, L10 and L11 after drilling an unsuccessful $80 million well. Woodside had farmed in to the permits in 2003.

5.3 Vietnam

Origin has recently been awarded Block 121 in the Song Hong Basin offshore Vietnam. The block covers an area of 7,561 sq km. One well has been drilled. Origin holds 100% working interest in the block. The PSC contract is currently being negotiated.

The Song Hong Basin is the largest sedimentary basin in Vietnam, comprising over 220,000 sq km. The basin axis is NW-SE and a small portion, known as the Hanoi Graben, is located onshore in the NW. The basin is a Tertiary aged rift with sediments ranging in age from Eocene to Recent. Over 10,000 metres of sediment are present in some parts.

There is a signature bonus of $520,000 due upon signature of the PSC. Historical costs have been $557,000. This has comprised data purchases, travel and legal. The Phase 1 work commitment is summarised in **Table 24**:

TABLE 24

VIETNAM PHASE 1 EXPLORATION COMMITMENT (100%) - $million

Block	Activity	Year 1	Year 2	Year 3
Block 121	G&G Studies	$0.4	-	-
	2D/3D Seismic	$2.0	$11.3	-
	Wells	-	-	$20.8

GCA is unaware of any recent transactions nearby to Origin's Block 121 acreage. However Singapore Petroleum signed an agreement in 2004 to acquire 10% of ATIP's interest in Blocks 102 and 106 in the northern part of the Song Hong Basin. They took an additional 10% in 2005 for an aggregate value of $9.4 million. In 2006 Santos and Singapore Petroleum acquired Blocks 101 and 100/04, also in the northern part of the Song Hong Basin. The terms included acquisition of 3D seismic and one well in the first three year term.

5.4 Exploration Permit Valuation

GCA has reviewed the past and future work commitments for these concessions and, where available, has also reviewed recent nearby transactions. Based on the sunk costs, work commitments and likelihood of securing farm-in partners GCA places a range of values on the exploration permits as summarised in **Table 25**:

TABLE 25

EXPLORATION PERMIT VALUATION SUMMARY (100%)
As Estimated by GCA specifically for Valuation Purposes, as at 30 June 2008

Case	Estimated Value
Low	$ 10 million
Most Likely	$ 42 million
High	$ 83 million

The Low Case is based on Origin being successful in securing farm-ins for only half of the areas and the terms would be to pay past costs only.

The Most Likely Case is based on farm-ins being secured for half of the areas and the farm-inee carrying Origin through the first phase of drilling.

The High Case scenario is that all blocks are successfully farmed out and that Origin is carried through the first drilling phase.

6. LIMITATIONS

In carrying out this review, GCA has relied upon information and data provided by Origin which comprised details of the petroleum assets, basic exploration and engineering data, interpretation and other technical reports, and cost data, supplemented by public domain data as was appropriate. No new mapping or detailed interpretation was carried out, but the data supplied were reviewed and audited with due diligence to provide appropriate confidence in its validity. The opportunity was also taken to discuss with Origin both base and interpretative data.

GCA has no reason to believe that any material facts have been withheld from it, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

GCA has not verified the legal status of tenements reported on in this document nor undertaken any due diligence on any contracts or agreements or any other legal or accounting matters and is not qualified to provide an opinion thereof.

This assessment has been conducted within the context of GCA's understanding of the effects of petroleum legislation, taxation and other regulations that have been represented to currently apply to these properties.

It should be understood that the evaluation of petroleum properties involves judgments in respect of a series of issues and parameters that cannot be measured precisely, including the volumes of hydrocarbons that can be produced and sold in the future, the revenues that those hydrocarbons may generate and the costs of producing them.

The opinions expressed herein represent GCA's judgment based upon its evaluation of these issues, the data that has been made available and the company's professional experience in the consideration of these matters. Any evaluation may be subject to significant variation over time as new information becomes available or perceptions of market conditions change.

7. QUALIFICATIONS

GCA is an independent international energy advisory group of over 45 years standing. A substantial part of GCA's work involves the technical evaluation of petroleum properties and the provision of independent valuation of assets for inclusion in company or stock exchange statutory documentation.

This report has been compiled under the supervision of Mr David Ahye. Mr Ahye is a Principal Advisor and Regional Manager, Asia Pacific of Gaffney, Cline & Associates Singapore & Sydney Offices, with over 33 years of industry experience. He holds B.Sc. (Hons.) Chemical Engineering and is a member of the Society of Petroleum Engineers and South East Asia Petroleum Exploration Society. The technical analysis was performed primarily by Mr Murray Freeman, Mr Bruce Gunn and Mr Adrian Starkey. Mr Freeman has a B. Sc., B.E. (Chem. Eng.) from Sydney University and a M.S. (Chem. Eng.) from MIT, Massachusetts, and 39 years experience in the petroleum industry. He is a member of the Society of Petroleum Engineers and the Petroleum Exploration Society of Australia. Mr Gunn is a Senior Petroleum Engineer with Gaffney, Cline and Associates based in Sydney with over 25 years experience in the petroleum industry, internationally and within Australia. He holds B.Sc (Hons) and M.Sc degrees and is a member of the Society of Petroleum Engineers. Mr. Starkey holds an M.Eng. (Hons) in Mechanical Engineering and an M.Sc. in Petroleum Engineering. He is a UK Chartered Engineer (C.Eng.) and is a member of the Society of Petroleum Engineers (SPE) with more than 17 years of experience in reservoir engineering and field development.

8. DECLARATION

In preparing this report, GCA served as an independent technical specialist. No GCA employee involved in the compilation of this document has any pecuniary or other interest that could be reasonably regarded as capable of affecting his or her ability to provide an unbiased opinion in relation to the proposed transaction. GCA will receive a fee for the preparation of this report. This fee is not contingent on the outcome of the proposed transaction.

GCA has given its written consent to the inclusion of this report in an Independent Expert's Report to be issued in the form and context in which it is included. This report or any reference thereto may not be included in any other document or distributed for any other purpose without the prior written consent of GCA to the purpose of such distribution and to the form and context in which the report or reference appears.

Yours sincerely
GAFFNEY, CLINE & ASSOCIATES

David S. Ahye
Regional Manager, Asia Pacific

APPENDIX I

GLOSSARY OF TERMS

GLOSSARY OF TERMS

$	Australian dollars
$k	Thousand Australian dollars
AAPG	American Association of Petroleum Geologists
bbl	Barrel
bbl/d	Barrels per day
bcf	Billion cubic feet
CSG	Coal Seam Gas
DST	Drill stem test
g/cc	Grams per cubic centimetre
FEED	Front End Engineering and Design
GIIP	Gas Initially In Place
GJ	Gigajoule (10^9 joules)
GRV	Gross Rock Volume
J	Joule
kbbl	Thousand barrels
kbbl/d	Thousand barrels per day
km	Kilometre
ktonnes	Thousand tonnes
LNG	Liquefied Natural Gas
LPG	Liquefied petroleum gas
m	Metre
m^3	Cubic metre
MMbbl	Million barrels
MMcf	Million standard cubic feet
MMtonnes	Million tonnes
m SS	Metres SubSea
p.a.	Per annum
PRMS	Petroleum Resources Management System
PJ	Petajoule (10^{15} joule)
scf	Standard cubic feet
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
sq km	Square kilometres
TJ	Terajoule (10^{12} joules)
TJ/d	Terajoules per day
WPC	World Petroleum Council
US$	United States dollars
1C	Low estimate of Contingent Resource
2C	Best estimate of Contingent Resource
3C	High estimate of Contingent resource
1P	Proved
2P	Proved plus Probable
3P	Proved plus Probable plus Possible

APPENDIX II

ORIGIN'S PERMITS

ORIGINS PERMITS+

Basin/Project Area	Permits (Interest) (* Denotes Operatorship)
Australia	
Surat Basin (Qld)	PL 14 (100%*); PLs 56 and 74 (69.0%*); PL 30 (75.0%*); PLs 21, 22, 27 and 64 (87.50%*); PLs 53, 174 and 227 (100%*); ATP 470P Redcap (90.0%*); ATP 470P Formosa Downs (49.50%*); PL 71 (Production) (90.0%*); PL 71 (Exploration) (72.0%*); PL 70 (100%*) and PL (Application) 264 (90%*); ATP 471P Weribone Pooling Area (50.64%*); ATP 336P and PLs 10W, 11W, 12W, 28W, 69 and 89 (46.25%); PL 11 Snake Creek East 1 Exclusion Zone (25.0%); ATP 647P (Block 2656 only) (50.0%*); and ATP 754P (50.0%*).
Denison Trough (Qld)	PLs 41, 42, 43, 44, 45, 54, 67, 173, 183 and 218 (50.0%*); ATP 337P (50.0%); ATP 337P Mahalo (30.0%); and ATP 553P (50.0%)
Galilee Basin (Qld)	ATPs 666P, 667P and 668P (ATP 668P being transferred to Origin) (100.0%*))
CSG (Qld)	
– *Spring Gully*	PLs 195 and 203 and ATP 592P (94.50%*); PL 204 (99.725%*); and PL 200 (95.7104%*)
- *Fairview*	PLs 90, 91, 92, 99, 100, 232, 233, 234, 235 and 236 and ATP 526P (23.93%)
- *Peat*	PL 101 (100%*)
- *Argyle/Kenya/Bellevue*	PLs 179, 180(A), 228, 229 and 263(A) and ATP 620P (40.625%), ATP 610P and PL 247(A) (29.375%); and ATP 648P, PL 257(A) and PL 259(A)(31.25%)
- *Talinga/Orana*	PLs 209, 226, 215(A), 216(A) and 225(A) and ATP 692P (100%*)
- *Other(Bowen Basin)*	PLs 219 and 220 (100%*); ATP 653P and ATP 745P (23.85%); and ATP 804P (29.29825%)
- *Other (Surat Basin)*	ATP 606P (92.7162%*); ATP 631P (18.0965%); ATP 663P (100%*); ATP 702P, PLs 265(A) and 266(A) (100.0%*); ATP 792P (92.7162%*) and ATP 793P (100.0%*) (ATPs 792P and 793P subject to EA approval)
Onshore Otway Basin	
- *SA*	PRL 13 (50.0%); PRL 1 and 2 and PPLs 62, 168 and 202 (100.0%*) (Sold to Adelaide Petroleum under agreement dated 4 July 2008)
- *Victoria*	PPLs 6 and 9 and PRL 1 (90.0%*); PPLs 4, 5, 7, 10 and 12 (100.0%*); PPL 2 (Ex. Iona) (100.0%*); and PPL 8 (100.0%*).
Offshore Otway Basin	
- *Victoria*	VIC/L23 and VIC/P43 (30.75%); and VIC/P37(V) (100.0%*).
- *Tasmania*	T/L2, T/L3, T/30P and T/34P (30.75%)
Bass Basin (Tasmania)	T/L1 and T/RL1 (42.50%*); T/18P (39.0%*); and T/44P (60.0%*)
Onshore Perth Basin (WA)	EP 320 and L11 (67.0%*); EP 368 (15.0%); EP 413 and L14 (49.189%*); and L1/L2 (excluding Dongara, Mondarra and Yardarino) (50.0%)
Offshore Bonaparte (WA/NT)	NT/RL1 and WA6R (5.0%)

Cooper Basin	
- *Qld*	SWQ Unit Subleases (16.7375%); Aquitaine A & B Blocks and associated PLs (25.0%); Aquitaine C Block and associated PLs (27.0%); and Wareena Block and associated PLs (10.0%)
- *SA*	SA Unit PPLs (13.19%); Patchawarra East Block PPLs (10.536%); Reg Sprigg West Unit (PPLs 194 and 211) (7.902%)
New Zealand	
Taranaki Basin	PMP 38151, PMP 38155, PML 38138, PML 38139, PML 38140 and PML 38141 (100%*) and PML 38140 (below base of Tikorangi Formation), PML 38141 (below base of Tikorangi Formation), PEP 381201 and PEP 38495 (50.0%*).
	PML 38146 (50.0%*) and PEP 38485 (33.333%)
Northlands Basin	PEP 38618 and PEP 38619 (50.0%*)
Canterbury Basin	PEP 38262 and 38264 (100.0%*)
Kenya	
Lamu Basin	L8 and L9 (75.0%*)
Vietnam	
Song Hong Basin	Block 121 (100.0%*) (Subject to negotiated PSC)

+ Includes both conventional oil and gas and coal seam gas permits

APPENDIX III

EXTRACTS FROM THE PETROLEUM RESOURCES MANAGEMENT SYSTEM

Extracts from the Petroleum Resources Management System

Definitions and Guidelines ([1])

March 2007

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

(1) the area delineated by drilling and defined by fluid contacts, if any, and

(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the

[1] These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

reservoir that can be judged with reasonable certainty to be commercially productive. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain**.** Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CONTINGENT RESOURCES

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Development Pending

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclarified or on Hold

A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

Appendix 9

Market Evidence – Energy Generation and Retailing[1] Transactions

Electricity Generation in Australia and New Zealand

There have been a large number of transactions involving generation assets in Australia and New Zealand since the mid 1990's as deregulation of each country's energy sectors has progressed. In particular, as growth in the demand for electricity has been revealed to be in excess of projected supply, consolidation in the Australian generation sector has accelerated. A selection of relevant electricity generation transactions since 2000 for which there is sufficient information to prepare meaningful market parameters is set out below:

Recent Transaction Evidence – Electricity Generation in Australia and New Zealand

Date	Target	Fuel[2]	Type[3]	Consid-eration[4] (millions)	EBITDA Multiple[5] (times)		EBIT Multiple[6] (times)		Price per MW[7] (millions)	
					Historical	Forecast	Historical	Forecast	Unadjusted	Adjusted
Australia										
Jul 08	73% of Ecogen generation business	G	P	A$87	na[8]	na	na	na	A$0.24	A$0.24
Jul 08	Uranquinty Power Station	G	P	A$700	na	na	na	na	A$1.09	A$1.09
Dec 07	15% of Braemar Power Station	G	P	A$237	na	9.3	na	na	A$0.96	A$0.99
Dec 07	30% of Uranquinty Power Station	G	P	A$250	na	na	na	na	A$0.93	A$0.96
Sep 07	33% of AlintaAGL's cogeneration business	G	C	A$902	na	na	na	na	A$1.40	A$1.45
Jun 07	IPO of Transfield Infrastructure Services Fund	G/C/W[9]	P/B/C/I	A$560	9.4	9.0	na	na	A$1.39[10]	A$1.45
Apr 07	Wattle Point Wind Farm	W	na	A$225	na	na	na	na	A$2.47	A$2.58
Mar 07	Powerdirect Australia's generation business	B	C	A$70	na	na	na	na	A$1.63	A$1.72
Mar 07	4.71% of Loy Yang A Power Station	C	B	A$1,367	na	12.9	na	na	A$1.92[10]	A$2.03

1 There have been a substantial number of well documented transactions in the energy sector in Australia and New Zealand in recent years. The major recent Australian energy sector transaction was the acquisition of Alinta by the Babcock & Brown/Singapore Power Consortium. Alinta owned 29 energy businesses and assets including gas transmission and distribution assets, electricity distribution assets, power generation assets, energy retail assets and asset management businesses. The final terms of the transaction announced in May 2007 valued Alinta at approximately A$8 billion and implied a current year multiple of 15.4 times EBITDA. As a result of movements in the value of the scrip portions of the consideration, the value received by Alinta shareholders on completion of the transaction on 31 August 2007 was A$7.6 billion (a current year multiple of EBITDA of 14.8 times). As these multiples reflect the blend of Alinta's various businesses, the transaction is not meaningful for assessing valuation parameters for Origin's electricity generation and energy retailing activities and therefore has not been presented in this appendix. Furthermore, it should be noted that at 30 June 2008 BBP has written down the value of the assets acquired in this transaction by a substantial amount and therefore the transaction may not provide good market evidence in the current market.

2 C = Coal; G = Gas; W = Wind; H = Hydro; B = Biomass; D = Diesel; J = Jet fuel; GT = Geothermal

3 P = Peaking; B = Base load; I = Intermediate; C = Cogeneration

4 Implied equity value if 100% of the company or business had been acquired.

5 Represents gross consideration divided by EBITDA. EBITDA is earnings before net interest, tax, depreciation, amortisation, investment income and significant and non-recurring items.

6 Represents gross consideration divided by EBIT. EBIT is earnings before net interest, tax, investment income and significant and non-recurring items.

7 Represents gross consideration divided by MW of installed capacity on a proportional basis. In some transactions price per MW is based on broker estimates of the price paid for the generation asset acquired. Multiples presented in the table have been adjusted to allow for inflation since acquisition so that all multiples reflect current dollars.

8 na = not available

9 TSI Fund derives 97% of its cash flows from electricity generation (predominantly from gas fired power stations) with the remainder from water filtration plants.

10 Price per MW is distorted to the extent that non generation assets were also acquired (e.g. TSI Fund also owns two water filtration plants, Loy Yang comprises a power station plus a coal mine and electricity dispatch and marketing business and Pacific Hydro has a substantial portfolio of development assets).

Recent Transaction Evidence – Electricity Generation in Australia and New Zealand

Date	Target	Fuel[2]	Type[3]	Consid-eration[4] (millions)	EBITDA Multiple[5] (times)		EBIT Multiple[6] (times)		Price per MW[7] (millions)	
					Historical	Forecast	Historical	Forecast	Unadjusted	Adjusted
Jan 07	Torrens Island Power Station	G	B	A$572	na	na	na	na	A$0.45	A$0.47
Jan 07	Hallett Power Station	G	P	A$117	na	na	na	na	A$0.65	A$0.69
Nov 06	IPO of BBP	G	B/P	A$898	13.3	10.7	26.6	18.6	A$0.77	A$0.82
Jul 06	9.3% of Loy Yang A Power Station	C	B	A$1,237	na	10.6	na	na	A$1.85[10]	A$1.96
Jul 06	Lonsdale Power Station	D	P	A$11	na	na	na	na	A$0.55	A$0.58
Jun 06	NRG Energy's South Australian power assets	C	B	A$317	11.8	10.3	na	na	A$0.68	A$0.72
Apr 06	33% of AlintaAGL[11]	na	na	A$1,112	na	12.6	na	14.2	na	na
Feb 06	Angaston Power Station	D	P	A$25	na	na	na	na	A$0.64	A$0.69
Oct 05	Southern Hydro	H	P	A$1,425	na	19.5	na	na	A$1.94	A$2.12
Oct 05	Valley Power	G	P	A$242	na	na	na	na	A$0.81	A$0.89
Mar 05	Singapore Power's merchant energy business[11]	G	P/I	A$2,128	11.7	na	na	na	A$0.55-0.63[12]	A$0.61-0.70
Mar 05	Pacific Hydro	H/W	na	A$801	19.7	15.3	23.4	18.7	A$3.88[10]	A$4.33
Apr 04	TXU's Australian assets[11]	G	P/I	A$5,100	9.2	8.6	na	na	na	na
Mar 04	Duke Energy Australian and New Zealand assets[11]	G	P/C/I	A$1,690	17.0	15.5	na	na	na	na
Jul 03	Loy Yang A Power Station	C	B	A$3,500	7.2	8.3	9.4	11.6	A$1.75[10]	A$2.03
Jun 03	50% of Redbank Power Station	C	B	A$55	na	10.8	na	16.2	A$2.59	A$3.02
Mar 03	Southern Hydro	H	P	A$591	na	na	na	na	A$1.10	A$1.28
Dec 02	Mount Stuart Power Station	J	P	A$93	na	na	na	10.9	A$0.32	A$0.38
Dec 02	Ecogen electricity generation assets	G	I/P	A$81	8.7	8.4	12.1	11.4	A$0.21	A$0.25
Jul 01	50% of South West Cogeneration Joint Venture	G	C	A$137	na	na	na	na	A$1.14	A$1.40
Apr 01	Power Facilities Pty Limited	H	na	A$85	na	na	na	na	A$1.37	A$1.69
New Zealand										
May 07	10% of King Country[11]	H	na	NZ$94	12.1	8.9	16.0	11.0	na	na
Oct 06	23.77% of TrustPower[11]	H/W	na	NZ$1,944	12.6	11.4	14.8	13.3	na	na
Jul 04	51.2% of Contact Energy[11]	H/W/GT/G	na	NZ$3,270	12.3	9.4	17.8	12.8	NZ$1.82[13]	NZ$2.05
Dec 02	Taranaki Combined Cycle Power Station	G	B	NZ$491	na	na	na	na	NZ$1.38	NZ$1.60
Dec 02	Cobb Hydro Power Station	H	B	NZ$93	na	na	na	na	NZ$2.89	NZ$3.37
Nov 02	50% of Southdown Power Station	G	C	NZ$161	na	na	na	na	NZ$1.36	NZ$1.59

Source: Grant Samuel analysis[14]

A brief summary of each transaction is set out below.

[11] These transactions include other energy assets such as distribution and transmission assets and retailing businesses. In these cases, financial information on the generation assets is not available on a standalone basis and the earnings multiples presented represent a blend of the assets acquired. Caution should be used in considering the blended earnings multiples.

[12] Based on broker estimates for the price paid for generation assets acquired.

[13] Based on broker estimates for the price paid for generation assets acquired. Contact Energy operates hydro, thermal and geothermal generation assets and therefore the data presented is a blended price per MW.

[14] Grant Samuel analysis based on data obtained from IRESS, company announcements, transaction documentation and, in the absence of company published financial forecasts, brokers' reports. Where company financial forecasts are not available, the median of the financial forecasts prepared by a range of brokers has generally been used to derive relevant forecast value parameters. The source, date and number of broker reports utilised for each transaction depends on analyst coverage, availability and corporate activity.

Electricity Generation - Australia

Ecogen Generation Business / Industry Funds Management

On 18 July 2008 Babcock & Brown Power ("BBP") announced the sale of its 73% interest in the Ecogen Generation Business ("Ecogen") to Industry Funds Management ("IFM") for A$87 million plus the assumption of A$93 million in debt. Ecogen is comprised of the 510MW gas-fired thermal Newport Power Station and the 519MW dual fuel fired Jeeralang Power Station both located in Victoria. The price per MW implied by the transaction is low reflecting that Ecogen had granted a power purchase agreement providing the owner the right to call on Ecogen to supply as much as 966MW of electricity from two gas fired power stations in Victoria.

Uranquinty Power Station / Origin Energy Limited

On 4 July 2008 Origin announced that it had acquired 100% of Uranquinty Power Station from BBP for an enterprise value of A$700 million. The 640MW gas fired power station is currently under construction near Wagga Wagga, New South Wales and is expected to be commissioned in late 2008. Uranquinty Power Station is to be operated as a peaking load plant.

Braemar Power Station / Babcock & Brown Power

On 18 December 2007 BBP announced that it would acquire from ERM Group a 15% minority interest in Braemar Power Station for A$35.5 million taking its interest to 100%. The 455MW gas fired power station is located south west of Dalby, Queensland and was commissioned in September 2006 as an intermediate load plant.

Uranquinty Power Station / Babcock & Brown Power

On 18 December 2007 BBP also announced that it would acquire from ERM Group a 30% minority interest in Uranquinty Power Station for A$75 million (including a A$50 million funding commitment) taking its interest to 100%. BBP acquired its existing 70% interest in July 2007 at financial close for the development. The 640MW gas fired power station is currently under construction near Wagga Wagga, New South Wales and is expected to be commissioned in late 2008. Uranquinty Power Station is to be operated as a peaking load plant.

AlintaAGL's Cogeneration Business / Babcock & Brown Power

In May 2007 a consortium comprising Singapore Power Limited ("Singapore Power") and three Australian Securities Exchange ("ASX") listed funds managed by Babcock & Brown Limited ("Babcock & Brown") (including BBP) announced that it had signed an agreement with Alinta Limited ("Alinta") to acquire all of Alinta's issued share capital. This transaction was implemented on 31 August 2007 and, as a consequence, Alinta's 67% interest in AlintaAGL was acquired by BBP. AlintaAGL, a joint venture company with AGL Energy Limited ("AGL Energy") (33%), comprised a retail gas and electricity business in Western Australia ("Alinta Retail") and an electricity cogeneration business also in Western Australia. The cogeneration business was based on an arrangement with Alcoa to develop cogeneration facilities at Alcoa's alumina refineries in Western Australia. At the time of the transaction Pinjarra Units 1 and 2 were operating and Wagerup Units 1 and 2 were being commissioned for a total installed capacity for AlintaAGL of 640MW.

Acquisition of Alinta by the consortium triggered AGL Energy's option to acquire BBP's 67% in AlintaAGL. On 21 September 2007, BBP set the exercise price of A$1,060 million (equating to A$1,582 million for 100% of the equity of AlintaAGL[15]). After allowing for AlintaAGL's debt of A$506 million (relating to the cogeneration business) the option price implied an enterprise value of A$2,088 million for 100% of AlintaAGL. No financial information is publicly available for AlintaAGL. However, BBP disclosed that the option price implied a value of A$1,200 per mass market customer for Alinta Retail and A$1.4 million per MW for the cogeneration business. AGL Energy declined to acquire the 67% interest and the sale of its 33% interest in AlintaAGL to BBP was completed at the exercise price in December 2007. The price per MW for the cogeneration business is relatively high reflecting, in part, growth expectations associated with the relationship with Alcoa.

Transfield Services Infrastructure Fund

In April 2007, Transfield Services Limited ("Transfield"), a global provider of operations, maintenance and asset and project management services, announced that it would spin-off its investments in five power stations (with a proportional share of installed capacity of 992.8MW) and two water filtration plants as an ASX listed entity.

[15] Alinta and AGL Energy had agreed that transactions in relation to AlintaAGL would be based on a pro rata share of full underlying value (i.e. no discounts for minority interests).

Transfield Services Infrastructure Fund ("TSI Fund") proposes to build a diversified portfolio of infrastructure assets. Its initial portfolio comprises a 100% interest in each of Townsville, Collinsville and Kemerton power stations, a 30% interest in BP Kwinana Cogeneration Plant, a 14.03% interest in Loy Yang A Power Station ("Loy Yang") and a 50% interest in each of the Macarthur and Yan Yean Water Filtration Plants. TSI Fund began trading on the ASX on 12 June 2007. The multiples shown in the table are calculated by reference to the application price of A$2.10 per security and reflect revenue, EBITDA and price per MW on a proportionately consolidated basis. The historical numbers are for the year ending 30 June 2007. The earnings multiples decline to 5.6 and 9.0 respectively in 2008 (on a non proportional calculation basis these multiples are higher and similar to those for the BBP initial public offering discussed below). The price per MW is overstated to the extent that the price reflects two water filtration plants as well as the five power stations. As the offering reflects sharemarket prices the implied multiples do not include a premium for control.

Wattle Point Wind Farm / Energy Infrastructure Trust

In April 2007 Alinta sold Wattle Point Wind Farm to Energy Infrastructure Trust for A$225 million. Energy Infrastructure Trust acquires or develops energy related utility and infrastructure assets in Australia and New Zealand and is managed by a wholly owned subsidiary of Australia and New Zealand Banking Group Limited. Wattle Point Wind Farm is located at Wattle Point on South Australia's Yorke Peninsula. It consists of 55 wind turbines with a total installed capacity of 91MW and commenced operations in 2005. The wind farm is considered to be highly productive. No financial information is publicly available for Wattle Point Wind Farm.

Powerdirect Australia generation business / AGL Energy Limited

In March 2007, AGL Energy acquired Powerdirect Australia ("Powerdirect") from the Queensland Government for A$1.2 billion. Powerdirect is one of Australia's top five energy retail businesses with 473,200 electricity customers and a generation business. AGL Energy forecast that the purchase price implied a multiple of 9.8 times EBITDA for 2008/09, the first year under AGL Energy's lower cost structure, and provided an analysis of the multiples implied by the price paid by business as follows:

Powerdirect - AGL Energy's Acquisition Analysis

Business	Value (A$ million)	FY09 EBITDA multiple (2008/09)	Key Valuation Metric
Retail	570	9-10x	A$1,300/customer
Small contestable	265	23-24x (pre AGL cost structure)	na
Large customers / wholesalers	295	6-7x	na
Power generation	70	8-9x	na
Total	**1,200**	**9.8x**	**na**

The power generation business has 43MW of installed capacity and includes two biomass fuelled plants utilising bagasse from sugar cane produced at the Isis Mill in Childers and nut shells from the Suncoast Gold macadamia operation near Gympie. AGL Energy attributed A$70 million of the purchase price to the power generation business implying A$1.63 million per MW. Powerdirect's expertise in biomass generation represented a strong base for the expansion of AGL Energy's renewable power generation assets in Queensland.

Loy Yang A Power Station / Transfield Services Limited

In March 2007, Transfield announced it had increased its interest in Loy Yang to 14.03% through the acquisition of a 4.71% interest from Mitsui & Company for a total acquisition and associated cost of A$64.4 million. Loy Yang is the largest power station in Victoria with a generation capacity of 2,120MW and accounts for approximately 25% of that state's installed generation capacity. The price per MW is overstated to the extent that the price paid reflects the associated coal mine and dispatch and marketing company as well as the power station. As the transaction involves a minority interest the implied multiples do not include a premium for control although it is likely that the vendor was aware of Transfield's objective of increasing its interest to a strategic size.

Torrens Island Power Station / AGL Energy Limited

In January 2007 announced the acquisition of the 1,280MW Torrens Island Power Station from TRUenergy Pty Limited ("TRUenergy"), the Australian energy business of CLP Holdings Ltd ("CLP"), for A$476.4 million plus the assumption of net debt of A$95.6 million. CLP is Hong Kong's largest power producer and acquired the power station from Singapore Power in March 2005 which in turn had acquired it from TXU Corporation ("TXU") in April 2004. Torrens Island Power Station is South Australia's largest generator supplying approximately 25% of South Australia's electricity requirements. The plant has eight steam turbines capable of being fuelled by either natural gas or fuel oil, although natural gas is the primary fuel source. The power station

is utilised for both peaking and intermediate purposes. As part of the transaction AGL Energy also acquired a 10 year, 300 petajoule gas sales agreement expiring in 2017 together with the associated SEAGas pipeline haulage contract which expires in 2019. The acquisition increased AGL Energy's generation capacity by more than 60%. No earnings are publicly available for Torrens Island Power Station. The price paid per MW for Torrens Island Power Station is low as AGL Energy also assumed existing hedge positions which were expected to be earnings decretive in 2008 and as the power plant has a limited remaining life (constructed in 1967).

Hallett Power Station / TRUenergy Pty Limited

In January 2007 AGL Energy sold its Hallett Power Station to TRUenergy for A$117 million. Hallett Power Station is located approximately 210 kilometres from Adelaide in South Australia. The plant has 11 gas turbine generators capable of being fuelled by either natural gas or fuel oil, although natural gas is the primary fuel source. The power station has an installed capacity of 180MW and is used for peaking purposes. No earnings are publicly available for Hallett Power Station.

Babcock & Brown Power

In November 2006, the initial public offering on the ASX at A$2.50 per stapled security of BBP was announced. BBP comprises a portfolio of majority interests in six operating power stations, a majority interest in one power station under construction (due to be completed in late 2008) and a 50% interest in Oakey Power Station. This portfolio comprises base load, intermediate and peaking power stations with a total generation capacity of 2,922MW. BBP also has a gas-fired base load power generation position of up to 180MW in the South Australian market through a series of contracts. The multiples calculated are based on the application price of A$2.50 per stapled security. The historical earnings for the year ending 30 June 2006 do not include any contributions from Braemar Power Station which was commissioned in August 2006 and therefore are not meaningful. Furthermore, the forecast earnings for the year ending 30 June 2007 do not reflect a full year contribution from Braemar and therefore the multiples are marginally overstated. For the purposes of this analysis, the multiples in the table are based on the forecast earnings for BBP. If a proportional share of earnings from Oakey Power Station is allowed the EBITDA multiples for BBP would be around 12.5 and 10.2 times respectively (sufficient information is not available by which to estimate EBIT). The price per MW is calculated by reference to BBP's proportional interest in total installed generation capacity. As the offering reflects sharemarket prices for electricity generation assets the implied multiples do not include a premium for control.

Loy Yang A Power Station / Transfield Services Limited

In July 2006, Transfield announced it would acquire a 9.3% interest in Loy Yang and adjacent coal mine and 13.8% of the attached dispatch and marketing company from Commonwealth Bank of Australia. The price per MW is overstated to the extent that the price paid reflects the associated coal mine and dispatch and marketing company as well as the power station. As the transaction involves a minority interest the implied multiples do not include a premium for control.

Lonsdale Power Station/ Infratil Limited

In July 2006 Infratil Limited ("Infratil"), a New Zealand listed company with investments in energy, airport and public transport sectors, acquired Lonsdale Power Station in Adelaide, South Australia for A$11 million. The power station has installed capacity of 20MW and operates as a diesel peaking plant. No financial information is publicly available for Lonsdale Power Station.

NRG Energy Inc's South Australian power assets / Babcock & Brown Limited

In June 2006, Babcock & Brown announced it would acquire the South Australian power assets of NRG ("NRG Flinders"). The assets include two coal fired power stations, the coal mine that supplies the power stations (and the associated rail infrastructure and township), a number of contracts and head office personnel. NRG Flinders is the leading base load power supplier in South Australia with a total capacity of 760MW and accounts for 50% of energy produced in the state. Price paid per MW paid is relatively low as a result of existing hedge positions for Northern and Playford Power Stations and obligations under a power purchase agreement to acquire electricity output from Osborne Cogeneration Plant.

AlintaAGL / AGL Energy Limited

In April 2006 Alinta and The Australian Gas Light Company ("AGL") announced that they had reached agreement to merge and restructure their respective businesses to create two separate listed companies: Alinta focussed on ownership and management of energy infrastructure assets and AGL Energy focussed on energy retailing, trading and generation. One element of the transaction (which was implemented in October 2006) was

that AGL Energy would subscribe for a 33% interest in AlintaAGL, a joint venture company owning Alinta Retail and an electricity cogeneration business. AGL Energy was also granted call options to acquire the remaining 67% of AlintaAGL over a five year period. The effect of the second call option is that, if it is exercised, Alinta must provide a price for its 67% interest and if AGL Energy does not agree to pay that price then Alinta must buy AGL Energy's 33% interest for the same price per share. The subscription price of A$367 million paid by AGL Energy for its 33% equity interest implies a value for 100% of the equity in AlintaAGL of A$1,112 million. No financial information is publicly available for AlintaAGL. The earnings multiples presented were calculated by the independent expert for the transaction. No price per MW is publicly available.

Angaston Power Station/ Infratil Limited

In February 2006 Infratil acquired Angaston Power Station in the Barossa Valley, South Australia for A$25 million. The power station has installed capacity of 39MW and operates as a diesel peaking plant. No financial information is publicly available for Angaston Power Station.

Southern Hydro / The Australian Gas Light Company

In October 2005, AGL announced it would acquire Southern Hydro for A$1.425 billion from New Zealand energy utility Meridian Energy Limited ("Meridian"). Southern Hydro consisted of 11 hydro power stations in Victoria and New South Wales and Australia's largest wind farm in South Australia with total installed capacity of 736.3MW, two development projects (total 142MW) and potential for further expansion. The acquisition increased AGL's generation capacity by 73% and diversified its generation mix, allowing AGL to better manage its retail customer load and reduce electricity purchases from third parties, especially during periods of peak demand. The multiples implied by acquisition price are high and reflect the strategic benefits of the acquisition to the wider AGL business. AGL stated that the assets had been purchased on an EBITDA multiple of 11 times assuming long term average water levels and full capture of portfolio benefits which are expected to occur from 2009.

Valley Power / Snowy Hydro Limited

On 17 October 2005, Snowy Hydro Limited ("Snowy Hydro"), a New South Wales based electricity generator and retailer, announced the acquisition of Valley Power for A$242 million. Valley Power is a 300MW gas fired peaking plant located adjacent to the Loy Yang B coal fired power plant in the Latrobe Valley in Victoria. A 60% interest in Valley Power was acquired from a 70:30 joint venture between International Power plc ("International Power") and Mitsui & Co Ltd which had acquired the interest as part of the US$2.3 billion acquisition of Edison Mission Energy's international generation portfolio in December 2004. Other Australian assets acquired by the joint venture in that transaction were the Loy Yang B power plant and 70% of the Kwinana cogeneration plant in Perth – however no financial data for the Australian components of that transaction are publicly available. The 60% interest in Valley Power was divested in accordance with an agreement with the Australian Competition and Consumer Commission at the time of the Edison transaction. The remaining 40% interest in Valley Power was acquired by Snowy Hydro from Contact Energy Limited ("Contact Energy"), a New Zealand energy generator and retailer.

Pacific Hydro Limited / Industry Funds Management

Following a strategic review by the board of Pacific Hydro Limited ("Pacific Hydro"), Spanish infrastructure developer Acciona SA ("Acciona") announced on 29 March 2005 that it would offer A$4.50 per share for Pacific Hydro. On 19 April 2005, Pacific Hydro's 32% shareholder, IFM made a A$4.60 per share offer. On 29 April 2005, Acciona responded with a A$4.90 per share offer and IFM immediately countered with an offer for A$5.00 per share which was ultimately successful. Pacific Hydro was an independent renewable power producer with a portfolio of operating and development hydro projects and wind farms in Australia, the Philippines, Chile and Fiji. Pacific Hydro's installed capacity at the time of the transaction was 227.5MW but it had assets at various stages of development for a further 1,282.5MW. As a consequence, the earnings multiples and price per MW are high to the extent that the price paid reflects Pacific Hydro's development assets.

Singapore Power Limited's Merchant Energy Business / CLP Holdings Ltd

In March 2005, as a consequence of a strategic decision to focus on its core competencies of energy transmission and distribution, Singapore Power announced the sale to CLP of the merchant energy business it had acquired from TXU for A$2.128 billion. CLP is Hong Kong's largest power producer and owns the 1,480MW Yallourn power station in Victoria. CLP's objective is to build a diversified and integrated energy business in Australia, focussing on electricity and gas retail, with a portfolio of assets in support of that business.

The merchant energy business acquired included the fifth-largest energy retailer in Australia with over 1.1

million customers in four states (approximately 600,000 electricity customers and 500,000 gas customers), the 1,280MW Torrens Island Power Station in South Australia, a 33% interest in the SEAGas pipeline between Victoria and South Australia and an underground gas storage plant. CLP also acquired Singapore Power's right to call on Ecogen Power to supply as much as 966MW of electricity from two gas-fired power stations in Victoria. Therefore, the earnings multiples presented reflect the blended earnings of these assets (being energy generation, retailing and transmission assets).

Torrens Island Power Station (previously known as Optima Energy) had been acquired by TXU from the South Australian Government under 100 year lease arrangements for A$315 million in June 2000. It is South Australia's largest generator (an estimated 50% of the state's installed capacity) supplying approximately 30% of South Australia's electricity requirement. The plant has eight steam turbines capable of being fuelled by either natural gas or fuel oil. No earnings are available for Torrens Island Power Station on a standalone basis. Brokers estimate that CLP paid in excess of A$700 million due to available synergies, as South Australia is peaking generation constrained and as it would cost around A$800-900 million to build a similar plant. The prices per MW presented are based on broker estimates as to the price paid for Torrens Island Power Station.

TXU's Australian Assets / Singapore Power Limited

In April 2004, Singapore Power acquired TXU's Australian assets for A$5.1 billion. These assets included significant electricity and gas networks in Victoria, retail electricity and gas businesses supplying approximately one million customers in Victoria and South Australia, the 1,280MW Torrens Island Power Station in South Australia, a 33% interest in the SEAGas pipeline between Victoria and South Australia and an underground gas storage plant. Therefore, the earnings multiples presented reflect the blended earnings of these assets (being energy generation, retailing, transmission and distribution assets). No price per MW data is publicly available for this transaction.

Duke Energy's Australian and New Zealand Assets / Alinta Limited

In March 2004, Alinta announced that it had reached an agreement to purchase the Australian and New Zealand gas assets of Duke Energy for A$1.69 billion, following Duke Energy's decision to exit the Asia-Pacific region. The assets acquired were three gas transmission pipelines and three gas-fired power stations in Australia and one gas-fired power station in New Zealand. The pipelines had a combined length of 2,156 kilometres and the power plants had a combined capacity of 452MW. The power plants were the 160MW Port Hedland Power Station and 90MW Newman Power Station in Western Australia, the 94MW Bairnsdale Power Station in Victoria and the 108MW cogeneration Glenbrook Power Station in New Zealand. In addition, Alinta became a party to a joint venture heads of agreement in relation to negotiations concerning the ownership and operation of the 240MW Bell Bay Power Station in Tasmania. The acquisition provided Alinta with a stable and secure income stream and strong potential for volume growth, particularly from the pipeline assets on Australia's east coast. No purchase price or earnings are publicly available for the generation assets on a standalone basis and therefore the earnings multiples presented reflect the blended earnings of the transmission and generation assets.

Loy Yang A Power Station / Great Energy Alliance Corporation

In July 2003, Great Energy Alliance Corporation ("GEAC") announced it would acquire Loy Yang for A$3.5 billion. Loy Yang is Victoria's largest power station with a 2,000MW capacity and is fuelled by an adjoining brown coal mine with a reserve life of more than 45 years. Loy Yang also sells coal under contract to the adjacent Loy Yang B Power Station. GEAC was a consortium consisting of AGL (35%), Tokyo Electric Power Company Incorporated (35%) and an investor group lead by the Commonwealth Bank of Australia (30%). The price represents a A$1.4 billion discount to the price achieved in the privatisation of the asset in 1997 and a substantial discount to the estimated replacement cost.

Redbank Power Station / Prime Infrastructure Trust

On 20 June 2003, Prime Infrastructure Trust announced the acquisition of a 50% interest in Redbank Power Station for A$A27.5 million. Redbank Power Station is a coal fired base load power station located in the Hunter Valley of New South Wales with a total nominal capacity of 132MW. The plant has a long term (30 year) power purchase hedge arrangement with EnergyAustralia, the largest electricity distributor in Australia. The power station is fuelled by coal supplied by the adjacent Warkworth Mine. No historical earnings are publicly available for the Redbank Power Station. Price paid per MW for Redbank Power Station is relatively high due to the low cost source of fuel from the adjacent mine and a 30 year take or pay power purchase hedge agreement with EnergyAustralia.

Southern Hydro Pty Limited / Meridian Energy Limited

In March 2003, Meridian announced the acquisition of Southern Hydro Pty Limited ("Southern Hydro") from United States company Alliant Energy Corporation ("Alliant") for A$591 million. Southern Hydro owned and operated 10 hydro electricity power stations in Victoria. These plants have installed capacity of 509MW and operate as peaking generation plants in the national electricity market. Southern Hydro also trades in a range of energy risk management products and wholesales energy. Meridian plans to integrate Southern Hydro with the operations of Power Facilities Pty Limited ("Power Facilities") which it acquired in 2001 (see below). No financial information is publicly available for Southern Hydro.

Mount Stuart Power Station / Origin Energy Limited

In December 2002, Origin Energy Limited ("Origin") announced the acquisition of Mount Stuart Power Station from AES Corporation ("AES") for A$A93 million. The power station is a 288MW gas turbine peaking plant in Townsville in Queensland which supplies power to the Queensland Government owned entity, Enertrade, under a long term power purchase agreement and also has the right to sell power in excess of Enertrade's requirements. The plant runs on kerosene but can be readily converted to natural gas and has been designed to allow for future expansion.

Ecogen Electricity Generation Assets / Prime Infrastructure Trust and Babcock & Brown Limited

In December 2002, Prime Infrastructure Trust and Babcock & Brown announced they would acquire the Ecogen electricity generation assets from AES for A$81 million plus the assumption of an A$125 million debt facility. The Ecogen electricity generation assets consisted of two gas-fired plants in Victoria with a total nominal capacity of 960MW. AES has acquired these plants from the Victorian Government in 1999. The 510MW Newport Power Station is used for intermediate and peaking loads and the 450MW Jeeralang Power Station is operating as a peak generator. The plants are subject to a long term electricity hedge agreement with TXU which expires in 2019. The historical multiples are calculated by reference to the year ending 30 June 2003 (i.e. the current financial year). The price paid per MW of A$0.215 million per MW was stated as being significantly below current replacement cost.

South West Cogeneration Joint Venture / Origin Energy Limited

On 6 July 2001, Origin announced the acquisition of a 50% interest in the South West Cogeneration Joint Venture for A$68.5 million. The joint venture owns and operates a 120MW gas fired cogeneration facility which supplies steam and power to the Worsley Alumina Refinery near Bunbury in Western Australia and electricity to Western Power Corporation. No earnings are publicly available for the South West Cogeneration Joint Venture.

Power Facilities Pty Limited / Meridian Energy Limited

In April 2001 Meridian announced the acquisition to Power Facilities for NZ$107 million. Power Facilities is involved in the generation and wholesaling of energy, operating five hydro generation facilities in New South Wales and Victoria with installed capacity of 62MW. Electricity output is sold under long term contract to local power retailers. This transaction was New Zealand based Meridian's first move into the Australian market. No financial information is publicly available for Power Facilities.

Electricity Generation – New Zealand

King Country Energy Limited / King Country Electric Power Trust

King Country Energy Limited ("KCE") owns four small generation plants and a 50% interest in Mangahao Power Station (33.5MW proportional installed capacity) and is the largest electricity retailer in the Waitomo, King Country and Ruapehu/Waimarino districts with over 18,000 customer sites. In November 2006 Todd Energy Limited ("Todd"), a founding shareholder holding 35.38%, announced an offer for KCE at NZ$4.40 per share. Todd did not receive sufficient acceptances and this offer lapsed in January 2007. On 12 January 2007 KCE's second largest shareholder King Country Electric Power Trust ("KCEPT") announced a partial offer to increase its interest from 10% to 27.5% at a price of NZ$4.80, subject to a public consultation process and shareholder approval. On 26 February 2007, Todd announced a partial offer at NZ$5.00 per share for 14.72% to increase its interest in KCE to 50.1%. During the period of Todd's offer, KCEPT acquired the 8% interest of Waitomo Energy Consumer Trust plus a further 2% from public shareholders at NZ$5.00 per share, increasing its interest in KCE to approximately 20%. Todd's offer lapsed in June 2007. The earnings multiples presented reflect KCE's blended earnings and are based on NZ$5.00 per share.

TrustPower Limited / Infratil Limited

On 30 October 2006, Infratil announced that it had acquired Alliant Energy New Zealand Limited ("AENZ") from Alliant for NZ$510 million (including NZ$65 million assumed debt). AENZ holds interests in two publicly traded New Zealand companies: 23.77% in TrustPower Limited ("TrustPower") and 5.07% in Infratil. Alliant sold AENZ as an international presence is no longer consistent with its long term strategy. TrustPower is an integrated generator and retailer in New Zealand, being the fourth largest electricity retailer. The acquisition of AENZ increases Infratil's interest in TrustPower to 59%, however, it proposes to sell down its interest to 50.5%, thereby increasing TrustPower's free float. If the shareholding in Infratil is valued based on the current market price, the transaction implies a value of NZ$1.944 billion for 100% of TrustPower, a 12% discount to the market price on the day prior to announcement. Notwithstanding the strategic nature of the interest acquired, the multiples implied by the transaction therefore do not include a premium for control. Furthermore, the earnings multiples presented reflect the blended earnings of TrustPower's businesses.

Contact Energy Limited / Origin Energy Limited

In July 2004, Origin announced that it had signed an agreement to purchase Edison Mission Energy's 51.2% interest in Contact Energy for NZ$5.67 per share through the acquisition of the New Zealand company which holds Edison Mission Energy's shareholding. Contact Energy is a diversified New Zealand electricity and gas utility. It is New Zealand's second largest electricity generator with 1,940MW of installed capacity in New Zealand, has 387,000 electricity and 107,000 gas customers and is a gas wholesaler with contracted rights to approximately 30% of New Zealand's natural gas reserves. The transaction was completed on 1 October 2004. Acceptances received under a simultaneous full takeover offer for the remaining shares in Contact Energy, as required by the Takeovers Code, increased Origin's interest marginally to 51.4%. The earnings multiples presented reflect the blended earnings of Contact Energy's businesses. The price per MW presented is based on broker estimates for the price paid by Origin for each type of generation asset acquired.

Taranaki Combined Cycle Power Station / Contact Energy Limited

In December 2002, NGC Holdings Limited ("NGC") announced the sale of Taranaki Combined Cycle Power Station ("Taranaki") to Contact Energy for NZ$491.4 million. Taranaki is a 357MW gas fired combined cycle power plant located near Stratford in Taranaki. No earnings are publicly available for Taranaki.

Cobb Hydro Power Station / TrustPower Limited

In December 2002, NGC announced the sale of Cobb Hydro Power Station ("Cobb") to TrustPower for NZ$92.5 million. Cobb is a 32MW hydro power station northwest of Nelson on the South Island. No financial information is available for Cobb. The price per MW presented is relatively high.

Southdown Power Station / Mighty River Power Limited

In November 2002, NGC announced the sale of its 50% interest in the Southdown Power Station and the power purchase agreement for the Rotokawa Geothermal Power Station ("Rotokawa") to Mighty River Power Limited ("Mighty River") for NZ$39.5 million. Mighty River paid NZ$7 million to terminate the output arrangements for Rotokawa giving it a 100% interest in that plant. Therefore, the transaction implies a price of NZ$65 million for 100% of the Southdown Power Station. No financial information is publicly available for the power plant.

Electricity and Gas Retailing in Australia and New Zealand

There have been a large number of transactions involving electricity and gas retailers in Australia and New Zealand since the mid 1990's as deregulation of each country's energy sectors has progressed. A selection of relevant retailing transactions in the last decade for which there is sufficient information to prepare meaningful market parameters is set out below:

Recent Transaction Evidence – Electricity and Gas Retailing in Australia and New Zealand

Date	Target	Consid-eration (millions)	EBITDA Multiple (times)		EBIT Multiple (times)		Price per Customer[16]	
			Historical	Forecast	Historical	Forecast	Unadjusted	Adjusted
Electricity Retailing – Australia								
Feb 07	Powerdirect Australia	A$1,200	na	14.6	na	15.0	A$1,300	A$1,400
Dec 06	8.89% of Jackgreen	A$28	na	na	na	na	A$820[17]	A$870
Nov 06	Sun Retail	A$1,202	na	9.0	na	10.0	A$1,100	A$1,160
Dec 05	Australian Energy	A$99	19.6	12.6	20.5	na	A$2,187[18]	A$2,390
Mar 05	Singapore Power's merchant energy business	A$2,128	11.7	na	na	na	A$750-800[19]	A$840-950
Apr 04	TXU's Australian assets	A$5,100	9.2	8.6	na	na	na	na
Jul 02	Pulse Energy	A$880	7.8	7.4	8.4	8.4	A$750[19]	A$890
Jul 02	CitiPower Retail	A$137	na	na	na	na	A$527	A$630
Apr 01	Powercor Retail	A$235	5.7	na	na	na	A$404	A$497
Mar 00	United Energy Retail	A$350	na	na	5.9	na	A$625	A$822
Jan 00	ETSA Power	A$175	8.0	na	na	na	A$238	A$314
Gas Retailing – Australia								
Sep 07	33% of Alinta Retail	A$680	na	na	na	na	A$1,200	A$1,250
Nov 06	Sun Gas Retail	A$75	11.5	9.0	na	na	A$1,059	A$1,120
Apr 06	33% of AlintaAGL	A$1,112	na	12.6	na	14.2	na	na
Mar 05	Singapore Power's merchant energy business	A$2,128	11.7	na	na	na	A$800-900[19]	A$890-1,000
Apr 04	TXU's Australian assets	A$5,100	9.2	8.6	na	na	na	na
Jul 02	Pulse Energy	A$880	7.8	7.4	8.4	8.4	A$850[19]	A$1,010
Mar 00	Ikon Energy	A$310-364	na	na	na	na	A$600-700[19]	A$790-920
Mar 99	Energy 21	A$474	na	13.7	na	na	A$878	A$1,187
Mar 99	Ikon Energy	A$420	na	na	na	na	A$833[19]	A$1,127
Jan 99	Kinetik Energy	A$332	na	na	na	na	A$830[19]	A$1,123
Electricity and Gas Retailing – Australia								
May 07	50% of Simply Energy	A$284	na	na	na	na	A$710	A$740
Mar 07	42% of Victoria Electricity	A$94	na	na	na	na	A$667	A$710
Apr 05	50% of EnergyAustralia's business in Vic and SA	A$120	na	na	na	na	A$686	A$760
Mar 05	Singapore Power's merchant energy business	A$2,128	11.7	na	na	na	A$820[19]	A$915
Apr 04	TXU's Australian assets	A$5,100	9.2	8.6	na	na	na	na
Jul 02	Pulse Energy	A$880	7.8	7.4	8.4	8.4	A$816	A$970
Electricity Retailing – New Zealand								
May 07	10% of King Country Energy	NZ$94	12.1	8.9	16.0	11.0	na	na
Oct 06	23.77% of TrustPower	NZ$1,944	12.6	11.4	14.8	13.3	na	na
Jul 04	51.2% of Contact Energy	NZ$3,270	12.3	9.4	17.8	12.8	NZ$225[19]	NZ$250

16 Represents gross consideration divided by mass market customers. In some transactions (e.g. Singapore Power's merchant energy business, Contact Energy) price per customer is based on broker estimates of the price paid for the retail businesses acquired. Multiples presented in the table have been adjusted to allow for inflation since acquisition so that all multiples reflect current dollars.

17 Not a control transaction but acquisition increased Babcock & Brown Limited's interest in Jackgreen to 19.99%.

18 Australian Energy Limited was focused on small to medium sized commercial customers and not mass market customers.

19 Based on broker estimates.

Recent Transaction Evidence – Electricity and Gas Retailing in Australia and New Zealand								
Date	Target	Consid-eration (millions)	EBITDA Multiple (times)		EBIT Multiple (times)		Price per Customer[16]	
			Historical	Forecast	Historical	Forecast	Unadjusted	Adjusted
Jul 01	On energy (South Island)	NZ$36	na	na	na	na	NZ$311	NZ$374
Aug 00	TransAlta New Zealand	NZ$689	7.8	7.1	11.4	11.0	na	na
Jul 00	Empower Limited	NZ$23	na	na	na	na	NZ$400[20]	NZ$493
Sep 99	Eight retail customer bases	NZ$134.3	na	na	na	na	NZ$380	NZ$496
Gas Retailing – New Zealand								
Oct 06	25.1% of Wanganui Gas Limited	NZ$32	7.7	na	9.9	na	NZ$800-1,000[21]	NZ$850-1,060
Jul 04	51.2% of Contact Energy	NZ$3,270	12.3	9.4	17.8	12.8	NZ$350[19]	NZ$400
Sep 02	NGC's retail business	NZ$62	na	na	na	na	NZ$463	NZ$543

Source: Grant Samuel analysis

A brief summary of each transaction is set out below.

Electricity Retailing – Australia

Simply Energy / International Power plc

In May 2007, International Power announced that it had exercised its option to acquire the remaining 50% of the EnergyAustralia and International Power (Australia) Retail Energy Partnership for A$142 million. The business sells electricity and gas to retail customers in Victoria and South Australia. Since the retail partnership was formed in July 2005 the number of customer accounts has increased from 175,000 to over 400,000. As part of the acquisition International Power launched a new retail brand "Simply Energy" for the business. No financial information is publicly available for Simply Energy. There is also no breakdown of customers or price paid between electricity and gas retailing and therefore the price per customer data presented is a blended number.

Victoria Electricity Pty Limited / Infratil Limited

On 30 March 2007, Infratil announced the acquisition of options to acquire the remaining 42% of Victoria Electricity Pty Limited ("Victoria Electricity") on or before 30 April 2007 for A$39.3 million plus deferred payments which could increase the aggregate purchase price up to A$56.3 million if growth targets are met by 31 December 2008. Infratil and its 42% partners had established the business in 2002 as a start-up electricity retailer in Victoria. A Victorian retail electricity licence was secured in August 2002 and its first customer revenue was generated in 2004. Victoria Electricity secured a number of other energy retailing licences over the next three years: gas licence in Victoria (2004), electricity licence in South Australia (2005), electricity licence in Queensland (2006) and electricity licence in New South Wales (2007). Victoria Electricity is a growing business reaching 150,000 accounts by December 2006 of which approximately 100,000 were dual fuel accounts in Victoria. By mid March 2007 total accounts had grown to approximately 180,000.

The base exercise price implied an enterprise value for 100% Victoria Electricity of A$120 million. Infratil announced that implied price per customer of A$720 but this was calculated based on customers as at 31 December 2006 and after excluding working capital of $12 million. In order to be consistent with other transactions in this appendix, the price per customer data presented has been calculated on the basis of the enterprise value of A$120 million and 180,000 customers (A$667 per customer). Insufficient data is available to split the purchase price between electricity and gas retailing and it is noted that over 60% of Victoria Electricity's customers are dual accounts.

In January 2007, Infratil also acquired a 51% interest in Perth Energy Pty Limited ("Perth Energy") for A$7 million. Perth Energy is based in Perth, Western Australia and is a retailer of electricity to approximately 50,000 small enterprise customers. It also has a 90MW gas fired power project at Kwinana, Western Australia under development. Insufficient financial information is available by which to determine the price per customer implied by the transaction.

[20] Price per customer based on price paid for mass market customers only.

[21] Based on estimated customer numbers as only incomplete information available publicly.

Powerdirect Australia / AGL Energy Limited

In March 2007, AGL Energy acquired Powerdirect Australia ("Powerdirect") from the Queensland Government for A$1.2 billion. Powerdirect is one of Australia's top five energy retail businesses with 473,200 customers (including 396,200 residential, rural and small to medium sized enterprise accounts in Queensland and a further 35,600 accounts outside Queensland and 37,800 small business accounts and 3,600 large customer/wholesale accounts in NSW, Victoria and South Australia) and a generation business with 43MW of installed capacity (including two biomass fuelled plants). AGL Energy forecast that the purchase price implied a multiple of 9.8 times EBITDA for 2008/09, the first year under AGL Energy's lower cost structure. The multiples shown in the table are a blend of the multiples applicable to Powerdirect's businesses. AGL Energy provided the following analysis of the multiples implied by the price:

Powerdirect - AGL Energy's Acquisition Analysis

Business	Value ($ million)	FY09 EBITDA multiple (2008/09)	Key Valuation Metric
Retail	570	9-10x	$1,300/customer
Small contestable	265	23-24x (pre AGL cost structure)	na
Large customers / wholesalers	295	6-7x	na
Power generation	70	8-9x	na
Total	**1,200**	**9.8x**	**na**

Jackgreen Limited / Babcock & Brown Limited

In December 2006, Babcock & Brown announced an increase in its holding in Jackgreen Limited ("Jackgreen") from 11.1% to 19.99%. The investment took the form of a private placement over two tranches, with the shares placed at 20 cents raising A$2.77 million. Jackgreen is a renewable energy business which retails electricity in New South Wales, Victoria, South Australia and Queensland, and a holds gas retailing licences in South Australia and New South Wales. At the time of the transaction Jackgreen had approximately 30,000 customers. Although not a control transaction, Babcock & Brown became the largest shareholder in Jackgreen following the placement.

Sun Retail Pty Ltd / Origin Energy Limited

In February 2007, Origin acquired Sun Retail Pty Ltd ("Sun Retail") from the Queensland Government for A$1.202 billion. Sun Retail, formed from the ENERGEX retail business, comprises three businesses: mass market and wholesale electricity retailing and LPG marketing and distribution. In terms of the mass market retail business Sun Retail has around 833,000 electricity customers predominantly located in south east Queensland. Origin provided the following analysis of the acquisition price:

Sun Retail - Origin's Acquisition Analysis

Business	Value ($ million)	Key Valuation Metric
Mass market retail	916	$1,100 / customer
Wholesale	220	$0.61 / MWh
LPG	66	$2,130 / tonne
Total	**1,202**	**na**

Australian Energy Limited / Ergon Energy Pty Ltd

In December 2005, Ergon Energy Pty Ltd ("Ergon Energy") announced that it would acquire Australian Energy Limited ("AEL") via a scheme of arrangement. The consideration offered was A$1.95 cash for each share in AEL. AEL is an electricity retailer with operations in Victoria, South Australia and New South Wales. It focuses primarily on the small and medium sized business market with select residential customers and at 31 December 2005 had 45,500 customers. Ergon Energy is owned by the Queensland government and operates an electricity distribution business in Queensland as well as retailing electricity to large customers outside of Queensland. Ergon Energy expects to grow AEL's existing operations nationally, complementing Ergon Energy's existing channel segments.

EnergyAustralia's retail business in Victoria and South Australia / International Power plc

On 18 April 2005, International Power and EnergyAustralia (a New South Wales government owned energy utility) announced the formation of a retail energy partnership to service Victoria and South Australia. The basis for the partnership was EnergyAustralia's existing electricity and gas retail customer base in those states and International Power paid A$60 million for a 50% interest in the partnership. EnergyAustralia commenced energy retailing in Victoria and South Australia in 2003 and at the time of the transaction had approximately 175,000 customers. EnergyAustralia is one of Australia's largest energy retailers with approximately 1.5 million customers. No financial information is publicly available for EnergyAustralia's Victorian and South Australian retail business. There is also no breakdown of customers or price paid between electricity and gas retailing and therefore the price per customer data presented is a blended number.

Singapore Power Limited's Merchant Energy Business / CLP Holdings Ltd

In March 2005, as a consequence of a strategic decision to focus on its core competencies of energy transmission and distribution, Singapore Power announced the sale to CLP of the merchant energy business it had acquired from TXU for A$2.128 billion. The merchant energy business acquired included the fifth-largest energy retailer in Australia with over 1.1 million customers in four states (approximately 600,000 electricity customers and 500,000 gas customers), a 1,280MW gas-fired power plant in South Australia, a 33% interest in the SEAGas pipeline between Victoria and South Australia and an underground gas storage plant. CLP also acquired Singapore Power's right to call on Ecogen Power (50% owned by Babcock & Brown Infrastructure) to supply as much as 966MW of electricity from two gas-fired power stations in Victoria. Therefore, the earnings multiples presented reflect the blended earnings of these assets (being energy generation, retailing and transmission assets). The prices paid per customer for the electricity and gas retailing businesses presented are based on broker estimates as to the prices paid for each business.

TXU's Australian Assets / Singapore Power Limited

In April 2004, Singapore Power acquired TXU's Australian assets for A$5.1 billion. These assets included significant electricity and gas networks in Victoria, retail electricity and gas businesses supplying approximately one million customers in Victoria and South Australia, the 1,280MW Torrens Island Power Station in South Australia, a 33% interest in the SEAGas pipeline between Victoria and South Australia and an underground gas storage plant. Therefore, the earnings multiples presented reflect the blended earnings of these assets (being energy generation, retailing, transmission and distribution assets). No price per customer data is available for the electricity and gas retailing businesses for this transaction.

Pulse Energy Pty Ltd / The Australian Gas Light Company

In July 2002, AGL announced it would acquire Pulse Energy Pty Ltd ("Pulse Energy") for A$880.0 million. Pulse Energy was a joint venture between United Energy Limited, Shell Australia, The Energy Partnership (50% AMP Henderson Global Investors Limited and 50% Aquila Limited) and Woodside Petroleum Limited. It was the largest energy retailing business in Victoria with 560,000 electricity customers and 520,000 gas customers. The majority of Pulse Energy's customers were residential and small business customers with 22% buying both gas and electricity from Pulse Energy. The acquisition enhanced AGL's presence in Victoria and gave the company an almost 30% market share of the eastern Australian retail energy market. AGL expected to generate significant operating synergies from the acquisition. The earnings multiples presented reflect the blended earnings of both the gas and electricity retail businesses. The values paid per customer presented are based on broker estimates as to the prices paid for each of the retailing businesses.

CitiPower Retail / Origin Energy Limited

In July 2002, Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited ("CKI/HEH") acquired AEP Resources Inc's CitiPower unit ("CitiPower") for A$1.55 billion. CitiPower was an electricity utility that served Melbourne and its surrounding suburbs. CKI/HEH subsequently sold CitiPower's electricity retail business to Origin for A$137 million. CitiPower's retail business comprises 260,000 residential and small business customers in Melbourne's central business district and inner suburbs and 4,000 large commercial and industrial customers throughout the eastern seaboard. There are no earnings publicly available for CitiPower Retail.

Powercor Retail / Origin Energy Limited

In September 2000, CKI/HEH acquired Powercor Australia Limited ("Powercor"), Victoria's largest electricity distributor, for A$2.3 billion. Powercor's 80,000 kilometre electricity network covers an area of 150,000 square kilometres in the state of Victoria. CKU/HEH subsequently sold Powercor's electricity retail business to Origin

for A$235 million plus the benefits from Powercor's wholesale position for A$80 million. Powercor Retail served 582,000 customers in western Victoria.

United Energy Retail / Pulse Energy Pty Limited

The Pulse Energy joint venture was announced in March 2000 and established in June 2000. United Energy Limited contributed its electricity retail business for A$350 million (A$625 per customer) plus A$118 million in cash to acquire a 25% interest in Pulse Energy. United Energy Retail served 560,000 electricity customers in Melbourne's south east and the Mornington Peninsula.

ETSA Power / The Australian Gas Light Company

In January 2000, CKI/HEH acquired ETSA Utilities, a South Australian electricity distribution company. ETSA Utilities' network serviced approximately 765,000 customers in Adelaide and the surrounding area through an electricity network spanning 79,000 kilometres. AGL subsequently acquired ETSA Utilities' retail business, ETSA Power, for A$175 million. ETSA Power had 733,783 electricity customers in South Australia.

Gas Retailing - Australia

Alinta Retail / Babcock & Brown Power

In May 2007 the Singapore Power/Babcock & Brown Consortium announced that it had signed an agreement with Alinta to acquire all of its issued share capital. This transaction was implemented on 31 August 2007. Under the transaction Alinta's 67% interest in AlintaAGL was to be owned by BBP. Implementation of the transaction triggered AGL Energy's option to acquire Alinta's 67% in AlintaAGL. On 21 September 2007, Alinta set the exercise price of A$1,060 million (equating to A$1,582 million for 100% of the equity of AlintaAGL). After allowing for AlintaAGL's debt of A$506 million (primarily relating to the cogeneration business) the option price implied an enterprise value of A$2,088 million for 100% of AlintaAGL. No financial information is publicly available for AlintaAGL. However, BBP disclosed that the option price implied a value of A$1,200 per mass market customer for Alinta Retail and A$1,400 per KW generation capacity installed. AGL Energy declined to acquire the 67% interest and in December 2007 the sale of its 33% interest in AlintaAGL to BBP was completed at the exercise price.

Sun Gas Retail / AGL Energy Limited

In November 2006, AGL Energy announced the acquisition of the Sun Gas retail business for A$75 million (A$1,059 per customer) from the Queensland Government. Sun Gas has approximately 70,800 residential and industrial and commercial customers located primarily in South-East Queensland, and is the second largest Queensland gas retailer.

AlintaAGL / AGL Energy Limited

In April 2006 Alinta and AGL announced that they had reached agreement to merge and restructure their respective businesses to create two separate listed companies: Alinta focussed on ownership and management of energy infrastructure assets and AGL Energy focussed on energy retailing, trading and generation. One element of the transaction implemented in October 2006 was that AGL Energy would subscribe A$367 million for a 33% interest in a joint venture company to be known as AlintaAGL. AlintaAGL would own Alinta Retail and an electricity cogeneration business. Alinta Retail is the major retailer of gas to residential and small business customers in Western Australia (approximately 540,000) as well as supplier of gas to large commercial and industrial businesses in Western Australia. Alinta Retail had also commenced retail electricity sales in Western Australia in July 2005 and has approximately 1,000 retail customers.

The subscription price of A$367 million paid by AGL Energy for its 33% equity interest in AlintaAGL represents 33% of full underlying value, thereby implying a value for AlintaAGL of A$1,112 million. No financial information is publicly available for AlintaAGL. The earnings multiples presented were calculated by the independent expert for the transaction and represent the multiples implied by the subscription price paid. No price per customer data is publicly available for this transaction.

Ikon Energy / Pulse Energy Pty Limited

The Pulse Energy joint venture was announced in March 2000 and established in June 2000. The Energy Partnership contributed its gas retail business, Ikon Energy, for an undisclosed sum plus an undisclosed cash sum to acquire a 25% interest in Pulse Energy. Ikon Energy served 520,000 retail gas customers in Melbourne's southern and south eastern suburbs as well as industrial customers across Victoria. The price paid and price per customer are based on broker estimates.

Energy 21 / Boral Limited

In March 1999, Envestra Limited and its 20% shareholder Boral Limited ("Boral") (now Origin) jointly announced that they had reached agreement to acquire the gas distribution and retail business of Stratus and Energy 21 from the Victorian Government for a total consideration of A$1.67 billion. Under the agreement Envestra acquired Stratus for A$1.196 billion which Boral acquired Energy 21 for A$474 million. Energy 21 has a gas retail customer base of 425,000.

Ikon Energy / The Energy Partnership

In March 1999 it was announced that The Energy Partnership has acquired the gas distribution company Multinet and gas retailer Ikon Energy from the Victorian Government for a total of A$1.97 billion. Ikon Energy serves 504,000 retail gas customers in Melbourne's southern and south eastern suburbs as well as industrial customers across Victoria. The price paid and price per customer are based on broker estimates.

Kinetik Energy / TXU Corporation

In March 1999 it was announced that TXU has acquired the gas distribution company Westar and gas retailer Kinetik Energy from the Victorian Government for a total of A$1.617 billion. Kinetik Energy serves 396,000 retail gas customers in Western Victoria, outer western and north east metropolitan Melbourne including the central business district. The price paid and price per customer are based on broker estimates.

Electricity Retailing – New Zealand

King Country Energy Limited / King Country Electric Power Trust

KCE owns four small generation plants and a 50% interest in Mangahao Power Station (33.5MW proportional installed capacity) and is the largest electricity retailer in the Waitomo, King Country and Ruapehu/Waimarino districts with over 18,000 customer sites. In November 2006 Todd, a founding shareholder holding 35.38%, announced an offer for KCE at NZ$4.40 per share. Todd did not receive sufficient acceptances and this offer lapsed in January 2007. On 12 January 2007 KCE's second largest shareholder KCEPT announced a partial offer to increase its interest from 10% to 27.5% at a price of NZ$4.80, subject to a public consultation process and shareholder approval. On 26 February 2007, Todd announced a partial offer at NZ$5.00 per share for 14.72% to increase its interest in KCE to 50.1%. During the period of Todd's offer, KCEPT acquired the 8% interest of Waitomo Energy Consumer Trust plus a further 2% from public shareholders at NZ$5.00 per share, increasing its interest in KCE to approximately 20%. Todd's offer lapsed in June 2007. The earnings multiples presented reflect KCE's blended earnings and are based on NZ$5.00 per share.

TrustPower Limited / Infratil Limited

On 30 October 2006, Infratil announced that it had acquired AENZ from Alliant for NZ$510 million (including NZ$65 million assumed debt). AENZ holds interests in two publicly traded New Zealand companies: 23.77% in TrustPower Limited ("TrustPower") and 5.07% in Infratil. TrustPower is an integrated generator and retailer in New Zealand, being the fourth largest electricity retailer. If the shareholding in Infratil is valued based on the current market price, the transaction implies a value of NZ$1.944 billion for 100% of TrustPower, a 12% discount to the market price on the day prior to announcement. Notwithstanding the strategic nature of the interest acquired, the multiples implied by the transaction therefore do not include a premium for control. Furthermore, the earnings multiples presented reflect the blended earnings of TrustPower's businesses.

Contact Energy Limited / Origin Energy Limited

In July 2004, Origin announced that it had signed an agreement to purchase Edison Mission Energy's 51.2% interest in Contact Energy for NZ$5.67 per share. Contact Energy is a diversified New Zealand electricity and gas utility. It is New Zealand's second largest electricity generator with 1,940MW of installed capacity in New Zealand, has 387,000 electricity and 107,000 gas customers and is a gas wholesaler with contracted rights to approximately 30% of New Zealand's natural gas reserves. The transaction was completed on 1 October 2004. Acceptances received under a simultaneous full takeover offer for the remaining shares in Contact Energy, as required by the Takeovers Code, increased Origin's interest marginally to 51.4%. The earnings multiples presented reflect the blended earnings of all of Contact Energy's businesses. The prices paid per customer presented are based on broker estimates as to the prices paid for each of the retailing businesses.

On energy (South Island) / Meridian Energy Limited

On 13 July 2001, Meridian acquired the South Island electricity customer base of NGC's On energy retail business for an estimated NZ$36 million. This business represented approximately 115,000 customers located primarily around Christchurch. This transaction was one of two by which NGC withdrew from the retail electricity market in New Zealand. No financial information is publicly available for the business acquired.

TransAlta New Zealand Limited / Natural Gas Corporation Holdings Limited

In August 2000 NGC announced its intention to make an offer for all of the shares in TransAlta NZ that it did not already own at NZ$2.79 cash per share. NGC also made an offer for the subordinated capital notes issued by TransAlta NZ that it did not already own (this offer was subsequently revised to be restricted only to the notes held by Hutt Mana Energy Trust). TransAlta NZ is a generator of electricity and retailer of electricity and gas. It has the capacity to generate over 3,600 GWHr of electricity annually and supplies 475,000 electricity customers in the North and South Islands and 31,500 gas customers in the Wellington and Hutt Valley region and bottle gas customers in the South Island. TransAlta NZ is a significant net electricity retailer and therefore highly exposed to the volatility of wholesale electricity prices. NGC owned 75.8% of the issued shares of TransAlta NZ and 73.5% of the subordinated capital notes, having acquired both interests from TransAlta Corporation of Canada in March 2000 at the same prices offered to the minorities in August 2000.

Empower Limited / Contact Energy Limited

In July 2000, Contact Energy announced that it had acquired the independent electricity retailer Empower Limited ("Empower") for NZ$23 million. Empower has over 25,000 high value residential and business customers. The price paid comprised NZ$6 million for approximately 15,000 residential customers (NZ$400 per customer) and NZ$17 million for the business customer base and other assets.

Eight retail electricity businesses / Contact Energy Limited

During the year ended 30 September 1999 Contact Energy acquired eight electricity retailing customer bases for NZ$134.3 million. These acquisitions gave Contact Energy a total of 345,000 electricity customers. The customer bases were acquired at relatively low values of approximately NZ$380 per customer in a market where other acquisitions were reputedly made at levels as high as NZ$1,200 per customer. The lower price paid may in part reflect the mix of customers acquired and their low average consumption (i.e. Contact Energy has 22% of customers by number although its retail sales represent only 12% by volume).

Gas Retailing – New Zealand

Wanganui Gas Limited / Wanganui District Council Holdings Limited

On 30 October 2006, Vector Limited ("Vector") announced the sale of its 25.1% interest in Wanganui Gas Limited ("Wanganui Gas") to the 74.9% shareholder Wanganui District Council Holdings Limited for NZ$8 million. Wanganui Gas is a retailer of energy to residential and small business customers on the North Island. It is primarily a gas retailer (with approximately 35,000 customers) and has expanded into electricity retailing recently (customer numbers not disclosed). Wanganui Gas also distributes gas in the Wanganui region. As the transaction involves a minority interest the implied multiples would not reflect a premium for control. On the other hand, the interest sold was strategic in size and nature although this may be offset in part by the limited range of potential acquirers for the interest. Due to incomplete customer information, the price per customer data presented is estimated by reference to a range of 35,000-45,000 customers and therefore caution is required when considering this data.

NGC's retail gas business / Genesis Energy Limited

In September 2002 Genesis Energy acquired On gas (the retail gas business of NGC) for an estimated NZ$62 million including NZ$17 million for the existing debtors and unbilled sales amounts. This business represented approximately 95,000 residential customers. This transaction concluded NGC's withdrawal from mass market energy retailing in New Zealand. No financial information is publicly available for the business acquired. The price paid per customer is calculated excluding the proportion of the price attributable to debtors and unbilled sales.

LPG Distribution in Australia and New Zealand

There have been a limited number of transactions involving liquefied petroleum gas ("LPG") distribution activities (i.e. wholesaling and retailing) in Australia and New Zealand in recent years. A summary of the transactions since 2000 for which there is sufficient information to prepare meaningful market parameters is set out below:

Recent Transaction Evidence – LPG Distribution in Australia and New Zealand

Date	Target	Consideration (millions)	Revenue Multiple (times)		EBITDA Multiple (times)		EBIT Multiple (times)		Price per Tonne[22]	
			Historical	Forecast	Historical	Forecast	Historical	Forecast	Unadjusted	Adjusted
Australia										
Nov 06	Sun Retail LPG	A$66	na	0.7	na	9.0	na	10.0	A$2,130	A$2,250
Feb 06	Speed-E-Gas	A$18	na	na	na	na	na	na	A$2,615	A$2,830
Jun 03	Treston Gas	A$4	na	na	na	na	na	na	A$340	A$400
New Zealand										
Mar 07	Rockgas	NZ$156	1.6	na	7.9	7.5	11.5	na	NZ$1,662	NZ$1,750

Source: Grant Samuel analysis

A brief summary of each transaction is set out below:

Sun Retail Pty Ltd / Origin Energy Limited

In February 2007, Origin acquired Sun Retail from the Queensland Government for A$1.202 billion. Sun Retail, included a LPG marketing and distribution business to which Origin allocated A$66 million of the total purchase price, equal to A$2,130 per tonne of LPG sold. No other financial information is available for Sun Retail LPG. The earnings multiples presented reflect the blended earnings of all of Sun Retail's businesses and therefore should be considered with caution.

Speed-E-Gas (NSW) Pty Limited / Origin Energy Limited

In February 2006, Origin acquired Speed-E-Gas (NSW) Pty Limited, a supplier of LPG cylinders in Sydney and Newcastle, New South Wales for A$18 million. Speed-E-Gas was Origin's cylinder distributor and did not operate in the bulk LPG market.

Treston Gas / Origin Energy Limited

In June 2003, Origin acquired the Shepparton based Victorian LPG supplier, Hylemit Pty Limited, trading as Treston Gas, for A$4 million. Treston Gas operated in country Victoria and increased Origins LPG sales by approximately 12,000 tonnes per annum.

Rockgas Limited / Contact Energy Limited

In March 2007, Contact Energy announced the acquisition of Rockgas Limited ("Rockgas") from Origin for NZ$156 million. Rockgas is New Zealand's largest supplier of LPG, with an estimated 50% of the market. It supplies over 300 bulk industrial customers, 7,000 commercial customers and 17,000 residential customers plus a further 15,000 customers through a franchise network. It also distributes to over 300 automotive LPG refuelling outlets around New Zealand via Caltex, Mobil and Challenge networks.

[22] Represents gross consideration divided by tonnes of LPG sold annually. Multiples presented in the table have been adjusted to allow for inflation since acquisition so that all multiples reflect current dollars.

Appendix 10

Market Evidence – Comparable Listed Energy Entities

The valuations of the electricity generation and retail businesses of Origin Energy Limited ("Origin") and Contact Energy Limited ("Contact Energy") have been considered in the context of the sharemarket ratings of listed Australian and New Zealand energy entities. While none of these entities is precisely comparable to Origin's activities, the sharemarket data provides some framework to assess valuation parameters for the retail and generation businesses. Origin has been included in the table as it is useful benchmark for the valuation of Contact Energy.

Sharemarket Ratings of Selected Listed Generation and Retail Energy Entities[1]

Entity	Market Capital-isation[2] (millions)	EBITDAF Multiple[3] (times)	EBITDA Multiple[4] (times)			EBIT Multiple[5] (times)			Value per MW[6] (millions)	Value per Customer[7] ('000)
		Historical	Historical	Forecast Year 1	Forecast Year 2	Historical	Forecast Year 1	Forecast Year 2		
Australia										
Origin	**A$9,340.5**	**12.7**	**13.7**	**10.8**	**9.1**	**19.4**	**14.7**	**12.1**	**A$6.36**	**A$3,704**
AGL Energy	A$6,486.3	12.9	23.8	8.6	7.9	35.4	10.8	10.0	A$2.07	A$2,081
BBW	A$1,072.7	14.1	14.0	11.5	11.5	25.0	21.2	20.5	A$1.69	na[8]
Energy Developments	A$444.1	9.1	9.1	6.7	6.3	18.0	11.5	10.4	A$1.48	na
TSI Fund	A$369.4	10.7	10.7	8.0	7.6	17.9	13.2	12.3	A$1.05	na
BBP	A$112.6	9.4	7.8	9.5	8.4	12.0	16.8	13.9	A$1.27	A$4,804
Viridis	A$134.7	10.1	8.3	7.2	6.9	33.8	20.1	19.0	A$1.92	na
New Zealand										
Contact Energy	NZ$5,410.4	11.6	11.7	11.1	10.2	16.0	15.4	14.2	NZ$2.64	NZ$7,979
TrustPower	NZ$2,494.4	15.1	15.0	13.1	10.8	17.8	15.7	12.7	NZ$4.34	NZ$11,609

Source: Grant Samuel analysis[9]

The multiples shown above are based on sharemarket prices as at 5 September 2008 (except for Origin and Contact Energy which are based on sharemarket prices as at 29 April 2008, the day prior to the announcement of BG Group's approach) and do not reflect a premium for control.

All of the companies have a 30 June year end with the exception of TrustPower Limited ("TrustPower") which has a 31 March year end.

The following should be noted in relation to the above analysis:

1 The data presented for each entity is the most recent annual historical result plus the subsequent two forecast years.

2 Market capitalisation based on sharemarket prices as at 5 September 2008, except for Origin and Contact Energy which are based on the sharemarket price as at 29 April 2008 (the day prior to the announcement of BG Group's approach).

3 Represents gross capitalisation (that is, the sum of the market capitalisation adjusted for minorities, plus borrowings less cash as at the latest balance date) divided by EBITDAF. EBITDAF is earnings before net interest, tax, depreciation, amortisation, investment income, significant and non-recurring items and changes in the fair value of financial instruments.

4 Represents gross capitalisation divided by EBITDA. EBITDA is earnings before net interest, tax, depreciation, amortisation, investment income and significant and non-recurring items.

5 Represents gross capitalisation divided by EBIT. EBIT is earnings before net interest, tax, investment income and significant and non-recurring items.

6 Represents gross capitalisation divided by MW of capacity. Capacity includes 100% owned installed generation capacity and excludes committed capacity and capacity for equity accounted investments.

7 Represents gross capitalisation divided by mass market electricity and gas customers.

8 na = not applicable

9 Grant Samuel analysis based on data obtained from IRESS, company announcements and, in the absence of company published financial forecasts, brokers' reports. Where company financial forecasts are not available, the median of the financial forecasts prepared by a range of brokers has generally been used to derive relevant forecast value parameters. The source, date and number of broker reports utilised for each company depends on analyst coverage, availability and recent corporate activity.

- electricity prices fluctuate and energy entities minimise their exposure to price volatility by adopting an integrated business model with both generation and retail activities as well as by entering into derivatives contracts, including swaps, caps, options and long term contracts. For accounting purposes, most electricity derivatives qualify for hedge accounting and, at period end, unrealised gains and losses relating to the fair value of those instruments are recognised directly against equity. However, for that portion of electricity derivatives that do not qualify for hedge accounting, unrealised gains and losses are recognised through the income statement and can substantially impact earnings.

  As energy entities have varying exposure to electricity price fluctuations there can be differences in earnings margins between entities as well as significant movements in earnings from period to period. For example, AGL Energy Limited ("AGL Energy") is a net buyer of electricity whereas Babcock & Brown Power ("BBP") is a net seller of electricity. At 30 June 2007, when forward electricity prices were high, AGL Energy's earnings were positively impacted by fair value adjustments while BBP was adversely impacted. This situation was reversed at 30 June 2008 when forward electricity prices were lower. As a consequence, historical EBITDA and EBIT multiples are distorted by the unrealised derivative gains and losses (particularly if material in size). However, due to a lack of publicly available information on the derivatives books during accounting periods, broker forecasts do not attempt to forecast such profit impacts. Therefore, there is a disconnect between the historical and forecast EBITDA and EBIT multiples presented in the above analysis. This is eliminated by calculating historical EBITDAF multiples which ignore the impact of unrealised derivatives gains and losses on earnings;
- Babcock & Brown Wind Partners ("BBW"), Energy Developments Limited ("Energy Developments"), Transfield Services Infrastructure Fund ("TSI Fund") and Viridis Clean Energy Group ("Viridis") are electricity generators with no retail activities while the other entities have both retail and generation activities. As a consequence, the industry metrics of value per MW and value per customer presented are not truly meaningful across the entire peer group (i.e. the metrics calculated for the integrated energy companies reflect all of the entity's activities). However, value per MW is appropriate for the abovementioned pure generation entities. On this basis, generation entities with a greater emphasis on renewable energy resources (e.g. BBW, Energy Developments and Viridis) appear to trade at relatively high multiples of MW of capacity. Higher multiples for these companies may also reflect their significant development portfolios;
- AGL Energy's forecast earnings multiples are relatively low. This may, in part, be a result of its share price not fully reflecting the market value of its 24.9% interest in Queensland Gas Corporation Limited ("QGC"), a company involved in the exploration for and production of coal seam gas in Southern Queensland. This investment was acquired in March 2007 for A$330.1 million and currently has a stockmarket value of around A$975.0 million despite few earnings stream from the investment as yet. AGL Energy's forecast EBITDA multiples increase to around 8.5-9.0 times if the QGC investment is allowed for at acquisition cost rather than at current market value;
- BBW's earnings multiples are relatively high, reflecting earnings emerging from acquisitions and developments during 2007 and 2008. BBP's earnings multiples are distorted to the extent that earnings exclude its proportional interest in Oakey Power Station and the impact on its market rating from recent refinancing issues; and
- the multiples for the New Zealand companies are high in comparison to the Australian entities reflecting the focus on renewable fuel sources in New Zealand. TrustPower relies entirely on renewable energy sources (hydro, wind) and Contact Energy also has a significant investment in renewable energy generation (hydro, geothermal). TrustPower's higher multiples relative to its peers may be attributed to a higher payout ratio (96% compared to 25-70% for other energy companies), a limited free float (16.5% of total shares on issue) and illiquid trading. Similarly, Contact Energy's multiples may reflect the relatively low liquidity of its shares.

A brief description of each entity is set out below:

AGL Energy Limited

AGL Energy was formed when The Australian Gas Light Company merged its infrastructure operations with Alinta Limited ("Alinta") in October 2006. It is an integrated energy conversion and retailing business with interests in upstream CSG assets. It sells and markets gas and electricity in New South Wales, Victoria, Queensland, South Australia and the ACT. It has approximately 3.6 million residential and small business commercial customer energy accounts including 1.3 million dual fuel accounts and 0.35 million LPG accounts

(through its 50% interest in Elgas Limited). AGL Energy's wholesale operations purchase and generate the electricity and related products sold by the retail operations in addition to purchasing and managing gas, transportation and storage services for AGL Energy's retail and wholesale customers. AGL Energy has a diverse power generation portfolio including base, peaking and intermediate generation spread across traditional (gas and coal) generation as well as renewable sources (hydro, landfill gas and biogas) with installed generation capacity of 3,600MW as well as 200MW of capacity under construction. It supplies approximately 50% of its base load electricity requirements and 55% of its peak load requirements. AGL Energy also has interests in coal seam gas assets through its 24.9% shareholding in QGC and 50/50 joint venture in the Moranbah Gas Project with Arrow Energy Limited. AGL Energy's historical multiples are not meaningful due to a number of acquisitions and divestments during 2007 and 2008.

Despite its generation capacity, AGL Energy is a net buyer of electricity and it uses a variety of derivatives (swaps, caps and options) to hedge future transactions generally for up to five years in order to minimise the exposure to fluctuations in wholesale market electricity prices. Lower forward electricity prices at 30 June 2008 resulted in substantial unrealised losses being recognised in the income statement, resulting in high EBITDA and EBIT multiples for that year. The historical EBITDAF multiple is a better measure of its relative market rating. Furthermore, AGL Energy's forecast earnings multiples are relatively low which may reflect that the market is not allowing for the full market value of its 24.9% interest in QGC in its share price.

Babcock & Brown Wind Partners

BBW is an investment fund focused on wind energy generation assets which listed on the ASX in October 2005. BBW's portfolio consists of 63 operational wind farms in Australia, Europe and the United States and 10 wind farms under construction. In 2008, approximately 47% of BBW's EBITDA was sourced from Europe, 35% from the United States and 18% from Australia. Its consolidated wind farms have installed generation capacity of approximately 2,535MW as well as 406MW of capacity under construction and are diversified by geography, currency, equipment supplier, customer and regulatory regime. Revenue is predominantly contracted, providing stable cash flows. The 2008 multiples calculated for BBW are high as a consequence of significant acquisition and development activity in that year. The EBITDA multiple declines to 11.8 times in 2009 (forecast year 1) although that is also relatively high due to the growth embedded in the portfolio and may also reflect the market's positive view of its carbon rating. The market is expecting BBW to sustain a high level of growth to continue in the medium term. On 21 August 2008 BBW agreed to sell its Spanish wind farm portfolio for an enterprise value of $1.42 billion and is continuing to pursue sales initiatives in France and Portugal.

Energy Developments Limited

Energy Developments is an international renewable energy provider with operations primarily in Australia, as well as the United States, United Kingdom and France. It has 54 projects with 552MW of installed capacity and 45MW of capacity under construction. Energy Developments has three core power generation businesses: landfill gas (decomposition of organic refuse to generate mostly methane and carbon dioxide with water vapour which can be used for power generation), coal mine methane and remote area (six power plants which utilise natural gas and distillate to provide power to remote areas) and is currently developing capabilities in liquefied natural gas and compressed natural gas power generation and energy solutions. Since 31 December 2007, Energy Developments' share price has declined by 24%, reflecting lower green energy certificate prices and uncertainty as to the value of green credits under a national emissions trading scheme and well as gas supply issues at German Creek and delays in commissioning at West Kimberley. These factors also contributed to lower earnings in 2008. Energy Developments initiated a strategic review on 4 July 2008 (including its potential sale).

Transfield Services Infrastructure Fund

TSI Fund is an investment fund which owns a portfolio of interests including five power stations, two water filtration plants and four wind farms. It was listed on the ASX in June 2007. TSI Fund derived 93% of its 2008 EBITDA from three wholly owned (predominantly gas fired) power stations and the remainder from wind farms. Together, these generation plants represent 818MW of installed capacity. In addition, TSI Fund has 40MW of committed wind farm capacity. It has power purchase agreements for each of its wholly owned power stations. It also has a 14.03% interest in Loy Yang A Power Station and a 30% interest in BP Kwinana Cogeneration Plant as well as investments in water filtration plants.

Babcock & Brown Power

BBP is an investment fund focussed on conventional electricity generation assets, with around 70% of fuel sourced from gas. It was listed on the ASX in December 2006. The listing of BBP brought together a collection of eight power generation assets. BBP expanded its business rapidly both organically and through acquisition. It expanded its installed capacity and entered the retail gas market segment in August 2007 through its participation in the consortium which acquired Alinta Limited and acquired the remaining 33% interest in AlintaAGL from AGL Energy in December 2007. Consequently, the historical multiples presented are not meaningful. Currently BBP has 12 operating peak and base load power stations throughout Australia and New Zealand as well as two power stations under construction, with installed (consolidated) generation capacity of 2,667MW and 650MW of capacity under construction and operates Alinta Retail, the major gas retailer in Western Australia (540,000 retail customers).

BBP is a net generator of electricity and primarily sells electricity into the market. It has entered into long-term power purchase agreements and hedging agreements to reduce its exposure to decreases in spot electricity prices. A significant proportion (90%) of BBP's electricity derivatives do not qualify for hedge accounting. This primarily relates to the agreement with EnergyAustralia in relation to Redbank Power Station which fixes electricity prices received by BBP until 2023. Lower forward electricity prices at 30 June 2008 resulted in substantial unrealised gains being recognised in the income statement, resulting in low EBITDA and EBIT multiples for that year.

Since 31 December 2007, BBP's share price has declined by 94% as a consequence of the implications of the turmoil in global credit markets on refinancing $2.7 billion of debt. BBP has engaged UBS to conduct a strategic review of its operations which includes potential asset sales to pay down debt. In July 2008, BBP sold the Uranquinty Power Station and Ecogen power generation business and in August 2008 announced the sale of Tamar Valley Power Station.

Viridis Clean Energy Group

Viridis is a clean energy infrastructure fund which invests in a diversified global portfolio of clean energy assets and listed on the ASX in September 2005. Diversification is achieved by holding investments in different geographic regions with varying climatic and seasonal conditions and across a number of technologies and fuel sources. Landfill gas makes up 63% of the value of the fund with wind assets accounting for the remainder. The majority of these assets are situated in the United Kingdom (60% of the value of the fund), followed by the Germany (31%) and the United States (9%). Viridis' consolidated earnings reflect 188MW of installed generation capacity. Approximately 45% of electricity generated is sold at market prices while the remainder is contracted at fixed or escalating fixed prices. Viridis' historical earnings multiples are high due to lower earnings in the first half of 2008 associated with unscheduled maintenance at wind farms in Germany, higher operating costs in the United States and lower repatriated earnings from the United States as a result of the weaker United States dollar.

Contact Energy Limited

Contact Energy is an integrated energy conversion and retailing business in New Zealand. It is the country's second largest electricity generator (i.e. 25-30% of New Zealand's total generation capacity) operating 10 power stations in New Zealand. It has 1,960MW of installed capacity and 223MW of capacity under construction. It also owns a minority interest in the Oakey Power Station in Australia. A significant portion Contact Energy's electricity generation capacity comes from renewable resources, including hydro (38%) and geothermal (15%), with the remainder coming from natural gas (47%). In addition, Contact Energy is New Zealand's second largest energy retailer, with around 648,000 electricity and gas customers, representing 27% of New Zealand's total retail electricity market, 40% of the retail gas market and 50% of the LPG market.

TrustPower Limited

TrustPower is an integrated electricity generator and retailer operating in New Zealand. It has substantial generation capacity consisting entirely of renewable energy sources, including 34 small to medium sized hydro and wind generation power stations located throughout the North and South Islands of New Zealand. It has 594MW of installed capacity and 98MW of capacity under construction (mainly wind-generated) in both New Zealand and South Australia. TrustPower is one of New Zealand's largest electricity retailers with an estimated 222,000 customers (i.e. 11.5% market share). Its major shareholders are Infratil Limited (50.5%) and Tauranga Energy Consumer Trust (33%) and therefore it has a limited free float.