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Simulation of a Shale Gas Field Development: An Example from Western Australia

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Abstract

Shale gas exploration activities have been growing rapidly in Australia. A flow rate of up to 2 MMSCFD has been reported recently from the first exploratory vertical well in the Cooper Basin in South Australia. Perth and Canning Basins in Western Australia are also reported to be highly prospective. However, shale gas production differs from conventional reservoirs primarily because of extremely low permeability and other petrophysical characteristics. Commercial production requires massive hydraulic fracturing often in long horizontal completions.

The potential development of a shale gas field in Western Australia has been simulated to optimize production and minimize development cost through sensitivity analyses. Conditions in Australia are particularly challenging often because of significantly higher costs in drilling, completion and fracturing than those of the US. The minimum number of wells and the maximum Net Present Value (NPV) was iterated by simulation. The factors influencing their overall success of the field development project were investigated in order to generate a workflow model suitable for a variety of cases. The influence of well fracture and other parameters such as completion length, fracture geometry, permeability and gas price was tested against NPV to optimize the development. Optimization of any development should be possible by iterating on any parameter and the related variables. Whilst in conventional gas there is a clear understanding of what is economically viable, this is not the case in shale gas particularly in Australia. Before embarking on any drilling, testing or development activities simulation sensitivity studies of this nature are essential.

Introduction

Optimizing production from shale gas, which has become a major source of energy, is currently a focus of intense research at many leading universities. This work will ultimately lead to more efficient ways to extract gas, e.g. by using less water and proppant. Successful exploitation of shale gas is very challenging. It requires massive hydraulic fractures and deals with complex heterogeneity. It is very important therefore, to parameterize the shale in terms of porosity, organic carbon content, permeability, mineralogy and fracture systems. Understanding the stress regimes is also critical in selecting the correct production strategy. Currently, there are no commercial shale gas operations in Australia, but many companies are actively involved in the exploration and evaluation phase. The conditions are particularly challenging in this part of the world because of lack of infrastructure and stringent environmental procedures which have a significant impact on cost.

Previous studies have shown that the most influential parameters for a successful shale development are stimulated network permeability, fracture interaction and half-length as well as rock compaction (Zhang et al. 2009). The last two have not been considered in this work.

This study has focused on the potential development of a shale-gas field in the Perth Basin. A field development was simulated using the exploration data from the first shale gas well drilled in the Perth basin. This work is not only limited to reservoir characteristics, but also involves the economics associated with production, cost and the tax regime including royalties. In particular, horizontal well completion, fracture half-length, conductivity and the impact on the field performance in terms of NPV, are investigated for a range of development options. The goal of this study is to identify the critical technical parameters which optimize the field development. It also endeavors to address the question whether shale gas in the Perth

Basin is economically viable given the high costs for exploration and well completion. This is of great interest to prospective explorers in this part of the world.

Perth Basin Exploration Well

Perth and Canning Basin, two prospective exploration areas in Western Australia, are subdivided as offshore and onshore. They are both under-explored in terms of their shale gas potential. The Canning Basin has a maximum sediment thickness of over 15 km containing depositions ranging from the early Ordovicium to the early Cretaceous. The Perth basin has thick sediments formed in the late Permian during the breakup of Gondwana. It is bounded to the east by the Darling Fault, which trends north south and exhibits up to 15 km displacement (Cadman et al. 1994). The 30,000 km^2 mapped thus far, in the Perth Basin, are estimated to hold 750 Tcf of shale gas resources assuming a conservative recovery factor of 20 % (Evans 2011).

The reservoir in which the exploration well was drilled has been estimated to have an areal extent of 88 km^2. The well was drilled vertically to a total depth of 3320 m. The total cost is estimated at AUD $14M including $6M for hydraulic fracturing. This stimulation will be in five stages, over a total interval of 260 m, using 60 degree phased guns at 6 shot per foot (SPF). Due to the large thickness, there is little concern regarding fracture containment within the shale. Tracers are planned to identify the flow of fracturing fluid from multiple zones during the flowback operations. If hydraulic fracturing and the subsequent well test are successful, it is planned to develop the reservoir using horizontal wells.

Much of the data in this study came from mud and wireline logging, such as Spectral Gamma Ray, Borehole Resisitivity, Neutron-Density, Cross Dipole Sonics and other acoustic measurements. 100 m of core was recovered. Pressure decay and pulse decay permeability, gas, water and hydrocarbon saturations as well as porosities and densities were determined from core analysis. Furthermore, geomechanical information from selected cores such as Young's Modulus, Poisson Ratio and Unconfined Compressive Strength (UCS) were measured. Faults and fractures were analyzed from image logs. No natural fractures were identified below 2675 m. Three key shale gas target reservoirs were investigated (Formation A, B and C) and their key reservoir parameters are listed in the Table 1.

Table 1: Reservoir Parameters for shale gas well in the Perth basin

Formation	Gross Thickness (m)	Depth (mTVD)	Lithology	Porosity (%)	K (md)	Sw (%)	Pres (psi)	Temp (ºC)	Fluid
Formation A	450	2659	Shale	3.0	0.0001	30	3895	122	Gas
Middle of Formation B	250 (total)	2858	Shale	5.0	0.0001	35	4595	129	Gas
Lower part of Formation B	250 (total)	2923	Shale	6.0	0.0001	50	4700	131	Gas
Formation C	330	3023	Sandstone/ Shale	7.0	0.0001	45	4558	135	Gas
Formation D	22	3273	Sandstone	7.0	0.001	45	4934	144	Gas

It can be seen that these shale formations have a massive combined thickness of over 1 km. However, in order to determine whether this play is prospective, some key criteria need to be met. These are summarized and compared with US data in Table 2.

It becomes obvious that most of the critical shale gas indicators in the Perth and Canning Basin have been found to be favorable and comparable to those in the US. TOC content, porosity and the high siliciclastic content are particularly favorable. On the other hand, the relatively high clay content and water saturations are less favorable. The latter generally affects production adversely because of pore blockage. Capillary suction tests, however, show that these clays are reactive only to freshwater and are relatively insensitive to salt solutions (1 to 5 % KCl and NaCl).

The thermal maturity should ideally be greater than 1.4 R_o to be in the dry gas window. The average R_o for formation C is 1.32. Other important and desirable shale gas parameters are reservoir temperatures greater 230 ^OF, Young's Modulus more than $3x10^6$ PSIA, Poisson's ratio < 0.25 and a gas filled porosity >2 % (King 2010). The accurate determination of Kerogen type and mineral content are also critical as these properties directly impact gas in place estimations, hydraulic fracturing and rock quality (Sondergeld 2010). The Kerogen type in this case has been analyzed to be type 3 gas prone and dry gas prone Kerogen.

Table 2: Comparison with US Shale Gas Indicators

USA Shale Gas Indicators	Perth Basin Well X
Fine grained siliclastics <4 microns	Yes
Predominantly marine deposits (low feldspar/kaolinite/thorium)	Mixture
Total organic carbon (TOC) preservation – under reducing conditions ~ 2% levels, Pyrite	TOC >2% , Average of 3.5 %, up to 7.7 TOC in Formation C
Presence of fabric building detritus – assist in fraccing	Yes – high siliclastic content, average is 49%
No dilution, preservation of organic matter, no re-transportation	Bioturbation only, clastic mixing and heterogeneity
<24% clay content preferred (these are not really shales – more shaly arenites)	Average is 33% in grab samples in Formation C and 35 % in Formation D
Drill wells into the MINIMUM stress direction	Min Stress direction is N – S, Sh_{max} close to Sh_{min}
<4% Smectite is ideal, higher illite and chlorite = less bound water	Average in shales is 7 % in grab samples in Formation C
Carbonate content is OK as it creates a supporting fabric	Formation B has carbonate, Formation C is much less
>100nD (nano darcies) permeability is ideal	Variable: 0.1 to 100 nD
Low Sw (10 – 15%) preferably	Sw is 45% PV average in Formation D
Effective Porosities in the range of 4 – 12%	Effective Porosities range 1.51 – 6.61 (Ave 4.2)

The gas filled porosity and permeability vs. depth for a section of the well are shown in Figure 1. It can be seen that gas filled porosity reaches over 4% with a permeability of 0.65 nano Darcy (nD) at 2830 m measured depth. Therefore, it would be a very challenging task to make this reservoir flow at a commercial rate with such extremely low permeability and high water saturation. Clearly this requires stimulation by hydraulic fracturing. It may be possible to predict the effects of stimulation by rigorous reservoir simulation.

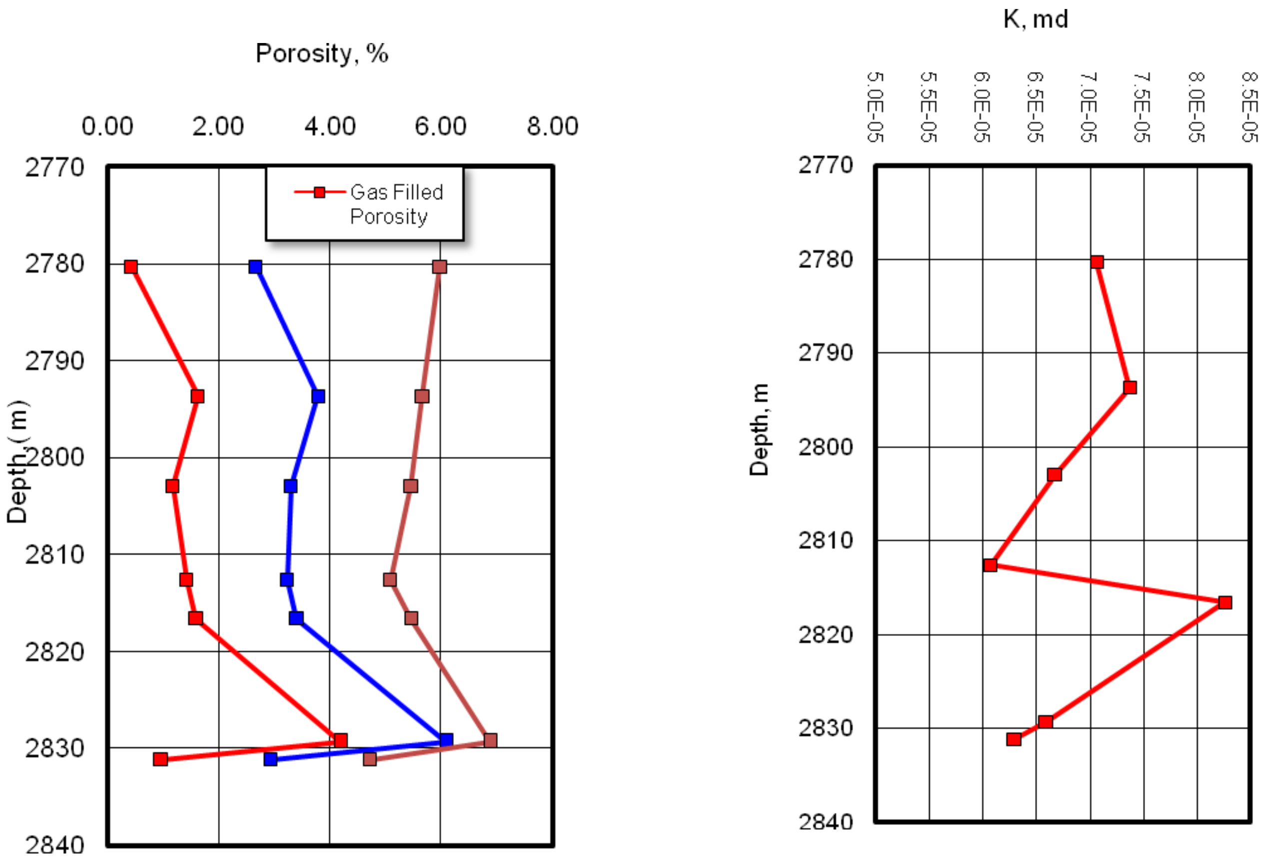

Figure 1: Gas Filled Porosity vs. depth and permeability vs. depth for a section of the well

Simulation of the Shale Gas Field Development

The primary aim of this simulation study was to address the key questions of whether development of this field is economically viable given the lack of infrastructure and high costs in Australia. If so, what would be the optimum number of wells (vertical or horizontal)? Also what are the effects of horizontal well length, number of fractures and conductivity on the economics and ultimate recovery?

Simulations were performed for horizontal wells with varying number of fractures orientated perpendicular to the wellbore. Formation C was chosen for the development because it is the key target. The base case parameters, are shown in Table 3, and reflect the exploration well data. These were varied as part of the sensitivity analysis to determine their impact on NPV and ultimate recovery.

Table 3: Base case Reservoir Parameters

Reservoir Parameters	Value
P (psi)	4560
T(°F)	275
Kx (md)	0.0001
Ky (md)	0.0001
Kz (md)	0.0001
h (feet)	1080
Φ_t (%)	4.2
S_g (%)	42
C_f (1/psi)	6.97E-006
X Reservoir (feet)	59,000
Y Reservoir (feet)	28,800

The average value of gas saturation, porosity and permeability are considered for the investigated shale gas interval. The fluid characteristics, which were assumed, are shown in Table 4.

Table 4: Base case Fluid Characteristics

Fluid Parameters	Value
Gas Gravity	0.65
CO_2 (%)	0
N_2 (%)	0
H_2S (%)	0

Gas analysis showed that the amount of CO_2, N_2 and H_2S are small compared to Methane. Thus, their concentrations were regarded as insignificant for this study. The base case economic parameters are summarized in Table 5.

Table 5: Base case Economic Parameters

Economic Parameters	Value
Well Cost ($)	12,000,000
Compression ($/hp)	500
Fixed Operating Cost ($/well/month)	1000
Variable ($/Mscf)	0.20
Royalty (%)	5
Working Interest (%)	100
P_{Outlet} (psia)	700
Comp. Eff. (%)	95
Surface Loss (%)	0
Gas Price ($/Mscf)	10
Discount Rate (%)	10

It was assumed that, for future developments in the Perth Basin, well costs would drop to AUD$12M from the current $14M. A comparatively low royalty of 5% was assumed to reflect the Government's incentives to encourage shale gas development (Wood Mackenzie 2010). The simulation constraints considered for this study are summarized in Table 6.

Table 6: Base case Simulation Constraints

Constraints	Value
P_{wf} (psi)	500
T_{flow} (month)	240
Time step (month)	1
Maximum Rate Limitation (MMscf/d)	10

The minimum flowing bottom hole pressure (p_{wf}) has been limited to 500 psi. The simulation time is considered to be 240 months with a time step size of 1 month. The model allows calculating the pressure response from horizontal wells in a bounded reservoir (Thompson et al. 1991). Homogenous conditions are assumed. The well interference is calculated using the principle of superposition. The additional pressure drop caused by a finite conductivity fracture is simulated through the dimensionless fracture conductivity, which can be described by Eq. 1 (Economides, and Martin, 2007).

$$C_{fD} = \frac{k_f \cdot w}{k \cdot x_f} \quad (1)$$

Due to extremely low permeabilities, infinite conductivity fractures with the dimensionless value $C_{fd} > 100$ (Gringarten & Ramey 1974) were assumed. Thus the fractured well can be considered as a well producing similarly to a hypothetical well of enlarged radius equal to x_f (half of the fracture length). The fracture half-length used for this case is calculated based on the maximum amount of proppant (mass or volume) planned to be used in the fracturing program (as a design constant). The fracture length and width have been calculated assuming that all the volume of the proppant will be laden into the fracture optimally in order to provide maximum dimensionless fracture conductivity. Thus the corresponding fracture length and width are considered to be optimum. The base case fracturing parameters are presented in Table 7.

Table 7: Base case Fracturing Parameters

Fracturing Parameters	Value
Proppant Mass, lbm per fracturing stage	464,000
Proppant Density (Sand) (g/cm^3)	2.65
Proppant Porosity (%)	20
Reservoir Permeability k, (mD)	0.0001
Fracture Permeability kf, (mD)	10000
Fracture height, hf, (feet)	164
Drainage radius, x_e, (feet)	1000

From Table 7, the proppant mass, reservoir permeability and fracture height are known from the designed fracturing program. The optimum fracture length (x_f) and width have been estimated using Eqs 2-5 (Economides & Martin 2007).

$$N_{prop} = \frac{4k_f * V_f}{kV_{res}} \quad (2)$$

$$C_{FDOpt} = 1.6 + \exp\left[\frac{-0.583 + 1.48\ln N_{prop}}{1 + 0.142\ln N_{prop}}\right] \quad (3)$$

The proppant volume is calculated by:

$$V_{prop} = \frac{m_{prop}}{\rho_{prop}(1-\emptyset)} \quad (4)$$

The optimum fracture half-length x_f is then calculated by:

$$V_{prop} x_f = \left[\frac{V_{fp} k_f}{C_{fDopt} hk}\right]^{1/2} \quad (5)$$

where,

N_{prop} = the proppant number;
V_f = the volume of the fracture in one wing (ft),
k_f = fracture prermeability (mD)
ρ_{prop} = proppant density (lb_m/ft^3)
ϕ = porosity (fraction)
h = reservoir thickness or height of the fracture (ft)
k = reservoir permeability (mD)
$C_{fd,opt}$ = Optimum dimensionless fracture conductivity.

It is planned to develop the field using horizontal wells with base case well parameters as shown in Table 8.

Table 8: Base case Field Development and Well Parameters

Field Development Parameters	Value
Horizontal Well Length (ft)	2500
Optimum Fracture half-length (ft)	500
Dimensionless Fracture Conductivity Number	100
Number of Fractures	10

The gas content (G_{cf}) was calculated from the log data using Eq 6 (Craft & Hawkins 1991):

$$\mathrm{Gcf} = \frac{1}{\mathrm{B_g}} \cdot (\phi_{\mathrm{eff}} \cdot (1\text{-}\mathrm{S_w})) \cdot \frac{\psi}{\rho_\mathrm{b}} \tag{6}$$

where G_{cf} is the free gas volume (scf/ton); B_g is the gas formation volume factor; ϕ_{eff} is effective porosity (vol/vol); ρ_b is the bulk density (g/cm^3); ψ is a conversion constant (32.1052) and S_w is water saturation (vol/vol). Gas formation volume factor, B_g was calculated from Eq. 7:

$$B_g = \frac{p_{sc} z (T + 459.69)}{z_{sc}(T_{sc} + 459.69)p} \tag{7}$$

With p_{sc} as the pressure (psia), z_{sc} real gas deviation factor (dimensionless) and T_{sc} is the temperature (^{o}F) all at standard conditions. T is the temperature (^{o}F) and p the pressure (psia), both at reservoir conditions.

Applying these equations, an average gas content of 22 scf/ton was calculated for Formation C. It was assumed that a small amount of gas was adsorbed to the shale. Thus, the following desorption parameters were defined for the base case in Table 9. The Langmuir isotherm analysis was neglected, as no Langmuir isotherm data was available at the time of this study.

Table 9: Desorption Parameters

Desorption Parameters	Value
V_L (scf/ton)	22
P_L (psi)	1000
Bulk density (g/cm^3)	2.65

The bulk density was determined from wireline logs. The gas content was calculated from the above equations and the Langmuir Pressure was assumed and, therefore, varied during the sensitivity analysis. Furthermore, it was presumed that the gas desorption is only taking place at low pressures, thus a comparatively low Langmuir pressure, compared to the reservoir pressure, was considered.

The simulation results showed that the total gas in place (GIP) of Formation C for the entire reservoir is calculated to be 9.78TCF. However, less than 1 percent of the GIP is recoverable, which is mainly due to the maximum rate limitation set, as a constraint, in Table 6. The highest NPV with a value close to US$200M was calculated for a total of eight wells, which are assumed to be evenly spaced throughout the reservoir (Figures 2 and 3). It is evident from Figure 2 that the NPV increases with the number of wells up to the optimum value which is controlled by the degree of interference between wells (e.g. well & fracture spacing and length of fractures). Further influencing factors are the well productivity and ultimate recovery (e.g. gas content, permeability, thickness, fracture conductivity etc) and economic parameters. For this particular field, the limiting number is eight.

More than eight wells lead to a decreasing NPV which becomes negative after 25 wells (Figure 2). The raw gas produced per well and recovery factors are presented in Figure 3 as a function of number of wells. It is clearly depicted (by the red line) that the raw gas produced per well decreases with time as more wells are drilled and interfere with each other. As a result, the recovery factor remains constant after eight wells.

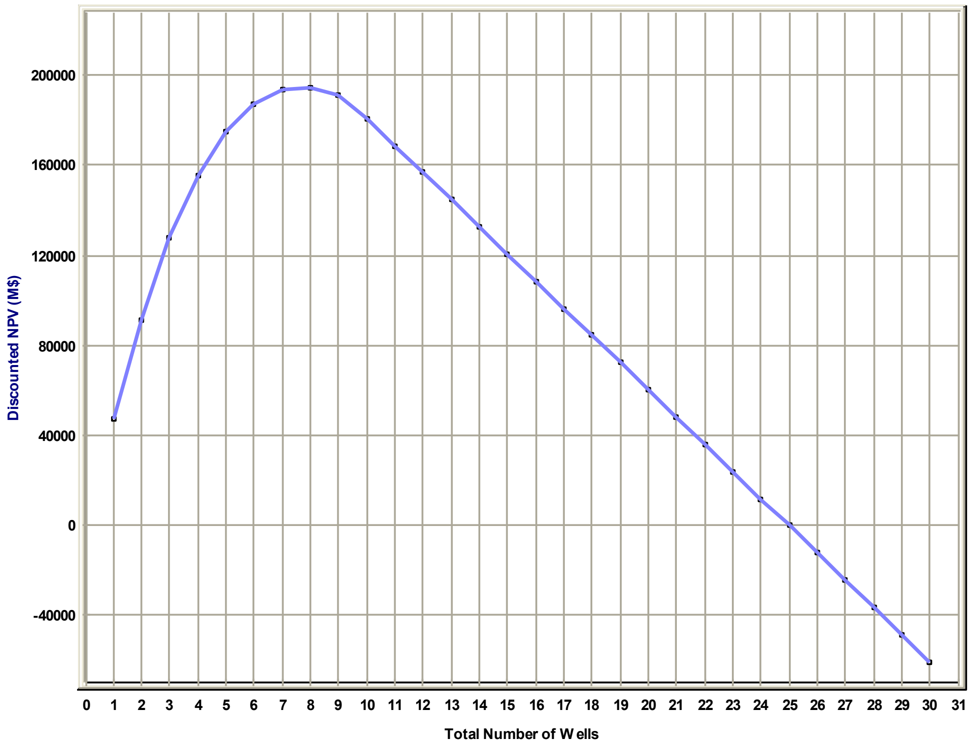

Figure 2: Discounted NPV versus total number of wells

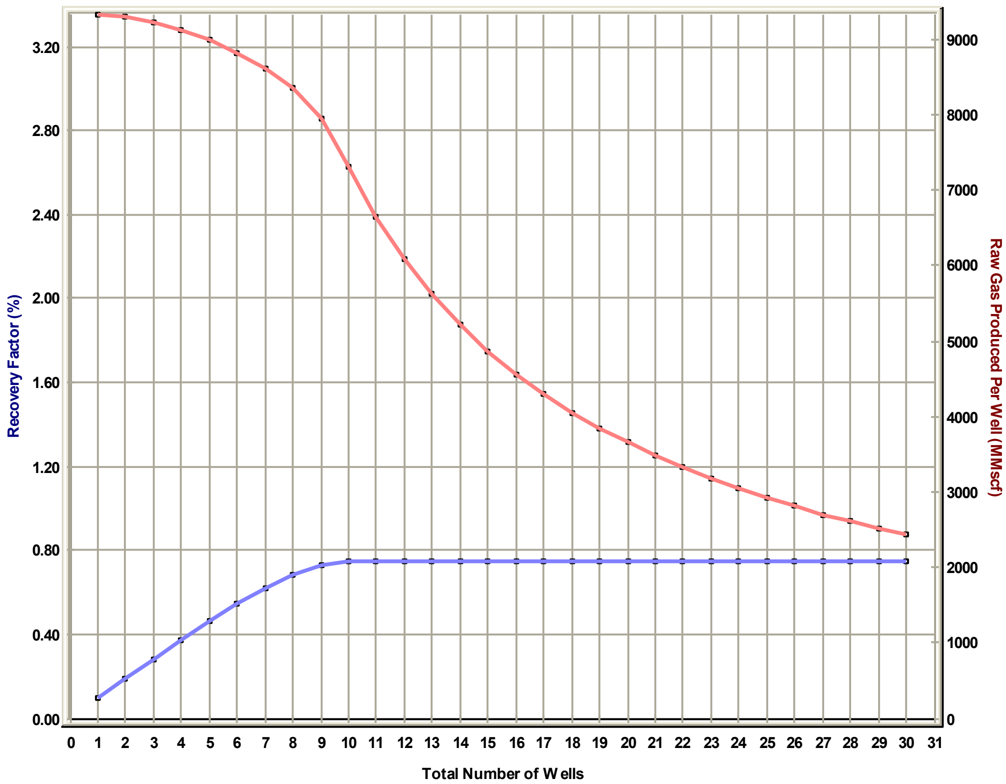

Figure 3: Recovery and Raw Gas Produced per well vs. total number of wells

Sensitivity Analysis

In order to investigate the effect of key parameters on the NPV, the recovery factor and cumulative gas production, sensitivity analysis was performed for different scenarios. These are presented in Table 11. During the sensitivity analysis, one single parameter was changed and compared to the base case. The different scenarios were run for a maximum number of eight wells. It was assumed that rig availability was not an issue for the development. Thus all eight wells were brought on stream over a period of 12 months.

Table 11: Sensitivity Analysis

Parameter Change	Value	NPV (Mill US $)	Recovery Factor (%)	Scenario
Fractures	6	182.1	0.61	1
Fractures	8	194.5	0.66	2
Fractures	10	199.0	0.68	3
Dimensionless Fracture Conductivity (FCD)	50	197.6	0.68	4
FCD (dimensionless)	150	199.2	0.68	5
Kx (mD)	0.001	209.3	0.75	6
Gas Content (scf/ton)	30	201.2	0.63	7
Gas Content (scf/ton)	40	202.8	0.63	8
Porosity (%)	6	209.3	0.57	9
Porosity (%)	2	141.1	0.54	10
Gas Saturation (%)	65	209.3	0.54	11
Gas Saturation (%)	20	122.3	0.73	12
Length of horizontal well (feet)	2000	182.4	0.60	13
Length of horizontal well (feet)	3000	207.3	0.73	14
Langmuir Pressure (psia)	500	207	0.65	15

The cumulative gas production for different scenarios is plotted as a function of time in Figure 4. The results show that the overall NPV and recovery factor vary significantly. As expected, the highest NPVs are returned for cases in which the porosity and gas content are high for a given permeability. The cumulative gas production reaches up to 70,000 MMscf (scenarios 2-9, 11, 13 and 15) over the 20 year simulation time period. (Figure 4, Table 11).

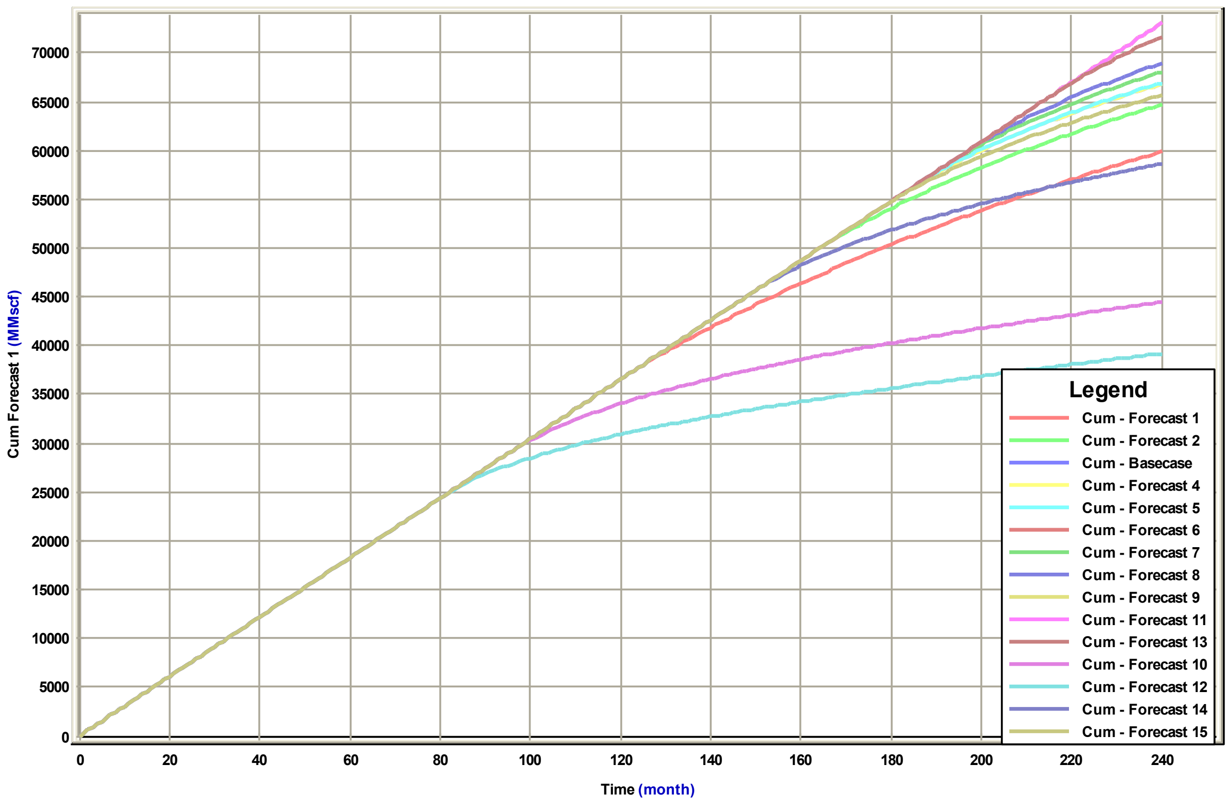

Figure 4: Forecast Cumulative Productions for different scenarios

All scenarios are able to sustain an extended plateau period. Clearly, the longest plateau-period (18 Years) could be sustained with a horizontal well length of 3,000 m (Figure 5). Payback occurs in three years with a maximum exposure varying from \$40 to \$60M.

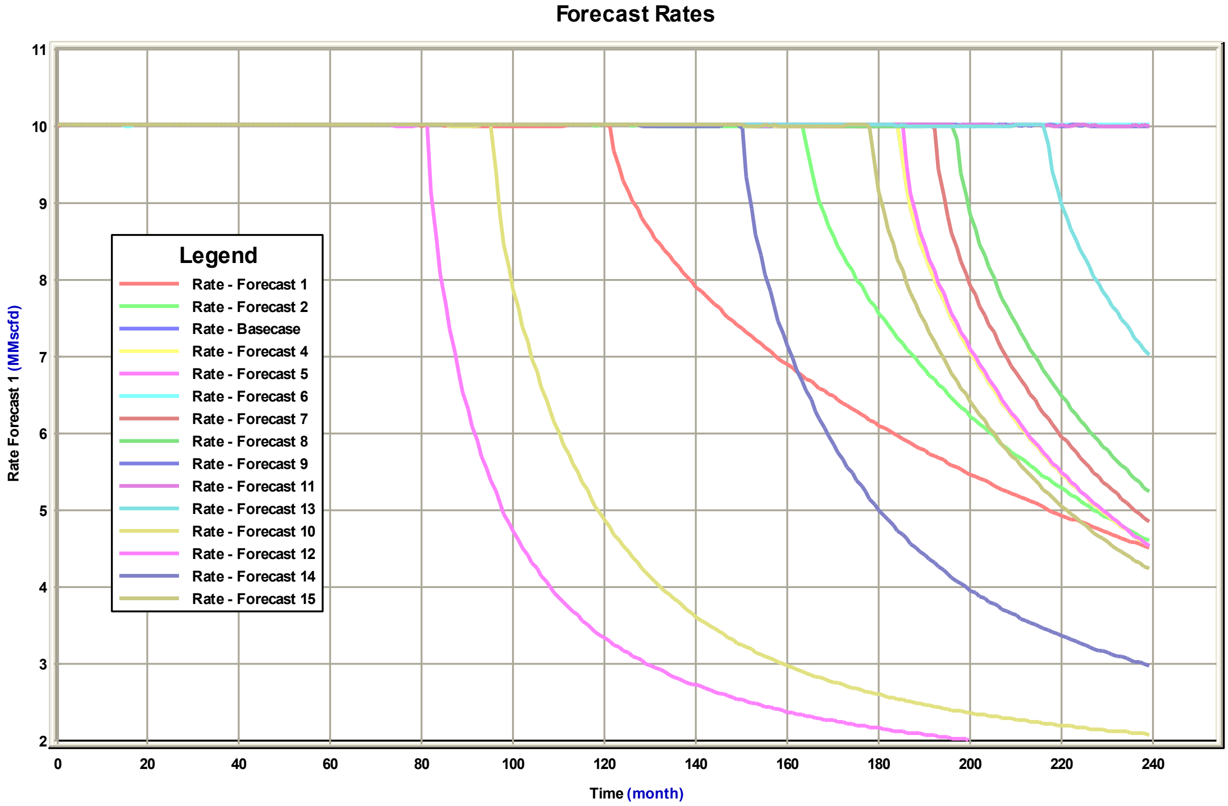

Figure 5: Rate vs. Time for different scenarios

Conclusions and Recommendations

A shale gas field development for the Perth Basin has been simulated based on data from the first exploration well. A sensitivity analysis has been performed to investigate the effect of key parameters on the NPV, recovery factor and cumulative gas production. The conclusions are:

- The simulation results suggest that, despite the high costs associated with drilling and fracturing and the relatively low gas content shale gas development in the Perth Basin can be profitable.
- The test case indicated the optimum development would generate an NPV of up to \$209M from eight horizontal wells. Key risk factors are unfavorable gas saturation, porosity and gas content.
- Horizontal well lengths of 2,000 to 3,000 m were investigated. Longer completion extends plateau production and can affect the optimum stimulation stages. For a 2,500 m long horizontal well, with fracture half-length of 500 ft and a dimensionless fracture conductivity of 100, the optimum number of hydraulic fractures is 10.
- It is recommended that this simulation be updated with the data generated from the hydraulic fracturing and well testing.

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