

Global shale gas development risk: conditional on profits beating the time-value of money

Ruud Weijermars^{1,2*} quantifies the major risks in the economic appraisal of shale gas projects. Sensitivity analyses of well roll-out rate scenarios in emergent shale plays show which field development strategies deliver the highest return on investment at the lowest cost of capital.

Governments around the world are scrambling to assess the extent of their shale gas resources. Landmark studies of shale-gas resource potential have been published for global regions (Rogner, 1997; DOE/EIA, 2011a; JRC/EC, 2012) and countries (Canada: PTAC, 2006; China: MLR, 2012; Germany: BGR, 2011; Netherlands: TNO, 2009; Poland: PGI, 2012; US: PGC, 2009; NPC, 2011). These reports provide important clues about the critical risks and opportunities of shale gas projects, in conjunction with preliminary estimates of the resource potential, which is significant for global energy security and national energy strategy planning. The resource estimates are progressively refined and the gas volumes can be quantified in terms of liquids in place (OGIP), technically recoverable resources (TRR), economically recoverable resources (ERR), and proved reserves with an estimated ultimate recovery (EUR).

Simultaneous with the assessment of potential shale gas resources the debate is unfolding about operational risks of shale gas development. Governments, shale operators, investors, and concerned citizens are part of a stakeholder discourse that must carefully weigh the arguments in favour and against further shale development. Politicians and associations around the globe commission studies to assess the engineering principles of hydraulic fracking (DOE, 2009; NEB, 2009; API, 2011; CAPP, 2012; JRC/EC, 2012). Meanwhile, the

US, EU, France, and UK have all issued recommendations addressing shale gas development concerns (SEAB, 2011; EU Report, 2011; BRGM, 2011; Royal Society Report, 2012). The IEA has issued its golden rules for shale gas operations (IEA, 2012), stressing the importance for the global economy to facilitate and increase the pace of shale gas development. In the end, sustained societal support is needed for realizing shale gas field development projects with an economic scale and profitable drilling programme.

This study offers recommendations for improving the economic valuation of shale gas resources, a key topic which has remained under-exposed in all major shale gas reports. When exploration and production licences are finally granted, companies willing to develop the shale-gas potential must generate enough return on investment over the lifecycle of the project. Regional variations in well productivity, gas price, and well roll-out rate (related to the alignment speed of stakeholders) may all affect the net present value (NPV) and internal rate of return (IRR) of shale gas projects. Quantitative examples of various well roll-out-rate scenarios are evaluated based on the degree of societal support for field development. The field development scenario with a robust economic performance at the lowest cumulative cash flow deficit lowers the cost of capital for shale gas operators. Less financing requirement helps to narrow the gap between the

estimated TRR and the feasible ERR, which adds valuable EUR volumes.

Economic performance risk

The economic risk of shale gas projects remains high as has become apparent from the North American track record (Weijermars and Van der Linden, 2012). From an investor perspective, capital tied up in a shale gas project must generate profits that pay for the value depreciation of the money invested – over the project lifecycle (factoring in the cost of capital) – and additionally must yield a premium return that satisfies investors for the risk taken (Weijermars and Watson, 2011). When evaluated on a competitive capital basis, the development of shale gas resources will only continue and succeed if these represent sound investment opportunities with sustainable profits.

The economic evaluation of shale gas projects is easily perturbed by positive bias in the uncertainty modelling of well productivity as well as by incomplete economic risk analysis, which originates at two managerial levels. Operational petroleum engineers, in their bottom-up assessment of field performance, encounter difficulties in establishing reliable well productivity estimates (Berman, 2009, 2010; Moridis et al., 2010; Giles et al., 2012), and are under pressure from top management to raise the aggregated EUR. Economic risk analysis for shale gas projects is managed at the corporate

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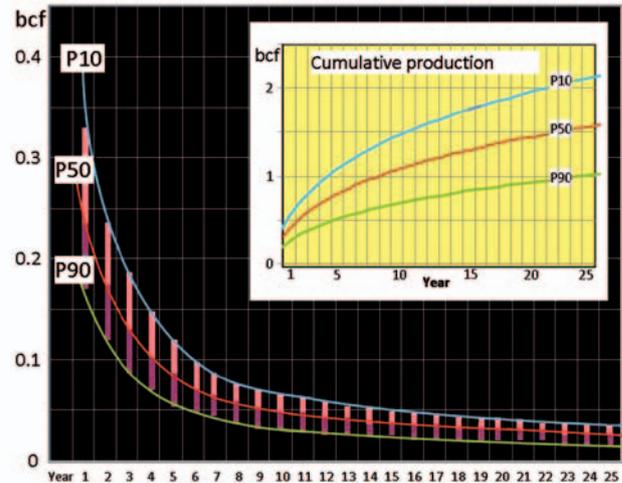
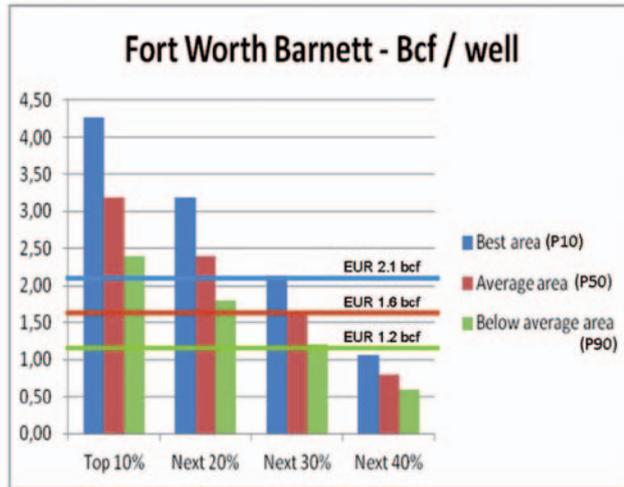


Figure 1 a) Spatial distribution of EUR per well in the Fort Worth core area of the Barnett shale play. [Based upon the available company EUR estimates aggregated for NEMS of the US Department of Energy in the Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS, in DOE/EIA, 2011b)]. b) Probability distribution spread of well productivity showing P90–P50–P10 wells for each of the areas distinguished. Inset shows the cumulative production (EUR) for the proxy well P50 for the average area and uncertainty range P10 and P90 for best area and below average area, respectively.

level, and uses the EUR of aggregated wells to build cash-flow models for the entire shale field. The mismatch between expected and actual performance recorded for North American shale gas projects is due to a combination of optimistic EUR estimates and too high gas price assumptions in the cash-flow projections.

Realistic appraisals are needed to ensure shale investments and national energy security policies are not based on incomplete definitions of resource categories, unfounded assumptions of well-life longevity, or flawed uncertainty analysis. Uncertainties in project parameters, including speed of project roll-out, need to be factored into economic appraisals of shale gas resources. The time-value of money concept mandates that appraisals of net-present value should be based on correct estimates of future income earned, appropriately risked and discounted to ensure the inflation rate is taken into account. Even when approached in this fashion risks will remain high.

The four most critical sources of risk and uncertainty that may affect the economic performance of shale gas projects are: (1) spatial variations in well productivity, (2) uncertainty in net-present value, (3) well-roll-out delays, and (4) volatility of collateral value in proved undeveloped reserves.

Economic risk in this study refers to volatility in gas markets and the wider range of risk and uncertainty that may impact the return on investment of shale gas projects. Only those risk factors that are specifically relevant for shale gas projects are outlined, but other risks that are generic for hydrocarbon projects such as operational risks, well integrity, country risk, and other sources of uncertainty also apply and must be routinely accounted for in shale project validation.

Performance risk

Spatial variation in well productivity

Shale gas well performance may vary greatly due to geological heterogeneity in petrophysical parameters such as fraccability and maturity of the organic content conversion to hydrocarbons. The majority of US shale gas wells have been drilled less than five years ago, which limits the accuracy of the monitored well productivity. A presentation by W.J. Lee at Texas A&M in 2010 of US gas well productivity, using 46,506 shale gas wells, gave an average EUR of 1.14 bcf/well. Decline curve analysis (DCA) of individual shale gas wells commonly provides poorly constrained well productivity estimates, which means the uncertainty spread in EUR estimates is wide. Theoretically,

the aggregated EUR estimates progressively improve over time, based on the statistical significance of realized productivity of individual wells.

In the Barnett shale play, the reported spread in well performance for sub-areas is considerable. In the ‘best areas’ for the Barnett, mean EUR estimates range from 2.1 to 3.0 bcf/well (Valkó, 2009), which reflects different assumptions in DCA and spatial sample variations in the ‘best area’. Spatial variations in shale gas well productivity reported by companies for the Fort Worth core area of the Barnett shale play are plotted in Figure 1a. Wells are grouped in best area (40% of total acreage), average area (30% of total acreage), and below average area (remaining 30% of total acreage). Within each production area, wells are ranked according to productivity in pools of top 10%, next 20%, next 30%, and next 40%. The overall average for the Fort Worth Barnett core area of 1.6 bcf/well (Figure 1a, reported in OLOGSS to the Department of Energy) is adopted in this study. Other mean EUR estimates for representative samples of horizontal Barnett wells range between 1.4 bcf/well (Valkó, 2009) and 2.0 bcf/well (Fan et al., 2011). The ‘worst areas’ have a mean EUR of 0.59 bcf/well (Valkó, 2009).

The uncertainty range in EUR estimates for individual wells must be factored into estimates of aggregated field performance to account for the spatial variation in well productivity. Our solution is to adopt a DCA proxy well with an assigned spatially averaged well productivity. The spatial spread in well output is captured by assigning P10–P50–P90 probabilities to productivity of the proxy well based on spatial averages for the best area, average area, and below average area. Figure 1b plots the Fort Worth core area proxy well of 1.6 bcf/well (mean EUR) with an initial productivity of 1.6 MMcf/day (0.3 bcf/y) and captures the recorded spatial spread in well productivity curves with probabilities P10–P50–P90. Table 1 shows the well productivity parameters used for the DCA.

In view of the relatively rapid decline in shale gas well productivity, individual well life can be argued to range between 10 and 25 years. This does not affect our results as tail-end productivity contributes little to the overall EUR and is negligible. However, we use a standardized 25-year lifecycle in our cash flow analysis to allow for comparisons of the various field development scenarios considered (see below).

Uncertainty in net present value (NPV)

An optimum appraisal of field economics for a new shale gas project must be based on a cash flow forecast, including the uncertainty range of the gas production profiles and gas price sensitivity. Our P10–P50–P90 proxy wells for the Fort Worth Barnett area have been used as the basis for a comprehensive sensitivity analysis.

The models produced in this study are based on well productivity decline functions and discounted cash flow equations. Algorithms for DCA, distributions for estimating well productivity spreads, and discounted cash-flow analysis are outlined in an online repository (Alboran, 2012). The algorithms are incorporated in a pro-

Costs and rates	Barnett
Well CAPEX (\$/MM)	4
OPEX (\$/Mcf)	1.2
Other OPEX (\$/Mcf)	0.3
Royalty Rate (%)	12
Effective Corporate Tax (%)	25
Depreciation (%)	10
Discount rate (%)	10
Proxy well	
EUR P10-P50-P90 (bcf)	2.1-1.6-1.2
Type of distribution	Normal
Arps P50-P10 q_i (bcf/yr)	0.3-0.55
Decline rate (loss factor)	0.8
Decline exponent (b)	1.3

Table 1 Rates used in DCF and DCA analysis.

prietary Excel-based interface, which enables the calculation of the field-development scenarios used to produce the plots in this study. This purpose-built tool is suitable for evaluating the discounted cash flow of both single and multiple wells in shale gas field development projects.

The present sensitivity analysis of cash flows uses representative input parameters for capital expenditure (CAPEX) and operating expenses (OPEX), royalties, taxes, depreciation, and discount rate (Table 1). Gas prices are varied between 2 and 10 \$/Mmbtu. In our models 1000 cubic ft (1 Mcf) of gas is equivalent to a calorific value of 1 million British thermal units (1 Mmbtu) used in spot market pricing. Deviations in calorific value (higher for wet gas and lower for dry gas) and the revenues added by sales of any comingled natural gas liquids can be accounted for in the model, but were not considered in the present study.

Figure 2a shows the IRR for P10–P50–P90 dry gas wells (1 Mmbtu/Mcf) and sensitivity to gas-price fluctuations. In all cases the initial gas price is for the first year of well production and is, over the well’s productive lifecycle, adjusted for inflation at 2.5% on yearly basis. P90 wells have negative IRR for 6 \$/Mmbtu (Figure 2a). The best 10

percentile (P10) wells have IRR above 20%, and P50 wells have marginal IRR (Figure 2a) with negative NPVs when discounted at 10% rate (Figure 2b). The gas price sensitivity of the discounted NPV for P10–P50–P90 proxy wells is summarized in Figure 2b. The undiscounted NPV is summarized in Figure 2c. The break-even gas price for Fort Worth P50 wells ranges between 4.25 \$/Mmbtu (undiscounted, Figure 2c) to 7 \$/Mmbtu (discounted, Figure 2b), which emphasizes that corporate statements about break-even prices are only meaningful if the discount rate is specified. The cash flow analysis further shows that the NPV for wells for an initial gas price of 6 \$/Mmbtu ranges between +\$1.4 to -\$2.7 million (P10 and P90 discounted, Figure 2b) and +\$6 and -\$2.2 million USD (P10 and P90 undiscounted, Figure 2c). The sensitivity analysis of Figures 2a–c shows that P50 wells in the Fort Worth core area are sub-economic for gas prices below 6 \$/Mmbtu.

When the gas price was frequently rising above 6 \$/Mmbtu at the end of 2004, the huge expansion of the Barnett shale gas drilling began as is apparent from the steep rise in the gas rig count between 2004 and 2008 (see Weijermars and Van der Linden, 2012). However, shale gas profits are highly sensitive to gas price

fluctuations, as analyzed for the Fort Worth core area proxy well (Figures 2a–c). If Barnett operators could have anticipated the gas price slump and been able to factor in this slump when they made their major investment decisions for wells drilled between 2004 and 2008 (before the actual gas price depression occurred) their NPV and IRR estimations for these wells would have been lower and many wells would never have been drilled.

Our sensitivity analysis for P10–P50–P90 proxy wells is only valid for the Barnett’s Fort Worth core area, not for the total Barnett. The Fort Worth area is considered prime shale gas acreage, a so-called sweet spot. Our analysis showed that the NPV and IRR of shale gas wells is unevenly distributed, even in a prime production area. Companies homing in on the best Fort Worth acreage no longer make a profit at today’s gas prices. The unavoidable conclusion is that none of the Barnett’s P50 and P90 wells have been profitable at gas prices for the past four years, which hovered about 3 ± 1 \$/Mmbtu. Figure 2a shows the IRR for the P50–P90 proxy wells is negative for gas prices of 3 ± 1 \$/Mmbtu, and below the commonly used minimum hurdle rate of 15%, providing an IRR floor for oil and gas project approval. The NPV of the portfolio of P10–P50–P90 wells for the entire Barnett basin has turned negative at current low gas prices. However, our sensitivity analysis also indicates there is considerable potential for future value when gas prices recover. The IRR and NPV for future gas prices can be inferred from Figures 2a–c.

Well roll-out delays

A major hurdle for shale gas development in locations where individual landowners have no authority to grant drilling rights to operators (unlike the US), is the potential impact of project delays on the internal rate of return (IRR). For example, in Europe (and elsewhere) an emerging shale gas boom is mostly obstructed by the slow speed of decision-making, which precludes any planned, fast progress in well roll-

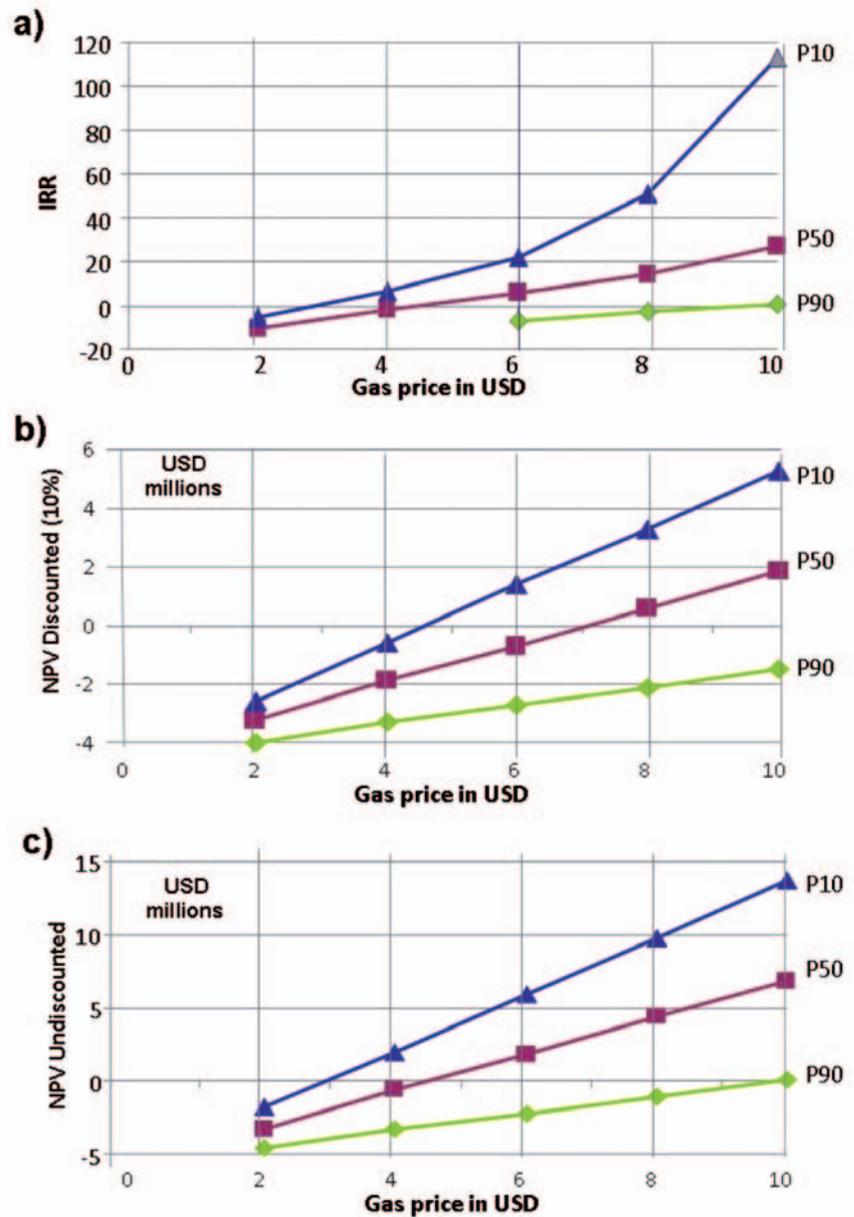


Figure 2 Gas price sensitivity of the economic performance of P10–P50–P90 proxy wells for the Fort Worth core area. a) IRR (internal rate of return); b) Discounted NPV; c) Undiscounted NPV. Gas prices indicated are for year 1, and have been inflation corrected at 2.5% per year over the well lifecycle.

out. Drilling permits are being either delayed or rescinded as concerns have been raised worldwide about potential water pollution and seismic risk due to fracking.

The possibility of stakeholder misalignment also means the development pace of shale gas fields is not only constrained by a company’s capital investment capacity (based on creditworthiness and retained earnings, or lack thereof), but also becomes dependent on external risk factors like the

opposition to fracking. Consequently, uncertainty analysis needs to account for both the geological spread in well productivity and the impact of the field development rate on the time-value of money.

Figure 3 considers four possible scenarios for project completion speed and well roll-out rate which relate to various degrees of stakeholder alignment. All four scenarios complete a capital investment programme of 500 wells in 10 years time. This is a modest

rate by any standard; earlier estimates for Europe indicated 1000 shale gas wells need to be drilled yearly over five years (2015–2020) to be able to cover 5% of gas demand in 2020 (Bernstein, 2010; Geny, 2010; Weijermars et al., 2011). For comparison, the US drilled about 19,000 shale gas wells in 2008 alone, which was the peak year of its shale gas bonanza.

Stakeholder misalignment may affect well roll-out-rates of new shale gas projects in unpredictable ways, but the four scenarios capture typical trends (Figure 3). Scenario A has stakeholder support rising and waning but manages to realize the 500 wells in step with the level of stakeholders support, it is a fast deployment scenario. Scenario B has only 50% stakeholder support but proceeds with a steady drilling schedule of 50 wells per year. Scenario C assumes steadily growing stakeholder support as the drilling programme develops and more wells are realized toward the end of the field development period. Scenario D has 100% support at the outset and starts with a massive drilling programme of 100 wells per year, but eroding stakeholder support slows down the drilling rate as indicated in Figure 3.

In real life, the rate of field development can be affected by various bottlenecks: the speed of geological modelling, available operator services, regulatory permit process, creditor investment decisions, gas transmission

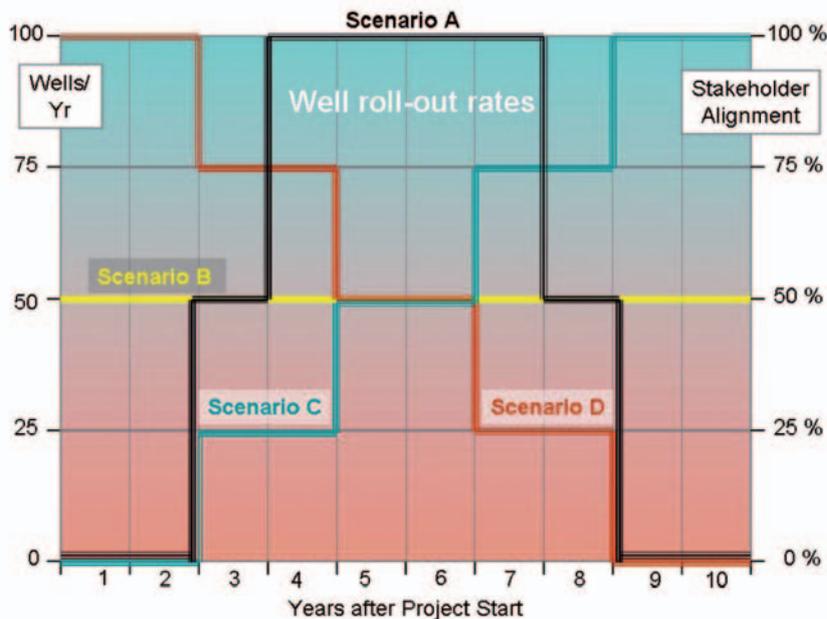


Figure 3 Four well rate roll-out scenarios A–D considered in this study for a 10 year CAPEX investment in a shale field development project with a 25-year lifecycle. All scenarios realize 500 wells within the first 10 year of the field development period, but at different rates. The wells realized in each year vary (left-hand scale), and may be effectuated by different degrees of stakeholder alignment for an operator's shale gas project (right-hand scale).

access capacity, gas market maturity, and generic stakeholder alignment speed. All these possible sources of delay in the shale gas project roll-out process are considered here as an integral part the stakeholder alignment process, which is the term used to grade the degree of success in completing capital investments on time and executing the shale field development project as planned.

The economic performance indicators of all four scenarios have been

evaluated for the full range of gas prices between 2 and 10 \$/Mmbtu. The balance of well revenue and cost, which is net cash, differs considerably for each scenario. Figures 4a–d show the annual production output profiles for each of the four field development scenarios. The lifecycle of the field development is longer than the 10-year CAPEX program as the aggregated EUR is produced over a 25-year period.

Figures 5a–d show the undiscounted net cash flows for P10–P50–P90 proxy

Scenario	A @ 6 \$/Mmbtu			B @ 6 \$/Mmbtu			C @ 6 \$/Mmbtu			D @ 6 \$/Mmbtu		
	P10	P50	P90	P10	P50	P90	P10	P50	P90	P10	P50	P90
Proxy Wells	P10	P50	P90	P10	P50	P90	P10	P50	P90	P10	P50	P90
IRR (%)	28.5	7.5	-	26.3	7.3	-	31.3	8.4	-	24.4	6.5	-
NPV undiscounted (billion USD)	3	1	-1	3	1	-1	3	1	-1	3	1	-1
Breakeven (yrs)	8	14	>25	8	14	>25	10	15	>25	7	14	>25
Max Cash deficit (billion USD)	-0.4	-0.9	-1.7	-0.2	-0.6	-1.6	-0.2	-0.9	-1.6	-0.4	-0.7	-1.6
NPV 10% discounted (billion USD)	0.6	-0.1	-0.8	0.6	-0.1	-0.8	0.6	-0.05	-0.7	0.7	-0.2	-1.0
Breakeven (yrs)	9	18	>25	9	18	>25	11	25	>25	8	>25	>25
Max Cash deficit (billion USD)	-0.3	-0.6	-1.0	-0.2	-0.5	-1.0	-0.1	-0.4	-0.8	-0.3	-0.7	-1.2

Table 2: Economic performance indicators.

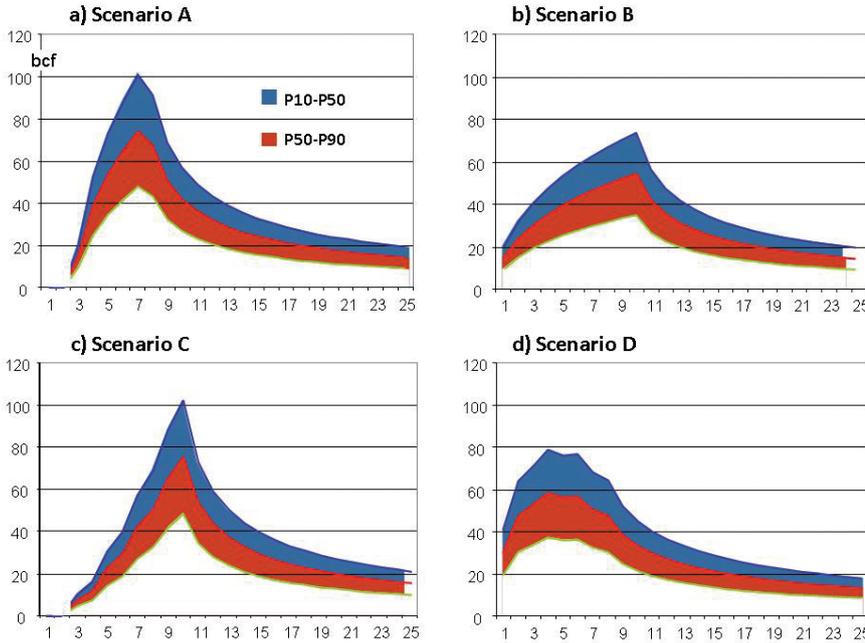


Figure 4 (a-d) Annual production output over the lifecycle of the shale-gas project for each of the four scenarios considered. For all scenarios 500 wells are deployed, with the spread in production profiles determined by the P10–P50–P90 proxy-wells of Figure 1b.

wells assuming a median gas price of 6 \$/Mmbtu. The cumulative discounted (10%) cash balance is summarized in Figures 6a–d. A ranking of the most favorable well roll-out scenario can use minimum cumulative cash flow deficit as a criterion. Larger cash flow deficits require more borrowing and thus increase the cost of capital. Scenarios A and B both have cumulative discounted net cash deficits that for P90 wells reach up to -\$1 billion, and for scenario D up to -\$1.2 billion (Table 2). Scenario C has the mildest financing requirement as cumulative net cash is lowest at -\$800 million for P90 wells (Fig. 6c). Break-even for the best P10 wells takes 7–8 years for scenario D, 8–9 years for scenario A and B, and 10–11 years for scenario C (Table 2). Please note that only the graphs for cumulative discounted cash flow (with the upper range of break-even periods) are included in this paper (Figures 6a–d); the cumulative undiscounted cash flow (with the 1 yr shorter break-even times) are not shown for brevity.

Figure 7a shows for all scenarios the IRR sensitivity to gas price fluctuations. Scenarios A and C have higher IRR than scenarios B and D due to investments

starting earlier for scenarios B and D. Undiscounted NPVs are the same for all scenarios (inset Figure 7a), as the number of 500 wells completed is the same

for all options. However, the discounted NPVs differ between scenarios (Figure 7b). Scenario D maintains the highest NPV for P10 wells, but the lowest for P90 wells, due to negative earnings for P90 wells and early development that depresses the NPV more than for the slower well roll-out scenarios.

Table 2 ranks the key metrics for each of the scenarios considered. Undiscounted NPVs are the same for all scenarios. Discounted NPV for P10 wells in scenario C is slightly lower than for scenario D. Payback period of scenario C is slightly longer than for the other scenarios. Scenario C has the most attractive economic performance, because its IRR is highest while its maximum cash deficit is lowest of all scenarios. Discounted cash positions for P10–P50–P90 wells become least negative for scenario C (Figure 6c), which has the lowest cost of capital of all scenarios considered. A detailed analysis of the cost of capital linked to various financing mechanisms for oil and gas companies has been discussed elsewhere (Weijermars, 2011a).

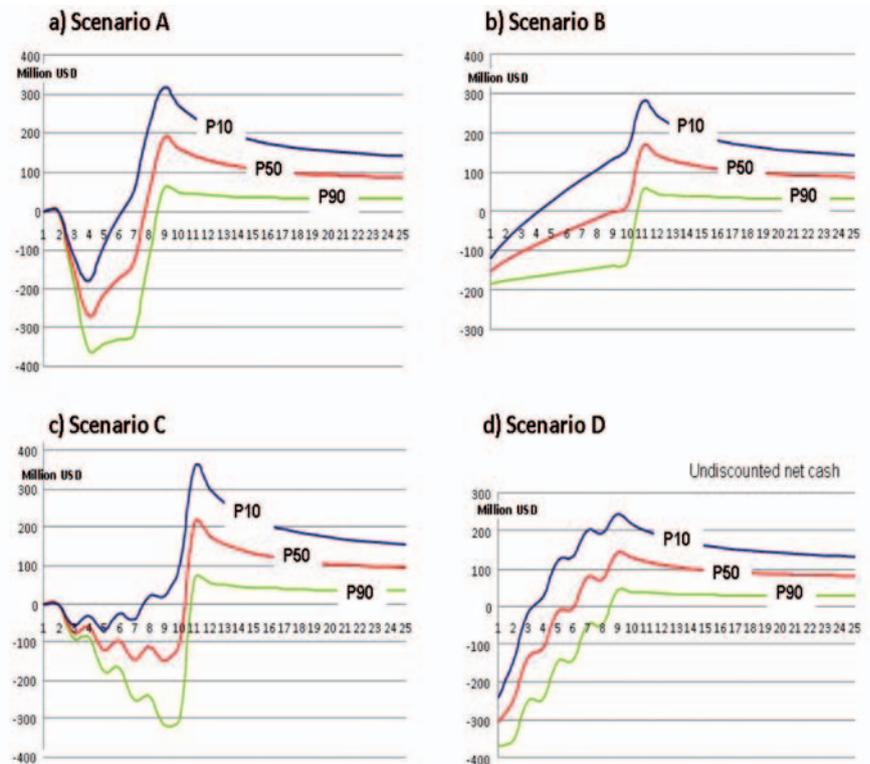


Figure 5 (a–d) Undiscounted net cash flow for the four well roll-out scenarios, assuming a gas price of 6 \$/Mmbtu in year 1 (inflation corrected at 2.5% over the project lifecycle). All four scenarios produce gas from 500 wells, but these are deployed at different speeds as detailed in Figure 3.

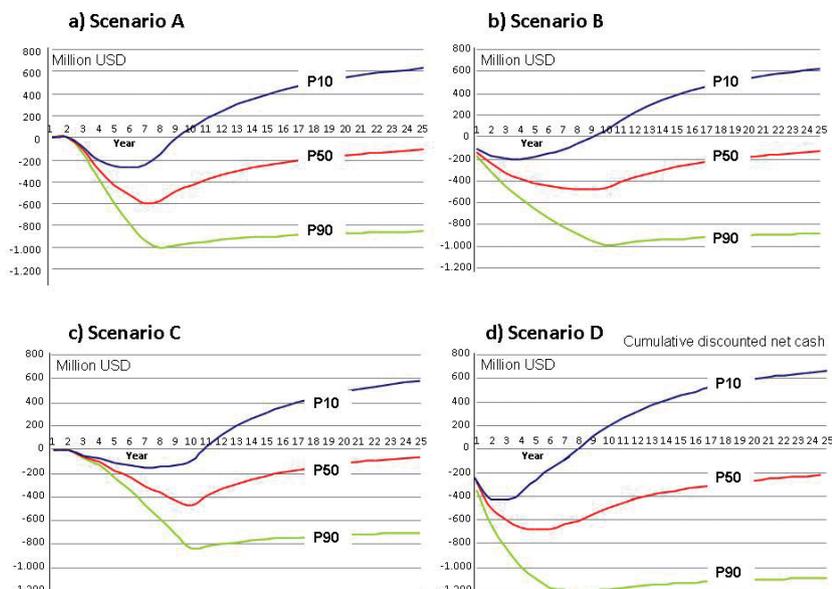


Figure 6 (a-d) Cumulative cash flow for the four well roll-out scenarios with assumptions as detailed in Figures 5 a-d.

Volatility of collateral value in undeveloped proved reserves

The cash flow shortage in the first period of a shale gas field development project puts companies under pressure to replenish negative cash flow from operations with capital raised from financing activities (Weijermars and Watson, 2011). For raising new finance, the NPV of proved developed reserves (PDs) and proved undeveloped reserves (PUDs) can serve as debt collateral. In contrast, contingent resources are not reserves and thus contribute little or nothing to NPV collateral for debt leverage – it is a binary on/off switch (Box 1 and Figures 8a and b). The risk that shale gas operators run, when gas prices drop, is that PUDs need impairment when production from PDs is no longer economic under 12-month trailing average gas prices. Companies must then duly impair PUDs when overall project costs have become sub-economic, as mandated by SEC (see Box 1).

Any downgrading of PUDs is supposed to be done by industry ‘self-regulation’. But rather than downgrading PUDs, a significant proportion of US shale-gas companies have in the past four years continued to sink cost in wells to convert PUDs into PDs (Weijermars, 2012), although these wells may not, in fact, ever have been

economic (on a full cost basis). Once a company has sunken the cost for well development of a PUD, it becomes proved developed reserves (PDs). By sinking the cost for well development a company secures the future value of their acreage with newly ‘proved’ reserves, but net cash flow from gas production may remain negative all the way. The avoidance of the downgrading of proved reserves to contingent resources averts the evaporation of a company’s debt collateral, but does not guarantee any future profits from gas production as long as gas prices stay depressed.

In contrast to PUD impairment, PDs are less susceptible to impairment when gas prices drop. PDs need only be ever impaired if the annualized cash flow, which excludes CAPEX of completed wells by sinking cost, turns negative. This would require gas sales to dip below operating expenses, a worst case scenario which started to play out when gas prices dipped briefly below 2 \$/Mmbtu in Q1 2012. Unless that happens again in the subsequent well lifecycle, SEC rules leave room for continued classification of a developed well’s reserves as PDs for as long as its annualized cash flow remains positive.

Today, PUDs still account for nearly half of the US shale gas proved reserves.

Cash-strapped US shale gas companies are under continued pressure to maintain all these PUDs on their balance sheets (Olsen et al., 2011), as without these proved undeveloped reserves many operators will land into co-lateral default. When gas prices do not recover and lift PUDs above break-even using a 12-month trailing price average, reserve downgrades will be unavoidable. The business impact may be severe because with an unusually high gearing ratio (debt leverage) of 0.7 for US shale gas operators (Weijermars, 2012), there is no feasible gearing room for any refinancing. Nearly all of the combined market capitalization of US shale gas independents is either a going concern or at risk of becoming illiquid (Dell and Lockshin, 2010).

Recommendations and Conclusions

Shale operators may consider the following recommendations to help improve the accuracy of cash-flow projections for shale projects:

Operators try to find sweet spots but shale gas well productivities still have a large spread. This spread in well productivity must be taken into account when field NPV and project IRR are calculated, using conservative gas price assumptions. Uncertainty on the productivity of the aggregated wells in a shale play and the additional effects of external uncertainties, such as gas price volatility and delays in well roll-out rates must be taken into account without bias in the cash flow analysis. New shale gas projects should only be approved if the NPV is positive, and when the project profitability (IRR) is competitive and well above the corporate hurdle rate of 15%.

Drilling permit procedures and stakeholder discussions may preclude project development at a speed directed by corporate need to invest capital at a rate that optimizes the time-value of money. Four scenarios for well roll-out rate in emerging shale fields have been evaluated, based on which we conclude a field development plan with incremental increases in drilling rate,

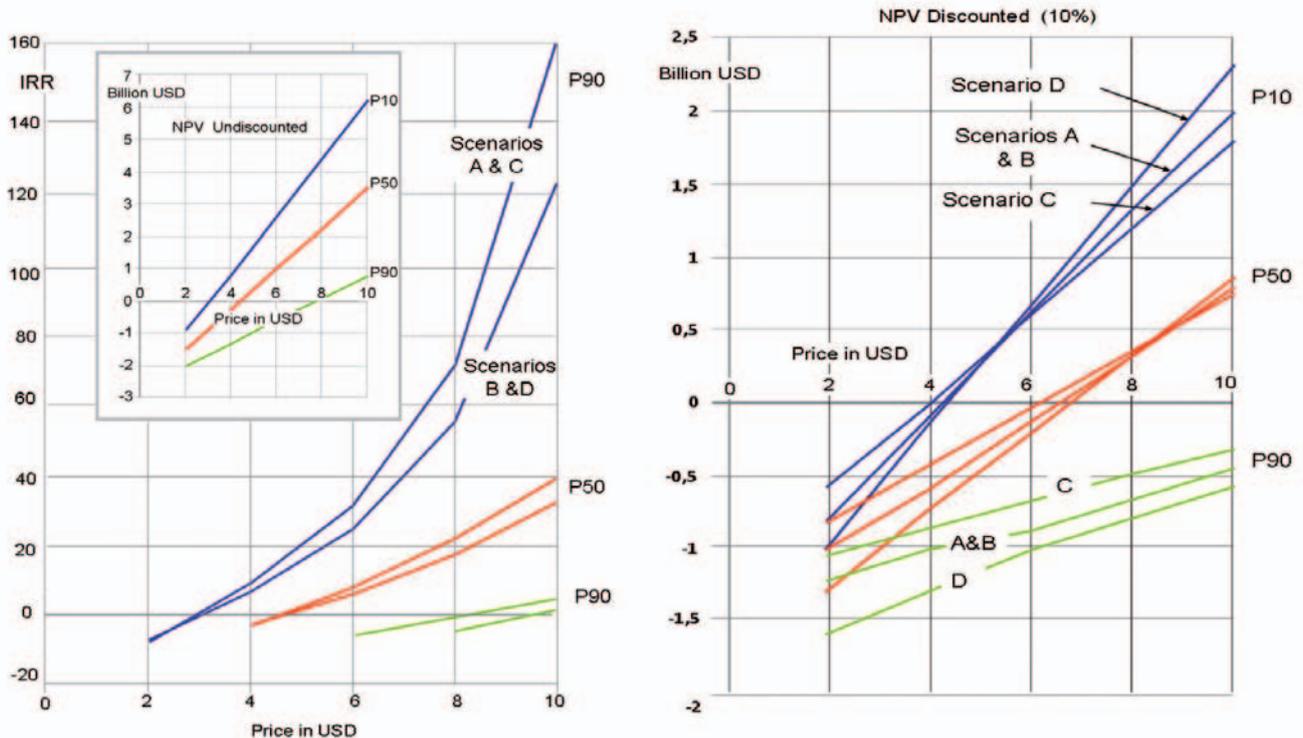


Figure 7 Gas price sensitivity-analysis for P10–P50–P90 proxy wells of Fort Worth core area for each of the four scenarios considered. a) IRR (inset shows undiscounted NPV). b) Discounted NPV. Gas prices indicated are for year 1, and have been inflation corrected at 2.5% per year over the project lifecycle.

in step with growing stakeholder support, delivers the highest returns on investment and requires the least cost of capital.

For the economic appraisal of mature North American shale plays use of P50 proxy wells, although at liberty with SEC guidelines, seems economically justified. However, new shale plays in Europe and elsewhere have no producing shale gas wells to constrain the uncertainty. This means that first appraisals may use US shale gas analogues for preliminary well productivity estimates, but these should take P90 proxy well values. Using P50 cannot be

justified as the likelihood of evening out poor P90 wells with P10 wells (sweet spots) is not present in emerging shale gas plays where the value of information is limited in the early stage of field development. Companies should use in their economic appraisal, following the PRMS (WPC, 2011) and SEC (2009) reporting guidelines, the conservative 90% certainty EUR volume to assess the NPV of a shale field.

A recent shift to drilling for wet gas and oil in shale assets has slightly eased negative operational earnings. The cash flow predictions and economic valuation of drilling operations in wet

gas and oil windows of shale plays should equally avoid the optimistic bias endemic to shale gas projects.

Governments can facilitate inventories of gas-in-place (GIP) and technically recoverable resources (TRR), but ultimately any gas will only be produced if companies can make a profit. Governments may help mitigate the economic risks of shale resource development by attending to the following issues:

1. Reported shale gas reserves provide the basis for long-term energy security planning at regional and national level. Misrepresentations or inaccuracy in the reporting of shale gas resources (TRR and ERR) and reserves (EUR and PUD) could lead to unexpected energy shortages or unrealistic expectations for future energy supply (Brooks, 2012). The economic gap between estimates of technically recoverable resources and actual economically recoverable resources may be much wider than hitherto realized, and should be assessed to ensure long-term energy security.

Box 1 Reserves classification and downgrading principles

In the past, operators may have used different price/costs for Probable and Possible reserves versus that used for Proved. Under PRMS and SEC 2009 this is no longer allowed – all reserves technical categories use the same economic criteria – so 100% move to Contingent Resources when the project cash flows are negative. There is always some issue within company’s whether projects economics should be based on 1P (90% certainty of volumetric estimate) or 2P (50% certainty of volumetric estimate), but as far as the SEC is concerned this must be based on the proved reserves criterion (1P).

2. Reserve-reporting guidelines must be strictly enforced to protect shale gas investors against undue volatility in company asset value (SEC, 2009). The reporting of proved reserves for shale gas projects requires more scrutiny to reassure investor interests are prudently managed by the company (Olsen et al, 2011; Weijermars, 2012).
3. Investors are increasingly reluctant to provide credit to independent shale gas companies. This is now a major economic obstacle to the development shale gas resources in Europe. Governments may need to provide credit facilities in addition to tax incentives to jump-start the development of shale gas resources. This schedule is less likely to succeed in Europe and the US, where sovereign debt levels prompt for budget austerity.
4. Regulatory intervention to mitigate volatility in gas prices by providing a price floor for natural gas production could be considered to stimulate the development of economically recoverable resources as advocated in an earlier study (Weijermars 2011b).

Australia and Poland seem to be progressing fastest in providing the most attractive shale gas resource development incentives. China and Russia are also taking measures to help develop their shale resources. Argentina's shale plays may become more interesting once the development policies are clarified by the government.

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Disclaimer

This study analyzes shale gas economics based on data abstracted from industry reports and academic studies. The analysis of these empirical data inevitably involves a degree of interpretation and uncertainty connected to the assumptions made. Although the results

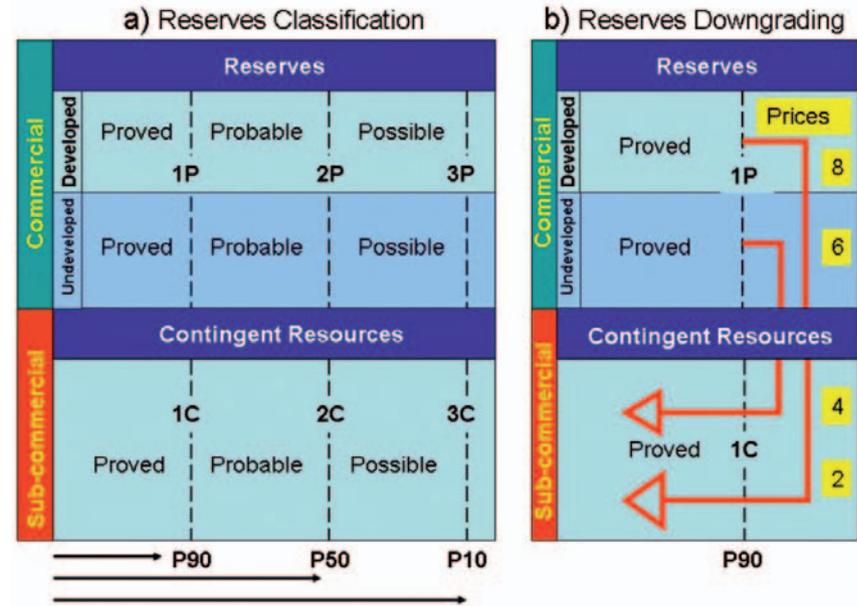


Figure 8 a: Proved-reserves classification (according to PRMS/SEC) are those P90 volumes that can be produced with reliable technology and with economic profit using 12 month averaged market prices over the past reporting year. b: Downgrading of proved reserves to PRMS contingent resources is mandatory when depressed US natural gas prices render shale-gas plays sub-commercial (yellow labels, indicated in \$/Mmbtu). Projects that do not meet the economic hurdle are relegated to Contingent Resources - it is an off/on switch, so 1P moves to 1C, 2P to 2C and 3P to 3C.

derived here are reproducible using the outlined research methods, the author, Alboran Energy Strategy Consultants and publisher take no responsibility for any liabilities claimed by companies that hold assets in the field areas included in this study.

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