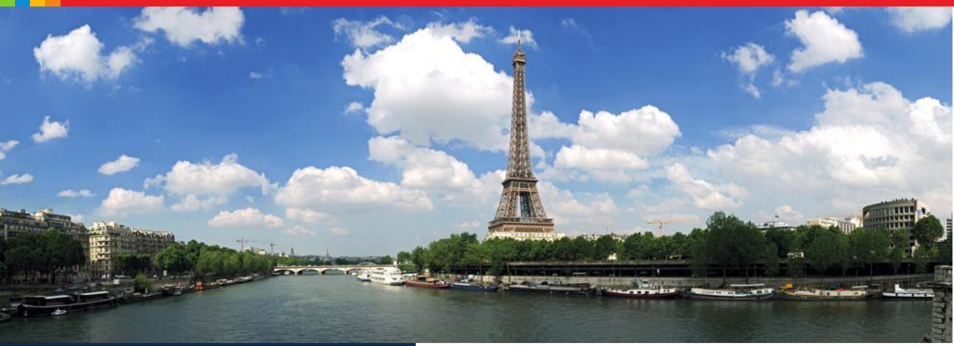
2012-2015 Triennium Work Reports



# Implications of Developing Unconventional Gas

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# 2012-2015 Triennium Work Report

June 2015

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**International Gas Union**



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## Executive Summary

- Based on our investigations over the Triennium, the study group agrees that the development of unconventional gas in North America is having a profound impact on gas markets globally. It has changed the energy mix in the US, reduced gas prices and stimulated economic development. Outside the US it has had direct impacts on other gas markets. The growth of gas use in the US has stimulated coal exports to Europe, reducing European gas demand. The US is now emerging as an LNG supplier to Asia, with prices linked to Henry Hub, rather than oil. And the growth of shale gas and oil in the US has led to lower oil prices worldwide, with implications for gas prices linked to oil.
- However our assessment is that the shale revolution in the US is unlikely to be replicated in other countries on a significant scale, at least not this decade. The circumstances in other countries differ materially from those in the US in terms of geology, community attitudes, regulation and costs. The only significant exception at this stage is the growth of LNG based on Australian coal bed methane.

**North America**

- Without question, one of the most fascinating industry stories in recent years has been the dramatic increase in the production from US unconventional gas resources, and more precisely from gas shale formations. In last years the commercial production of unconventional gas reserves in the United States has brought about a structural shift in the world's supply of natural gas and as a consequence fundamental changes in the global gas market. Large volumes of LNG (10-13 BCM), which were expected to be imported by the US, unexpectedly came onto the global market. The market, which was expected to become a seller's market for the foreseeable future, is certainly not a seller's market at the moment.

**Europe**

- The great success of unconventional gas production in the US has led to a significant research into unconventional gas reserves in Europe. Although this research is not very advanced yet, its outcomes have already made clear that the Europe's unconventional gas reserves are very substantial. This report looks at the potential for shale gas development in Europe and considers the interaction between the European market and the development of Europe's "unconventional gas" potential.
- The report concludes that in Europe the development of shale gas will not result in an ushering into a new era of cheap gas, with the potential to revolutionize the European energy scene, boosting energy security or provide a transition to a low-carbon economy.
- All geological surveys consulted whilst preparing this report are aligned: Europe has a significant unconventional gas resource potential. However, the development of these resources has been hampered by technological challenges and the excessive financial costs associated with the extraction. The current volatility in the European gas market, mainly resulting from the recent drop in oil price, is not conducive to create – in the near term - the investment climate needed to successfully address these challenges.
- However, economic and population growth will continue to put pressure on the world's energy supplies, and so all fuel sources – including Europe's unconventional gas resources - will be needed. The industry has always changed, and has caused changes in the societies in which it operates. Those responsible both inside and outside the industry need to try to understand what is happening now and how it may affect the future, to explain their strategies clearly and to adapt to new situations as they develop. In a world where technology and environmental threats are changing industries and society so rapidly, the slowly turning LNG-supertanker is not an

image that excuses inertia in the industry and those who deal with them. All who are in the industry or who are involved with it need to share clear thinking about the future.

- Realizing the potential for shale gas as a profitable alternative energy source requires all stakeholders in this debate to work together, requires a constructive dialogue between the industry, the public in general and the local communities in regions effected by the exploitation in particular and the government, ranging from the local government all the way to the EU legislative bodies. Private companies cannot develop a full-scale shale gas industry on their own. They need governments to support them with a combination of direct financial incentives and investments in transportation infrastructures. Governments also need to facilitate a dialogue between the industry and the public. Such a dialogue is essential to define the right balance between the economic benefits a rapid development of an unconventional gas industry would bring to Europe's economies and the environmental cost Europe is willing to pay to harvest these benefits.
- Despite the current setback, natural gas in Europe has still the potential of entering its "Golden Age" and play its role of "bridge fuel" towards a "carbon-free renewable" dominated energy supply, but only if a significant proportion of its unconventional gas resources – mainly shale gas – can be developed profitably and in an environmentally acceptable manner. Numerous hurdles need to be overcome, not the least the social and environmental concerns associated with the extraction of shale gas. The technology and know-how for shale gas to be produced in a way that satisfactorily meets these challenges can – with the right gas price incentive - be developed, but a close, continuous and transparent collaboration between governments, the public at large and industry will be required if public confidence is to be earned and maintained.
- The changes that Europe's unconventional gas industry now faces requires a visionary response embedded in a transformational evolutionary path rather than epic, revolutionary responses, for the industry to evolve and prosper. Europe's gas industry is best placed to lead the formulation of this visionary response and to implement this vision by managing and promoting a constructive, open dialogue with all stakeholders involved.

**Asia Pacific**

- The North American unconventional gas (UCG) revolution is having a bigger impact on Asia Pacific gas markets than any developments within the region. As a result of US shale gas production, LNG demand in the US and Europe has fallen, with cargoes initially redirected to Asia. With burgeoning gas production the US is now emerging as an LNG exporter. The surge in US shale oil production has also ultimately led to a fall in oil prices, reducing LNG costs to Asian buyers and creating challenges for UCG development in the region.
- Although the region has substantial UCG potential it is unlikely that the US revolution will be replicated in Asia.
- Of Asia Pacific countries Australia is the most advanced in UCG development, primarily coal bed methane (CBM). This has been facilitated by favourable geology and a free market for upstream oil and gas investment. CBM production is expected to reach 44 Bcm by 2020. However opposition from community and activist groups has restricted CBM development outside Queensland. While the country has significant potential for shale and tight gas, development of these resources is in its infancy and subject to government inquires about fracture stimulation. The fall in the oil price will also impede further development.
- China has substantial UCG potential and is targeting shale gas production of 30 Bcm by 2020. It also produces CBM, with 3 Bcm of production in 2013. UCG is likely to provide a valuable addition to conventional gas production and imports but is not expected to revolutionise Chinese gas production in the way it has in the US. Challenges include less favourable geology, population density, unfavourable topography and the absence of a free and competitive upstream gas market. Gas prices remain regulated, although prices are being allowed to increase.

- India and Indonesia have substantial UCG resources but numerous challenges including absence of infrastructure, unattractive fiscal regimes and controls over gas prices.
- Russia has substantial potential shale oil and gas resources but at a very early stage of appraisal. Participation by western companies is currently being affected by sanctions.

**Latin America**

- The most prospective country for developing unconventional gas in South America is considered to be Argentina;
- There are some challenges that are expected to shift unconventional gas production growth in Argentina to the period of 2025-2035;
- No large-scale unconventional gas production is forecasted in Colombia, Brazil and other South American countries (despite having the resource potential according to EIA).

# A. Americas

## 1. United States of America

### (1) History

The US Department of Energy along with the major players in the US gas industry have been funding research and trial projects on unconventional gas extraction techniques for decades. As a result, in the 1990s, technologies of extraction of coal-bed and tight formation gas through hydraulic fracturing were proven and commercialized. However, they did prove to be economically viable only in the high oil and gas prices environment.

A steep increase of oil and gas prices in the 2000s contributed to the wave of investments in oil and gas R&D. Higher gas prices were supported by sentiment that Canadian gas production potential was limited, indigenous US gas production would inevitably decline and import dependence would increase. USA was supposed to become largest world LNG importer. Many industry players (e.g., Statoil, Repsol, Qatar Petroleum and a few other IOCs and NOCs) signed up for long-term ship-or-pay terminal use agreements (TUA), credit support commitments, invested billions of dollars in infrastructure equity. As a result, total regasification capacity exceeded 200 bcma in 10 years' time.

Such expectations pushed spot and forward gas prices up, stimulated investment and gas production (eg, Barnett shale development in and around Dallas, Texas).

### (2) Factors which Influence the Future of Unconventional Gas in USA

**Drivers**

These new developments were backed by specifics of the US market:

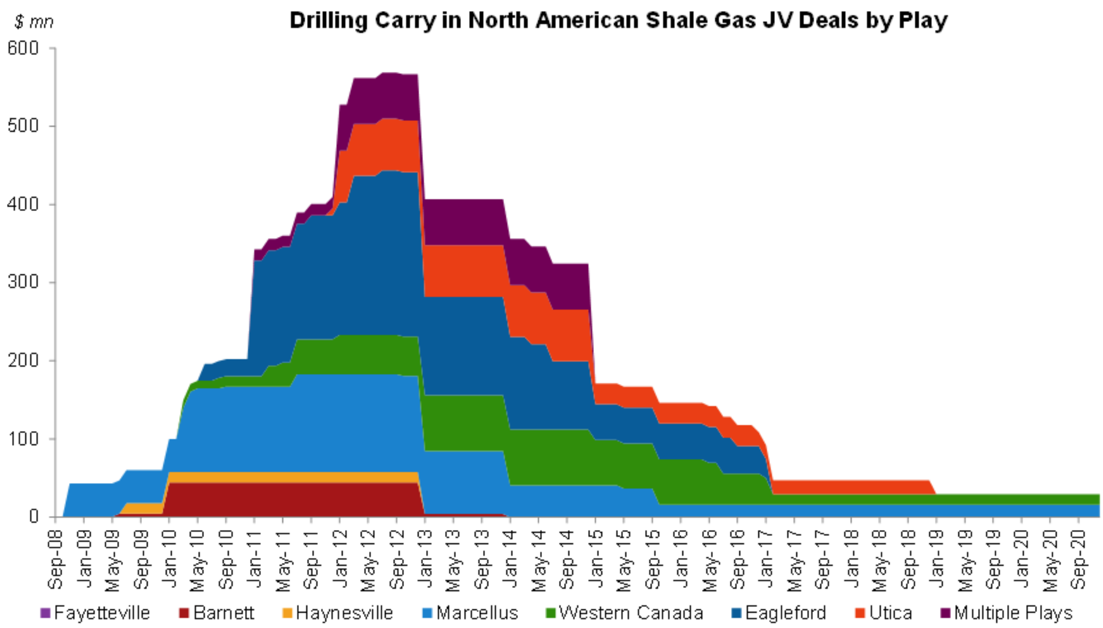
- thousands of small and mid-sized E&P companies looking for new opportunities to deploy existing equipment and skilled employees;
- a robust oil services industry;
- conventional prospects that became increasingly expensive to drill and produce from for small players;
- the US and Canadian laws granting subsurface mineral rights to surface property owners – easy to access plots of lands;
- unrivalled ability of US financial sector to attract into new and promising commercial opportunities.

Unexpected financial crisis of 2008 resulted in demand and price cutbacks. In April 2012 US gas prices hit the bottom (ie, USD1.8 per MMBtu).

In 2009-2012 producers carried on production due to a number of other factors which were not directly linked to price dynamics, eg:

- hold-by-production requirements which supported further identification of upstream gas acreages and provided independent producers in the US incentives to drill;
- efficient hedging policy of the US producers which allowed to lock in profits for next couple of years after the crisis;
- M&A activity. The US started a global shale gas campaign which promoted attractiveness of shale development in other countries and investments into the US producing assets as a way to gain access to unique knowledge and shale gas production technologies. International oil and gas players continued investing in USA and Canada assets (now, however, not in downstream business but unconventional plays) via M&A deals. In 2008-2012 investors spent around USD170 bln. Most of the deals were linked to cash, carry and drilling commitments for 2–3 years period which supported drilling activity (see graph below).

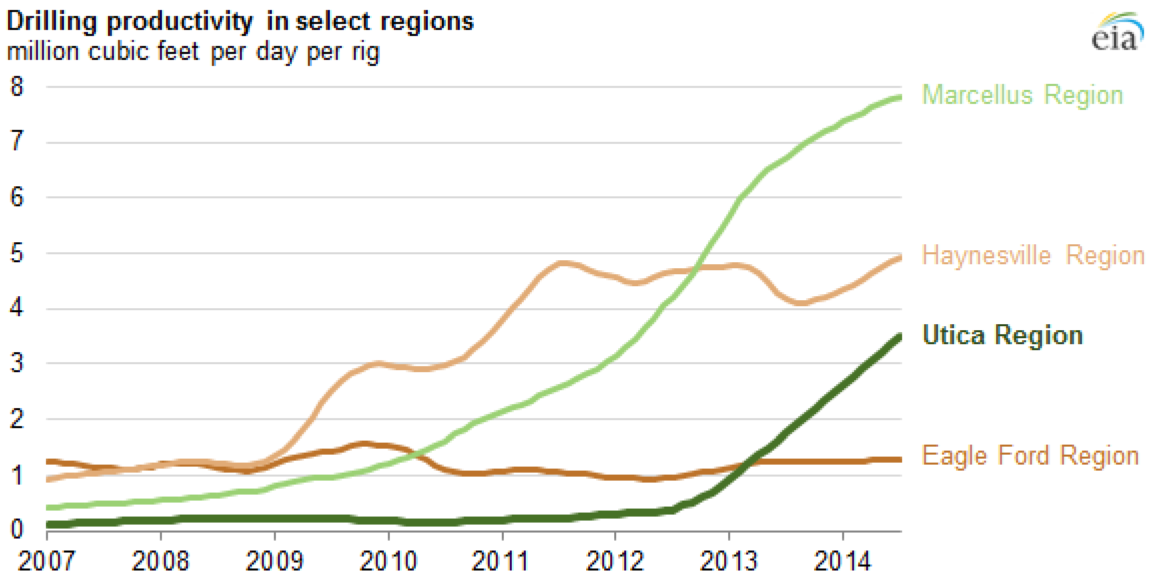
**Figure A-1-1 Drilling Carry in North American Shale Gas JV Deals by Play**




*Source: PFC*

– improvements in drilling techniques and cost optimization. In 2006-2009 there were 1200-1600 gas drilling rigs in operation. After 2009 gas rig count dropped abruptly to about 700 and then stabilized at the level of 900-1000 in 2010-2011. However, gas production rates did not decrease but kept growing at similar or even faster pace than in 2006-2009 due to increase in productivity and new techniques (decrease in a number of drilling days per rig, pad drilling, increase of lateral length and number of frackstages per lateral, well spacing).

**Figure A-1-2 Drilling productivity in select regions**



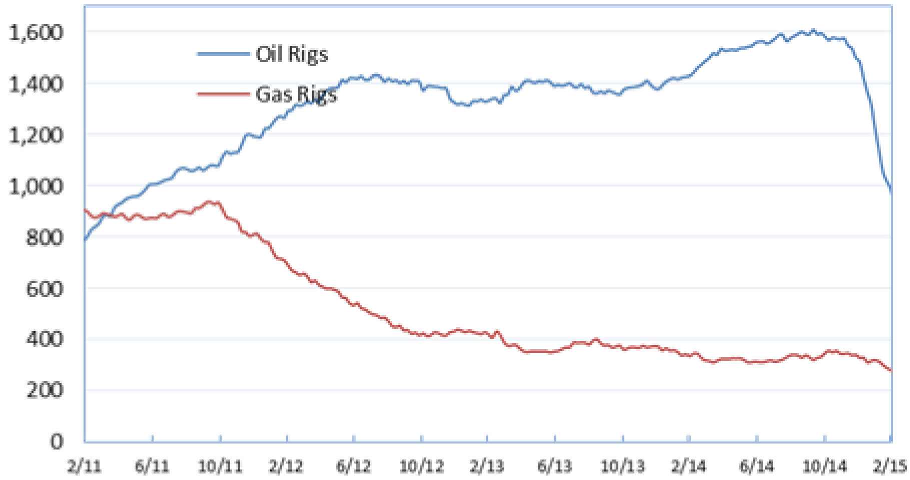

*Source: U.S. Energy Information Administration, Drilling Productivity Report*

– development of liquid-rich shale deposits. In 2011 producers started to curtail production from dry gas wells as prices were no longer supportive and "inertia" effects lapsed. As of 1st quarter 2015, there are about 583 more oil-directed drilling rigs than gas-directed drilling rigs. In 2011 a number of oil rigs outstripped quantity of gas rigs for the first time in 18 years, and this trend is still in place. Associated gas coming from "wet" (shale oil and gas condensate wells) is the last but not yet the least factor supporting shale gas production. As the oil and oil products prices came down in 2014 US producers who had hedged at least part of their liquids hydrocarbons can still have some access to cash from such sales at higher price.

**Table A-1-1 Rig operations in the US**

| | 3/20/2015 | 3/13/2015 | WoW Δ | MoM Δ | YoY Δ |
|---|---|---|---|---|---|
| Oil rigs | 825 | 866 | -41 | -194 | -648 |
| Gas rigs | 242 | 257 | -15 | -47 | -84 |
| Others | 2 | 2 | 0 | 0 | -2 |
| | | | | | |
| Vertical | 148 | 166 | -18 | -55 | -236 |
| Horizontal | 829 | 849 | -20 | -150 | -377 |
| Directional | 92 | 110 | -18 | -36 | -121 |
| Total | 1,069 | 1,125 | -56 | | |

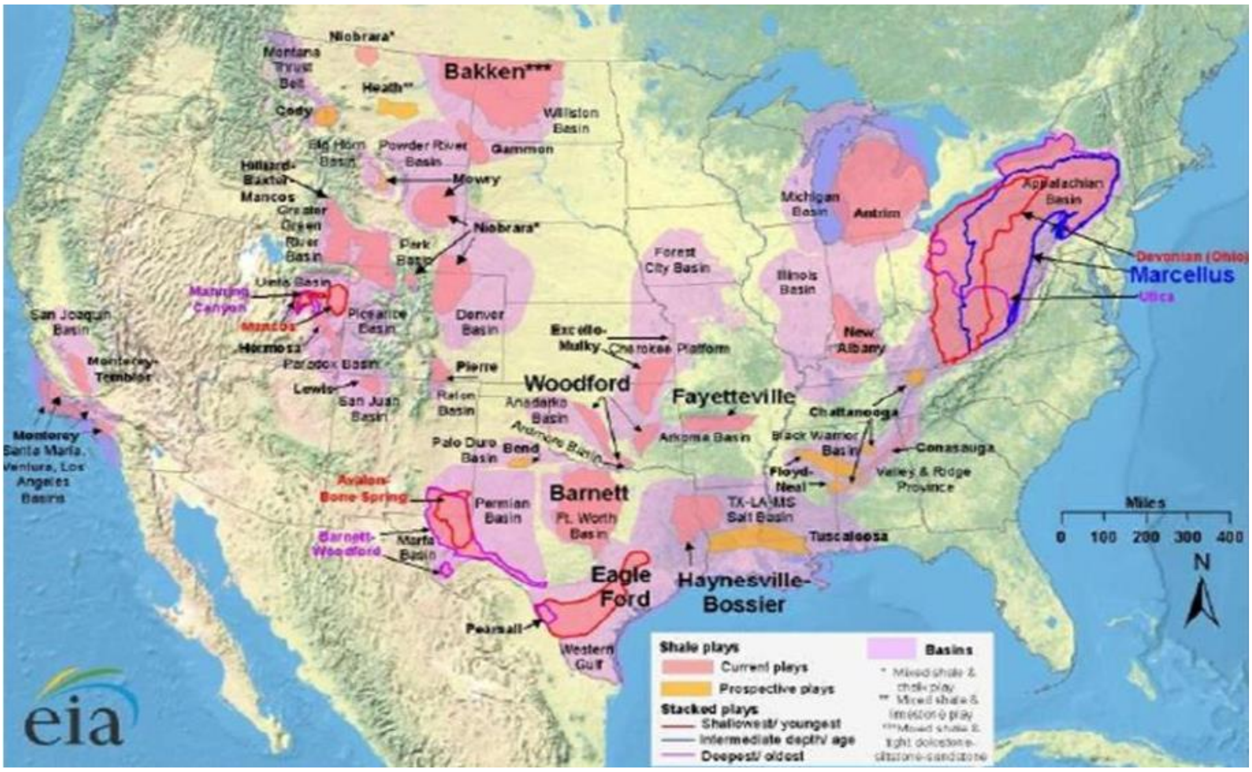
**Figure A-1-3 Rig operations in the US**




*Source: GM&T /Baker Hughes*

– putting into production of drilled but not completed wells in Marcellus shale. Wells were blocked from producing because of limited infrastructure at the time of drilling. As infrastructure problem has been resolved these wells became important source of production growth.

**Figure A-1-4 Shale plays in lower 48 states**




*Source: EIA DOE*

Unlike conventional reservoirs which have predictable production plateau for decades once major investments are borne, shale gas needs continuous support from external factors.

With a steep production decline of regular shale wells, decrease of dry gas rig count, unblocking of Marcellus's non-producing wells and decreased oil prices it will be soon become apparent whether there are new drivers to support further growth of shale gas production. In other words, the period of 2009-2013 can be described as "shale gas breakthrough". Now, as "bullish" factors seem to fade away, it is crucial to identify the sources for sustainability of shale gas production.

**Challenges**

***Environmental regulation***

One of the key environmental impact issues is the risk of contamination water resources. Water issues are prominent because water use in shale production is a significant and accompany full well development process at all stages.

Wile water demand is high for the shale development process, the US Environmental Protection Agency (EPA) reports that, on average, these requirements only constitute 0.1-0.8 percent of total usage by volume in each respective water basin.

The shale industry is required to participate in the EPA's study on the overall effect of hydraulic fracturing practices on drinking water. Started in 2011 this study requires additional disclosure from select shale service companies, as well as intensive investigations at select shale locations throughout the US. The study analyzes the following main issues:

- Water Acquisition – Are there large volume water withdrawals from ground and surface water?
- Chemical Mixing – Are there surface spills on or near well pads of hydraulic fracturing fluids?
- Well Injection – What is the current injection and fracturing process?
- Flowback – Are there surface spills on or near well pads of the flowback?
- Wastewater Treatment – How is wastewater treated?

The study includes a review of the published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies and case studies.

The EPA released a progress update in December 2012. The report described 18 research projects underway to answer research questions above and presents the progress made as of September 2012 for each of the projects. Through 2013 EPA arranged a number of technical workshops. The final report in accordance to the EPA plan was to be delivered at the end of 2014.

Oil and gas operations have historically been regulated mainly at the state level, though the expansion of hydraulic fracturing activities has brought with it an expansion in the number and sources of regulations facing operators. As with other oil and gas production activities, shale companies are currently subject to US regulations and protocols, such as the Oil Pollution Act, the Clean Water Act, the Clean Air Act and the Resource Conservation and Recovery Act.

In 2011 shale gas was also suggested to be under Safe Drinking Water Act. Under EPAct 2005 hydraulic fracturing is not considered federal regulation under SDWA. There were two amendments to the SDWA under review — one to amend the definition of underground injection to include hydraulic fracturing, and another to create a new disclosure requirement for the chemicals used in hydraulic fracturing.

Together, these regulations expose shale companies to an array of compliance issues, including greenhouse gas reporting requirements, animal habitat protection, safe operating practices, permits for drilling and constructing wells, and land-use practices, as well as noise and air quality mitigation procedures.

If the EPA study determines fracturing operations are significantly impacting drinking water sources it could influence legislators to act to remove some of the existing exemptions under federal laws.

Several states, including Pennsylvania, Illinois, California, Colorado, and Ohio, have recently developed comprehensive regulatory schemes specifically to permit and regulate fracturing activities, while states like Wyoming, Texas, and Oklahoma have added new rules for fracturing to existing oil and gas programs. An even larger group of states has now adopted fracturing fluid disclosure laws. For example, in March 2014, Wyoming instituted one of the nation's strongest requirements for water well testing near drilling sites. Colorado also introduced the country's first standards for methane emissions from oil and gas operations.

Rather than waiting for federal regulators to intercede, industry is actively engaging with states and other stakeholders to develop rules that make sense for their operations. The Center for Sustainable Shale Development (CSSD), a collaborative effort between environmental organizations and energy companies, is an example of this type of industry engagement. CSSD has established 15 initial performance standards to address air and water quality concerns relevant to oil, gas, and shale development. Four Marcellus shale operators announced they will undergo voluntary audits under a new verification protocol for compliance with CSSD standards.

In one of the articles published by Oil&Gas Journal Baker & McKenzie experts state that in the near term, EPA and other federal agencies will continue to act within their limited statutory authority while exploring the areas beyond it. There are several rulemakings currently ongoing at the federal level related to hydraulic fracturing. Most recently, in May 2014, EPA released an advance notice of proposed rulemaking under the Toxic Substances Control Act (TSCA) related to chemicals used in the fracturing process. The notice suggests the EPA may consider developing a mechanism to encourage further disclosure of fracturing chemicals, either by regulation under TSCA or through a voluntary program.

At the same time, EPA has demonstrated that it is willing to exercise any authority available to it in the event of a potential environmental emergency related to fracking. For example, despite the exemption for hydraulic fracturing under the SDWA, the statute provides EPA an "imminent and substantial endangerment" response authority, which EPA has used to investigate groundwater contamination allegations in Pavillion, Wyo., Dimock, Pa., and Parker County, Tex. These cases were investigated and EPA made conclusions that no contamination occurred due to fracking.

However a number of scientists (Geoffrey Thyne, Duke and Stanford Universities' scientists) in US believe that groundwater contamination in mentioned states could have seen the result of gas producers' activities.

There are also studies which say the rate of earthquakes above magnitude 3 in the midcontinental U.S. has been rising steadily from 21 events a year, on average, with a steep acceleration after 2010 and a peak of 188 events in 2011. Some scientists think that it's re-injection of wastewater that causes seismic activity.

USA National Academy of Sciences stated on July 29, 2014 that casing and cement impairment in oil and gas wells can lead to methane migration into the atmosphere and/or into underground sources of drinking water. An analysis of 75,505 compliance reports for 41,381 conventional and unconventional oil and gas wells in Pennsylvania drilled from January 1, 2000-December 31, 2012, was performed with the objective of determining complete and accurate statistics of casing and cement impairment. Statewide data showed a sixfold higher incidence of cement and/or casing issues for shale gas wells relative to conventional wells. For post-2009 drilled wells, risk of a cement/casing impairment is 1.57-fold higher in an unconventional gas well relative to a conventional well drilled within the same time period. Unconventional gas wells in northeastern Pennsylvania are at a 2.7-fold higher risk relative to the conventional wells in the same area. The predicted cumulative risk for all wells (unconventional and conventional) in the northeastern region is 8.5-fold greater than that of wells drilled in the rest of the state.

Other environmental issues are landscape impact and pollution by chemical spills including risks associated with natural disasters.

Pennsylvania imposed September 18, 2014 a record fine on Range Resources for contaminating groundwater under six of its water impoundments in Washington County in the southwestern corner of the state. The state's Department of Environmental Protection requires the company to pay USD4.15 million fine, "the largest against an oil and gas operator in the state's shale drilling era," according to DEP. Range also was ordered to close five impoundments and upgrade two others to meet tougher standards that are now being developed, the agency said. The previous record fine occurred in May 2011 when DEP fined Chesapeake Energy a little over $1 million for groundwater contamination in Bradford. Range acknowledged that it found higher levels of chlorides at some of its older facilities in Washington County, but said no drinking water sources were affected and the salt did not impose a health or safety risk. "Testing has confirmed that no constituents were discovered in the monitoring wells at concentrations exceeding health-based maximum concentration levels, as determined by the US Environmental Protection Agency," the company said. Range said it was cooperating with DEP to address the problem. "This landmark consent order establishes a new, higher benchmark for companies to meet when designing future impoundments, which is an environmental win for Pennsylvania," DEP.

In accordance to Platts publications in October 2014 scientists in one study connected higher concentrations of methane in sampled drinking water wells with poor well construction techniques. Scientists from the Department of Energy's National Energy Technology Laboratory (NETL) released a technical report of a small study of Marcellus Shale wells in Greene County, Pennsylvania, that they said showed the fissures created by fracking stopped 5,000 feet below the overlying fresh water aquifer.

"There was no detectable upward migration of gas or fluids from the hydraulically fractured Marcellus Shale", NETL said. The study by NETL's Office of Research and Development used natural and man-made tracers to see if upward fractures continued out of their target zone and connected the aquifer with the underlying fracked well and its fluids.

The researchers found that the frack fissures did travel about 3,800 feet higher into the gas-bearing portions of the Upper Devonian Shale above the Marcellus and then stopped – midway between the Marcellus and the surface. Poor casing and cementing of a small number of shale gas wells in Pennsylvania and Texas, not hydraulic fracturing, were linked to water contamination, a study published in the Proceedings of the National Academy of Sciences concluded.

Scientists from Duke, Stanford, The Ohio State University, Dartmouth and the University of Rochester used tracers to analyze the natural gas content of more than 130 drinking water wells in the two states and found methane contamination but no sign of interaction with hydraulic fracturing fluids. "Our data clearly show that the contamination in these clusters [seven in Pennsylvania and one in Texas] stems from well-integrity problems such as poor casing and cementing," Ohio State professor Thomas Darrah said. Darrah led the study, which he began when he was a research scientist at Duke. The study ruled out the possibility that methane migrated into drinking water because of fracking, the study said. Instead, the methane appears to be coming into drinking water wells from sources close to the surface: leaking gas wells, the study surmised.

In four clusters, methane entered the drinking water well because there was insufficient cement surrounding the wellbore. In three clusters, methane was detected coming from wells with faulty casings and, in one case, methane was found in drinking water because of an underground well failure, the study said.

The scientists examined 113 wells in Pennsylvania and 20 in Texas' Barnett Shale in 2013 and 2013. The team used noble gases as tracers because the inert gases don't react to their surroundings. "This is the first study to provide a comprehensive analysis of noble gases and their isotopes in groundwater near shale gas wells," Darrah, who plans to continue the study, said. "The good news is that most of the issues we have identified can potentially be avoided by future improvements in well integrity," he added.

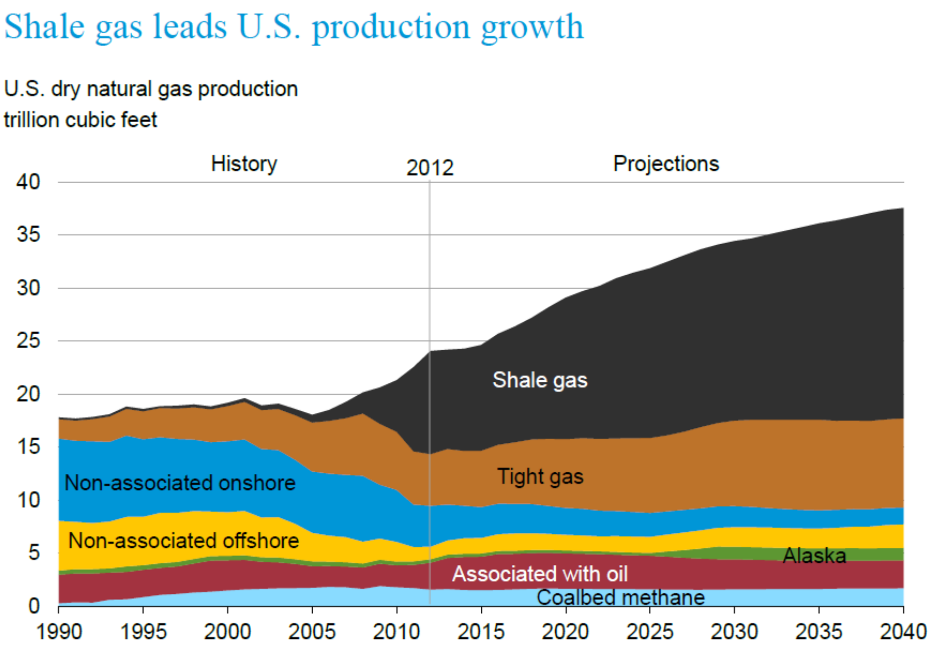
### (3) Impact of unconventional gas

#### Volumes

Above mentioned developments contributed into material increase in shale gas production - today 40% of all US gas production comes from shale deposits. In total unconventional gas together with coalbed methane (CBM) and tight gas secures about 70% of total dry gas production.
The estimate of 2013 and 2014 shale gas production provided by Energy Information Administration of Department of Energy (EIA DOE, Annual Energy Outlook 2014 dated May 2014) is around 264 bcm (9.4 tcf) and 273 bcm (9.6 tcf) accordingly. 2012 shale gas production has been adjusted and is now 275 bcma compared to figure released in April 2013 (230 bcm (8.1 tcf)).

Newly forecast is more optimistic about gas production then previous one. According to EIA forecast overall growth in natural gas production by 2030 is now forecasted to be + 290 bcm (previous growth forecast was +166 bcma) of which 74% come from shale gas developments. Serious growth in this new outlook is envisaged from tight gas resources. This means by 2030, CBM added, 77% of total US dry gas production will come from unconventional reservoirs.

**Figure A-1-5 Shale gas leads U.S. production growth**




*Source: EIA DOE AEO 2014*

Proved dry natural gas reserves as of the end of 2010 set another record in the US gas industry as it reached 8.6 tcm — the highest level from 1970 when 8.2 tcm were booked and 4 tcm growth from 1997 ("breakpoint" when the trend of decrease in gas reserves was broken). Such reserves are enough to secure R/P ratio of 13 years. In 2011 trend continued and reserves reached 9.5 tcm with R/P ratio growing to almost 15 years.

Lower natural gas prices drove down U.S. proved reserves in 2012 back to 8.7 tcm, Proved reserves are volumes of natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. In 2014 proved reserves increased again to the level of 9.6 tcm.

**Interstate gas trade**

Natural gas production in the northeastern United States rose from 2.1 billion cubic feet per day (Bcf/d) in 2008 to 12.3 Bcf/d in 2013. Marcellus production alone increased dramatically over the past five years from 1.3 Bcf/d (roughly 130 bcma) in 2010 to its early 2015 level of 14.6 Bcf/d (150 bcma).

This trend has reduced the cost and increased the supply of natural gas in the Northeast. This additional supply has encouraged greater use of natural gas in the Northeast, especially for power generation, and has also reduced net inflows of natural gas into the region from other regions such as the Gulf of Mexico, the Midwest, and eastern Canada.

Between 2008 and 2013, natural gas net inflow from eastern Canada to the Northeast fell by 82%. Lower production at Sable Island and higher demand for natural gas in eastern Canada contributed to the decrease of natural gas imported into the Northeast from eastern Canada. The Northeast began exporting greater volumes of natural gas to eastern Canada by pipeline from TGP's border crossing in Niagara, New York, following expansions completed on TGP.

In addition, greater natural gas production in the Northeast has contributed to the inflow decreases from the Midcontinent to the Northeast along the Rockies Express Pipeline. Also, rising production in the Marcellus Region has outpaced growth in the region's pipeline capacity, which has resulted in multiple pipeline expansion projects focused on removing bottlenecks in the Marcellus Region. In accordance to EIA estimates more than 16 Bcf/d (roughly 160 bcma) of brownfield expansions and flow reversals make up most of the proposed increases to Marcellus and Utica takeaway capacity through 2016, followed by greenfield projects that, if developed, represent more than 10 Bcf/d (100 bcma) in increased takeaway capacity to come online in 2017-2018.

**Table A-1-2 Natural gas inflows to the Northeast**

| January-September average | Eastern Canada | Midcontinent | Southeast | LNG imports |
|---|---|---|---|---|
| 2008 | 2.5 | 1.2 | 7.9 | 0.5 |
| 2013 | 0.4 | 0.6 | 3.5 | 0.2 |
| Change | -2.0 | -0.6 | -4.4 | -0.3 |
| % change | -82% | -48% | -56% | -54% |

*Source: EIA based on Bentek Energy*

**Pricing**

Financial crisis has triggered a long period of price slump on the US gas market. In 2009 average Henry Hub (HH) price dropped from USD8.85 to USD3.85 per MMBtu. Prices were 4.49 and 3.95 in 2010 and 2011 accordingly. 2012 was the toughest (in April it hit USD1.8 per MMBtu). HH gas price on Jan. 25, 2013 was USD3.4 per MMBtu and stays in the same range through September 2013. In August 2014 HH was traded at about USD4,0 per MMBtu.

Price drop resulted in review of market/balance value of gas fields. A few major players such as BP, BG, BHP Billiton, Encana were forced to write down some value of gas assets (total loss value is estimated at about USD7 bln (Pace Global estimates the total was USD13.8 bln)).

Shale gas changed regional prices structure inside US. Natural gas prices in the Northeast, such as the Dominion South trading point in southwestern Pennsylvania, have increasingly been below the Henry Hub price (up to 40%), in part because of increased access to Marcellus gas. Such situation has never happened before. Production in the Marcellus Region surpassed winter demand for natural gas in Pennsylvania and West Virginia several years ago and is now on track to be enough to equal the demand in those states plus New York, New Jersey, Delaware, Maryland, and Virginia combined.

EIA slightly increased its HH forecast in new 2014 release and forecasts that HH spot gas prices will remain below USD4 per MMBtu (real terms (RT) 2012) through 2016 (in previous outlook this threshold was achieved in 2018). In the long–term HH in real terms will be below USD6 till 2030. In terms of money of the day (MOD) this translates into USD4.95 per MMBtu through 2020 reaching USD6.5 per MMBtu in 2025 and 8.1 on 2030.

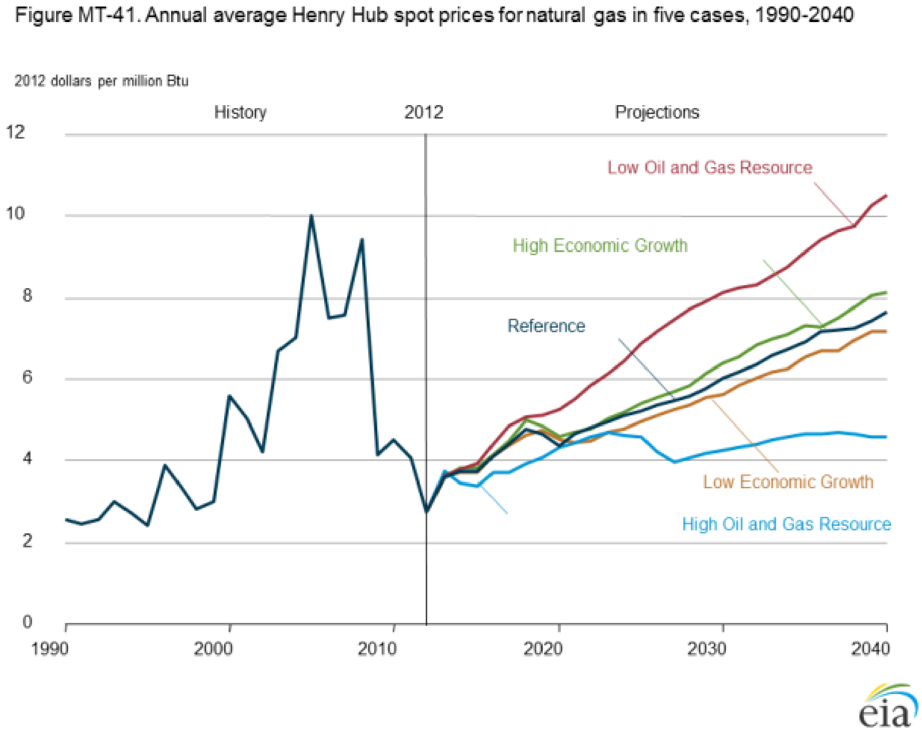
The approach to price forecasting is based on the future Estimated Ultimate Recovery (EUR) and well efficiency which effect average shale well breakeven costs. Thus the main factor effecting prices in future is to high extent geology risk. From the graph below one can see that geology factor (low or high resource cases) effects price much more compared to economic development factors (high or low economic growth cases).

Under DOE methodology the EUR in the Reference case is based on natural gas production rates achieved in a limited portion of the shale formation and is assumed to be representative of the entire formation. Low or high cases assume EUR 50% lower or 100% higher accordingly compared to Reference case which is 1.04 bcf per well (based on the range of 0.01 to 11 bcf per well). Depending on actual drilling success the range of HH price (RT2012) in 2020 is from 5.3 to 4.4 and 8.14 to 4.25 in 2030 depending on scenario. The price range has increased compared to previous report, e.g. from 7.1 and 3.3 in 2030 accordingly.

As EIA describes these cases do not represent a confidence interval for the shale gas resource base, but rather illustrate how different assumptions can affect projections of domestic production, prices, and consumption.

The U.S. Geological Survey (USGS) conducts quantitative assessments of potential oil and gas resources of the onshore United States and State waters. Since 2000, 132 assessments have been performed for continuous (unconventional) oil and gas resources, based on geologic studies and analysis of well-production data. Assessment methods are documented in Crovelli (2000, 2003), Klett and Charpentier (2003), Klett and Schmoker (2003), and Schmoker (2003). Each assessment unit (AU) was divided into cells, with each cell representing a well-drainage area. The estimates of resource potential were derived from estimates of the potential number of undrilled productive cells and of the productive capacities of those cells.

**Figure A-1-6 Annual average Henry Hub spot prices for natural gas in 5 cases, 1990-2040**




*Source: EIA DOE AEO 2014*

Estimated ultimate recovery (EUR) distributions were estimated for each AU, based on decline-curve analysis from monthly production data (IHS Energy, 2011) of hundreds to thousands of wells per AU. The EUR distribution used for each assessment calculation was specifically that for undrilled cells. Commonly, this EUR distribution for undrilled cells is closely similar to the distribution for drilled cells. In general, wells drilled early in the development of an AU, before drilling and completion techniques are optimized, have relatively low EURs. This can cause the estimated EURs for undrilled cells to be higher than those for drilled wells. Conversely, if the geologically most favorable parts of the AU have already been drilled, the EURs for undrilled cells may be lower than those of drilled wells.

Based on distributions it can be seen that mean EURs of major plays like Marcellus, Haynesville, Eagle Ford are higher than AEO Reference case assumption of 1.04 bcf per well. However it should be noted that probability of reaching EUR level which is higher than Mean level is less than 30%. And accordingly, it is 70% probability that EUR will be lower than Mean level.

**Table A-1-3 Input data for estimated ultimate recovery distributions for United States shale-gas assessment units, values in billions of cubic feet of natural gas**

| AU number | AU name | Province | Year assessed | Minimum EUR | Median EUR | Maximum EUR | Mean EUR |
|---|---|---|---|---|---|---|---|
| 50490161 | Haynesville Sabine Platform Shale Gas | Gulf Coast Mesozoic | 2010 | 0.02 | 2 | 20 | 2.617 |
| 50490163 | Mid-Bossier Sabine Platform Shale Gas | Gulf Coast Mesozoic | 2010 | 0.02 | 1 | 10 | 1.308 |
| 50580161 | Woodford Shale Gas | Anadarko Basin | 2010 | 0.02 | 0.8 | 15 | 1.233 |
| 50670468 | Interior Marcellus | Appalachian Basin | 2011 | 0.02 | 0.8 | 12 | 1.158 |
| 50490167 | Eagle Ford Shale Gas | Gulf Coast Mesozoic | 2010 | 0.02 | 0.8 | 10 | 1.104 |
| 50620362 | Fayetteville Shale Gas - High Gamma-Ray Depocenter | Arkoma Basin | 2010 | 0.02 | 0.8 | 10 | 1.104 |
| 50450161 | Greater Newark East Frac-Barrier Continuous Barnett Shale Gas | Bend Arch-Fort Worth Basin | 2003 | 0.02 | 0.7 | 10 | 1.000 |
| 50440161 | Delaware/Pecos Basins Woodford Continuous Shale Gas | Permian Basin | 2007 | 0.02 | 0.6 | 8 | 0.842 |
| 50440162 | Delaware/Pecos Basins Barnett Continuous Shale Gas | Permian Basin | 2007 | 0.02 | 0.6 | 8 | 0.842 |
| 50580261 | Thirteen Finger Limestone-Atoka Shale Gas | Anadarko Basin | 2010 | 0.02 | 0.5 | 10 | 0.785 |
| 50620261 | Woodford Shale Gas | Arkoma Basin | 2010 | 0.02 | 0.5 | 10 | 0.785 |
| 50210364 | Gothic, Chimney Rock, Hovenweep Shale Gas | Paradox Basin | 2011 | 0.02 | 0.4 | 10 | 0.672 |
| 50630561 | Devonian Antrim Continuous Gas | Michigan Basin | 2004 | 0.02 | 0.4 | 4 | 0.523 |
| 50620363 | Fayetteville Shale Gas - Western Arkansas Basin Margin | Arkoma Basin | 2010 | 0.02 | 0.3 | 6 | 0.470 |
| 50210362 | Cane Creek Shale Gas | Paradox Basin | 2011 | 0.02 | 0.3 | 5 | 0.446 |
| 50440163 | Midland Basin Woodford/Barnett Continuous Gas | Permian Basin | 2007 | 0.02 | 0.3 | 5 | 0.446 |
| 50490165 | Maverick Basin Pearsall Shale Gas | Gulf Coast Mesozoic | 2010 | 0.02 | 0.25 | 5 | 0.391 |
| 50450162 | Extended Continuous Barnett Shale Gas | Bend Arch-Fort Worth Basin | 2003 | 0.02 | 0.2 | 5 | 0.334 |
| 50390761 | Niobrara Chalk | Denver Basin | 2001 | 0.025 | 0.2 | 2 | 0.261 |
| 50620262 | Chattanooga Shale Gas | Arkoma Basin | 2010 | 0.02 | 0.1 | 6 | 0.223 |
| 50670467 | Foldbelt Marcellus | Appalachian Basin | 2011 | 0.02 | 0.1 | 5 | 0.208 |
| 50620364 | Caney Shale Gas | Arkoma Basin | 2010 | 0.02 | 0.08 | 5 | 0.179 |
| 50670469 | Western Margin Marcellus | Appalachian Basin | 2011 | 0.02 | 0.05 | 5 | 0.129 |
| 50640361 | Devonian to Mississippian New Albany Continuous Gas | Illinois Basin | 2007 | 0.01 | 0.08 | 1 | 0.110 |
| 50670462 | Northwestern Ohio Shale | Appalachian Basin | 2002 | 0.01 | 0.04 | 0.5 | 0.055 |
| 50670463 | Devonian Siltstone and Shale | Appalachian Basin | 2002 | 0.01 | 0.03 | 0.5 | 0.044 |

Source: http://pubs.usgs.gov/of/2012/1118/OF12-1118.pdf

On the other hand since 2011 (data used by USGS) rig efficiency has increased: rig count in US has so far decreased 3 times while country production levels have been stable or growing. This is reflected in 2014 EUR estimates by such major consulting firms like Wood Mackenzie and CERA where EUR for major shale gas plays is 3-4 times higher compared to USGS data.

Shale deal economics may also include entry costs (M&A costs), deal structure (cash and carry) and disproportionate capex contribution to calculate fair breakeven price for investor. The latter factor is important because significant part of shale capital budgets come from international investors. Unfortunately, there are no published studies which would show returns related to acquisitions of US shale gas properties (e.g. for Statoil, BHP Billiton, others).

There is also a debate whether the US industry can sustainably produce low cost shale gas due to high NGL factors or significant amount of associated gas in shale oil deposits. Analysis of 2013 and 2014 outlooks gives an answer that associated gas will be marginal source of gas for US with its share around 7-10% through 2030. NGL production growth rate is only 1% on average till 2030. This means probably that shale gas production will be driven by the economics of dry gas reservoirs developments. Low oil price environment confirms such assumptions. Based on statistics one can see that major gas producing region in US at low oil price environment is Marcellus shale which economics are mostly driven by dry gas well efficiency.

**Local demand impact**

AEO 2014 provides estimate of 725 bcm for consumption in 2013 while actual statistics on EIA site state 739 bcm. The new data from EIA site shows that gas consumption in 2014 reached record high level of 758 bcm.

Consumption by residential consumers was at record level in 2014 (144 bcm). In general residential consumption has been in a corridor of 130-140 bcma for the last 10 years due to limited reaction of final prices to end-users and due to low elasticity of demand (mostly driven by weather).

But other main sectors – power and industry contributed significantly into gas demand growth being stimulated by affordable gas.

There was a record of gas consumption by power industry of 258 bcm in 2012. In 2013-2014 this figure was at the level of 230 bcma. The share of power sector in gas demand reached record 31% in 2011, 36% in 2012 and 30-31% in 2013-2014. Gas price decline put gas power generation in a favorable position in many parts of the US — from underutilized combined-cycle gas-fired turbines (CCGT) to a cost effective generation vs conventional coal-fired generation.

In fact, there was tremendous growth in gas-fired generation capacity (GFGC) from 2000 to 2013. GFGC more than doubled from 219 GWt to 488 GWt.

The coal-fired generation capacity stayed at the same level during past decade: 315-316 GWt. Coal capacity retirements have started only in recent years and in 2012 declined to 310GWt and more retirements are projected.

Starting from 2009 (post–crisis period) industrial consumption grew by 37 bcm and reached 217 bcm in 2014 which is comparable to 2001-2002 consumption levels, still far away from 240 bcm consumed in 1997.

DOE changes its view on industrial demand future compared to what was forecasted in previous AEO reports. Now EIA forecast steady increase in gas consumption by industry. There will be major gas demand growth by next several years. Demand will keep increasing in long-terms by at lower pace. This is change from previous approach when industrial demand was projected to be in stagnation in a long run due to international competition.

In power sector trends are quite similar to industry. Gas–fired generation segment will be growing steadily through 2030. The gas demand in this sector will reach 285 bcm in 2030.

DOE view on GFGC also slightly changed in 2014. Year earlier there were projections that almost no GFGC additions would happen till 2023. In 2014 version of report CCGT capacities (major source of GFGC) are forecasted to grow by 7% in next 3 years (increase from 189GW in 2013 till 202GW in 2016) with next major growth period starting in 2020 adding another 55 GW in 10 years (from 205 in 2020 to 260GW in 2030).

The coal-fired generation capacity will keep decreasing by 2017 and no more additions will happen.

In total DOE predicts gas consumption to increase by additional 105 bcm in 2030. The figure has doubled since AEO published last year.

EIA also zero out GTL sector gas consumption while year before it predicted 10-15 bcm of demand in this sector.

**Import - export impact**

***Pipeline***

Recent price levels for US gas relative to the price of gas in other global markets impact export/import dynamics. There has already been a significant change in the net export balance for gas trade by pipeline with US’s neighbors, Canada and Mexico. In 2014 AEO EIA plans US to become net exporter not by 2021 as in previous reports, but in 2018.

During the 1990s net US exports to Mexico were negligible, but began to grow post-2000 as the Mexican government elected to replace oil-fired steam power generation with CCGT plants to maximize oil export and reduce generation costs. The outlook shows growing US gas exports to Mexico. In 2014 net exports to Mexico were 20 bcm — new record of US/Mexico trade. In terms of interstate capacity there seems to be significant upside for export to Mexico as total capacity in accordance to EIA data is about 39 bcm per year.

Mexican CFE has a US$4,637mil budget to expand its infrastructure and erect four combined cycle plants that would link up with five pipelines that would bring shale gas from Waha (TX) to Mexico.

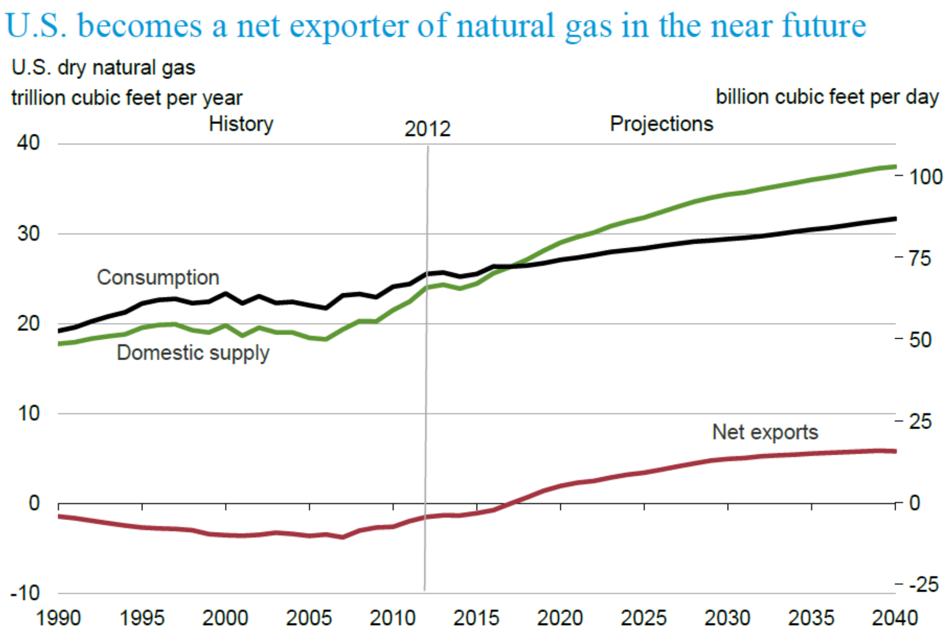
The Canadian data series documents the substantial growth of US imports during the 1990s – a rough plateau through the first half of the 2000s, followed by a steady decline in net US imports. Net export from Canada to US decreased from picking 102 bcm in 2002 to 53 in 2014.

By contrast, domestic Canadian demand – particularly for processing – grew rapidly. Simultaneously, net gas deliveries from the US to Canada (particularly to the more densely populated provinces in the east) began to increase. Subject to a North American price recovery, shale gas development in Alberta and British Columbia should reduce the rate of decline of Canadian gas production, if not reverse it. But growing domestic demand and the increasing probability of Canadian LNG exports to Asia will support the recent trend of increasing US exports, adding to net US requirements for indigenous gas production.

Based on statistics one can see that about 40 bcma of additional demand in a period 2008-2014 (period of exponential shale gas production growth) came from Canada (indirectly, via Canadian exports decrease) and Mexico.

Taking into account efforts of Mexico and Canada to develop own shale gas resources and given US aspiration to become exporter to these countries it will be very important to monitor situation in Mexico and Canada.

**Figure A-1-7 U.S. becomes a net exporter of natural gas in the near future**




*Source: EIA DOE AEO2014*

***LNG***

Declining US gas prices and increasing production, which have reduced US LNG imports to minimal volumes, have also pushed the financially-troubled owners and capacity holders of newly-built US LNG import terminals to find alternative uses for idle capacities. As a result, export terminals are becoming more of a focus for project developers.

(Application and approval)

24 LNG export projects with the total capacity of around 29.9 bcfd (309 bcma) submitted application of LNG exports. In May 2011, Cheniere Energy's Sabine Pass project received the first export permit from the DOE to ship LNG to non-FTA countries.

From May 2013 to March 2014, DOE approved 8 applications of LNG exports to non-FTA countries for 7 projects. The total maximum volume of approved LNG exports is 12.7 Bcf/d (around 130 bcma). Following Sabine Pass in 2011, DOE approved in succession, namely, Freeport, Lake Charles, Cove Point, Cameron, Jordan Cove, Oregon.

**Table A-1-4 DOE's authorization to export LNG to non-FTA countries**

| LNG projects | location | promoter | DOE's approval of exports to non-FTAs | max volume of exports (Bcf/d) | planned start of exports |
|---|---|---|---|---|---|
| Sabine Pass | Louisiana | Cheniere | May-11 | 2,20 | 2016 |
| Freeport | Texas | Freeport LNG | May-13 | 1,40 | 2018 |
| | | | November-13 | 0,40 | 2018 |
| Lake Charles | Louisiana | Southern Union | August-13 | 2,00 | 2019 |
| Cove Point | Maryland | Dominion | September-13 | 1,77 | 2017 |
| Cameron | Louisiana | Cameron LNG | February-14 | 1,70 | 2018 |
| Jordan Cove | Oregon | Jordan Cove | March-14 | 2,00 | 2019 |
| Oregon | Oregon | LNG Development | July-14 | 1,25 | 2019 |
| 7 projects, 8approvals of export | | | | 12,72 | |

However not all projects even having exports approved have taken FID – FIDs have been taken by Sabine Pass, Cameron and Freeport. Some site preparation works started at Cove Point project.

(Governmental stance for approval)
The US Government's position is to make decision with respect to each LNG export project. The main concern regarding the export of natural gas is the impact on domestic prices, DOE commissioned two reports on LNG exports. The first one was released in January 2012, which was to evaluate the price impact of several LNG export scenarios. The second one by NERA was released in December, 2012, which was intended to focus on the macroeconomic benefits of LNG exports. NERA report concluded that the price impact would be much smaller and LNG exports could be beneficial to the US economy in general.

The results of NERA study might be interpreted in a way that it is better for USA to become crude hydrocarbons producer and exporter (i.e. oil and gas industry and export cash will support growth in the wider economy and industrial segments). Following announcement of the results of NERA report, LNG exports of 6 projects have been approved to non-FTA countries during the period of from 2013 to 2014. As mentioned in section "Pricing" above such results might be explained by estimation methodology i.e. the fatal effect which geology has on prices rather than factors of gas demand and economic growth.

(Anti LNG exports activities)
The main opposition comes from consumer advocacy groups focused on affordability of electricity, the industrial and petrochemical lobby, and congressional Democrats such as Representative Ed Markey of Massachusetts and Senator Ron Wyden of Oregon. Consumer advocacy groups want to keep domestic supplies in the US in order to maintain low natural gas prices and cheap electricity prices. Manufacturing and industrial groups also want to use domestic gas supplies because cheap natural gas improves their members' competitive advantage in the global market.

On the local level, opposition by environmentalists and the public poses the most risk to LNG projects in Maryland (the Sierra Club to Cove Point) and Oregon.

There are certain new features for US LNG project business model which are summarized in table below. New business-models for LNG projects in US transfer price risk onto LNG buyer and create serious long-term cash commitment for liquefaction fee payments on use-or-pay basis.

Impact on international LNG market will depend on desire of end-buyers and traders to further increase its exposure to Henry Hub index in their fuel portfolio, take both volume and price risk and commit on a long-term basis to cover liquefaction costs to project developers (USD150+ mln a year per 1 mtpa of volumes/capacity)

**Table A-1-5**

| | Historical | US |
|---|---|---|
| Reserves certificate | Yes | No |
| Long term contract duration | 15-20 years | 20 |
| Price link | Buyer market (NBP, Oil, JKM, JLC, HH) | Supplier's market (HH) |
| Price structure | Netback | Cost-plus |
| Price risk taker | Seller | Buyer |
| Price review | Possible | No |
| Take-or-pay payment | Yes | No |
| Free compensation for ToP (make-up) | Yes | Not applicable |
| Use-or-pay charge (UoP) for LNG plant | No | Yes |
| Compensation for UoP | Not applicable | No |
| Sales basis | FOB, DES | FOB |
| Destination restrictions | No, for FOB sales | No, for FOB sales |
| Capex overbudget risk taker | Seller | Seller, Buyer, Capacity holder (depending on commercial agreement) |

## (1) History

Canada has short history of commercial-scale shale gas development along with long history of research and attempts for it. In 19th century, there was first industry report of natural gas in Quaternary in deposits overlying the Utica play in Quebec. Years later, first geological report was issued indicating gas in groundwater during oil & gas and water well drilling in 1950s. Hydraulic fracturing was suggested on the Utica play in 1953. After almost two decades, vertical and horizontal drilling started in Villeroy (45km southwest of Quebec city) on Utica and Lorraine play in 1971. No commercial production was made at this time for the inadequate technology.
The first shale gas production in Canada was made in Montney play in 2005. Two years later, Horn River also started to see shale gas production in 2007. These plays are located in Northeast British Columbia. Industry interests in other Canadian shale plays started in Alberta, New Brunswick, and Quebec, around the same period.

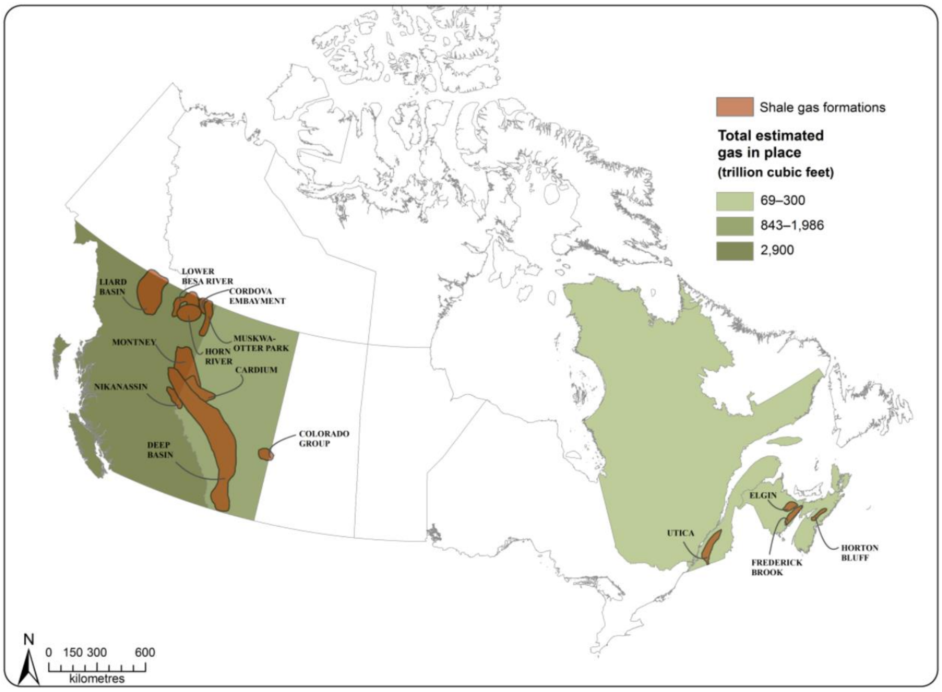
Currently the production is primarily focusing in British Columbia, and more specifically, focusing on two plays mentioned above. However, Canadian shale gas development is still much less active than in US. It is considered because Canada has still vast resources of conventional oil and gas. In contrary to US where declining production was one of the major factors in gas market once, Canada's current issue is shrinking export to US with its rising independency.

## (2) Factors which Influence the Future of Unconventional Gas in USA

### Drivers

There are some drivers considered attributable to:
- numbers of independent E&P companies and service companies under competition
- easy access to acreage under individual ownership of subsurface mineral rights
- access to US and Canada financial sector capable to support capital-intensive shale gas development

**Figure A-2-1 Shale plays in Canada**




*Source: Parliament of Canada*

**Challenges**

***Market Environment***

The most important hurdle of Canadian shale gas development is the low gas price in the local gas market. AECO, the benchmark price of Canadian gas market, has been pulled down by fall of Henry Hub because AECO is correlated well to Henry Hub. It is so because Canada has long been one of the main suppliers to US gas market. Collapse of AECO has been damaging economics of not just shale gas development, but all natural gas development business in Canada. As well known, and mentioned in US status report already, US shale gas is the main factor that has forced Henry Hub down, lifting US gas independency.

This new market environment means two important points as below:

- Quantity: US import, the largest market for Canadian gas, is declining and will do so further ahead
- Price: With import demand reduction on Canadian gas and low Henry Hub, AECO will find itself difficult to come back up
- Business: Low AECO would inevitably continue to harm business economics of Canadian shale gas development

Simply, it can be said that Canada is the country mostly affected by US shale gas development. The current market environment above indicates Canadian natural gas upstream business will continue to face shrink, until Henry Hub bounces up again. It is pointed as the main reason why Canada is turning into LNG export.

However, in LNG market, Canada has to survive inevitably export competition. And again, the most important competitor is US. Canadian LNG exporters have long suffered from marketing failure because they have sticked to oil-link price formula, while US LNG exporters offer Henry Hub-link price formula. Shortly, current difficulties of Canadian shale gas development is deteriorating economics and shrinking market.

As of this report, oil price collapse since second half of 2014 has mostly closed the price gap between these two different LNG price systems. It could provide some opportunities for Canadian LNG exporters to ensure markets, however, much lower price than they had looked for.

***Environmental regulation***

The environmental concern about shale gas development has been also suggested in Canada. Especially, water concern about hydraulic fracturing has been in controversy in Quebec where some part of Utica play is located. In 2009, the first public protest has occurred. This year can also be noted for release of the movie “Gasland”. In next year, public hearings and consultations on shale gas development was held. And then in 2011, new regulation was announced, leading to temporary moratorium of hydraulic fracturing in Quebec. In 2013, Quebec introduced five-year ban on hydraulic fracturing in St. Lawrence Lowlands, the region between Montreal and Quebec City. And in 2014, New Brunswick also introduced a new regulation that requires five conditions for permission. These conditions are namely:

- Social license
- Credible information on the impacts of hydraulic fracturing on health, environment, and water allowing the creation of a regulatory regime with good enforcement capabilities
- Consultation with First Nation communities
- Mechanism to maximize the benefits, including development of royalty structure

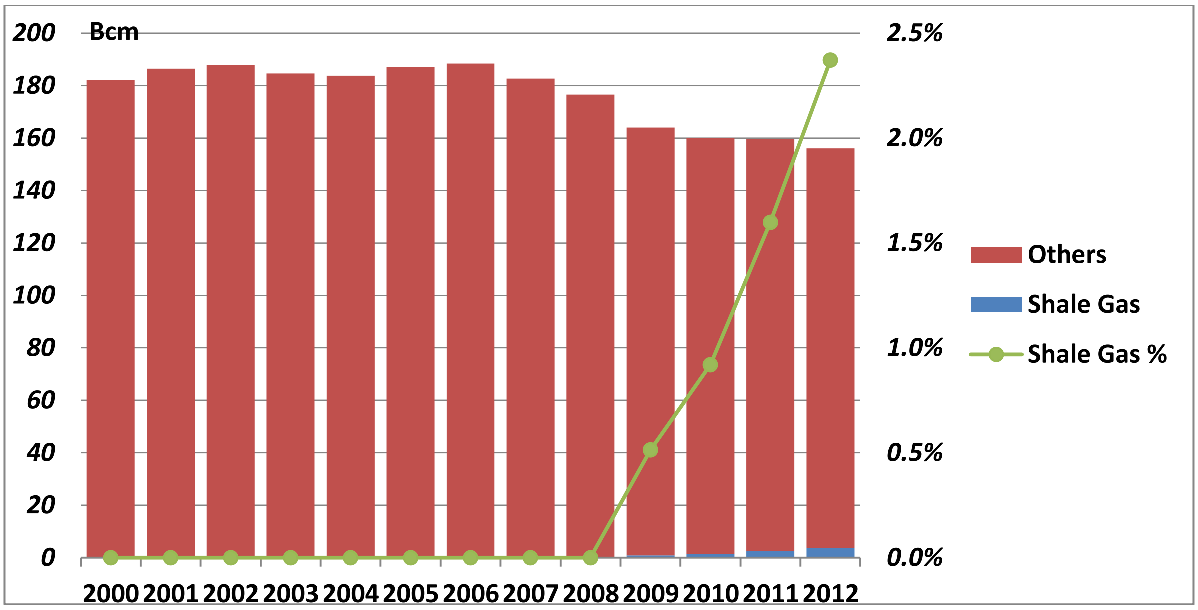
### (3) Impact of unconventional gas

**Volumes**

Currently, Canada NEB (National Energy Board) does not publish official statistics of shale gas production. Therefore, those figures are taken from IEA Unconventional Gas Database that contains production data of shale gas, tight gas, and CBM by country. However, it should be noted that this database is not actual record but only estimate by IEA based on various sources. Primary data source for this IEA DB is Rystad Energy.

As seen in the chart below, Canadian shale gas production started 2009 with 0.843Bcm, and then has slowly grown but still only 3.701Bcm in 2012, making 2.4% of overall natural gas production. As the percentage indicates, it is still too early to evaluate market impact of shale gas.

**Figure A-2-2 Natural gas production in Canada**




*Source: IEA, Unconventional Gas Database*

## (1) History

Although there is no large-scale commercial production of unconventional gas in South America yet, there are efforts being made to start and further develop the industry in some of the countries. The history of unconventional gas industry on the continent began in the mid-90's by drilling the first coal bed methane (CBM) test well in north-east Colombia, the country that produces more than 90 % of South American coal. According to local studies Colombia may hold up to 1 tcm (35,3 tcf) of CBM potential gas-in-place resources, but since the first test well no significant progress has been reported.

First commercial unconventional gas production in South America was achieved in September 2009 from Total-operated Aguada Pichana tight gas field in Neuquén basin in Argentina, but the volumes produced are low due to just few wells being drilled to date. Further development of Total's tight gas project in Neuquén Basin will substantially depend on improving gas pricing mechanisms, which are now state-controlled in Argentina with prices kept below fair market value of natural gas.

**Table A-3-1 Shale gas and shale oil technically recoverable resources (TRR) in South America according to EIA reports (2011, 2013)**

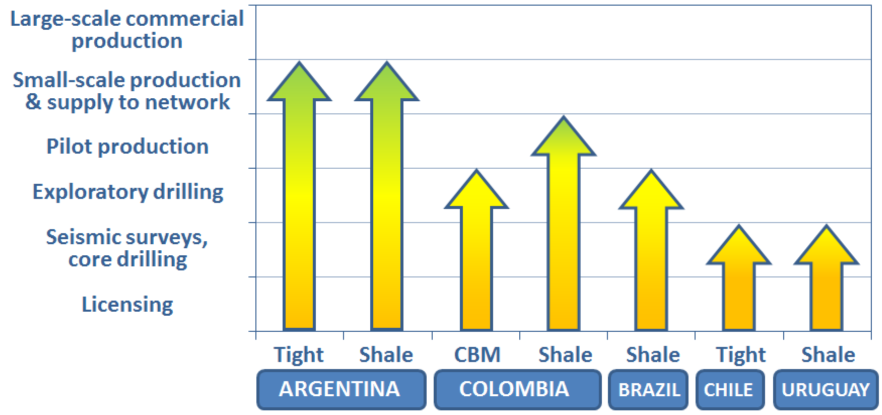
| # | Country | 2011 EIA report | 2013 EIA report | | | | **Shale gas TRR revision, EIA 2013/2011** | |
|---|---|---|---|---|---|---|---|---|
| | | TRR, tcm | TRR, tcm | Share in South America | Share globally | Shale oil TRR, bbl | Volume, tcm | Percentage |
| 1 | Argentina | 21,9 | 22,7 | 56,1 % | 11,0 % | 27,0 | +0,8 | +3,6 % |
| 2 | Brazil | 6,4 | 6,9 | 17,1 % | 3,4 % | 5,3 | +0,5 | +8,4 % |
| 3 | Venezuela | 0,3 | 4,7 | 11,7 % | 2,3 % | 13,4 | +4,4 | +1418 % |
| 4 | Paraguay | 1,8 | 2,1 | 5,2 % | 1,0 % | 3,7 | +0,3 | +21,0 % |
| 5 | Colombia | 0,5 | 1,6 | 3,9 % | 0,7 % | 6,8 | +1,1 | +189,5 % |
| 6 | Chile | 1,8 | 1,4 | 3,4 % | 0,7 % | 2,3 | -0,4 | -25,0 % |
| 7 | Bolivia | 1,4 | 1,0 | 2,5 % | 0,5 % | 0,6 | -0,4 | -25,0 % |
| 8 | Uruguay | 0,6 | 0,1 | 0,1 % | 0,0 % | 0,6 | -0,5 | -90,5 % |
| **South America total** | | **34,7** | **40,5** | **100,0 %** | **19,6 %** | **59,7** | **+5,8** | **+16,7 %** |

As for shale gas, exploration drilling started in 2010 in the above-mentioned Neuquén basin in Argentina (considered to hold both tight and shale gas resources), followed in 2011 by Colombia and Brazil tapping their Middle Magdalena and São Francisco basins respectively. Although some positive well testing results have been initially reported, most of the operators have subsequently shifted their focus from gas to oil being attracted by its more market-friendly pricing. At present some pilot projects are underway in Argentina and Colombia, but the large-scale production of shale gas in South America may be challenging given the existing geological, infrastructural and market limitations.

According to recent study published by EIA in 2013, South America holds some 20 % of world's TRR of shale gas (and about one sixth of shale oil global TRR). These resources are allocated unevenly with a bulk, more than 40 % of total South American shale gas TRR, granted to Argentina's Neuquén basin. A detailed breakdown is presented in Table 1.

The current state of unconventional gas industry development in South America split by countries and types of resources is shown on graph below. As there is no unconventional gas activity reported in Venezuela, Paraguay and Bolivia, these countries are out of scope of further analysis.

**Figure A-3-2 Current state of unconventional gas development in South America**




- None of the unconventional gas projects in South America have reached the scale that would represent commercial development; nevertheless, there is already some small-scale tight gas and shale gas production in Argentina from Vaca Muerta and Los Molles formations of the Neuquén basin with unconventional gas being supplied to consumers via local pipeline network.
- The degree of state support and ability to attract foreign investment and expertise are essential for the development of unconventional gas industry in South America. Key national oil companies (NOCs) and international supermajors, so-called «Big Oil» companies, involved in unconventional gas exploration and production (E&P) in the above-mentioned countries are listed in table below.

**Table A-3-2 Key companies involved in unconventional gas E&P in South America**

| # | Country | NOC | International supermajors |
|---|---|---|---|
| 1 | Argentina | YPF | Chevron, ExxonMobil, Shell, Total |
| 2 | Colombia | Ecopetrol | ConocoPhillips, ExxonMobil, Shell |
| 3 | Brazil | Petrobras | Shell |
| 4 | Chile | ENAP | - |
| 5 | Ururguay | - | Total |

### (2) Factors which Influence the Future of Unconventional Gas in South America

**Argentina**

Argentina is the most prominent Latin American country in the unconventional gas development. Neuquén basin is a mixture of tight sandstone and shale, so it has production potential of both tight and shale gas. Its shale gas potential has been reported as the most prospective area in Latin America.

Development of Neuquén basin has been progressed slowly due to volatile politics and low gas prices. Gas Plus Program, a new pricing policy which was announced in December 2010, provided opportunities for gas producers and boosted investments. It allows producers to lift their gas prices higher than regulated price if their production is from unconventional basins.

Until now, there have been several short-term contracts between producers and CAMESA, the national power generator with reportedly higher prices than regulated one. There is no long-term contract under Gas Plus scheme yet.
Baker Hughes, one of the top service companies, completed its first Argentine shale gas well with multistage hydraulic fracturing operations in July 2011. It was an important signal of retake-off of the development of the Neuquén basin. YPF reported in the annual report 2012 that it has completed several horizontal wells in Neuquén and has made 150 mmboe discovery in its Vaca Muerta formation.

| | |
|---|---|
| *Basins:* | Neuquén *(the most prospective)*; San Jorge; Austral-Magallanes; Parana. |
| *Drivers:* | High resource estimates; favorable geological characteristics; promising initial well results; existing pipeline infrastructure; moderate social concerns; high gas demand. |
| *Challenges:* | Difficult water sourcing and delivery; costly storage and disposal of produced water; limited access to services, equipment and manpower; improving but still low gas prices; concerns over government intervention; overall macroeconomic instability. |

**Colombia**

Unconventional gas industry in Colombia is just starting to speed up. But despite shortage of available geological data and some unsettled hydraulic fracturing regulation issues there is already a number of supermajor companies testing the Middle Magdalena Valley's shale oil and gas potential. One of the reasons of such an activity is unconventional hydrocarbons-friendly fiscal and investment climate; however, still remaining threat of guerilla attacks may limit the extent of further development.

| | |
|---|---|
| *Basins:* | Middle Magdalena Valley *(the most prospective)*; Llanos; Catatumbo; Cesar (CBM). |
| *Drivers:* | Existing pipeline infrastructure; fiscal incentives (royalty rates for unconventional gas are subject to 40 % discount); demand for additional gas supply. |
| *Challenges:* | Lack of geological data; regulatory framework for hydraulic fracturing is not established; difficult water sourcing; limited availability of proppant and fracking services; permitting may take up to 12 months; gas prices are low and regulated; fear of rebel activity. |

**Brazil**

According to EIA study, Brazil may have 14 basins prospective for unconventional oil and gas exploration, but the available public data is insufficient to assess the commercial potential of these resources. Recent activity demonstrates that looking for shale oil and gas in São Francisco basin may be the most reasonable option, although risky given just a few exploratory wells have been drilled by now.

It is interesting to note that some of the drivers and challenges for unconventional gas development in Brazil are generally opposite to those indicated for Argentina and Colombia: water sourcing is not expected to be a problem, proppant for hydraulic fracturing is sufficient and being exported to Argentina for operations in Neuquén basin, gas prices are relatively fair; on the other hand, the pipeline infrastructure is undeveloped and requires massive capital investments.

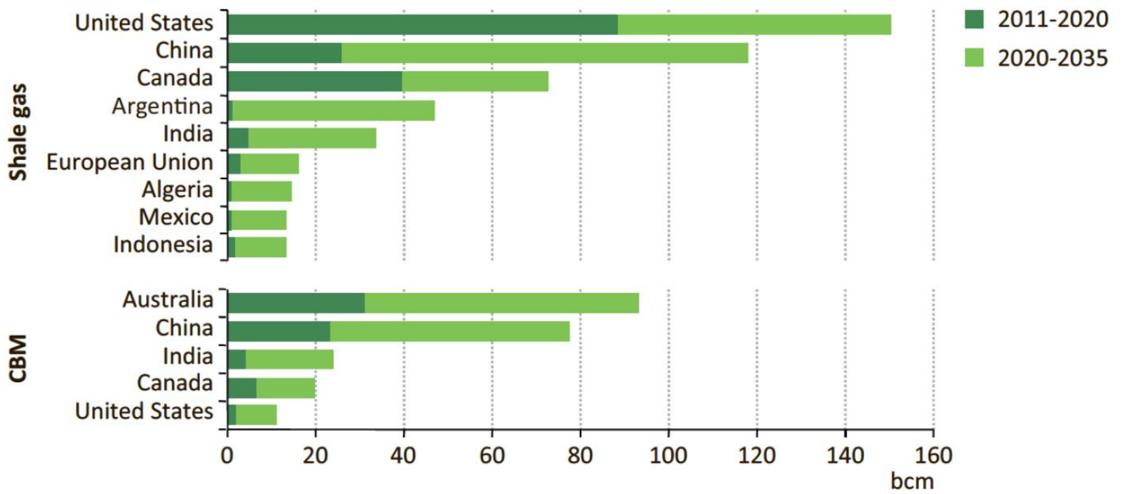
| | |
|---|---|
| *Basins:* | São Francisco *(the most prospective)*, Paraná, Solimões, Amazonas. |
| *Drivers:* | Gas prices are fairly high; abundant supply of fresh water and proppant for hydraulic fracturing; good road network; state and local government support (indigenous gas production may cut dependence on imports from Bolivia). |
| *Challenges:* | Exploration and well testing results are not disclosed; remoteness of available drilling rigs and special equipment; undeveloped pipeline infrastructure; lack of environmental regulations and fiscal incentives to encourage unconventional gas E&P. |

### (3) Impact of Unconventional Gas in South America

Given the complexity and natural origin of certain challenges denoted above, as well as lack of rigs for horizontal drilling and special equipment for hydraulic fracturing, it is unlikely that South America would be able to reach a large-scale commercial production of shale gas until the end of this decade.

International Energy Agency (IEA) within the scope of its World Energy Outlook 2013 anticipates growth of unconventional gas production as shown on graph below.

**Figure A-3-3 Growth of unconventional gas production by type in selected regions in the New Policies Scenario**

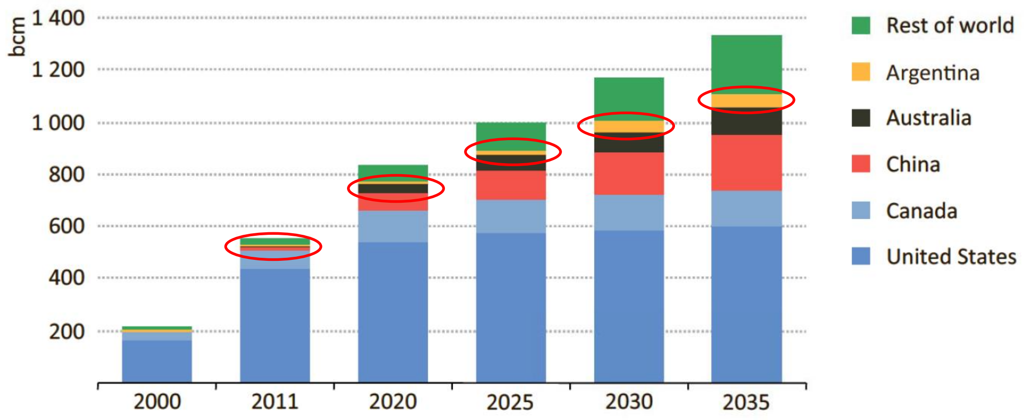



*Source: IEA, World Energy Outlook 2013*

Therefore the development of unconventional gas industry in South America, particularly in Argentina, is expected to result in some infrastructural, fiscal and environmental improvements, technological advancements and revaluation of current resource estimates. Significant increase in production of tight gas and shale gas in Argentina will take place after 2020 reaching up to cumulative 50 bcma by 2035. Large-scale production of CBM in South America is not anticipated until 2035.

A five-year breakdown of IEA's unconventional gas production forecast is shown on graph below.

**Figure A-3-4 Unconventional gas production by selected country in the New Policies Scenario**




*Source: IEA, World Energy Outlook 2013*

To sum up the analysis of implications of developing unconventional gas in South America there are four key-notes that should be emphasized:

- firstly, the most prospective country for developing unconventional gas in South America is considered to be Argentina;
- secondly, there are some challenges that are expected to shift unconventional gas production growth in Argentina to the period of 2025-2035;
- thirdly, no large-scale unconventional gas production is forecasted in Colombia, Brazil and other South American countries (despite having the resource potential according to EIA).

# B. Asia Pacific

## Introduction

This section aims to:

- Identify the supply potential and characteristics for unconventional natural gas resources in the Asia-Pacific region.
- Analyse changes in government policies, energy mixes and business strategies in countries in the region with abundant unconventional gas resources.
- Identify the issues and challenges in relation to developing unconventional natural gas
- Analyse the potential impact on the gas supply demand balances in the region from Asia Pacific unconventional gas development together with the regional impact of global unconventional gas development (primarily in North America).

Unconventional gas (UCG) is defined to include Coal Bed Methane (CBM), shale gas and tight gas (essentially any gas produced from continuous reservoirs).

The section starts by considering the implications of North American developments generally for the regional demand and supply balance and then the unconventional gas development progress and potential in Australia, China, India, Indonesia, Japan and Russia and the implications of North American unconventional gas development for Japan.

## 1. North American developments

North American UCG development is already having a significant impact in the Asia-Pacific region and is likely to have an even bigger impact in future.

North American success with CBM and shale gas has stimulated activity in the region to see whether it is possible to replicate this success. Critical success factors for UCG development, largely in place in North America, include:

- suitable geology
- an appropriate and attractive fiscal regime
- political support
- access to infrastructure
- ease of land access
- a large and diverse population of risk-taking independent oil companies
- oil-field services capacity
- avenues to profitable commercialisation

The greatest success with UCG development in the region so far has been achieved with CBM in the Australian state of Queensland, where most of these factors apply. Queensland CBM is the basis of the three LNG projects under construction to supply Asian markets.

Notwithstanding having substantial volumes of gas in place, UCG development has not proceeded as quickly in China, India or Indonesia due to the absence of other critical success factors.

Beyond UCG development in the region, North American UCG is already having indirect impacts on the Asia-Pacific gas market through LNG.

As a result of US UCG development, the US has not developed as an LNG importer in the way expected by major producers. The switch from coal to cheap gas in US power generation has also boosted US coal exports to Europe, reducing demand for gas, including LNG. (Lower gas demand has also been driven by the recession and rise of renewables.) The end result has been increased LNG flows to the Pacific, where demand was boosted by the 2011 Great East Japan Earthquake, together with growing LNG demand in other countries such as China.

The fall in European gas demand has also been a factor in Russia finalising the agreement to supply pipeline gas to China.

Further to these developments, the US is now poised to become a major LNG exporter, based on low Henry Hub gas prices reflecting the shale gas revolution. While the magnitude of US exports is still uncertain, there is no doubt that US LNG is attractive to Asian buyers. The US projects are stalling other LNG project proposals that would require oil-linked pricing. This includes Gorgon Train 4 in Australia and Kitimat and Pacific Northwest in Canada.

Alongside the US shale gas revolution has been the shale oil revolution, dramatically increasing US oil production. This is now impacting global oil prices, with substantial falls expected in the price of LNG imported by Asian buyers under oil-linked contracts. This may also discourage UCG development in the region if gas is sold on an oil-linked basis or if UCG is liquids-rich.

## 2. Australia

Australia has the most highly developed unconventional gas resource in the Asia-Pacific region in the form of CBM in the state of Queensland.

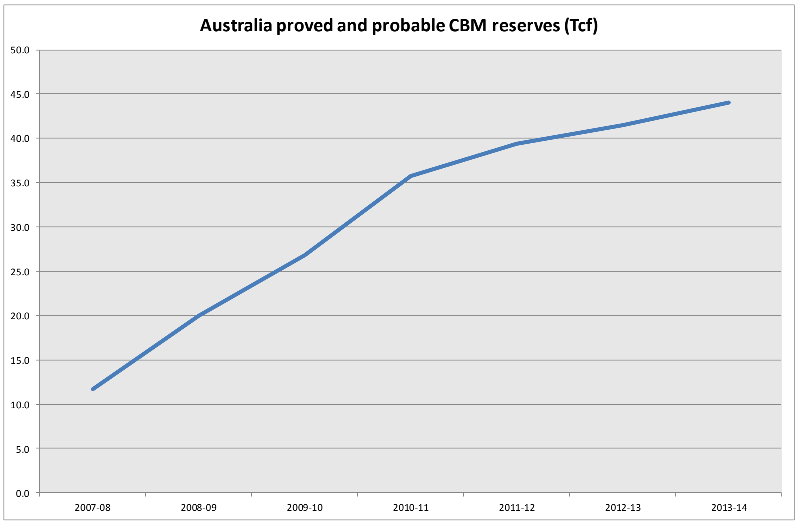
In 2013-14 production reached 252 Bcf (7.1 Bcm), all for domestic use, and proved and probable reserves reached 44.1 Tcf (116 Bcm). Three LNG projects based on CBM are currently under development, which will lead to a six-fold increase in production to around 44 Bcm pa . Shale/Tight gas is at a very early stage. While there is substantial potential there are only two producing wells. However there is exploration underway in the Cooper, Canning and Perth basins and in the Northern Territory.

### (1) CBM supply potential

Over the last six years proved and probable CBM reserves have increased nearly four-fold (**).**

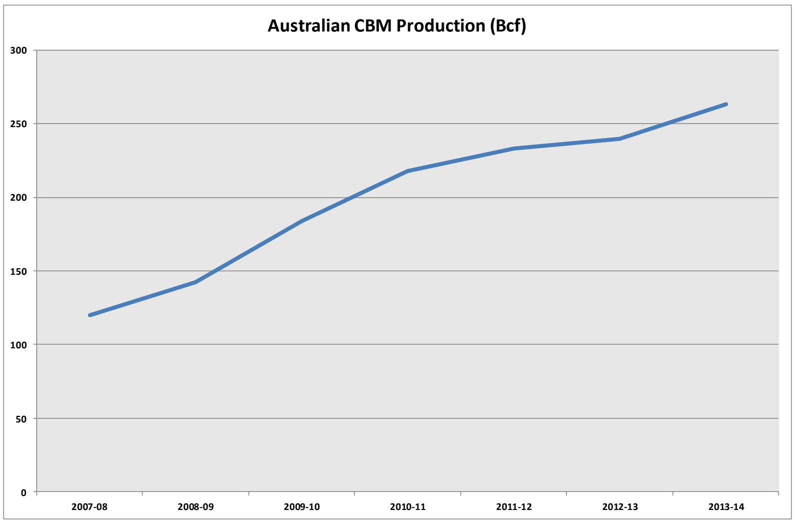
**Figure B-2-1**).

**Figure B-2-1 Australian proved and probable CBM reserves, June 2008 to 2014 (Tcf)**




*Source: EnergyQuest*

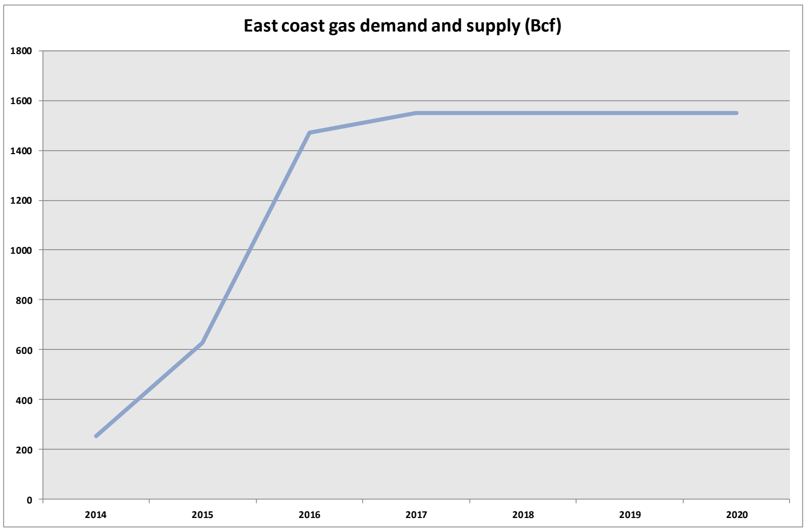
**Figure B-2-1 Australian CBM production 2007-08 to 2013-14 (Bcf)**




*Source: EnergyQuest*

Production has more than doubled (Figure B-2-1) and is expected to increase six-fold when all LNG projects are in production (Figure B-2-2).

**Figure B-2-2 Australian CBM production outlook 2014 to 2020 (Bcf)**



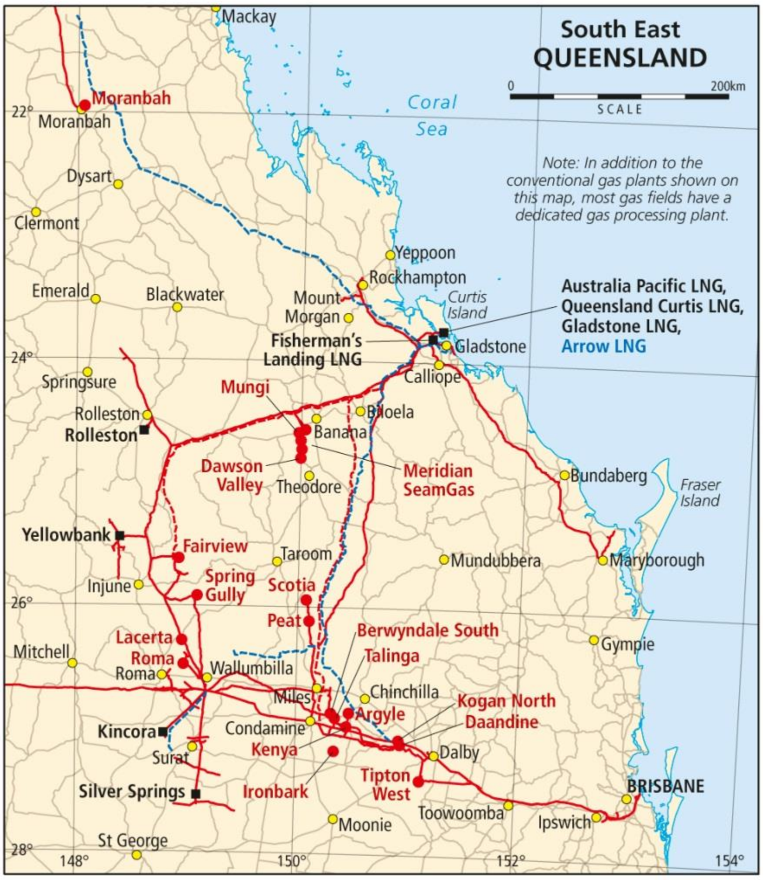

*Source: EnergyQuest*

### (2) CBM LNG projects

There are three CBM LNG projects under construction, all in Queensland: GLNG, QCLNG and APLNG (Figure B-2-3). These are the world's first CBM to LNG projects. All of the projects have substantial requirements in field development: typically around 6,000 wells to be drilled over the life of a two-train project and over 10,000 km of gas and water gathering lines to be laid plus compression, gas plants and multiple reverse osmosis water treatment plants. In addition each project has one or more 400-500km 42 inch gas transmission pipelines and two LNG trains. There are also substantial infrastructure requirements, notably one of Australia's largest harbor dredging projects.

The LNG plants for the three projects are being built on Curtis Island in Gladstone.

**Figure B-2-3 Queensland CBM LNG projects**




*Source: EnergyQuest*

QCLNG was the first CSG LNG project sanctioned, in October 2010. It is operated by QGC, a subsidiary of BG Group, with CNOOC and Tokyo Gas interests. The 8.5 million tonne per annum (Mtpa) two-train project achieved first LNG in early January 2015 (Figure B-2-4). BG has sales agreements with Tokyo Gas, Chubu Electric, GNL Quintero Chile, Singapore Power Gas and

CNOOC. The cost has increased from US$15 billion net to US$20.4 billion. Around half of the increase is due to changes in exchange rates. The remainder primarily reflects higher costs for the upstream and pipeline components of the project. The project will source its gas primarily from QGC's fields in the Surat Basin.

GLNG was the first CSG to LNG project to be announced, in July 2007, and was sanctioned in January 2011. The cost of the two train 7.8 Mtpa LNG project has increased from US$16 billion to US$18.5 billion. First LNG is planned for the second half of 2015. The interest holders are Santos 30%, Petronas 27.5%, Total 27.5% and Kogas 15%. The project includes the development of CSG resources in the Fairview field in the Bowen Basin and Roma fields in the Surat Basin, supply of 700 Bcf of conventional gas from the Cooper Basin, construction of a 420km gas transmission pipeline to Gladstone and two LNG trains on Curtis Island. GLNG has binding LNG sales agreements with Petronas and Kogas for 7 Mtpa in aggregate.

**Figure B-2-4 loading of first QCLNG cargo, January 2015**

*Source: QGC*

APLNG is a joint venture between ConocoPhillips, Origin Energy and Sinopec. In July 2011 it sanctioned the first train and in July 2012 the second train of the two train 9 Mtpa project, with first LNG in 2015. Sinopec has offtake agreements for 7.6 Mtpa and a 25% interest in the project. Kansai Electric also has an offtake agreement. Total capital expenditure for the project is estimated to be US$20 billion for the period from final investment decision (FID) until the commencement of gas deliveries from Train 2, expected in early 2016. Upstream development is based on APLNG's Surat Basin fields with a 530km pipeline to Gladstone, where construction of the LNG plant is well underway.

### (3) CBM market environment

Australia is one of the world's major coal exporters and hence it was natural to assess the country's CBM potential. In the 1980s and 1990s there was interest by large international companies (Conoco and Amoco), following on from CBM development in the US. However this was largely unsuccessful. The coals targeted were those with high gas content but had low permeability.

Subsequently smaller US and Australian companies identified sweet spots and began to develop small scale production projects. This was facilitated by a Queensland government policy requiring at least 13% of power to be generated by gas. In the early to mid-2000s larger Australian gas companies (Origin Energy and Santos) also acquired CBM interests. It was soon realised that the potential size of the CBM resource was much greater than could be commercialised in the domestic gas market and companies began to look at LNG export options. This led to

PETRONAS and KOGAS joining forces with Santos (GLNG), BG taking over QGC (QCLNG) and ConocoPhillips joining forces with Origin Energy (APLNG). Overseas companies were attracted by the presence of a large uncommitted gas resource in an OECD country in the Asia-Pacific region.

Australia welcomes foreign investment in a free market economy. The federal government and the Queensland government have been keen to encourage gas development for both domestic and export purposes. Wholesale gas prices are not regulated and companies are free to export.

### (4) CBM development issues and challenges

While eastern Australia has more than adequate CBM resources to meet demand, ensuring sufficient deliverability to keep six LNG trains full is a major technical challenge, involving management of thousands of wells plus hundreds of megalitres of associated water (and the resulting salt from water treatment). Companies need to drill more wells than originally expected and extend their drilling to areas of lower productivity.

Development of three major projects simultaneously has created challenges in securing labour, in logistics and in controlling costs.

The CBM LNG developments are located in populated areas, a first for the LNG industry in Australia. Historically, most Australian gas development has either been offshore or in remote onshore areas. While all the projects undertook extensive community consultations and environmental impact statements prior to approval, the massive scale of development was not fully anticipated and has created tensions with some farmers and local communities, which companies have had to address. Australia has a fiercely competitive political climate, with political parties constantly jostling for power and numerous interest groups keen to express their views.

There are also inevitable uncertainties about the environmental impact of such massive developments, particularly on agriculture. Potential CBM environmental impacts include impact on groundwater, disposal of saline water, impact on vegetation, traffic and noise, greenhouse emissions.

The degree of environmental regulation has increased over the life of the LNG projects, increasing costs.

While CBM development is going ahead in Queensland, it has almost ground to a halt in NSW due to opposition by land owners and environmental groups. Like Queensland, NSW has substantial CBM resources but there is little prospect of these being developed, notwithstanding the fact that the state is likely to face a gas shortage as a result. Similarly there is a moratorium on onshore gas development in Victoria such that it is difficult to assess whether or not the state has substantial onshore gas resources.

Opposition to gas development in NSW and Victoria has tended to focus on fracking, notwithstanding the fact that fracking has been employed onshore Australia for many years and only a small proportion of CBM wells are fracked.

The growth of LNG, based on CBM has raised concerns about domestic gas availability and price. Most Australian domestic gas is sold under long-term bilateral contracts indexed to inflation. While retail gas prices are regulated in some states, the domestic wholesale gas price is set by the market. Historically domestic gas prices have been US$3-4/Mmbtu but are now increasing to US$6-9/Mmbtu due to the pressure of LNG demand and rising production costs. Some domestic contracts are also being linked to oil prices.

Domestic gas-users have expressed concerns about gas price rises, potential oil indexation (prior to the fall in oil prices) and lack of availability of new contracts and have called for reservation of a percentage of gas for domestic use. This has not been accepted by either the federal or east coast state governments.

### (5) CBM market impacts

CBM development initially led to a jump in the size of east coast gas reserves and supply of cheap gas for power generation.

The development now of LNG means that CBM will not only be supplying local markets but also Japan, Korea, China, Singapore and Malaysia. Altogether the CBM LNG projects have 24.0 Mtpa contracted to Asian buyers, 11.2 Mtpa to China, 3.6 Mtpa to Malaysia, 3.6 Mtpa to Korea, 3.0 Mtpa to Singapore and 2.6 Mtpa to Japan.

The growth in CBM for LNG however has tightened the domestic gas market.

### (6) Potential for shale and other unconventional gas

While Australia has substantial resources of conventional gas and CBM, it is also believed to have substantial shale gas potential in the Cooper, Canning, Georgina, Maryborough and Perth basins. The 2013 study carried out for the US Energy Information Administration by Advanced Resources International estimates that Australia may have over 400 Tcf (11,330 Bcm) of risked recoverable shale gas resources (EIA, 2013). There is also potential for tight gas and other forms of unconventional gas.

The EIA report suggests that, of the six Australian basins assessed, the Cooper Basin, Australia's main onshore gas-producing basin, with existing gas processing facilities and transportation infrastructure, could be the first commercial source of shale hydrocarbons. The Basin's Permian-age shales have non-marine (lacustrine) depositionals and the shale gas appears to have elevated $CO_2$ content, which adds to risk. Companies operating in the Cooper Basin (Santos, Beach, Origin Energy and Senex) have booked 5 Tcf (142 Bcm) of shale and other unconventional 2C resources. There are now two wells in production and companies are drilling and fracturing the first horizontal wells. The Cooper Basin also has potential in basin centred gas and deep coals.

The Perth Basin in Western Australia has prospective marine shale targets of Triassic and Permian age. There are also tight gas resources. AWE has recently announced a 360 Bcf (10 Bcm) tight gas discovery.

The large Canning Basin in Western Australia has deep, Ordovician-age marine shales that are roughly correlative with the Bakken Shale in the Williston Basin in the US.

In Northern Territory, the Pre-Cambrian shales in the Beetaloo Basin and the Middle Cambrian shale in the Georgina Basin have reported oil and gas shows in shale exploration wells. Origin Energy and Sasol have farmed into the Beetaloo Basin and Statoil is undertaking a drilling program in the Georgina Basin, with oil shows. Santos is drilling in the McArthur Basin and Total has farmed into the southern Georgina Basin.

### (7) Shale gas market environment

There is significant company interest in shale and other unconventional gas in Australia. The increase in domestic gas prices can drive activity in basins accessible to the domestic gas market. Elsewhere any liquids-rich discoveries could spur development of associated gas.

Opposition to fracking is an issue in NSW and Victoria and there have been inquires into fracking in the Northern Territory and Western Australia, but without ultimately inhibiting development. The South Australian and Queensland governments are encouraging unconventional gas development.

In its 2013 Global Petroleum Survey, the Fraser Institute (2014) ranks South Australia, the Northern Territory and Western Australia in the second quintile globally for their investment climate for upstream petroleum development. Queensland has slipped to third quintile reflecting increased regulation.

### (8) Shale gas development issues and challenges

There are significant challenges to development of other unconventional gas. In the Cooper and Perth basins exploration can build on previous drilling results. They also have existing infrastructure and access to markets. However the other basins of interest cover vast areas with relatively little historical drilling data. Distances are also a challenge for mobilising drilling rigs and frack spreads. Australia only has a limited number of drilling rigs and frack spreads.

### (9) Shale gas market impact

Shale and other unconventional gas is unlikely to have any major market impact before 2020.

# 3. China

## (1) CBM supply potential

Liu (2012)[1] quotes Chinese CBM reserves no deeper than 2,000 m as 388 Tcf (11,000 Bcm), the world's third-largest CBM resource.

BP estimates Chinese gas production in 2013 as 4.1 Tcf (116 Bcm) and consumption as 5.7 Tcf (161 Bcm). Consumption is expected to grow to 12-14 Tcf (340-400 Bcm) by 2020.

There are various estimates of Chinese unconventional gas production, but they generally suggest that it is modest. The EIA (2014a) quotes 2012 CBM production as 441 Bcf (12.5 Bcm) from both surface wells and coal mines, with a target of 700 Bcf (20 Bcm) by the end of 2015. However China produces more CBM than it uses, with significant waste. Natural Gas Asia[2] quotes the Ministry of Land and Resources (MLR) estimates of 2013 CBM production (utilised) of 106 Bcf (3 Bcm). China is aiming to increase the utilisation rate from 40% to 60% by the end of 2015.

According to the EIA ( (2014a), China's first commercial CBM pipeline became operational in late 2009, linking the Qinshui Basin with the West-to-East pipeline. Two additional long-distance pipelines have become operational, and several more are under construction. China also uses many small liquefaction plants and trucks to transport CBM to demand centres.

## (2) CBM market environment

China is encouraging use of gas to reduce pollution. Domestic gas is also cheaper than imported gas. Utilisation of coal mine methane also reduces coal mine risks. Domestic gas prices are also being increased to encourage development of domestic supplies. Liu (2012) lists the fiscal incentives that were in place for CBM development as of 2012.

Chinese CBM development is dominated by two state-owned companies, China United Coal Bed Methane Corporation (CUCBM, jointly owned by China Coal and CNOOC) and CNPC. These companies partner with private companies, both local and foreign.

## (3) CBM development issues and challenges

According to the EIA ( (2014), although CBM production is increasing, company developers face regulatory hurdles, technical challenges, a lack of pipeline infrastructure from coal mining areas to gas markets, and high development costs. At times, there are conflicting interests between governing bodies when dealing with mineral and land rights. The local governments hold rights to coal mines, whereas the central government has rights to natural gas and CBM. China's State Council issued a policy guideline in September 2013 encouraging investment in CBM exploration and development and more pipeline infrastructure through financial incentives and tax breaks to producers and reform of local price controls.

## (4) CBM market impact

The Chinese market environment is positive for CBM development with a strong demand for gas, rising gas prices and government encouragement. China also has a long history of coal development and substantial CBM resources. However CBM production is still only modest at less than 3% of domestic gas production (and less than half that of Australia in absolute terms)

[1] https://www.iea.org/media/weowebsite/workshops/goldenrules/Xiaoli_LIU.pdf

[2] http://www.naturalgasasia.com/chinas-2013-shale-gas-output-stood-at-200-mcm-11454

and CBM production has consistently lagged official targets. In addition to the challenges listed above, one possible explanation is that development is effectively monopolised by CNPC and the state companies that own CUCBM and that CBM is not the highest priority for these companies[3]. The record so far suggests that, despite ambitious targets, CBM's contribution to Chinese gas production is likely to remain modest.

### (5) Potential for shale and other unconventional gas

According to the EIA ( (2013), China has an estimated 1,115 Tcf (31,600 Bcm) of risked, technically recoverable shale gas, the world's largest shale resource, mainly in marine- and lacustrine-deposited source rock shales of the Sichuan (626 Tcf), Tarim (216 Tcf), Junggar (36 Tcf), and Songliao (16 Tcf) basins. Additional risked, technically recoverable shale gas resources totalling 222 Tcf exist in the smaller, structurally more complex Yangtze Platform, Jianghan and Subei basins. The risked shale gas in-place for China is estimated at 4,746 Tcf (134,500 Bcm).

Resource estimates from other sources are lower. In 2012 the MLR reported total shale gas technical reserves of 883 Tcf (25,000 Bcm).

The EIA (2014a) quotes 2012 shale gas production of 1.8 Bcf (51 MMcm). Natural Gas Asia quotes 2013 shale gas production of 9.7 Bcf (276 MMcm). The government had a target of 230 Bcf (6.5 Bcm) by the end of 2015 and at least 2,100 Bcf (59 Bcm) by 2020. However the 2020 target has now been slashed to 1,050 Bcf (30 Bcm), approximately 8% of forecast 2020 gas demand. This is still ambitious at 108-times more than current production. China's shale resources are mostly deeper than those in the US and have more clay so are more difficult to frack. Some of the biggest resources are in regions, such as Sichuan province, that have seismic activity and suffer from water shortages.

One recent positive development is Sinopec's Fuling project in south-west China, which produced 4.5 Bcf in 2013 and by April 2014 was producing at 94 million cubic feet per day (IEA, 2014a). Sinopec has drilled 79 horizontal shale gas wells in Fuling since 2012 and has put 27 into production[4]. The company has built nearly 35 Bcf per annum of production capacity at the field, which has proven reserves of 3.7 Tcf.  Output from a single well has reached 3.5 million cubic feet per day. Sinopec plans to invest US$3.4 billion to drill 253 wells from 2013 to 2015 (averaging US$13.6m per well) and expects to produce more than 35 Bcf this year and around 120 Bcf next year.

The IEA believes that the revised shale gas target is achievable. More than 150 shale gas wells have been drilled in China as of early 2014 and about one third of them are horizontal wells. More than 70% of the horizontal wells have been connected to the network. More pipelines and other infrastructure are under construction in Sichuan and will be finished before 2015.

### (6) Shale gas market environment

According to the EIA (2014a) CNPC and Sinopec own almost 80% of China's shale gas resources. China's national oil companies (NOC) are in discussion with several foreign companies for partnering on potential shale gas projects in order to gain necessary technical skills and investment for developing these geologically challenging resources. CNPC and Shell signed the first PSC for the Fushun-Yonghchuan block of shale gas in the Sichuan Basin in March 2012. Shell also has partnered with Sinopec and CNOOC on two other shale gas plays. After investing $950 million between 2011 and 2013 on shale gas exploration in China, Shell plans to spend another $1 billion each year for the next five years to develop these resources. Sinopec is working with Chevron and ConocoPhillips to explore shale gas resources in the Qiannan and Sichuan basins, respectively.

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[3] This point is made by Holly Morrow of the Harvard Kennedy School in work-in-progress on unconventional energy; lessons learned from around the world.

[4] http://interfaxenergy.com/gasdaily/article/13614/china-preparing-to-unveil-third-shale-gas-auction

Policy uncertainties include future liberalisation of prices and third-party access which are also important factors, along with the absence of a single set of detailed rules to regulate shale gas activity.

According to a JP Morgan report (Darling, 2014), gas from Fuling has been sold as LNG for public transport at US$12/Mcf.

China held its first shale gas licensing round in 2011 for four blocks in the Sichuan Basin and awarded the tenders to two Chinese companies, including Sinopec and Henan Coal. Tendering is available not only to NOCs but also to private and local companies, and foreign investors may participate indirectly if they hold a PSC contract with a participating Chinese firm. The State Council released shale gas from the jurisdiction of the NOCs, allowing the MLR to open a larger second bidding round in mid-2012. The MLR awarded 19 blocks to 16 domestic companies, mostly to coal producers, power companies, and local energy firms. Since these companies have limited shale gas experience and the capital required for such projects, they may partner with China's larger state-owned companies or foreign companies.

According to the IEA (2014a), another tender for shale gas was to take place in late 2014, after having been delayed from December 2013, but had not taken place as of January 2015. The blocks to be offered were located in Sichuan, Chongqing and Hubei. As the three incumbents hold rights to the most lucrative shale gas blocks, the MLR is envisaging having the companies relinquish the blocks in order to reoffer them during the tender.

This tender would have been the third, after a first in 2011 and a second in 2012. A progressive opening to a wider range of companies has been observed as the government wishes to develop its shale gas resources quickly. While the first tender was restricted to six state-owned companies, the second was open to private companies and foreign joint ventures as well as state-owned enterprises.

The new regulations issued in 2013 to further develop Chinese shale gas include subsidies and tax incentives. The government will offer subsidies of CNY 0.4/m3 (US$ 2/MMBtu) for shale gas, and the subsidies categorise shale gas as a special type of mineral. The current wellhead cost of shale gas in Sichuan is estimated to be close to US$ 10/MMBtu (IEA, 2014a).

### (7) Shale gas development issues and challenges

According to Liu (2012), shale gas challenges include:

- Pressure on the demand for water resources.
- Underground water protection
- Water recycling and utilisation
- Waste treatment and waste disposal
- Pressure on land acquisition and land lease fees
- Restrictions on mining in forests and hills/alteration and destruction of eco-systems

More than 60% of China's shale resources are in areas facing high water stress or arid conditions.

### (8) Shale gas market impact

Substantial effort is currently going into development of China's shale gas resources. While early targets are now seen to be too ambitious, companies are achieving successes such that by 2020 shale gas is expected to supply a material although modest component of the much higher levels of gas demand expected.

# 4. India

## (1) Supply potential

India has significant recoverable shale gas and CBM potential. However development so far has been limited.

It has the world's fourth largest coal reserves and estimated CBM resources of 92 Tcf (2,600 Bcm) (JP Morgan, 2014). However a large amount of this remains undiscovered, with production not expected to exceed 50 Bcf (1.4 Bcm) per annum.

India's potentially technically recoverable shale gas reserves are estimated to be 96 Tcf (272 Bcm) (EIA, 2013). Most of India's unconventional gas potential is concentrated in the Cambay Basin, which is located in Gujarat—the Indian region with the most developed gas midstream infrastructure. Additional shale gas potential in the Krishna-Godvari Basin will be able to take advantage of infrastructure built recently to move offshore gas to market.

## (2) Market environment

India remains significantly short of domestic gas supply, with the shortfall being met by LNG imports. According to BP India produced 1.2 Tcf (34 Bcm) in 2013, with demand of 1.8 Tcf (51 Bcm).

India's gas consumption is projected to grow at about 1.6% per year through 2020, from about 6 Bcf per day in 2013. However, latent demand is strong—consumption has been limited by the availability of domestically produced gas, with some potential demand simply going unmet. LNG imports are on the increase and serve those sectors that can afford to pay global market prices for gas. Meanwhile the residential and commercial sector makes up only about 3–4% of gas consumption, though this sector should grow as a result of plans to expand urban gas distribution.

India ranks in the fourth quintile in the 2013 Fraser Institute survey of the investment climate for upstream petroleum development (Fraser Institute, 2014)).

India has organised five CBM rounds since 2002 (the last one was launched in December 2013), and despite interest from some companies, results have been disappointing in terms of production per well according to the IEA (2014a). The IEA believes that CBM production is unlikely to reach even a few billion cubic metres by the end of the decade.

After a few years of discussion, India finally issued a policy on shale gas in late 2013, whereby it authorised its NOCs to explore shale resources from onshore blocks awarded to them before the New Exploration Licensing Policy (NELP) started in 1999. ONGC will take up 175 blocks, Oil India will do it in 15 blocks in three assessment phases of up to three years each. Royalty and taxes will be payable on par with conventional oil/gas being produced from the respective areas. In a second stage, the government plans to offer shale gas (and oil) blocks to other (private) companies through another Cabinet approval, but the decision shows a preference towards NOCs. As in the case of conventional gas, international oil companies may remain relatively absent from India's unconventional scene. ONGC announced that 30 shale gas wells would be drilled over the next two years, while the company also signed an agreement with ConocoPhillips in 2013 to undertake shale gas exploration. The IEA believes that the shale gas industry in India is likely to remain in its infancy over the remainder of the decade.

At the moment gas prices in India are too low to stimulate unconventional gas production. According to Interfax[5], the government implemented a long-awaited gas pricing formula on 1 November 2014 that increased the wellhead price from $4.20/MMBtu to $5.61/MMBtu (based on the gross calorific value). However, that price is expected to fall to $5/MMBtu by the end of 2017, which will cut margins for gas producers even as their costs rise. Indian gas prices are among the lowest in the region. This, along with uncertain prospects in largely unexplored basins, reduces

[5] http://interfaxenergy.com/gasdaily/article/14351/indian-price-hike-will-fail-to-kickstart-power-plants

the attractiveness of India as a future E&P destination. Prices in China, Thailand, the Philippines and Indonesia range between $8.20-11.90/MMBtu. Prime Minister Narendra Modi's price reform is a more moderate version of the measure the previous government had planned to implement, which would have raised the price to around $8.40/MMBtu from 1 April and been revised every quarter.

### (3) Development issues and challenges

Land acquisition is difficult, with economic rights to resources not lying with landowners. Competition for water resources is high. The interests of numerous water users, including communities and local municipalities need to be taken into account.

### (4) Market impact

Unconventional gas is not likely to have a material impact on Indian gas production over the remainder of this decade. Indian companies have been active securing offtake agreements from US LNG projects (7.3 Mtpa) with pricing linked to Henry Hub to reduce the cost of LNG imports.

# 5. Indonesia

## (1) CBM potential

Indonesia has one of the world's largest CBM resource bases. According to ARI, gas initially in place (GIIP) stands at 453 Tcf (12,800 Bcm). The four largest and most prospective basins are South Sumatra (183 Tcf), Barito (102 Tcf) Kutai (80 Tcf) and Central Sumatra (53 Tcf). The Barito and Kutai basins are both located in Kalimantan. One CBM play in South Sumatra is considered to have high potential. However Santos has recently exited its acreage in South Sumatra due to poor permeability and the unattractiveness of the fiscal regime for CBM.

Drilling costs are high, PSC terms are not suitable for CBM development and the regulatory environment is not suitable for the manufacturing-style development necessary for CBM.

## (2) Shale gas potential

Indonesia has estimated shale gas resources of 574 Tcf (16,300 Bcm).

The major geological risk for shale gas plays in Indonesia is their young geological age and, associated with this, their relatively low maturity for gas generation. Of the 31 shale gas plays, six are considered to have both low risk and high potential; these six plays contain 43% of the total GIP resources.

Three shale gas plays on Sumatra—the Bampo Shale, the Brown Shale, and the Talang Akar Shale—are of high potential and contain a quarter of the country's total in-place resources.

The Barito Tanjung Shale on Kalimantan and the Aifam Shale on West Papua show similarly high potential, with the latter exhibiting the highest gas richness.

## (3) Unconventional resource development

In 2015 three unconventional blocks were awarded to local E&P companies, following on the first shale block award in 2014. Recent announcements indicate that more unconventional blocks are expected to be offered in 2015, reflecting the emphasis on this sector to drive longer-term production growth.

Current activity in the unconventional resource sector in Indonesia is focused on Coal Bed Methane (CBM) and remains in its infancy despite considerable resource potential. Total recoverable CBM reserves are estimated at 550 MMBoe, which represents only a fraction of the resource potential. The most active CBM license to this point is the Sanga Sanga CBM J PSC in Kutei, which covers the CBM resource potential of this longstanding conventional gas permit. The PSC is operated by VICO (Virginia Indonesia Company), a joint venture company owned by BP and Eni.

## (4) Development issues and challenges

According to JP Morgan (JP Morgan, 2014) some of the challenges for Indonesian CBM and shale projects are:

- Land acquisition issues: currently, land acquisition law dictates that any land acquisition projects must be negotiated with the government through the National Land Agency. This leads to a lengthy bureaucratic process. Many shale reserves are located near densely populated areas; this makes land acquisition a tough issue.

- Legislative issues: the lack of standardized regulation on acquisition and compensation for CBM/shale projects hinders development. One example is the need for guidelines for "damages" based on (land) surface use. Another example is the lack of CBM specific regulation, which means developers conform to conventional oil/gas requirements instead, creating inefficiencies.
- Difficulty in procurement of CBM rigs: companies are facing difficulties in procuring CBM rigs, due to rig shortages and the long bureaucratic process of procurement.

## 6. Russia

### (1) Shale oil and gas resources

Russia has the largest resources in the world of technically recoverable shale oil at about 75 billion barrels, according to the EIA (2013), which estimates 1,920 Tcf of shale gas in-place, with 285 Tcf (8,100 Bcm) as technically recoverable shale gas resource. Those figures are based solely on the Bazhenov shale formation in West Siberia.

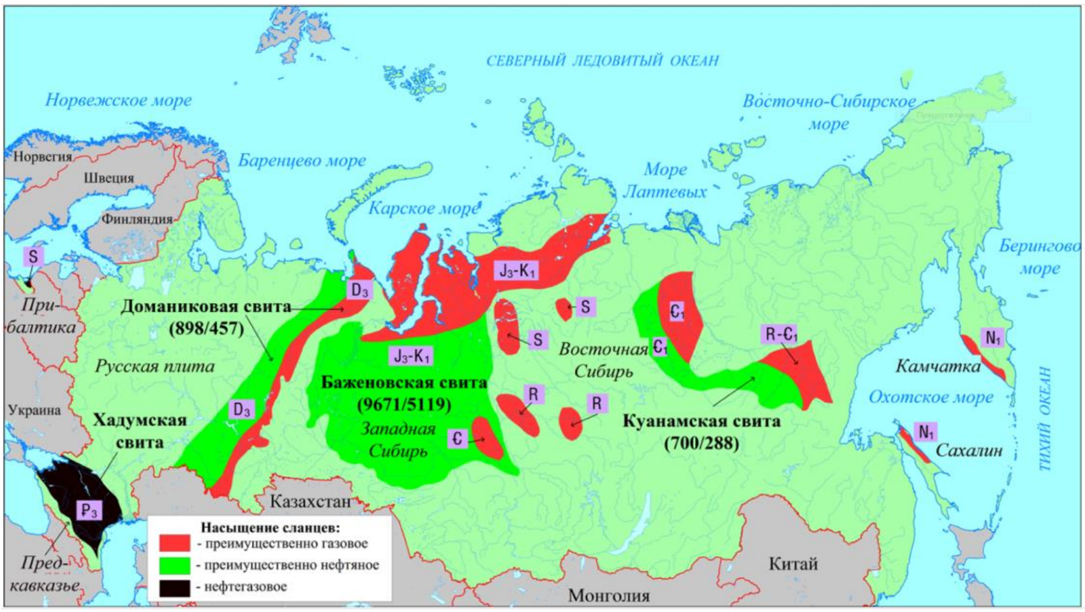
The Bazhenov is an enormous play that underlies most of West Siberia's conventional reservoirs. Limited exploration means resource estimates vary widely.

Wood Mackenzie assumes the Bazhenov contains 2,300 billion barrels of oil in place, around five times more than the well-known Bakken play in North Dakota. Wood Mackenzie assumes, however, 10 billion barrels of this are recoverable at present, with the play still in a pilot project phase. EIA estimates 1,243 billion barrels of risked shale oil in-place.

Apart from the Bazhenov formation, Russia's main shale oil and gas regions are the Achimov field in northern Siberia, Domanik in the Volga-Urals region and Khadum near Stavropol in the south.

According to Russian geologists V. Vysotski and A. Zharkov from Vniizarubezhgeologia and All Russia Petroleum Research Exploration Institute (VNIGRI), respectively, Russia's recoverable shale gas resources could amount to 9,5 trillion cubic meters and recoverable shale oil resources could reach 11,3 billion tons (Figure B-6-1).

Figure B-6-1 Shale oil and gas resources in Russia



Note: Tight oil, million  tons/Shale gas, billion cubic metres

Russia's Federal Agency for Mineral Resources will begin in 2015 to conduct audits of its unconventional hydrocarbons resources, Natural Resources and Environment Minister Sergei Donskoi announced in 2014. The audits will be carried out in East and West Siberia and in Russia's southern regions, where shale formations are believed to be enormous.

**(2) Shale Oil Projects**

Interest in the Bazhenov formation and other shale prospects has risen since September 2013, when Russian President V. Putin introduced tax breaks for unconventional projects in September 2013. Putin took this step in a bid to spur shale oil and gas development and to counter declining production levels at ageing oilfields in Western Siberia. After the tax concessions were unveiled, a number of international oil companies (IOCs) began moving to seek partnerships with Russian operators.

In early 2014 Shell, BP, Total, Statoil had shale oil JVs with Russian companies.

Equity in the Salym Petroleum Development (SPD) venture is split 50:50 between Shell and Gazprom Neft. SPD holds licences for the Salym group of deposits – namely, Verkhne-Salym, Zapado-Salym and Vadelyp (sections of the Bazhenov shale formation), which contain more than 1 billion barrels of crude in recoverable reserves.

Rosneft and ExxonMobil signed a joint venture (another section of the Bazhenov play) agreement in December 2012. Rosneft has a 51% stake in theJV.

On May 23, 2014, Total announced that it had signed an agreement with LUKoil on the joint exploration and development of the Bazhenov shale. LUKoil will hold 51 % in the joint venture, while the French company will own the remaining 49%. The partners will initially assess the technical feasibility of developing Bazhenov's shale oil resources on four licences, covering 2,700 square km.

On May 24 2014 Rosneft and BPagreed to jointly explore for shale oil in the Volga-Urals region of central Russia. Rosneft will hold 51% of the joint venture, which will target the Domanic formation, while BP will have 49%.

In December 2014, Norway's Statoil and Rosneft signed a shareholders and operating agreement for a joint venture to assess the feasibility of commercial production from the Domanik shale formation in the Samara region.

**(3) Western sanctions imposed in the summer of 2014 will slow the rate of shale oil drilling. In October 2014 Gazprom neft and Shell indicated that it would halt Bazhenov research at their Salym Petroleum Development JV due to sanctions and  ExxonMobil appeared to walk away. Surgutneftegaz will continue to be the most active Bazhenov explorer. CBM**

Forecasted methane resources of the major coal basins in Russia are estimated to contain 83.7 trillion cubic meters making up approximately one-third of the country's forecasted natural gas resources (Figure B-6-2). Kuzbass is distinguished from the rest of Russia's coal basins and may reasonably be considered as the world's largest among the explored CBM basins. The basin's forecasted methane resources are estimated at over 13 trillion cubic meters.

Figure B-6-2 CBM resources in Russia


These estimates are given for the coal and methane resources deposited at a depth of 1,800–2,000 meters. Deeper coal deposits of the basin keep the immense amount of methane estimated at 20 trillion cubic meters that seems to be sufficient in the long run. The resource base of Kuzbass ensures large-scale production of methane (beyond the mine fields) as a separate mineral resource.

On February 12, 2010 Gazprom launched Russia's first CBM production facility at the Taldinskoye field. In 2014 CBM production at the Taldinskoye field accounts 2,8 mcm.

## 7. Japan

### (1) Development of unconventional natural gas in Japan

#### Shale oil and gas

Because of its geological youth, Japan is not thought to have any commercially viable shale gas reserves[6]. Shale oil reserves, on the other hand, are being developed and commercial production began at an oil field in Akita prefecture in April 2014 following a period of trial extraction by Japan Petroleum Exploration Co., Ltd. (JAPEX). However, this project accounts for only 1% (35 kiloliters/day) of total domestic oil output.

#### CBM

Japan has some domestic coal reserves and used to extract coal from domestic coalmines, but almost all coal is now imported and domestic production had stopped for economic reasons. Although around 24 Bcm of reserves of CBM have been confirmed in the Ishikari coalfield in Hokkaido[7], no concrete steps have yet been made toward commercial production.

#### Methane hydrate

The Japanese government is presently spearheading the collection of basic data and development of extraction technologies with a view to commercial development of methane hydrate resources. According to estimates by the National Institute of Advanced Industrial

[6] Source: Japan Oil, Gas and Metals National Corporation (JOGMEC), JOGMEC News, Analysis, and other sources.

[7] Underground Resources Innovation Network, Effective Use of Hokkaido Coal.

Science and Technology (AIST), Japan has enough reserves in the waters off its coasts to meet its domestic natural gas consumption for 100 years[8].

Tests are currently being conducted as part of moves toward commercial development of methane hydrate resources under Japan’s Plan for the Development of Marine Energy and Mineral Resources. The world’s first offshore methane hydrate production test was successfully performed off the cost of Mie prefecture in 2013, but extended continuous production has yet to be achieved.

As the cost of production is presently estimated to be two to four times the LNG import price, methane hydrate is not yet as economically viable as conventional gas.

### (2) Implications of expansion of unconventional natural gas production

**Enhancement of stability on LNG procurement**

Japanese LNG buyers are pursuing imports of shale gas from North America. As Table **B-7-1** shows, five companies have signed contracts to purchase a combined total of 4.79 million tons, and some Japanese buyers have also entered liquefaction processing contracts. At those companies that have decided to buy North American shale gas, purchases of such gas remain below 30% of their total LNG procurements to date.

Canada also plans to export shale gas-sourced LNG, and it is projected that Japan will import 25 million tons from the U.S. and Canada combined. This is equivalent to 30% of Japan’s annual LNG imports. It remains unclear whether shale gas procurements will continue to grow, due to the uncertainty of following criteria: relationship between diversification of LNG sources and security of supply, timing of U.S. shale gas export projects start-up, risks associated with fluctuations in the Henry Hub price, and de-regulation of the Japanese electricity and gas markets.

In addition to the shale gas LNG, Tokyo Gas and Kansai Electric will source CBM in the form of LNG from the QCLNG project in Queensland, Australia. Tokyo Gas will also acquire stakes in gas fields and liquefaction facilities at the QCLNG project, from which it plans to purchase CBM.

**Table B-7-1 Japanese Buyers planned LNG purchases and Japanese firms' involvement in plant construction at major North American shale gas projects (1,000 tons/year)**

| | Project | Planned start date of supply | Production Volume | Liquefaction processing contract | Buyer and quantity purchased | Plant construction |
|---|---|---|---|---|---|---|
| U.S. | Cameron LNG | 2017-2018 | 12,000 | Mitsubishi Corp.: 4,000<br>Mitsui Co., Ltd.: 4,000<br>GdF Suez: 4,000 | Tokyo Electric: 800<br>Toho Gas: 300<br>Kansai Electric: 400<br>Tohoku Electric: 570<br>Tokyo Gas: 520 | Chiyoda Corp. |
| | Cove Point LNG | 2017 | 5,000 | ST Cove Point: 2,300 (Sumitomo Corp./Tokyo Gas joint venture) | Tokyo Gas: 1,400<br>Kansai Electric: 800 | IHI |
| | Freeport LNG | 2018 | 11,000 | Osaka Gas: 2,200<br>Chubu Electric: 2,200<br>Toshiba Corp.: 2,200 | — | Chiyoda Corp. |

[8] Research Consortium for Methane Hydrate Resources in Japan, Japan’s Methane Hydrate R&D Program, and other sources.

| | | | | | | |
|---|---|---|---|---|---|---|
| Canada | LNG Canada | 2019 | 12,000 (max. 24,000) | Shell: 6,000<br>Mitsubishi Corp./KOGAS: 1,800<br>China National Petroleum Corp.: 2,400 | — | Chiyoda Corp. |
| | Cordova | — | 3,500 | Mitsubishi Corp. et al. | — | — |

*Sources: Compiled from Institute of Energy Economics, Japan, 2014 1st-Half significant topics in LNG industry*, press reports, and press releases.

**Impact on prices and markets of LNG**

- Impact on Japanese LNG import prices[9]
    - LNG imports have risen since the 2011 Great East Japan Earthquake driven by demand for alternatives to nuclear power, purchasing at higher import prices than Europe and North America. Different from traditional LNG linked to oil prices, shale gas from the U.S. is indexed to the Henry Hub price, which makes it approximately 20%-30% cheaper than the relatively more expensive LNG bound for Asia (although less so following the collapse in oil prices). It is thought that this may therefore impact on LNG prices in the future.
- Impact on gas prices in Asia
    - Some forecasts predict U.S. shale gas exports will reach 70 million tons, and other Asian LNG importers as well as Japan are expected to expand their purchases of shale gas at prices not linked to oil. The growth of U.S. shale gas on the market may also ease supply and demand, increase market liquidity, and have downward impact on LNG prices in Asia as a whole.

**Increase in participation to oil and gas business**

- Japanese involvement in development of North American shale gas resources[10]
    - Japanese firms are getting involved in developing shale gas in the U.S. and Canada, and building LNG terminals to export shale gas. They come from a range of fields, and include trading companies, resource developers, electricity and gas utilities, and engineering companies.

**Table B-7-2 Main Japanese firms involvement in North American shale gas and oil development projects**

| Company | Japanese firm | Site | Details |
|---|---|---|---|
| Trading | Mitsui Co., Ltd. | Eagle Ford, Texas<br>Marcellus, Pennsylvania | Shale oil and gas development<br>Shale gas development |
| | Mitsubishi Corp. | Cordova, British Columbia<br>Montney, British Columbia | Shale gas development<br>Shale gas development |
| | Sumitomo Corp. | Burnet, Texas<br>Permian Basin, Texas<br>Marcellus, Pennsylvania | Shale gas development<br>Shale oil development *1<br>Shale gas development |
| | Itochu Corp. | Rocky Mountains, near Texas<br>Niobrara, Wyoming | Shale gas development (investment in stake)<br>Shale oil development |

[9] Japan Electric Association Newspaper Division, The Shale Revolution and Energy in Japan.

[10] Japan External Trade Organization, The U.S. Shale Gas Revolution and Its Impact on Japanese Firms.

| Company | Japanese firm | Site | Details |
|---|---|---|---|
| Resource developers | Marubeni Corp. | Eagle Ford, Texas<br>Niobrara, Wyoming | Shale oil and gas development<br>Shale oil development |
| | Sojitz Corp. | Carthage, Texas | Shale gas development |
| | Toyota Tsusho Corp. | Alberta | CBM development |
| | INPEX Corp. | Cordova, British Columbia | Shale gas development (joint investment with JGC Corp.) |
| | JAPEX | Eagle Ford, Texas<br>North Montney, British Columbia | Shale oil development<br>Shale gas development |
| | Idemitsu Kosan Co., Ltd. | Alberta, Canada | Shale gas development |
| Utilities | Tokyo Gas | Burnet, Texas<br>Cordova, British Columbia | Shale gas development<br>Shale gas development |
| | Osaka Gas | Eagle Ford, Texas<br>Cordova, British Columbia | Shale oil / gas development *2<br>Shale gas development |
| | Chubu Electric | Cordova, British Columbia | Shale gas development |
| Engineering | JGC Corp. | Eagle Ford, Texas | Shale oil development |
| Shipping | Nippon Yusen K.K. | Cameron, Louisiana | Shale gas liquefaction |

*Sources: Compiled from JETRO, The U.S. Shale Gas Revolution and Its Impact on Japanese Firms, press reports, and press releases.*

*1 Sumitomo Corp. released the recognition of the impairment loss of approximately 170 billion yen on Consolidated Financial Statement on Sep. 29th, 2014.

*2 Osaka Gas released the impairment loss of approximately 29 billion yen as an extraordinary loss in its Third Quarter consolidated financial forecast of FY2014.3, on Dec. 20th, 2013.

**Opportunity in oil and gas related industry**

- Japanese firms are also investing in other North American business related with development of shale gas and oil. These include the construction of a hydrogen plant by Taiyo Nippon Sanso Corp. to supply hydrogen to resin manufacturers, the acquisition of oil well casing plant and equipment by Nippon Steel & Sumitomo Metal Corp., and the expansion of carbon fibre factory capacity by Toray Industries Inc. to supply manufacturers of natural gas containers.

***Impact on LPG prices***

- Japan imported around 13,240,000 tons of LPG in FY2012. It depends on the Middle East for approximately 90% of its LPG, which is imported at a contract price determined by exporting countries with reference to oil prices.

- The shale gas revolution is also increasing production of LPG derived from U.S. shale, bringing down the U.S.'s benchmark Mont Belvieu LPG price index. Responding to these developments, Japan's oil refiner-distributors are beginning to procure U.S. shale-derived LPG at a price linked to the Mont Belvieu price. Astomos Energy Corp., ENEOS, Iwatani Corp., and others plan to begin or expand LPG procurements from the U.S., and this is likely to have impact on Japan's LPG market.

**Table B-7-3 Main Japanese firms' LPG procurement from North America (1,000 tons/year)**

| Company | Site | Volume | Planned start date |
|---|---|---|---|
| Astomos Energy Corp. | Houston, Texas | 350 | 2013 |
| ENEOS | Houston, Texas | 200 | 2014 |
| Iwatani Corp. | Houston, Texas | 80 | (released on May 2013) |
| Tonen General | Houston, Texas | 600 *1 | (released on May 2013) |
| Itochu Corp. | Beaumont, Texas | 3,000 *2 | |

*1 Tonen General reportedly plans to procure 600,000 tons of LPG in multi-years.
*2 Itochu Corps. reportedly plans to procure 3,000,000 tons of LPG to East Asia including Japan

**Impact on the Japanese petro-chemical industry**

- In the U.S., the decline in energy costs and electricity charges resulting from the shale gas revolution is reportedly making the petro-chemical industry competitive once again. Even if Japanese firms import low-priced shale gas, the cost of liquefaction and transportation to Japan is also necessary, and therefore it is expected to mean that U.S. industry will continue to enjoy a competitive advantage.
- More specifically, ethylene, plastic, nitrogen fertilizer, and other petro-chemical manufacturers in U.S. are pushing ahead with investing in expanding production capacity, and Japan's petro-chemicals and manufacturing industries are expected to become less competitive relative to their North American competitors.
- On the other hand, some Japanese firms are responding to these developments by investing in North America. Specific projects include construction of a resin plant by Kuraray Co., Ltd., expansion of PVC resin and resin fuel production capacity by Shin-Etsu Chemical Co., Ltd., enhancement of natural gas steelmaking facilities by Kobe Steel, Ltd., and development of natural gas power plants by Toshiba Corp.

**Impact on the environment**

- Environmental impact as energy option for generating electricity
    - If more electricity is generated using LNG derived from low-priced shale gas rather than oil or coal, this will have a positive environmental impact in the form of lower CO2 emissions. On the other hand, if nuclear power plant shut down continues, its replacement with LNG will result in relatively higher CO2 emissions. Both positive and negative impacts are thus anticipated, depending on which energy sources are replaced by shale gas, and to what extent[11].

[11] Japan Electric Association Newspaper Division, The Shale Revolution and Energy in Japan.

# C. Europe

Without question, one of the most fascinating industry stories in recent years has been the dramatic increase in the production form US unconventional gas resources, and more precisely from gas shale formations. In last years the commercial production of unconventional gas reserves in the United States has brought about a structural shift in the world's supply of natural gas and as a consequences fundamental changes in the global gas market. Large volumes of LNG (10-13 BCM), which were expected to be imported by US, unexpectedly came onto the global market. The market, which was expected to become a seller's market for the foreseeable future, is certainly not a seller's market at the moment.

The great success of unconventional gas production in the US has led to a significant research into unconventional gas reserves in Europe. Although this research is not very advanced yet, its outcomes have already made clear that the Europe's unconventional gas reserves are very substantial. This report looks at the potential for shale gas development in Europe and considers the interaction between the European market and the development of Europe's "unconventional gas" potential.

The report concludes that in Europe the development of shale gas will not result in an ushering into a new era of cheap gas, with the potential to revolutionize the European energy scene, boosting energy security and providing a transition to a low-carbon economy.

All geological surveys consulted whilst preparing this report are aligned: Europe has a significant unconventional gas resource potential. However, the development of these resources has been hampered by technological challenges and the excessive financial costs associated with the extraction. The current volatility in the European gas market, mainly resulting from the recent drop in oil price, is not conducive to create – in the near term - the investment climate needed to successfully address these challenges.

However, economic and population growth will continue to put pressure on the world's energy supplies, and so all fuel sources – including Europe's unconventional gas resources - will be needed. The industry has always changed, and has caused changes in the societies in which it operates. Those responsible both inside and outside the industry need to try to understand what is happening now and how it may affect the future, to explain their strategies clearly and to adapt to new situations as they develop. In a world where technology and environmental threats are changing industries and society so rapidly, the slowly turning LNG-supertanker is not an image that excuses inertia in the industry and those who deal with them. All who are in the industry or who are involved with it need to share clear thinking about the future.

Realizing the potential for shale gas as a profitable alternative energy source requires all stakeholders in this debate to work together, requires a constructive dialogue between the industry, the public in general and the local communities in regions effected by the exploitation in particular and the government, ranging from the local government all the way to the EU legislative bodies. Private companies cannot develop a full-scale shale gas industry on their own. They need governments to support them with a combination of direct financial incentives and investments in transportation infrastructures. Governments also need to facilitate a dialogue between the industry and the public. Such a dialogue is essential to define the right balance between the economic benefits a rapid development of an unconventional gas industry would bring to Europe's economies and the environmental cost Europe is willing to pay to harvest these benefits.

Despite the current setback, natural gas in Europe has still the potential of entering its "Golden Age" and play its role of "bridge fuel" towards a "carbon-free renewable" dominated energy supply, but only if significant proportion of its unconventional gas resources – mainly shale gas – can be developed profitably and in an environmentally acceptable manner. Numerous hurdles need to be overcome, not the least the social and environmental concerns associated with the extraction of shale gas. The technology and know-how for shale gas to be produced in a way that satisfactorily meets these challenges can – with the right gas price incentive - be developed, but a close, continuous and transparent collaboration between governments, the public at large and industry will be required if public confidence is to be earned and maintained.

The changes that Europe's unconventional gas industry now faces requires a visionary response embedded in a transformational evolutionary path rather than epic, revolutionary responses, for the industry to evolve and prosper. Europe's gas industry is best placed to lead the formulation of this visionary response and to implement this vision by managing and promoting a constructive, open dialogue with all stakeholders involved.

### Definitions

**Definition of Unconventional Gas.**

Unconventional natural gas resources are found in less permeable rock formations, where hydrocarbon accumulations may be distributed over a much larger area than conventional gas. Unconventional gas resources typically require well-stimulation measures in order to be made productive, with recovery rates that are much lower than in conventional gas - typically of the order of 15 – 30 % of original gas in place.

There are three main types gas of unconventional natural gas produced today:

- Tight gas: this is natural gas trapped in low permeability tight formations, which include sandstones and carbonates, as well as shales.
- Coal-bed methane (CBM): this is natural gas trapped in coal seams, adsorbed in the solid matrix of the coal
- Shale gas: this is natural gas trapped in fine-grained sedimentary rock called shale formations, which are only a subset of all low permeable tight formations.

Among three main types of unconventional resources, shale gas seems to be the most promising with gas analysts estimating that shale gas could increase the world's known reserves of natural gas by 20% or more.

The oil and natural gas industry typically prefers to refer to tight oil or gas production rather than shale oil or gas production, because it is a more encompassing and accurate term with respect to the geologic formations from which the oil or gas is produced. Organizations such as EIA have adopted this convention, and the estimates of tight oil or gas production and resources provided include, but are not limited to, production from shale formations.

Brief descriptions of resource and reserves for natural gas used in this report

| Name | Short description | Includes gas in un-discovered formations | Includes gas not economically recoverable with current technology | Includes gas that is not recoverable with current technology | Includes gas that is not expected to become recoverable |
|---|---|---|---|---|---|
| **Original gas in place** | Total volume present | ✓ | ✓ | ✓ | ✓ |
| **Ultimately recoverable resources** | Total volume recoverable over all time | ✓ | ✓ | ✓ | |
| **Technically recoverable resources** | Recoverable with current technology | ✓ | ✓ | | |
| **Economically recoverable resources** | Economically recoverable with current technology | ✓ | | | |
| **1P/2P/3P reserves** | Specific probability of being produced | | | | |

Based on "Unconventional Gas – A review of Estimates" - ICEPT Working Paper, September 2012 - Ref: ICEPT/WP/2012/015

## 1. Europe's Energy Balance

Europe will remain, certainy in the near term, confronted with an increased dependency on energy imports. This import dependency will impact Europe's security of supply picture, which effects the competitiveness of Europe's economy, because of its increased exposure to price volatiy on the global energy market.

This challenge is particularly reflected in natural gas. Natural gas accounts currently roughly for one quarter of the EU's primary energy consumption. Its import dependency has risen up to 67% in 2011 and is projected to continue increasing. High reliance on imports and low diversification of energy resources, among other factors, contributes and will continue to contribute to increasing gas prices in the European market. Whilst still being lower than prices on some Asian markets, natural gas prices are three to four times higher than in the US.

### Europe's Gas Demand.

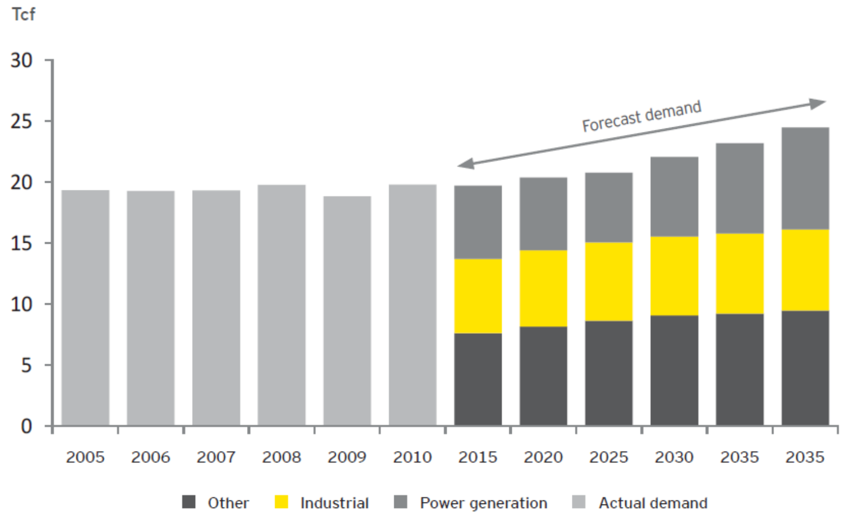
Europe, which consumed more than 500bn cubic metres (bcm) of natural gas at its peak at the height of the boom, saw its demand fall to 448 bcm in 2013. The final number for 2014 are not yet know, but there seems to exist a consensus amongst analysts that consumption level will have fallen further to around 420 bcm.

The economies in Europe are still recovering from the impact of the recession and sovereign debt crises (2008) and from the more recent Euro-crises. This weaker economy combined with the push towards renewable energies are two key contributors to the drop in European gas consumption to a level of roughly 15 years ago. Two other important factors explaining this dramatic drop in gas consumption are

- the switch by power generators away from gas towards coal, because of the price difference. The availability of cheaper gas supplies in the US resulted in a switch from coal to natural gas in power generation and the displaced US coal supplies found their way to Europe, where it undermined the economics of gas as a feedstock for power stations. This has seen utility companies increase their use of coal, despite EU environmental policies designed to curb the use of fossil fuels in the energy mix; and
- the lower carbon taxes that favoured the use of dirtier fuels, resulting the shutdown of gas-fired power stations across Europe.

The International Energy Agency forecasts that the EU gas consumption will not regain its 2010 level until mid-2030.

**Figure C-1-1 Gas Demand Forecast in Europe.**




*Source: US Energy Information Administration and Ernst & Young's "Shale gas in Europe: revolution or evolution?"*

This weak demand outlook raises questions on Europe's ability to diversify its energy supplies and to achieve its climate change goals at an affordable cost. To meet these objectives it is essential for Europe to secure cheaper supplies, and for instance facilitate in close collaboration with the industry the development of Europe's shale gas resources. Instead Europe is spending vast sums of subsidies to improve the economic attractiveness of renewable energy sources, such as wind and solar, only leading to higher energy prices for businesses and households.

However, there is still a future for gas in Europe.
Despite Europe's predicted sluggish economic growth, natural gas will be needed as Europe shifts further away from nuclear power. Nuclear energy is – once more - seriously being challenged in Europe. Nuclear power had been enjoying something of a renaissance in some European countries prior to the accident at Japan's Fukushima power plant in March 2011. Since then, a number of countries have announced reviews of the safety of existing nuclear plants or have decided not to extend their operational life. A large number of existing nuclear plants will be retired in the next 20 years. The gap in Europe's energy mix created by the phasing out of so many nuclear plant is an opportunity for natural gas to regain market share – assuming that it is price competitive.

Europe's longer-term carbon reduction targets mean that coal's revival as the fuel for power generation is likely to be relatively short-lived. Emissions from new gas-fired power generation would be lower than from existing coal plants. The power generation sector is likely to significantly drive the increase in gas demand in Europe beyond 2020.

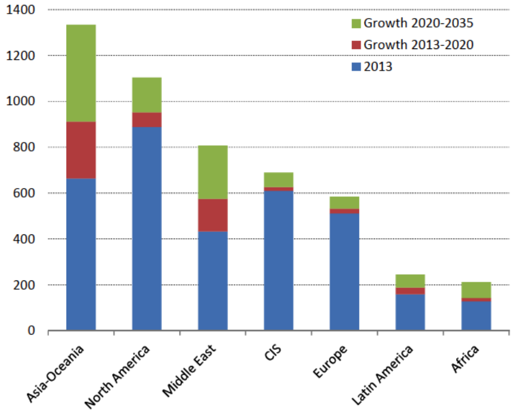
Cedigaz in its February 2015 presentation "Medium and Long Term Natural Gas Outlook" illustrates such a less negative outlook, and predicts a slight increase by 2030 in Europe's gas consumption.

**Table C-1-1 Regional natural gas demand prospects**

| | 2013 | 2020 | 2035 | %/year 2013-35 |
|---|---|---|---|---|
| | | | | |
| NORTH AMERICA | 889 | 953 | 1104 | 1.0% |
| *of which : US* | *724* | *757* | *850* | *0.7%* |
| | | | | |
| LATIN AMERICA | 159 | 188 | 245 | 2.0% |
| | | | | |
| EUROPE | 512 | 532 | 585 | 0.6% |
| *of which:* | | | | |
| *Turkey* | *44* | *58* | *79* | *2.7%* |
| *Germany* | *93* | *91* | *95* | *0.1%* |
| *United Kingdom* | *74* | *78* | *80* | *0.4%* |
| | | | | |
| CIS | 610 | 627 | 690 | 0.6% |
| *of which: Russia* | *435* | *440* | *470* | *0.4%* |
| | | | | |
| AFRICA | 128 | 142 | 212 | 2.3% |
| | | | | |
| MIDDLE EAST | 433 | 576 | 807 | 2.9% |
| | | | | |
| ASIA-OCEANIA | 664 | 912 | 1334 | 3.2% |
| *of which: China* | *169* | *355* | *615* | *6.1%* |
| | | | | |
| WORLD | 3394 | 3930 | 4977 | 1.8% |

*Source: Medium and Long Term Natural Gas Outlook, February 2015 - Cedigaz*

**Figure C-1-2  Natural gas demand growth by region**



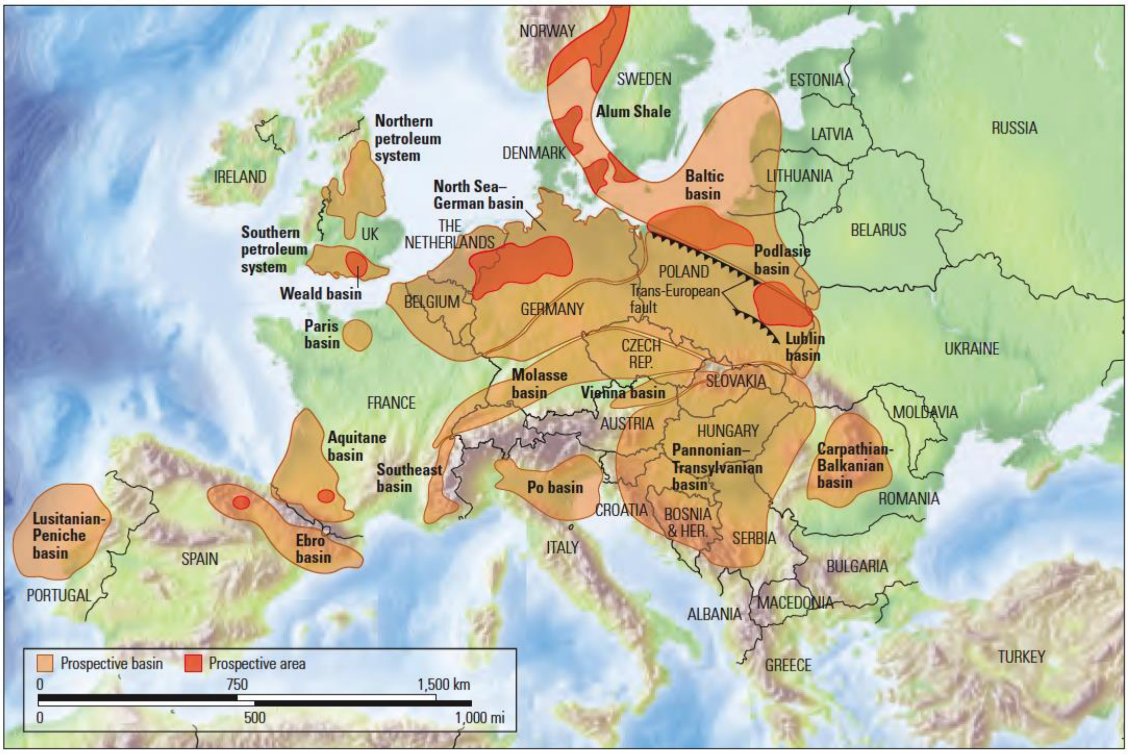

*Source: Medium and Long Term Natural Gas Outlook, February 2015 - Cedigaz*

The development of Europe's unconventional gas resources has the potential to bring direct or indirect economic benefits to countries as well as local communities, enterprises and citizens, for instance through regional investments in infrastructure, direct and indirect employment opportunities, and public income via taxes, fees and royalties. The enthusiasm and speed with which the oil and gas industry will actively engage itself in changing Europe's current energy mix in favour of natural gas will dependent on the level of comfort the industry has in the predicted gas demand growth.

The next chapter of this report illustrates that Europe's unconventional resources are very significant. However, oil and gas companies will only consider investing in the development of these unconventional gas resources if they are convicted that the produced unconventional gas will be in the longer term socio-economically competitive. So, reconciliation between the gas and renewable sector as well as between the gas industry and the general public is necessary. Without such reconciliation, the demand growth in Europe for gas will remain sluggish and Europe's unconventional resources will not play a role of significance in meeting this demand.

Unconventional hydrocarbon reserves in the EU are significant. Tight gas resources are believed to be present in at least 14 countries across Europe, with three-quarters of estimated reserves concentrated in just four countries: Russia, Poland, Ukraine and France. Limited exploration activity is being carried out in Austria, Germany, Hungary, Ireland, Poland, Sweden and the UK.

**Figure C-2-1 Shale basins in Europe.**



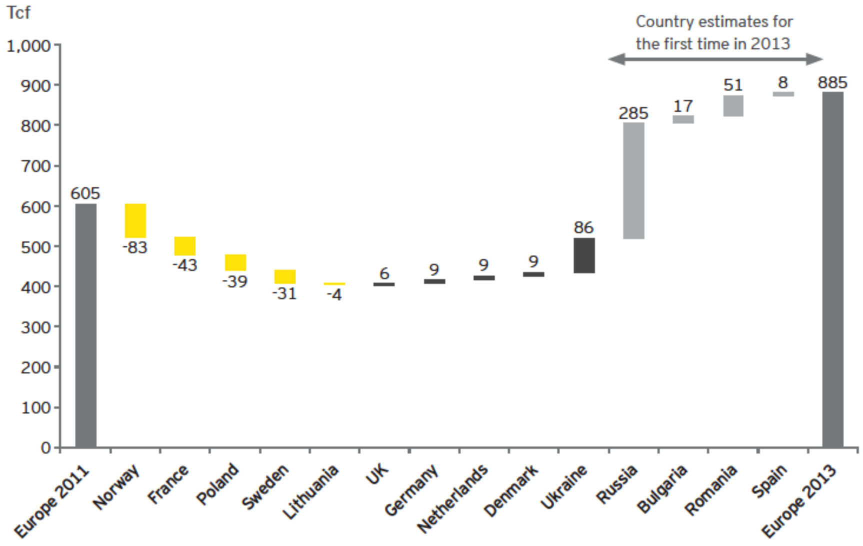

^ Europe shale basins. (Adapted from Kuuskraa et al, reference 6.)

*Source: U.S. Energy Information Administration (April 2011), copyright Schlumberger. Used with permission.)*

The report “*World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*” published by US Energy Information Administration (U.S. EIA) in April 2011, estimated the technically recoverable shale gas resources in Europe at 605 Tcf of (17,134 Bcm), with a total shale gas in-place volume of 2 587 Tfc (73,263 Bcm).

In June 2013 the EIA published revised estimates. As illustrated in the chart below, the estimates for France, Norway, Poland, and Sweden were revised downwards, while the estimates for Denmark, Germany, Netherlands, United Kingdom and Ukraine were adjusted upwards. The 2013 revision also includes four new countries: Russia, Bulgaria, Romania and Spain. According to the 2013 study Europe has 885 Tcf (25,063 Bcm ) of technically recoverable shale gas resources. This implies that Europe’s shale gas resources collectively accounted for almost 12% of the global shale gas resource potential.

**Figure C-2-2 Estimates of technically recoverable shale gas resources in Europe**




*Source: US Energy Information Administration and Ernst & Young's "Shale gas in Europe: revolution or evolution?"*

However, these estimates need to be taken as very preliminary.

The exploration of Europe's tight gas resources is still at its embryonic stage. At present, the industry does not yet possesses the knowledge and expertise to provide a semi-accurate assessment of the in-place volume of gas present in tight reservoirs in the subsurface in Europe, or to calculate the volume that can be technically produced from these reservoirs. Experience gained in the US learns for instance that the petro-physical properties of shales vary from one rock formation to another across different regions. *A fully reliable assessment will demand a detailed exploration activities and gaining production experience.*

Every tight gas play is different and requires tailored exploitation. So, a step-change in gathering information that allows properly describing and modeling the various tight gas reservoirs is required to gain a better understanding of the potential of the "tight gas" plays in Europe. Estimates of technically recoverable shale gas resources are certain to be revised, upward and downward, over time as new information is gathered.

Technological progress has enabled access to unconventional fossil that were previously technically too complex or too costly to extract. However, there is still significant uncertainty on the economically recoverable portion of these resources. There has been no commercial production of shale gas in Europe yet, although a few pilot production tests have already been conducted.

Although only a fraction of the tight gas resources in the various countries is likely to prove commercial, bringing this fraction of unconventional gas reserves into production, will result in a diversification of Europe's gas supply, and at the same time assists in addressing Europe's security of supply and reducing its dependence on gas imports. The development of Europe's tight gas resources would provide Europe's energy-intensive industries access to lower-cost energy supplies.

**Contribution of Unconventional Gas to Europe's Gas Supplies**

Little optimism remains for what at the start of the decade was considered Europe's trump card to significantly decrease its dependency on imports to meet its growing energy demand. Once thought to have huge potential across a region stretching from Lithuania in the north to Bulgaria in the south to the United Kingdom in the west, projects have fallen by the wayside over the past years due to poor drilling results, intense environmental opposition and political and geopolitical uncertainties.

The initial excitement over the European shale gas saw a rush of interest from majors, with the likes of ExxonMobil, Chevron, Total and Eni taking interests in licenses across Europe, with exploration activities occurring, primarily through joint ventures to share risk and know-how. However, operators found the "shale gas" geology across the various European basins to be much more difficult than they originally anticipated. European shale plays are much deeper than those in the US, making drilling and extraction much more challenging. The industry learned that every shale play is different and requires a tailor-made exploitation approach.

Environmental opposition across Europe has held up exploration drilling. The resulting paucity of wells drilled did not help to reduce the uncertainty about actual reserves and what percentage of those reserves is recoverable. The unconventional resources tend to be situated close to and under densely populated areas. European environmental laws, which tend to be quite strict combined with the wide spread environmental concerns for instance over the chemicals used in fracking techniques results in a significant geographic share of the resource that will remain undeveloped.

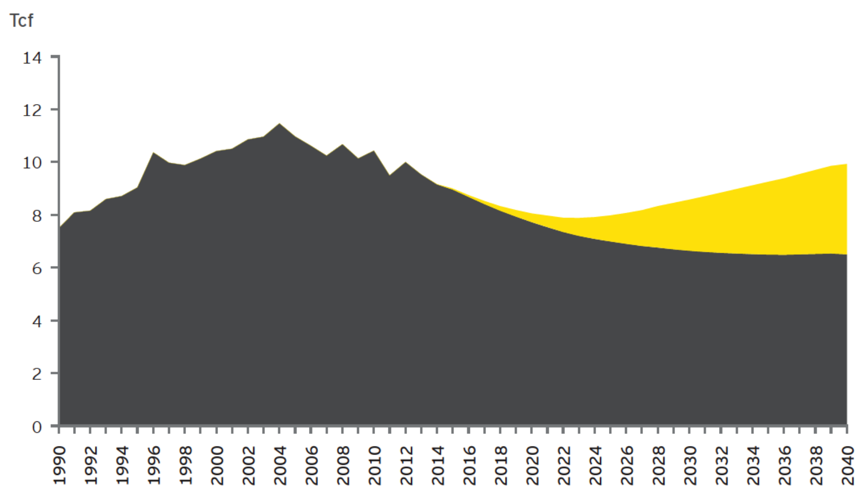
The development of unconventional gas resources in Europe is highly uncertain. Technological innovations are needed to bring down the costs of shale gas production; but high production costs and low margins are curbing the appetite for investment in shale gas production start-ups. Due to a wide range of techno-economic, environmental and regulatory obstacles, the prospect of large-scale shale gas production from unconventional resources in Europe remains very, very slim.

EIA's 2013 forecast of the volume of shale gas produced in Europe in shown in the chart below. These projections, made in 2013, indicate that any meaningful contribution from Europe's unconventional resources to meet the European demand should only be expected well into the next decade.

While the EU will not become self-sufficient in natural gas, natural gas production from shale formations could, at least partially, compensate the decline in Europe's conventional gas production and avoid an increase in Europe's reliance on gas imports. Indeed it would be, in the EIA's best case scenario, able to contribute almost half of Europe's's total gas production and meet about around 10 % of its gas demand by 2035[12]. Potential production of natural gas from shale formations have triggered high expectations across Europe, with unconventional resources seen as:

- a possible substitute for more carbon-intensive fossil fuels,
- an indigenous source of natural gas reducing dependency on non-EU energy suppliers,
- a possible driver of jobs, economic growth and additional source of public revenues.

**Figure C-2-3 Forecast shale gas production in OECD Europe**

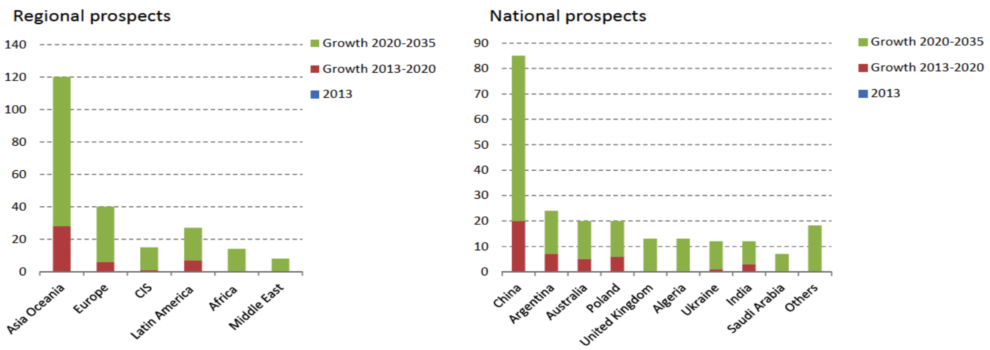



[12] IEA 2012

*Source: US Energy Information Administration and Ernst & Young's "Shale gas in Europe: revolution or evolution?"*

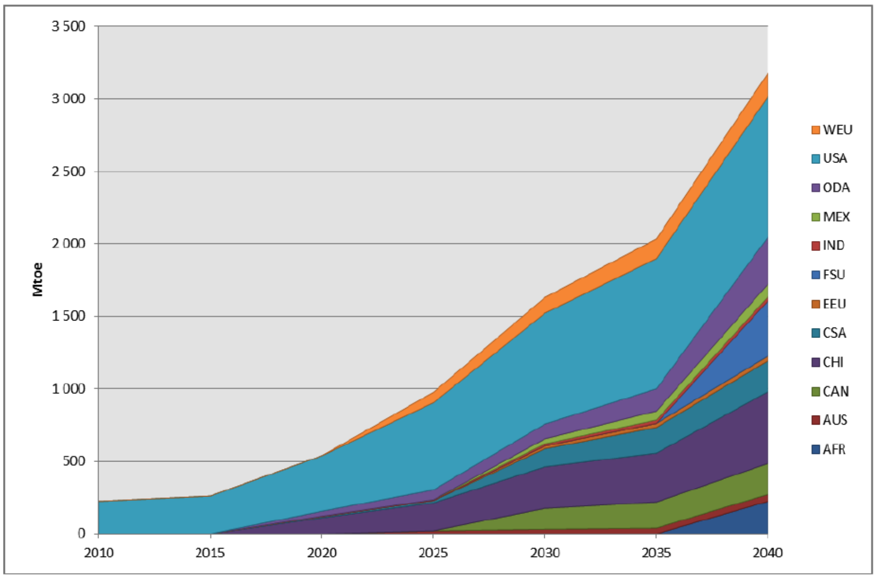
However, the nature of the recent precipitous decline in the oil (and gas) price will determine the future of Europe's unconventional gas. The US shale oil & gas revolution is a classic example of the impact technological innovations sustained by prolonged period of high prices can have on an industry. In case the current price drop turns out to be a short-term decline soon reversed as the world bounces back to a more solid \$ 100/b price range, a scenario can be constructed whereby the take-off of commercial unconventional gas production in Europe is pushed back by a few years. In case the current price drop marks the end of a commodity "super cycle" with project margins further evaporating, the yellow portion in the chart below needs to be reduced very significantly and pushed many more years out into the future.

**Figure C-2-4 Potential for shale gas production prospects outside North America**




*Source: Medium and Long Term Natural Gas Outlook, February 2015 - Cedigaz*

**Figure C-2-5 Unconventional gas production (JRS report - optimistic high-- - growth scenario)**




*Source: Unconventional Gas: Potential Energy Market Impacts in the European Union, JRC Scientific and Policy Reports, 2012*

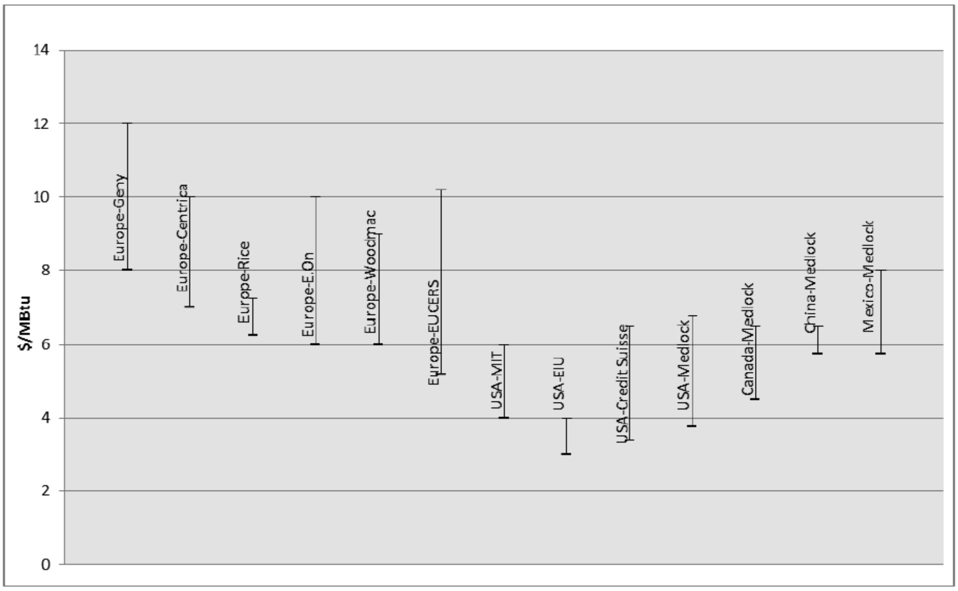
**Breakeven cost of Europe's Unconventional gas.**

The European Commission report' s "*Unconventional Gas: Potential Energy Impact in the European Union*, 2012" provides an overview of estimates made by various institutes and consultants for the break-even cost for a number of European shale gas reservoirs. The diagram below, taken from that report, contrasts the break-even estimates for European shale development with the break-even cost for some US shale gas developments.

Two key learnings from the diagram is that

- There is not one break-even price for gas shale development. The cost to produce gas from an unconventional resource is basin & formation specific.
- The break-even cost for European shale gas developments are consistently higher than the cost to produce US gas shale. Break-even price estimates for the shale gas developments in the USA are in the range between $3-7/MBtu. Estimates for Europe vary between $5-12/MBtu, that is ca. EUR 23 -53/MWh. Currently gas prices on the European prompt market oscillate around 26 EUR/MWh,

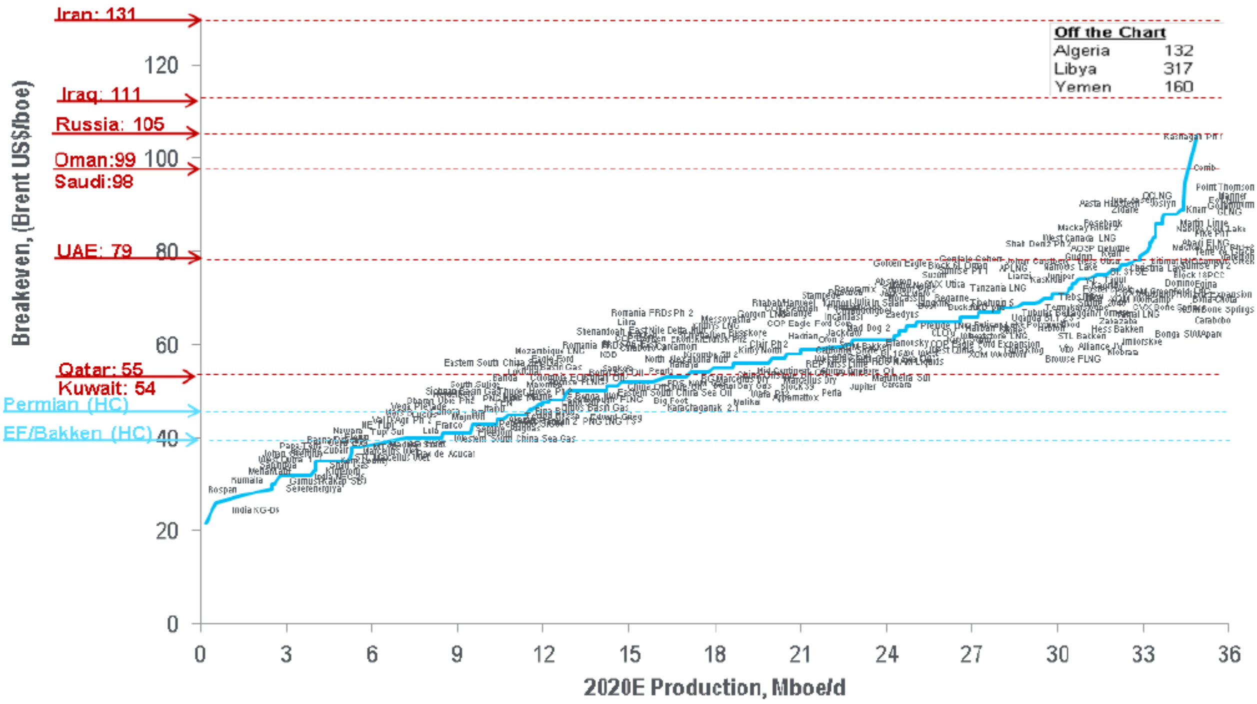
**Figure C-2-6 Break-- - even prices for unconventional gas production**




*Source: Unconventional Gas: Potential Energy Market Impacts in the European Union, JRC Scientific and Policy Reports, 2012*

This broad spread in break-even cost estimates was recently confirmed by a study carried out by Citigroup. For that study, Citigroup collected the breakeven price of all oil projects – including oil shale projects – in the world. (See diagram below).

**Figure C-2-7 Breakeven price of all oil projects – including oil shale projects**

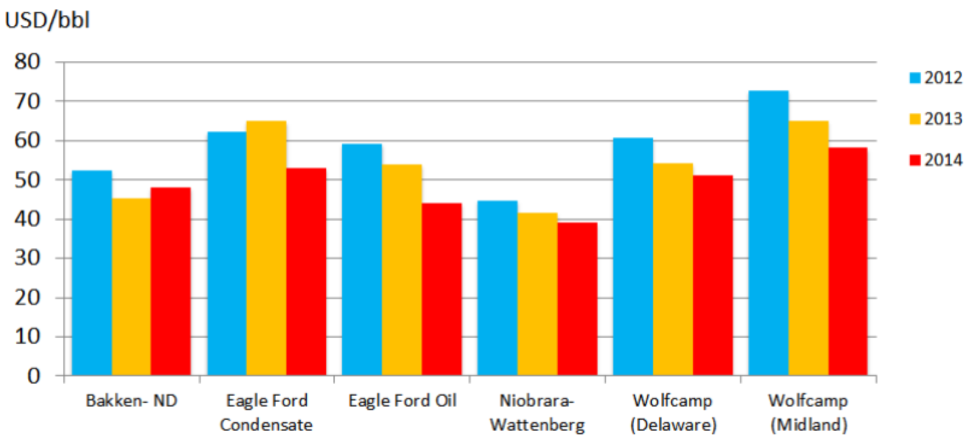



*Source: CitiGroup, Commodities Price Reset, Outlook for 2015, 1 December 2014*

Another important learning from the US shale success story is the breakeven price in the main plays decrease year-on-year, as a result of both a reduction on well cost and an increase in EUR per well.

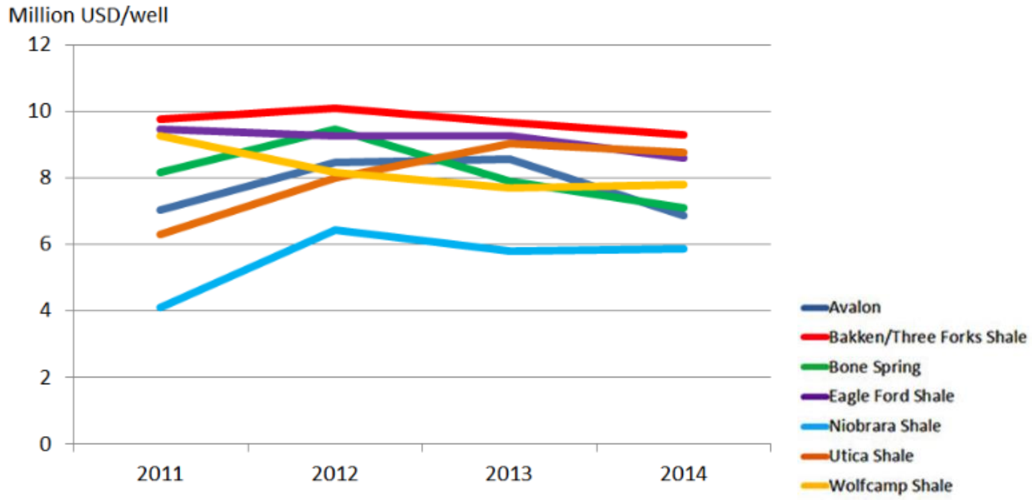
- A reduction in well cost (figure below) is due to shorter drilling time (increase pad drilling) and shorter completion time (increased use of zipper fracs).
- An increase in EUR has been observed thanks to better well placement and advances in known completion techniques i.e. modified zipper fracs. (figure 2 below)

**Figure C-2-8 WTI breakeven price per shale play**




*Source: Rystad Energy Research & Analysis*

**Figure C-2-9 Drilling and completion well cost per shale play.**




*Source: Rystad Energy Research & Analysis - Ucube*

## 3. The European Gas Market

European gas market has changed significantly in recent years, both in terms of fundamentals (financial crisis, decline in gas demand) as well as pricing (renegotiation of the long term gas contracts, growth of the trading on natural gas hubs in Continental Europe).

The share of gas-on-gas competition in Europe has more than doubled since 2005. The most well- established and liquid spot gas market in Europe is in the UK, which moved earlier and more decisively than other European countries to introduce competition into energy markets. There are seven other spot market hubs across Europe: Zeebrugge (Belgium), TTF (the Netherlands), NCG (Germany), Gaspool (Germany), PEG (France), PSV (Italy) and CEGH (Austria). The development of some of these trading hubs has been hindered by a lack of liquidity and also by infrastructure capacity or access issues.

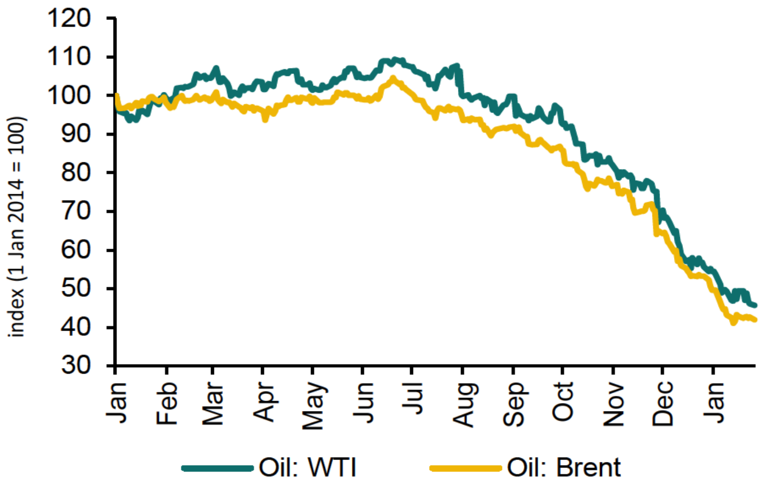
While the proportion of short-term, spot- traded gas in the supply mix has grown in recent years, oil-indexed pricing remains prevalent in longer-term contracts in Europe. Around 50%–60% of gas consumed in Europe still has oil price escalation in the contract price. This means that any fall in gas prices resulting from the buildup of shale gas production in Europe would not be as dramatic as in the US.

Natural gas prices in Europe are affected by the North American unconventional gas developments. U.S. no longer needs to import LNG – it is redirected to Asia, South America and Europe. U.S. also significantly increased volume of coal exports to Europe. Impact unconventional gas production might have on European gas prices is likely to remain moderate, especially if compared to the evolution in the US. This is due to expected relatively low volumes and higher production costs and the fact that prices are still largely set through long term oil-indexed contracts.

### The current volatile market and the prospect of developing Europe's unconventional gas

The collapse of crude oil prices in the second half of 2014 caught the industry by surprise. The price of Brent crude fell more than 50 per cent from $115 per barrel (bbl) in June to below $50/bbl by early January in 2015. After years of relative stability, giving rise to confidence and investment in the oil and gas sector – including the unconventional gas plays, major uncertainty is now being dominating the discussion in many board rooms and impacting companies' balance sheets.

**Figure C-3-1 Oil price for period January 2014 to January 2015.**




*Source: Thomson Reuters Datastream*

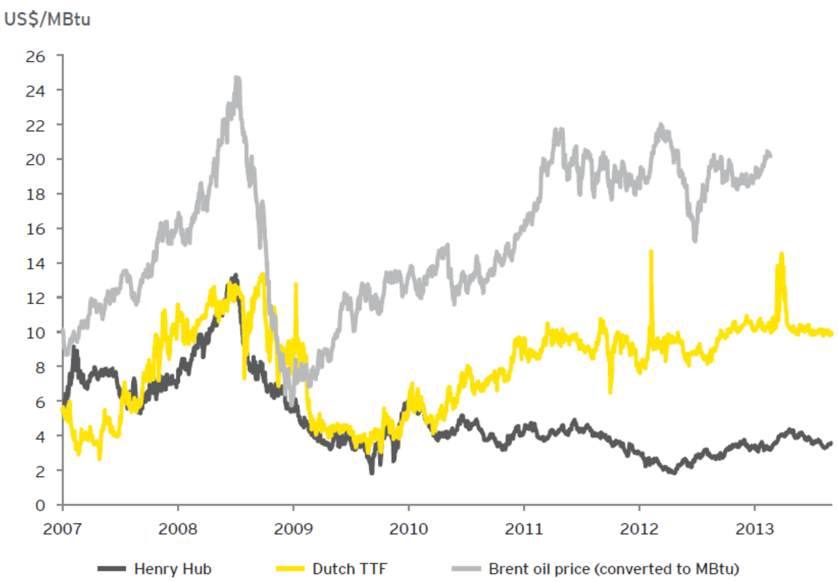
The oil & gas industry is facing serious funding difficulties that will have an almost immediate impact on production. The US shale sector's main source of funding is debt. According to The Economist, cumulative debt in the US shale industry stood at $260 billion in December 2014. Investors and debt markets are likely to become more reluctant to fund further investment. High cost and high risk projects including European shale gas development are likely to become more challenging in a lower price environment as potential investors become concerned by increasing price volatility.

**Saudi Arabia is not driving prices down.**
Over the past decades, Chinese economic growth has been driving the price of oil higher. The growth in global demand in recent years has been more subdued, this whilst supply – mainly from non-OPEC producing countries – has increased leading to a surplus of oil in the market. As Daniel Yergin stated, we have entered a new era that "is defined by the incredible surge in U.S. oil production, which has risen 80% since 2008—an increase that exceeds the output of 11 of the 12 OPEC countries."
Crude oil production in the United States increased from five million bpd in 2008 to nine million bpd in 2014. This has been possible because years of historically high and stable crude oil prices made shale projects economically viable. At its last meeting in November OPEC responded to the current surge in supply by maintaining production levels.

However, assuming that a similar decline in production costs as seen North America can be duplicated by the European unconventional gas players the potential still exists for unconventional gas to play a significant role in meeting Europe's gas demand.

The price paid by European end-consumers for natural gas is key for the future development of unconventional gas resources in Europe. As can be seen from figure below, gas prices in Europe have typically been higher than in the US since 2008.

**Figure C-3-2 Natural gas prices at selected trading hubs compared with Brent oil price**




*Source: Thomson Reuters Datastream*

The relatively higher gas prices that can be realized in Europe offsetting – in part or in full - the higher development costs suggest that shale gas projects in Europe could still be economic.

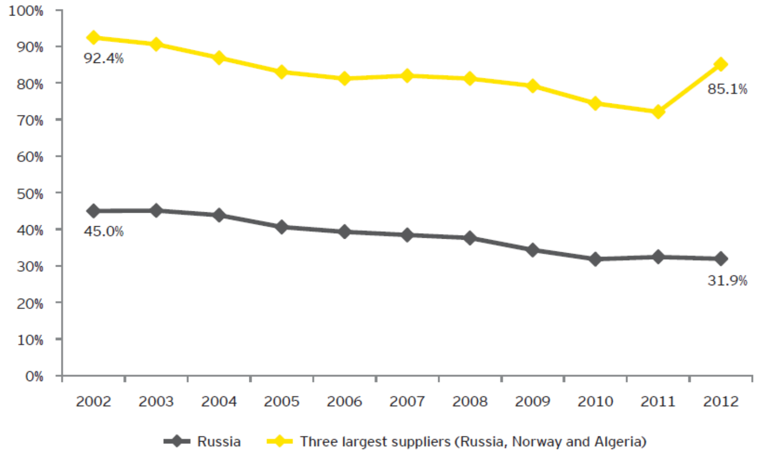
> The US shale oil & gas revolution provides a good example for what a prolonged period of higher prices can to do to an industry.
> Higher gas prices in the early to mid-2000s helped support the ramp-up in development of shale gas in the US. It provided North American shale projects the largest IRR among other common global oil developments whilst providing the shortest payback time. The latter has been the driving force behind the steep shale activity increase of recent years and the emergence of so many small independent players in the US.

## 4. Competing Gas Supplies

**Pipeline gas**
At present, Russia is the major supplier of pipeline gas to Europe and will continue to fulfill this role in the short to medium term. However, Russia's share of gas imports into Europe fell from 45% in 2002 to around 32% by 2012, largely due to increased competition from Norway and LNG supplies from Qatar. In 2014, Russia sent some 155bn cubic metres (bcm) of gas into Europe, some 30 per cent of overall demand, and more than half of that – 82bcm – passed through Ukraine.

In March 2014, after Russia annexed Crimea and the west started imposing sanctions on Moscow, energy security re-immerged as a top-priority on Europe's energy agenda. Concerns about its exposure to Russian gas imports increased in April, when President Putin warned that Russia might halt gas supplies to Ukraine unless action was taken over Kiev's unpaid bills.

**Figure C-4-1 Pipeline gas supplies into the European market**

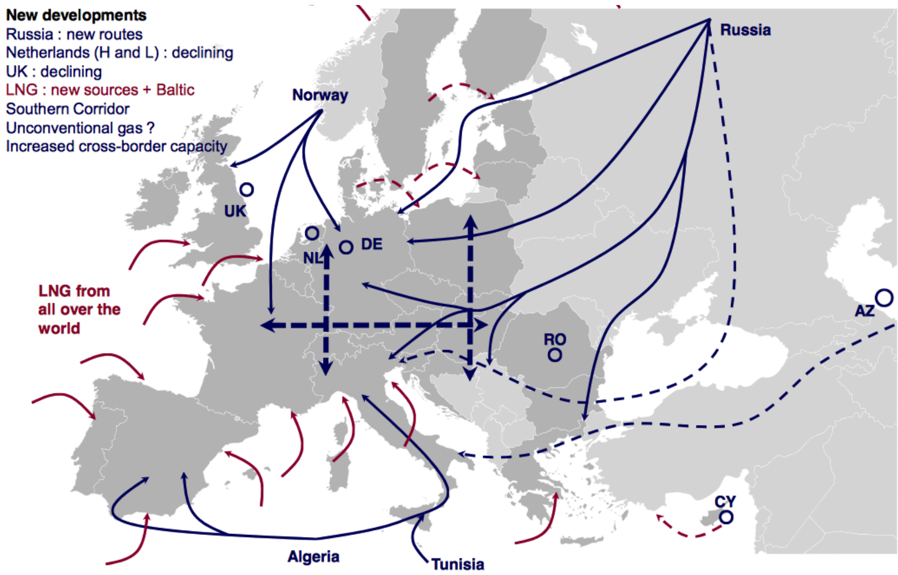



*Source: Eurostat and Ernst & Young's "Shale gas in Europe: revolution or evolution?"*

Brussels has made it a priority to diversify its gas supplies, but Europe's options are limited. The development of Europe's indigenous unconventional gas resources is one of these options.
So, Russia stands to be particularly challenged by the shale gas boom. Therefore, it is not surprising that Russia has been publicly airing doubts about the viability of shale gas. But progress has been slow: some countries, such as France and Bulgaria, have banned hydraulic fracturing processes, and while countries such as the UK are eager to exploit shale reserves, public opposition is strong. In Poland, thought to have enormous reserves, drilling results been discouraging, and some companies have given up.

Pipeline supplies from Russia are not without their own challenges, including the distance of some reserves from market and political issues around cross-border gas transit. Further challenges include the harsh conditions in some locations, the scale of investment in the development of new reserves, and how quickly these reserves can be brought to market.

**Figure C-4-2 Gas supplies into the European market.**



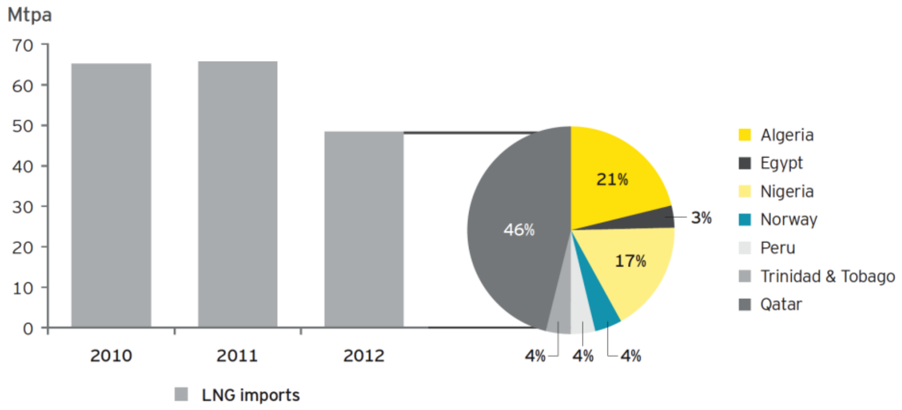

*Source: "Gas supply situation of Europe today and in the future", Gas Infrastructure Europe - Gas Sensor Workshop, 27 February 2014*

Shale gas will need to compete with other energy sources, where investments in infrastructure have already been made. New interconnectors between European countries have made them more resilient. Connecting pipelines have been built between Romania and Hungary, Hungary and Croatia, Slovenia and Austria, and Poland and the Czech Republic.

**LNG Imports.**
The shale gas boom in the US has rendered a number of LNG import terminal facilities redundant, and some operators are seeking to converting their facilities so that they can export LNG. Over the last three years, LNG volumes that were initially intended to supply the North American market have been diverted to other markets, including Europe. LNG supplies at spot prices were, at times, considerably lower than the oil-linked price of contracted natural gas supplies delivered to Europe by pipeline.

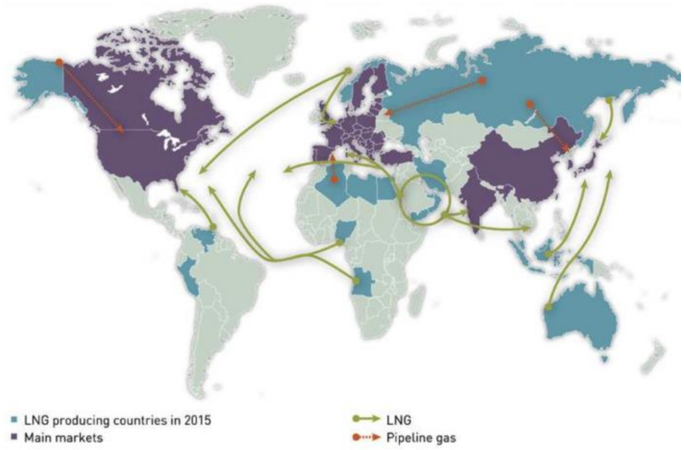
According to the International Gas Union, global trade in LNG fell by 1.6% in 2012 after 30 consecutive years of growth. Europe was badly hurt by the 2011 Fukushima nuclear disaster, which led Japan to swap to gas-fired power generation and signaled a move of LNG cargoes from Europe to Asia. In 2012, Europe's net imports of LNG were about 48 bcm, the lowest since 2004, and well below the 90 bcm peak in 2011. Strong demand from Asia, particularly from Japan and Korea, meant that around 70% of spot cargoes were supplied to these markets to take advantage of higher prices.

**Figure C-4-3 LNG imports into the European market**




*Source: International Gas Union.*

**Figure C-4-4 Global gas trade**




*Source: Total's "Natural Gas, the Second-Leading Fossil Fuel in the Energy Mix by 2035".*

Qatar is the largest supplier of LNG to Europe, with 46% share of the LNG import market. However, after rising steadily between 2002 and 2011, Qatar's share of all imports to Europe, including pipeline supplies, fell from 11% in 2011 to 8.7% in 2012. New LNG import capacity is being added in Europe at sites in Italy, Spain, Portugal, France, Lithuania and Poland. The Swinoujscie terminal in northwest Poland is projected to become operational in 2014.

However, if Europe wants more LNG, it will have to pay for it. The continent spends about $11 per mBTU for gas, while in Asia, LNG fetches about $15 per mBTU.

## 5. Gas Transmission Infrastructure

The EU is heavily dependent on gas imports, which currently account for 60% of domestic consumption. Currently, it imports its gas through pipelines from Russia, Norway, Algeria and Libya, whereas LNG is shipped to Europe from Norway, Nigeria, Algeria, Libya, Egypt, Qatar and Trinidad & Tobago. However, over the years, the EU has managed to diversify its gas supplies to a considerable extent, although it still imports around 40% of all its gas from Russia.

Concerns about the diversity of supply in the EU, therefore, provide in many European capitals a strong impetus for the development of shale gas in Europe. However, the potential impact of shale gas on import dependence varies from one EU Member State to another. The availability and connectivity of the gas transmission infrastructure across Europe is another potential barrier to the efficient development of shale gas in Europe.

Significant investments are required in the gas transmission infrastructure to upgrade the Europe's gas network so that it is able to cope with increased gas flows – in case Europe's unconventional gas development takes off. Also, cross-border pipeline connections will need to be improved if shale gas production reaches a level that makes it possible for the shale gas produced in a region to be consumed also in neighboring region. An example of such investment to improve the connectivity across the European gas market is the Polish-Czech gas interconnector in Cieszyn (southern Poland) opened in September 2011. The new interconnector could form part of an enhanced north-south gas corridor.

The infrastructure requirements associated with shale gas development are not limited to pipeline transportation capacity. Requirements would potentially include new access roads for access to water supplies, wastewater treatment and processing facilities, gas storage capacity and also site traffic.

**Ownership/operation of pipelines and access to pipeline capacity.**
The EU gas market is currently not yet fully liberalized. There are still a number of limitations as far as access to transport capacity is concerned. Although the physical infrastructure may be in place, it is not accessible to all operators. Access to natural gas transmission pipeline capacity in Europe is still often controlled by the large national utility companies and governed by national-level regulations.

EU's Third Gas Package aims to eliminate the remaining restrictions in order to create a truly liberalised single market for gas. However, not enough progress has yet been achieved at Member State level. Eighteen of the twenty-seven EU Member States face court proceedings for non-compliance with EU internal energy market regulations. Such market imperfections discourage investments in the development of shale gas by stakeholders - regardless of their size - who do not possess pre-booked or guaranteed transport capacity.

> Every gas producer in the US, regardless of size, can place competitive bids for pipeline throughput capacity in a free market situation. The transport capacity is not exclusively reserved for the pipeline owner or for a few short-listed large producers. Such a market structure ensures that smaller, independent shale gas developers have a secured access to the gas market, thereby guaranteeing a channel to reimburse their upstream investment. Without such a liberalised market structure, the US shale gas boom would have been significantly impeded .

## 6. Environmental sensitivities of unconventional gas

Exploration and extraction of energy sources always represent an encroachment on nature and the environment. Unconventional gas production is no exception as it involves environmental pressures and risks both in the immediate vicinity of the production facilities and underground.

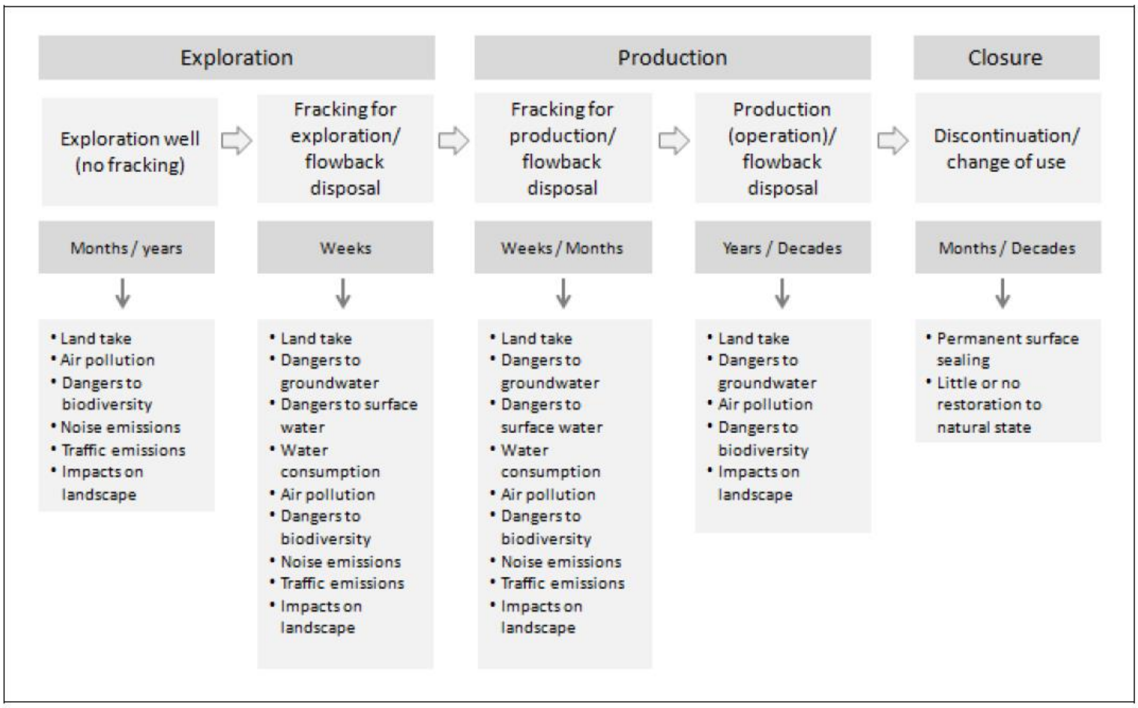
Whilst the industry is studying the safety aspects of unconventional gas production, including the impact on the environment, it has not much to work from with fewer than 10 hydraulic fracturing processes been carried out in Europe by mid-2013. However, with public opposition mounting, all of Europe's unconventional gas developers are meeting strong opposition from environmental groups on the basis of health and safety concerns related to hydraulic fracturing technology and water usage. Public protests against exploratory drilling for shale gas have been held in Romania, Lithuania, Poland, the Netherlands and the UK.

An important part of the population also perceives an insufficient level of precaution, transparency and public consultation in relation to the development of unconventional gas resourcesm, and of shale gas in particular. The public clamor for government action could result in moves to regulate or limit the exploration and production of shale gas. The industry needs to control reputational risk and turn public opinion around. Negative public opinion about the environmental safety of unconventional natural gas developments, and more precisely around hydraulic fracturing undermines the development of the industry. There is broad consensus within the industry that significant investments (initially more time than money) will therefore be required by industry to change public opinion, promote confidence with governments and the public in general and to build trust with local communities.

All industry players will need to consider adopting leading practices to mitigate environmental impact, preserve reputation, and avoid more stringent regulation, which could preclude growth of the industry. By developing and demonstrating a commitment to self-regulating / policing framework, unconventional gas producers can forestall future protests and negative regulatory repercussions for the entire industry.

A schematic overview of the mean risks the general public associates with the development of shale gas and coal bed methane is provided in the table below. A few of these main risks are commented on in the following paragraphs.

**Table C-6-1 Impact and risks of shale gas development on the environment.**




*Source: Fracking for Shale Gas Production SRU/Statement No. 18–2013 - ISSN 1612-2968*

**Understanding the subsurface**

The primary environmental concern living with the public is the risk of contamination of drinking water supplies by the chemicals used in the hydraulic fracturing process.

Producers need to understand the geology of formations they want to produce from and know how to model the impact of hydraulic fracturing with accuracy. The European unconventional gas industry has a unique opportunity to gather data and to carry out studies before the gas drilling and fracking begins. These results could then be compared with post- drilling results to better understand the impacts.

**Proper well construction**

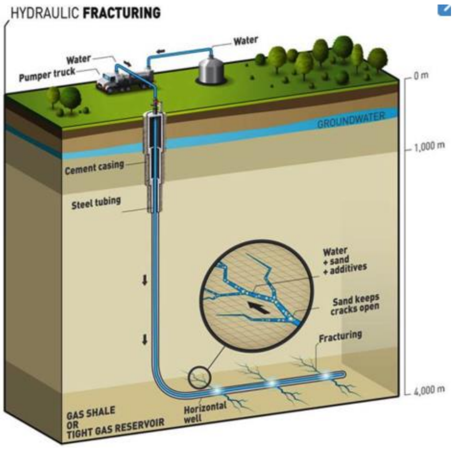
The aim of the fracking process is to create permeability where Nature did not. Injecting highly pressurized water into the rock creates a network of cracks that allow the gas to migrate to the wells. The injection water is mixed with:

- proppants, materials such as sand or ceramics that hold the cracks open once they have been formed;
- a limited quantity of additives (in the order of 0.5% of the total injection volume). These additives are mainly bactericides, gelling agents, and surfactants. The composition of the additive package depends primarily on the well conditions: pressure, temperature, proppant quantity. In addition to sterilizing and preventing bacterial contamination of the reservoir, the additives serve to improve the efficiency of the process.

Fracking chemicals used in the process could leak into other reservoirs, find their way into aquifers and ultimately into drinking water supplies. Fracturing fluids are physically separated from the water table by cement and steel casings, however the risk of groundwater pollution from improperly constructed wells cannot be ruled out.

Industry players in the US have recently opted for an increased transparency and disclosure on the chemicals used in the hydraulic fracturing process. Other shale producers contend that the composition of fracturing fluids is proprietary information. At a minimum, the industry needs to commit to a proper well construction to isolate the production zone from underground sources of drinking water.

**Figure C-6-1 Concept of hydraulic fracking.**




*Source: Total's "Shale Gas and Tight Gas: Multifractured Horizontal Wells ".*

| |
|---|
| Shell Oil has attempted to instill better industry practices and improve public perception by releasing its set of "Global Onshore Tight/Shale Oil and Gas Operating Principles".<br>These principles comprise a framework for how Shell and other oil and gas producers should protect the environment and the communities in which they drill for and produce natural gas and oil. They include:<br>- Safe well design and operation<br>- Protection of groundwater and reduction of water use<br>- Emissions reduction and fugitive emissions control<br>- Reduction of surface impact<br>- Transparency and community engagement |

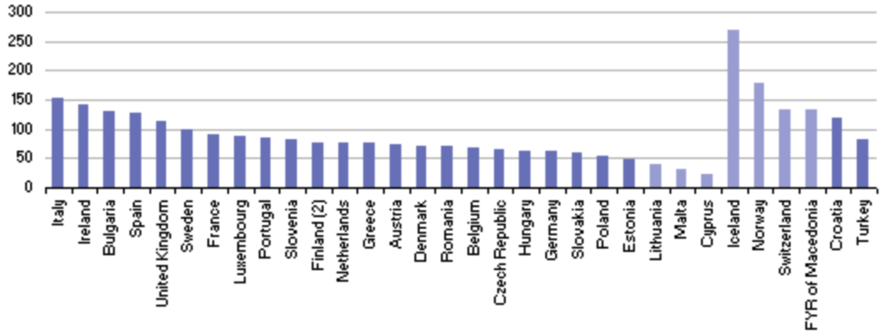
**Surface Water and Soil Risks**

Risks may also arise from the volume of chemicals that need to be stored at the drilling site and from the liquid and solid waste produced during drilling and fracking. Disposal of the water that flows back to the wellhead after fracturing is another concern the industry needs to address. Wastewater has to be stored, treated for chemicals and disposed of appropriately.

**Water Usage Risks**

Fracking of a gas shale reservoir is water intensive, and with it comes a number of issues: availability; transport to site location; chemical composition; treatment of flow back water which returns from the well; and finally return of the water to the hydrological cycle. A wide use of fracking technology even in the water-rich areas of Europe causes risks. Freshwater resources per capita in Europe based on a 20 year average (1 000 cubic metres).

**Figure C-6-2  Freshwater resources per capita in Europe (20 year average)**




(1) Spain, Italy, the Netherlands, Austria, Portugal, United Kingdom and Turkey, 2008; Germany, Ireland, Greece, France, Slovakia, Sweden and Norway, 2007; Switzerland, 2006; Finland and Iceland, 2005; Latvia not available.
(2) Estimate.

*Source: Eurstat, August 2011  -  Total freshwater abstraction by public water supply, 2009 (1).png*

Only nine EU Member States possess larger freshwater resources per capita than the US, which has 9 344 m3 per capita per year. The environmental (and social) implications of water use for shale gas exploitation needs to be assessed carefully, on a case-by-case basis. While the overall water footprint of shale gas production might be negligible in terms of national per capita water resources, on a local scale the production of shale gas could have a substantial impact on freshwater supply. Seasonal variations in water supply should also be taken into account.

Operators are currently exploring ways to use and recycle the water produced from hydraulic fracturing. The use of recycled water could significantly reduce the demand for surface water withdrawal and wastewater treatment or disposal.  Europe’s stringent regulation combined with industry initiatives such as this one will help to ensure a growing public confidence, which is necessary for the unconventional gas resources to be translated into reserves.

**Seismic Risks**

Land subsidence has for a long time been associated with coal mining activities.  The removal of material causes overlying surface rock to sink or collapse. However, this is also happen with conventional oil and gas production.  A case study is the Groningen field in the north of the Netherlands. The phenomenon of tremors is as such not unique to shale gas exploitation.

A good example a positive interaction between a unconventional gas company and the general public is Cuadrilla Resources’ reaction to tow tremors near its Blackpool site.  Drilling activity by Cuadrilla Resources at a site near Blackpool in the UK was voluntarily suspended in May 2011 while investigations took place into whether hydraulic fracturing operations caused two small tremors.  An independent study commissioned by Cuadrilla Resources concluded that the seismic events were due to an unusual combination of geology factors at the well site coupled with the pressure exerted by water injection as part of operations. The authors of the report noted that the combination of geological factors was extremely rare and unlikely to occur together again at future well sites.

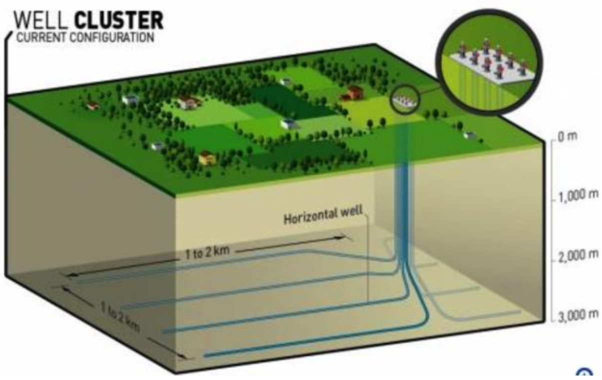
**Surface physical impact**

In densely populated Europe, access to land and land usage will to be important issues.
Wells in an "unconventional" formation drain a smaller volume of rock than wells in a conventional gas reservoir.  The resulting physical footprint for an unconventional gas

development, therefore runs the risk to be significantly larger than that of a conventional oil or gas field development.

To limit the physical footprint of the operations, the industry developed the technology to allow wellheads to be grouped together in clusters. These superpads enable the drilling of multiple horizontal wells from a single pad (up to 10 to 15 horizontal wells). This significantly helps to reduce the geographical footprint of for instance gas shale operations. It also reduces the need for new transport infrastructure and minimizes the site traffic on roads.

**Figure C-6-3 Concept of well cluster development**




*Source: Total's "Shale Gas and Tight Gas: Multifractured Horizontal Wells "*

## 7. Social acceptance of unconventional gas

National energy policy considerations, including security of supply concerns and, emissions targets, will shape individual countries' attitudes to unconventional gas development. This, coupled with a lack of consistent evidence on the impact of hydraulic fracturing on the environment and public health, has resulted in a situation where opinion on shale gas development in Europe has become polarized.

There are many social issues related to the acceptance by the general public in Europe of the shale gas industry. Europe has a high population density and stringent environmental regulations. Issues like noise pollution might be more of a problem in densely populated regions of Europe than what the US experience might suggest.

In 2012, the European Commission commissioned a public consultation on the future development of unconventional fossil fuels such as shale gas. Almost 23,000 people from across Europe participated in the consultation. The majority of respondents agreed that there is

- a need for more public information and
- a lack of public acceptance of unconventional fossil fuels.

The study findings suggest that around 60% of the EU public is opposed to shale gas production when statistics are weighted by population in each member state.

The divergence of opinion is perhaps best illustrated by the differing policy positions of Poland, the UK and France.

- Less than 5% of individual respondents from Poland believe that unconventional resources should not be developed in Europe. The Polish Government is also very supportive of shale gas development. However, the initial excitement has been tempered by significant downgrades to resource estimates, mixed drilling results, exits of some large companies and uncertainty over the regulatory regime. As a result, progress to date has been fairly slow, with only around 50 test wells drilled in Poland by mid-2013.

- On 30 June 2011, France became the first country in Europe to ban hydraulic fracturing. The permanent ban replaced a temporary suspension of shale drilling activity that had been put in place earlier in the year. Operators with shale gas acreage in France opposed the ban, claiming that, while alternatives to hydraulic fracturing exist, they may not be economically viable. However, French President Francois Hollande has ruled out exploration for shale gas during his presidency.

- In contrast, the UK Government is a strong supporter of unconventional gas development and established an Office of Unconventional Gas and Oil to focus regulatory effort. The UK Government is also considering offering fiscal incentives to local communities to gain their support for shale gas exploration.

- The public opposition to the development of shale gas in Germany is gathering momentum. The German state of North Rhine-Westphalia has announced that it will no longer permit exploratory drilling projects using hydraulic fracturing until it receives the findings of a study it has commissioned into the environmental risks associated with shale gas.

It is correct to state that the European public has not yet giving the unconventional gas industry a "license to operate". They are waiting for the results of in-depth studies to be carried out on the environmental impact of shale gas exploration before fully accepting its development in their own countries. The industry needs to recognize that there are important research areas related to hydraulic fracturing other than those involving drinking-water resources that both Governments and the general public are waiting for. These include: potential effects on air quality, ecosystem impacts, seismic risks, public safety concerns, occupational risks and economic impacts.

To get its “license to operate” the industry will have to work with the various levels of Governments in Europe:

- Governments need to promote public confidence in the regulation of shale gas activity, and
- operators need to demonstrate that their operations are sustainable and properly managed.

Environmental concerns are likely to bolster public support for a strengthening of the regulatory regime governing shale gas development.

The industry not earning the trust of the general public, not earning its “social license to operate,” will result in a bolstering of the public support for a strengthening of the regulatory regime governing shale gas development.

## 8. A Pan-European Legislation not for tomorrow

Requests for European Commission action to ensure the safe and secure extraction of unconventional fuels is steadily growing louder and more frequent. The emergence of European unconventional gas industry poses a dual question for the EC, i.e. whether the existing EC regulations are sufficient to ensure the integrity of the natural environment, and, whether the existing EC regulations are sufficient to ensure a stable and predictable environment for the industry to development to its full potential.

The European Parliament adopted two resolutions in November 2012 respectively on environmental impacts[13] as well as on industrial, energy and other aspects of shale gas and shale oil[14]. In October 2013, the Committee of the Regions issued an opinion[15] providing the perspective of local and regional authorities on unconventional hydrocarbons.

Since 2012 the Commission has published three studies on unconventional resources. The studies look at

- the potential effects of these fuels on energy markets,
- the potential climate impact of shale gas production, and
- the potential risks shale gas developments and associated hydraulic fracturing may present to human health and the environment [16].

In order to canvas the public sentiment around the unconventional fuels, including shale gas, the European Commission launched at the end of 2012 a public consultation titled „Unconventional fossil fuels (e.g. shale gas) in Europe". The consultation was closed on 23rd March 2013. Most respondents asked for additional EU action related to unconventional hydrocarbons (e.g shale gas) developments in the EU [17]. The results of the public consultations (http://ec.europa.eu/environment/integration/energy/pdf/Shale%20gas%20consultation_report.pdf) together with the results of the reviews of environmental regulations are expected to help the Commission in taking decisions regarding further steps leading to a potential detailed regulation of unconventional gas development.

There is an ongoing debate within the European Union concerning the principles that should apply in Europe in respect to unconventional gas exploration and production. The priority is to balance the environmental interests and the security of gas supply to Europe. The current status of environmental protection regulations and their implementation by entities engaged in unconventional gas exploration and production activities is being verified in order to obtain assurance that the EU regulatory framework is sufficient to guarantee a high level of environmental and human safety.

The Commission agreed to develop a framework for safe and secure unconventional hydrocarbon extraction in the EU following the objectives:

– to ensure that opportunities to diversify energy supplies and to improve competitiveness can be safely and effectively taken up in those member states that choose to do so,
– to provide clarity and predictability for both market operators and citizens, including for exploration projects,
– to fully consider greenhouse gas emissions and management of climate and environmental risks, including to health, in line with public expectations.

On 22 January 2014 the European Commission released a communication on shale gas and an accompanying recommendation on shale gas regulation. The recommendation sets out non-binding minimum principles for member states who wish to carry out hydrocarbon exploration and production using "fracking". The recommendation applies to "fracking", which is defined as the

13 http://www.europarl.europa.eu/sides/getDoc.do?type=TA&reference=P7-TA-2012-0443&language=EN
14 http://www.europarl.europa.eu/sides/getDoc.do?type=TA&reference=P7-TA-2012-0444&language=EN
15 http://cor.europa.eu/en/news/Pages/fracking-environmental-impact.aspx
16 Regulation 1907/2006/EC on the Registration, Evaluation, Authorisation and Restriction of Chemicals (REACH)
17 http://ec.europa.eu/environment/integration/energy/pdf/Shale%20gas%20consultation_report.pdf

process of injecting 1,000m3 or more of water per fracturing stage or 10,000m3 or more of water during the entire process into a well. Key elements of the recommendation are:

- a strategic environmental assessment is carried out prior to granting licenses for hydrocarbon exploration and/or production which are expected to lead to operations involving fracking.
- a site specific risk characterisation and assessment is carried out, relating to both the risks underground and above ground.
- baseline reporting (e.g. of water, air, seismicity) takes place, in order to provide a reference for subsequent monitoring or in case of an incident.
- the public is informed of the composition of the fluid used in the process on a well by well basis as well as on waste water composition, baseline data and monitoring results.
- drilling wells are properly insulated from surrounding geological formations.
- venting (release of gases into the atmosphere) is limited to exceptional operational safety cases, flaring (controlled burning of gases) is minimised, and gas is captured for subsequent use (e.g. on-site or through pipelines).
- operators provide a financial guarantee (or equivalent) covering the permit provisions and potential liabilities for environmental damage prior to the start of operations.

The recommendation provides that its effectiveness will be reviewed 18 months after its publication. Subsequent to the review, the Commission will decide whether it is necessary to put forward legislative proposals with legally-binding provisions on the exploration and production of hydrocarbons using fracking. In the recommendation, member states are “encouraged” to apply the minimum principles.

The Commission is also reviewing the current reference document (BREF) on extractive waste under the Mining Waste Directive. The aim is to ensure that the BREF covers the management of waste from hydrocarbon exploration and production involving fracking, in order to ensure that waste is appropriately handled and treated and the risk of water, air and soil pollution is minimised.

It will also propose that the European Chemicals Agency makes certain changes in the existing database of registered chemicals under the REACH Regulation (which regulates chemicals) so as to improve and facilitate the search of information on registered substances used in the process.

Further, a European Science and Technology Network on Unconventional Hydrocarbon Extraction will be established. This is intended to bring together practitioners from industry, research, academia and civil society and will collect, analyze and review results of exploration projects. It will also assess the development of technologies used in unconventional gas and oil projects.

These activities of the Commission give a clear indication that the EC intends to work towards a EU-wide legislation covering environmental standards in shale gas extraction. However, despite all these efforts, the options for the EC to create a pan-European regulatory framework governing the unconventional gas (&oil) activities are limited. The recommendation falls far short of the prescriptive legislation anticipated and sets out a voluntary approach to fracking, aimed at ensuring a minimum standard. The EC has no jurisdiction over sovereign states' subsoil laws or resource development programs.

Member states have the responsibilities to decide their energy mix, as long that their strategies and legislation comply with the environmental rules. The hydrocarbon regulation drafted by individual states – often years ago - for conventional exploration and production activities may not apply to or stimulate the development of an unconventional gas & oil industry in Europe. At present, different national standards and safety requirements hinder the transfer of equipment and techniques between countries. Such a pan-European regulatory framework would require unanimous support from all member states, an almost insurmountable feat. For instance, Poland and the UK are bound to veto any attempt to limit shale gas development through new EU-wide regulation.

## 9. Europe's oil field service industry

The service level intensity for shale gas development is typically higher than for more conventional oil and gas developments. A study by Boston Consulting and Gény compares the cost of drilling a shale well in Europe with the costs in the US and estimates that overall a well cost in Europe are at least 200% higher than in the US.  The study identifies the following parameters as the main reasons:

- the less developed geological knowledge,
- the higher population density,
- the less competitive oil service industry,
- the dearth of rigs and qualified staff to operate installations,
- the reduced scope for standardization due to more heterogeneous shale plays,
- the higher depth of the shale plays,
- the scarcer water resources, and
- the higher infrastructure cost

A few of these parameters are discussed in the following paragraphs.

**Preparing a drilling site, mobilizing suppliers and equipment** refers to mobilizing suppliers and bringing the equipment (rigs, casing, tubing, etc.) on site. The low number of drilling rigs in Europe is especially critical in that respect.  Europe has fewer than 50 onshore rigs actively exploring for or developing oil and gas at any one time, compared with up to 2,000 in the US.   Because of the poor rig availability and the higher costs of the oil service industry, it is estimated that costs for these activities are 50% higher in Europe than in the US.

**Table C-9-1  Worldwide rig count.**

BAKER HUGHES INCORPORATED

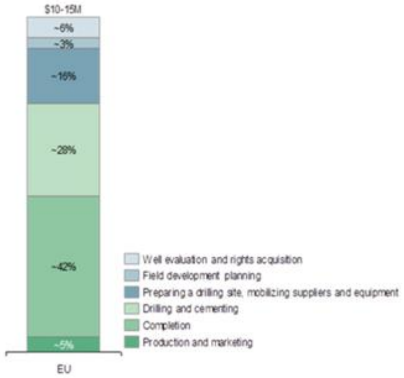
WORLDWIDE RIG COUNT

| 2015 | Latin America | Europe | Africa | Middle East | Asia Pacific | Total Intl. | Canada | U.S. | Total World |
|---|---|---|---|---|---|---|---|---|---|
| Jan | 351 | 128 | 132 | 415 | 232 | 1258 | 368 | 1683 | 3309 |
| Feb | 355 | 133 | 132 | 415 | 240 | 1275 | 363 | 1348 | 2986 |

*Source: Baker Hughes*

**Drilling and cementing**.  The drilling of an unconventional gas well well can take up to two months, with drilling costs ranging  between €75,000 to €126,000 a day.  As Europe has a higher geological heterogeneity of shale plays than the US, there is less scope for standardization of well drilling, leading to a 40% higher cost. Also, shale plays in Europe are deeper than in the US, driving up the cost another 20%. The higher cost of the service industry in Europe adds another 20%.

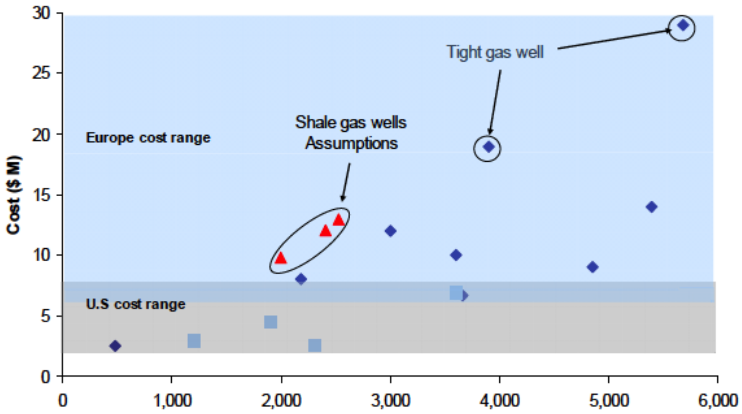
**Figure C-9-1  Estimated total cost of a shale gas well in Europe**




*Source: Insead's "Europe's shale gas competitiveness challenge and consequences for the petrochemical sector" - Karel Cool, March 15, 2013*

**Completion** activities relate primarily to hydraulic fracturing or "fracking." Completion amounts to more than 40% of the total cost of the well. The cost of water is a key cost component for this stage and is substantially more expensive in Europe than in the US. The OECD notes that industrial customers in the US pay \$0.33/m³ in rural areas whereas rates for comparable use are \$1.5/m³ in Germany, \$1.05/m³ in the Netherlands and \$1.23/m³ in the UK. This generates an estimated increase of 10% for the completion costs compared to the US. The service industry is again required, adding another 20% extra to completion costs. Infrastructure (i.e. petrol, water treatment) is also more expensive in Europe than in the US, increasing the completion costs by a further 20%.

**Figure C-9-2 Shale gas well total costs in Europe and the US**




*Source: The Oxford Institute for Energy Studies – NG 46, Can Unconventional Gas be Game Changer in European Gas Markets? Florence Geny, December 2010*

It is highly unlikely that a major part of the US land rig feet will relocated to Europe. Not all US equipment is suitable for use in Europe, where the geology is different. US equipment does not necessarily meet the standards mandated in Europe. Bringing the US equipment in compliance to European standards will involve additional investments in the equipment and delays in the import process. Moreover, the transport of equipment across European borders might be hindered by differing regulatory requirements and health and safety standards among EU member states.

For the development of the European unconventional gas resources to take off new, high-specification equipment is needed. This will require in turn a significant capital expenditure and firm commitments from operators. So, most industry observers do not expect to see shale gas production across Europe reach commercial levels for at least another 10 years. Given the lead time to first production and the likelihood that developments will evolve more slowly, this will give the service industry the breathing room needed to gear up to meet the requirements of the industry.

## 10. Conclusion

There is limited evidence of possibilities for a prosperous unconventional gas development in Europe, in the short or medium term. The unconventional gas potential in Europe is generally estimated to at best compensate the declining indigenous conventional production.

As a result of the great success of unconventional gas production in the US, industry players got - around the turn of the century - interested in Europe’s significant unconventional gas resources. Governments – including the EU – supported this unconventional gas drive, mainly because of its potential to reduce Europe’s dependence on imports. Advocates of shale gas development in Europe put forward improved energy security as one of the key benefits, helping countries become more self-sufficient.

However, the journey towards an economically attractive development of Europe’s unconventional gas industry has – thus far – turned out to be more challenging than initially thought. Despite its abundance and advantages of less clean-burning fuels, a number of risks could impact its future viability:

- **Geology and resource potential.** The geology of Europe’s unconventional resources is more complex than initially anticipated. The extension of these resources, the characteristics of the reservoir, including the gas deliverability, the natural fracture system … they all need further data gathering to better understand the uncertainties and risks. This subsurface knowledge gap is hampering the development of unconventional gas in Europe.

- **Environmental concerns.** The experience of unconventional gas exploitation is very limited with only a moderate number of shale gas wells drilled, and only a handful being fracked. The lack of understanding how to stimulate the production from Europe’s unconventional gas resources puts a significant upwards pressure on costs associated with the exploitation of these resources.

- **Social acceptance.** Europe’s high population density restricts intensive vertical drilling across vast areas. This necessitates the industry to rely on horizontal pad drilling and fracking to access sufficient reservoir rock to make an unconventional gas development economically attractive. The relatively low water availability per capita ratio in Europe is another constraint the industry will have to deal with going forward.

- **Regulatory regime.** The underground resources are the exclusive property of national governments, providing no incentives for private initiatives and for local communities to support the exploitation of the unconventional resources.

- **Service industry capabilities.** The scarcity of innovative smaller players in Europe’s unconventional gas industry is evidenced by the shortage of drilling equipment and trained staff. A successful economic exploitation of Europe’s unconventional resources dependents on all European governments working towards creating a diverse and highly competitive energy sector accommodating a number of smaller and independent venture companies that continuously refined shale gas technology, along with a large number of service companies.

- **Gas transmission infrastructure.** The EU gas market and pipeline infrastructure is still largely monopolised by large companies that dominate the EU energy sector.

Economic and population growth will continue to put pressure on the world's energy supplies, and so all fuel sources– including Europe's unconventional gas resources - will be needed. The industry has always changed, and has caused changes in the societies in which it operates. The schismatic changes of the 1970s opened a new era.

The combination of changes that Europe's unconventional gas industry now faces requires a visionary response embedded in a transformational evolutionary path rather than epic, revolutionary responses, for the industry to evolve and prosper. Those responsible both inside and outside the industry need to try to understand what is happening now and how it may affect the future, to explain their strategies clearly and to adapt to new situations as they develop. In a world where technology and environmental threats are changing industries and society so rapidly, the slowly turning LNG-supertanker is not an image that excuses inertia in the industry and those who deal with them. All who are in the industry or who are involved with it need to share clear thinking about the future.

## 11. Recommendations

Many industry players hope that the US shale gas revolution can be replicated in Europe. However, the unconventional gas debate across Europe has become increasingly contentious, and environmental concerns are likely to bolster public support for a strengthening of the regulatory regime governing shale gas development.

Realizing the potential for shale gas as a profitable alternative energy source requires all stakeholders in this debate to work together, requires a constructive dialogue between the industry, the public in general and the local communities in regions effected by the exploitation in particular and the government, ranging from the local government all the way to the EU legislative bodies. Private companies cannot develop a full-scale shale gas industry on their own. They need governments to support them with a combination of direct financial incentives and investments in transportation infrastructures. Governments also need to facilitate a dialogue between the industry and the public. Such a dialogue is essential to define the right balance between the economic benefits a rapid development of an unconventional gas industry would bring to Europe's economies and the environmental cost Europe is willing to pay to harvest these benefits.

The opportunity exists for the European gas industry players to take the lead in setting up and formalizing this dialogue, by focusing the engagement with governments and the public on the following topics:

- **Technology and collaboration are the keys to an acceptable exploitation of Europe's upstream unconventional gas reserves.**
  Research is not at a standstill, and new technologies will be developed that will help lower the cost of gas extraction in Europe from unconventional resources and improve the efficiency of development and production activities. Local service companies will carve out new revenue streams and gain a foothold in unconventional gas development activity across Europe. Small- to mid-cap independent companies will focus on the nascent shale gas industry in Europe. The timing and the scale of the impact of a successful technological breakthrough heavily dependent of this dialogue.

- **Financing future investment is not a question of quantity but of quality: matching opportunities and risks with sources of funds.**
  Finance for the private sector in Europe's unconventional gas development depends on investors' beliefs about growth, risk and the prospects for positive change. Inertia is not an option if the industry is to maintain and improve the terms on which it gets finance.

  For investors who look for growth in value or volume, many private-sector companies currently involved in Europe's unconventional gas sector seem configured for the "conventional" era and not for the "future"; their public strategies look recycled, not renewed. Few of the European unconventional gas players seem to question the arguments for vertical integration and there is a legacy of implied obligations to 'meet demand' rather than to engage with the changing forces shaping that demand.

- **The industry needs to control reputational risk and turn public opinion around.**
  Negative public opinion about the environmental safety of the hydraulic fracturing process is undermining the development of this industry, particularly where the process is used in – or directly under – populated areas. Many industry members realize that more needs to be done to change public opinion and promote public confidence. Producers need to show that they fully understand the geology of shale gas formations and know how to model the

impact of hydraulic fracturing with accuracy. As the reputational impact of Japan's nuclear incident keeps on showing, any environmental or safety lapses could tarnish the entire industry and attract more regulation. Any risks that are shown to be linked to shale gas development need to be balanced with its potential contribution to energy security and economic development. All industry players will need to commit to adopting leading practices to mitigate environmental impact, preserve reputation, and avoid more stringent regulation which could preclude growth of the industry.

- **Europe's energy security issue.**

  The geopolitics of gas are changing fundamentally as interregional trades divides between the Atlantic Basin and Asia-Pacific markets. For Western countries, the risk is price, not supply, since disruptions to Asian supplies will affect the gas price.

  There is no denying of the economic benefit of an unconventional gas industry could bring to countries in Europe. The increase in government revenues from taxes on shale activity, and private sector job creation, would be especially welcome in these times of fiscal austerity. The chemical industry in Europe is facing severe threats to the extent where its survival is at stake. Helped by the gas shale boom, the natural gas costing to the chemical industry in US has reduced from 12$/MBTU to 3$/MBTU whereas the costing for natural gas has been oscillating in Europe between 8$/MBTU – 11$/MBTU. Such a huge price differential definitely attracts investment in favor of the US companies.

  Political and physical security measures have not yet caught up with these new realities. Unconventional gas will undoubtedly have important – and unpredictable – strategic implications on geopolitics and the energy industry. The development of shale gas production in Europe and potential imports from the United States could help ease European reliance on Russian gas. In turn, Russia will need to develop its capacity to deliver its natural gas to new markets.

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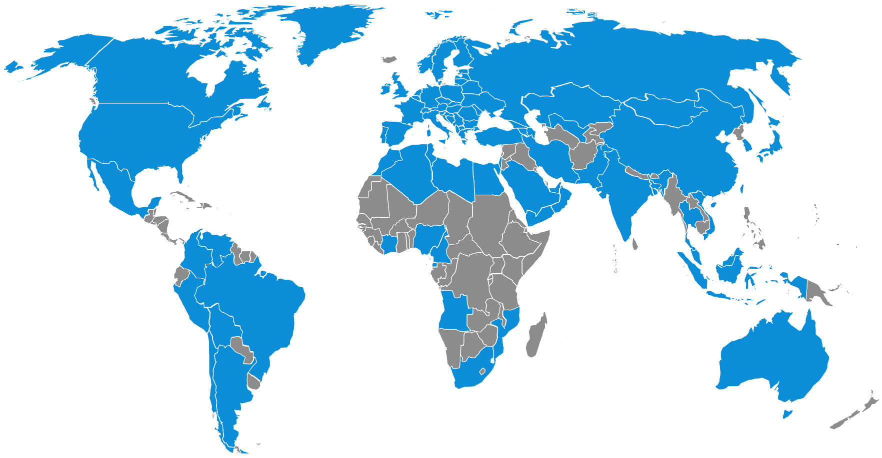

The International Gas Union (IGU) was founded in 1931 and is a worldwide non-profit organisation promoting the political, technical and economic progress of the gas industry with the mission to advocate for gas as an integral part of a sustainable global energy system. The IGU has more than 142 members worldwide and represents more than 97% of the world's gas market. The members are national associations and corporations of the gas industry. The working organisation of IGU covers the complete value chain of the gas industry from upstream to downstream. For more information please visit **www.igu.org**

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