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The Uncertainty of Future Commercial Shale Gas Availability

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Abstract

Numerous top-down resource estimates have indicated that shale deposits hold enormous volumes of methane globally. Until recently detailed delineations of shale gas resources and their production have occurred exclusively in North America. The driving forces and enabling conditions behind the rapid exploitation of shale gas resources in North America are assessed to determine if these are transferable to the rest of world. No two shale deposits are created equal and the mere existence of shale does not guarantee success of future gas production. A formation may hold too little oil or gas — or it may not be brittle enough for fracking to work effectively. The challenge is to find so-called 'sweet spots', i.e., plays with high flow rates, once stimulated. The amount of shale gas that can be commercially produced under current and future market conditions is determined by the quantity and thermal maturity of shale's organic content, by regional technology cost, access to transmission pipelines and regional gas price levels. The shale gas rush in North America has caused a precipitous drop in natural gas wellhead prices - from some \$11/GJ in 2008 to less than \$3/GJ in 2012. A review of the economics of shale gas production indicates that (a) the resource appraisal process for conventional gas resources is unsuitable for unconventional gas resources; (b) field development requires continuous (on-the-go) investment in fracking to stimulate well pressure, and (c) depressed US gas prices currently fail to cover full finding and development costs. Unless well technology improves and completion cost declines rapidly, the maturation process of technically recoverable shale gas resources to proved reserves will be delayed. Time value of money effects undermine the commercial availability of shale gas, particularly in regions where ineffective permitting procedures and slow societal acceptance tend to put additional negative pressure on shale field development speed.

Introduction

Shale is the most abundant sedimentary rock on Earth. Known for quite some time to host enormous quantities hydrocarbons, commercial extraction was long hampered by a lack of geological resource delineation, high finding and development costs and insufficient flow rates (due to low permeability of shale formations) when tapped with conventional gas production technology. Until the Millennium turn, shale gas production had supplemented US natural gas supplies for decades albeit at a very low rate of 1% to 2% of total supply. This changed fundamentally in the early years of the 21st century when rising US wellhead gas prices stimulated the large-scale extraction of shale gas from the Barnett play in Texas. The perseverance of the entrepreneurship of Mitchell Energy and advances in shale gas extraction technology played a primary role in the successful development of the Barnett play. This early success in producing shale gas at competitive cost jump-started the US shale gas boom (Wang and Krupnick, 2013). By 2012 shale gas production reached 9.7 trillion cubic feet (Tcf) or almost 40% of total US dry gas production (EIA, 2013a).

Rapid market penetration of shale gas led to oversupply in the North American gas market and gas prices plummeted from an annual average of \$10.40/GJ in 2005 to \$2.61/GJ in 2012 (EIA, 2013b). While this precipitous drop in natural gas prices has generated sizable consumer benefits, at the same time it wiped-out producer rents. Still, shale gas production kept growing despite prices hardly recovering from this low level during a period of rather depressed demand due to the lingering economic recession. Meanwhile, rig counts have begun to decline and mimic the decay of gas prices, indicating that shale gas producers at current prices hold back on further investment in dry gas production capacity. While this is common business sense there are other factors that may affect the future of shale gas economics. Commercial shale gas availability is the result of a myriad of sub-surface and surface factors aligning favorably ranging from in-place resources (gas-in place), the technically recoverable

part of resources and technology advances in finding sweet spots to gas market prices (break-even prices), expected rates of return, regulation and public acceptance (Kuhn and Umbach, 2011; Weijermars, 2013a,b). This paper briefly reviews these factors and attempts to shed some light on the uncertainty of future commercial shale gas availability.

Regional spread of shale gas resource estimations

While shales are the most abundant sedimentary rocks in the Earth's crust, this does not automatically imply the presence of sufficient total organic content (TOC) - a prerequisite for potential oil and gas in place. Next, even a sufficiently high TOC of least 2% is no guarantee for technically, let alone economically, recoverable gas volumes. Resource assessments such as the joint effort carried out by the US Energy Information Administration (EIA), US Geological Survey (USGS) and Advanced Resources International (ARI), therefore, first estimate a value for total gas-in-place based on the shale deposit's geological structure and depositional environment, depth, thickness and geographic extent, TOC and thermal maturity. The gas-in-place is then "risked", i.e. factors such as current state of technology, other relevant knowledge about the deposit such as prospective flow rates, and data quality are taken into consideration (EIA, 2013c).

Applying recovery factors to the risked gas-in-place derived from the geology and resource recovery rates of analog shale formations in developed plays leads to estimates of "technically recoverable resources" (TRR). Typical recovery factors range from 15% to 35% - a wide range reflecting the uncertainty associated with any shale resource assessment (EIA, 2013c). Still the TRR neither provides any hard information on the estimated ultimate recovery (EUR) nor about the long-term financial viability of wells drilled in a particular play. Clearly, the ultimate size of TRRs and the commercially recoverable part (EURs) are subject to change as knowledge, exploration and production experience accumulate.

Global shale gas resource assessments have a relatively short history. A first assessment by Rogner (1997) based on a comprehensive literature review estimated total gas-in-place of 16,100 Tcf of which close to 6,000 Tcf was considered recoverable. The most recent assessment of global shale gas resources carried out by ARI on behalf of EIA (2013c) evaluated the in-place and technically recoverable oil and gas of 95 shale basins and 137 shale formations in 41 countries. Fig. 1 shows the global distribution of the assessed shale basins (red shade).
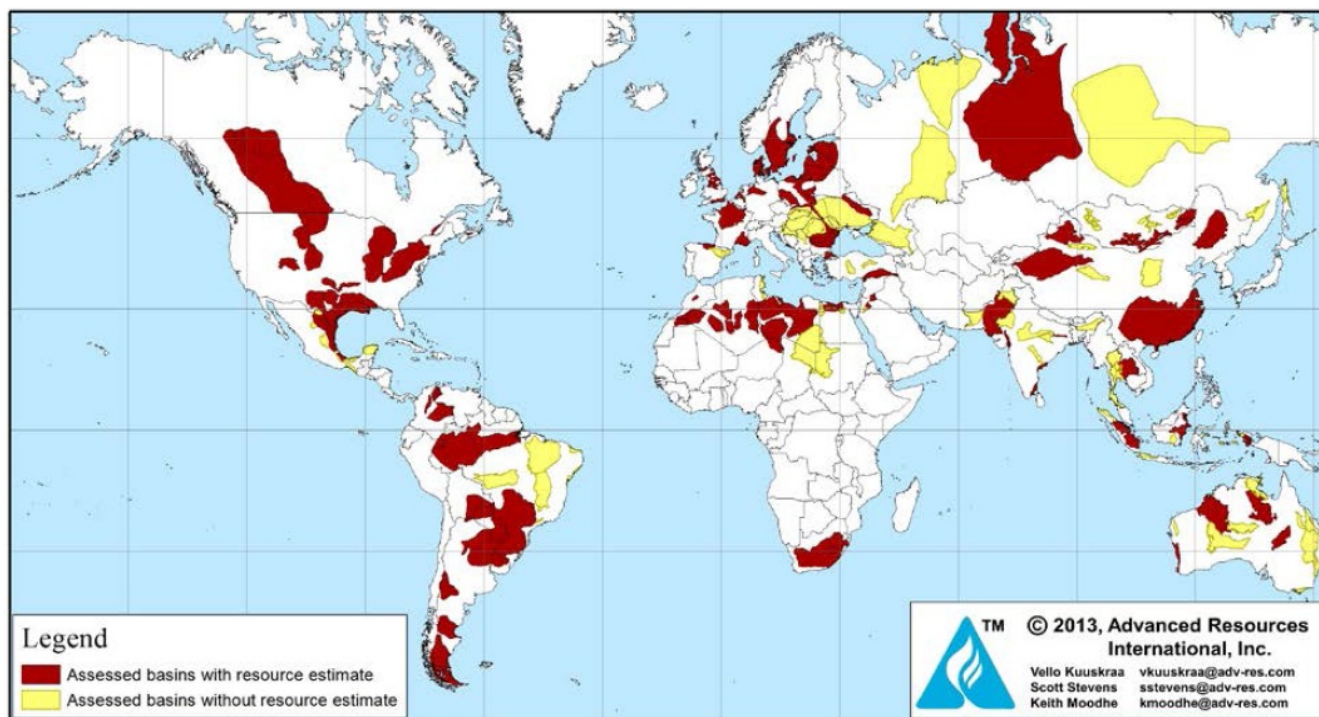
Figure 1: Shale basins assessed in the latest ARI study (EIA, 2013c).

According to Fig. 1, there are still large areas (yellow shade, portions of white and even shallow offshore shelves) which have yet to be assessed. Even with this limited coverage, the assessed gas-in-place (35,800 Tcf) and TRR (7,800 Tcf) are already enormous (see Tab. 1). To put the global TRR of 7,800 Tcf of shale gas resources into perspective, global conventional natural gas reserves are assessed at some 6,600 Tcf (BP, 2013). While the conventional gas reserves are proved according to the Petroleum Resources Management System (PRMS) (PRMS, 2007; SPE, 2011), shale gas resources are

contiguous at best. These shale resources need further investigation and final investment commitment to mature into reserves. It is worth noting that additional conventional gas resources of 6,800 to 8,400 Tcf are identified (GEA, 2012). Reserves reported by BP, Oil&Gas Journal or USGS are generally those quantities that geological and engineering information indicate with reasonable certainty that can be recovered in the future from known reservoirs under existing economic and operating conditions (BP, 2013). The USGS and the German Federal Institute for Geosciences and Natural Resources (BGR) also report conventional resources, i.e., detected quantities that cannot be profitably recovered with current technology, but might be recoverable in the future, as well as those quantities that are geologically possible, but yet to be found.

Table 1: Risked shale gas-in-place and technically recoverable resources (source: EIA, 2013c).

Continent	Risked gas-in-place (Tcf)	Risked technically recoverable (Tcf)
North America w/o USA	4,647	1,118
USA	4,644	1,161
Australia	2,046	437
South America	6,390	1,431
Europe	4,895	883
Africa	6,664	1,361
Asia	6,495	1,403
TOTAL	35,782	7,795

A comparison of the 2011 and 2013 assessments by ARI (EIA, 2011, 2013c) reveals that the 2013 assessment includes both sizable upward and downward revisions of estimates for major shale basins. Data from exploration wells drilled after 2011 in several countries outside the USA and Canada have helped delineate the resource size and quality. However, the overall increase of gas-in-place in shale basins is gigantic and the net increase of TRR is primarily the result of the wider geographical coverage of the 2013 assessment. The global volumes of gas-in-place are generally not contended and expert opinions begin to diverge on TRR due to uncertainty about recovery factors. The divergence of expert opinions - and thus uncertainty - is even wider when volumes of economically recoverable shale gas are debated.

Uncertain economics

Estimations of shale gas TRR are largely determined by (a) subsurface factors such as TOC, permeability, depth, pressure, homogeneity, single or multiple layer reservoirs and (b) technology performance such as exploration, drilling and well stimulation techniques. Economically recoverable resources (ERR) require additional conditions. Gas demand and gas market prices are the most important determinants followed by the up-front investment costs for field development, terms of finance and return-on-investment expectations. Other factors influencing ERR include (but are not limited to) environmental legislation, mineral rights, population density, proximity to gas transmission/delivery infrastructures and public acceptance.

The economic development of any shale gas resource faces three major uncertainties. First, no two shale basins are created equal. Hence the knowledge gained from the development of one play is not necessarily transferable to another play. Given the relatively short history of shale gas exploration there is still ample opportunity for moving up the learning curve, especially for better estimating the ultimate recovery (EUR) of a well in the early stages of play development. Second, the accumulated exploration and production evidence from the Barnett, Haynesville-Bossier, Fayetteville, Woodford, Eagle Ford and Marcellus formations seem to indicate that the commercially viable plays are not uniformly distributed but concentrated in limited sections of their respective basins. Traditional approaches to resource assessments, therefore, tend to overestimate recoverable gas reserves. The third factor is the production profile of a well over its lifetime (as well as the lifetime itself). Unlike conventional gas (vertical) wells that produce relatively stable volumes of gas of up to 25 years and more, declining productivity rates of horizontal shale gas wells of 40% to 60% from the initial output level have been observed during the initial 24 months of well operation (USGS, 2012; Hughes, 2013).

The unprecedented growth of the North American gas output was enabled by a long streak of very creative financing. Cheap credit and risk prone investors (and not operational profits on shale gas sales) essentially fuelled the rapid expansion of shale gas production in the US (Weijermars, 2012; Hughes, 2013). The advent of shale gas caused a situation of excess supply which depressed prices and gas demand did not respond to lower prices – most sectoral gas demand has been flat since 2008 in large part due to the on-going economic recession. Exceptions have been the electricity generating sector and to a lesser extent the petrochemical industry (see Fig. 2). In electricity generation surplus gas has displaced coal. In the absence of carbon

dioxide emission regulation, this market is essentially determined by price competition with coal and thus limits any upward gas price flexibility. The US petrochemical industry improved its international competitiveness thanks to cheap gas supplies.

Depressed North American gas prices have brought a significant number of US and Canadian shale operators to the brink of financial collapse (Weijermars and Watson, 2011). Private investors have financed the North American shale gas boom, but the industry has been losing money on practically every shale gas well drilled in the past five years. With prices hovering between $3/GJ to $3.50/GJ, the industry responded by reducing drilling activity as shown by the decline of the rig count, i.e., the number of active rigs operating in the field (see Fig. 3). Plans to build a dedicated high pressure export pipeline to Mexico, and refurbish LNG ports with liquefaction trains to export LNG to Europe and Asia are underway, but this takes time and US gas prices have only modestly gained since these plans were announced. The production of shale gas itself clearly is not bringing easy profits, although shifting to shale gas liquids may improve margins (but only by small fractions). What is needed in the short run is production cutbacks to increase the Hotelling rent on gas production. In the longer run, improved exploration and production technologies need to be developed at lower cost, especially for finding the optimal development of known strata and "sweet spots".
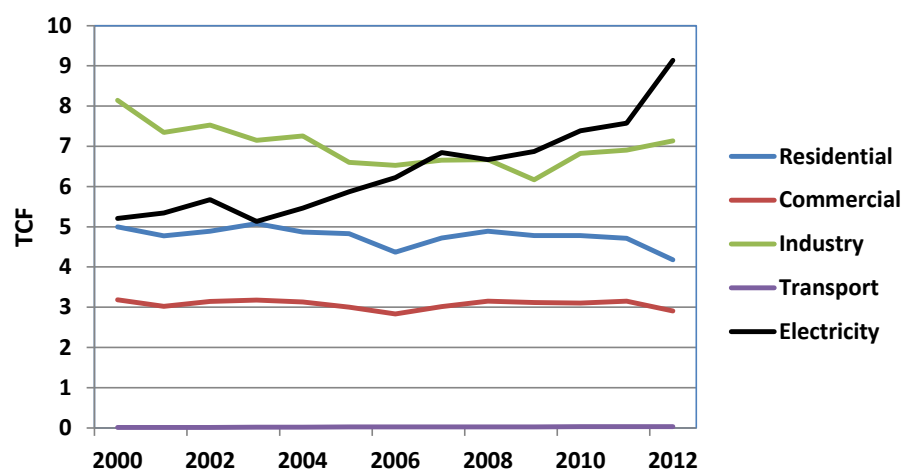

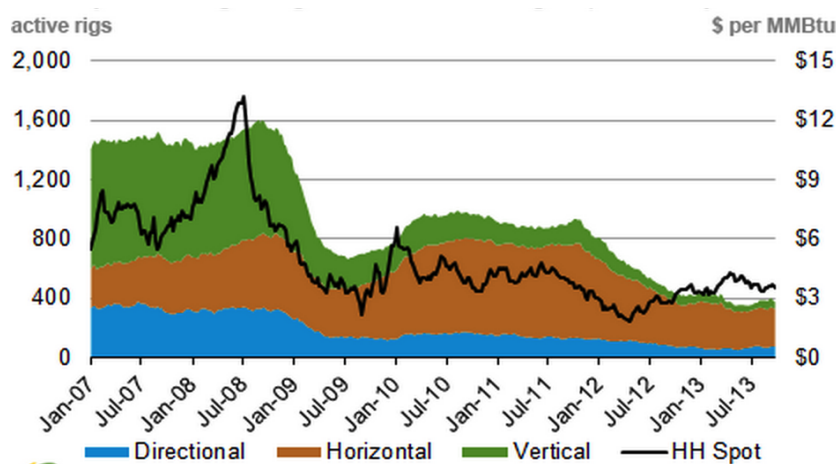Figure 2: US gas demand by sector (source: EIA, 2013d).
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Figure 3: Weekly natural gas rig count and Henry Hub (HH) gas spot price (source: EIA, 2013e).

Because of the need for horizontal drilling and hydraulic fracturing, production of shale gas is inherently more costly than conventional gas. According to Lake et al. (2012), drilling the well accounts for approximately 60% of total investment with well completion, essentially the hydraulic fracturing stage, making up the remaining 40%. Shale gas development presents also higher risks than conventional gas development. The productivity of a shale gas deposit cannot be known until after the well has been fractured and the bulk of the costs of completing the well have been expended. Consequently, the option to shut-in the well prior to incurring the costs of completing the well is not as valuable for shale gas wells as for conventional gas wells. In the latter case measurements taking during the drilling allow the discontinuation of well development (shut-in of the well) if insufficient well productivity is indicated or gas prices fall precipitously.

The investments in existing shale gas wells represent 'sunk costs' and producers will operate them as long as gas prices cover variable production costs which for most existing US shale gas wells is still the case. At investment costs of up to $9 million per well and more (Lake et al., 2012; Hughes, 2013), current gas prices do not support an expansion of shale gas production. Rather the industry is facing the dilemma of rapidly declining well productivity - a characteristic of horizontal drilling and hydraulic fracturing which despite the usual multi-stage fracking approach per fracking only opens a limited domain of productive area per fracking. This means that a dependable supply of natural gas from shale formations requires a sustained program of drilling, completion, and exploration (Lake et.al, 2012) just to maintain current levels of shale gas output. This investment is presently not forthcoming (see rig count in Fig. 3). This is unlikely to change unless gas prices return at least to the $6/GJ to $7/GJ range.

Technology gains versus gas price volatility

Shale assets will be more expensive to produce than the past legacy oil and gas conventional fields. However, shale gas drilling on land costs only a fraction of the wells drilled in the frontier reservoirs of the last remaining conventional hydrocarbons located in deep and risky off-shore basins. Kruuskraa (2010) noted that higher quality gas shales are "today the low cost portion of the natural gas price/supply curve". Low US gas prices were the result of a market awash in gas and lack of demand. Shale gas extracted from excellent sweet spots can be produced at low cost.Technology improvements have been realized at breath-taking speed, halving shale drilling times and thereby halving drilling cost, while doubling well length and doubling the well's initial productivities -- all over the past five years. But the US gas price decline just moved faster downward than technology gains could make up for.

There are several ways to increase the output volume and longevity of production from regions with shale TRR in place. Fig. 4 highlights the competitive effects of future gas prices and future shale technology cost required to render shale gas production profitable in the US and elsewhere. The principal drivers for reserves growth are (Fig. 4): (a) higher wellhead gas prices due to increased demand, and (b) lower production cost due to technology innovation (and some aid by favorable taxation policies). Both drivers can improve shale gas economics. Fastest reserve growth can be realized when the gas wellhead price, taxation policies and technology innovations all develop favorably. For example, federal or regional government decisions for favorable taxation and royalty policies can help shale gas companies to unlock new reserves from known, technically recoverable resources. Gas prices are uncontrollable and shale gas operators must turn a profit from their assets at prevailing wellhead prices. The critical impact of well technology innovation which effectively raises the EUR/well while simultaneously lowering the cost per well is a reduction of capital expenditure and a boost of well productivity at the same time.
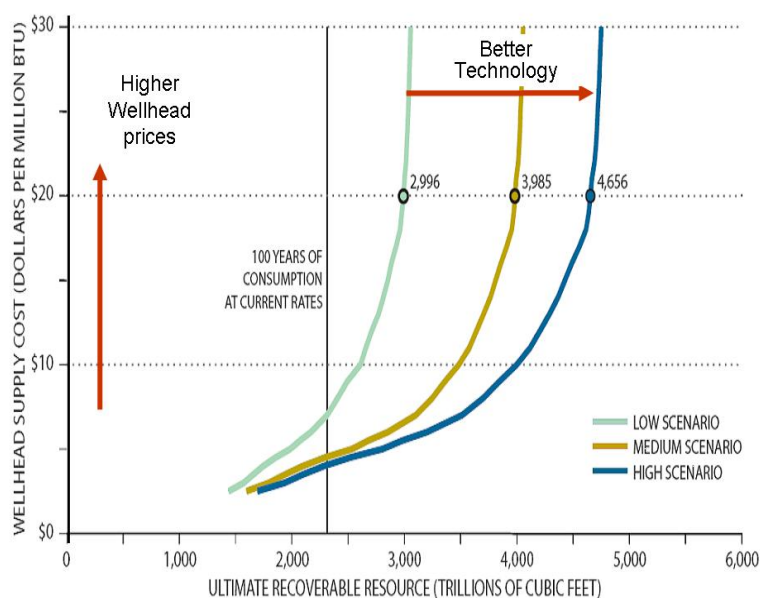

Figure 4: Volume of ultimate recoverable gas resources in North America shifts with the prevailing gas price (vertical scale). Further growth of economic producible resources at a given gas price is possible by optimization of exploration and recovery technology, as exemplified by three distinct scenarios (source: MIT, 2010, 2011; NPC, 2011).

Concerns about environmental compliance

The extraction of shale gas can cause a variety of environmental impacts ranging from methane leakages, contamination of ground water, poor air quality, induced seismicity or degraded agricultural lands and recreational areas. The drilling and hydraulic fracturing processes of shale gas development require significant amounts of water potentially adding to water stress in arid locations. The fracking fluids are admixed with a wide range of chemicals which return to the surface with the flowback water after completion of the fracking stage. These chemicals include acids to "improve gas flow, biocides to prevent organisms from growing and clogging the shale fractures, corrosion and scale inhibitors to protect the integrity of the well, gels or gums that add viscosity to the fluid and suspend the proppant, and friction reducers that enhance flow and improve the ability of the fluid to infiltrate and carry the proppant into small fractures in the shale" (Clark et al., 2012). The flowback water may also contain dissolved constituents from the formation itself such as naturally occurring hazardous materials.

Methane emissions from shale gas production primarily occur after the fracturing process when flowback water is removed from the well prior to the beginning of gas production. Flaring and reduced emissions completions (RECs) that capture methane that otherwise would be vented to the atmosphere have reduced emissions from flowback water by approximately 50% (Clark et al, 2012). Methane can migrate into ground water through fractures from the fracking process as well as natural fissures. During production, methane may escape through faulty casings around the gas wells into shallow aquifers and ground water. The literature, however, is inconclusive about the quantities and potential environmental and health impacts of gas leakage from shale gas operations (Howarth et al., 2011; Burnham et al., 2012; Cathles et al., 2012). A comprehensive assessment on emissions from shale gas operations is currently being carried out by the US Environmental Protection Agency (EPA) and results are expected to be published in 2014 (EPA, 2012). The findings of this and similar studies may evoke regulatory intervention which can adversely affect the economics of shale gas production.

Variable play development speed

Many shale rich areas are located in countries with limited domestic conventional gas resources (e.g., Poland), rapidly declining reserves (e.g., UK) or energy hungry, large emerging economies (e.g., China). Unsurprisingly, the shale gas boom in the US has sparked interest in this resource around the world and has intensified national exploration efforts to establish the presence and volume of prospective shale gas resources. However, there is a large global diversity in incentives and conditions for shale field development.

US shale gas fields provide important guidance for the economic development of shale gas wells in emergent shale plays elsewhere in the world. However, the US experience cannot be easily transferred to other countries. There are a number of below and above ground factors that set the US apart from other countries. The US is the country with the best delineated shale gas deposits with several tens of thousands shale gas wells drilled during the past decade (Stark et al., 2012). In contrast, to date fewer than 100 wells have been drilled in China (Tollefson, 2013), less than several dozens in Poland (SGE, 2013) and only a few test wells in Argentina. These are countries which have high hopes for rapidly maturing and developing their national shale gas resources. It will require enormous expenditures in shale gas exploration and test wells to assess whether commercially viable quantities of shale gas exist. Shale gas is not a quick fix solution for future gas supplies as the exploration and subsequent basin development will take up to a decade before larger quantities of commercial shale gas will enter the market place.

Long-term government policy promoting the development of new sources of gas has been one major factor in support of the shale gas development success in the US. These policies included a DOE-industry program for shale gas exploration and drilling technology development dating back to the 1970s, deregulation of wellhead gas prices, open access to interstate natural gas pipelines, incentive pricing and tax credits (Wang and Krupnick, 2013). These institutional and policy prerequisites are currently still lacking in most countries with emerging shale gas development ambitions. Public opposition to shale gas development is rising in several countries which prompted some governments (e.g., Bulgaria, France and Romania) to ban even shale gas exploration.

In addition, the US has a large number of well capitalized mid-size independent oil and gas companies with a tradition of entrepreneurial risk-taking ('wildcatting') culture. Shale gas exploitation is a highly capital-intensive undertaking and requires the capability of committing to large scale risky investment in shale gas development. Other factors that delay and limit the rate of shale gas development outside the US include generally immature national shale gas industries, lack of specialized drilling and hydraulic fracturing equipment with a need to rely on equipment imports and service support from abroad. Mineral rights in the US are in private ownership, while elsewhere mineral rights are often state-owned. The main reasons for the tepid development of some of the most promising shale plays abroad have been populist government policies, technology import hurdles, profit repatriation, gas market price caps below production costs, lack of transparency and data sharing, and a

generally unattractive business environment. 'Resource nationalism' (Wang, 2013) can provide insurmountable barriers for competition, innovation and foreign participation.

Selected country perspectives

Poland

Poland provides and instructive example for the troublesome road toward securing future shale gas supplies. In 2011 the EIA (2011) reported for Poland technically recoverable shale gas resources of 187 Tcf. Two years later these were revised downward to 148 Tcf (EIA, 2013c). In 2012 the Polish Geological Institute published a recoverable range of 12 Tcf to 27 Tcf for the Baltic-Podlasie-Lublin basins, based on a more constrained set of key parameters. The wide range of TRR assessments exemplifies the uncertainties involved in the early stages of shale gas development. The lower TRRs are still several times larger than Poland's conventional gas reserves, which led several international companies (e.g., Chevron, ExxonMobil, Talisman and Marathon Oil) to start drilling test wells while several dozens of companies competed for Poland's gas concessions (to date 111 have been granted for exploration). Altogether, 43 exploration wells have been drilled until 2013, of which nine carried out hydraulic fracturing and four had horizontal sections (SGE, 2013). Some of the wells showed reasonable rates of gas flow but generally the results did not mirror the experience from US shale gas wells and commercially viable gas flows have not yet been discovered. In addition, the costs per well were higher by 50% to 100% than in the US - in large part due to the immature industry in Poland and the "need to import equipment, fracking crews, etc." (Anderson, 2013). Early 2013, several companies like Talisman, Marathon and Exxon were withdrawing their immediate interest in Polish shale gas after having invested $500 million. In addition to the disappointing well flow tests, quoted reasons for withdrawing are the lack of clear regulation, mineral laws that are still tailored to state controlled geological and mining companies, and the lack of information sharing on geological subsurface data (Jędrysek, 2013). Meanwhile, Chevron and other companies continue their bet on shale gas success in Poland and are advancing exploration and test well drilling. Their target is to commence commercial shale gas production in 2015.

Argentina

A natural gas exporter for many years, Argentina turned into a net gas importer in 2004. Shale gas was earnestly discovered only in 2010 in the Vaca Muerta formation in the Neuquen basin. Until then the Neuquén basis was operated as a conventional gas field nearing depletion. The state-run energy firm YPF reviewed legacy core data from old wells and found indications for shale oil and gas below the strata of conventional gas. Argentina's shale gas TRR have been estimated at 802 Tcf (EIA, 2013c) making the country one of the top three countries (along with China and the US) with technically recoverable shale gas resources. Recently, YPF presented estimates of 1,181 Tcf of shale gas for the giant Vaca Muerta formation alone (Reuters, 2013). However, exploration and production interest for these vast shale gas resources has been lukewarm. By the end of 2012, just seven shale gas wells have been completed by YFP and foreign partners, mostly re-entries conventional wells. Another 20 wells are expected to be completed in 2013. Hydraulic fracturing has been applied to only a few wells. These numbers pale against the drilling boom observed in the US during the early days of the shale gas bonanza and point to a long and time-consuming march up the learning curve before commercially attractive sweet spots can be found and developed.

The Argentine government has taken steps to improve the business environment by raising gas wellhead prices and cutting back subsidized gas tariffs. A price increase to $7.50 per million BTU has recently been announced, which should help attract some smaller, independent foreign exploration and production companies as well as investors to Vaca Muerta (Wang, 2013). For example, in September 2013 YPF and the local unit of Dow Chemical agreed to invest a total of $188 million to drill 16 shale gas exploration wells - still a long way from the estimated $75 billion estimated needed for the development of the Vaca Muerta formation.

Australia

Australia's shale gas TRR is estimated at about 437 Tcf (EIA, 2013c). Australia's business environment, rule of the law and governance makes it a comfortable place for global majors to invest and do business. It can also look back on a tradition of foreign investment and technology transfer in the mining and hydrocarbon sectors. Indeed most of fracking and multi-pad drilling equipment operating in Australia is imported from the US. Australia's shale deposits are located in remote areas where drilling and fracking are not interfering with land use and therefore are less disruptive to other segments of the economy. Potential opposition from local farmers and environmentalists has been negligible. Remoteness, however, is no guarantee against opposition from green citizen groups as demonstrated by recent objections to coal bed methane extraction in New South Wales.

Shale gas production in Australia would probably be earmarked for LNG exports but there is a growing domestic gas demand. Cook et al (2013) estimate the production costs of Australian shale gas at $6/GJ to $9/GJ. Long-term contracts for wholesale gas trades in the domestic market are between $4/GJ and $6/GJ. The current netback price for LNG exports to Japan is around $10/GJ. A development of Australian shale gas resources for domestic markets is unlikely to occur until domestic

and international netback prices are equalized. Given the estimates of a much higher capital intensity of Australian shale gas development compared with the US international netback LNG prices would have to stay above $10/GJ in real terms. Clearly, there is an imminent need to reduce this capital intensity through accelerated technology learning for shale gas production costs to eventually lead to competitive market prices. Recently, two wells in Australia's Cooper Basin have shown encouraging gas flows with decline rates similar to the average decline rates of the US.

Skills and engineering capabilities in coal bed methane production are rapidly expanding in Australia. Some of these capacities are also applicable to shale gas development but many skills remain specific for shale gas development such as fracking. The domestic capacities to cost-competitively manufacture drilling and production technology are still in their infancy (Cook et al., 2013). Limited access to drill rigs may also delay early and rapid shale gas development.

China

China is currently a real contender in the global race to develop domestic shale gas resources. Estimates of shale gas TRR in China amount to 1,115 Tcf (EIA, 2013c). Shale gas development in China is still in its infancy and faces significant challenges. Impediments range from low capitalization to preferential treatment of state-owned enterprises in bidding for national shale gas exploration rights. In 2012, the auction for 19 shale gas blocks involved 16 winning companies of which six were central level state-owned enterprises, eight provincial level state owned enterprises, and only two were private companies (Chou, 2013). The successful bidders committed to invest about $21 billion in geological surveys and shale gas development. The set-up of joint ventures has been slow and most ventures have yet to start serious exploration programs. The production-sharing contract between CNPC and Shell of March 2013 is a first of its kind and many more have to follow to get shale gas exploration programs off the ground. By the end of 2012, some $1.13 billion has been invested in exploring China's shale prospects (Major and Koecher, 2013).

A combination of hard and soft factors has hampered rapid development of domestic shale gas resources. Among the hard factors are the uncertain hydrocarbon content of China's shale basins, lack of gas transmission infrastructure to deliver the gas, absent manufacturing capacity of shale gas development equipment and water stress, i.e., low or no water availability for hydraulic fracturing in many shale gas basins as well as potential land-use conflicts in densely populated areas. With regards to geology, most Chinese shale seams are, on average, buried twice as deep as in the US (Accenture, 2013) and shale formations often "have a high clay content which makes them more pliable and less apt to fracture" (Tollefson, 2013). Hence, US shale gas development models are not directly transferable and the more complex geology will require major technology innovation to bring down drilling, fracking and well completion costs. Estimates of water demand for fracking would capture some 30% of the water currently required by other industries (Coronel, 2013).

Among the soft factors that impede shale gas development in China are an initial reluctance to involve foreign companies in its domestic shale gas development, lack of domestic shale gas development expertise, especially of mid-size independent EP companies with a tradition of risk-taking, property and mineral rights owned by the government requiring complex production sharing agreements, regulated gas well head prices, dominance of a few state-owned EP companies and high regulatory uncertainty. State-owned CNPC and Sinopec have both undertaken some efforts to drill shale wells in China's most promising Sichuan/Chongqing basin, but none have shown commercially viable gas flows. High development cost and low regulated gas prices have tempered their enthusiasm (Tollefson, 2013). Shale gas output in 2012 was 0.5 Tcf - a far cry from the official target of 230 Tcf per year set for the end of 2015 in the Chinese Shale Gas Development Plan (Nakano et al., 2012). For China to develop its shale gas resources at the targeted output rate of 3,000 Tcf (~85 bcm) by 2020 clearly foreign expertise and technology transfer by way of joint ventures are required. China recognizes this need and has opened-up to foreign involvement; it even has begun to invest in US drilling companies.

Although there are significant obstacles in recovering and commercializing shale gas (and oil) in China, the prospects for successful shale gas development look rather promising. The Government of China is highly supportive of the development of its domestic shale resources. State-owned national companies (e.g. CNPC, Sinopec and CNOOC) hold most of the permits for shale gas development. Their huge capitalization allows for the large scale investment and provides the ability to assume risks. Demand risk is absent because the domestic gas demand is expanding with double-digit growth rates. CNOOC has acquired some of Chesapeake's US shale assets in 2011and its $15 billion takeover of Canada's Nexen in 2013 gives it further access to North American technology. Sinopec has also invested in several North American shale assets.

The provision of some time-limited economic incentives for shale gas development is further evidence of the Chinese government's continued commitment to domestic shale resource development. The government has also commenced the introduction of market reforms. In July 2013, China's National Development and Reform Commission (NDRC) announced an average increase of 15% for city gate gas prices across the country. At wellheads, this increase translates to approximately 25% higher producer revenues. The NDRC has plans to further deregulate wellhead prices of natural gas and may introduce full market competition, while retaining control over tariffs for pipeline transportation. What is needed next is a better understanding of the shale gas productivity of China's abundant shale gas resources. Essential know-how of fracking and

equipment manufacturing needs to be further developed. The existing pipeline infrastructure needs to be expanded to connect shale gas locations with the main demand centres (which can be thousands of kilometres apart). Gas market reforms should indeed open-up new opportunities for fair competition and allow producers to recover costs and earn a profit.

Discussion

Leadership in global shale gas initiatives is increasingly important, and a globally shared vision of strategies to realize future shale projects is still under development. The shale debate is raging and the outcome remains uncertain – which is a business risk for new shale development projects everywhere. However, if due diligence is followed in decision-making and risk analysis (Weijermars and van der Linden, 2012) this provides a guarantee that global shale plays will not become bubble assets. America's drive for energy independence has led to a rush into shale gas projects. The unprecedented growth of US shale gas output was enabled by a decade-long streak of creative financing. Cheap credit and fast-moving investors essentially lead to the nascent revival of the US petrochemical industry. Meanwhile, the approximately 7,200 shale gas wells drilled across the US in 2012 cost over \$42 billion, which is unfortunately not cash balanced by 2012 gas sales that generated just \$33 billion (Hughes, 2013).

One thing we must learn to accept is that shale assets will be more expensive to produce than the past legacy oil and gas conventional fields. Although it may only be a matter of time before US shale gas production will become profitable, we must also bear in mind that the boundary between a visionary drive for new energy solutions and an overhyped illusion may be a thin one and comes at a cost. The decision-making processes that have led to the superfast development of North American shale assets arguably were affected more by an emotive drive for energy security and less by accurate modelling of the US gas market capacity when shale gas investments were made. Oversupply and price collapse are the result. This could have been avoided by a more informed decision-making process.

The emotional component that influences preferences in decision-making has been termed affective forecasting (Wilson and Gilbert, 2003), which is demonstrably perjured by cognitive bias. This is a normal human trait, but not a useful attribute for rational energy investment decisions. Cognitive bias favours positive outcomes which may lead to misjudgements of the degree of risk and uncertainty involved in energy development projects that must ensure security of supply for nations and regions. When shale gas development decisions do not result in economically viable solutions, stubborn neglect of subsequent warning signals of flagging performance may be due to the mechanism of focusing illusion. Schkade and Kahneman (1998) coined the term focusing illusion for the human tendency to concentrate and settle on certain judgments of positive expectation. To avoid stakeholder processes from becoming dominated by affective forecasting that develop into focusing illusions we recommend external, independent auditing for a reality check of shale development strategy and project choices.

Conclusions

Current estimates of the unrisked quantity of global shale gas resources that is technically recoverable (7,800 Tcf) surpass the concurrently established volume of risked gas reserves from conventional reservoirs (6,600 Tcf). Shale gas development in the US has shown that commercial development is possible, but overproduction in a closed domestic gas market will depress wellhead prices until future demand and exports outpace production. Macroscopic modeling of regional and national gas markets is essential to avoid a repeat of such margin losses in future shale gas projects. Technology gains and firmer gas prices will support the commercial development of global shale gas resources. However, in locations dominated by public concerns and negative perceptions about the environmental footprint of shale gas wells, shale development loses economic attractiveness. The degree of uncertainty about the economic viability of shale gas projects remains high, especially in regions where government policies are unfavorable on issues such as geological information sharing, and when the investment framework and decision-making process slows the internal rate of return. Shale gas development companies are eager to explore and develop new shale fields only when compensated adequately for the time value of money and risk taken. At present, the resource maturation process of unrisked shale resources is often fraught with complexities that may erode the economic margins of their development. We recommend independent auditing for a reality check of strategy and choices in shale projects in order to avoid stakeholder processes from becoming dominated by affective forecasting that may develop into unsustainable focusing illusions.

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