



# Economic appraisal of shale gas plays in Continental Europe



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## HIGHLIGHTS

- ▶ Economic feasibility of five European shale gas plays is assessed.
- ▶ Polish and Austrian shale plays appear profitable for P90 assessment criterion.
- ▶ Posidonia (Germany), Alum (Sweden) and a Turkish shale play below the hurdle rate.
- ▶ A 10% improvement of the IRR by sweet spot targeting makes all plays profitable.

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## ABSTRACT

This study evaluates the economic feasibility of five emergent shale gas plays on the European Continent. Each play is assessed using a uniform field development plan with 100 wells drilled at a rate of 10 wells/year in the first decade. The gas production from the realized wells is monitored over a 25 year life cycle. Discounted cash flow models are used to establish for each shale field the estimated ultimate recovery (EUR) that must be realized, using current technology cost, to achieve a profit. Our analyses of internal rates of return (IRR) and net present values (NPVs) indicate that the Polish and Austrian shale plays are the more robust, and appear profitable when the strict P90 assessment criterion is applied. In contrast, the Posidonia (Germany), Alum (Sweden) and a Turkish shale play assessed all have negative discounted cumulative cash flows for P90 wells, which puts these plays below the hurdle rate. The IRR for P90 wells is about 5% for all three plays, which suggests that a 10% improvement of the IRR by sweet spot targeting may lift these shale plays above the hurdle rate. Well productivity estimates will become better constrained over time as geological uncertainty is reduced and as technology improves during the progressive development of the shale gas fields.

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## 1. Introduction

There is a growing interest in the assessment of the world's shale gas resource potential, which has intensified regional exploration efforts that must establish the presence and volume of prospective natural gas resources. US shale gas fields provide important guidance for the economic development of shale gas wells in emergent shale plays elsewhere in the world. A principal reason why the development of shale plays remains economically risky is that the estimated ultimate recovery (EUR) is poorly constrained during the early stages of field development.

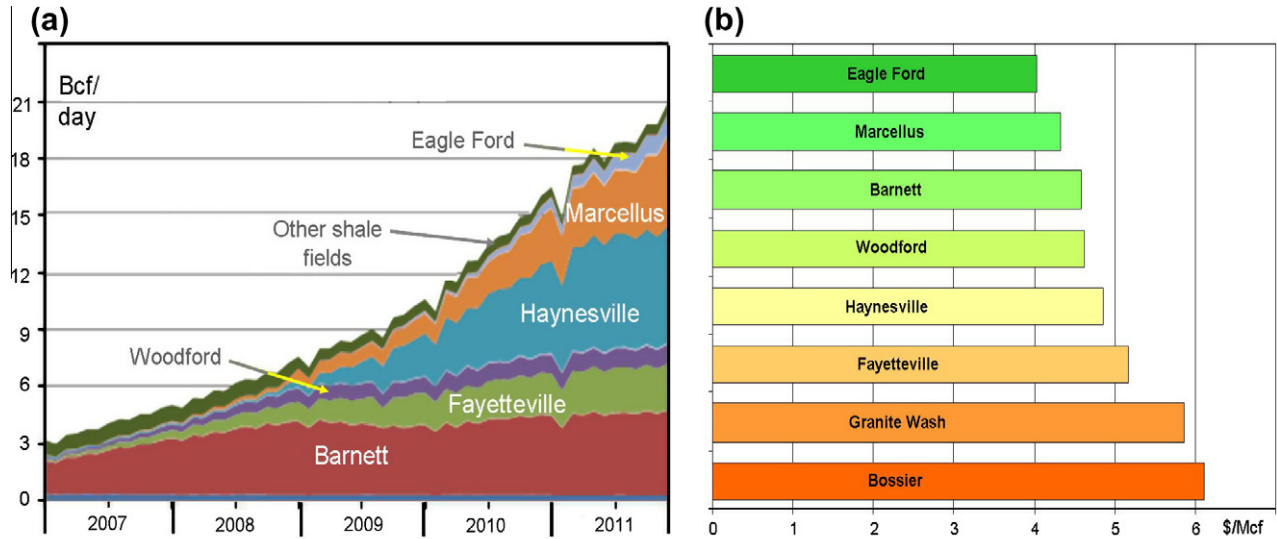
We model the economic potential of five potential European shale gas fields. Not all shale gas plays are equal, and reservoir quality varies within the plays and between the plays as has become apparent from US shale plays. Fig. 1a provides a concise

overview of the major US shale gas growth areas [1]. By 2009, the production of US domestic gas from unconventional resources (tight sands, coal beds and shale) surpassed the domestic output of conventional gas [2]. By 2012, shale gas accounted for over half of all the US gas produced from unconventional (or continuous) resources. Fig. 1b shows that the marginal breakeven costs for US shale gas basins differ [3], which is a consequence of variations in well productivity (due to intrinsic petro-physics of the reservoir and the variation in well effectiveness) and differences in field development cost.

This study makes a first attempt to evaluate the economics of five potential shale gas plays in Europe (Austria, Germany, Poland, Sweden and Turkey). Well productivity type curves are established for each play based on an earlier review of estimated ultimate recovery (EUR) for the plays [4]. Decline curve analysis provides the well productivity model that fits the prior published EUR data. Subsequently, the net present value (NPV) and internal rate of return (IRR) of each shale play are calculated by applying discounted cash flow analysis, using representative inputs for gas price, pro-

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**Fig. 1.** (a) Major US shale gas plays and production since 2000 [1]. (b) Breakeven marginal prices for major US shale gas play, duly accounted for or limited to “best” well performance. (Data source: Bloomberg & Credit Suisse [3]).

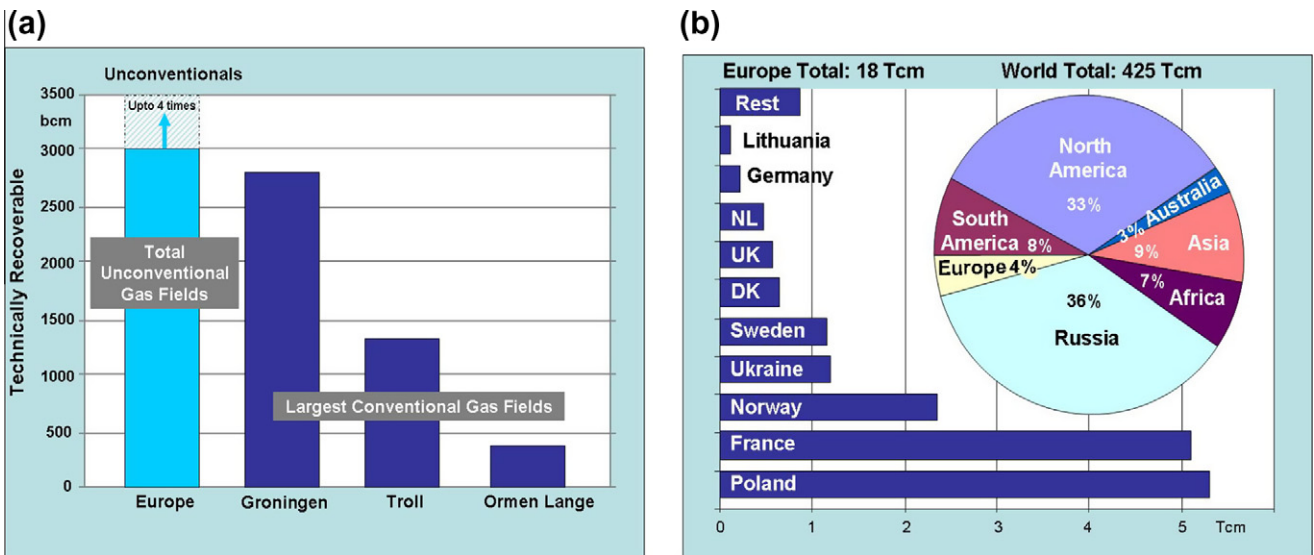
duction cost, taxes, depreciation and discount rate. The sensitivity of IRR and NPV to variations in EUR is modeled for each play, which thus provides the minimum EUR for which wells are economic – a directive for ‘sweet spot targets’. A stochastic approach that accounts for the spatial spread of well productivities is included, using production volume probabilities P10–P50–P90. The spread in NPV and IRR related to the well productivity uncertainty range provides an indication for the risk taken when only few wells are drilled and provides a screening criterion for selecting the best field development opportunities.

**2. European shale plays**

Europe’s unconventional gas resources in place were first ranked in a global perspective by Rogner [5], who estimated some 1255 trillion cubic feet (Tcf) gas in place from the following unconventional resources: shale gas: 549 Tcf; tight sands: 431 Tcf; and

coal-bed methane: 275 Tcf. Europe ranks at the lower end of global unconventional resource potential, with only 4% of the worldwide total (Asia and North America lead, with respectively 30% and 25% of GIP). This is partly due to the exclusion of Poland, Hungary and Romania in Rogner’s assessment of 1997 [5]; appraisals for these countries were not available at that time.

The technically recoverable shale gas volumes for Europe were estimated to range between 150 and 200 Tcf by WoodMacKenzie [6]. CERA [7] considered technically recoverable shale gas to range between 106 to 423 Tcf (3–12 Tcm), and the US Department of Energy raised this to 18 Tcm [8]. This number also has been confirmed in resource appraisals by BGR [9], Medlock et al. [10] and in the review by McGlade et al. [11]. Fig. 2a places the shale gas resource estimates in perspective by comparison to Europe’s three major producing conventional gas fields (Groningen in Netherlands; Troll and Ormen Lange on Norway’s Continental Shelf). Fig. 2b confirms that the TRR estimates differ greatly per country:

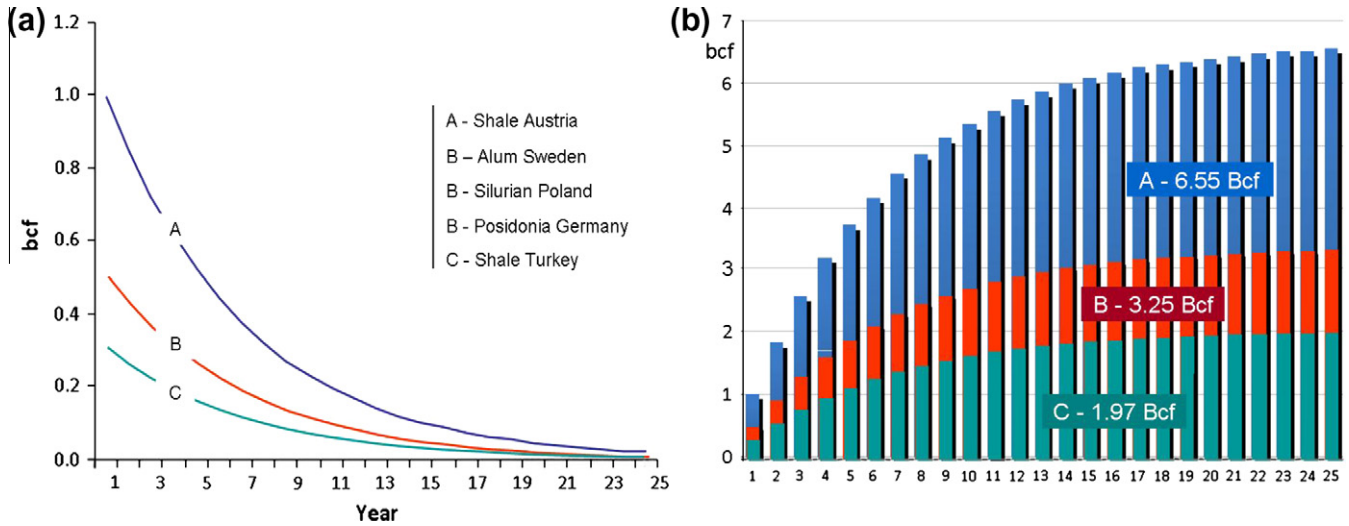


**Fig. 2.** (a) Relative sizes of Europe’s largest conventional gas fields (Groningen, Troll and Ormen Lange Gas Fields), and an early estimate of 12 Tcm for Europe’s total recoverable unconventional gas. (b) World shale gas inventory of 2011 estimates 425 Tcm recoverable resources, of which only 18 Tcm (4%) occurs in Europe. The country spread of the 18 Tcm is indicated by the horizontal bars (Source: DOE/EIA [8]; Weijermars and McCredie [12]).

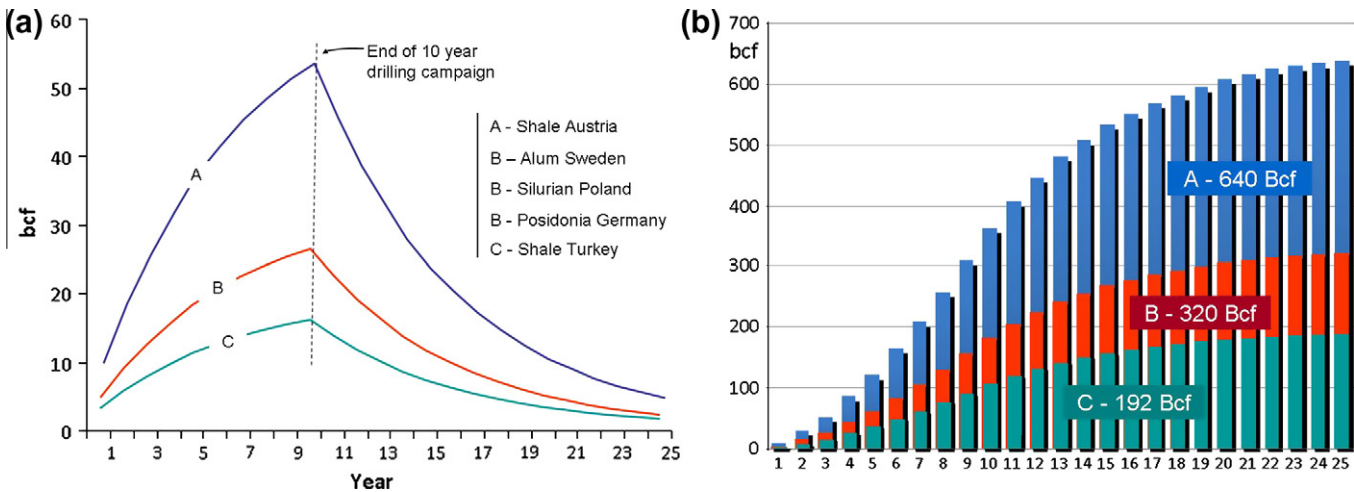
**Table 1**  
Selected properties European shale gas basins. Data Source: Kuhn and Umbach [4].

Property	Alum Sweden	Silurian Poland	Posidonia Germany	Shale Austria	Shale Turkey
Basin area (Sq. km)	2010	23,816	7500	900	18,000
Depth (m)	100–3500	2000–4000	0–2500	4500–8000	2500–3500
Thickness (m)	30–100	30–300	20–500	1,500	100–400
TOC (%)	2–25	7	2–12	1.5–2	4
Ro (%)	1.4–3.0	1.0–4.0	0.5–1.5	0.7–1.6	0.5–3.0
Tcf (OGIP)	39	844	94	750	151
RF	0.14	0.17	0.18	0.04	0.15
EUR/Well <sup>a</sup> (Bcf) 40 years	4.8	4.8	4.8	8	2.2

<sup>a</sup> Used as input for Table 2.



**Fig. 3.** (a) Production profiles for single gas wells with initial production rates  $q_i = 0.3, 0.5$  and  $1$  bcf/year and a decline factor of  $15\%$  ( $a = -0.15$ ). (b) Cumulative production (25 year lifecycle) gives corresponding EUR of  $1.97, 3.25$  and  $6.55$  bcf/well.



**Fig. 4.** (a) Production profiles for gas field projects with 100 wells, drilled over a decade at a rate of 10/year, each well with  $q_i = 0.3, 0.6$  and  $1$  bcf/year and  $a = -0.15$ . (b) Cumulative production (25 year lifecycle) gives the corresponding EUR of  $192, 320$  and  $640$  bcf for the respective fields.

Poland, France, Norway and Ukraine host the larger estimates. The pie diagram included in Fig. 2b gives a summary of the TRR estimates for shale around the world, as estimated by Advanced Resource International in a study commissioned by the US Department of Energy [8]. This inventory confirms that Europe's 18 Tcm of shale gas potential is a relatively poor endowment compared to other world regions. However, if fully developed, these

resources could provide Europe with another 25 years of natural gas supplies at projected consumption levels of between 600 and 700 bcm/year. The strategic vulnerability of natural gas supply to Europe due to its growing reliance on imports has been highlighted elsewhere [12–14].

Poland is Europe's leading shale gas resource holder (Fig. 2b). It also has the largest proportion of coal (55%) in its primary energy

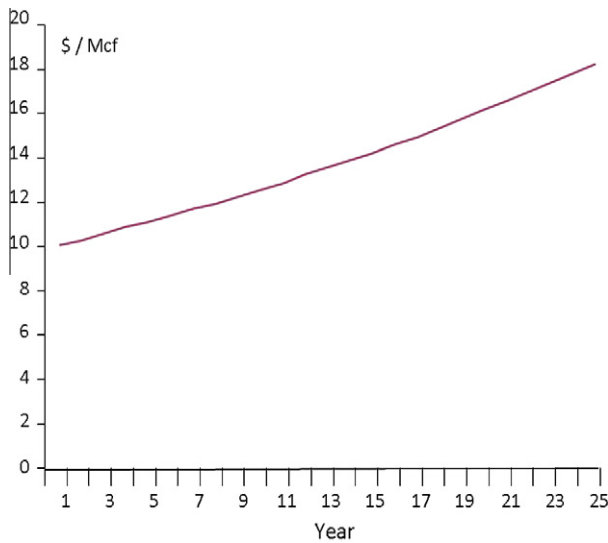


Fig. 5. Continental European gas price trend mode, forward corrected for inflation, using Eq. (2) and  $P_1 = \$10/\text{Mcf}$  and  $b = 0.025$ .

Table 2  
Selected rates European shale gas basins.

	Alum Sweden	Silurian Poland	Posidonia Germany	Shale Austria	Shale Turkey
EUR/Well (Bcf- 25 years) <sup>a</sup>	3.25	3.25	3.25	6.55	1.97
Productivity year 1 flow rate (bcf/ year) <sup>a</sup>	0.50	0.50	0.50	1.00	0.30
Well CAPEX (\$/MM) <sup>b</sup>	15	14	13	24.5	8.1
OPEX (\$/Mcf) <sup>b</sup>	0.6	0.5	0.6	0.4	1.2
Other OPEX (\$/Mcf) <sup>b</sup>	1.4	1.0	1.2	1.0	1.0
Royalty rate (%) <sup>b</sup>	0	1.5	8	10	13
Corporate tax (%) <sup>b</sup>	28	19	30	25	20
Depreciation (%) <sup>c</sup>	10	10	10	10	10
Discount rate (%) <sup>c</sup>	5	5	5	5	5

<sup>a</sup> Data Source: Prorated from Table 1.

<sup>b</sup> Data Source: Kuhn and Umbach [4].

<sup>c</sup> Data Source: Alboran Research.

supply. The production of natural gas from its indigenous shale resources could help Poland reduce greenhouse gas emissions by replacing coal as the fuel of choice for its aging coal-fired power stations, as well as reduce Poland's dependency on Russian gas imports.

France possesses Europe's next largest shale gas resource base (Fig. 2b), but the local opposition against shale gas development is significant and it is set to maintain its nuclear options. Opposition to shale gas development finds stronger political support in countries where shale gas threatens to displace existing energy sources with a strong support base (like the nuclear power lobby in France).

Norway has substantial shale gas resources (Fig. 2b), but development may be slow. Shale gas will have to compete with the more profitable conventional gas production from the Norwegian continental shelf. Even without actualizing its shale gas potential, Norway remains Europe's major oil and gas producer and exporter for decades to come.

Ukraine holds Europe's fourth largest shale gas deposits (Fig. 2b), but has an energy policy that is still influenced by Russian energy strategy. As a result, development of shale gas in Ukraine will be politically much more complex than in Poland.

Sweden is Europe's smallest gas consumer, with gas accounting for only 2.6% of its primary energy supply and no gas retail market. The development of shale gas would require the development of a local gas market with the additional infrastructure constraints. The Alum shale potential for commercial gas production has been negatively assessed by Shell engineers [15].

Denmark, the UK, the Netherlands and Germany are all major gas consumers, with extensive gas infrastructure and mature retail markets. Their domestic gas supply from conventional sources is declining. These countries are well placed to benefit from domestic shale gas development, which could delay expensive gas imports. The strategic importance of shale gas development for the Netherlands has been outlined elsewhere [16,17].

The outlook for shale gas in Europe has been briefly evaluated in earlier studies [4,18–21]. Table 1 provides a concise overview of key data for five emerging shale plays. Europe's gas shales are underexplored, and any estimates about possible well economics are very preliminary. The Posidonia shale has been alluded to as a close analog of the Woodford shale [19], which enables a reservoir analog approach [22] for an early assessment of its resource potential.

### 3. Methodology

The results documented in this study are based on generic equations for discounted cash flow analysis (DCF analysis, Appendix A) and well productivity decline analysis (DCA methodology, Appendix B). The algorithms are incorporated in a proprietary excel-based interface developed by Alboran Energy Strategy Consultants, which enabled the calculation of field development scenarios and was used to produce the plots in the present study. A concise manual is made available as a complimentary resource in an online repository [23]. The supporting methodologies are outlined in Appendices A–D.

#### 3.1. Well productivity model

Understanding the well productivity of representative US shale gas plays provides important guidance for the economic development of shale gas wells in emergent shale plays elsewhere in the world. A review of US well productivities, using 46,506 shale gas wells, gives a 40-year mean EUR of 1.14 Bcf [24]. In the Barnett, the mean EUR for representative horizontal wells is 1.4 bcf/well [25], but there is considerable spread in well performance for sub-areas. In the 'best areas' for the Barnett a representative mean EUR is 2.1 bcf/well, and the 'worst areas' have a mean EUR of 0.59 bcf/well [25].

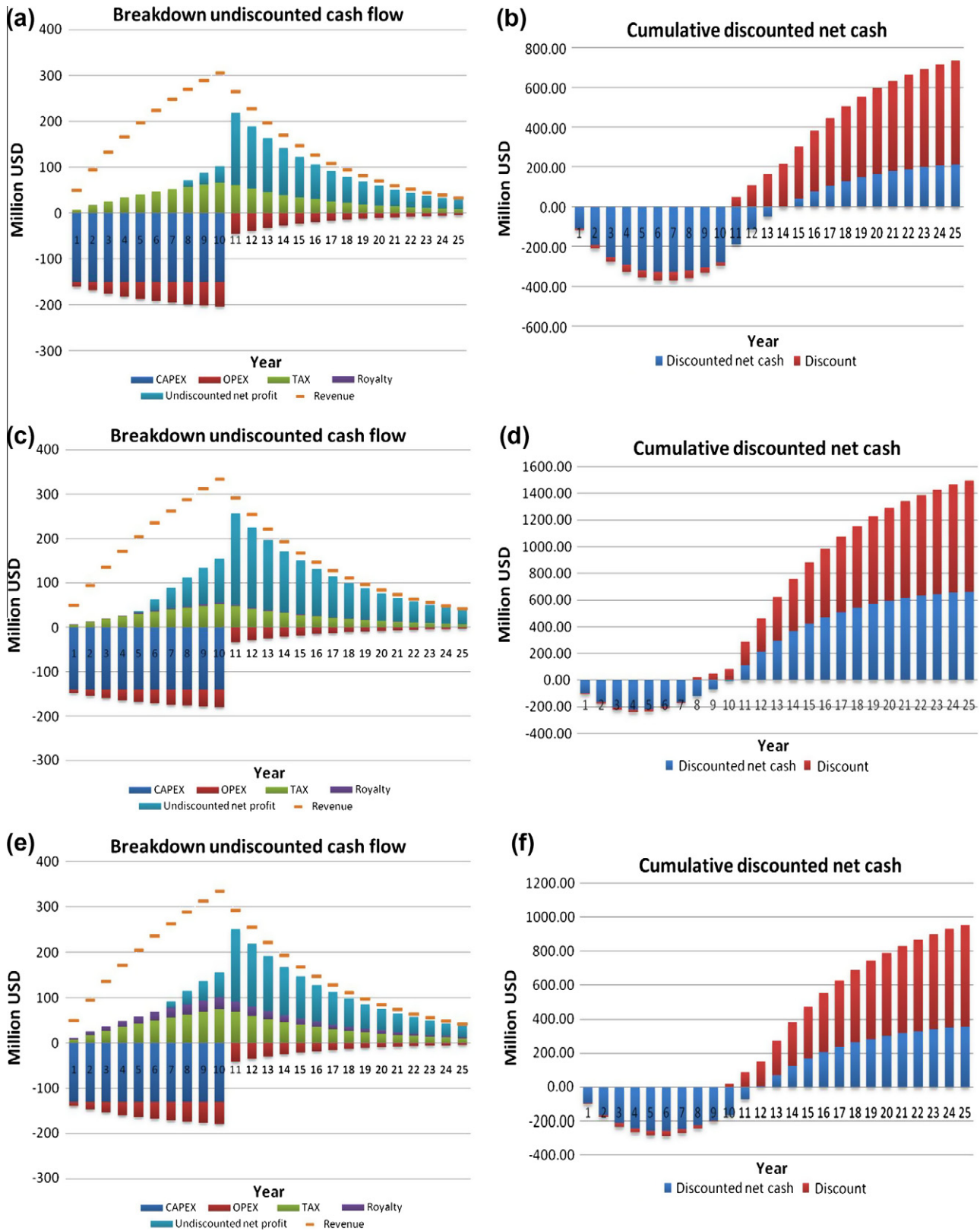
For this study, we assume the well EUR can be modeled by an exponential decline function:

$$q_n = q_i(1 + a)^n \quad (1)$$

$q_n$  is the flow rate in year  $n$ ,  $q_i$  the starting flow rate in first year, and ' $a$ ' the annual decline rate (remember this is a negative fraction), and ' $n$ ' the number of years.

Fig. 3a plots the well productivity over a 25 year lifecycle ( $n = 1, \dots, 25$ ) using the gas production type curves for single wells in each of the five shale plays assessed here. Estimates for the 25 year lifecycle EUR/well (Table 2) are prorated from the EUR/well for a 40 year lifecycle (Table 1, based on review by Kuhn and Umbach [4]). The well flow rates of Fig. 3a were obtained by fitting the EUR with an appropriate decline function using Eq. (1). The corresponding cumulative production over the 25 year well life is given in Fig. 3b.

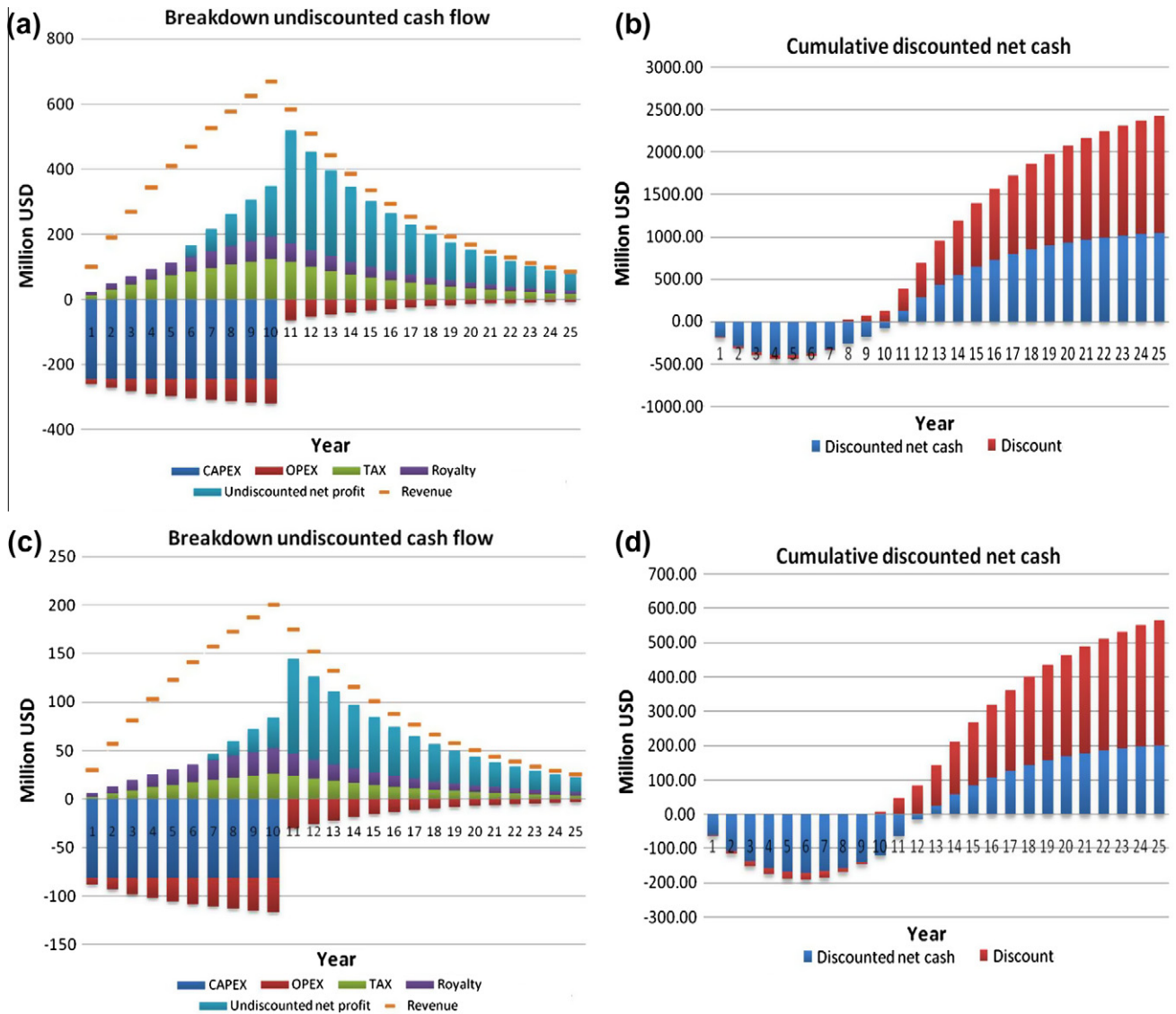
Fig. 4a shows the annual production for the individual field development projects in the shale plays drilling 100 wells in the



**Fig. 6.** (a–f) Cash flow models for emerging Continental European shale gas plays, with initial gas price at \$10/Mcf and data given in Table 2. (a) Alum shale, Sweden. (b) Cumulative 5% discounted cash flow, with NPV = \$737 million and IRR 10% (before discounting), discounted payback 14 years. (c) Silurian shale, Poland. (d) Cumulative 5% discounted cash flow, with NPV = \$1497 million and IRR 20% (before discounting), discounted payback at 10 years. (e) Posidonia shale, Germany. (f) Cumulative 5% discounted cash flow, with NPV = \$953 million and IRR 13% (before discounting), discounted payback at 12 years.

first decade at a rate of 10 wells per year. The annual well output increases with the number of wells, but abrupt decline sets in after the drilling ceases in year 10. The gas output of the aggregated

wells declines over the remaining 15 years of the 25 year field life (Fig. 4a). The cumulative gas output for each of the five shale gas plays is given in Fig. 4b. Appendix B provides further guidance



**Fig. 7.** (a–d) Cash flow models for emerging Continental European shale gas plays, with initial gas price at \$10/Mcf and data given in Table 2. (a) Gas shale, Austria. (b) Cumulative 5% discounted cash flow, with NPV = \$2427 million and IRR 18% (before discounting), discounted payback 11 years. (c) Gas shale, Turkey. (d) Cumulative 5% discounted cash flow, with NPV = \$565 million and IRR 12% (before discounting), discounted payback at 13 years.

**Table 3**  
Ranking of European shale gas basins.

	Alum Sweden	Silurian Poland	Posidonia Germany	Shale Austria	Shale Turkey
NPV (\$ million)	737	1497	953	2427	565
IRR (%)	10	20	13	18	12
Largest negative cash flow requirement (\$ million)	–390	–220	–300	–480	–190
Payback (years)	14	10	12	11	13
Ranking <sup>a</sup>	E	A	C	B	D
Score <sup>b</sup>	1.35	13.6	3.44	8.27	2.74

<sup>a</sup> Most attractive – least attractive: A–F.

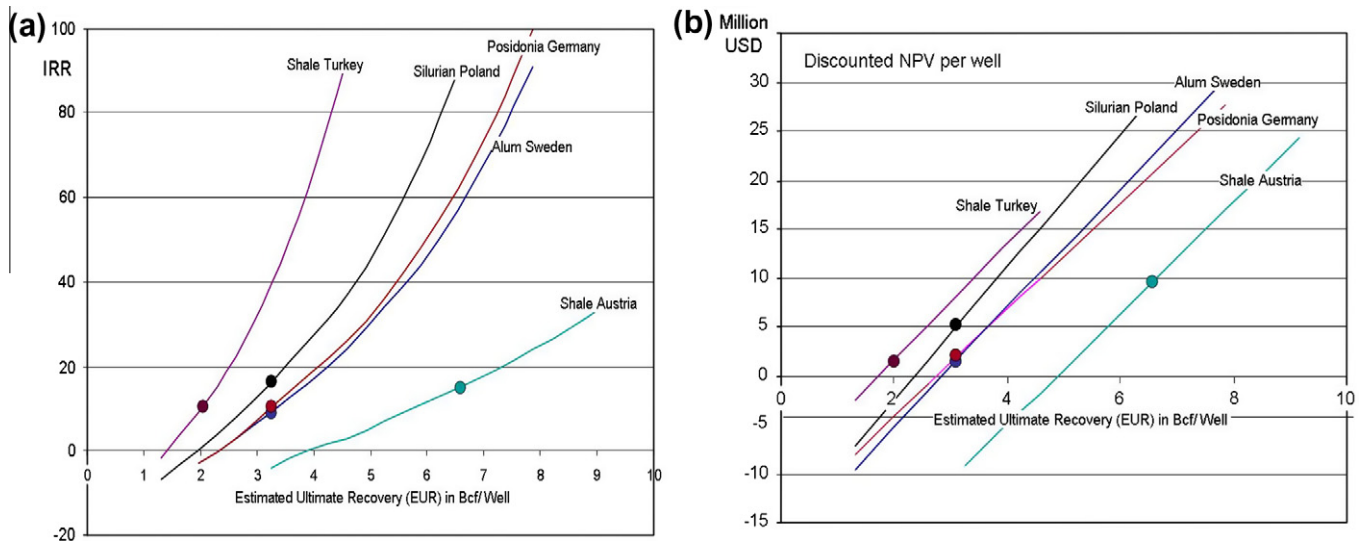
<sup>b</sup> Ranking based on NPV times IRR, divided by cash flow requirement times payback.

for the estimation of well productivity by decline curve analysis using empirical gas flow rates.

### 3.2. Gas price model

The total revenue and economic margin on the natural gas sales from shale fields remains critically vulnerable to volatility in

wellhead prices. The gas price development is an external uncertainty, sometimes affected by policy measures. A major advantage for European gas producers is that the Continental European gas price is much less volatile and generally higher than in the UK and US [26–30], where the majority of gas sale contracts are spot-market indexed and any volatility in spot market wholesale gas prices is directly passed on to the gas prices at the wellhead.



**Fig. 8.** (a) Sensitivity of IRR per well to EUR variations. (b) Sensitivity of discounted NPV per well to EUR variations for each of the five plays analyzed here. Dots show the EUR values corresponding to the estimates given in Table 2.

Continental wholesale gas prices have been between two to five times higher than in the US (between 2008 and 2012), because Continental European gas contracts are still predominantly oil-indexed and long-term [29]. UK gas prices tend to move in a price deck between US and Continental European gas prices [30]. US spot gas prices have collapsed due to overproduction of natural gas in the closed North American market. The North American spot gas prices continue to depress the wellhead prices of all gas producers who deliver their gas on spot-market indexed contracts.

Our cash flow models for shale gas plays in Continental Europe adopt an initial gas price set at \$10/Mcf, with a forward correction for inflation modeled by an annual inflation factor of 2.5% (Fig. 5):

$$p_n = p_i(1 + b)^n \quad (2)$$

$p_n$  is the wellhead gas price in year  $n$ ,  $p_i$  the wellhead gas price in the first year, and ' $b$ ' the annual inflation rate affecting the gas price, and ' $n$ ' the number of gas production years. In our models 1000 cubic ft (1 Mcf) of gas is equivalent to a calorific value of 1 million British thermal units (1 Mbtu) used in market pricing. Alternative functions for modeling gas price trends and background on what drives regional gas prices are highlighted in Appendix C.

### 3.3. CAPEX, OPEX and taxes

The outlay of capital expenditure (CAPEX) and operating expenditure (OPEX) can be controlled by the operator. Appendix D summarizes the basics of CAPEX estimates and factors affecting corporate cost of capital (both controllable), discusses the details of OPEX outlays (controllable), and provides examples of royalties, tax rates, depreciation, and discount rates – all of which affect the outcome of the cash flow model for a specific field asset. The taxes and royalties due are mostly controlled by the governing petroleum extraction laws and rules. Table 2 shows the typical values used in our cash flow model simulation for the European shale gas fields.

## 4. DCF analysis of European shale plays – base case

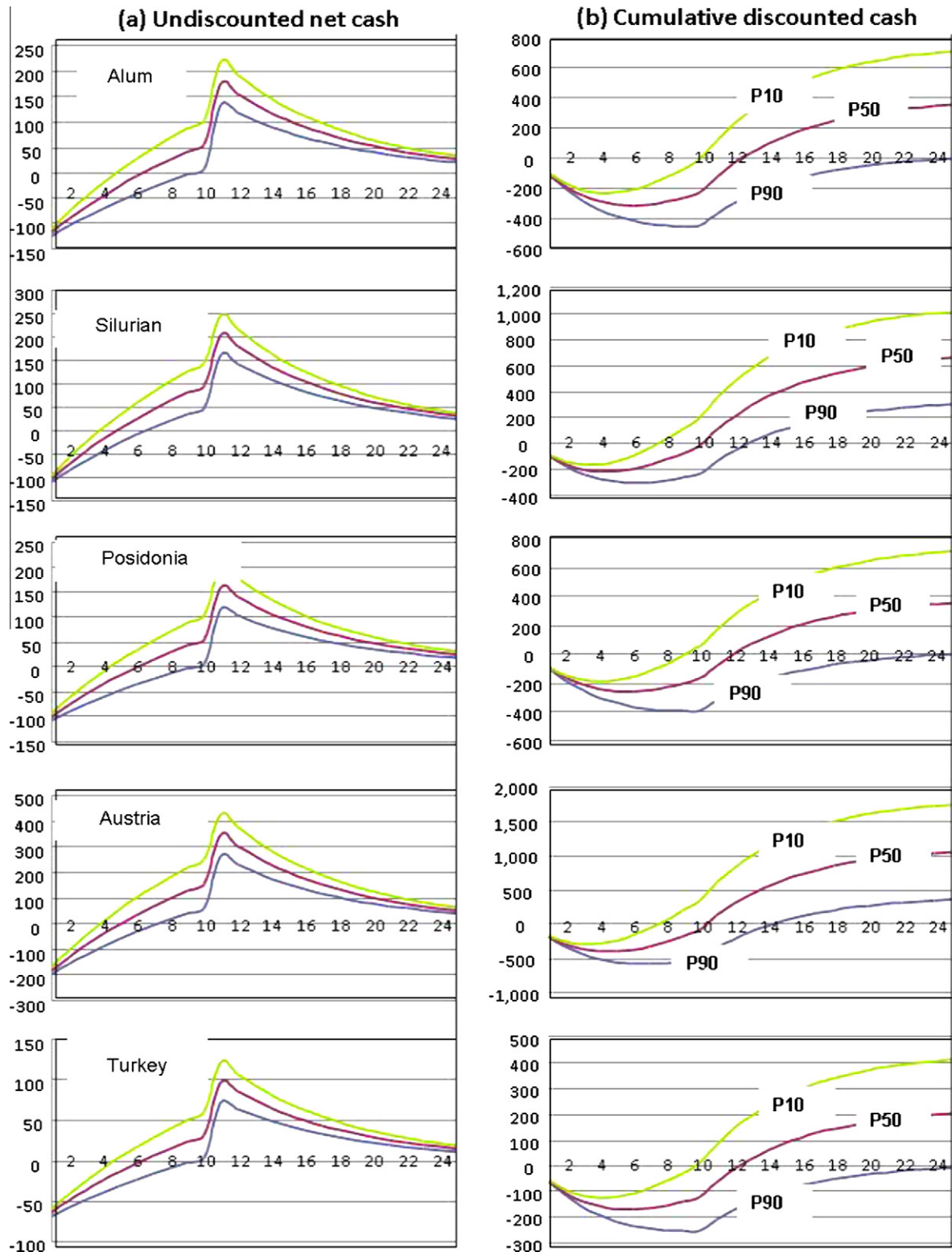
Our discounted cash flow (DCF) models for the shale plays in Continental Europe are based on the production profiles of Fig. 4a and b, a common gas wellhead price assumption of Fig. 5, and the specific field development expenditures as specified in Table 2.

The cash flow models, based on the base case well rates of Fig. 4a and b, show positive internal rates of return for all five major European prospective shale gas plays (Figs. 6 and 7). The IRR ranges between 20% for Polish Silurian shale at the top-end and 10% for Swedish Alum shale at the bottom-end. The undiscounted cash flow differs for each shale gas project (Figs. 6 and 7, left-hand panels) due to the differences in estimated well performance (EUR, Table 1), different cost base (OPEX, CAPEX) and more or less favorable royalty and taxation rates (Table 2). For all fields, the plateau of cumulative discounted cash flow is reached 25 years after the start of the standardized 100 well field development program (Figs. 6 and 7, right-hand panels). For the same 25 year lifecycle, the NPVs are all different, controlled by the local well productivity, cost structure and taxation policy. The 100 well field development project represents different NPV in different plays: \$737 million in the Alum shale (Sweden), \$1497 million in the Silurian shale (Poland), \$953 million in the Posidonia shale (Germany), \$2427 million in the Austrian shale, and \$565 million in the Turkish shale. The annualized revenues and break-down of the costs and benefits are specified in the undiscounted cash-flow curves of Figs. 6a,c, and 7a and c.

The outcome of the base case cash flow models for European shale plays (Figs. 6 and 7) are ranked, according to the key performance indicators (KPIs) given in Table 3. The ranking is based on NPV times IRR, divided by cash flow requirement times Payback. Our ranking suggests that Polish shale provides the most attractive investment option and Alum shale the least attractive.

### 4.1. Sensitivity of IRR and NPV to well productivity variations

Considerable uncertainty in our assessment of European shale gas economic resides in the EUR/well assumed for each play (Table 2). No conclusive well performance data are available from any European well tests. Well productivities for European shale plays can be constrained using US well analogs, which is practical until the first European development projects will finally get started. Based on comparisons to US analogs we can already conclude that the published EURs [4] seem optimistically high compared to productivities of US shale gas analog basins; the EUR is probably between 1.5 and 3 times too optimistic (author view). Given that the Woodford (~2 bcf/well, 25 year) provides a close analog for the European Posidonia shale, its estimated EUR of 3.25 bcf/well (25 year) may be 1.6 times too optimistic.



**Fig. 9.** (a and b) Uncertainty range of well productivity used P10–P50–P90 gas flow rates as input for cash flow projections for each of the five plays considered. (a) Spread in annual undiscounted net cash flow (in million USD) due to uncertainty about well productivity that can be realized (P10 – upper green curve for best wells; P50 – middle red curve for average wells, and P90 – lower blue curve for below average wells). (b) Corresponding spread in cumulative discounted net cash (equal to the discounted NPV) in million USD. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

We performed a Monte-Carlo simulation to calculate the sensitivity of the IRR and NPV on well productivity for the five plays considered. Fig. 8a summarizes the IRR sensitivity to spatial variations in well productivity (which determines the EUR). The Turkish

shale play considered here is best positioned for a rapid improvement of the IRR when well productivities improve during the progressive development of the shale gas field as geological uncertainty is reduced and technology improves. Of all shale



projects assessed here, the IRR of the Austrian shale play is least sensitive to EUR fluctuations (Fig. 8a). Additionally, the sensitivity of the discounted NPV to EUR variations for each field development project is summarized in Fig. 8b. The NPV is highest for the Austrian shale based on the well EUR estimations of Table 2. The NPV sensitivity to EUR variations is nearly similar for all plays considered. Differences in tax and royalty rates between the various countries are responsible for the slopes of NPV lines not being strictly parallel.

The results of Fig. 8a and b show the sensitivity of IRR and NPV to variations in individual well productivities within shale fields. The EUR range shown in Fig. 8a and b can be assumed representative for P50 wells in the shale plays considered. However, in the early development stage of an emergent shale gas play, it is unlikely that P50 well productivity can be attained when only a few wells are drilled. In order to provide an indication of the risk taken when only few wells are drilled, we incorporated into the discounted cash flow model a stochastic well productivity range, using a P10–P50–P90 spread for the gas flow rate (P90 for 90% certainty; P50 for 50% certainty and P10 for 10% certainty). The P50 values adopted in Table 2 for each play were assigned a Gaussian distribution for the well productivity spread with best wells (P10) set at 4/3 times P50 values (and P90 wells at about 3/4 times P50 values). These seem reasonable well productivity ranges based on our analysis of well spreads in US shale gas fields.

The undiscounted annual net cash flow and the corresponding cumulative discounted cash flow for P10–P50–P90 wells are summarized in Fig. 9a and b. These results provide additional criteria for play ranking. New shale plays in Europe and elsewhere have no producing shale gas wells to constrain the uncertainty of well productivity. Using P50 for a first economic appraisal cannot be justified as the likelihood of evening out poor P90 wells with excellent 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 the SPE Petroleum Resource Management System [31] and the SEC reserve reporting guidelines [32], which require conservative 90% certainty for EUR estimates of proved reserves. Contingent resources can be upgraded to reserves only when commercially producible. Companies therefore are well advised to use the EUR volume of P90 wells to assess the NPV of a new shale gas field. Fig. 9b shows that the P90 discounted cumulative net cash is zero for the Alum shale (Sweden), the Posidonia shale (Germany) and Turkey shale. This means their discounted P90 NPVs are all zero. In contrast, the discounted P90 NPVs for the Silurian shale in Poland and the Austrian shale are both positive, turning these two plays into the most attractive field development projects of the five options assessed. However, the IRR for P90 wells in the Posidonia (Germany), Alum (Sweden) and Turkish shale plays is about 5% for all three plays assessed (5%, 5% and 4.7%, respectively), which means that a 10% improvement in the IRR due to sweet spot targeting may lift the latter three shale plays above the corporate hurdle rate (commonly set at 15%).

## 5. Discussion and conclusions

For the sustained success of shale gas operations in North America, and for the successful development of new shale gas plays elsewhere in the world, the returns on investments in shale gas projects must remain profitable. A recent study by the US National Petroleum Council [33] stated that cheap and abundant US shale gas supplies could be sustained for long periods of time. Brooks [34] pointed out the weak economic fundamentals and inadequate economic assessment. The NPC report [33] ignored supply and demand dynamics currently setting wellhead prices for natural gas at

levels well below the true economic cost required to develop shale gas resources. Persistently low US natural gas prices have put severe pressure on the operational earnings of US natural gas producers since mid 2008. North America's shale gas companies have been unable to demonstrate a competitive advantage over conventional operators [35], weakened by gas prices that remain low as long as gas output rises faster than demand in a closed North American gas market.

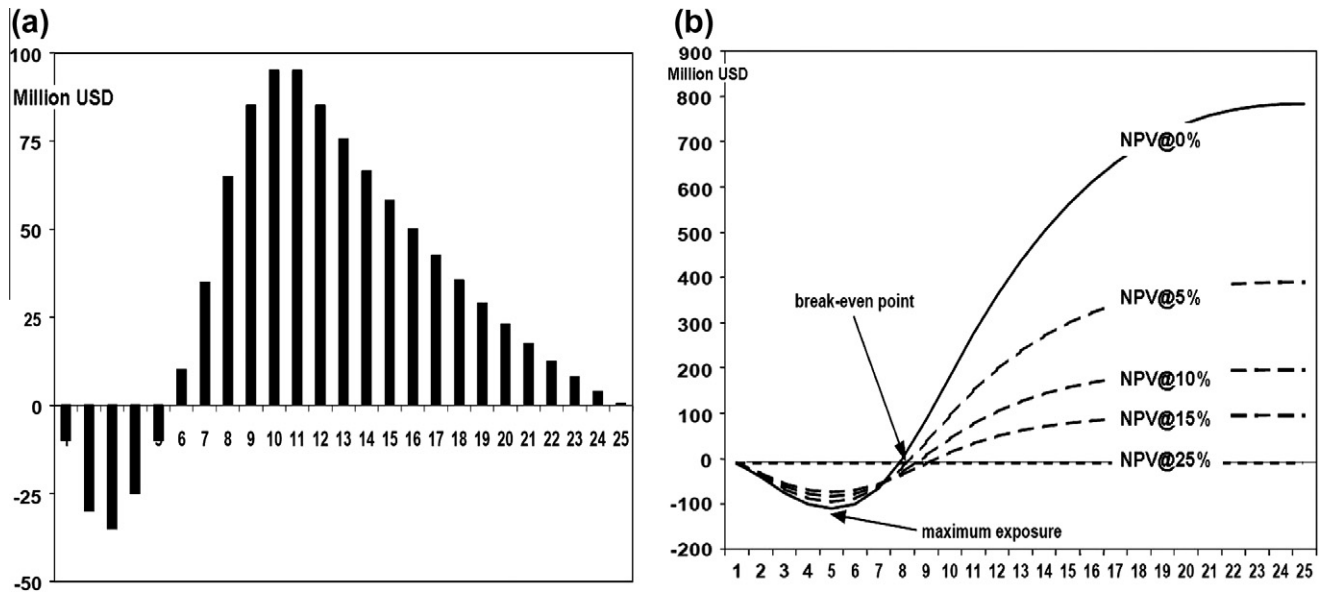
Cash flow analysis of a representative peer group of US shale gas operators [35,36] showed that their 2009 income was negative, whereas the income of the integrated oil majors remained robust. Clearly, North American shale gas plays are not the easy cash cows as sometimes asserted, and operational profits are presently not materializing for a large number of US and Canadian shale gas operators [37]. Land acquisition cost is increasingly booked by shale gas companies as sunk cost, separate from operational results, and becomes part of a land speculation investment. Consequently, only part of the current depletion, depreciation, and amortization is accounted for in the commercial assessment of Fig. 1b.

Field development plans for shale gas assets must use investment models based on realistic estimates of well productivity, price volatility and field development costs to ensure cash flow will remain positive [38]. This study is a first attempt to provide such models for emerging shale gas plays in Continental Europe. The cash flow models outlined in this study are based on well productivity decline curve analyses, which show cumulative cash flows will reach plateau after between 10 and 20 years of production. Longer well-lifecycle assumptions seem unrealistic for the economic assessment of shale gas plays in Europe and elsewhere. Emerging shale gas plays typically have a high degree of subsurface uncertainty due to which field development in the early stage inevitably includes wells with a lower productivity and marginal cash flow. The mean EUR for the field can grow when drilling rigs zoom in on the so-called sweet spots of a developing shale gas play. We showed a play ranking methodology based on the product of NPV and IRR divided by cash flow times payback to rank the relative value potential and economic viability of European shale gas provinces. This revealed the Polish Silurian shale as the most promising target and the Swedish Alum shale as the least promising target. The rankings of the other major European shale gas prospects are included in Table 3.

A bottleneck for the development of shale gas resources in Europe and elsewhere could become the stakeholder discussion, which delays the approval speed for the required permits. Mineral-rights are administered and granted by the federal government in all European nations – and not by the landowners like in the US. A major hurdle for commercial development of European shale gas plays lies in the slow and complex decision-making process for exploration and production licenses.

Local municipality councils can uphold the permission to drill. For example, Cuadrilla Resources planned to drill and test just two wells in the Netherlands in 2011, but local authorities under pressure of local community activists delayed the drilling plans for over a year (an a quick resolution seems remote). The modest field development rate of 10 well per year assumed in our analysis is slow compared to US standards, where several hundred wells have been annually drilled in active shale gas plays.

In each country, time to first production can be accelerated if the IEA golden rules [39] are applied to provide incentives for shale gas operators so these can establish an operational scale required to support a cost-effective shale gas service industry. Most production acreage in Western Europe is already under production licenses by conventional oil and gas companies, which handicaps the development of the unconventional resources. As long as conventional oil and gas fields remain profitable to the current concession holders, they are unlikely to farm-out their lucrative acreage



**Fig. A1.** (a) Annual cash flow ( $A$  in Eq. (A1)) over the 25 year lifecycle of a synthetic gas project. (b) Cumulative cash flow or net present value for this project climbs to 800 million USD if undiscounted for the time value of money [taking discount factor  $F = 0$  in Eq. (A3), giving maximum possible NPV@0%]; for a discount rate of 25% this project has NPV = 0, which is why the IRR for this project is 25%.

for shale gas extraction for fear of negative press from shale gas critics. In Eastern Europe, the situation is different: plenty of shale acreage has been acquired by major oil companies and smaller independents alike, with the specific purpose to explore and develop shale gas and tight gas resources.

Once exploration licenses are granted, shale gas companies can set out to explore and begin to evaluate TRR, IRR and NPV estimates which are essential to assess the profit potential of the new shale gas plays. Shale gas operators must zoom in on leads, prospective resources and then proceed to detect sweet spots that provide the attractive EUR for proved reserves. Rigorous economic analysis of shale gas wells under various assumptions is required to assure the sustainability of shale gas production and future field development activity [40]. Operationally Europe still has a lack of land gas rigs and mobile fracking fleets, all of which have to be brought in from US suppliers. This will make their deployment potentially more costly than in the US. Well performance metrics and cost control as well as tax liabilities also affect the EUR growth rate. Proved reserves can be claimed as collateral for further investor support, but securing the first reserves may require tens of wells to be drilled which is often beyond the means of junior shale gas companies.

To bring the new shale gas to market there must be a reference wellhead price from a regional gas market that includes the cost of gathering and connection to the main grid. If not yet established, such tie-in cost must be socialized and preferably co-financed by a gas transmission company with support from the national gas grid owners. If the cost of new gas gathering systems is prohibitive, gas-to-wire solutions may provide an attractive alternative.

Earlier studies have shown that drilling about 1000 wells per year would after 5 years result in 1 Tcf (~28.5 bcm) gas production for Europe [18,19]. A production output of 1 Tcf/year would cover approximately 5% of Europe's gas demand, but its realization is unlikely to proceed fast. Unless new policies clear the way to facilitate faster drilling permission processes, operators cannot turn shale gas plays into profitable business opportunities. Our appraisal emphasizes that discounted cash flow models are paramount for setting effective targets for production output and well technology expenditure to ensure positive returns on investment in new shale gas plays. The commercial success of shale gas operators in Europe

and elsewhere will be determined by their ability to control field development cost and optimize cash flow by selective drilling of only the most attractive resource opportunities.

We developed our own cash flow model, which is used by Alboran Energy Strategy Consultants for proprietary studies and field development plan evaluation. Numerous other software packages for financial modeling and evaluation of oil and gas projects are available from the market. While these model tools can be helpful, they do not provide a guarantee that output is relevant if users are indifferent to the complexities of assessing shale gas economics. Concepts like stochastic or discrete uncertainty modeling and time value of money are crucial for forward field development planning based on realistic well productivity assessment and sound economic appraisal.

#### Disclaimer

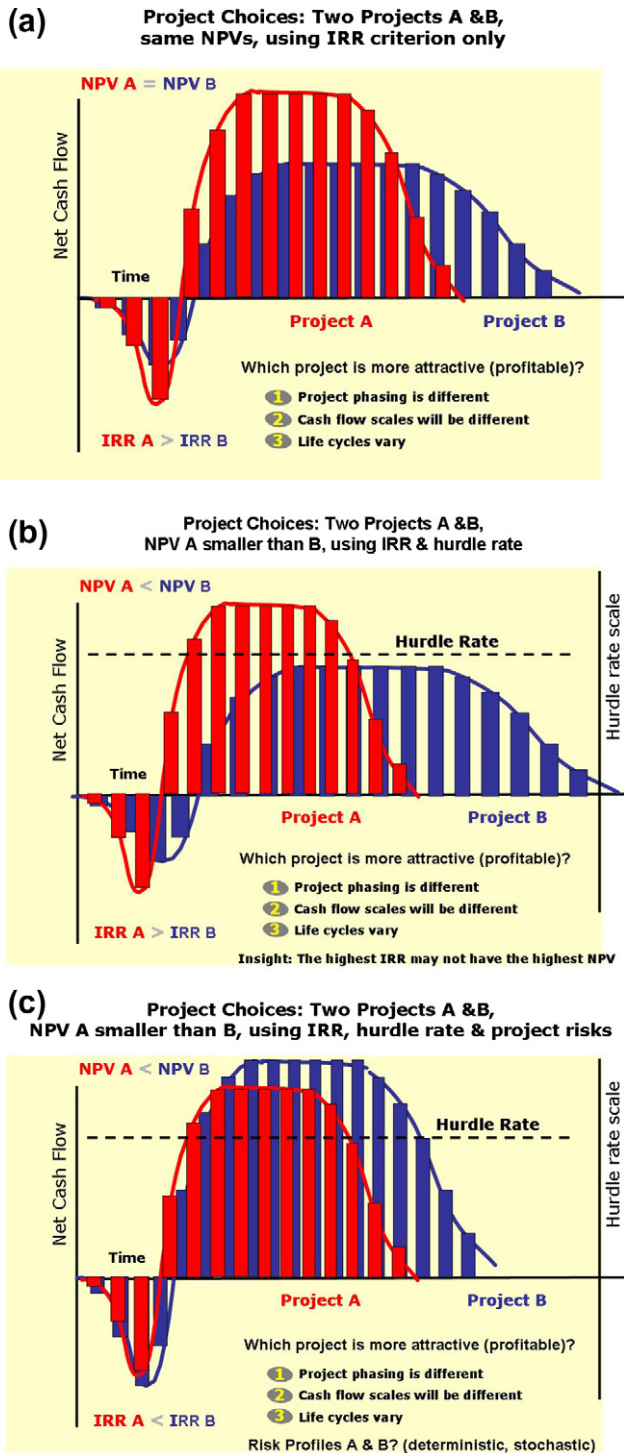
This study analyzes shale gas cash flow based on data abstracted from industry reports and academic studies. The analysis of these empirical data inevitably involves a degree of interpretation and uncertainty connected to the assumptions made. Although the results derived here are reproducible using 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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#### Appendix A. DCF analysis – methodology

We developed a comprehensive cash flow model by programming Visual Basic functions in Microsoft Excel. We define future cash flows based on annually averaged gas price projections and representative annual production volumes for a 'typical' well or array of wells. The logical functions used in our cash flow models are outlined below.



**Fig. A2.** (a–c) Cash flow models for NPV and IRR play a role in project validation and project ranking based on the required hurdle rate and performance expectation (Source: Alboran Research).

#### A.1. Cash flow

In any operational year the non-discounted cash flow is equal to gross revenue–CAPEX–OPEX–royalties–tax. The annual *non-discounted* cash balance ( $A$ ) follows from:

$$A = (P * Q) - \text{CAPEX} - \text{OPEX} - (C_R * P * Q) - (C_T * \text{Income}) \quad (\text{A1})$$

where  $P$  is wellhead gas price (hedging effects not taken into account),  $Q$  is annual production output,  $C_R$  is the royalty rate,  $C_T$  is the tax rate; Income is given by:

$$\text{Income} = (P * Q)(1 - C_R) - \text{OPEX} - \text{D}(\text{CAPEX}) \quad (\text{A2})$$

with  $\text{D}$  the depreciation rate of capital investments (CAPEX). Fig. A1a plots the annual cash flow ( $A$ ) for a typical conventional oil and gas project.

#### A.2. Net present value

The total, *discounted* cumulative cash flow, i.e. the cash flow aggregated over the lifecycle of the project is equal to the net present value (NPV):

$$\text{NPV} = \sum [A_t / (1 + F)^t] \quad (\text{A3})$$

with discount factor,  $F$ , the annual rate of discount accounting for the time value of money – commonly tied to financial market investment rates. The discount rate may be applied over the field lifecycle; with project time  $t$  starting at year 0 and ending at  $t = n$ . Fig. A1b plots the NPV at various discount rates according to Eq. (A3). For  $F = 0$ , the NPV is undiscounted.

#### A.3. Internal rate of return

The internal rate of return (IRR) is the average rate of return over the lifecycle of the project which is exactly that specific discount rate for which the NPV equals zero. If setting a discount rate at 25% reduces the NPV to 0, then you have found the IRR; in the case of Fig. A1b the IRR is 25%; technically the project NPV then turns 0. The relative IRR and NPV of different potential investment projects can be used to rank them for a final investment decision. Fig. A2a–c shows examples of such relative NPVs and IRRs for competing project options A and B. Project B of Fig. A2a is more attractive over project A, because B has a higher IRR. Project A of Fig. A2b is more attractive than project B in spite of its NPV being smaller than for B, but the IRR for A is superior. Project B is not acceptable in this case, because its IRR is below the corporate hurdle rate. Project B of Fig. A2c is clearly more attractive than A, which has a lower NPV and lower IRR than project B. As both project A and B are above the corporate hurdle rate, both projects could be adopted for a final investment decision. To conclusively decide whether project B remains attractive over A, it would be wise to include the uncertainty range (NPV and IRR sensitivities) in a stochastic or deterministic uncertainty modelling approach.

## Appendix B. DCA – methodology

### B.1. Empirical shale gas production decline curves

The gas flow rates commonly peak a couple of days after well clean up and flow rate decline sets in. Fig. B1a shows an example of production decline in the first year of well life. Over time, the decline is slowing down (Fig. B1b) and the empirical relationship to model the decline of flow rates,  $q$ , (Mcf/day) from a gas well, a hyperbolic decline function was proposed by Arps [43]:

$$q(t) = q_i / (1 + bDt)^{(1/b)} \quad (\text{B1})$$

with initial well rate,  $q_i$  (Mcf/time), decline constant or loss ratio,  $D$  (fraction/time), dimensionless decline exponent ‘ $b$ ’, and time,  $t$  (day/month/year). The function  $q(t)$  plots linearly in  $\log(q) - \log(t)$  space, with slopes determined by  $b$  values [44]. When  $b = 0$ , Eq. (B1) simplifies into an exponential decline function:

$$q(t) = q_i \exp(-Dt) \quad (\text{B2})$$

For the special case where  $b = 1$ , Eq. (1) simplifies into a harmonic decline function:

$$q(t) = q_i [1 / (1 + Dt)] \quad (\text{B3})$$

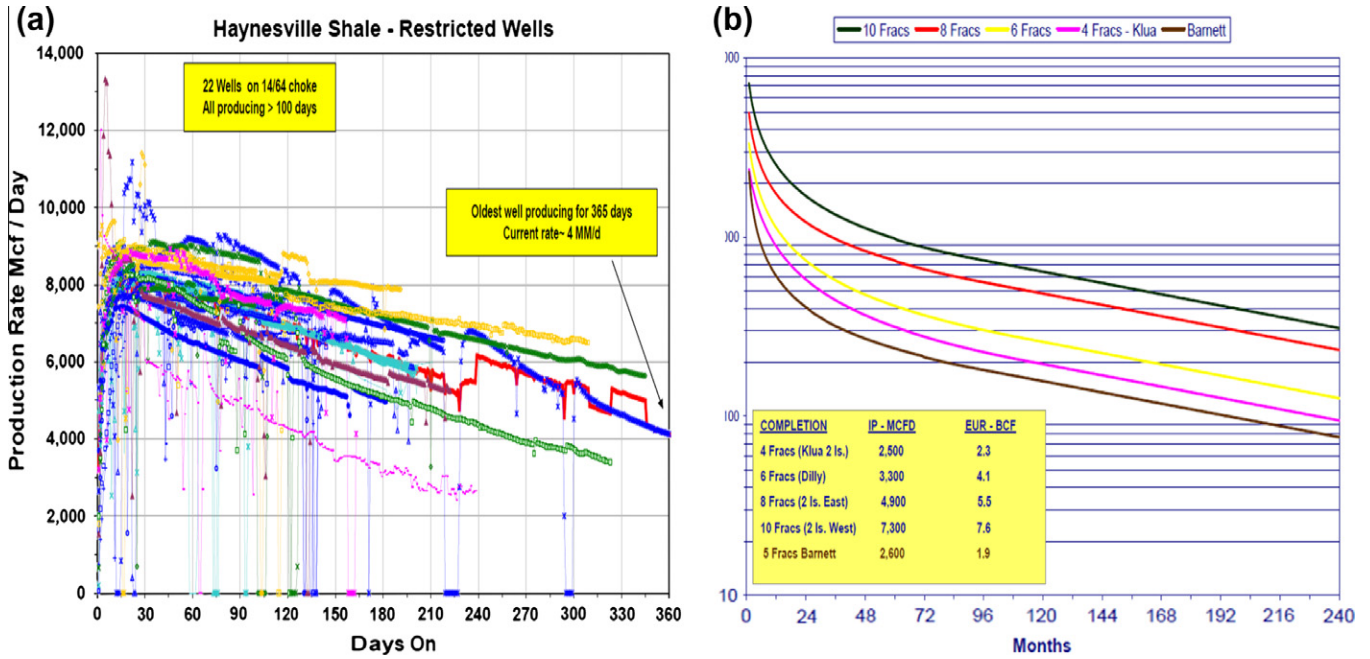


Fig. B1. (a) Production log for 22 producing wells (Source: Petrohawk [41]). (b) Production stimulation by increasing frac stages in the US Horn River Basin (Source: Apache [42]).

and  $q_i$  is the initial flow rate and,  $D$ , the power-law decline constant (unit: 1/time to power  $n$ ).

When attempting to find the constants in Arps' hyperbolic decline equation for tight gas and shales wells, the "best fits" often require values of "b" to be greater than one [45]. However, values of  $b$  equal to or greater than one can cause the reserves derived using Arps' decline equation to have physically unreasonable properties [25,45]. For describing the production rate from shale and low permeability reservoirs, an extension to simple exponential decline forecast model has been proposed [46–48], which is a Power Exponential Decline function (PED):

$$q(t) = q_i \exp(-D_0 t - D_i t^n) \tag{B4}$$

with,  $q_0$ , the initial flow rate,  $D_0$ , the initial decline rate as a fraction loss over time, and,  $D_i$ , the power-law decline constant (unit: 1/time to power  $n$ ).

A Levenberg–Marquardt minimization technique can be incorporated [49] to account for the fluctuation level in the production rate by minimizing the squared difference between the measured and calculated rates. For the simple exponential decline of Eq. (B2), this function is:

$$q(t) = q_i \exp(-Dt) + q_i f_n (0.5 - r) \tag{B5}$$

The "scatter level",  $f_n$ , varies between 0 and 1, and the random number,  $r$ , also varies between 0 and 1. The distribution of the random number can be a normal distribution, or skewed lognormal distribution. For the PED of Eq. (B4), this function is:

$$q(t) = q_i \exp(-Dt - D_i t^n) + q_i f_n (0.5 - r) \tag{B6}$$

The cumulative production of all wells, using the values  $Q_n$  from the wells  $W_n$  is equal to the total production  $TQ_n$  in year  $n$  and for all previous production years is given by:

$$TQ_n = \sum_{k=1}^n Q_k \times W_{(n+1)-k} = \sum_{k=0}^{n-1} Q_{k+1} \times W_{n-k} \tag{B7}$$

For example, the total production in year 4 equals  $TQ_4 = Q_1 W_4 + Q_2 W_3 + Q_3 W_2 + Q_4 W_1$ .

The EUR is given by the cumulative production at which the average reservoir pressure is equal to the wellbore pressure [48]. It was noted by Lee and Sidle [45] that this definition needs to be corrected by subtracting production volumes that are below the economic limit to comply with SEC and PMRS reserves definitions.

### Appendix C. Gas price modeling

#### C.1. Historic gas prices

Natural gas prices are subject to regional market dynamics and may differ considerably in the world's major gas markets (Fig. C1). The oil-indexing of the Continental European gas prices ensures that these rise in step with the recovery of the global oil prices [30]. The European and US gas markets in effect have become

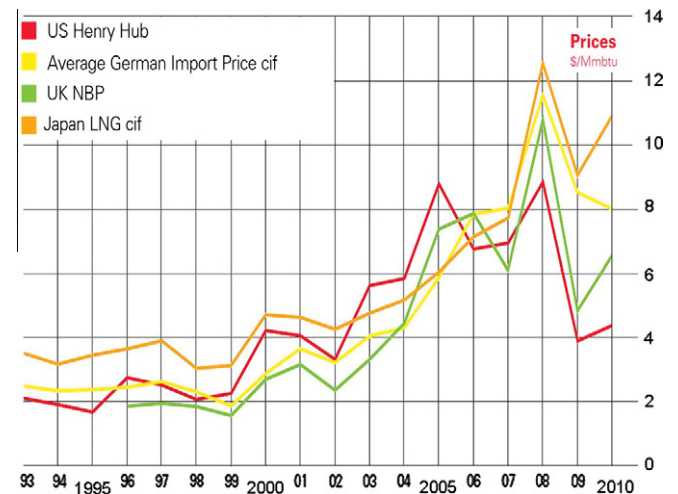
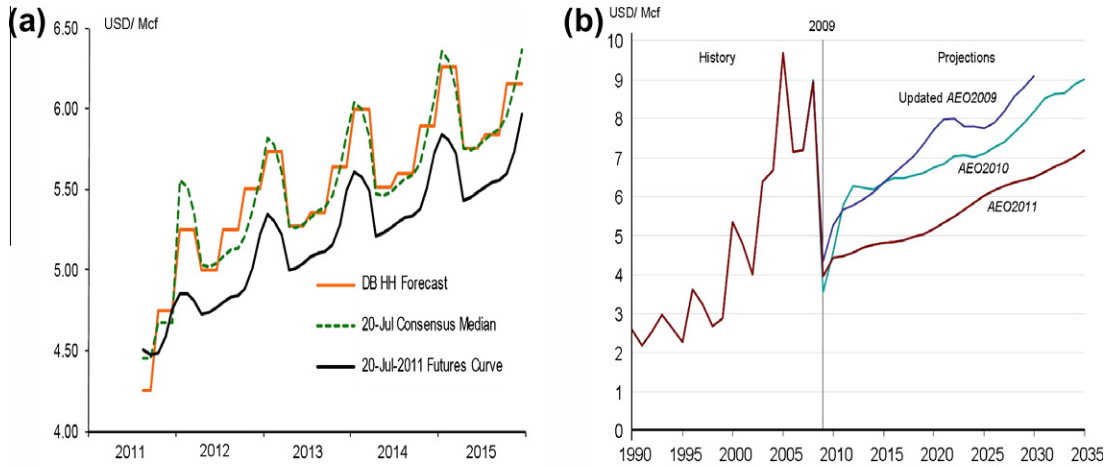
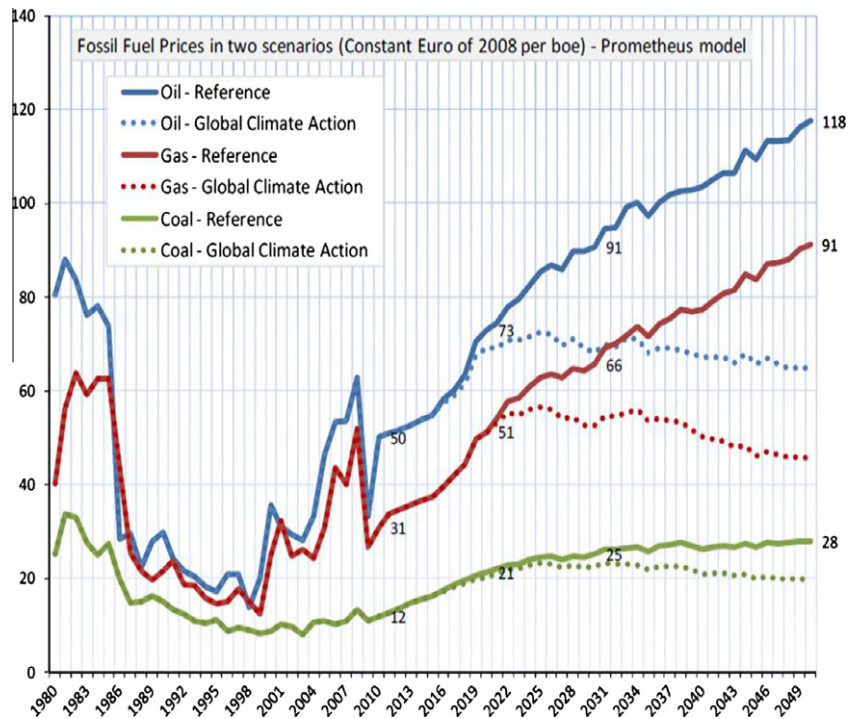


Fig. C1. Annually averaged prices for natural gas (\$/Mmbtu ~ \$/Mcf) in the world's major gas markets (Source: BP [5]).



**Fig. C2.** (a) Forward short-term price curve for US spot gas for the Henry Hub reference point based on NYMEX futures and slightly higher projections by the Deutsche Bank. (b) US gas price projections (annual averages; real, inflation adjusted historic prices) according to 2009 long-term forward model by the Energy Information Administration (Source: DOE/EIA [52,53]). The AEO 2011 model is the reference scenario.



**Fig. C3.** Fossil Fuel prices for Europe in two scenarios modeled by the E3MLab, National Technical University Athens [54].

decoupled, which may result in a large price differential between these two major gas markets [29]. Since the onset of the Great Recession in 2008, natural gas prices in the various regional gas markets have maintained distinct price levels (Fig. C1). The average Japanese 2010 LNG price was nearly \$11/Mcf, long term contract gas deliveries in Continental European fetched \$8/Mcf, the UK spot gas price at the National Balance Point was about \$6.50/Mcf, and the US Henry Hub reference spot gas price averaged \$4.40/Mcf [50]. The variations in gas prices for US end-consumers has been analyzed in-depth elsewhere [51].

*C.2. Future gas prices for the US*

The short term US gas price forecast (with seasonal swings in step with the demand cycle) is given in Fig. C2a. The baseline is

set by the NYMEX gas future contracts, and the higher scenarios are by Deutsche Bank economists, projecting a median US gas price of \$6/Mcf by 2015. Fig. C2b shows the mid and long term US gas price scenarios by the US Energy Information Administration. The model assumes price pressure from shale gas production in a constrained North American gas market will keep US gas prices relatively low for the next few decades. This US gas price scenario sets a lower limit for gas prices in other world regions.

Demand for gas continues to grow in all major gas markets. Even assuming such unconventional gas will come on stream worldwide, Europe and Asia will continue to compete for access to LNG and pipeline gas imports to fill an imminent gas supply gap. Consequently, gas prices are set to rise further over the next decades.

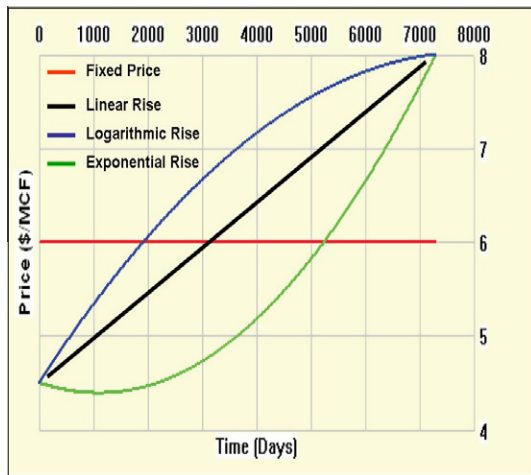


Fig. C4. Examples of gas price function assumption (adapted from [49]).

### C.3. Future gas prices for the EU

Europe is already paying high prices for fossil fuel energy imports. For example, wholesale gas prices in Continental Europe are between two to five times higher than in the US [26–30]. Little downward pressure on EU natural gas prices is to be expected in the coming decades, as natural gas import dependency will rise to 75% by 2030 [14].

Future fossil fuel prices for Europe are modeled in the Prometheus model, the European Commission's Energy-Economy-Environment System Model (E3M), developed at the E3MLab of the National Technical University of Athens [54]. Fig. C3 shows that natural gas prices will continue to rise over the next three decades, unless downward price pressure is imposed by Global Climate Action. The baseline trajectories for the EU27 price of oil, gas and coal assumes a conventional development of the world energy system. Fig. C3 further shows that the switching to renewable energy in the Global Climate Action scenario can provide downward pressure on fossil fuel prices. Switching to renewable sources requires heavy upfront investments to accelerate the energy transition, but fossil fuels cannot be phased out at once [55].

Table D1

Typical cost & expenditure for oil & gas companies.

Term	Description	Alternative terms & explanations
LOE	Lease operating expenses or OPEX	Lifting cost, production cost, includes gas processing cost, i.e. removal of water, CO <sub>2</sub> and H <sub>2</sub> S
Basis	Gathering & transportation cost	Cost for bringing gas from the wellhead to the entry point of the gas transmission operating system
G&A	General & administration costs	Overhead cost of the company, including insurance policy payments
Direct Taxes	Direct taxes other than income taxes	Production, severance and labor taxes; may include royalties
Interest	Cost of debt capital	Cost depends on credit rating of the company
Exploration	Cost of exploration or finding cost. Firms that use the successful effort accounting method capitalize only those exploration costs associated with successfully locating new reserves. Cost for dry holes and unsuccessful plays are immediately expensed	Firms that use the SEC full-cost accounting method retain all exploration costs and account for cost of dry holes and asset impairments. Includes cost of geophysical data acquisition (logs, seismics) and evaluations of resource potential. This cost then prorates over the FD&A of successfully developed assets
Acquisition	Acquisition accounts for cost of land leases, any signing bonuses and permits, plus title searches	Purchases of new acreage by new project, joint venture or M&A activity; cost of future acreage may be more expensive to acquire when signing bonuses go up (or reverse)
F&D	Finding & Development cost (F&D) is complementary to purchases and acquisitions when accounting for finding and development cost, excluding the cost of land lease	F&D accounts for cost of exploration, drilling and well completion cost; including the cost of any hydraulic fracturing and other well stimulation techniques
FD&A	All-in finding cost, defined as all costs incurred for acquisition, finding (exploration), and development (drilling and well completion), divided by the sum of reserve extensions, additions, and revisions	Reserves replacement cost; cost of any EOR or overhaul is also accounted for in FD&A, incurred cost will lead to higher recovery factor and increases reserves; cost of abandonment of platforms & wells not
DD&A	Depletion, depreciation & amortization; Depletion means depreciation of cost for replacement of reserves produced; the depreciation matches diminished value of assets acquired via past FD&A cost	Impairment of gas property asset carrying value can lower current DDA cost; downtime of well will mean production is deferred; no depreciation cost over deferred production
Other Depreciation, Amortization	Depreciation & amortization of additional property & equipment, often gathering and midstream pipelines	May also include depreciation cost of company vehicles used for operations and any storage facilities
Impairment	Impairment of gas property asset carrying value. Impairments include amortization of unproved oil and gas property costs, as well as impairments of proved oil and gas properties	Unproved and proved properties with significant acquisition costs are amortized over the lease term and any impairment in value is immediately expensed based on NPV analysis
Abandonment R&D	Cost of abandonment of installations Cost of research and development	Asset retirement cost Major companies incur significant R&D cost (commonly 1% of earnings), which is expensed on the income statement before income taxation
Discount	Discount value is commonly set at 10% in SEC filings and accounts for risk premium	Corporate hurdle rate, accounting for return on capital risked
Comments		
Depreciation	Depreciation refers to prorating a tangible asset's cost over that asset's life. The cost is spread out over the predicted life of the field, with a portion of the cost being expensed each accounting year	For example, an office building and fixed wellheads can be used for a number of years before these become run down and obsolete
Amortization	Amortization usually refers to spreading an intangible asset's cost over that asset's useful life. For example, the cost of a licence is spread out over its life cycle, with each portion being recorded as an expense on the company's income statement	It is important to note that in some countries (e.g., Canada) the terms amortization and depreciation are often used interchangeably to refer to both tangible and intangible assets

#### C.4. Price algorithms

For the economic evaluation of shale gas wells, assumption of a constant gas price over the life cycle of the well would underestimate the true NPV of the well. Gas price functions, used in economic models of gas production, can be: fixed (no change), linear (steady change), exponential (late gas price riser), or logarithmic (early price riser, Fig. C4a). Such models smoothen the seasonal changes that affect US wellhead prices (Fig. C2a). To account for seasonality, future gas prices can be modelled using a linear regression function (Fig. C4b) [56,57]:

$$y_i = \beta_1 x_{i1} + \dots + \beta_n x_{in} + \varepsilon_i = x'_i \beta + \varepsilon_i \quad (C1)$$

with index 'i' accounting for the number of years of possible gas sales from the well. Several price functions can be adopted. Our model uses the simple inflation function given in Eq. (2) of the main text.

#### Appendix D. Cost and expenditure estimates

This section outlines the typical cost and expenditure for shale gas companies. Table D1 provides an overview of terms and a brief explanation of their meaning (after [35]).

##### D.1. CAPEX

The capital expenditure for a shale gas development is to a large degree determined by its subsurface properties and technology solutions selected for extraction. Most of the items included in Table D1 are CAPEX items, which cover drilling, well completion and tie-in cost. Decisions about well development technology may have a cardinal impact on the cash flow performance for the shale gas field development project. CAPEX also includes the cost of land acquisition for access to the acreage (FD&A). Leasehold access and associated signing bonuses are another way of securing access to shale gas acreage. Acreage value goes up when well EURs increase in 'sweet spots'. Some typical CAPEX items are listed in Table D2.

##### D.2. OPEX

The operating expenditure (OPEX) for large conventional oil and gas projects is often indexed at 5% of total CAPEX. However, for shale gas wells it may be more appropriate to index OPEX to well flow performance. For example, for the Barnett OPEX has been

**Table D2**

Typical US cost of CAPEX items. Source: East Resources (see [57])

Tangibles	Cost in USD
Conductor casing	
24'	62/ft
20'	48/ft
9.625'	29/ft
Surface production	20,000
Well completion	
Horizontal well drilling	5,000,000
Multilateral well-drilling	11,000,000
Frac Job	1,000,000
Intangibles	
Site preparation	100,000
Drilling contractor services	120,000
Materials & supplies	50,000
Logging, stimulation & perforations	400,000
Power, water disposal	37,000
Installation, completion labor	40,000

fixed at \$1/Mcf as a benchmark [58], and operating cost inflation over time should be accounted for by an annual cost inflation rate of 2.5%. An additional rate for general and accounting cost should be added at a rate of 0.5 \$/Mcf.

##### D.3. Royalties, tax liabilities, depreciation and discount rate

The economic analysis of shale gas wells is critically dependent on reliable information on regional rates for royalty, tax liabilities, depreciation and discount rates. For example, Alberta (Canada) uses a 30% Crown's royalty for large profitable conventional gas production, but allows much lower rates for low productivity wells according to an elaborate royalty formula based on production rates and whether gas is from 'old, conventional' or 'new, unconventional' wells. US royalty rates range between 12% and about 20%. Royalty rates in Poland are 1–5% and income tax is 19% (see Table 2, main text). Depreciation rates for investment in tangibles must comply with the established accounting practices. The discount rate to be used for the time value of money is sometimes prescribed by a regulatory agency. For example, the SEC mandates 10% discount rate should be used in economic assessments related to reserves reporting. A lower discount rate of 5% was applied in the DCF analysis of the main text (Table 2). This does not affect the IRR estimates (commonly used for project appraisal), but the NPVs quoted will be lower if higher discount rates are used.

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