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Shale Gas

Strategic, technical, environmental and regulatory issues

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PREFACE

In January 2016, the book "*Gas no convencional: shale gas. Aspectos estratégicos, técnicos, medioambientales y regulatorios*" was published. As we pointed out in the prologue of the book, the study of unconventional gas is within the lines of knowledge of the Energy Chair of Orkestra of the University of Deusto. In fact, three main lines of study are currently covered. Namely Energy markets, Energy Industry and Technology, and Energy Policy.

The approach to the shale gas study that the reader has in his hands, in our view, covers a wide scope of topics, including the strategic aspects, the technical topics related to the exploration, drilling and hydraulic fracturing, as well as the environmental aspects and the regulation processes for exploration.

One of the characteristics of the research of the Energy Chair is to try to work with a network of institutions, universities and professionals with experience and knowledge in the specific topics that we analyze. In this case, from the very beginning, it was though that the creation and implementation of a group of experts would be particularly valuable, so an Advisory Group and a Reviewers Group were put in place. The relevant professionals and institutions that we have the honor to count on are reflected in this study.

Given the participation of the members of the Advisory Group and the Reviewers Group, the first draft of the study was written in English. At the beginning of the project, Nerea Álvarez, mining engineer, produced a first draft. The English version was translated into Spanish and later, when Claudia Suárez joined the Energy Chair of Orkestra, she was fully involved to revise, extend and improve the study.

In the process, we decided to focus our improvements in the Spanish version and to publish a book in Spanish. This study does not cover exactly all aspects and details dealt with in the book. Therefore, the document cannot be considered, in strict sense, a full and complete translation of the book, although many improvements of the Spanish book have been incorporated to the first draft in English.

This study covers a wide variety of issues related to shale gas. It begins with the examination of the role of natural gas worldwide, paying special attention to the situation in Europe, Spain and the Basque Country. We also examine the strategic issues, technical and environmental questions, as well as the regulatory process. The first chapter explains the role of natural gas, focusing on United States, Europe and Spain, with particular emphasis on the strategic issues related to the development and implications of shale gas.

The term "unconventional gas" is used to refer to the natural gas contained in reservoirs where hydrocarbons do not migrate any great distance, so source rock and reservoir rock are the same. Depending on the kind of rock in which these reservoirs were formed, we distinguish different types of unconventional gas: tight gas, shale gas and

Coal Bed Methane (CBM). Our study focuses particularly on shale gas and, in chapter 2, an explanation albeit not very extensive is given.

One of the issues often raised with regard to unconventional gas is the quantity of resources and reserves that exist in the different areas or regions in the world. The concepts and definitions of resources and reserves are developed in Chapter 3, with figures on quantities and accumulations – worldwide, in Europe and Spain.

In order to gain a better understanding of the environmental issues involved in the extraction of unconventional gas, an explanation of the technology used in exploration and production is essential. Chapters 4 and 5 both address technological aspects, with Chapter 4 concentrating on the drilling phase and Chapter 5 covering the hydraulic fracturing and production phases.

One of the most widely publicized aspects of this industry relates to its environmental implications. Chapter 6 offers a review of environmental issues related to drilling and hydraulic fracturing operations, in particular, those related to water and fluids, induced seismicity, naturally-occurring radioactive materials and atmospheric emissions.

Another issue of great interest to the industry and the general public concerns the regulation governing shale gas exploration, production processes and environmental matters. Though this varies between different regions and jurisdictions, the basic legislation for Spain and Europe, including the UK, is discussed in Chapter 7 and a brief review of American regulations has been appended at the end of the chapter.

Going now to the section of acknowledgements, we would like first to give special thanks to Macarena Larrea (PhD), one of the members of the team of the Energy Chair, for her thoroughly revision and support with data, information and improvements to the whole work, particularly in chapters 1 and 7.

We would also like to thank to the members of the Advisory Group (Olivier Appert, Ángel Cámara, Jorge Civis, Miguel Gómez, José María Guibert, Cayetano López, Jorge Loredo, Mike Paque, Luis Eugenio Suárez and Barry Smitherman) and Reviewers Group (Didier Bonijoly, Mª del Mar Corral, Gurcan Güllen, Maximiliam Khun, Yolanda Lechón, Roberto Martínez, Mariano Marzo, Amy Myers, Javier Oyakawa, Andrew Pickford, Grzegorz Pienkowski, Fernando Recreo and Benito Reig) for the comments and suggestions, which have given perspective and rigor to the study. Likewise, we would like to acknowledge the effort of the numerous people who have made contributions to this work (Luis Felipe Mazadiego, Antonio Hurtado and Sonsoles Eguilior for their comments in the water epigraph; Pablo Cienfuegos, for assisting us in chapter three; Graciano Rodríguez and José María Moreno, for bringing their knowledge and experience in the revision of chapters four and five; Fernando Pendás, for the improvements in chapters two and three. We would also like to thank to Rosa Domínguez-Faus, Virginia Ormaetxea, Marina Serrano, Luis Gorospe, Ramón Gavela, Jeff Maden, Raphael Anchia, Fernando Maravall and Vicente Luque-Cabal.

Last but not least, we would like to thank the support of the Basque Energy Agency (*Ente Vasco de la Energía, EVE*) for making possible the publication of this study.

Following the usual convention, errors are only attributable to the authors.

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1. THE ROLE OF NATURAL GAS. SITUATION AND PROSPECTS. OVERVIEW OF EUROPE AND SPAIN.

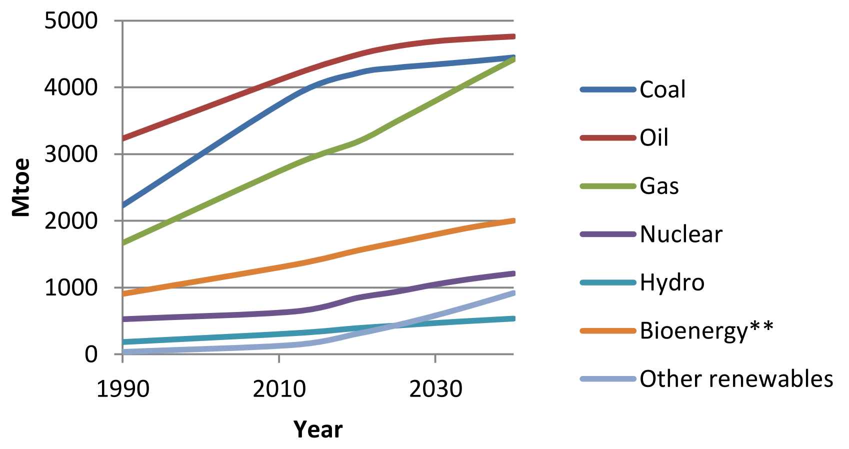
This chapter discusses the implications of shale gas from a strategic perspective, within the wider framework of natural gas. The aim is to provide an introduction to the current and prospective situation of gas at a global level, giving a broad overview and identifying the main issues of trade and worldwide gas resources in order to identify issues related to shale gas.

We shall start by analyzing global production and demand for natural gas, going on to focus on countries where shale gas plays an important role, such as the US and China. Finally, we will analyze the situation in Europe, Spain and the Basque Country.

1.1. An overview of the current situation and perspectives for gas at a global level

In recent decades, the volume and market share of natural gas as a primary energy source has increased across the world. This trend is expected to continue in the future, with a consequent increase in production in absolute terms. It is also projected that the growth rate for natural gas will be higher than that of any other primary energy.

FIGURE 1. World primary energy demand by fuel in the New Policies Scenario[3]



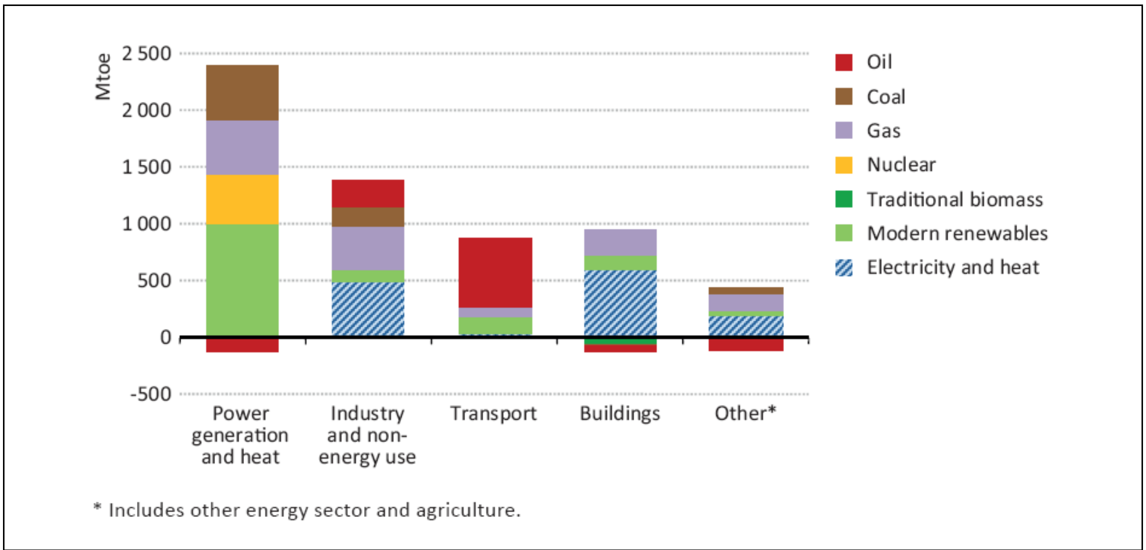
Source: Own elaboration based on (OECD/IEA, 2014b)

[3]The New Policies Scenario assumes the continuation of policies legally enacted as of mid-2014 combined with cautious implementation of announced commitments and plans. These proposals include targets and programs to support renewable energy, energy efficiency and alternative fuels and vehicles, as well as commitments to reduce carbon emissions. In this scenario, global GDP increases by 3.4% per year (2012-2040); the global population expands from 7 billion in 2012 to 9 billion in 2040 (0.9%/yr on average); oil prices reach $132/bbl by 2040 and there is a degree of convergence between the regional markets of North America, Asia and Europe.

The FIGURE 1 shows the historical situation and trends. The International Energy Agency (IEA) forecasts that gas demand will increase from 2,844 Mtoe[4] (3.4 tcm) to 3,182 Mtoe by 2020 and to 4,418 Mtoe (5.4 tcm) by 2040, with its share of total consumption rising from 21% to 24% (OECD/IEA, 2014b).

Demand for natural gas will increase as a result of its use in electricity generation and heating, but also in industry and buildings. All in all, this will boost penetration at a global level. The introduction of gas in transport is also expected to contribute to an increase in demand in the medium and long term, especially among heavy-duty vehicles (see FIGURE 2).

FIGURE 2. Change in energy demand by sector and fuel in the New Policies Scenario, 2011-2035



Source: (OECD/IEA, 2013)

1.1.1. Production

Examining the natural gas market, one can observe major differences between regions. Four main areas may be identified: the United States, Asia/Oceania (including South East Asia), Europe/Eurasia and the Middle East and North Africa (MENA).

Over the last seven years, there has been a sharp increase in gas production in the United States (6325 bcm[5], 2005-2014), Qatar and the rest of the Middle East, as well as in China and Russia. Part of this increase in production has been due to demand in those areas (such as the Middle East, the United States and China). Demand also increased in Japan and Korea, but in the European Union, gas use fell by 40 bcm over the same period.

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[4] Mtoe = Million tons of oil equivalent.
[5] bcm = Billion cubic meters.
This data refer to *marketed production*. The EIA defines it as *gross withdrawals less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations. It also includes all quantities of gas used in field and processing plant operations*.

Looking to the future, the greatest growth in absolute terms will take place in Asia, the Middle East, America and Latin America. In Europe, gas production is expected to be lower in absolute terms for the remainder of this decade (see TABLE 1).

TABLE 1. Natural gas production by region in the New Policies Scenario (bcm)

				1990-2012		2012-2020	
	1990	**2012**	**2020**	**Delta**	**CAAGR (%)**	**Delta**	**CAAGR (%)**
OECD	881	1195	1423	314	1,6%	228	2,4%
Americas	643	885	1036	242	1,7%	151	2,1%
Europe	211	278	234	67	1,4%	-44	-2,0%
Asia	28	64	157	36	5,8%	93	18,2%
Non-OECD	1178	2210	2753	1032	4,0%	543	3,1%
E. Europe/Eurasia	831	873	918	42	0,2%	45	0,6%
Asia	130	423	527	293	10,2%	104	3,1%
Middle East	92	529	572	437	21,6%	43	1,0%
Africa	64	213	236	149	10,6%	23	1,3%
Latin America	60	172	196	112	8,5%	24	1,7%
World	2059	3438	3872	1379	3,0%	434	1,6%
European Union	213	174	144	-39	-0,8%	-30	-2,2%

Source: Own elaboration from (OECD/IEA, 2014b)

Note: CAAGR = Compound Average Annual Growth Rate

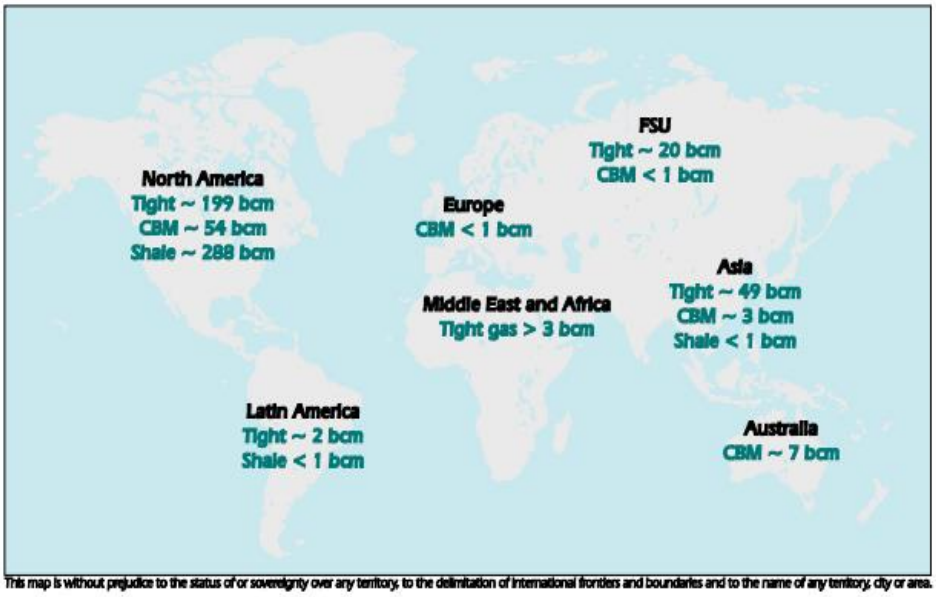
According to the IEA, global unconventional gas production came to 627 bcm in 2013, as compared to estimated output of 606 bcm in 2012. These estimates include CBM, tight gas and shale gas. As the FIGURE 3 shows, unconventional gas production in 2013 was mainly distributed between North America, Asia, Australia and the former Soviet Union (OECD/IEA, 2014a).

As for shale gas production, the United States, Canada and China are currently the only three countries in the world that are producing commercial amounts of natural gas from shale formations.

In the US, the largest growth in shale gas production has taken place in the Marcellus Shale formation of the Appalachian Basin, where dry natural gas production has more than tripled in the three years from 2011 to 2014, from an average of 4.8 bcf/d (0.134 bcm/d) to 14.6 bcf/d (0.41 bcm/d, 150 bcm/yr). (See FIGURE 4)

Canadian shale gas production increased from 1.9 bcf/d (0.05 bcm/d) in 2011 to an average of 3.9 bcf/d (0.12 bcm/d, 44 bcm/yr) in 2014, including production from the Monthey formation (whose natural gas is not classed as shale gas production by the Canadian National Energy Board, but is included in the Canadian shale gas production total).

FIGURE 3. Unconventional gas production in 2013

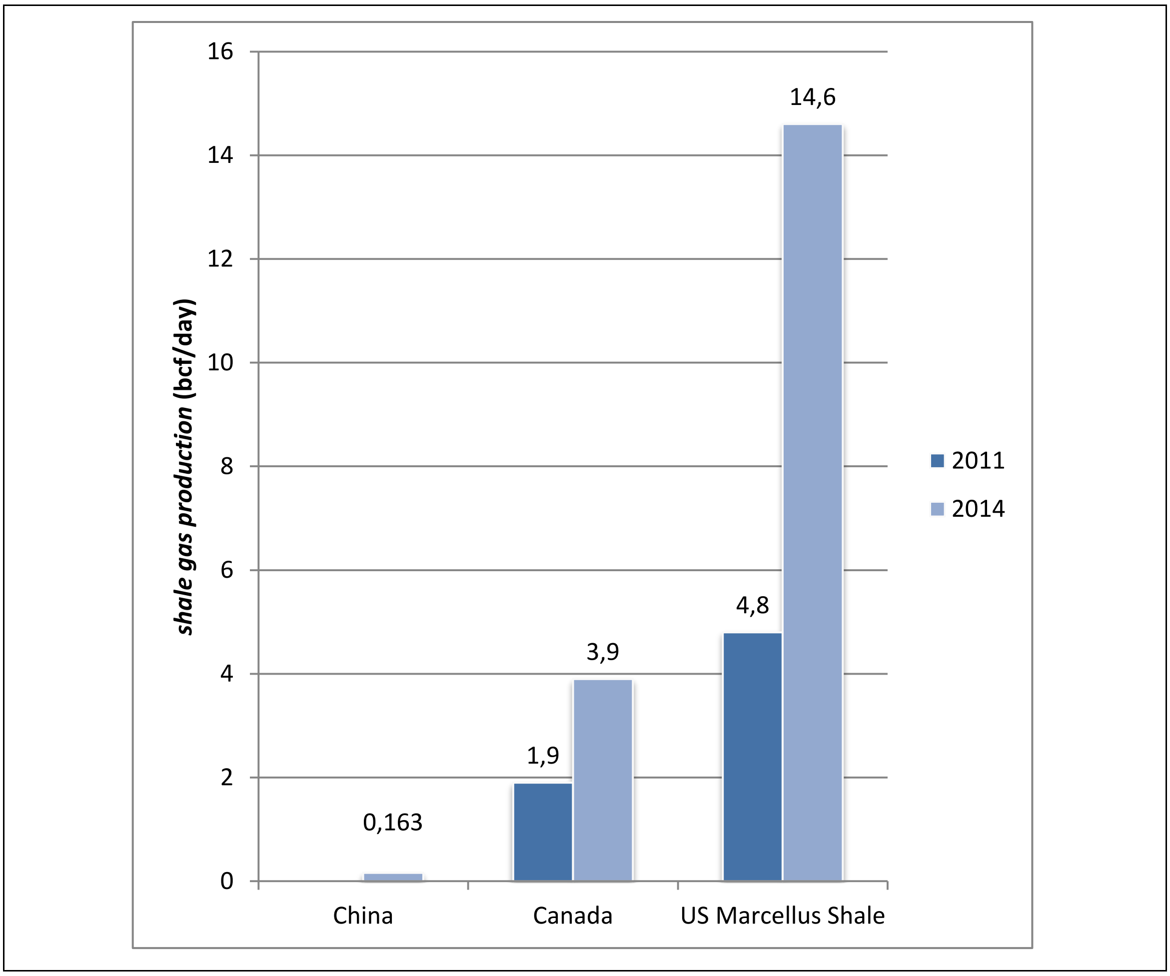


Source: (OECD/IEA, 2014a)

In China, Sinopec and Petrochina have reported commercial production of shale gas from fields in the Sichuan Basin. Their combined shale gas output has reached 0.163 bcf/d (0.005 bcm/d), or 1.5% of the country's total natural gas production (US Energy Information Administration, 2015b).

However, considerable exploration activity is being conducted in several other countries, including Algeria, Australia, Colombia, Mexico and Russia, where shale gas development is conditional on a number of factors, including ownership of mineral rights, tax regimes and social acceptance, as well as the ability to drill properly and complete a specific number of wells in a single productive geologic formation.

FIGURE 4. Average shale gas production per day (bcf/d)



Source: Own elaboration from (US Energy Information Administration, 2015b)

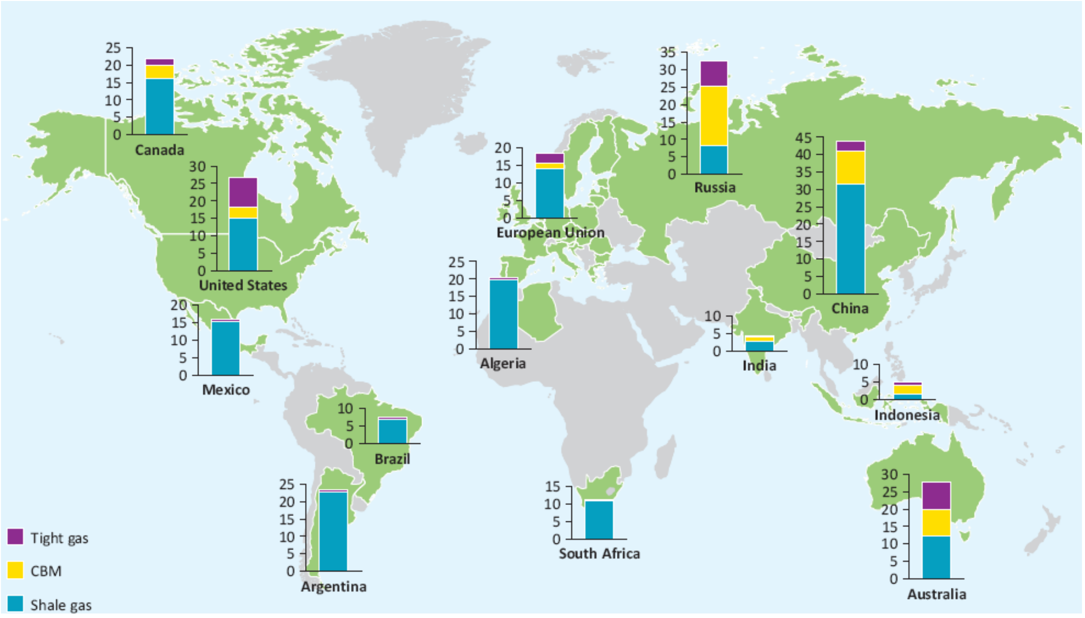
1.1.2. Resources and reserves[6]

Proven reserves of gas amount to 186 tcm[7]. Technically recoverable resources, on the other hand, total more than four times as much, at 810 tcm – equivalent to 235 years of production at current annual production rates (WEO, 2013). An important proportion of these reserves consists of unconventional gas, with tight gas, shale gas and coal bed methane (CBM) accounting for 81, 212, and 50 tcm respectively. In other words, of a total of 810 tcm in technically recoverable resources, 343 tcm are unconventional and 468 tcm conventional (OECD/IEA, 2013) (BP, 2014).

This study examines the areas or regions of the world in which unconventional gas is relevant or important as shown in the map below. The greatest potential is found in China, followed by Russia, the US and Australia. Europe has a potential of around 15 tcm.

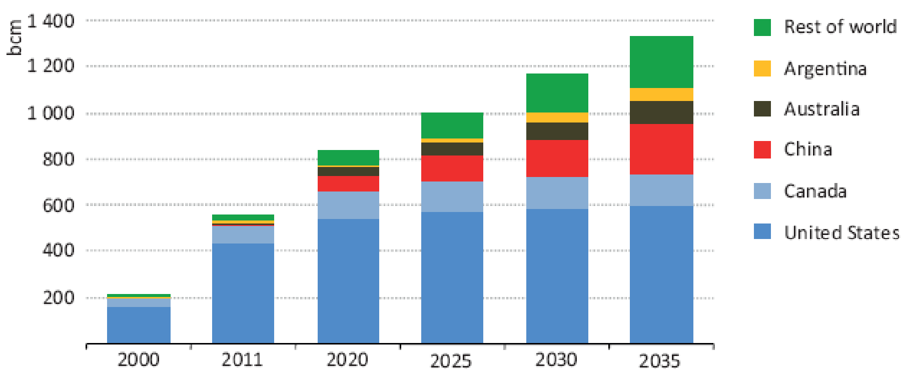
[6] For concepts and definitions on resources and reserves see Chapter 3 and Annex 3.
[7] tcm = trillion cubic meters.

FIGURE 5. Remaining unconventional gas resources in selected regions, end-2012 (tcm)



Source: (OECD/IEA, 2013)

FIGURE 6. Unconventional gas production by selected countries in the New Policies Scenario



Source: (OECD/IEA, 2013)

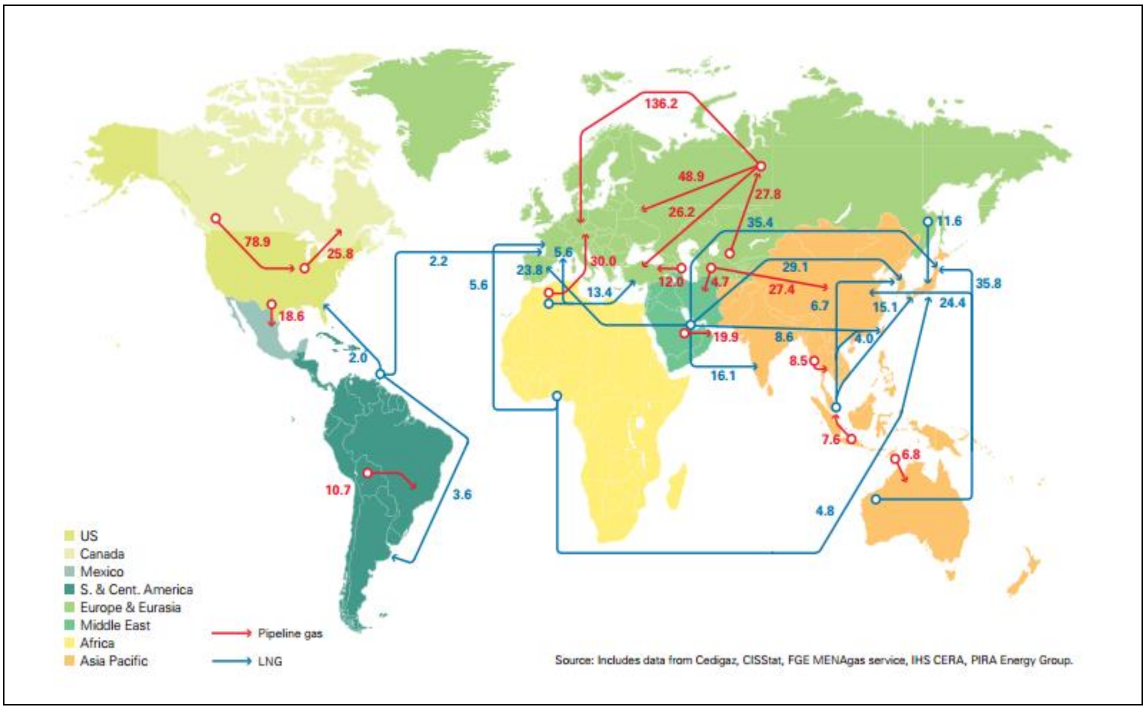
Global production of unconventional gas in 2011 was estimated at around 560 bcm (0.56 tcm) (232 bcm of shale gas, 250 bcm of tight gas and 78 bcm of coal bed methane). The WEO 2013 analysis anticipates that between 2011 to 2020, more than half of the growth in unconventional gas production will come from the two largest established producers, the United States and Canada. In 2011, these two countries accounted for 90% of total unconventional gas production. By 2020, their share in global unconventional gas production is predicted to drop to 80%, as production in China and Australia starts to grow.

The FIGURE 6 gives an overview of anticipated future production increases, with the US continuing to lead the field and Canada and China also playing significant roles, particularly from 2020 on. It is important to note that the main growth in unconventional gas outside the US will take place after 2020.

1.1.3. Trade and markets

With more resources available and production more diversified globally, a more global and interconnected gas market is emerging. As a result, gas trade has risen by 80% over the last two decades as shown in the general overview of trade among regions and/or countries in the map below (see FIGURE 7).

FIGURE 7. Major international trade routes of natural gas in 2014



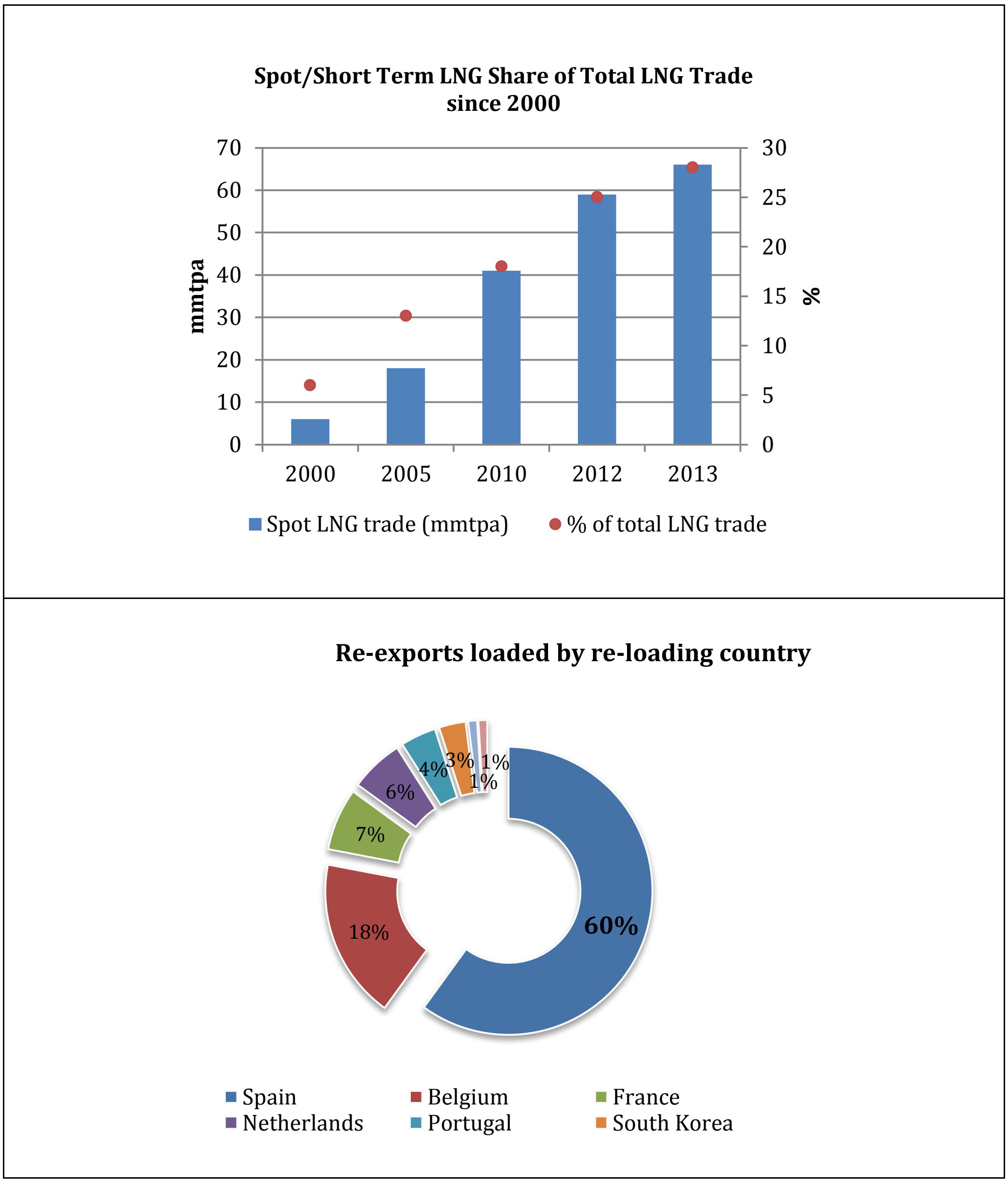
Source: (BP, 2015)

Natural gas trade is expected to increase from 685 bcm in 2011 to 864 bcm in 2020. The chief areas of exportation will be Eurasia (179 bcm), Africa (127 bcm) and the Middle East (119 bcm), with the US also emerging as an exporter by that date (43 bcm) as well as being a game changer in shale gas. The main importers will be Europe (288 bcm), China (130 bcm), Japan (117 bcm) and India (25 bcm) (OECD/IEA, 2013).

In terms of price formation, the development of traded gas –predominantly determined by global trade in LNG rather than inter-regional pipeline trade– and the increase in the use of spot pricing, together with re-exportation (see FIGURE 8) have contributed to the creation of a global market, although there is no “unique” global pricing as there is in the oil market (GIIGNL, 2012).

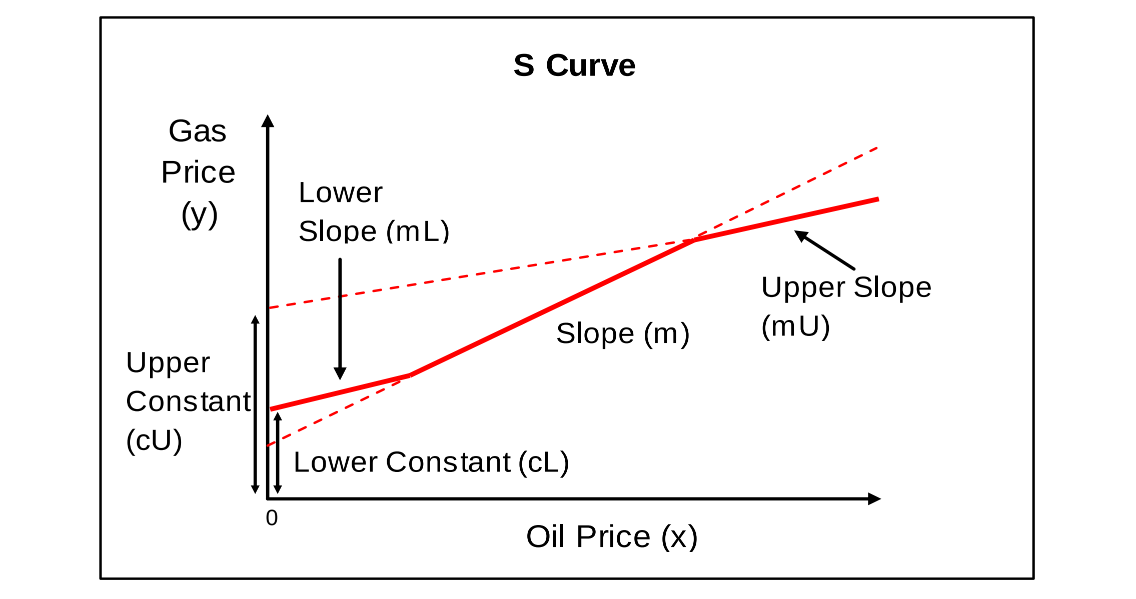
Indeed, three different regions can be distinguished in terms of price formation. In the US, gas-to-gas competition and the gas hubs –particularly Henry Hub (HH) – play a predominant role. In the Far East and Asia Pacific region, the gas price is mainly oil-indexed with a typical S-Curve. In Europe, most gas is oil-indexed, although there is a trend towards gas-to-gas competition.

FIGURE 8. Short term LNG trade and re-exports



Source: Own elaboration based on (GIIGNL, 2013; GIIGNL, 2015)

FIGURE 9. Typical S-Curve for the gas price



Source: (Kuhn, 2013b)

Worldwide, oil indexation is losing weight, although from 2005 to 2012 its share of the total volume of traded gas only slipped back marginally from 60% to 58%, while the share of gas-to-gas competition rose from around 20% to 37%. This process can also be seen in Europe, where the share of gas sales priced using indexation to the oil price and others fell from 72% in 2007 to 59% in 2013, with the share of gas-to-gas competition increasing from 22% in 2007 to 41% in 2013.

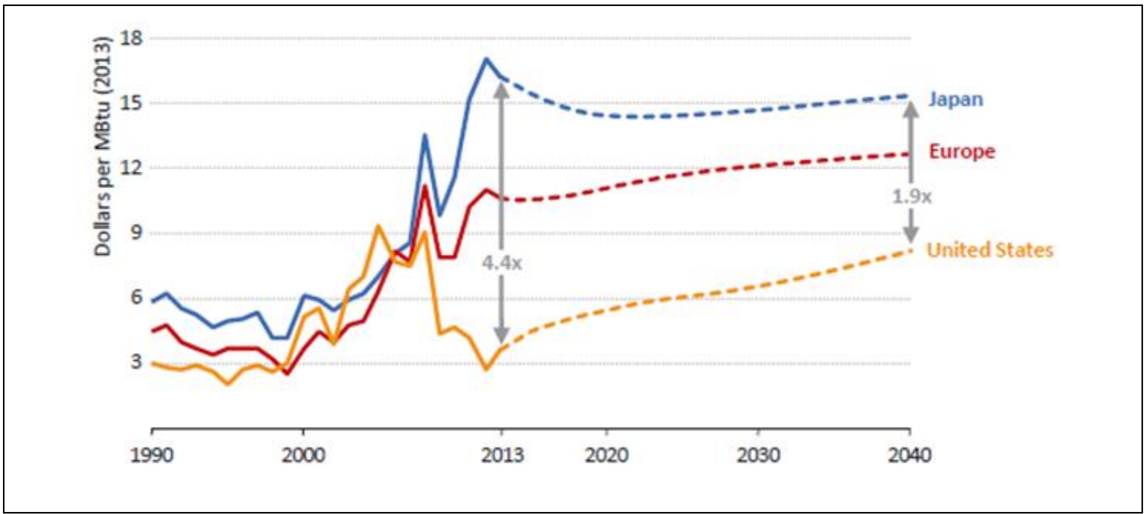
Historically, because of trends in Brent and WTI (West Texas Intermediate) and the dynamics of the gas markets with regard to US prices, gas prices have generally been lower in the US than in Japan, the Far East and Europe (see FIGURE 10)

These price differentials are forecast to persist even in a scenario of price convergence and assuming oil prices of $113/bbl in 2012 and $121/bbl in 2035 (in 2012 dollars). To a certain extent, it is accepted that this situation will persist in the current context, although some analysts also foresee a European market with a mix of HH reference plus US$2 and oil indexation. Oil indexation is predicted to remain in the Far East (OECD/IEA, 2013)(Bros, 2012).[8]

Given the importance of Henry Hub prices, we shall return to this topic in the section dealing with the USA. Analyzing prices is a difficult business and forecasting them even more so. However, the main message here is that regional gas pricing will continue, at least until a decision on conventional and unconventional gas exploration is reached, probably by around 2020. The main conclusion may be that as a first approach, the estimated cost of producing conventional and unconventional gas should be compared to the cost on domestic or regional markets, taking international gas prices into account.

[8] Estimations may widely depend on time and source. See for instance, section 1.2.2

FIGURE 10. Natural gas prices by region in the New Policies Scenario



Source: (OECD/IEA, 2014b)

1.2. The USA and "The Shale Gas Revolution"

The rise in unconventional oil and gas production in the USA has been driven by a long wave of technological innovations that allowed the 'code' of the source-rock to be 'cracked'. Albeit at high cost, these technological developments continuously reduced the cost of drilling and increased well productivity. However, the most basic factor of success in North America has been the availability of the resource itself. North America –and the USA in particular– have been shown to have access to world-class source rock which is extensive, organic rich and matured in the oil or gas window (Kuhn, 2014).

'New' technologies (or rather the new combination of technologies) provided an opportunity to extract commercial volumes of resources which had previously been deemed "uneconomic". Any discussion of this combination must deal with two key technologies: horizontal drilling and hydraulic fracturing.

Hydraulic fracturing –or *fracking*– is a process whereby a fracturing fluid, mainly water, sand and chemicals, is pumped at a sufficiently high pressure to fracture the target formation and release the natural gas. In order to reach this formation, which lies at a depth of over 2,500 meters, exploration wells are needed. Using directional techniques, these wells are drilled horizontally in order to reach the greatest possible volume of rock. However, neither of these technologies is new.

Horizontal drilling emerged in the 1930s and the first hydraulic fracturing operation[9] was carried out in 1947 in the United States (Stevens, 2012).

Besides the combined technologies of horizontal drilling and hydraulic fracturing, several factors have facilitated the so called "shale gas revolution" in the USA. These issues are related to technology, geology, fiscal credits and the existence of an active and well-developed services industry. In addition, the US government has invested a million dollars a year in improving shale gas exploration and production. Government support for the development of unconventional hydrocarbons has taken the form of subsidies and tax breaks, funding for R&D (research and development) funding and regulation of the market. The result is twofold: a regulatory framework that provides a business-friendly environment with a stable investment climate through fiscal benefits; and a legal structure that supports private property rights over oil and gas, allowing different operators to compete to acquire the rights from the leaseholders. This has turned private individuals and mineral owners into stakeholders in the success of the enterprise, allowing access to resources on private lands and considerably contributing to social acceptance.

The shale gas revolution has had important consequences in the USA. First, it has increased the national resource base. Secondly, it has increased domestic natural gas and oil production[10], leading to an improvement in the country's energy self-sufficiency to the point that the USA is now a net exporter of natural gas. Thirdly, it has improved the competitiveness of North American industry due to low gas prices and the displacement of coal. Lastly, it has had a major influence on the economy and employment, as discussed in Section 1.2.3.

1.2.1. Shale gas production

The FIGURE 11 below shows the various shale plays[11] in the USA, while FIGURE 12 gives figures for shale gas production from different USA basins and fields, showing the sharp increase in production between 2000 and 2013.

Unconventional resources are estimated to be five times as great as those of conventional gas. Public attention was first drawn to the issue of unconventional reserves in 2007 when the 'US Potential Gas Committee' raised its estimates of unproven US gas reserves by 45% (from 32.7 trillion cubic meters (tcm) to 47.4 tcm) to allow for shale gas developments (Kuhn & Umbach, 2011).

[9] This was the first hydraulic 'frack', though a purist might say that acid jobs, which were already being carried out in the 1930s, should also be classed as hydraulic fracking since the acid is injected at pressures high enough to break down the formation. Fracking using explosives was patented as early as 1865.

[10] With a surfeit of natural gas leading to a drop in prices, companies in the US have turned to shale plays with a high liquid content. Oil production from the Bakken shale alone has already passed the million-barrel-per-day mark and the US is now contemplating exporting domestic oil.

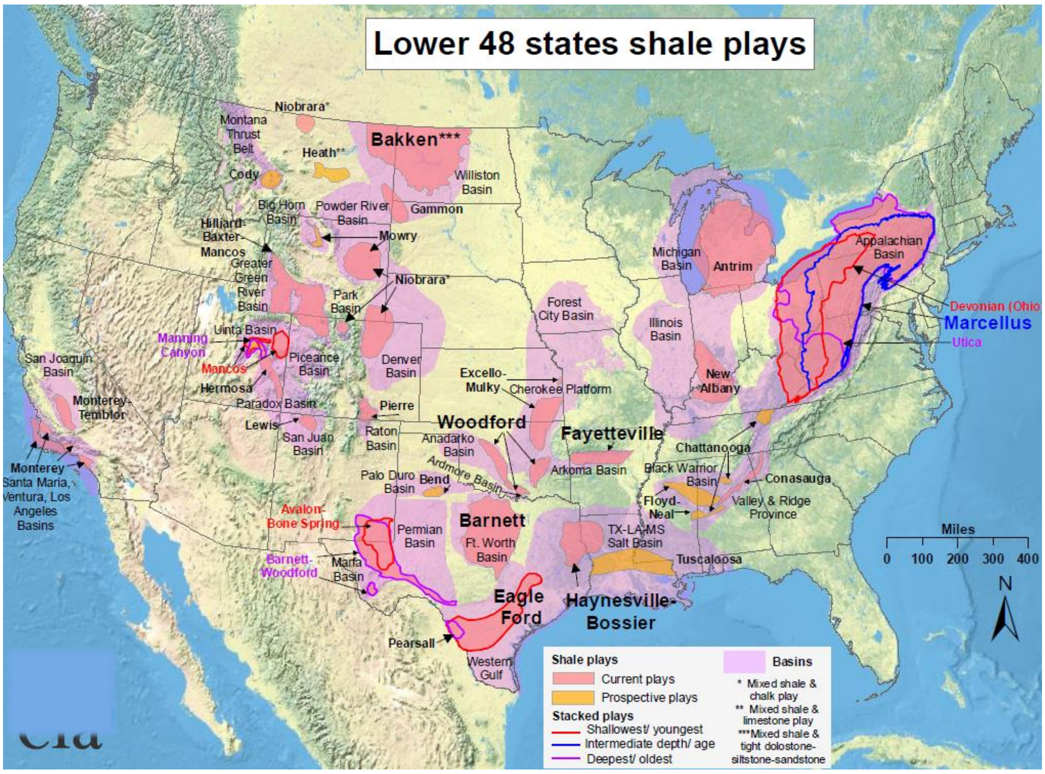
[11] See Chapter 3 for definition.

Whereas in January 2000, monthly production of shale gas stood at around 1.5 bcf/d, by January 2013 that figure had risen to around 35 bcf/d (≈ 362 bcm/yr). From 2000 to 2009, the total share of shale gas in US natural gas production leapt from just 1% to 40%.

The Estimated Ultimate Recovery[12] (EUR) of shale gas in the reference case is 208 tcf (5574 bcm), based on an average of 1.04 bcf/per well (range of 0.01-11.32) for shale gas and a well spacing of 100 acres (reference case) (20 – 406 acres range).

The cost of production affects the level of resources as higher “prices” render it more attractive to develop more costly reserves (See FIGURE 13).

FIGURE 11. Shale plays in USA

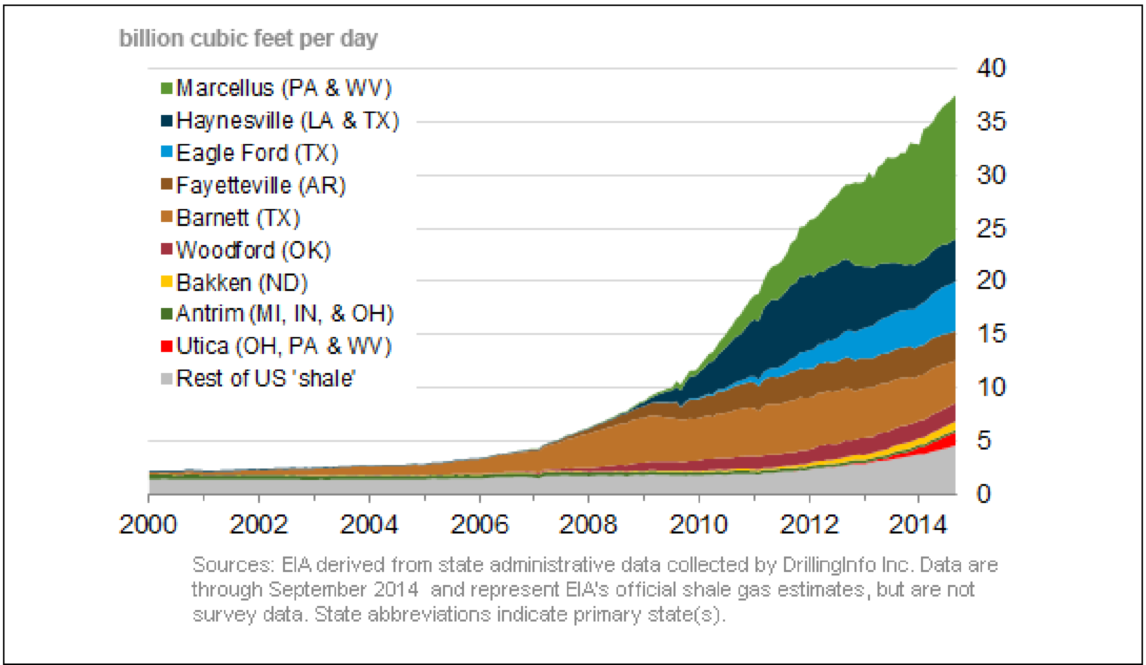


Source: (US Energy Information Administration, 2011a)

Given the importance of forecasts of oil and gas prices (discussed below), the EIA assumes oil prices of 136[13] and $220[14]/bbl[15] for the WTI, and 141 and $229 /bbl for the Brent (both references for 2040 and the reference scenario). As far as Henry Hub (HH) prices are concerned, the EIA assumes a growing trend meaning that in terms of “delivered prices”, the current rate of around $3.73[16]/MBtu[17] will rise to $6.72/MBtu by 2025 (US Energy Information Administration, 2015a).

[12] See Chapter 3.1. for definition.
[13] In 2013 U.S. dollars
[14] Nominal dollars
[15] bbl = barrel.
[16] Nominal dollars
[17] Btu= British thermal unit.

FIGURE 12. Monthly dry shale gas production

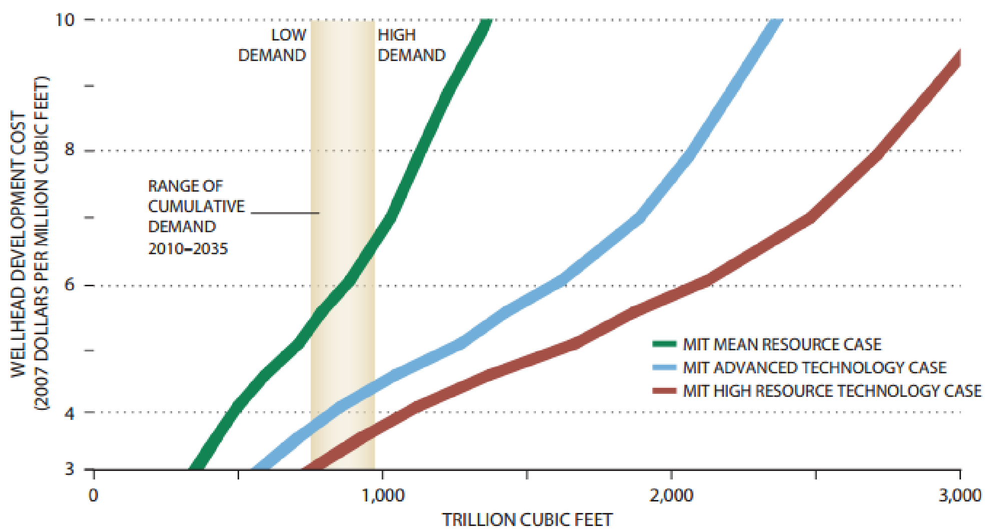


Source: (US Energy Information Administration, 2014)

According to the EIA analysis, USA dry natural gas production will increase by 1.3% per year throughout the reference-case projection, outpacing domestic consumption by 2019 and spurring net exports of natural gas. Higher volumes of shale gas production are central to higher total production volumes and a transition to net exports. As domestic supply has increased in recent years, natural gas prices have declined, making the United States a less attractive market for imported natural gas and more attractive for exports (See FIGURE 15) (EIA, 2014a).

A combination of continued low levels of LNG (liquefied natural gas) imports in the projection period and the forecast US exports of domestically-sourced LNG would make the United States a net LNG exporter by 2017. US exports of domestically sourced LNG (excluding exports from the existing Kenai facility in Alaska) will begin in 2016 and could rise to a level of 1.6 trillion cubic feet per year (tcf/yr) by 2027. It is expected that half of US exports of LNG will come from the lower 48 states and the other half from Alaska.

FIGURE 13. North American Natural Gas Resources Can Meet Decades of Demand



Note: The y-axis represents estimated wellhead cost of supply. The cost of supply can vary over time and place in light of different regulatory conditions, different technological developments and deployments, and other different technical conditions. In none of these cases is "cost of supply" to be interpreted as an indicator of market prices or trends in market prices, since many factors determine prices to consumers in competitive markets.

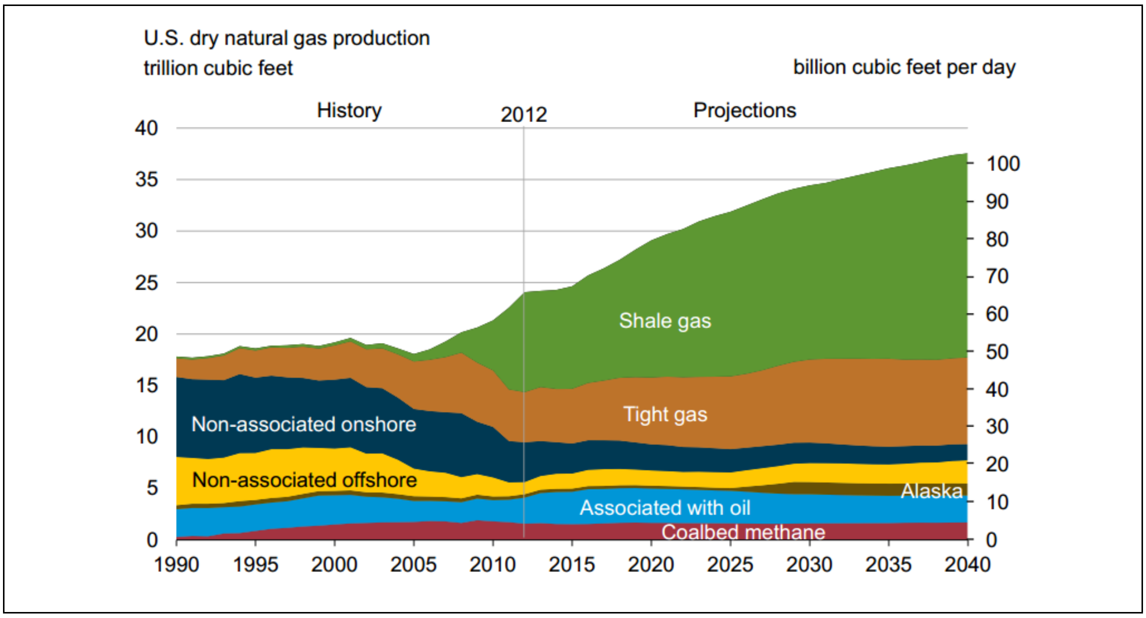
Source: (National Petroleum Council, 2011)

The prospects for global LNG exports are uncertain, depending on factors that are difficult to gauge, such as the development of new production capacity in foreign countries, particularly from deep-water reservoirs, shale gas deposits, and the Arctic. In addition, future USA exports of LNG depend on a number of other factors, including the speed and extent of price convergence in global natural gas markets and the extent to which natural gas competes with other fuels on domestic and international markets.

The US Energy Information Administration (EIA) forecasts that by 2035 shale gas will account for 46% of the United States gas supply. Among other factors, this will be made possible by the technologies of horizontal drilling and hydraulic fracturing, explained in detail in Chapters 5 and 6 of this study.

The US Energy Information Administration expects shale gas to represent 56% of total US natural gas supply by 2040. This will be made possible by the development of shale gas, tight gas and coal bed methane resources. Shale gas production, which is expected to grow by more than 10 Tcf (283 Bcm) from 2012 to 2040, will be the largest contributor to natural gas production growth, with its share of total production rising 34% by 2040.

FIGURE 14. Natural gas production by source, 1990-2040 (trillion cubic feet)



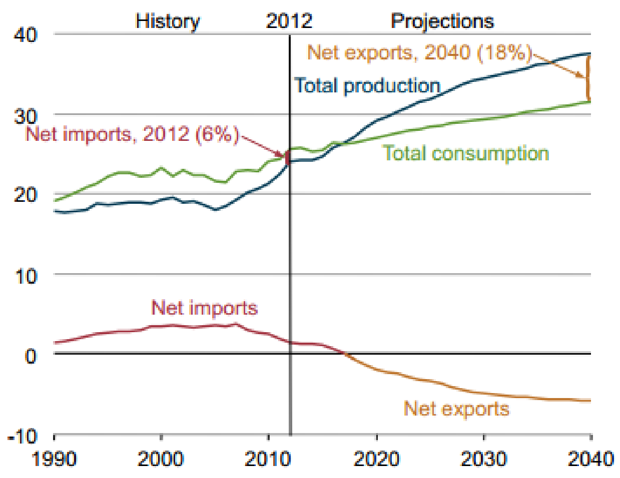
Source: (US Energy Information Administration, 2014)

The USA could achieve energy self-sufficiency by around 2020 (see FIGURE 15), with some of its regasification plants currently being transformed into liquefaction plants. In this respect it is relevant to note that a liquefaction plant costs a minimum of \$5bn (and some projects can go above \$35bn), whereas a regasification plant costs less than \$1bn. Due to the difference in capex[18], the re-gas capacity/production ratio was 2.3 in 2011 on a worldwide basis, implying a theoretical load factor of 35% for all re-gas capacity (Bros, 2012).

Based on their disclosed capex, most LNG projects in Australia stand at a level of \$2.5 bn/mtpa. In this context the capital costs of liquefaction plants in the US may have a much lower capex (Bros, 2012). Among other consequences, this could lead to the emergence of the US as a major potential LNG exporter.

[18] Capex = Capital expenditure.

FIGURE 15. Total US natural gas production, consumption, and net imports in the reference case, 1990-2040 (trillion cubic feet)



Source: (US Energy Information Administration, 2014)

This shift from regasification to liquefaction has been buoyed by the fact that some companies have received authorization to export. In less than four months, Chenière, the first company to be granted a DoE[19] authorization to export US LNG to FTA[20] and non-FTA countries, managed to sell all its LNG (16 mtpa) under a Henry-Hub linked formula (LNG delivered Free On Board: 115% HH + fixed fee). The fixed fee is for remuneration of the liquefaction plant, which will therefore operate as a tolling plant. BG well purchased 3.5 mtpa (4.7 bcm/y) of LNG from Sabine Pass under a 20-year LNG Sale and Purchase Agreement. Gas Natural Fenosa, Kogas and Gail will each purchase 3.5 mtpa (4.7 bcm/yr) from trains 2, 3 and 4, respectively.

In April 2012, Cameron LNG signed commercial development agreements with Mitsubishi and Mitsui to develop and build a liquefaction export facility in Louisiana. In May 2012, GDF SUEZ signed an agreement with Cameron LNG to negotiate a 20-year liquefaction contract for 4 mtpa[21] (5.4 bcm/y). As of May 2012, several projects with a total capacity of 102 mtpa have filed applications with the US DoE seeking authorization to export LNG (Bros, 2012)

[19] DoE = Department of Energy.
[20] FTA = Free trade agreements.
[21] mtpa = million tons per annum

The main LNG projects in North America are listed in TABLE 2.

TABLE 2. List of North American LNG projects

Project name	State	Company	Start up	Size (bcf/day)	Status
United States					
Sabine Pass	Louisiana	Cheniere Energy	2015	2.2	Approved to export to non-FTA
Freeport LNG	Texas	Freeport/Macquarie	2015	1.4	DOE non-FTA approval pending
Freeport LNG (second application)	Texas		TBD	1.4	DOE non-FTA approval pending
Lake Charles	Louisiana	Southern Union/BG	2018 (estimate)	2.0	DOE non-FTA approval pending
Cove Point	Maryland	Dominion	2016	1.0	DOE non-FTA approval pending
Jordan Cove	Oregon	Fort Chicago/Energy Projects Development	2017	1.2	Expected to submit non-FTA request shortly
Cameron LNG	Louisiana	Sempra	TBD	1,7	DOE non-FTA approval pending
Gulf Coast LNG Export (greenfield facility)	Texas	Michael Smith	TBD	2,8	DOE non-FTA approval pending
Kenai	Alaska	ConocoPhillips	TBD	0,13	Approved to export to non-FTA

Port of Valdez	Alaska	ConocoPhi II i ps/Exxon/B P	TBD	2	Proposal phase
Total US				**15,8**	
Canada					
Kitimat LNG	BC	Apache/EOG/ Encana	2015	1,4	Received NEB approval
LNG Export Co-op	BC	LNG Partners/ Haisla	2014	0,25	Received NEB approval
TBD	BC	Shell/Mitsubis hi Corp/Korea Gas Corp/Chinese National	TBD	2	Proposal phase (acquired land in Kitimat)
TBD	BC	Petronas/Pro gress	TBD	TBD	Undergoing feasibility study
TBD	BC	Inpex/Nexen	TBD	TBD	Undergoing feasibility study
Total Canada				3,65	
Total North America (BCF/DAY)				19	

Source: (Kuhn, 2014)

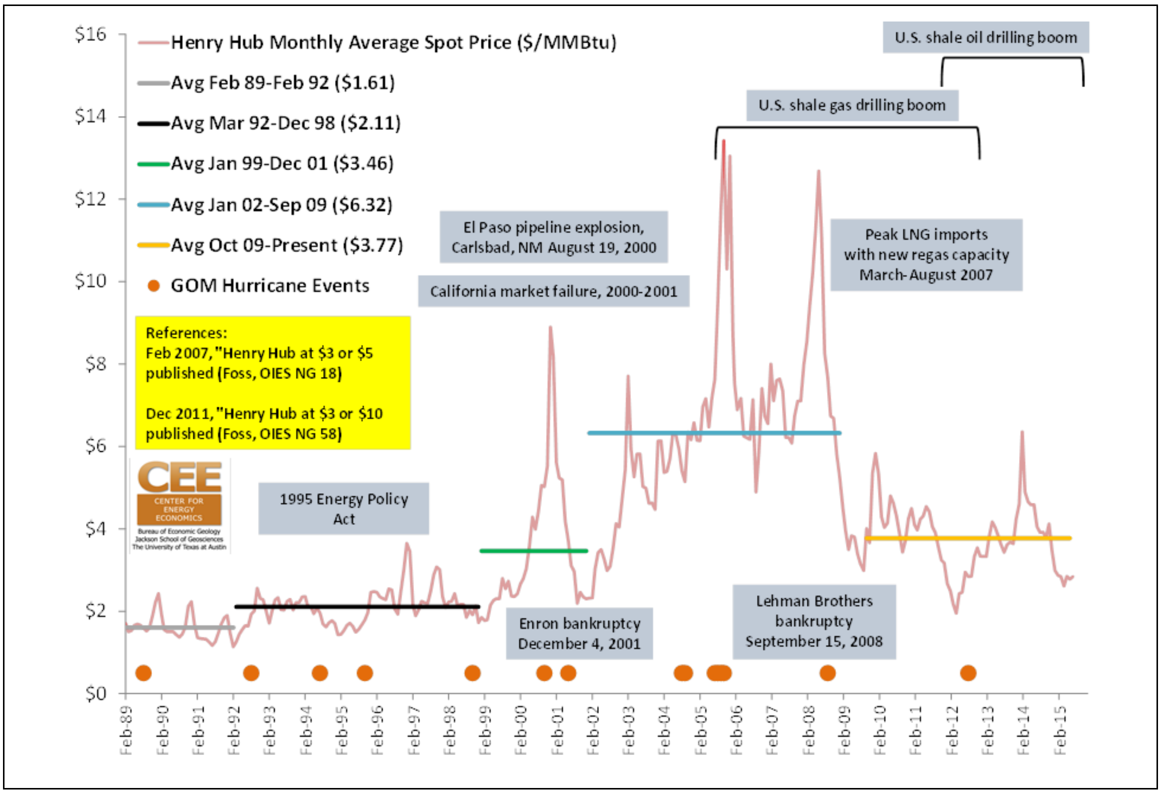
1.2.2. Prices

Natural gas in the USA is generally referenced to and priced at the Henry Hub. The Henry Hub price is an important factor in discussing the strategy of shale gas; firstly, because of the influence of the development of shale gas in the USA, but also because of the progressive influence in Europe of the HH as a reference price for delivery spots and for use in renegotiating long-term contracts.

One way of expressing the interrelation between shale gas production and price is to consider that the increase in shale gas has cut previously high gas prices by around $4/MBtu. This impact is discussed in greater perspective and depth below.

MM. Foss has analyzed the evolution of gas prices, concluding that the fundamentals of excess supply vs. demand have been one of the most powerful reasons for the variation in Henry Hub prices. Variations in supply with a huge increase in shale gas production have contributed to reducing gas prices.

FIGURE 16. Henry Hub price ($/million Btu)



Source: (Michot Foss, 2015)

Given the importance of future estimates and forecasts for oil and gas prices, it is worth noting that the EIA assumes $136[22] and $220[23]/bbl[24] for oil (West Texas Intermediate, WTI), and $141 and $229/bbl for Brent, both projected to 2040 in the EIA reference scenario. For Henry Hub prices, the EIA assumes an upward

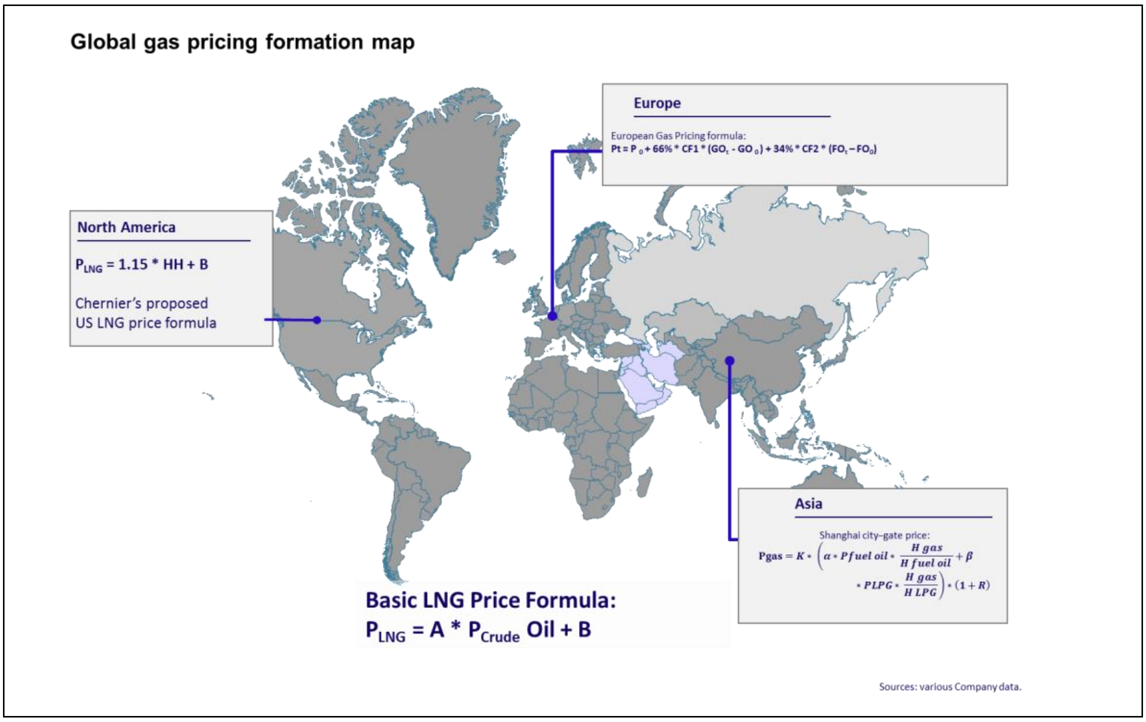
[22] In 2013 dollars.
[23] In nominal dollars.
[24] US Dollars per barrel.

trend such that, in terms of supplied prices, the real level of \$3.73/MBtu[25] in 2013, will increase to \$6.72/MBtu in 2025 (US Energy Information Administration, 2015a).

Generally speaking, some references to gas prices in the USA can encourage shale gas production. For example, prices are indicated to establish the economic viability of specific areas. These prices are compared with market prices, in particular with the Henry Hub.

The map below shows some formulas used for price formation in different regions of the world (see FIGURE 17).

FIGURE 17. Global gas pricing formation map



Source: (Kuhn, 2013a)

Note: P (related to price); GO (related to Gasoil); FO (related to fuel oil); different coefficients (B, CF1, CF2, K, α, pt and R)

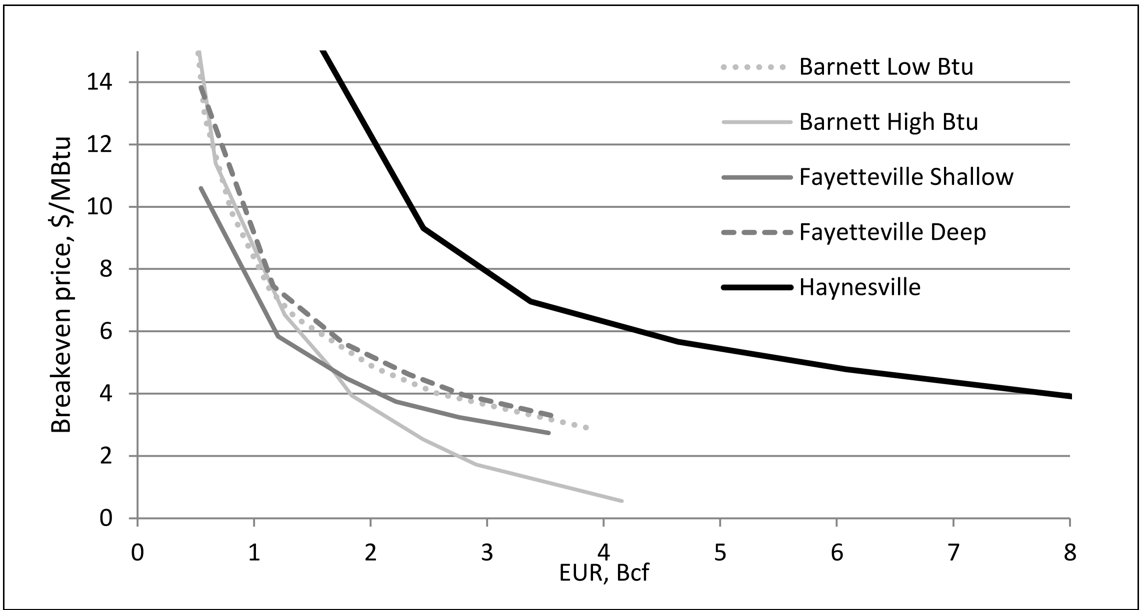
Specifically with regard to the profitability of plays, the return of investment for a shale gas well will depend on a number of different factors, such as production rate over time, well cost (drilling and completion), operating costs, water costs, tax regime and natural gas prices, as well as the presence of by-products in the reservoir (natural gas liquids), which can increase added value (Ikkonikova et al., 2015).

The following figure (Ikkonikova et al., 2015) plots the distribution of breakeven prices for wells in three different North-American shale gas fields with similar EUR (Estimated Ultimate Recovery) values, established on the basis of a 10% IRR (Internal Rate of Return) (see FIGURE 18).

[25] British Thermal Unit.

(Ikkonikova et al., 2015) conclude that forecast productivity maps cannot be used to highlight areas attractive for investment, since different factors need to be taken into consideration, including geologic attributes, pipeline constraints, regulation and tax regimes.

FIGURE 18. Breakeven prices vs. EUR depending on depth and liquids (high/low Btu)



Fuente: (Ikonnikova, Browning, Gülen, Smye, & Tinker, 2015)

1.2.3. Economy and Employment

The shale gas revolution has played an important role not only in energy prices but also as a strategic energy reserve. Growth in production has led to an increase in employment directly or indirectly related to shale gas production.

The direct impact is measured in terms of jobs, labor income, and value added within the oil and natural gas industry. The indirect impact is measured in terms of jobs, labor income, and value added throughout the supply chain of the oil and natural gas industry. The induced impact is measured in terms of jobs, labor income, and value added resulting from household spending of income earned either directly or indirectly from spending by the oil and natural gas industry.

For Bacon, R. et al. (2011), the employment created can be divided into direct employment (those employed by the project itself), indirect employment (those employed in supplying the inputs to the project), and induced employment (those employed to provide goods and services to meet consumption demands of additional directly and indirectly employed workers). A further distinction is made between employment for Construction, Installation and Manufacture (CIM), and employment for Operation and Maintenance (O&M). The effect on incomes and employment can be measured by multiplying the changes in different employment categories by estimated wage rates (Bacon & Kojima, 2011).

An estimation of direct employment for a project requires information on the expenditure, technology and scale of the project, and the typical employment per dollar spent for that category of project. Indirect and induced employment are calculated less often, and require the availability of an input-output (IO) table that can link the output of the project sector to all supply sectors, both immediate and indirect. According to the IHS (2014), in 2012 the shale industry alone supported more than 524,000 jobs and this figure is expected to rise to over 757,000 by 2025.

Regarding direct, indirect and induced employment, the following table shows data gathered by other source (see TABLE 3).

TABLE 3. Shale Natural Gas employment contribution (thousands of workers)

	2010	2015
Direct	148.1	197.9
Indirect	193.7	283.1
Induced	259.4	388.4
TOTAL	601.3	869.6

Source: Own elaboration from (America´s Natural Gas Alliance, 2011)

Another relevant datum is the quality of jobs created through shale gas, as reflected in higher-than-average wages (IHS, 2014). Across thirty shale gas-producing states, the average hourly wage for the industry is $23.16. Average pay for non-shale related production, professional and business-services workers ranges from $13.10 to a high of $22.00 per hour (America´s Natural Gas Alliance, 2011).

TABLE 4. USA employment in different industries

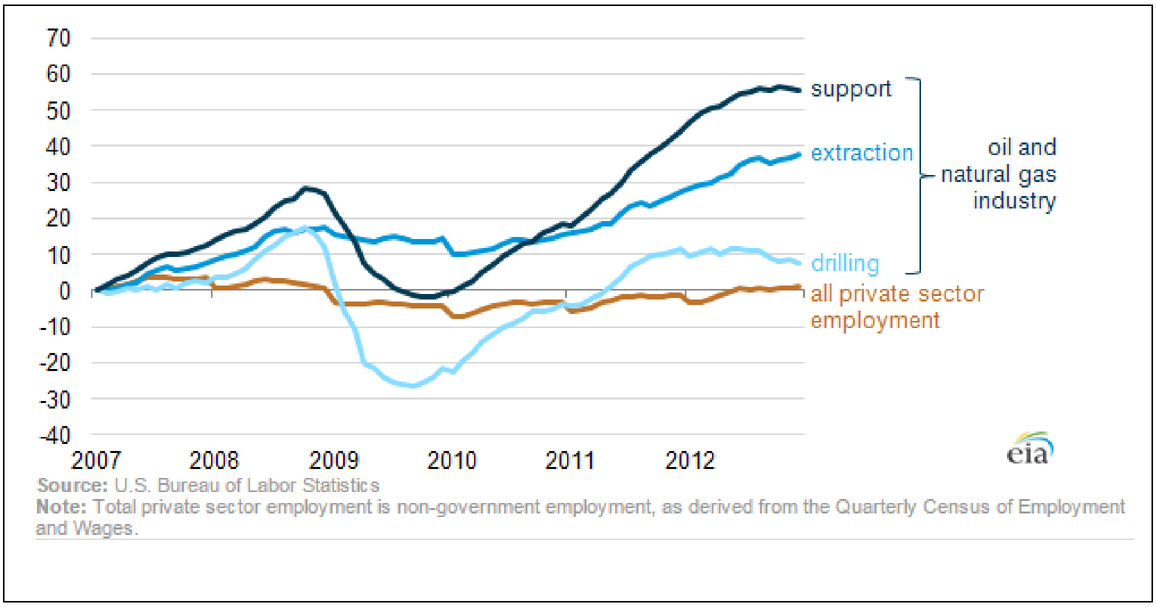
	Total employment (2011) (thousands)	Percentage of total USA employment (%)
Shale natural gas	601	0.4
Agriculture. Forestry. Fishing and Hunting	1.167	0.7
Construction	5.652	3.6
Manufacturing	11.748	7.4
Public administration	7.328	4.6
Utilities	804	0.5
Finance and insurance	5.540	3.5
Information	2.817	1.8
Education	12.099	7.6
Health care and social assistance	18.368	11.5
Retail trade	14.73	9.3
Professional. Scientific and technical Service	7.783	4.9
TOTAL USA employment	159.206	100.0

Source: Own elaboration from (U.S. Bureau of Labor Statistics, 2013)

When analyzing the employment generated by shale gas in the USA, it is important to compare these data with employment rates associated with other industries in the country. In TABLE 4, the first column shows the number of workers in each of the industries analyzed and the second the respective percentage of the total USA population.

Although shale gas is not the largest industry in absolute terms (see TABLE 4), it has contributed to the growth of employment in an economy in which other sectors showed little or no growth, as illustrated in the following figure.

FIGURE 19. Percentage change in employment in the oil and natural gas industry and private sector employment in general



Source: (EIA, 2014)

In the case of Texas, in 2013, the 21-county Eagle Ford Shale region in the south-east of the State produced almost $72 billion and supported 196,660 workers in different oil and gas industries[26]. Direct employment represented around 20% of the total employment generated, indirect employment 50% and induced employment 30% (Centre for Community and Business Research UTSA, 2014).

Taking into account the area accounting for the largest proportion of production (15-county Eagle Ford Shale), upstream activities can be divided in two different categories: drilling of new wells and support activities for oil and natural gas extraction. These activities together accounted for 65 billion dollars of a total of 106 billion generated in the region, with 104,380 jobs. In other words, oil and gas exploration and production activities were responsible for 70% of all jobs created in the region, or 53% in the 21-county area (CCBR UTSA, 2014).

Having reviewed the shale gas revolution in the USA, in the next section we will examine some other countries or regions that may be considered potentially relevant for the shale gas industry.

[26] Oil and gas, drilling of oil and gas wells, support activities for oil and gas operations, oil and gas pipelines and construction of related structures, oil refineries and petrochemical plants.

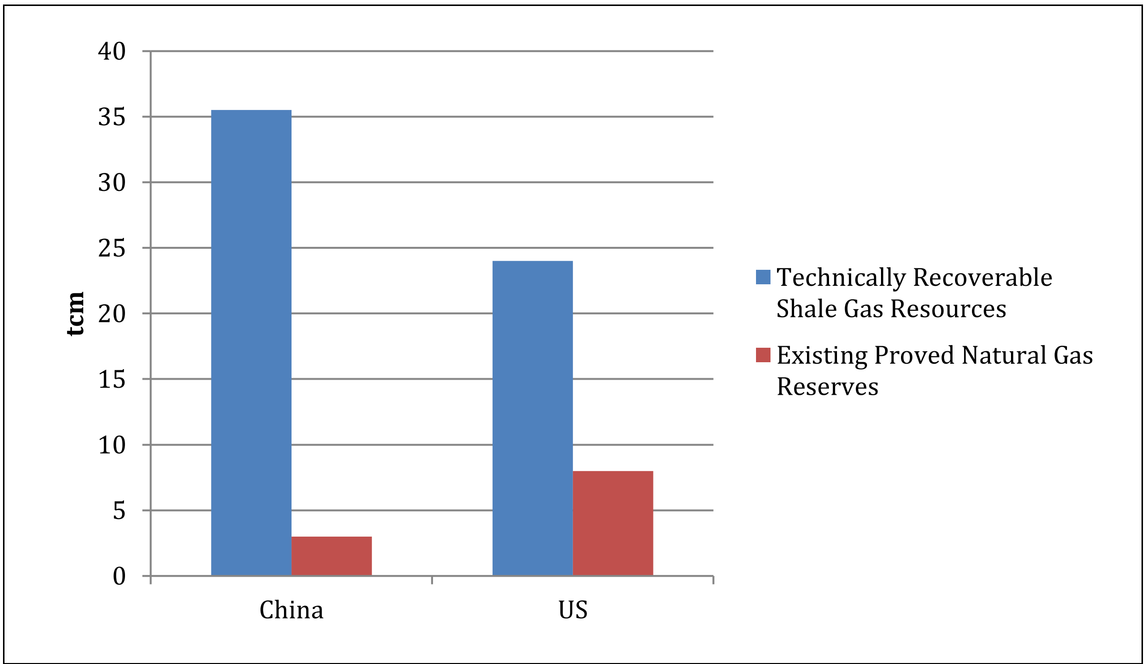
1.3. China

As the USA Department of Energy highlighted in a study published in April 2011, China is another major resource holder of unconventional oil and gas. The study, which focuses on major shale gas areas outside the USA (excluding the Middle East and Russia), shows that China holds the largest shale gas resources in the world (1.5 times more than the USA), as shown in FIGURE 20 (US Energy Information Administration, 2011a).

China is not only the world's major shale gas holder. According to the US DoE, the country's technically recoverable shale resources are twelve times the existing proven reserves (as compared to only 3 times for the USA). If China were to follow the USA model, then, its long-term shale gas production could potentially reach 500 bcm/yr (Bros, 2012).

However, an EIA report published in June 2013 concludes that: "Considerable work is needed to define the geologic sweet spots, develop the service sector's capacity to effectively and economically drill and stimulate modern horizontal shale wells, and install the extensive surface infrastructure needed to transport product to market" (EIA, 2013b).

FIGURE 20. Shale gas resources vs. proven gas reserves



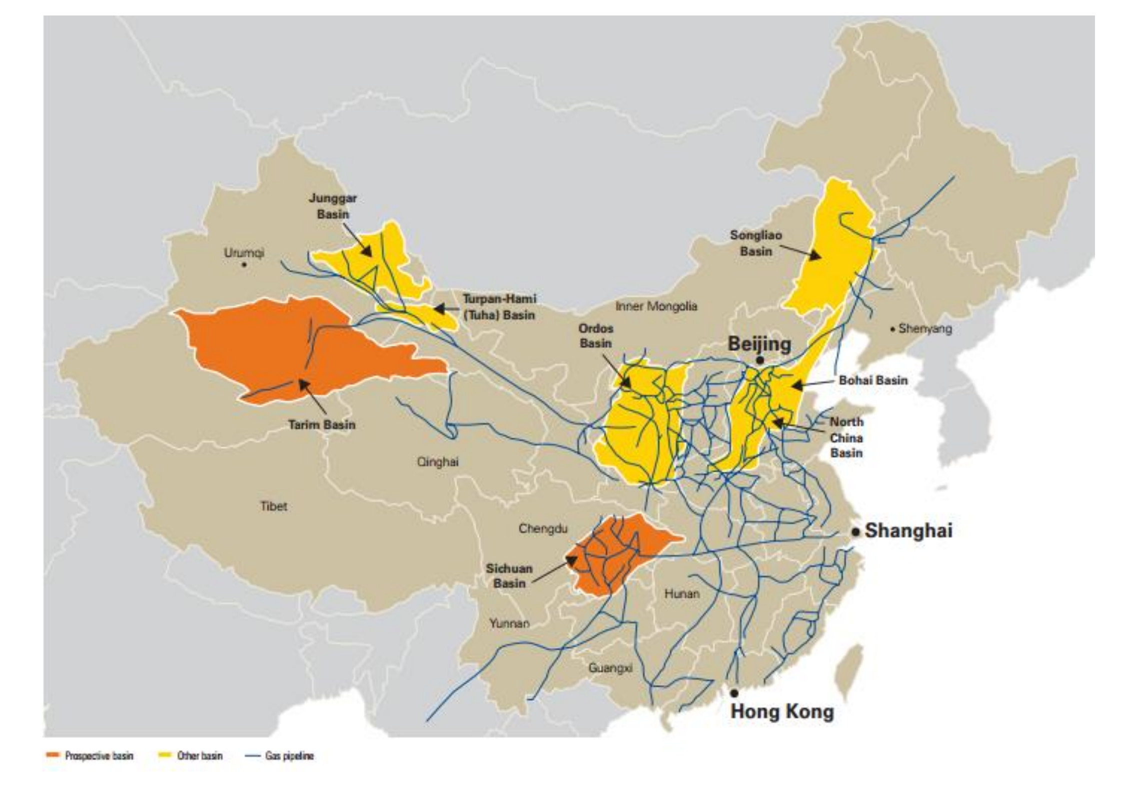
Source: Own elaboration from (Bros, 2012)

In March 2012, the Chinese Ministry of Land and Resources announced that its surveys indicated that the country had onshore exploitable shale gas reserves of 25 tcm[27]. Although the Chinese figure is lower than that estimated by the US

[27] tcm = Trillion cubic meter.

Department of Energy, it confirms that China has the largest shale gas reserves in the world. The largest Chinese unconventional gas basins are shown in FIGURE 21.

FIGURE 21. Shale gas deposits and basin in China



Source: (KPMG, 2013)

A shale gas subsidy of CNY 11.25[28] per MBtu is available for shale extracted up to 2015, representing approximately 45% of the current Henry Hub price. This is further evidence of the Chinese government's commitment to shale gas, which is considered to be "encouraging foreign investment industries" in the country, albeit these are limited to equity joint ventures and contractual joint ventures.

In December 2009, Petro China began shale gas exploration in the south-western Sichuan province, but China needs American technology to resolve problems and frack the reservoirs.

For Bross (2012), an even faster way to boost unconventional gas production in China would be for independent North American gas producers to enter China with their technologies. However, independent producers and the Chinese government have major difficulties in adapting to such a situation.

Aware of this situation, large Chinese oil and gas companies have turned to a strategy of buying holdings or equity in American companies. In 2010, CNOOC bought a one-third stake in Chesapeake's holdings in the Eagle Ford shale in south Texas (USA) and in January 2011 it agreed to purchase a 33% interest in

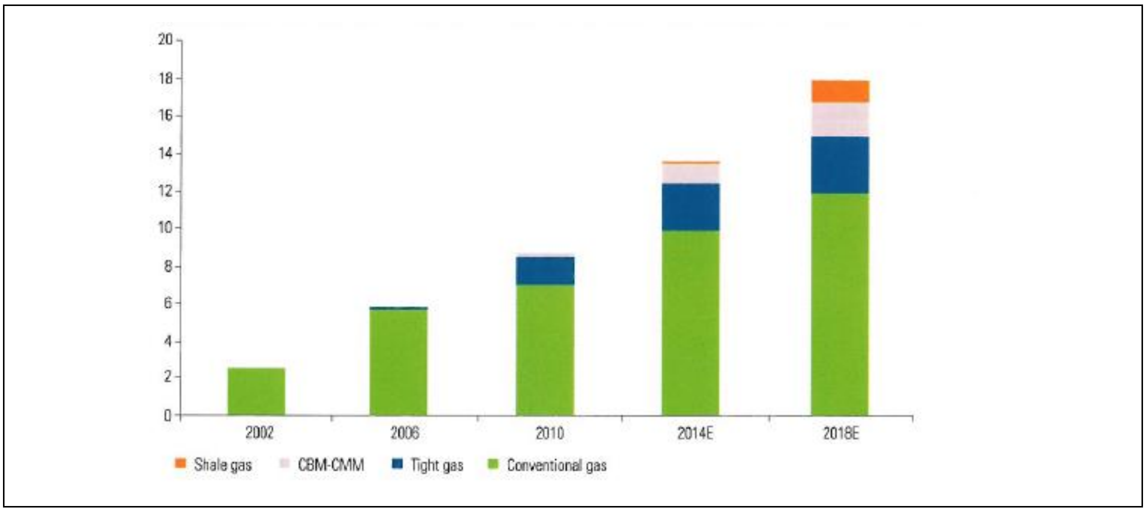
[28] US$1.8

Chesapeake's oil and natural gas leasehold acres in Colorado and Wyoming. In 2011, Sinopec purchased Daylight, which exploits numerous hydrocarbons plays in Alberta and north east British Columbia (Canada). In 2012, it struck a deal with Devon for a one-third stake in five USA shale oil and gas fields. In 2012, Shell signed a production-sharing contract with the China National Petroleum Corporation (CNPC) to develop a shale gas block in the south-western Sichuan province, the first such deal in China (EIA, 2011).

China not only has the resources; it also has the engineers and manpower needed. Furthermore, independent and service companies could provide the technologies. However, in order to market its shale gas resources, it will have to enlarge its network of pipelines. Given that these are built by state firms, it is not clear whether gas prices would need to increase to provide sufficient incentive for additional pipeline construction (Bros, 2012).

On the production side, China has already seen strong growth with its new strategy of accessing unconventional technology and is seeking to monetize its unconventional gas resources rapidly. Production growth should therefore come from both conventional and shale gas production, as FIGURE 22 below shows.

FIGURE 22. China domestic gas production – billion cubic feet per day (bcf/d) 2012-2018



Source: (KPMG, 2013)

In 2015, official estimates indicated that annual shale gas production stood at around 6 bcm (although other sources estimate around 2 bcm). For 2020, production could be in a range of between 26 and 36 bcm. In the future, natural gas will be progressively more important as coal is substituted by cleaner energy sources. In the long term, China will be interested in reducing its natural gas imports.

1.4. Europe

Europe is also thought to have considerable volumes of unconventional gas. However, before discussing these reserves in detail, we first need to examine the broader situation of natural gas in Europe.

1.4.1. Natural gas demand and production

Overall, gas demand in Europe has been affected by the economic slowdown and it remains uncertain whether demand will recover to 2007-2008 levels. With renewables eating into the market share of fossil fuels for power generation, gas has additionally lost part of its share to coal due to unfavorable economics. With gas consumption in the power sector declining by 12% and 7% respectively in 2012 and 2013, the role of natural gas in power generation needs to be reexamined.

Nevertheless, with the loss of flexible supply capacity, national governments and regulators are looking for ways to manage the transmission systems with large amounts of connected intermittent supply and envision implementing new measures to provide sufficient reward to dispatchable generators. These measures will undoubtedly help gas to find a new role in the changing energy mix.

Besides lower industrial and electricity demand, oil indexation of gas has further contributed to depressed demand, as other fuels became more competitive. While gas-fired power generation has remained relatively expensive, gas was among the first fuels to be affected by lower electricity demand by being pushed out of the merit order. Furthermore national and European policies on efficiency and renewable energy sources have raised additional questions about the future trajectory of European gas demand.

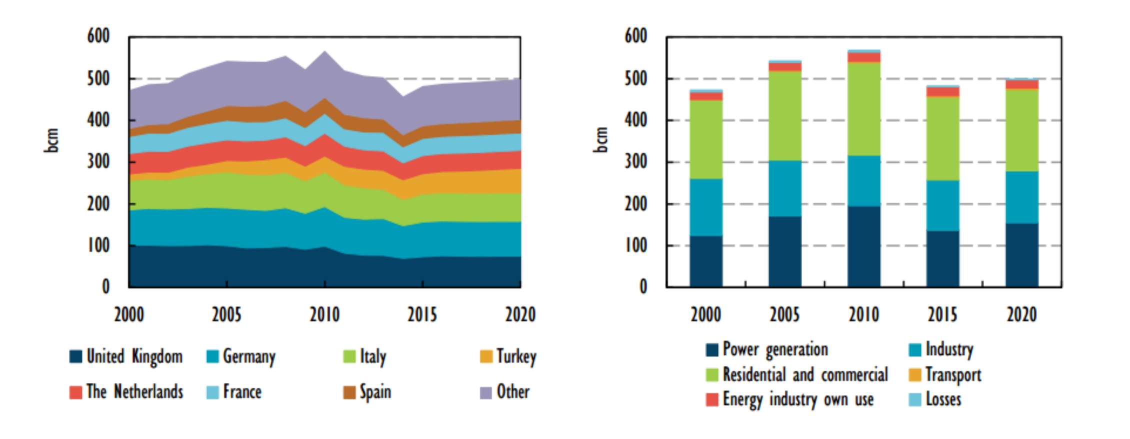
Despite these uncertainties, some fundamental drivers continue to underpin gas demand in Europe throughout the projection period. Leading them is the use of gas for electricity generation (as the FIGURE 23 shows). Efficient combined-cycle gas has important advantages over competing fuels, notably over coal, which has been the main rival to gas for thermal generation in Europe. These include lower up-front investments, shorter construction lead times, more flexible operation and lower greenhouse gas emissions. In this respect, an increase in carbon prices in the European Emissions Trading Scheme (EU-ETS) could improve the position of gas versus coal (IEA, 2009).

A rise in natural gas demand between 1980 and 2000 was mostly due to increased use of natural gas use in power generation, a trend that although volatility, is expected to continue over coming years. Domestic use of natural gas has also risen sharply in recent years while natural gas demand in industry remains largely steady.

Consumption in Europe varies from country to country and the prospects for natural gas production also differ. When examining statistics on consumption or demand of natural gas in Europe, it is therefore necessary to bear in mind that in some countries the demand is much higher than the European average.

In terms of short-term future prospects, gas demand is expected to see moderate growth in the OECD/Europe, averaging an annual increase of 0.6%, mainly due to higher consumption in the residential and power generation sectors. Within this trend, the IEA highlights the importance of Turkey, which will account for two thirds of total growth. In the industrial sector, gas demand will remain stable over the period (FIGURE 23).

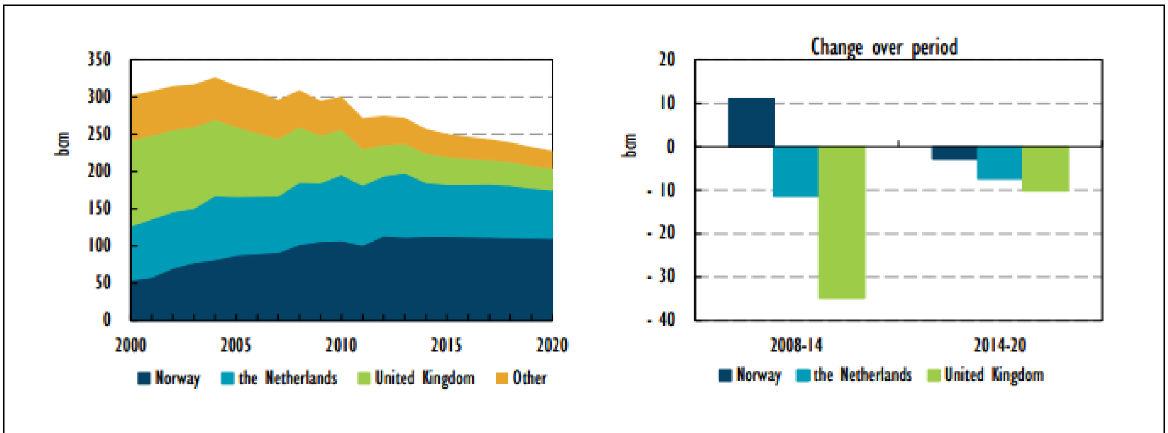
FIGURE 23. Natural gas demand in OECD/Europe by country and sector



Source: (OECD/IEA, 2015)

In contrast, domestic production will continue to fall over the next five years, decreasing by around 30 bcm by 2020 (75 bcm since 2010). This fall will be sharper among the leading suppliers: the United Kingdom, Norway and the Netherlands (FIGURE 24).

FIGURE 24. Natural gas supply in OECD/Europe by country, 2000-20



Source: (OECD/IEA, 2015)

Given economic and energy perspectives in Europe, a key factor for gas development is its competitiveness. Driven by the profound changes in the global gas market –such as the shale revolution in the USA– the high volumes of spot LNG available, combined with low European demand and European spot prices trading below oil indexed contract prices, have contrived to initiate a number of changes.

1.4.2. Prices and markets

The European gas market is currently volatile and going through profound changes, driven by policy decisions and a backdrop of challenging market fundamentals, with the on-going energy security discussion adding further uncertainty.

At the same time, utilities with a high exposure to oil-indexed gas procurement have been losing money in gas offtake or suffering a fall in market share to competitors with access to more attractive spot price trading. These developments have increased pressure for major European suppliers to concede to pricing formulas that better reflect market conditions. The incorporation of gas-to-gas competition, the progressive incorporation of market-price indexation in long term contracts (e.g. GDF Suez, ENI, EON with gas-market pricing percentages of up to 25%) are all reinforcing this trend. Many analysts believe that these factors will further assist the penetration of gas in Europe. The balance of expert opinion currently suggests that the EU will continue to move slowly away from oil indexation because of the persisting risk of future exposure to discount hub prices (Pearson, Zeniewski, Gracceva, & Zastera, 2012).

On the other hand, the increase in the volume of LNG and re-exports discussed in the first section of this chapter may facilitate greater availability and supply of natural gas. With demand for spot cargos increasing and LNG supplies previously destined for North America being re-routed, global LNG trade volumes increased two-fold between 2000 and 2010, and increasing LNG liquefaction and regasification capacity looks set to continue driving this trend for the foreseeable future. As a major consumer of natural gas, Europe is robustly contributing to this trend and the EU's current regasification capacity of 150 bcm looks set to double by 2020.

There is therefore ample evidence that LNG is changing the characteristics of global gas markets. Between 2009 and 2010, increased LNG capacity in regasification terminals in North-West Europe strengthened the link between the UK and USA gas hub prices, enabling many EU member states to benefit from cheap spot-traded gas partially resulting from increased unconventional gas production in the USA.

Another important factor that might affect gas pricing and thus gas use in Europe is the development of regional gas hubs and regulatory programs, such as the gas target model. In this respect –and particularly in relation to the Iberian Gas Hub– the objective of a gas target model in 2014, and the increasing quantities traded in the various gas hubs in Europe, together with the development of new infrastructures will contribute to more dynamic pricing and thus to a better use of gas (Alvarez Pelegry, Figuerola Santos, & López, 2013).

We have seen that prices in Europe are higher than in the USA and lower than in the Far East. The spread between the different regional prices is fueling the development of a more global LNG market through arbitrage between the different regions. In Europe, many consider that competitive gas prices have a positive impact in facilitating gas penetration and increasing gas demand.

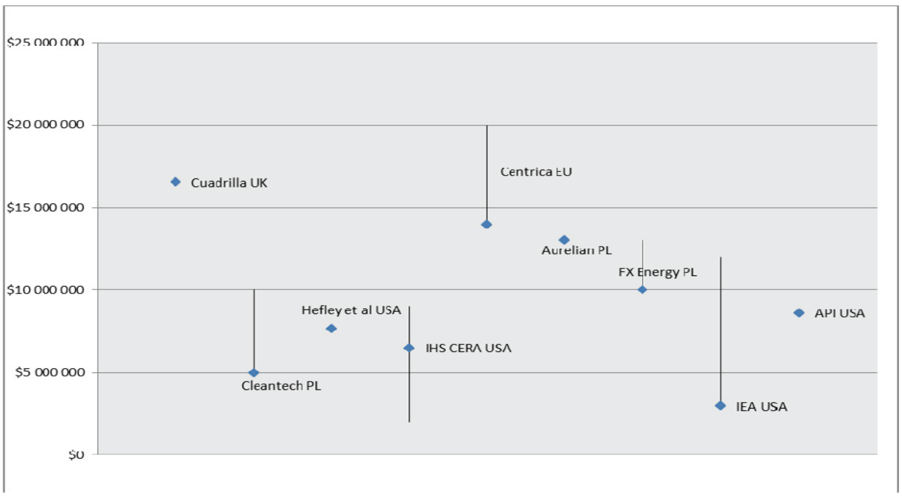
Certainly, the primary market for any shale gas produced in Europe would be the new domestic demand in European countries, but it might also replace long term contracted gas when renegotiations take place or when long term consumer contracts expire.

For the time being, unconventional gas has helped to shift the balance from a seller-dominated market to a buyer-dominated one. The introduction of unconventional gas onto the European market would give buyers more leverage when renegotiating their demands for Russian gas, which are, for the most part, oil-indexed. Thus, unconventional gas, even when it is not produced in Europe, puts a certain price cap on high (Russian) gas prices, as it can become a potential source of diversification, particularly if gas prices are higher than the break-even point for European unconventional gas. All this has the potential to make unconventional gas development economically feasible and more politically appealing (Kuhn & Umbach, 2011).

1.4.3. Exploration and production costs

In this context, it is useful to try to assess or estimate the cost of shale gas production in Europe. A preliminary view is given in the figure below, which gives estimates of the cost in different countries.

FIGURE 25. Total per-well production cost for shale gas

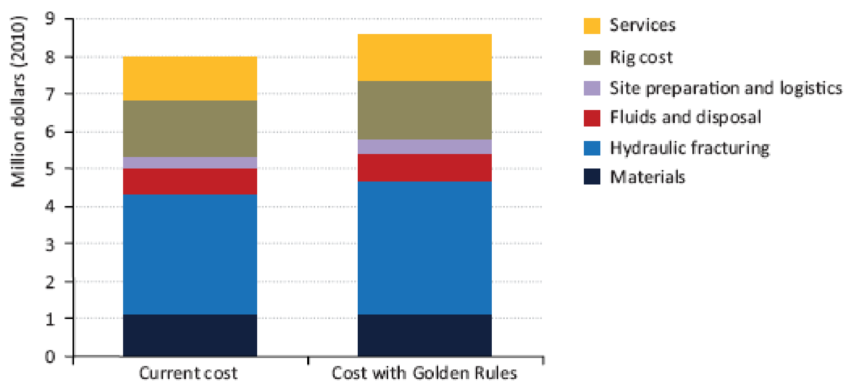


Source: (Pearson et al., 2012)

It is sometimes argued that differences in property rights, population density and stricter environmental regulation might hinder the development of shale gas in Europe.

The issue of environmental impact and the area required for shale gas exploration and development will be dealt with in Chapter 6. However, it is worthwhile previewing here the cost implications of stricter environmental guidelines and/or regulations. In this respect, the IEA has proposed "golden rules for a golden age" of gas and has estimated the cost of drilling under such rules (see FIGURE 26 below)

FIGURE 26. Impact of the Golden Rules on the cost of a single deep shale-gas well



Notes: Materials include all tangible material that is used in the well construction and remains in the well when it is completed, such as steel casing, valves and plugs.

Services include various services, other than hydraulic fracturing services, that are used in well construction: directional drilling services, cementing services, casing services, wire line and testing services.

Source: (OECD/IEA, 2012)

It is important to note that the costs given in the IEA (2009) figure may not be representative of the real drilling costs in Europe and in Spain, at least in the initial phases of exploration and development.[29]

In this respect, it may be assumed that the success of shale gas development in Europe will greatly depend on the ability to increase the efficiency of drilling by industrializing the drilling process, and utilizing rig automation technology and equipment to target zero harmful emissions, thus generating the smallest possible environmental footprint and a related reduction in drilling and fracturing cost, which could result in a 50% cost reduction for large-scale drilling campaigns. All of these developments would have to be backed by human and technical resources with sufficient capacity to support field developments and the required infrastructure.

[29] More references on exploration and production costs fir Europe can be seen in "Gas no convencional: shale gas. Aspectos estratégicos, técnicos, medioambientales y regulatorios". Álvarez Pelegry & Suárez Diez (2016). Marcial Pons. http://www.orkestra.deusto.es/es/investigacion/publicaciones/libros-informes/otras-colecciones/814-gas-noconvencional-shale-gas-aspectos-estrategicos-tecnicos-medioambientales-regulatorios

1.5. Spain

Spain is a medium-sized gas market on the European stage, with gas accounting for 21.5% of the primary energy mix (Sicilia Salvadores, 2014). In this respect, it stands behind some major European economies such as Germany and Italy, but within an important group of countries with long experience in gas developments and large markets, such as France and the Netherlands. Spain was also the largest consumer of LNG in Europe in 2013 (12.03 Bcm) and is the fifth-largest LNG importer in the world after Japan, South Korea, India and Taiwan.

Spain is almost entirely dependent on gas imports, with about 60% in the form of LNG and the rest supplied through pipelines. LNG imports are therefore more important here than in other EU countries, where LNG imports account for less than 15% on average (Peris Mingot, 2014).

As for the origin of these gas imports, whereas some countries are entirely dependent on Russian natural gas, Spanish gas supply is highly diversified, with a concentration among non-OECD countries. In 2013, Spain imported natural gas from eleven different countries, including Algeria, France, Qatar, Nigeria, Trinidad and Tobago, Peru and Norway (Peris Mingot, 2014).

1.5.1. Gas infrastructures and consumption

Spain currently has six international connections (two with North Africa, two with France and two with Portugal) and seven regasification plants (six in operation), which received a total of 241 LNG carriers in 2014.

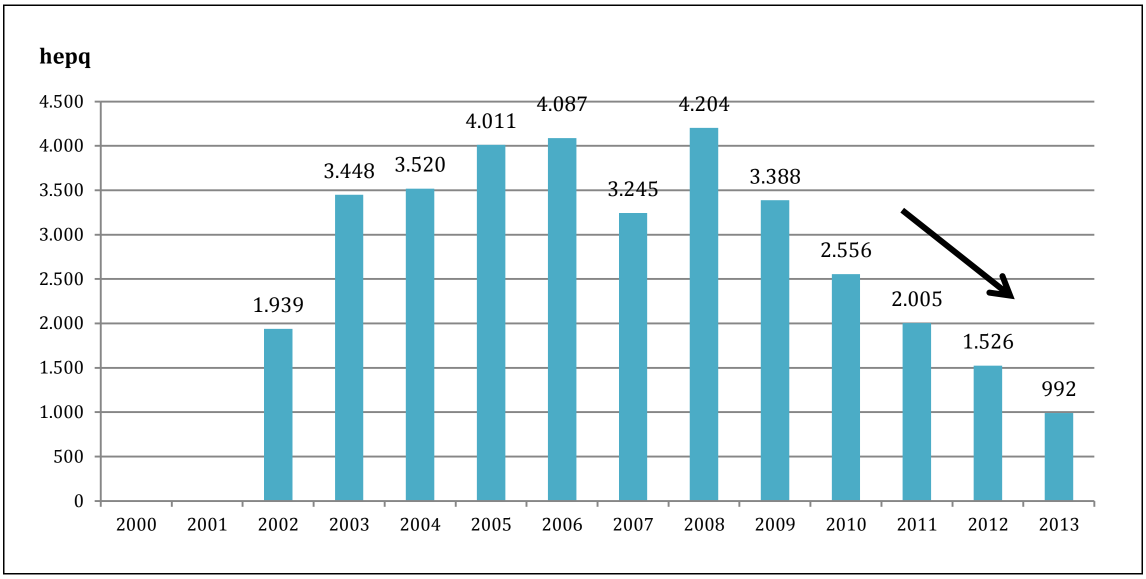
The potential for gas penetration is closely linked to infrastructure development which has been backed by strong investments – more than €16 billion in the period from 2000 through 2014, i.e. about €1.1 billion per year on average. These investments have focused on transmission and distribution pipelines, whose accumulated length increased from 37,022 km in 2000 to 81,806 km in 2014 and also on an increase in the number of municipalities with gas consumption from 948 in 2000 to 1,638 in 2012 and a sharp rise in gas customers, from 4,203,168 in 2000 to 7,555,661 in 2014. (Enagás, 2015; Sedigas, 2015)

One of the major drivers of gas consumption has been in the power industry, with the amount of electricity generated from gas rising from 10.3 Twh (5.3%) in 2000 to 51.8 Twh (17.2%) in 2014, peaking in 2009 at 161 Twh (40%). However, this use of gas for electricity generation has been falling back since 2008, mainly due to changes in energy policies, greater use of coal, and the economic crisis, with lower electricity demand and an increase in renewable generation.

Compared to some countries in Europe, the structure of gas consumption in Spain is atypical. The industrial sector is the largest consumer, accounting for 64.7% of total consumption in 2014. It is followed by the power sector (17.2%) and the domestic and commercial sectors (16.3% of total consumption), with the remaining 1.8% going to non-energy uses.

Prospects for gas demand in industry may be positive, provided competitiveness can be improved and gas demand for power generation may increase given the future development of renewable technologies, which need gas to cover intermittency and the currently low operating hours of combined cycles (FIGURE 27).

FIGURE 27. Equivalent annual hours of operation of combined cycle natural gas power stations in Spain



Source: (Díaz, Larrea, Álvarez, & Mosácula, 2015)

Gas also has potential for growth on conventional markets (residential and domestic). By the end of 2014, customer figures had risen to 7.55 million, up 1.1% on 2013. This is significant taking into account the limited addition of new housing due to the economic crisis.

By region, the highest number of supply points per 100 persons is in Cantabria (29.5), followed by Catalonia (28.6), while the lowest figures are in Andalusia (5) and Murcia and Extremadura (6 each). The potential for gas penetration is clear if one considers that Spain accounts for 6.2% of total European consumption and that the country has around 156 consumers per 1,000 inhabitants, as compared to a European average of 233. Germany has 238 consumers per 1000 population, while the Netherlands has 438 (FIGURE 28).

1.5.2. Prices

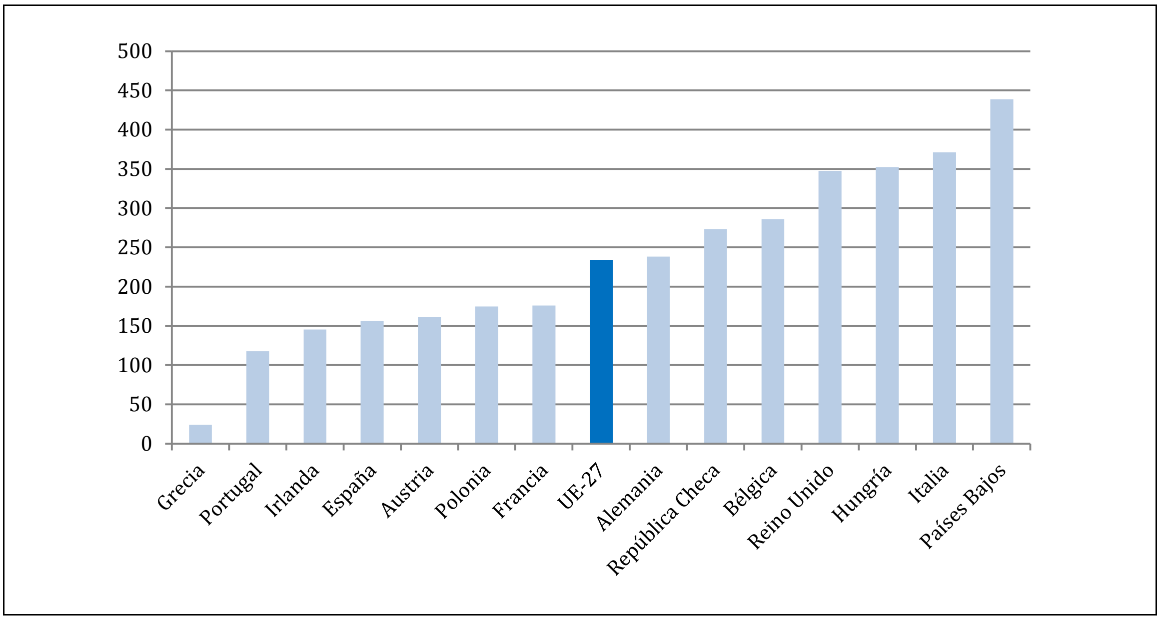
LNG prices in Spain are influenced by the spot price, especially by Asian markets, which, as we have seen, are large gas users, with high demand for LNG imports. Japan and Korea have pricing formulas for purchasing that are very closely related to oil with "mitigation" in the higher and lower prices.

The price of gas in Spain is mainly linked to oil prices through indexation in long-term contracts. With increasing competition on the gas market the weight of oil will probably decrease, and the sharp rise in LNG will favor the role of spot pricing.

Domestic production would certainly meet part of the demand and help create a more dynamic market. (Álvarez Pelegry, 2015)[30]

On the other hand, as we have seen in the previous section, organized markets ("hubs") may play a relevant role in gas prices and market conditions. A substantial number of long-term contracts were signed at the beginning of the last decade, mainly as a result of gas requirements for combined cycles. Because these contracts have a term of around 20 years, by 2020-2025 some contracts will either have expired or will up for renegotiation, with the possibility of decreasing contract quantities. This will create an interesting window of opportunity for developing gas equity ahead of this time.

FIGURE 28. Consumers by 1000 people in the EU and comparison with Spain



Note 1: Millions (key figures on Europe. 2012 edition. Eurostat. European Commission.
Note 2: Thousands: Source: Statistical Report 2012. Eurogas.
Note 3: Spanish population figures, BOE 29.12.2012; Sedigas consumers. 2012 data.
Source: Own elaboration based on (Sedigas, 2013)

Spain has practically no domestic conventional gas production[31]. In 2011, 45 Mtoe (0.05 bcm) was produced, as compared to 310 Mtoe in 2004 (0.3 bcm). However, this has not always been the case. Historically, gas production in the Basque Country totaled around 8 bcm between 1986 and 1994, an average of about 0.7 bcm per year.

From the point of view of Spain's balance of trade, energy imports –mainly oil and gas– have contributed to a growing trade deficit over the last decade (rising from 30% in 2007 to 60% in 2010). The cost of gas imports came to €3 billion in 2003,

[30] A more detailed analysis of the potential of the domestic market related to the development in gas distribution grids can be seen in (Álvarez Pelegry & Suárez Diez, 2016)
[31] In 2012, Spain produced 674 gigawatt hours of gas from 4 different fields (three of which are now gas storage sites), representing 0.18% of the demand for gas: http://www.cores.es/sites/default/files/archivos/publicaciones/informe-est-2012-julio-2013.pdf

climbing to €10 billion in 2012 – though still far short of the €60 billion cost of oil imports in 2012. Any domestic gas production would therefore contribute positively to the Spanish economy.

A summary

The Spanish gas market has a relevant size and plays an important role in the European dimension. However, there is still place for growth and there is room for penetration when compared to those European countries with higher tradition and weight of gas in the energy mix.

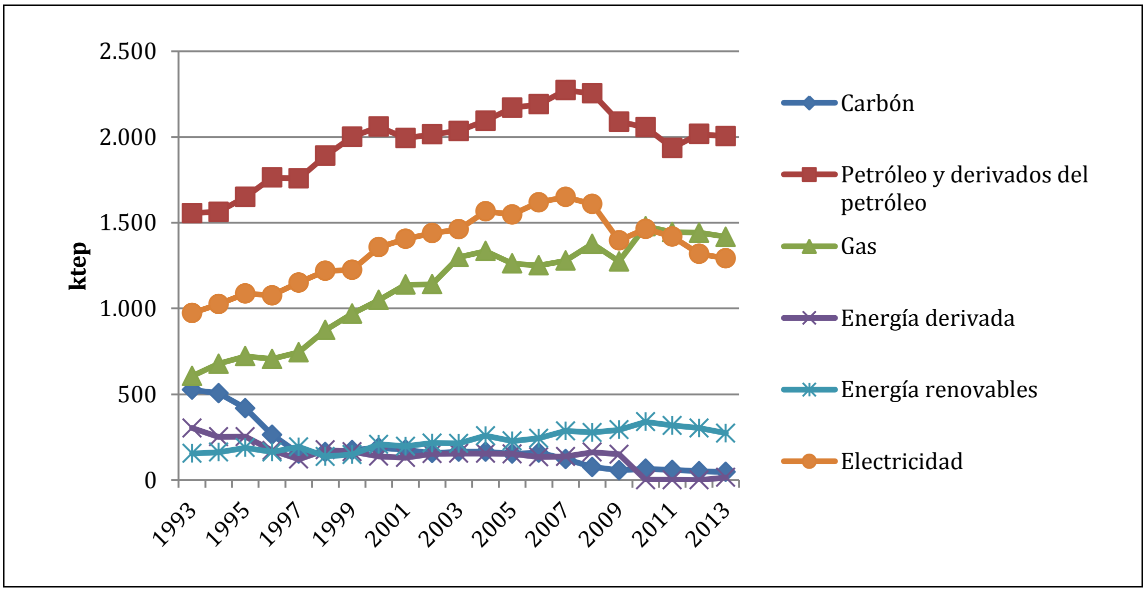
A higher demand of natural gas may be expected in Spain, from the power sector (combine cycles and cogeneration) given the current low levels in the industrial, tertiary and residential sectors.

The formation of gas prices in Spain (mainly based on crude oil prices) together with the high gas imports (practically all gas demand) lead us to think that an eventual domestic gas production would be positive, as a consequence of the reduction of gas imports, considering among other benefits, the diversification and revitalization of gas markets, inducing by this way potential improvements for competitiveness.

1.6. Basque Country

The period between 1990 and 2011 has seen a major transformation in the energy mix of the Basque Country. The share of gas as a primary energy source doubled from 12% in 1990 to 21% in 2000, peaking at 41% in 2010. In terms of final energy, its share rose from 15% in 1993 to 21% in 2000 and 28% in 2013 (See FIGURE 29).

FIGURE 29. Final energy consumption by energy source in the Basque Country (ktoe)



Source: (Álvarez Pelgry, Larrea, Mosácula, & Díaz, 2013)

1.6.1. Gas demand

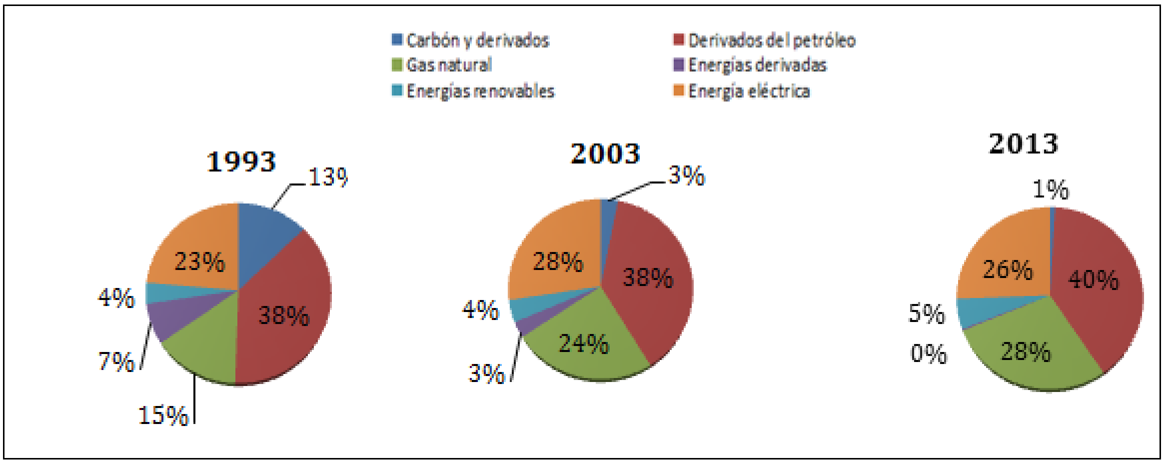
Gas development in the Basque Country has been characterized by political support and continued implementation.[32] In 1993, natural gas consumption stood at 682 ktoe, climbing to 2,423 ktoe in 2013 and trebling its market share. This has largely been due to continuous improvement in the supply infrastructure (including domestic production from the Gaviota field), with consequent enlargement and renovation of gas transmission and distribution networks, which have expanded coverage and improved supply security (FSC, 2012).

Natural gas consumption stood at 31.3 TWh in 2013, with a peak in 2008 of 45 TWh, and continued increase in consumption from 1993 (FIGURE 30).

As in other regions and in Spain in general, increase in consumption was largely driven by demand for gas for combined cycles. However increased penetration of gas in industry was also important, rising from 19% in 1995-1999 to 29% in 2005-2009 and 33% in 2010-2012. During the same period, electricity consumption in industry fell from 65% (1995) to 56.6% (2012).

For Basque industry as a whole, although electricity bills represented 57.7% of total energy expenditure, on average, spending on natural gas during the period 2005-2009 accounted for 29%. Prices have risen from €5/MBtu in 1995-1999 to €6.4/MBtu in 2000-2004, peaking at €10/MBtu in 2005-2010.

FIGURE 30. Final energy consumption by energy source in the Basque Country



Source: (Álvarez Pelgry et al., 2013)

In the tertiary sector, over 60% of municipalities receive gas via pipeline, with the figure rising to over 80% if liquefied petroleum gas distribution networks are taken into account (Basque Government, Department of Industry, Innovation,

[32] For a detail of the Energy Policies in the Basque Country since 1982 see (Álvarez Pelegry & Suárez Diez, 2016)

Trade and Tourism and EVE, 2012). In 2011 there were 513,444 gas customers in the Basque Country (see TABLE 5).

TABLE 5. Basque municipalities serviced by gas

	Total municipalities	Number of municipalities with access to natural gas	Percentage of municipalities with natural gas access	Population	Natural gas customers[33]
Vizcaya	112	70	61%[34]	1,136,716	243,313
Álava	51	15	30%[35]	320,297	78,316
Guipúzcoa	88	60	68%[36]	707,298	191,815
TOTAL	251	145	-	2,164,311	513,444

Source: (M.Larrea, 2015)

As the above table shows, there are on average 23.41 natural gas clients per 100 inhabitants in the Basque Country. These figures are higher than for the rest of Spain (15.65 customers /100 inhabitants). Nonetheless, only 54% of buildings in the Basque Country have natural gas heating facilities. According to EUROSTAT data, 54% of homes in Europe use natural gas for heating (45% with individual systems, and 9% with centralized systems).

There is therefore still a potential gas market in the Basque Country. Promoting gas consumption in this sector would have a positive environmental impact and would also generate employment as well as boosting the number of gas consumers. The development of cogeneration in public buildings and micro-generation in the residential area, together with the introduction of latest-generation heat pumps and gas furnaces would also contribute to increased gas consumption.

In the transport field, development and utilization of gas engines as an element of diversification would contribute to increased gas consumption and further environmental improvements.

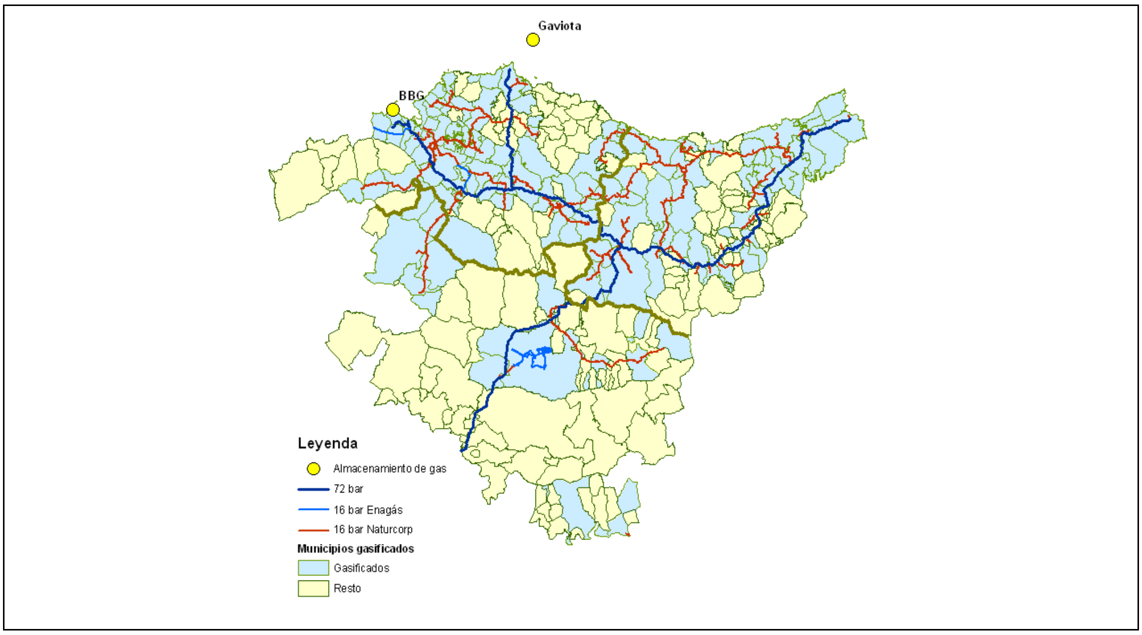
1.6.2. Gas Infrastructures

In consonance with increased gas penetration since the nineties, there have been infrastructure improvements and enlargements in gas distribution networks for domestic and commercial use.

The main transmission lines and distribution grids in the Basque Country total about 3,700 km (see FIGURE 31 below). These infrastructures provide an excellent base for further development of gas in the territory.

[33] Data as of 31/12/2012.
[34] 77% propane networks included.
[35] More than 94% of total population.
[36] 92% propane networks included

FIGURE 31. Gas infrastructure in the Basque Country



Source: (EVE, 2011)

There is also an international interconnection with France (Irun – Biriatou) which should be strengthened and which has opened up the connection to the European infrastructure market. Connectivity is based on the demand in the area of influence on either side of the border. This interconnection is primarily being used for export. In 2010, it had a nominal output capacity of -9 (-5) GWh / day with a peak production of -9 GWh / day (CNE, 2012).

Following the initiative of ERGEG (European Regulators Group for Electricity and Gas), two procedures called *open seasons* were developed. Based on those interconnection capacity was allocated and it was decided to increase two-way capacity to and from France through Larrau to 165 GWh/day (equivalent to 5.2 bcm) from 2013 with a further 60 GWh in exports to France through Irun from the end of 2015. (CNMC, 2014)

In addition, since 2003, Bilbao Port has had an LNG Regasification Terminal (Bahia Bizkaia Gas) with a total storage capacity of 450,000 cubic meters of LNG and a regasification capacity of 800,000 Nm^3 / h of natural gas. Among others, it supplies the Bahía de Bizkaia Electricidad (BBE) combined cycle, located in the same area, with the rest of the gas being injected into the natural gas transmission grids.

In addition to the regasification terminal, gas infrastructures in the Basque Country include the Gaviota underground gas storage facility. This is located 8 km off the Biscay coast and occupies an area of 64 km^2, at an average depth of 2,150 m. It has 1,701 MNm^3 of cushion gas, 779 MNm^3 of working gas, an injection capacity of 4.5 Mm^3/day and an extraction capacity of 5.7 MNm^3/day.

Between 1986 and 1994, the Gaviota field produced about 7.2 bcm of natural gas. In 1994 it was turned into an underground gas storage facility, taking advantage of its natural characteristics. This helped to address a shortage of LNG storage capacity for strategic reserves and favored the transformation of the Basque manufacturing and industrial structure. Prospects for obtaining new gas in the region now focus on exploration for shale gas and possible future development of unconventional gas production.

The existing gas infrastructure in the region is positive for the Basque Country and has also resulted in a culture of gas development that should improve and boost the future promotion of gas, including local exploration and production.

A summary

The natural gas plays an important role in the Basque energy mix and its role is expected to increase. Furthermore, the continuous implementations of energy policies as well as the strong development of infrastructures have considerable advantages and provide a very good basis for potential growth.

Given the importance of natural gas in the Basque industry, with high weigh in the Gross Domestic Product (GDP), we must consider the positive effects that a domestic resource could induce in the current situation of gas imports. For example, the development of 1 bcm of domestic production would suppose a 30% of self-supply in the Basque Country. This would improve the energy independency of the Basque Country in comparison to other territories.

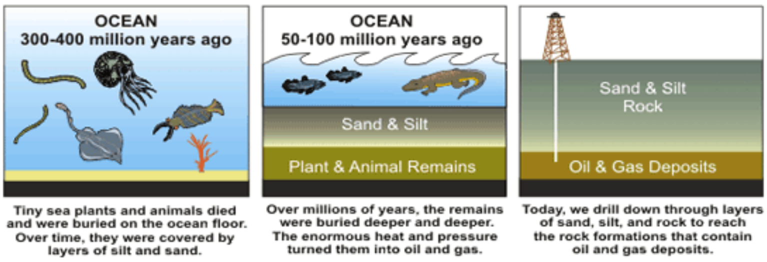
Moreover, this development would revitalize the energy supply, with positive effects over the territorial competitiveness and the industries and services involved and/or related to the gas value chain.

2. WHAT IS UNCONVENTIONAL GAS?

To understand what makes unconventional hydrocarbons different to conventional ones, a brief look at the basic geology seems appropriate. This chapter discusses the origins and formation of conventional and unconventional gas. It concentrates primarily on shale gas –the main theme of this study– although there is also some discussion of tight gas and coal bed methane.

Gas has its origins in organic matter –dead plant and animal material– which is buried and preserved in ancient sedimentary rocks. The most common organic-rich sedimentary rock and the source rock for most gas and oil is black shale. Over millions of years, these remains have sunk deeper and deeper and –as we will see– a combination of heat and pressure has turned them into oil and gas (see FIGURE 32).

FIGURE 32. Petroleum and natural gas formation



Source: (eia.gov, 2014)

Increased heat and pressure fosters the decomposition of carbon compounds. Larger organic molecules crack to form lower-weight compounds, leading to the separation of volatile products (hydrogen and simpler chain carbons such as methane) and liquid products. The transformation of this organic material, called kerogen, into oil and gas hydrocarbons leads to a progressive increase in the hydrogen/carbon ratio.

Generally speaking, the lower the temperature and the smaller the depth, the heavier the resulting hydrocarbon component. Temperature is the critical factor, although the amount of time that the organic material is exposed to heat and pressure is also important in the production of hydrocarbons.

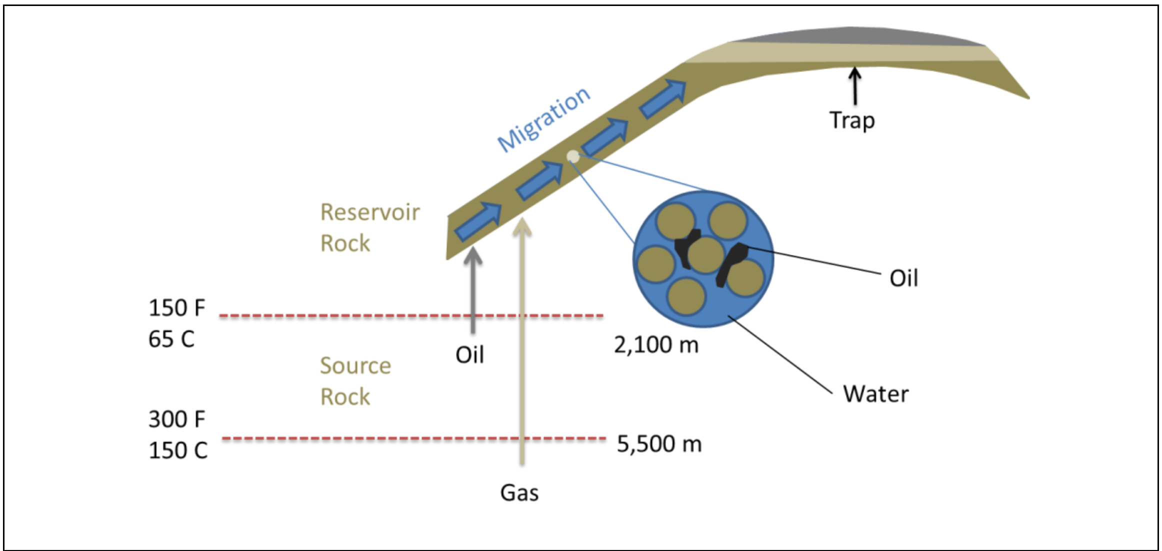
Oil generation begins at 65 °C, peaks at 90 °C and stops at 175 °C. This temperature range –between 65 °C and 175 °C– is known as the oil window. Above and below the oil window, decay of organic remains will generate gas: Below 65 °C, biogenic gas (generated by microbes) or swamp gas will result; above 175 °C, the result will be thermal gas.

Temperatures at the lower end of the oil window generate heavy oils, with higher temperatures creating lighter (and more valuable) hydrocarbons. If the rock temperature becomes too high (above 260 °C) then the organic material (and therefore the oil generation potential) is destroyed, though any natural gas already formed remains stable up to much higher temperatures (Devereux, 1999).

Hydrocarbons are therefore generated where organic matter accumulates over time (in a source rock). Conventional reservoirs are possible when nature provides the following conditions: generation, migration, reservoir and trap-and-seal.

Source rock must exist with sufficient organic matter to have generated gas or oil in the geological past. These hydrocarbons should be able to migrate from the source rock to the reservoir. The reservoir rock should have favorable porosity and permeability (typically, gas and oil are held in sedimentary rocks such as sandstones and certain limestones, connected to the source rock via migration paths). Finally, the presence of a trap or specific geologic/geometric configuration of the reservoir is required to prevent lateral escape of gas. The seal, often known as a cap rock due to its spatial position in the reservoir, is a low permeability barrier which seals the reservoir and prevents the gas and/or oil from escaping. Typically, these cap rocks are shales, salts and clays (See FIGURE 33).

FIGURE 33. Generation and migration of gas and oil



Source: Own elaboration from (Hyne, 2012)

To answer our initial question –What is unconventional gas? – The response is that there is actually no "typical" unconventional gas. Gas is generally extracted from reservoirs, and, over the last couple of centuries, the more accessible reservoirs have been defined as "conventional". Reservoirs may experience high or low pressure and high or low temperatures; they may be deep or shallow, blanket or lenticular, homogeneous or naturally fractured; they may contain one single layer or multiple layers. The characteristics of each unique reservoir can be defined by a function, whilst the economic situation defines the "optimum drilling, completion, and stimulation method."(Holditch et al., 2007). The challenge is to release the gas in each unique reservoir from rock that can be as impermeable as concrete. Thus when permeability requires stimulation to achieve sustained gas flow, the process is labeled "unconventional" gas exploration.

A conventional reservoir is a reservoir in which buoyant forces keep hydrocarbons in place below a sealing cap rock. Reservoir and fluid characteristics of conventional reservoirs typically permit oil or natural gas to flow readily into wellbores. The term conventional is used to make a distinction between shale and other unconventional reservoirs, in which gas might be distributed throughout the reservoir at the basin scale, and in which buoyant forces or the influence of a water column on the location of hydrocarbons within the reservoir are not significant.

In the case of unconventional reservoirs, hydrocarbons are generated in the same way but in this case, they do not migrate very far. Much of the reserve remains in the source rock[37], so the source rock and the reservoir rock are the same. This is due to the low permeability of source rock which can be 1,000 times less than in conventional reservoirs.

Unconventional reservoirs can be formed in different kinds of rock, so there are different kinds of unconventional gas: tight gas sands, shale gas and coal bed methane (CBM) (illustrated in FIGURE 34 and FIGURE 35). This classification is used to describe types of unconventional gas.

FIGURE 34. Different kinds of reservoirs rocks

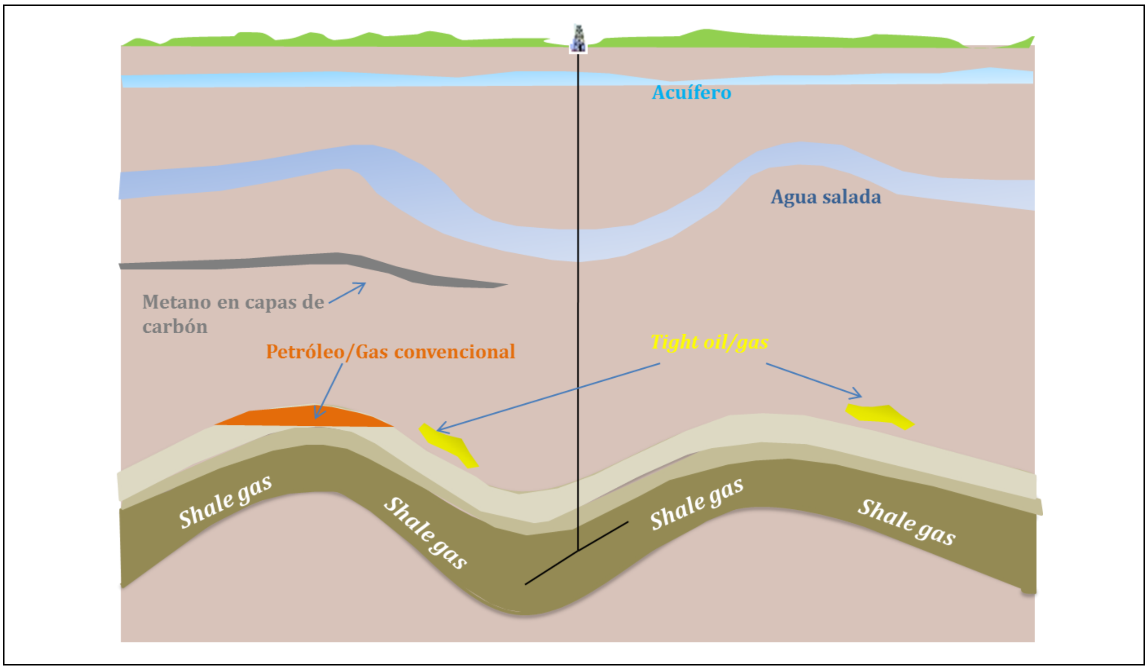
Source: (Holditch, S.A. 2007)

FIGURE 35 also shows the different types of conventional and unconventional reservoirs. The different kinds of source rocks and the relation between permeability and porosity are further explained in BOX 1.

One of the most important characteristics of unconventional reservoirs is that they cannot be economically extracted using the usual technology. The reason is that there is insufficient permeability, with the gas absorbed or trapped in the source rock. It is therefore necessary to fracture these rocks, allowing the gas to flow to the surface. These fractures may be horizontal or vertical. The technique used in this kind of reservoir will be explained in Chapters 4 and 5 of this report.

[37] Source rocks are so called because they provide the hydrocarbons found in conventional oil and gas fields. The oil and gas that has been unable to escape from the source rock is what we call shale oil and shale gas.

FIGURE 35. Schematic geology of natural gas resources

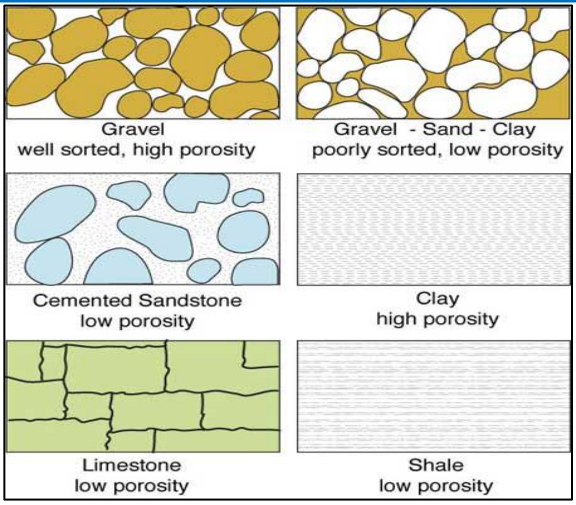


Source: Own elaboration from (US Energy Information Administration, 2011b)

BOX 1: Porosity and Permeability

When materials have internal spaces, these are called pores. Porosity is the fraction of the total rock volume occupied by the pore spaces. Porosity is expressed as a percentage. This property is very important because without it, oil or gas cannot accumulate in a reservoir. There is a theoretical maximum porosity of 48%[38] in clastic rocks and this occurs when the grains are identical spheres. It is unusual to encounter sandstones with a porosity as high as 25% (Conaway, 1999).

FIGURE 36. Porosity

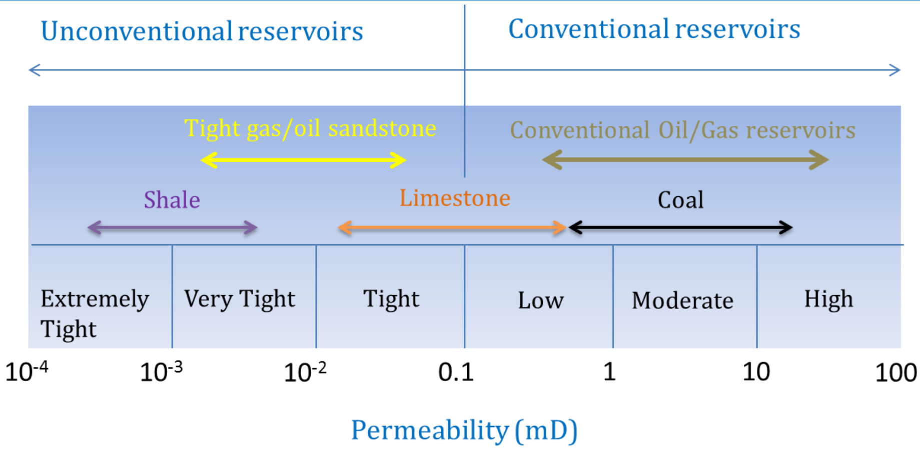


Source: (Adini, 2011)

If the pores are interconnected, fluids (gas, oil or water) can flow through the rock. This property of a rock to allow fluid to flow through it is called permeability. If a rock is permeable, it must be porous; nevertheless a porous rock can be impermeable.

Permeability is measured in darcys. A cube of rock with sides measuring 1cm x 1cm x 1cm that transmits fluid with a viscosity of one centipoise at a rate of 1 cc per second with a pressure differential of 1 bar has a permeability of one darcy (D). In layman's terms, a rock with a permeability of one darcy is very permeable. Most reservoir rocks are measured in milidarcys (1/1000th of a darcy) rather than darcys (Devereux, 1999).

FIGURE 37. Permeability range of producing formations where fracturing is required



Source: Own elaboration from (Canadian Society of Unconventional Resources, 2012)

[38] For clastic rocks. Limestones could have higher solution porosity, although this would be very rare.

2.1. Shale gas

Shale gas is natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas (see FIGURE 38).

FIGURE 38. Shale rocks

Source: (USGS, 2005)

Shale gas reservoirs are located in many formations from the Cambrian to the Cenozoic[39]. These formations have generated reservoirs whose properties vary depending on the geological environment.

Shale has very low porosity and very low permeability. Shale minerals are flat crystals that stack up like plates on a shelf. When clays are originally deposited, they are comprised of 70% - 80% water. As the water is squeezed out of the clay during diagenesis, these flat crystals are pressed very close to each other. Shale has tiny pores, connected by miniscule passages. It takes a long time for the water and oil produced within the shale source rock to be squeezed out by pressure (Devereux, 1999).

In areas where conventional resource plays are located, shales can be found both above and below the reservoir rock and can be the source of the hydrocarbons that have migrated upwards or laterally into the reservoir rock.

Shale gas resource plays differ from conventional gas plays in that the shale acts as both the source for the gas and the zone (also known as the reservoir) in which the gas is trapped. The very low permeability of the rock causes the rock to trap the gas and prevents it from migrating towards the surface. The gas can be held in natural fractures or pore spaces, or can be adsorbed into organic material.

Gas is present in shales in three different forms: a) adsorbed gas, which is gas attached to organic matter or to clays; b) free gas, which is gas held within the tiny spaces in the rock (pores, porosity or micro-porosity) or in spaces created by the

[39] For example, the Eocene Cambay shales of India.

rock cracking (fractures or microfractures) and c) solution gas, which is gas held within other liquids, such as bitumen and oil.

Compared to most conventional reservoirs such as sandstone, limestone or dolomite, gas shales have extremely low permeability. Effective bulk permeability in gas shale is typically much less than 0.01 millidarcys (mD) (0.001 – 0.1/1 mD for tight gas), although exceptions exist where the rock is naturally fractured, e.g. the well-fractured Antrim shale in the Michigan Basin in the USA.

It is important to know the organic geochemistry of the rock where the shale gas is located. The principal aspects related to organic geochemistry are: total organic carbon (TOC), types of kerogen and thermal maturity.

TOC is the total amount of organic material (kerogen) present in the rock, expressed as a percentage of weight. Generally, the higher the TOC, the greater the potential for hydrocarbon generation (an appropriate range would be 1% - 8% TOC). The TOC figure measures the quantity but not the quality of carbon organic content in sediment or rock samples (Escudero Martínez, Álvarez García, & Ordoñez Alonso, 2013).

Shales contain organic matter (kerogen) which is the source material for all hydrocarbon resources. Over time, as the rock matures, hydrocarbons are produced from the kerogen. These may then migrate, either as a liquid or a gas, through existing fissures and fractures in the rock or through the natural interconnections between pore spaces until they reach the earth's surface or until they become trapped by strata of impermeable rock. Porous areas beneath these 'traps' collect the hydrocarbons in a conventional reservoir, frequently a sandstone.

The total organic carbon content of rocks is obtained by heating the rock in a furnace and combusting the organic matter to carbon dioxide. The amount of carbon dioxide liberated is proportional to the amount of carbon liberated in the furnace, which in turn is related to the carbon content of the rock. The carbon dioxide liberated can be measured in several different ways, one of which is called the Rock Eval Test[40].

Many source rocks also include inorganic sources of carbon such as carbonates and most notably calcite, dolomite, and siderite. These minerals break down at high temperature, generating carbon dioxide and thus their presence must be corrected in order to determine the organic carbon content.

[40]Rock Eval is the trade name for a set of equipment used in the laboratory to measure the organic content of rocks, as well as other properties of the organic substances that help identify the kerogen type. Rock-Eval combusts a crushed sample of rock at 600 °C. Refractory organic matter such as inertinite does not combust readily at 600 °C so most coal samples yield Rock-Eval measured TOC values much lower than the real values because of incomplete combustion.

The most commonly utilized scheme for classifying organic matter in sediments is based on the relative abundance of elemental carbon, oxygen, and hydrogen plotted graphically as the H/C and O/C ratio on a so-called Van Krevelen diagram.

Instead of plotting the elemental ratios, it is common to plot indices determined by the Rock Eval Test. In pyrolysis techniques, two indices are determined: the Hydrogen Index (HI), calculated as milligrams of pyrolyzable hydrocarbons divided by TOC, and the Oxygen Index (OI), milligrams of pyrolyzable organic carbon dioxide divided by TOC. Cross-plots of both elemental H/C and O/C ratios or of HI and OI are used to distinguished between four 'fields' which are referred to as Types I, II, III, and IV of kerogen.

The different types of organic matter are of fundamental importance since the relative abundance of hydrogen, carbon, and oxygen determines what products can be generated from the organic matter upon diagenesis.

The thermal maturity of the rock is a measure of the degree to which organic matter contained in the rock has been heated over time, and potentially converted into liquid and/or gaseous hydrocarbons. Thermal maturity is measured using vitrinite reflectance (Ro).

Thermal maturity is important since the hydrocarbon potential of organic carbon depends on the thermal history of the rocks containing the kerogen. The outcome is determined both by the temperature and by the time at that temperature. Medium-range temperatures (< 175° C) produce mostly oil and a little gas. As we have already seen, higher temperatures produce mostly gas.

Vitrinite reflectance (Ro) is used as an indicator of the level of organic maturity (LOM). Ro values of between 0.60 and 0.78 usually represent oil prone intervals. Ro > 0.78 usually indicates gas prone. High values can suggest "sweet spots" for completing gas shale wells.[41] (Ro>1.3 for shale gas)

2.2. Other unconventional gases

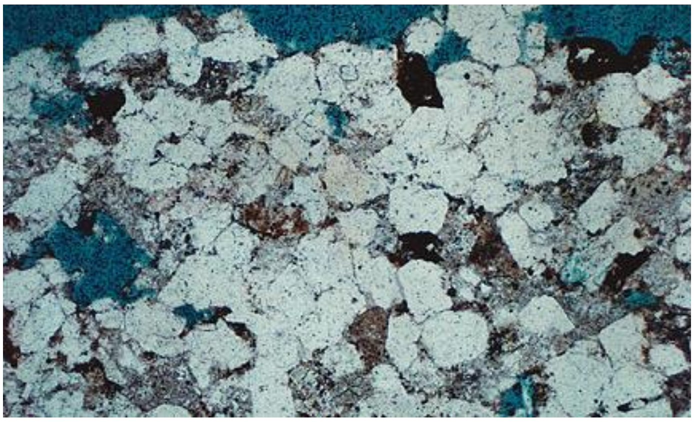
Other unconventional gas includes tight gas and coal bed methane. Tight sand gas accumulations occur in a variety of geologic settings where gas migrates from a source rock to a sandstone formation, but it is limited in its ability to migrate due to reduced permeability in the sandstones.

Any analysis of a tight gas reservoir should always begin with a thorough understanding of the geologic characteristics of the formation. The important geologic parameters for a trend or basin are the structural and tectonic regime, the regional thermal gradients, and the regional pressure gradients. Knowing the stratigraphy in a basin is very important and can affect the drilling, evaluation,

[41]Vitrinite reflectance measurements are made using immersion oil with a refractive index of 1,518 at 546 nm and 23 °C and spinel and garnet standards of 0.42%, 0.917% and 1.726% reflectance for calibration. Fluorescence-mode observations are made on all samples and provide supplementary evidence concerning organic matter type, and exinite abundance and maturity.

completion and stimulation activities. Important geologic parameters that should be studied for each stratigraphic unit are the depositional system, the genetic facies, textural maturity, mineralogy, diagenetic processes, cements, reservoir dimensions, and presence of natural fractures.

FIGURE 39. Tight sand section



Source: (USGS, 2005)

One of the most difficult parameters for assessing tight gas reservoirs is the drainage area, size and shape. In tight reservoirs, months or years of production are normally required before the pressure transients are affected by reservoir boundaries or well-to-well interference. As such, the reservoir engineers need to know the depositional system and the effects of diagenesis on the rock to estimate the drainage area, size and shape for a specific well and thus to estimate reserves. Oblong (or noncircular) drainage volumes are likely caused by depositional or fracture trends and the orientation of hydraulic fractures.

Normally, a tight gas reservoir can be described as a layered system. In a clastic depositional system, the layers are composed of sandstone, siltstone, mudstone, and shale. To optimize the development of a tight gas reservoir, a team of geoscientists, petrophysicists, and engineers must fully characterize all the layers of rock above, within, and below the pay zones in the reservoir.

The most important mechanical property is in-situ stress, often called the minimum compressive stress or the fracture-closure pressure. When the pressure inside the fracture is greater than the in-situ stress, the fracture is open. When the pressure inside the fracture is less than the in-situ stress, the fracture is closed. Values of in-situ stress can be determined by using logs, cores, or injection tests. To optimize the completion, it is very important to know the values of in-situ stress in each rock layer.

Typical conventional natural gas deposits boast a permeability level of 0.01 to 0.5 Darcy, but formations trapping tight gas reserves display permeability levels of merely a fraction of that figure, in the miliDarcy or microDarcy range.

Coal bed methane is a gas formed as part of the geological process of coal generation and is contained in varying quantities within all coal reserves. Thermal alterations in the coal result in thermogenic methane formation. The methane is stored within the coal layers, creating a reservoir of gas due to chemical absorption of the gas by the coal. Coal has a high proportion of methane, with small amounts of ethane, propane, butane, carbon dioxide and nitrogen.

Coal-bed methane has posed one of the greatest safety problems in the mining industry. Over the centuries, miners developed a range of methods for extracting coal bed methane from coal and mine workings. They later realized that this gas could be employed as a fuel in the form of natural gas.

Coal is defined as a rock containing at least 50% organic matter by weight. The precursor of coal is peat, plant matter deposited over time in fresh-water swamps associated with coastal deltaic rivers.

In the geological process of coal formation, several “carbonization products” appear, one of which is methane. Methane generation is the result of two processes. When the temperature is below 50 °C, biogenic methane results from microbial decomposition of plant litter; when the temperature is above 50 °C, the methane is thermogenic due to the depth and heat.

Low rank coals tend to have lower gas content than high-rank coals such as anthracite. Anthracite can have extremely high gas content, but the gas tends to desorb so slowly that anthracite is an insignificant source of coal bed methane. Commercial coal bed methane production takes place in medium-rank coals, usually low- to high-volatile bituminous coals.

Coal has a very low permeability, typically ranging from 0.1 to 30 milliDarcy (mD). Because coal is a very weak material and cannot support much stress without fracturing, it is almost always highly fractured. The resulting network of fractures commonly gives coal a high rate of secondary permeability. Groundwater, hydraulic fracturing fluids, and methane can easily more flow through the network of fractures. Because hydraulic fracturing generally enlarges pre-existing fractures and rarely creates new ones, this network of natural fractures is very important for the extraction of methane from coal.

3. CONVENTIONAL AND UNCONVENTIONAL GAS RESOURCES. SITUATION IN SPAIN AND THE BASQUE COUNTRY

In this chapter, we will offer a range of data from different sources on estimated resources and reserves – worldwide, in Europe, in Spain and in the Basque Country.

For a better understanding of the reserves and resources issue, it may be helpful to look at the definitions of resources and reserves given by a number of different institutions (which are explained in Annex 3). We also include a comparison of these definitions and a brief discussion of the various methodologies used, in order to give a better understanding of the published data on reserves and resources.

We then go on to review official data on shale gas resources and reserves – globally, in the USA and in Europe, with particular focus on Germany, Poland, the United Kingdom, Spain and the Basque Country. These data are summarized at the end of the chapter.

3.1. Preliminary considerations and concepts

The basic principles of resource classification were established by McKelvey in 1972, in accordance with the Society of Petroleum Engineering (SPE). These remain the basis for the current system.

As the table below shows, two main factors or issues are considered – namely whether or not the resources have been discovered and whether or not they are commercially viable. Combining discovery and commercial viability allows us to establish the "significance" of the reserves.

As we shall see further on, the issue can be represented as a pyramid. At the wide base are the as yet undiscovered resources. The more we progress in terms of knowledge, certainty, technical/economic feasibility and marketability, the further up the pyramid we go towards the 'reserves' tier with proven reserves (with different types of probability) at the apex.

TABLE 6. Modified McKelvey Box showing terminology for recoverable resources

	Discovered	Undiscovered
Commercial	Reserves	Prospective resources
Sub-Commercial	Contingent resources	

Source: (SPE, WPE, & AAPG, 2001)

There are a considerable number of different definitions of resources and reserves. These may be influenced by the type of resource under consideration (e.g. gas, oil, coal or minerals). Moreover, different institutions have approached this classification with different probabilistic or deterministic methodologies. There are also some differences depending on the purpose and final use of the data. This is the case of the SEC (U.S. Securities and Exchange Commission), which uses various definitions for reporting the potential of different types of resources to investors and geological institutions from different countries.

In this section we shall refer briefly to methodology. The guidelines issued by the SEC and the SPE/WPC/AAPG (Society of Petroleum Engineers with the World Petroleum Councils and the American Association of Petroleum Geologists) can be found in Annex 3.

Before dealing with resources and reserves, a brief introduction to some associated definitions is advisable. In this sense, some concepts such as basin, play, field, formation, accumulation and project are gathered in the following table.

TABLE 7. Some basic definitions related to resources or reserves

Term	Definition
Basin	A basin is a large area with a relatively thick accumulation of sedimentary rocks (10,000 to 50,000 ft.[42]). The deep part of the basin where crude oil and natural gas forms is called the kitchen. The shallow area surrounding the deep-water part of the basin is called the shelf.[43] A basin may be filled with sediments; examples include the Gulf of Mexico[44], the Basque Cantabrian basin and the Ebro basin).
Play/reservoir	A play is a proven combination of reservoir rock, seal rock and trap type that contains commercial amounts of petroleum or gas in an area. A reservoir is a subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum or gas that is confined by impermeable rock or by water barriers and is characterized by a single-pressure system.
Field	A field is an area consisting of a single reservoir or multiple reservoirs all grouped within, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both.
Formation	A formation (or geological formation) is the fundamental unit of lithostratigraphy. A formation consists of a given number of rock strata with comparable lithology, facies or other similar properties. Formations are not defined by the thickness of their component rock strata and the thickness of different formations may therefore vary widely. The concept of formally defined layers or strata is central to the geologic discipline of stratigraphy. A formation can be divided into members, which are themselves grouped together in groups.
Accumulation	The term 'accumulation' is used to identify an individual body of moveable petroleum or gas in a reservoir. For an accumulation or reservoir to be considered 'known', and hence to contain reserves or contingent resources, it must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum or gas in the reservoir or shale gas either by flow to the surface or –at least– by recovery of a sample of petroleum or gas from the well. However, where log and/or core data exist, this may suffice, provided there is a good analogy to a nearby and geologically-comparable known accumulation.
Project	The term 'project' is a key concept when discussing a commercial reserve. It represents the link between the petroleum accumulation and the decision-making process, including budget allocation.

Source: Own elaboration from (SPE et al., 2001) and (Hyne, 2012)

Given here are the definitions provided by the Society of Petroleum Engineers, the Securities and Exchange Commission (SEC), the US Energy Information

[42] Approximately 3,000 – 15,000 metres

[43] Shelf is a term used to describe a sedimentary environment and has little to do with where it is located in a geologic basin.

[44] If deposition is still occurring in a basin, we say that it is "partially filled," as in the case of the Gulf of Mexico. However, this cannot be said of the Basque-Cantabrian or Ebro basins, as these two basins are already as full as they can be, unless they suffer further subsidence in the geological future.

Administration (EIA), the World Energy Council (WEC), the International Energy Agency (IEA), the UK Geological Survey, BP and the ACIEP (*Asociación Española de Compañías de Investigación, Exploración y Producción de Hidrocarburos*); finally, we offer references related more to the mineral industry. Hopefully, these will provide a better understanding of the definitions and issues surrounding the terms 'resources' and 'reserves'. These are also described in Annex 3.

Before reviewing the different definitions of resources or reserves, it is worth examining some basic terms related to the methodology, including basin, play, reservoir, field and formation.

As stated, these terms, which relate mainly to the geology of the resource, need to be completed with the concept of the commercial viability of the resources. The distinction between commercial and sub-commercial known accumulations (and hence between reserves and contingent resources) is of key importance in ensuring a reasonable level of consistency in the reporting of reserves. Based on the above classification system, it is clear that the accumulation must be assessed as commercial before any reserves can be assigned.

The term 'reserves' is widely misused. The SPE insists that the following expressions should not be employed: geologic reserves (sometimes used to denote petroleum-initially-in-place); technical reserves (used to classify sub-commercial discovered volumes, defined here as contingent resources); speculative reserves (used for undiscovered volumes, defined here as prospective resources); initial or ultimate reserves, (used instead of Estimated Ultimate Recovery (EUR), defined here as estimated remaining recoverable quantities plus cumulative production).

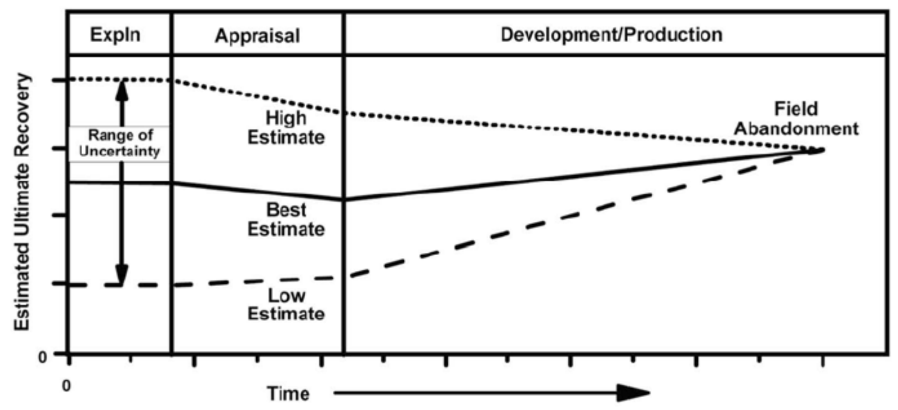
Although the "SPE/WPC Petroleum Reserves Definitions" do leave some uncertainty as regards the commercial criteria to be reflected in the reserve categories (proved (or proved), probable, and possible), they do clearly state that reserves (of all categories) must be commercial. Contingent resources, for example, may include quantities estimated to be recoverable from accumulations for which there is currently no viable market or where commercial recovery is dependent on the development of new technology.

Any estimation of quantity for an accumulation or group of accumulations is subject to uncertainty and should, in general, be expressed as a range. The function of the three primary categories of reserves (proved, probable, and possible) in the "SPE/WPC Petroleum Reserves Definitions"[45] is to cover the range of uncertainty in estimating the potentially recoverable volume of petroleum from a known accumulation. Such estimates, which are made initially for each well or reservoir, may be calculated deterministically or probabilistically and are then aggregated for the accumulation/project as a whole.

[45] See Appendix 3 for more details.

The FIGURE 40 illustrates the concepts of low, best and high estimate, and shows how the estimates become more precise over time as the gas field is developed and these estimates converge with production data.

FIGURE 40. Uncertainly in resources estimation



Source: (SPE et al., 2001)

A deterministic estimate is a single discrete scenario within a range of outcomes. In the deterministic method, a discrete value or array of values for each parameter is selected based on the estimator's choice of the values that are most appropriate for the corresponding resource category. A single outcome of recoverable quantities is derived for each deterministic increment or scenario.

However, in the probabilistic method the estimator defines a distribution representing the full range of possible values for each input parameter. These distributions may be randomly sampled to compute a full range and distribution of potential outcomes of results of recoverable amounts. This approach is most often applied to volumetric resource calculations in the early phases of exploitation and development projects. Deterministic and probabilistic methods may be used in combination to ensure that the results of the two methods are reasonable.

The SPE/WPC guidelines define proved reserves as "those quantities of petroleum which, by an analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions[46], operating methods, and government regulations."

[46] With regard to the current economic conditions, the SPE/WPC guidelines state as follows: "Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves."
The "averaging period" is consistent with the purpose of the reserve estimate and may vary for different types of industry project. Thus, proved reserve booking decisions can be made without overemphasis on temporary "one-day," "year-end," or "date-of-estimate" prices that temporarily

3.2. *Five steps for basin and formations assessments*

The US Energy Information Administration's methodology for conducting basin and formation-level assessments of shale gas and shale oil resources includes the following five steps.

Resource assessment begins with compilation of data from multiple public and private proprietary sources to define the shale gas and shale oil basins and to select the major shale gas and shale oil formations to be assessed. The stratigraphic columns and well logs, showing geological age, source rocks and other data, are used to select the major shale formations for further study. The first step is therefore to conduct a *preliminary geological characterization of shale gas basin and formation* (EIA, 2013b).

Having identified the major shale gas and shale oil formations, the next step is to undertake a more intensive study to *define the areal extent for each of these formations.* For this, a review of the technical literature for regional as well as detailed, local cross-sections is made to identify the shale oil and gas formations of interest. The regional cross-sections are used to define the lateral extent of the shale formation in the basin and/or to identify the regional depth and gross interval of the shale formation.

The next step is to *define the prospective area* for each shale gas and shale oil formation, in order to establish the portions of the basin that are deemed to be prospective for development of shale gas and shale oil. The criteria used for establishing the prospective area include: depositional environment, depth, total organic content, thermal maturity and geographic location. The prospective area, in general, covers less than half of the overall basin area. Typically, the prospective area will contain a series of higher quality shale gas and shale oil areas, including a geologically favorable, high resource concentration "core area" and series of lower quality and lower resource-concentration extension areas.

After the previous step comes the estimate of the *risked shale gas in-place. Gas-In-Place (GIP)* is the gas contained in the porosity of the rock and the adsorbed gas.

The calculation of free gas in-place for a given area (one acre or one square mile) is governed, to a large extent, by four characteristics of the shale formation: pressure, temperature, gas-filled porosity and net organically-rich shale thickness. These data are combined using established Pressure-Volume-Temperature (PVT) reservoir engineering equations and conversion factors to calculate free GIP per acre.

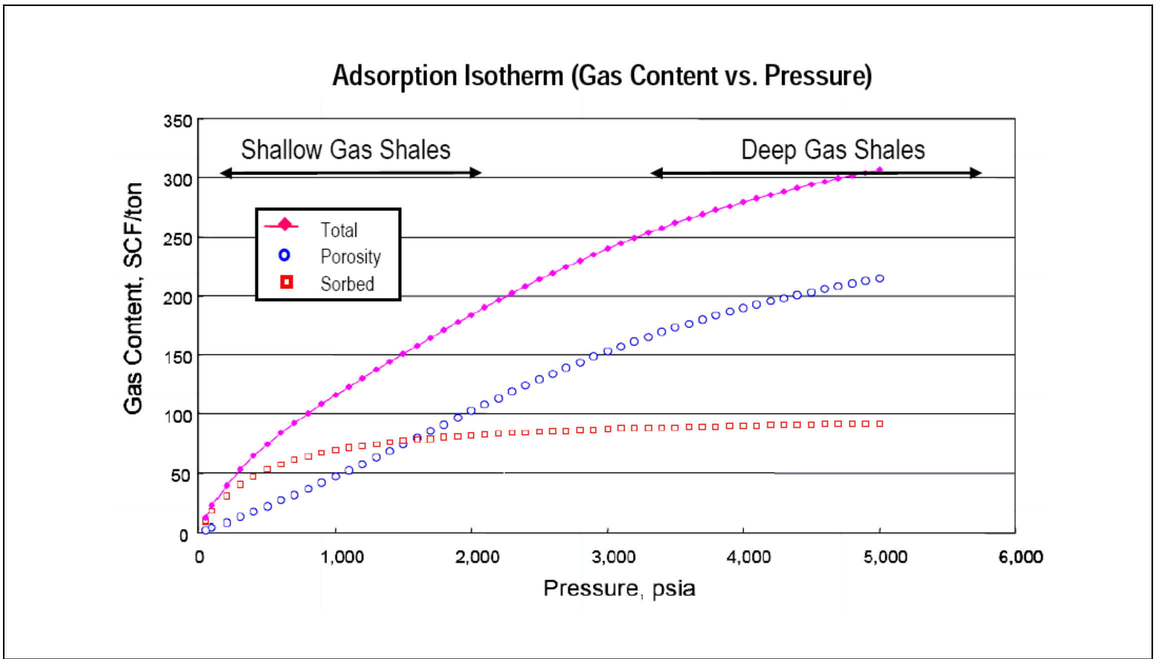
deviate from historical averages caused by transitory world events or crises. There are many documented examples in the recent technical literature to support the logic of using 12 months as the best time period for estimating product prices and operating costs. As a guideline for the "averaging period" for estimating proved reserves, the specified time period would normally be a prior 12-month average determined at the date of the reserve estimate, provided it is permissible under relevant reporting regulations.

In addition to free gas, shales can hold significant quantities of gas adsorbed in the surface of the organics (and clays) in the shale formation. The gas content (GC) (typically measured as cubic feet of gas per ton of net shale) is converted to gas concentration (adsorbed GIP per square mile) using actual or typical values for shale density.[47]

Risked GIP is the fraction of GIP remaining after applying certain success factors i.e. using information available on the productivity of the formation and other factors that might limit its development. Finally, *Risked Recoverable* is the fraction of Risked GIP that can be technically recovered.

The free gas in-place and the desorbed GIP are combined to estimate the resource concentration (Bcf/m^2) for the prospective area of the shale gas basin. The figure below illustrates the relative contributions of free (porosity) gas and adsorbed gas to total gas in-place, as a function of pressure.

FIGURE 41. Combining free and adsorbed gas for Total Gas-In-Place



Source: (EIA, 2013b)

Finally, *the technically recoverable shale gas resource is established* by multiplying the risked GIP by a shale oil and gas recovery efficiency factor, which incorporates a number of geological inputs and analogs appropriate to each shale gas and shale oil basin and formation.

The recovery efficiency factor uses information on the mineralogy of the shale to determine its favorability for applying hydraulic fracturing to "shatter" the shale matrix and also considers other information that would impact shale well productivity, such as: presence of favorable micro-scale natural fractures; the

[47] Density values for shale are typically in the range of 2.65 g/cc and depend on the mineralogy and organic content of the shale.)

absence of unfavorable deep cutting faults; the state of stress (compressibility) for the shale formations in the prospective area; and the extent of reservoir overpressure as well as the pressure differential between the original reservoir rock pressure and the reservoir bubble-point pressure.

Three basic shale gas recovery efficiency factors from 15% to 25% are used in resource assessment, incorporating shale mineralogy, reservoir properties and geologic complexity.

For favorable gas recovery, a 25% recovery efficiency factor of the gas in-place is assigned to shale gas basins and formations with low clay content, low to moderate geologic complexity and favorable reservoir properties such as an overpressured shale formation and high gas-filled porosity. A 20% recovery efficiency factor is used for average gas recovery from shale gas basins and formations with a medium clay content, moderate geologic complexity and average reservoir pressure and properties. Finally, for a less favorable gas recovery, a 15% recovery efficiency factor of the gas in-place is assigned to shale gas basins and formations that have medium to high clay content, moderate to high geologic complexity and below-average reservoir properties.

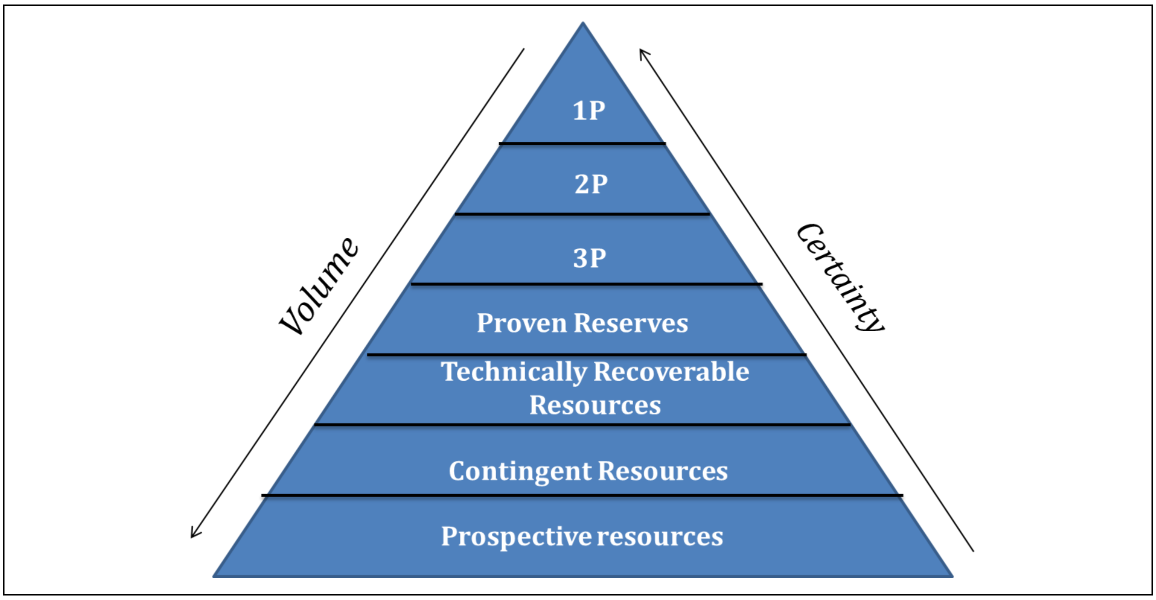
Occasionally, a recovery efficiency factor of 30% may be allocated to shale areas with exceptional reservoir performance or established rates of well performance. A recovery efficiency factor of 10% is applied in cases of severe under-pressure and reservoir complexity. The recovery efficiency factors for associated (solution) gas are scaled to the oil recovery factors (EIA, 2013b).

3.3. Definitions: A summary

Taking into account the issues discussed in the previous sections and based on the criteria of volume and certainty, the FIGURE 42 gives an outline of resources and reserves. The apex of the pyramid corresponds to a higher degree of knowledge and certainty that the shale gas will be commercial, as a result of greater information provided by geological studies, seismic data interpretation and ultimately, exploration drilling.

The other concept reflected in this pyramid is that the less the volume, the greater the certainty. So, proven, probable plus possible reserves are smaller than proven reserves and even smaller than resources.

FIGURE 42. An illustrative outline of resources and reserves



Note: See Appendix 3 for 1P, 2P and 3P definitions.

Source: Own elaboration

Using the terms, concepts and methodology explained above and taking into account the definitions of different institutions described in Annex 3.

The TABLE 8 summarizes the definitions of the various terms as given by each institution consulted. As we shall see, most of the published data for the estimation of reserves and resources of shale gas are for technically recoverable resources (TRR), those portions of gas that are technically recoverable, regardless of economic criteria. In summaries of resources and reserves, the data is therefore shown in TRR tables.

TABLE 8. Summary of terminology used

	SPE	SEC	PGC	EIA	WEC	IEA	USGS	ACIEP	BP	GSB
RESERVES	Reserves (1P, 2P, 3P)	Proved reserves Proved, developed gas reserves Proved, undeveloped reserves		Reserves Proved Energy Reserves	Recoverable reserves Estimated reserves Additional recoverable reserves	Reserves (1P, 2P, 3P)	Reserves (1P, 2P, 3P)	Reserves (P90, P50, P10)	Discovered reserves	Reserves
RESOURCES	Contingent resources Prospective resources		Technically recoverable resources (TRR) Probable, possible, speculative resources Gas in place	Technically recoverable resources Risked Shale gas in Place		Remaining recoverable resources Ultimately recoverable resources (URR)	Technically recoverable resources Known gas	Contingent resources Prospective resources	Ultimately recoverable resources Discovered resources Undiscovered resources	Recoverable resources Gas in place

Source: Own elaboration

3.4. Estimations of resources and reserves

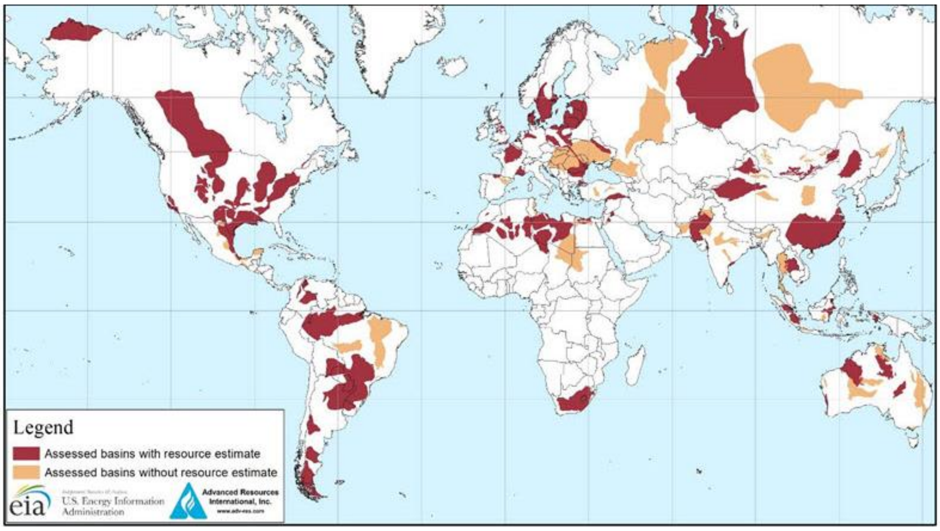
Having explained the terminology and definitions used, in this section we shall set out the data on resources and reserves published by some of the institutions referred to in the previous section.

We will look at figures on the world situation, the USA, Europe (with particular focus on the United Kingdom, Poland and Germany) and finally, Spain and the Basque Country.

3.4.1. *Worldwide*

Taking into account the issues related to reserves discussed in Section 3.1 and 3.3, the red areas in the following figure show the location of estimated resources whereas areas shaded orange are assessed basins with no resource estimate.

FIGURE 43. Map of basins with assessed shale gas oil and shale gas formations. as of May 2013



Source: (EIA, 2013a)

The following map (see FIGURE 44) shows unconventional gas resources in a number of regions of the world, including the United States, Canada, Argentina, China, the European Union and Australia. Note the clear predominance in this area of China (43 tcm), Argentina (23 tcm) and North America (45 tcm in total).[48]

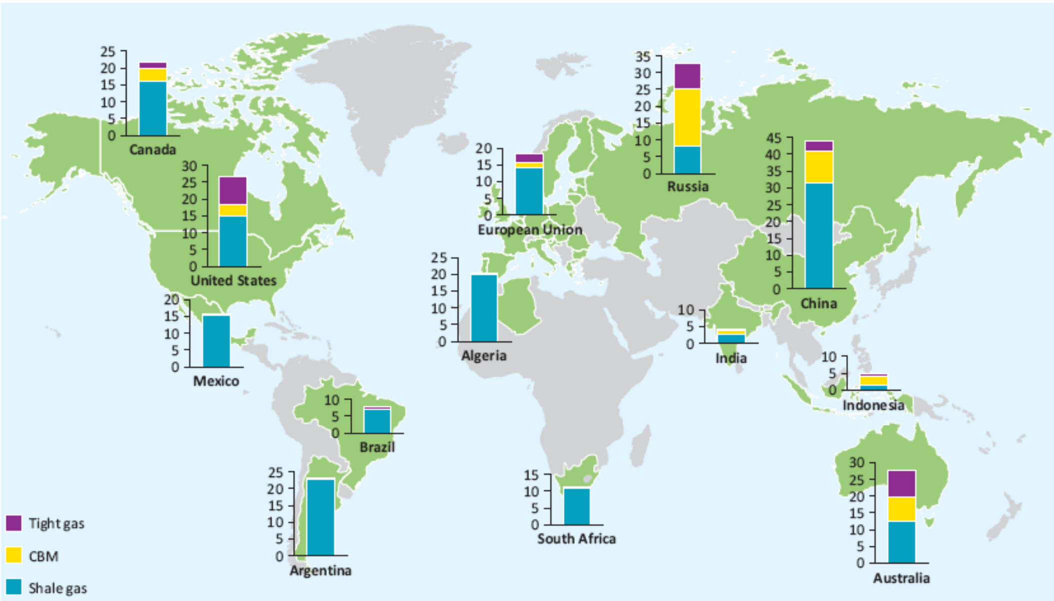
Shale gas resources in the world, as assessed by the EIA, amount to 31,138 tcf (881,730 bcm) of risked shale gas in place and 6,634 tcf (187,854 bcm) of Technically Recoverable shale gas.

The EIA estimates should be considered "risked", i.e. the methodology employed "recognizes the sparseness and uncertainty of data and includes conservative discounting of the potential resource". In other words, exploration activity has

[48] tcm = trillion cubic meters = 10^{12} m^3

been sparse in many shale basins, which means that no reliable seismic and well data are yet available.

FIGURE 44. Remaining unconventional gas resources in selected regions. End-2012 (tcm)

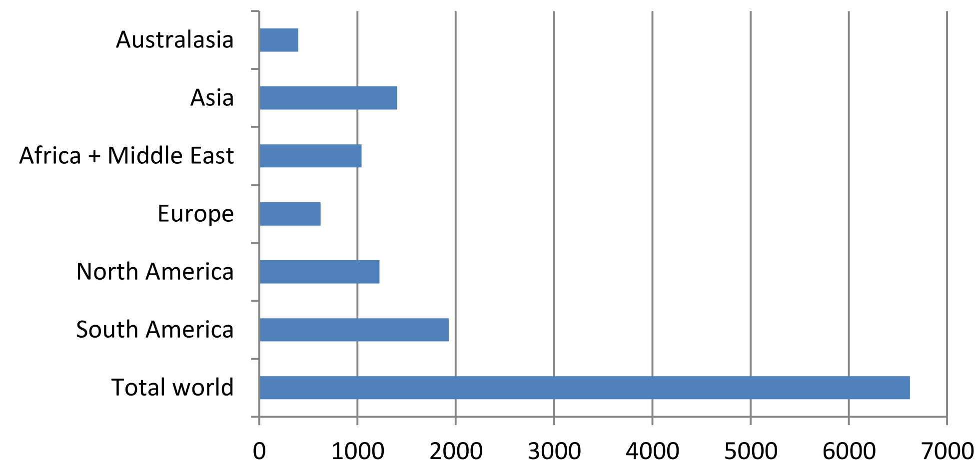


Source: (OECD/IEA, 2013)

The WEC estimate for total worldwide recoverable shale gas is 6,622 tcf (187,514 bcm) while the IEA estimates 208,000 bcm of shale gas in Technically Recoverable Resources (TRR).

The following figure shows the WEC's breakdown of resources and reserves by region.

FIGURE 45. "Risked" recoverable shale gas reserves by region in tcf (2011)



Source: Own elaboration from (WEC, 2013a)

The TABLE 9 compares the figures on worldwide TRR provided by various institutions in different units. It shows that worldwide shale gas resources stand in a range of between 188 and 212 tcm.

TABLE 9. Shale gas resources estimates by institutions[49]

	Worldwide Technically Recoverable Resources (TRR)		
	tcf	bcm	tcm
IEA	7,487	212,000	212
EIA	6,634	187,854	188
WEC	6,622	187,514	188

Source: Own elaboration from (EIA, 2013b; OECD/IEA, 2013; WEC, 2013b)

3.4.2. *United States*

Having looked at worldwide resources, we shall now turn to the estimates for the USA. In Section 1.2, we discussed the USA and the "Shale Gas Revolution". In that section we looked at shale plays in the USA and examined production and gas resources in the strategic framework. In this subsection, we shall limit ourselves to summarizing the main figures published by different institutions for technically recoverable resources of shale gas in the USA, as estimated by the EIA. These can be seen in the following table.

TABLE 10. Shale gas resource estimates by institution

	US Technically Recoverable Resources (TRR)		
	tcf	bcm	tcm
EIA	1,685	47,714	48
WEC	1,931	54,680	55
EU Joint Research Center	1,660	47,000[50]	47

Source: Own elaboration from (CNE, 2012; EIA, 2013b; JRC, 2013a; WEC, 2013b)

3.4.3. *Australia, Canada, Mexico, Argentina*

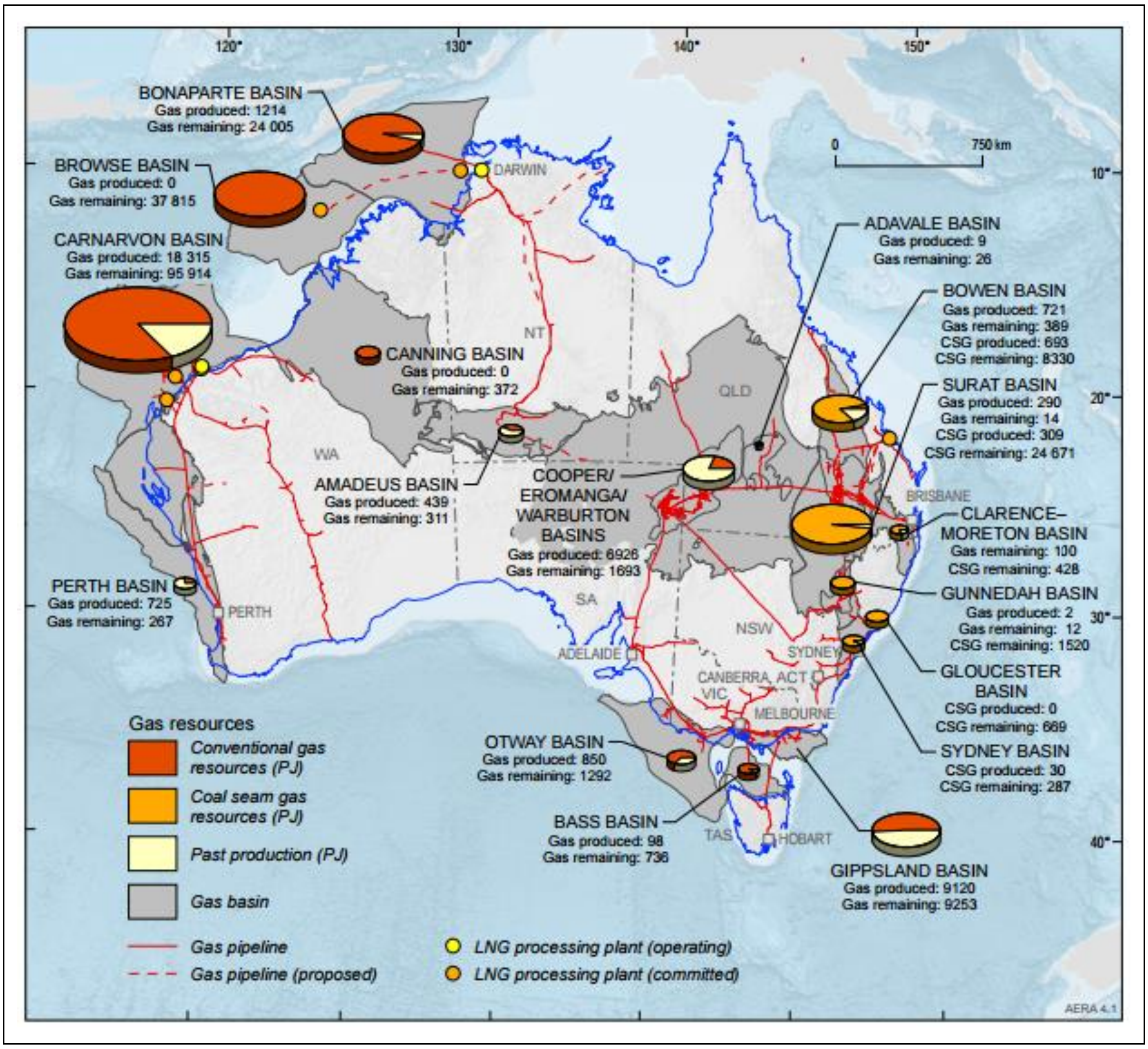
Australia

Australia has a number of sedimentary basins which are prospective for unconventional gas. Interest in unconventional gas has traditionally been limited, due to large conventional fields and small domestic markets. Many parts of Australia are unpopulated and lack even basic infrastructure such as roads, making exploration difficult and costly. However, in the longer term, this may make land-use conflict less of an issue and allow the development of resources, once markets recover and the local shale gas industry reaches critical mass.

[49]tcf = trillion cubic feet
bcm = billion cubic meters
tcm = trillion cubic meters
[50]47,00; 20,000; 13,000 (high, best and low estimation)

Unlike more densely populated continents, Australia's domestic natural gas markets are fragmented, with three structurally different and physically separate markets: Western; Eastern & Southern; and Northern Australia.

FIGURE 46. Natural gas basins, pipelines and LNG plants in Australia



Source: (Geoscience Australia and BREE, 2012) © Commonwealth of Australia (Geoscience Australia) 2015. This product is released under the Creative Commons Attribution 4.0 International License. http://creativecommons.org/licenses/by/4.0/legalcode

Western Australia's gas market, with almost half of the reserves, is essentially based on onshore production from the Carnarvon, Browse and Bonaparte basins. This production primarily supplies the external LNG market with smaller volumes going to the domestic market via pipeline to demand centers in the Southwest, Pilbara and Goldfields regions. The domestic gas plants are located in the north of the state and the gas is piped over 2,000 kilometers to end users in the south of the state. Domestic plants are linked to LNG projects and there is now a domestic gas reservation policy which requires new LNG proponents to supply the local market. Some gas is supplied via stand-alone domestic gas plants. A very minor amount of gas is produced for the domestic market by conventional onshore production in the Perth Basin.

The eastern and southern states (Queensland, New South Wales, Victoria, South Australia and Tasmania) are connected by an interlinked pipeline network supplied primarily by onshore production. The Cooper and Gippsland basins have been the traditional source of most of the gas supplied to these markets although these fields are now mature. Attention has shifted to the onshore Surat and Bowen basins where Coal Seam Gas reserves (CSG or CBM[51]) are almost entirely committed to meeting Liquefied Natural Gas export requirements over the next twenty years. As LNG facilities come into operation, the price of gas on the east-coast is expected to further "internationalize" as domestic prices shift upwards to levels more closely aligned with East Asian spot markets.

Finally, Northern Territory gas is sourced from offshore production in the Bonaparte Basin. This predominantly services markets in Darwin as well as a growing LNG sector.

In a study titled *Engineering Energy: Unconventional Gas Production,* the Australian Council of Learned Academics (ACOLA) noted that Australia has a number of basins which are prospective for shale gas resources, but there is a high degree of uncertainty. The EIA estimates that Australia has 437 tcf of technically recoverable shale gas resources.[52] Geoscience Australia and BREE forecasts an amount of 396 trillion cubic feet (tcf) of undiscovered shale gas (EIA, 2013b; Geoscience Australia and BREE, 2012).

The ACOLA study estimates are based only on data from four basins. However, if all prospective basins are taken into account, the amount could be in excess of 1000 tcf, which might include significant quantities of wet gas. Nonetheless, reliable economic reserves are not available due to the lack of exploration or drilling in most basins (ACOLA, 2013). In this context, further exploration will be important in order to turn prospective resources into contingent resources and then commercial reserves.

The Canning basin, in the north-west of Western Australia is thought to be the largest, although it remains largely unexplored. Its remoteness, with subsequently high exploration costs, has meant that active exploration and development has tended to coincide with periods of relatively high oil prices. Despite significant activity around 2012, there has been a slowdown in exploration which is now mainly being conducted by local companies.

The other focus of shale gas exploration has been in the Cooper basin, largely due to a longer industry presence as well as proximity to pipeline network

[51] Coal Bed Methane is referred to as Coal Seam Gas in Australia.
[52] Trillion cubic feet.

infrastructure and processing facilities. In 2012, Santos initiated the first commercial shale gas development with the Moomba-191 vertical shale well.

Despite a period of optimism and investment in exploration and seismic studies, the anticipated rapid expansion in shale gas has failed to materialize. Industry insiders expect that commercial quantities of shale gas may not begin to flow (most likely initially from the Cooper basin) until the 2020s. Development of the shale gas industry will probably proceed at a slow pace and will be linked to LNG price trends, cost structures and reform of regulation.

Like Canada and the USA, Australia's states wield considerable power over drilling and environmental regulations. There is significant disparity between states, with Queensland (home to numerous CBM operations) having the largest unconventional sector and the most established regulatory framework. Some states, including Tasmania, have opted to ban hydraulic fracturing. Western Australia permits hydraulic fracturing under existing legislation, but a review is currently being undertaken. Scarce fresh water and proximity to farmland have been the major flashpoints, resulting in restrictions and a very uncertain regulatory framework in New South Wales.

A recovery in Asian gas markets and an expected decline in conventional production in the Cooper basin are the most likely stimuli for a new wave of shale gas activity in Australia. Close interaction between LNG and domestic prices makes the debate on energy use and shale gas in Australia different to that in other jurisdictions.

Canada

Canada covers an area of ten million square kilometres (3.9 million square miles), making it the second largest country on earth. Some shale basins, such as Utica, straddle the border with the United States to the south.

Canada is a federation and there are significant differences in the regulation and treatment of shale gas between the different provinces (the equivalent of USA states) (Pickford, 2015).

As the world's fifth-largest producer of natural gas, Canada accounts for around 5% of global production and 30% of the country's energy needs are met by gas.

Existing production predominantly centres on the Western Canadian Sedimentary Basin, which includes British Columbia, Alberta, and Saskatchewan. Additional gas is produced from offshore Nova Scotia and smaller amounts are produced in Ontario, New Brunswick, and Nunavut. Whereas conventional natural gas is in general decline, production of Canadian unconventional natural gas has been increasing, albeit from a small base.

Geological data indicate that Canada has vast shale gas potential. However, most of these areas remain unexplored. In 2013, the US Energy Information Administration estimated that the country had 573 trillion cubic feet (tcf) of technically recoverable natural gas. (EIA, 2013b)

In 2012, shale gas accounted for 15 percent of total natural gas production in Canada. Combined with shale gas's 39% share of production in the USA, this makes North America the world's largest producer of shale gas. Nonetheless, shale gas production in Canada is still a new industry and not as widespread as in its southern neighbour. Production activities in Canada are primarily concentrated in western Canada and notable industry exploration has been pursued in only four provinces, so it has some way to go before it reaches its potential. (Parl.gc.ca, 2014)

British Columbia, on the west coast of Canada, produced a daily average of 2 bcf of shale gas and accounted for more than 25 percent of total Canadian production. This is concentrated on the Montney and Horn River basins in the northeast of the province. There is also some shale gas production in Alberta (less than 0.1 percent of Western Canada's production) and several exploration wells have been drilled in Utica shale (Quebec), Nova Scotia and New Brunswick (Atlantic Canada). (Parl.gc.ca, 2014)

Despite their proximity to Pennsylvania, which is producing significant volumes of shale gas from the Utica basin, Quebec, Nova Scotia and New Brunswick have effectively restricted gas exploitation. With powerful hydro-electric interests, these provinces have on occasions been the scene of violent protests against the industry and public acceptance is particularly low. Further growth in shale gas development in western Canada will be influenced by LNG export opportunities. However, as of mid-2015, a depressed gas price and regulatory uncertainty makes this unlikely in the short- to medium-term.

Despite the fact that the shale gas industry in Canada is still at an early stage, the National Energy Board estimates that production will increase from 0.47 bcf/d in 2011 to 4.03 bcf/d in 2035. By 2035, shale gas is expected to account for up to 24 percent of total Canadian gas production.

Mexico

Natural gas demand in Mexico is significant and the latest IEA report estimates an annual growth rate of 3.8% between 2014 and 2020 (95 bcm in 2020). Three quarters of this amount is forecast to come from the power industry.

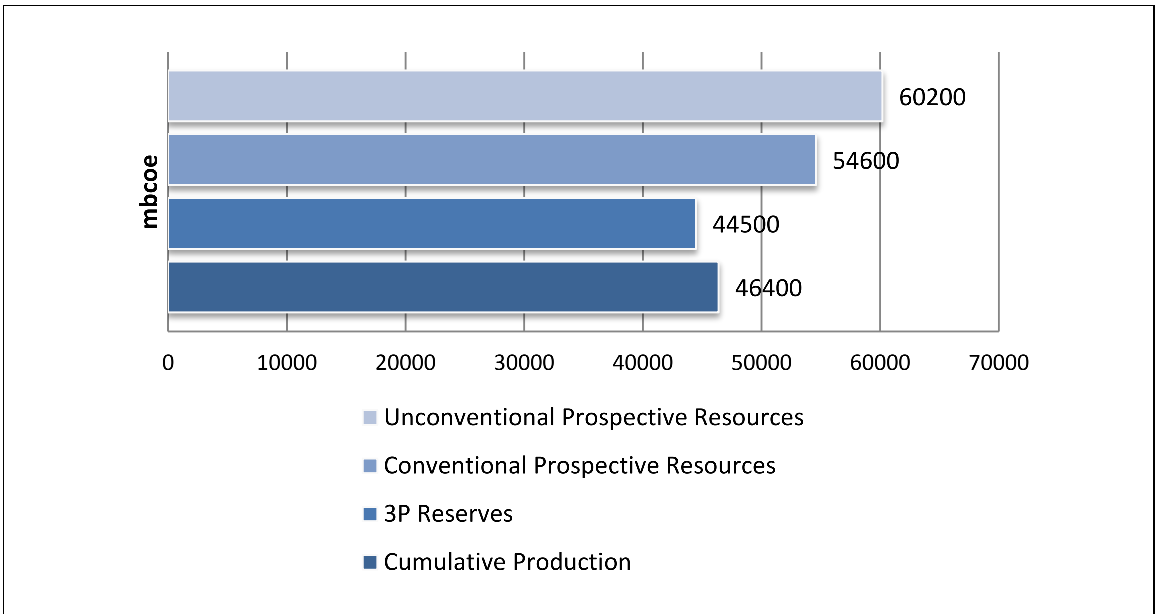
According to the EIA-2013's estimates, Mexico has the potential to produce hydrocarbons from shales throughout the onshore Gulf of Mexico region. Mexico's technically recoverable resources come to 545 tcf of natural gas and 13.1 billion barrels of oil and condensate. (EIA, 2013b) In 2013, these figures made Mexico one of the world's top ten countries in terms of technically recoverable unconventional resources.

By the end of 2014, estimates for potential shale gas resources in Mexico had fallen to 141.5 tcf (4 tcm), 74% and 79% down on the EIA's 2013 and 2011 estimates, respectively. Nonetheless, shale gas exploration is still of interest, as the country's resources exceed its proven reserves eightfold (481 bcm). These shale accumulations are mainly distributed in five major basins: Sabinas-Burgos-Picachos (1.9 tcm of shale gas and 0.6 bboe of shale oil), Tampico-Misantla (0.6 tcm of shale gas and 30.7 bboe of shale oil), Veracruz (0.6 bboe of shale oil) and Chihuahua[53] (CNH, Comisión Nacional de Hidrocarburos, 2014; Lozano-Maya, 2015).

The first exploratory shale gas well was drilled in 2011 (Coahuila) and was economically successful. Nonetheless, the geological structure of the basins is more complex in the east and south of Mexico and the potential is less certain (shale drilling has not yet occurred in these areas) (EIA, 2013b).

The latest data on Mexican resources and reserves are shown in the figure below. As can be seen, prospective resources (conventional and unconventional) together come to more than 100 billion barrels of crude oil equivalent (bboe).

FIGURE 47. Hydrocarbon resources and reserves in Mexico (million barrels of crude oil equivalent)



Source: (Budebo, 2015)

In February 2012, Mexico's Energy Strategy included shale gas in national energy planning for the first time and a new well basin in northern Mexico (Chuhuahua) was added to the EIA's previous assessment of 2011. However, despite a target of

[53] Data from the Chihuahua basin are not available in this reference.

drilling 20 exploratory wells by 2014, only seven gas wells had been drilled in Northern Mexico to February 2013, some of which were successful commercial producers (Lozano & APERC, 2013). At the end of 2014, more than 17 wells had been drilled in Mexico, of which 11 were declared as commercial in dry natural gas production, condensates, or both.

Given the country's potential for natural gas and oil, the new hydrocarbons law, included in the 2014 energy reform, allows private entrepreneurship, encourages investment and promotes domestic production. Development of the shale gas industry will partly depend on the investments and profitability of conventional and unconventional gas plays. In any event, the new liberalizing regulatory framework is positive for shale gas development in Mexico.

As the country's learning curve improves, labor, materials and technology costs are likely to fall. However, Mexico will also need to overcome a number of challenges, such as water availability and the creation of new infrastructures for marketing the extracted gas, as well as an improvement in the competitiveness of domestic production versus the gas imported from the USA.

However, all these challenges might represent an opportunity for the country. Mexico could improve North-American gas imports as a way of expanding its own market, growing inside a progressively more competitive environment, capable of encouraging domestic production in the long term (Lozano-Maya, 2015).

Argentina

Possibly the largest prospective shale gas resources outside North America are in Argentina, primarily in the Neuquen Basin (Vaca Muerta). There is additional shale resource potential in three other sedimentary basins (Parana, San Jorge and Austral-Magallanes) but as yet, these have not been tested (EIA, 2013b).

According to EIA estimates, Argentina has 802 tcf of risked shale gas in place out of 3,244 tcf of risked, technically recoverable shale gas resources. Risked shale oil in place resources are estimated at 480 billion barrels, of which about 27 billion barrels of shale oil may be technically recoverable (EIA, 2013b).

There have been significant exploration programs and early-stage commercial production is underway in the Neuquen Basin by Apache, ExxonMobil, TOTAL, YPF and smaller companies. The marine-deposit black shales in Vaca Muerta formations have been tested with approximately 50 wells to date, with mostly good results (EIA, 2013b).

The Neuquen basin covers an area of approximately 120,000 square kilometers on the border between Argentina and Chile and holds 35% of the country's oil reserves and 47% of its gas reserves. Within this basin, the Vaca Muerta shale formation holds as much as 240 trillion cubic feet of exploitable shale gas.

To date, 412 wells have been drilled to explore unconventional hydrocarbons, 94% for oil and 6% for natural gas. 91% of all these wells were drilled vertically with five hydraulic fracturing steps (López Anadón, 2015). In September 2014, the Loma Campana area, which covers 1% of the land area in Vaca Muerta, contained 245 wells, producing more than 20,000 boe/day.

The development of more efficient technology has allowed operators to cut drilling costs (7.5 million dollars per well so far) and construction times (the new equipment has sped up transport from one site to another). These developments have helped make Loma Campana the largest commercial unconventional oil development outside the USA (A. Pérez, 2014; US Energy Information Administration, 2015b).

However, as the Argentine Oil and Gas Institute explained at the World Gas Congress 2015 (Paris), Argentina still has a number of goals to achieve in order to develop this industry further. Certain provisions of the Hydrocarbons Act would need to be modified, since existing regulation does not allow concession periods to be extended and most expire between 2015 and 2017. This makes exploration works more difficult and the country is therefore working on a series of changes, such as the establishment of new schedules depending on the type of resource (25 years for conventional resources, 35 years for unconventional and 30 years for offshore resources). Furthermore, provinces could extend their permits for an additional 10-year period and production royalties would be increased by up to 18%.

Some logistical aspects also need improving, *inter alia* the capacity of the existing infrastructures to evacuate output; the availability of drilling and fracturing equipment; a skilled workforce; productivity; and access to international markets (López Anadón, 2015).

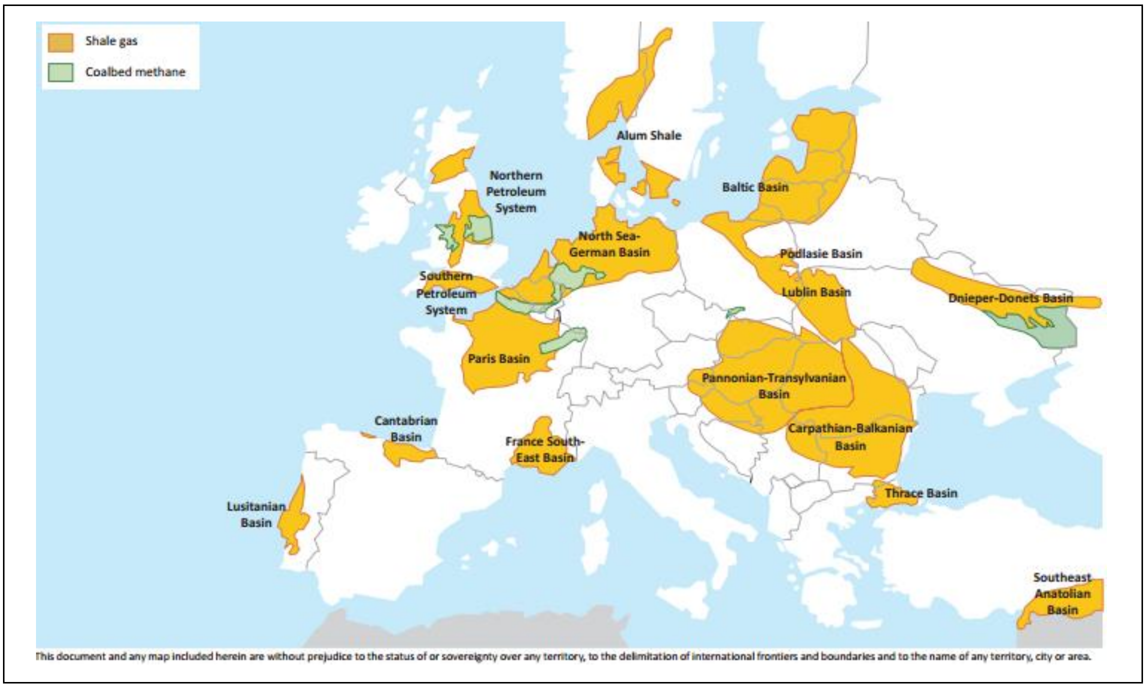
3.4.4. *Europe*

The FIGURE 48 shows different shale basins in Europe. These basins are not necessarily technically or economically recoverable and the map mainly shows the existence of shale gas in place (GIP).

In the case of Europe, the EIA estimates 4,897 tcf (138,668 bcm) of risked shale gas in place and 882 tcf (24,975 bcm) of technically recoverable shale gas. As can be seen, the quantities of risked shale gas in place are larger than those of technically recoverable shale gas.

According to the WEC, recoverable reserves of shale gas in Europe (see TABLE 11) amount to 624 tcf (17,670 bcm). In contrast, European shale gas resources are estimated at 14,000 bcm (494.40 tcf).

FIGURE 48. European shale gas basins



Source: IEA, 2012

The table below summarizes different estimates for technically recoverable resources of shale gas in Europe.

TABLE 11. Shale gas resources estimations by institution

	Technically Recoverable Resources in Europe (TRR)		
	tcf	bcm	tcm
EIA	882	24,975	25
WEC	624	17,670	18
EU Joint Research Center	622	17,600[54]	18

Source: Own elaboration from (EIA, 2013b; JRC, 2012; WEC, 2013b)

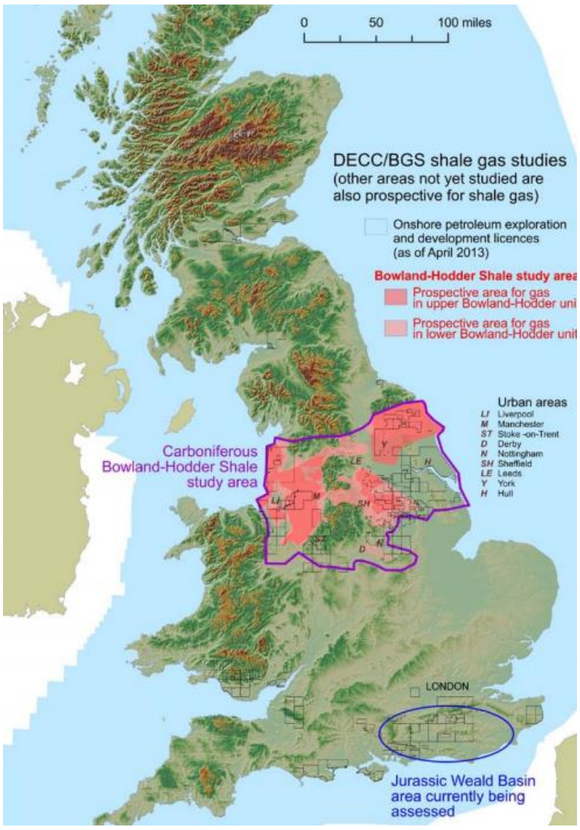
United Kingdom

The British Geological Survey (BGS) has published a study (BGS & DECC, 2013) analyzing the potential of the Carboniferous Bowland shale play in the United Kingdom (UK), shown in the map below (FIGURE 49). This study focuses on the Bowland basin and other British basins with potential for shale gas production.

The study explains the methodology used to determine shale gas reserves and resources. For the purposes of resource estimation, the Bowland-Hodder unit is divided into two units: an upper post-rift unit in which laterally contiguous, organic-rich, condensed zones can be mapped, even over the platform highs, and an underlying syn-rift unit, expanding to thousands of feet thick in fault-bounded basins, where the shale is interbedded with mass flow clastic sediments and re-deposited carbonates. The FIGURE 49 shows the location of this dominium.

[54] 17,000; 15,900; 2,300 (high, best and low estimation).

FIGURE 49. Location of the DECC/BGS study area in central Britain



Source: (BGS & DECC, 2013)

The results of this study are set out in the following table. [55]

TABLE 12. Shale gas results of Carboniferous Bowland shale gas study

	Total gas-in-place[56] estimates (Tcf)			Total gas-in-place estimates (Tcm)		
	Low (P90)	Central (P50)	High (P10)	Low (P90)	Central (P50)	High (P10)
Upper unit[57]	164	264	447	4.6	7.5	12.7
Lower unit[58]	658	1065	1834	18.6	30.2	51.9
Total	822	1329	2281	23.3	37.6	64.6

Source: (BGS & DECC, 2013)

[55]The EIA estimates a potential of 26 tcf (736 bcm) of shale gas Technically Recoverable Resources in the UK. The very sustainable difference with the BGS may be due to the difference between GIP and TRR and the number of plays assessed.

[56] **Gas-In-Place (GIP)** refers to the entire volume of gas contained in the rock formation, not the amount that can be recovered.

[57] **Upper unit**: port-rift unit in which laterally continuous organic rich, condensed zones can be mapped, even over the platform highs. This unit is more prospective and its productive zones are hundreds of meters thick.

[58] **Lower unit:** Underlying syn-rift unit, expanding to thousands of meters thick in fault-bounded basins, where the shale is interbedded with mass flow clastic sediments and re-deposited carbonates. This unit is largely undrilled, but in those zones where it has been penetrated, there are organic-rich shale intervals, whose lateral extent is unknown. (BGS & DECC, 2013)

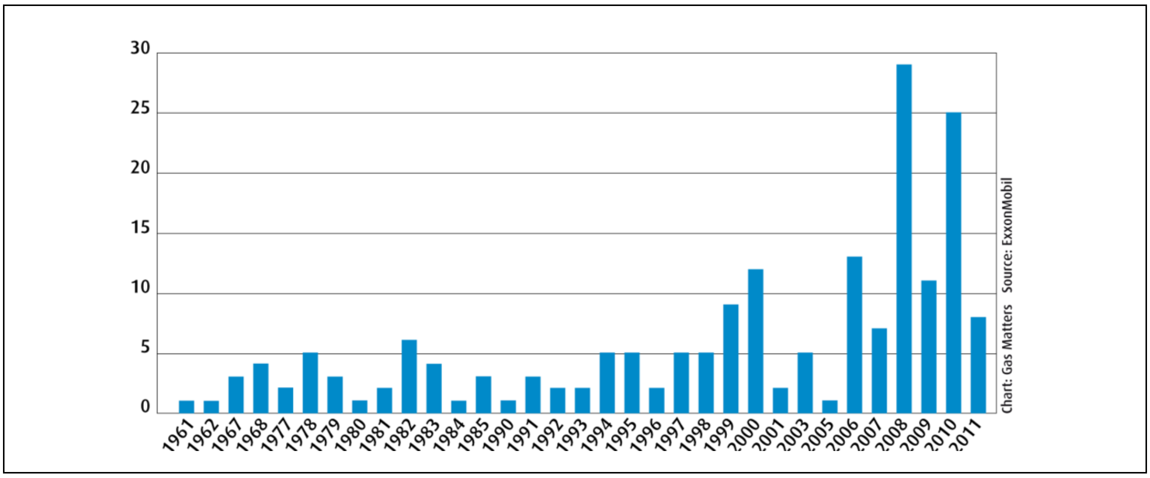
Germany

The *Bundesanstalt für Geowissenschaften und Rohstoffe* (BGR) is entrusted with official research and data gathering on resources in Germany. It published its first report on potential resources and reserves in May 2012.

Total shale gas resources (GIPs) are estimated to lie within a range of between 6,800 bcm and 22,600 bcm, Based on US experiences BGR estimates that 10% of the resources could be technically produced. That would give prospective resources of 700 to 2300 bcm, which would enormously boost German gas reserves.[59] As can be seen in TABLE 12, the EIA's estimates for Germany are for 17 tcf (481,38 bcm) of shale gas TRR.

German shale gas resources are very likely to be of a magnitude that makes further exploration activity worthwhile, but there is a *de facto* fracking moratorium in place, which currently allows no assessment of the technical and economic potential of these resources[60]. The global discussion on shale gas and dwindling indigenous production from conventional resources is keeping the discussion on shale gas alive. On 1st April 2015 the German government introduced a bill regulating hydraulic fracturing in Germany. The bill will be debated in the German parliament and there may be some amendments before it is finally approved (Gas Matters, 2013) (Shale Gas Information Platform (SHIP), 2015).

FIGURE 50. Number of fracs in Germany



Source: (Gas Matters, 2013)

[59]ExxonMobil is the most active promoter of shale gas in Germany. After acquiring the US shale gas producer XTO Energy in 2010, it began to assess the potential for shale gas production. Exxon has the largest interest because it is the largest producer of natural gas in Germany, and has already carried out some exploration with fracking technology in Lower Saxony.
The German gas exploration and production (E&P) industry likes to point out that fracking has been conducted in Germany since the 1960s to produce tight gas. Fracking is used for roughly one third of current indigenous production, and since 2010 a number of wells have been fracked during exploration of shale gas resources (Gas Matters, 2013).

[60] Legally no law or ban in this regard has been passed in Germany but the administration has been advised not to process any applications and permits until the legal situation is fully resolved.

As the FIGURE 50 shows, hydraulic fracturing techniques have been used in Germany since the 1960s for conventional gas production. This experience has resulted in more than 150 hydraulic fracturing jobs –six for shale gas exploration– reaching depths of 5000 meters in some cases. Indeed, hydraulic fracturing is still permitted in Germany for conventional gas production (Rice-Jones, 2015; Shale Gas Information Platform (SHIP), 2015).

Poland

Finally, Poland is the European country where shale gas exploration works have been developed to the greatest extent. In 2013, the EIA estimated the country's shale gas TRR at 148 tcf (4,190.89 bcm).[61]

The most promising prospective shales in the country, which may contain unconventional oil and gas reserves, are found in three sedimentary basins: Baltic, Podlasie and Lublin. These basins show a similar vertical facies pattern to the lower Paleozoic succession and a relatively simple tectonic setting.

The oldest formations, located in the lower part of the basin's section, are the Upper Cambrian to Tremadocian bituminous shale, developed only in the northern part of the onshore Baltic Basin and in its offshore part. This shale is a source rock for conventional hydrocarbon fields in the Middle Cambrian reservoir. However, its thickness is limited, particularly in the onshore part of the basin, with a maximum of only several meters, while in the Polish offshore sector it is up to 34 m thick.

The next most organic-rich shale formation is the Upper Ordovician shale, mainly Caradoc, developed in the central and western part of the Baltic Basin, as well as in the western part of the Podlasie Basin. The Upper Ordovician shale thickens from the east to the west and north-west: in the Baltic Basin onshore it grows from 3.5 m to 37 m and offshore from 26.5 m to 70 m while in the Podlasie Basin and the basement of the Płock-Warszawa Trough it increases from 1.5 m to 52 m.

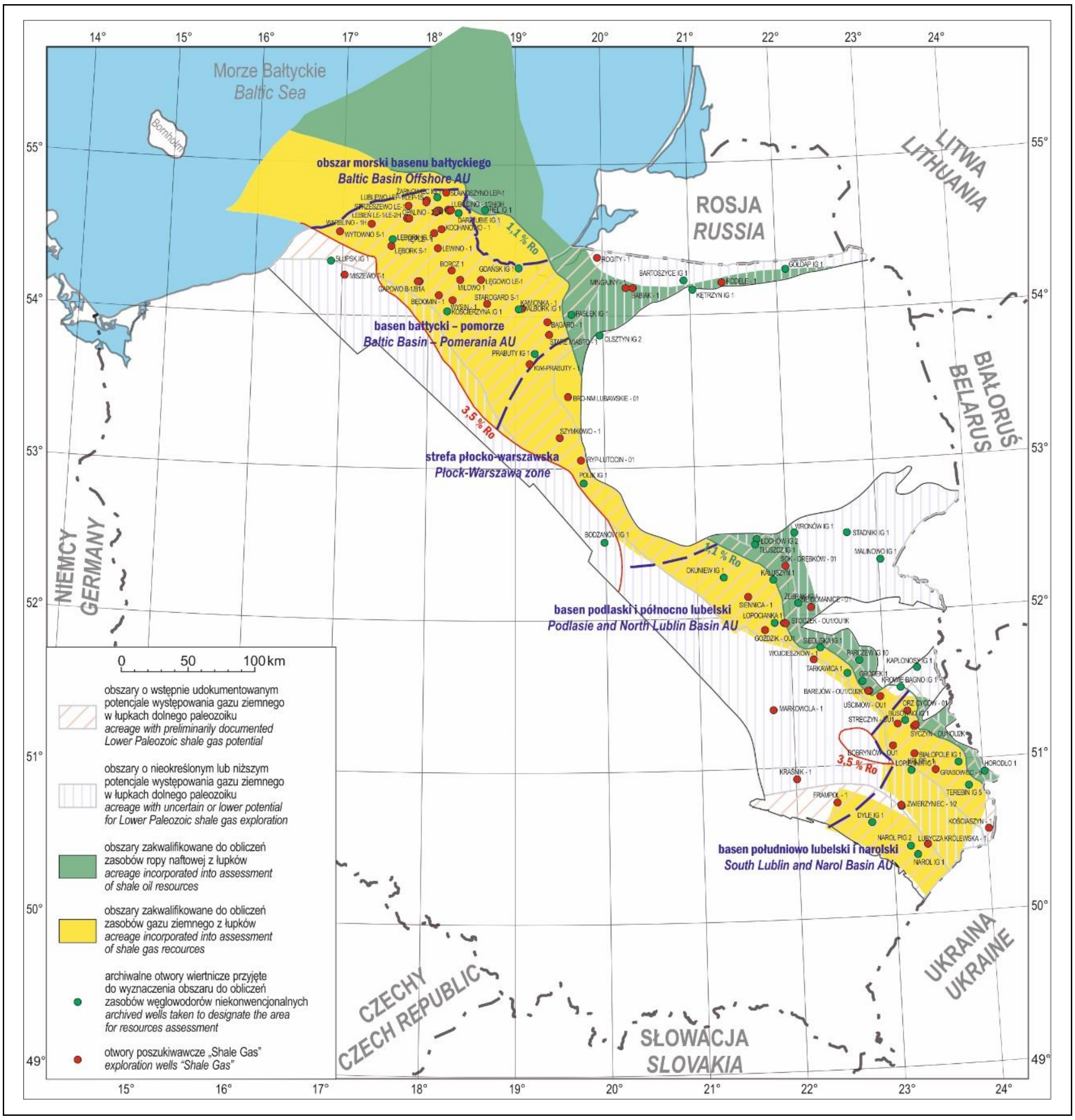
The last prospective formations in the lower Paleozoic are Wenlock claystones and mudstones. The lateral thickness of these sediments varies significantly from less than 100 m in the eastern part of the Podlasie Basin and Lublin Basin to more than 1000 m in the western part of the Baltic Basin.

In general, the burial depth of the Upper Ordovician and Lower Silurian shale increases from east to west. In the Polish part of the Baltic Basin the recent burial depth of these formations increases from approximately 1000 m in the eastern part to more than 4500 m in the western part. In the Podlasie Basin the recent depth of this formation also increases from the east, where it is approximately

[61]BNK Petroleum has six shale-gas concessions in Poland. It has drilled five wells in the Baltic basin and is hoping to spud another well in the fourth quarter of 2013. However, its plans depend on the government, which has not yet approved drilling (Petroleum Economist, 2013).

5000 m, to the west where it reaches 4000 m near Warsaw. In the Lublin Basin, lateral changes in the burial depth of the Lower Paleozoic shale are more complex due to the presence of a system of faults with significant offsets limiting individual tectonic blocks, as well as considerable lateral differences in the thickness of younger sediments resting on the analyzed complex. Generally the depth of shale in the Lublin Basin increases from around 1000 m to 3000-3500 m.

FIGURE 51. Distribution map of oil- and gas-prone areas in the Ordovician-Silurian basin divided into segments representing separate assessment units



Source: (Dyrka, Roszkowska-Remin, & PGI-NRI, 2015; Kiersnowski H., 2013)

Like burial depth, revealed thermal maturity of the Lower Paleozoic shale in the Baltic-Podlasie-Lublin Basin increases from east and north-east to west and south-west (Nehring-Lefeld et al., 1997; Swadowska & Sikorska, 1998; Grotek, 2006), gradually going from immaturity, through the oil window and wet gas window to the dry gas window and even overmaturity near the western margin of the East European Craton (Dyrka et al., 2015).

In 2012, the Polish Geological Institute – National Research Institute carried out an assessment of shale gas and shale oil resources in Poland. Recoverable shale gas and shale oil resources from the onshore and offshore Baltic – Podlasie – Lublin Basin are estimated at a maximum of 1920 bcm (1.92 tcm) and 535 million tons (3905 million barrels) respectively. Taking into account the constraints on key parameters of the calculations, the highest probability range of recoverable resources is 346 - 768 bcm (PGI-NRI Report, 2012) for shale gas and 215 – 268 million tons (1569 – 1956 million barrels) for shale oil.

These three basins are the object of advanced drilling operations to identify their unconventional hydrocarbon potential. The group conducting the most intense exploration for unconventional oil and gas deposits includes PGNiG, PKN Orlen, BNK Petroleum, Chevron, ConocoPhillips, San Leon Energy and 3Legs Resources, which have drilled 69 test boreholes over the past few years (Dyrka et al., 2015).

shows the Polish sedimentary basins and well locations. The red dots indicate wells drilled for shale gas exploration, with green dots showing wells drilled to designate the area for resource assessment. The yellow area is the zone studied for shale gas determination and the green one for shale oil.

3.4.5. *Spain and the Basque Country*

The methodology used by the ACIEP to estimate the resources and reserves of oil and gas is explained below (ACIEP & GESSAL, 2013). To assess hydrocarbon potential, Spain is divided into domains based on geological and geographical criteria, identified according to their exploration implications as being either Onshore (land area) or Offshore (sea area). These domains have been established as the exploratory concepts to be used for evaluating conventional and non-conventional resources.

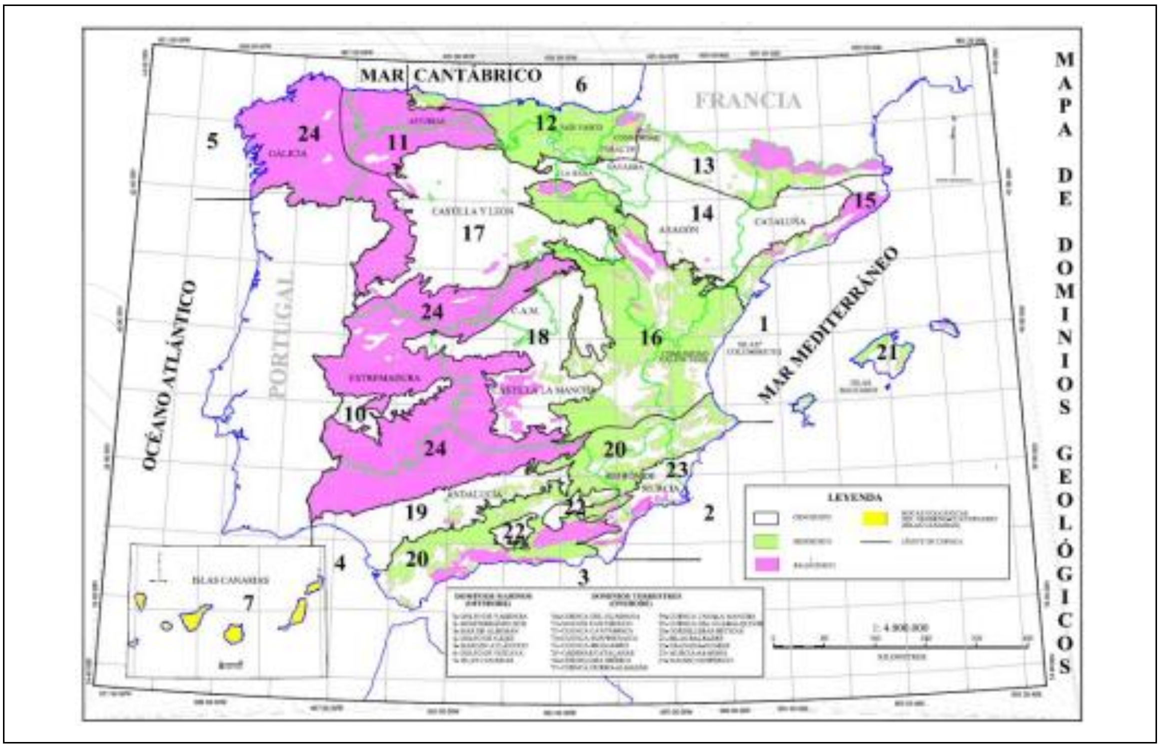
Calculation of prospective unconventional shale gas resources takes into account a maximum formation top depth of less than 4,000 meters and a formation thickness of over 50 meters.

The ACIEP estimates the recoverable volumes based on geological knowledge of the area and establishes a minimum to maximum range using the following procedure: calculation of the total volume of rock from a specified area and thickness, and determination of the average density from well-logging. The tonnage of rock is calculated from the volume and density data. This value is used to quantify the cubic meterage of gas per ton of rock and the percentages of free and adsorbed gas. These data are supplemented with data from the scientific literature based on experiences in the United States (Jarvie, 2012).

A range of values in bcm of raw gas (GIP) is subsequently used to apply a recovery factor of 0.16 (low), 0.22 (medium) and 0.24 (high). The mean values for the “Barnett Shale" unit, considered as a reference for calculating the EUR, are used. Finally, these results are multiplied by a factor of reliability for the input data, ranging from 0.95 for well-known concepts to an intermediate degree of 0.8 and 0.6 for lower levels of knowledge.

The different basins in Spain and the domains covered in the study are shown in the map below (FIGURE 52).

FIGURE 52. Distribution of geological domains in Spain



Source: (ACIEP & GESSAL, 2013)

Taking these domains into account, the estimated resources are shown in the following table.

Based on the data in TABLE 13, Spain has an estimated 1,977 bcm (70 tcf) of recoverable shale gas. This figure does not include other unconventional gases such as tight gas and coal bed methane (CBM). Total prospective resources of unconventional gas in Spain are estimated at 2,026 bcm (71 tcf), of which 41 bcm correspond to CBM and the remaining 7 to tight gas.

It may be helpful to look at drilling activity in Spain, since on the one hand, it shows the basis of the estimates, and on the other, it highlights how little drilling has been undertaken in Spain as compared to other countries.

TABLE 13. Summary of prospective shale gas resources

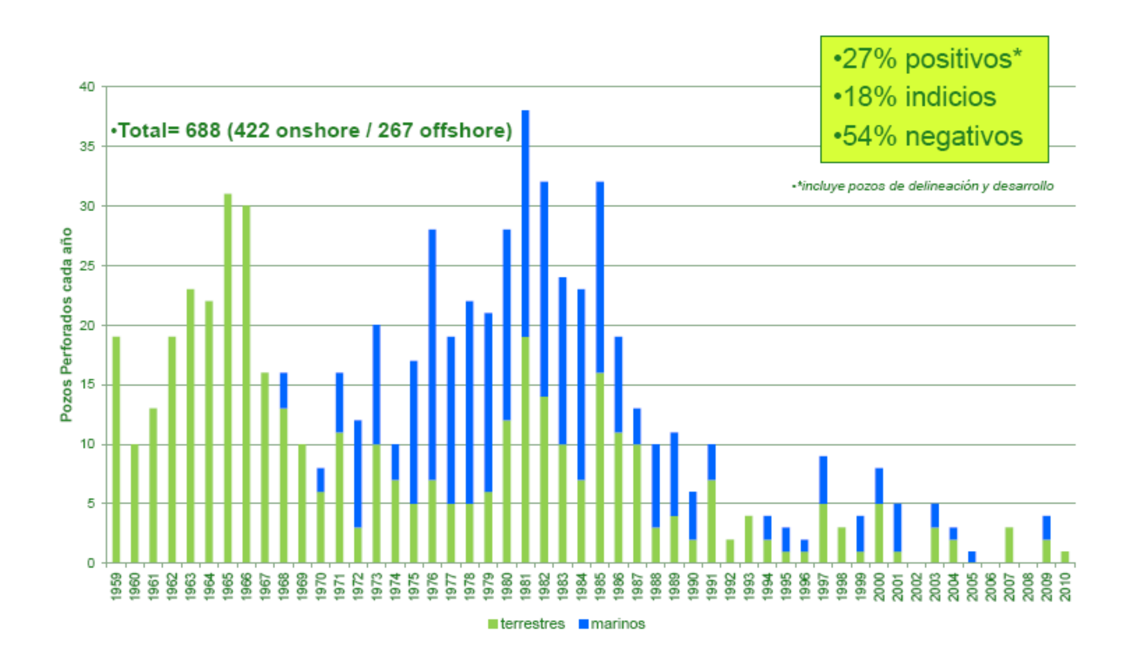
	Prospective resources	
GEOLOGICAL DOMAINS	**tcf**	**bcm**
Basque-Cantabrian Basin (12)	38[62]	1,084
Pyrenees (13)	9	260
Duero Basin (17)	3	72
Ebro Basin (14)	1	32
Iberian Chain (16)	3	95
Catalan Coastal Ranges (15)	1	15
Guadalquivir Basin (19)	3	79
Betic Basin (20.21.22.23)	-	-
Hesperian Massif (24)	12	340
TOTAL	70	1.977

Source: (ACIEP & GESSAL, 2013)

Note: Prospective resources are explained in Appendix 3 (Resources and reserves: some definitions).

The figure below shows trends in well drilling from 1959 to 2010. Since 1999 there has been practically no activity and, in some years, no wells at all were drilled.

FIGURE 53. Wells drilled in Spain



Note: Pozos perforados cada año = Drilled wells per year; positives = positive; Indicios = shows; Negativos = negative.

Source: (Martin, 2013)

[62] Clearly higher than the 8 tcf given in (Deloitte, 2013), which only includes the Jurassic play of the Basque Cantabrian Basin. The ACIEP takes into account more than one play, so Spanish resources are underrated in Table 15.

Finally, we will examine the available information on potential shale gas resources in the Basque-Cantabrian Basin. The FIGURE 54 below shows a map of Spain with the shale gas basins identified by the EIA, highlighting the Basque-Cantabrian Basin. Although we have already referred to the domains established by the ACIEP, mention must also be made of the EIA's figures, given its description of the Basque Cantabrian Basin and the widespread dissemination of its findings.

FIGURE 54. Spain shale gas basins

Source: (EIA, 2013b)

The EIA considers that the Basque Cantabrian Basin contains a series of organic-rich Jurassic-age shales with potential for wet gas and condensate. The Jurassic-age (Liassic) marine shale in the Basque-Cantabrian Basin contains an estimated 42 tcf (1,190 bcm) of risked shale gas resource in place, with a risked technically recoverable shale gas resource of about 8 tcf (227 bcm) (Table 14). (EIA, 2013a)

TABLE 14. Shale gas reservoir properties and resources of Spain

Basic Data	Basin/Gross Area		Basque-Cantabrian (6.620 mi²)
	Shale Formation		Jurassic
	Geologic Age		L – M. Jurassic
	Depositional Environment		Marine
Physical Extent	Perspective Area (mi²)		2,100
	Thickness (ft.)	Organically Rich	600
		Net	150
	Depth(ft.)	Interval	8,000 - 14,500
		Average	11,000
Reservoir properties	Reservoir pressure		Slightly Overpressed
	Average TOC (wt. %)		3.0%
	Thermal maturity (% Ro)		1.15%
	Clay Content		Medium
Resource	Gas Phase		Wet gas
	GIP Concentration (bcf/mi²)		49.8
	Risked GIP (tcf)		41.8
	Risked Recoverable (tcf)		8.4

Source: ARI, 2013 in (EIA, 2013b)

The entire package of Jurassic shales, including the Lias Shale, within the 2,100 mi^2 [63] prospective area of the Basque-Cantabrian Basin has a resource concentration of about 50 bcf/mi^2 of wet shale gas and 3 million barrels/mi^2 of shale condensate.

Other shales in the Basque Cantabrian Basin include the Cretaceous Shales. The thick Cretaceous-age (Albian-Cenomanian) Valmaseda Formation holds an estimated 185 bcm (6.5 tcf) of shale gas based on a study of 13 wells in the Gran Enara field in northern Spain (EIA, 2013b).

According to ACIEP, the Basque-Cantabrian Basin has a potential of 1,084 bcm (38 tcf). The major difference with the EIA estimate (8 tcf) is due to the fact that the EIA based its estimate on only one play, the Jurassic one (see TABLE 14 and TABLE 15), whereas the ACIEP analyzed different plays in Spain.

TABLE 15. Top countries with technically recoverable shale gas (tcf)

Country	Tcf	Plays assessed
US	1161	17
China	115	18
Argentina	802	6
Algeria	707	11
Canada	573	13
Mexico	545	8
Australia	437	11
South Africa	390	3
Russian Federation	287	2
Brazil	245	3
Venezuela	167	1
Poland	148	5
France	137	3
Ukraine	128	3
Libya	122	5
Pakistan	105	2
Egypt	100	4
India	96	4
Paraguay	75	1
Colombia	55	3
Romania	51	2
Chile	48	1
Indonesia	46	7
Bolivia	36	1
Denmark	32	1
Netherlands	26	3
United kingdom	26	2
Turkey	24	2
Tunisia	23	2
Bulgaria	17	1
Germany	17	2
Morocco	12	2
Sweden	10	1
Spain	**8(69.8)**	1
Western Sahara	8	1
Jordan	7	2
Thailand	5	1
Mongolia	4	2
Uruguay	2	1
Norway	0	1
	7797	158

Note: Spanish data are from the Basque Cantabrian Basin.

Source: (Deloitte, 2013)

The TABLE 15 lists countries by their estimated technically recoverable shale gas resource. These figures were calculated by the EIA (data in bcm are reflected in

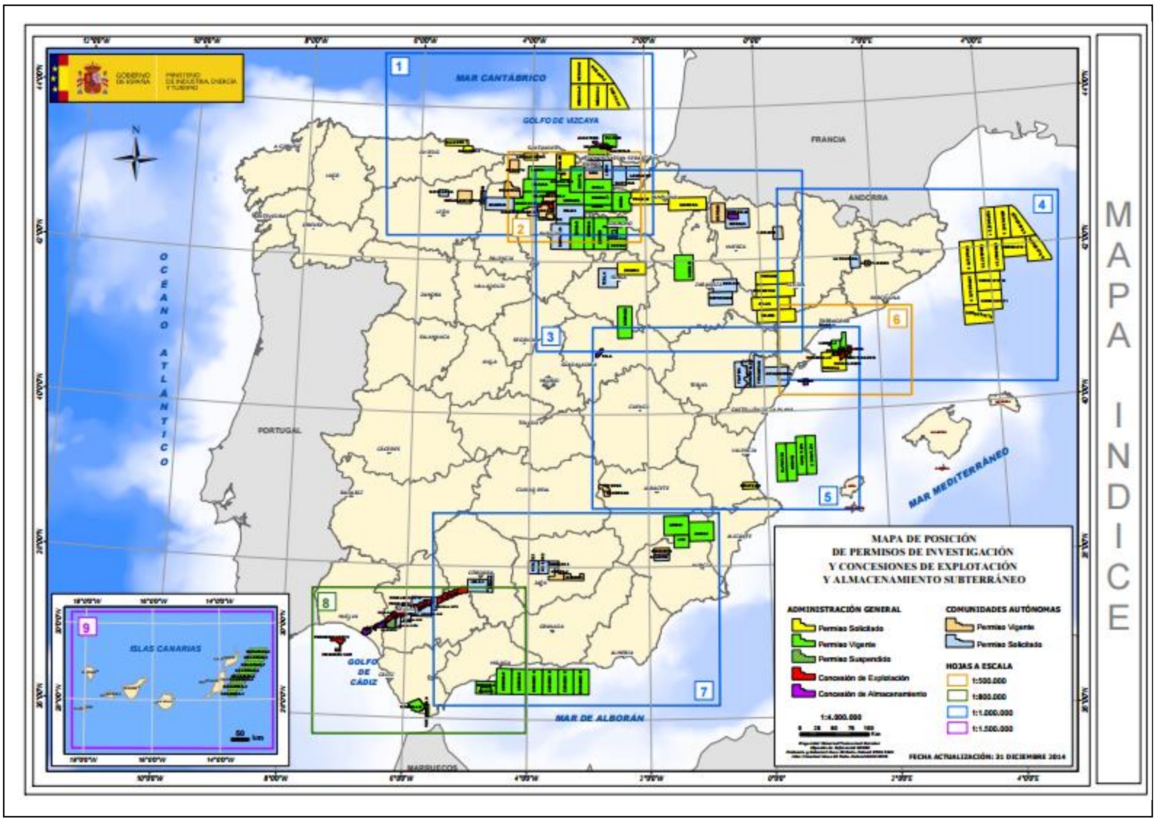
[63] mi^2 = square mile

this chapter in each section). As explained above, the estimate for Spain is based on only one play and does not reflect the country's real potential[64].

Despite the low level of drilling activity, oil and gas companies have shown considerable interest in shale gas in Spain, as can be seen in the following figure, illustrating Spanish map exploration permits active in 2013. The high level of activity in the Basque-Cantabrian basin is obvious.

In December 2014, there were 70 hydrocarbon exploration permits in Spain, with a further 75 applications still pending. This represents an overall increase of 80% in exploratory interest in just five years, according to the ACIEP[65].

FIGURE 55. Exploration permits in Spain (December 31st, 2014)



Source: (Ministerio de Industria, Energía y Turismo, 2015)

3.5. Some conclusions

This chapter uses a wide set of definitions, all of which make a clear distinction between reserves and resources. In distinguishing between proven and unproven reserves a key factor is the existence of drilling, and (for proven reserves), the economic and commercial feasibility.

[64] 1 bcm = 0.0353 tcf
1 tcf = 28.3 bcm

[65] These figures were presented at the Second Annual East Atlantic Oil and Gas Summit 2013.

Worldwide, North America is clearly the leading continent in the exploration and production of unconventional hydrocarbons, with a predominance of USA. Other countries are making significant advances although at different rates. In this respect, some projects deserves special attention, such as the production of CBM in Australia and the recent developments in Loma Campana (Argentina), where the exploration has obtained commercial results with considerable reduction of drilling costs.

Studies of shale gas reserves in Europe are still at an early stage, and perhaps the most extensive data are those published by the EIA. Studies have been conducted by the BGS in the UK (for the Bowland Basin), the BGR in Germany, the Polish Geological Institute in Poland and the ACIEP in Spain.

The table below gives a summary of the most representative data, showing technically recoverable resources by regions and institutions, expressed in bcm.

TABLE 16. Summary of Technically Recoverable Resources of Shale Gas (bcm)

	EIA	WEC	EU Joint Research Center	ACIEP	IEA
Worldwide	187,854	187,514	-	-	212,000
US	47,714	54,680	47,000	-	-
Europe	24,975	17,670	17,600	-	-
Germany	481	-	-	-	-
Poland	4,191	-	-	-	-
UK	736	-	-	-	-
Spain	227	-	-	1,977	-
Basque Cantabrian Basin	-	-	-	1,084	-

Source: Own elaboration

Poland is the most advanced country in shale gas exploration in Europe. With more than 70 wells drilled, Poland still has to continue with the exploration in order to better define the potential of hydrocarbons in the three sedimentary basins that have been assessed.

In the Spanish case, historically there is no much much tradition of assessment by seismic surveys and for significant drilling. Indeed, very few wells have been drilled in Spain since 1990. It is therefore not possible to make a rigorous estimate of proven reserves until sufficient seismic studies and drilling have been carried out.

However, in terms of resources, based on geological information and studies, there are sufficient grounds for believing that there are significant resources, which could become reserves and proven reserves with seismic surveys and drilling. The key element here is to advance in the research and exploration in order to determine the real potential.

The data compiled to date by the ACIEP shows that there are potential reserves, in particular, in the Basque-Cantabrian Basin. Any comparison of the potential supply with a possible substitution of actual demand in Spain measured in years (the equivalent of the Reserves/Resources ratio) may prove biased if compared to total energy demand, and it would be more advisable to compare it to a percentage of substitution of domestic demand.

4. TECHNOLOGIES IN UNCONVENTIONAL GAS EXPLORATION "SHALE GAS"

This chapter describes the general issues related to exploration activities, and the design and drilling of an exploration well, its main components and activities, vertical and horizontal drilling and their applications in the exploration of unconventional hydrocarbons.

Basically, exploration consists of a series of techniques ranging from geophysics to drilling designed to determine the potential of gas in the subsurface. Based on the information obtained, future exploration wells can then be planned.

Hydraulic fracturing –or "fracking"– is a reservoir stimulation technique, initially used during the exploration phase to assess the potential of unconventional oil and gas reservoirs. Hydraulic fracturing is not a drilling process. The fracking equipment arrives on site only after the drilling rig has been demobilized, all core and cuttings samples have been analyzed, petrophysical studies completed and the fracturing propagation model and treatment program designed.

4.1. Exploration

Exploration includes a number of different techniques ranging from geological surveys to the application of chemistry to the study of the terrain using geochemical techniques.

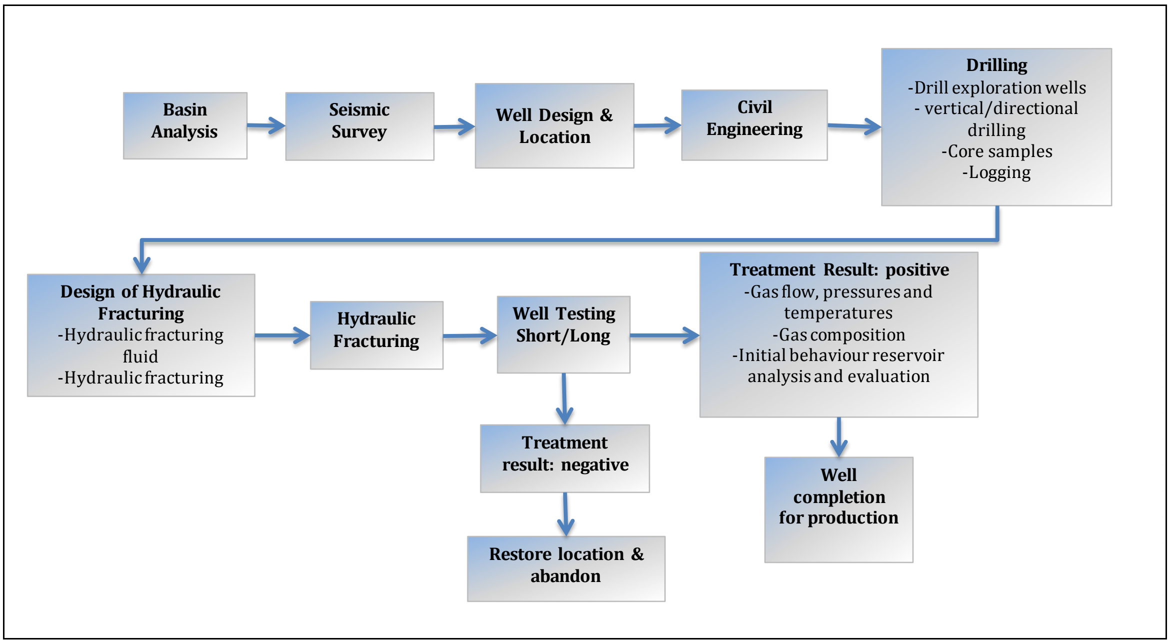
Exploration also involves geophysics, with the use of gravity meters to collect data that can be used to define the regional tectonic regime and prioritize areas for seismic work, and magnetometers –which are very sensitive to rocks containing highly magnetic material– to measure the strength of the earth's magnetic field at a given location.

The flow chart of the exploration process may help to follow Chapters 4 and 5. (See FIGURE 56)

Using some or all of these techniques an area of interest can be identified. An exploration well is then bored at the site to determine whether or not the target geological formation contains hydrocarbons.

Seismic data are of critical importance. They are the only widely-used data that give a comprehensive –albeit fuzzy– picture of the underground geology of the whole area of study. Few gas fields have been discovered in recent decades without the aid of seismic data and it is difficult to conceive exploration and production of gas today without them (Gluyas & Swarbrick, 2007).

FIGURE 56. Diagram of the different phases in the exploration process



Source: Own elaboration

Seismic imaging of the earth's shallow structure uses energy waves generated by a sound source and collected some distance away. A typical sequence of seismic acquisition from basin entry to production is as follows. Regional two-dimensional (2D) lines are shot through the basin. 2D seismic information is obtained across the area licensed by the exploration company. Following a gas discovery by drilling, 3D or possibly further 2D seismic acquisition will be undertaken if the detail from the original seismic data is deemed insufficient. One or more repeated 3D surveys are then commonly obtained throughout the production life of large fields and in well-explored basins. 3D surveys may be acquired for further exploration and reserves (Gluyas & Swarbrick, 2007)[66].

The primary purpose of an exploration well is to obtain the necessary information about the area of interest to decide whether to continue exploration work or abandon the play. Production wells cannot be properly designed until the reservoir is studied in enough detail (pressures, fluids and gases present, porosity, permeability, consolidation of the reservoir rock, and many other factors). Many features of subsurface conditions cannot be predicted from the first well. Well design therefore has to include certain contingencies to allow for unexpected conditions that may appear during drilling. Exploration wells normally cost more than appraisal or production wells due to the amount of information required, necessitating the use of special logging tools, core samples, testing equipment, etc. In an exploration well, there are many unknowns. Compared to a development well (drilled in a known area), at least one extra casing string may be needed to isolate unexpected problems and allow the target areas to be reached.

[66] For more information about seismic prospecting, see Appendix 5

There is a maximum depth that can be drilled safely below any particular casing. Among other factors, this depth will depend on: the formation strength at the casing shoe depth; the density of the drilling fluid in the well; the hole diameter; the maximum volume of formation fluid that can be allowed into the well (known as the influx volume) the density of the formation fluid that might enter the well in a kick situation, etc.

The ideal depth to set each casing can be determined by identifying which formations are suitable for the casing shoe and calculating how far to drill before the kick tolerance becomes too small. This information also dictates how many different hole sections (and casings) are needed. Designing the casing strings is a fairly complex job. Computer programs are now used to obtain the most cost-effective solution, while still meeting the requirements of the well.

Once all the relevant data have been collected and the well design agreed upon, the next stage is to write a drilling program. While the well design shows the final status of the well required, the drilling program will instruct the rig crew on how all the operations have to be performed and in what sequence.

In locations (pads) where other wells have been drilled close to the new one, detailed trajectory information needs to be obtained and an anti-collision directional drilling program implemented. Each formation sequence drilled will have its own particular directional characteristics. If these can be determined, the well can be designed to hit the target by following these natural tendencies as much as possible. Even in the case of a vertical well, the rock will have certain characteristics that may tend to cause deviations from the vertical.

All of this subsurface data must be gathered, collected, summarized, and presented in ways that will be useful when working on the well design. Computerized databases and other software tools are very valuable, although there are other ways of working with the data that need not necessarily be high tech (Devereux, 1999).

Among other elements, the well drilling and geological programs contain a set of advisory data for the rig crew showing how the well can be drilled most efficiently. The supervisors in charge of the drilling operations may need to deviate significantly from the program if necessary for reasons of safety or efficiency. A well program should never be thought of as a precise set of instructions, but rather as advice that can be changed if the need arises. However, it is also important that the program contains information on why major decisions have been made, so that all this original information can be combined with new information to make the most informed decisions possible.

4.2. Building the well location

Once the well has been designed, the first thing that has to be done is to build the well location. The location is similar for vertical wells and for multi-well pads in horizontal drilling and high volume hydraulic fracturing.

The area has to be cleared, leveled and prepared to accommodate the drilling facilities, including construction of an access road for trucks.

Among other factors, location size depends on the site topography, the number of wells and the equipment requirements in each phase – drilling, fracturing jobs, testing and completion.

FIGURE 57. Drilling site during and after drilling operations

Source: (West Virginia Surface Owners' Rights Organization, 2008)

In the USA, the most common development method is horizontal drilling from multi-well pads with six or eight wells (or more) drilled sequentially from a single pad. Each pad requires an area sufficient to accommodate fluid storage and equipment associated with the fracturing operations. In the UK, the well pads planned by Cuadrilla for exploration and production for the Bowland Shale are approximately 0.7 ha (after partial reclamation), and will contain 10 wells (Regeneris Consulting, 2011 in (Tyndall Centre, 2011)). The photographs below illustrate this case in a site in the UK.

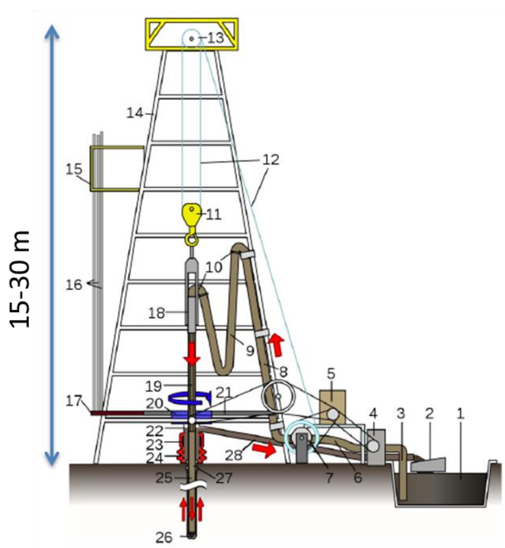
The average spacing interval for horizontal wells in the shale gas plays is 160 acres per well (approximately 65 ha per well), so a 640-acre section of land could be developed by as few as 4 horizontal wells, all drilled from a single well-drilling pad.

A multi-well pad in Arkansas could occupy approximately 3.5 acres (1.4 ha) plus roads and utilities, resulting in a total of 6.9 acres (2.8 ha) in the drilling phase. This area is considerably reduced after partial reclamation at the beginning of the production phase, as the pictures below show (Spellman, 2013).

4.3. Main equipment for vertical drilling

In this section, we will review the main components needed for drilling the well. First it is important to note that a drilling operation requires logistical support and the infrastructure necessary to handle traffic.

FIGURE 58. Drilling equipment



1.Mud tank
2.Shale shakers
3.Suction line (mud pump)
4.Mud pump
5.Motor or power source
6.Vibrating hose
7.Draw-works
8.Standpipe
9.Kelly hose
10.Goose-neck
11.Traveling block
12.Drill line
13.Crown block
14.Derrick
15.Monkey board
16.Stand (of drill pipe)
17.Pipe rack (floor)
18.Swivel (On newer rigs this may be replaced by a top drive)
19.Kelly drive
20.Rotary table
21.Drill floor
22.Bell nipple
23.Blowout preventer (BOP) Annular type
24.Blowout preventer (BOP) Pipe ram & blind ram
25.Drill string
26.Drill bit
27.Casing head or Wellhead
28.Flow line.

Source: (Tosaka, 2008) and own elaboration.

Drilling rigs can be broken down into separate packages that are transported by truck. Each rig has a procedure detailing "what goes where and in what order" for the most efficient assembling of the rig.

The rig substructure and the mast are constructed from steel beams welded together. The substructure is a large frame which supports the drill floor and the derrick. It is generally about 5 to 9 meters above ground level, and supports the derrick (also commonly known as the mast), which is 25 to 40 meters high. A illustration of general nature can be seen in the following figure.

FIGURE 59. Rotary drilling rig

Source: (Álvarez Sánchez, 2013)

The picture below shows the site with the drilling equipment fully installed.

FIGURE 60. Drilling equipment installed

Source: (EPA, 2011)

The height and structural size of the derrick are determined by the depth to be drilled. As drilling proceeds, the derrick must be able to support the entire length of the well's drill string or casing. The casing, which has a wider diameter and, therefore, more steel, is heavier than the drill string drill pipe.

Simpler structural requirements make the smaller rig used for shallow well cheaper to build, less expensive to use, and more mobile. Smaller rigs can be moved from one location to another on land in 24 hours. The larger rigs may require a week or more due to the number of truck loads required (90-100 for a 2000 HP rig).

On 'spud day', when the rig is ready to start operating, a diverter needs to be attached to the conductor pipe installed during civil engineering in order to establish the first safety barrier in the closed circuit of the mud system. The diverter contains a large rubber seal that is forced under hydraulic pressure to squeeze in around the well's drill string and seal it. If a kick is experienced while drilling shallow formations below the conductor pipe, the flow is diverted away from the rig by closing the diverter and opening the valve on the pipe leading downwind.

On the top of the diverter there is a section of pipe (called a bell nipple) with an outlet to the side. This side outlet directs mudflow from the rig along a channel to the solids-control equipment and then back to the mud tanks, where, after conditioning, the pumps circulate it back down the hole.

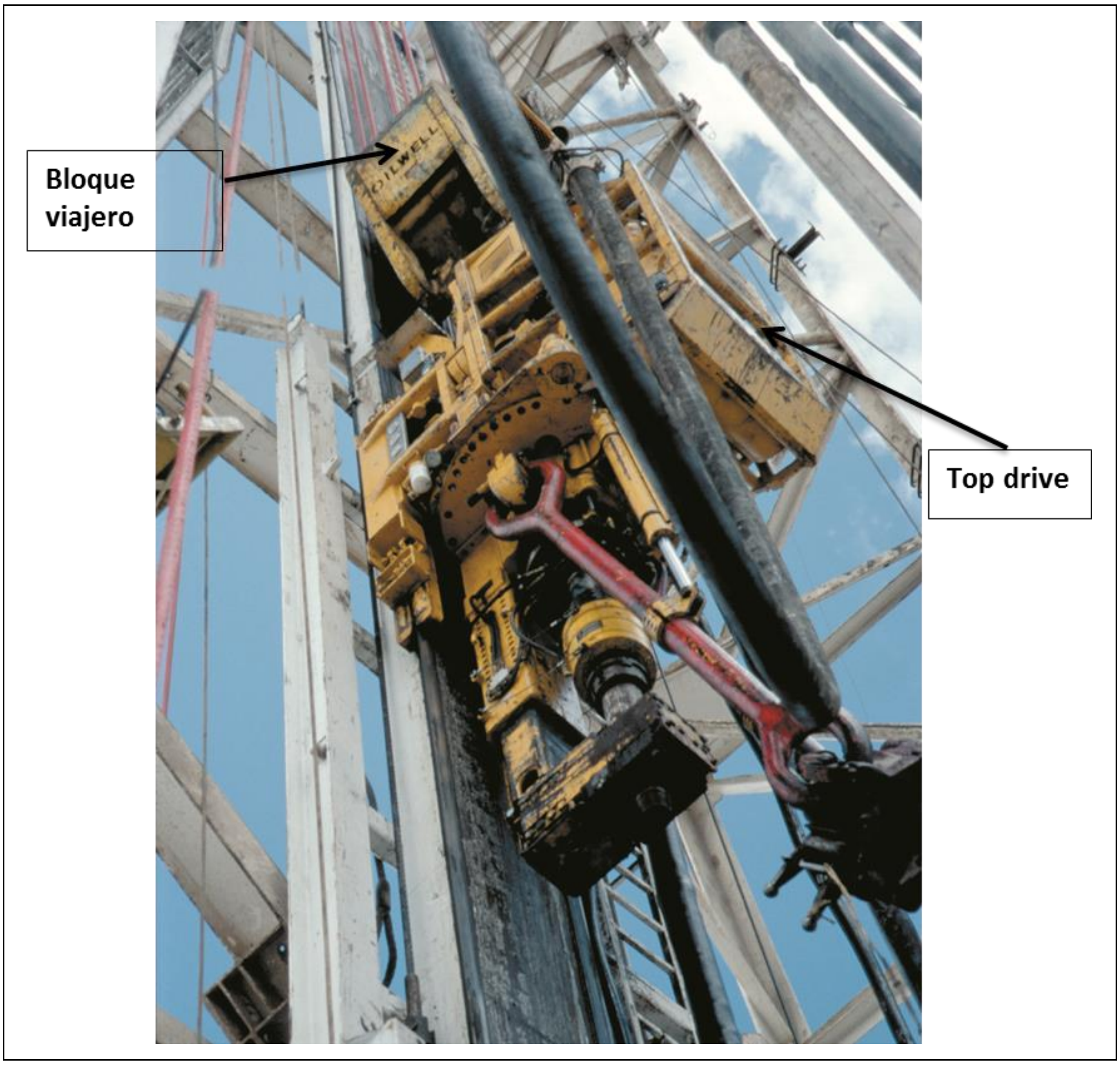
The rig hoisting system is used to withdraw the drill string from the hole, replace a drill bit and to add additional pipe to the drill string as the hole is deepened. It is also used to support the casing when it is run in the hole.

Most rigs now work with a Top Drive system. A top drive consists of a powered rotating motor (electric or hydraulic) suspended from the hoisting equipment, capable of rotating the drilling string and at the same time circulating the drilling mud through the drill string at high pressure. A top drive system is now replacing the rotating function of the rotary table assembly, or Kelly. (The Kelly bushing and regular swivel were used successfully during much of the twentieth-century development of the oil and gas industry).

The top drive system increases safety due to the reduced number of connections and also allows the drill string to be pulled out of the hole while in rotating mode, thus keeping the system in circulation.

The top drive system includes an Inside Blowout Preventer (IBOP) which is similar to conventional upper and lower Kelly cocks valves on Kelly rotary systems. If a kick occurs during drilling, the driller can close the IBOP by remote control. This prevents the kick from being released into the air through the top drive.

FIGURE 61. Top drive and travelling block



Source: Image courtesy of *Petroleum Extension (PETEX™)*, *University of Texas at Austin.* See also (Bommer, 2008).
Note: Bloque viajero = Travelling block

Another of the most important components in the drilling equipment is the drill bit. In modern systems, the drill bit must be rotated by the top drive to drill to greater depths.[67]

[67]The classical components of the rig (now substituted by modern mechanics such as the top driver and others) include elements such as the Kelly, the Kelly bushing, the rotary table, and the rig engines, which provide power to turn the rotary table which, in turn, rotates the well's drill string. The Kelly connects the top of the well's drill string in the hole to the hoisting and mud systems. The Kelly bushing is the apparatus that sits on the rotary table and grasps the Kelly. The drill pipe is round and provides little stability for the strength of the rotational forces to be transferred to the rotary table. The Kelly is a hollow, 40 foot-long, heavy steel pipe with a square or hexagonal cross section. It is screwed into the top of the latest piece of drill pipe to go into the hole. The shape of the Kelly makes it more "grabbable" than a round pipe. Not only does the Kelly provide the means by which the drill pipe is rotated, it also moves up and down through the rig floor as the hole is

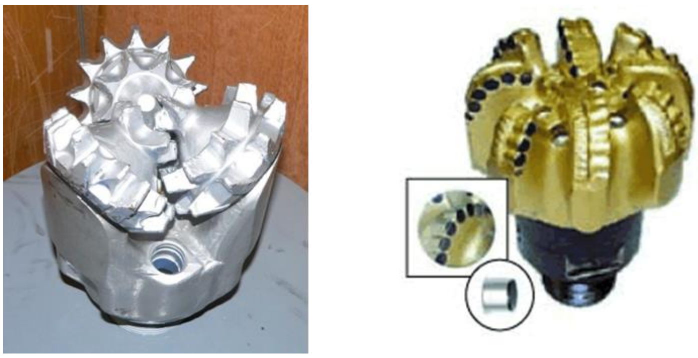
FIGURE 62. Drill pipes

Source: (Álvarez Sánchez, 2013)

To drill the hole, the well's drill string is rotated and the bit, which is attached to the bottom, gouges or cuts the rock. Soft formations are penetrated by gouging and jetting. In harder, more brittle rock, progress is generally slower and is achieved more by pulverizing and crushing the rock (Raymond, MS. & Leffler, WL., 2006). Two main types of bit are used for drilling: roller cones and fixed cutters.

Roller cone, or rock bits have steel cones, which turn and mesh as the bit rotates. Most roller cone bits have three cones, although they can also have two or four. Bit manufacturers either cut teeth out of the cones or insert very hard tungsten carbide cutters into them. The teeth or cutters gouge or scrape out the formation as the bit rotates. Tungsten carbide bits cost more than steel-tooth bits, but their improved performance may offset their higher cost.

FIGURE 63. PDC bits and a diamond bit



Source: (Conaway, 1999)

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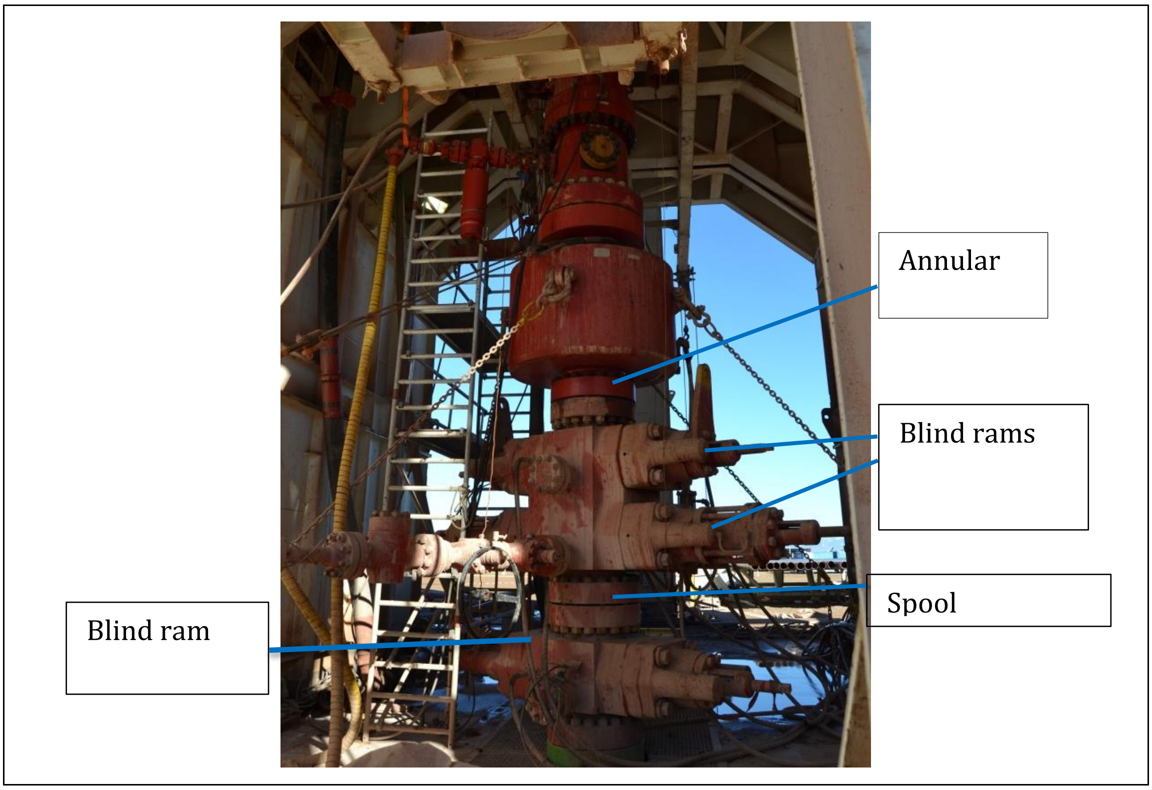
deepened. A smooth, vertical motion is enabled by wheels located in the Kelly bushing. The Kelly bushing is firmly attached to the rotary table during drilling but is pulled out of the way along with the Kelly before any drill pipe is taken out of the hole (Raymond, MS. & Leffler, WL., 2006).

Some fixed cutter bits are diamond-based and do not have cones or teeth. Instead, manufactures embed industrial diamonds into the bottom and sides of the bit. Because diamonds are so hard, such bits are especially suited for drilling hard, abrasive rock formations. Polycrystalline Diamond Compact (PDC) bits are now used, which feature specially manufactured synthetic diamond cutters, or compacts. Rather than cutting or gouging the formation, these bits shear it, thus requiring less weight on the bit to provide efficient drilling.

The rate of penetration depends on many factors, as well as the rock being drilled (the lithology). The next most important determining elements are the weight on the bit and its speed of rotation. The weight on the bit depends on the heavy components (drill collars) of the drill string. However, as the bit goes deeper, it can no longer support the full weight of the drill string. Drillers continuously and carefully monitor the amount of weight they allow the hoisting system to release onto the bit. They also manage the speed at which the bit turns by controlling the speed of rotation of the rotary table or top drive system.

The blowout preventers are the main safety barrier against unexpected events that might occur during drilling operations. Blowout Preventers (BOPs) come in a variety of configurations and sizes, mostly dictated by the pressures they are expected to handle and the environment in which they are designed to work. BOPs are powerful hydraulic rams that can close around the drill pipe; close against the drill pipe (cutting it off if necessary) or close off the open hole if a fluid surge occurs when there is no pipe in the hole. Each type of preventer is a separate component of a BOP stack. Onshore, the BOP stack is bolted to the top of the wellhead. The figure below shows arrangements of blowout preventer ready for installation.

FIGURE 64. BOP installed



Source: (Álvarez Sánchez, 2013)

4.3.1. *Muds and muds circulation*

We shall now address the mud circulation system and its importance in drilling operations.

Drilling muds have several functions: they contain the formation pressures; lubricate and cool the bit; remove the cuttings to the surface; and maintain the integrity of the well bore from collapse. Drilling mud is normally a mixture of water (saltwater in offshore wells), bentonite clay and chemical additives that give the mud the properties required in handling and drilling the well: rheology,[68] density, viscosity, etc.

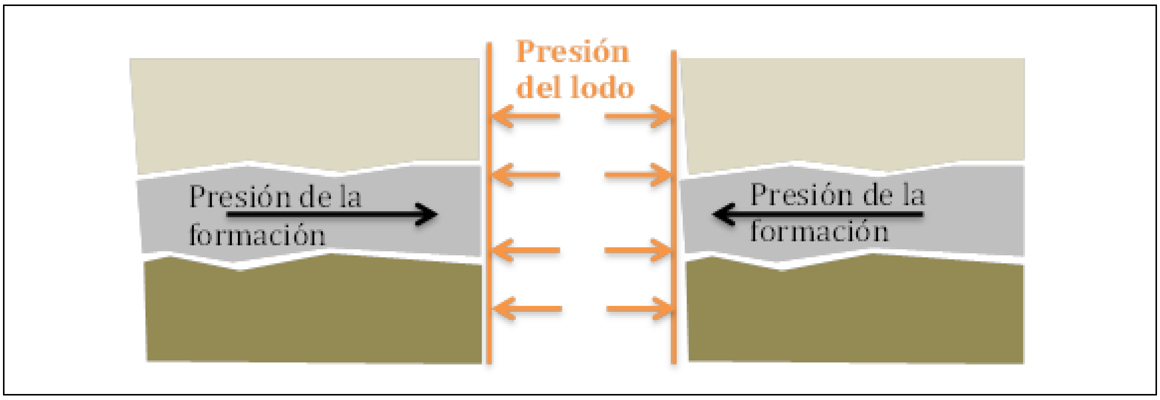
As mentioned, drilled rock cuttings are removed from the well by pumping a drilling fluid (mud) through the drill string. The fluid flows to the surface through the annulus between the well bore and the drill string, lifting the rock cuttings with it. At the surface, special equipment (called solid-control equipment) separates the drilling fluid from the cuttings. The cuttings are stored, normally in tanks, before being disposed of by the waste management system.

[68] The property of drilling muds to retain the cuttings in suspension in the system, even under static conditions without circulation, is called the rheology.

In order to create a hydrostatic column sufficient to control formation pressures, weighting agents are added to the mud system. The agents most commonly used are calcium carbonate for pressures up to 1.40 sg and barite above 1.4 sg.[69]

As the drill bit reaches farther into the earth, it encounters higher pressures. These can come from the fluids contained within the pores of the rock, from the weight of the rock itself, or from a combination of the two. The pressure by water alone increases by about 0.43 psi[70] for every foot of depth. Other geological forces could push the pressures higher.

FIGURE 65. Mud and earth pressures



Source: Own elaboration from (Raymond, MS. & Leffler, WL., 2006)
Note: *Presión de la formación* = formation pressure, *presión del lodo* = mud pressure

Drillers carefully watch the flow of mud circulating out of the hole and into the system in order to determine whether the weight of mud in the hole is sufficient to contain the pressurized fluids down the hole. If not, they increase the weight of the mud by adding weighting agents.

Choosing the right composition of drilling muds often requires a specialist, particularly when choosing an additive to improve viscosity, reduce filtrate loss, improve bit lubricity, prevent corrosion, reduce foaming, and deal with dozens of other potential problems. The choice of additives used in the mixture of sludge depends on the rock to be drilled and its conditions. It is also important to analyze the additives needed to give the highest performance possible.

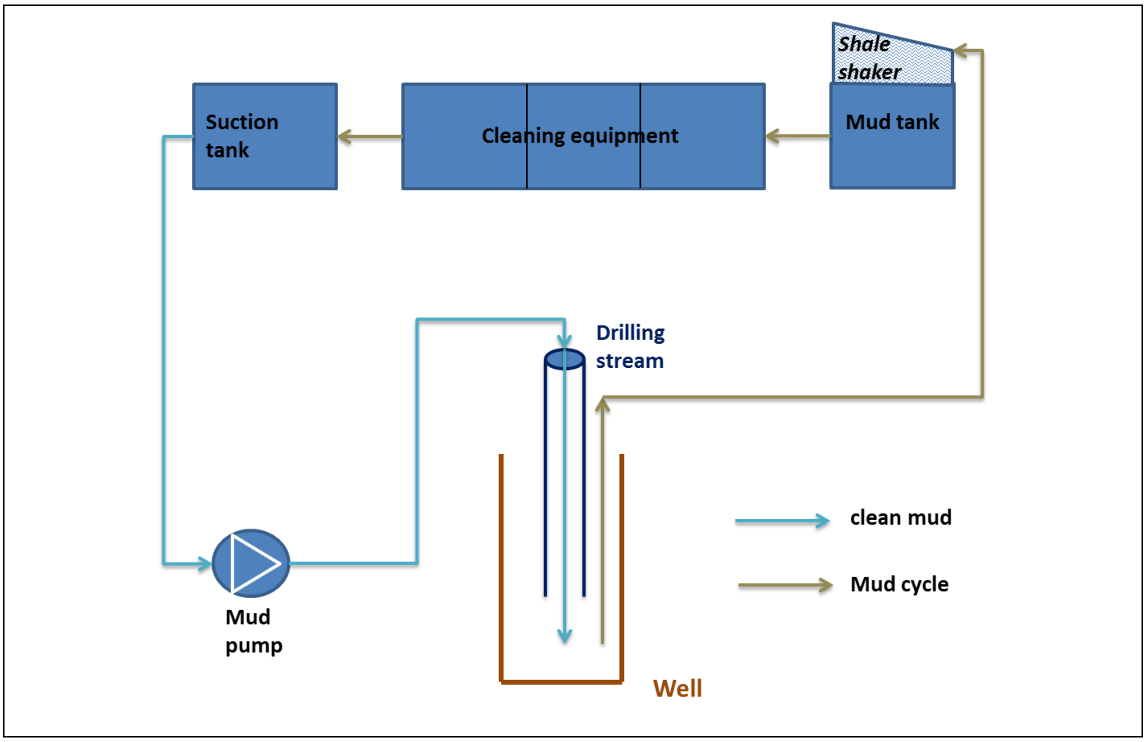
Certain circumstances call for a very lightweight mud system, for example where the pressure in the formation is low. Another, even lighter-weight technique is to use air or a mixture of air and water as the circulating fluid.

Sometimes a well penetrates a zone where the porosity is so high or the formation's pressure is so low that the mud escapes rapidly into the formation, rather than continuing to flow out of the hole. This area is called a *zone of lost circulation*.

[69] sg = specific gravity.
[70] pounds per square inch

The mud-mixing and circulating system begins in a large tank beside the rig. Onshore, fresh water is added to the tank from a nearby water well or lake or is trucked into the location. The mud materials are added directly to the water, and the entire system is constantly stirred to prevent heavier material from settling out of the system. (See FIGURE 66, 67 and 68)

FIGURE 66. Mud circulation system



Source: Own elaboration based on (Fernández, 2013)

FIGURE 67. Shale shakers. Drilling fluid carrying rock debris is passed through vibrating screens

Source: (SGEIS, 2011)

From the tanks, the mud is pumped up the standpipe, down through the drill string, and out the jets on the drill bit at the bottom of the hole. There, the drill cuttings are picked up and circulated up through the annular space (the annulus) between the drill string, the drill pipe and the hole and, farther up, between the drill string, the drill pipe and whatever casing has been placed in the hole in earlier operations.

After exiting the hole through the bell nipple, the mud is piped back toward the circulation tanks, passing through a series of vibrating screens (shale shakers) and a solids removal system in order to restore the mud to optimal conditions. The rock cuttings separated from the fluid are collected in a pit or a tank prior to disposal.

The mud-circulating system is driven by large positive displacement pumps, powered by electric motors of close to 2,000 horsepower. Typically, the system has at least two pumps, each with its own motor conveniently located beside the circulating tank. One of the pumps operates continuously during drilling, while the second is on standby. The photograph above shows the shale shakers and mud pumps.

FIGURE 68. Mud system equipment

Source: (Álvarez Sánchez, 2013)

4.3.2. *Casing and cementing*

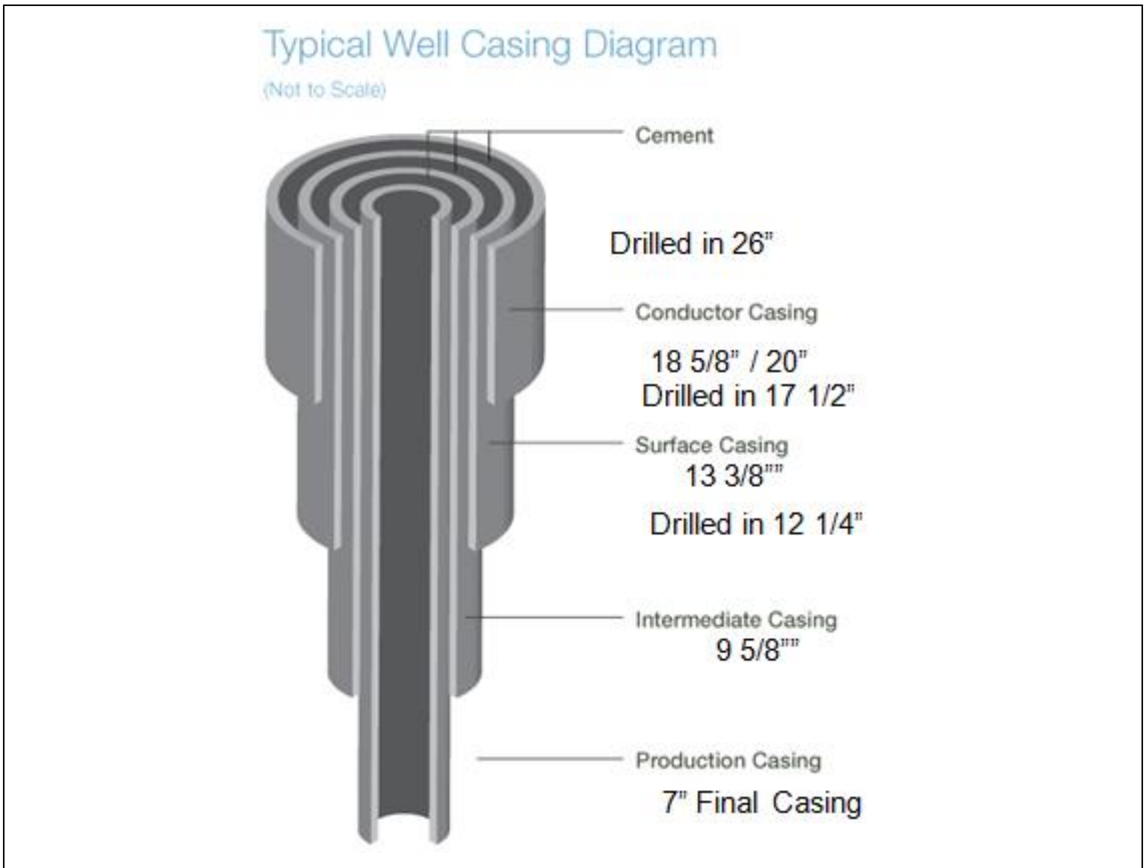
Having described the main equipment used for vertical drilling and mud circulation, we shall now go on to explain the process of drilling, casing and cementing.

During the civil engineering required to prepare the site for the drilling equipment, (See Section 4.2.), a conductor pipe is installed in the ground and secured with concrete. A square concrete pit (called the cellar) is built around this conductor pipe with enough space to accommodate the well head flanges and BOP below the rig substructure.

The FIGURE 69 shows how a well progresses in a series of "hole sections" which are drilled in progressively smaller hole sizes. The diameter shown in the figure is illustrative and will be used in the following description. Casings are run to consolidate current progress, to protect some zones (such as freshwater sources) from contamination as the well progresses, and to give the well the ability to sustain high pressures. Once the casing string has been run and cemented, the designated well head section is attached to it. The new casing and its corresponding well-head section is now a closed high-pressure system isolated from the previous drilled phases.

At the start of the drilling operations, a large diameter bit (normally 26") drills the first section of hole through the conductor pipe. A downward force needs to be applied to penetrate the rock. This force is provided by the weight of a thick pipe, called a drill collar, which is screwed on top of the drill bit. Standard drill collars normally used for the first section have a diameter of 9 ½" or 11 1/4" and weigh 3.1 to 4.2 tons for each piece of pipe (9 m).

FIGURE 69. Typical well casing diagram (not to scale)



Source: (Encana.com, 2015)

As well as having weight applied to it, the drill bit also needs to be rotated. With enough "weight on bit" and "rotary speed", the bit will drill rock. Stronger rock requires greater weight to be applied to the bit, so that the pressure exerted by each tooth is greater than the compressive strength of the rock. Close to the surface, the rock is usually fairly soft and easily drilled so a lower weight is not a problem.

As the bit penetrates the rock, cuttings are generated which must be removed from the wellbore to prevent blockage of the system. This is achieved by pumping mud fluid down the hollow drill string.

The drilling mud exits through the nozzles in the drill bit and flows back to the surface, carrying the cuttings with it, through the space between the bore hole and the well's drill string, which is called the "annulus". The speed at which the fluid moves up the annulus is measured in feet (or meters) per minute. This speed is called the "annular velocity" or "AV". To lift the cuttings upward, a minimum AV of about 50 feet per minute (fpm) is required. The number of gallons per minute (gpm) required to achieve a particular AV can easily be calculated. The larger the hole size, the more gallons per minute must be pumped.

In this initial phase, for every thirty feet drilled, another drill collar is screwed onto the top of the drill collars already in the hole. When there are enough drill collars to give all the required weight on the bit, a drill pipe is added to the drill string, again in 30-foot lengths. (Each length of drill pipe is called a joint). Before drill pipes can be screwed onto the drill collars, a special short length of pipe with a drill pipe connection on the top and a drill collar connection on the bottom is added. These special short pipes are called subs. When they are used to convert one size or type of connector to another, they are called crossover subs. The sub connecting the drill bit to the lowest drill collar is called the bit sub.

Although the drill collars have straight or helical sides, the drill pipe has a bulge at each end. The drill pipe itself is fairly thin and there is not enough metal to make a connection onto the pipe itself, so a thick section, with the threaded connection on it, is welded to each end of a length of pipe. The pipe part of the drill pipe is called the pipe body and the connection part is called the tool joint. The components from the drill bit to the bottom of the drill pipe are called the Bottom Hole Assembly (BHA).

Once the well has been cleaned twice from the bottom up using circulation and before the drill string is pulled out of the hole, a tool called a "Totco Ring" is dropped down the inside of the string. A timer mechanism is set to a preset time after dropping (enough for it to reach a Totco ring) and the instrument then takes a vertical measurement of the inclination of the wellbore. Drillers can thus tell whether the well is vertical or whether it has started to wander off course while drilling. This process is called "taking a survey".

Once the 26" hole has been drilled, the 20" or 18 5/8" diameter casing is run into the hole. The annulus space between casing and formation is cemented up to the surface to ensure stability and integrity of the well bore.

There are four design criteria for casing string: tension strength, which is the maximum admissible tension for the pipe without reaching its elastic limit; burst pressure, the maximum admissible pressure that pipes can resist internally; collapse pressure, the maximum admissible pressure that pipes can resist externally without deformation in the internal diameter; and corrosion, which needs to be taken into account when sour gas (SH_2/CO_2) has been detected. In this case, the use of stainless steel pipes with a different Cr content (13 % to 22%) is necessary (NACE[71] Standards).

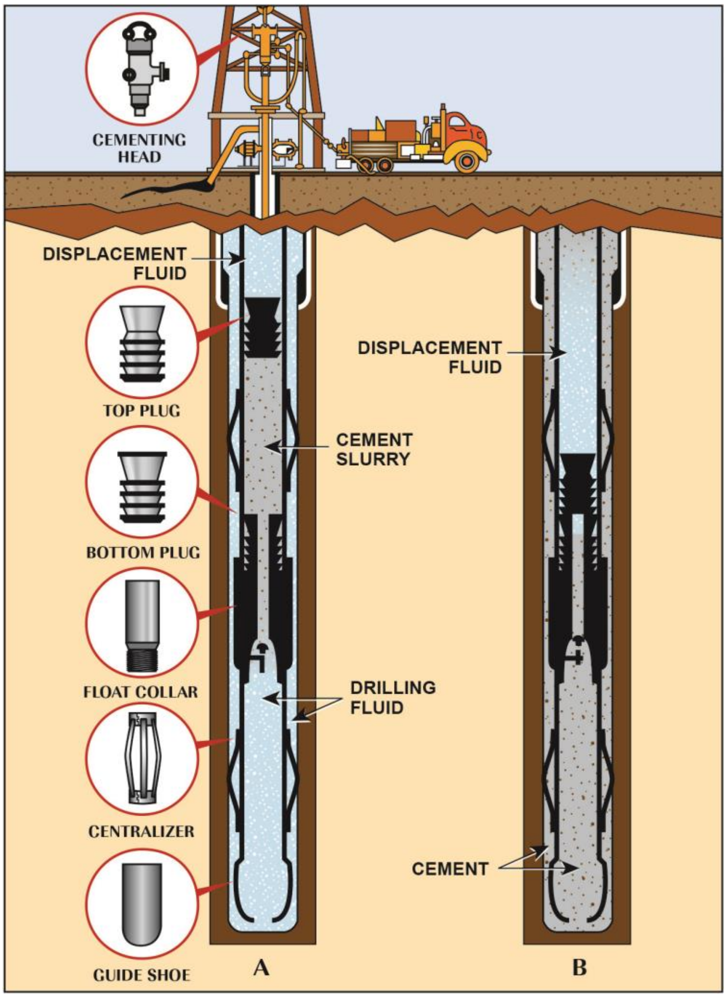
Design and selection of the casing is of utmost importance. The casing must be able to withstand the various compressive, tensional, and bending forces that are exerted while running in the hole, as well as the collapse and burst pressures to which it might be subjected during different phases of the well's life. For example, during cementing operations, the casing has to withstand the hydrostatic forces exerted by the cement column; after cementation, the casing must withstand the collapsing pressures of certain subsurface formations. These subsurface pressures exist regardless of the presence of hydrocarbons.

After the casing has been run into the drilled hole, it has to be cemented in place. This is a critical part of well construction and is a fully designed and engineered process. The purpose of cementing the casing is to provide zonal isolation between different formations (including complete isolation of levels containing groundwater) and to provide structural support for the well. Cementing is essential to maintain integrity throughout the life of the well and as part of corrosion protection for the casing.

As described by (Bommer, 2008), cement[72] supports and protects the casing and bonds it to the hole. The cement also seals the annular space between the casing and the hole, preventing fluids and/or gases in one formation from migrating to another. Cement mixers continuously blend the water and cement to make a uniform mixture as the cement pumps push it down the casing and into the *annulus*. High-pressure pumps move the slurry through steel pipes or lines to a *cementing head*, or plug container (see FIGURE 70).

[71] National Association of Corrosion Engineers
[72] Commonly known as slurry.

FIGURE 70. Cementing the casing job in progress and finished job



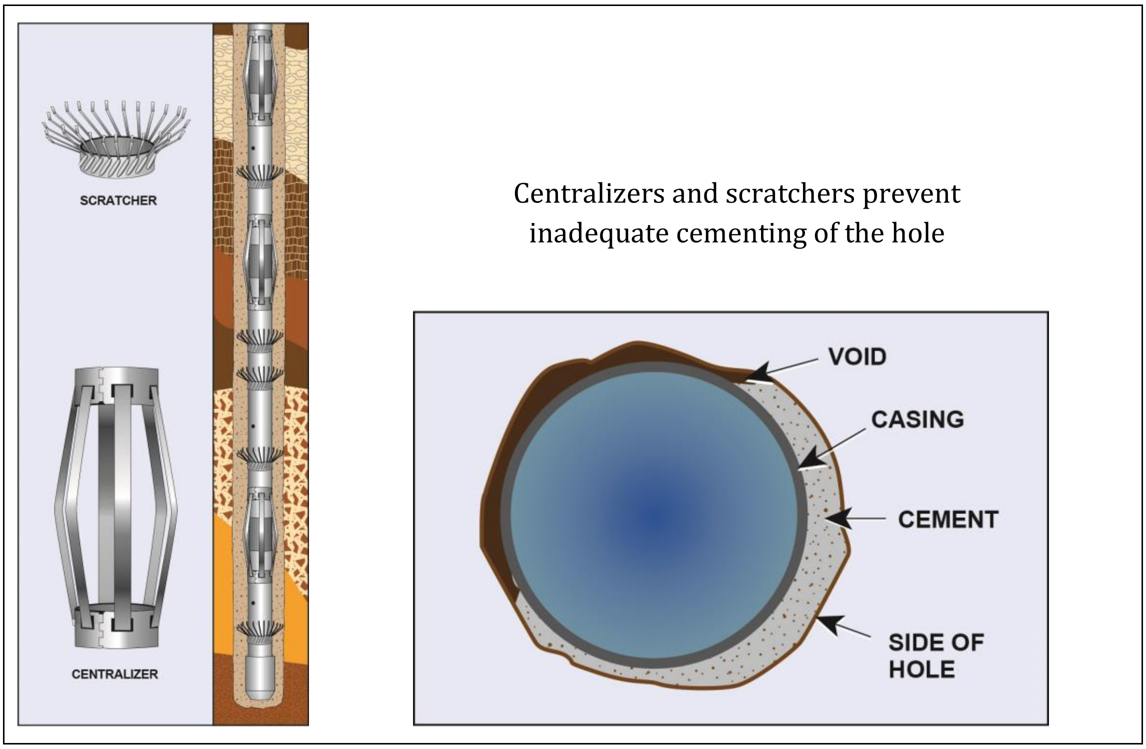
Source: Image courtesy of *Petroleum Extension (PETEX™), University of Texas at Austin.* See also (Bommer, 2008).

Just before the slurry reaches the head, a member of the crew releases a rubber plug, called a *bottom plug,* from the cementing head. The bottom plug separates the cement slurry from any drilling fluid inside the casing and prevents the mud from contaminating the cement. The slurry moves the bottom plug down the casing. The plug stops, or *seats*, in the float collar. Continued pumping breaks a membrane on the bottom plug and opens a passageway. Slurry then travels through the bottom plug and on down the last few joints of the casing. It flows through an opening in the guide shoe and up the annular space between the casing and the hole. Pumping continues until the slurry fills the annular space.

As the last of the cement slurry enters the casing, a crewmember releases a second plug, called a top plug, from the cementing head. A top plug is similar to a bottom plug except that it has no membrane or passage. The top plug separates the last of the cement to go into the casing from the displacement fluid.

The top plug seats on, or *bumps*, the bottom plug in the float collar. The only cement is in the casing below the float collar and in the annular space. The rest of the casing is full of displacement fluid. It is critical that the cement fills the annular space from the bottom of the surface casing to the ground level.

FIGURE 71. Scratchers and centralizers in the casing string and top view of casing not centered in the hole



Note: A mud-filled channel remains where the casing touches the side of the hole. The mud-filled channel will not be sealed.
Source: Images courtesy of *Petroleum Extension (PETEX™), University of Texas at Austin.* See also (Bommer, 2008).

After the cement company has pumped in the cement and removed its equipment, the operator and drilling contractor have to wait for the cement to harden. This period of time is referred to as *waiting on cement*, or WOC. Once the cement has hardened, the first section of the wellhead is installed and the BOPs are positioned or *nippled up* on top of the wellhead.

Centralizers will be strapped around the outside of the casing to keep the casing centered in the middle of the borehole (see FIGURE 71). This ensures that the cement fills evenly around the outside of the casing and that there are no gaps in it, showing the top view of a casing not centered in the hole.

It is very important to assess the behavior of the cement pumped into the annulus space. Pressure trials and registries (logs) are therefore performed to verify that the cement fulfils the required conditions. The most common log used for evaluating cement is the CBL (Cement Bond Log). The CBL tool relies on the fact that sound moves differently through different materials (steel, cement, rock formation). Its operation is quite simple. The transmitter/receiver probes are lowered into the well. They then emit sound waves and record the returning signals, which are digitally processed to give information on the cement job.

At the top of the surface casing is a screw thread, using which the first section of the well-head, the “head housing”, is attached to the surface casing. The housing has a flange on top, which is used to attach the BOP. In addition, this spool will support the weight of the next casing. A casing hanger is screwed on to the top of the next string of casing. The casing hanger sits in the casing head and supports the weight of the intermediate casing string.

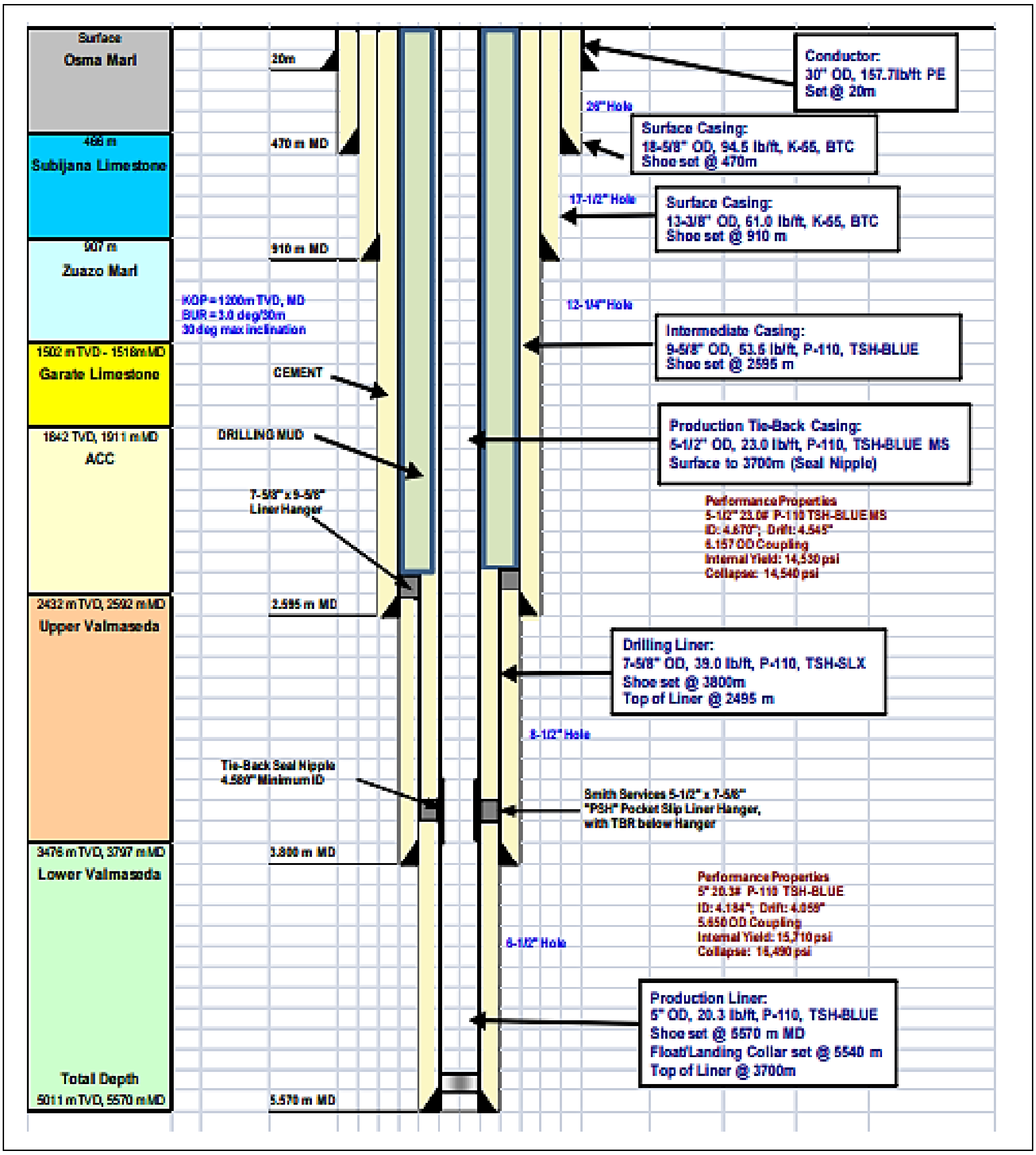
Once the casing head housing is in place, the BOP can be positioned and attached to the top of the casing head housing. The BOP equipment and control system must be operating and pressure-tested to ensure that everything is working properly.

After drilling to the original depth through the float collar, cement, float shoe and some virgin formation (4 or 5 meters), the strength of the formation below the casing shoe has to be tested. The test can be performed at a specific pressure (formation integrity test, FIT) or by trying to establish the leak-off point (LOT). The drill bit is pulled back until it is situated inside the surface casing. The BOP is then closed so that it forms a seal around the drill pipe.

Fluid is then slowly pumped into the well through the drill pipe. The well becomes pressurized up to the predesigned FIT or to the LOT (pressure where the exposed formation allows fluid to leak in). The actual pressure on the formation is calculated by adding the final surface pressure to the hydrostatic pressure of the fluid in the well (Azar & Samuel, 2007).

In a typical Bottom Hole Assembly (BHA) the configuration to be used varies in the different drilling phases, with some special tools installed: back pressure valves, stabilizers, bumper subs, jars, heavy weight drill pipes, etc. The well can continue being drilled to the design depth for the next casing in accordance with the drilling program. In the following phase, the process of drilling, casing and cementing is identical to that already described. The sequence is repeated as often as necessary, and as mentioned above, the number of intermediate casings in each well is determined by their length, the formations drilled and the pressures to which the borehole will be subjected.

FIGURE 72 Final state of an exploration well



Source: (Grupo EVE, 2012)

The well-head is constructed by adding each new section on top of the previous one, in accordance with the casing cementing sequence. The BOP will be nippled up on top of each spool section of the well-head in order to maintain the safety and integrity of the well at all times. Sometimes, depending on the number of drilling phases planned, the last phase of drilling includes running out the liner. A liner is essentially a string of casing that does not extend to the surface and which is suspended from and connected to the previous casing with a hanger, which uses hardened steel teeth to dig into the last casing inside diameter (ID) in order to suspend the liner. FIGURE 72 shows a typical wellbore diagram.

4.3.3. *Core sampling*

While the reservoir section is being drilled, there are usually indications at the surface of hydrocarbon presence.

The main purpose of exploration wells is to obtain the maximum amount of information about the reservoir. The best way to assure this is by taking core samples while drilling through the reservoir and even through the overlying strata.[73] If hydrocarbons are detected during drilling of the well, the drill bit is removed and the drilling BHA is replaced with a coring assembly (Devereux, 1999).

A core is taken by drilling with a special bit (called a core bit) which has a hole in the middle through which a column of uncut rock will protrude. There is a special mechanism for gripping this rock and placing it in a special container (Devereux, 1999).

Coring is slow and expensive but the value of the information usually makes it worthwhile because it allows better decisions to be made in designing the test and in the future development of the reservoir. Once the reservoir is cored the driller will run in with a normal drill bit, ream through the cored section and continue drilling to Total Depth (TD) (Devereux, 1999).

Well testing and stimulation jobs, including hydraulic fracturing, will be based on appraisal of the well log, records and analysis of rocks and the presence of hydrocarbons during the drilling phase.

As explained by Devereux (1999), logging tools are run into the hole suspended from a steel wireline, which has electric wires inside capable of transmitting signals from the logging tool to the surface. Wireline well logs can be of different types: electrical log, induction log and laterolog, gamma ray log, radioactive logs, photo-electric factor log, caliper log, sonic or acoustic velocity log, dipmeter, nuclear magnetic resonance log and computer-generated log (Devereux, 1999).

A drilling-time log is a record that contains the main data provided by the drilling equipment: rate of penetration (ROP), torque, bottom-up time for samples, gains or losses of drilling mud, etc.

[73] Core sampling is expensive and it is not always possible to take samples from the overlying strata. Nonetheless, although most samples are taken in the target formation, information from the overlying strata can be very useful for determining working pressures, for example.

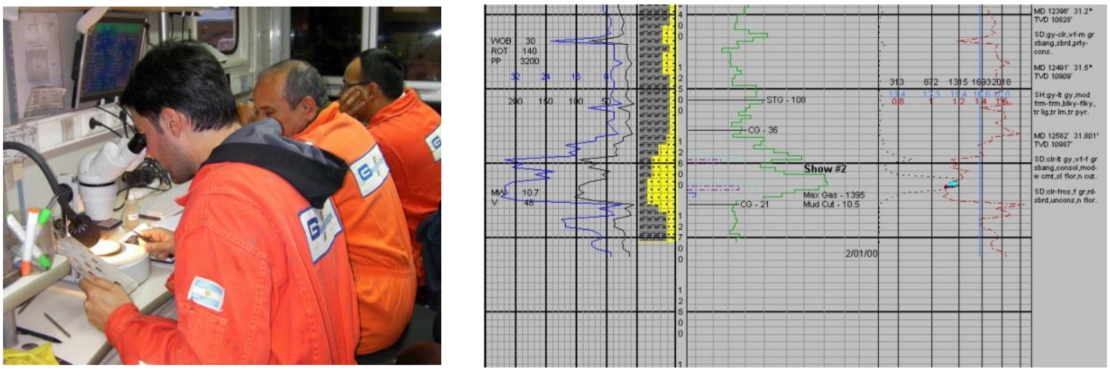
FIGURE 73. Log tools

Source: (Álvarez Sánchez, 2013)

Data from drilling equipment is integrated with the geological sampling and analysis in the mud logging unit in real time. The mud loggers then issue a "master log".

The master log is a physical description of the rocks to the depth to which the well has been drilled, including their composition, texture, color, grain, size, cementation, porosity and other characteristics. It also includes information on any traces of subsurface natural gas and crude oil as the well is being drilled and the main drilling data such as ROP, mud weight, torque, etc.

FIGURE 74. Mud Logging Unit



Source: (Ddbon, 2012; Mudgineer, 2000)

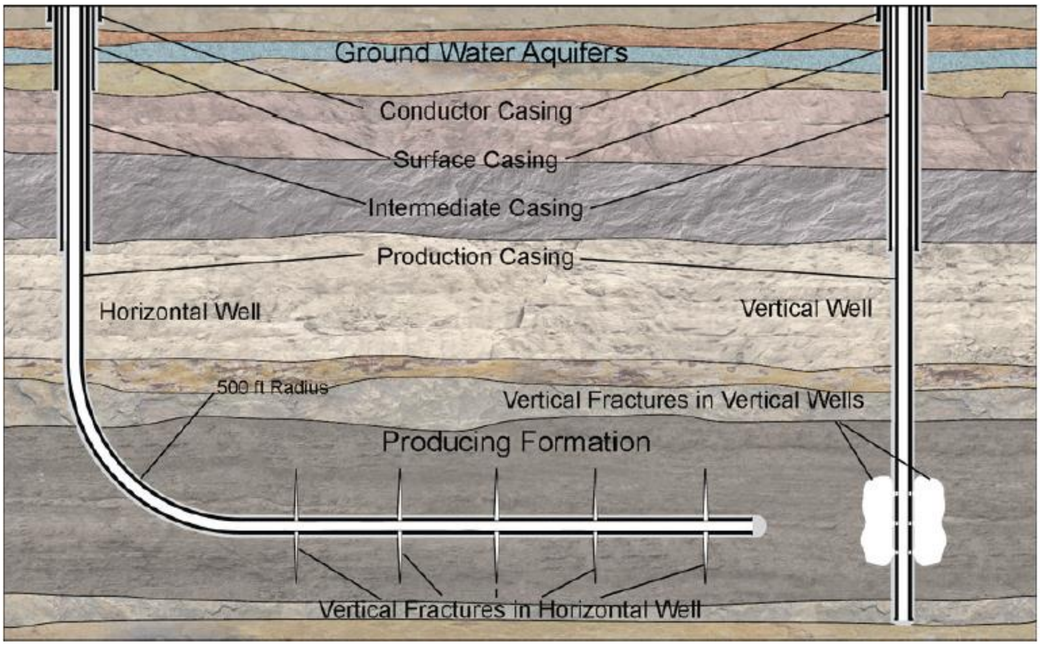
Finally, reference should also be made to the field of reservoir geomechanics, whose purpose is to describe what happens in the reservoir between scattered well points. This requires combining the geological model with the data acquired from drilling of the wells such as cores, logs, tests, and fluid samples. It is important to monitor any input and output flow in any new well and keep a record of any formation breakdown caused by excessive pressure on the walls of the well.

Reservoir geomechanics involves making a set of assumptions concerning the physical state of the "system" for which an appropriate mathematical description must be sought for clarification purposes. These assumptions are used to build a hypothesis that must be checked with the calculations based on both information and models.

4.4. Directional and Horizontal drilling

Directional drilling allows drilling within and in line with hydrocarbon-bearing layers which, depending on the formation, will be more than 10-24 m thick. In most major US shale plays, the angle of the hydrocarbon layer can be up to 90°, in which case the operation is known as horizontal drilling. In the UK, Cuadrilla Resources believe that the shale within its license is much thicker, reportedly 1000 m, which is part of the reason for its large resource estimate. Horizontal drilling maximizes the rock area which, once fractured, comes into contact with the wellbore, thus maximizing well production in terms of the flow and volume of gas that can be obtained from the well. (See FIGURE 75).

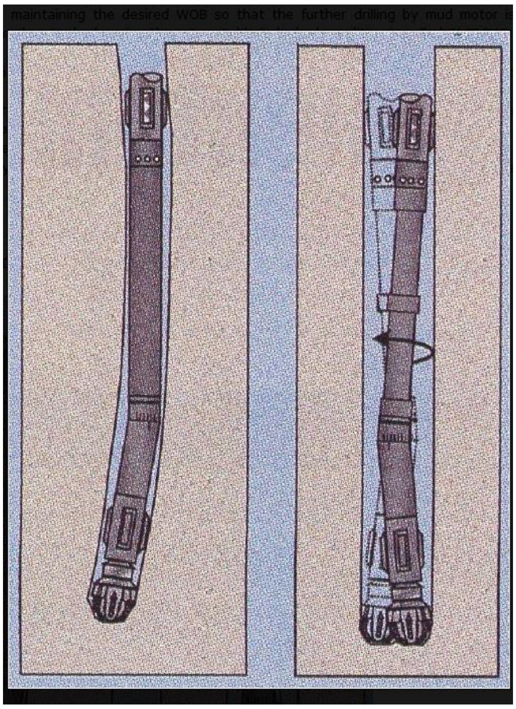
FIGURE 75. Comparison of well sites



Source: (API, 2009)

Horizontal wells are initially drilled vertically up to a point known as the KOP (Kick-Off Point). Below the KOP, the angle of the well increases to intersect and then follow the formation layer of interest. The deviated and horizontal section of the hole is drilled with a downhole motor which operates using the hydraulic pressure of the drilling fluid. Downhole motors can be drilled in two ways; firstly (first picture in FIGURE 76) in "sliding" mode when the drilling needs to be directional and the operator has to be able to control the direction (as described above); and secondly in "rotating" mode, for drilling a vertical section.

FIGURE 76. Downhole motors



Source: (Warren, 1998)

In some wells –vertical and horizontal– an "open-hole" completion is an alternative to setting the casing through the hydrocarbon-producing formation to the total depth of the well. In this case, the bottom of the production casing is installed on top of the productive formation.

The use of horizontal drilling for hydraulic fracturing also results in differences in the surface distribution of wells drilled into the target formations. The modern process of hydraulic fracturing has developed and is now typified by the clustering of several wells on "multi-well" pads, with each well drilled horizontally and multi-stage "slickwater" fracturing utilized.

Horizontal drilling from multi-well pads is now the most common development method in, for example, ongoing development of the Marcellus Shale reserves in the northern Pennsylvania. A "well pad" is typically constructed in the center of what will be an array of horizontal wellbores. Up to sixteen, but more commonly six or eight wells, are drilled sequentially in parallel rows from each pad, each well typically being around five to eight meters apart at the surface. In the UK, Cuadrilla Resources reports that its well pads will each have ten wells. Each horizontal wellbore may typically be around 1-1.5 km in lateral length but can be longer (Broderick et al., 2011 in (Tyndall Centre, 2011).

As the array of the wells drilled from each well pad is able to access only a discrete area of the target formation, shale gas development also requires an array of well pads arranged to cover the target formation.

5. TECHNOLOGIES IN UNCONVENTIONAL GAS PRODUCTION "SHALE GAS"

5.1. Hydraulic fracturing or fracking[74]

Although fracking is usually referred to as an unconventional technology, the technique has been around for sixty years. Hydraulic fracturing began as an experiment in 1947 (Grant, Kansas) and the first commercially successful application followed in 1949 (Oklahoma). As of 2012, 2.5 million hydraulic fracturing operations had been performed worldwide on oil and gas wells; over one million of which were in the U.S. (King, 2012).

When discussing technologies in unconventional oil and gas production –and 'shale gas' production in particular– one first needs to clarify what is meant by 'unconventional'. As discussed earlier (see chapter 2), unconventional gas production refers to gas extracted from formations where the permeability of the reservoir rock is so low that the gas cannot flow easily (e.g. tight sands), or where it is tightly absorbed and/or attached to the rocks (e.g. coal-bed methane).

In the United States, definitions of unconventional and conventional gas were arbitrarily assigned under fiscal regulations implemented in the 1970s. According to the tax code, unconventional gas is gas produced from a tight gas well whose permeability is less than or equal to 0.1 microDarcy. The permeability of the well was used to determine whether it would receive state or federal tax credits for gas production. However, gas flow rates are determined by a number of economic and physical properties that do not depend on permeability, and choosing a single value of permeability to define unconventional or tight gas is therefore of limited significance. For example, in deep, high-pressure, thick reservoirs, commercial completions can be achieved when the formation's permeability to gas is in the microDarcy range (0.001 mD) (Holditch et al., 2007).

In both conventional and unconventional oil and gas production, the concept of applying two or more recovery technologies, one after another, to a reservoir is well established. When primary production declines and becomes less economic, producers examine the possibility of flooding the reservoir with water as a secondary recovery technique. Finally, tertiary methods may be applied when water floods yield diminishing returns (Speight, 2009).

Hydraulic fracturing is a well stimulation method in which liquid under high pressure is pumped down a well to fracture (i.e. create cracks in) the reservoir

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[74] The technique, a way of "completing" oil and gas wells, or preparing them to produce energy, is called hydraulic fracturing, or "fraccing". Hydraulic fracturing is the process where fractures in a reservoir are opened up by high-pressure, high-volume injection of liquids through an injection well. (Speight, 2011)

Years later, hydraulic fracturing came to be known in the popular media as "fracking" (with a "k" replacing the "c"). From the outset, industry representatives were deeply antagonistic to the term because of its resemblance to the common expletive and also its similarity to "fragging", the act of attacking fellow soldiers. "Fracking" also rhymes with "hacking", another word with negative connotations. Energy veterans claim that "fracking" was coined by those with a bias against the industry. (Zuckerman, 2013) rock adjacent to the wellbore. The fluid applies pressure to the lithostatic gradient (the weight of the rock above the place where the pressure is applied) and the local resistance of the rock. A fracture is thus created that can extend over several hundreds of meters, provided that enough fluid is injected to maintain sufficient pressure to sustain the load (Pijaudier-Cabot, 2013).

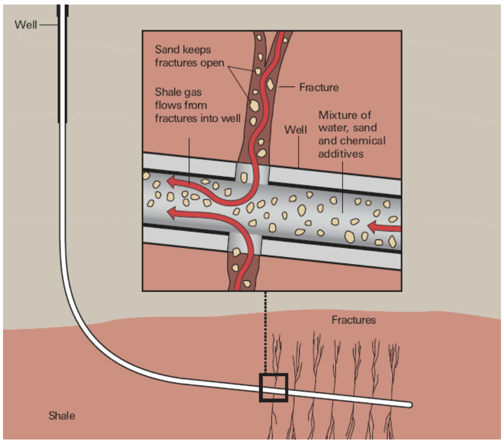
In short, in low-permeability reservoirs, hydraulic fracturing is a necessary stimulation method required to make production economical; in medium-permeability reservoirs, on the other hand, stimulation by fracturing is used to accelerate recovery.

Today, when we speak of “hydraulic fracturing”, we are generally referring to slickwater hydraulic fracturing, with horizontal drilling and multi-stage fracturing, a technique that is not new but has long been safely used in the industry in reservoir stimulation and enhanced recovery.

The process of slickwater hydraulic fracturing consists of injecting fracturing fluids (typically 99.5% water) and proppants (small, granular solids like sand) at high enough pressures to break the rocks, thus creating a network of fractures that allows the permeability of the rock to be increased or to connect with other fractures extending from a wellbore into targeted rock formations. Proppants are pumped into the fractures thus created in a viscous fluid to help ensure the crack remains open after the hydraulic pressure is no longer being applied. This creates a highly conductive path between the reservoir and the wellbore and helps to increase the rate at which oil and gas can be produced from reservoir formations; the goal in any hydraulic fracturing procedure is to limit fractures to the target formation. Excessive fracturing is undesirable as it will increase the cost of the process.

During hydraulic fracturing, the fluid is pumped into the production casing, through the perforations (or open hole), and into the targeted formation at pressures high enough to cause the rock within the formation to fracture. In the field, this is known as “breaking down” the formation. As high-pressure fluid injection continues, this fracture can continue to grow or propagate. The fluid must be pumped at a fast enough rate to maintain the pressure required to propagate the fracture. This pressure is known as the propagation pressure or extension pressure. As the fracture continues to propagate, a proppant, such as sand, is added to the fluid. When pumping is halted, and the excess pressure is removed, the fracture will try to close. The proppant keeps the fracture open, thus allowing oil and gas to flow more readily through this higher permeability fracture. See FIGURE 77.

FIGURE 77. Diagram of the hydraulic fracturing operation

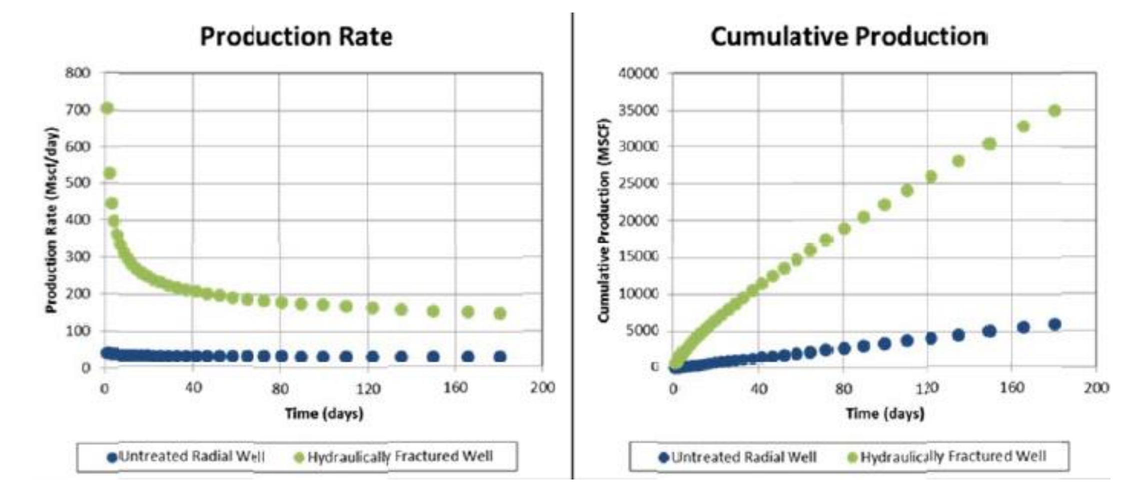


Source: (Bickle et al., June 2012)

The process of hydraulic fracturing increases the exposed area of the productive formation, creating a high-conductivity path that extends for a significant distance from the wellbore through a targeted hydrocarbon-bearing formation, so that hydrocarbons and other fluids can flow more easily from the formation rock, into the fracture, and ultimately to the wellbore.

The figure below shows a comparison between the production rate and the cumulative production for an untreated well and a well that has been subjected to a hydraulic fracture treatment. The graph clearly shows that hydraulic fracture treatments significantly increase the production of natural gas from the formations. In both graphs, the blue curve represents the untreated well and the green curve shows the well treated with hydraulic fracturing (See FIGURE 78).

FIGURE 78. Comparison of production rate and cumulative production for an untreated well and a well treated with hydraulic fracturing



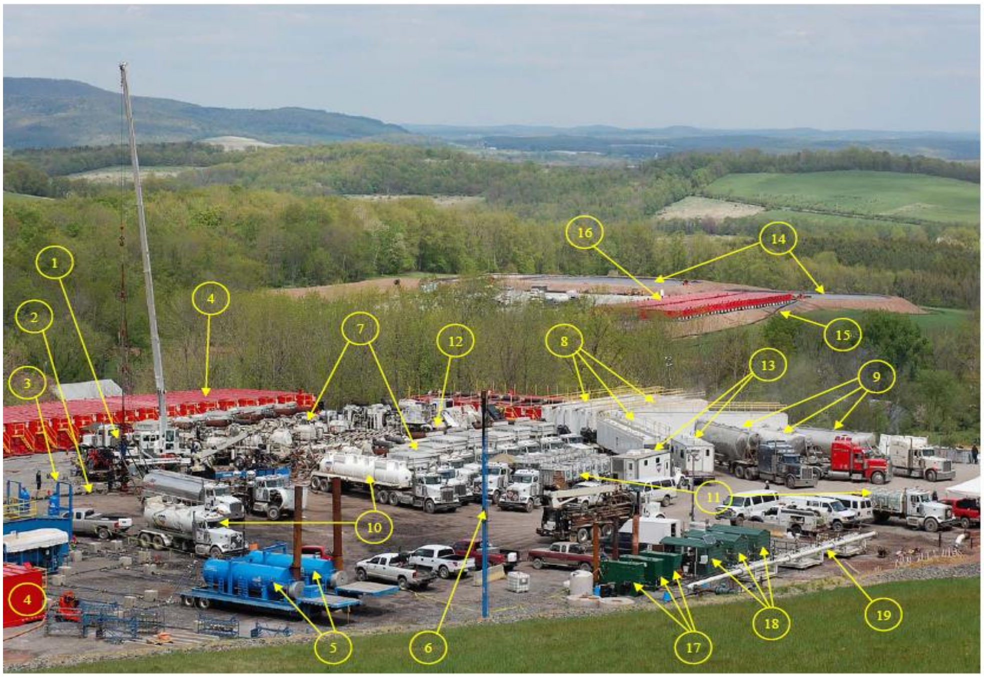
Source: (PXP & Halliburton, 2012)

The oil and gas industry has moved on a lot since "slick water" hydraulic fracturing was first used to stimulate wells artificially. Over the years, the technique has been improved and refined and more recently, adapted to maximize exploitation of shale gas formations.

In this regard, hydraulic fracturing has advanced continuously over recent years with technological innovations that address public concern regarding environmental issues associated with well drilling and completion, such as air emissions and other land and water-related aspects. Water consumption has been reduced, there is now full disclosure of the chemicals used and several hazardous chemicals are being replaced. Other solutions for reducing water consumption are also emerging, for example, adapting chemical formulations to use seawater, produced water, or recycled flowback fluids, thus reducing the need for fresh water.

The photographs below (FIGURES 79 and 80) show a site with hydraulic fracture equipment installed. The first picture gives an overview of the pad with all its components. The second picture shows greater detail of some of the machinery not clearly visible in the first photograph. The last picture shows the equipment needed during well production.

FIGURE 79. Hydraulic fracture operation

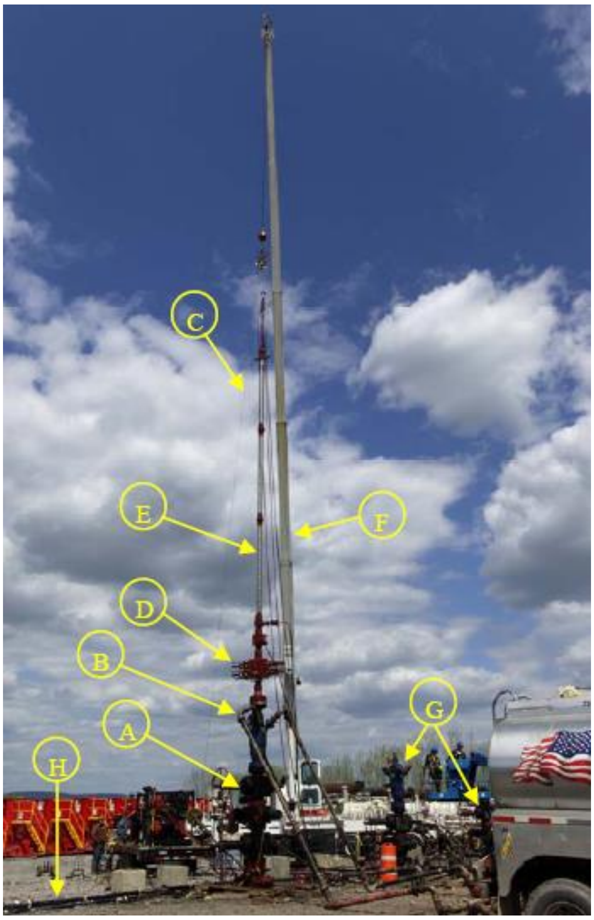


Source: (SGEIS, 2011) Courtesy of New York State Department of Environmental Conservation.

The numbers in FIGURE 79 refer to the following components: 1. Well head and frac tree with 'Goat Head'; 2. Flow line (for flowback & sting); 3. Sand separator for flowback; 4. Water tanks; 5. Line heaters; 6. Flare stack; 7. Pump trucks; 8. Sand hogs; 9. Sand trucks; 10. Acid trucks; 11. Frac additive trucks; 12. Blender; 13. Frac control and monitoring center; 14. Fresh water impoundment; 15. Fresh water supply pipeline; 16. Extra tanks. and production equipment; 17. Line heaters; 18. Separator-meter skid; and 19. Production manifold.

The next picture shows the wellhead and well intervention equipment in detail, including: the well head and frac tree with its valves (A); the goat head (B), used for frac flow connections; the wireline (C) which is used to convey equipment into the wellbore; the wireline blowout preventer (D) whose function was explained in Chapter 4; the wireline lubricator (E) and the crane for supporting wireline equipment (F). Other nearby wells can also be seen (G) together with the flow line (H) for carrying flowback and testing fluids to and from the well.

FIGURE 80.Wellhead and Frac Equipment



Source: (SGEIS, 2011) Courtesy of New York State Department of Environmental Conservation.

As we have been explaining, hydraulic fracturing is only one of the phases in the exploration process, and not the longest one (see FIGURE 90). It is important to keep in mind what the well pad will look like during the production phase, once exploration is over. FIGURE 81 shows the appearance of the well pad when production has just begun. The rotary rig and most of the other components have been removed prior to fracking the well and most other components have also been removed, reducing the visual impact of the operation. It is even possible that the site may be further restored unless further wells are to be drilled from the same pad.

FIGURE 81. Production equipment during well production

Source: (West Virginia Surface Owners' Rights Organization & McMahon, 2015)

The preliminary operations include mobilizing fracturing units (pumps and related equipment to be connected to the frac tree) and a coiled tubing and/or wire line unit and filling, as well as construction of the pits or storage tanks on the fracking site with water pumped or trucked in. The pumping units are installed (usually 10 to 20 depending on the pumping capacity of the units) along with the manifold, mixers and sand bins and sand control center. Correct performance of the communication systems, flow lines and security systems is checked.

Then, the well is completely filled with a solution of water, salt and/or KCl. It has already been isolated from the formations penetrated by casing pipes and cement, which have been pressure-tested for leaks and certified. In the event of any anomaly in the cement bond log (wireline register) or integrity tests, the corresponding remedial work is carried out before proceeding with execution of the well.

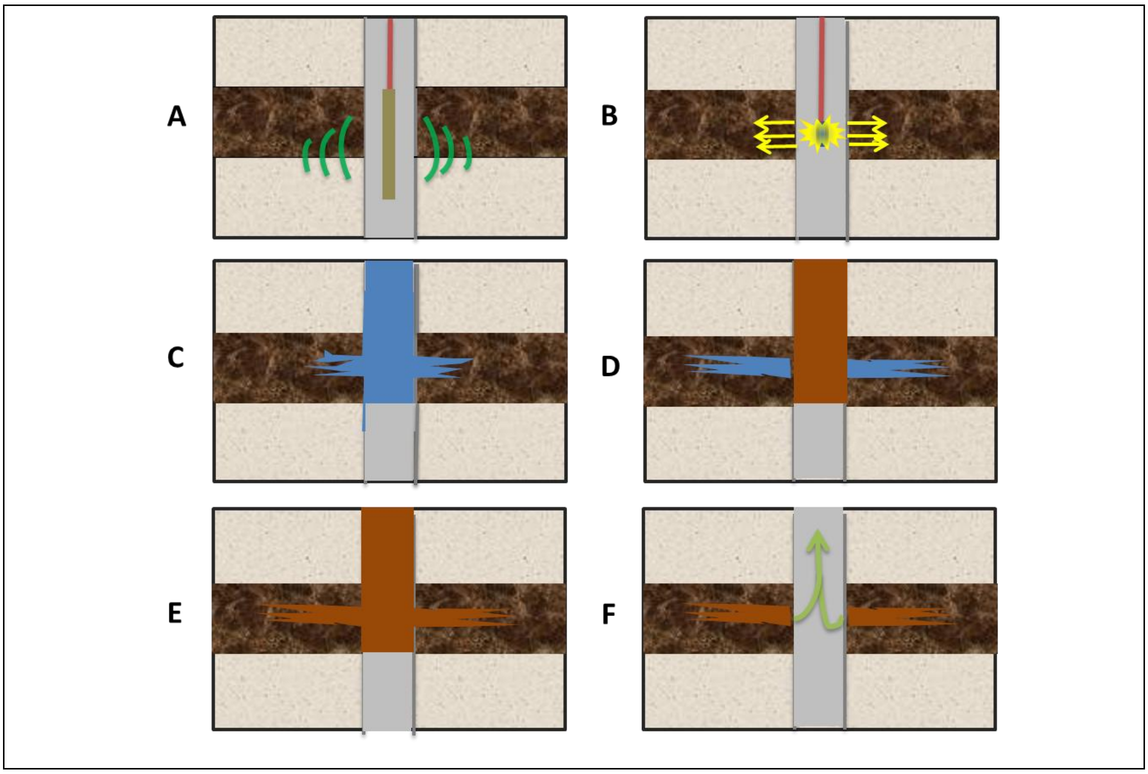
The following sequence is then completed before the casing is perforated: the well is pressured-up to see if there are any annulus leaks; pipeline integrity is then tested and, finally the pressure testing equipment is removed.

Once the well has been pressure-tested, perforating guns are loaded into the well via a wireline unit (alternatively, a sand-drilling apparatus is lowered via coiled tubing)[75]. The explosive charges in the perforating gun are controlled and triggered by an electronic detonator and shoot various bullets through the casing and cement in a pre-determined manner.

Once communication between the well and the formation has been established via the holes made by the perforating charges, a *mini-frac* is carried out by pumping water into the well until the formation breaks down, as evidenced by a drop in pressure. The data from this operation are used to make last minute changes to the design of the *frac program*.

The well is stimulated in various stages, starting at the deepest end of the well, pumping slugs of treated water (slick water) and proppants in sequence, starting with the area of least interest. As each treatment stage is completed (4 to 5 hours), pumping stops and the pressure in the well returns to its original state. A mechanical isolation plug is placed above the top perforation level, using a wireline unit, so that the fractured interval is isolated from higher levels. The process is repeated until all remaining stages have been completed.

FIGURE 82. Hydraulic fracturing process in sequence[76]



Source: Own elaboration (PXP & Halliburton, 2012)

FIGURE 82 shows an illustration of a multiple fracturing process. Drawing A shows the casing being logged to ensure the cement has bonded the casing to the

[75] The following operations are: rigging-up and testing of wire line equipment; running the gun into the in hole (RIH) to the lowest zone to be opened (locating tool at required depth and firing gun to open a tunnel linking the well bore to the formation in a specific area) and pulling the gun out of the hole (POOH) and charging another one in order to drill another zone of interest.
[76] The figure should be read from left to right and top to bottom.

formation correctly. Drawing B shows the moment when charges from the perforating gun pass through the casing and cement and enter the formation, bringing the formation into contact with the well. A typical stage may be around 100-meters long. Drawings C and D illustrate the introduction of the fracking fluid (blue) at a high enough pressure to break down (fracture) the formation, passing through the perforations made in the well casing. Drawing E shows the proppant material being introduced into the fractures. The function of the proppant is to keep the induced fracture open. Once injection is complete (in this case, two zones have been fracked), some of the frac fluid returns back to the borehole in a process known as flow-back (Drawing F). During flowback, paths are created in the propped-open fractures through which gas can flow to the well bore and ultimately be extracted.

At this point, the fracturing process is considered to be complete. On average, the fracturing process may require anywhere from one to 10 days to complete, depending on the number of zones to be treated.

Once the rock has been fractured, fracturing fluids flow back out of the well and in many cases, especially in developing fields, they are recycled and reused. If not, they are properly treated at authorized disposal facilities.

Once the equipment for the hydraulic fracturing treatment –i.e. pumps and trucks– has been removed, the traffic flow associated with the work is almost finished. In most cases, the only equipment remaining typically consists of production valves and collection equipment. The fractured reservoir zones are several thousand feet below the surface, far below the water-bearing bodies that supply drinking water. The hydrocarbon reservoirs are sealed by the surrounding rock formations and contain a finite amount of producible material.

5.1.1. *Hydraulic fracturing fluid, flowback and produced water*

Hydraulic fracturing fluid

As already explained, hydraulic fracturing consists of pumping a fluid into the formation to break down the reservoir in order to achieve gas flows.

Several stages can be identified in the fracturing process. The hydraulic fracturing fluid (water with friction-reducing additives) helps to initiate the fracture and assist in the placement of proppant material. A proppant concentration stage may consist of several substages of water combined with proppant material. The grain size of the proppant material and the proppant concentration will vary during the treatment, starting with a lower concentration of finer particles and ramping up to higher concentrations of coarser particles. In a final flush stage, a volume of fresh water or brine is used to flush the excess proppant from the wellbore. The following table gives information on the basic fracturing treatment fluid.

Well spacing has become "self-healing" to prevent unintended leak paths. Multipad drilling has been introduced to minimize the surface footprint. Field fleets have been converted to operate on natural gas or electricity in order to reduce greenhouse gas emissions. Further enhancements to produced and flow-back water treatment technologies are being developed and evolving alternatives to water will reduce net water consumption.

TABLE 17. Basic fracturing treatment fluid[77]

PRODUCT		FUNCTION	AMOUNT 1 stage (100 m)
Hydrochloric Acid (HCl) (Diluted in water at 15%)		Cleans the perforations	5.7 m^3 (0,85 HCl and 4.85 m^3 of water)
Slick Water	Water	Base fluid	3,125 m^3
	Bactericide	Bactericide	1.56 m^3
	Friction reducer	Decreases velocity loss	1.5 m^3
Sand		Keeps induced fractures open	113.5 t

Source: Own elaboration from Hydraulic Fracturing Service Company (2013)

In addition, several new and emerging techniques are now available, complying with the highest environmental standards. Further regulation will help the industry by establishing benchmarks for good practice and implementing guidelines and rules for the exploitation of "unconventional" hydrocarbons. Public concern, for example over the use of toxic substances and the amount of water used, should be taken into account in the regulatory process, as well as the supporting services.[78]

Nonetheless, hydraulic fracturing is still the preferred method in the industry at this time.

The fluids most commonly used for hydraulic fracturing are water-based. The water can be extracted from surface water bodies, such as rivers and lakes, or from groundwater bodies, such as aquifers or public and private water sources. Sand is added as a proppant to keep fractures open. Various chemicals are also added. During multistage fracturing, a series of different volumes of fracturing fluids are injected with specific concentrations of proppant and other additives, allowing each stage to address local conditions, such as shale thickness, presence of natural faults and proximity to other well systems (API, 2009).

[77] For more information on the technical functions of the components of the fracturing fluid, see Appendix 4.
[78] Further classification for future treatment types can be seen in (Yang et al., 2013)

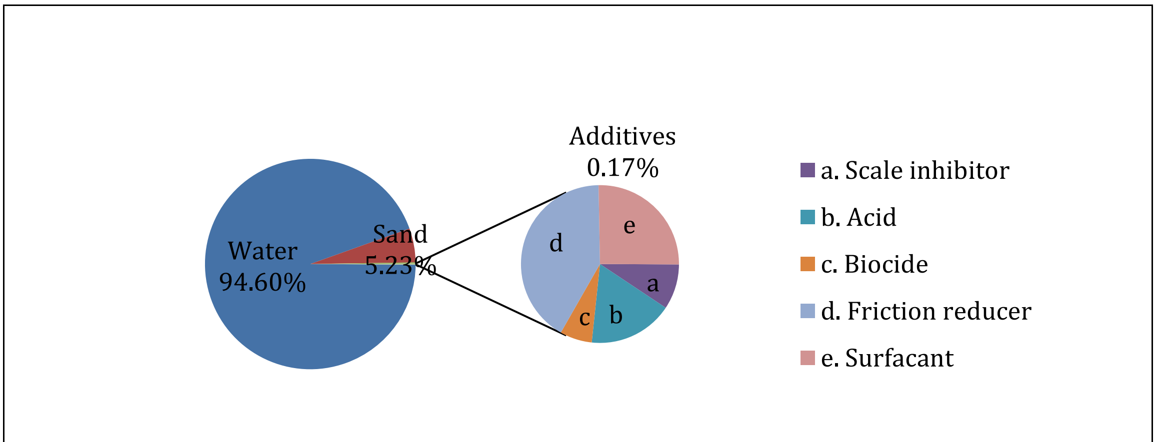
As we have seen in this chapter, these operations require a range of equipment, including fluid storage tanks, proppant transport equipment and blending and pumping equipment. These components are assembled and linked up to monitoring systems so that adjustments can be made to fluid volume and composition, fluid injection rate and pressure (Bickle et al., June 2012).

Water and additives are blended on site in a truck-mounted blending unit. Hoses are used to transfer liquid additives from storage containers to the blending unit or the well directly from the tank truck. Dry additives are poured by hand into a feeder system on the blending unit. The blended fracturing solution is immediately mixed with proppant (usually sand) and pumped into the wellbore.

A proppant is solid material suspended in the fracturing fluid which holds the hydraulic fractures open. A variety of natural and manmade materials are used as proppant, including sand, resin-coated sand, and manmade ceramics. The selection of proppant depends on the stress conditions of the reservoir. Until the introduction of viscous fluids, such as crosslinked water-based gel in the mid-1960s which allowed higher sand concentrations to be pumped, the concentration of sand proppant remained low. The varying sand concentrations are needed to achieve higher proppant distribution in the fracture created. Proppant distribution is related to conductivity in the reservoir.

Chemical additives may include inhibitor to prevent the build-up of scale on the walls of the well; acid to clean deposits on steel materials; biocide to kill bacteria that might produce hydrogen sulfide and lead to corrosion; friction reducer to reduce friction between the well and the fluid injected into it; and surfactant to reduce the viscosity of the fracturing fluid. Benzene, toluene, ethyl benzene and xylene, all considered carcinogenic, are no longer used as additives in hydraulic fracturing. The typical percentage of chemical additives for a specific shale formation is 0.17% (See FIGURE 83). Other figures range from 0.44% to 1.2%.

FIGURE 83. Typical composition of fracturing fluid by volume



Source: (Royal Academy of Engineering, The Royal Society, 2012)

In a properly designed and executed well development plan, the toxic chemicals – principally low-dose biocides– can be replaced with materials that are effective but biodegradable and are often used in municipal drinking water preparation. The most commonly used biocide, glutaraldehyde (Kari, 1993 in (King, 2012)), is the same material that is used in hospitals and food preparation, with relatively low concentrations but a total volume that is comparatively large. One of the most pressing issues in the oil and gas industry is to examine and adopt other technologies, chemical and non-chemical, to replace as many non-green chemicals as possible (Jordan, 2010; Paktinat, 2011 in (King, 2012)).

Generally, between one and five chemicals are used in a slick water frac job. However, other trace chemicals used in product preparation, such as carriers and impurities, can be found in some fracturing fluids. Even the fresh water supplies used in fracturing often contain a group of common minerals and metal ions, plus several "tag-along" trace chemicals, by-products of manufacturing or other traces that have nothing to do with the petroleum industry (King, 2012) (See TABLE 18).

TABLE 18. Common additives used in slick water fracturing in shales

Most Common Slick Water Frac Additives	Composition	CAS Number	Percentage of shale fracs that use this additive. (NB NOT by concentration)	Other uses
Friction Reducer	Polyacrylamide	9003-05-8	Nearly 100% of all fracs use this additive	Adsorbent in baby diapers, flocculent in drinking water preparation
Biocide	Glutaraldehyde	111-30-8	80% (decreasing)	Medical disinfectant
Alternate Biocide	Ozone, Chloride dioxide UV.	10028-15-6 10049-04-4	20% (increasing)	Disinfectant in municipal water supplies
Scale Inhibitor	Phosphonate & polymers	6419-19-8 And others	10 – 25% of all fracs use this additive	Detergents and medical treatment for bone problems
Surfactant	Various	Various	10 to 25% of all fracs use this additive	Dish soaps, cleaners

Source: Own elaboration based on (King, 2012)

The risks associated with the use of chemicals are regulated by EU Regulation 1907/2006.[79] Concerning the REACH[80], it is an integrated system set up by the European Union, along with a European Chemicals Agency, for the registration, evaluation, authorization and restriction of chemicals. REACH requires firms that manufacture and import chemicals to evaluate the risks resulting from the use of those chemicals and to take the necessary steps to manage any identified risks. The

[79] Regulation (EC) No 1907/2006 of the European Parliament and of the Council of 18th December 2006 concerning the Registration, Evaluation, Authorization and Restriction of Chemicals (REACH), establishing a European Chemicals Agency (ECHA), amending Directive 1999/45/EC and repealing Council Regulation (EEC) No 793/93 and Commission Regulation (EC) No 1488/94 as well as Council Directive 76/769/EEC and Commission Directives 91/155/EEC, 93/67/EEC, 93/105/EC and 2000/21/EC.
[80] For more information about REACH, see Appendix 6

burden of proving that chemicals produced and placed on the market are safe lies with the industry.

Today's fracturing fluids are primarily water and sand, sometimes with a gelling agent and a small percentage of different additives (lubricating substances) needed to reduce the pressure required at the surface and additives to control external agents (bacteria). These additives are common chemicals that are a part of our everyday lives. For example, the material used to make the fluid thick (viscous) is usually a natural polymer derived from guar beans (the same agent that is used in cosmetics, ketchup and soft ice cream). The exact formulation varies and depends on well conditions and reservoir characteristics.[81] The Ground Water Protection Council (GWPC) has characterized the blend as "soup".

The Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC) host a hydraulic fracturing chemical disclosure registry called FracFocus and its website includes a publicly-available list with information on the additives used in hydraulic fracturing treatments.

The placement of hydraulic fracturing treatments in the reservoir is sequenced to meet the particular needs of the formation. Although hydraulic fracturing treatments are essentially the same for all wells, each gas zone is different and the steps and type of fracturing treatment may therefore vary depending on unique local conditions. Each fracture treatment must be tailored to the site. The exact blend of hydraulic fracturing treatment blend consisting of fluid, sand and chemical additives and the exact proportions will vary depending on depth, thickness and other site-specific characteristics of the target formation.

Flowback water

The fracturing fluid returns to the surface allowing the oil or gas to exit the reservoir. These flowbacks are monitored to control pressure and other issues which are necessary to know if the process is going to be successful.

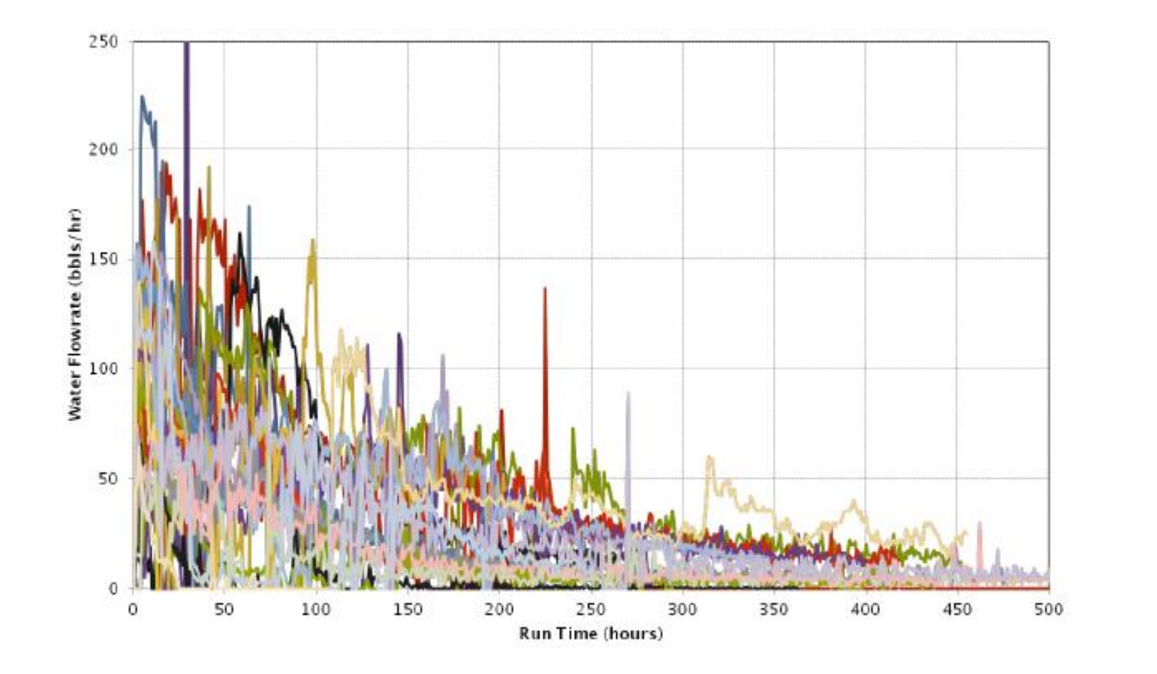
Flowback generally consists of fluids with the same geochemical identity as those of the hydraulic fracturing fluid. Approximately 60% of total flowback occurs in the first four days after fracturing. The flowback is collected after previously being treated in a separator vessel installed downstream of the production tree. Fluids from the well pass through a control valve (choke) to the double phase separator, where the gas and fluids are separated. The gas is piped to the flare and the liquid (flowback) is diverted through the control valve to the storage pit or tanks. In principle, by storing flowback fluids, operators can re-use much of it in future fracturing operations, for example, in other wells on the well pad. This requires filtering and dilution with freshwater and application of other treatment methods necessary to provide the necessary characteristics for usability. It is not possible to

[81] A typical fracturing fluid composition is shown in Figure 78

predict the exact level of possible water re-use, since it varies from one situation to another.

An EPA study looked at over 90 wells in the Marcellus shale formations. A database was developed on controlled and uncontrolled water sources and outlets. The FIGURE 84, taken from the EPA study, shows the flow data for flowback water. As can be seen below, the flow rate of flowback water declines very quickly.

FIGURE 84. Water flow rate during flowback period (2-3 weeks)



Source: (EPA, 2013)

Produced water

Produced water is water from underground formations that is brought to the surface during gas or oil production. Because the water has been in contact with hydrocarbon-bearing formations, it contains some of the chemical characteristics of the formations and the hydrocarbons. It may include water from the reservoir, water previously injected into the formation, and any chemicals added during the production processes. The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geology of the formation, and the type of hydrocarbon product being produced. Produced water is mainly salty water whose properties and volume also vary throughout the lifetime of a reservoir (Argonne National Laboratory, 2009; The Produced Water Society, 2014).

Unlike flowback water, produced water is naturally occurring water found in shale formations that flows to the surface throughout the entire lifespan of the gas well. At a certain point in time, the water recovered from a gas well goes from being flowback water to produced water. This transition point can be hard to determine, but it is sometimes identified on the basis of the rate of return, measured in barrels per day (bpd), and by looking at the chemical composition. Flowback water produces a higher flowrate over a shorter period of time, greater than 50 bpd. Produced water produces a lower flow over a much longer period of time, typically between 2 and 40 bpd. The chemical composition of flowback and produced water is very similar, so a detailed chemical analysis is recommended to distinguish between the two (The Institute for Energy & Environmental Research, 2014).

5.1.2. *Control of fracking*

Microseismic monitoring of hydraulic fracturing work is an invaluable tool for controlling the propagation of fractures induced during the job. The information provided by this method includes: the azimuth of the fractures created, the complexity of the network of fractures, horizontal distance of the fracture from the injection well, and the progression of vertical fractures, indicating how far up or down from the perforations in the well casing for that stage the fractures propagate.

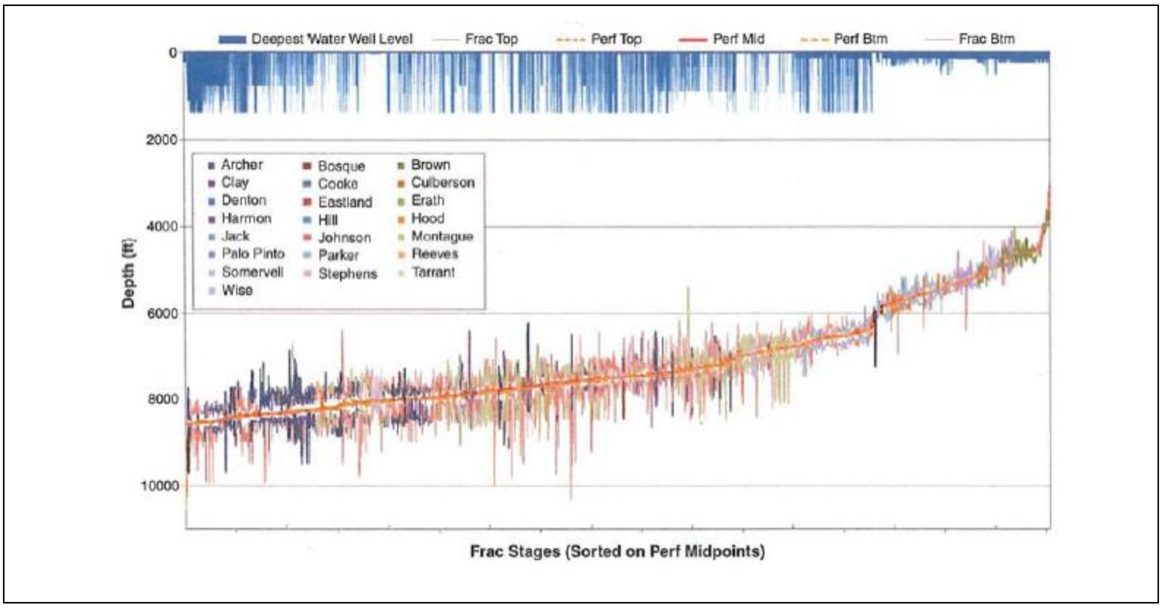
Good process monitoring and quality control during the hydraulic fracture treatment is essential for successful treatment and in order to protect the groundwater if the well simulation is very close to the surface. Some monitoring parameters need to be observed in virtually all hydraulic fracture treatments, while others are employed from time to time based on site-specific needs. Sophisticated software should be used to design hydraulic fracture treatments before they are implemented. The same software should be used during the treatment to monitor and control treatment progression and fracture geometry in real time. During the hydraulic fracture treatment, certain parameters should be monitored continuously. These include surface injection pressure (psi), slurry rate (bpm), proppant concentration (ppa), fluid rate (bpm), and, sand or proppant rate (lb/min).

The data collected are used to refine computer models which are used to plan future hydraulic fracture treatments. In areas with significant experience in performing hydraulic fracture treatments, the data collected on previous fracture treatments in a particular area is a good indicator of what may happen during the treatment.

The FIGURE 85 shows the digital register of microseismic monitoring in Barnett Shale.[82] As can be seen, the vertical fractures never come close to the surface.

[82]"Geologists had known for decades that the Barnett Shale was a rich source rock for gas and smaller amounts of oil, but had no idea how to extract it profitably. George P. Mitchell was determined to unlock that prize and his company drilled the first Barnett shale well in Wise County in 1981.
"His was not an overnight success story. Industry peers questioned the wisdom of punching multi-million dollar wells into rocks with lower permeability and porosity than cement. Mitchell's own engineers told him that he was wasting his money. His board of directors repeatedly told him to give up the search. Undeterred, he persevered with the hunt for almost 20 years. The breakthrough came when one of Mitchell's engineers, Nick Steinsberger, recommended trying to pry open the

FIGURE 85. Barnett Shale Mapped Frac Treatments/TVDs



Source: (Bickle et al., June 2012)

5.2. Well completion

Once a natural gas or oil well has been drilled and it has been verified that commercially viable quantities of natural gas or oil are present for extraction, the well must be 'completed' to allow natural gas flow in safe conditions out of the formation and up to the surface.

According to (Bommer, 2008), if the well does not contain hydrocarbons –or not in sufficient quantity to make completion financially viable– the well will be *plugged and abandoned* (P&A). To P&A a well, the drilling rig pumps several cement plugs through the drill pipe. The cement plugs are used to isolate and seal unprofitable hydrocarbon zones from nonhydrocarbon-bearing zones and to seal freshwater zones from saltwater-bearing zones. The intervals between cement plugs are left full of drilling mud.

Finally if the well is on land, the well site will be restored after the drilling rig has been removed from the location.

5.3. Production

Once drilling and hydraulic fracturing operations are complete, a production Christmas tree is installed over the wellhead to collect and transfer gas through a pipeline for subsequent processing. Production from a well on a given well pad may begin before other wells have been completed (Conaway, 1999).

shale rock. It worked. Finally, Mitchell was seeing the fruits of decades of work. The second component of the shale revolution was horizontal drilling. That came later, in the 1990s and was the real key to unlocking the Barnett and other shales, including the Marcellus in Pennsylvania and later the Bakken and Eagle Ford shale-oil fields". (Petroleum Economist, 2013)

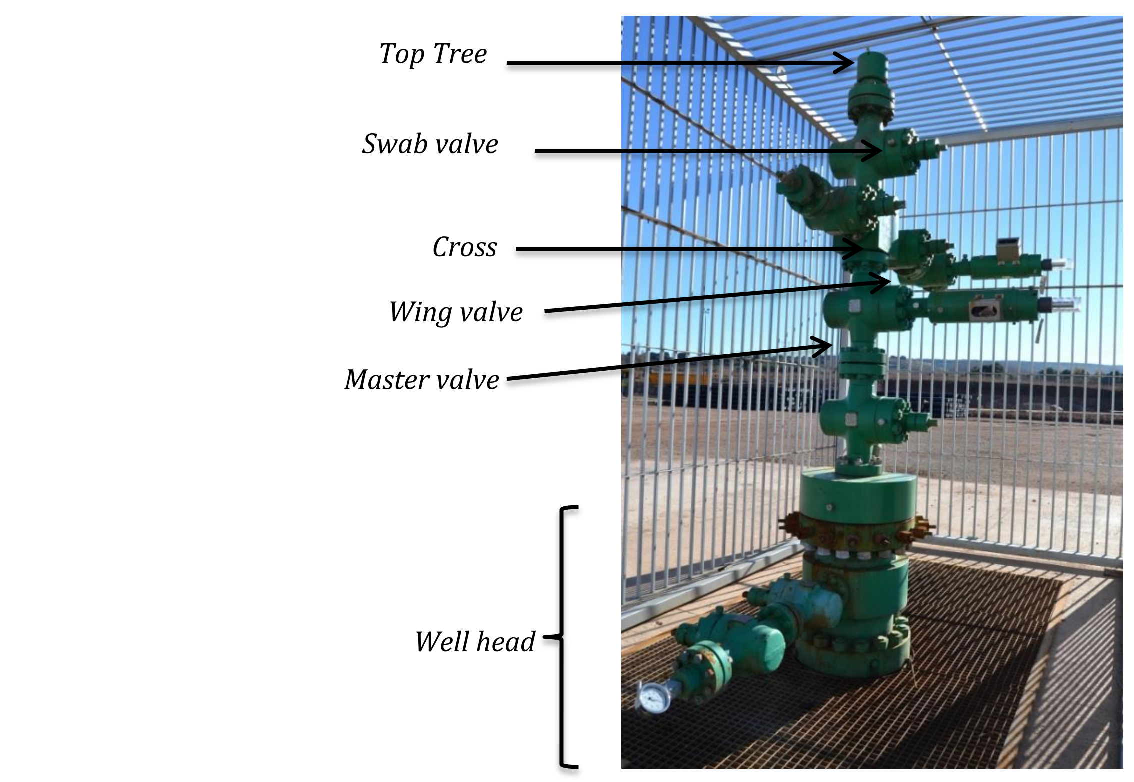
When production starts, the pad is almost empty. The picture below shows a well ready to go into production. In this case[83] the gas treatment facility has yet to be built.

FIGURE 86. Overview of a well ready for production

Source: (Álvarez Sánchez, 2013)

[83] This well is not for shale gas production but the appearance is similar.

FIGURE 87. Typical Christmas tree installation



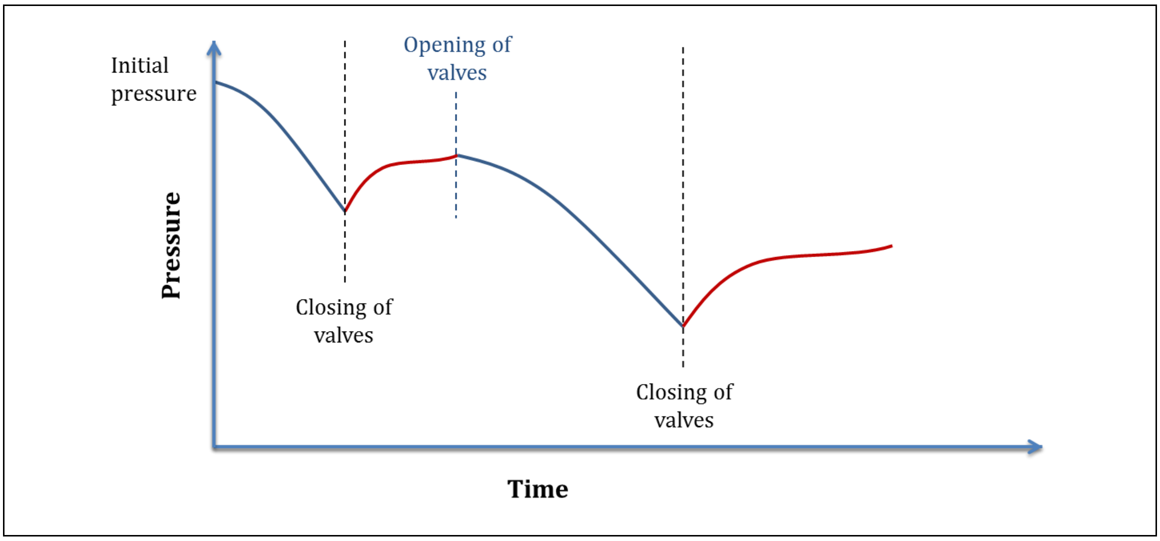
Source: (Álvarez Sánchez, 2013)

In hydrocarbon wells, the term 'Christmas tree' is used to describe the manifold valves that control flow out of the well. The tree is designed and built to work at full reservoir pressure plus a significant safety margin. The functions of the various valves are as follows (see FIGURE 86): the master valves are used to shut in the well; the crown (or lubricator) valve is used when a lubricator is attached to perform through-tubing well services; the wing valve is normally used for routine opening and closing of the well; the choke is a valve with variable outlet to control well flow and pressure. This valve also protects downstream equipment by confining full well pressure to the tree. The safety valve automatically shuts the well down if unsafe conditions occur (Conaway, 1999).

Once the well is ready, a Long Term Test (LTT) can be run. The main purpose of the LTT is to produce enough gas to create a production model based on the well's flow and pressure performance. To do this, the properties of both the reservoir and the produced fluid are tested.

Once the fluid produced by the well is considered to be representative of the reservoir, different periods of flowing and shut-in pressure are alternated. In flowing periods, falling pressures are studied and in shut-in periods the operator studies how the well behaves as pressure again increases (see FIGURE 88). Depending on the time of the test, a distinction can be drawn between short-term tests (normally lasting days) and long-term tests, which can take some months.

FIGURE 88. Illustrative change in pressure during production tests

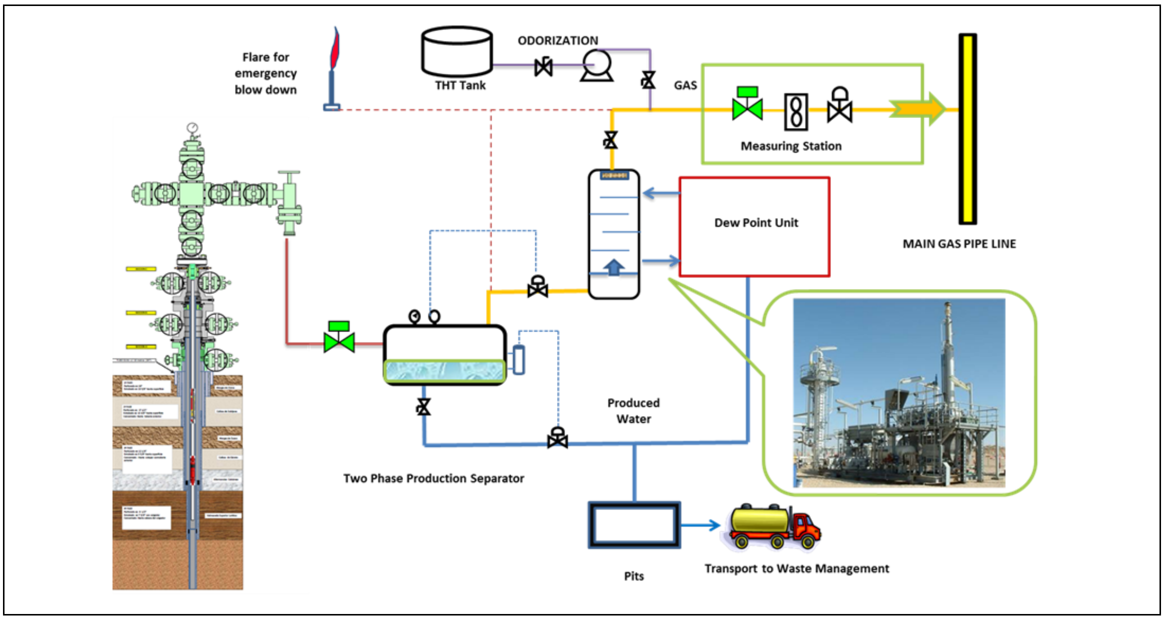


Source: own elaboration based on (Hyne, 2012)

Data collected in LTTs are used to determine the commercial viability of gas production. An LTT is similar to commercial production of a well where the gas is conditioned for sale in a processing plant and injected into the gas network. A diagram of the facility is shown in FIGURE 89.

Processing the gas includes separating out the water, oil and condensate that come with the gas when it is produced. All of the water is not removed; only enough to lower the water content to a specified dew point. Unwanted gases, like CO_2 and H_2S are also removed during conditioning of the gas. Finally, the gas is mixed with tetrahydrothiophene (THT) so that leaks can be detected by odor and the gas is measured and sent to the gas grid.

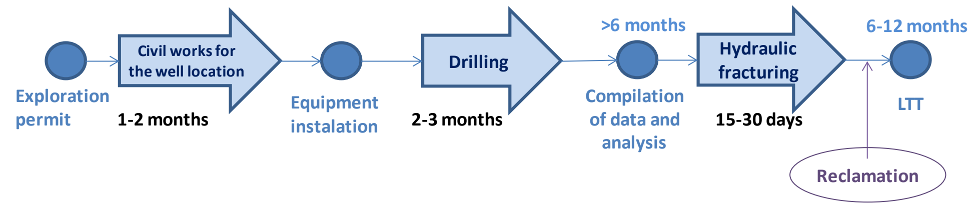
FIGURE 89. Diagram of proposed treatment for a long-term test



Source: (Grupo EVE, 2012)

To conclude this chapter, the FIGURE 90 offers an overview of the time frame in the exploration process. The time scale is for a single well (one pad, one vertical well and one or two horizontal branches).

FIGURE 90. Phases of a gas exploration project (per well)



Source: own elaboration based on (BNK, 2015)

6. ENVIRONMENTAL ISSUES IN THE EXTRACTION OF UNCONVENTIONAL GAS

In this chapter we will review the environmental issues related to shale gas exploration. For this purpose, we have analyzed the technical literature, as well as recommendations and reports from a number of institutions such as the European Commission, the European Parliament, the Environmental Protection Agency (EPA), universities and research centers.

This chapter is divided into nine sections. Following a brief explanation of risk management, we will try to examine the environmental implications of shale gas exploration, mainly those related to water and fluids, seismicity, radioactivity, surface requirement, air emissions and noise. The chapter ends with some conclusions.

6.1. Risk

Before addressing the risks associated with exploration and production of hydrocarbons, it may be helpful to explain the difference between risk and anthropogenic hazard.

'Risk' is the non-standardized probability of specific negative effects occurring within a given period of time. In the case of environmental risks, the specific effects considered are those affecting nature, people or objects.

The concept of hazard, on the other hand, refers to anything that might potentially have adverse effects and, consequently, cause harm to the population and/or the environment. This concept is related to the intrinsic characteristics of a substance, a plant or the physical/geological status of a site (European Commission, 2009). If the source of risk lies in human activity, the hazard is categorized as being anthropogenic.

No human activity is free from risk and shale gas extraction is no exception. This technology has a risk level that is similar to other types of industrial activity, particularly those related to the oil and gas industry (DNV, 2013); (Ewen et al., 2012); (Zoback et al., 2010). As in other industries, exploration and production of hydrocarbons is subject to the possibility that accidents or anomalies may occur in the working area – in this case, the subsoil.

In this respect, an examination of risk also involves an analysis of probability and consequences and the type of effect or impact they might have. At present, risk management is a generally accepted tool for making decisions and controlling risks in a wide variety of industrial and non-industrial human activities. Risk is an important element in the implementation of a large number of safety regulations, corporate policies and best industry practice (Richard, 2011).

Risk management (DNV, 2013) provides a broad framework for aiding decision-making through the identification, analysis, evaluation, and control of risks, including, of course, those related to health and safety. A key aspect is the need to ensure the identification of significant risks, so that appropriate measures can be taken (risk analysis). An identified risk can be assessed or monitored, reduced, accepted or eliminated.

Following analysis, a risk may be assessed and classed as acceptable, unacceptable, etc. These categories are determined by drawing up a balance between risk control strategies, cost and effectiveness, and the needs, problems and concerns of stakeholders or those who might be affected. This is an essential element in the strategic planning of any activity or deal (Freeman, 1984).

Risk management necessarily involves an evaluation of inherently uncertain circumstances and events. This means estimating the two components of risk: the probability that the risk event or condition will occur (the uncertainty component of risk) and its potential impact. When evaluating the significance of a particular risk, it is necessary to take both components into consideration.

In the case of shale gas projects, we also have the risks arising from the operation of surface facilities associated with the project. These are similar to those associated with other types of industrial project and their evaluation is common practice. Because estimations of probabilities and consequences are based directly on experience, the reliability of their assessment is high, but usually not bias-free (Pérez, MP, 1988; Slovic, P. y Fischhoff, B., 1977). Examples of risk involved in some shale gas operations and their comparable industries include injection operations, well completion, stewardship, local/regional hazards, and geotechnical safety (Behdeen et al., 2013).

Security and risk management related to shale gas projects should be considered to be part of a continual and iterative process throughout the project life cycle. Based on appropriate methodologies, a robust and reliable framework should be established to identify, assess and manage risks and uncertainties, covering all phases of the project, including the exploration phase, which will typically involve fewer or less rigorous processes and engage fewer or more down-scaled systems, equipment, infrastructure, etc. than other phases (DNV, 2013).

During the early planning phase, when the key issue is to select a business model and technical concept, the principal risk activities will be identified to establish risk criteria and safety targets and to ensure that that there are no “showstoppers”. This may require qualitative approaches. At this stage in the development of a plan, detailed Quantitative Risk Analysis (QRA) will be of limited value, since no detailed information describing the facilities will be available as input.

The process of risk identification and subsequent risk assessment should therefore be tailored to the relevant stage of development for a project, reflecting the decisions to be made and the level of detailed information available. In addition, as mentioned, it is important to note that no two gas extraction projects are the same, because of the variations imposed by the geology of each specific site and its behavior in relation to the fracking process (IRGC, 2013). Consequently, the level of risk will vary from one site to another. In other words, it is not possible to establish a general risk prioritization. However, we *can* take advantage of the experience in risk management and best practice in one area to minimize the risks in others.

Even though any assessment of the significance of each specific risk (probabilities and consequences) will depend on the unconventional gas exploitation site, concerns in this area are mainly related to the following aspects: gas migration; migration of fluids; water use; management of produced water; additives; Naturally Occurring Radioactive Materials (NORM); surface spills; anthropogenic road traffic, dust, noise and light; well construction; and seismicity (Bunger et al., 2013).

The risks of unconventional gas projects are linked to several natural and engineered factors, which need to be properly addressed to lessen both the risk and its potential damage.

Since exploration or development wells intersect different formations, each with its own characteristics and presence of fluids, special care must be taken in the design and installation of well barriers in order to isolate the different geological units and producing zones.

Another critical point that needs to be considered is the geological environment (geology, hydrogeology, geochemistry and geomechanics) of the formations from which the unconventional gas is extracted. This environment will condition the movement of fracturing fluids (including any additives) and what happens to them after hydraulic fracturing of the target formation – i.e. whether these fluids enter overlying formations or come to the surface (PXP & Halliburton, 2012).

It is important to define the area of influence properly. It should be no smaller than the expected footprint of the horizontal sections of the wells, if any. The environmental effects that need to be studied are those associated with processes that might affect the atmosphere, soil, subsoil and surface water, processes affecting groundwater and processes related to soil movements caused by subsidence or induced seismicity.

6.2. Drilling operations

In this section we will review how the drilling operations (explained in detail in Chapters 4 and 5) may affect the environment and how these effects can be solved or mitigated. We will also examine what aspects need to be considered to avoid such problems.

The primary objections to drilling usually involve noise (which can be reduced by using electric rigs), visual impact (drill rigs involved in most unconventional well drilling are between 50 and 100 ft. high), dust (if air drilling is used, special equipment is required to control air and cuttings), time on location (see FIGURE 90), water and mud storage (pits or steel tanks), chemicals in the mud (typically natural bentonite clay, barium sulfate weighting agent and water), pressure control (both surface and subsurface) and air emissions from diesel engines.

In hydraulic fracturing operations, other environmental aspects are also taken into consideration, such as the surface area required, heavy goods traffic, water consumption, chemical additives used in the fracturing fluid, control of flowback and produced water and induced seismicity.

Each of these objections can be addressed by proper application of technology, third party inspections, high operational standards and best practice. Increased use of electric rigs, which are more common in condensed pad operations, reduces noise and limits emissions.

Acoustic barriers are commonly placed around generators and other cyclic and continuously rotating equipment. When possible, lower profile rigs are used on shallower wells; however the trade-off is that larger rigs are usually faster. Paving any roads, re-routing heavy or frequent loads, scheduling crew transfers at off-peak times and dust mitigation on air drilling projects are all methods that have been used to reduce dust and traffic. Using pipelines to transfer water to and from the well location sharply reduces truck traffic, reducing dust and emissions.

Areas of concern include recovery, storage and transfer of fluids used or recovered in well operations. These concerns can be addressed with covered storage, isolated pits, steel tanks or other environmentally acceptable alternatives (Patel, 2009). Most chemicals used will be adsorbed in the formation or spent (degraded) on use. A closed loop system (total reuse) is also desirable to reduce costs and to minimize possible losses to the drilling muds (King, 2012).

Poor well construction can have major environmental consequences; inadequate design or execution increases the risk of unwanted migration of gas or fluids between the formations cut by a well. The risk rating here is related to risks occurring during the well construction and development phase. The causes of groundwater contamination associated with well design are generally related to the quality of the well structure (the casing and cement used).

Scientific reports on the potential environmental impacts of fracking demonstrate that environmental risks depend primarily on the quality and integrity of the borehole casing and cementing job, rather than the fracking process itself (Healy, 2012).

Although fracking has been performed in some areas for decades without apparent problems, we cannot rule out the possibility that lack of evidence of such leaks might simply be due to the slow progress of some of the processes involved. In any case, the risks of these failures occurring may be controlled and reduced by following industry best practice. Because of the potential for groundwater contamination from the wells, the fundamental rule is that decommissioned wells must be effectively sealed. (FROGTECH, 2013)

During the well construction and development phase there is a risk of subsurface groundwater contamination due to drilling muds, additives and naturally occurring chemicals in well cuttings (AEA, 2012). Given the limited extent of potential effects and the established issues under consideration, such impacts are considered to be of “minor” potential significance. In view of the limited number of incidents associated with the drilling and casing stage of the process in peer-reviewed and other literature, the frequency has been classed as “rare” for both individual facilities and cumulative impacts. It is also important to achieve a high standard of well integrity to ensure impacts are properly controlled during subsequent stages in the process. (AEA, 2012).

The most recent report by the German National Academy of Science and Engineering (Acatech), published in June 2015, concluded that, “*a general ban on hydraulic fracturing cannot be supported on the basis of scientific and technical facts*”. The scientists call for high safety standards and clear regulation which need to be monitored. (Acatech, 2015) Along similar lines, Public Health England has stated that “*the currently available evidence indicates that the potential risks to the public health from exposure to the emissions associated with shale gas extraction are low if the operations are properly run and regulated*”. (Kibble et al., 2014)

6.3. Water and fluids

Water is probably the most significant environmental issue – or at least, one of the ones that has been most widely debated. It is important to have a good understanding of water consumption and wastewater treatments and liquid waste management. This section offers a comparison with water use in other common activities.

6.3.1. *Water withdrawals*

Many processes associated with the production of unconventional gas make use of water resources. This can impact the quality and availability of water in the production area, generating an imbalance between supply and demand of water resources in the area.

It is important to note that the societal impact on water resources is extensive and varied. Water is not required solely for drinking and irrigation purposes. It is also necessary to ensure that water withdrawals during periods of low stream flow do not affect recreational activities, municipal water supplies or other industrial facility usages, such as use by power plants.

In shale gas extraction, we need to differentiate between “water withdrawals” and “water consumption”. A report by the Joint Research Centre in 2013 defines “water withdrawal” as “the total amount of water taken from a water body/resource and destined for use in the shale gas extraction process (the majority of which is used for fracking)” and “water consumption” which is “the amount of water that is used up during the fracking process or, more specifically, that which is lost". Thus, if no water is returned, the total amount of water withdrawn is consumed. (JRC, 2013a)

The water required in the hydraulic fracturing process can be obtained from many different sources, such as surface/ground water, water from local suppliers, wastewater treated by local/industrial plants at the production site, water from the cooling circuit of power plants and/or water recycled from flow-back/produced water in the shale gas play.

Estimates indicate that the amount of water needed to operate a hydraulically fractured shale gas well over a ten-year period may only be equivalent to the amount needed to water a golf course for a month, the amount needed to run a 1,000 MW coal-fired power plant for 12 hours or the amount lost to leaks in the United Utilities' regions in North West England every hour (Moore, 2012; Royal Academy of Engineering, The Royal Society, 2012).

A comprehensive study of the water required to develop the Barnett Shale, conducted on behalf of the Texas Water Development Board (Harden, 2007), provides a review of the literature on specific water consumption. Older uncemented horizontal wells, with a single frac stage, needed about 4 MMGal (~ 15,000 m^3) of water. In newer cemented horizontal wells, the fracturing work is performed at various stages on several perforation clusters at the same time. The typical distance between two fracturing stimulation stages in the same horizontal well is 400-600 ft. (130-200 m). In the Eagle Ford Shale area, the range of fracturing stages is between 12 and 21 stages per horizontal well, with an average of 17 stages per well (JRC, 2012).

The table below shows data on estimated per-well water requirements for four shale gas plays currently being developed in the USA.

For a rough upscaling, 15,000 m^3 per well seems to be a realistic measure of the total amount of water needed to develop a single horizontal well in the USA. Taking a 15-staged fracture job per lateral well, an average consumption of 1000 m^3 of water per single frac stage can be assumed.[84]

These figures can be compared with water consumption by sectors in the same areas of the USA. The table below shows the distribution of water used in the four shale gas plays referred to in the table below.

[84] Statistical analysis of about 400 wells resulted in an average water consumption of 2,000-2,400 gal/ft. (25-30 m^3/m) for water fracs (Grieser 2006) and about 3,900 gal/ft (~42 m^3/m) for the slickwater fracs used more recently, where the distance in meters corresponds to the length of the horizontal part of the well (Schein et al., 2004).

TABLE 19. Water consumption per well in 4 shale gas plays (USA)

	Volume of drilling water per well		Volume of fracturing water per well		Total volumes of water per well	
Shale gas play	gallons	m³	gallons	m3	gallons	m³
Barnett	400,000	1,514	2,300,000	8,705.5	2,700,000	10,219.5
Fayetteville	60,000	227.1	2,900,000	10,976.5	2,960,000	11,203.6
Haynesville	1,000,000	3,785	2,700,000	10,219.5	3,700,000	14,004.5
Marcellus	80,000	302.8	3,800,000	14,383	3,880,000	14,685.8

Source: Compiled by the authors from (Spellman, 2013)

As can be seen, although the water used in hydraulic fracturing is not fully recovered, this quantity is only required for short periods (unlike other industrial uses) so it typically accounts for a very small percentage of the total water demand (less than 1%) in any shale gas basin (JRC, 2012).

TABLE 20. Distribution of water consumption by sector in the shale gas areas (USA)

	Public supply	Industry and mining	Power generation	Livestock	Shale gas	Total water use
Shale gas play	%	%	%	%	%	(10^9 m^3/yr)
Barnett	82,7	4,5	3,7	2,3	0,4	1,77
Fayetteville	2,3	1,1	33,3	0,3	0,1	5,07
Haynesville	45,9	27,2	13,5	4	0,8	0,34
Marcellus	11,97	16,13	71,7	0,01	0,06	13,51

Source: Compiled by the authors from (JRC, 2012)

The TABLE 21 shows the "water use efficiency" –i.e. the amount of water used in gallons for every MMBtu of energy produced by different energy resources. It is worth noting the remarkably low consumption of water in the case of shale gas compared to other energy sources.

With regard to the impact of water withdrawals on water quality, there are concerns that hydraulic fracturing might require volumes of water that would significantly deplete local water resources (Entrekin et al., 2011). Reported estimates for the volume of water required for shale gas extraction vary according to local geology, well depth and length and the number of hydraulic fracturing stages (Bickle et al., June 2012).

As regards shale gas exploration in Europe, a report by the Polish Environment Ministry, which examined environmental conditions during recent exploration work in the country, indicates that "*water abstraction under relevant water permits at all test sites had no effect on the status of groundwater resources and did not cause a lowering of the groundwater level*" (Konieczynska et al., 2015)

TABLE 21. Fresh water consumption in the energy industry

Energy resource	Range in gallons of water per MMBtu of energy produced
Natural shale gas	0.60 – 1.80
Natural gas	1 – 3
Coal (no slurry transport)	2 – 8
Coal (with slurry transport)	13 – 32
Nuclear (processed uranium ready to use in plant)	8 – 14
Conventional oil	8 – 20
Synfuel – coal gasification	11 – 26
Oil shale petroleum	22 – 56
Tar sands petroleum	27 – 68
Synfuel-Fisher Tropsch (coal)	41 – 60
Enhanced Oil Recovery (EOR)	21 – 2,500
Fuel ethanol (from irrigated corn)	2,510 – 29,100
Biodiesel (from irrigated corn)	14,000 – 75,000

Source: Compiled by the authors from (Tamim, Hill, & Poole, 2009)

Regional management of water resources is important to ensure that the effects of hydraulic fracturing can be managed within the context of competing demands on water resources and changes in climate.

Although the water needed for an individual shale gas well may represent a small volume over a large area, the withdrawals may have cumulative impacts on watersheds in the short term. Even in areas of high precipitation, it can be difficult to satisfy regional needs for water due to a variety of factors, such as growing population, other industrial water demands and seasonal variations in precipitation (Spellman, 2013).

The rate of water extraction is also important. Hydraulic fracturing is not a continuous process. Water is required during drilling and then at each stage in the fracturing process. Operators should consult water utilities companies to schedule operations in such a way as to avoid periods when water supplies are more likely to be under stress (Moore, 2012).

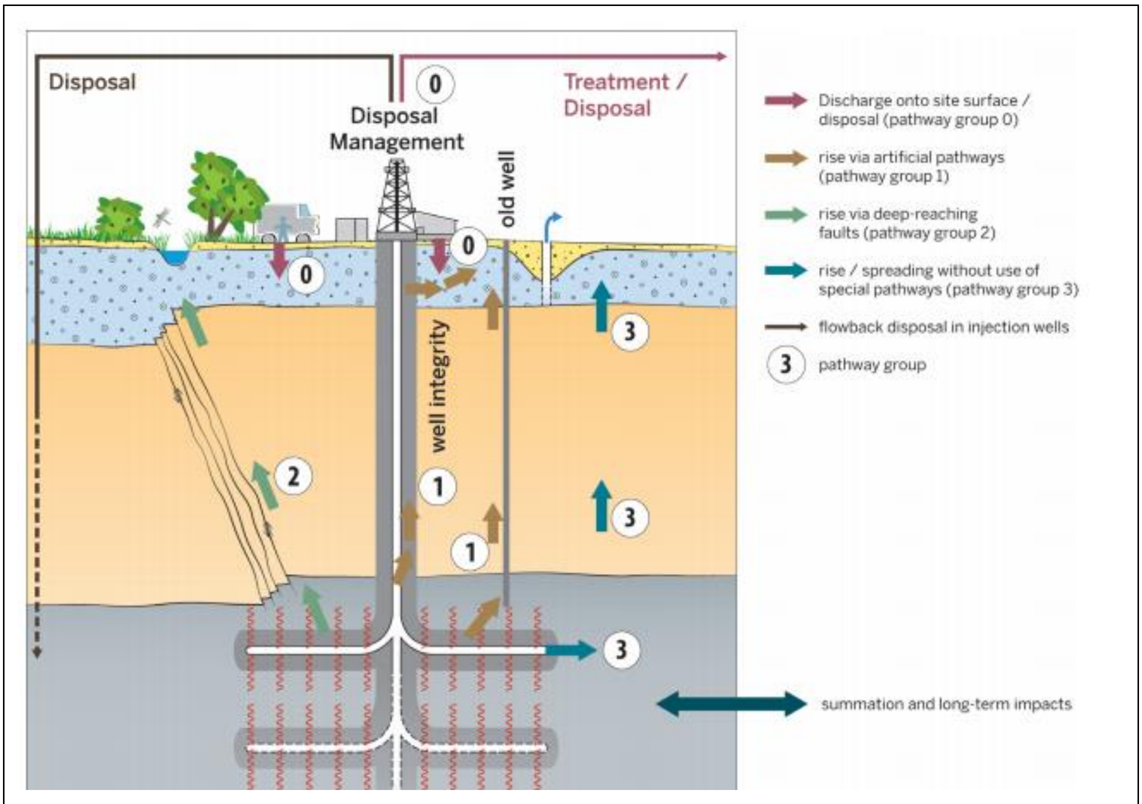
One alternative that states and operators are pursuing is to make use of seasonal changes in river flow to capture water during periods when surface water flows are greatest. Utilizing seasonal flow differences allows withdrawals to be scheduled to avoid potential impact on municipal drinking water supplies or on aquatic or riparian communities (Spellman, 2013).

6.3.2. *Potential impact on ground water*

Regarding the potential impact of the hydraulic fracturing process on ground water, it is important to note that this depends on two different factors – firstly, on the risk related to the fracturing fluid (which varies depending on the chemical composition and the additives selected by the operators) and secondly on the risk related to produced water (and consequently on the geological properties of the target formation).

There are three mechanisms that could potentially result in contact between fluids from drilling and fracturing and sensitive groundwater. Firstly, the down hole flow and flowback of the fracturing fluids, drilling fluids, produced water and gases in the well could result in contact with groundwater if the wells are not properly constructed. Secondly, subsurface drinking water supplies could also be contaminated during surface events, such as accidental spills and leakage from surface impoundment used to store fracturing fluid and flowback. Thirdly, groundwater could potentially be contaminated in the event that fractures extend beyond the production zone. The likelihood of aquifer contamination through natural and induced fractures is remote when the separation between the drinking water sources and the producing zone is greater than 600 meters. However, where the depth separation is smaller, the risks are greater (AEA, 2012; IEA, 2012).

FIGURE 91. Schematic description of potential impact pathways[85]



Source: (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, 2012)

FIGURE 91 shows four different groups of potential impact pathways. Pathway group 0 refers to pollutant discharges that occur directly at the ground surface, via accidents, disruptions and, in particular, improper handling of fracking fluids and management of flowback (not including disposal). Pathway group 1 includes potential discharges and spreading along wells (well leakages can lead to unwanted entry of fracking fluids into the annulus or into the neighboring rock). Failures in cementations and/or casings can eventually become impact pathways

[85] It is important to note that the figure is not scaled. There is a minimum of 1000 meters between the aquifer and the target formation.

in the long term. Pathway group 2 is related to geological faults and Group 3 involves the extensive rise/lateral spread of fluids through geological strata (Álvarez & Fundación Gómez Pardo, 2014; Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, 2012).

In FIGURE 91, Groups 1, 2 and 3 can only be considered as a risk during hydraulic fracturing operations. Once these are complete and flowback commences, the differential pressure between the well and the hydraulically fractured zones makes fluids migrate towards the area of least pressure (i.e. the well).

There are various possible measures that need to be considered for limiting possible ground water contamination risks. These include: restricting hydraulic fracturing in areas with potentially significant groundwater risks (less than 600 meters of separation between the base of a freshwater aquifer and the level to be fracked); using the appropriate standard of well casing (API grade); quality assurance of the cementing of the casing using cement bond logs and/or pressure tests; proper liner construction; and proper pad design and construction to prevent filtration of stored fluids to the subsurface. Proper impoundment design and construction will prevent a failure or unintended offsite discharge. Control of the fracturing process in the exploration stage is important to ensure that no leakage takes place via extended fractures into the groundwater zone.

Groundwater monitoring is now an established feature of hydrocarbon and mineral extraction and industrial process operations in Europe, but it is often performed only in the case of a pollution event occurring or being suspected. For other installations such as landfill sites, groundwater monitoring is conducted routinely. Some drinking water wells may be private wells which do not meet relevant construction standards. This may compromise the ability to take representative samples (AEA, 2012).

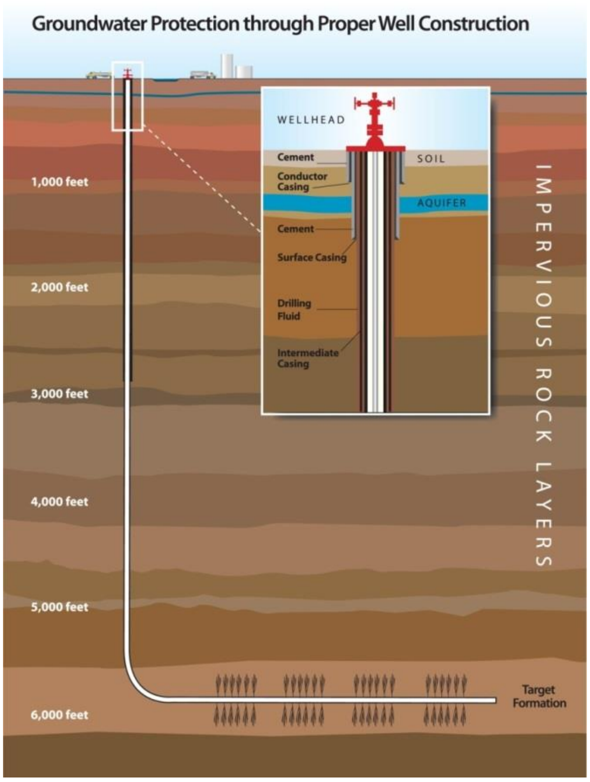
Requirements for systematic groundwater quality monitoring will not in themselves prevent pollution, but are an important element in identifying any contamination issues which might arise, enabling remedial actions to be taken if necessary.

The monitoring program needs to take into consideration the pollutants of potential concern, including methane, fracturing fluid constituents, and contaminants likely to be present in produced waters, as determinants to indicate any unacceptable discharges into the controlled water.

In the USA, issues have been identified in which groundwater contamination has been tentatively identified (EPA, 2011; Osborn et al., 2011) but establishing the source of contamination is highly complex given the absence of baseline monitoring data (AEA, 2012).

Where possible, it is recommended that a baseline of surface and groundwater chemistry be established given the need to establish the source of any contamination, essential in subsequent mitigation of any possible impact. It is important that any regulatory regime be sufficiently flexible to accommodate the range of circumstances likely to be encountered in practice. Once the baseline has been established, the monitoring program should continue throughout the exploration and production phases to spot any changes in surface or groundwater quality (AEA for the European Commission, 2010).

FIGURE 92. Groundwater protection through proper well construction



Source: (EIA, US Department of Energy, 2015)

Most accidents involving groundwater contamination appear to be due to avoidable incorrect handling. For the ENVI, the basic problem is not inadequate regulation, but enforcement of that regulation through adequate supervision. It is necessary to ensure that best practice is not only available, but also commonly applied (ENVI European Parliament, 2011).

There has been one high profile example of groundwater contamination, possibly due to fracking, by chemicals (BTEX[86], other organics and methane) in Pavillion, Wyoming. However the source of these contaminants has not been scientifically proven to be related to fracking. Two conventional gas wells (not shale gas) in the Wind River Basin which had been fracked to increase production are suspected to have been the source of contamination. The hydraulic fracturing occurred within 372 meters of the surface, while domestic groundwater bores in the area are screened as deep as 244 meters below the surface (FROGTECH, 2013).

[86] Benzene, toluene, ethylbenzene, and xylenes.

The ultimate pathway of contamination in Pavillion has not been fully determined, but it is important to note that apart from two production wells, none of the gas wells are cased below the level of the local groundwater system (FROGTECH, 2013). This possible contamination was reported by EPA investigators, but the State of Wyoming regulatory agency responsible for monitoring groundwater contamination has strongly disputed the EPA's findings[87].

The latest EPA report states that after five years reviewing data from more than 950 different sources, they *"did not find evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States*" and "*the number of identified cases was small compared to the number of hydraulically fractured wells.* [...] *This finding could reflect a rarity of effects on drinking water resources, but may also be due to other limiting factors". (EPA, 2015)*[88]

6.3.3. *Fluid storage*

Since the very first oil and gas wells were drilled, "pits" have been used to hold drilling fluids and waste. Pits can be holes excavated in the ground or above-ground containment systems in steel or other materials. They are used to store produced water, for emergency overflow, temporary storage of oil, for burn-off waste oil and for temporary storage of the fluids used to complete and treat the well. (See FIGURE 93)

The containment of fluids within a pit is the most critical element in preventing contamination of shallow ground water. The failure of a tank, pit liner, or the line carrying fluid ("flowline") can result in a release of contaminated materials directly into the ground floor and in the worst case into surface water and shallow ground water. Environmental clean-up of these accidentally released materials can be a costly and time-consuming process. It is therefore vitally important to isolate the site from surface water sources, install barriers, draw up a contingency plan and prevent any release. Obviously, the danger associated with the fluid storage will depend on the characteristics of the fluid stored.

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[87] Other groundwater contamination incidents have been blamed on hydraulic fracturing, but with no scientific evidence to back these claims. One of the most well-known incidences is the case of lighting the gas from a water faucet in Pennsylvania, as seen in the movie *"Gasland"*, which was later shown not to be due to fracking.

[88] EPA limiting factors can be seen in the source cited above.

FIGURE 93. Shale gas production and impoundment in Marcellus (USA)

Source : image courtesy of *Petroleum Extension (PETEX™), University of Texas at Austin*. See also in (Bommer, 2008)

For pits excavated in the ground (see FIGURE 93), pit lining is mandatory to prevent any infiltration of fluids into the subsurface. Selection of the lining material will depend on the fluids to be placed in the pit, the duration of the storage and the soil conditions. Typically, pit liners are constructed and equipped with a first layer of compacted clay, followed by a shotcreting layer (gunite) and a final layer composed of synthetic materials such as thermo-welded polyethylene.

In the USA, depending on the state, there are a number of rules regarding pits and the protection of surface and ground water. In addition to liners, some states also require pits used for long term storage of fluids to be placed at a minimum distance from surface water to minimize the chances of surface water contamination if an accidental discharge from the pits should occur. In California, for example, pits may not be placed in areas considered to be "natural drainage channels". Some states also explicitly prohibit or restrict the use of pits that intersect the water table.

Various systems have been developed to avoid the use of pits by keeping fluids inside a series of pipes and tanks throughout the entire fluid storage process. The likelihood of groundwater contamination is thus minimized, since the fluid never comes into contact with the ground (Fracfocus.org, 2014).

Construction of storage ponds requires excavation and building berms. Temporary tanks can be placed on leveled ground, which involves less land disturbance and therefore makes restoration easier during the well production phase. The use of tanks has other benefits, as outlined by New York State DEC: "*Tanks, while initially more expensive, experience fewer operational issues associated with liner system leakage. [...] In addition, tanks can be easily covered to control odors and air emissions from the liquids being stored. Precipitation loading in a surface impoundment with a large surface area can, over time, increase the volumes of liquid needing treatment. Lastly above-ground tanks can also be dismantled and reused*".

However, there are also some drawbacks to the use of tanks. For example, the storage volume is limited by the capacity of each tank. The greater the volume, the greater the visual impact, and if smaller volumes are used, the number of tanks needed will increase, together with the volume of truck traffic and air emissions from diesel engines.

6.3.4. *Wastewater treatment*

Some of the injected fluid is recovered and handled using a variety of methods such as treatment and discharge, recycling, temporary storage in pits or containers and underground injection control.[89] New technology is constantly being developed to improve waste water management and re-usability.

According to a JRC report, given the constraints on both underground injection and discharge in the USA, serious investment will be required to advance treatment technologies that enable companies to reuse fluids for subsequent fracturing jobs (JRC, 2012).

Many different technologies are available for the treatment and reuse of produced water. The EPA has categorized most of these into eight different treatment types, summarized in the following table.

[89] Although underground injection is a common practice in the USA, it is unlikely that this technique will be allowed in Europe.

TABLE 22: Possible treatments for recycling and reusing produced water

Treatment	Description
Sedimentation and filtration	Gravity separation in a tank or impoundment. This involves simply storing fluid for a period of time to allow the suspended solids to "fall" out of the solution. Filtration typically involves the use of a "sock" or "sand" column filter to remove solid particles from the solution.
Chemical precipitation	Use of chemicals and the processes of coagulation, flocculation and sedimentation to remove contaminants from the solution by augmenting the tendency of small particles in aqueous suspension to attach to one other and accumulate in size and weight, thus allowing gravity settling to take place.
Dissolved air flotation	Use of a chemical polymer with an air or gas stream injected through a column of fluid to help contaminants float to the surface where they can be removed with a skimming mechanism at the top of the column. Particularly effective for hydrocarbon-free produced waters (hydrocarbons naturally float in water).
Evaporation	Natural process of evaporation to turn a portion of produced water into water vapor. Many providers use waste heat to drive their evaporation systems.
Thermal distillation	The most common type is Mechanical Vapor Recompression (MVR). MVR utilizes low pressure to evaporate produced water and mechanically recompresses steam to produce the distilled water effluent. It requires pretreatment with either chemical precipitation or dissolved air flotation in order to remove suspended solids and hydrocarbons.
Electro-coagulation	An electrically driven treatment process that utilizes fewer chemicals. In these systems an electric charge is passed through the fluid stream which changes the surface charge in the solid particles and causes them to agglomerate and drop out of the solution or be more efficiently filtered from the solution. This is a good system for removing suspended solids and most heavy metals.
Crystallization	The most advanced treatment available for produced water on the market today. Crystallizers are used to remove all dissolved solids (including all salts) from the solution and can achieve zero liquid waste discharge (with only solid, salt and distilled water outputs). It requires pretreatment via chemical precipitation, dissolved air flotation or membrane filtration, all followed by distillation.
Reverse Osmosis (RO) membranes	The treatment requires very uniform water quality and comprehensive pretreatment to ensure suspended solids and hydrocarbons do not impact the membrane or they can immediately foul or ruin most RO membranes. Due to high salinity variety in water quality, RO has limited potential in most unconventional plays.

Source: Compiled by the authors from (EPA, 2013)

Reuse of produced water will reduce the amount of make-up water required for hydraulic fracturing and the potential impacts from water resource depletion. Less than 100% of fracturing fluid is recovered; typically between 11% and 75% of the injected fluid is recovered as flowback. This means that even if all recovered fracturing fluid is reused, additional make-up water is still required. A disadvantage of this measure is that treatment of the flowback may be costly and may generate treatment residuals (sludge and brines) requiring management and disposal (AEA, 2012).

The use of lower quality water (e.g., seawater, brackish water or even acid water from mines) for fracturing fluid make-up will reduce depletion of drinking water sources, but this measure also requires treatment such as reverse osmosis that may be quite costly (AEA, 2012). The salt in the water also increases the friction between the fracking fluid and the pipes through which it must flow, thereby requiring increased surface pumping equipment, which is very costly, or the addition of friction-reducing chemicals to the salt water. Moreover, the salt is corrosive.

Some drilling operators elect to re-use a portion of the wastewater to replace and/or supplement fresh water in formulating fracturing fluid for a future well or re-fracturing the same well. Re-use of shale oil and gas wastewater is, in part, dependent on the levels of pollutants in the wastewater and the proximity of other fracturing sites that might re-use the wastewater. This practice has the potential to reduce discharges to surface ponds, minimize underground injection of wastewater and conserve and reuse water resources.

Mobile solutions to treat wastewater at the wellhead enable recycling and reuse of flowback without the need to store wastewater in on-site surface ponds, or to truck flowback wastewater for disposal at off-site deep-well injection locations. Recycled wastewater is treated in a specific way at each different frac well site, with treatment adapted to the local geology of that specific well site. The drawback of mobile wellhead solutions is that they do not provide continuous processing to handle produced wastewaters.

Centralized treatment of wastewater is emerging as a viable solution for long-term efficiency in managing water sourcing and wastewater treatment in hydraulic fracturing. Wastewater received by the plant is identified as originating from a specific well. The usage requirements for that wastewater are specified and the wastewater is then processed accordingly. Once processed, the wastewater is piped directly to the targeted well site.

Central wastewater treatment facilities processes may include: primary three-phase separation to remove dissolved natural gas, floating gel, oil, sand and suspended solids, followed by storage for equalization of chemical composition and flow, secondary separation, utilizing dissolved air or gas flotation for removal of a wide variety of contaminants including polymers, oils and suspended solids. Bactericide is added to control bacterial growth. Other processes include removal of metals (by precipitation) and salts (by reverse osmosis) and sludge management for dewatering collected solids.

These centralized plants can be integrated with alternative water sources to supplement fresh water needs for fracking. Sources include abandoned mines, storm water control basins, municipal treatment plant effluent, and power plant cooling water.

Pennsylvania's Susquehanna River Basin Commission (SRBC) and its Department of Environmental Protection stress that future trends in water use for oil and gas drilling should represent greater reuse of water for fracking, and more use of other waters –such as treated wastewater and acidic mine drainage– in the hydraulic fracturing process.

6.4. Induced seismicity

In this section we will try to explain the seismic effects related to fracking and the ways in which these are monitored and controlled.

Induced seismicity is seismicity caused by human/external activity over and above natural background levels in a given tectonic setting. A distinction is drawn between induced seismicity and triggered seismicity, where human activity affects earthquake recurrence intervals, magnitude or other attributes. However, the physics involved in triggered and induced seismicity is thought to be identical (IEAGHG, 2013).

As we have seen, the aim of hydraulic fracturing is to improve fluid flow in an otherwise impermeable volume of rock, previously considered as source rock for more conventional (higher permeability) reservoirs. Stimulation is carried out to enhance well production and is achieved by injecting fluid at a sufficient pressure to cause brittle failure (cracking of the rock), and develop a network of connected fractures to increase permeability and provide conduits for gas flow from the strata (Green et al., 2012).

Induced seismicity may be caused by mechanical loads which can cause changes to the stress regime. Fluid pressures also play a key role in seismicity as pore pressures act against gravitational and tectonic forces and, if increased sufficiently, may cause rock failure. Basic mechanisms for induced seismicity from introduction of excess pore pressure have been described in Zoback (2007). Hydraulic fracturing occurs when the fluid-injection pressure exceeds the rock fracture gradient (Majer et al., 2012).

Induced seismicity from (uncontrolled) fracture[90] propagation is a potential risk in shale gas production (ACOLA, 2013); the stimulated fractures may extend several hundred meters into the rock (Davies et al., 2012). It is necessary to evaluate the potential for and effects of induced seismicity during risk assessment of storage/ fracking projects.

[90] A distinction should be drawn between fractures and faults. Faults imply movement of a mass of rock, something which does not occur in this case. (See the definition of 'fault' in Julia A. Jackson's Glossary of Geology (1997)).

6.4.1. *Measuring seismicity magnitudes*

Scales of seismic magnitude are calibrated using the Richter scale. In 1935, Charles Francis Richter established the first scale of magnitude taking a base ten logarithm of maximum ground motion (in microns) as his reference value. Seismic intensity is an indication of how much a seismic event affects structures, people and landscapes at the Earth's surface.

The effect a given seismic event will have at the earth's surface depends on several factors. The greater the depth at which a seismic event occurs, the more its radiated energy is attenuated and dispersed.[91] Different materials attenuate seismic waves to different degrees. Soft rocks, such as shale, attenuate seismic waves more than hard rocks, such as granite.

The frequency of the radiated seismic waves is proportional to the size of the fracture. Since engineered hydraulic fractures are typically small, seismic events induced by hydraulic fracturing only produce high frequency radiated seismic waves, and therefore do not cause shaking of the ground that might damage buildings. The number of people who feel small seismic events will depend on the background noise (Bickle et al., June 2012).

The table below shows the effects that are felt according to the local magnitude of the quakes. It is important to understand this, because we will later refer to local magnitudes of seismic events and their consequences.

Induced earthquakes are indistinguishable from natural earthquakes in terms of their physical parameters such as frequency-magnitude distributions or waveforms produced (IEAGHG, 2013). Events of less than M_L 2 are considered as micro-seismic events and can only be detected using seismological equipment, whereas events greater than M_L 2 may be felt at the surface (IEAGHG, 2013).

TABLE 23. Effects of quakes

Magnitude (M_L)	Effects felt at the surface
-3.0	Not felt
-2.0	Not felt
-1.0	Not felt
0.0	Not felt
1.0	Not felt, except by a very few under especially favorable conditions
2.0	Not felt, except by a very few under especially favorable conditions
3.0	Felt by few people at rest or in the upper floors of buildings; similar to the passing of a truck
4.0	Felt by many people. often up to tens of kilometers away; some dishes broken; pendulum clocks may stop
5.0	Felt by all people nearby; damage negligible in buildings of good design and construction; few instances of fallen plaster; some chimneys broken

Source: (Bickle et al., June 2012)

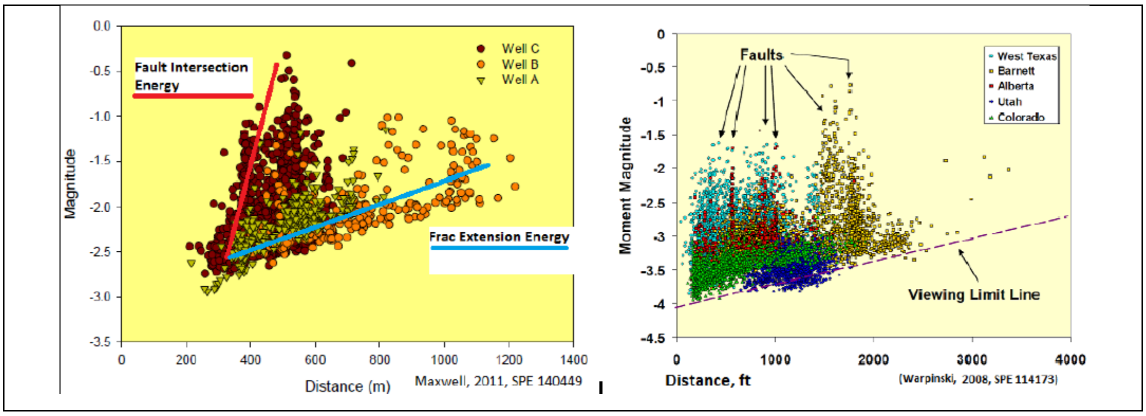
[91] Attenuation is due to the Q factor of the rocks (absorption of energy) while dispersion is the effect of the spherical divergence of the energy (the same energy is spread over an increasing larger spherical area as it radiates away from the point of release of the energy).

In any case, the number of people who are able to feel these low intensity quakes depends on the background noise in a specific area. Each day, around one thousand events of between 2 and 2.9 M_L occur naturally in the world (Consejo Superior de Colegios de Ingenieros de Minas, 2013).

6.4.2. *Seismicity induced by fracking*

Although more than one million wells have been hydraulically fractured in the US (Monitor Publishing Inc., 2014), only a small number of cases have been reported of "undesired" induced seismicity directly caused by hydraulic fracturing. In general, the short duration of the process and the relatively small volumes of rock involved may limit the potential for inducing large, damaging events.

FIGURE 94. Energy in frac range (-3 to -2) and fault range (-2 to -0.5). Energy level and viewing distance



Source: (King, 2012)

Links have been established between earthquakes and oil and gas activities such as deep well disposal of some produced water as well as the injection of other fluids such as military waste and the large volumes of water injection encountered in geothermal energy production. Most of these events have involved extremely large, continuously injected volumes and much deeper injection points. However, this wastewater management method is independent of the hydraulic fracturing itself and is subject to progressively more regulation in some states.[92]

Magnitudes of induced seismicity during hydraulic fracture stimulation in hydrocarbon fields such as the Barnett Shale and the Cotton Valley are typically less than 1 M_L., meaning that these events are not detected unless a local monitoring network is in place. Moreover, it is worth noting that many USA shale gas plays are in relatively remote locations, with no monitoring networks in place (Green et al., 2012). Approximately 3% of the 75,000 hydraulically fractured wells in the US in 2009 had microseismic monitoring (E&P & Mason, 2014) and this trend is expected to increase in the future.

[92] For more information on regulation of injection wells in the United States, see *http://water.epa.gov/type/groundwater/uic/basicinformation.cfm.*

Micro-earthquakes (i.e. those with magnitudes of below M_L 2) are routinely produced as part of the hydraulic fracturing process used to stimulate the production of oil and/or gas, but the process as currently practiced appears to pose a low risk of inducing earthquakes of M_L 3-4. The largest induced earthquake in Canada was magnitude M_L 3.6, which is too small to pose any risk to public safety or the environment (Ellsworth et al., 2013).

Events of over M_L 3 that occur in association with fracturing (e.g., M_L 4 on December 31st , 2011, in Youngstown, Ohio) often appear to have been induced by disposal of the wastewater used to generate fractures and not by the stimulation itself (CO2CRC, 2012). Another example is the M_L 5.6 quake registered in Oklahoma, where deep waste water injection works damaged a federal road (Ghose, 2013).

There are very few instances where seismic events have occurred due to a hydraulic fracturing operation for shale gas. The nearest incident to Spain was in the Bowland basin in England (Royal Academy of Engineering, The Royal Society, 2012). Two seismic events of magnitude M_L 1.5 and M_L 2.3, respectively, occurred near Blackpool in the Bowland basin of England, most likely due to a hydraulic fracturing operation.

Hydraulic fracturing causes some energy releases in the formation which are similar to those produced by earthquakes, but there are significant differences in the frequency and magnitude that allow the small-magnitude sounds of shear fracturing and the sounds of even the smallest earthquake to be distinguished. The measurement of micro-acoustic energy generated during hydraulic fracturing (shear fracturing) registers magnitudes of about -3 to -1 on the open ended (logarithmic) Richter scale (King, 2012). (See FIGURE 94) The magnitude of these micro-earthquakes is very different from the energy released by a tensioned fault.

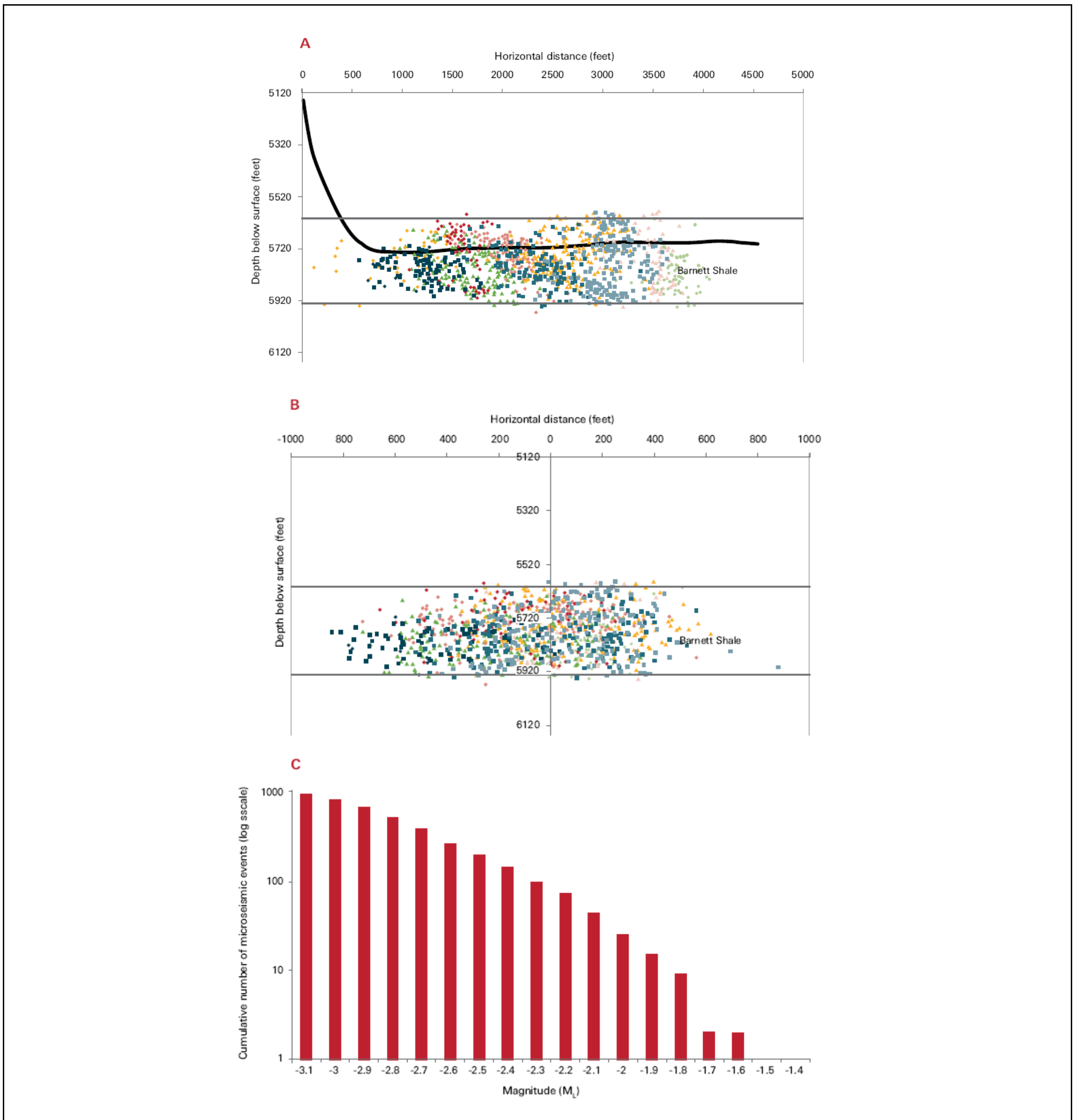
In addition, operators have other incentives to carefully monitor fractures and ensure they propagate in a controlled way, remaining within the target shale formation. Excessive, uncontrolled fracture growth is uneconomic, since it requires extra chemicals, pumping equipment and manpower, making the project more expensive. Various methods are available to monitor fracture growth before, during and after operations (Bennett et al, 2006).[93]

In FIGURE 95, "A" shows a horizontal view of microseismic events throughout a horizontal well. The thick black line represents the horizontal well. Note that the vertical axis does not begin at the surface but at depth (5,120 feet). Each dot represents a separate microseismic event. Each color represents a distinct fracturing stage. "B" shows a cross sectional view of the microseismic events and "C" shows the distribution of these microseismic events by magnitude.

[93] For further information on ways to control fractures, see (Bennett et al, 2006).

Hydraulic fracturing causes a break in the rock to release the pressure applied to the rock at the wellbore. The resulting crack is narrow, usually between 2 and 3 mm wide and grows outward and upward, widening slightly until a barrier is encountered or there is sufficient leak-off into side fractures or permeable formation to stop the fracture from growing (King, 2012).

FIGURE 95. Microseismic monitoring of a typical hydraulic fracturing operation in the Barnett Shale. Texas.



Source: (Zoback et al., 2010)

6.4.3. *Best practice*

Technology, standards and best practice that can minimize the risks associated with shale gas development are already being used by most companies and more are being developed. Monitoring and mitigation of induced seismicity should be an important component of commercial-scale projects. Prediction of the potential seismicity prior to injection will make it possible to identify possible risk reduction measures to keep the levels of induced seismicity within acceptable limits (Zoback et al., 2010).

In a report to the Department of Energy and Climate Change, experts from the British Geological Survey, the Keele University and GFrac Thecnologies recommended a series of specific measures to mitigate the risk of future earthquakes in the Bowland Basin (Green et al., 2012). The hydraulic fracturing procedure should invariably include a smaller pre-injection and monitoring stage before the main injection. Initially, smaller volumes should be injected, with immediate flowback, and the results monitored for a reasonable length of time. Meanwhile, the fracture diagnostics (microseismic and prefrac injection data) should be analyzed to identify any unusual behavior post-treatment, prior to pumping the job proper.

Until the characteristics of fracking in a particular formation are well established, in addition to real-time monitoring, tiltmeters and a permanent buried seismometer system record the usual ground deformation and microseismic events, respectively, that accompany any fracking activity. These can be used to establish exactly how far the fractures penetrate into the surrounding rock. This will allow the effectiveness of the fracture to be evaluated but also ensure that the size is as predicted and that the fracture has not extended further than planned, e.g., toward any near surface fresh water aquifer (DePater et al., 2012).

In the UK, operators will be required to review the available information on faults in the area of the well to confirm that wells are not drilled into, or close to, existing active faults which could provide the mechanism for triggering an earthquake. Background seismicity will then be monitored for a period of several weeks before fracking operations commence to provide a baseline against which activity detected during and after fracturing operations can be compared (DECC, 2013).

In their report to the DECC on the Bowland basin, the experts also recommended various measures to mitigate the risk of induced seismicity. As operational detection data from fracking operations develops, the DECC, with expert advice, will consider the most appropriate criteria for determining the threshold.

This approach is similar to (IGME, 2014) which recommends geological studies to characterize the potential faults, monitoring seismology, reinjection monitoring, monitoring and registering of microseismic activity and surveillance based on a stop light system (there is no reference in the information to Spain).

A threshold value and a stop light system depend on the rock unit involved. For this reason, a universal limit is not scientifically justified. In the UK, an M_L 1.7 limit was established after hydraulic fracturing operations in Blackpool. However, Green et al. (2012) recommend a lower limit (M_L 0.5) for the following operations in the Bowland Basin.[94] This threshold value will eventually have to be adjusted as more

[94] The Bowland shale formation is a heterogeneous, relatively impermeable, rigid and brittle rock.

experience is accumulated. For example, some events of 1.0 have occurred in the Musaka/Erie (Warpinski. 2012), 0.8 in the Woodford shale and 0.7 in both the Marcellus and Barnett, and may be expected to occur again in the same areas.

On the other hand, maximum events of 0.0 can be expected in the Eagle Ford. -0.1 in Fayetteville, -0.2 in Haynesville, -1.5 in Bakken, -2.7 in Monterey and -3.0 in the Piceance.

Given the size of microseismic events expected (magnitudes of under M_L 1.0), the size of the earthquakes induced so far (non-demanding: all less than M_L 4.4) and the rate of occurrence of quakes higher than M_L 2-3 (only 4 wells out of more than one million wells fracked), there is no clear justification for requiring monitoring of every well fracked, except in potentially sensitive locations.

It is worth noting that the criteria and threshold values vary significantly amongst different authors and institutions/associations.[95] There is a case for arguing that these limits should be established individually on the basis of the specific geological and technical characteristics of each play.

6.5. Naturally Occurring Radioactive Materials (NORM)

In this section, we will explain what radioactivity is, how it occurs in the environment and how fracking affects this radioactivity. We shall also describe the mitigation measures that are required to avoid its effects on humans and the environment.

The term NORM (Naturally Occurring Radioactive Material)[96] is frequently used when discussing human activities that result in concentrated radioactive isotopes such as uranium, thorium or potassium or their radioactive decay products such as radium and radon. In the natural state, these materials are usually well below safe limits of exposure; it is only when they are concentrated that problems may occur.

All geological formations contain naturally-occurring radionuclides. That includes all of the soil, sand and rocks we walk over and live on. Oil and gas bearing geologic formations are no exception. In addition to the background radiation at the earth's surface, these naturally-occurring radionuclides can also be brought to the surface in the natural gas and oil production process. Due to their entrapment process, oil fields often occur in "formation water" aquifers that contain brine as a connate fluid. Radioactive materials are prevalent in many soils and rock formations and consequently in any water that comes into contact with them. Extraction and processing of these resources may expose or concentrate naturally-occurring radionuclides.

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95 See (DePater et al., 2012; Green et al., 2012; King, 2012)

96 Naturally Occurring Radioactive Materials (NORM). Material containing no significant amounts of *radionuclide*s other than *naturally occurring radionuclide*s. The exact definition of 'significant amounts' varies by regulatory decision. They include materials in which the *activity* concentrations of *naturally occurring radionuclides* have been altered by human made processes. These are sometimes referred to as technically-enhanced NORM or TENORM (IAEA Radioactive Waste Management Glossary 2003 ¡Edition write and cite¡).

The average person in the US is exposed to about 360 millirems[97] of radiation from natural sources each year. A millirem, or one thousandth of a rem is a measure of radiation exposure. More than 50% of this exposure level comes from background radiation sources.

Materials and areas with NORM and other radioactive potential in modern homes include granite counter tops, radon gas accumulation in basements, smoke alarms, televisions, low sodium substitutes and some glass and ceramics (US Environmental Protection Agency, 2014).

Consumer products contribute 10 millirem/yr, while living or working in a brick structure can add another 70 millirem/yr. A person who smokes one and a half packs of cigarettes per day increases his or her exposure by 8,000 millirems/yr, while porcelain front teeth can add another 1,600 millirems/yr to a person´s exposure level (King, 2012).

In the case of industrial activities, certain dose limits have been established for both employees and the general population. Logically, the dose limit for the population is much lower (50 times lower) than for people working in the industry. These limits are 50[98] mSv/yr (5,000 mRem/yr) for radiation workers and 1 mSv/yr for the general public (CSN, 2010).[99]

Average radiation limits have been determined for people working at nuclear plants and other radioactive facilities. Generally, the radiation received by workers varies from 1 to 2 mSv/yr in nuclear plants and comes to 0.7 mSv/yr (70 mRem/yr) in other radioactive facilities. Based on these data, the Spanish Nuclear Safety Council (CSN) has determined that 98.65% of radiation workers receive an equivalent dose of less than 5 mSv/yr (50 mRem/yr), four times below the authorized limit (100 mSv/5 years is equivalent to 20 mSv/yr; 2,000 mRem/yr) (CSN, 2010).

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[97] The unit employed to measure exposure to radiation is the rad. One rad (absorbed radiation dose) corresponds to the absorption of 1x10-2 joules of energy per kilogram of material. However, the effect of the dose of one rad on living matter varies and a unit is therefore needed that will take this variation into account.
The rem (Roentgen equivalent for man) is the rad multiplied by the relative biological effectiveness (Q). The Q factor takes into account the fact that the same doses of different types may have different effects.
The total radiation received from normal sources for most of the population is 0.13 rem (130 millirem, mrem) per year. The dose received from a chest X-ray is about 20 mrem.
Since 1976, the rem has been defined as being equal to 0.01 sieverts. A sievert is a measure of the health effect of low levels of radiation on the human body (Petrucci, Herring, Madura, & Bissonnette, 2011).

[98] But less than 100 mSv in 5 years

[99] These limits do not include the radiation from natural exposure, diagnosis or medical treatments (radiographies, radiotherapy, etc.). It should be taken into account that the aforementioned limits are determined on the basis of the estimated risk of a particular dose. An activity is considered to be safe when the risk of suffering from serious/mortal illnesses is less than 1/10,000. Equivalent dose limits, in particular, are determined for a risk of 1/100,000 or 10^{-5}.

6.5.1. *Radioactivity in oil and gas exploration*

In discussing radioactivity in exploration work, it should be remembered that radionuclides are naturally present in geologic formations. They consequently, remain in the rock pieces of the drill cuttings brought to the surface. NORM are also found in solution in produced water, and, under certain conditions,[100] can precipitate out in scale or sludge. However, the radiation from these NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

The principal concern for NORM in the oil and gas industry is that, in basins[101] with uncommonly high radioactivity levels, radionuclides may concentrate in the field production equipment or as sludge or sediment inside tanks and process vessels that come into prolonged contact with formation water (BSEECE, 2014 in (Spellman, 2013)).

The occurrence of such problems, particularly barium ions and radioactive isotopes in flowback fluids, is generally limited to a few areas and they generally last only for a short time, as natural fluid flow from the shales decreases in the first few days after fracturing.

NORM waste problems are generally associated with long-term operations of oil and gas fields (Graham Sustainability Institute, 2013). The extraction process concentrates naturally-occurring radionuclides and exposes them to the surface environment and human contact. Mismanagement of this waste can result in radiological contamination of soils or surface water bodies. For this reason, NORM above the natural background radioactivity levels require special handling for removal and disposal (NY DEC, 1999; Resnikoff et al., 2010).

In the United States, maximum dose rates are usually in the range of up to a few microsieverts[102] per hour. In exceptional cases, dose rates measured directly on the outer surfaces of production equipment have reached several hundred microsieverts per hour. In practice, restrictions on access and occupancy time are found to be effective in limiting annual doses to low values (IAEA, 2003). Studies have shown that exposure risks for workers and the public are low for conventional oil and gas operations (Spellman, 2013).

Workers at drill sites in Pennsylvania may be more likely to be in regular contact with the Marcellus Shale and the current legal occupational exposure limit in the United States for occupations working around radiation, as established by the Occupational Safety and Health Administration (OSHA), is 5,000 mrem per year (50 times the level for the general public). Assuming constant exposure on the

[100] In plays that are particularly rich in radionuclide concentration.
[101] The best-known basin with an anomalous radionuclide concentration of this kind is *Marcellus Shale.*
[102] The sievert (symbol: Sv) is a derived unit of ionizing radiation dose in the ¡International System of Units¡. It is a measure of the health effect of low levels of radiation on living matter.

worksite for 2000 working hours per year (40hours/day at 5 days for 50 weeks), the exposure limit is about 2.5mrem/hr. This is much higher than the Marcellus Shale maximum of 0.09 mrem /hr.[103] Altogether, radiation levels in the Marcellus Shale itself are sufficiently low that they are not expected to affect the public or drill site workers (Marcellus Shale, Paleontological Research Institution, 2011).

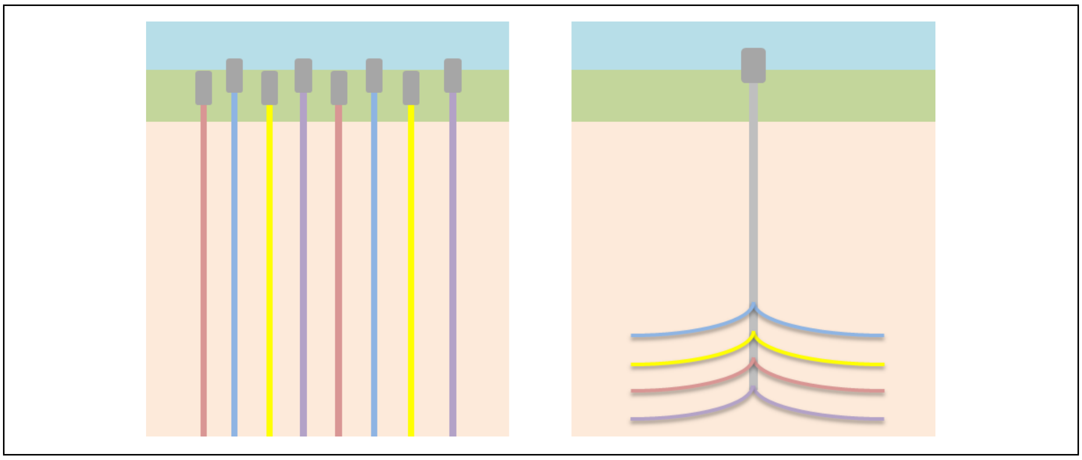
6.6. Ground occupation, pad operations, well abandonment and reclamation

In this section, we shall explain various environmental implications of surface works. We shall also consider some of the measures used to reduce surface requirements, improve operations and reclaim the site after the exploration phase.

Surface installations, referred to in Chapter 4, require an area of approximately 3.0 hectares per pad[104] during the fracturing and completion phases (DEC NYS, 2011).

It is important to note the arrangement of the wells in traditional well-spacing as compared to the idealized horizontal layout. The FIGURE 86 shows how the same area can be covered in different ways, with the need for space on the surface varying considerably.

FIGURE 96. Types of well pad depending on the technology used. Traditional vertical well spacing and idealized horizontal well spacing



The picture om the left shows traditional vertical well spacing (16 separate pad sites needed for 16 wells). The picture on the right shows idealized horizontal well spacing (1 pad site yields up to 16 wells).

Source: Own elaboration based on (Deloitte, 2013)

[103] The maximum recorded reading from Marcellus Shale to date is equivalent to 0.09 mrem/hr; this value was taken from direct measurements of the rock. Taken at face value, this shale might at first appear to be well above the federal limit: 0.09 mrem x 24 hr/day x 356.25 days/yr give an annual value of nearly 800mrem/yr (for comparison, average background radiation is about 620 mrem/yr). However, this calculation is not technically correct, since it assumes full body contact with the shale over the entire period. There is no feasible scenario in which either a member of the general public or a worker would receive either full-body or yearlong contact with the shale, much less both (Marcellus Shale, Paleontological Research Institution, 2011).

[104] Ground occupation can be greatly reduced by miniaturizing the equipment, using slim holes.

As it can be observed, increasing well spacing and using multiple wells per pad reduces the total land disturbed by well pad construction. Fewer pads means fewer roads, pipelines and other rights of way.

In all cases, the land used both for the hydraulic fracturing equipment and for the fluid storage should be minimized. The soil must also be reclaimed to initial conditions once the hydraulic fracturing work has concluded.

In addition to the well pads, the associated infrastructure (access roads and pipelines) also results in increased land take and fragmentation of habitats (Lechtenböhmer et al. 2011; AEA, 2012). Appropriate siting can reduce the amount of land disturbed for constructing roads, pipelines, and other infrastructure. This can also help minimize adverse impacts on sensitive receptors such as residential areas and ecosystems.

Operators need to take environmental and health concerns into account when selecting sites for shale gas extraction facilities, in order to reduce land take and facilitate ultimate site reclamation. HVHF (High Volume Hydraulic Fracturing) operations should be located near existing roads, rights of way and pipelines, as far as practicable. Developers should also select sites which minimize alteration of surface terrain, avoiding sites that require cut-and-fill construction (API, 2011).

Developers should select sites with the minimum impact on sensitive locations such as residential areas or habitat sites, by virtue of their distance, the use of screening or other means. There are no specific legislative or regulatory initiatives in place regarding proximity to existing gas pipelines, although gas developers operating in close proximity in British Columbia are required to work together to reduce environmental impact (Province of British Columbia, 2011). As well as their environmental benefits, reduced construction and transportation requirements cut costs for well installation and site reclamation, although this may be offset by the additional cost and difficulty of acquiring land near roads and rights of way (AEA, 2012).

In Europe, the European Academies and Science Advisory Council (EASAC) has analyzed a variety of issues of concern in relation with shale gas. One of these refers to the method chosen for exploring this resource, bearing in mind that Europe is a heavily populated continent, so there is more likely to be a conflict of interests between different land uses.

In this regard, the report points out that initial hydraulic fracturing schemes in the USA were only accepted in remote places due to the potential impact on heavily populated areas. However, the concentration of multiple wells per location and the directional drilling technique, as utilized in Pennsylvania (with comparable population densities to Europe), offer a potential extraction area of 10 square kilometers or more from a single pad, with a resulting reduction in surface land use. The report also mentions that even in clusters with a radius of only 3 km, it is viable to produce unconventional gas in heavily populated areas (European

Academies & Science Advisory Council (EASAC), 2014).(European Academies & Science Advisory Council (EASAC), 2014)

6.6.1. *Restoration and abandonment.*

Land disturbed during well construction and development should, as far as possible, be reclaimed. This minimizes the amount of land taken long-term or permanently from alternative uses (e.g. agriculture or wildlife habitats). As soon as practicable, all temporary equipment should be removed, and adjoining areas reclaimed and restored. This will reduce the size of the site and the overall footprint during the production phase (API 2011 in (AEA, 2012)).

During site preparation, all surface soils removed in cut-and-fill operations must be stockpiled for reuse during interim and final reclamation. Topsoil should be segregated from subsurface materials to improve the effectiveness of reclamation activities. Non-productive, plugged, and abandoned wells, well pads, roads and other infrastructure areas should be reclaimed. Reclamation should be conducted as soon as practicable and should include interim steps to establish appropriate vegetation during substantial periods of inactivity. Native tree, shrub, and grass species should be used in appropriate habitats (DEC NYS, 2011).

There is generally little difference between conventional and unconventional wells in the post-abandonment phase, except for the presence of unrecovered hydraulic fracturing fluids in the shale formations in the case of hydraulically fractured wells. The issue of potential concern would be the risk of fracturing fluids moving to aquifers or surface waters via the well and/or via fractures introduced during the operational phase.

However, production of gas from the shale formation will reduce its internal pressure. With this negative pressure differential, the direction of fluid flow will be into rather than out of the formation. Even if there were a possibility of re-pressuring the shale formation, the fractures introduced during the operational phase have a tendency to close little by little, reducing the possibility that they might become a path for the movement of trapped fracturing fluids. In any case, the 600 or more meters of rock between the shale formation and any aquifer will keep a permanent barrier between the two systems. The only possible avenue of escape would be through a well bore that has lost its integrity.

The presence of high salinity fluids in some shale gas formations indicates that there is normally no pathway for release of fluids to other formations (DEC NYS, 2011). Furthermore, some of the chemicals used in fracturing fluids will be adsorbed in the rocks (e.g. surfactants and friction reducers) and some will be biodegraded *in situ* (e.g. guar gums used for gels). For shale gas operations at significant depths, the volume of rock between the producing formation and the groundwater is substantially greater than the volume of fracturing fluid used (AEA, 2012).

The consequences for land in the post-abandonment phase are judged to be comparable to that of many other industrial and commercial land-uses, and these are of only minor significance. There is little evidence available to evaluate the likelihood of effects on biodiversity during the post-abandonment phase[105], (AEA, 2012).

In the case of shale gas prospecting and exploration operations in Poland, an assessment of the impact on protected areas was carried out. The analysis covered some environmentally valuable areas within a radius of 15 km from the drill sites, such as nature reserves, national parks, protected landscape areas and Natura 2000 sites. The analysis did not reveal any impact on these protected areas, apart from two in which drill sites were located. No potential impact was found on more distant areas, such as changes in the water regime or permanent air pollution with gas or dust.

The report also notes that impacts come most frequently from transport and suggests that vehicular traffic is probably the most important indirect impact when drill sites are properly located. Operators should therefore take this factor into consideration in exploration projects, as with residential buildings (Konieczynska et al., 2015).

6.7. Atmospheric emissions

This section analyses the air pollution and noise that might be caused by drilling and completion operations on the well pad and looks at as well as some mitigation measures and obligations that should be taken into account during well-drilling.

6.7.1. Emissions from diesel engines

Emissions from gas production come from direct emissions (lost gas or fugitive emissions and CO_2 from combustion of natural gas) and indirect emissions from trucks, pumps and processing equipment used in drilling, fracturing and production.

Although gas is a very clean burning, low-emission fuel, emissions produced over its life cycle must be taken into account. These include fugitive emissions and indirect emissions from diesel pumps and trucks. Current research on replacing all or part of the diesel fuel with natural gas is being pilot-tested at a number of sites, but the quickest way to reduce emissions is by minimizing the traffic of water trucks and transferring water via pipelines.

The machines used for drilling and fracturing processes, such as diesel engines, are probably the same, as are the air pollutants emitted by these machines. TABLE 24

[105] In the Western Plains area, well production areas provide islands of safety for plant and animal species that would otherwise be grazed or hunted, respectively, thereby preserving the original vegetation and small wildlife of the area. A similar phenomenon has been observed in the Gulf of Mexico where oil and gas production platforms have become havens for fish and other water life reproduction, safe from the fishing industry. Abandoned platforms have become artificial reefs, attracting sport fishermen.

shows the emission of air pollutants from stationary diesel engines used for drilling, hydraulic fracturing and well completion based on diesel engine, emissions data from GEMIS (2010), diesel requirements and a natural gas yield assumed for the Barnett Shale in (Howarth et al., 2011).

TABLE 24. Typical specific emissions of air pollutants from stationary diesel engines used for drilling, hydraulic fracturing and completion

	Emissions per engine mechanical output [g/kWh_{mech}]	Emissions per engine fuel input [g/kWh_{diesel}]	Emissions per natural gas throughput of well [g/kWh_{NG}]
SO_2	0.767	0.253	0.004
NO_x	10.568	3.487	0.059
PM	0.881	0.291	0.005
Co	2.290	0.756	0.013
NMVOC	0.033	0.011	0.000

Source: (ENVI European Parliament, 2011)

There is no direct link between the regulation of shale gas activities and motor vehicle air pollution, as Directive 2005/55/EC on pollutant emissions from heavy-duty vehicles 132 (the "Emission from Diesel and Gas Directive"); replaced by Regulation 2011/582/EU on emissions from heavy-duty vehicles 133; aims at manufacturers or importers of new vehicles, rather than at operators willing to perform shale gas activities.

In Europe, strict regulations and strict monitoring are recommended to minimize the risk of spills. Specifically, it is recommended that statistics on accidents be gathered at a European level, in order to analyze the causes of the accidents and to draw the corresponding conclusions. In specific cases where companies have particularly negative track records, the possibility of excluding them from further exploration or production rights might be considered. Similar cases are being discussed in the European Parliament in relation to offshore oil and gas activities (ENVI European Parliament, 2011).

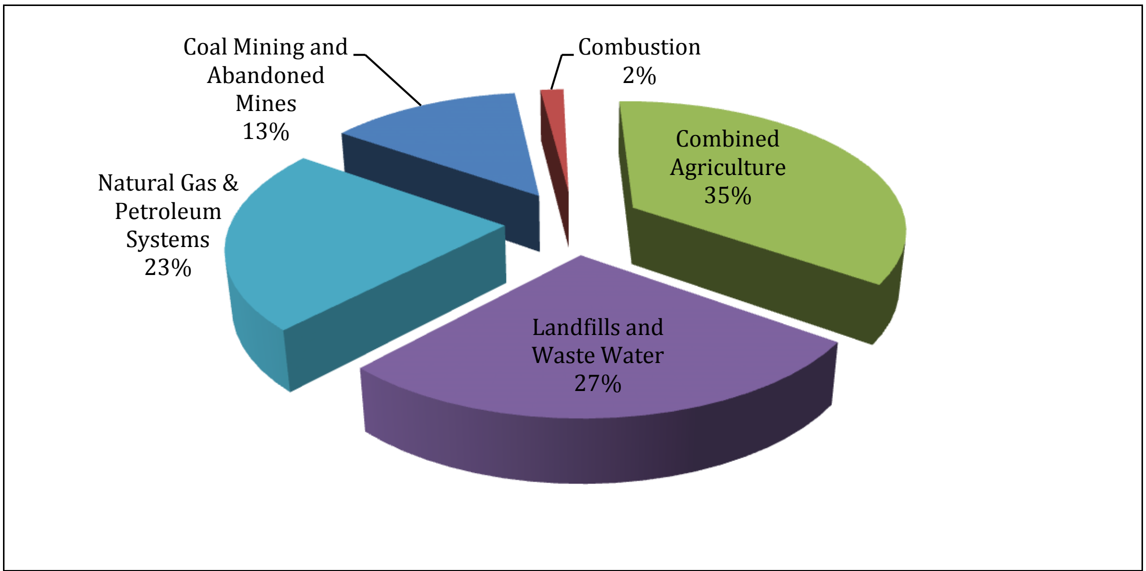
6.7.2. Fugitive methane emissions

Methane is a gas emitted by different sources both natural (e.g. wetlands) and artificial (e.g. industry and agriculture), the last one the main cause of methane emissions in United States (epa.gov, 2015). Although methane is not a toxic gas, it has begun to be produced in excessive quantities in recent years. Current atmospheric concentrations have reached levels considered dangerous due to its contribution to greenhouse effect and global warming.

The FIGURE 97 shows the different sources of methane emissions in the United States. Methane emissions from the oil and natural gas industry account for 23% of the total in the country. This is lower than the proportion from agriculture, landfills and wastewater but higher than for coal. However, gas produces roughly half the CO_2 of coal when it is burned. Of the four major methane gas contributors, gas is the only one whose methane emissions can be brought quickly under control by changes in well development operations. Note also that the methane emissions shown are a total from both gas and oil production.

Biogenic sources of methane from agriculture, landfills and waste water treatment are mixed gases that require significant treatment to be effectively separated and used, while methane emissions from coal present a significant challenge to collect even a low grade fuel, often only a small percent in the air at any time.

FIGURE 97. Human activities related methane sources in the USA



Source: EPA Publication sources of methane in (King, 2012)

Fugitive methane emissions can be defined as methane emissions that cannot be measured conventionally. For this reason, they are often assessed using mathematical models based on different hypotheses. Collecting representative data from specific areas or activities is therefore a considerably challenging task.

Several scientific articles and reports have been published on fugitive methane emissions from shale gas wells in the United States. One of the best known and most cited is the study by Howarth & Ingraffea (2011), which concludes, using mathematical models, that up to 7.9% of total shale gas production is directly released into the atmosphere as methane (Howarth et al., 2011).

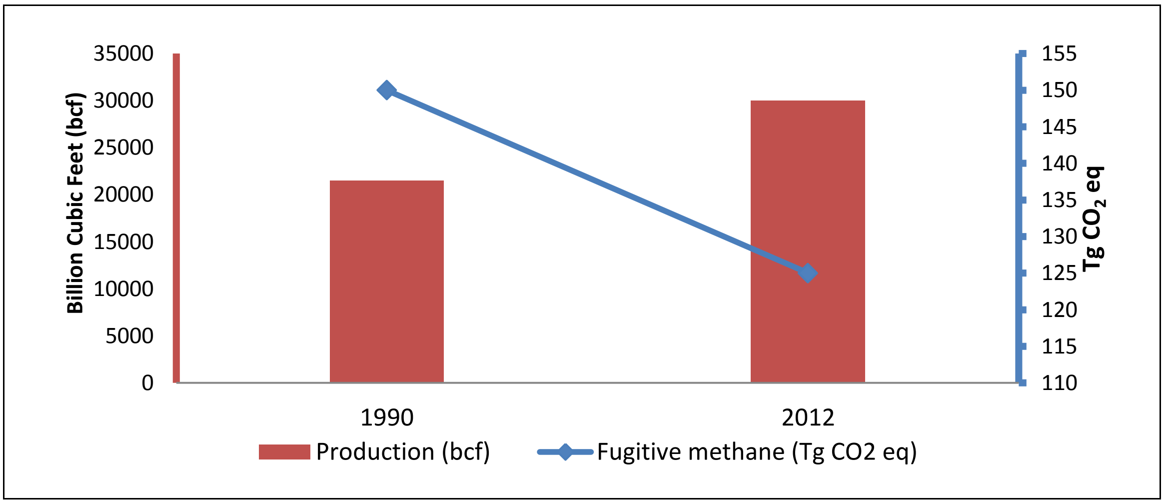
However, these conclusions have been challenged by other authors. For example, the study considers a 20-year time framework, five times lower than the timeframe commonly used by other scientists (usually 100 years). This places natural gas in an unfavorable position when compared with coal, whose emissions are assessed in a 100 year horizon. It should be noted that methane is a more powerful greenhouse-effect gas than carbon dioxide (in terms of equivalent CO_2) though it has a shorter residence time in the atmosphere (from nine to fifteen years as compared to one hundred years for carbon dioxide), so its effects on global warming are attenuated faster.

Cathles *et al.,* (2011), for example, argue that Howarth's assumption on the initial rate of gas emission is misleading. Howarth holds that if no infrastructures (pipelines) exist, this gas is released directly into the atmosphere. However, direct venting of wells, a common practice in the past, is no longer used by operators. Instead, special separators are used to obtain gas, water and condensates (where they exist) separately. This process is known as *green completion or Reduced Emissions Completion* (REC). Furthermore, if the gas separated from the flowback fluid cannot be sold, it is burnt in a flare, so the methane is converted into carbon dioxide (Cathles, Brown, Taam & Hunter, 2011).

The USA Environmental Protection Agency, which publishes an annual overview of greenhouse gases, shows that fugitive methane emissions in the USA dropped by 11% between 1990 and 2012. Over that period, which coincides almost exactly with the shale oil and gas revolution in the country, methane emissions from sources related to agriculture increased while emissions associated with oil and gas production decreased (see the FIGURE 98).

This downward trend in emissions will be furthered at a global level with the implementation of various improvement plans and alternatives to gas flaring during flowback. There are notable differences between countries and regions depending on the exploration and production area and the design and working of gas systems.

FIGURE 98. Drop in methane emissions from natural gas in the USA



Source: epa.gov, 2015

6.8. *Noise*

Noise levels vary during the different stages in the preparation and production cycle. Well drilling and hydraulic fracturing process itself are the most significant sources of noise.

Noise from excavation, earth moving, plant and vehicle transport during site preparation has a potential impact on both residents and local wildlife, particularly in sensitive areas. The site preparation phase typically lasts up to two months but is not considered to differ greatly from other comparable large-scale activities, such as construction.

Gas flaring during flow back and testing can also be noisy. For an individual well the time span of the drilling phase will be quite short but during this time it will be continuous, 24 hours a day.

The effect of noise on local residents and wildlife will be significantly higher where multiple wells are drilled from a single pad, which typically lasts over a five-month period.

Effective noise abatement measures reduce the impact in most cases, although the risk is considered moderate in locations where proximity to residential areas or wildlife habitats is required. On the other hand, the noise produced during drilling is much lower than other human activities, such as the noise generated by traffic on a national highway.

At a European level, the following directives refer to noise and emissions: Directive 2009/42/EC related to the assessment and management of environmental noise and Directive 2000/14/EC on noise emission in the environment by equipment for use outdoors.

6.9. Some conclusions

Risk

No human activity is free from risk and the extraction of shale gas is no exception. This technology has a similar risk level to other types of industrial activity, particularly those related to the oil and gas industry. In this respect, an approach to risk also involves analyzing probability and consequences and grading them in relation to the kind and type of impact.

Given the variations imposed by the geology of each site and its behavior in connection with the fracking process, no two gas extraction projects are the same. The level of risk will therefore vary from one site to another and it is not possible to develop a general risk prioritization. However, it is possible to take advantage of experiences in risk management and good practices in one area to minimize risks in others.

Furthermore, adequate regulation, good practices, right technical procedures and responsible implementation are important elements that contribute to safe operations and to diminish environmental impacts.

Drilling and fracturing operations

The primary objections to drilling are usually related to noise, visual impact, dust, time on location, water and mud storage, chemicals in the mud, pressure control and air emissions from diesel engines.

In hydraulic fracturing operations, other environmental aspects are also considered, such as surface requirement, truck traffic, water consumption, chemical additives used in the fracturing fluid, control of flowback and produced water and induced seismicity.

Each of these objections can be addressed through proper implementation of technology, third-party inspections, high operational standards and best practice. Increasing electric rigs, more common in condensed pad operations, are being used to reduce noise and control emissions.

Volume of water

Estimates for the water volume required for shale gas extraction vary depending on local geology, well depth and the length and number of hydraulic fracturing stages. It is important to note that hydraulic fracturing is not a continuous process. Water is just required during drilling and fracturing stages. Appropriate water management is very important to ensure the availability of hydric sources for other uses.

Furthermore, reuse of produced water will reduce the amount of make-up water required for hydraulic fracturing. Typically between 11% and 75% of the injected fluid is recovered as flowback. This means that although all the fracturing fluid recovered is reused, additional make-up water will still be required. In any case, total water consumption accounts for such a small percentage that it does not amount to 1% of overall consumption in any of the studied basins.

Compared to other energy sources, shale gas involves remarkably low water consumption. Water consumption in the conventional natural gas sector is among the least intensive of all energy sources (in terms of volume of water per energy unit).

Potential impact on aquifers

Hydraulic fracturing is carried out at thousands meters depth. The likelihood of aquifer contamination through natural and induced fractures is remote when the separation between the drinking water sources and the producing zone is greater than 600 meters. At 2,000 meters the produced water is mainly seawater from the geologic formation. Proper casing and cementing of the well is of vital importance in order to ensure good sealing.

Good process monitoring and quality control during hydraulic fracture treatment are essential to protect groundwater. Nowadays, microseismic monitoring is used to control the lateral extension of fractures, preventing them to go beyond the target formation.

Fluid storage

The most critical element in preventing contamination of shallow ground water is the containment of fluids within a pit. The failure of a tank, pit liner, or the line carrying fluid (the "flowline") can result in a release of contaminated materials directly into surface water and shallow ground water.

Pit lining is mandatory in the case of excavated pits to prevent any infiltration of fluids into the subsurface of the ground. The lining required depends on the fluids being placed in the pit, the duration of storage and the soil conditions. Typically, pit liners are constructed and equipped with a first layer of compacted clay, followed by a shotcreting layer (gunite) and a final layer comprised of synthetic materials such as thermo-welded polyethylene or treated fabric.

A number of systems have been developed to avoid the use of pits, by keeping fluids in a series of pipes and tanks throughout the entire fluid storage process. However, there are some disadvantages to the use of tanks. For example, the storage volume is limited by the capacity of each tank. The greater the volume, the more the visual impact, whereas if smaller volumes are used, the number of tanks needed will increase, as will truck traffic and emissions from diesel engines. It is necessary to assess the most suitable storage system for each individual location.

Fracking fluid disclosure

The most commonly used hydraulic fracturing fluids consist mainly in water and sand. Chemical additives are also added in a low percentage, which does not normally reach 1%, in order to reduce friction loses and control external agents, among other functions.

There is a trend towards the use of chemical compounds that are also employed in other industries. For example, common biocides are the same as those used in hospitals and for food preparation. Benzene, Toluene, Ethilbenzene and Xilene (BTEX) are no longer used as additives.

Furthermore, the REACH system requires firms that manufacture and import chemicals to evaluate the risks resulting from the use of those chemicals and to take the necessary steps to manage any identified risk. Although some chemicals are not specifically identified for hydraulic fracturing (due to its utilization in other activities), the REACH system is an advantage regarding the control of this type of chemical compounds in Europe.

Induced seismicity

Magnitudes of induced seismicity during hydraulic fracture stimulation in hydrocarbon fields are typically less than 1 M_L (normally between M_L-3 and M_L-1). This means that these events are undetected unless a local monitoring network is in place. Events of over M_L 3 that occur in association with fracturing often appear to have been induced by disposal of the wastewater used to generate fractures, rather than by the stimulation itself.

The criteria and definition of the threshold value varies between different authors and associations. Moreover, these limits should be established in accordance with the geological and technical characteristics of each play.

NORM

Average radiation limits have been determined for people working at nuclear plants and other radioactive facilities. Generally, the radiation received by workers varies from 1 to 2 mSv/yr (100-200 mRem/yr) in nuclear plants and stands at around 0.7 mSv/yr (70 mRem/yr) in other radioactive facilities. These levels are considered to be safe.

Maximum dose rates in shale gas fields are usually in the range of up to a few microsieverts per hour (much lower than those mentioned before). In particular cases, such as Marcellus shale (USA), dose rates measured directly on the outer surfaces of production equipment have reached higher than average values. However, studies have shown that, even in the case of such an unusual geologic formation like Marcellus, exposure risks for workers and the public are too low to affect the general public.

Ground occupation and visual impact

Surface installations require an area of approximately 3.0 hectares per multi-well pad during the fracturing and completion phases. This is reduced, after partial restoration, to approximately 0.5 hectares per multi-well pad.

Increasing well spacing and using multiple wells per pad reduces the total land take up for well pad construction. Fewer pads require fewer roads, pipelines, and other rights of way.

Moreover, appropriate siting can reduce the amount of land disturbance involved in constructing roads, pipelines, and other infrastructure and minimize adverse impacts on sensitive locations such as residential areas or ecosystems.

The visual impact is temporary and different depending on the phases of the exploration and production process. Reference times per pad are normally placed between two and three months for drilling and between several days and a few weeks for hydraulic fracturing. In the production phase of the wells, there is a minimum visual impact.

Atmospheric emissions and noise

Emissions from gas production come from direct emissions (lost gas or fugitive emissions and CO_2 from natural gas fuel combustion), and indirect emissions from trucks, pumps and processing equipment used in drilling, fracturing and production. In Europe, strict regulations and strict monitoring are recommended to minimize the risk of spills.

An annual overview of greenhouse gases by the US Environmental Protection Agency, shows that fugitive methane emissions dropped by 11% between 1990 and 2012 in the USA. Over that period, which coincides almost exactly with the shale oil and gas revolution in the country, methane emissions from sources related to agriculture increased, while emissions associated with oil and gas production fell.

This downward trend in emissions will be furthered at a global level by the implementation of various improvement plans and alternatives to avoid gas flaring during flowback. There are notable differences between countries and regions, depending on the exploration and production area and the design and working of gas systems.

Noise from excavation, earth moving, plant and vehicle transport during site preparation has a potential impact on both residents and local wildlife, particularly in sensitive areas. The site preparation phase is not continued and permanent, and is not considered to differ greatly in nature from other comparable large-scale activities, such as construction.

7. EXPLORATION AND PRODUCTION OF UNCONVENTIONAL GAS. BASIC LEGISLATION

In this chapter, we shall review Spanish legislation relating to shale gas exploration and production, analyzing the Spanish Hydrocarbon Act and its associated regulation and summarize the main issues as they pertain to shale gas exploration and production.

We shall go on to o look at the recommendations of the European Commission and general European legislation and identify the requirements related to environmental issues. In order to give a better understanding of the regulatory framework, we will also review the regulation in the UK and some states of the USA.

7.1. Spanish regulations on exploration, "investigación" and production of unconventional gas

Under Spanish law, oil and gas are the property of the state and a concession is therefore required from the state to extract the resource. The rules for granting exploration permits, and exploration authorizations are as established in the law governing the Legal Regime for Oil and Gas Exploration (*Ley sobre el Régimen Jurídico de la Investigación y Exploración de los hidrocarburos*, 1958), which contains hydrocarbon regulations.

The 1974 Hydrocarbon Act (Act 21/1974 of June 27, 1974) was amended by Royal Decree 2362/1976, of July 30, 1976, before being repealed by the current act (Act 34/1998 October 7, 1998). The 1976 decree establishes more detailed requirements for exploration and production activities.

Other relevant legislation includes Act 12/2007 of July 2, 2007, partially amending Act 34/1998, and Act 12/2013 of October 29, 2013, which, for the first time in national law, includes the concept of hydraulic fracturing techniques (amending Act 34/1998). Act 8/2015 of May 21, 2015, which also amends Act 34/1998, regulates both specific fiscal and non-fiscal measures in relation *inter alia* to the exploration and production of hydrocarbons. All of this legislation shares a common base which has been modified to adapt to significant changes and new needs.

The 1998 Act and its subsequent amendments regulate hydrocarbon reservoir exploration, "investigation"[106] and exploitation of underground hydrocarbon storage; transmission activities, industrial handling and storage of hydrocarbons by operators and storage incidentally related to the production facilities themselves.

[106] Throughout this text, "*investigación*", as used in the Spanish Hydrocarbons Act, is translated as exploration, as understood in the upstream sector of the petroleum industry, rather than as research or investigation, the literal translation.

Under the terms of the 1998 Act, holders of exploration permits or exploitation concessions shall be entitled, with prior approval from the Ministry of Industry or the regional (autonomic) authority, to carry out the activities regulated in the authorization. If necessary, they can also benefit from compulsory expropriation or temporary occupation of property and certain rights required for performance of the work and the facilities and services required for their operations. The occupation must be authorized by the Provincial Delegation of the Ministry of Industry, Energy and Tourism (MINETUR).

Exploration permits and exploitation concessions may be granted to a single company or group of companies (joint venture) that meet the required conditions and demonstrate their legal, technical and financial capacity to perform the exploration and exploitation of the resources in the licensed areas.

The holders of exploration permits and exploitation concessions must provide the information required by MINETUR and the regional authority, such as investments, geological and geophysical reports, drilling reports, etc., as well as any other additional details required by law. The data provided will be treated in strict confidence and will not be communicated to third parties without the express authorization of the owner during the term of the permit or concession.

Act 8/2015 includes a new Article (art 35 bis) concerning the regime governing "administrative and notification silence"[107]. Article 36 also amends the scope of Act 34/1998, Title II on exploration, investigation and exploitation of hydrocarbons.

7.1.1. *Regulation of hydrocarbon exploration*

The 1998 Hydrocarbons Act changed the regulation reserving the title of public domain for the Spanish state and recognizing free enterprise. Reservoirs are public state domain (*dominio público estatal*) as defined in Article 132.2 of the Spanish Constitution.

The state can therefore issue exploration and investigation[108] concessions (exploration authorization and investigation permit), with the operator as the legal entity responsible.

The Act also introduces criteria of environmental protection, covering the various phases of reservoir exploration and production.

The regional authorities (autonomous communities) grant authorizations for exploration permits wholly within their own territory (i.e. not entering any other autonomous community or the sea) and are responsible for legislative development in those areas.

[107] *silencio administrativo*: failure by a public administrative body to reply within the stipulated time limit to a complaint lodged against its procedure or a challenge to its decisions (Alcaraz Varó, E. Hughes, B. Diccionario de Términos Jurídicos, Ariel 2003)

[108] In the UK, there is an appraisal stage. In Spain, this is considered a part of exploration.

Exploration authorizations allow geophysical work or other geological work that normally does not involve deep drilling (drilling is allowed, but to no more than 300 meters).

An exploration permit entitles the holder to exclusive exploration rights in the area in question, with a minimum area of 10,000 ha and a maximum of 100,000 ha, for an initial period of 6 years. This period can be extended for an additional period of 3 years with an obligation to relinquish 50% of the original area of the permit. A permit also entitles the holder to obtain an exploitation concession subsequently if a commercially viable accumulation of hydrocarbons is discovered.

The permit application must include, *inter alia*, an annual work plan, an investment plan, an environmental protection plan and a restoration plan. The permit holder is required to submit a work program (*Plan de Labores*) and an investment schedule for the 6 year-period of the permit.

Act 12/2007 of July 2, 2007 introduced certain modifications in respect of the 1998 Act. The permit application must be published in the Official State Gazette (*Boletín Oficial del Estado*, BOE) and also, where applicable, in the Official Gazette of the Autonomous Community by which the permit has been awarded.

During the two months following publication of the application in the Official Gazette, competing offers (bids) may be tendered, and submissions made by any parties who consider they are being affected. The Hydrocarbons Act specifies the criteria for evaluating the different bids. The most important of these are the size of the investment plan, the schedule for execution of the work program, and the bonus offered above the annual fee to be paid annually to the state by the permit holder (the hydrocarbon fee) (Act 12/2007 of October 7, 2007. First Additional Provision).[109]

7.1.2. *Regulation of hydrocarbon production*

The granting of an 'exploitation' –or production– concession gives its holders the exclusive right to exploit any hydrocarbons discovered in the area, carrying out the necessary operations (upon approval from the Ministry of Industry, Energy and Tourism) to exploit the resource adequately for an initial period of 30 years, which may be extended for two additional 10-year periods.

All applications for an exploitation concession and for the two possible extensions must be submitted to the Ministry of Industry, Energy and Tourism. Applicants must submit a technical and economic document detailing the following items: the location and extension of the concession and other technical data; the proposed concession; the proposed overall operational plan; the proposed investment program; an Environmental Impact Statement (EIS) to be evaluated by the environmental authority; an estimation of recoverable reserves and production profile; and an abandonment and restoration plan.

[109] Act 8/2015 maintains the same fees as in Act 12/2007

If approved, the government authorizes the exploitation concession by Royal Decree, upon consideration of a report issued by the autonomous community concerned.

7.1.3. *The New Hydrocarbons Act.*

On January 16th 2015, the Spanish Council of Ministers submitted a bill to amend the 1998 Hydrocarbons Act. This was passed into law as Act 8/2015, regulating specific fiscal and non-fiscal measures related to hydrocarbon exploration and production.

Amongst the most important of the new measures is the introduction of a new tax on the value of the extraction of oil, gas and condensates (*Impuesto sobre el valor de la extracción de gas, petróleo y condensados*). The tax is levied at various rates depending on the location of the well (onshore or offshore) and the type of extraction required (unconventional or conventional).

Unconventional extraction is defined as extraction that requires the use of hydraulic fracturing techniques ("fracking"), consisting of the injection of at least 1,000 cubic meters of water per fracture stage in a well or more than 10,000 cubic meters of water during the entire fracturing process. Conventional extraction is defined as the exploitation of hydrocarbons by means of all other techniques.

The new law also modifies the 'surface royalties' (*canon de superficie*), including new rates on the use of exploratory well drillings in exploitation concessions and investigation permits and the acquisition of seismic surveys.

Finally, the act introduces a number of incentives for the autonomous communities and local entities in which hydrocarbon exploration and production activities are conducted. Holders of exploitation concessions are required to pay three different fees for land use.

The first of these is a fee for the amount of gas extracted (in cubic metres), for which operators will have to install measurement equipment on site. The tax scale distinguishes between conventional and unconventional extraction as well as on-shore and off-shore activities. Tariffs 3 and 4 of the surface royalties also include the drilling of wells and seismic data collection.

The third fee is an annual payment to land owners. Concession holders are required to pay an amount (Qi) which is determined using the following formula:

$$Q_i = Q_T \times \frac{S_i}{S_T}$$

Where Q_T is equivalent to 1% of the monetary value of the quantity of hydrocarbons extracted, Si is the surface area of the owner's land and ST is the total surface of the exploitation concession.

7.1.4. *Environmental regulation related to hydrocarbon activities: exploration and production*

Until December 12, 2013, Spanish environmental regulation was contained in Royal Decree-Law 1/2008 of January 11, 2008 (the Project Environmental Impact Assessment Act) and Act 6/2010 of 24 March 2010 amending Royal Decree-Law 1/2008. The Environmental Assessment Act (Act 21/2013 of December 9, 2013) came into effect in December 2013 .

The 2013 Act states that environmental assessment is one of the essential tools for protecting the environment. The main obligation, under this act and Royal Decree-Law 1/2008, is that any plan, program or project that might have significant effects on the environment must be subjected to adequate and specific environmental assessment prior to its approval or authorization. One important new feature is that the legal nature of environmental procedures and environmental authorizations (Environmental Impact Statements) are defined in accordance with case law consolidated during the term of this legislation. If the necessary environmental authorization is not issued within the statutory time limit, the assessment will not be considered to be favorable.

The law facilitates the incorporation of sustainability criteria in strategic decision-making, through the evaluation of plans and projects. It ensures proper prevention of possible specific environmental impacts through an evaluation of the potential risks that might arise in the execution of a plan or project, establishing effective preventive, corrective or compensatory measures.

This law establishes the legal framework for evaluating plans, programs and projects, and establishes a set of common rules to facilitate implementation of the regulations. It contains sixty-four articles divided into three main titles: a) Title I, which contains the general principles and provisions; b) Title II, which contains provisions governing the environmental assessment procedures; and c) Title III, which covers monitoring and sanctions.

The basic principles covered by the act are the protection and improvement of the environment through the implementation of preventive and precautionary actions: correction and compensation of potential impacts on the environment; rationalization, simplification and coordination in environmental assessment procedures; and cooperation and coordination between the state and the autonomous communities. It also addresses proportionality between the effects of plans, programs and projects on the environment and the type of assessment procedure used to evaluate them. The law also takes into account criteria based on sustainable development and integration of environmental considerations into decision-making to furnish the necessary information required by the general public.

The Ministry of Agriculture, Food and Environment (MAGRAMA) is the authority ultimately responsible for approving or authorizing environmental assessment of plans, programs or projects that come under the competence of the state. In cases in which the project has to be assessed by an autonomous community, it is the responsibility of the bodies determined by each autonomous community to approve or authorize the program or project.

Any dispute that might arise between the substantive body and the environmental agency is to be resolved on the recommendation of the administration that has handled the procedure, i.e. the Council of Ministers or the governing council or body determined by the autonomous community.

The autonomous regions submit proposals to be included in the environmental impact assessment, where appropriate, and in the process of granting and modification of the integrated environmental authorization.

Strategic Environmental Impact Assessment

With regard to the relationship between the Strategic Environmental Impact Assessment (*Evaluación de Impacto Ambiental Estratégica*) and the Project Environmental Impact Assessment, note that in accordance with EU directives, the former does not substitute the latter. In the Strategic Environmental Impact Assessment, strategic plans submitted by public authorities are assessed, whereas in the Project Environmental Impact Assessment, individual projects submitted by public or private companies are assessed. The environmental sustainability report, regulated by Act 9/2006 of April 28, 2006 is now called the strategic environmental assessment. The ordinary procedure of the strategic environmental impact assessment ends with the strategic environmental statement, which has the legal status of a mandatory report that cannot be appealed and must be published in the official gazette (BOE).

With regard to the deadlines, a period of twenty two months, extendible for two more months on justified grounds, is established for an ordinary strategic assessment and four months for a simplified strategic evaluation assessment.

Ordinary and Simplified Environmental Impact Assessments

Although Act 21/2013 allows for the possibility of making an ordinary or simplified Environmental Impact Assessment, exploration and production of unconventional gas through hydraulic fracturing techniques is included in Group 9 of Annex I of the Environmental Act. This means that an ordinary Environmental Impact Assessment is required. When the area of a permit affects two or more autonomous communities, the Ministry of Industry, Energy and Tourism (MINETUR) is the body responsible for granting permits. For an environmental point of view the substantive body is the MINETUR, although the final Environmental Impact Statement (*Declaración de Impacto Ambiental*, DIA) is issued by the Ministry of Agriculture, Food and Environment (MAGRAMA).

The regular assessment procedure begins with an environmental impact application received by the environmental body. Before the environmental impact assessment procedure begins, the following steps must be taken: the environmental body establishes the scope of the environmental impact assessment. The maximum period for completing this process is three months. The body responsible for deciding the authorization procedure of the project will then provide a public information review period and will receive enquiries and submissions from affected administrations and the general public.

The public information and enquiries procedure continues for one year from the publication of the data. After this period, if the ordinary environmental impact assessment has not begun, the body declares these procedures to have expired.

Following the preliminary proceedings, the ordinary environmental impact statement will be processed in accordance with the following steps: initiation request; technical analysis of the environmental impact record and environmental impact statement.

The environmental body must perform these procedures within four months of receipt of the completed environmental impact record. This period may be extended for two additional months if reasonable grounds are given.

Projects predating the 2013 Environmental Impact Act

As mentioned above, projects initiated before December 2013 were subject to RD-L 1/2008. In this case, Provision III of Act 17/2013 guaranteeing supply and increased competition in insular electric systems establishes that hydrocarbon exploration or exploitation wells requiring the use of hydraulic fracturing shall be subject to an ordinary environmental impact statement.

Summing up, the administrative procedure of the environmental impact statement begins with the submission by the developer of an application for approval from the relevant authority with an initial document and any other environmental documentation requested. Furthermore, the scope of the environmental study is determined by the relevant environmental authority.

The table below shows the main aspects of the administrative exploration authorizations and environmental impact assessment.

Act 6/2015 concerning additional environmental protection measures

On June 30, 2015, as a result of a citizens' initiative, the Basque Parliament approved Act 6/2015 concerning additional environmental protection measures with regard to hydraulic fracturing operations to be conducted in the Basque Country. The act, which contains six articles and two transitory provisions (derogatory and final), is based on the principles of caution and prevention which shall apply to oil and gas exploration and production.

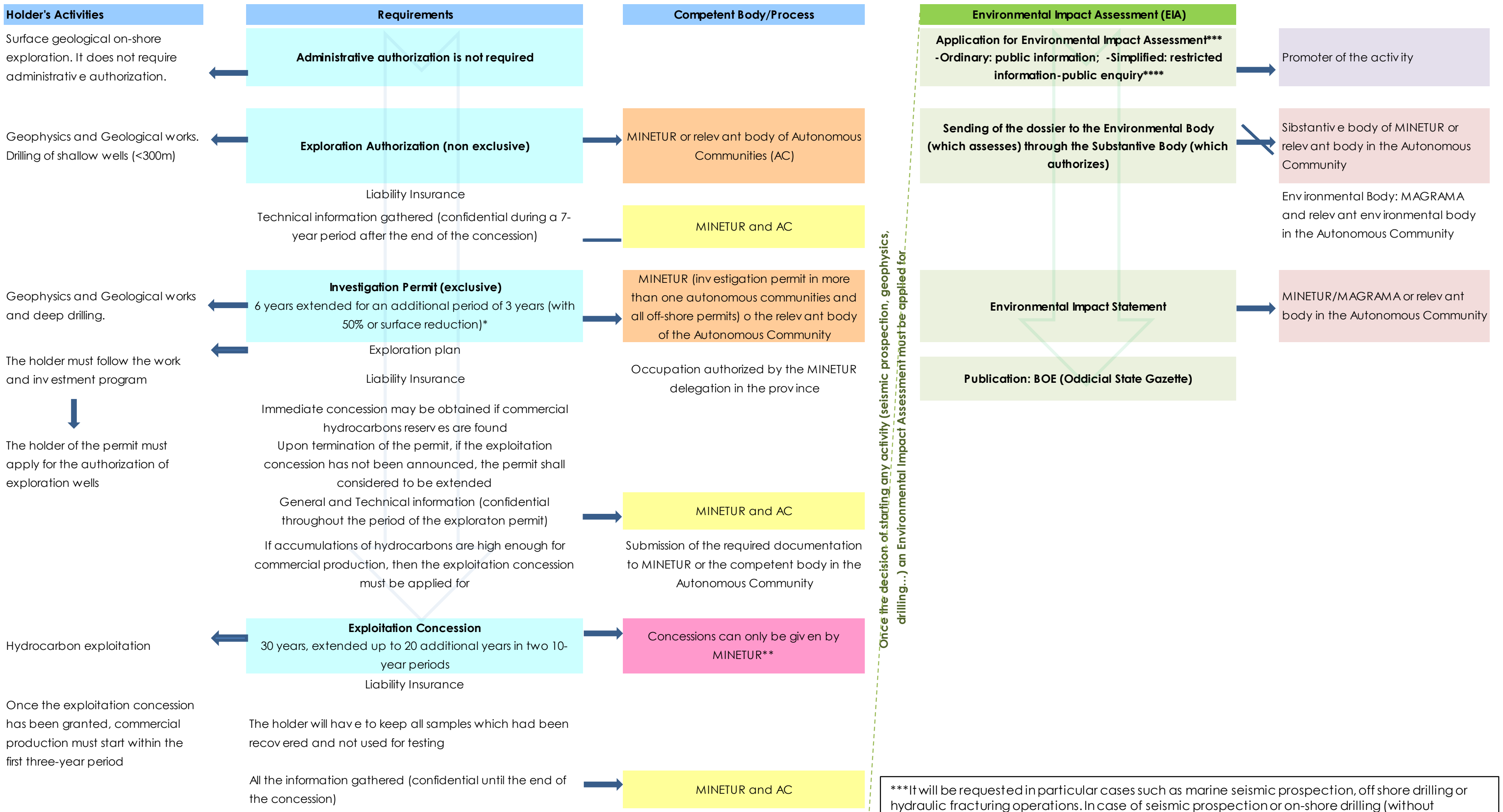
The most important measures are contained in Articles 3, 4 and 5. Under Article 3, whose effects are backdated to existing permits (from July 21, 2006), Article 28 of the 2006 Land Use and Urban Planning Act is amended with the insertion of a new paragraph banning hydraulic fracturing in non-building lands where it might have negative effects on geological, environmental, visual or socioeconomic characteristics. Article 4 requires any program or sectorial strategy considering the use of hydraulic fracturing for the production of hydrocarbons to have a strategic environmental impact assessment. Article 5 bans hydraulic fracturing in places classified as of medium, high and very high vulnerability in the aquifer contamination vulnerability map of the Basque Country.

Disagreement has arisen between the Spanish central government and the government of the Basque Country regarding all the articles and provisions in this act. According to the Official State Gazette (BOE), a bilateral cooperation committee was created on September 16, 2015 to address these differences.

TABLE 25. Administrative authorizations: main aspects related to I&E and environmental impact assessment

	EXPLORATION (*INVESTIGACIÓN Y EXPLORACIÓN*) –I&E-	ENVIRONMENTAL IMPACTS(EI)
What is granted?	- Right to explore hydrocarbon reservoirs for appraisal and exploitation. - Right to perform exploration work in free areas (where there is no current license or concession). - Exclusive right to explore the possible existence of hydrocarbons within the granted area. - Exclusive right to obtain concessions. - Right to develop any resources discovered.	- Right to carry out the project that has been assessed (if the project receives a favorable environmental assessment).
Basic requirements	- Individual company or group of companies (joint venture). - Liability insurance. - Warranties in accordance with the investment plan. - Completion of the plan and investment programs within the specified periods.	- An environmental impact assessment must be submitted and evaluated before approval, adoption or consent of the project. - Identification of the developer, substantive body and project description. - Summary result of the process. - Technical analysis by the environmental body. - Establishment of preventive and corrective measures. - Countervailing measures. - Environmental monitoring program. - If appropriate, establishment of a monitoring committee.
Documentation required	- Accreditation of the legal, technical and economic-financial capacity of the applicant. - Area/Surface of the exploration permits (*permiso de investigación* included). - Exploration plan, including work program, investment plan, environmental protection measures and restoration plan. - Proof of the creation of a warranty.	- A request for scope of environmental impact is required: the definition, characteristics and location of the project; alternatives considered and territorial and environmental diagnosis affected. - The Environmental Impact Statement must contain: project overview and timing estimation; main alternatives studied; evaluation of foreseeable effects, corrective and preventive action, environmental monitoring program and summary and conclusions.

FIGURE 99. Scheme-Summary of the Administrative Process in Spain



*In reality, it has been shown that between 1 and 4 years are needed to obtain the Environmental Impact Autorization for geophysical studies and between 2 and 6 years for drilling an exploration well.
**The draft of RD is prepared by MINETUR and processed by the Council of Ministers
Note 1: The investigation permit is prorogated until the resolution of the exploitation concession, in case it was requested but not solved before the deadline.
Note 2: Contrary to the investigation permit and the exploitation concession, the exploration authorization is not absolutely necessary

***It will be requested in particular cases such as marine seismic prospection, off shore drilling or hydraulic fracturing operations. In case of seismic prospection or on-shore drilling (without hydraulic fracturing), the simplified EIA is requested.
****In case of Simplified EIA, MAGRAMA open request to public enquiry, to a group consisting on 20-25 agents (affected or interested) approximately, which will assess the dossier and conclude: to grant, or restart the ordinary process

(Larrea, 2015)

7.2. European regulatory framework

With regard to European Regulations, several reports and recommendations are relevant.

There is no specific regulation for shale gas activities but there are, to our knowledge, three relevant documents:

- Report on environmental impacts of shale gas and shale oil extraction activities of the Committee of Environment, Health and Safety (European Parliament, 2012).
- The Commission Recommendations on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high volume hydraulic fracturing (European Commission, 2014)

7.2.1. Report of the Committee on the Environment, Public Health and Food Safety (ENVI)

The report of the Committee on the Environment, Public Health and Food Safety (European Parliament, 2012) highlights the findings of prevailing expert opinion that the inherent risks of Unconventional Fossil Fuel (UFF) extraction, most of which are common to conventional fossil fuel extraction, could be managed through pre-emptive measures, including proper planning, testing, use of new technologies, best practices and continuous data collection, monitoring and reporting.

In relation to the environmental aspects of hydraulic fracturing the report makes a number of points: it acknowledges that the rock types present in each individual region determine the design and method of the extraction activities; it also calls for mandatory authorization preceding geological analysis of the deep and shallow geology of a prospective shale play, including reports on any past or present mining activities in the region; and it recognizes the relatively high water volumes involved in hydraulic fracturing;

However it points out that such high water volumes are not particularly significant compared to the needs of other industrial activities. It also highlights the need for advance water provision plans based on local hydrology. Given the depth (over 3km) at which hydraulic fracturing takes place, the report argues that the main concern regarding groundwater contamination is well integrity and the quality of casing and cementing and stresses that effective prevention requires consistent monitoring and strict adherence to the highest established standards and practices in well-bore construction. It argues that both industry and the relevant authorities should ensure regular quality control for casing and cement integrity.

The European Parliament noted the significant potential benefits of producing shale gas and oil and called on the Commission to introduce a Union-wide risk-management framework for the exploration and production of unconventional fossil fuels, aimed at ensuring that harmonized provisions for the protection of human health and environment apply to all Member States.

In its conclusions, the European Council (European Council, 2013) stressed the need to diversify Europe's energy supply and develop indigenous energy resources to ensure the security of the supply, reducing the Union's external energy dependency and stimulate economic growth.

7.2.2. *Report of the European Commission on minimum principles for the exploration and production of hydrocarbons.*

The European Commission (European Commission, 2014), has issued recommendations on exploration and production of hydrocarbons (such as shale gas) using hydraulic fracturing. The Commission outlined the potential new opportunities and challenges related to unconventional hydrocarbon extraction in the Union as well as the main elements deemed necessary to ensure the safety of this technique.[110]

[110] Both general and environmental legislation of the Union apply to hydrocarbon exploration and production operations involving high-volume hydraulic fracturing. In particular, Council Directive 89/391/EEC laying down provisions on health and safety of workers introduces measures to encourage improvements regarding safety and health of workers at work. Council Directive 92/91/EEC sets minimum requirements for protecting the safety and health of workers in mineral-extracting industries through drilling. Directive 94/22/EC of the European Parliament and of the Council on conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons requires that authorizations be granted in a non-discriminatory manner. Directive 2000/60/EC of the European Parliament and of the Council establishing the water framework requires the operator to obtain authorization for water extraction and prohibits the direct discharge of pollutants into groundwater. Directive 2001/42/EC of the European Parliament and of the Council laying down provisions on strategic environmental assessment requires assessment of plans and programs in the areas of energy, industry, waste management, water management, transport or land use; Directive 2004/35/EC of the European Parliament and of the Council laying down provisions on environmental liability applies to occupational activities encompassing activities such as the management of waste and water abstraction. Directive 2006/21/EC of the European Parliament and of the Council laying down provisions on mining waste regulates the management of surface and underground wastes resulting from the exploration and production of hydrocarbons using high-volume hydraulic fracturing. Directive 2006/118/EC of the European Parliament and of the Council laying down provisions on groundwater obliges Member States to enforce measures that prevent or limit the input of pollutants into groundwater. Regulation (EC) No 1907/2006 of the European Parliament and of the Council on the registration, evaluation, authorization and restriction of chemicals (REACH) and Regulation (EU) No 528/2012 of the European Parliament and of the Council on the making available on the market and use of biocidal products apply to the use of chemicals and biocidal products that may be used for fracturing. Directive 2008/98/EC of the European Parliament and of the Council on waste sets out the conditions applicable to the reuse of the fluids that emerge at the surface following high-volume hydraulic fracturing and during production. Regulation (EU) No 525/2013 of the European Parliament and of the Council on a mechanism for monitoring and reporting greenhouse gas emissions and Decision No 406/2009/EC of the European Parliament and of the Council on the effort of Member States to reduce their greenhouse gas emissions up to 2020 apply to fugitive methane emissions. Directive 2010/75/EU of the European Parliament and of the Council laying down provisions on industrial emissions applies to installations within which activities listed in Annex I to that Directive are operated. Directive 2011/92/EU of the European Parliament and of the Council laying down provisions on environment impact assessment requires an environment impact assessment for projects involving the extraction of petroleum and natural gas for commercial purposes if the amount extracted exceeds 500 tonnes/day in the case of petroleum and 500,000 m^3 per day in the case of gas and a screening for deep-drilling projects and surface installations for extracting oil and gas. Council Directive 96/82/EC on the control of major-accident hazards involving dangerous substances and, as of June 1, 2015, Directive 2012/18/EU of the European Parliament and of the Council oblige operators of establishments where dangerous substances are present above certain thresholds defined in Annex I to these Directives to take all necessary measures to prevent major accidents and to limit their consequences for human health and the environment. This applies, *inter alia*, to chemical and thermal processing operations and related

However, the Union's environmental legislation was developed at a time when high-volume hydraulic fracturing was not used in Europe. Therefore, certain environmental aspects associated with the exploration and production of hydrocarbons involving this practice are not comprehensively addressed in current European legislation, particularly with regard to strategic planning, underground risk assessment, well integrity, baseline and operational monitoring, capture of methane emissions and disclosure of information on chemicals used on a well by well basis.

The recommendation of the European Commission lays down minimum principles to be applied as a common basis for the exploration or production of hydrocarbons where high-volume hydraulic fracturing is necessary at this point in time. The Commission defines 'high-volume hydraulic fracturing' as being the injection of 1,000 m^3 or more of water per fracturing stage or 10,000 m^3 or more of water during the entire fracturing process into a well.

The objective is to lay down the minimum principles needed to support Member States who wish to carry out exploration and production of hydrocarbons using high-volume hydraulic fracturing, while ensuring that public health, climate and environment are safeguarded, resources are efficiently used, and the public is kept informed.

Recommendation to member states

Before granting licenses for exploration and/or production of hydrocarbons which might lead to the use of high-volume hydraulic fracturing, Member States should prepare a *strategic environmental assessment* to prevent, manage and reduce the impacts on, and risks for, human health and the environment. This assessment should be carried out on the basis of the requirements of Directive 2001/42/EC.

Where an environmental assessment is required, an environmental report must be prepared identifying, describing and evaluating the likely significant effects on the environment resulting from implementing the plan or program, with reasonable alternatives, taking into account the objective and the geographical scope of the plan or program. The environmental report should include all information that may reasonably be required taking into account current knowledge and methods of assessment, the contents and level of detail in the plan or program; its stage in the decision-making process and the extent to which certain matters are more appropriately assessed at different levels in that process in order to avoid duplication of the assessment.

Member States should provide *clear rules on possible restrictions of activities*, for example in protected, flood-prone or seismic-prone areas, and on minimum distances between authorized operations and residential and water-protection areas. They should also establish minimum depth limitations between the area to be fractured and

storage in the framework of the exploitation of minerals in mines and quarries as well as to onshore underground gas storage.

groundwater and should take the necessary measures to ensure that an environmental impact assessment is carried out, based on the requirements of Directive 2011/92/EU.

Member States should take the necessary measures to ensure that the geological formation of a site is suitable for the exploration or production of hydrocarbons using high-volume hydraulic fracturing. They should ensure that operators carry out a *characterization and risk assessment of the potential site*, surrounding surface and underground area. The risk assessment should be based on sufficient data to enable the characterization of the potential exploration and production area and identification of all potential exposure pathways. This would make it possible to establish the risk of leakage or migration of drilling fluids, hydraulic fracturing fluids, naturally occurring material, hydrocarbons and gases from the well or target formation as well as the risk of induced seismicity.

The risk assessment should be based on the best available techniques and take into account the relevant results of the information exchange between Member States, the industries concerned and non-governmental organizations promoting environmental protection organized by the Commission. The risk assessment should also anticipate the changing behavior of the target formation, geological layers separating the reservoir from groundwater and existing wells or other manmade structures exposed to the high injection pressures used in high volume hydraulic fracturing as well as the volumes of fluids injected; additionally, it should state that a minimum vertical separation between the zone to be fractured and the groundwater must be respected and, finally, it should be updated during operations whenever new data are collected.

Before high-volume hydraulic fracturing operations start, Member States should ensure that *the operator determines the environmental status (baseline) of the installation site* and its surrounding surface and the underground area potentially affected by the activities; the baseline must be appropriately described and reported to the competent authority before operations begin.

A baseline should be determined for quality and flow characteristics of surface and ground water, water quality at drinking water abstraction points, air quality, soil condition, presence of methane and other volatile organic compounds in water, seismicity, land use, biodiversity, status of infrastructure and buildings and existing wells and abandoned structures.

"Member States should ensure that operators develop project-specific water-management plans to ensure that water is used efficiently during the entire project"; develop transport management plans to minimize air emissions; capture gases for subsequent use, minimize flaring and avoid venting; carry out the high volume fracturing process in a controlled manner and with appropriate pressure management with the aim of containing fractures within the reservoir and avoiding induced seismicity; and ensure well integrity through well design, construction and integrity tests.

Operators should also develop risk management plans and determine the measures necessary to prevent and/or mitigate the impacts and implement the measures necessary for response, stop operations and urgently take any necessary remedial action if there is a loss of well integrity or if pollutants are being accidentally discharged into groundwater and should report immediately to the competent authority in the event of any incident or accident affecting public health or the environment.

Member States should *"ensure that using chemical substances in high-volume hydraulic fracturing is minimized."* The ability to treat fluids that emerge at the surface after high-volume hydraulic fracturing must be taken into consideration during selection of the chemical substances to be used.

Member States should ensure that the operator monitors the following operational parameters: the precise composition of the fracturing fluid used for each well; the volume of water used for the fracturing of each well; and the pressure applied during high-volume fracturing. Monitoring of the fluids that emerge at the surface following high-volume hydraulic fracturing should include the return rate, volumes, characteristics and quantities re-used and/or treated for each well. Air emissions of methane, other volatile organic compounds and other gases that are likely to have harmful effects on human health and/or the environment should also be checked.

Member States should ensure that operators monitor the impacts of high-volume hydraulic fracturing on the integrity of wells and other manmade structures located in the surrounding surface and underground area potentially affected by the operations.

Member States should ensure that *the operator provides a financial guarantee or equivalent* covering the permit provisions and potential liabilities for environmental damage prior to the start of operations involving high volume hydraulic fracturing.

Member States should ensure that a survey is carried out after each installation's closure to compare the environmental status of the installation site and its surrounding surface and the underground area potentially affected by the activities with the status prior to the start of operations as defined in the baseline study.

7.3. UK regulatory framework

In this section we will discuss the process required to obtain a Petroleum License in the UK. We will describe the bodies involved in the process to obtain these permits, focusing particularly on the Environmental Impact Assessment and restoration. Finally, we will explain what a Petroleum License is.

7.3.1. Bodies involved in the Petroleum License

The bodies involved in the Petroleum License in the UK include the Department of Energy and Climate Change which issues Petroleum Licenses, gives consent to drill under the License once other permissions and approvals are in place, and is responsible for assessing risks and monitoring seismic activity, as well as granting consent for flaring or venting. The Minerals Planning Authorities (MPA) grants permission for the location of any wells and well pads, and imposes conditions to ensure that the impact on the use of the land is acceptable. The Environment Agency (EA), which protects water resources (including groundwater aquifers), ensures appropriate treatment and disposal of mining waste, atmospheric emissions to air, and suitable treatment and management of any naturally occurring radioactive materials. Finally the Health and Safety Executive (HSE), regulates the safety aspects of all phases of extraction, and has a particular responsibility for ensuring the appropriate design and construction of a well casing for any borehole.

Other bodies which may be involved in the granting of consent for the process include: the Coal Authority, whose permission will be required should drilling pass through a coal seam; Natural England, which may need to issue European Protected Species Licenses in certain circumstances; the British Geological Survey (BGS), which needs to be notified by licensees of their intention to undertake drilling and, upon completion of drilling, must also receive drilling records and cores; and the Hazardous Substances Authorities, who may need to provide hazardous substance consents.

TABLE 26. Bodies involved in obtaining a Petroleum License and permissions to drill

BODY	AUTHORISATION
DECC[111]	Issues Petroleum Licenses, gives consent to drill under the License once other permissions and approvals are in place, and is responsible for assessing risks and monitoring seismic activity
MPA	Grants permission for the location of any wells and well pads, and imposes conditions to ensure that the impact on the use of the land is acceptable
EA	Protects water resources (including groundwater aquifers), ensures appropriate treatment and disposal of mining waste, emissions to air, and suitable treatment and manages any naturally occurring radioactive materials
HSE	Regulates the safety aspects of all phases of extraction, and has a particular responsibility for ensuring the appropriate design and construction of a well casing for any borehole.
Coal Authority	Permission required should drilling pass through a coal seam
Natural England	Issues European Protected Species Licenses in certain circumstances
BGS	Needs to be notified by licensees of their intention to undertake drilling and, upon completion of drilling, must also receive drilling records and cores
Hazardous Substances Authorities	Provides hazardous substances consents

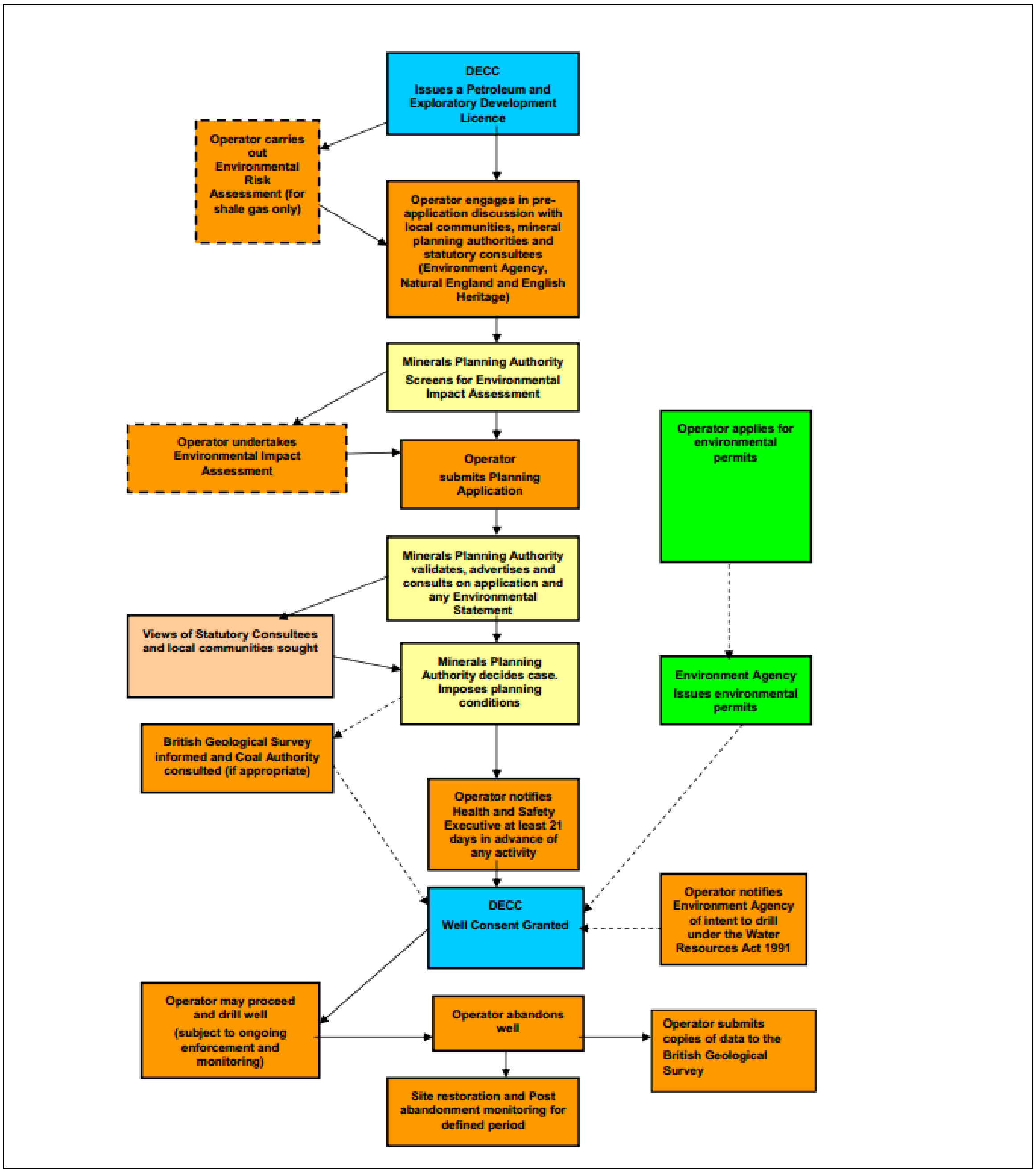
Source: Compiled by the authors

7.3.2. *Process to obtain the License*

Three phases of onshore hydrocarbon extraction are considered: exploration, testing (appraisal) and production. Planning permission is required for each phase of hydrocarbon extraction, although some initial seismic work may need planning consent under the Town and Country Planning (General Permitted Development) Order 1995.

[111] Only the DECC is involved in the issuance of a Petroleum License; the rest are involved with permission to drill and subsequent operations.

FIGURE 100. Outline of process for drilling an exploratory well



Source: (DECC, 2013)

The exploratory, appraisal or production phase of hydrocarbon extraction can only take place in areas where the Department of Energy and Climate Change has issued a license under the Petroleum Act 1998 (Petroleum License).

An application can come from a single company or from a group of companies. All companies must demonstrate their financial viability. To be awarded a license, a company must have a place of business within the UK. There is no limit to the amount of acreage that can be applied for, but there may be limits to the amount of acreage that DECC will offer an applicant.

The applicant must propose a Work Program, which corresponds to the minimum amount of exploration or production work that the applicant will carry out if it should be awarded a License. The agreed Work Program will form an important part of the License itself, and the License will expire at the end of the initial term if the Work Program has not been completed by then. Along with the technical work already carried out, this is one of the main factors that the DECC will use to judge between competing applications.

Most licenses follow a standard format, but the DECC is flexible with this and will consider adapting new licenses to suit special scenarios. The Secretary of State has discretion in the granting of licenses, which is exercised to ensure maximum exploitation of national resource.

As can be seen in the FIGURE 100 summarizing the process, the MPA consults the views of statutory and local communities.

The planning and other regulatory regimes are separate but complementary. The planning system controls the development and use of land in the public interest. This includes ensuring that new development is appropriate for its location, taking into account the effects (including cumulative effects) of pollution on health, the natural environment or general amenity, and the potential sensitivity of the area or proposed development to adverse effects from pollution.

When a decision is made on a planning application, only planning matters considered to be "material considerations" can be taken into account. There is no exhaustive list of what constitutes a material planning consideration. The Government, in its July 2013 Planning practice guidance for onshore oil and gas (2013), listed the following as some "principal issues" for consideration: noise associated with the operation, dust, air quality, lighting, visual intrusion into the local setting, landscape character, archaeological and heritage features, traffic, risk of contamination to land, soil resources, the impact on the best and most versatile agricultural land, flood risk, land stability/subsidence, internationally, nationally or locally designated wildlife sites, protected habitats and species, and ecological networks, nationally protected geological and geomorphological sites and features and site restoration and aftercare.

Some issues may be covered by other regulatory regimes but may be relevant to minerals planning authorities in specific circumstances. For example, the Environment Agency is responsible for ensuring that risk to groundwater is appropriately identified and mitigated. Where an Environmental Statement is required, the Minerals Planning Authorities can and do play a role in preventing pollution of the water environment from hydrocarbon extraction, principally through controlling the methods of site construction and operation, robustness of storage facilities, and in tackling surface water drainage issues.

The submission of a valid application for planning permission requires: a completed application form; compliance with national information requirements; the correct application fee; and provision of local information requirements.

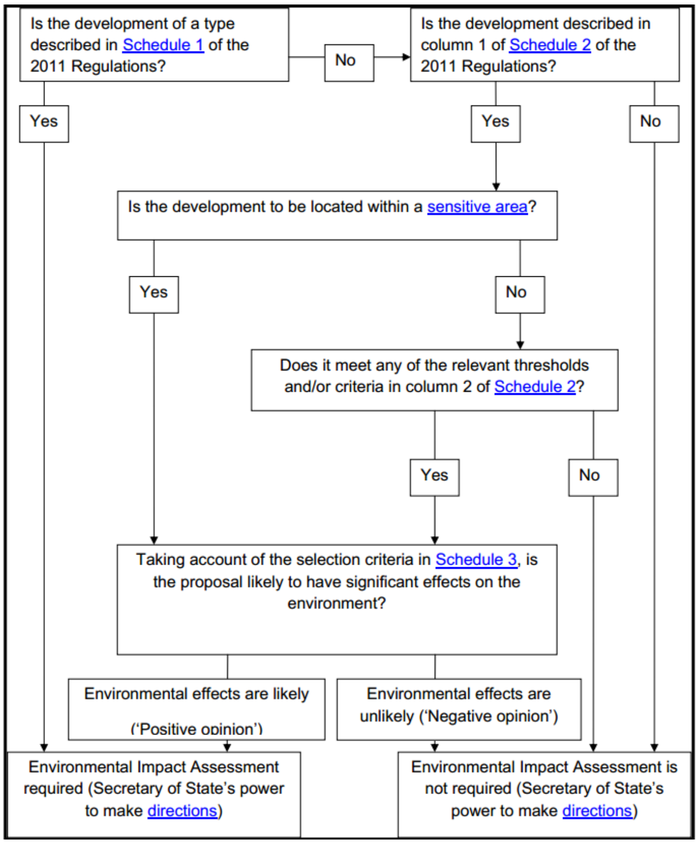
An application for planning permission for hydrocarbon extraction must be accompanied by plans and drawings; an ownership certificate and Agricultural Land Declaration; and design and access statements (where required).

7.3.3. *Environmental Impact Assessment and Restoration*

The Minerals Planning Authority must carry out a screening exercise to determine whether any proposal for onshore oil and gas extraction requires an Environmental Impact Assessment. A flow chart summarizing the screening process can be seen in FIGURE 101.

In this figure several questions about the project are raised in relation to the schedules for the 2011 Town and Country Planning regulations. The assessment, positive or negative, of each question posed leads the MPA to decide whether the project requires an Environmental Impact Assessment or not.

FIGURE 101. Establishing whether a proposed development requires an Environmental Impact Assessment



Source: (DECC, 2013)

In the case of shale gas exploration, this issue is described in Column 1 of Schedule 2 as 'deep drillings', and it is therefore necessary to decide whether an Environmental Impact Assessment is required to analyze whether the development will be located in a sensitive area. A sensitive area means any of the following: land notified in the Wildlife and Countryside Act; a National Park; the Broads; a property appearing on the World Heritage List; a scheduled monument within the meaning of the Ancient Monuments and Archeological Areas Act; an area of outstanding natural beauty designated as such by an order made by Natural England or a European site within the meaning of Regulation 8 of the Conservation of Habitats and Species Regulations.

If the area is deemed sensitive, it must take into account criteria in Schedule 3 to determine whether the development will have significant effects on the environment. These criteria are the characteristics of the development, such as the size, the accumulation with other developments, the use of natural resources, the associated production of waste, pollution, noise or risks. Other criteria include the location of the development, due to areas of the development being more sensitive; and finally the characteristics of the potential impact that must be considered in relation to criteria such as the extent of the impact, the magnitude, probability, duration or frequency.

In the case of production, an EIA is obligatory because this activity is covered by Paragraph 14 of Schedule 1 when the natural gas extracted for commercial purposes exceeds 500,000 cubic meters per day.

The EIA must cover the geographical area where the impacts occur, both above and below ground. This is likely to be larger than the application area.

The list of environmental aspects that might be significantly affected by a development includes human beings; flora; fauna; soil; water; air; climate; landscape; material assets, including architectural and archaeological heritage; and the interaction between all of these. Among other things, consideration should also be given to the likely significant effects of the development on the environment resulting from the use of natural resources, the emission of pollutants, the creation of nuisances and the elimination of waste.

In addition to the direct effects of a development, the Environmental Statement should also describe indirect, secondary, cumulative, short, medium and long-term, permanent and temporary, positive and negative effects where they are significant. These are comprehensive lists, and a particular project is unlikely to give rise to all of these effects. A full and detailed assessment should only be submitted of those impacts that are likely to be significant.

Responsibility for the restoration and aftercare of hydrocarbon extraction sites lies with the operator or in the absence of an operator, with the landowner. The operator should submit proposals for restoration and aftercare as part of the planning application.

A financial guarantee to cover restoration and aftercare costs will normally only be justified in exceptional cases. Such cases include very long-term new projects where progressive reclamation is not practicable and where incremental payments into a secure fund may be made at appropriate stages in the development of site operations, where there is reliable evidence of the likelihood of either financial or technical failure, but these concerns are not sufficient to justify refusal of permission.

7.3.4. *Petroleum License*

A Petroleum License grants the company a limited right which is restricted to the area where exploration and production operations take place. In the offshore, this area is determined by the UKCS (United Kingdom Continental Shelf), which is divided into quadrants of one degree latitude and one degree longitude. Each quadrant is divided into 30 blocks measuring 10 minutes of latitude and 12 minutes of longitude. Some blocks are divided further into part blocks where some areas are relinquished by previous licensees.

Petroleum Exploration and Development Licenses are valid for a sequence of periods, called terms. These are designed to comprise the typical life cycle of a field: exploration, appraisal and production. Each license will expire automatically at the end of each term, unless the license has sufficiently progressed to warrant an extension into the next term.

The initial term is usually an exploration period. For Petroleum Exploration and Development Licenses, the initial term is set at 6 years and includes a work program of exploration activity that DECC and the licensee will have agreed on during the application process. This license will expire at the end of the initial term unless the licensee has completed the work program. At this time the licensee must also relinquish a fixed amount of acreage (usually 50%).

7.4. Some relevant issues of American regulation concerning environmental issues related to shale gas

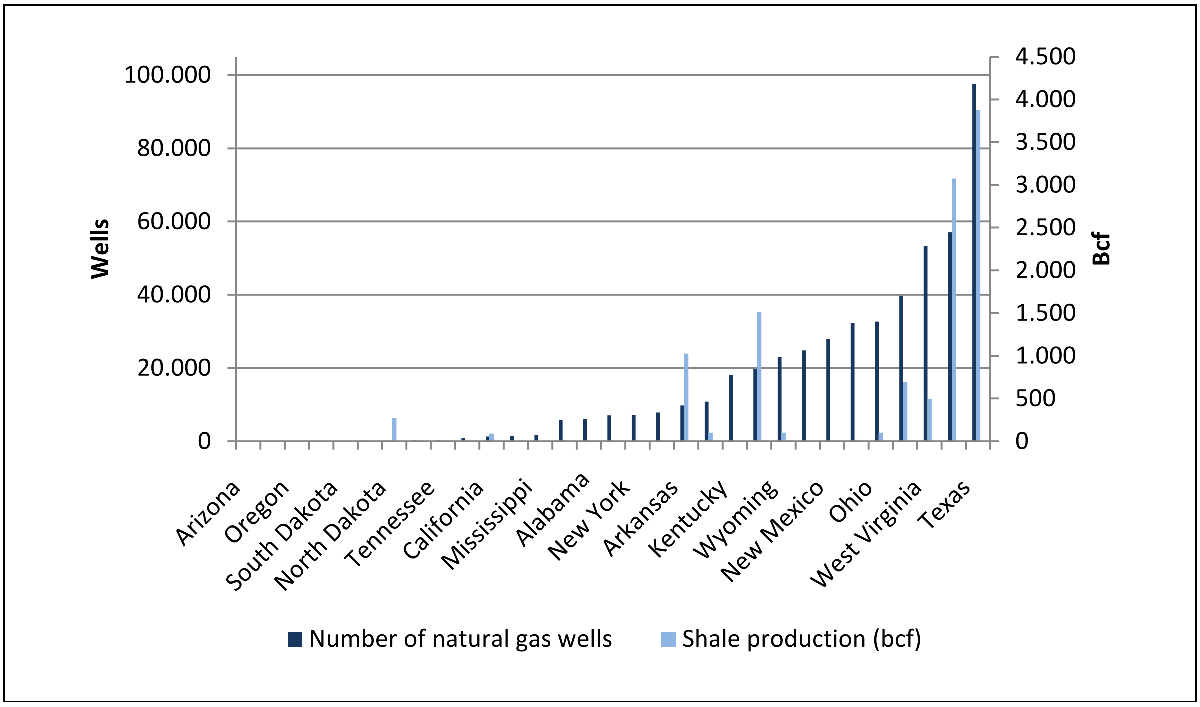
Given the development of shale gas in various states of the US, it may be helpful to review some references that might be useful in identifying the main environmental aspects taken into account in that country.[112]

States with shale gas production or with potential future production have regulations on different environmental aspects and issues, while issues related to internalizing externalities are a matter for federal government.

Some territories such as Alabama, Colorado and California have developed regulation on various issues related to shale gas. However, as gas development has boomed with an expansion in horizontal drilling and hydraulic fracturing, municipalities, states, and regional entities have responded in very different ways.

[112] For this paper, they have been taken extensively from Richardson, et al. (2013).

FIGURE 102. Number of elements regulated quantitatively



Source: (Larrea, 2015) based on data from EIA

So far, state modifications of legislation and regulation have come in several forms. Some states, such as Colorado, Ohio, Pennsylvania and West Virginia, have made relatively comprehensive revisions to their oil and gas codes. Others states, including Arkansas, Montana and Texas, have made more targeted changes. In some cases, states have not only modified the regulatory content but have also expanded the numbers of oil and gas staff available to enforce regulations and provide new funding and training requirements for this staff.

In 2011 the Department of Environmental Conservation of New York State DEC NYS published its Supplemental Generic Environmental Impact Statement (DEC NYS, 2011). The paper reviewed the environmental specifications of different institutions including the Ground Water Protection Council (GWPC), ICF International NYSERDA; Alpha Environmental Consultants, Colorado Oil & Gas Conservation Commission, Pennsylvania Environmental Quality Board and the Environmental Protection Agency (EPA). DECNYS considered the conclusions of GWPC[113] and Alpha[114] to be the most

[113] The GWPC concludes, based on its review of the regulations of 27 states, including New York, that state oil and gas regulations are adequately designed to protect water resources directly. Hydraulic fracturing is one of the eight topics reviewed. The other seven topics were permitting, well construction, temporary abandonment, well plugging, tanks, pits and waste handling/spills.

[114] Alpha supplemented its regulatory survey with a discussion of practices directly observed during field visits to active Marcellus sites in the northern tier of Pennsylvania (Bradford County).

Alpha's review of the specific hydraulic fracturing procedure focused on regulatory processes, i.e. notification, approval and reporting among the nine states surveyed.

Topics reviewed by Alpha include: pit rules and specifications, reclamation and waste disposal, water well testing, fracturing fluid reporting requirements, hydraulic fracturing operations, fluid use and recycling, material handling and transport, minimization of potential noise and lighting impacts, relevant to the mitigation and prevention of risks. We have therefore used these recommendations, together with the study by Richardson *et al* (2013)[115] as a reference in preparing this section.

In December 2014, the New York State Department of Health published a report containing a review of environmental and health issues related to high volume hydraulic fracturing for shale gas development (New York State Department of Health, 2014). The report emphasizes the importance of carrying out systemic, long-term research on the possible effects of hydraulic fracturing on the environment.

FIGURE 103. Information needed to fully evaluate and compare state shale gas regulations

Scope	•What is being regulated? Selection and preparation of the drill site, drilling, hydraulic fracturing, wastewater management and storage, production, completion, etc.
Tools	•How is it being regulated? Enforced compliance regulation; performance standards; responsibility regulation, etc.
Rigor	•How rigorously is it being regulated? The assessment may be complicated by various factors, such as whether it is measurable or comparable.
Application	• How consistent and effective is the regulation? How do regulators and inspectors make operators comply with the rules?
Results	• What are the costs and benefits? How do rules reduce environmental risks associated with shale gas development? Are compliance costs justified?

Source: (Larrea, 2015) based on (Richardson, Gottlieb, Krupnick, & Wiseman, 2013)

To compare and assess the regulation in different territories, much information is required, given that each one has different ways of regulating (command-and-control rules, standards, case-by-case regulation, etc.), monitoring compliance, obtaining results, etc. The FIGURE 104 shows what information is required to assess and compare regulation.

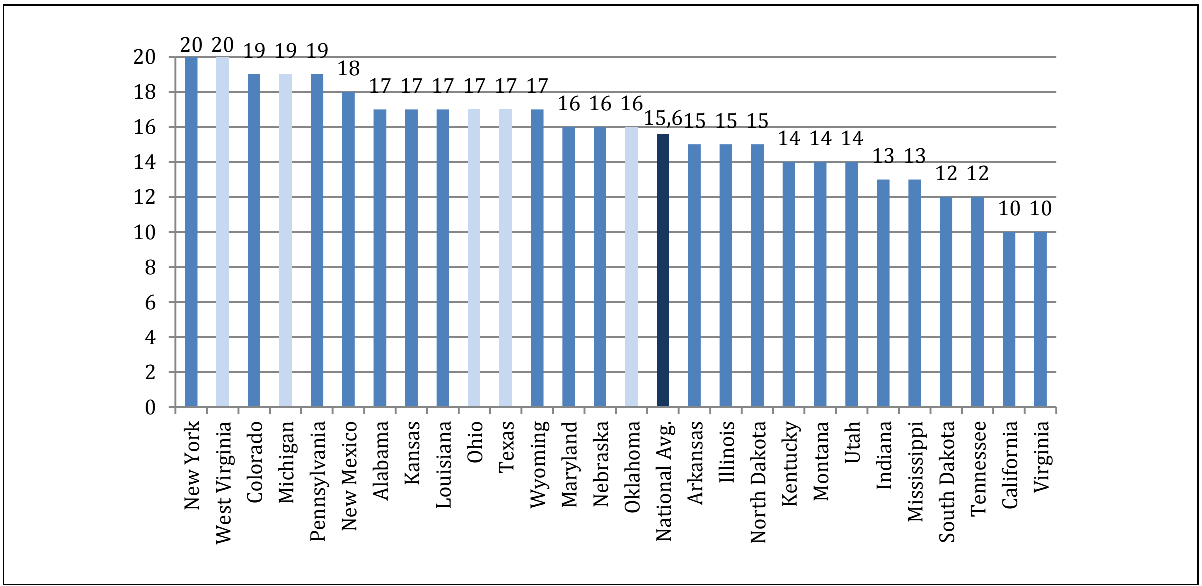
setbacks, multi-well pad reclamation practices, naturally occurring radioactive materials and storm water runoff.

[115] The elements analyzed in Richardson's report include topics related to the selection of drill sites, drilling, hydraulic fracturing, fluid storage, gases, production, abandonment and restoration.

Richardson's report, which covers the largest number of states of the three reports mentioned above, shows that there are between ten and twenty regulated elements in each state reviewed (see FIGURE 102). It can also be seen that, in the top five states by number of gas wells, the number of aspects regulated is consistent with the average. This is the case of Oklahoma, Texas, Ohio; Michigan and West Virginia.

It is also important to mention command-and-control rules. Although case-by-case regulation is also included in some of the regulated issues, it is worth mentioning which of those regulated elements are quantified: 4 in South Dakota, 7 in Texas and 10 in Pennsylvania.

FIGURE 104. Number of gas wells by state



Source: (Richardson et al., 2013)

Note: light blue represents those states with more gas wells in 2012. Dark blue shows the national average.

As we have said, we use the study by Richardson, et al. (2013) to review the specifications of American regulation on certain issues of shale gas exploration and extraction. In some cases, we also provide figures to aid comprehension. In particular, we will focus on topics such as drilling unit size, setback restrictions from buildings and water sources, casing and cementing, water withdrawals, fracking fluids, disclosure requirements, fluid storage and underground storage of waste fluids.

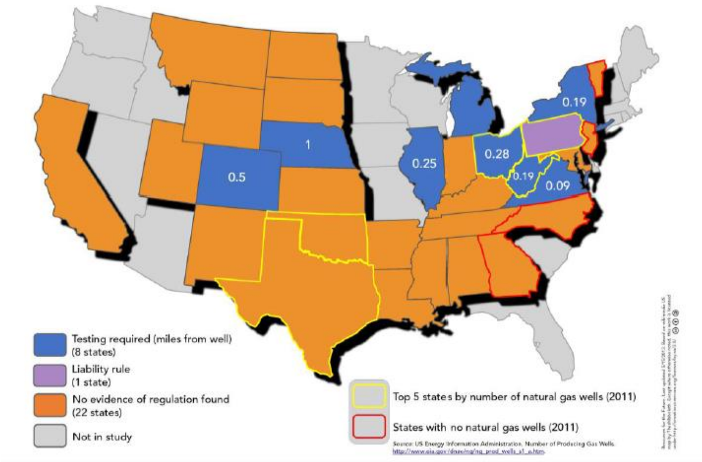
Restrictions on setback from buildings and water sources

States may regulate not only well spacing, but also a minimum distance from unit boundaries. The drilling unit size is usually one square mile (260 ha).

Generally, setback rules are more prevalent in the northeast and in mountain states. Eleven states (Arkansas, California, Kentucky, Maryland, New Jersey, Ohio, Oklahoma, South Dakota, Texas, Utah, and Wyoming) regulate well spacing statewide, with a minimum distance between wells ranging from 100 to 3,750 feet, although these rules allow various exceptions and may be superseded by field-specific requirements.

A contiguous block of 6 states from New York to Michigan and 3 mountain states (New Mexico, Colorado, and Wyoming) make up 9 of the 11 states with both building and water setback rules (Tennessee and Arkansas are the other two). However even in the contiguous northeast block, setback rules vary to a great extent from 50 to 2,000 feet for water, and from 100 to 1,000 feet for buildings.

FIGURE 105. Regulations related to testing of water supply sources



Note: This figure also shows where driller liabilities are established.

Source: (Richardson et al., 2013)

Notably, the states in the east with predrilling water well testing requirements have much smaller testing radii than the western states. Predrilling testing requirements are more common to the east of the Mississippi. On the other hand, in Western states that require testing, this needs to be carried out over a much greater area. Thus, the smallest testing radius in the west (0.5 miles) is greater than the largest testing radius in the east (0.28 miles).[116]

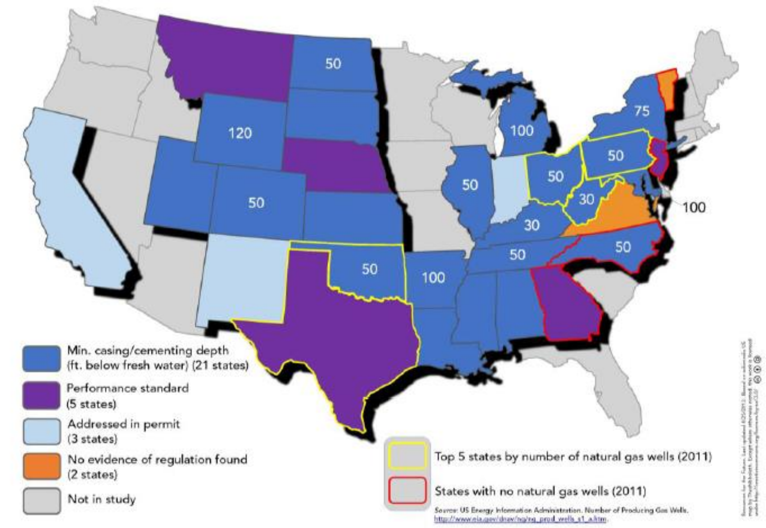
Casing and cementing

Emphasis on proper well casing and cementing procedures is identified by the GWPC and state regulators as the primary safeguard against groundwater contamination during the hydraulic fracturing procedure. Based on the regulatory statements summarized above, this approach has been found to be effective. Improvements to casing and cementing requirements, along with enhanced requirements concerning other activities such as pit construction and maintenance, are appropriate responses to problems and concerns that arise as technologies advance.

[116] Note that the area covered by testing requirements increases nonlinearly as the radius increases. For example, a 1-mile radius testing requirement in Nebraska and Oklahoma covers more than 16 times the area of Illinois' 0.25mile radius requirement. Of course, wells may be much more common in the more densely settled (and wetter) eastern states, so it is unclear whether the western testing rules result in a greater number of actual tests.

Regulations on cement type show few obvious geographic patterns. A block of states in the northeast (nearly identical to the block discussed before with setback restrictions from water sources) regulates cement type with command-and-control tools. This is relatively uncommon in the rest of the country. Many western states favor regulating cement on a case-by-case basis.

FIGURE 106. Casing and cementing depth regulations



Source: (Richardson et al., 2013)

According to Alpha Environmental Consultants, Wyoming appears to be the state where most information is required. Wyoming requires the operator to notify the state regulatory agency of the specific details of a completed fracturing job. Wyoming requires a report on any fracturing and any associated activities such as shooting the casing, acidizing and gun perforating. The report must contain a detailed account of the work done; the manner in which it is undertaken; the daily volume of oil or gas and water produced, prior to and after the action; the size and depth of drilling; the quantity of sand, chemicals and other material used in the activity and any other pertinent information.

Surface casing cement circulation rules are among the most homogeneous, as the large majority of states require cementing to the surface. Intermediate and production casing regulations, on the other hand, are highly heterogeneous. Midwestern and northeastern states seem to favor cementing intermediate casing to the surface.[117]

The GWPC found that states generally focus on well construction (i.e. casing and cement) and noted the importance of proper handling and disposal of materials. It recommends adequate surface casing and cement to protect ground water resources, adequate cement on production casing to prevent upward migration of fluids during all

[117] In the case of Texas, for example, Rule 3.13 of the administrative code ("Cementing, drilling, well control and completion requirements") refers to casing.

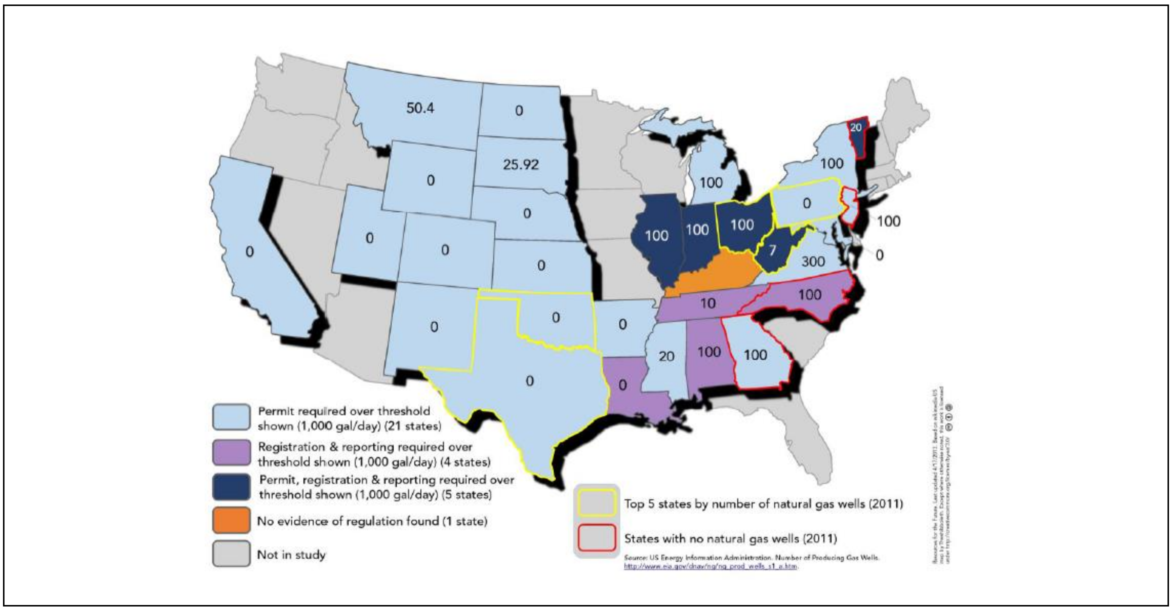
reservoir conditions, use of centralizers and the opportunity for state regulators to witness casing and cementing operations.

Water withdrawals

Although several states have discussed drafting rules on water withdrawal restrictions specific to the shale gas industry, none have yet passed such legislation.

Thirty states do regulate surface and groundwater withdrawals under general regulations. Most of these (26) require general permits for surface and/or groundwater withdrawals. About half (12) require permits for all withdrawals. The remaining fourteen states require permits only for withdrawals above a specified threshold. Eight states require registration and reporting of water withdrawals. Of the states that require reporting, only Louisiana does so for all withdrawals. The remaining seven states require reporting only for withdrawals over a specified threshold, and one state, Kentucky, exempts the oil and gas industry from water withdrawal regulations. In addition to these permitting or reporting requirements, some states have other regulations governing water withdrawals.

FIGURE 107. Water withdrawal regulations



Source: (Richardson et al., 2013)

Fracking fluid disclosure

The federal Safe Drinking Water Act (SDWA) authorizes state regulation of underground fluid injection, under EPA guidance.

Among other requirements, application of the SDWA to fracturing fluids would have required "inspection, monitoring, recordkeeping and reporting" by state regulators. In practice, this would probably have required the disclosure of fracturing fluid composition.[118]

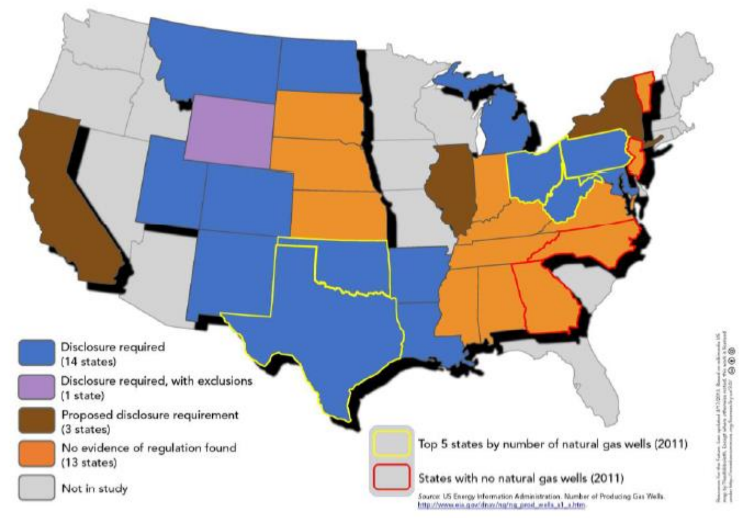
The US Department of the Interior has also issued draft rules requiring fracturing fluid disclosure for wells drilled on federal lands, and the EPA has indicated that it will require disclosure under the Toxic Substances Control Act.

In the light of current regulation, fracturing fluid disclosure in some form seems to be emerging as a prevailing rule among states. Moreover, most states (19, including all the major gas-producing states) already have rules proposed or in force.

The GWPC recommends identification of fracturing fluid additives and concentrations, as well as a higher level of scrutiny and protection for shallow hydraulic fracturing or when the target formation is in close proximity to underground sources of drinking water.

However, the GWPC did not recommend additional controls on the actual execution of the hydraulic fracturing procedure itself for deep non-coal bed methane wells that are not in close proximity to drinking water sources, nor did the GWPC suggest any restrictions on fracture fluid composition for such wells.

FIGURE 108. Fracking fluid disclosure requirements



Source: (Richardson et al., 2013)

Of the states Alpha surveyed, West Virginia, Wyoming, Colorado and Louisiana require notification or approval prior to conducting hydraulic fracturing operations. Pre-approval for hydraulic fracturing is required in Wyoming and the operator should provide information in advance regarding the depth to perforations or the open hole interval, the water source, the proppants to be used and the estimated pump pressure.

[118] In 2005, however, the Congress amended the SDWA to exclude fracturing fluids other than diesel fuel. Fracturing fluid disclosure has since then become a controversial issue, with environmental groups (and some in the industry) calling for states to require disclosure, independently of federal law. Many states have done so.

Consistent with GWPC's recommendation, information required by Wyoming Oil and Gas Commission Rules also includes the trade name of fluids.

Fluid storage

Options available to operators for temporary storage of wastewater vary greatly between states and within each state depending on the type and composition of wastewater.[119] Different wastes have different viscosity, toxicity and other characteristics and are therefore regulated differently.

Fluids are most commonly stored in open pits or closed tanks. Some state regulations mention storage of wastewater in ponds, sumps, containers, impoundments and ditches but all of these can be considered subtypes of pits or tanks.

Ten states require sealed storage (in tanks) for at least some types of fluid (no states require tank storage for all types of fluid). In sixteen states, there is no evidence of regulations requiring sealed tank storage for any fluids, which can be interpreted as meaning that these states allow all fluid types to be stored in open pits. In the third group, three states require a specific permit application for fluid storage. All states covered in the study regulate open-pit storage in various ways.

Tanks, according to the GWPC, should be constructed of materials suitable for their usage. Containment dikes should meet a permeability standard and the areas within containment dikes should be kept free of fluids except for a specified length of time after a tank release or a rainfall event.

The GWPCs recommendations target "long-term storage pits." Permeability and construction standards for pit liners are recommended to prevent downward migration of fluids into ground water. Excavation should not be below the seasonal high water table.

The GPWC recommends against the use of long-term storage pits where underlying bedrock contains seepage routes, solution features or springs. Construction requirements to prevent ingress and egress of fluids during a flood should be implemented within designated 100-year flood boundaries. Pit closure specifications should address disposal of fluids, solids and the pit liner. Finally, the GWPC suggests prohibiting the use of long-term storage pits within the boundaries of public water supply and wellhead protection areas.

Underground injection of waste fluids

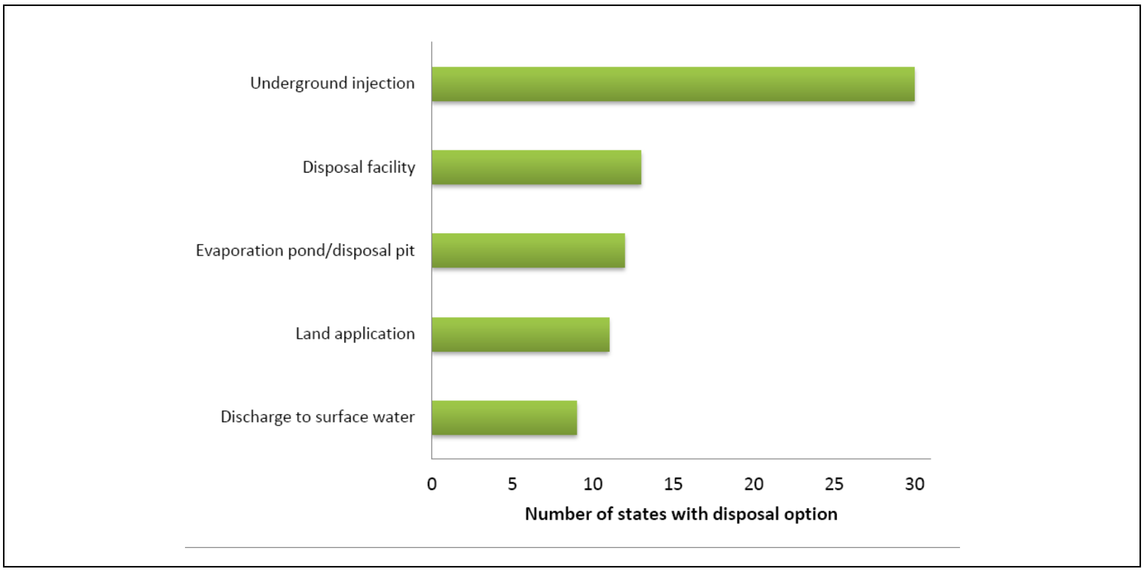
The American Petroleum Institute (API) states that "disposal of flow back fluids through injection, where an injection zone is available, is widely recognized as being environmentally sound, is well regulated, and has been proven effective." This recommendation is echoed by the thirty states that (limiting regulations and local or temporary moratoria aside) allow the practice.

[119] The GWPC did not provide thresholds for defining when hydraulic fracturing should be considered "shallow" or "in close proximity" to underground sources of drinking water.

Underground injection of waste fluids is allowed at the state level in thirty of the states analyzed in Richardson's report. All of these states, however, regulate the practice in some way. The details of underground injection restrictions and regulations vary from state to state. For example, Montana requires underground injection of all fluids with more than 15,000 parts per million of Total Dissolved Solids (TDS). Ohio requires brine to be disposed of by injection into an underground formation unless the board of the county commissioners permits surface application to roads, streets, and highways. Only North Carolina expressly prohibits underground injection of fluids produced in the extraction of oil and gas.

In fact, underground injection is the most common option for flowback/wastewater disposal, as can be seen in FIGURE 109 below, showing the most common fluid disposal options available under state regulations.

FIGURE 109. Flowback/Wastewater disposal options



Source: (Richardson et al., 2013)

Recycling of wastewater for future fracking is often not explicitly discussed in state regulations, but we assume it is permitted in all states, and this option is therefore not shown. Some states do mention or encourage recycling in their regulations, as detailed below. Otherwise, underground injection is the disposal option most often explicitly mentioned and permitted by state regulations (30 out of 31 states). Disposal of wastewater at treatment facilities is the second most common form of wastewater disposal allowed (13 states).

In the area of waste handling, the GWPC suggests actions focusing on surface discharge because "approximately 98% of all material generated is water" and injection via disposal wells is highly regulated. Surface discharge should not occur without the issuance of an appropriate permit or authorization, based on whether or not the discharge could enter a surface water body.

7.5. Some conclusions

Administrative procedures in Spain related to exploration, investigation and exploitation of shale gas are covered at the maximum regulatory level by various laws.

In the hydrocarbons sector, the 1998 Hydrocarbons Act (Act 34/1998) and the 2007 and 2015 Hydrocarbon Acts (Acts 12/2007 and 8/2015) which partially modify the 1998 Act form the applicable legislation. Previous laws governing this sector were Act 21/1974 and the 1958 Act governing the Legal Regime of Hydrocarbons.

Environmental regulation is covered by Royal Decree-Law 1/2008, modified by Act 6/2010 governing the environmental impact assessment of projects, complemented by the provisions of Act 17/2013, which includes drilling using hydraulic fracturing techniques. The Environmental Assessment Act (Act 21/2013) came into effect in December 2013.

Under Act 21/2013, drilling projects using hydraulic fracturing techniques for investigation or exploitation are subject to an Environmental Impact Statement that concludes with the issuance of an environmental impact statement by the environmental authority. The project must perform and comply with the principles of the environmental impact statement and its corresponding statement. One of the main issues in the assessment process *per se* is that the environmental authority must determine the scope and level of detail of the studies and analyses that have to be carried out.

The environmental impact study is made public and opened to enquiries. During this phase of the assessment, interested parties and the general public may make submissions. The environmental law requires participation of the public authorities and the general public in the procedure before the Environmental Impact Statement is granted by the relevant administrative body.

In the Basque Country, Act 6/2015 prevents hydraulic fracturing operations from taking place in Basque territory on caution and prevention principles. However, this situation has engendered some disagreement (between the central Spanish government and the regional Basque government) which has yet to be resolved by the Constitutional Court.

The European Union has stressed the importance of developing shale gas resources and has also issued a considerable number of recommendations specifically addressing the particularities of shale gas exploration and production. These recommendations must be covered in the legislation of each Member State, taking into account distinctive domestic features such as geology and other relevant issues.

The UK and USA are essential reference points in any discussion of shale gas regulation. The UK is a member of the European Union and has developed regulation on environmental impact assessment and exploration licenses. The United States, as we have seen, is the country with the most experience in exploration, drilling and production of unconventional hydrocarbons. A review of a representative number of US states shows that many environmental aspects are covered by regulation. In particular, in the five states with the largest shale gas production, environmental aspects are covered not only from a qualitative but also a quantitative perspective.

A review of certain environmental issues in the USA shows that requirements vary depending on the characteristics of each state, such as geography, size, geology and others. Some key points of the regulation focus on procedures, good practice, risk assessment, and monitoring of the process.

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ANNEXES

ANNEX 1: Some notes on the units and conversions utilized in the document

1 acre = 0.405 Ha = 4046.85 m^2

1 bbl = One billion barrels

1 bboe = One million barrels of oil equivalent

1 bcf/d = One billion cubic feet a day ≃ 9.8 bcm/year

1 bcm = billion cubic meters = 1000 million m^3 = 10^9 m^3

1 bl = barrel = 42 gallons = 159 liters

1 bpm = beats per minute

1 cc = cubic centimeter

1 D = 1 Darcy

1 ft = foot = 0.305 meters

g = grams.

g/cm^3 = grams per cubic centimeter (it may also appear as g/cc)

1 ha = 10,000 m^2

Km = kilometer

Ktoe = 1000 tons of oil equivalent

lb/min = pounds/minute

mbcoe = million barrels of crude oil equivalent

Mcf = million cubic feet

mD = miliDarcy = 10^{-3} D

MMBtu = One Million British Thermal Units equivalent to 0.252 Gcal or 1.0651.10^{-3} TJ

MMGal = million gallons = 15,000 m^3

MNm^3 = millions of cubic meter (measured in normal conditions of temperature and pressure).

MNm^3/d = million cubic meters per day (measured in normal conditions of temperature and pressure)

MNm^3/h = million cubic meters per hour (measured in normal conditions of temperature and pressure)

mREM/yr = MiliREM (An acronym for roentgens equivalent per man. Related to the adsorption of radiation on parts of the body over time. One Rem ≈ One Roentgen)

1 mt LNG = One million tons of liquefied natural gas ≃ 1.35 bcm of natural gas

Mtoe = One Million tons of oil equivalent

Mtpa = million tons per year (1bcm = 1.3 mtpa)

MWh = megawatt per hour

ppa = pounds of aggregated proppant (1 ppa = 0.12 g/cm^3)

psi = Pounds per Square Inch = 14 bar. Psia when ambient pressure is considered (a = absolute)

1 rem = 1 rad x Q (Q is the quality factor. It is usually around 1 for X-ray, γ-ray and β-; 3 for slow neutrons; 10 for protons and fast neutrons and 20 for α particules.

1 tcf[125] = one trillion cubic feet = 10^{12} ft^3 = 28.3 bcm = 0.0283 tcm

1 tcm = One trillion cubic meters = 10^{12} cubic meters

1 Tg = 10^{12} g

SCF/ton = Standard Cubic Feet per ton

Sg = specific gravity.

Sv = Sievert (derived unit of ionizing radiation dose in the International System of Units (SI). It is a measure of the health effect of low levels of radiation on the human body.

1 Sv = 100 Rem (Both measures are related to equivalent doses)

[125] Following the usual American nomenclature.

ANNEX 2: Abbreviations and Acronyms

2D = Two Dimensional

AAPG = American Association of Petroleum Geologists

ACATECH = National Academy of Sciences and Engineering of Germany

ACIEP = Asociación Española de Compañías de Investigación. Exploración y Producción de Hidrocarburos.

ACOLA = Australian Council of Learned Academies

AEO = Annual Energy Outlook

API = American Petroleum Institute

AV = Annulus velocity

bboe = billion barrels of oil equivalent

bls/h = barrels per hour

BGR = German Bundesanstalt für Geowissenschaften und Rohstoffe

BGS = British Geological Survey

BHA = Bottom Hole Assembly

BOE = Boletín Oficial del Estado

BOP = Blow Out Preventer

Bpm = Fluid rate and slurry rate: barrels per minute

BTEX = Benzene. toluene. ethylbenzene. and xylenes

Btu = British thermal unity

CA = Coal Authority

CAAGR = Compound average annual growth rate

CADEM = Centro para el Ahorro y Desarrollo Energético y Minero

CAPEX = Capital Expenditure

CAPV = Comunidad Autónoma del País Vasco

CAS = Chemical Abstracts Service

CBL = Cement Bond Log

CBM = Coal Bed Methane

CIM = Construction. Installation and Manufacture

CNOOC = China National Offshore Oil Corporation

CNPC = China National Petroleum Corporation

CNY = Chinese Yuan

CO_2 = Carbon Dioxide

CSA = Chemical Safety Assessment

CSG = Coal Seam Gas

CSN = Consejo de Seguridad Nuclear

CVC = Basque-Cantabrian Basin

D = Darcy (Measurement of Permeability)

DECC = UK Department of Energy and Climate Change

DIA = Environmental Impact Declaration

DoE = Department of Energy

E&P = Exploration and production

EA = Environmental Agency

ECHA = European Chemical Agency

EIA = US Energy Information Administration

EIA = Environmental Impact Assessment

ENVI = Committee on the Environment. Public Health and Food Safety

EOR = Enhanced Oil Recovery

EPA = Environmental Protection Agency

ERC = Environmental Release Category

ERG = Environmental Federation of Geologists

EVE = Basque Energy Agency (Ente Vasco de la Energía)

EU = European Union

EUR = Estimated Ultimate Recovery

FERC = Federal Energy Regulatory Commission

FIT = Formation integrity test

FOB = Free on Board

FPM = Feet per Minute

FTA = Free Trade Agreement

GHG = Greenhouse gases

GIIGNL = International Group of Liquefied Natural Gas Importers

GIP = Gas in Place

gpm = gallons per minute

GSL = Gas Services Limited

GWPC = Ground Water Protection Council

ha = hectare

HH = Henry Hub

HI = Hydrogen Index

HSA = Hazardous Substances Authorities

HSE = Health and Safety Executive

HVHF = High-Volume Hydraulic Fracturing

IAEA = International Atomic Energy Agency

IBOP = Inside Blowout Preventer

IEA = International Energy Agency

IGI = International Gemological Institute

IGU = International Gas Union

IMMM = Institute of Materials. Minerals and Mining

IO = Input output

IOGCC = Interstate Oil and Gas Compact Commission

JORC = Joint Ore Reserves Committee

JRC = Joint Research Centre

KOP = Kick Off Point

LNG = Liquefied Natural Gas

LOM = Level of Organic Maturity

LOP = leak-off point

LOT = leak off test

LTT = Long Term Test

MAGRAMA = Spanish Ministry of Agriculture. Food and Environment

MENA = Middle East and North Africa

mi = mile

MINETUR = Spanish Ministry of Industry. Energy and Tourism

M_L = Ritcher local magnitude

MMUSD = Million dollars (from United States)

MPA = Minerals Planning Authorities

NACE = National Association of Corrosion Engineers

NEB = National Energy Board

NGPA = Natural Gas Policy Act

NORM = Normally Occurring Radioactive Materials

NYSDEC = New York State Department of Environmental Conservation

OGIP = Original Oil/Gas In Place

OI = Oxygen Index

O&M = Operation and Maintenance

OSHA = Occupational Safety and Health Administration

P&A = Plugged and Abandoned

PDC = Polycrystalline Diamond Compact

POOH = Pulling out of the Hole

Psi = injection pressure (pounds per square inch)

QRA = Quantitative Risk Analysis

REACH = Registration, Evaluation, Authorisation and Restriction of Chemicals

REC = Reduced Emissions Completion

RIH = Running in Hole

Ro = Vitrinite reflectance

ROP = Rate of Penetration

SEC = U.S. Securities and Exchange Commission

SDWA = Safe Drinking Water Act

SGEIS = Supplemental Generic Environmental Impact Statement

SPE = Society of Petroleum Engineers

SRBC = Susquehanna River Basin Commission

SU = Sector of Use

tcf = Trillion cubic feet

TD = Total Depth

TDS = Total Dissolved Solids

THT = Tetrahydrothiophene

TLT = Long Term Test

TOC = Total Organic Content

TRR = Technically Recoverable Resources

UFF= Unconventional Fossil Fuel

UK = United Kingdom

UKCS = United Kingdom Continental Shelf

URR = Ultimately Recoverable Resources

USA = United States of America

USGS = United States Geological Survey

WEC = World Energy Council

WEO = World Energy Outlook

WPC = World Petroleum Engineers

WTI = West Texas Intermediate

WY = Wyoming

ANNEX 3. Resources and reserves: Some definitions

After having developed some terms, concepts and methodology in section 3.1. We are going to review some of the definitions that have been published by different institutions related to resources and reserves. Among them we include the Society of Petroleum Engineers (SPE), the Securities and Exchange Commission (SEC), the Energy Information Administration (EIA), the World Energy Council (WEC), the International Energy Agency (IEA), the USGS, BP, the British Geological Survey (BGS), ACIEP and the Joint Ore Reserves Committee (JORC), whose definitions refer more to minerals but can be of some use.

The Society of Petroleum Engineers (SPE) provides a classification for resources and reserves as follows.

Resource is defined as the estimated recoverable quantities from accumulations that have been discovered but are currently considered as sub-commercial, and from those accumulations that have yet to be discovered. These are referred to as Contingent Resources and Prospective Resources respectively.

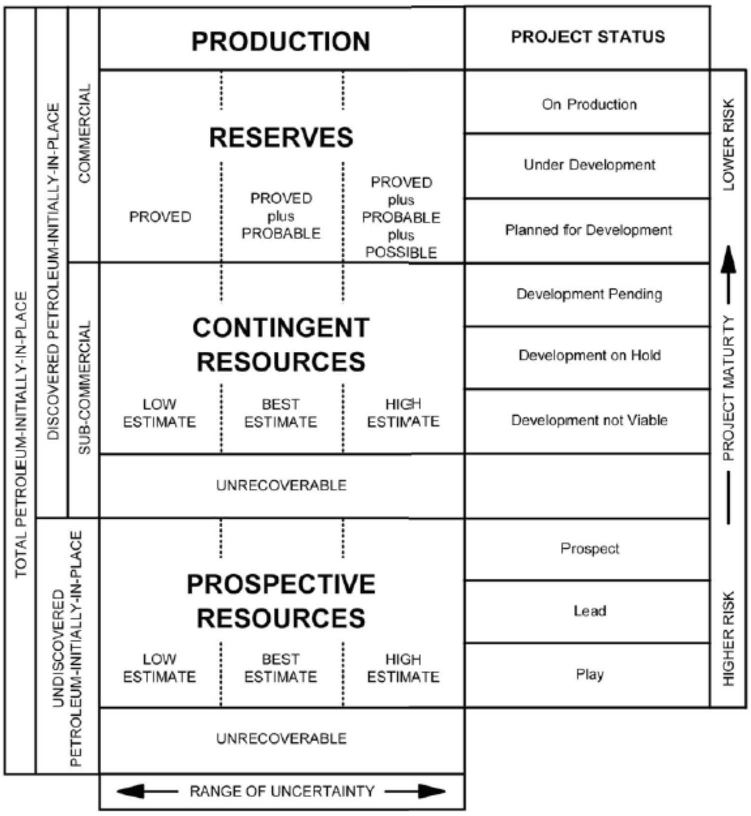
Prospective Resources (undiscovered resource) are those quantities of hydrocarbons which are estimated to be potentially recoverable from undiscovered accumulations. This estimate is based on various technical assessments, including seismic data, and is clearly subject to considerable uncertainty given the absence of well data.

Contingent Resources (or technical reserves) are those quantities of hydrocarbons which are estimated, at a given date, to be potentially recoverable form known (discovered) accumulations, but which are not currently considered to be commercially recoverable. Contingent resources may be of a significant size, but still have constraints to development. These constraints, preventing the booking of reserves, may relate to commercial factors or to technical, environmental or political barriers.

For resources to be matured from Prospective to Contingent one or more exploration wells are clearly required to prove the existence of hydrocarbons and allow for a refined estimate of potential recoverability. As for reserves and contingent resources, prospective resources may be subdivided into three categories. Low Case, Best Case and High Case estimate, based on a probabilistic assessment.

The following figure shows the SPE classification system, where each accumulation is categorized according to its project status/maturity, which reflects the actions (business/budget decisions) required to move it towards commercial and production.

FIGURE 110. Resource classification system



Source: (SPE et al., 2001)

SPE defines *reserves* as those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. Reserves are presented as proven, probable and possible depending on the likelihood of their recovery.

Proven (1p) reserves: are those reserves that, to a high degree of certainty (90% confidence or P90), are recoverable from known reservoirs under existing economic and operating conditions. There should be relatively little risk associated with these reserves. A further sub-division distinguishes between proven developed reserves (reserves that can be recovered from existing wells with existing infrastructure and operating methods) and Proven undeveloped reserves (which require incremental development activity).

Proven plus Probable (2P) reserves: These are those reserves that in the analysis of geological and engineering data are suggested as more likely than not recoverable. There is at least a 50% probability (or P50) that reserves recovered will exceed the estimate of Proven plus Probable reserves. Based on the probability analysis it is the most likely level of hydrocarbon to be recovered.

Proven, Probable plus Possible (3P) reserves: These are those reserves that, to a low degree of certainty (10% confidence or P10) are recoverable. There is a relatively high risk associated with these reserves. Reserves under this definition include those with a

90% chance of recovery (proven), a 50% chance of recovery (probable) and up to a 10% chance of recovery (possible). Evidently, 3P reserves are the least conservative, and, whilst ultimately 90% recovery may occur, from the outset the odds are that use of this measure will overstate the level of recovery. (SPE et al., 2001)

The U.S. Securities and Exchange Commission (SEC) has its own definitions. Under SEC rules, reserves can only be recorded if according to SEC guidelines, they are deemed to be proved. Two types of recoverable reserves exist, proved developed and proved undeveloped.

Proved oil & gas reserves are estimated quantities of oil, gas, LNG´s, synthetic oil/gas and other non-renewable natural resources that are intended to be upgraded into synthetic oil/gas, whose geological and engineering data demonstrate with a reasonable certainty, that they are recoverable from known reservoirs under existing economic conditions. A reservoir is considered proved if economic production is supported by the actual production of a conclusive formation test. Adjacent undrilled areas that can, with reasonable certainty, be judged as continuous as well as economically producible can also be classified as reserves. In the absence of data on fluid contacts, reserves are limited by the lowest known hydrocarbons as established by geosciences, engineering and reliable technology. Reserves that can be produced economically through improved recovery techniques can also be included as proved if they have been successfully tested and such a project has been approved.

Proved developed oil & gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Reserves are also considered “developed” if the cost of any required equipment is relatively minor compared to the cost of a new well, Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as “proved developed reserves” only after tested by a pilot project or after the operation of an installed program that has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil & gas reserves: These are (summarily) those reserves expected to be recovered with reasonable certainty from new wells on undrilled acreage or from existing wells where major expenditure is required for re-completion. Proved undeveloped reserves should only be booked, where it is expected that production will commence within five years unless specific circumstances exist. Following a review of SEC regulation, companies may now also book volumes to prove undeveloped reserves that can be recovered through improved recovery projects where the intended EOR technique has been proved effective by actual production from projects in the same reservoir or in an analogous reservoir, or based on other evidence that uses reliable technology to establish reasonable certainty. (Deutsche Bank, 2013)

The Energy Information Administration (EIA) (EIA, 2013b) leads to three key assessment values for each major shale oil and gas formation:

Shale Gas and Shale Oil In-place Concentration, reported in terms of billion cubic feet of shale gas per square mile or millions of barrels of shale oil per square mile. This key resource assessment value defines the richness of the shale gas and shale oil resource and its relative attractiveness compared to other gas and oil development options.

Risked Shale Gas and Shale Oil In-Place, reported in trillion cubic feet (tcf) of shale gas and billion barrels (bbl) of shale oil for each major shale formation.

Risked Recoverable Gas and Oil, reported in trillion cubic feet (tcf) of shale gas and billion barrels (bbl) of shale oil for each major shale formation. The risked recoverable shale gas and shale oil provide the important "bottom line" value that helps the reader understand how large the prospective shale gas and shale oil resource is and what impact this resource may have on the gas and oil options available in each region and country.

Reserve is the portion of the demonstrated reserve base that is estimated to be recoverable at the time of determination. The reserve is derived by applying a recovery factor to that component of the identified resource designated as the demonstrated reserve base.

Proved energy reserves[126] are the estimated quantities of energy sources that an analysis of geologic and engineering data demonstrates with reasonable certainty to be recoverable under existing economic and operating conditions. The location, quantity, and grade of the energy source are usually considered to be well established in such reserves. *Technically recoverable resources* are those that are producible using current technology without referring to the economic viability thereof.

The World Energy Council (WEC) (WEC, 2013b) defines some concepts related to natural gas as *Proved amount in place*, being the resource remaining in known natural reservoirs that has been carefully measured and assessed as exploitable under present and expected local economic conditions with existing available technology.

Proved recoverable reserves are the volume within the proved amount in place that can be recovered in the future under present and expected local economic conditions with existing available technology.

Estimated additional amount in place is the volume additional to the proved amount in place that is of foreseeable economic interest. Speculative amounts are not included.

Estimated additional reserves recoverable is the volume within the estimated additional amount in place that geological and engineering information indicates with reasonable certainty that might be recovered in the future.

R/P (reserves/production) ratio is calculated by dividing proved recoverable reserves at the end of 2008 by production (gross less reinjected) in that year. The resulting figure is the time in years that the proved recoverable reserves would last if production

[126] Note: this term is equivalent to "Measured Reserves" as defined in the resource/reserve classification contained in U.S. Geological Survey Circular 831. 1980. Measured and indicated reserves, when combined, constitute demonstrated reserves.

were to continue at 2008 level. As far as possible, natural gas volumes are expressed in standard cubic meters, measured dry at 15°C and 1,013mb, and the corresponding cubic feet (at 35,315 cubic feet per cubic meter). (WEC, 2013b)

The International Energy Agency (IEA) (OECD/IEA, 2013) also defines the different categories of hydrocarbons resources. It defines *Reserves* as the portion of energy resources that can be recovered economically by using current technologies and for which a project has been defined.

Estimates of reserves in each category can change as the underlying assumptions are modified or new information becomes available. For example, as the oil price rises, some resources that were previously classified as non-commercial may become profitable and could be moved into the possible, probable or proven (3P) reserves category upon definition of a suitable project.

Remaining recoverable resources refers to the volume of remaining hydrocarbons that could still be produced. The part of remaining recoverable resources beyond volumes already identified as reserves are referred to as "*other remaining recoverable resources*". These latter resources consist on volumes that are not financially viable to recover for a number of reasons. Such reasons could include: the fuel price; lack of available technology; or resources that are based on geological research but are yet to be discovered.

Ultimately Recoverable Resources (URR) for the IEA is a critical variable for modeling and analysis, much more than the (often more widely-discussed) number for oil and gas reserves. URR gives an indication of the size of the total resource base that is recoverable with today´s technologies, including both the part that is known and the part that remains to be found in existing and undiscovered fields.

Although IEA distinguishes between conventional and unconventional resources throughout this analysis, the division between the two, in practice, is an inexact and artificial one. There is no unique definition that allows us to differentiate between them.

The World Energy Outlook (WEO) resources database and the projections for it rely extensively on the work of the United States Geological Survey (USGS), in particular, its World Petroleum Assessment, published in 2000, and subsequent updates.

The USGS assessment divides the resource base into three parts: *Known oil or gas,* including both cumulative production and reserves in known reservoirs; reserves growth, an estimate of how much oil or gas may be produced from known reservoirs on top of the "known oil or gas". As the name indicates, this is based on the observation that estimates of reserves (plus cumulative production) in known reservoirs tend to grow with time as knowledge of the reservoir and technology improves. Undiscovered oil or gas is a basin-by-basin estimate of how much more oil or gas may be found based on knowledge of petroleum geology.

The USGS points out that their estimates are for *technically recoverable resources*, not necessarily resources that are economically recoverable. On the other hand, the methodology used by USGS, which is largely based on drawing analogies with already producing reserves, implies that a large fraction of the volumes categorized as undiscovered oil or gas and reserves growth may be recoverable without significant changes in price and technology.

Once resources have been discovered and positively appraised, they become *reserves*. Depending on the degree of certainty of their value and the confidence in their development, reserves, are further classified as *Proven (1P), Probable (2P) or Possible (3P)*, like in the SPE definitions which we have seen before.

BP considers and defines these concepts related to natural gas. *Ultimately Recoverable Resource (URR)* is an estimate of the total amount of oil or gas that will ever be recovered and produced. It is a subjective estimate based on only partial information. Whilst some consider URR to be fixed by geology and the laws of physics, in practice, estimates of URR continue to increase as knowledge grows, technology advances and economics change. Economists often deny the validity of the concept of ultimately recoverable reserves as they consider that the recoverability of resources depends on changing and unpredictable economics and evolving technologies. The ultimately recoverable resource is typically broken down into three main categories: *cumulative production, discovered reserves and undiscovered resource.* Cumulative production is an estimate of all of the oil produced up to a given date.

Discovered reserves are an estimate of future cumulative production from known fields and are typically defined in terms of a probability distribution. Discovered reserves are typically broken down into proved, probable and possible reserves. Like reserves, *undiscovered resource* is also defined typically in terms of a probability distribution. Estimates of *'yet-to-find'* resource are made based on a range of geological, technological and economic factors. BP´s classification of reserves in Proven, Probable and Possible is similar to SPE.

The British Geological Society (BGS) (BGS & DECC, 2013) defines the following terms for the better understanding of its reports and results. A *resource* (which is what the BGS report has assessed) refers to an estimate of the amounts of oil and gas that are believed to be physically contained in the source rock.

There are many categories and classifications of resources. The BGS report uses the *Gas In Place (GIP)* which is an estimate of the total amount of gas that is trapped within the shale rock. Because of measurement uncertainty, the BGS report provides a range of value of the GIP rather than a single value. There is an 80% chance the true GIP value lies within this range, a 10% chance that it lies below and a 10% chance that it lies above.

Reserves refer to an estimate of the amount of oil or gas that can technically and economically be expected to be produced from a geological formation. A further classification of resources but which is not used in the BGS report is the *Technically*

Recoverable Resource (TRR). This is an estimate of the amount of gas that might be technically recovered if production were not constrained by economics. TRR estimates will therefore always be larger than reserves estimates.

The Asociación Española de Compañías de Investigación, Exploración y Producción de Hidrocarburos y Almacenamiento Subterráneo (ACIEP) also defines Prospective Resources, Contingent Resources and Reserves as follows.

Prospective Resources are accumulations of undiscovered hydrocarbons (oil and gas), but of occurrence estimated from indirect evidence. They are set according to probabilistic analysis, risk factors and assuming an uncertainty range P 10, P 50, and P 90 (relative to % of occurrence).

Contingent Resources are discovered and recoverable accumulations of hydrocarbons, whose extraction are not commercial at present, but can be profitable in the future, according to the advancement of the state of the art. technology or the price of crude. *Reserves* are resources tested and commercially recoverable.

The Joint Ore Reserves Committee (JORC) code, which is the Australasian code for the reporting of exploration results, mineral resources and ore reserves uses the same terminology as the IMMM (Institute of Materials. Minerals and Mining), IGI (International Gemological Institute), GSL (Gas Services Limited), and ERG Reporting code (European Federation of Geologists), defining some concepts related to minerals.[127]

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[127] The exploration results include data and information generated by mineral exploration programmes that might be of use to investors but which do not form part of a declaration of Mineral Resources or Ore reserves.
A mineral Resource is a concentration or occurrence of solid material of economic interest in or on the Earth´s crust in such form, grade (or quality), and quantity that there are reasonable prospects for eventual economic extraction. Mineral Resources are sub-divided, in order of increasing geological confidence, into Inferred, Indicated and Measured categories.
Inferred Mineral Resource: it is that part of a Mineral Resource for which quantity and grade (or quality) is estimated on the basis of limited geological evidence and sampling. *Indicated Mineral Resource* is that part of a Mineral Resource for which quantity, grade (or quality), densities, shape and physical characteristics are estimated with sufficient confidence to support mine planning and evaluation of the economic viability of the deposit.
Measured Mineral Resource is that part of a Mineral Resource for which quantity, grade (or quality), densities, shape, and physical characteristics are estimated with sufficient confidence to support production planning. Ore Reserve is the economically mineable part of a Measured and/or Indicated Mineral Resource. *Probable Ore Reserve* is the economically mineable part of an Indicated, and in some circumstances, a Measured Mineral Resource and a Proved Ore Reserve is the economically mineable part of a Measured Mineral Resource.

ANNEX 4. List of technical functions required in fracturing fluids and examples of chemicals from the literature

Technical function	Description of purpose	Examples of chemicals
Proppant	Keeps fractures open to allow gas/fluid to flow more freely to the well bore	Silica, quartz sand (sintered bauxite. Zirconlum oxide, ceramic beads)
Acid	Clears the production casing by removing cement, drilling mud and drilling debris from casing perforation by dissolving near wellbore acid-soluble minerals and initialing cracks in the rock	Hydrocloric acid Formic acid Acetic acid
Biocide	Eliminate bacteria in the water that degrade the gels and produce corrosive-by-products (e.g. hydrogen sulphide) Prevent microbial growth from occurring downhole which could restrict flow network. Added in liquid from to the water.	Glutaraldehyde Quaternary ammonium chloride Bromine Methanol Naphthalene Tetrakis hydrozymethyl phosphonium sulphate (THPS) 2,2-dibromo,3-nitriloproprionamide (DBNPA) Sodium hypochlorite
Clay stabiliser	Prevents swelling, shifting and migration and esplandable clay minerals (wáter sensitive and clay minerals) which could block pore spaces and therefore reduce permeability, shut off flow paths (e.g. creates a brine carrier fluid)	Potassium chloride Sodium chloride Tetramethil ammonium chloride (TMAC) Choline chloride
Iron control	Prevents precipitation of metal oxides which could plug off the pipes and the rock formation	Citric acid Acetic acid Thioglycolic acid Sodium erythorbate ADTA
Scale inhibitor	Prevents the precipitation of carbonates and sulphates (calcium carbonate, calcium sulphate, barium sulphate) which could plug off the formation Prevents scale deposits in the pipe	Ammonim chloride Ethylene glycol Copolymer of acrylamide and sodium acrylate Acrylic acid polymers Carboxiclic acid Sodium polycarboxylate Phosphoric acid salt Hydrochloric acid
Corrosion inhibitor	Reduce rust formation (iron oxides) on steel tubing, well casings, tools and tanks (used only in fracturing fluids that contain acids to protect well integrity from acid corrosion)	Ammonium bisulphite
PH adjusting agent	Adjusts and controls pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers	Sodium and potassium carbonate Sodium hydroxide Potassium hydroxide

		Acetic acid
Anti-freezing or winterizing agent	Lowers freezing points and/or increases boiling point	Methanol Isopropanol Ethylene glycol Ethanol
Crosslinker	Mantein fluid viscosity as temperature increases	Potassium hydroxide Borate salts (e.g. potassium metaborate, sodium tetraborate) Boric acid Tetranolamine zirconate Zirconium complex
Gelling agent	Increases fluid viscosity allowing the fluid to suspend and carry more proppant into the fractures	Guar and gum and guar derivatives Hydroxyethil cellulose
Friction reducer	Slicks the water to minimize friction (extra pressure, interfacial tension) between the fluid and the contact surface the pipe to maintain laminar flow while pumping and allow fracturing fluid to be injected at optimum rates and pressures (reduces the power required to inject the fluid into the well). Often provided in dry powder from, most commonly added as a liquid to the water by mixing with a mineral oil base fluid for stabilization purposes.	Polyachylamide (typically a medium to long chain polyacrylamide)
Solvent (non-emulsifier, carrier fluid)	Additive which is soluble in oil, water and acid-based treatment fluids, which is used to control the wettability of contact surfaces or to facilitate delivery of gelling agents/friction reducers	Various aromatic hydrocarbons Petroleum distillates (hydrotreated light petroleum distillates, diesel fuel) Lauryl sulphate
Surfactant	Reduces surface tension of the fluid on the fracture face thus aiding its recovery and eliminate emulsions of oil and water	Methanol Isopropanol Ethoxylated alcohol Lauryl sulphate Ethylene glycol Isobutanol Ethylene glycol monobutyl ether Fluoro-surfactants Nano-surfactants
Breaker	Allows a delayed break down of the gel polymer chains to reduce the viscosity of the fluid after fracturing and enhance its recovery	Ammonium persulfate Magnesium peroxide Magnesium oxide Peroxydisulphates Ethylene glycol

Source: (JRC, 2013b)

ANNEX 5: Some notes about REACH (Registration, Authorization and Restriction of Chemicals)

The purpose of the REACH is to ensure a high level of protection for human health and for the environment, and to strengthen the competitiveness of the chemical sector and promote innovation.

Registration

Registration is the key component of the REACH system. Any producer or importer of articles shall submit a registration to the Agency for any substance contained in those articles, if both the following conditions are met: the substance is present in those articles in quantities totalling over 1 tonne per producer or importer per year or the substance is intended to be released under normal or reasonably foreseeable conditions of use. This shall not apply where the producer or importer can exclude exposure to humans or the environment during normal or reasonably foreseeable conditions of use including disposal.

The information to be notified shall include the following: the identity and contact details of the producer or importer as specified; the registration number that the Agency shall assign to each registration, which is to be used for all correspondence regarding the registration until the registration is deemed to be complete; and the identity of each substance (this information should be sufficient to enable each substance to be identified). If it is not technically possible or if it does not appear scientifically necessary to give information on one or more of the items below, the reasons shall be clearly stated; the classification of the substance according to its hazard classification; a brief description of the use of the substance and its tonnage range, such as 1-10 tonnes, 10-100 tonnes and so on.

The CAS number[128] is important when identifying a substance. The multiplicity of names can make a search for chemicals somewhat difficult and frustrating. However, if you search for a chemical by the CAS number it will be correct even if the name on the fracturing record does not match. For example if the fracturing record listed the chemical Hydrogen chloride and it was searched for by a name using a chemical search site, no results may be found. But if the search is done using CAS # 007647-01-0. Hydrochloric acid may be given, which is another name for Hydrogen chloride. Therefore, by using the CAS number the issuing of multiple names for the same chemical can be avoided. (Fracfocus.org, 2014)

[128] CAS Registry Number (often referred to as a CAS Number) is a unique numeric identifier that designates only one substance. With no chemical significance it represents a link to a wealth of information about a specific chemical substance.

Evaluation

In order to ensure a harmonised approach, the Agency, in cooperation with the Member States, shall develop criteria to prioritise substances with a view to further evaluation. Prioritisation shall be on a risk-based approach. The criteria shall consider: hazard and exposure information and tonnage.

Substances shall be included if there are grounds for considering that a given substance constitutes a risk for human health or the environment. The Agency shall be responsible for coordinating the substance evaluation process and ensuring that substances on the community rolling action plan are evaluated.

Authorisation

The Agency shall be responsible for making decisions on applications for authorisations in accordance with this title.

The authorisation shall be granted if the risk to human health or the environment from the use of a substance arising from the intrinsic properties is adequately controlled and documented in the applicant's chemical safety report, taking into account the opinion of the Committee for Risk Assessment. When granting the authorisation, and in any conditions imposed therein, the Commission shall take into account all discharges, emissions and losses, including risks arising from diffuse or dispersive uses, known at the time of the decision.

Authorisations granted in accordance with Article 60 shall be regarded as valid until the Commission decides to amend or withdraw the authorisation in the context of a review.

Some groups of substances (listed in the Regulation) are, however, exempt from the obligation to register, for instance: polymers (however monomers which make up polymers must still be registered); some substances for which the estimated risk is negligible (water, glucose, etc.); naturally occurring and chemically unaltered substances and substances used in research and development, under certain conditions.

Evaluation makes it possible for the Agency to check that industry is fulfilling its obligations and avoiding tests on vertebrate animals when unnecessary. Two types of evaluation are provided: dossier evaluation and substance evaluation.

All chemicals used in fracking process have to pass the REACH evaluation and this evaluation must be favorable to allow its use.

The European Commission together with the Joint Research Centre (JRC) published a report (JRC, 2013b) in which the assessment of the use of substances in hydraulic fracturing of shale gas reservoirs under REACH are evaluated.

In order to understand whether the use of certain substances for hydraulic fracturing of shale gas reservoirs has been registered under REACH, and eventually how the companies are dealing with the registration of such a use, a number of REACH registration dossiers related to 16 substances, which may be connected with this specific application, have been assessed.

The main outcome of the assessment is that neither hydraulic fracturing nor shale gas was explicitly mentioned in the investigated dossiers. Hydraulic fracturing of shale gas reservoirs was not identified as a specific use for any of the substances and a dedicated Exposure Scenario was not developed by any registrant.

However, some of the identified uses in the investigated dossiers may implicitly cover hydraulic fracturing of shale gas reservoirs. In most of the cases, the use description system enabled the identification of these uses based on two simple information items: the use name as formulated by the registrant; and the Sector of Use (SU) assigned by the registrant to the use name and chosen among several options provided by the ECHA. Specifically, the selection of SU 2a 'Mining (without offshore industries)' and SU 2b 'Offshore industries' by the registrant allowed a correct interpretation of the use name and consequently the identification of the potentially relevant uses.

For most of the investigated substances, a Chemical Safety Assessment (CSA) for the environment was not performed by the registrant based on the justification that no hazard was identified for the substance.

The DG Environment identified 16 substances that may be connected with shale gas extraction and based on that 782 REACH registration dossiers were selected and sent by the ECHA to JRC-IHCP for assessment at the end of June 2012. The selection included all submitted dossiers from the 1st of June 2008 till the 16th of May 2012. The assessment did not address all of the received registration dossiers, but focused on the most relevant ones for each substance. The list of substances and the corresponding number of dossiers received are reported in TABLE 27. The substances were chosen based on literature information coming from the USA experience with hydraulic fracturing of shale gas reservoirs.

Based on the experience gained during the assessment of the dossiers, it can be concluded that some actions could increase the availability of information on use, exposure and risk management for substances used in hydraulic fracturing of shale gas reservoirs. First of all, the possibility of defining a more specific use name that addresses hydraulic fracturing could be explored by industry. Secondly, the current use descriptor system under REACH may be complemented by an additional ERC (Environmental Release Category) covering the case of a substance that is intentionally introduced into the environment to carry out its technical function. Finally, the environmental exposure assessment may benefit from the development of a model that covers the direct introduction of substances into the underground and possible upwards migration. (JRC, 2013b)

TABLE 27. Substances selected by DG Environment for the assessment and correspondent number of REACH registration dossiers received

Substance name	Number of dossiers
2-ethylhexane-1-ol	10
Acetic acid	53
Acrylamide	46
Ammonium	133
Boric acid	39
Citric acid	22
Distillates (petroleum), hydrotreated heavy naphentic	21
Distillates (petroleum), hydrotreated light naphentic	15
Ethylene glycol	83
Ethylene glycol monobutyl ether	7
Glutaraldehyde	2
Hydrochloric acid	120
Isopropyl alcohol	10
Methanol	110
Residual oils(petroleum), hydrotreated	9
Sodium hydroxide	102
Total	**782**

Source: (JRC, 2013b)

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