US shale gas production outlook based on well roll-out rate scenarios

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HIGHLIGHTS

- Future gas production output from US shale plays up to 2025 is modeled.
- Three distinct drilling scenarios are assumed for the six major US shale plays.
- Cumulative US production output from the combined shale plays is quantified.
- Bottom-up model is compared with top-down NEMS forecasts.
- Our scenario models indicate that steady growth of US shale gas supply cannot be ascertained.

ARTICLE INFO

ABSTRACT

This study models the uncertainty range in the future gas production output from US shale plays up to 2025. The future spread in gas output in our models follows from variations in the number of wells that will be drilled according to three distinct scenarios. Each scenario assumes a well development plan for the six major shale plays over the studied period and then quantifies the cumulative US production output from the combined shale plays. We compare the bottom-up model results with other model projections for future US shale gas output, including the top-down shale gas production forecasts by the US National Energy Modeling System (NEMS). The remarkable growth of North American gas output from unconventional resources has been highlighted in numerous industry reports and government publications, but what has remained relatively underexposed is the deterioration of economic margins due to the failure to predict the gas price decline in the North American market. The past development record of North America's shale gas resources suggests that security of future gas supplies seems ensured, but here we develop a contrarian view. Our scenario models take into account the effect of recent declines in gas rig counts and decline in gas well completions due to the depressed gas prices. A scenario with declining shale gas output – one of three scenarios considered – cannot be excluded as being unlikely to occur, which means the future security of US gas supply that assumes a steady growth of shale gas supply cannot be ascertained at present.

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1. Introduction

In the 1990s the US feared a growing natural gas supply gap would occur due to the steady decline of gas output from its conventional gas resources. The projected shortage was an incentive to construct new landing terminals for re-gasification of liquefied natural gas (LNG) with an appropriate capacity. The US was expected to become the world's second largest LNG importer by 2010 [1]. In 2012, the US total LNG re-gasification capacity of the combined LNG terminals on the US Atlantic and Gulf of Mexico coasts amounted to about 15 Bcf/d, but the shale gas revolution has made LNG importation completely redundant. The progressive downgrading over the past years of the anticipated need for LNG

importation is summarized in Fig. 1a. The explosive growth in US shale gas production output over the past decade occurred so fast that the anticipated decline in gas supplies from North American resources did not occur. The LNG re-gasification capacity built by the US is highlighted in Fig. 1b. The capacity of the US LNG re-gasification terminals in the US lies largely idle, representing a combined capital waste of over $40 billion, but plans for exportation refits are gaining momentum.

The rise in US natural gas output was the more remarkable, because it occurred in spite of a decline in gas production from its conventional resources (Fig. 2). The domestic gas production growth is entirely due to the development gains from three major unconventional gas resources (tight sand, coal and shale), and is lead by the steep rise of shale gas output (Fig. 2). Net gas imports have shrunk since 2005 and come exclusively from Canada via long distance pipelines. At the end of 2012, shale gas accounted for 24% of US gas demand and even the 10% net gas importation from Canada is extracted for a majority proportion from non-conventional gas fields [2]. The development of North America's unconventional gas resources suggests that security of supply seems ensured, but here we develop a contrarian view based on scenario models of future US gas output that take into account the recent decline in gas rig counts due to the depressed gas prices.

The earlier shale gas production boom was facilitated by rising gas prices and easy credit facilities in the first half of the past decade. US gas rig counts have closely followed the early rise of North American gas prices (Fig. 3), as rising gas prices encouraged investors to make positive final investment decisions for shale field development. The remarkable growth of North American gas output from unconventional resources has been hailed in numerous industry reports and government publications [3–6]. But what has remained relatively underexposed is the subsequent failure to predict the magnitude and effect of the gas price decline in
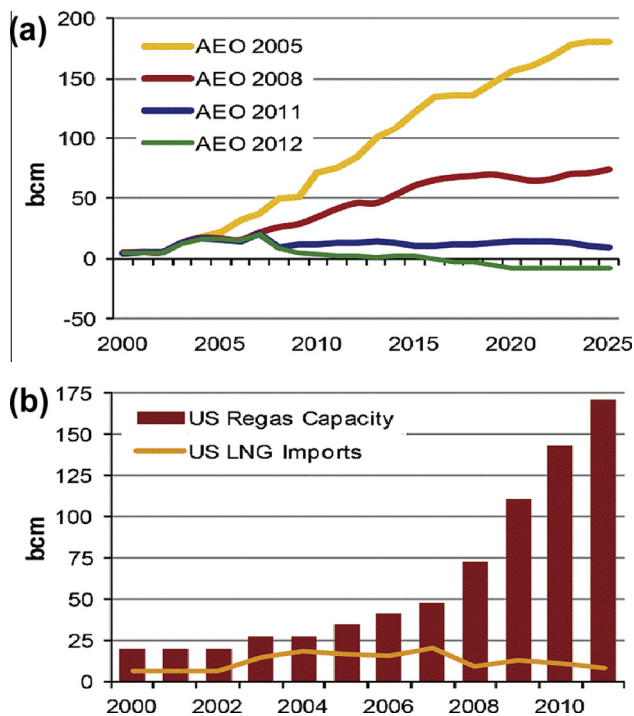

Fig. 2. US historic gas production record (in Trillion cubic feet per year – Tcfa) and forecast till 2035. Shale gas accounts for 24% of US 2012 total gas demand, but DOE/EIA expects this to have doubled by 2035. According to the US Department of Energy (DOE), US gas net imports will be displaced further by growth in the domestic shale gas production (US Energy Information Administration, Department of Energy).

Fig. 3. US Henry Hub gas prices (solid shaded spikes are daily averages; left hand scale) and total US gas-rig count (single curve: right hand scale) over the period covering the US shale-gas bonanza (1999 to medio 2012). Active drilling rigs were scaled back when gas prices dropped. US gas prices for 2012 dropped below January 1999 levels, hovering about $2/Mmbtu, and the gas-rig count fell back below 500. (Henry Hub prices from NYMEX and gas-rig counts after Baker Hughes.)

Fig. 1. (a) Progressive reduction of forecasted US LNG importation need (in billion cubic meter – bcm), according to the US Energy Information Agency in its annual energy outlook reports (AEO, 2005, 2008, 2011, 2012). (b) The LNG landing terminals were constructed with a capacity (bcm) that is hardly utilized (see LNG import curve) due to the emergence of domestic US shale gas production (PFC Energy Consultants).
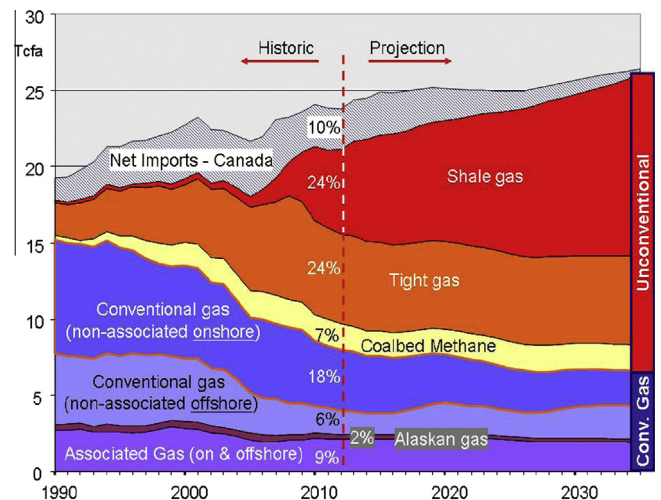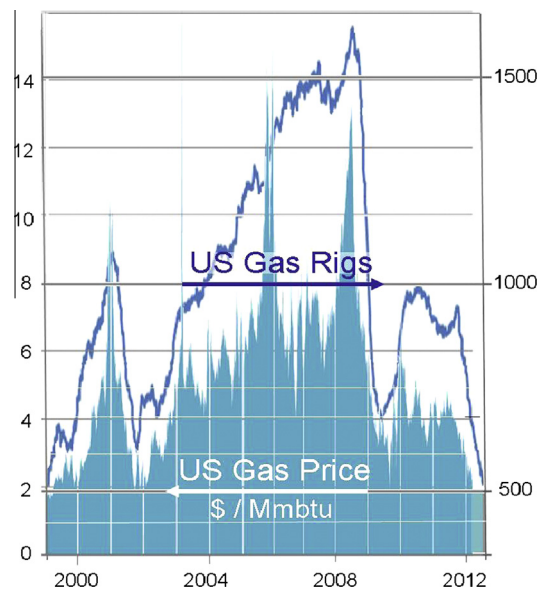
the North American market. The US National Energy Modeling System [7,8] used to model the gas price forecasts in the annual energy outlook by the Energy Information Administration (EIA), did not predict the steep gas price decline that occurred between 2008 and 2012 in any of its gas price scenarios over the past five years. For example, the AEO2012 gas price forecast (Fig. 4), which is based on model input data as per January 2010, was unable to predict the gas price dip below $2/Mmbtu that occurred in the first half of 2012. In fact, a low gas price case of $4/Mmbtu was assumed, which is considerably higher than the 12 month average price for 2012. The principal reasons for the large difference between the NEMS gas price forecasts and the actual prices are discussed in Appendix A.
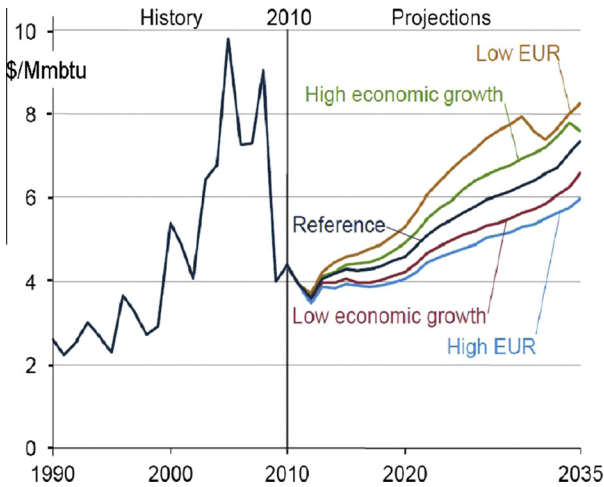
Fig. 4. Historic Henry Hub gas prices (annually averaged) and NEMS gas price forecast scenarios till 2035, according to AEO 2012 (US Energy Information Administration, Department of Energy). Low and high EUR refer to higher or lower than expected estimated ultimate recovery (EUR) from the shale gas wells.

The steep rise in the number of producing gas wells realized in the first half of the past decade was responsible for the growth of gas output from the US shale plays. But the number of active gas rigs has declined since 2008 (Fig. 3), which means a continued rise in US shale gas output is by no means ensured. We now know that overproduction began to push North American gas prices far below production cost after 2008. Since then, the gas bills of US consumer have been subsidized on average for more than half by shale gas investors. This can be inferred from the fact that the revenues from

US natural gas sales after 2008 paid for only half of the operating cost [9,10], the rest of the capital cost and operating expenses of shale gas producers has been paid for by financing activities: new share issues, short-term and long-term loans, asset sales and volumetric production payments.

With fewer rigs drilling for gas in all of the major US shale-gas plays (Fig. 5a–f), the point where productivity decline of older wells will start to outpace the production added by newly drilled wells is getting nearer. For all of US shale plays, the gas rig counts exhibit a continual decline since the gas price deteriorated after its 2008 peak and failed to recover in the five years passed since (till December 2012 cut-off date when the scenario models for our study were completed). For gas rig counts to go up, the gas price needs to rise. Unless the gas rig counts go up again, the gas output of the US shale plays will remain flat for 2013 and is likely to shrink in the second half of 2014 onward (see Section 4). Although fewer rigs are active, drilling and completion jobs have become more efficient and rig count decline does not necessarily everywhere translate to fewer wells being drilled. The decline in the Barnett and Haynesville, the two US shale gas fields with the largest output, is real. Also fewer wells are drilled in the Woodford and Fayetteville, but in the Eagle Ford and Marcellus well numbers seem relatively steady in spite of the rig count declines (see Section 3).

This study models future US shale gas output scenarios based on a bottom-up approach using the production profiles of actual wells drilled. Using actual wells drilled rather than rig counts as model inputs with extrapolation of well rates to the future gives projections of how the US gas production profile may change in the future. The three output scenarios modeled are based on historic well roll-out rates and forward production modeling assuming various possible options for future well roll-out rates. The number of annual wells drilled in each play is matched with
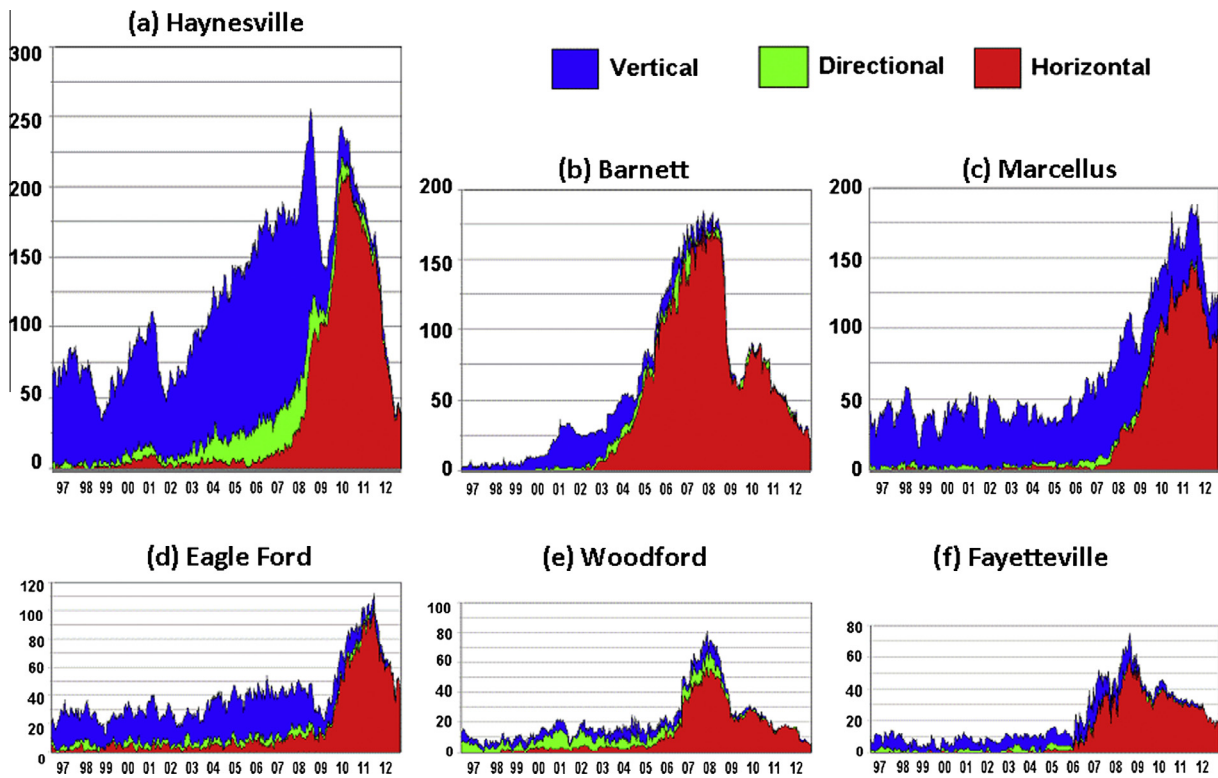
Fig. 5. (a–f) Rig counts (vertical scales) for the major US shale-gas plays over 16 year time span (1997–2012). For all US shale plays the principal final investment decisions for field development (mostly using horizontal wells) were taken shortly before the financial crisis of 2008. Subsequently, rig counts followed the gas price decline. a: Haynesville, Louisiana. b: Barnett, Texas. c: Marcellus, Pennsylvania. d: Eagle Ford, Texas. e: Woodford, Oklahoma. f: Fayetteville, Arkansas (Rig counts courtesy Baker Hughes and WTRG Economics).
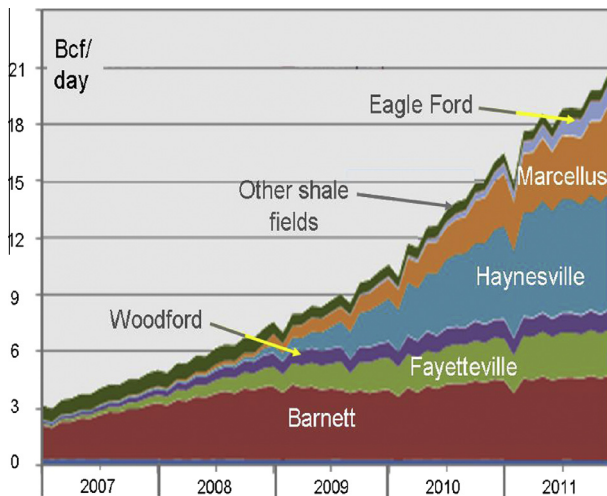
Fig. 6. Growth of US shale-gas daily production output (billion cubic feet per day) since 2007 due to the cumulative effect of earlier accelerating gas drilling activity and shifts to horizontal wells (AEO 2012 US Energy Information Administration, Department of Energy).

calibrated production curves (Section 2) to determine US shale gas output scenarios up to 2025 (Section 3). We then compare the bottom-up model results with the NEMS top-down shale gas production forecasts and highlight the differences (Section 4). We also discuss our model limitations and effects of technology learning, deterioration of public support and restrictive regulation (Section 5.1) Our scenarios are compared with other recent bottom-up and top-down US gas models to benchmark the validity of our results (Sections 5.2–5.4).

2. Future shale gas production scenarios

US shale gas production occurs mainly in six major plays, as becomes obvious from the historic production output profiles compiled in Fig. 6. The future production output in each of the US major shale gas plays will most likely follow the recovery path of US gas prices. Higher gas prices will enable the development of more technically recoverable shale gas resources (TRR) that are presently not economically recoverable resources (ERR), which means that rising gas prices can close the economic gap between TRR and ERR [11–13].

We have already demonstrated that the US gas price is an excellent predictor for the gas rig count (Figs. 3 and 5). For our production scenario models, historic well counts provide a better starting point than rig counts. We have abstracted well counts from the State records for each of the major shale gas plays (Fig. 7a–f). The number of annual well additions between 2001 and 2012 is based on the registered record, and the well additions between 2013 and 2025 may vary according to three scenarios modeled in this study. These scenarios assume different well roll-out rates, all of which are feasible depending on developments in the North American gas market that control the future gas price:

– *Scenario A ("Shale Drilling Rebound Scenario")* assumes a sustained recovery with new well addition rates increasing after 2014. After a brief period of constant well additions at 2012 levels in 2013 and 2014, each subsequent year new wells are added with 100 more wells than in the preceding year in each of the major shale gas plays up to 2025. This scenario requires gas prices to firm up in 2013 and 2014, supported by LNG export licenses to connect the US gas market to the global LNG market so that rising gas prices will justify accelerated development of US shale gas.

– *Scenario B ("Steady Shale Drilling Scenario")* assumes steady well roll-out rates with an equal number of new wells drilled each year, adopting 2012 well addition rates for the next 13 years until 2025. LNG exports are not necessary in this scenario but domestic supply must be kept slightly tighter than demand in the North American gas market, so that a gas price rebound helps investors to capitalize their shale asset value. Gas prices then justify a continuation of new drilling programs at the already high rates seen in 2012.

– *Scenario C ("Declining Shale Drilling Scenario")* assumes well addition rates to decelerate and each year 100 fewer wells are drilled than in the preceding year to finally settle at only 100 new wells being drilled annually in each of the major US shale gas plays. The decline in new well additions in this scenario is due to a lack of earnings from shale gas investments. The pace is set by a sluggish recovery of the US gas price and the negative or slim economic margins on shale gas projects make the investment required to add more new wells unattractive. In this scenario, the US gas price fails to firm up fast enough to make shale gas projects profitable.

3. Modeling methodology

In our model the annual production output for each shale play is calculated based on the cumulative production of all wells. The production of individual wells is modeled by a decline function, adopting the estimated ultimate recovery (EUR) values used in AEO2012 [14], Table 7) and the key components are summarized in Table 1. Shale gas resource assessments are periodically published by the USGS (cf. [15] and additional data from State agencies are used as a guide for the key parameters assumed in AEO2012. The exponential decline function adopted here is as follows:

$$Q_n = Q_1 \cdot (1+r)^{n-1} \tag{1}$$

with Q_1 the production in year 1 and decline factor r. We use a constant decline factor of -0.15. The production in year n is given by Q_n. Fig. 8 shows the typical production profiles for each shale play over the maximum lifecycle of 25 years for wells drilled in and after 2001. The average well production rate is given in Table 1 which are the inferred values that correspond to the EUR averages of AEO2012, assuming a moderate 20 year lifecycle for individual wells. As wells are drilled in subsequent years, we can model production output over 12 years forward. The total shale field production TQ_n in year n for the number of wells W is given by:

$$TQ_n = \sum_{k=1}^{n} Q_k W_{(n+1)-k} = \sum_{k=1}^{n} Q_{k+1} W_{n-k} \tag{2}$$

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 decline curves will never assume zero flux as is visible in the type curves of Fig. 8. Appendix B gives a more detailed set of algorithms and rationale for the bottom-up modeling of shale gas well productivities.

Fig. 9a shows the actual total gas output recorded shale wells in the Barnett play by the Texas Railroad Commission between 2001 and 2012 together with our model output curve, which is based on the aggregated well output using the number of historic wells in Fig. 5b with an average decline function for the Barnett (parameters given in Table 1) and field output calculated according to Eq. (2). The difference between the real production and the model production is due to the parameterization of our average Barnett well – which remains constant over all years – while in reality each year well production averages have varied. Fig. 9b and c shows the Marcellus and Eagle Ford results, both the most active current plays. In this study we present visual comparisons of the model curves and recorded historic production. A quantification of the matches by
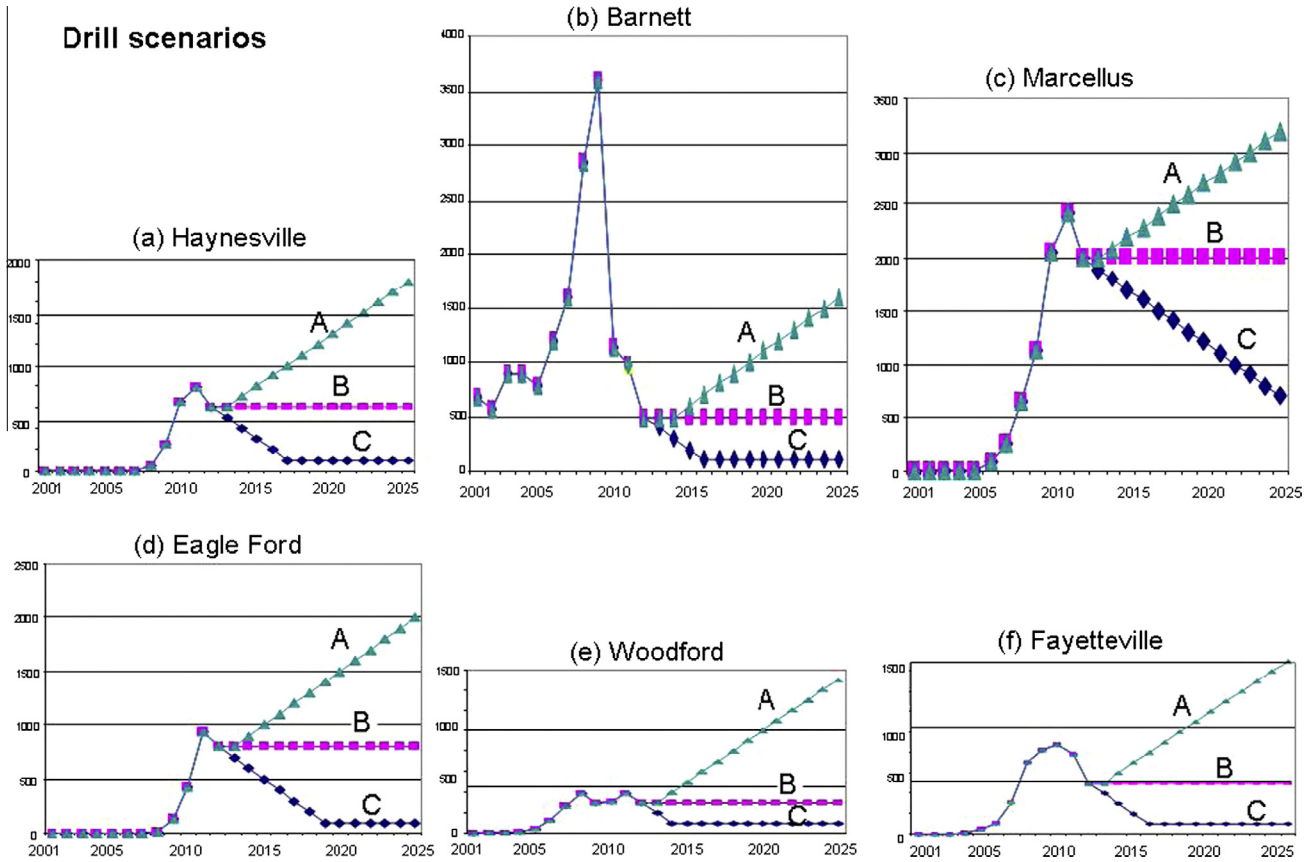
Fig. 7. (a–f) Number of wells drilled each year (vertical scales) between 2001 and 2012 as reported by producers to the States (see Appendix B). The new wells added between 2013 and 2025 follow the three well roll-out scenarios A–C considered in our study.

Table 1
Key parameters for decline curve analysis.

Shale play	EUR (Bcf in 20 yrs)	Q_1 (Bcf)	r (%)
Haynesville	2.67	0.42	−0.15
Eagle Ford	2.36	0.37	−0.15
Woodford	1.96	0.30	−0.15
Marcellus	1.56	0.24	−0.15
Barnett	1.41	0.22	−0.15
Fayetteville	1.30	0.20	−0.15

statistical means is not attempted here. Nonetheless, our adopted model well values (Table 1) give reasonable fits for the realized historic production and our modeled outputs (Fig. 9a–c). There is a distinct trend which shows that recorded output outperforms the model output, which can be attributed to better wells (longer and more frack stages) being drilled in recent years. Similar trends occur for the other US shale plays as well.

Fig. 10a–f shows the total production output for each US shale play. These cumulative output estimates are based on Eq. (2), using the well numbers of Fig. 7a–f and production parameters of Table 1. For each incremental rise in the gas price the proportion of the play that can be developed increases as more TRR are shifted toward the ERR domain.

4. Results

A careful evaluation of Figs. 7a–f and 10a–f reveals that the Marcellus has become the "hottest" US shale gas play, with the largest field output of all six shale plays (and for each of the three scenarios). The Woodford and Fayetteville are the smaller producers. The steep decline in well counts for the Barnett since 2008 also
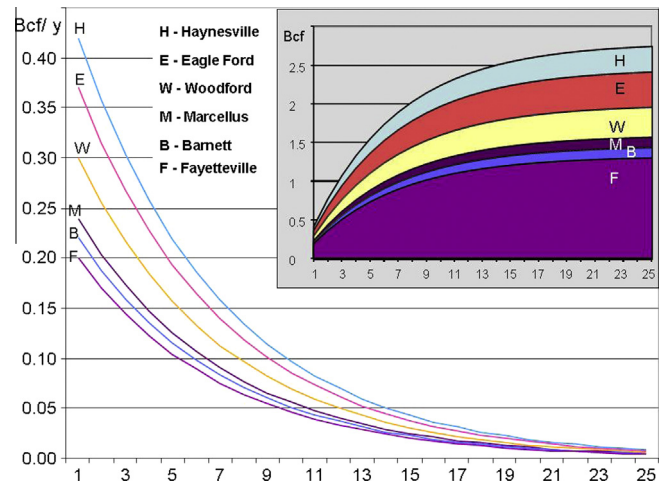
Fig. 8. Average total production for representative shale wells in each of the six major US shale plays [14], here converted to exponential decline curves. Inset shows corresponding cumulative production profiles.

makes it a smaller producer in the decade to come. The Haynesville and Eagle Ford have established themselves as medium-size gas producers when compared to the Marcellus.

Fig. 11 shows the combined annual output for the six major US shale gas plays consequent to our model well rates (Table 1) and historic wells drilled according to Fig. 7a–f using Eq. (2) to quantify the aggregated production. Comparison of Fig. 11 with Fig. 6 reveals that the recorded output and model outputs match up closely. Fig. 12a–c shows the combined annual output for the six US

Fig. 9. (a–c) Comparison of real production with model production for (a) the Barnett, (b) Marcellus, and (c) Eagle Ford shale plays.

Production scenarios

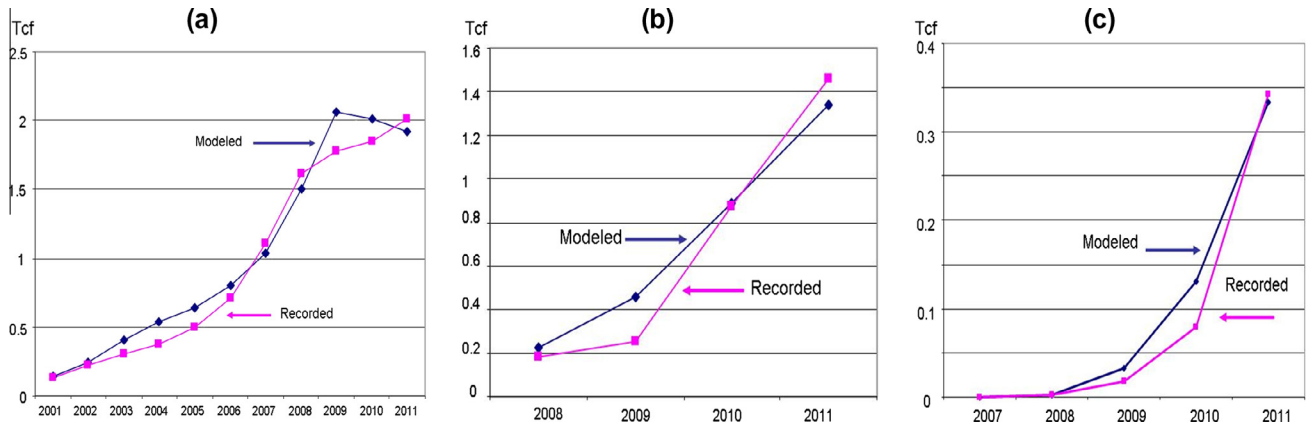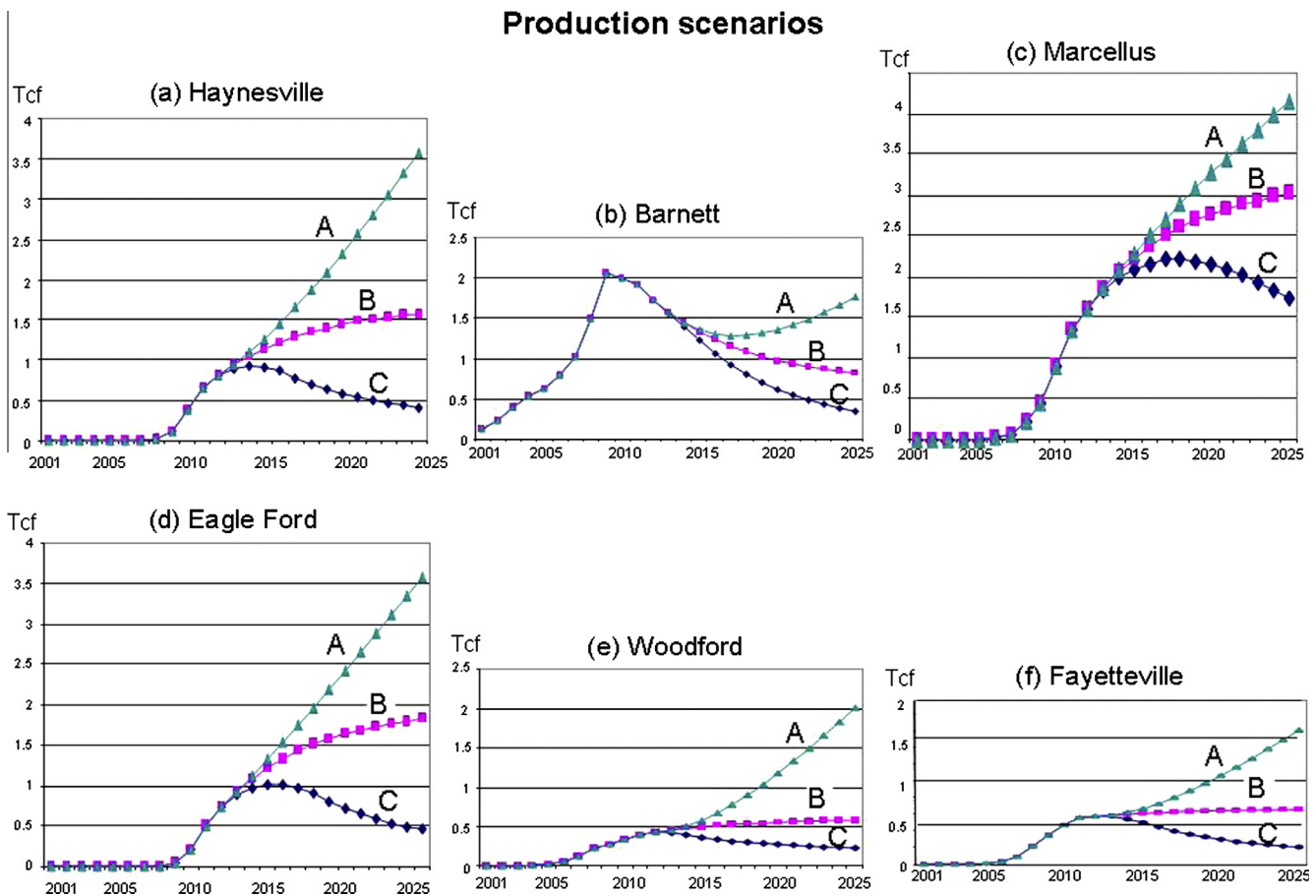**Fig. 10.** (a–f) Production scenarios for the six major US shale gas plays according to the three well roll-out scenarios A–C considered in our study.

shale gas plays over the full model period between 2001 and 2025 according to each of the three scenarios modeled.

Scenario A (Fig. 12a) shows the kind of production growth to over 16 Tcf in 2025 that is commonly favored in most US shale gas reports [4]. Scenario B (Fig. 12b) realizes only half that total output in 2025. In the Declining Shale Drilling Scenario (Scenario C, Fig. 12c) the rise in shale gas output culminates in 2014, but the rate of gas output than declines and if prolonged will deliver only just over 3 Tcf in 2025. In fact, the shale gas production growth has already decelerating since 2011, which is what has been observed after drilling slowed. This is why we cannot exclude Scenario C as a future possibility from today's perspective.

Fig. 13 shows the US shale gas production according to NEMS model projections of AEO2012 to 2035 [14]. Also included are our bottom-up gas output curves according to the three scenarios modeled. Our Scenario A converges on the Higher TRR case of AEO2012, which assumes both tighter well spacing (8 wells per square mile, which gives each well a drainage area of 80 acres) and 50 % higher EUR as compared to the reference case. Scenario A uses a constant EUR for the 25 year field life modeled (Table 1). Our Scenario B converges on the Low EUR case of AEO2012, which assumes well output is 50 percent lower than in the reference case. Scenario B uses constant EUR for the field life (Table 1) and assumes a steady number of new wells is drilled each year.
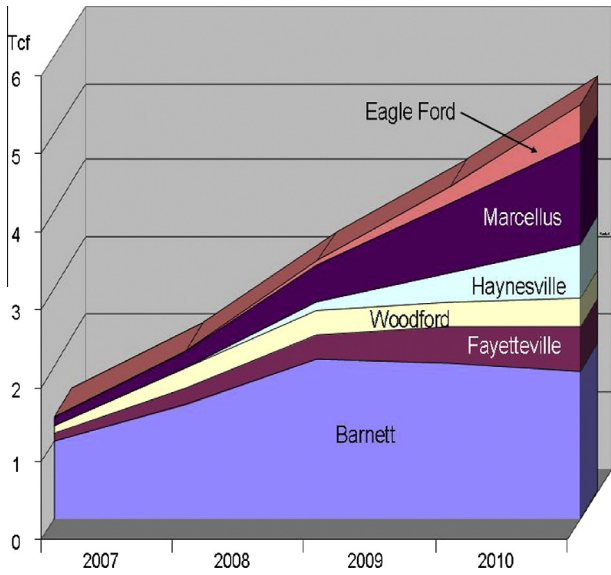
Fig. 11. Total US shale gas output (per year) predicted by our model using historic well counts for the period 2007–2010.

Fig. 12. (a–c) Forward projections of total US shale gas output up to 2025, according to the three scenarios A–C modeled in our study.
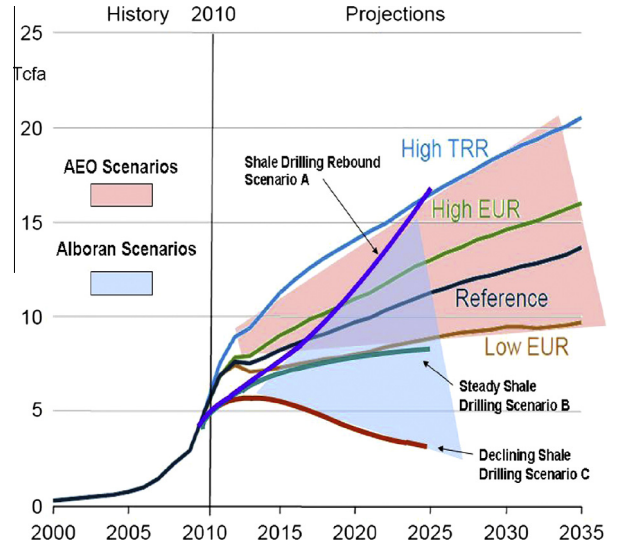
Fig. 13. Summary of spread in annual shale gas output according to projections of AEO2012 (High TRR, High EUR, Reference, Low EUR; [14]. US shale gas output range of AEO2012 Scenarios is confined in the pink band. Superposed are the US shale gas output estimates according the three Scenarios (A–C) modeled in this study. US shale gas output range of our Alboran Scenarios is confined in the blue band. Scenarios A and B are bracketed by the AEO2012 High TRR and Low EUR cases. Our declining shale gas output due to drilling Scenario C lies below the range of AEO2012, but cannot be discarded as unfeasible according to our analysis. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

be excluded as unrealistic. In view of the weakness in US gas prices since 2008, no quick recovery seems in sight until 2015. Earliest 2015 shale gas supply will be tighter, which then could help lift North American gas prices. However, the shift to shale oil continues to add associated gas to the market. Shale gas margins therefore will remain slim and most shale development projects will be just breaking-even. In the short-term, there is too little room for higher margins in a closed US gas market where gas demand remains limited and modest consumption growth only occurred by displacing coal as the fuel of choice for power stations. This displacement can last only as long as the price of calorific value for gas stays lower than coal, a trend which has already reversed when this study went to press. A shift by power stations from gas to coal will no longer ease the US oversupply of natural gas, which will delay the recovery of US natural gas price (i.e., slows it).

5. Discussion

The modeled US gas production outlook in this study is determined by the three scenarios based on drilling rate developments in each of the six major shale gas plays. The adopted drilling rates are entirely phenomenological, in the sense that the gas output scenarios follow from the assumed drilling rates multiplied by average well rates for the plays considered. This approach was made possible by accepting a number of critical simplifications, which are discussed in Section 5.1. We discuss the larger range of uncertainties in Section 5.2, which also compares our conclusions to those of other recent modeling results. Sections 5.3 and 5.4 compare our scenarios for the Barnett and Haynesville plays with several detailed production forecasts based on well analyses in independent recent studies.

5.1. Model limitations and assumptions

Our modeling focussed on the six major US shale gas plays, and did not separately model the additional gas produced from "other"
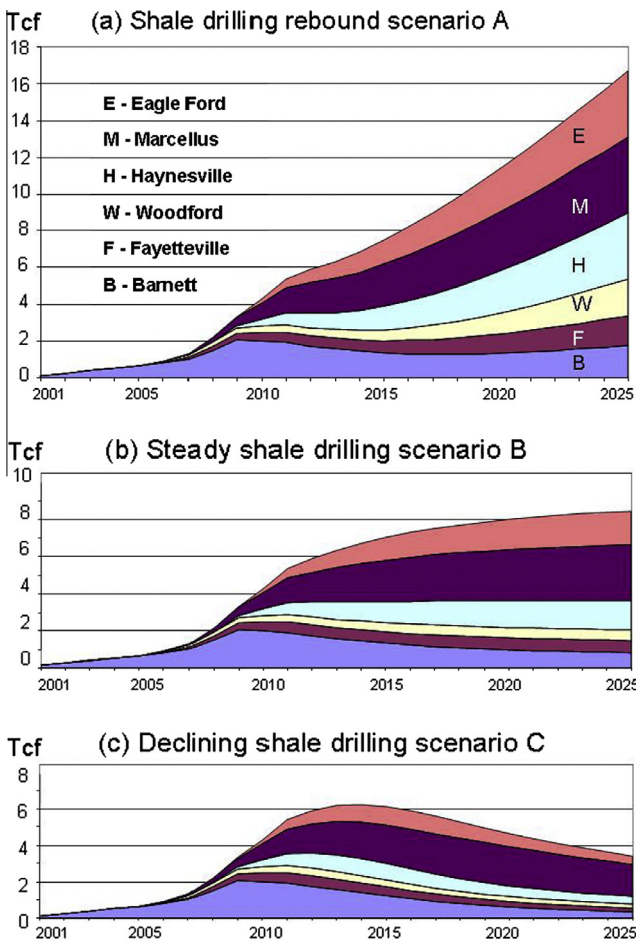
Our Scenario C predicts a decline in US shale gas output and falls outside the uncertainty range considered by AEO2012 (Fig. 13). This is remarkable because we think Scenario C cannot

shale fields (including wet gas and oil windows), which was justified by our observation that these account historically (2007–2011) for only a minor percentage of the total production in the period (see Fig. 6). More recent data show the output share of 'other' US shale gas plays has grown rapidly, and accounted for 9% of US shale gas production in 2012 (Table 2; after [16,17]. Our focus on the six major US shale gas plays may be turn out to give too conservative estimates, especially when shale oil production in the Bakken and elsewhere continue to expand and will bring larger volumes of associated gas to the market. On the other hand, associated gas from shale oil wells coming to market will work against a recovery of the gas price. Gas output of primary shale gas wells likely will continue to decline due to the lack of an economic business case.

The drilling rates assumed in our three scenarios are deterministic and should be interpreted only as possible future developments. The real forward drilling rates will in the future evolve as a function of gas price. This dependency of drilling rates on the gas price is not separately modeled here but assumes a generic causality as inferred from Fig. 3. Of course, the current gas rig count and well rate decline can be reversed if future gas prices render drilling new wells profitable again, which is when the optimistic gas output growth Scenario A may develop. If gas prices stay depressed below the commonly assumed hurdle rate of $6 to $7/Mmbtu, then a pessimistic Scenario C may turn out to be more realistic. The intermediate gas output Scenario B assumes a modest gas price rebound so that drilling as usual can be resumed. No attempt is made here to predict future gas prices. A concise discussion of the price dynamics in the US and other global gas markets has been detailed elsewhere [10,18–20].

We do not take into account the considerable technology advances which may accelerate the productivity of wells over time and therefore improve on the model parameters given in Table 1. For example, technology improvements have lead to well productivity gains in the Barnett. Fig. 9a shows our model curve with production decline after 2008 due to decline in the well addition rates, but real production did not drop that fast due to the new wells drilled being better producers [21]. Such well productivity improvements are also reflected in Fig. 9b and c, but have not been separately included in our model, which therefore may be biased toward conservative well productivity profiles. Scenario C of our study does not account for future technology improvements and thus provides a lowermost case for the shale gas output curve. Neither does our model evaluate the effect of local variations in decline functions. Gas output curves for Scenario C will shift slightly upward after revisions to account for technology gains in future drilled wells. If substantial increases in TRR or well productivity were to occur, the number of new wells required to realize the modeled output of Scenario A can simply go down commensurate with the well output efficiency gains. The shape of the decline curves may vary spatially and over time and is affected both by intrinsic geology and petro-physics as well as by well-spacing and well technology innovation. For a given EUR accelerated production in the first years of a well's life cycle improves well

economics (due to the effect of discount on the cash flow being reduced). Appendix C discusses the effects of technology learning gains on well productivity in competition with gas wellhead price volatility.

The type curve and decline factors assumed in Table 1 may vary in future reality more than assumed in our forward scenario analysis. Fig. 9 showed that the improving well productivities are indeed not accounted for by using type curve based on past productivity averages. However, at this stage we do not want to make our scenario models more complex by including well productivity learning curves. Appendix B outlined details of our modeling method. Based upon our results, we conclude US gas price decline has been so fast over the period 2008–2012 that it has outpaced concurrent technology gains that halved drilling cost.

The adopted drilling adjustment rate of 100 wells per year was chosen uniformly and not scaled for individual shale play size. The uniform shifts in drilling rates assumed in each of our three Scenarios are an oversimplification because it is unlikely that all plays will shift drilling rates at the same pace. Regional market conditions as a downstream factor and variation in acreage quality as an upstream factor as well as midstream pipeline capacity are all factors that may lead to different plays developing at different speeds. Such changes are excluded in Scenario B, but arguably inflate Scenarios A and C for smaller plays at the expense of bigger plays, but we assume the overall effect will average out. Also past field development speed and drilling rates are used by us as a starting point and may be considered to already reflect some of these differences in development speed.

In spite of the above simplifications, we believe macroscopic scenario models of future gas output based on forward projections of generalized drilling rates and well productivity averages are merited. Such models may certainly be developed with larger resolution per play, but the general trends highlighted in the three scenarios presented here show a possible spread in US gas output curves, and provide a benchmark for future studies. US energy security cannot be fully ascertained from today's perspective with an obvious trend of accelerating decline in shale gas drilling rates. At this moment in time there simply is no real certainty that Scenario C is less likely to occur.

5.2. Uncertainties and comparison with other model projections

Scenarios for future US shale gas output provide important guidance for possible future global gas market developments. An earlier study by researchers at the James Baker Institute for Public Policy at Rice University compared two global gas trade scenarios till 2040, one with and one without shale gas supplies [22,23]. The two scenarios allow a comparison of the importance of shale resources to US energy security, and demonstrated how shale development may affect international gas market trades. However, the Rice World Gas Trade Model assumed a steady shale gas supply growth in their shale gas model, and considered no uncertainty spread for the shale gas supply. We believe this is too simplistic in view of the volatility seen in the economic fundamentals that control the development rate of shale gas fields.

The uncertainties that may affect the rate of shale gas development (in the US and elsewhere) have been concisely outlined by Rogner and Weijermars [24]. The main uncertainty sources are (1) resource size, (2) technology capacity, (3) economic factors, (4) public acceptance and (5) concession policies and regulations. These uncertainties continue to jeopardize any future plans for drilling and fracking operations in the US and elsewhere, as briefly outlined for each principal source. **Resource size and technology capacity:** Volumes of gas-in-place are generally not contended and expert opinions on TRR diverge and recovery factors remain disputed. This is also very much depends on the technical capacity

Table 2
Production output shares of the six major US shale gas plays and other plays.

| Play	Production (bcm/year)	Share (%)
Barnett	50	18
Fayetville	29	10
Woodford	13	5
Haynesville	70	25
Marcellus	69	25
Eagle Ford	22	8
Other US shale gas plays	24	9
US total shale gas	276	100

to stimulate shale well productivity in the right place, which is still disappointing for the majority of shale wells drilled, completed and fracked. **Economics:** Gas demand and gas market prices are the most important, but volatile, determinants for which portion of TRR will actually be economically recoverable (ERR). The viability of a business case further varies with availability and preparedness of risk prone investors to help raise the credit required for the up-front investment sum for field development. Terms of equity and debt financing must be favorable and return-on-investment expectation must remain optimistic. Time value of money will kill the profits of any shale gas project if drilling permits cannot be granted timely. Other factors influencing ERR include proximity to gas transmission and delivery infrastructure, environmental legislation, population density, and degree of public support. **Public acceptance:** Public sentiment in the US and elsewhere continues to be aroused by media hype about the promise of shale gas and undiminished concerns about the environmental impact and safety aspects of fracking [17]. **Concession policies and regulations:** Restrictive access to the subsurface may bar access to TRR volumes. For example, concession holders containing conventional hydrocarbon reservoirs will not jeopardize their current operations and renege access to their acreage via shale gas farm-in agreements. Natura2000 regions and drinking water basins are also barred for access. Finally, moratoria on fracking and banning shale gas development altogether remain external uncertainties that follow from the law of unintended consequences [25].

A recent study applied the Global Gas Model (GGM, a partial equilibrium model allowing for shifts in gas trade flows – LNG and pipelines – and gas value chain infrastructure expansion) to analyze three global gas scenarios production paths which included constraints for US shale gas development [17]. The GGM database comprises gas market data for 98 countries and model results follow from an intricate trade off between profit maximizing agents (producers, traders, and transmission and storage providers) and market developments taking into account such factors as climate and energy policies. A brief summary of the three GGM scenarios modeled by Richter [17] is merited for comparison purposes.

– *A Base Case scenario* complies with the New Policy Scenario (NPS) of the WEO2012 [26] and assumes a 60% increase of global gas consumption between 2010 and 2040 distributed over 119 nodes of GGM [17]. The US becomes a net exporter of natural gas: 50 bcm in 2040. In NPS, a quarter of 2035 global gas production comes from shale formations, mostly in the US (370 bcm), China (90 bcm) and Canada (60 bcm), according to IEA [26]. It is important to note that Australian, Russian, and Argentine shale gas contributions remain insignificant in NPS [26].
– *A Constant Shale scenario* keeps the global annual shale gas output at 224 bcm from 2015 onward, resulting in a decline of US total gas production. The regional pattern of US shale production is reported in GGM by 10 regions and their shale gas contribution is weighed by TRR size of the nearby shale plays [17].
– *A Low Shale scenario* assumes a decline in global shale production output according to the Energy Watch Group's pessimistic view of future shale gas outlook [27]. US gas production contracts by 420 bcm in 2040 as compared to the GGM Base Case,
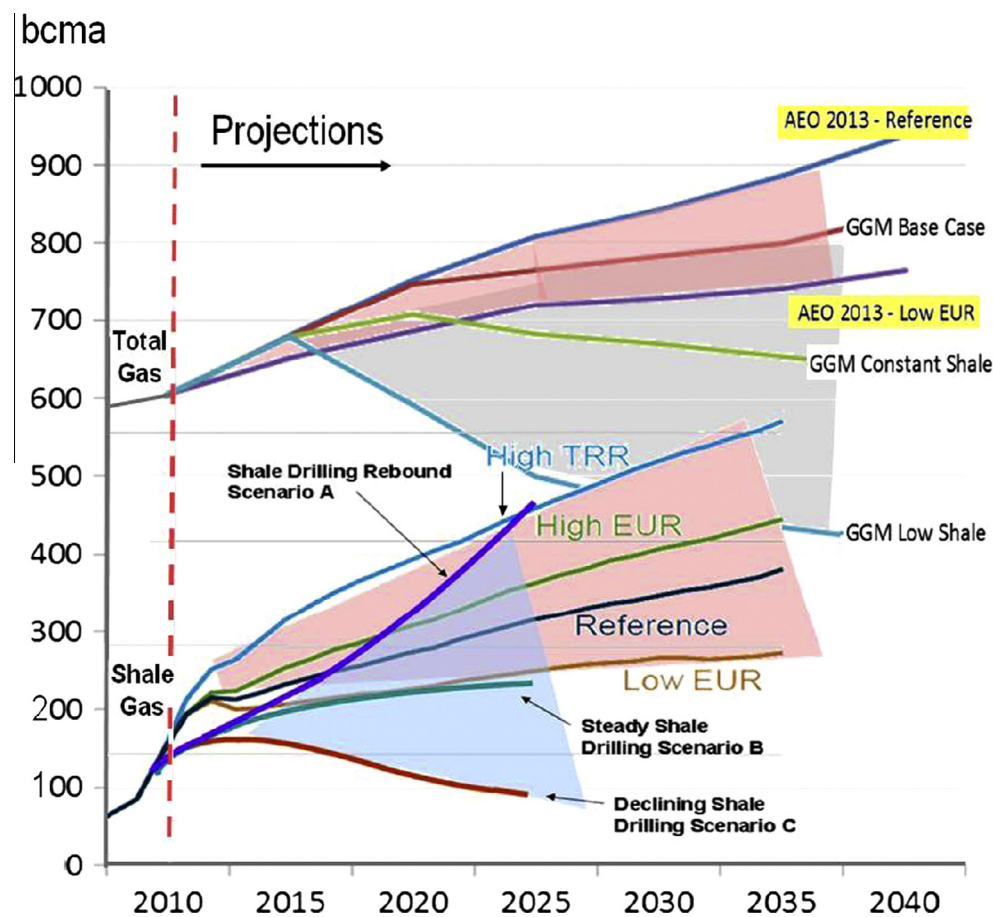
Fig. 14. Upper half of graph shows US total gas production outlook according to AEO2013 (pink shaded region: Reference and Low EUR projections; [28]) and GGM scenarios (gray shaded region: Bases Case, Constant Shale and Low Shale; [17]. Lower half of the graph shows US aggregated shale gas production outlook according to AEO2012 [14] (pink shaded region: High TRR, High EUR, Reference and Low EUR; [14] and our Alboran shale production scenarios (blue shaded region: Drilling Scenarios A–C; this study, see also Fig. 13). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)
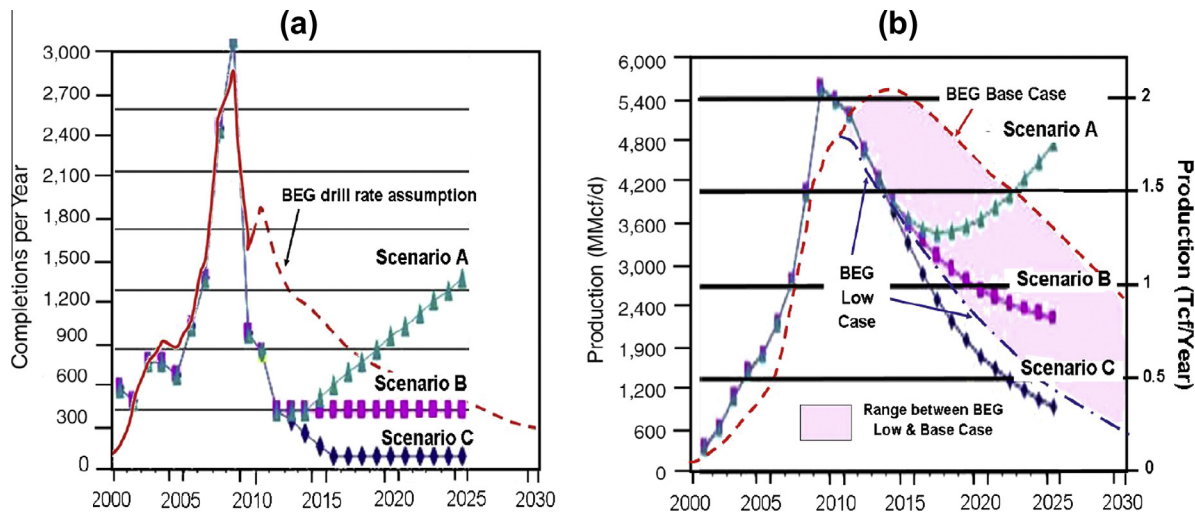
Fig. 15. (a) Comparison of our well addition rates for the three Scenarios A–C for the Barnett play (see Fig. 7b) and the rate assumed in the BEG Base Case [21]. Well completions for 2011 and 2012 assumed in the BEG model were much higher than the actual completions reported to Texas RRC for 2011 and 2012 (see Appendix B). Our models were finalized later and included 2011 and 2012 well numbers of RRC, extrapolating new wells from 2013 onward, while the BEG Base Case extrapolated wells from 2011 onward. (b) Comparison of cumulative production outlook for the Barnett shale play according the three Scenarios A–C (see Fig. 10b) with those suggested by the BEG Low Case and BEG Base Case [21].

and implies LNG importation by as much as 100 bcm in 2040 (from Algeria, Nigeria, Russia, Venezuela and Trinidad & Tobago). Current US re-gasification capacity can handle such LNG import volumes (Fig. 1b). US export pipelines to Mexico are phased out as of 2035. Europe and Asia must balance constrained availability of LNG due to North American LNG demand by pipeline imports from the Middle East and Russia. LNG exports from the US and Canada that featured in the GGM Base Case cease to exist.

Fig. 14 includes the US total gas production according to the GGM Base Case, GGM Constant Shale, and GGM Low Shale [17]. Also included are the US total gas production Reference and Low EUR cases based on NEMS according to AEO2013 [28]. For comparison, Fig. 14 includes the shale shares according to the model results of Fig. 13. This shows that NEMS forecasts remain optimistic for output growth of both US shale gas [14] and US total gas (DOE/IEA, 2013b). Top-down constraints of GGM Constant Shale and GGM Low Shale scenarios result in declines of US total gas output. The trend of GGM Low Shale output curve matches that of Alboran Scenario C, due to decline in shale gas drilling rates. This scenario fully supports the conclusion that existing US LNG re-gasification capacity terminals (Fig. 1b) may be needed to meet US gas demand in the next few decades, as was also suggested as a possible future option in a call for cautious planning by Richter [17].

5.3. Comparison of Barnett production forecasts

A recent model for the production outlook of the Barnett play development until 2050 by the Bureau of Economic Geology (BEG) used production of data more than 15,000 historic wells to forward model field development scenarios until 2050 [21]. In the BEG model, the number of wells that will be drilled between 2011 and 2030 was estimated based on changes in economic incentives for drilling new wells, with further assumptions for the period remaining between 2030 and 2050 [21]. Fig. 15a compares the total number of wells according to our drilling scenarios A to B with the BEG Base Case well rates. The high number of wells assumed for 2011 and 2012 in the BEG model were higher than the actual completions for 2011 and 2012. According to the Texas RRC 1,146 new wells were drilled in the Barnett shale in 2010, which is

substantially lower than the well numbers used in the BEG model (Fig. 15a). Although the high granularity built into the BEG model suggests a high degree of certainty, its forecasts are skewed to the higher end. An unanticipated steep drop in well rates occurred immediately after their well number inputs for the model were fixed in 2010. Missing out these well declines has arguably inflated the well completion rates used in the BEG model from 2011 onward. However, it is difficult to try to beat time and build in the latest reported well data: While our drilling scenarios account for the lower well completion rates reported for the Barnett in 2011 (984), well rates for 2012 reported to the RRC (see Appendix B) ended up being higher than used in our study (476 modeled versus 840 reported), which is due to late well reporting by operators. We can now conclude that our well numbers for 2012 are too conservative, whereas 2012 well additions assumed by BEG are too high.

Fig. 15b compares the total production output projections of our Scenarios A–C with those for the BEG Base Case and BEG Low Case projections – an additional BEG High Case (c.f., [21] is not further considered here; it would jump out of the top of our production plot. The BEG Low Case nearly matches our Scenario C (Fig. 15b). The Barnett shale play has reached plateau in 2010 and 2014, respectively, according to the BEG Low Case and BEG Base Case (Fig. 15b). As is also projected to occur in our Scenarios B and C, annual production of the Barnett may have begun a steady decline. Although the BEG Low Case was deemed less realistic by Browning et al. [21], we consider the BEG Low Case and our Scenario C not unlikely to occur. The cumulative production of Barnett shale gas up to 2012 was 13 Tcf [21], and the BEG Low Case predicts an EUR of 26.7 Tcf (or 6% recovery factor of OGIP). If real, this implies half of the Barnett's EUR has already been depleted in 2012. Although based on a low case price of $3/Mmbtu, the BEG Low Case may be closer to reality because the well numbers used for the BEG model in the time window 2011 to 2018 were probably too high, and we suggest that even for $4/Mmbtu the BEG Base Case may play out. BEG colleagues considered their Base Case to be the more likely to occur, which assumes that 40% of EUR has been produced and 60% of the shale gas remains to be produced until 2050 [21]. The BEG Base Case EUR is 45.1 Tcf up to full depletion in 2050 [21], which divided by initial gas-in-place estimations of 444 Tcf [21] suggests a recovery factor of 10% of OGIP. If we discard the BEG High Case, the Barnett ultimate recovery ranges
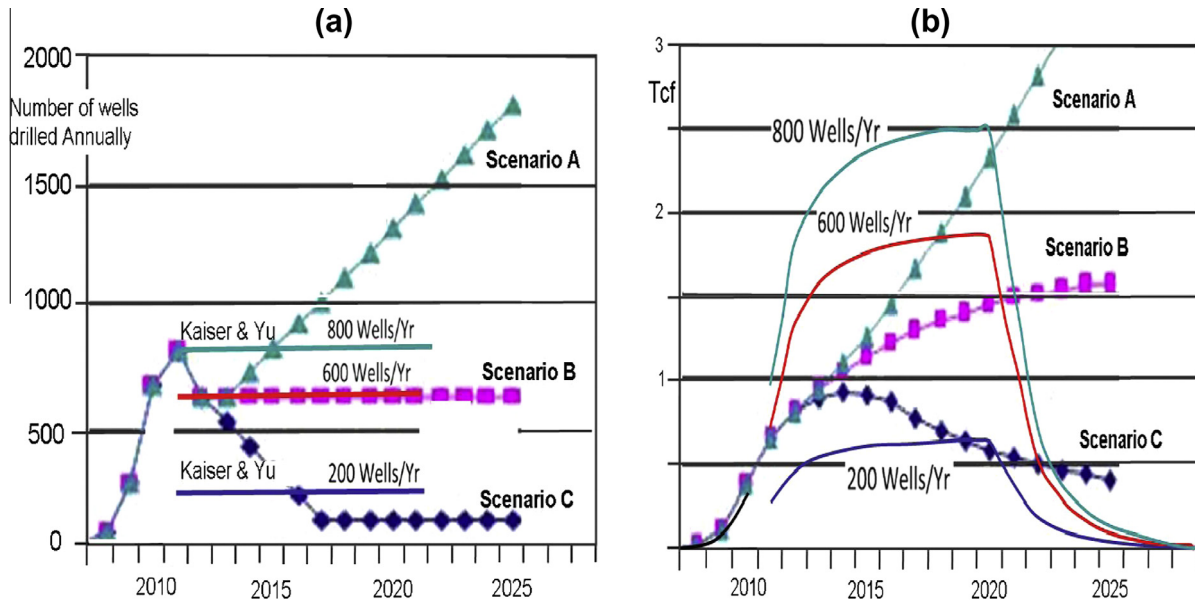
Fig. 16. (a) Comparison of our well addition rates for the three Scenarios A–C for the Haynesville play (see Fig. 7a) with those in a study by Kaiser and Yu [31], which assumed three drilling rate options over the next decade fixed at 200, 600 or 800 new wells per year. (b) Comparison of cumulative production outlook for the Haynesville shale play according the three Scenarios A–C (see Fig. 10a) with the three projections of Kaiser and Yu [16].

between 6 and 10% of OGIP in the BEG study. We contend that our bottom-up scenario model, although less granular than the BEG model [21], is capable of capturing the essential behavior of the Barnett shale play.

We emphasize that future drilling rates assumed in our models are dependent of economic factors, mainly the future gas price, which is why we considered three vastly differing drilling scenarios. A detailed case study showing how dramatic gas price volatility can alter the economic outlook of shale gas projects in the Barnett play has been recently documented for a specific shale project executed at Dallas-Fort Worth Airport [29]. Over the period 2007–2012, the airport gained $305 million from the combined proceeds of a signing bonus, royalties and facilities rentals, while the operator (Chesapeake) lost over $316 million on the project. Meanwhile, drilling at the airport has grinded to a halt, and the

airport's income from royalties of gas production has dwindled to a fraction (just $7.7 million in 2012, due to fast well declines). Another detailed economic analysis of wells in the core area of the Barnett shale gas play (Fort Worth region) accounted for the reported uncertainty in well productivity and found P10 wells give IRRs above the commonly used corporate hurdle rate of 15% only if the wellhead price is above $5/Mmbtu; P50 wells require a price higher than $7/Mmbtu to exceed the hurdle rate [30].

5.4. Comparison of Haynesville production forecasts

After our modeling was completed, a detailed study of Haynesville play production potential was published [31]. Fig. 16a compares the total number of wells assumed from 2011 onward by Kaiser and Yu [31] and those assumed in our Scenarios A-C (as
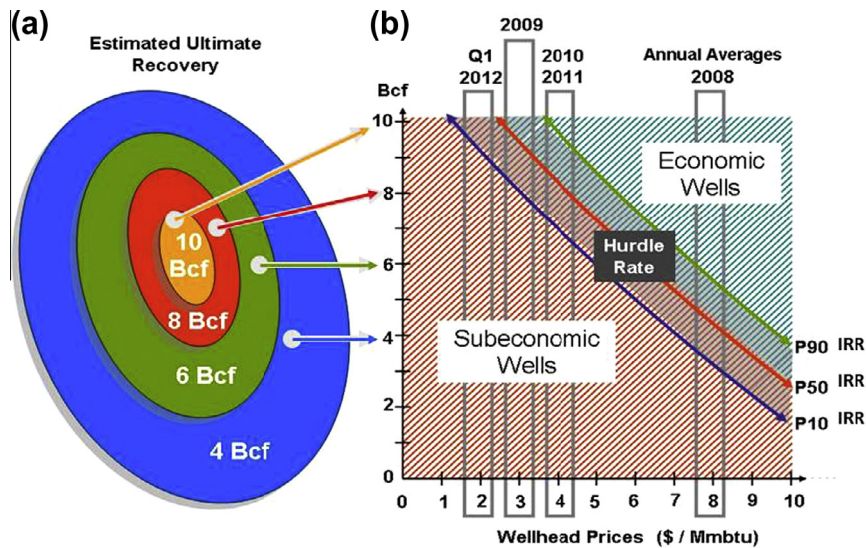
Fig. 17. (a) Idealized map view of the core area of the US Haynesville shale gas play with EUR zones for shale gas wells, adapted from Petrohawk well data. (b) Hurdle rate curve (taken at IRR = 15%) separates economic wells from sub-economic wells. The hurdle rate spread shown is for best producing wells (P10), average (P50) wells, and below average (P90) wells. The columns outlined show the annually averaged wellhead prices for 2008–2012 (Q1). (After NPV and cash flow analyses with representative input parameters by Weijermars and Van der Linden [13]).

per Fig. 7a). Kaiser and Yu [31] did not consider adding any new wells after 2020. Drilling rates of 800 new wells per year assumed in one of the three scenarios by Kaiser and Yu [31] actually were reached in 2011, but did not occur in 2012 (their study input data were fixed in 2010). The drilling rates of our Scenarios B are identical to the 600 wells/year assumed by Kaiser and Yu [31,39].

Fig. 16b compares the forward production output estimates for Haynesville shale gas according to our Scenarios A-C with and those provided by Kaiser and Yu [31] from 2011 onward. Haynesville shale gas production ceases after 2028 in the models of Kaiser and Yu [31], which is entirely due to their model input choice not to add any new wells after 2020. Direct comparison of our respective results therefore only is useful for the period up to 2020. The 2020 production estimates for our Scenario B differs from that for the 600 wells/year production reported by Kaiser and Yu (Fig. 16b). The productivities per well assumed by Kaiser and Yu [31] were not explicitly stated in their study, and may have been different from our 20 year EUR of 2.67 Bcf/well (Table 1). A scenario with 800 well completions per year may be too optimistic. We are unable to explain why our Scenario C with only 100 wells/year drilled results in higher production output than for the 200 wells/year in the model by Kaiser and Yu [31]. In spite of our different assumptions, the gap between production estimates for Scenarios A and C widens in 2020 to as much as 1.5 Tcf (Fig. 16b), which is comparable to the spread between the 200 wells/year and 800 wells/year projections for 2020 (Fig. 16b) by Kaiser and Yu [31]. If Scenario C plays out, the implication for total US shale gas output in 2020 is that 1.5 Tcf less gas comes to market than in Scenario A (Fig. 16b). Adding to this number the decline in production from the Barnett shale play which by 2020, according to Scenario C, is another 1.5 Tcf less (Fig. 15b), the US market will have 3 Tcf less gas from the Barnett and Haynesville plays than in 2012, unless the well rates follow another path, i.e., upward, which requires a fast recovery of US natural gas wellhead prices.

Our earlier, detailed economic analysis of the Haynesville play used P10, P50, P90 wells for the sweet spot core region and historic wellhead gas prices (annually averaged) for the period 2008–2012 [13]. Fig. 17 highlights the IRR sensitivity of the Haynesville play to regional variations in well productivity and gas wellhead price. The majority of Haynesville wells had indeed become sub-commercial for the gas prices fetched between 2009 and 2012. The lack of economic incentives for drilling new wells in the Haynesville led to a sharp production decline after peaking in 2012 [33], which makes our Scenario C the more likely at present.

6. Conclusions

The North American shale gas bonanza has demonstrated to the rest of the world that gas extraction from shale deposits is technically possible. The shale gas industry itself apparently had no macro-economic modeling capacity to check whether accelerated US shale gas output could lead to overproduction. NEMS is used by the Energy Information Administration (EIA) to model projections for future US gas prices and future shale gas output, which are published in the Annual Energy Outlooks (AEO). The retrospective review of AEO gas wellhead price projections analyzed over the 25 year period (1985–2009; see Appendix A for details) reveals NEMS projections were correct for 4 years, but too high for 18 years and too low for 3 years. We believe NEMS projections for shale gas output in AEO2012 [14] are at the upper end of the uncertainty spread for all cases (Fig. 13, High TRR, High EUR, Reference, and Low EUR), and miss out on signals of decline in US shale gas development.

It is relatively easy to complement NEMS with a fast bottom-up modeling procedure as described and demonstrated in this study.

AEO is the principal model source where full uncertainty in the future shale gas development scenarios should be taken into account. A drawback of AEO projections is that these are 2 years delayed (see Appendix A), which is a long information gap. The delay in publicizing accurate shale well data affects the quality of both shale gas investment decisions and energy security planning, especially as shale gas wells decline relatively fast. We argue that additional fast modeling results as produced here are merited. Getting to grips with the uncertainty spread of future shale gas supplies requires timely modeling work and the present study attempts to provide such a timely view. The model of Richter [17] independently produced when our model scenarios were completed provides further support for the need to include in US gas models the more conservative option of negative growth.

Recently formulated guidelines for Energy Strategy Research emphasized that strategy analysis based on energy modeling seeks to alert for national energy strategies that facilitate choices or bias based on populist demand or special interest groups [40]. The US shale gas potential has been positively assessed in numerous studies [4–6], but the impact of economic realities has been neglected in most studies. This has been previously highlighted in a critical review by Brooks [32], was elaborated in Richter [17] and is further highlighted in our study (see also Appendix A). Our bottom-up models alert for the possibility that sustained losses on US shale gas operations may lead to a decrease in the number of new shale gas wells drilled over the next decade.

Our model projections for future shale gas production output include a declining drilling scenario with only 3 Tcf produced from US shale fields in 2025 (Scenario C, Fig. 12c) instead of 18 Tcf (Scenario A, Fig. 12a). A decline in drilling activity will inevitably lead to a lower shale gas output, although technology gains would fortunately counter some of the predicted output decline related to the lower drilling rates. Our conclusions may be unpopular among undeterred shale gas advocates, but should be given a fair thought and suggests continued close monitoring of future well rate trends in US shale gas plays is urgently needed to avoid being surprised by falling shale gas output. The US gas market has already been suffering a negative price shock due to the unexpected fast growth of shale gas production over the past decade that has lead to oversupply. The gas price weakness in the period 2008–2013 could have been predicted ahead of the price crisis by applying the simple bottom-up modeling procedure described here. An "unexpected" shale gas output decline, unforeseen due to the lack of unbiased modeling capacity, may lead to another price shock, this time upward [34]. Industry is well advised to maintain a state-of-the-art gas market model, including the effects of the inter-fuel shifts between coal and gas as well as the impacts of LNG exports. A recent study explores just that [35].

Use of units

Imperial units still dominate the professional literature on oil and gas projects, because US oil industry uses such units. European companies use both Imperial and metric units. This study uses both systems in accordance with the sources used, and brief conversion rules are given here: 1000 cubic feet ∼ 28.32 cubic meters; 1 cubic meter ∼ 35.31 cubic feet; Prices of natural gas are given in $/Mmbtu, which approximates $/GJ or $/Mcf; the calorific value of 1 Mmbtu approximately equals 1 GJ; for standard gas 1 Mmbtu ∼ 1 GJ ∼ 1 Mcf = 1000 cubic feet.

Disclaimer

This study analyzes shale-gas economics based on data abstracted from government reports and company data. The analysis

of these 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 authors, 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.

Acknowledgements

Appendix A. US National Energy Modeling System (NEMS)

The principal reasons for the large difference between the gas price forecasts by the National Energy Modeling System (NEMS) and the actual gas price development in the US gas market are discussed in this section. A brief outline of NEMS is merited.

NEMS [7,8] is a sophisticated energy system model developed by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). The main purpose of NEMS is to produce the Annual Energy Outlook, the closest the US has to official government energy forecasts, but it is also used by the EIA in studies for Congress and other Federal agencies. Applications for which the EIA uses NEMS include analyzing the effects of existing and proposed government laws and regulations related to energy production and use; the potential impact of new and advanced energy production, conversion, and consumption technologies; the impact and cost of greenhouse gas control; the impact of increased use of renewable energy sources; and the potential savings from increased efficiency of energy use; and the impact of regulations on the use of alternative or reformulated fuels. NEMS is also used by non-government groups, such as the Electric Power Research Institute, and a number of universities and private companies. The time horizon of NEMS is currently to 2035, with the United States sub-divided into a number of regions, depending on data availability. For example, the end-use consumption modules use the nine Census divisions, whereas the electricity market module uses 15 supply regions based on those of the North American Electric Reliability Council.

NEMS is a modular system, with each module representing a different fuel supply market, conversion sector, or end-use consumption sector within the energy system. The model incorporates delivered prices of energy to end users and the quantities consumed, by product, region, and sector. Other data includes economic activity, domestic production, and international petroleum supply. NEMS uses a market-based approach to energy analysis. For each fuel and consuming sector, the model balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The modular design of NEMS permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached annually through the projection horizon. There is a 2 year delay between the data sets on which modeling is based and the results when finally published.

The EIA has assessed in a retrospective review [36] the differences between past model forecasts made by NEMS with the actual market developments. The fuel with the largest difference between the NEMS projections and actual consumptions has generally been natural gas. Over the 25 year period analyzed between 1985 and 2009, the averaged AEO gas wellhead price projections based on NEMS were higher than the market predicted for 18 of the 25 years, correct for 4 of the 25 years and too low for only 3 years. The bias towards high gas price projections is evident from this record. The average gas price overestimation was by a factor 1.76 (18 year average, as can be inferred from analyzing Table 8 in EIA, 2011). NEMS has been used to prepare the Annual Energy Outlooks since AEO1994.

According to the self-assessment by the US Energy Information Administration [36], technological improvement expectations embedded in early AEO models proved conservative and advances that made petroleum and natural gas less costly (or more attractive) to produce were missed in the NEMS projections. During most of the past decade, the AEO reference case has overestimated natural gas consumption levels (see Table 9 in [36] which explains the systematic overestimation of the gas wellhead price. In short, the overproduction of natural gas in a closed North American gas market was not accounted for by NEMS. The present author believes additional bias enters into the annual projection process, because of assumptions about world oil prices and the macro-economic growth environment. Natural gas calorific parity relative market share of the various fuels may be another source of bias, with natural gas trading at ever larger discounts relative to oil. NEMS does not include the specific full cycle cost of shale gas production, which is another shortcoming.

Appendix B. Methodology and algorithms for bottom-up shale gas production models

The bottom-up model applied in our study to develop projections for US shale gas output uses *DCF Shale Scenario Builder*™, a proprietary model developed by Alboran Energy Strategy Consultants (see [37]. The cumulative production of multiple wells (W_n) is computed based on the input of the annual production of individual wells. The production unit is bcf/year for gas and MMbbl/year for oil. The production levels are calculated for all wells over the course of 25 years, according to a specified production profile for each well (basic options offered are a decline function or Arps formula). The decline function asks the user to enter the initial production, as well as the annual decline rate (see Table B1). The production decreases exponentially. Arps curves are characterized by the decline constant and the decline exponent, determining productivity decline curve. The user is asked to enter both parameters, together with the initial production. The formula is shown in Table B1.

The total production of all wells uses the cumulative production volumes Q_n of each well, W_n, according to data from the wells sheet. The total production, TQ_n, in year n is given by:

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

For example, the total production in year 4 equals $TQ_4 = Q_1 W_4 + Q_2 W_3 + Q_3 W_4 + Q_4 W_1$. For further details see Alboran's online Tool Guide for *DCF Shale Scenario Builder*™ [37]. Well numbers used in our study were abstracted from files reports of the states from the following sources.

Data sets used for gas rig counts in US shale plays (Haynesville, Barnett, Marcellus, Eagle Ford, Woodford, Fayetville) are:

http://www.energyeconomist.com/a6257783p/archives/ee120213r.html.
http://www.energyeconomist.com/a6257783p/exploration/detail/haynesvl/Haynesville_Overview.html.
http://www.energyeconomist.com/a6257783p/exploration/detail/barnett/Barnett_Overview.html.

Table B1
Production input.

Input functions	Formula	Input variables	Unit (gas)	Unit (oil)
Decline function	$Q_n = Q_1(1+r)^{n-1}$	Q_1 – Production year 1 r – Annual decline rate Q_1 – Production year 1	Bcf/year Bcf/year	MMbbl/year
Arps formula	$Q_n = \dfrac{Q_1}{(1+bD(n-1))^{\frac{1}{b}}}$	D – decline constant b – decline exponent		MMbbl/year

Table C1
Selected rates typical US shale gas basin (after [38].

Scenario	Base case well	Well technology innovation scenarios	
		A	B
EUR/ Well 25Yrs	2[*]	3[**]	4[***]
Well CAPEX ($/Mmbtu)	4	3	2
OPEX ($/Mmbtu)	1.2	1.2	1.2
Other CAPEX ($/Mmbtu)	0.3	0.3	0.3
Royalty Rate (%)	20	20	20
Corporate Tax (%)	20	20	20
Depreciation (%)	10	10	10
Discount rate (%)	10	10	10

[*] Average for base case wells, $q_i = 0.3$ bcf/y.
[**] Average for 'better' drilling Technology A wells, $q_i = 0.45$ bcf/y.
[***] Average for still 'better' drilling Technology B wells, $q_i = 0.6$ bcf/y.
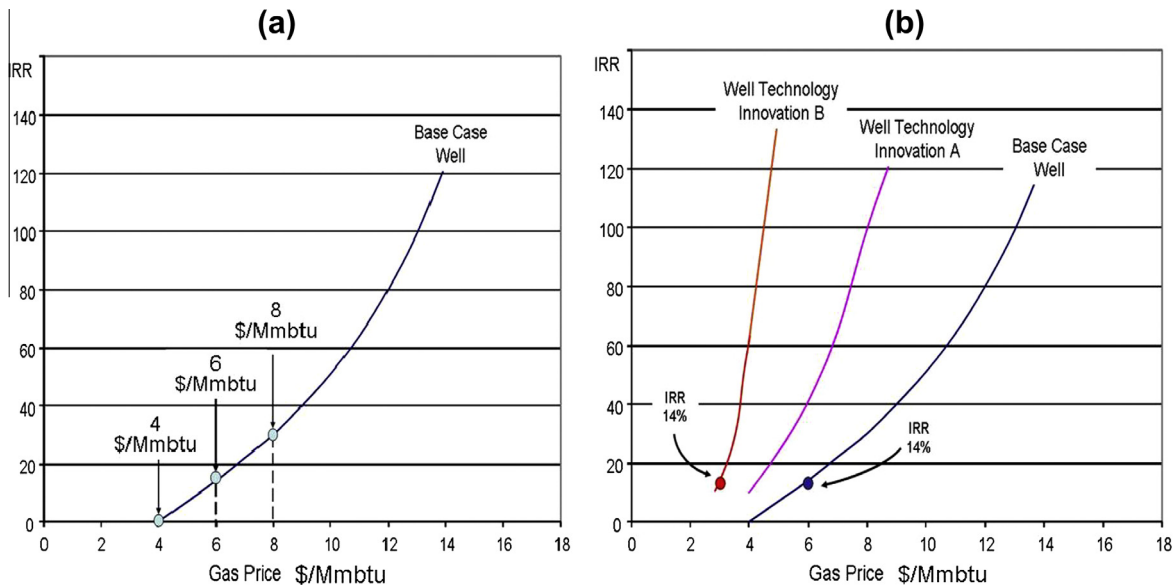
Fig. C1. (a) Sensitivity of IRR for gas production using Base Case Wells (all input parameters specified in Table C1). At $4/Mmbtu the IRR of Base Case Wells is exactly 0 and NPV = 0. At $6/Mmbtu the Base Case Well IRR improves to14%. For $8/Mmbtu gas price, the IRR is a handsome 30%. (b) Sensitivity analysis of IRR to gas price fluctuations for all well technologies considered: Base Case Well, Well Technology A, and Well Technology B. The IRR for Well Technology B and lowered gas price of $3/Mmbtu can with Base Case Wells only be realized if the gas price is twice as high ($6/Mmbtu).

http://www.energyeconomist.com/a6257783p/exploration/detail/MAR/Marccellus_Overview.html.
http://www.energyeconomist.com/a6257783p/exploration/detail/eaglford/Eagle_Ford_Overview.html.
http://www.energyeconomist.com/a6257783p/exploration/detail/woodford/Woodford_Overview.html.
http://www.energyeconomist.com/a6257783p/exploration/detail/AR/Arkansas_Overview.html.

Data sets used for gas well counts in US shale plays (Haynesville,Barnett, Marcellus, Eagle Ford, Woodford, Fayetville) are:

http://dnr.louisiana.gov/index.
http://www.rrc.state.tx.us/barnettshale/index.php.
http://www.wvgs.wvnet.edu/www/datastat/.
http://www.rrc.state.tx.us/eagleford/.
http://www.ogs.ou.edu/OilGas/pdf/2011DrillingHighlights.pdf.
http://www.aogc.state.ar.us/fayprodinfo.htm.

Appendix C. Technology learning curve effects

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/well improves when the subsurface model of an emerging shale gas play becomes more reliable over time. Uncertainty is reduced because the well population grows and brings in more data as operations zoom in on the so-called sweet spots of a developing shale gas play.

Further gains are possible when well technology innovation lowers drilling, completion and fracking cost. New and cheaper technology is needed to develop each well more effectively. Cash flow analysis can be used to assess the rate of technology improvement required to turn shale gas plays into positive net cash flow territories. Table C1 shows the typical input values used for a cash flow simulation of **Base Case Well** for a typical shale gas field. A Base Case Well with output of 2 EUR is assumed, which is representative for wells in the best areas of the Barnett and Fayetteville assessment units [15]. Sensitivity of the IRR of a Base Case Well to gas price fluctuations is summarized in Fig. C1a. For a gas price below $6 /Mmbtu the corporate hurdle rate (commonly at 15% or higher) is not satisfied from the gas production sales by the base case wells. Heavy losses are incurred when the gas prices drop below $4 /Mmbtu (Fig. C1a). The 2 EUR/well used for the IRR computation of Fig. C1a is based on a full 25 year well life cycle NPV model [38].

Well Technology A (Table C1) assumes a 50% EUR enhancement over the base case well, and the average CAPEX/well is reduced by 25% over the well's life cycle. Field development with Well Technology A rather than Base Case Wells improves the cash flow: the NPV of Well Technology A for an initial gas price assumption of $4/Mmbtu is comparable to that of $6.5/Mmbtu using Base Case Wells (Fig. C1b). **Well Technology B** (Table C1) assumes a 100% EUR enhancement over the Base Case Well, and well CAPEX is halved as compared to the Base Case. The effect on cash flow of using Well Technology B at $4/Mmbtu gas price is even larger than the effect of a price hike to $8/Mmbtu using Base Case Wells (Fig. C1a). Clearly, the assumed rate of technology innovation can make any US shale gas operation profitable, even at $4/Mmbtu. It appears that Well Technology Innovation B can outpace a price drop effect; the Base Case Well IRR of 14% for $6/Mmbtu can be realized by using Well Technology B even when the gas price drops to $3/Mmbtu.

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