AUSTRALIAN COUNCIL OF LEARNED ACADEMIES (ACOLA)

Securing Australia's Future: Project Six
Engineering Energy: Unconventional Gas Production

SECOND INTERIM REPORT ON SHALE GAS FINANCIAL MODELLING

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SUMMARY

This second interim report to the EWG summarises the work undertaken to date to financially model the extraction of shale gas in Australia.

This second interim report should be read in conjunction with the first interim report of 16th November, 2012. This first interim report outlined the basis for the financial model and undertook a simulation of shale gas economics in the United States.

In this second report, the fiscal regimes of the two countries are first qualitatively compared. Australian fiscal arrangements are then applied to shale gas financial and operating parameters from two United States gas fields in order to determine the influence of the fiscal regime on the "required gas price" for financial viability. It is found that the fiscal regime is essentially neutral, with the determined required gas prices much the same for the same input parameters.

Discussions at the ACOLA Shale Gas Workshop held in Canberra on 13-14 December, 2012 revealed some preliminary shale gas extraction costs for Australia. These costs have been incorporated into the Australian fiscal regime in the present financial model to determine the range of required gas prices for Australian investment conditions. In the most likely base case, determined from cost information provided by Santos Limited[1] and the South Australian Department of Manufacturing, Innovation, Trade, Resources and Energy (DMITRE)[2], gave a range of required wellhead gas prices in Australia now of approximately $5.50 to $9/GJ in the present model. This range agrees with public information supplied by Santos for Australian conditions.

In order to understand the sensitivity of the financial model to the key input parameters, sensitivity analysis has been undertaken in this report by varying the following parameters in the present report using the shale gas financial model:

- Drilling and completion capital costs

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[1] Cruickshank C, GM Development and Technical Services, Santos: ACOLA Shale Gas Workshop, Canberra 13-14 December, 2012.
[2] Pepicelli D, Petroleum Engineer. South Australia Department of Manufacturing, Innovation, Trade, Resources and Energy, Personal Communication and ACOLA Shale Gas Workshop, Canberra, 13-14 December, 2012.

- Initial gas production rate
- Decline rate of producing wells
- Operating costs

As in the first report, it has been found that for feasible values of these parameters, the most important parameter is the "capital intensity" of the shale gas operation. This parameter is the (*drilling and completion costs*) divided by (*initial gas production from the wells in the field*). Based on the information provided at the Canberra workshop, this parameter is currently higher in Australia than in the United States. Cost reductions in Australia will be required to reduce this capital intensity and thereby reduce the required gas price.

The sub-surface geological stress regime in Australia has led to conjecture that several vertical wells may be preferable to a single, long horizontal well in Australia. This is because the principal stress direction in Australia is orthogonal to that in the United States, and vertical wells with horizontal fracking fissures may be preferable. The present model is unconcerned as to the stress direction and simply requires the capital cost and initial gas flows from the various options. This comparison has not been undertaken for this second interim report, but the model is ready to simulate these different cases as soon as better data becomes available.

FISCAL REGIME IN AUSTRALIA versus the UNITED STATES

In order to calculate the present value of an investment, the fiscal regime of the country in question must be employed in the cash flow calculations. It is useful to compare and contrast the characteristics of these two fiscal regimes.

United States Fiscal Regime:

As reported previously, the fiscal regime that applies to the petroleum industry in the United States consists of a combination of corporate income tax, severance tax and royalty payments.[3] The following situations generally apply in the United States:

<u>Royalties:</u> Royalties are 12.5 to 25% onshore, negotiated with the mineral interest owner. Royalties are taken as 12.5% in this work, payable to the private owner after gas production commences.

<u>Income Tax:</u> Income taxes are 35% applied at the federal level, plus generally 5% applied at the State level (range 0% to 12%), giving an overall income tax level of 38.25% applied to net earnings (EBIT).

<u>Severance Tax:</u> The severance tax is payable to the State where the product is extracted. Severance tax varies from State to State, and is payable against revenue regardless of any profits made. It is taken as 5% in this work.[4]

[3] "Global Oil and Gas Tax Guide", Ernst and Young, 2012, pp. 532
[4] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, Appendix 2D: Shale Gas Economic Sensitivities, pp. 1.

<u>Land Leases:</u> In the USA, land leases are paid to the private owner of land on which drilling and extraction is carried out. Land leases are variable, with an average value taken as \$5,000 per acre in this work[5] (range \$2,500 to \$10,000 per acre). The land size required for one well in the USA is 640 acres (one square mile)[6], so the average lease cost per well is \$3.2M. Lease costs are capitalised in the year in which they are incurred.

<u>Drilling costs:</u> Drilling and Completion costs (IDC) are variable depending on the field.[7] Ranges of between \$3.5M to \$7M per well have been reported.[8,9] Drilling and completion costs are capitalised in the year in which they are incurred.

<u>Depreciation:</u> *Drilling and Completion Capital Costs:* It is beneficial in terms of cash flow to depreciate capital expenditures as fast as possible. The current US law allows development costs to be depreciated in the first year in which they are incurred for an independent producer.[10] In other words, the depreciation rate is 100% for this type of investor. If the producer is an integrated oil and gas company, the law allows 70% depreciation in the first year, with the remaining 30% depreciated over the next 60 years (0.5% per year after the first year). In this work, the 100% depreciation rate on drilling and completion has been assumed, as for an independent producer.

Lease Costs: Depreciation on lease costs is allowed as a function of depletion rate of the well.[11] The depreciation rate is determined as the (*original cost*) times (*the current year production*), divided by the (*ultimate total production*) from the well. Because shale gas production rates decline quickly, depreciation of lease costs is rapid in the USA situation. This method has been adopted in the first interim report to determine the lease cost depreciation value each year.

<u>Operating Costs:</u> Operating costs are taken as being variable, with an average value of \$0.75/MMBtu of gas produced (range \$0.50 to \$1.00/MMBtu).[12]

<u>Cost of Capital:</u> The weighted average cost of capital (WACC) of the investing firm has been taken as 10% for the first interim report.

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[5] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, Appendix 2D: Shale Gas Economic Sensitivities, Table 2D.1(b).
[6] Hefley W E, et al., "The Economic Impact of the Value Chain of a Marcellus Shale Well", University of Pittsburgh, August 2011, pp. 11.
[7] Hefley W E, et al., "The Economic Impact of the Value Chain of a Marcellus Shale Well", University of Pittsburgh, August 2011, pp. 65.
[8] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, Appendix 2D: Shale Gas Economic Sensitivities, Table 2D.1(a).
[9] Hefley W E, et al., "The Economic Impact of the Value Chain of a Marcellus Shale Well", University of Pittsburgh, August 2011, pp. 65
[10] "Global Oil and Gas Tax Guide", Ernst and Young, 2012, pp. 539.
[11] "Global Oil and Gas Tax Guide", Ernst and Young, 2012, pp. 538.
[12] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, Appendix 2D: Shale Gas Economic Sensitivities, Table 2D.1(b).

Australian Fiscal Regime:

The fiscal regime that applies in Australia to the petroleum industry consists of a combination of corporate income tax, GST, and a combination of a petroleum resource rent tax (PRRT) and royalty-based taxation.[13][14]

Royalties: Royalties in Australia are paid to the states based on the value of the petroleum product extracted. They range from are generally 10% to 12.5% onshore, depending on the Australian State that owns the resource. The value of the product is determined by deducting the costs involved in processing, storing and transporting the petroleum to the point of sale from the gross value of the product at the wellhead. Royalties may be credited against the PRRT (below). In this work, a value of 10% has been assumed for State Royalties.

Land Owners: Land owners in Australia do not own the petroleum resource under their land. This is owned by the individual Australian States, who are paid a royalty (see above). However, native title can lead to payments to indigenous communities upon which the petroleum resource is being extracted and access to land may require further payments to other land owners. These payments are individually negotiated. At the recent Shale Gas Workshop in Canberra (13-14 December 2012), it was indicated[15] that these payments could be up to 10% of revenue. For the purposes of the present preliminary modelling, a mean rate of 5% has been assumed with a range of 0% to 10%.

PRRT: The petroleum resource rent tax is a Federal scheme that applies to onshore petroleum extraction activities from 1st July, 2012 (The "Expanded PRRT Scheme"). The taxable profit for PRRT purposes is:

Taxable profit = (*assessable receipts*) – (*deductible expenses*)

PRRT is imposed on a project basis. A liability to pay PRRT is incurred where (*assessable receipts*) is greater than (*deductible expenses*). PRRT is paid at a rate of 40%.

PRRT is levied before income tax, and is deductible for income tax purposes. Any royalties paid to States are granted as a credit under the expanded PRRT scheme.

"*Assessable receipts*" include all receipts, whether of a capital or revenue nature, related to a petroleum project.

"*Deductible expenses*" include expenses of both a capital and revenue nature. There are three categories of these expenses: (i) exploration expenses, (ii) general

13 "Global Oil and Gas Tax Guide", Ernst and Young, 2012, pp. 23-36.
14 Australian Tax Office, "Calculating PRRT Liability", "Assessable Receipts", and "Deductible Expenditure", www.ato.gov.au/business
15 Cruickshank C, GM Development and Technical Services, Santos: ACOLA Shale Gas Workshop, Canberra 13-14 December, 2012.

project expenses (including land, development, drilling, completion and costs of production), and (iii) closing down expenses.

Income Tax: Commonwealth Government income taxes are 30% applied to net earnings (EBIT). Since PRRT is deductible for income tax purposes, the income tax is levied after PRRT is paid from the EBITDA, and the EBIT is then determined from the post-PRRT EBITDA by deducting depreciation.

Land: In Australia, costs associated with land acquisition are regarded as "deductible expenditure" for the PRRT and capital costs (with associated depreciation) for income tax purposes. In the present model, land owner lease payments have been expensed and deducted from wellhead revenue. A value of 5% (range 0% to 10%) of revenue has been used, based on discussions at the December Shale Gas Workshop.[16] This value and its financial treatment needs to be further refined through discussion with experts in the field.

Drilling costs: Drilling and completion costs are regarded as "deductible expenditure" for the PRRT and capital costs (with associated depreciation) for income tax purposes.

Depreciation: Exploration permit costs, land costs and drilling and completion costs can be depreciated in Australia and deductible against income for income tax purposes. There are two ways in which the decline in value of the asset may be determined: (i) the diminishing value method (DV), or (ii) the prime cost method (PC). In this work the PC method has been used.

DV = (base value) x 200% / (asset effective life)

PC = (asset's cost) x 100% / asset effective life

An immediate 100% write-off is available for assets employed in undertaking exploration activities. Otherwise, the capital asset is written off with either the DV or PC method with an "asset effective life" capped at between 15 and 20 years. Taxpayers are able to self-assess a "lower effective life" if this is indeed the case. In this work, a value of 15 years has been used for effective life. This value needs to be further refined through discussion with experts in the field.

Thus, for the Australian fiscal regime, the following relationships effectively have been applied in the present model for a fiscal year:

Gross Income = Revenue – Operating Costs – Landowner lease costs

State Royalty = (Gross Income) x (Royalty Rate)

PRRT Taxable Profit = (PRRT Assessable Receipts) – (PRRT Deductible Expenditure)

PRRT Liability = (PRRT Taxable Profit) x (PRRT rate (40%)), for PRRT Taxable Profit >= 0

[16] Cruickshank C, GM Development and Technical Services, Santos: ACOLA Shale Gas Workshop, Canberra 13-14 December, 2012.

Amount Payable = (PRRT Liability) or (State Royalty), whichever is greater

EBITDA = (Gross Income) – (Amount Payable)

EBIT = EBITDA – Depreciation

NOPAT = EBIT x (1- income tax rate (30%))

FCF = NOPAT + Depreciation – Capital Expenditure

The above fiscal parameters need to be validated with financial experts in the field, since some of the parameters and their treatment remain ambiguous or uncertain (for example, landowner costs and self-assessment of the effective life of a shale gas asset).

Methodology for the Financial Model

The financial model developed in this work calculates the gas price required at the wellhead to ensure that an investment in shale gas earns at least the cost of capital. It is a probabilistic calculation, which means that several of the important variables are probabilistically distributed. These include:

- The parameters for the gas well decline rate over time
- The probability distributions of the initial decline rates for a gas field
- The development and completion costs, and leasing costs, of gas wells
- Operating costs

The model does not include co-produced liquids at this stage.

The first interim report presented the flowchart for the calculation, which is iterative in order to build up the probability distribution of the required gas price to make the shale gas investment viable for the owners of the gas extraction company. The overall iteration is undertaken by Oracle "Crystal Ball" (CB), a plug-in for Microsoft Excel. Thousands of iterations for each run are performed using this software for each run.

Any given CB iteration calculates the financial outcomes, including required gas price, for a fixed set of input variables. These input variables are either fixed throughout the whole calculation procedure (e.g. the cost of capital), or constant for each CB iteration (e.g. a capital cost selected from a probability distribution defined in CB). Visual Basic language, a component of Microsoft Excel, has been used to undertake most of the calculations and to control CB in the model via a "Macro". Further details are given in the first interim report.

Comparison of Fiscal Regimes – Australia vs. United States

As noted above, the fiscal regime in Australia is different to that in the United States. These differences have been added to the model in order to simulate the Australian situation.

In summary, there are uncertainties in potential shale gas extraction in the Australian context *versus* the United States. The following points summarise these differences:

- In Australia, the petroleum resource is owned by the States, and any royalties are payable to the State, not the land-owner.
- The extended Petroleum Resource Rent Tax (PRRT) implemented by the Australian Federal Government in July 2012, essentially supersedes State royalty taxes in terms of the amount payable by the petroleum company to governments in Australia over-and-above income tax. The PRRT is generally higher (40%) than State severance taxes and private royalties paid (say 17.5%) in the United States.
- Income taxes are lower in Australia than in the United States (30% *vs.* 38.25%).
- Australian land acquisition (or lease) costs are likely to be lower than those in the United States, especially in remote regions. However, payment under the Native Title Act to indigenous landowners could be significant in Australia.
- Australian drilling and completion costs are likely to be higher than in the United States, due to remoteness and higher costs generally in Australia. This also applies to Australian operating costs.
- The costs associated with infrastructure (electrical power, fuel, pipelines, other transportation) are likely to be higher in Australia than in the United States.
- The key operational parameters – (i) initial gas production from shale gas wells, (ii) the probability distribution of initial gas production rates, and (iii) the decline rates of Australian wells in different locations, are still essentially unknown. This is because only very few wells have been recently drilled in Australia and the data is not yet available.

In order to evaluate the influence of the two different fiscal regimes, the shale gas well production data and drilling and completion costs for two fields from the United States was simulated as if those wells were located in Australia. The two fields in question were the Barnett and the Marcellus. The Australian fiscal regime (as described above) was applied to these wells, with landowner costs the same as in the USA and treated as capital. In this way, the two fiscal regimes could be directly compared. Details on the data for these fields is given in the first interim report.

Table 1 shows the "required gas price" calculated for the two fiscal regimes for the data of the Marcellus and Barnett fields. As can be seen, the calculated gas prices in the two countries are very similar, indicating that for the same well data the two fiscal regimes are more-or-less equivalent. This is an interesting result, since the natures of the two fiscal regimes are quite different. However, the various royalties and taxes come together in the two countries to give essentially the same result.

Table 1: Comparison of "Required Gas Price" using two different gas field data parameters in Australia and the United States.

Shale Gas Field	**United States fiscal regime**	**Australian fiscal regime**
Marcellus	\$3.94/MMBtu	\$3.95/MMBtu
Barnett	\$6.29/MMBtu	\$6.54/MMBtu

PRELIMINARY ANALYSIS OF SHALE GAS ECONOMICS IN AUSTRALIA

Shale Gas Well Properties

The properties of the shale gas wells in a field need to be defined probabilistically in order to undertake a financial calculation. There are two key parameters in this regard: (i) the probability distribution of the initial gas production levels from wells in the field, and (ii) the decline rate of production over time from the wells in the field.

Initial Gas Production Distribution

Figure 1 shows a typical probability distribution of initial gas production (IP) in the United States. In this case it is from the Barnett shale gas field. Also shown is the best fit to the data using a log-normal distribution. The best-fit parameters from CB in this example are: mean=1,700, standard deviation=1,250 and location=-550. The fitted distribution is the best fit to the original data, which was taken manually from a diagram in a publication from MIT.[17]

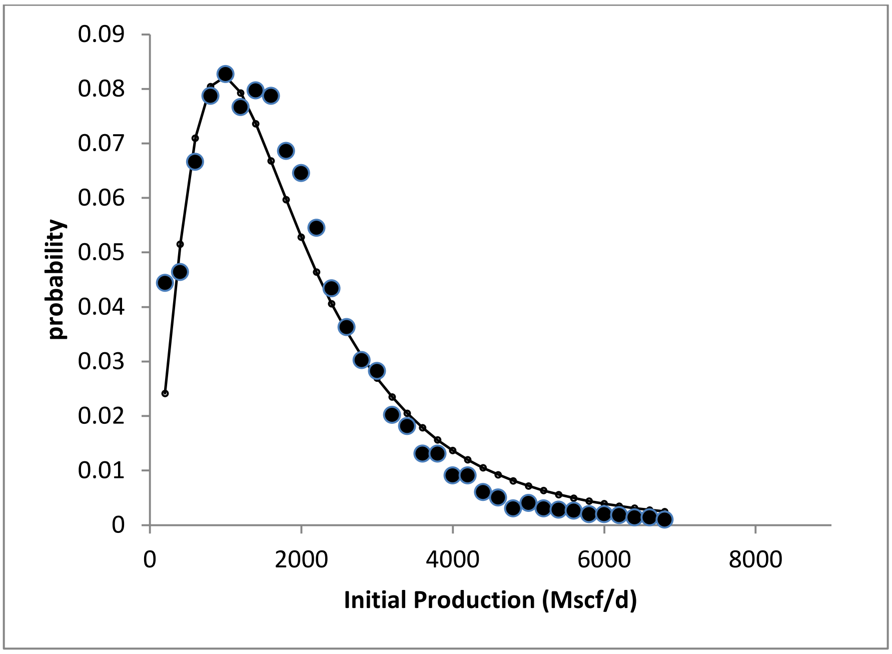

Figure 1: Probability distribution of initial gas production (IP) in Barnett shale gas field 2005-10

In Australia, very few shale gas wells are in production: two recent examples are (i) the Santos "Moomba – 191" vertical well in the Cooper Basin[18], and (ii) the Beach Petroleum Encounter -1 well[19], also in the Cooper Basin. It was reported at the recent Canberra Shale Gas Workshop and has been noted in public shareholder documents that the Moomba-191 well has three fracking sections

[17] Jacoby H D, O'Sullivan F M, Paltsev S, "The Influence of Shale Gas on US Energy and Environmental Policy", *Econ Energy Env Policy*, Vol 1, No. 1, 2012, pp. 41.
[18] Santos Media Release, 19 October, 2012.
[19] Beach Energy, ASX Release, 10 July, 2012.

and had an initial gas production of 3,000 Mscf/d.[20] The well has only been in production for 12 weeks, and since then the production has declined to around 2,500 Mscf/d. Beach Petroleum reported that the Encounter-1 well had 6 fracture stimulation stages and flowed at a maximum rate of 2,100 Mscf/d.

Clearly, since there are few producing wells in Australia, a probability distribution similar to that shown in Figure 1 is not available for Australian conditions. In this report, a log-normal distribution of initial gas flows like that shown in Figure 1 has been assumed, with a mean of 3,000 Mscf/d and a standard deviation of 2,200 Mscf. This assumption is based on the observed initial production in the Moomba-191 well. The mean value of initial production rate for a given field in Australia could be different to this value and for this reason a sensitivity analysis has been undertaken in the work presented here. For this sensitivity analysis below, the initial production parameter has been varied in the range 1,500 to 5000 M scf/d.

Hyperbolic Gas Production Decline

Each well in a shale gas field declines rapidly in production. This rapid decline is usually modelled as a hyperbolic decline[21] of the form:

$$q = q_i(1+D_i bt)^{-1/b} \qquad (1)$$

where $0 <= b <= 1$ and $D_i >= 0$

A diagram showing several reported hyperbolic decline curves for gas fields in the USA has been reported for the Haynesville, Marcellus, Eagle Ford, Woodford and Fayetteville fields[22] The data presented in this publication are available in a spreadsheet, so this was downloaded and the data for each of the fields was fitted to the decline equation (1) above using Excel "Solver" to minimise the least squares error and estimate the parameters. This analysis was reported in the first interim report.

The average parameter values for the fields in the United States from the first interim report were D_i=0.86 and b=0.31, and these were the parameters used in the generic decline curve in the financial model for the analysis of fields in the United States. These average decline parameters have been applied here to the Moomba-191 initial production rate of 3,000 Mscf/d and the result is shown in Figure 2.

It is clearly too early in the life of the well to determine whether the Moomba-191 or the Beach Petroleum Encounter-1 wells will follow the average decline curve of wells in the United States. However, the data at this early stage seems close to this curve, as shown in Figure 2 below. Time will tell if this trend continues.

[20] Cruickshank C, GM Development and Technical Services, Santos: ACOLA Shale Gas Workshop, Canberra 13-14 December, 2012.
[21] Cheng Y, Wang Y, McVay D A, Lee W J, "Practical Application of a Probabilistic Approach to Estimate Reserves Using Production Decline Data", SPE Economics and Management, 2010, pp. 19-29.
[22] Annual US Energy Outlook 2012, US Energy Information Administration, DOE/EIA 0383(2012), Fig. 54, pp. 59.

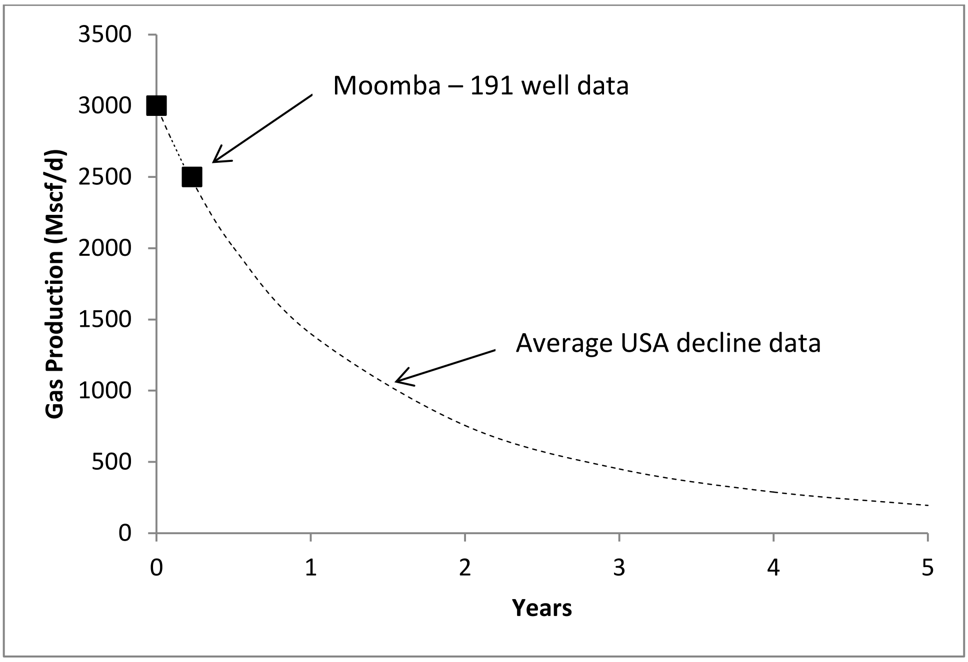

Figure 2: Hyperbolic decline of a shale gas well with an initial production of 3,000 Mscf/d together with reported Moomba-191 well data.

For the purposes of the preliminary financial modelling in this second interim report, the average decline rate for the fields in the United States has been assumed. A sensitivity analysis of this parameter has also been conducted in the present work by varying D_i in the range 0.1 to 0.95, below.

Other Input Financial Data for the Australian Case

The following further assumptions have been made in order to financially model the economics of shale gas in Australia:

<u>Exchange Rate:</u> $1.00 USD per $1.00 AUD

<u>State Royalties:</u> 10% (expensed against (*revenue – costs*))

<u>Landowner costs:</u> 5% (expensed against *revenue*)

<u>Petroleum Resources Rent Tax (PRRT):</u> 40%, according to Australian fiscal rules

<u>Income Tax:</u> 30%

<u>Depreciation:</u> According to Australian fiscal rules, with an effective asset life of 15 years

<u>Cost of capital:</u> 10%

<u>Operating cost:</u> $1.00/MMBtu (sensitivity range $0.5 to $1.50)

Capital Costs:

Information on capital costs of well drilling and completion in Australia were discussed at the recent Canberra Shale Gas Workshop. Information was also provided by the South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE). The following points summarise the discussion:

- Costs of drilling and completion in Australia are "3 to 4 times" those in the United States. For a $3.5M well in the Barnett field, this would indicate a cost of $10.5M to $14M in Australia.[23]
- A 3km deep vertical well in the Cooper Basin would cost $11-12M for drilling and completion with up to 6 fracking stages, as a "rough" estimate.[24]
- Santos has publically announced a shale gas price in the range of $6 to $9 per GJ in Australia.

Clearly, more information is required on this important parameter. However, for the purposes of this preliminary analysis a base-case a capital cost for drilling and completion of **$12M** has been assumed. Sensitivity analysis in the range $6M to $16M for this cost has also been undertaken in the present study, below.

Model Results

Base Case

The base case assumptions for "price of gas required" at the wellhead are:

- Drilling and completion cost: $12M per well
- Initial production (IP) rate: mean = $3,000 Mscf/d, as a log-normal distribution with a standard deviation of 2,200 Mscf/d (as in the Santos Moomba-191 well).
- Well decline rate: Average of USA rates, with D_i = 0.86 and b = 0.31
- Operating cost: $1.00 per MMBtu

Probabilistic ranges on these parameters are given in the Appendix.

Under these assumptions, the base case "price of gas required" was calculated by the present financial model for Australia as:

Price of gas required **= $7.37**/MMBtu, range **$5.61 to $9.13**/MMBtu

This value is close to that reported by Santos as "$6 to $9 per GJ" for the Cooper Basin.

[23] Cruickshank C, GM Development and Technical Services, Santos: ACOLA Shale Gas Workshop, Canberra 13-14 December, 2012.
[24] Pepicelli D, Petroleum Engineer. South Australia Department of Manufacturing, Innovation, Trade, Resources and Energy, Personal Communication and ACOLA Shale Gas Workshop, Canberra, 13-14 December, 2012.

Capital Cost Sensitivity

In order to assess the sensitivity of the model to the capital costs of drilling and completion in Australia, the capital cost was varied from $6M to $16M per well. The results of this analysis are shown in Table 2 below. In the following the "lower" and "upper" values in the ranges refer to one standard deviation below and above the mean. In all the sensitivity analyses below, all parameters other than the parameter being varied to test sensitivity have been held constant at the values in the base case above.

Table 2: Sensitivity of "price of gas required" (RGP) to capital costs of drilling and completion in Australia.

Capital cost ($M/well)	RGP ($/MMBtu)	Lower Range of RGP	Upper Range of RGP
$6M	$4.20	$3.06	$5.35
$8M	$5.26	$4.05	$6.48
$10M	$6.31	$4.82	$7.80
$12M	$7.37	$5.61	$9.13
$14M	$8.36	$6.53	$10.20
$16M	$9.38	$7.26	$11.49

As can be seen from Table 2, the required gas price is very sensitive to the capital costs of drilling and completion.

Initial Well Production Sensitivity

The initial production rate (IP) was varied in the model to determine the sensitivity of the "required gas price" to this parameter. The standard deviation of the log-normal probability distribution of initial well productions for the field was also adjusted in proportion to the given IP rate in the simulation (see Appendix). Table 3 shows these results.

Table 3: Sensitivity of "price of gas required" (RGP) to initial gas production rate (IP) in Australia.

IP Rate (Mscf/d)	RGP($/MMBtu)	Lower Range of RGP	Upper Range of RGP
1,500	$12.99	$9.58	$16.40
2,000	$10.05	$7.44	$12.65
3,000 (base case)	$7.37	$5.61	$9.13
4,000	$6.12	$4.68	$7.56
5,000	$5.36	$4.14	$6.56

As can be seen from Table 3, the "required gas price" is very sensitive to the initial gas production rate. This is particularly true at lower IP rates, where the required gas price is modelled to be relatively high. The Beach Petroleum Encounter-1 well had a stated maximum production rate of 2,100 Mscf/d, which would imply a relatively high "required gas price" of around $10/GJ, all other factors being constant. Clearly, information on this gas production parameter is required in order to remove uncertainty about shale gas costs in Australia.

Decline Rate Sensitivity

The decline rate of gas production from the initial rate is modelled by a hyperbolic decline with parameters D_i and b. The model is most sensitive to the parameter D_i , as shown in Figure 3. For a value of b = 0.31 (the average of the United States data examined), large changes in decline rate can be modelled by simply varying the parameter D_i , as shown in the figure. In the United states, shale gas well declines are fitted by the parameter D_i close to a value of D_i = 1.0 (*viz*. a rapid decline).

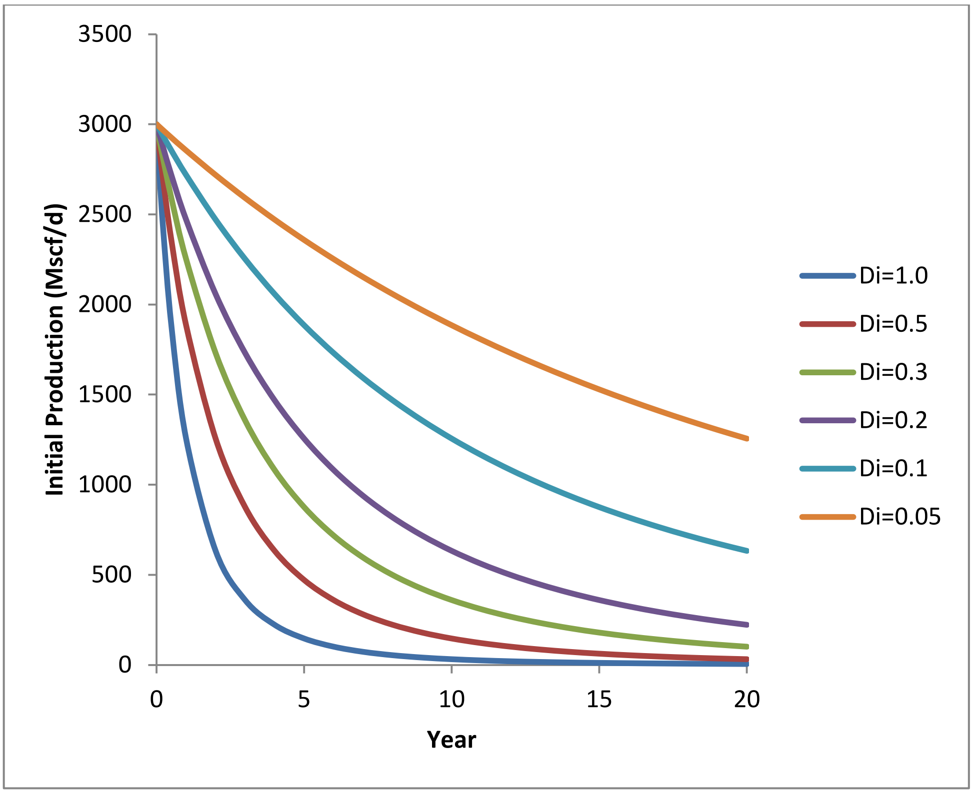

Figure 3: Decline rates from an initial production rate of 3,000 Mscf/d for varying values of the parameter D_i for b = 0.31

Table 4 shows the sensitivity of “required gas price” to the decline parameter D_i and the curves in Figure 3.

Table 3: Sensitivity of "price of gas required" (RGP) to decline parameter D_i in Australia.

Decline Parameter D_i	RGP($/MMBtu)	Lower Range of RGP	Upper Range of RGP
0.2	$4.35	$3.46	$5.25
0.3	$4.95	$3.87	$6.03
0.5	$5.94	$4.52	$7.36
0.86 (base case)	$7.37	$5.61	$9.13
1.0	$7.59	$5.76	$9.43

As can be seen from the table, the lower decline rates for low values of D_i has the effect of decreasing the "required gas price" because the gas flow during the life of the well remains at a high level. However, at values between 0.8 and 1.0, which is the case generally in the United States where wells decline rapidly, the "required gas price" is not particularly sensitive to the decline rate parameter D_i. The exception to this is the Haynesville field in the United States, which was reported at the Canberra Shale Gas Workshop to have a very rapid decline and thus a higher "required gas price" than a simple analysis would indicate[25]. It remains to be seen how shale gas wells decline in Australia over time in comparison to those in the United States and what financial effects this will have.

Operating Cost Sensitivity

The operating cost for wells in the United States was reported as $0.75/MMBtu by the MIT study. For the work here, the base operating cost was assumed to be $1.00/MMBtu, reflecting higher costs in Australia. The sensitivity to this parameter was evaluated by running the financial model with operating costs in the range $0.50 to $1.50/MMBtu, as shown in Table 4.

Table 4: Sensitivity of "price of gas required" (RGP) to operating costs in Australia.

Operating Cost ($/MMBtu)	RGP($/MMBtu)	Lower Range of RGP	Upper Range of RGP
$0.50	$6.77	$4.98	$8.55
$1.00 (base case)	$7.37	$5.61	$9.13
$1.50	$7.91	$6.09	$9.73

As can be seen from Table 4 above, the model is relatively insensitive to a wide range in operating costs. This conclusion was also made by the MIT study.

[25] O'Sullivan F, Professor MIT, Workshop Comments, ACOLA Shale Gas Workshop, Canberra, 13-14 December, 2012.

Capital Intensity

In the first interim report, it was found that the capital intensity in terms of (*drilling and completion costs*) divided by (*initial gas production rate*) gave a reasonable correlation with the "required gas price" in the context of gas fields in the United States. The results from the first interim report and the present sensitivity analysis have been plotted together in Figure 4 below.

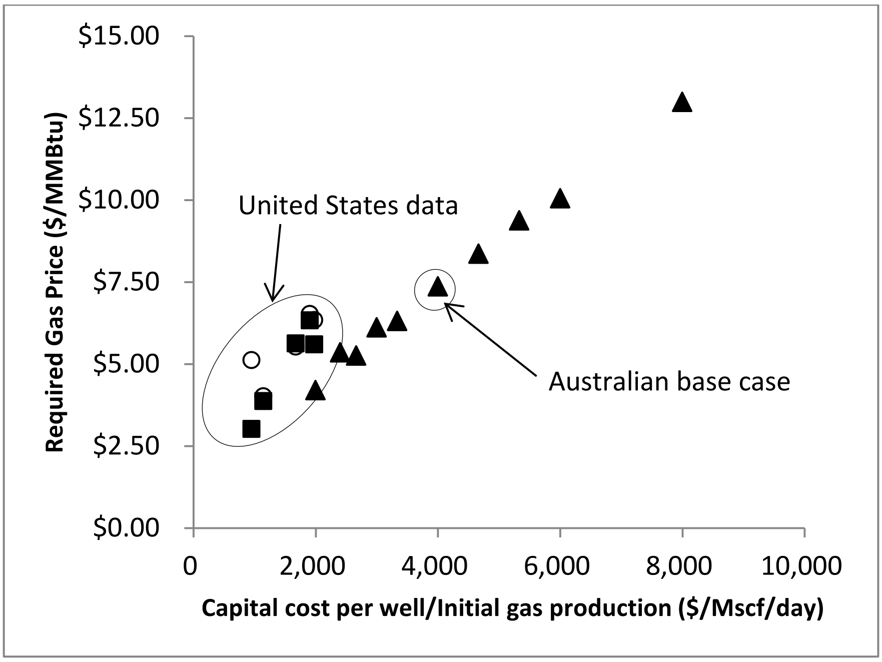

Figure 4: Required gas price plotted as a function of capital intensity. (Data taken from the first interim report and the present sensitivity analysis.)

Figure 4 shows that, at present, the capital intensity in Australia is higher than in the United States and this leads to a predicted higher "required gas price" at the wellhead. For Australian shale gas prices to be competitive with those in the United States this capital intensity will need to be reduced through technology learning here over time, assuming that shale in Australia behaves similarly to that in the United States in terms of gas initial production rate and gas production decline rate. These effects are still to be evaluated in Australia through the drilling of more shale gas wells and gathering of well production information.

Australian Geological Stress Regime

It has been noted that the sub-surface stress regime in Australia is different to the United States.[26] Here, the principal stress favours horizontal cracking in the shale rocks whereas in the United States vertical cracking is favoured. This means that in Australia a number of shorter vertical wells could be a more productive solution than a few long horizontal wells. Moreover, these vertical wells could lead to a "stacked play", where gas is extracted from a variety of lithologies in the vertical direction in a basin.

The present financial model is unconcerned as to whether the wells are vertical or horizontal. It simply requires the capital costs of drilling and completing the wells, the initial gas production rates,

[26] Johnson J and Stacey A, Geoscience Australia, Personal Communication, December 2012.

and the rate of decline in gas production as the major parameters. In principle, the model can be adjusted to compare vertical *vs.* horizontal well scenarios provided the capital cost and production data are available. This type of analysis has not been carried out in this second interim report due to lack of available data. However, if such data was available or scenario assumptions could be made, then the model could be run to examine these possibilities.

INTERIM CONCLUSIONS

The Australian fiscal regime, with State Royalties and an onshore Petroleum Resource Rent Tax, produces much the same "required gas price" when data from United States shale gas fields is input to the financial model. There should therefore be no inherent disadvantage to investors in Australia relative to the United States from this factor.

Costs for shale gas extraction in Australia have been stated to be higher than the United States. It has been indicated that a 3km deep vertical well in South Australia would cost $11-12M for drilling and completion. Santos has stated that capital costs for drilling and completion are "3 to 4 times" these costs in the USA.

One producing well in Australia - Santos' Moomba 191 well – had an initial production rate (IP) of 3,000 Mscf/d, which is in the mid-range for wells in the United States. After 12 weeks production this rate has fallen to 2,500 Mscf/d, which aligns with average decline rates in United States wells. . A second well – Beach Petroleum's Encounter - 1 well – had a maximum production rate of 2,100 Mscf/d. However, it is too early to determine whether these wells will continue to show the decline characteristics of United States wells, or what the probability distribution of the initial production rates will be in these or other fields in Australia. These will be revealed over time as more shale gas wells are drilled here.

Assuming that an initial gas production of 3,000 Mscf/d is typical of shale gas wells in Australia, and that well drilling costs are $12M per well, the present financial model has predicted a range in "required gas prices" at the wellhead from approximately $5.50 to $9.00/MMBtu, with a mean gas price of approximately $7.50/MMBtu. These values agree well with required prices quoted by Santos of $6 to $9/GJ.

Sensitivity analysis has shown that the most important parameters that influence the "required gas price" are (i) the capital costs of drilling and completion and (ii) the initial gas production rates from shale gas wells (the IP rate). A reasonable correlation has been obtained in this study between a "capital intensity" factor, calculated by dividing the capital costs by the IP rate, and the "required gas price". The base case Australian situation yields higher capital intensity than the United States. If this is validated, the capital intensity needs to be reduced here by extensive "learning-through-doing" if Australian shale gas prices are to match those currently found in the United States. Clearly, Australia is early on the shale gas learning curve.

Further scenario analyses examining the use of horizontal *vs*. vertical unconventional gas wells in Australia could be undertaken with the present model, provided cost data and gas production rates are available or can be estimated.

APPENDIX

Probabilistic Parameters in Key Variables – Australian financial model.

The probability distributions of all the appropriate variables were defined in the Crystal Ball plug-in package in Microsoft Excel.

Well drilling and completion costs were modelled probabilistically by a normal distribution function with a mean and standard deviation given by:

Capital cost ($M/well)	Standard Deviation ($M/well)
$6M	$2.0M
$8M	$2.0M
$10M	$2.5M
$12M	$3.0M
$14M	$3.0M
$16M	$3.5M

Operating costs were modelled probabilistically by a triangular distribution with a most likely, low and high values of:

Operating Cost Likely Value ($/MMBtu)	Low Value ($/MMBtu)	High Value ($/MMBtu)
$0.50	$0.25	$0.75
$1.00	$0.75	$1.25
$1.50	$1.00	$2.00

The well decline parameter D_i was probabilistically modelled with a normal distribution with a mean and a standard deviation of:

Mean D_i	Standard Deviation D_i
0.2	0.02
0.3	0.03
0.5	0.05
0.86 (base case)	$0.07
1.0	$0.07

The well decline parameter b was probabilistically modelled with a triangular distribution with a most likely value of 0.31, a minimum value of 0.01 and a maximum value of 1.0 for each case.

The initial gas flow probability distributions were described by the log-normal distribution shown in Figure 1, with means and standard deviations as follows:

Mean IP (Mscf/d)	Standard Deviation IP (Mscf/d)
1,500	1,100
2,000	1,467
3,000 (base case)	2,200
4,000	2,933
5,000	3,668

In each case the *location* of the log-normal distribution was -400 and the *upper truncation* was 10,000 Mscf/d. The minimum initial gas flow was set at 200 Mscf/d.