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CAN THE US SHALE REVOLUTION BE DUPLICATED IN EUROPE?

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Can the US shale revolution be duplicated in Europe?

by

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Abstract
Over the past decade, the rapid increase in shale gas and shale oil production in the United States has profoundly changed energy markets in North America, and has led to a significant decrease in American natural gas prices. The possible existence of large shale deposits in Europe, mainly in France, Poland and the United Kingdom, has fostered speculation on whether the "shale revolution", and its accompanying macroeconomic impacts, could be duplicated in Europe. However, a number of uncertainties, notably geological, technological and regulatory, make this possibility unclear. We present a techno-economic model, SHERPA (SHale Exploitation and Recovery Projection and Analysis), to analyze the main determinants of the profitability of shale wells and plays. We calibrate our model using production data from the leading American shale plays. We use SHERPA to estimate three shale gas production scenarios exploring different sets of geological and technical hypotheses for the largest potential holder of shale gas deposits in Europe, France. Even considering that the geology of the potential French shale deposits is favorable to commercial extraction, we find that under assumptions calibrated on U.S. production data, natural gas could be produced at a high breakeven price of $8.6 per MMBtu, and over a 45 year timeframe have a net present value of $19.6 billion – less than 1% of 2012 French GDP. However, the specificities of the European context, notably high deposit depth and stricter environmental regulations, could increase drilling costs and further decrease this low profitability. We find that a 40% premium over American drilling costs would make shale gas extraction uneconomical. Absent extreme well productivity, it appears very difficult for shale gas extraction to have an impact on European energy markets comparable to the American shale revolution.

1 Introduction

Over the past decade, the rapid increase in oil and gas production from shale deposits in the United States has profoundly changed energy markets in North America. In the early 2000s, a combination of improved horizontal drilling and hydraulic fracturing technology allowed to extract natural gas from formerly inaccessible shale deposits. An environment of increasing gas prices in the first half of the last decade, along with modifications to the environmental regulatory framework brought by the Energy Policy Act of 2005 (Pub.L. 109–58, 2005), have made these new natural gas reserves commercially exploitable.

The impact on domestic natural gas production in the United States was large and swift: while annual gross withdrawals of natural gas had been oscillating since the mid-1990s between 23.7 and 24.5 Tcf per year, they grew by 29% from 2005 to 2013 to reach 30.2 Tcf in 2013 (EIA, 2014b). The application of the same technology to tight oil deposits (sometimes also referred to as "shale oil") has been arguably even more dramatic. Breaking a long-term decline trend which had seen a 44%

decline between 1985 and 2008, domestic U.S. crude oil production has increased by 55% since 2008 to reach 7.4 MMbbl/day in 2013.

The rapid expansion of U.S. fossil fuel production has had a number of macroeconomic impacts, notably in the form of increased activity from intensive drilling, lowered natural gas prices, and a reduction in fossil fuel imports. However, the magnitude of these impacts remains a matter of controversy. Some reports, notably IHS (2011) and IHS (2013), have estimated that drilling activity, combined with the on shoring of some industries back in the United States – petrochemical in particular – could support up to 870,000 jobs by 2015.

These conclusions are challenged by studies such as EMF (2013) or Spencer, Sartor & Mathieu (2014). Recognizing that shale well drilling only has a highly localized impact on activity and employment, EMF (2013) estimates that shale development would only boost GDP by "a modest 0.46%", and downplays the importance of shale gas as a "game-changer" for the U.S. economy. Similarly, Spencer, Sartor & Mathieu (2014) highlight that the small share of energy-intensive industries in the U.S. economy and of natural gas expenditures in households' budgets limit the overall macroeconomic impact that can be expected from the steep reduction in natural gas prices.

Still, the existence of potentially large shale deposits in Europe, notably in France, Poland and the United Kingdom, has fostered speculation on whether the oft-called "shale revolution" could be duplicated on the continent. This issue is particularly relevant for natural gas, as European dependency on foreign exports has important energy security and geopolitical ramifications, notably *vis-à-vis* the Russian Federation (IEA, 2012).

Gény (2010) examines this issue and concludes that the large differences in terms of onshore drilling industry maturity, ease of access to land, mineral ownership rights and environmental regulations make U.S. operational and business model for shale gas development inapplicable to the European context. Absent a focus on geological "sweet spots, R&D, workforce training, and new technology developments", the shale revolution appears impossible to replicate in Europe. On the same note, Spencer et al. (2014) finds that "[i]t is unlikely that the EU will repeat the US experience in terms of the scale of unconventional oil and gas production", and that "[s]hale production would not have significant macroeconomic or competitiveness impacts for Europe in the period to 2030-2035".

These analyses are hampered by the lack of data on the geology of European shale deposits, on shale gas wells productivity or on drilling costs in Europe. In the present paper, we propose to compensate for this by using historical production data from the U.S. case to calibrate a model of shale gas production – notably regarding well productivity, drilling costs and operational costs. We then adapt those assumptions to the European context through an analysis of its specificities. This model can then be used to simulate shale gas production scenarios in European countries.

We choose to focus our scenarios on France, as it is the largest potential holder of shale gas resources in continental Europe. Besides, the ban on all exploration and extraction of shale deposits passed in 2011, then confirmed by the French Constitutional Council in 2013[1], makes it a good case study of the impact of the regulatory environment on shale development.

The paper is structured as follows: we first present a techno-economic model, SHERPA (SHale Exploitation and Recovery Projection and Analysis), to analyze the main determinants of the profitability of shale wells and plays. We then perform a detailed analysis of U.S. production data in

[1] "France's constitutional council upholds ban on fracking", *Financial Times*, 11 October 2013

leading shale plays, which allows us to calibrate SHERPA. We then examine the specificities of the European context that have a bearing on the technical and economic assumptions used. We finally present three scenarios of production based on different geological and technical hypotheses for France, the largest potential holder of shale gas deposits in Europe; estimate them with SHERPA; and conclude.

2 Modeling shale production

In order to model shale production scenarios in Europe and identify the main parameters that determine the cost of the production flow along with its volume, we develop a techno-economic model named SHERPA (Shale Extraction and Recovery Projection and Analysis). This section presents the model and specifies its equations.

Production profile of a single well

Oil and gas wells follow a well-identified production profile during their life cycle (Arps, 1944). Their production flow usually reaches its maximum early on, and then decreases at a decline rate that can vary over the well's lifespan.

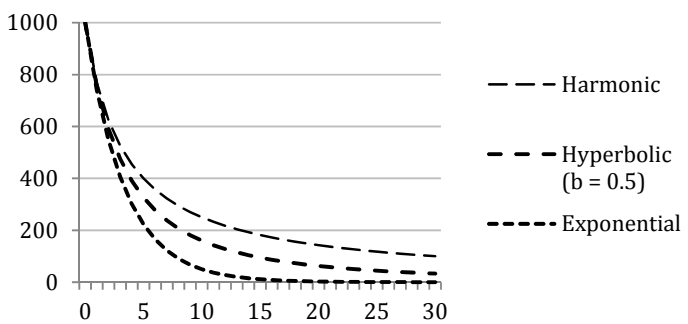
This production profile has been characterized by Arps (1944). In its most generic formulation, the production of a well can be expressed as follows:

$$q(t) = q_0 \frac{1}{(1 + bD_0 t)^{\frac{1}{b}}} \tag{1}$$

where q_0 is the initial production, D_0 the initial decline rate, and b $(0 \leq b \leq 1)$ a parameter controlling the evolution of the decline rate over time. The parameter b notably determines the type of decline (see Figure 1):

- *exponential* $(b = 0)$, where production decreases over time with a constant decline rate. If this decline rate is high, most of the production is front-loaded over the first years of exploitation;
- *hyperbolic* $(0 < b < 1)$, where the decline rate decreases over time. If this decrease is fast enough, the impact of high initial decline rates on the well's production can be balanced by a longer well lifespan;
- *harmonic* $(b = 1)$, which is a special case of hyperbolic decline. It is the slowest of all three types of declines, *i.e.* the one that yields the largest late-life production flows.

Figure 1: Types of well production decline ($q_0 = 1000$, $D_0 = 15\%$)



This equation highlights the two most important parameters when estimating the expected output of a well over its entire lifespan: the well's initial production and the dynamic of the decline rate over the well's life cycle.

In this paper, we shall consider a discretized version of the Arps equation to estimate the monthly production of the wells that will be modeled. Using a decline rate of δ_n in month n, the production for month n can be expressed as:

$$q_n = q_0(1 - \delta_n)^n \tag{2}$$

The total production over the well's lifetime, N_w, which amounts to its Estimated Ultimate Recovery (EUR), becomes:

$$Q_{well} = \sum_{n=0}^{N_w} q_0(1 - \delta_n)^n \tag{3}$$

If we then suppose that drilling costs amount to I, the marginal cost per unit of production amounts to c_m, and the wholesale price amounts to p, the Net Present Value (NPV) of this production is, for a discount rate of r:

$$NPV_{well} = \sum_{n=0}^{N_w} \frac{q_0(p - c_m)(1 - \delta_n)^n}{(1 + r)^n} - I \tag{4}$$

The breakeven price, p^*, corresponds to the price for which this NPV is zero. From equation (4), we find p^*, which can be split into a marginal component and a fixed costs component which amortizes the initial drilling costs:

$$p^* = c_m + \frac{I}{\sum_{n=0}^{N_w} \frac{q_0(1 - \delta_n)^n}{(1 + r)^n}} \tag{5}$$

Production of a play and production plateau

In order to model the total production of a play, we consider the production profile of a representative well. Thus, we capture the diversity observed across American plays in well productivity and decline speed solely through this "average" well. This approach allows us to analyze the aggregate production of the play across its entire lifespan. This hypothesis is a simplification since it is well documented that the productivity of shale wells vary greatly, including within a single play (EIA, 2011). However, it is expected that this diversity would mostly bear on the dynamics of the drilling effort – with the most productive spots being drilled first once identified. Characterizing the representative average is sufficient to estimate field-wide variables of interest to the present study, such as aggregate production flow, expected total production, or average breakeven price.

Let us consider a play for which the production of the representative well is described by equation 2. If D_n wells are drilled in month n, then the production of the play in month n, Q_n, is expressed as:

$$Q_n = \sum_{i=0}^{n} D_i q_0 (1 - \delta_{n-i})^{(n-i)} \tag{6}$$

If we call D_R the highest drilling rate over the production period of the play N_p, and δ the smallest decline rate observed in any given month across the lifespan of the representative well:

$$\begin{aligned} D_R &= \max_{0 \le n \le N_p} D_n \\ \delta &= \min_{0 \le n \le N_w} \delta_n \end{aligned} \tag{7}$$

Then we obtain the following upper bound on the production of the play:

$$Q_n \le \frac{D_R q_0}{\delta} \tag{8}$$

This inequality illustrates an important phenomenon. The production of the play is at all times bounded by a production plateau, whose value only depends on the average initial production, the lower bound of the decline rate across the lifespan of the representative well, and the maximum drilling rate. As the drilling rate increases towards its maximum value, and as the play matures, the production of the entire play actually converges towards a plateau which is strictly bounded by equation 7, with the speed of convergence depending on the steepness of the decline rate. This plateau corresponds to the phase in the play life cycle when drilling new wells can only offset the declining production of old wells, without increasing the aggregate production of the play. Yet, if the average decline rate is low, this plateau can be so high as to never be bounding within the play's lifespan.

Indeed, in the case of conventional oil and gas fields, the observed annual decline rates can be estimated to be around 3 to 4 % (Höök, Hirsch, & Aleklett, 2009): in that case, the production of the field remains below 95 % of the plateau's value during the first 75 years of extraction. However, for annual decline rates closer to the 50% levels observed on shale deposits (see Table 3), the same threshold can be reached within four years only.

This phenomenon of production plateau, where new wells are only drilled to maintain existing production volume, is thus characteristic of shale plays. Once reached, breaching the production plateau entails improving well productivity through better technology, or increasing the drilling rate. Geological constraints can set hard limits on well productivity, although recent improvement in drilling and fracturing technology have achieved some improvements (EIA, 2014a); the simplest way to maintain production growth is to sustain a continuous increase in the drilling rate.

3 Data calibration

Calibrating the equation describing the production profile of the representative well (equation 2) requires detailed knowledge of the geological characteristics of the play considered. Great uncertainties remain in Europe over the actual volume of resources in place and of technically and commercially recoverable reserves (IFPEN, 2013). Besides, since only around 50 experimental wells

have been drilled on the continent so far (Spencer et al., 2014), production data has yet to be made available publicly.

It is therefore necessary to gather this calibration data from a different source. Ever since the commercial extraction of shale deposits began during the last decade, close to 60 shale gas plays have been drilled in the United States (Hughes, 2013). 30 out of these 60 plays have proved profitable, with only six of those accounting for more than 90% of the total natural gas production from shale deposits in the United States (EIA, 2013). Production data from North American plays thus covers a wide variety of distinct geological configurations. A detailed analysis of this data can provide a basis for the calibration of our model.

In a number of States, home to some of North America's largest shale plays, production reports provided by operators are made available publicly. This data provides a very precise description of the shale well production profiles. Using this information, we can estimate realistic intervals for the key parameters f equation 2, initial production and decline rate.

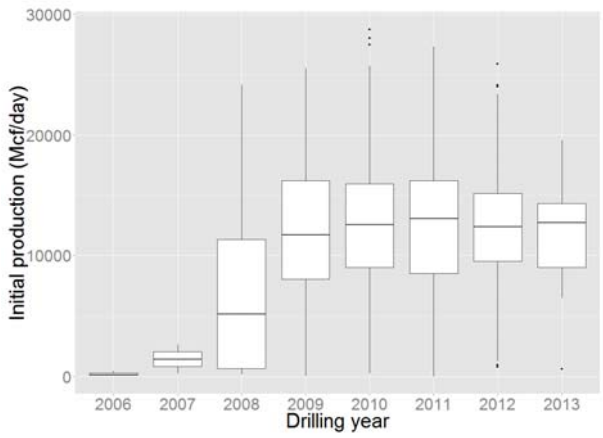
Initial production

We have undertaken this statistical analysis in two major natural gas-producing plays, Haynesville and Fayetteville. The production data was obtained from the Louisiana Department of Natural Resources and from the Arkansas Oil and Gas Commission. We therefore restrict our analysis to the portion of the Haynesville play located in Louisiana and the Arkansas section of Fayetteville. Our data includes initial production and drilling date for 2,432 wells in Haynesville, and monthly production and drilling date for 4,882 wells in Fayetteville.

We first estimate the average initial production of wells in each play, and examine its evolution over time by year of drilling. The results are presented in Figure 2 below.

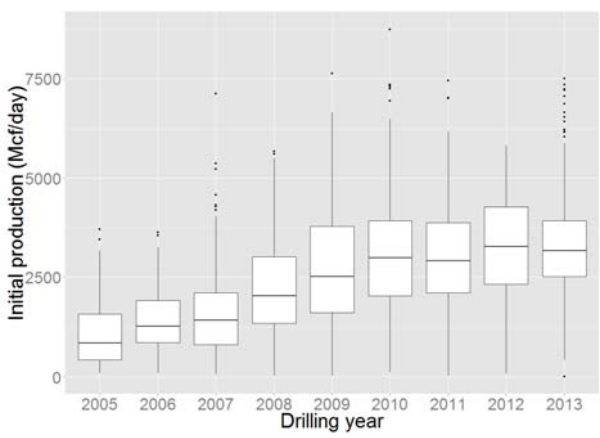
Figure 2: Well's initial production by drilling year in the Haynesville and Fayetteville

Haynesville (Louisiana)



Source: Louisiana's Department of Natural Resources / Author's calculations

Fayetteville (Arkansas)



Source: Arkansas Oil and Gas Commission / Author's calculations

We find that the evolution of initial production exhibits a common pattern in both plays. In a first period, ranging from 2006 to 2009 in Haynesville and from 2005 to 2010 in Fayetteville, average initial productions gradually increase with drilling year. Provided that decline rates remain constant across drilling years, this indicates an improvement in well productivity over time in each of the

plays. Indeed, a simultaneous increase of decline rates over time could cancel out the impact of improved initial productions over the well's total lifecycle production.

This improvement can be driven by at least two causes: an improvement in extraction and fracturing technologies, which leads to an increase in recovery rates of natural gas from the shale resource (EIA, 2014); and a better knowledge of the field's geology, notably the identification of so-called "sweet spots" – regions of the play where well productivity tends to be optimal – which once found concentrate the drilling activity, thereby increasing average well productivity in the play (EIA, 2011). In both cases, this first period of increasing well productivity can be understood as a learning phase, either at the play level – during which operators increase their geological knowledge of the shale play –, or at the industry level – whereby technologies used to extract shale deposits are improved simultaneously across all plays. Further research will be needed to distinguish the relative contributions of each of these factors in the observed overall increase in well productivity over time.

Once this learning phase is over, average initial production reaches a stable level that has been roughly maintained to the present, although the distribution of initial productions has varied over time in each play. In the Louisiana section of Haynesville, average initial production stabilizes between 11,930 and 12,880 Mcf/day, while in the Arkansas section of Fayetteville, it is comprised between 3,000 and 3,348 Mcf/day.

To complement the results of this analysis, we extend our estimates with those of Hughes (2013), who has conducted a similar study on the largest shale plays in the United States. His estimates for the average initial production of a well in each of these plays are collected in Table 1.

Table 1: Average initial production of a well in the six largest shale gas plays in the U.S.

	Haynesville	Barnett	Marcellus	Fayetteville	Eagle Ford	Woodford
Initial production *(Mcf/day)*	8,201	1,619	1,947	2,069	1,920	2,292

Source : Hughes (2013)

With the exception of Haynesville, the average initial production of a well is remarkably similar in five of the six main American shale gas plays, between 1,600 and 2,300 Mcf/day. The discrepancy between our estimates and Hughes' (2013) for the Haynesville and the Fayetteville has two causes: first, his analysis was conducted over the whole play in each case, while we only had access to the portion of the plays located in States that release public production data from operators; second, Hughes' (2013) averages are calculated over every wells ever drilled in the play – even though our analysis shows that there has been a significant increase in initial productions over time. This implies that estimates of average initial production made over the whole play's lifespan are necessarily lower than the post-learning phase plateau we identified in our analysis, since they include wells drilled while technological and geological knowledge was still improving.

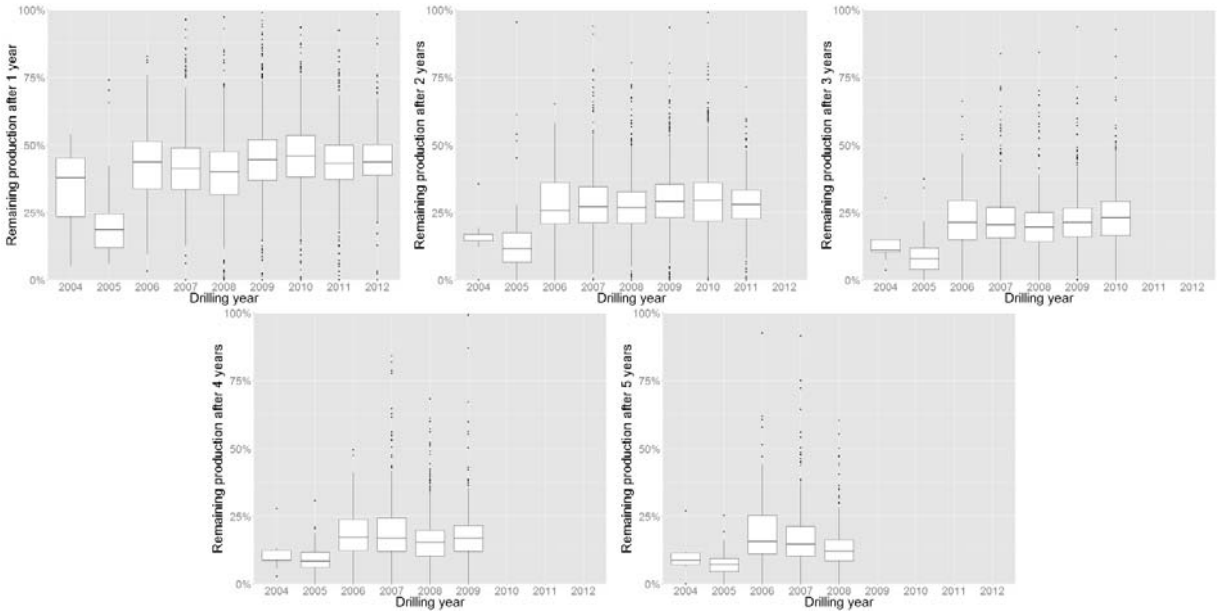
Decline rates

The data provided by the Arkansas Oil and Gas Commission for the Fayetteville play includes monthly production reports by well. This allows us to estimate average decline rates over the entire play, along with their evolution by drilling year. Unfortunately, this was not possible with the Haynesville data, which only provides initial production for each well.

Figure 3 shows the average ratio of remaining production to initial production for a Fayetteville well after one to five years of extraction, as a function of the well's drilling year. The decline in production over time is very steep: after three years, the production flow is reduced on average to

28.3% of its initial value; after five years, the remaining flow is 15.5% of initial production on average.

Figure 3: Average remaining production as a percentage of initial production after 1 to 5 years, by drilling year



Source: Arkansas Oil and Gas Commission / Author's calculations

With the exception of the first two years for which we have data in the Fayetteville, which concerns only 1% of the sample, the average decrease in production after one to five years is remarkably stable over drilling years – and therefore, so are the associated decline rates. This indicates that unlike initial production, the average well's production profile does not exhibit a learning phase after which observed decline rates would be reduced. It is therefore reasonable to assume that average decline rates estimated over the whole play's lifespan are applicable to the most recent wells. Table 2 presents our estimates for the average year-on-year decline rates of a well in the portion of the Fayetteville play located in Arkansas.

Table 2: Average year-on-year decline rates of a well in Fayetteville (Arkansas)

	Decline in year 1	Decline in year 2	Decline in year 3	Decline in year 4	Decline in year 5
Fayetteville	57%	34%	24%	21%	9%

Source: Arkansas Oil and Gas Commission / Author's calculations

To get decline rates estimates for other U.S. shale gas plays, we complement our analysis with that of Hughes (2013). His estimates for the average year-on-year decline rates of a well in Haynesville, Barnett and Marcellus are presented in Table 3Table 1.

Table 3: Average year-on-year decline rates of a well in the three main shale gas plays in the U.S.

	Haynesville	Barnett	Marcellus
Decline in year 1	68%	61%	47%
Decline in year 2	49%	32%	66%
Decline in year 3	50%	24%	71%
Decline in year 4	48%	18%	47%
Decline in year 5		15%	

Source : Hughes (2013)

First, Table 2 and Table 3 illustrate the large diversity of decline rates observed across shale gas plays. Second, we find that in general, the production decline cannot be described as either exponential, since the annual decline rate varies over the well's lifespan, nor hyperbolic, since decline rates do not decrease monotonically over time. We therefore calibrate equation 2 with a monthly decline rate that varies for each year of production. Beyond year 5, annual decline rates are assumed constant.

The production profile of the representative well is tied to the specific shale play considered, in particular to its geological characteristics. Still, in keeping with our approach of using historical U.S. production data to calibrate SHERPA, we use a weighted average of the decline rates estimated above, using the 2012 annual production of each shale play examined as weight. The results are presented in Table 4.

Table 4: Decline rates used in the SHERPA model

Decline in year 1	Decline in year 2	Decline in year 3	Decline in year 4	Decline in year 5
59%	46%	44%	36%	13%

4 Specificities of the European context

Gas price formation

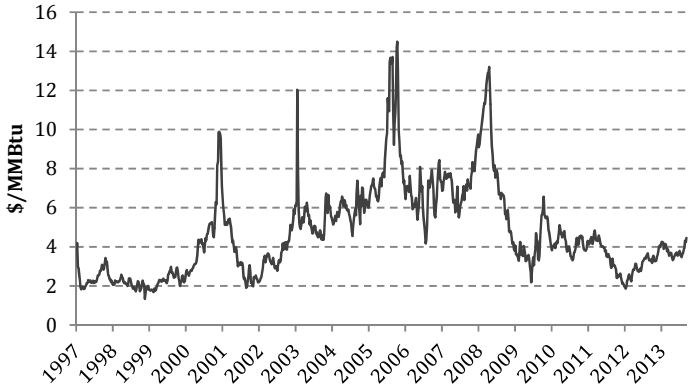
The large drop in natural gas prices over the past decade, from a weekly average high of 14.49 $/MMBtu in December 2005 to a low of 1.86 $/MMBtu in April 2012[2] (see Figure 4), has been one of the more significant consequences of the large increase in domestic gas production in the United States.

Unlike other energy commodities, crude oil in particular, the market for natural gas is still fragmented into several regional markets. The price of natural gas is therefore different in the United States, Europe and East Asia (IEA, 2012). Hence, the decrease in gas prices illustrated in Figure 4 has remained localized in the United States.

This is due in large part to the difficulty of transporting natural gas. Across oceans, where pipelines cannot be used, natural gas must be liquefied and transported in LNG tankers. This entails building very expensive processing facilities to liquefy the gas on departure, and gasify it back on arrival. In addition, processing plants used for liquefaction cannot be used for gasification without costly retrofitting (IGU, 2012).

[2] Henry Hub Natural Gas Spot Price, weekly averages. Source: U.S. EIA

Figure 4: Henry Hub natural gas weekly average price (1997-2013)



Source: U.S. EIA

Besides, gas price formation mechanisms are distinct in each of the major markets. In the United States, the price of natural gas is set through gas-on-gas competition. Natural gas is traded over a variety of time frames (*e.g.* daily, monthly or annually) at a number of physical hubs – Texas's Henry Hub being the largest –, and the interplay of supply and demand determines the price. In such a market, changes in the balance between supply and demand have an immediate impact on prices. The United States, which until the late 2000s expected domestic natural gas production to decline, had built LNG plants to import gas, but not to export it (EIA, 2011). When shale gas extraction rapidly grew, the newfound domestic production of natural gas changed the local balance of supply and demand immediately. From 2008 to 2012, domestic production grew at a rate of 3.6% per annum, outpacing consumption, which only grew at 2.3% per annum[3]: this led to the large drop in prices.

In Europe, gas price formation follows a different mechanism. Traditionally, European natural gas supplies have been priced through a mix of long-term contracts with producing countries and spot market pricing. Long-term contracts are mostly priced using a mechanism known as oil price escalation, whereby gas prices are linked, usually through a base price and an escalation clause, to the price of competing fuels – typically crude oil (IGU, 2012). Oil price escalation used to dominate natural gas price formation in Europe. However, since the late 2000s, oil indexation of natural gas contracts has been decreasing: as of 2012, 51% of European gas consumption was priced through an oil price escalation clause, down from 59% in 2010. Meanwhile, from 2007 to 2012, spot-priced natural gas volumes have doubled, to reach 44% of consumption (EC, 2013).

This pricing structure makes European wholesale gas prices less elastic to changes in the balance of supply and demand. While an increase in domestic production could improve the bargaining power of European countries with their suppliers, the impact of introducing small volumes of domestic shale gas production in the European supply mix on gas prices is unclear.

We therefore choose to estimate the profitability of shale gas extraction at a given wholesale price. For our main scenarios, we use the Russian Natural Gas border price in Germany, which is a common benchmark for gas prices in continental Europe, averaged over the period 2011-2013. We obtain a wholesale price hypothesis of $11.6/MMBtu. We then explore the sensitivity to that hypothesis in several variants.

[3] Source: U.S. EIA Natural Gas statistics

Drilling costs

Public data on drilling costs is scarce, which makes their calibration difficult. According to the U.S. EIA, drilling costs per well in the leading shale plays of Marcellus, Bakken and Eagle Ford are comprised between $6.5 and $9 million, including both horizontal drilling and hydraulic fracturing (EIA, 2012).

However, these estimates cannot be used directly in the European context. Notably, one of the main drivers of drilling costs is the depth of the well and the length of its lateral (Pulsipher, 2007). Table 5 presents average drilling costs and average depth in the main U.S. shale plays.

Table 5: Average drilling costs and depth of the main U.S. shale plays

	Haynesville	Barnett	Marcellus	Fayetteville	Woodford	Granite Wash
Average drilling costs *(million USD)*	9.5	3.5	5.3	2.8	8.5	7.8
Average depth *(ft)*	12,100	7,900	6,200	3,600	13,100	13,100

Source : Nickelson (2013), Berman et Pittinger (2011)

As shown in the above table, drilling costs increase with average deposit depth: the most expensive wells are located in the deepest shale deposits, between 12,000 and 13,000 ft on average. Most European deposits have been identified in geological strata located at comparable depth : the majority of the French resources would be found between 10,000 and 14,000 ft, between 10,000 and 12,500 ft in Poland, between 11,500 and 14,500 ft in Germany, between 11,000 and 12,500 ft in the Netherlands, and around 11,000 ft in Spain; only British shale deposits would be located at a shallower depth of 8,000 ft (EIA, 2013).

These elements lead us to estimate that drilling costs will on average be higher in Europe than in the United States. This is indeed the conclusion of Wood Mackenzie (2012) on the economic potential of shale gas resources in the United Kingdom, which estimated that should the British shale resources be developed, the average drilling costs would reach $17 million. This would amount to more than one and a half times the average well cost in the Haynesville, where drilling costs are the highest of any American play. Oil services company Schlumberger also estimated in 2011 that drilling costs in Poland could turn out to be three times higher than in the United States[4].

Finally, it should be noted that the availability of drilling equipment is much higher in the United States than in Europe. In the first quarter of 2014, more than 1,700 drilling rigs were being operated in the United States, including both oil and gas plays of the conventional and unconventional varieties (EIA, 2014). This is to be contrasted with less than a hundred rigs available across the entire European continent in 2013 (Hsieh, 2011). Further, only a small fraction of these rigs can be used to drill shale gas wells: for example, in 2011, out of 15 drilling rigs available in Poland, only 5 were suitable to shale gas extraction. These capacity constraints could limit the drilling rate in European countries, at least in the first years of production.

Regulatory environment

In addition to the improvements made to hydraulic fracturing and horizontal drilling technologies, the expansion of commercial shale gas extraction was also enabled by changes made to the

[4] "Shale-Gas Drilling Cost in Poland Triple U.S., Schlumberger Says", *Bloomberg*, 29 November 2011

regulatory framework governing oil and gas production – especially regarding environmental regulations.

Indeed, the Energy Policy Act of 2005 (Pub.L. 109–58, 2005) brought some significant modifications to the environmental legislations regulating oil and gas drilling in the United States. Passed at a time when conventional gas plays were exhibiting signs of depletion (EIA, 2005), the Energy Policy Act defined new core principles for American energy policy, with a particular emphasis on reducing future dependency on fossil fuel imports. The Act included a number of measures aiming to increase domestic fossil fuel production. Notably, two existing environmental laws were amended to facilitate the use of hydraulic fracturing – and thus the extraction of oil and gas from shale deposits:

- the Safe Drinking Water Act (Pub. L. 93-523, 1974), which regulates the public drinking water supply, and ensures its quality and suitability for human consumption. Originally, this Act banned any drilling in the vicinity of underground water reservoirs. Section 322 of the Energy Policy Act of 2005 lifts this ban for oil and gas drilling.

- the Clean Water Act (Pub. L. 92-500, 1972), which governs water pollution. This Act notably defines what constitutes a water pollutant. Through an amendment to section 502 of the Clean Water Act, the Energy Policy Act of 2005 excludes from this definition "water, gas, or other material which is injected into a well to facilitate production of oil or gas".

These changes, made to two pillars of the environmental regulatory framework of the United States, were essential to enable the widespread use of hydraulic fracturing, and thus the shale revolution. The former ban on drilling close to water reservoirs would have prevented a number of commercial wells from ever being drilled. Similarly, without the chemical additives that were formerly listed as pollutants by the Clean Water Act, hydraulic fracturing would be much less effective, and well productivity would be significantly lower.

Environmental regulations in Europe are much stricter. In particular, the use of chemical additives in the fracturing fluid, the transportation and storage of flowback mud from well fracturing, or the drilling of wells within proximity to water reservoirs or inhabitations would all be very difficult or outright forbidden under the current European environmental legislation, both at the Union and Member State level (Gény, 2010). Other measures targeting both safety and environmental protection, such as standards of safety valves and the compulsoriness of multiple casings around the well's body, would have a direct impact on drilling costs.

At this stage, it is impossible to know whether the European Union or some of its Member States will amend their existing legislations to lift some of the restrictions currently limiting the use of hydraulic fracturing. Fostering shale gas production on their territory would entail rescinding part of their environmental protection framework to favor domestic on shore drilling, as the Energy Policy Act did in the United States in 2005. Currently, compliance with the local legislation would lead to significantly higher drilling costs in Europe than in the United States (Gény, 2010).

5 Production scenarios for France

Scenarios

Based on the calibration obtained from the statistical analysis of U.S. production data, we design production scenarios for France, which is the largest potential holder of shale gas deposits in Europe. We focus our analysis on natural gas as according to EIA (2013), estimated technically recoverable resources of shale gas dwarf those of shale and tight oil in Europe. To simplify the

analysis, we consider the two potential shale fields in France, the Paris basin and the South-East basin, as one single field, on which we formulate aggregate hypotheses.

Further, our price hypotheses are based on the assumption that dry gas will be produced and marketed. We do consider the possibility of more valuable associated liquids such as ethane or butane being produced in a variant of the first scenario though.

We consider three main scenarios:

- The « **Central** » scenario aims to estimate what a realistic production scenario would be, should the geology of the French shale deposits prove favorable to commercial extraction.
  Based on this hypothesis, we assume that well productivity would be comparable to that of the main U.S. commercial shale gas plays: we therefore assume an average initial productivity of 2,200 Mcf/day, at the upper end of the range identified in Table 1.
  In our analysis of drilling costs, we observed that French shale deposits were located at a depth comparable to that of the Haynesville play, and that drilling costs were proportional to the deposit depth. We therefore assume average drilling costs of $10 million. This last hypothesis is conservative, as we consider that the European context – environmental regulations in particular – would only impose a half-million dollar premium (5%) per well on average in addition to the $9.5 million drilling cost average observed in the Haynesville.

- The « **Zero NPV** » scenario aims at determining, *ceteris paribus*, what premium on average drilling costs would cancel out the profitability of shale gas extraction in France.
  We therefore maintain the well productivity assumption of the Central scenario, and find that adding a 40% premium on drilling costs over those observed in Haynesville leads to an NPV over the entire duration of the scenario of zero.

- The « **Extreme** » scenario performs a sensitivity analysis on well productivity.
  We conserve the drilling costs assumption of the Central scenario, but associate it with an average well productivity comparable to that of the best play in the U.S., Haynesville, with an initial production of 8,000 Mcf/day. This hypothesis lies at an extreme end of the probability space, as it amounts to considering that both French shale gas fields would have an average well productivity comparable to that of the very best play known to date.

Further, in all scenarios, we consider a drilling rate of 30 wells per month, which amounts to more than 10,000 wells drilled over a period of 30 years.

Assumptions for these three scenarios are gathered in Table 6.

Table 6: Production scenarios assumptions

Scenario	**Initial production** (Mcf/day)	**Drilling cost** (millions USD)	**Drilling rate** (wells/months)
1) Central	2,200	10,0	30
2) Zero NPV	2,200	13,3	30
3) Extreme	8,000	10,0	30

In additions to these differentiating hypotheses, we also make the following assumptions across all scenarios:

- the drilling period lasts for 30 years;
- the drilling rate is increased progressively during the first three years of the scenario, in order to account for the learning phase of the industry;
- operational costs, estimated by Moniz, Jacoby & Meggs (2011) between $0.5 et $1 per Mcf, are pegged at $0.75 per Mcf; and
- technically recoverable resources (TRR) are estimated at 137 Tcf (EIA, 2013).

Finally, we assume that shale gas extraction will be managed by a state-owned company. Indeed, calls have been made – notably by the French Industry Minister – for shale gas production to be carried out by a public body, should the ban on shale gas exploration and extraction be lifted[5]. This leads us to use a discount rate of 4% in the calculation of net present values, as it is the standard rate used by the French Treasury to evaluate the profitability of government-sponsored projects (DG Trésor, 2005).

Results

We use the SHERPA model to estimate the average breakeven price and estimated ultimate recovery (EUR) per well, the share of technically recoverable resources extracted, and the net present value of the natural gas produced. Results are presented in Table 7.

Table 7: Main scenario results

Scenario	**Breakeven price** *(USD/MMBtu)*	**EUR** *(bcf)*	**Peak production** *(bcf/year)*	**Share of TRR produced**	**NPV** *(billion USD)*
1) Central	8.6	1.4	491	10%	19.6
2) Zero NPV	11.2	1.4	491	10%	0
3) Extreme	2.8	5.0	1,787	37%	228

Source : SHERPA model

The assumptions of the Central scenario bring the breakeven price of natural gas close to our gas price hypothesis. Therefore, the NPV of natural gas extracted over the entire scenario duration is fairly low, at $19.6 billion – which represents less than 1% of 2012 French GDP. At peak, domestic natural gas production would cover 31% of France's 2012 consumption of 1,560 bcf.

The second scenario illustrates the sensitivity of breakeven price to the average drilling cost. Under our gas price hypothesis, an increase of 33% in drilling costs over the Central scenario is enough to bring the breakeven price on par with our wholesale price assumption: the NPV is thus brought to naught. Similarly, a reduction in average well productivity – for example due to adverse geological conditions –, while maintaining constant drilling costs, would have quickly reduced the NPV to zero.

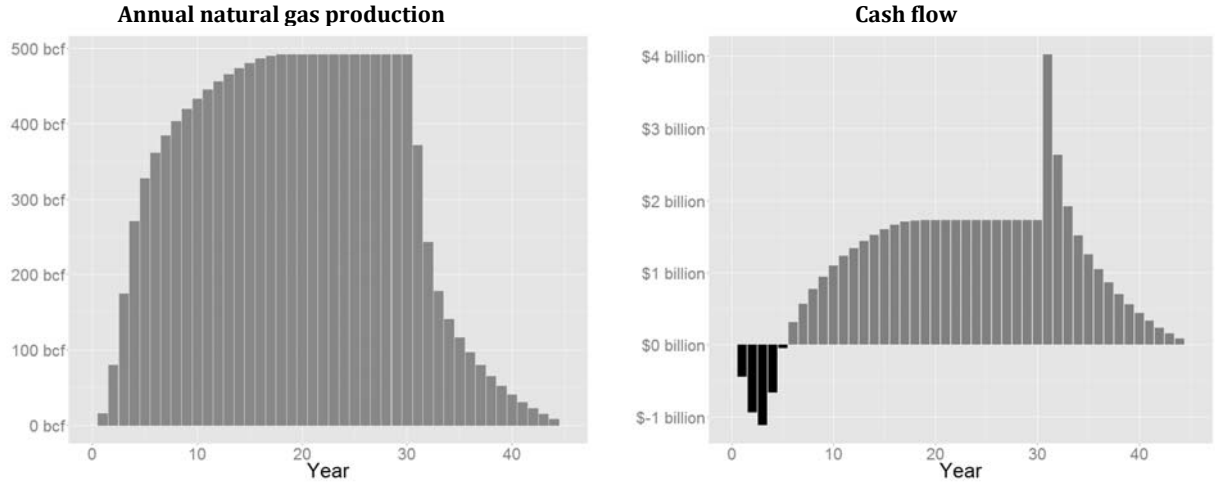
Finally, the third scenario highlights the importance of well productivity in determining the breakeven price, and therefore the profitability of natural gas extraction. Unsurprisingly, should French shale gas plays exhibit the same well productivity as the best American play known to date, the NPV of the gas produced would amount to several percentage points of French GDP. Under these

[5] "France plans to invest in state mining venture", *Financial Times*, 21 February 2014

extreme well productivity assumptions, France could even become a net natural gas exporter, as the peak annual domestic production is 200 bcf higher than the 2012 consumption.

The production profile and cash flow of the Central scenario are presented in Figure 5. For reference, the same charts are provided for all scenarios in the annex.

Figure 5: Central scenario results



Source: SHERPA model

The aggregate natural gas production increases over the first 15 years of the scenario, before reaching a plateau until year 30. This illustrates the phenomenon of production plateau described previously, and is due to the fact that past the first 3 years of ramp-up, the drilling rate remains constant throughout the drilling phase, at 30 wells per month. Since well productivity hypotheses are assumed to hold over the whole scenario's timeframe, production cannot increase beyond that plateau without an increase in the drilling rate. As soon as the drilling ceases in year 31, aggregate production undergoes a steep reduction, at an initial rate of 25% to 30% a year, then softening to around 20% after the first 5 years of terminal decline.

The large upfront drilling costs lead to negative cash flows for the first five years of the scenario. This negative runway increases for the first 3 years of the scenario as the drilling rate is ramped up to 30 wells per month. The positive spike in cash-flow in year 31 corresponds to the end of the drilling phase: wells that were drilled in earlier periods keep producing for 15 years, per the well life expectancy hypothesis, with no further expense but the $0.75/Mcf operational expense.

We then perform three sensitivity analyses on the Central scenario. We first consider the possibility that French deposits produce "wet" gas, *i.e.* both methane and associated natural gas liquids (NGLs) such as ethane or butane. We model this variant as a 10% increase in the wholesale price of natural gas over our hypothesis of $11.6/MMBtu, since on a per-Btu basis, NGLs command a higher price than natural gas on European markets[6]. One should note that the expansion of wet gas in the United States has actually brought down the price of some liquids. For example, the profitability of ethane is now on-par with natural gas on a per-Btu basis: the increased profitability of wet gas could therefore be transitory[7].

[6] Source: OPIS
[7] "Changes in Longitudes – Ethane Exports to Europe", *RBN Energy*, 24 March 2014

Next, we evaluate a Central scenario where the production would be undertaken by a private company instead of a state-owned structure. In this variant, we thus consider a discount rate of 10% instead of the 4% used in the standard Central scenario. This allows us to estimate the sensitivity of the breakeven price and the NPV to the discount rate.

Finally, we consider a variant of the Central scenario where natural gas prices do not remain stable, but instead halve over the duration of the scenario. This could occur if, for example, several European countries had shale gas deposits with favorable geology, and decided to start extracting their natural gas simultaneously. Their combined newfound domestic productions could lead to an oversupply of natural gas on the European market, or, equivalently, increase their bargaining power with foreign suppliers to renegotiate long-term contracts and lower natural gas prices in Europe.

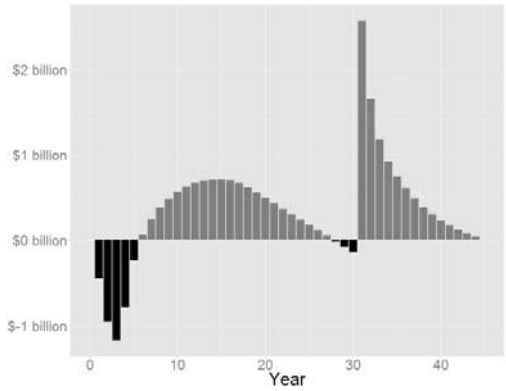
Table 8: Central scenario variants

	Assumptions		Results	
Variant	**Wholesale price** *(USD/MMBtu)*	**Discount rate**	**Breakeven price** *(USD/MMBtu)*	**NPV** *(billion USD)*
1a) Wet gas	12.7	4%	8.6	28
1b) Private	11.6	10%	9.5	5.5
1c) Decreasing gas price	11.6	4%	8.6	4.9

Source : SHERPA model

We find that an increase in wholesale gas prices of 10% over our main hypothesis of $11.6/MMBtu would increase the NPV by 43%, at $28 billion. This highlights the high sensitivity of the overall profitability of shale gas extraction to the wholesale gas price. Conversely, should gas prices decrease by half over the production period, the NPV would be reduced by 75%. As illustrated in Figure 6, in variant 1c, shale gas extraction even becomes briefly cash-flow negative at the end of the drilling period.

Figure 6: Cash flow for variant 1c – Decreasing gas price



Finally, increasing the discount rate to 10% also reduces the profitability of shale gas extraction sharply: the NPV is reduced by 72% compared with a 4% discount rate, and the breakeven price increases by 10% to $9.5/MMBtu. Thus, under our Central hypotheses, commercial production of shale gas by a private entity in France appears difficult.

6 Conclusion

To assess whether the American shale gas revolution can be duplicated in Europe, we have determined the main drivers of shale gas extraction profitability. To this end, we have presented a techno-economic model of shale gas production, SHERPA, which allowed us to identify the following key parameters: well productivity, as described by initial production and decline rates, and drilling costs.

The volume and geological characteristics of shale gas resources in Europe remain speculative. Besides, experimental drilling has remained very scarce. It is therefore not possible to assess well productivity in the potential European shale gas plays. At this stage, we cannot directly calibrate SHERPA on European production data.

To remedy this lack of data, we perform a detailed statistical analysis of existing production data in the leading U.S. shale plays to calibrate realistic ranges for initial productions and decline rates. We then analyze the specificities of the European context, notably in terms of gas price formation, drilling costs and environmental regulations, to define hypotheses reflecting these particularities.

Using SHERPA, we then estimate production scenarios for France, which is the largest potential holder of shale gas resources in Europe. All scenarios start from the premise that the geology of the French deposits proves conducive to the commercial extraction of shale gas.

However, even under that hypothesis, assuming well productivity comparable to that of five of the six largest U.S. shale plays, and conservative drilling costs of $10 million per well, we find that the breakeven price of shale gas extraction would be high and the profitability relatively low. Indeed, only under extreme well productivity hypotheses does the profitability of shale gas become significant.

Conversely, we find that increased drilling costs 40% above their American counterparts, a discount rate of 10% compatible with production by a private entity, or a progressive halving of wholesale gas prices over 45 years would all make shale gas extraction close to or entirely uneconomical in France.

Thus, it appears that even if the geology of European shale deposits was favorable, an expansion of shale gas production on a scale comparable to the American experience over the past decade cannot be reproduced in Europe at present. Only under the most favorable geological configurations could shale gas extraction prove highly profitable in Europe.

Absent extreme well productivity, or a technological improvement that would lower drilling costs or increase recovery rates while complying with local environmental regulations, it appears very difficult for shale gas extraction to have a significant impact on European energy markets.

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Annex

Figure 7: Central scenario results

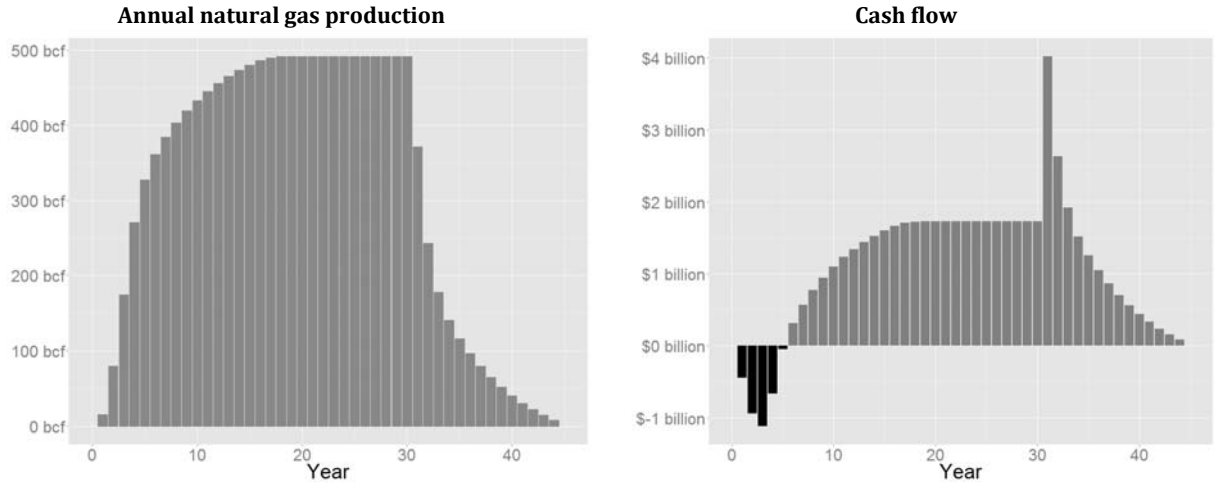


Figure 8: Zero NPV scenario results

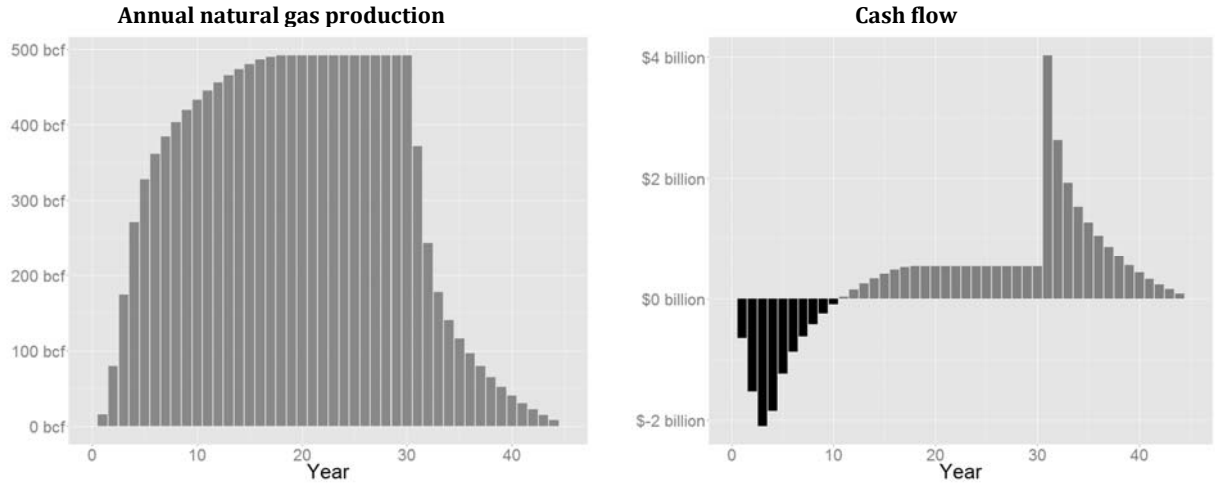


Figure 9: Extreme scenario results

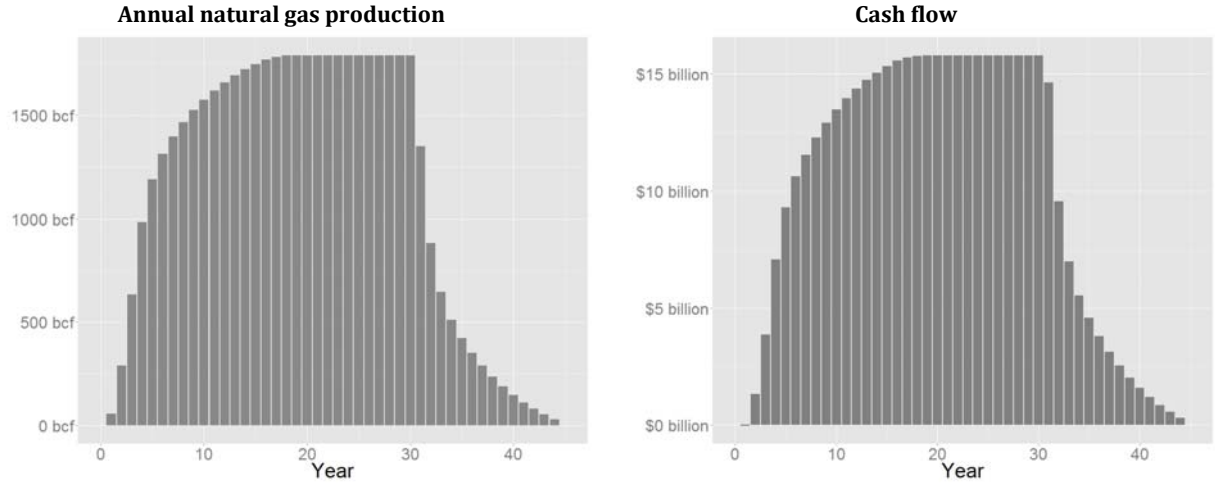
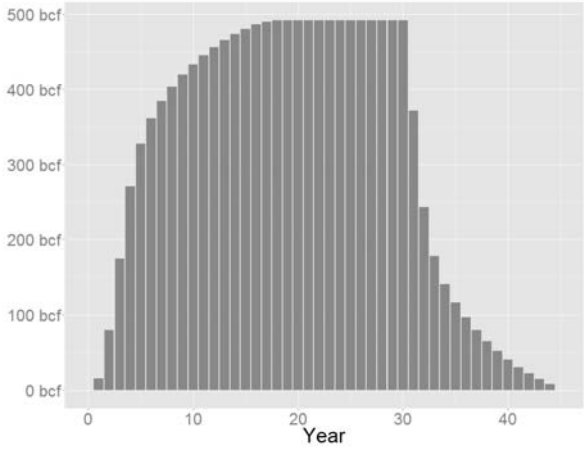


Figure 10: Central scenario, Wet gas variant results

Annual natural gas production



Cash flow

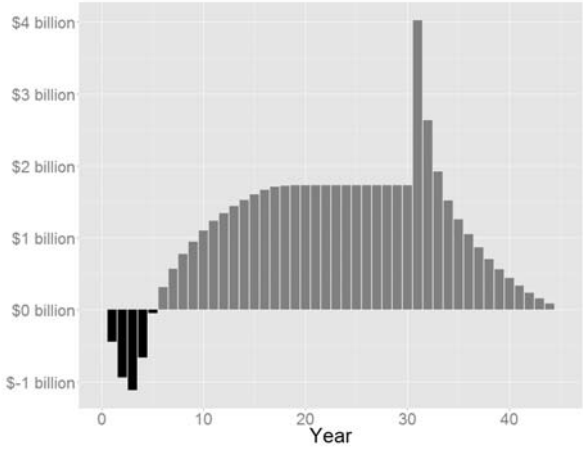
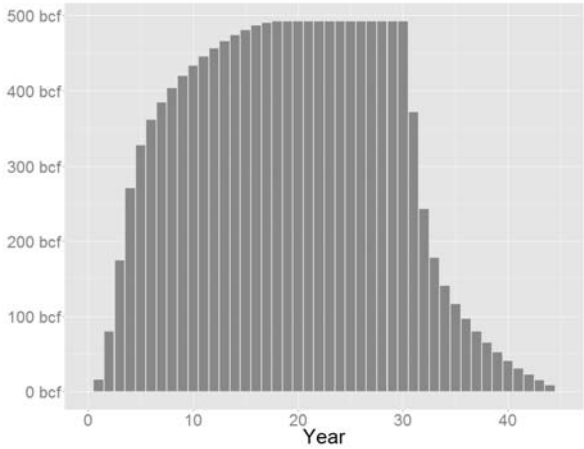


Figure 11: Central scenario, Private variant results

Annual natural gas production



Cash flow

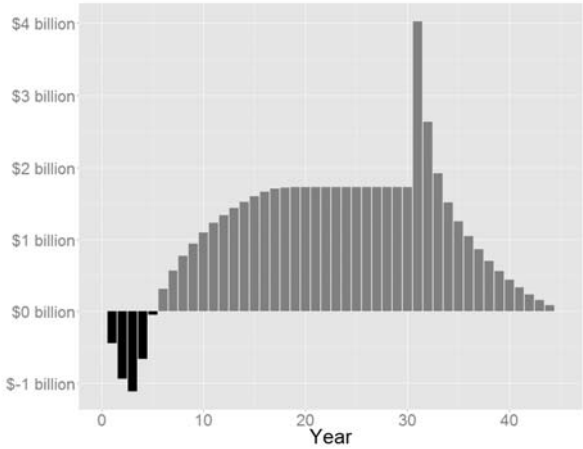
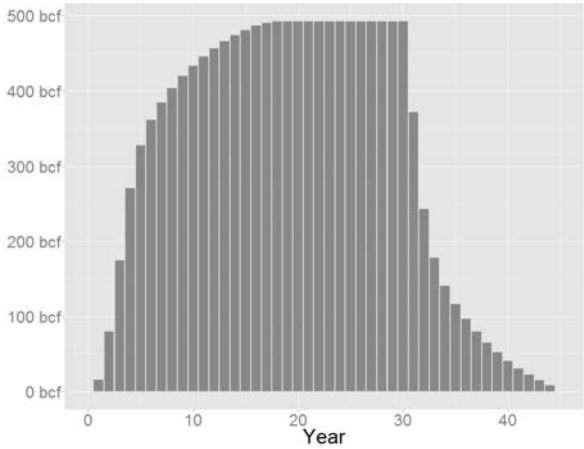
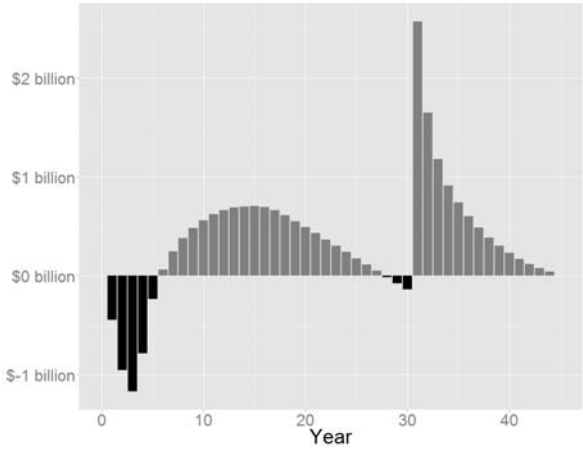


Figure 12: Central scenario, Decreasing gas price results

Annual natural gas production



Cash flow