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Industry View
Attractive

Primer

Australia Oil & Gas

Shale Gas: Grab a Surfboard…

...and get ready to ride the wave. Shale gas could be the next success-story for Australia Oil & Gas. Increasing news flow on this exciting potential means early investors could be well rewarded.

The best immediate leverage for stocks under our coverage is in **Beach Energy** and **AWE** while **Santos** retains the greatest exposure to acreage, plus it has production infrastructure. We have upgraded AWE to OW and company discussions are on pages 29-34.

It's very early days in Australia... and highly speculative, but we document a rising level of activity from over 25 local and foreign operators, consider the risks involved and put forward an investment strategy.

…following extraordinary success in the US. It took less than a decade for shale gas to completely re-shape US domestic gas industry dynamics (see page 6). The search for shale gas has now gone global, including into Europe, China and Australia.

Shale gas potential is enormous. In Australia, industry estimates are for as much as 400 Tcf of recoverable gas in total. The focus of the local industry over 2011 and 2012 will be to understand whether any of this gas can technically be produced.

Cooper and Perth basins are best understood and there is existing production infrastructure and pipelines. Other prospective basins are the Canning, Georgina and Beetaloo, but less is known about rock quality, and production and transport infrastructure is absent.

Surfing is risky. Around A$500mn in 2011 is needed and as with any exploration, there will be set-backs. The size of the prize is potentially very large, but unlocking the resource is likely to be an evolutionary process and as with any exploration there are likely to be setbacks. Collective industry results will be more important than singular outcomes at this time.

Upgrading AWE to Overweight from Equal-weight

Stock	Current Price (A$)	Rating	Target Price (A$) (no changes)
AWE (AWE.AX)	1.46	Overweight (prev. Equal-weight)	1.80
Beach Energy (BPT.AX)	1.00	Equal-weight	1.05
Santos (STO.AX)	14.27	Overweight	16.50

Source: Morgan Stanley Research

Companies active in Australia Shale Gas/Oil

Australian Listed (A$mn)	Ticker	Mkt Cap.	Key Region
Adelaide Energy	ADE.AX	51	Cooper
AWE	AWE.AX	759	Perth
Baraka	BKP.AX	46	Georgina
Beach Energy	BPT.AX	1,103	Cooper
Buru Energy	BRU.AX	139	Canning
Drillsearch	DLS.AX	118	Cooper
Emerald	EMR.AX	35	Canning
Empire Oil	EGO.AX	107	Perth/Canning
Exoma	EXE.AX	65	Galilee
Icon Energy	ICN.AX	87	Cooper
New Standard	NSE.AX	42	Canning
NorWest	NEW.AX	42	Perth
Oil Basins	OBL.AX	9	Canning
Origin Energy	ORG.AX	17,233	Cooper/Perth
Santos	STO.AX	12,547	Cooper
Senex	SXY.AX	265	Cooper
Strike Energy	STX.AX	56	Cooper
Transerv	TSV.AX	29	Perth
Overseas companies			
Alcoa (US$mn)	AA	17,197	Perth
Bharat (Rs mn)	BPCL.BO	229,087	Perth
CNOOC (HK$mn)	0883.HK	838,181	Galilee
Falcon ($Cmn)	FO.TO	94	Beetaloo
Hess (US$mn)	HES	25,923	Beetaloo
Mitsubishi Corp (¥bn)	8058.T	3,313	Canning
Petrofrontier ($Cmn)	PFC.TO	138	Georgina
Rodinia ($Cmn)	ROZ.TO	144	Officer

Source: Morgan Stanley Research, Factset

Contents

Valuation & Recommendations

News flow will drive any price increases for stocks active in the shale gas industry in Australia. Our fundamental stock valuations are unlikely to be affected for some time, until exploration activity results in reserve bookings which can be tangibly valued.

Our key methodology for all E&P in Australia is DCF sum-of-parts. The issue that arises is that exploration acreage without proven or producing reserves has no cash flow profile, thus we resort to industry accepted yardsticks.

One way to value acreage is to assess the investment that a company would be prepared to invest in an ongoing exploration program. The fact that two dozen companies are collectively intending to spend >US$500mn this year evidences that shale gas acreage has *some* value, but we do not have enough 'data points' yet to arrive at a 'number' that could be meaningfully applied, with any confidence.

Another accepted rule of thumb would be to use precedent transactions, either in terms of asset deals or M&A.

It would be obvious to plumb the US industry for a methodology, and we are frequently presented with transaction multiples for prospective acreage. Our data set for 86 acreage transactions in the US since 2009 shows an average price per acre of US$5,500 (with a very wide range though with prices as high as US$$30,000). However, we observe the bulk of transactions are in regions where the prospectivity is confirmed by nearby commercial production and where the production techniques to be applied and development costs reasonably well known. These parameters are not known in Australia, and moreover, the vast acreage positions that are typically held, in the order of thousands of square kilometers, renders applying an 'acreage value' meaningless. Consider the numbers that would result from applying $5,500/acre to Buru Energy's nine million acres or New Standard's eleven million acres. We could continue to embellish the point but suffice it to say that **we reject US-type benchmarks *at this time,*** and leave them in reserve for a future time once the exploration plays become de-risked.

Rather than value what we don't know, let's assess what we do know. Here are three considerations:

1. Understand where 'core value' is in case exploration fails

In our experience, Investors in exploration companies don't seek to value the unknown, but more importantly prefer to understand 'core' value for production and cash, then figure what the 'blue sky' is in the stock price, which is effectively the cost of the exploration option. At worst, if exploration fails, then the core value puts a floor under the stock price.

Exhibit 1 below summarizes what we asses to be core value for the three covered companies recommended in this report.

2. Invest ahead of the activity

Market releases detailing planned activity drive share prices in anticipation of future success and recent recovery in, or outperformance in, stocks such as BPT or AWE characterize this.

BPT has arguably been the most visible promoter of its shale gas program this year and in addition to positive conventional oil well results, the stock has outperformed domestic peers YTD. In this regard, AWE remains a laggard and expectation of a catch-up is implicit in our upgraded recommendation as well as what appears to be a discount to core value.

3. Assess the drilling and testing results when they become available.

In general, we would be looking for evidence this year that the shales respond to fracing. Given that most of the wells to be fracced are vertical wells, we would not expect commercial type flow rates, but we would anticipate operators to report the successful displacement of frac fluids into the shales, followed by the return of such and free gas flow. Failure to flow may evidence failure to frac and that may render the play worthless.

Many wells are planned to be cored. Cores are sent to labs for analysis and often the results are not known for months and even then, rarely reported on. Increasingly we would expect operators to make available such parameters as TOC, thermal maturity, shale mineralogy. The provision of such information may be valuable.

Recommendations and price targets

Santos. Our Overweight recommendation is unchanged as is our $16.50 price target. Our full value is $19.27 and this does MOT include any value for conventional and unconventional gas resources, or value for infra-structure. Included in this DCF is an unrisked estimate of the PNG and GLNG LNG projects which are under construction. We believe that investors are likely to apply some discount to these developmental assets given the construction risks, and the potential for projects to go overtime or cost more. Santos' shale gas activities, relative to their other activities, is small at this time and perhaps less well publicized, hence we reckon that the STO share price does not reflect anything for potential future upside.

Exhibit 1

SoP Valuations Separated Into Core+

	Santos	AWE	Beach
Core value			
Production value A$m	6783	864	623
Cash & investments A$m	1413	105	197
Core value A$m	8196	969	819
Core: A$/ share	**9.33**	**1.86**	**0.74**
Development A$m	8376	141	161
Exploration A$m	347	74	165
Total exploration & development assets	8722	215	326
Total E&D- A$/ share	9.93	0.41	0.30
Full value- A$/share	**19.27**	**2.27**	**1.04**
Production reserves- 2P mboe	1094	65.6	64.5
Value of core prod / boe- A$/bbl	7.49	14.77	12.70

Source: Morgan Stanley Research

AWE on our analysis, is trading below the value of core production and cash. We think this is because investors fear further value-destroying news. Over the past 1-2 years there have been a series of production downgrades, rising capex, and capital-eating exploration dry-holes. Thus, the company's position in shale gas is probably overlooked in our view, yet its upcoming activity this year is real and potentially very value additive. **We have upgraded our recommendation to Overweight, with a price target of $1.80 (which is unchanged).** Contributing to the upgrade is **but an extended period of share price underperformance tilts the risk-reward equation to reward.**

Beach Energy is active now, and we think near term news flow will likely power the price. With that in mind Morgan Stanley issued a positive Research Tactical Idea on May 18, 2011. Comparing core valuations though, it appears to us that there is already some value in the share price for the shale gas activity. We attribute this to BPT's comprehensive market presentations which provide some excellent detail and insight into the technical aspects behind its drilling for shale gas to date. Investors are clearly already ascribing some value to the shale gas activity and data to support this, or not, is expected over the next 30-40 days.

Shale Gas: Grab a Surfboard

The North American shale gas industry is a modern success story and the search for prospective shale gas acreage is now a global one. **Commercial production from shale hasn't been seriously attempted in Australia yet, but that is about to change.** A number of domestic and overseas companies are undertaking shale gas drilling and testing programs. Collectively the industry will spend about A$500mn this year on shale gas exploration, up from negligible levels a year ago.

Australia has large sedimentary basins with enormous shale gas potential too. The 'gas-in-place' resource is independently assessed [1] by ARI to be in the range of 1380–2300 trillion cubic feet (Tcf) of which over 400 Tcf could technically be recovered. Current technology as applied in the US, and existing knowledge of specific Australian shale gas sequences, give rise to a view **that production is feasible**.

If there is lots of gas why has no-one one chased it before? Lack of market opportunities and infrastructure constraints have historically inhibited gas exploration. Even the Queensland CSG industry only really 'took-off' after resource owners cracked open the LNG export market – and that was as recent as 2008.

Will it work? It should. The upcoming exploration wave aims to 'prove the concept' that production is feasible in the first instance. Some of the shale rocks in conventional production basins such as the Cooper and Perth basins, are reasonably well understood and appear to rank favourably against successful shale rock developments in the US. Fraccing of a handful of vertical wells has provided encouraging results but horizontal wells technology, a key success factor in the US, has yet to be deployed in Australia.

Will it be profitable? Commercial considerations are yet to be addressed and these are not insignificant in Australia. Shale gas is more expensive than conventional gas production, and can only succeed financially in markets where cheaper conventional production is depleting and gas prices are on the ascendancy. In Australia, low domestic gas prices are an existing barrier, but by the time this industry is ready to deliver, we anticipate domestic gas shortages and higher prices. LNG projects also provide access to higher prices.

[1] Advanced Resources International Inc. prepared for the US Energy Information Agency and US Department of Energy, published April 2011.

Where should investors look first? Current understanding is that the most prospective shale gas basins are the Cooper and Perth basins; both will see drilling activity this year and both have under-utilized production infrastructure to enable commercial production. Activity is underway in new/frontier areas too, by foreign operators, e.g. in the Georgina, Beetaloo and Officer basins, as well as by Australian companies in the Canning Basin. These latter regions are more remote and so face a higher initial economic hurdle, in our view.

What about other unconventional hydrocarbon plays? The scope of this report is limited to shale gas, which is just one sub-set of 'unconventional' oil and gas, which also includes coal seam gas and 'tight' gas production. We have chosen to limit the scope to shale gas operations, which is in its infancy, compared to coal seam gas, which in Queensland is well developed and we feel well known and understood by investors. However, the one caveat on this exclusion is that we note a number of companies are indicating the potential for shale and coal seam gas targets to co-exist in particular wells or basins, and those are referenced in this report as applicable.

Where is the 'thundering herd?' Apart from Santos, whose land position is a result of incumbency, and small investments by Hess and CNOOC, participation levels by global E&P companies are small.

By contrast, asset deals for US shale gas in the past three years exceed US$70bn, with super-majors typically buying smaller independent producers. The shale gas industry in Australia today is analogous to the coal seam gas industry a few years ago. Then CSG was a 'cottage' industry populated by many small companies experimenting with production and techniques. Once technical success became apparent, a consolidation phase followed very rapidly, and within two years, US$24bn changed hands for undeveloped gas resources and today super-majors dominate Australian CSG. **This could occur with shale gas too, but only after technical success is demonstrated, in our view.**

Investment strategy

AWE and **Beach Energy** offer the best leverage to near term exploration events, while **Santos** has the greatest absolute upside in terms of exposure to prospective acreage plus it has production infrastructure. We recommend investors increase exposure to these stocks. Importantly, there appears to be very little of this shale gas potential currently priced into the stock prices.

Why Lessons from the US are Important

The US has led the world in shale gas production and in a handful of years growth in US supply has fundamentally altered US gas industry dynamics.

The US shale gas resource is enormous. In December 2010, the EIA estimated the recoverable resource to be 827 Tcf, while other forecasts such as CERA and Colorado School of Mines put the figure far higher, in the 2000-3000 Tcf range. It's a moot point because the industry is still very 'young' with development of the key shale basins, such as the Barnett, taking-off from around 2000, the Fayetteville and Woodford around 2004, Marcellus late 2007, Haynesville 2008 and Eagleford 2010.

Whatever the figure, it swamps annual US shale gas consumption which is +/-24 Tcf pa.

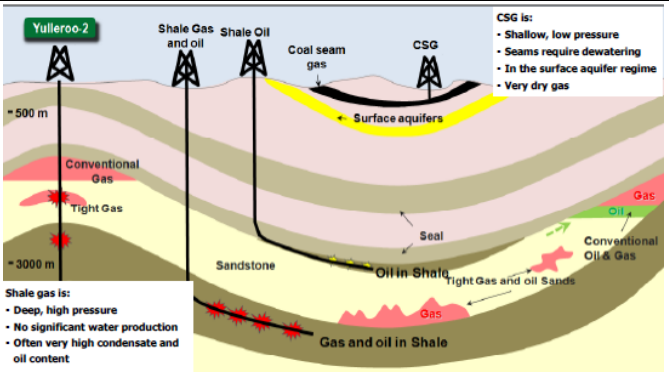
Currently, gas production is growing at about 10% CAGR and shale gas accounted for approximately 16% of all US gas production in 2010. Production is outpacing demand growth, as operators seek to exploit associated oil production and/or drill to hold leases. Oversupply has driven down US domestic gas prices and futures curves show no imminent recovery. Imports of gas into the US in the form of LNG, which was widely predicted as necessary a few years ago, have been killed off and many producers are pondering LNG export projects to deal out the growing excess into global markets.

What is shale gas (and oil)?

Basically, it is hydrocarbons which are locked into shale rocks. Shale is the most common sedimentary rock on the planet and shale formations can be very extensive. Shale is composed of very fine grained particles of clay and other minerals, predominantly calcite and quartz. Shale rocks also contain about 95% of the organic matter in all sedimentary rocks and heat and pressure from the burial process over millions of years turns this into oil or gas.

Shale gas (and coal seam gas) are commonly referred to as unconventional gas, as historically shale rocks were believed to be "non-reservoir" material. Because of the very fine grained characteristics of shale, permeability and natural porosity of shale rocks is very low compared to typical sandstone & limestone reservoirs, and hydrocarbons generated within the shale tend to remain trapped in-situ (unless subsequent faults open up leakage paths).

Exhibit 2
Types of Unconventional Gas Reservoirs



Source: Buru Energy

The lack of natural permeability and porosity is what differentiates shale rock from other sedimentary rocks such as sandstone and limestone. The latter two make up the majority of conventional oil and gas reservoirs around the world. A good conventional sandstone or limestone reservoir could have permeability in the 50-5000 milidarcy (md) range. Shale permeability is orders of magnitude lower, typically in the range from 0.0001 md to 0.01 md.

Thus, most shale sections when drilled, do not flow gas (or oil or water) let alone at commercial rates. Special drilling and production techniques are required to bring this resource out of the ground. Two technologies in particular have evolved in the past decade and are considered to be critical. These are:

Horizontal drilling. Whereas a typical vertical well may only access 50m or 100m of shale (depending on the thickness of the shale), horizontal wells that can 'follow' the shale beds horizontally for up to 3000m, exposing orders of magnitude more rock to the well-bore.

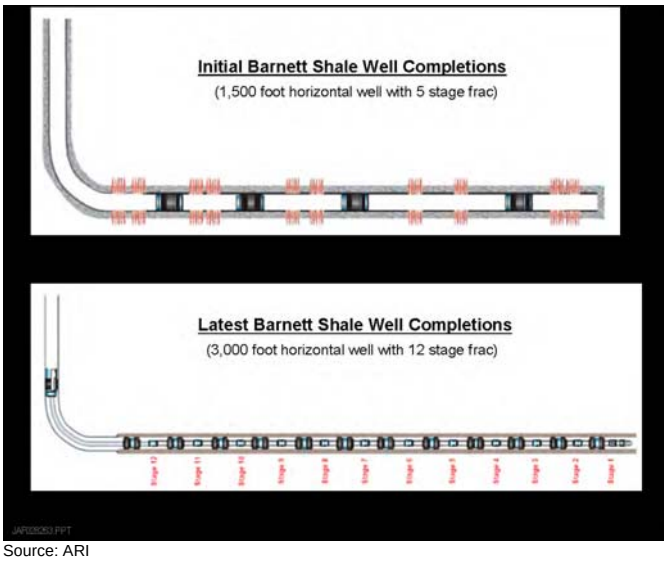
Hydraulic fracturing. Shale permeability is very low and so fluids remain trapped between the grains of sediment. Artificial stimulation is then needed to create fractures in the shale and open up flow paths for the gas to the well-bore. Hydraulic fracturing is the tool of choice, which involves firstly, shattering the rock to creature fractures with hydraulic impulses and secondly, keeping the fractures open by pumping in a proppant to keep the fractures open.

Fraccing is no simple task. Consider for a moment what sort of garden hose one would need to crack a slab of concrete by

spraying water on it! Fraccing technology has improved in recent years too, in terms of understanding what works best in certain shales, availability of greater power for pumping and development of different fluids and propping agents.
Multi-stage fraccing too is a recent innovation, whereby many parts of the shale are fractured in sequence, with the aim of creating a continuous, fractured reservoir.

Exhibit 2 shows what a typical multi-stage frac completion in the Barnett shale would look like now and how that has evolved over the last ten years. It is not uncommon to have up to 40 individual frac stages in a single well.

Exhibit 3
Typical Multi-Stage Frac – Barnett Shale



Source: ARI

Exhibit 3 shows the physical hardware needed on a well-site to conduct a reasonably big multi-stage frac. Cracking open tight rocks requires a lot of very powerful, high pressure pumping equipment, and uses large amounts of water (4-5 million litres for a big job) as well as lots of proppant. It is highly 'gear' intensive.

How is this different to existing conventional oil and gas production?

Shale gas (and oil) fields are different to conventional reservoirs in a number of ways and these differences need to be understood given that most investors in oil and gas companies are more familiar with the conventional E&P process.

Exhibit 4
…A Typical Frac Job Underway…'Gear' Intensive

Source: Trican frac job, Canada, as shown in Icon Energy march quarter 2011 report

Key differentiating characteristics are as follow:

The exploration and evaluation process. With conventional oil and gas exploration, success is often the binary result of a single well drilled into a prospect for the first time. A discovery is often readily apparent from the moment the drill bit hits the reservoir, from oil and gas shows in the rock cuttings, and if not contained, the reservoir will flow freely.

A successful conventional oil or gas discovery will flow freely and during the exploration phase is demonstrated through the recovery of samples from down-hole tools, or flow rates to the surface.

Shale gas exploration is completely different. Shale is common and finding it is very easy. **However when shale rocks are drilled, they do not flow.** In the first instance, estimating how much gas is trapped in the rock, requires a section of the rock to be brought to the surface, in the form of a core. The core is then sent to a specialized laboratory, where the amount of gas trapped in it is measured, and the mineral composition of the rock is determined. Measuring the gas volume is pretty obvious, understanding the mineralogy of the shale is equally important to understanding if it will fracture or not. **Thus coring is typically the first step** in evaluating a shale sequence.

The next phase of shale gas evaluation is attempting to fracture the shale and see if gas can be liberated and flow to the surface. Initially it's not critical that flow rates are high but rather the objective is to learn about how the shale responds to the frac – and not all shales are the same. During the evaluation phase, it's likely that a number of wells are drilled,

employing different completion and fracturing techniques, to see which works the best. It's not critical that a complex and expensive horizontal be drilled – that comes later with commercial development. Thus the exploration and evaluation phase for shale tends to be a lot more evolutionary than for a conventional field, and this process is similar to the way coal seam gas fields have been explored.

The development and production phases are different too, with typically low production rates and relatively small amounts of gas available from an individual well. This necessitates drilling many more wells than for a conventional field, and dictates a strong focus on efficient drilling to keep development costs down.

Recovery per well and production profile. A super producing gas well on a big offshore conventional gas field could, over its life, produce hundreds of billion cubic feet (Bcf) of gas with recovery factors for the gas-in-place as high as 70%. In contrast, even the best of shale gas wells produce a fraction of that. In the most prolific US gas fields (Marcellus, Haynesville) ultimate recovery per well for a modern horizontal well is approaching 5-6 Bcf, and recovery factors for the gas-in-place are in the order of 30-40% – and this would be considered to be a very good well. Given that hundreds of wells may be needed to develop a field, not all wells are successful (e.g. some may incur mechanical or equipment failures or the frac job may be botched) and so field-wide averages tend to be even lower.

Consider the results from the US:

- The US's biggest shale gas region, the Barnett shale, produced 1.8 Tcf in 2010 from 14,000 wells completed to date (compared to Woodside's operated North West shelf fields, which produce 1.2 Tcf pa from approximately from 50 wells). The ultimate recovery per well from the best part of the Barnett field, the 'core area' is 2.5- 3.0 Bcf/well. Areas to the south are less prolific, returning 1–2 Bcf/well.

- In the US's second-largest production region, the Fayetteville, average recoveries per well are 1.7 Bcf, although the trend is on an upward path as this is a relatively new area. To date, there are over 3000 wells on the Fayetteville trend.

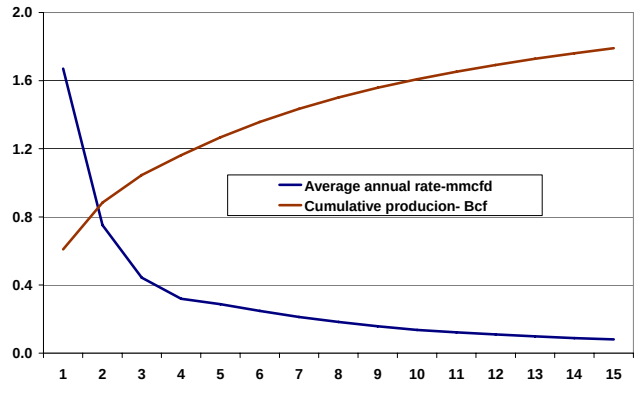
Production profile of a typical shale well is also very different to a conventional well. Wells in conventional gas fields can produce at very high and stable rates for years, as pressure in the gas reservoir gradually dissipates. For example in offshore Australia, individual wells in the North West can produce sustainably at around 100–200 mmcfd, and offshore Victoria in the Otway Basin, about 50–100 mmcfd. Shale gas wells in contrast, produce at very low rates, at an average of 1–2 mmcfd in the first year.

A typical well may deliver about 25% of its ultimate potential in the first year, after which depletion rates are very steep – in the order of 40-50% per annum for each of the next few years. Typically around 50% is recovered in the first four years. Exhibit 5 shows a typical shale gas well production profile.

The rapid decay rates require that in order to meet a base-load demand profile (such as for an LNG plant or base load power station) numerous wells are likely to be required with continual drilling of replacement wells.

Shale gas production has been described by some as more akin to a "manufacturing" operation due to the virtual continuous nature of drilling required to offset decline rates. This is likely an over-simplification but helps to demonstrate that the shale gas industry requires drilling operations on a large scale to be successful.

Exhibit 5
Typical Shale Gas Production Profile



Source: Morgan Stanley Research

Are there quality differences?

Apart from the fact that the gas (and oil) are produced from different rocks compared to conventional sandstone or limestone reservoirs, the products, ex-well, are no different to any other oil or gas field.

In addition to gas (methane) the produced hydrocarbons may include valuable by-products such as oil and condensates, and impurities such as CO2 and Nitrogen. Gas composition will largely depend on the organic matter contained in the sediments at the time of burial, as well as post-burial time,

temperature and pressure effects and this is common to any oil or gas field.

Other points of differentiation are subtle:

1. Water. Unlike CBM fields in their early years, or conventional fields in later years, water production tends to be minimal. Water in the shales is usually expelled as the shales are buried, but if there is any remaining or any which has been introduced by faulting, the effect would be to negate gas production in the first instance and render the shale as non-productive for gas.

2. By-product oil production. Shale gas fields can produce material quantities of valuable oil and condensate by-products, depending on the organic make-up of the shale and its thermal maturity for oil vs gas. A number of economically important 'shale gas' production regions in the US have significant associated oil production. The Eagleford shale region of South Texas for example, is particularly liquids-rich and for some project owners, the income from oil is more significant than that of the gas; and the Bakken shale in Canada is principally an oil producer.

3. Other impurities. Again, depending upon the composition of the rocks, shale gas can be accompanied by relatively high levels of CO_2 and inert gases such as nitrogen. For example in the Cooper Basin, in the objective REM shale sequence, gas from the Epsilon section averages 15% CO_2 and gas from the Patchawarra underlying the REM ranges from 8% to 40% CO_2. Removal of Nitrogen and CO_2 adds to development costs and complexity.

What makes a good shale gas deposit?

There are some factors common to the most prolific shale gas regions and exploration of shale resources in the first instance targets understanding of these parameters long before any extended well testing to establish production at the surface. From a market perspective, we suspect that a section of the investing community would hope or expect the results of a one well test will provide a defining moment in terms of the future value of a shale gas resource. In reality it won't happen this way. It took the US thousands of wells to ride the 'learning curve' (see Exhibit 7).

1. Thickness and lateral extent of the shale, pretty obviously, constrains the volume of productive rock and ultimately the amount of gas contained. Gas-in-place figures for key US shale regions range from 40 Bcf to 80 Bcf per square km. Also thick shales are relatively easier to drill and frac over extended horizontal sections, whereas thin shales pose additional problems of maintaining the well bore and frac fluids to the shale band.

2. Total organic carbon (TOC). Micro-organisms such as animal and plant matter provide the requisite carbon, oxygen and hydrogen needed to create natural gas and oil. Thus the organic content is an important measure of how much basic material there is in the shale that could be converted into gas and oil, given favourable temperature and pressure conditions. **For the major US production basis, TOC's range from 4% to 7% TOC**, while something less than 3% would be seen as too low to be prospective, in our view.

3. Thermal maturity, gas composition and liquids yield. Thermal maturity is the degree to which the shale formation has been exposed to temperatures and pressures sufficient to break the organic matter down into oil and gas. In general, cooler rocks closer to the surface may be more oil prone, while the deeper rocks subject to more heat and pressure are, more likely to be gas prone. Many of the economically important US shale regions have significant liquids by-product contribution which enhances the revenue stream.

Exhibit 6
Liquids Yield (%) Selected US Shale Plays

Bakken	80
Eagle ford	75
Barnett	45
Permian	65
Marcellus	Low
Fayetteville	Low

Source: Morgan Stanley Research, Conoco, Chesapeake

4. Pressure gradient. Some shale rocks are over-pressured, and this is the concentration of gas within a fixed volume of rock. The normal hydrostatic pressure gradient is 0.43 psi per foot of depth. In the US, over-pressure is common to successful fields, with the Barnett shale gradient at 0.55 psi/ft and the Haynesville shale at 0.85 psi/ft.

5. Depositional environment and mineralogy of the shale impact 'fraccability'. Lithology and depositional environment are important controls of the 'brittleness' of the shale and its response to fraccing. Marine shales tend to have a higher content of carbonates and quartz silicates which makes then relatively brittle and so marine shales are seen as prospective and 'fraccable'. Non-marine shales, which are laid down in lacustrine or fluvial depositional environments, tend to be relatively high in clay content. Clay is the bad guy in this

equation, as it tends to make the shale ductile and much less responsive to fraccing.

6. Significance of complex geology. Extensive faulting can limit the productive length of a horizontal well, introduce water into the shale matrix, and add to tectonic stresses which may further reduce natural permeability.

Learning effects: US shows the way but it can be a grind

The US shale gas industry appears to have been an overnight success. Industry promoters point to production statistics which show the relentless growth in US output in terms of volume, from 'X' Bcf in 2000 to 'Y' Bcf in 2010.

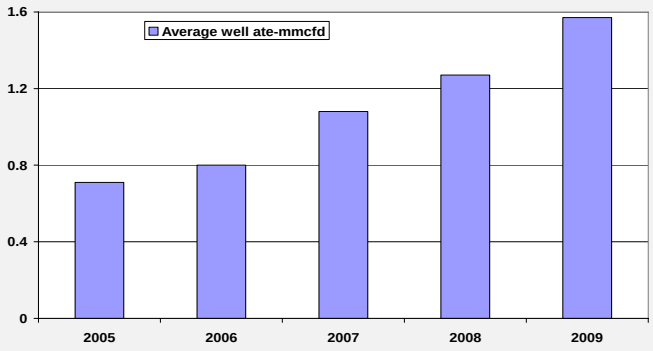
In reality it's been a long haul for the US industry. Pioneers such as Mitchell Energy have, since the early 1980s, been chipping away at the technology and costs. Now, thousands of wells have been drilled in the key producing basins and the learning effects from the sheer intensity and scale of activity while cumulative, in our view, probably represent a 'best case' scenario in terms of what can be achieved.

One study we have sighted, analyses the performance and learning effects at the Fayetteville shale in Arkansas. This is the second most important shale gas region in the US after the Barnett shale. Production has risen from 2 Bcf in 2000 to 760 Bcf in 2010 from a resource estimated to be 50 Tcf. This was one of the first US basins to be developed with horizontal drilling from 2005, and so the history of gains in well productivity is a 'showcase' for the industry learning curve.

Between October 2005 and September 2010, first year average production doubled from 0.8 Bcf/well to 1.6 Bcf/well. **However, it took 2840 wells to learn this.** The handful of wells drilled in Australia to date, is negligible compared to the US and demonstrates we have much to learn.

Exhibit 7

Fayetteville: Average First Year Well Production



Source. Oil & Gas Journal, April 4, 2011. Growth in first year production from wells completed in a given year.

What's in Australia and Will it Work Technically?

There have been no serious attempts yet to get after-shale gas and by this we mean drill extended reach horizontal wells and frac.

At this time, it is believed that the Perth and Cooper basins are likely to be the most attractive, with basic geological understanding from numerous conventional oil and gas wells that happen to have penetrated the shale sequences, many of which are deeper than the conventional fields. It just so happens too that these shales lie under conventional gas production facilities and infrastructure, so will provide very useful economic advantage compared to the exploration activity in more remote locations away from infrastructure. Basic information from the shales in the Perth and Cooper basins shows that:

- the shale sequences are thick;
- are moderate to high in organic content and thermally mature for gas;
- are generally over-pressured; and
- may respond positively to fraccing

These parameters, when displayed next to the best of the US shales as in Exhibit 9, are very encouraging.

The first and most basic question is, how will these rocks respond to fraccing? They should respond, and activity planned in 2011 across a number of JVs is designed to confirm this, long before establishing commercial flow rates. Analysis of a limited number of cores in shales from the Cooper and Perth basin wells would suggest that the mineralogy is favourable for fraccing, in terms of generally low clay content and high silica content which may make the shale brittle. A handful of frac jobs to date on specific wells have returned encouraging results, however, mineralogy alone is not a sufficient condition. Stress regimes have to be understood, and faults may impose limitations on the extent of productive horizontal sections.

Other basins seeing a pick-up in activity are the **Canning, Office, Beetaloo and Georgina.** Less is known about the rocks in these basins as there isn't as much data from conventional wells to leverage off. These basins are generally more remote from existing production infrastructure and have not witnessed commercial conventional production, with the modest exception of the Canning Basin 25 years ago.

Lack of depth to services sector is a constraint

If the local industry is to move beyond technical success to commercial production, then an aggressive build up in the supply chain for rigs, fraccing equipment and materials will be required. There just isn't enough 'kit' in the country at this time to drill and complete more than about a dozen wells in a year.

A good frac needs shear horse power, and some single frac jobs in the US require 40 trucks hooked up delivering 50,000 hp. About 85% of all fracturing 'spreads' are in the US. (A spread is the equivalent of four frac units of a certain size, plus blending and ancillary equipment). In North America there are about 870 spreads (i.e. about 3500 trucks). In Australia the number of 'spreads' is five, and operators which are active at the moment are having to share the limited number of trucks, as well as the costs of moving these trucks all over the country, from the Cooper Basin, to the Perth Basin, to the Georgina Basin, etc.

More high-specification drilling rigs will be needed. In the US there are over 950 land rigs operating. In Australia there are a handful spread across the country and they are not easily mobilized between regions. In WA, there is one rig being shared among operators. Into the future, the rig specs will go up too as some regions that target shales are +/-4000m, and **then** future development is likely to dictate extended horizontal sections.

The importance of production infrastructure

In our observations, the frenzy that goes with the cracking open of a new region can power equity prices but the economic realities are often glossed over during the discovery process. It's common for investors to look for leverage, and trade specific equities long before the economic questions are posed. In our view, specific regions of Australia are likely to be less competitive in terms of overall economics simply because of the absence of pipelines. Thinking back to the early days of the CSG industry in Queensland, it is not coincidental that the first fields developed were close to the few pipelines of the time. In its infancy, those CSG developers that ultimately became successful had access to markets and they started out by producing small volumes, selling cheaply and re-investing the cash flow back into the ground.

Some CSG companies operating in central NSW or central Queensland have yet to be commercially successful and infrastructure constraints are a contributing factor, in our view.

Thus the Cooper and Perth basins have a clear commercial advantage given that there is existing conventional gas production and they have all the production and pipelines necessary to get this gas to market. In the initial years of production shale gas could be blended in to the conventional gas stream, reducing the need for a large threshold volume.

Where is most of the current activity and what will it cost?

Exhibit 10 summarizes some of the more significant joint ventures which plan drilling or fraccing activity in 2011 and into 2012.

Activity is reasonably spread across the country including remote regions such as the Officer, Beetaloo and Georgina basins which have not witnessed much in the way of modern exploration.

The total investment at the industry level this year is in the order of A$500mn, which in total is a serious commitment. In general, individual wells plus completions are in the A$10mn-A$15mn range but it varies a lot with depth, location and the extent of the testing program.

Environmental considerations and concerns

Approximately 60% of all wells now drilled in the US are fracced and this includes every shale gas well (over 20,000) – but it only takes a few failures to raise objections.

There have been reports in the US of fraccing fluids contaminating groundwater, and the environmental debate is on the rise:

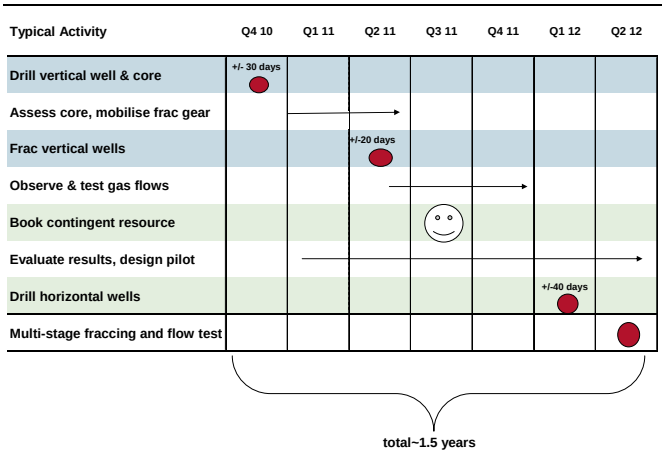
- In the US, New York State, which hosts part of the Marcellus shale, imposed a ban on fraccing in 2008, in response to environmental complaints. This ban remains as legislators grapple with balancing development and environmental management.
- In France, public concern about the potential effects of US Shale gas drove the governing UMP party to introduce a bill banning hydraulic fraccing. This bill was supported by the National Assembly in early May. A senate vote set for June 1 is still required before the bill is passed into Law.
- In South Africa, an indefinite plan has been imposed on fraccing in the sensitive Karoo Basin. Shell, in its EIP in support of a 24 well development, disclosed that each well would require between 300 kl and 6 ML of water. Opponents cite sourcing of water for fraccing in an arid region. The ban has impacted work by a dozen companies in the basin holding 'technical co-operation permits'

Fraccing and drilling fluids can leak to the surface as a consequence of failures with the completion, such as casing or cement failures, and in a 'conventional' well this would probably be accompanied with oil or gas and a blow-out may result. Unique to fraccing and where the industry has had to worker harder, is to avoid opening up fractures between the shales and any over- or under-lying permeable sections. Should this occur, then the frac fluids may escape into acquifers. Certain shales are more susceptible to this, such as those closer to the surface or closer to acquifers, or those where the shale is relatively thin. Where fraccing would appear to be least risky, is in deep wells or in wells with very thick shale sections.

How long should it all take?

Exhibit 8

Typical Timeline: From Exploration to Pilot Production



Source: Morgan Stanley Research

Exhibit 8 shows what we believe to be a realistic timeline, from the drilling of an initial exploration well through to a pilot production stage, and this particular example is modeled off the Beach Energy activity in PEL 218. All up, from drilling the vertical well to testing a multi-stage horizontal well, the duration approximates 1.5 years. Full scale commercial production, if warranted, would commence at the end of this time-line and could conceivably take another 1-2 years.

Exhibit 9

Geological Parameters of Key Shale Gas Regions

	Cooper Basin	Perth Basin							
	Permian REM	Carynginia & Kockatea	Marcellus	Haynesville	Bossier	Barnett	Fayetteville	Woodford	EagleFord
GIP- Bcf / sq.km	40-80	42	76	70		40	23	27	77
Technically recoverable Tcf	85	59	250-500	250	100	44	42		
Depth -top, m	3000	1600	1200	3200	3500	2000	1700	1800	2700
Depth- bottom, m	4000	3200	2600	4100		2600		3400	4000
Average depth				3500		2300	1500	2400	3200
Shale thickness(m)	>100m	60-90	60	60	75	110	40	55	75
Thermal maturity (Ro)	2 - 4	NA	1.8	2.7	2.7	2.4	2.4		
TOC (Av. %)	2.5 - 5	1 - 4	7	4		4.5	4	1 -14	4.5
Average log porosity-%		3 - 6	7	10	7.5	6	6	6	4 - 6
Pressure gradient-psi/ft	0.72	0.45	0.61	0.84	0.78	0.46	0.42		
Expected recovery factor-%		NA	20	25	28	20	30	15	20
Avg. UER/ horiz. Well- Bcf		NA	5.2	6.5	5.5	3	2.6		

Source: Chesapeake Energy, EIA, AWE reports, Beach Energy, Morgan Stanley Research, Oil & Gas Journal

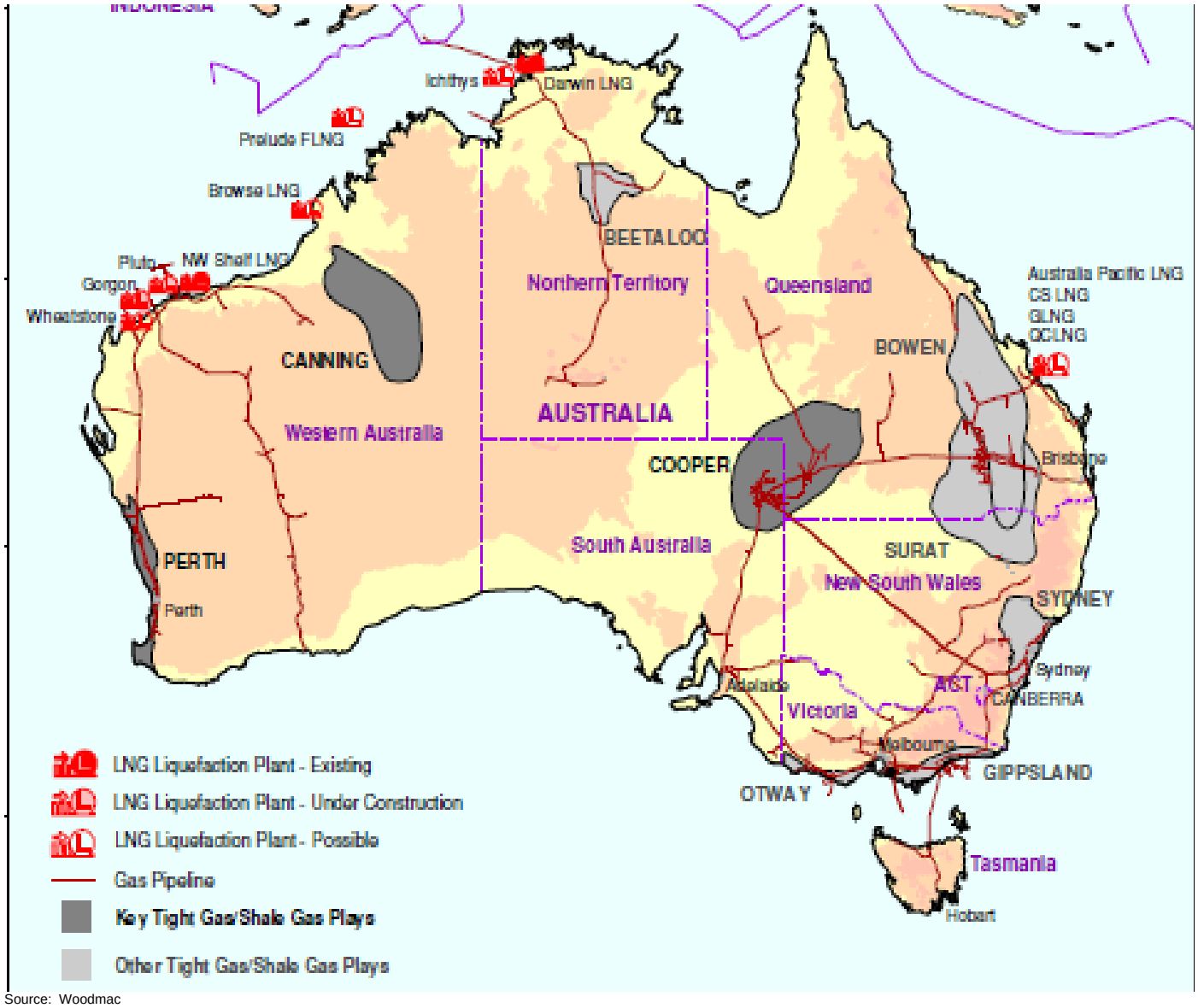
Exhibit 10

Company Activity Timeline, Capex & Resource Targets

Company	Location	Oil- U P R (*) B bbls-	Gas: U P R (^) Tcf -net(*)	GIP potential Tcf -net(*)	Capex-US$m Est 2011	Comments
Santos	Cooper Basin		26	44		Inc.tight gas & deep CGS, gross figure across all permits
Origin Energy	Cooper Basin			NA		13% of SACB & 16% of SWQ
Beach	Cooper Basin			NA		approx 20% in STO operated SACB and
Beach Adelaide	Cooper Basin- PEL 218 REM			40-80	30	Holdfast, Encounter well fracs
Strike Energy	Cooper Basin- PELs 94.95,96			7 - 18		Gross est. for Permian coals in PEL96
Icon Energy / Adelaide	Cooper Basin-Qld, ATP855		25			
Drillsearch	Cooper Basin- deep CSG & SG		8-17			CSG: 8 wells to be cored. SG not evaluated
Senex	Cooper REM-PEL517 Allunga Trough			38-60		Vintage Crop#1 to be cored in May
	Cooper REM-PEL517 -other			25-39		
	Cooper -Toolachie coals			17		
	Cooper -Patchawarra coals			7		
AWE NEW / Bharat	Perth basin-EP413		4	13-20	20	Arrowsmith2 drill, Woodada Deep, Senecia2, fracs
Origin Energy	Perth basin-L1 / L2			NA	20	2-4 wells planned, Corybas w/o
Transerv / Alcoa-JV	Perth Basin-Warro		1.1	8-10	100	Q2 2011: Warro4 frac; Tight sandstone
Buru / Mitsubishi	Canning			Large	150	Valhalla2 current, +5-9 wells, Yulleroo2 recompletion
New Standard Energy	Canning			Large	5	Recompletion of Lawford#1
Falcoln / Hess	NT- Georgina EP 76,98,117- conventio	1	1.6		90	Q3 2011: Re-open Shenandoah well & test
	NT- Georgina EP 76,98,117- tight SS		39			
	NT- Georgina EP 76,98,117- Shale	18	23			
Exoma / CNOOC JV	Qld- Galilee basin		3 (!)	>100	>50	May 2011: Saltern#1, then 12 more for CSG and SG
Petrofrontier / Baraka	NT: Georgina basin	26			32	Current: 6 wells & Seismic.

Source: Company data, Morgan Stanley Research
(*): U P R = Unrisked prospective recoverable oil. (^) = unrisked prospective recoverable gas . (!) = 3C resource for gas

Exhibit 11
Prospective Shale Gas Basins



Source: Woodmac

What are the Risks? Surfing is Risky...

Surfing is risky and so too is investing in companies engaged in exploration.

There are technical, logistical, commercial and environmental risks.

Technical risks

There are a number of technical risks. The key ones in our view are:

1) Failure of wells to respond to fraccing. Low or zero flow of gas from fracced wells would be a bad sign, but poses a number of questions as to why a particular well did not respond. Was there an equipment limitation? Was the geology unfavorable? Were the right zones fracced? Were the fraccing fluids correct?

2) Low flow rates. At this time, it's not known what magnitude of flows should be expected from wells that have been fracced, but industry views are that flows of +/- 2 mmcfd from a vertical section of a fracced well would be 'encouraging'. Low flow rates may result from a poor frac job, or maybe the rocks have a low gas content.

3) Equipment failure. Drilling and testing of deep shale gas wells imports a myriad of operational risks, all of which deny the equity market the data needed to support investment into speculative drilling. All to often, drill strings get stuck, logging tools fail and production testing gear fails. These 'mechanical' failures lead to companies reporting nil results of inconclusive results in market releases. In our view, investors typically view the lack of proof from equipment failure as bearish for the geology, which, however wrong such a conclusion is, does affect share price performance.

Logistical risks

The shortage of rigs with deep-drilling capacity and the lack of fraccing equipment, may result in constraints in terms of the timing of news flow. Given that equipment is being rotated from one region to another, there is risk of blow-out in exploration and development timelines, and risk of higher costs.

Commercial risks

Shale gas drilling and development is expensive. Gas prices are an important determinant of commercial viability. At this time, the price outlook is favourable in WA. In eastern Australia, higher gas prices are needed to make the unconventional industry viable. If marginal volumes of SG or CSG come in to the eastern market, at current prices, then the positive price uplift that the wider industry needs would be denied or deferred.

Industry fragmentation could work against a tightening gas market in eastern Australia. For example, what if Beach Energy and its partners are stunningly successful in its LEL 218 frac program this year? If they can develop some incremental gas production then there will be a temptation to sell-off this gas at low prices in order to recover some cash flow. This is what happened in the early days of the Queensland CSG industry, where volumes grew rapidly but also where small companies sold their output at low prices in order to generate re-investment.

Environmental risks

The movie documentary '*Gasland*' has generated debate about the potential negative environmental consequences of fraccing in the USA, by way of possible ground-water contamination.

In Australia, farming groups in Queensland are lobbying against a myriad of issues to do with the exponential invasion of farming and grazing lands for CSG development. This debate in our view is centered on land usage and land access.

With shale gas in Australia, operations are mostly in remote areas well away from land with alternative productive capability. For example, development of shale gas in the Cooper Basin would be considered a logical extension of conventional production on lands which have negligible alternative economic value.

Economic Considerations

Shale gas is typically more expensive than conventional gas reservoirs, and two parameters control the economics of shale gas development. These are:

1. Individual production well costs (including gathering lines and well-head compression). Fortunately for Australia, prospective shale gas basins sit under existing, under-utilized production infrastructure. Therefore, we believe the economics of shale development will be a function of individual well costs.

At this point in our heavy references to the US industry, comparisons are not relevant. We believe that typical well costs in areas like the Barnett, Fayetteville and Marcells are in the order of US$4mn-US$6mn per well. Average well costs in the US likely represent the global industry at its most efficient, with all the benefits of scale and depth of local drilling and fraccing services.

Shale gas wells gas fields are much more expensive to drill and develop than conventional fields. Factors driving well costs are:

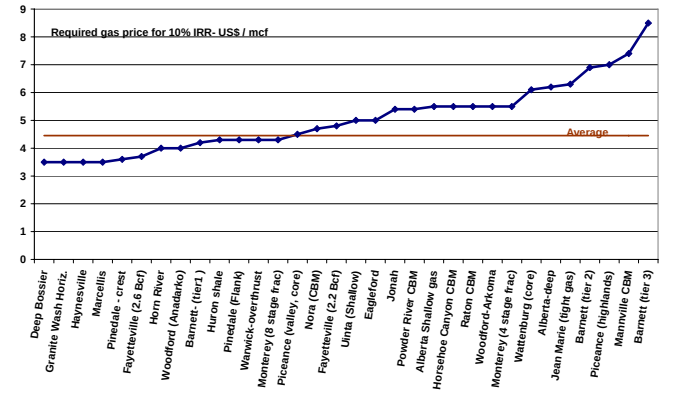
- **Well depth and well design.** Shale sequences are frequently deeper than overlying conventional traps, and require long-distance horizontal sections. They require more drilling time, more steel casing and during completion and fraccing, large amounts of special chemicals (fraccing chemicals and proppants)

- **Significant infield infrastructure costs.** Because individual wells flow at low rates, many wells are needed over a large area. This drives up land leasing or ownership costs, access associated costs (roads, fences) and infield gas gathering pipelines and compression.

If the typical well delivers 2 Bcf of gas at average prices in the order of US$4-US$5/mmcf then there is just enough economic headroom for production. Within any large region there are always 'sweet spots' and in the US, certain area recoveries per well can be as high as 4-5 Bcf and these wells would sit lower on the cost curve.

Cost curves for various shale gas regions vary widely and the core driver in the first instance is gas recovery per well in addition to liquids yield. Refer to Exhibit 12.

Exhibit 12
Cost Curves for US Unconventional Gas



Source: Morgan Stanley Research

Costs in Australia are higher. The US onshore oil and gas sector represents the drilling industry at its most efficient in our view, given the benefits of scale and depth of services.

Australia lacks scale in every part of the service supply chain. In the US there are 950 drilling rigs. In Australia there are only a few that are capable of deep drilling, and this rules out the fleet of small, truck mounted units active in the CSG fields. What is available has to be shared by different operating groups operating in remote regions which entails a lot of expensive mobilization costs. There are similar shortages of fraccing and other specialized equipment. While the US industry reflects 'mass production', each well in Australia is bespoke at this time.

Well costs that we are aware of are in the order of US$10mn-US$15mn each, but to be fair the industry is not cost focused at this time, as the focus is geological and technical. Commercial production however will require meaningful reductions in cost and that will only come as the industry builds scale. That will take time.

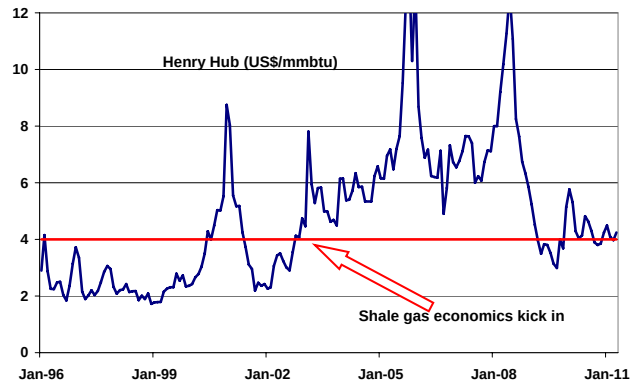
2. Gas Prices. The US shale gas industry might not be as strong as it is today, without positive price signals from the domestic market. For most of 15 years until about 2004, the US domestic gas market was well supplied and Henry Hub (HH) prices were sub-US$2/mcf. This was enough to provide returns to US Gulf of Mexico producers but not high enough to provide returns to 'unconventional' gas production. By about 2004 the US market was evidently tightening and HH prices started to break out of a five year bear trend (Exhibit 13). It was around this time too, that some heroic, and incorrect,

predictions were made that in the coming decade the US would face a growing shortfall which would necessitate LNG imports.

A prolonged period of HH prices north of $4/mbtu turned on the economics for unconventional gas production and the supply response we now observe has been remarkable. The current glut in the US has driven a de-rating in HH, but only back to the cost of marginal production

Exhibit 13

US Lesson: Rising Gas Prices Prompted Supply Response



Source: Morgan Stanley Research, Bloomberg

Like the US of 10-15 years ago, Australian gas prices have been unresponsive to global forces driving energy. On the east coast, legacy supply contracts still dictate that the bulk of conventional gas production is sold at the well-head for <A$4/GJ. If we assume that a similar figure is marginal in the US, where the industry is efficient and operates at scale, then local prices are not going to be enough to provide positive economics.

Gas prices are rising in Australia too, although less dynamically than was the case in the US. Gas prices in WA are moving into the A$6-A$8/GJ range, with some contracts for gas supply to bespoke mine sites oil linked and therefore even higher.

In eastern Australia, incumbent supply contracts begin to roll-off mid decade and will need to be re-bid. Conventional fields of the Cooper Basin, Otway and Bass Strait are mature and depletion effects will limit how much future market these fields can continue to service. Meanwhile, every producer has an LNG export project either underway or planned which will introduce a higher price to the eastern seaboard, and smaller suppliers are hoping to capture some of this too by winning third party supply deals. The net effect is that no new contracts have been written of any size since 2004 and some gas resource owners are unwilling to write supply deals longer than three years, after which multiple LNG production trains being constructed or planned on the east coast will create market opportunities for producers.

Something has to give, as new supply will be required for the local market. The most likely commercial scenario in our view is that the next suite of utility supply deals will be at prices approaching the alternative of LNG netback, which in the current market would be in the A$7-A$9/GJ range. For potential shale gas producers, this may be enough to underpin development and provide a profit but it's unlikely to be a windfall.

Theoretical economic scenarios

The interplay between individual well costs, recovery per well, and the revenue opportunity is captured in Exhibit 14. The Y axis is IRR, the X axis is the well-head gas price and the coloured lines represent well recoveries from 2.5 to 5 Bcf.

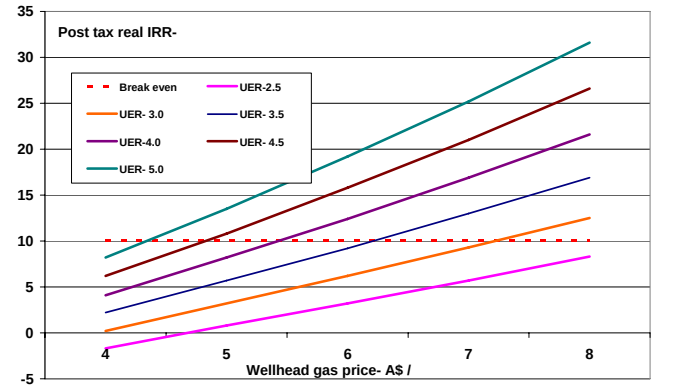
We have considered the effects of wells costing US$5m, US$10mn and US$15mn each. The low figure is probably not representative of current well costs, but could be achievable in areas such as the Cooper Basin (for example) where there is already some depth of support services.

In developing scenarios, we assume a range of gas prices at the wellhead, with the current market (about A$4/GJ) ranging to A$8/GJ. We feel the latter figure is probably representative of what might be paid by aggregators taking the gas into the LNG export market.

Finally, we consider the impact on returns given well recoveries which range from a low of 2.5 PJ to a maximum of 5 PJ, minus liquids yield. We figure these ultimate economic recoveries (UER) likely reflect reality.

Results of these scenarios show that, for example, a A$10m well delivering 3 Bcf of gas, needs to see a gas price just over A$7/GJ to provide a return in excess of 10%. However if this well can deliver 4 Bcf, then the breakeven gas prices falls to A$5.50/GJ. However, at current gas prices in the Cooper Basin around A$4/GJ, a A$10m well would need to deliver something more that 5.5 Bcf to earn a return.

Exhibit 14
Single Well Economics



Source: Morgan Stanley Research

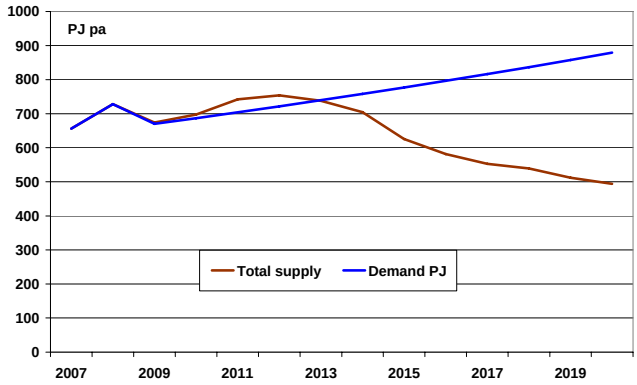
Domestic market shortfalls may drive development economics.

The bottom line for Australia is that at A$4/GJ at the wellhead, production is unlikely to be economic. This is almost the case for CSG in Queensland even today, where the industry has reached production scale, but where incumbent domestic gas contracts are being supplied at A$3-A$3.50/GJ.

However, there are important market opportunities emerging and positive pricing signals.

In eastern Australia, decline of conventional production from both the Cooper Basin and offshore Victorian gas fields and contract expiry, point to a domestic market shortfall after 2014. Refer to exhibit 15. Meanwhile, smaller CSG explorers in Queensland are holding off from selling domestically in the expectation that LNG exporters will require additional feedstock and thus offer LNG-netback prices which we estimate would be in the A$6-A$8/GJ range.

Exhibit 15
Eastern Australia Natural Gas Supply/Demand Balance



Source: Morgan Stanley Research

As well as the domestic market, LNG markets may continue to evolve. As is stands, some LNG developers now may appear to be short compared to contract positions. Santos' CSG fields in Queensland don't yet have enough identified gas to supply the GLNG off-take contracts and a similar situation may arise if BG Group builds a third LNG train at its Curtis Island project.

The situation in Western Australia is similar, with reports of gas prices at the city gate in Perth now at +/-A$8/GJ. Five years ago it was A$2-A$3/GJ. As for LNG, a potential mulit-user site at James Price Point could open up an export route for gas found anywhere in the Canning Basin, as well as act as a development hub for the offshore Browse Basin fields.

Basin Overview: Cooper Basin

Independent estimates of potential gas-in-place 342 Tcf with 85 Tcf potentially recoverable. The basin is huge, covering 130,000 km^2 and within it are four large deep troughs with shale gas potential (Exhibit 16). Geologically the Cooper Basin is better understood than other basins due to an over 40 year history of conventional oil and gas production from thousands of wells.

In addition to shale sequences, the Cooper Basin also has deeper coal and tight sandstone reservoirs that could also hold and produce hydrocarbons.

Data from numerous conventional wells indicate that the best shales are likely to be in the Nappamerri trough. The Nappamerri trough appears to be thermally mature, over-pressured and with moderate to high organic content. Prospective Permian shales occur at depths in the 3000m to 4300 m range. The best shale sections of the Permian sequence are the Roseneath, Epsilon and Muteree shales and collectively these are called the 'REM'. The Muteree shale averages about 50m thick with TOC averaging about 2.5% and potentially as high as 5%. The Epsilon is about 50m thick and is in fact a low permeability sandstone. The Roseneath is less extensive laterally, and with lower TOC. Beach Energy estimates that the GIP from the REM in its license could approach 80 Tcf, while Senex reports up to 99 Tcf from its permits also from the REM section.

A key geological risk for the Cooper Basin is that the target shales are non-marine, having been deposited in a lacustrine environment. This increases the risk of high clay content. Initial mineralogical data suggests that clay content is low (20%) with quartz about 50% and carbonate (siderite) 30%. If these parameters are correct then the shale should respond well to fraccing. However, the minerals analysis so far is from cuttings with core data not yet available publicly.

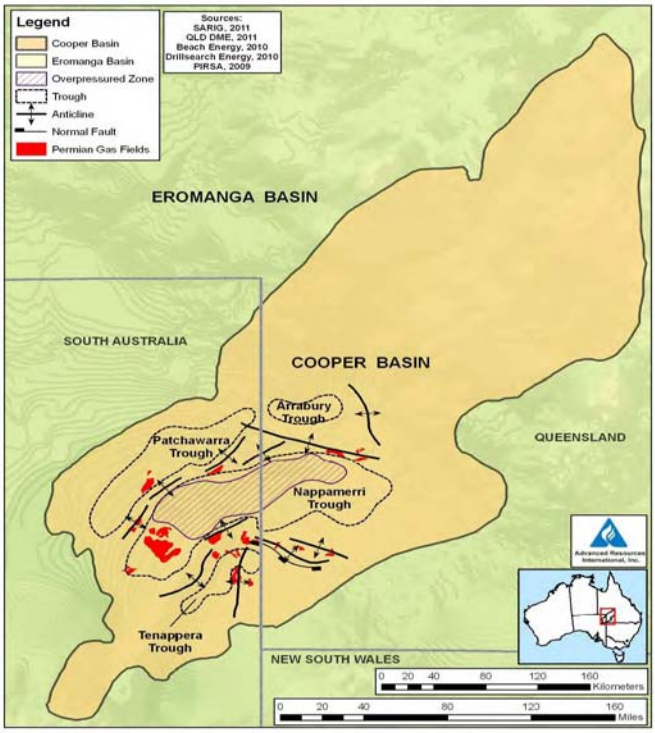
Parts of the basin may produce valuable liquids by-product. Most of the Nappamerri trough is considered mature for gas but flanks of the trough are interpreted to be within the "wet gas window" which is conducive to liquids production (Exhibit 17).

Companies currently active in the Cooper Basin for shale gas, or with significant acreage exposure are:

- Santos and its SACB joint venture partners, Beach Energy and Origin Energy
- Beach Energy and Adelaide Energy JV
- Senex
- Icon Energy

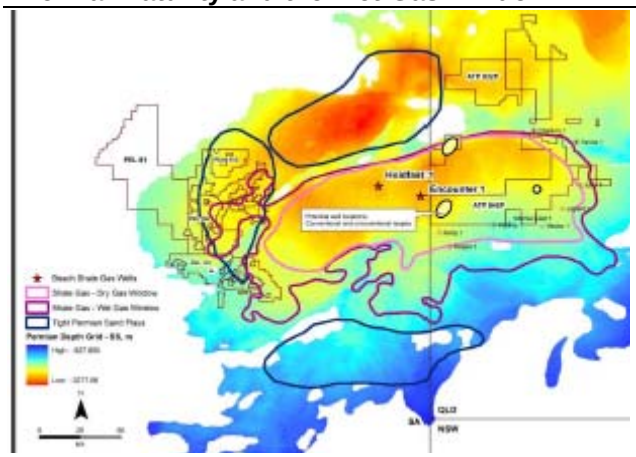
Other companies with acreage positions are Drillsearch, Cooper Energy, Innamincka Petroleum and AGL Energy.

Exhibit 16
Principal Troughs of the Cooper Basin



Source: ARI report for Department of Energy and the Energy Information Agency.

Exhibit 17
Thermal Maturity and the Wet-Gas Window



Source: Drillsearch Energy Presentation to investors May 2011

Beach Energy (90%) and its JV partner Adelaide Energy (10%) are the first to drill dedicated shale gas wells into the REM sequence of the Nappamerri trough. In the fourth quarter of 2010, two vertical wells were drilled in PEL 218 which covers 1600 km^2 of the Nappamerri trough.

The first well, Ecounter#1 was drilled to 3612m. From wireline logs, the REM sequence was a very thick 393m, with good gas shows. Five cores were cut and are being assessed for gas content and mechanical properties. A second well was drilled in the March quarter 2011. Holdfast#1 encountered 353m of REM shales and was extensively cored.

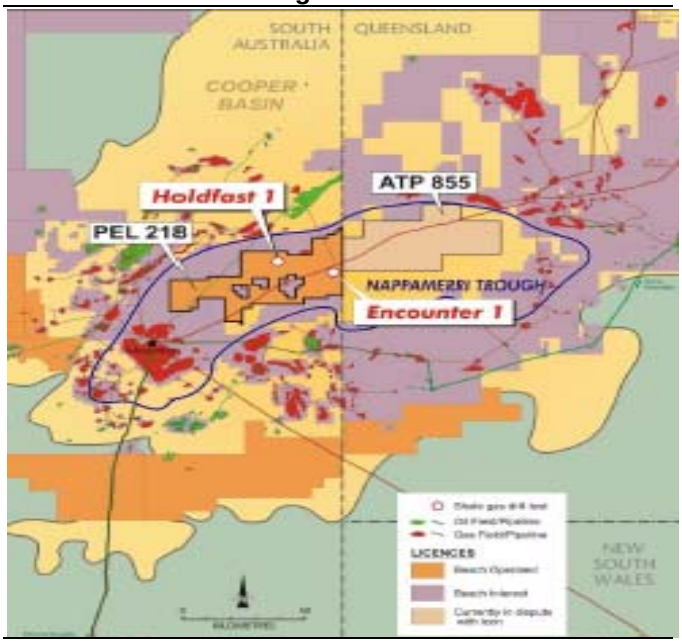
Beach has announced that the shales are in line with or thicker than expected, are gas saturated with no water, have TOC up to 5% and contain favourable mineralogy. **BPT claims that the Permian section of PEL218 could contain 40-80** Tcf of gas-in-place. The location is very favourable with the Mommba gas plant 50 km to the SW (Exhibit 18).

Date from the cores will be used to design the fracture stimulation program, which is expected to commence in June. Up to eight fracs are planned per well. Beach stresses that these are 'data gathering' wells, the objective being to learn how the shales respond to fraccing and to observe flow rates if any. Results of this program may lead to a contingent resource booking in the third quarter, and will aid the design of wells for the next phase, which is a pilot production program. This will require horizontal wells, and as such timing may be constrained by equipment availability. Latest guidance from BPT is for a pilot program to commence early 2012.

Santos has the largest acreage position and highest working interest in the basin, but has wider corporate objectives. Infill drilling activity is ramping up on the conventional gas fields, and in 2010 conventional 2P gas reserves rose meaningfully for the first time in a decade while a big increase in 2C bookings occurred at year end 2008. With large unconventional gas acreage in NSW and Queensland too, Santos has competing priorities and a limited budget. In its presentations, Santos points out that in addition to shale gas, the Cooper Basin contains deeper coal gas and tight gas sections and in total the 'unconventional' gas sequence approximates 1600m of sediments.

According to Santos, gross unrisked contingent resource is about 5 Tcf for unconventional gas, with potential for an additional 39 Tcf. The joint venture partners plan to drill and core a shale well at Moomba North in 2011. In addition a recent development well Moomba 185, was deepened with the Rosneath & Muteree shales cored. The Santos operated SACB are Santos 66.6%, Beach 20.2% and Origin Energy 13.2%. Partners in the Queensland portion of the Cooper Basin in the SWQ gas unit are Santos 60%, Beach 23.2% and Origin 16.7%.

Exhibit 18
Location of BPT shale gas wells



Source: Beach Petroleum

Senex Energy (SXY.AX, Not Covered) has grown rapidly in the past year via consolidation and now has a significant land position in the SA and Queensland Cooper Basin as well as parts of the CSG region in eastern Queensland. According to SXY presentations, the most prospective block for unconventional gas is the 100% owned PEL 516, to the south east of the Moomba gas plant. GIP estimates for the REM shales are assessed to be 38-60 Tcf, and in other parts of the block, 25-39 Tcf. These shales are at 2400-2600m depth and so lie within the 'wet gas window' according to SXY. Other SXY permits may be prospective for gas also in Toolachie and Patchawarr coal sections and could contain up to another 17 Tcf. A conventional oil well, **Vintage Crop#1**, **is planned in May in PEL516**, targeting the Jurassic oil sequences. In addition, SXY plans to core 45m of the Toolachie coals and REM shale. While SXY's activity in the Cooper is predominantly focused on the conventional oil and gas plays, the cores from Vintage Crop are the first step down the unconventional path. Results from the coring will help the planning of dedicated unconventional gas wells in other parts of PEL516 later in 2011 or 2012.

Drillseach Energy (DLS.AX, Not Covered) is solely focused on the Cooper Basin and immediate priorities are exploration and production of conventional oil and gas. DLS has acreage in the eastern, Queensland portion of the unconventional fairway, predominantly 100% owned permit ATP940. DLS believes this has deep CSG potential with an un-risked prospective resource estimate of 8-17 Tcf. Shale gas is under evaluation. In dollar terms, evaluation in 2011 is small (A$2.4mn) and involves seismic acquisition in ATP940 to define drilling targets, and coring of gassy coals in planned drilling of eight conventional wet-gas wells in the western part of the Cooper Basin.

Strike Energy (STX.AX, Not Covered) reports a prospective CSG resource in Permian coals within its PEL94, 95 and PEL96 in the southern Cooper Basin. JV partners include Beach Energy and Senex. A dedicated CSG well, Forge#1, was drilled in 3Q 2010 in PEL96, but only one of two reservoir objectives, the Epsilon, was cored before operational issues halted drilling. Additional exploration is planned from mid 2011. Strike believes that GIP in the permit could range from 7-18 Tcf with a prospective resource of 3.7-3.9 Tcf.

Icon Energy (ICN.AX, Not Covered) and Beach are in dispute over ownership rights to ATP855, which is in Queensland in the eastern portion of the Nappameri trough. Adelaide Energy is a joint venture partner. Three wells are planned but we are not aware of firm timing. Icon claims that about 30% of the Cooper Basin shale gas resource is in this block, with Icons (disputed) 80% working interest giving it a net, prospective recoverable resource of 20 Tcf.

Other ASX listed companies with acreage in the Cooper Basin include Cooper Energy (NC), Innamincka Petroleum, (NC) and AGL Energy[2]. These companies' E&P strategy at this time is predominantly on exploration and development of conventional oil and gas reservoirs.

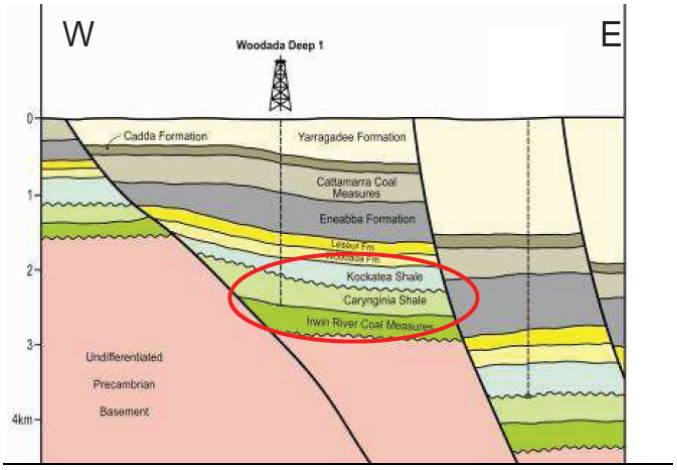
[2] AGL Energy (AGK.AX; A$14.21; UW) is covered by Morgan Stanley analyst, Mark Blackwell.

Perth Basin

Independent estimates of potential gas in place are 198 Tcf with 49 Tcf potentially recoverable. While smaller in extent compared to other sedimentary basins, the Perth Basin shales offer potentially better 'geology' (marine shales) and location and infrastructure advantages. Like the Cooper Basin the historical focus of activity has been on conventional fields and to date**, horizontal wells combined with modern fracs have not been attempted**.

The onshore basin covers about 50,000 sq km. The Dandaragan trough in the northern part of the basin contains the deepest and thickest shales. The sedimentary sequence is reasonably well understood from the approximate 100 conventional oil and gas exploration and production wells that have been drilled since the 1970s. The most significant gas fields to date are Dongara, Beharra Springs, Woodada and Mondarra which collectively contained around 600 Bcf. The most significant oil fields are Hovea, Jingemia and Mt Horner, which collectively host around 15 mbbls recoverable. Conventional production is mostly from the Wagina and Arranoo sandstones which are inter-bedded with the principle shale source rocks, namely the Irwin River Coal Measures (IRCM), Kockatea and Carynginia shales. Exhibit 19 shows key shale gas sequences in the Perth Basin

Exhibit 19
Perth Basin Shale Sequences



Source: AWE

The early Triassic **Kockatea shale** was deposited in a shallow marine environment. Sampling from the Hovea#3 well provides some data. TOC averaged 5.6%. The rocks are thermally less mature in parts of the basin and may possibly be oil-prone. Clay content could be an issue, with Hovea3 averaging 33%, and AWE reported that a core recovered from the lower Kockatea in the conventional Redback#2 well had discouraging high clay content. It is estimated that 20 Tcf could be recovered from an in-place resource of 100 Tcf in the Kockatea shale.

The early Permian **Carynginia** is a marine shale, varying in thickness from 240m to over 330m. TOC levels from cuttings and cores are as high as 11%, and thermal maturity indicating dry gas. ARI estimates that 29 Tcf of gas may be recoverable from 98 Tcf in place. **In April 2010**, AWE cut five cores from a 280m thick shale section from the Woodada Deep well and indicated that the upper and lower zones of the Carynginia had high clay content, but the middle zone more prospective. AWE reported that TOC ranged 1-4%, and porosity 3-6%. AWE estimated that a total in-place resource of 13–20 Tcf, with potentially 4 Tcf recoverable from within its license, assuming a recovery factor of 20%.

IRCM prospective too. Corybas#1 was drilled as a conventional gas well in 2005 and flow rates at the time considered uneconomic. In 2009, the well was worked over and a frac on the vertical section 2514-2536m resulted in an initial flow of 3.9 mmcfd. From a thin interval in a vertical well, this is a very encouraging result. Corybas#1 was completed for commercial production via the Dongara gas plant in April 2010. A few barrels of oil have also been recovered from the IRCM from Mt Horner oil wells.

Tight gas too

Other parts of the Perth Basin are prospective from other sedimentary units. Other sequences which are believed to be prospective are the Irwin River Coal Measures, Wagina sandstone, Yarragadee, Cattamarra coal measures and the Eneabba member. The latter three are Jurassic continental and marginal marine sediments and in most parts of the basin, characterized by gas shows but with poor reservoir quality. As such, they are candidates for **tight-gas exploration. The WA Department of Mines estimates that potential gas resources to be in the range 9-12 Tcf.** The most significant tight gas discoveries are Warro (discovered 1977), Witcher Range (1988) and West Erregulla (1990). There have been sporadic attempts to commercialize these rocks over the years but in common with the rest of the basin, horizontal wells and high-power multi-stage fracs have not been attempted.

Importantly for future developers, the Perth Basin offers gas production infrastructure, nearby markets and a rising gas price environment.

Supportive Gas Price Environment: Gas prices in Western Australia are among the highest in the country. We see evidence of oil price linkages in domestic contracts (CITIC contract), recent TAP reported realisations of A$6.30/GJ and reports of deals being done presently at around A$8/GJ. This is up to double prices on the east coast of Australia and reduces the reliance on associated liquids production from Shales to support project economics.

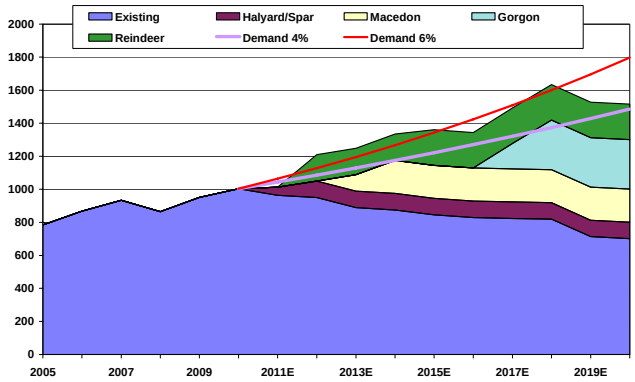
Production and transmission Infrastructure: There are a number of gas processing plants on depleted or semi-depleted fields all of which could handle more gas, namely Dongarra, Beharra Springs and Woodada. The Parmelia Pipeline (100 TJ/d capacity) connects these fields to markets around Perth. Currently there is less than 20 Tj/d going through this pipeline. Compared to gas coming from the North West Shelf, the Perth Basin is much closer to the Perth market and so benefits from lower gas transmission charges.

Market Opportunities: We cite demand forecasts for domestic gas in W.A out to 2020 of 4 - 6% pa (Economic Consulting Services, WA Department of Mines and Petroleum). But we also see a large **potential** increase in gas targeted for the domestic market, with the major contributors being Reindeer (2012), Gorgon (2016) and Macedon (2013). The rate at which these projects ramp-up, and demand expands, can be potentially meaningful on the supply demand balance of the WA gas market going forward. Refer to Exhibit 20, which gives the appearance of a market that is reasonably supplied, however any delays with big projects such as Gorgon would leave the market short.

Another factor to be considered in the longer term, is how long the North West Shelf can continue in its role as base supplier, as depletion effects from the offshore field will become very apparent late-decade. Big mining projects too can be very lumpy loads, and many remote mine sites still uses diesel for on-site power generation. Expansion of the mining sector may place considerable upward pressure on demand.

A looming shortfall, and rising gas prices, has prompted the states largest gas consumer to take action. Alcoa's alumina refining operations south of Perth require around 80 PJ of gas p.a. We note in prior years, that Alcoa has seeded companies exploring for gas. In 2010, Alcoa agreed to fund the A$100m for a drilling and fraccing program on Transerv's Warro 'tight gas' project, with the intention of stimulating new supply.

Exhibit 20
WA Domgas Market (TJ/d)



Source. Morgan Stanley

Activity update & timeline

Companies active in the Perth Basin this year include:

- AWE and its JV partners Origin Energy, Norwest Energy, Bharat Petroleum
- Transerv and Alcoa
- Empire Oil and Gas

Transerve and Alcoa[3] **(35%/65%)** have permits in the southern part of the Perth Basin which host the Warro gasfield which was first discovered in 1977. It is close to both the Parmelia and Dampier-Bunbury pipeline and is the closest field to Perth of those which are being tested this year. The reservoir section, the Yarragadee sands are deep (>3700m) and tight. Warro and other tight gas fields such as Witcher Range have not had the benefit of modern technology or horizontal wells but this could change. In 2010, gas-hungry Alco agreed to farm-in to earn up to 65% working interest in return for investing $100m into drilling and fraccing.

Warro#3 was drilled in 2010 and encountered 250m of net pay in eight zones. An 8-stage frac of the vertical section resulted in gas flows estimated to be >5mmcfd before water influx. Warro#4 was drilled in May 2011 and encountered 230m of net pay and is now complete and waiting on 24,000 HP frac fleet to come from the Cooper Basin. Faccing is set to take place once the equipment is mobilized in July 2011. TSV advise that it would view flow rates in the order of 2 mmcfd from only two fracs to be a good result technically. Alcoa has rights to take its share of gas produced pro-rata. Independent reservoir

[3] Alcoa (AA.N; US$16.09; OW) is covered by Morgan Stanley analyst, Paretosh Misra.

evaluators, Gaffney Cline, estimate that the total gas-in-place is 8-10 Tcf with a p50 recoverable estimate of 1.1 Tcf (Exhibit 21).

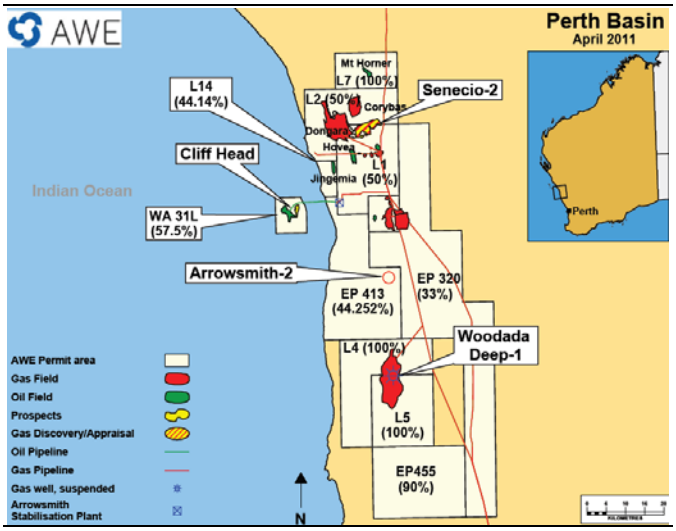
Exhibit 21
Transerv / Alcoa Activity Map

Source: Transerv investor presentation

AWE and **partners NorWest Energy (NWE.AX, Not Covered)** and **Bharat Petroleum**[4] plan to drill the **Arrowsmith 2** well commencing June, in permit EP413. Arrowsmith 1 was drilled in 1965 and flowed gas at 4 mmcfd, without artificial stimulation from the Carynginia sequence. Arrrowsmith 2 will be a vertical well only, with horizontal drilling potentially taking place in 2012 based on the results of the vertical frac. While large flow rates are not expected from Arrowsmith 2, the well will provide more data on the ability of the shales to be 'opened-up' and assist in the planning for horizontal drilling. Other participants in this program are Norwest Energy (NWE) and Indian company **Bharat Petroleum.** In 2010, Bharat agreed to a farm-in with NWE, by investing the first $10m of NWE's commitment in return for a 27.8% working interest. JV interests in Arrowsmith and permit EP413 are AWE 44%, NWE 27.8% and Bharat 27.8%.

After Arrowsmith, AWE plans to frac **the Woodada Deep** well, which was drilled and cored in 2010. This well is located about 20km south of Arrowsmith in 100% owned acreage. Also planned, is the recompletion and fraccing **of Senecio#2**. This well was drilled in 2005, and flowed at 2.5 mmcfd before declining rapidly, evidencing tight gas.

Exhibit 22
AWE Perth Basin License Interests



Source: AWE Investor presentation

AWE and Origin Energy (ORG.AX; A$16.45; UW) have overlapping interests in specific production licenses, namely L1, L2 950/50) and L14 and EP320 (ORG67, AWE33). Historically Origin's operated wells have been focused on conventional targets to tie-in to its Beharra Springs gas plant. The Redback and Redback South wells were conventional gas discoveries in 2010 in L14. However**, Corybas#1** was fracced in 2009 and flowed at 4 mmcfd from the IRCM thus confirming the productive potential of the unconventional / tight Irwin River Coal Measures. Origin has announced plans to acquire 2D and 3D seismic with the intention of drilling two to four wells to evaluate the blocks shale gas potential.

Exhibit 22 shows AWE and JV partner license areas in the Perth Basin

Empire Oil & Gas (EMR.AX, Not Covered) has extensive license interests in several onshore regions of WA, including the Perth Basin, Canning and Carnarvon. These licenses are prospective for conventional gas, shale gas and coal seam gas. In 2010 and 2011, EMR made two 'conventional' gas discoveries in block EP389, 50 km north of Perth. **GinGin West#1** was production tested in July 2010 and flowed gas from Cattamarra Coal Measure sandstone reservoirs at 8 mmcfd and 375 bcpd of condensate. A second well in thee block, Red Gully#1 also discovered gas and flowed at 12 mmcfd/832 bcpd on test. EMR plants to develop this field with a small gas plant capable of delivering 20 mmcfd. Exploration will continue in 2011, on the known gas accumulation at GinGin and on other prospects.

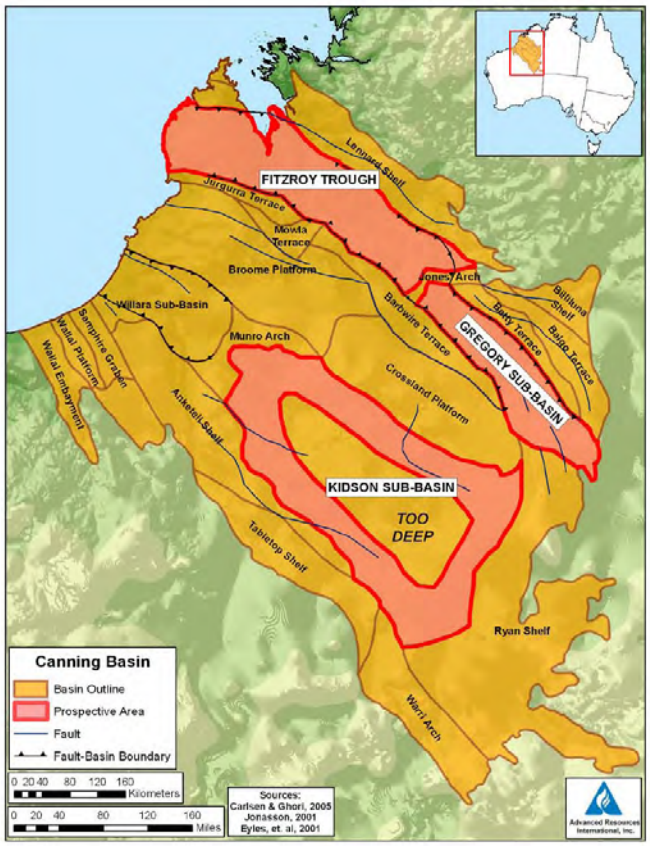
[4] Bharat Petroleum (BPCL.BO; Rs633.00; OW) is covered by Morgan Stanley analyst, Vinay Jaising.

Canning Basin

The Canning is a vast region and in the 1980s hosted a number of small oil discoveries, but exploration levels in the basin in the past decade have been low relative to other regions, due to its remoteness and modest success rates. **Only about 60 wells have penetrated the source rocks,** all on the uplifted terraces. Deeper shale source rocks have generally not been penetrated so source rock data is quite limited.

However the depositional environment points to marine and marginal marine shales in the Laurel and Goldwyer formations. Rock analysis of the Goldwyer shows TOC in the range 1-5% (average 3%) and some values in excess of 10%. Thermal maturity modeling suggests that much of the southern part of the basin is likely to be within the 'oil window' supportive of wet-gas production.

Exhibit 23
Canning Basin



Source: ARI

Significantly for the area, Mitsibushi farmed-in to Buru acreage in mid 2010, with the intention to earn a 50% working interest in return for spending A$152m on exploration and development, including A$40m to be spent on unconventional exploration.

Companies which have significant work programs in the region include:

- Buru Energy and Mitsubishi
- New Standard Energy
- Oil Basins Ltd
- Empire Oil & Gas

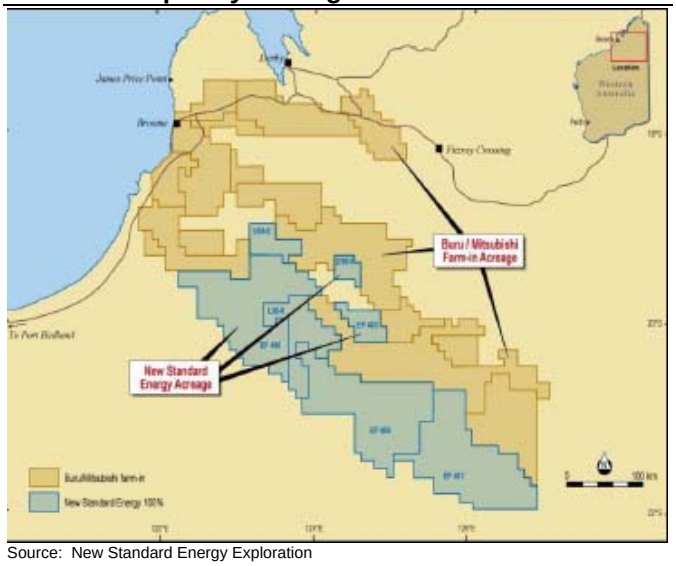
Activity update and timelines

Buru Energy (BRU, Not Covered) had net acreage interests of nine million acres and leads the way in terms of exploration history in this basin extending over a decade, including prior association with ARC Energy. Buru's drilling plans received a major boost when Mitsubishi farmed-in for a 50% interest in mid 2010, by funding 80% of Buru's exploration costs up to $152m. Under this arrangement, two wells were drilled in 2010. The first well, Paradise#1, was drilled in October 2010 in EP428, but had to be prematurely abandoned due to the onset of the wet season, at 1700m compared to a planned total depth of 2300m. The well encountered oil shows. The second well Nangu#i in EP471 targeted conventional reservoirs and was P&A'd without shows.

In Q1 2011, Buru engaged a drilling rig for the drilling of 6-10 wells in 2011. The first well in the 2011 campaign, **Valhalla#2** has spudded and targets multiple conventional and unconventional gas reservoirs.

In addition to exploration, testing operations are expected to continue on the **Yulleroo#2 wet-gas discovery,** in EP391. Yulleroo2 penetrated tight sand and Laurel shale sections over a gross column of 800m. Yulleroo2 was fracced in November 2010 but the frac job was only partially successful, lacking the power to overcome the downhole pressure. Despite this, the well did flow wet gas to surface. A work-over and re-completion is being considered as part of the 2011 work program.

Exhibit 24
Location Map: Key Acreage Holders



Source: New Standard Energy Exploration

New Standard Energy (NSE.AX, Not Covered) is predominantly focused on the Canning Basin and has assembled the largest acreage position in the Canning, in the order of 12m acres. A portion of these permits cover the Goldwyer shale oil/gas window. Estimates by independent assessor RISC are that the Goldwyer shale could contain 40 -480 Tcf of gas-in-place. Many of NSE's blocks are 100% owned and NSE are seeking farm-in partners to progress and fund planned drilling and coring activities.

Exhibit 24 shows the location of NSE and Buru acreage.

The forward work program for 2011 may also include a possible re-entry of the Lawson#1 well, which was suspended above the Laurel shale, in permit EP317 (Buru 35%, NSE 65%).

Oil Basins Ltd (OBL.AX, Not Covered), drilled Backreef#1 in December 2010 to 1800m in production licenses L6 and discovered a gross oil column of 49m, but stuck tools prevented wire-line sampling or production testing. OBL believes its licenses are prospective for CSG and shale gas, evident from the discovery of marine shale source rocks and TOC of 10% @850m in Borran#1 (drilled in 1982). However due to lack of cores and insufficient well depth, the assessment of prospectivity is inconclusive at this time. OBL is considering a re-entry of the Backreef well with a view to drilling and coring the deeper shale sequences. Relative to other parts of the Canning Basin, OBLs's licenses are close to Derby (about 3 km) and around 200km from the proposed LNG processing hub at James Price Point.

Several smaller companies have exposure to the Canning Basin including Emerald Oil & Gas (NC), Pancontinental Oil & Gas (NCC), FAR Ltd ((NCC) and Bounty Oil & Gas (NC).

Beetaloo, Galilee, Georgina & Officer Basins

These individually large sedimentary basins are physically and geologically separate, but have one common factor, and that is an absence of commercial production. Relative remoteness and lack of infrastructure does not help the commercial equation either, and so exploration activity levels have been negligible and limited to about 30 wells, mostly in the 1980s and a handful since.

We observe rising participation by foreign E&P companies in these rather more remote regions of Australia. It's always fair to ask why participation rates by domestic mainstream companies are by contrast, relatively low. Either the overseas entrants have a better perspective on how to unlock unconventional resources, or have a higher risk appetite. It's a moot point at this time, as various companies have raised capital and are planning drilling and evaluation programs over the next few years.

What these remote basins have in common, is a relative lack of exploration and in our view, the lack of infrastructure to support development has been an impediment. Also, the rocks in these basins are generally ancient, Cambrian age or earlier**. Modern technology is at hand, but even for those that can crack the technical barrier, scale is going to be needed to overcome upfront development and infrastructure costs.**

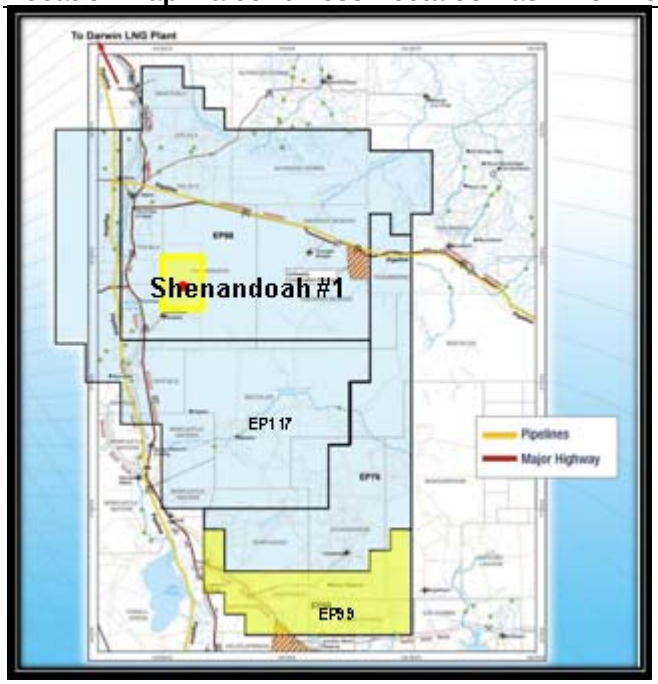
Unlike the search for shale gas elsewhere, the focus of operators in these regions is dominated by oil. PetroFrontier Corporation (PFC) states that its Georgina Basin acreage could contain 26.4bn bbls of recoverable shale oil. Rodinia Oil Corporation states its Officer Basin acreage could contain 26bn bbls recoverable in ten conventional prospects matured to date.

Beetaloo Basin

The Beetaloo (formerly McArthur Basin, exhibit 25) covers a large part of the inland Northern Territory. Dozens of blocks are open for application, but only four permits are actively being worked, all 100% owned by **Falcon Oil & Gas (Australia).** Which is a 73% owned subsidiary of Canadian company, Falcon Oil & Gas. Falcon's blocks are EP98, EP99, EP117 and EP76 and these blocks cover an area of over 25,000 km^2.

Remarkably for such a remote part of Australia, there is adequate infrastructure. There is a paved highway to Darwin (600-700 km to the north), the Amadeus gas pipeline with 20 Bcf pa passes through the block connecting Darwin to the Amadeus Basin, with a branch to the McArthur River base metals mine. Since the commencement of supply of gas from the offshore Blacktip gas field to Darwin a year ago, this pipeline is now little used.

Exhibit 25
Location Map: Falcon / Hess Beetaloo Basin Permits



Source: Falcon Oil & Gas AGM presentation

Over the past 30 years, twelve wells have been drilled, all had live oil and gas shows from sandstone reservoirs, but reservoir quality in Cambrian age and Pre-Cambrian age rocks over 1400 million years old, resulted in non-commercial recovery of oil or gas to surface. In this regard, the tight rocks of the Beetaloo would qualify the resource as 'unconventional'. Current understanding of basin stratigraphy is that there are thick, organic rich shales inter-bedded between prospective sandstone reservoirs. The Kyalla and Velkerrie shales are both interpreted to be about 800m thick and with TOC 2-4% in the Kyalla and up to 3-11% in the Velkerrie.

The un-risked prospective resource estimates according to Falcon are very large, totaling 64 Tcf for gas and 19 billion bbls for oil, in tight sandstones and shales. **In February 2011, Hess Corporation agreed to farm-in to a work-program** in return for a 62.5% participating interest. The program consists of a program of extensive seismic coverage and up to five exploration wells. The work program is set to commence with seismic after securing approvals, followed by the re-opening of

Shenandoah#1 planned for 3Q 2011, focused on testing numerous shows from the discovery well. Shenandoah #1 was drilled in 2007 to 1555m through the mid-Kyalla section, and deepened in August 2009 to 2714m penetrating the lower Velkerrie section. We figure the seismic plus well program costs could approach A$100mn and this is a significant investment in context with others in the industry at this time

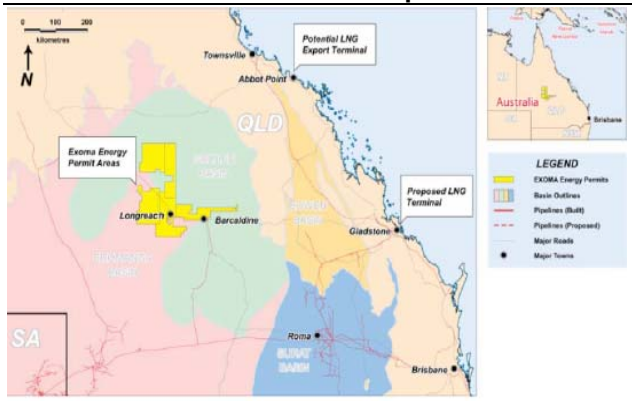
Galilee Basin

The Galilee Basin in central Queensland has seen rising exploration activity since 2007 predominantly for coal seam gas. The Galilee was recognized as prospective for CSG more than 20 years ago, with Enron, Exxon, Conoco and smaller companies all drilling exploratory wells, but at that time , domestic and export markets and infrastructure were not as developed in Queensland as they are today. Companies with acreage in the region are Comet Ridge, Galilee Energy and Origin Energy.

The first dedicated activity that we are aware of for shale gas is planned for this year in a JV **between Exoma Energy and CNOOC**[5]**.** In May 2011, CNOOC received Chinese Government consent to farm-in to Exoma acreage, and CNOOC plans to fund the first US$50mn exploration program in return for earning a 50% working interest. Drilling activity for CSG in Permian coal measures has commenced on May 27, 2011 with the spudding of a well, and the JV plans 13 wells in total. The primary objective is CSG but secondary objectives are the deeper Toolachie. Shale gas objectives will be tested too, via logging and sampling of cuttings. According to Exoma, the CSG 3C resource is estimated to be 2 Tcf, but the potential GIP for CSG and shale is >100 Tcf.

Exhibit 26

Exoma/CNOOC JV Location Map



Source: Exoma

[5] CNOOC (0883.HK; HK$19.38; OW) is covered by Morgan Stanley analyst, Wee-Kiat Tan.

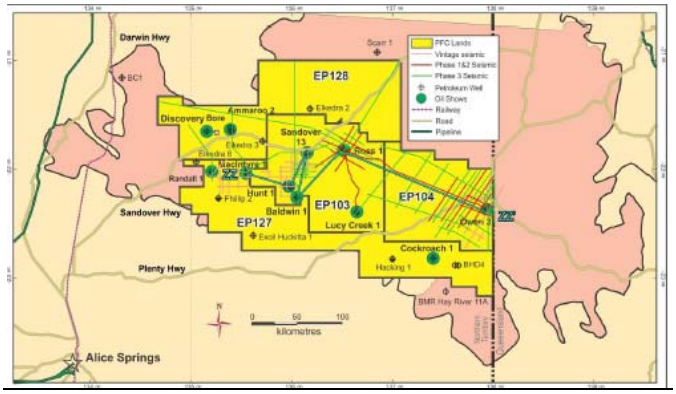
Georgina Basin

Canadian E&P company **PetroFrontier Corp (PFC)** has built a commanding acreage position in the Georgina Basin in the Northern Territory, 300 km north east of Alice Springs. It has 100% working interests in EP's 103, 104 and 75% interests is EP's 127 and 128. Australian listed **Baraka Energy Resources (BKP.AX, Not Covered)** has a 25% working interest in EP's 127 and 128. Petrofrontier believes the rocks are analogous to the Bakken unconventional oil field of Canada, with high TOCs (>5%) from Cambrian age source rocks. In general the region is poorly explored with a few conventional and stratigraphic holes drilled in the 1960s and 1980s which returned oil and gas shows but no flows to surface. Thick, organic rich shales however have never been tested.

One sequence in particular has been identified from 13 previous wells, the Arthur creek 'hot shales'. This shale has average log porosity ranging 4-13%, permeability 1–100 mD and TOC 5**%. PetroFrontier estimates the Arthur Creek shale could hold 26.4bn bbls of recoverable oil reserves.**

Exhibit 27

Location Map: PFC Georgina Basin Permits



Source: PetroFrontier May 17 operational update

PFC plans to drill up to six wells + seismic in 2011, of which three wells are planned to be vertical tests of conventional reservoirs and the balance horizontal wells to target oil rich shales. A rig is being mobilized and the first horizontal well, Baldwin#2 is **expected to commence in June in permit EP103**. That will be followed by another horizontal well MacIntyre#2 in permit EP127, and then Ross#2. Timing and location of following wells will depend on initial results. PFC has announced a 2011 investment of US$32m for this activity.

Officer Basin

Rodinia Oil Corporation of Canada is about to embark on a four well exploration program in the Officer Basin in South Australia. The Officer Basin is another remote basin that has witnessed minimal seismic acquisition or well drilling, although shows have been observed in water bores. A few wells were drilled in the 1960s and a three by Shell in the 1980s which are all interpreted to have been off-structure. However oil and gas shows provide evidence that there is an active generative petroleum system. Exploration targets are conventional sandstone sequences but the rocks are very old (Cambrian age) and reservoir parameters are likely to be poor, necessitating similar completion and fraccing techniques to unconventional operators. **Rodinia claims that ten prospects they have matured in their license areas have the potential to contain 26bn bbls of recoverable oil (unrisked).** Drilling is set to commence in June with the spudding of Mulyawara#1 and success would re-rate industry perceptions of this very large basin.

Exhibit 28
Officer Basin Location Map

Source: Rodinia Oil Corp.

Santos – Overweight, Strategic Value Unrecognized

Santos is the dominant acreage holder in eastern Australia for conventional, coal seam and shale gas.

It was Santos' declaration in 2007 that it intended to develop its burgeoning Queensland CSG production by taking it to Gladstone and turning it into LNG, which re-rated the eastern Australian CSG industry. Within a year, super-majors and international E&Ps had effected a massive industry consolidation. **Today, Santos' focus, and much of its balance sheet is devoted to delivering the GLNG project** and CSG exploration and appraisal activity continues in Queensland and the central NSW Gunnedah Basin, to support growth in CSG reserves to feed the GLNG plant. Santos claims its 15m (gross) acres in the Gunnedah Basin have >50 Tcf prospective resource potential for CSG.

Santos shale gas activity in the Cooper Basin so far, has been quiescent given priorities elsewhere but the geology is reasonably well understood from 40 years of conventional production. Underlying the conventional Jurassic traps are shale, tight gas and coal sequences. Santos believes the gross unconventional resource potential is >39 Tcf. One shale gas well is to be drilled and cored in 2011 at Moomba North. Leading into this, in May conventional Moomba gas well #185 had the REM sequence cored

Santos has substantial underutilized production infrastructure at Moomba and pipeline connections to every major domestic and export market. At Moomba, Santos has well established logistics and service company support. This is a substantial competitive advantage for commercial production.

Price target methodology. Our price target of A$16.50 is set in line with peer group discounts to the un-risked DCF estimate of $19.27 (Exhibit 29), unchanged. At the present share price, the market appears to be risking the key development assets of PNG LNG and GLNG at about 75% which seems reasonable, but discounts completely any value for ongoing conventional exploration, and the commanding unconventional acreage footprint and infrastructure. This makes STO a cheap asset in our view and the strategic nature of its acreage and infrastructure is unrecognized by the market.

Risk factors

Key macro risks are the oil price and AUD/USD exchange rate. At the company level, oil and gas field reserves, production, opex, and future capital costs are all subject to risk. PNG LNG and GLNG are material to the value equation and progress, and these projects bring development and construction risk.

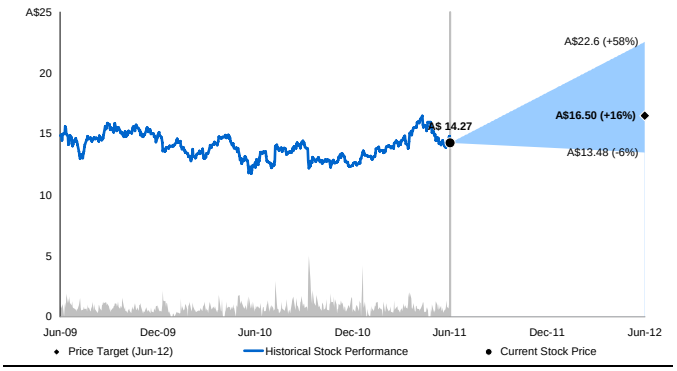
Exhibit 29

Santos DCF SoP (short version)

Production	A$m	$/share
Conventional gas production- Cooper	1802	2.05
Bayu-LNG	1737	1.98
WA / other-Oil	967	1.10
WA & Vic gas	2324	2.65
International oil & gas	926	1.05
Less G&A	-972	-1.11
sub total- core production	**6783**	**7.73**
Development		
PNG LNG - unrisked	4788	5.45
GLNG	3337	3.80
Bonaparte LNG	250	0.28
sub total- development	8376	9.54
Exploration	195	0.22
Investment in ESG	187	0.21
Other	152	0.17
sub total- exploration	534	0.61
Financial assets	1225	1.40
TOTAL SoP	16918	19.3

Source: Morgan Stanley Research. Full DCF by field is detailed in bespoke reports

Santos Risk-Reward



Scenario Summaries

Price Target A$16.50	Price target set at a small discount to DCF (WACC 10.9%)
Bull Case A$22.60	US$110/bbl normalized oil price. GLNG 2 train development costing US$14b and. Uncontracted LNG volumes sold at spot.
Base Case A$19.27	US$90/bbl normalized oil price. 2 train GLNG unrisked with $16B gross capex. Minimal value for other stranded gas and shale-gas
Bear Case A$13.48	US$75/bbl normalized oil price. GLNG comes in late and over-budget. Shale and stranded gas discounted to nil.

Source: FactSet, Morgan Stanley Research

Exhibit 30

Santos Financial Summary

Key Assumptions- Y/e Dec	2010	2011E	2012E	2013E
Realised oil price- A$/bbl	87.36	112.13	125.21	89.58
Production (mboe)	49.90	49.1	54.7	54.6
Profit & Loss				
Oil & Gas Sales Revenue	2227.8	2524.0	3301.3	2743.1
Royalty and pipeline tolls	46.0	79.7	79.6	79.5
Total operating Revenue	**2273.8**	**2603.7**	**3380.8**	**2822.7**
Other income	203.0	199.9	93.8	100.6
Asset sales	0.0	0.0	0.0	0.0
Reported revenue	**2476.8**	**2803.6**	**3474.6**	**2923.3**
-OPEX, inventory & 3rd party gas	721.0	784.5	812.3	792.5
-Pipeline tolls & tarifs	95.0	89.3	91.1	101.7
-Royalties	51.0	65.3	77.0	55.4
-S G & A other	97.0	92.0	100.0	120.0
-Forex / financial instruments / other	17.00	0.00	0.00	0.00
- Emissions costs	0.0	0.0	0.0	0.0
EBITDAX	1495.8	1772.5	2394.2	1853.7
-Depreciation & amortisation	595.0	589.3	650.4	634.4
-Exploration, writedowns & other	286.0	132.0	127.5	153.0
EBIT	**614.8**	**1051.2**	**1616.4**	**1066.3**
-interest expensed	133.0	199.0	214.1	236.2
Pre-tax operating profit	481.8	852.2	1402.2	830.1
PRRT after tax	51.0	125.4	148.8	134.0
Tax expense	145.0	255.7	420.7	240.7
Net operating profit-MS est.	**285.8**	**471.1**	**832.7**	**455.4**
+Non-recurring items, net of tax	214.0	109.6	0.0	0.0
Statutory profit	**499.8**	**580.7**	**832.7**	**455.4**
Preference & convertible dividends	0.0	0.0	0.0	0.0
Reported profit	**285.8**	**471.1**	**832.7**	455.4
Reconciliation: reported profit to adjusted operating profit				
Reported EBIT	614.8	1051.2	1616.4	1066.3
-less RRT after tax	51.0	125.4	148.8	134.0
-less interest & dividend income	140.0	169.9	93.8	100.6
-less other (insurance recoveries, forex)	63.0	30.0	0.0	0.0
-less profit on asset sales	0.0	0.0	0.0	0.0
+other / forex / financial insr.	17.0	0.0	0.0	0.0
= Operating EBIT inc. RRT	**377.8**	**725.8**	**1373.8**	**831.7**
+Interest, Dividend & other income	186.0	199.9	93.8	100.6
-Interest expense	133.0	199.0	214.1	236.2
-Tax & PRRT	145.0	255.7	420.7	240.7
-Preference Dividend	0.0	0.0	0.0	0.0
=Adjusted operating profit	285.8	471.1	832.7	455.4
Cashflow				
Receipts	2617.0	2803.6	3474.6	2923.3
-Operating costs & royalties	1348.0	1031.1	1080.3	1069.6
-Tax Paid	-71.0	255.7	420.7	240.7
- interest paid	73.0	199.0	214.1	236.2
Net operating cashflow	**1267.0**	**1317.8**	**1759.4**	**1376.7**
Proceeds from asset sales	752.0	299.5	0.0	0.0
-capex, exploration & development	1713.0	2857.6	2406.6	2305.4
-acquisitions & other	50.0	0.0	0.0	0.0
Net investing cashflows	1011.0	2558.1	2406.6	2305.4
PRE-FINANCING CASHFLOW	**256.0**	**-1240.3**	**-647.1**	**-928.7**
Ordinary dividends	316.0	263.0	263.6	263.6
Preference & convertible dividends	0.00	0.00	0.00	0.00
+ Equity	490.0	52.0	0.0	0.0
-Debt repayments (borrowings)	1656.0	358.3	429.6	397.9
+ other	0	0	0	0
Net financing cashflow	1830.0	147.2	166.0	134.3
Increase in cash	**2086.0**	**-1093.0**	**-481.2**	**-794.4**
Exchange rate & other/ asset sale adj.	-7.0	0.0	0.0	0.0
Net change in cash	2079.0	-1093.0	-481.2	-794.4
Carbon	**2010E**	**2011E**	**2012E**	**2013E**
CO2e (mt)	3.2	3.2	3.5	3.5

Balance Sheet Y/E Dec	2010	2011E	2012E	2013E
Payables	760	731	717	613
Interest bearing liabilities	370	0	0	0
Provisions & other	485	485	485	485
Total Current Liabilities	1615	1216	1202	1098
Non- Current Liabilities				
Interest bearing liabilities-non current	2787	3515	3945	4343
Provisions & other- non-current	1764	2574	3274	3274
Total Liabilities	6166	7305	8420	8715
Cash & investments	4319	**3226**	**2745**	**1950**
Receivables	687	939	985	920
Inventories & other	265	265	100	100
Total current ssets	**5271**	**4430**	**3830**	**2970**
Investments	346	346	346	346
Capitalised exploration & developmen	4015	5092	5917	6690
Land, buildings,plant and equipment	4062	4822	5625	6371
Intangibles (Goodwill)	0	0	0	0
tax & other	54	580	1236	1064
TOTAL ASSETS	13769	15280	16964	17450
preference capital	0	0	0	0
Ordinary capital	7605	7975	8544	8736
Shareholders Equity	7603	7975	8544	8736
Ratios, Margins & Valuation				
Weighted average shares	835.5	877.7	878.7	878.7
Current issued shares	874.991	877.913	877.913	877.913
Average share price	14.27	14.27	14.27	14.27
Market Cap	12486	12528	12528	12528
+plus net debt	-1162	289	1200	2392
+plus preference capital	0	0	0	0
-less investments	0.0	0.0	0.0	0.0
Enterprise Value	11324	12817	13728	14920
Operating EBIT	A$m	377.8	725.8	1373.8	831.7
Operating EBITDA		973	1315	2024	1466
Operating EBITDAX		1259	1447	2152	1619
Reported EPS	cps	59.8	66.2	94.8	51.8
Adjusted EPS	**cps**	**34.2**	**53.7**	**94.7**	**51.8**
D.P.S.	cps	37	30	30	30
Payout Ratio (%)	%	109	56	32	58
PER	**X**	**38.4**	**26.6**	**15.1**	**27.5**
EV / EBITDAX	**X**	**9.0**	**8.9**	**6.4**	**9.2**
EV / EBITDA	**X**	**10.6**	**9.7**	**6.8**	**10.2**
Yield	**%**	**2.6**	**2.1**	**2.1**	**2.1**
DCF valuation	**$/share**	**$ 19.27**	**WACC:**	**10.9%**	
Balance sheet & returns					
Net Debt / N.D. +Equity	%	-18%	4%	12%	21%
Interest cover	X	6.2	6.5	9.5	5.6
ROA	%	3.3	5.3	9.0	4.9
ROE	%	4.1	6.2	10.4	5.3
Unit revenue & costs					
Sales revenue / boe	A$/boe	44.65	51.39	60.35	50.23
Production cash cost / boe	A$/boe	19.32	21.00	19.75	19.58
EBIT / boe	A$/boe	7.57	14.78	25.11	15.23
NPAT / boe	A$/boe	5.73	9.59	15.22	8.34
NPAT / Sales margin	%	12.6%	18.1%	24.6%	16.1%
Reserves measures					
Reserves 1P- boe	**mboe**	**646**	**797**	**797**	**802**
Reserves 2P- boe	**mboe**	**1445**	**1450**	**1449**	**1458**
Contingent resources	**mboe**	**2261**	**2248**	**2248**	**2248**
2P / 1P		2.2	1.8	1.8	1.8
EV / 1P Reserves	**A$/bbl**	**17.53**	**16.08**	**17.23**	**18.60**
EV / 2P Reserves	**A$/bbl**	**7.84**	**8.84**	**9.47**	**10.23**
EV / 3P Resources	**A$/bbl**	**3.06**	**3.47**	**3.71**	**4.03**

Source: Morgan Stanley Research estimates

AWE Ltd – Overweight (prev. Equal-weight) for Perth Basin Exposure

AWE has a strong acreage position in the Perth Basin where the shale geology looks good (marine) and where there is existing production infrastructure.

Drilling activity is about to commence, with the drilling of Arrowsmith#2 (w.i. 44%), which is a vertical well targeting the Carynginia shale. This will be cored, and fracced in the September quarter as equipment becomes available. AWE also plans to frac the Woodada Deep well (w.i 100%). Independent of this program, Origin Energy is planning 2-4 shale wells in jointly owned Perth basin acreage. Recompletions of tight gas wells Senecio#2 and Corybas are also planned. These wells flowed at 2.5 mmcfd and 4 mmcfd before declining. Corybas production is from the IRCM sequence, thus extending the basins productive potential beyond the Kockatea and Carynginia sequences.

AWE has shale gas experience in the US where it has working interests in the Eagleford shale. AWE has 10% of the Sugarloaf AMI, where production is currently 12 mmcfd with liquids ratio 220 bbls per mmcfg. AWE's net 2P reserve is 8.6 mboe, as of March 2011. AWE's US shale gas activities help bring knowledge and may be a differentiating factor versus peers. Marathon's US$3.5bn acquisition of Hilcorp on June 2 implies a look-through valuation for AWE's US asset, in the order of US$300mn, which is higher than the risked estimate in our base case valuation.

Offsetting to an extent the shale gas opportunity there are some risks to the base business which is in production decline, and where too few wells are contributing to the total output thus exposing investors to downgrades from unexpected outages. We note that reserves at Tui are being reviewed, and that the BassGas MLE is cum an intensive capex phase which may stretch the balance sheet. However, we expect that these issues are recognized and may be factored into the stock price, with AWE performing very poorly over the past year, and now trading well below what we believe is core value.

Core value from production of 65 mboe of proven oil and gas, plus cash we calculate to be $1.74. This excludes AWE's valuable US shale gas of 2400 net acres with 8 mboe 2P in the Eagleford, which we risk at 50%.

Exhibit 31

AWE DCF SoP (short version)

	(A$mn)	(A$/share)
Core production	**864**	**1.65**
Developments - Sugarloaf (50% risked)	141	0.27
Exploration - conventional	74	0.14
Cash & Investments	105	0.20
TOTAL	1184	2.27

Source: Morgan Stanley Research. Full DCF SoP by field is shown in bespoke AWE reports

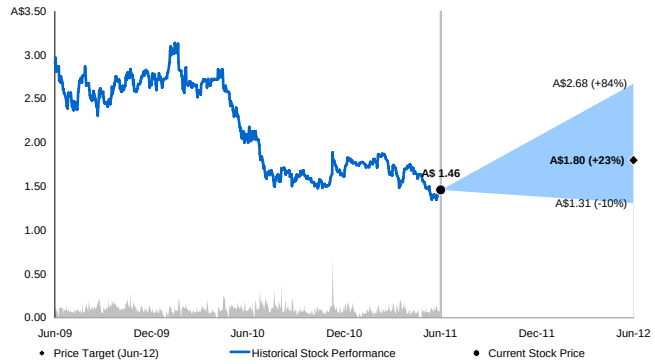
Price target methodology

Our DCF valuation is summarized in Exhibit 31 and is A$2.27, unchanged. Our price target is A$1.80 which is a material discount to DCF but in line industry average discounts. The stock price is trading at a large discount to both these figures reflecting disappointing shortfalls to production and exploration. The shale gas potential appears discounted to nil . The risk-reward equation is biased to reward, and shale-gas drilling news could catalyse a re-rating.

Company-specific risk factors

Key macro risks to our price target are oil prices and exchange rates. At the operational level, reliable production from key fields Tui, BassGas and Casino are important in sustaining cash flows. AWE is also sensitive to capex and there is risk of further capex pressure at BassGas.

AWE Risk-Reward



Scenario Summaries

Price Target A$1.80	DCF-based sum of the parts. We maintain a significant discount (20%) to our DCF, at the low end of peer group discounts, on expectations of ongoing strategic uncertainty.
Bull Case A$2.68	**Oil price of US$110/bbl** normalized, Adlephi 3P derisked to 75%
Base Case A$2.27	**Oil price of US$90/bbl.** Adelphi risked at 50%, Trefoil resource risked at 50%.
Bear Case A$1.31	**Oil price of US$75/bbl.** No value for static assets, investments and Adelphi acreage.

Source: FactSet, Morgan Stanley Research

Exhibit 23

AWE Ltd: Financial Summary

Profit & Loss		2010A	2011E	2012E	2013E
Oil-Brent	**US$/bbl**	**78.81**	**98.61**	**125.00**	**110.00**
Oil price- A$/bbl	US$/bbl	86.1	88.5	119.0	108.8
Production- liquids	mboe	3.5	2.7	2.7	2.8
Production- gas	PJ	15.8	20.6	22.8	24.0
Total production	**mboe**	**6.1**	**6.2**	**6.6**	**6.8**
Sales Revenue		354.2	307.0	402.6	382.0
+sale of assets/investments/Other		-	-	-	-
+other		1.8	1.6	1.4	1.4
Total revenue		**356.0**	**308.6**	**404.1**	**382.0**
-OPEX		128.6	128.1	128.8	127.9
-Tariffs		-	-	-	-
-General & other		22.9	17.2	18.4	18.6
-forex / other / inventory		9.2	5.6	-	-
-inventory & other		3.4	(4.7)	-	-
-cost of assets sold		(6.6)	-	-	-
EBITDAX		198.5	162.4	256.9	235.4
-Exploration expensed&impairments		126.6	88.0	37.8	37.8
EBITDA		71.9	74.3	219.1	197.6
-Depreciation & Amortisation		94.5	99.3	99.3	97.6
EBIT		**(22.5)**	**(24.9)**	**119.8**	**100.0**
interest capitalised		-	-	-	-
-net interest		1.3	4.2	(2.1)	(1.6)
Pre-tax operating profit		(23.9)	(29.4)	121.9	101.6
Tax expense		(20.4)	4.2	36.6	30.5
Royalties		25.4	(3.0)	29.0	23.8
Net operating profit		**(28.9)**	**(30.6)**	**56.3**	**47.4**
Minority interest		-	-	-	-
+non recurring items		-	-	-	-
Reported profit		**(28.9)**	**(30.6)**	**56.3**	**47.4**
Reported EBITDA		71.9	74.3	219.1	197.6
less interest income		-	-	-	-
less forex gains		9.2	5.6	-	-
less asset sales		6.6	-	-	-
less RRT tax provision		25.4	(3.0)	29.0	23.8
Mware EBITDA		49.2	83.0	190.1	173.9
Mware EBIT		(45.3)	(16.3)	90.8	76.2
Mware NPAT		(35.4)	(30.6)	56.3	47.4

Cashflow	2010A	2011E	2012E	2013E
Cash from operations	368.2	340.0	411.4	388.9
-Operating costs	155.5	183.8	176.2	170.3
-interest paid	3.7	4.9	5.3	5.3
-tax	100.9	29.5	36.6	30.5
Gross cashflow from operations	**108.1**	**121.8**	**193.4**	**182.8**
-exploration	148.2	56.7	54.0	54.0
-development	38.5	60.9	133.6	173.7
-acquisitions	118.0	33.9	-	-
+divestments / other	0.2	1.3	-	-
Pre-financing cashflow	**(199.4)**	**(29.2)**	**5.8**	**(45.0)**
-dividends	-	-	-	-
+equity/other	1.8	9.6	-	-
+debt raised/(repaid)	-	-	-	50.0
Net cashflow	(197.6)	(19.6)	5.8	5.0
+exchange rate adjustments	(23.2)	(3.9)	-	-
Increase in cash	**(220.7)**	**(23.4)**	**5.8**	**5.0**
Cash at BOP	356.1	135.3	111.9	117.7
Cash at EOP	135.3	111.9	117.7	122.7
Net debt at year end	**(135.3)**	**(111.9)**	**(117.7)**	**(72.7)**

Carbon	2010A	2011E	2012E	2013E
Price (A$/tCO2e)		-	-	-
CO2e (mt)		0.02	0.02	0.02
CO2e cost in Opex (A$m)		-	-	-

Balance Sheet	Y/eJune	2010	2011E	2012E	2013E
Cash		135.3	111.9	117.7	122.7
Inventories & other		10.4	14.0	14.0	14.0
Total current assets		211.0	185.2	209.4	210.2
Capitalised production & Dev		817.3	856.2	890.5	966.6
Capitalised exploration		271.3	190.8	207.0	223.2
Investments		10.6	12.5	12.5	12.5
Total assets		**1,317.1**	**1,274.9**	**1,385.2**	**1,502.5**
Payables		75.0	51.2	51.2	51.2
provisions & tax		17.9	-	-	-
other		1.0	1.0	55.0	75.0
Current debt		-	-	-	-
total current liabilities		93.9	52.2	106.2	126.2
interest bearing debt		0.0	-	-	50.0
other liabilities		125.3	185.8	185.8	185.8
Total liabilities		**219.3**	**238.0**	**292.0**	**362.0**
Shareholder funds		**1,097.8**	**1,036.8**	**1,093.2**	**1,140.5**

Valuation & ratios					
Share price		1.36	1.36	1.36	1.36
Weighted average shares					
Current issued shares		521.9	521.9	521.9	521.9
Diluted capital		523.5	535.9	535.9	535.9
Market Cap		710	710	710	710
+net debt		-135.3	-111.9	-117.7	-72.7
-less investments / other		-10.6	-12.5	-12.5	-12.5
Enterprise Value	A$m	564	585	580	624
M'ware EBIT	A$m	-45.3	-16.3	90.8	76.2
M'ware EBITDA	A$m	49.2	83.0	190.1	173.9
Reported EPS	cents	-5.5	-5.9	10.8	9.1
Modelware EPS	**cents**	**-6.8**	**-5.7**	**10.5**	**8.8**
DPS	cents	0	0	0	0
Payout ratio	%	0	0	0	0
PER	**X**	**NA**	**-23.8**	**12.9**	**15.4**
EV / EBITDA	**X**	**11.5**	**7.0**	**3.0**	**3.6**
EV / EBITDAX	**X**	**3.2**	**3.4**	**2.5**	**3.0**
Yield		-	-	-	-
DCF Valuation	**A$/share**	**$2.27**	**WACC**	**11.3**	
Bear / bull /Px target	**A$/share**				
Ratio analysis					
Net debt / ND + E	%	-14%	-12%	-12%	-7%
interest cover	x	-3.0	-3.6	22.8	19.0
Dividend payout ratio	%	0%	0%	0%	0%
EBIT / total assets (ROA)	%	-2%	-2%	9%	7%
Net profit / Shareholder funds (ROE)	%	-3%	-3%	5%	4%
Effective tax rate	%	85.5	-14.3	30.0	30.0
Unit revenues & costs					
Sales revenue / boe	$/boe	58.54	50.14	61.69	56.53
Cash cost / boe	$/boe	25.34	24.53	22.47	21.69
Non cash cost / oe	$/boe	36.35	30.44	20.92	20.04
EBIT / boe	$/boe	-3.71	-4.10	18.30	14.80
NPAT / boe	$/boe	-4.75	-4.97	8.60	7.01
EBIT / Sales	%	-6%	-8%	30%	26%
EBITDA/Sales	%	56%	53%	64%	62%
Reserves					
2P Reserves	**m boe**	66	72	68	65
Gas / Liquids split	**%**	**50**	**63**	**63**	**63**
EV / boe	**A$/bbl**	**8.53**	**8.18**	**8.49**	**9.62**
EV / boe	**US$/boe**	**8.93**	**8.09**	**8.90**	**9.74**

Source: Company data, Morgan Stanley Research
e = Morgan Stanley Research estimates

Beach Energy – Equal-weight, but Increasing Profile

Beach is no stranger to unconventional gas and was an early investor in CSG in Queensland, which was traded for a substantial profit. In the Cooper Basin, BPT is better recognized for its conventional gas production in JV with Santos, and in its own acreage where is has been very successful at finding and developing oil. Beach has a large footprint in the Cooper Basin and in particular has acreage over the core area of the Nappamerri trough. A key block is the 90% owned PEL218.

Two dedicated but vertical shale gas wells were drilled into PEL218 in 2010, namely Holdfast and Encounter. A fraccing program has commenced and results are to be expected over the next few weeks. If these wells flow gas at justifiable rates, then BPT plans to book contingent resources in Q3 2011. More importantly, the intent of the current program is to gather data to design a horizontal well and pilot production program for 2012. If so, this would place BPT ahead of the industry in terms of commercial production using the same techniques as are commonly applied in the US. Elsewhere in the Cooper Basin, BPT is a joint venture participant with Santos, which is independently assessing the potential of the REM sequence in the Moomba field. Santos claims its share of unconventional gas resources are >39 Tcf,

Our SoP is $1.04 (Exhibit 32), previously $1.03. At face value, BPT may not appear to offer much leverage to the shale gas activity. Core production from 65 mboe plus cash totals 74c. Within the 'exploration' figure, there is already a significant value for resources, so there is a degree of risk and data from the upcoming frac tests will be important to assess that.

The share price is beginning to rally as investors anticipate results. We believe this can continue for at least the next month and on May 18, we issued a positive Research Tactical Idea.

Exhibit 32

BPT DCF SoP (short version)

Production	A$m	A$/share
Cooper Basin oil & gas	723	0.66
less G&A	-100	-0.09
Core production value	623	0.56
Oil exploration	161	0.15
Gas exploration- Cooper	165	0.15
Subtotal- exploration	326	0.30
Cash & Investment	197	0.18
TOTAL	1145	1.04

Source: Morgan Stanley Research. DCF SoP by field is shown in bespoke reports

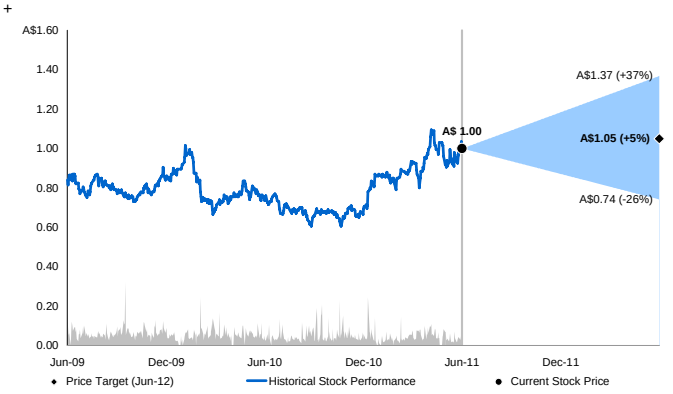
Price target

Our price target is set at around the DCF, and given that many peers trade at measurable discounts to DCFs and targets, the relative premium we assign to BPT is an explicit recognition that immediate news events will contribute to a rally. Market momentum may in fact take the price higher, but whether or not a sustained higher price can be justified or not, again depends on the next set of 'data points' from the company's shale gas activity.

Risk factors

Key macro risks to our price target are oil and gas prices and exchange rates. At the company level, production, reserves, opex and capex risks exist. We see risks to production and reserves from start-up operations in Egypt. Exploration in frontiers is expensive and the risk from dry wells is relatively large. Capture of value for shale gas and unconventional gas acreage via asset trade is source of upside risk.

BPT Risk-Reward



Scenario Summaries

Price Target A$1.05	Price target is set with reference to our base case valuation (WACC 11.1% for oil, 10.2% for gas).
Bull Case A$1.37	US$110/bbl normalized oil price. Un-conventional and contingent resources risked at 50%, assuming success from current work programme, early success in Impress acreage impounds greater value for resource (de-risk)
Base Case A$1.04	US$90/bbl normalized oil price. Western Flank drilling risked, assuming c.0.8mmbls per well. GLNG gas sales risked at 50% and residual Cooper contingent and unconventional risked at 10%.
Bear Case A$0.74	US$75/bbl normalized oil price. No value for 2C resource potential. Exploration in Western Flank fails. GLNG contract does not get signed.

Source: FactSet, Morgan Stanley Research

Exhibit 33

Beach Energy Ltd: Financial Summary

Profit & Loss	Y/e June	2010A	2011E	2012E	2013E
Exchange rate	US$/A$	0.9	1.0	1.0	1.0
Realised oil price	A$/bbl	86.8	96.7	119.9	109.2
Production-Oil & condensate	mbbls	2.9	2.4	2.8	3.2
LPG	k tonnes	43.4	40.2	39.0	36.8
Natural gas	PJ	23.7	21.8	21.3	20.3
Total production	**mboe**	7.4	6.5	6.8	7.0
Sales Revenue		**487.5**	**493.7**	**562.6**	**572.9**
other operating income		4.5	0.7	-	-
Operating revenue	**A$m**	491.9	494.4	562.6	572.9
+sale of assets & other		-	0.8	-	-
+interest income		5.9	10.9	7.1	10.6
Total revenue	**A$m**	497.8	506.1	569.7	583.6
-OPEX		167.6	162.7	148.3	141.1
-third party purchases		72.7	75.3	83.2	89.5
-Royalties		54.2	56.2	62.7	64.8
-General & other		21.1	22.3	22.9	23.4
-forex & hedging realised		4.7	4.7	-	-
-change in inventory		6.0	17.6	(10.0)	-
EBITDAX		171.5	167.3	262.6	264.7
-Exploration expensed		68.1	128.6	20.0	20.0
EBITDA		103.4	38.6	242.6	244.7
-Depreciation & Amortisation		114.2	102.4	111.8	121.2
EBIT		(10.8)	(63.8)	130.8	123.5
-borrowing costs		6.1	6.3	5.8	5.4
Pre-tax operating profit		(16.9)	(70.1)	125.0	118.1
Tax expense		(15.5)	(25.5)	37.5	35.4
Profit		**(1.4)**	**(44.5)**	**87.5**	**82.7**
Minority interest		-	-	-	-
+non recurring items A.T		34.5	(21.1)	-	-
Reported profit		**33.1**	**(65.6)**	**87.5**	**82.7**
Reconciliation to Mware EBITDA & EBIT					
Reported EBITDA		103.4	38.6	242.6	244.7
less interest income		5.9	10.9	7.1	10.6
less forex gains		(4.7)	(3.8)	-	-
less asset sales		-	-	-	-
Mware EBITDA		102.3	31.6	235.5	234.1
Mware EBIT		(11.9)	(70.8)	123.7	112.9
Mware NPAT		(1.4)	(44.5)	87.50	82.7
Beach Normalised NPAT		**40.8**	**47.5**	**101.5**	**96.7**

Cashflow	Y/e June	2010A	2011E	2012E	2013E
Cash revenues		491.4	489.3	569.7	583.6
-Operating costs		(313.3)	(307.3)	(317.1)	(318.8)
-interest paid		(0.6)	(3.4)	(5.8)	(5.4)
-tax		(49.2)	(10.0)	(37.5)	(35.4)
+other		0.2	(13.7)	-	-
Gross cashflow from operations		**128.5**	**154.9**	**209.3**	**223.9**
-capex- development		(112.0)	(65.7)	(87.8)	(80.1)
-exploration & appraisal		(35.0)	(98.3)	(80.0)	(70.0)
-acquisitions		(7.4)	(69.2)	-	-
+proceeds from sales / other		68.2	53.2	-	-
Pre-financing cashflow		**42.3**	**(25.2)**	**41.5**	**73.8**
-dividends		(26.5)	(15.3)	(19.4)	(19.5)
+equity/other		19.2	4.6	-	-
+debt raised/(repaid)		0.5	0.5	-	-
Net cashflow		35.5	(35.3)	22.1	54.3
+exchange rate adjustments		(1.7)	(5.4)	-	-
Increase in cash		**33.8**	**(40.7)**	**22.1**	**54.3**
Cash at BOP		136.2	170.0	129.2	151.4
Cash at EOP		170.0	129.2	151.4	205.7

Carbon Cost	2010A	2011E	2012E	2013E
Price (A$/tCO2e)	0	0	0	0
CO2e (mt)	0.47	0.42	0.44	0.45
CO2e cost in Opex (A$m)	0	0	0	0

Balance Sheet	Y/e June	2010A	2011E	2012E	2013E
Cash		169.9	129.2	151.4	205.7
Receivables		116.1	70.2	92.5	73.3
Inventories & other		116.9	82.5	96.4	102.7
Investments		-	-	-	-
Property, plant & equyipment		367.2	413.8	433.8	438.7
Capitalised development		573.9	529.2	547.6	555.6
Capitalised exploration & evaluation		269.2	356.0	353.6	349.6
Deferred taxes		63.9	43.8	43.8	43.8
other					
Total assets		1,677.0	1,624.7	1,719.2	1,769.4
Payables		93.9	76.6	110.0	115.0
provisions		79.1	124.0	117.0	99.0
other		10.0	11.1	11.1	11.1
interest bearing debt		-	-	-	-
Deferred taxes		119.0	106.7	106.7	106.7
Financial instruments		3.4	1.0	1.0	1.0
Total liabilities		305.5	319.5	345.9	332.9
Total parent entity interest		1,370.4	1,305.2	1,373.3	1,436.5
Minority interest		1.2	-	-	-
Shareholder funds		1,371.6	1,305.2	1,373.3	1,436.5

Key Ratios					
Share price		1.0	1.0	1.0	1.0
Weighted average shares		1,071.0	1,097.0	1,105.7	1,114.0
Current issued shares		1,099.0	1,099.0	1,099.0	1,099.0
Market Cap		1,099.0	1,099.0	1,099.0	1,099.0
+net debt		(169.9)	(129.2)	(151.4)	(205.7)
-less investments / other		-	-	-	-
Enterprise Value	A$m	929.1	969.8	947.6	893.4
M'ware EBIT	A$m	(11.9)	(70.8)	123.7	112.9
M'ware EBITDA	A$m	102.3	31.6	235.5	234.1
Reported EPS	cents	3.1	(6.0)	7.9	7.4
Modelware EPS	**cents**	**(0.1)**	**(4.1)**	**7.9**	**7.4**
Beach Normalised EPS	**cents**	**3.8**	**4.3**	**9.2**	**8.7**
DPS	**cents**	**1.8**	**1.8**	**1.8**	**1.8**
Payout ratio	%		-43	22	24
PER	**X**		**NM**	**13.4**	**14.5**
EV / EBITDA	**X**	9.1	30.7	4.0	3.8
EV / EBITDAX	**X**	5.5	6.1	3.7	3.5
Yield	**%**	**1.8**	**1.8**	**1.8**	**1.8**
DCF Valuation	**A$/share**	**$1.04**			
WACC oil / gas	%		11.5%	10.6%	
Ratio analysis					
Net debt / ND + E	%	-0.14	-0.11	-0.12	-0.17
interest cover	x	-1.97	-11.24	21.19	20.87
EBIT / total assets (ROA)	%	-1%	-4%	7%	6%
Net profit / Shareholder funds	%	2%	-5%	6%	6%
Effective tax rate	%	0.92	0.36	0.30	0.30
Unit revenues & costs					
Sales revenue / boe	A$/boe	66.17	76.13	82.88	82.25
Cash cost / boe	$/boe	32.97	37.19	34.45	32.93
Non cash cost / oe	$/boe	24.75	35.63	19.41	20.27
EBIT / boe	$/boe	-1.47	-9.83	19.27	17.73
NPAT / boe	$/boe	4.50	-10.12	12.89	11.87
EBIT / Sales	%	-2%	-13%	23%	22%
Reserves					
2P Reserves	**m boe**	**66**	**77**	**92**	**107**
Contingent Reserves	**m boe**	**297**	**297**	**297**	**297**
Gas / Liquids split	**%**	61%	69%	72%	75%
EV / boe- 2p	**A$/bbl**	**14.07**	**12.52**	**10.27**	**8.37**
EV / boe- 2C	**A$/bbl**	**3.13**	**3.27**	**3.19**	**3.01**
EV / boe	**US$/boe**	12.48	12.38	10.76	8.69

Source: Company data, Morgan Stanley Research E = Morgan Stanley Research estimates. Source: Company data, Morgan Stanley Research

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(as of May 31, 2011)

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Stock Rating Category	Count	% of Total	Count	% of Total IBC	% of Rating Category
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Underweight/Sell	**390**	**14%**	**108**	**11%**	**28%**
Total	**2,791**		**957**		

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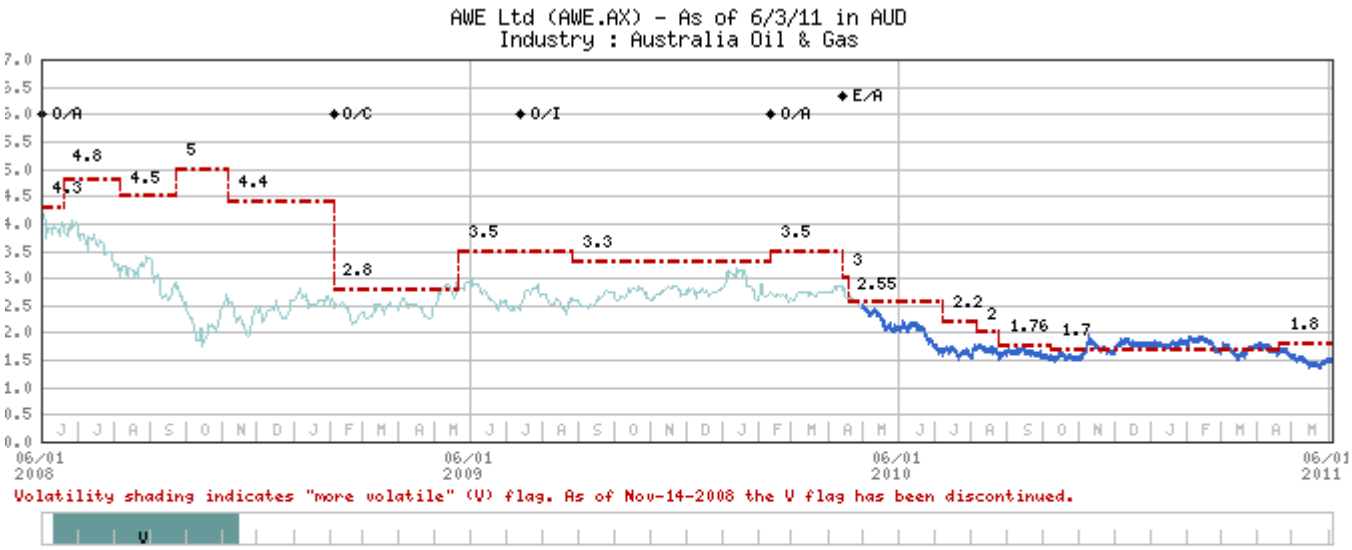
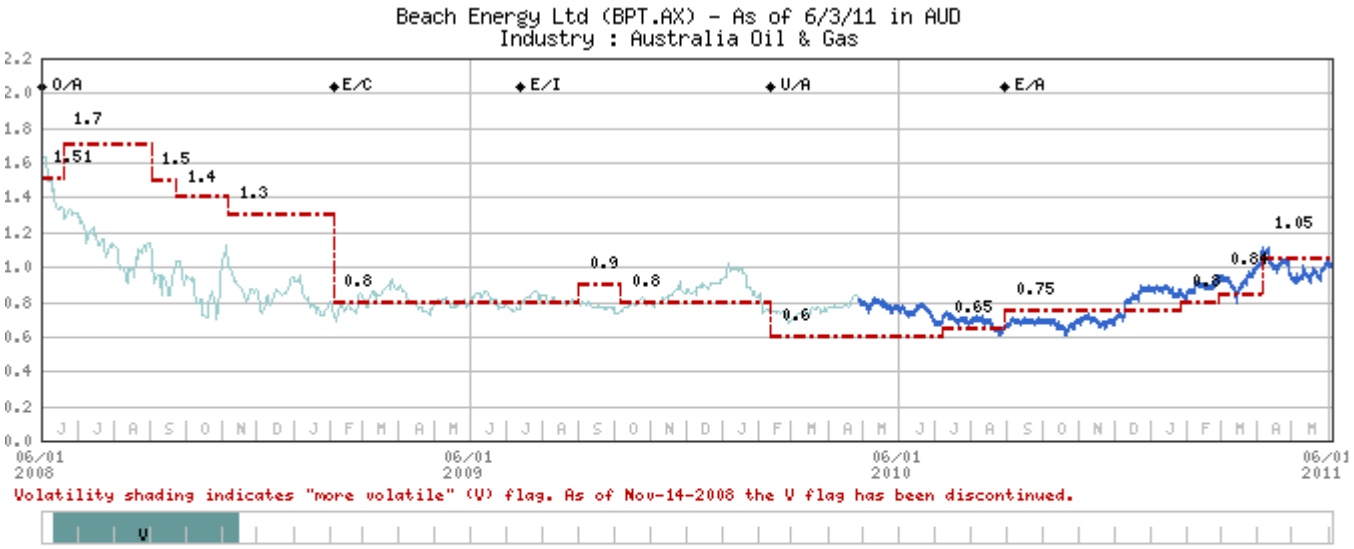
Stock Price, Price Target and Rating History (See Rating Definitions)



Stock Rating History: 6/1/08 : O/A; 2/4/09 : O/C; 7/14/09 : O/I; 2/12/10 : O/A; 4/14/10 : E/A

Price Target History: 5/8/08 : 4.3; 6/19/08 : 4.8; 8/6/08 : 4.5; 9/24/08 : 5; 11/7/08 : 4.4; 2/4/09 : 2.8; 5/22/09 : 3.5; 8/26/09 : 3.3; 2/12/10 : 3.5; 4/14/10 : 3; 4/18/10 : 2.55; 7/8/10 : 2.2; 8/6/10 : 2; 8/25/10 : 1.76; 10/8/10 : 1.7; 4/20/11 : 1.8

Source: Morgan Stanley Research Date Format : MM/DD/YY Price Target No Price Target Assigned (NA)
Stock Price (Not Covered by Current Analyst) Stock Price (Covered by Current Analyst)
Stock and Industry Ratings (abbreviations below) appear as ◆ Stock Rating/Industry View
Stock Ratings: Overweight (O) Equal-weight (E) Underweight (U) Not-Rated (NR) More Volatile (V) No Rating Available (NA)
Industry View: Attractive (A) In-line (I) Cautious (C) No Rating (NR)



Stock Rating History: 6/1/08 : O/A; 2/4/09 : E/C; 7/14/09 : E/I; 2/12/10 : U/A; 8/30/10 : E/A

Price Target History: 5/8/08 : 1.51; 6/19/08 : 1.7; 9/2/08 : 1.5; 9/24/08 : 1.4; 11/7/08 : 1.3; 2/4/09 : 0.8; 9/1/09 : 0.9; 10/7/09 : 0.8; 2/12/10 : 0.6; 7/8/10 : 0.65; 8/30/10 : 0.75; 1/27/11 : 0.8; 2/28/11 : 0.84; 4/7/11 : 1.05

Source: Morgan Stanley Research Date Format : MM/DD/YY Price Target No Price Target Assigned (NA)
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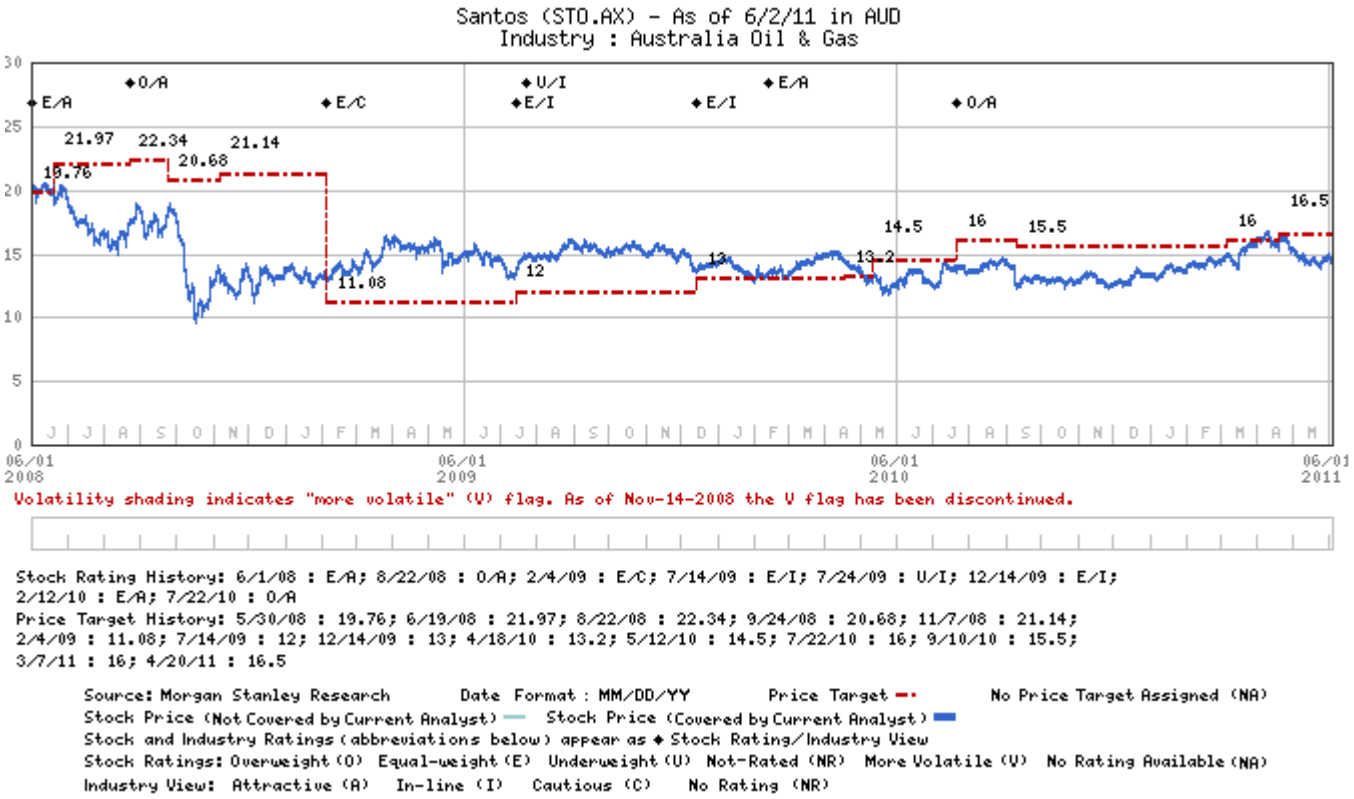

Stock Rating History: 6/1/08 : E/A; 8/22/08 : O/A; 2/4/09 : E/C; 7/14/09 : E/I; 7/24/09 : U/I; 12/14/09 : E/I; 2/12/10 : E/A; 7/22/10 : O/A
Price Target History: 5/30/08 : 19.76; 6/19/08 : 21.97; 8/22/08 : 22.34; 9/24/08 : 20.68; 11/7/08 : 21.14; 2/4/09 : 11.08; 7/14/09 : 12; 12/14/09 : 13; 4/18/10 : 13.2; 5/12/10 : 14.5; 7/22/10 : 16; 9/10/10 : 15.5; 3/7/11 : 16; 4/20/11 : 16.5

Source: Morgan Stanley Research Date Format : MM/DD/YY Price Target No Price Target Assigned (NA)
Stock Price (Not Covered by Current Analyst) Stock Price (Covered by Current Analyst)
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Industry View: Attractive (A) In-line (I) Cautious (C) No Rating (NR)

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Industry Coverage:Australia Oil & Gas

Company (Ticker)	Rating (as of)	Price* (06/03/2011)
Stuart Baker		
Caltex Australia Ltd (CTX.AX)	O (11/04/2010)	A$13.63
Eastern Star Gas (ESG.AX)	O (02/04/2009)	A$.66
Karoon Gas Australia (KAR.AX)	O (09/28/2009)	A$6.37
Oil Search Ltd. (OSH.AX)	O (08/22/2006)	A$6.63
Origin Energy Ltd. (ORG.AX)	U (05/09/2010)	A$16.15
Santos (STO.AX)	O (07/22/2010)	A$14.11
Woodside Petroleum (WPL.AX)	E (02/04/2011)	A$45.7
Philip J Bare		
AWE Ltd (AWE.AX)	O (06/03/2011)	A$1.45
Beach Energy Ltd (BPT.AX)	E (08/30/2010)	A$1
Horizon Oil (HZN.AX)	O (03/16/2011)	A$.36
New Zealand Oil & Gas (NZO.AX)	E (03/10/2009)	A$.68
ROC Oil Company (ROC.AX)	E (11/08/2010)	A$.35

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* Historical prices are not split adjusted.